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W3F1-2003-0074

November 13, 2003

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

SUBJECT: License Amendment Request NPF-38-249
Extended Power Uprate
Waterford Steam Electric Station, Unit 3
Docket No. 50-382
License No. NPF-38

REFERENCES: NRC Letter, T. Alexion (NRC) to C. Anderson (Entergy), "Application for License Amendment to Increase Authorized Power Level (TAC No. MB0789)," April 24, 2002

Dear Sir or Madam:

Pursuant to 10 CFR 50.90, Entergy Operations, Inc. (Entergy) hereby requests the following amendment for Waterford Steam Electric Station, Unit 3 (Waterford 3). Revisions to the Facility Operating License and Technical Specifications are requested to increase the unit's rated thermal power level from 3441 megawatts thermal (MWt) to 3716 MWt. This represents an 8% increase over the present licensed power level (i.e., Appendix K margin recovery power level) and a 9.6% increase over the original licensed power level and requires modification of the high-pressure turbine. Therefore, this power uprate is defined as an Extended Power Uprate (EPU). Relevant information is provided in the Attachments described below.

Attachment 1 contains descriptions and technical justifications for the proposed Operating License and Technical Specification changes. The NRC approved similar Operating License and Technical Specification changes for Arkansas Nuclear One, Unit 2 (ANO-2) as described in the Reference.

Attachment 2 contains Operating License and Technical Specification markups to facilitate identifying proposed changes.

Attachments 3 and 4 identify associated changes to the Technical Specification Bases and Technical Requirements Manual. These changes are provided for information only.

Attachment 5 contains the Extended Power Uprate Report (PUR). The PUR includes evaluations that demonstrate acceptable system and component performance under EPU conditions and analysis results confirming that acceptance criteria for Loss of Coolant Accident (LOCA) and non-LOCA safety analyses are met for the requested increase in core power. These analyses were performed consistent with the proposed Technical Specification changes. Environmental effects of the proposed power uprate are also evaluated and shown to be acceptable.

Attachment 6 contains a proprietary version of PUR Appendix 1 – Safety Evaluation Report Compliance. PUR Appendix 1 contains information proprietary to Westinghouse Electric Company (WEC), LLC.

Attachment 7 contains the non-proprietary (redacted) version of PUR Appendix 1 – Safety Evaluation Report Compliance and Attachment 9 contains WEC's application for withholding the proprietary information from public disclosure.

The proposed change includes commitments as summarized in Attachment 8.

Two additional license amendment requests are required in support of this EPU submittal. They will:

- Extend the Pressure Temperature (P-T) curves from 16 to 32 effective full power years (accounting for EPU conditions).
- Eliminate the Hydrogen Analyzer and Recombiner requirements from Technical Specifications consistent with the recent rule change to 10 CFR 50.44.

The Pressure Temperature Curve license amendment request was submitted on October 22, 2003 (W3F1-2003-0075). The Hydrogen Analyzer and Recombiner license amendment request is scheduled to be submitted by the end of 2003. The approval of the EPU submittal is contingent upon the approval of these additional submittals.

Control room dose for non-LOCA events is not addressed in this EPU submittal. In response to Generic Letter 2003-01, "*Control Room Habitability*," Entergy has committed to complete an evaluation of the control room envelope by the end of September 2004. Control room dose for non-LOCA events under EPU conditions will be addressed based on the results of the Generic Letter 2003-01 required evaluation. Additionally, LOCA and FHA control room doses provided in this submittal will be reevaluated, as necessary, based on the results of the Generic Letter 2003-01 required evaluation.

The proposed change has been evaluated in accordance with 10 CFR 50.91(a)(1) using criteria in 10 CFR 50.92(c) and it has been determined that this change involves no significant hazards considerations. The bases for this determination are included in the attached submittal.

Entergy requests approval of the proposed amendment by January 2005. Once approved, the amendment will be implemented during restart from refueling outage 13 in the spring of 2005 and unit operation at the increased power level will occur in Cycle 14.

If you have any questions or require additional information, please contact D. Bryan Miller at 504-739-6692.

I declare under penalty of perjury that the foregoing is true and correct. Executed on November 13, 2003.

Sincerely,

Joe Venable

J. E. Venable
Vice President, Operations
Waterford Steam Electric Station, Unit 3

JEV/GDH/DBM/cbh

Attachments:
1. Analysis of Proposed Technical Specification Changes
2. Proposed Operating License and Technical Specification Changes (mark-up)
3. Changes to Technical Specification Bases Pages – For Information Only
4. Changes to Technical Requirements Manual – For Information Only
5. Waterford 3 Extended Power Uprate Report
6. Waterford 3 Extended Power Uprate Report Appendix 1 – Safety Evaluation Report Compliance (Proprietary)
7. Waterford 3 Extended Power Uprate Report Appendix 1 – Safety Evaluation Report Compliance (Non-proprietary)
8. List of Regulatory Commitments
9. Westinghouse Electric Company Application for Withholding Proprietary Information from Public Disclosure

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Attachment 1

W3F1-2003-0074

Analysis of Proposed Technical Specification Changes

1.0 DESCRIPTION

This letter is a request to amend Operating License NPF-38 for Waterford Steam Electric Station, Unit 3 (Waterford 3).

The proposed change will revise the Operating License to permit Waterford 3 to operate at a maximum steady state reactor core thermal power of 3716 MWt. The requested increase constitutes an Extended Power Uprate (EPU) and is requested to provide greater unit electrical generating capacity. Entergy requests approval of the proposed amendment by January 2005. Once approved, the amendment will be implemented during restart from refueling outage 13 in the spring of 2005 and operation at the increased power level will occur in Cycle 14.

2.0 PROPOSED CHANGE

The requested change involves one revision to the operating license and several changes to the Technical Specifications. Each change is described below and evaluated in Section 4.0 of this attachment.

Operating license change:

License condition 2.C.1, Maximum Power Level

It is proposed to change the maximum core power level from 3441 MWt to 3716 MWt.

Technical Specification changes are identified below. Some changes are required for the EPU and others are requested improvements that are not required to support facility operation under EPU conditions. The required changes are identified as such in the description of the changes. The Technical Specification table of contents has been revised to be consistent with the proposed Specification changes. Changes to the table of contents are strictly an editorial/administrative matter, and are not discussed further.

Dose Equivalent I-131, Definition 1.10

The definition of DOSE EQUIVALENT I-131 is revised to be consistent with ICRP 30 dose conversion factors since ICRP conversion factors were used in dose consequence analyses. Reference to Table III in TID 14844 is replaced with reference to ICRP 30, Supplement 1 to Part 1, pages 192 – 212, Tables titled, “Committed Dose Equivalent in Target Organs or Tissues per Intake of Unit Activity.” This is an EPU related change.

Rated Thermal Power, Definition 1.24

Rated thermal power is changed from 3441 MWt to 3716 MWt. This is an EPU related change.

Table 2.2-1, Reactor Protective Instrumentation Trip Setpoint Limits, Functional Unit #7

The Steam Generator Pressure – Low trip setpoint is reduced from ≥ 764 psia to ≥ 662 psia and the allowable value is reduced from ≥ 749.9 psia to ≥ 647.9 psia. This is an EPU related change.

Borated Water Sources – Shutdown, Specification 3/4.1.2.7

Boron concentrations, in weight percent, are deleted in Specification 3.1.2.7, leaving concentrations expressed only in ppm. The range of boron concentration is specified as being between 4900 and 6125 ppm. The 4900 ppm represents an increase from the current minimum value of 3950 ppm (2.25 weight percent). The maximum value of 6125 ppm (3.50 weight percent) is unchanged. The boron concentrations specified in 3.1.2.7 are identified as indicated values. The increase in minimum required boron concentration is an EPU related change.

In Surveillance Requirement 4.1.2.7, Reactor Auxiliary Building air temperature and boric acid make-up tank solution temperature are identified as indicated values.

Borated Water Sources – Operating, Specification 3/4.1.2.8 and associated Figure 3.1-1

Figure 3.1-1 in 3.1.2.8a.2 is changed to new Figure 3.1-2. This is an EPU related change.

The value 475,500 gallons in 3.1.2.8b.1 is deleted, leaving the minimum required refueling water storage pool volume of 83% indicated level in the Specification. In 3.1.2.8b.2, the boron concentration values are identified as indicated values. In 3.1.2.8b.3, the boric acid solution temperatures in the refueling water storage pool are identified as indicated values.

In 4.1.2.8a, The Reactor Auxiliary Building air temperature is identified as an indicated value. In 4.1.2.8b, the BAMT temperature and the Reactor Auxiliary Building air temperature are identified as indicated values.

The page number for 3/4.1.2.8 is changed from 3/4 1-14 to 3/4 1-13.

Figure 3.1-1 is replaced with a new figure to reflect the revised minimum boric acid concentration of 4900 ppm and an increase in Boric Acid Makeup Tank (BAMT) minimum volume required when relying on one BAMT. New Figure 3.1-2 is added to reflect the revised BAMT boron concentration and volume requirements when relying on two BAMTs. This is an EPU related change.

The page number for Figure 3.1-1 is changed from 3/4 1-13 to 3/4 1-14.

Reactor Coolant Cold Leg Temperature, Specification 3.2.6

The cold leg temperature range is changed from 541°F – 558°F to 536°F - 549°F, and the temperatures are identified as indicated values. In addition, the temperature of

568°F that is allowed for 30 minutes after a power cutback is changed to 559°F and identified as an indicated value. The temperature changes are EPU related changes.

Pressurizer Pressure, Specification 3.2.8

The minimum pressurizer pressure value of 2025 psia is increased to 2125 psia, and the minimum and maximum pressurizer pressures are identified as indicated values. The increase in minimum pressurizer pressure is an EPU related change.

Table 3.3-4, Engineered Safety Features Actuation System Instrumentation Trip Values, Functional Units 4.b and 7.e.

The Steam Generator Pressure – Low Engineered Safety Features Actuation System (ESFAS) setpoints for main steam line isolation and emergency feedwater actuation are reduced from ≥ 764 psia to ≥ 662 psia and the allowable values are reduced from ≥ 749.9 psia to ≥ 647.9 psia. This is an EPU related change.

Operational Leakage, Specification 3.4.5.2c

The steam generator primary to secondary leakage rate of 1 gpm through all steam generators is reduced to 0.75 gpm. The leakage rate of 720 gallons per day through any one generator is reduced to 540 gallons per day. This is an EPU related change.

Pressurizer Heatup/Cooldown, Specification 3/4.4.8.2

The following are deleted from Specification 3/4.8.2:

- Requirement 3.4.8.2c regarding the maximum spray nozzle usage factor of 0.65
- Action statement b regarding requirements if the spray nozzle usage factor exceeds 0.65 and a reference to Table 5.7-1.
- Surveillance requirement 4.4.8.2.2 regarding determining every 12 hours that spray water differential temperature is within limits during auxiliary spray operation.
- Surveillance requirement 4.4.8.2.3 regarding recording of spray cycles and corresponding water differential temperature when spray is initiated with ΔT greater than 130 °F and when auxiliary spray is initiated with ΔT greater than 140 °F.

Minor editorial adjustments reflecting these deletions include:

- Relocating the word “and” from the end of requirement 3.4.8.2b to the end of requirement a.
- Deleting the “a” designator from in front of the remaining action.
- Renumbering Surveillance Requirement 4.4.8.2.1 to 4.4.8.2.

Specification 3/4.5.1 Safety Injection Tanks

Requirement 3.5.1b is revised to delete units of cubic feet for the contained borated water volumes. Volume requirements are stated only in terms of percent level. The maximum volume is changed from 83.8% to 77.8% level while the minimum volume remains unchanged. The boron concentrations in 3.5.1c and the nitrogen cover gas pressures in 3.5.1d are identified as indicated values.

Pressurizer pressures are identified as indicated in the action statements.

In footnote "*", the required SIT volumes in cubic feet are deleted leaving only percent level values. The maximum level is changed from 83.8% to 77.8% while the minimum levels remain unchanged. Boron concentrations and pressurizer pressures have been identified as indicated values.

The change in maximum SIT volume is an EPU related change.

Refueling Water Storage Pool, Specification 3/4.5.4

The value 475,500 gallons is deleted leaving the minimum required volume of 83% indicated in the Specification. The boron concentrations in 3.5.4b are identified as indicated values. The solution temperatures in 3.5.4c are identified as indicated values. The refueling water storage pool temperature and reactor auxiliary building air temperature in 4.5.4b, are identified as indicated values.

Containment Systems, Air Temperature, Specification 3.6.1.5

The maximum containment temperature of 120 °F is replaced with a range of greater than or equal to 90 °F and less than or equal to 120 °F. The temperatures are identified as indicated values. The action statement is reworded accordingly to require the temperature to be restored to within the required range. A footnote is added specifying that the minimum containment average air temperature limit applies only in Mode 1 at greater than 70% rated thermal power.

Turbine Cycle, Safety Valves, Specification 3.7.1.1 and Table 3.7-2, Maximum Allowable Linear Power Level – High Trip Setpoint With Inoperable Steam Line Safety Valves During Operation With Both Steam Generators

Currently, action statement "a" specifies that either the inoperable main steam safety valve be restored to operable or the linear power level – high trip setpoint be lowered as specified in Table 3.7-2 within four hours otherwise, be in hot standby within six hours and cold shutdown within the following 30 hours. Action statement "a" is revised to allow four hours to reduce power to the maximum allowable power as specified in Table 3.7-2 and to allow 12 hours to lower the linear power level – high trip setpoint as specified in Table 3.7-2. The shutdown statement is revised to be in hot standby within six hours and hot shutdown within the following 12 hours. This change is similar to a change approved for Arkansas Nuclear One, Unit 2 (ANO-2) via Amendment 222 dated September 29, 2000 and is consistent with Specification 3.7.1 in NUREG-1432, *"Standard Technical Specifications Combustion Engineering Plants."*

The title of Table 3.7-2 is revised from "Maximum Allowable Linear Power Level – High Trip Setpoint with Inoperable Steam Line Safety Valves during Operation with Both Steam Generators" to "Maximum Allowable Power and Linear Power Level – High Trip Setpoint with Inoperable Steam Line Safety Valves." The "List of Tables" in the Table of Contents is updated to reflect the name change of Table 3.7-2. These are administrative changes that will not be addressed further.

Table 3.7-2 is revised to add a column specifying the maximum allowable power when main steam safety valves are out of service in addition to the existing column which provides the value for the linear power level – high trip setpoint. The existing column for the linear power level – high setpoint will be re-titled and will contain new setpoint values that provide operational margin to the maximum allowable power. This change is consistent with NUREG-1432.

The maximum allowable power with one main steam safety valve out of service, following EPU, is changed from 86.8% to 85.3%. The maximum allowable power with two main steam safety valves out of service, following EPU, is changed from 69.4% to 66.7%. These changes are EPU related changes. The maximum allowable power values are identified as indicated values in Table 3.7-2.

Condensate Storage Pool, Specification 3/4.7.1.3

The Limiting Condition for Operation (LCO) of Specification 3.7.1.3 is restructured into parts “a” and “b”. Part “a” requires the minimum condensate storage pool volume be greater than or equal to 92% indicated level. This is an increase from the previous limit of 91% indicated level. Part “b” adds a requirement for an indicated temperature range of 55 °F to 100 °F for the condensate storage pool. Existing Surveillance Requirement 4.7.1.3.1 is restructured as two requirements to match the proposed LCO. Surveillance “a” verifies condensate storage pool volume within limits once per 12 hours and new surveillance “b” verifies condensate storage pool temperature within limits once per 24 hours when indicated reactor auxiliary building temperature is less than 55 °F or greater than 100 °F.

Main Steam Line Isolation Valves, Specification 4.7.1.5

The full closure time for the main steam isolation valves is changed from 4.0 seconds to 8.0 seconds.

Main Feedwater Isolation Valves, Specification 4.7.1.6

The full closure time for the main feedwater isolation valves is changed from less than or equal to 5.0 seconds to within 6.0 seconds.

Atmospheric Dump Valves, Specification 3/4.7.1.7

A new Technical Specification that addresses atmospheric dump valve (ADV) operability is added. This is an EPU related change.

Containment, Specification 5.2

This section is deleted.

Fuel Assemblies, Specification 5.3.1

Statements referencing initial core loading are deleted.

Section 5.7, Component Cyclic or Transient Limits, and Table 5.7-1

This section is being deleted from Technical Specifications and portions relocated to the TRM. The first page (5-7) of Table 5.7-1 is being modified to address changes in the heatup and cooldown cycles resulting from EPU and relocated to the TRM. The remaining two pages (5-8 and 5-9) of Table 5.7-1 are being deleted in conjunction with the changes being made to Technical Specification 3/4.4.8.2 discussed above.

Core Operating Limits Report, Specification 6.9.1.11.1

The following references are added to the COLR reference list:

- "Technical Manual for the CENTS Code," CENPD-282-P-A. (Methodology for Specification 3.1.1.1 and 3.1.1.2 for Shutdown Margins, 3.1.1.3 for MTC, 3.1.3.1 for Movable Control Assemblies - CEA Position, 3.1.3.6 for Regulating and group P CEA Insertion Limits, and 3.2.3 for Azimuthal Power Tilt).
- "Calculative Methods for the CE Nuclear Power Large Break LOCA Evaluation Model," CENPD-132, Supplement 4-P-A. (Methodology for Specification 3.1.1.3 for MTC, 3.2.1 for Linear Heat Rate, 3.2.3 for Azimuthal Power Tilt and 3.2.7 for ASI).

The addition of the references is an EPU related change.

In summary, Entergy has reviewed the operating license and Technical Specifications, and has determined that no revisions to those documents other than those noted above are required to properly control plant operations and configuration under EPU conditions. Mark-ups of the proposed TS changes are provided in Attachment 2.

In some instances, the Technical Specification changes described above necessitate revision of the Technical Specification Bases. Marked-up Bases pages are provided in Attachment 3 for information only. Additionally, in some instances, the Technical Specification changes described above necessitate revision of the Technical Requirements Manual. Marked-up Technical Requirement Manual pages are provided in Attachment 4 for information only.

3.0 BACKGROUND

The NRC originally licensed Waterford 3 on March 16, 1985 for operation at a reactor core power not to exceed 3390 MWt. By Amendment No. 183, dated March 29, 2002 the NRC granted a measurement uncertainty recapture uprate allowing Waterford 3 to operate at a core power level not to exceed 3441 MWt, a power increase of approximately 1.5%.

This requested license amendment would authorize Waterford 3 to operate at 3716 MWt, an increase of approximately 9.6 percent over the originally licensed power level and approximately 8.0 percent over the current licensed power level. The proposed change is thus an Extended Power Uprate (EPU). Draft NRC Review Standard (RS)-001, "Review Standard for Extended Power Uprates," Reference 1, was used as guidance in preparing this license amendment request to the extent the draft standard is consistent with the licensing basis of Waterford 3. In addition, the ANO-2 EPU application, Reference 2, including Requests for Additional

Information (RAIs) and associated responses, were reviewed for guidance. The ANO-2 EPU application was approved by Reference 3.

The following plant modifications are planned in order to implement EPU:

- Upgrade the high pressure turbine.
- Rewind the main generator and provide associated auxiliaries.
- Install higher capacity main generator output circuit breakers, disconnect switches, and bus work.
- Main transformers modifications.
- Replace/upgrade, as necessary, control valves for the heater drain system.
- Replace atmospheric dump valve controllers with more accurate digital controllers.
- Instrument and control changes (e.g., lower steam generator pressure trip setpoint.)
- Replace reheat system safety valves.
- Stake the condenser tubes.

Entergy plans to implement the Waterford 3 EPU in one increment. Completion of plant modifications necessary to implement the EPU is planned prior to the end of refueling outage 13 in the spring of 2005. With the approval of this license amendment request, the plant will be operated at 3716 MWt starting in Cycle 14.

4.0 TECHNICAL ANALYSIS

The acceptability of each proposed operating license and Technical Specification change is addressed below.

The Technical Specification table of contents is being revised to be consistent with the proposed Specification changes. This is strictly an editorial/administrative matter and is not discussed further.

The Technical Specifications contain a mixture of analytical and indicated plant values based on various factors (e.g., safety setpoint, sensitivity of safety analysis to value, initial condition, instrument uncertainty considerations, etc.). Choosing an indicated value or an analytical value for a limit depends on which value is judged most appropriate in each particular instance. For some initial conditions, the analytical value equals the indicated value. For more sensitive parameters, the indicated value varies from the analytical value to explicitly account for instrument inaccuracies and other process requirements thus providing increased assurance that expected automatic action occurs at or before the specified limit is reached. In an effort to improve clarity for the Operators, the word “indicated” or phrase “an indicated” is being added to identify those values in Technical Specifications that can be compared directly to plant instrument readings to ensure Technical Specification compliance. This is considered to be an editorial enhancement to aid the Operator and is not discussed further.

The Extended Power Uprate Report (PUR) is contained in Attachment 5 of this license amendment request. The PUR summarizes the evaluations performed to assure acceptable unit operation at EPU conditions and is therefore referenced throughout this section as additional technical justification for the EPU related changes.

License condition 2.C.1, Maximum Power Level

It is proposed to change the maximum core power level from 3441 MWt to 3716 MWt. The PUR (Attachment 5) evaluates structural integrity, Structure, System, Component (SSC) performance, and facility response to small and large break LOCAs and non-LOCA events evaluated in Waterford 3 FSAR, Chapter 15. The PUR evaluations were performed consistent with EPU conditions and the proposed Technical Specification changes identified in Section 2.0 and evaluated below. PUR evaluation results demonstrate that SSC structural limits and performance requirements are met and safety analysis results meet acceptance criteria. The environmental effects of facility operation at a core power level of 3716 MWt were evaluated in the PUR and shown to be acceptable.

Dose Equivalent I-131, Definition 1.10

The definition of DOSE EQUIVALENT I-131 is revised to be consistent with ICRP 30 dose conversion factors since ICRP conversion factors are used in EPU dose consequence analyses (reference PUR Section 2.13.0.5). Reference to Table III in TID 14844 is replaced with reference to ICRP 30, Supplement 1 to Part 1, pages 192 – 212, Tables titled, "Committed Dose Equivalent in Target Organs or Tissues per Intake of Unit Activity." ICRP dose conversion factors have been accepted by the NRC for performing dose consequence analyses.

Rated Thermal Power, Definition 1.24

Rated thermal power is changed from 3441 MWt to 3716 MWt. Justification for increasing thermal power to 3716 MWt is discussed above with respect to operating license condition 2.C.1.

Table 2.2-1, Reactor Protective Instrumentation Trip Setpoint Limits

The Steam Generator Pressure – Low trip setpoint is reduced from ≥ 764 psia to ≥ 662 psia, with the allowable value reduced from ≥ 749.9 psia to ≥ 647.9 psia. Since the steam generator operating pressure at EPU conditions is lower than at the current power level, the setpoint and allowable values are reduced to maintain adequate margin to trip at EPU conditions. Results of safety analyses performed consistent with the revised values are provided in PUR Section 2.13, and demonstrate acceptable results.

Borated Water Sources – Shutdown, Specification 3/4.1.2.7

The increase in the minimum required boron concentration (to 4900 ppm) and minimum BAMT volume ensures that shutdown margin requirements will be met during shutdown conditions. This minimum concentration resulted from the evaluation of the Chemical and Volume Control System (CVCS) described in PUR Section 2.1.11.

Boron concentrations in weight percent have been deleted, leaving concentrations expressed only in ppm, units more commonly used by Operations. The change is editorial and improves clarity by eliminating reference to the same parameter in dual units.

Borated Water Sources – Operating, Specification 3/4.1.2.8 and associated Figure 3.1-1

The increase in the minimum required boron concentration (to 4900 ppm) and minimum BAMT volume ensures that shutdown margin requirements will be met during natural circulation cooldown to shutdown cooling entry conditions. This minimum concentration, revised Figure 3.1-1, and new Figure 3.1-2 resulted from the evaluation of the Chemical and Volume Control System (CVCS) described in PUR Section 2.1.11.

Deleting the refueling water storage pool (RWSP) volume in gallons and leaving only the minimum required volume of 83% in the Specification, is an editorial change that improves clarity by eliminating reference to the same parameter in dual units. Indications of RWSP level are provided in percent, not gallons.

Changing the page numbers such that Figures 3.1-1 and 3.1-2 come after Specification 3/4.1.2.8 is an editorial change to make the Technical Specifications more user friendly.

Reactor Coolant Cold Leg temperature, Specification 3.2.6

The cold leg temperature range is changed from 541 °F – 558 °F to 536 °F - 549 °F to maintain margin to the new operating point nominal temperature of 543 °F at EPU conditions (reference PUR Table 1-1). Safety and structural analyses were performed consistent with the revised temperature range, and results presented in the PUR demonstrate acceptable results. In addition, the temperature of 568 °F that is allowed for 30 minutes after a power cutback was changed to 559 °F to maintain the existing 10 °F difference to maximum T_{cold}.

Pressurizer Pressure, Specification 3.2.8

The minimum pressurizer pressure value of 2025 psia is increased to 2125 psia to regain thermal margin under EPU conditions. Safety analyses were performed consistent with this proposed value and results documented in the PUR Section 2.13 demonstrate acceptable results.

Table 3.3-4, Engineered Safety Features Actuation System Instrumentation Trip Values, Functional Units 4.b and 7.e

The Steam Generator Pressure – Low ESFAS setpoints for main steam line isolation and emergency feedwater actuation are reduced from ≥ 764 psia to ≥ 662 psia and the allowable values are reduced from ≥ 749.9 psia to ≥ 647.9 psia. Since the steam generator operating pressure at EPU conditions is lower than at the current power level, the setpoint and allowable values were reduced to maintain adequate margin to engineered safety features actuation at EPU conditions. Results of safety analyses performed consistent with the revised values are provided in the PUR Section 2.13, and demonstrate acceptable results.

Operational Leakage, Specification 3.4.5.2 c

The steam generator primary to secondary leakage rate of 1 gpm through all steam generators is reduced to 0.75 gpm. The leakage rate of 720 gallons per day through any one generator is reduced to 540 gallons per day. These leak rate reductions are made to provide margin for use in dose consequence analysis at EPU conditions. Dose consequences for events in which steam generator leakage is relevant are provided in the PUR Section 2.13 and demonstrate acceptable results.

Pressurizer Heatup/Cooldown, Specification 3/4.4.8.2

The following are deleted from Specification 3/4.4.8.2:

- Requirement 3.4.8.2c regarding the maximum spray nozzle usage factor of 0.65.
- Action statement b regarding requirements if the spray nozzle usage factor exceeds 0.65 and reference to Table 5.7-1.
- Surveillance requirement 4.4.8.2.2 regarding determining every 12 hours that spray water differential temperature is within limits during auxiliary spray operation.
- Surveillance requirement 4.4.8.2.3 regarding recording of spray cycles and corresponding water differential temperature when spray is initiated with ΔT greater than 130 °F and when auxiliary spray is initiated with ΔT greater than 140 °F.

These deletions are being made because the requirements to which they pertain in Technical Specification Table 5.7-1 are being deleted. See the evaluation below for justification of the Table 5.7-1 deletions.

Specification 3/4.5.1 Safety Injection Tanks

Requirement 3.5.1b is revised to delete units of cubic feet for the contained borated volumes. Volume requirements are stated only in terms of percent to eliminate reference to the same parameter in dual units. SIT level indications used by Operations are in terms of percent level.

The maximum volume is changed from 83.8% to 77.8%. Results of LOCA analyses performed consistent with this SIT maximum volume are presented in the PUR Section 2.12 and meet acceptance criteria.

In footnote "*", the required SIT volumes in cubic feet are deleted to avoid reference to the same parameter in dual units. The maximum level is changed from 83.8% to 77.8% to be consistent with the revised upper limit in requirement 3.5.1b. As stated above, SIT level indications used by Operations are in terms of percent level.

Refueling Water Storage Pool, Specification 3/4.5.4

The Technical Specification currently cites the minimum required borated water volume of the refueling water storage pool as 475,500 gallons (83% indicated level.) The value 475,500 gallons is deleted, leaving the minimum required volume of 83% in the Specification. Dual reference to the same parameter in different units is thus eliminated. RWSP level indications used by Operations are in terms of percent level.

Containment Systems, Air Temperature, Specification 3.6.1.5

The maximum containment temperature of 120 °F is replaced with a range of greater than or equal to 90 °F and less than or equal to 120 °F. The reworded action statement specifies corrective measures when containment air temperature is outside the required range, consistent with the temperature range specified in 3.6.1.5.

The minimum temperature limit of 90 °F, currently maintained in the TRM, is added to the Specification since minimum containment temperature is an initial condition for ECCS analyses. The revised action statement allows the same time for restoration of minimum containment average air temperature to within limits as is currently allowed to reduce the temperature below the maximum limit. The TRM requirement for minimum containment temperature is being deleted.

A footnote is added specifying that the containment average air temperature limit applies only in Mode 1 at greater than 70% rated thermal power. Below 70% rated thermal power, sufficient margin is available with the lower decay heat to offset credible lower containment temperatures.

Results of containment integrity and LOCA analyses performed consistent with the maximum and minimum temperatures are presented in PUR Sections 2.5.2.1 and 2.12, and demonstrate acceptable results.

Turbine Cycle, Safety Valves, Specification 3.7.1.1 and Table 3.7-2, Maximum Allowable Linear Power Level – High Trip Setpoint With Inoperable Steam Line Safety Valves During Operation With Both Steam Generators

Currently, action statement “a” specifies that either the inoperable main steam safety valve (MSSV) be restored to operable or the linear power level – high trip setpoint be lowered as specified in Table 3.7-2 within four hours otherwise, be in hot standby within six hours and cold shutdown within the following 30 hours. Action statement “a” is revised to allow four hours to reduce power to the maximum allowable power as specified in Table 3.7-2 and to allow 12 hours to reset the linear power level – high trip setpoint as specified in Table 3.7-2. The shutdown statement is revised to be in hot standby within six hours and hot shutdown within the following 12 hours.

Deletion of the option to restore the inoperable MSSV to operable is an administrative change in that the option to restore the valve to operable within four hours is implied in the revised action statement. Action statements can be exited by restoring inoperable equipment to operable or by exiting the mode of applicability. The revision to reduce power as specified in Table 3.7-2 within four hours is a neutral change because this power reduction is required by the current action statement otherwise a plant trip would result when the trip setpoint is reduced. Four hours is a reasonable time period to reduce power level and in accordance with NUREG-1432, is based on the low probability of an event occurring during this period that would require activation of the main steam safety valves. The revision to allow 12 hours for the reduction of the trip setpoint is less restrictive in that eight additional hours are allowed to complete this task. This 12 hour allowance was previously approved for ANO-2 via Amendment 222 dated September 29, 2000, allows a reasonable time period for lowering the trip setpoint, and

is reasonable due to the low probability of the occurrence of a transient that could result in steam generator overpressure during this period. Additionally, the limiting event for secondary system over pressurization (i.e., loss of condenser vacuum) does not credit the linear power – high trip for mitigation.

Changing the shutdown statement from cold shutdown within the following 30 hours to hot shutdown within the following 12 hours is acceptable because the Specification is only applicable in modes 1, 2, and 3. Once the unit enters mode 4 (i.e., hot shutdown) the Specification is no longer applicable and the action can be exited therefore this is a neutral change.

These changes are similar to changes approved for Arkansas Nuclear One, Unit 2 (ANO-2) via Amendment 222 dated September 29, 2000 and are consistent with NUREG-1432, *"Standard Technical Specifications Combustion Engineering Plants."*

Table 3.7-2 is revised to add a column specifying the maximum allowable power (in percent rated thermal power (RTP)) when MSSVs are out of service in addition to the existing column which provides the value for the linear power level – high trip setpoint. The existing column for the linear power level – high setpoint will be re-titled and will contain new setpoint values that provide operational margin to the indicated maximum allowable power.

The addition of the indicated maximum allowable power column is consistent with NUREG-1432. This change is acceptable because it assures the initial power level assumed in the loss of condenser vacuum event with MSSVs inoperable is protected. The maximum allowable power levels are those power levels previously listed under the trip setpoint column reduced for EPU conditions. These values are determined based on the loss of condenser vacuum event assuming one and two main steam safety valves are inoperable at the start of the event.

# of MSSVs OOS	Current Trip Limit (%RTP)	EPU Indicated Limit (%RTP)	EPU Analytical Limit (%RTP)	EPU Trip Limit (%RTP)
1	86.8	85.3	87.3	= 93.3
2	69.4	66.7	69.9	= 74.7

The indicated EPU maximum allowable power levels listed in the table are adjusted downward from the analytical values to account for power measurement uncertainties. Results of the loss of condenser vacuum event analyzed consistent with these assumed initial power levels are presented in PUR Section 2.13.2.1.3, and demonstrate that steam generator pressure does not exceed ASME Code limits.

The linear power level – high trip setpoints listed in Table 3.7-2 are set 8% RTP above the indicated maximum allowable power level. As stated above, these trip setpoints are not credited in the loss of condenser vacuum event and are reduced to enforce the maximum allowable power level with main steam safety valves inoperable. The 8% RTP margin between the indicated maximum power limit and the trip setpoint is consistent with the 8% margin between the 100% RTP licensed power limit and the normal 108% RTP linear power level – high trip setpoint therefore the trip setpoints are reasonable. Having a trip setpoint slightly higher then the indicated maximum allowable power is

consistent with NUREG-1432 and is acceptable since the linear power level – high trip is not credited in the loss of condenser vacuum event.

Condensate Storage Pool, Specification 3/4.7.1.3

The minimum indicated condensate storage pool volume Technical Specification limit is increased from 91% to 92%. This is being done to more accurately account for process measurement uncertainty. There is no change in the actual minimum required analytical limit used in the safety analysis.

The indicated temperature range of 55°F to 100°F for the condensate storage pool is added since the pool water temperature is an input to various safety analyses. The lower limit used for analysis is 50°F. A lower limit of 55°F is used in the Specification so as to be consistent with the lower limit of the RWSP, in Specification 3.5.4, and other similar Specifications to simplify Operator logs.

PUR analyses performed assuming a water temperature range of 50°F to 100°F demonstrated acceptable results (reference PUR Section 2.13).

The restructured surveillance requirement continues to verify water volume is within limits once per 12 hours. In addition, the restructured surveillance requirement also requires verification that water temperature is within the new limits at least once per 24 hours when reactor auxiliary building temperature is less than 55°F or greater than 100°F. The 24 hour frequency for verifying water temperature, when reactor auxiliary building temperature is less than 55°F or greater than 100°F is consistent with the frequency currently used for verifying RWSP temperature in Specification 3.5.4. Like the RWSP, the condensate storage pool is located inside the auxiliary building protected from the direct effects of the outside atmospheric conditions.

Main Steam Line Isolation Valves, Specification 4.7.1.5

The full closure time for the main steam isolation valves is changed from the static test value of 4.0 seconds to the analysis value of 8.0 seconds which includes an assumed 1.0 second instrument response time. A closure time of 4.0 seconds, measured under static test conditions, demonstrates closure under plant operating conditions within the 8.0 seconds assumed in the safety analysis. This change simply represents a preference for citing the closure time analysis value in the Technical Specifications. No change is being made to either the test closure interval or the closure interval assumed in the safety analyses.

PUR analyses using at least an 8.0 second closure time demonstrated acceptable consequences (reference PUR Section 2.13.)

Main Feedwater Isolation Valves, Specification 4.7.1.6

The full closure time for the main feedwater isolation valves is changed from 5.0 seconds to 6.0 seconds. 6.0 seconds is the bounding analysis value that includes a 1.0 second instrument response time. The 5.0 second closure time did not include the 1.0 second instrument response time which was separately accounted for in the safety

analysis assumptions to arrive at a bounding analysis value closure time of 6.0 seconds. This change is made only to include the instrument response time in the analysis closure time cited in the Technical Specifications. Consistency is thus achieved with Specification 4.7.1.5 described above. No change has been made to the closure time of 6.0 seconds assumed in the safety analyses.

PUR analyses using at least a 6.0 second closure time demonstrated acceptable consequences (reference PUR Section 2.13).

Atmospheric Dump Valves, Specification 3/4.7.1.7

This is a new Specification that addresses atmospheric dump valve (ADV) operability for the following:

- Plant cooldown to shutdown cooling entry conditions with offsite power unavailable.
- Small break LOCA (SBLOCA) mitigation above 70% of rated (EPU) thermal power.
- Containment isolation.

The ADVs were previously credited only for cooldown to shutdown cooling entry conditions (primary safety function) and containment isolation (secondary safety function). ADV operability for cooldown is presently addressed in TRM requirement 3/4.7.1.7 while ADV operability for containment isolation is presently addressed in Technical Specification 3/4.6.3. There is currently no Technical Specification specifically addressing overall ADV operability.

For EPU, the ADVs are credited for SBLOCA mitigation at greater than 70% rated (EPU) thermal power. Therefore, a new Technical Specification ensuring ADV operability for this purpose is proposed. Since a new ADV Specification is being added, it was deemed appropriate to address ADV operability for cooldown and containment isolation in the new Specification as well. Consequently, Technical Specification 3/4.7.1.7 is being created to address the cooldown, SBLOCA mitigation, and containment isolation functions of the ADVs.

One ADV in conjunction with one high-pressure safety injection pump are credited for SBLOCA mitigation as discussed in Section 2.12.4 of the PUR. For SBLOCA mitigation the ADVs must be in automatic with a setpoint of less than or equal to 1000 psia when operating at greater than 70% rated EPU thermal power. Therefore, the limiting condition for operation has been modified by a footnote indicating when the automatic actuation function of the ADVs is not required to be operable (i.e., when less than or equal to 70% power for greater than 6 hours). This is consistent with the SBLOCA safety analysis assumptions.

Actions (a) and (b) specifically address the inoperability of the automatic actuation capability of one and both ADVs, respectively. A 72 hour Allowed Outage Time (AOT) is provided for when the automatic actuation capability of one ADV is inoperable. This AOT is consistent with the AOT for the inoperability of one high-pressure safety injection pump and is therefore considered appropriate. If the ADV automatic actuation capability is not restored to operable within the AOT, the action to reduce power to less than or equal to 70% power results in exiting the applicability of the specification in 12 hours (six hours to get to 70% power plus six more hours for decay heat to reduce)

which is also consistent with the time allowed to exit the mode of applicability for an inoperable high-pressure safety injection pump. When the automatic actuation capability of both ADVs is inoperable, Action (b) requires that automatic actuation capability of one ADV be restored to operable within 1 hour or power be reduced to less than 70% power within the next 6 hours. Once again, the specification will no longer be applicable 6 hours after reaching 70% power for the automatic actuation capability. These action times are consistent with the action times that would be required if both high-pressure safety injection pumps were found to be inoperable. Therefore, the proposed action times are considered to be acceptable.

Action (c) addresses the manual capabilities of the ADVs required for the cooldown and containment isolation functions. A 72 hour AOT is provided to restore the ADV to operable and is consistent with the current licensing basis regarding the cooldown function contained in the TRM. For the containment isolation function, the 72 hour AOT is a relaxation from the 4 hour AOT currently specified in Specification 3.6.3, Containment Isolation. This relaxation is considered acceptable based on the main steam system being a closed system inside containment and the capability to isolate the ADV with the block valve if needed. Due to the importance of the opening function of the ADVs, isolation of the ADV for extended periods of time is not appropriate therefore a shutdown is required if the ADV can not be restored to operable. The time allowed for exiting the mode of applicability is consistent with most other Section 3.7 Technical Specifications that are applicable in modes 1, 2, 3, and 4. Therefore the proposed times are considered to be acceptable.

Surveillance requirements and frequencies proposed for the ADV automatic actuation channels are consistent with those approved in Amendments 114 and 102 for South Texas Project Units 1 & 2 dated August 19, 1999 and are therefore considered to be appropriate. The surveillance requirement to cycle each ADV through a complete cycle is consistent with NUREG-1432, Rev. 2 and the current licensing basis as stated in the TRM. This requirement provides assurance that the ADVs can be used for cooldown and can be closed when needed for containment isolation. These surveillance requirements and frequencies are therefore considered to be appropriate for the ADVs.

The existing TRM requirement for ADVs,3/4.7.1.7, is being deleted since it is now replaced by Technical Specification 3/4.7.1.7.

Results of the SBLOCA analysis and cooldown analysis that credit the ADVs are presented in PUR Section 2.12.4 and demonstrate that acceptance criteria are met.

Containment, Specification 5.2

This specification has been deleted because it contains information available in other Licensee controlled documents and it achieves a level of detail consistent with that of NUREG-1432 (Reference 4). The deleted information is not required to be in the Technical Specifications.

Fuel Assemblies, Specification 5.3.1

References to the initial core loading are deleted since they are historical information that is no longer required. This change is editorial only.

Section 5.7, Component Cyclic or Transient Limits, and Table 5.7-1

Transient logging requirements for the pressurizer spray valves, contained on the second and third pages of Table 5.7-1, are deleted based on calculations showing that transient logging is not required. The deleted provisions of Technical Specification 3/4.4.8.2 identified above pertain to these deleted transient logging requirements.

Evaluations were performed in response to NRC Bulletin 88-08 of systems connected to the RCS that may be subjected to thermal stratification. These evaluations included defining new transients for the pressurizer spray system based on Waterford 3 plant-specific conditions. The new transients were defined to account for potential thermal shocks due to initiation of main and auxiliary pressurizer spray. The effects of reactor coolant pump operation on main spray bypass flow were also considered because characteristics of the bypass flow also affect the spray nozzle.

The existing stress and fatigue analysis of the spray nozzle was revised. The revised analysis included evaluation of the new transients. In addition, the revised analysis included an inelastic analysis of the nozzle and a more realistic assessment of the fatigue calculation for the original design basis transients. For example, the original analysis used a carbon steel fatigue curve for the safe end region of the spray nozzle, a conservative approach for the nozzle material. Consequently, an appropriate stainless steel fatigue curve was used in the reanalysis. The analysis was performed in accordance with Section III of the ASME Boiler and Pressure Vessel Code, 1971 Edition with Addenda through Summer, 1971. Based on the more realistic evaluation of the original spray system transients and the new plant-specific Waterford 3 transients, the spray nozzle reanalysis showed that fatigue of the nozzle will not be significant over the 40 year plant design life. Consequently, the spray nozzle requirements in Table 5.7-1 that pertain to transient logging and calculation of the spray nozzle usage factor may be deleted.

Section 5.7 and the remainder of Table 5.7-1 are being relocated to the TRM in order to achieve a level of detail consistent with NUREG-1432 (Reference 4).

Core Operating Limits Report, Specification 6.9.1.11.1

The following references are being added to the COLR reference list for the CENTS code and the 1999 large break LOCA evaluation model since these methodologies are used in EPU analyses:

- "Technical Manual for the CENTS Code," CENPD-282-P-A. (Methodology for Specification 3.1.1.1 and 3.1.1.2 for Shutdown Margins, 3.1.1.3 for MTC, 3.1.3.1 for Movable Control Assemblies - CEA Position, 3.1.3.6 for Regulating and group P CEA Insertion Limits, and 3.2.3 for Azimuthal Power Tilt).
- "Calculative Methods for the CE Nuclear Power Large Break LOCA Evaluation Model,": CENPD-132, Supplement 4-P-A. (Methodology for Specification 3.1.1.3 for MTC, 3.2.1 for Linear Heat Rate, 3.2.3 for Azimuthal Power Tilt and 3.2.7 for ASI).

The NRC documented approval of these methodologies in the following letters:

- NRC letter, M. J. Virgillo (NRC) to S. A. Toelle (CE), "Acceptance for Referencing of Licensing Topical Report CENPD-282-P, Technical Manual for the CENTS Code (TAC No. M82718)," March 17, 1994.
- NRC letter, S. A. Richards (NRC) to P. W. Richardson (Westinghouse), "Safety Evaluation of Topical Report CENPD-132, Supplement 4, Revision 1, "Calculative Methods for the CE Nuclear Power Large Break LOCA Evaluation Model (TAC No. MA5660)," December 15, 2000.

5.0 REGULATORY ANALYSIS

5.1 Applicable Regulatory Requirements/Criteria

The proposed changes have been evaluated to determine whether applicable regulations and requirements continue to be met.

Entergy has determined that the proposed changes do not require any exemptions or relief from regulatory requirements, other than the Operating License, and do not affect conformance with any General Design Criterion (GDC) differently than described in the Final Safety Analysis Report (FSAR).

5.2 No Significant Hazards Consideration

The proposed Extended Power Uprate (EPU) will increase the maximum steady state core power for Waterford 3 to 3716 MWt, an approximate 8.0% increase above the currently licensed power level of 3441 MWt. The following operating license changes are proposed to support the EPU request.

- Raise rated thermal power from 3441 MWt to 3716 MWt.
- Revise the definition for Dose Equivalent Iodine to reference ICRP 30.
- Lower the plant protection system and engineered safety features actuation system trip setpoints and allowable values for steam generator pressure – low.
- Increase minimum required boron concentration and minimum volume limits for the boric acid makeup tanks.
- Lower the reactor coolant system cold leg operating temperature range.
- Raise the minimum pressurizer pressure limit.
- Lower the primary to secondary operational leakage limit.
- Lower the maximum safety injection tank volume requirement.
- Lower the allowed power level operating limit when main steam safety valves are inoperable.
- Add a new Technical Specification specific to the atmospheric dump valves.
- Add references for two NRC approved analysis methodologies.

In addition to the changes proposed for the EPU, a number of non-EPU related changes have been proposed. These include:

- Deleting dual limits (in different units) in various Technical Specifications leaving a single limit in the units used by Operations.
- Specifying indicated Technical Specification limits as "indicated" values.
- Deleting unnecessary pressurizer spray nozzle fatigue monitoring requirements.

- Incorporating the existing licensing basis lower containment air temperature limit into Technical Specifications.
- Incorporating the existing licensing basis minimum and maximum temperature limits for the condensate storage pool into Technical Specifications.
- Increasing the indicated minimum condensate storage pool level limit to more accurately address process measurement issues (analytical limit did not change).
- Revising the main steam and feedwater isolation valve stroke times to achieve consistency and to incorporate instrument response time (analytical values did not change).
- Deleting historical or unnecessary information to improve consistency with NUREG-1432, Rev.2 (Reference 4).

Entergy Operations, Inc. has evaluated whether the proposed amendment involves a significant hazards consideration by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

1. Does the proposed change involve a significant increase in the probability or consequences of an accident previously evaluated?

   Response: No.

   The impacts of the proposed EPU on plant Systems, Structures, and Components (SSCs) were reviewed with respect to SSC design capability, and it was determined that following completion of plant changes to support the EPU, no system, structure, or component would exceed its design conditions or limits. Evaluations supporting those conclusions were performed consistent with proposed Technical Specification changes. Consequently equipment reliability and structural integrity will not be adversely affected. Control system studies demonstrated that plant response to operational transients under EPU conditions does not significantly increase reactor trip frequency, so there will be no significant increase in the frequency of SSC challenges caused by reactor trip.

   New systems are not needed to implement the EPU, and new interactions among SSCs are not created. The EPU does not create new failure modes for existing SSCs. Modified components do not introduce new failure modes relative to those of the components in their pre-modified condition. Consequently, new initiators of previously analyzed accidents are not created.

   The fission product barriers -- fuel cladding, reactor coolant pressure boundary, and the containment building -- remain unchanged. The spectrum of previously analyzed postulated accidents and transients was evaluated, and effects on the fuel, the reactor coolant pressure boundary, and the containment were determined. These analyses were performed consistent with the proposed Technical Specification changes. The results demonstrate that existing reactor coolant pressure boundary and containment limits are met and that effects on the fuel are such that dose consequences meet existing criteria at EPU conditions.

   The non-EPU related proposed changes do not affect reactor operations or accident analyses and have no radiological consequences.

Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the proposed change create the possibility of a new or different kind of accident from any accident previously evaluated?

Response: No.

New systems are not required to implement the EPU, and new interactions among SSCs are not created. The EPU does not create new failure modes for existing SSCs. Modified components do not introduce failures different from those of the components in their pre-modified condition. Consequently, no new or different accident sequences arise from SSC interactions or failures.

Training will be provided to address EPU effects, and the plant's simulator will be updated consistent with EPU conditions. Operating procedure changes are minor and do not result in any significant changes in operating philosophy. For these reasons, the EPU does not introduce human performance issues that could create new accidents or different accident sequences.

The increase in power level does not create new fission product release paths. The fission product barriers -- fuel cladding, reactor coolant pressure boundary, and the containment building -- remain unchanged.

The non-EPU related proposed changes introduce no new mode of plant operation.

Therefore, the proposed change does not create the possibility of a new or different kind of accident from any previously evaluated.

3. Does the proposed change involve a significant reduction in a margin of safety?

Response: No.

Structural evaluations performed at EPU conditions demonstrated that calculated loads on affected SSCs remain within their design allowables for all design basis event categories. ASME Code fatigue limits continue to be met.

Fuel performance evaluations were performed using parameter values appropriate for a reload core operating at EPU conditions. Those evaluations demonstrate that fuel performance acceptance criteria continue to be met. Reload evaluation processes ensure that fuel in the actual Cycle 14 reload core, the first to be operated at the increased power level, will meet regulatory criteria.

LOCA and non-LOCA safety analyses were performed under EPU conditions. Emergency core cooling system performance was shown to meet the criteria of 10CFR50.46. The non-LOCA events identified in Waterford 3 FSAR Chapter 15 were shown to meet existing acceptance criteria. The LOCA and non-LOCA analyses were performed consistent with the proposed Technical Specification changes.

The containment building response to mass and energy releases was evaluated under EPU conditions. The evaluations showed that temperature and pressure limits were met.

No plant changes associated with the EPU reduce the degree of component or system redundancy.

Except for the deletion of pressurizer spray nozzle fatigue monitoring, existing Technical Specification operability and surveillance requirements are not reduced by the non-EPU related proposed changes, thus no margins of safety are reduced. A more realistic assessment of pressurizer spray nozzle fatigue has shown that nozzle fatigue will not be as significant over the plant design life as had been previously concluded, thus no margins of safety are reduced.

Therefore, the proposed change does not involve a significant reduction in a margin of safety.

Based on the above, Entergy concludes that the proposed amendment presents no significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of “no significant hazards consideration” is justified.

5.3 Environmental Considerations

The environmental considerations evaluation is contained in Extended Power Uprate Report (PUR), Section 5, Environmental Considerations. It concludes that EPU will not result in a significant change in nonradiological impacts on land use, water use, waste discharges, terrestrial and aquatic biota, transmission facilities, or social and economic factors, and will have no nonradiological environmental impacts other than those evaluated in the Final Environmental Statement. PUR, Section 5 further concludes that EPU will not introduce any new radiological release pathways, will not result in a significant increase in occupational or public radiation exposures, and will not result in significant additional fuel cycle environmental impacts.

Therefore, the proposed amendment does not involve a significant change in the types or significant increase in the amounts of any effluent that may be released offsite nor does it involve a significant increase in individual or cumulative occupational radiation exposure.

6.0 PRECEDENTS

An approximate 7.5% power uprate was approved for Arkansas Nuclear One, Unit 2 by issuance of License Amendment 244, TAC MB0789, dated April 24, 2002 (Reference 3). ANO-2 is also a CE designed NSSS plant.

7.0 REFERENCES

1. Office of Nuclear Reactor Regulation (NRR) draft Review Standard (RS)-001, "Review Standard for Extended Power Uprates," December 2002
2. ANO-2 Letter 2CAN12000, C. Anderson (Entergy) to Document Control Desk, “Application for License Amendment to Increase Authorized Power Level,” December 19, 2000
3. NRC Letter, T. Alexion (NRC) to C. Anderson (Entergy), “Application for License Amendment to Increase Authorized Power Level (TAC No. MB0789),” April 24, 2002
4. NUREG–1432, Vol. 1, Rev. 2, Standard Technical Specifications Combustion Engineering Plants, June 2001

Attachment 2

W3F1-2003-0074

Proposed Operating License and
Technical Specification Changes (mark-up)

or indirectly any control over (i) the facility, (ii) power or energy produced by the facility, or (iii) the licensee of the facility. Further, any rights acquired under this authorization may be exercised only in compliance with and subject to the requirements and restrictions of this operating license, the Atomic Energy Act of 1954, as amended, and the NRC's regulations. For purposes of this condition, the limitations of 10 CFR 50.81, as now in effect and as they may be subsequently amended, are fully applicable to the equity investors and any successors in interest to the equity investors, as long as the license for the facility remains in effect.

(b) Entergy Louisiana, Inc. (or its designee) to notify the NRC in writing prior to any change in (i) the terms or conditions of any lease agreements executed as part of the above authorized financial transactions, (ii) any facility operating agreement involving a licensee that is in effect now or will be in effect in the future, or (iii) the existing property insurance coverages for the facility, that would materially alter the representations and conditions, set forth in the staff's Safety Evaluation enclosed to the NRC letter dated September 18, 1989. In addition, Entergy Louisiana, Inc. or its designee is required to notify the NRC of any action by equity investors or successors in interest to Entergy Louisiana, Inc. that may have an effect on the operation of the facility.

C. This license shall be deemed to contain and is subject to the conditions specified in the Commission's regulations set forth in 10 CFR Chapter I and is subject to all applicable provisions of the Act and to the rules, regulations and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

1. Maximum Power Level 3716

EOI is authorized to operate the facility at reactor core power levels not in excess of ~~3441~~ megawatts thermal (100% power) in accordance with the conditions specified herein.

2. Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A, as revised through Amendment No. 183, and the Environmental Protection Plan contained in Appendix B, are hereby incorporated in the license. EOI shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

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CORE ALTERATION

1.9 CORE ALTERATION shall be the movement or manipulation of any component within the reactor pressure vessel with the vessel head removed and fuel in the vessel. Suspension of CORE ALTERATION shall not preclude completion of movement of a component to a safe conservative position.

COLR - CORE OPERATING LIMITS REPORT

1.9a The CORE OPERATING LIMITS REPORT is the Waterford 3 specific document that provides core operating limits for the current operating reload cycle. These cycle-specific core operating limits shall be determined for each reload cycle in accordance with Technical Specification 6.9.1.11. Plant operation within these operating limits is addressed in individual specifications.

DOSE EQUIVALENT I-131

1.10 DOSE EQUIVALENT I-131 shall be that concentration of I-131 (microcuries/gram) which alone would produce the same thyroid dose as the quantity and isotopic mixture of I-131, I-132, I-133, I-134, and I-135 actually present. The thyroid dose conversion factors used for this calculation shall be those listed in Table III of TID-14844, "Calculation of Distance Factors for Power and Test Reactor Sites."

Ē - AVERAGE DISINTEGRATION ENERGY

1.11 Ē shall be the average (weighted in proportion to the concentration of each radionuclide in the reactor coolant at the time of sampling) of the sum of the average beta and gamma energies per disintegration (in MeV) for isotopes, other than iodines, with half-lives greater than 15 minutes, making up at least 95% of the total noniodine activity in the coolant.

ENGINEERED SAFETY FEATURES RESPONSE TIME

1.12 The ENGINEERED SAFETY FEATURES RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its ESF actuation setpoint at the channel sensor until the ESF equipment is capable of performing its safety function (i.e., the valves travel to their required positions, pump discharge pressures reach their required values, etc.). Times shall include diesel generator starting and sequence loading delays where applicable. The response time may be measured by any series of sequential, overlapping, or total steps so that the entire response time is measured. In lieu of measurement, response time may be verified for selected components provided that the components and methodology for verification have been previously reviewed and approved by the NRC.

FREQUENCY NOTATION

1.13 The FREQUENCY NOTATION specified for the performance of Surveillance Requirements shall correspond to the intervals defined in Table 1.1.

ICRP-30, Supplement to Part 1, Pages 192-212, Tables titled, "Committed Dose Equivalent in Target Organs or Tissue per Intake of Unit Activity."

RATED THERMAL POWER

1.24 RATED THERMAL POWER shall be a total reactor core heat transfer rate to the reactor coolant of ~~3441~~ 3716 MWt.

REACTOR TRIP SYSTEM RESPONSE TIME

1.25 The REACTOR TRIP SYSTEM RESPONSE TIME shall be the time interval from when the monitored parameter exceeds its trip setpoint at the channel sensor until electrical power is interrupted to the CEA drive mechanism. The response time may be measured by any series of sequential, overlapping, or total steps so that the entire response time is measured. In lieu of measurement, response time may be verified for selected components provided that the components and methodology for verification have been previously reviewed and approved by the NRC.

REPORTABLE EVENT

1.26 A REPORTABLE EVENT shall be any of those conditions specified in Section 50.73 to 10 CFR Part 50.

SHIELD BUILDING INTEGRITY

1.27 SHIELD BUILDING INTEGRITY shall exist when:

a. Each door in each access opening is closed except when the access opening is being used for normal transit entry and exit, then at least one door shall be closed,

b. The shield building filtration system is in compliance with the requirements of Specification 3.6.6.1, and

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

SHUTDOWN MARGIN

1.28 SHUTDOWN MARGIN shall be the instantaneous amount of reactivity by which the reactor is subcritical or would be subcritical from its present condition assuming all control element assemblies are fully inserted except for the single assembly of highest reactivity worth which is assumed to be fully withdrawn.

TABLE 2.2-1
REACTOR PROTECTIVE INSTRUMENTATION TRIP SETPOINT LIMITS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. Manual Reactor Trip	Not Applicable	Not Applicable
2. Linear Power Level - High		
Four Reactor Coolant Pumps Operating	≤ 108% of RATED THERMAL POWER	≤ 108.76% of RATED THERMAL POWER
3. Logarithmic Power Level - High (1)	≤ 0.257% of RATED THERMAL POWER (6)	≤ 0.280% of RATED THERMAL POWER (6)
4. Pressurizer Pressure - High	≤ 2350 psia	≤ 2359 psia
5. Pressurizer Pressure - Low	≥ 1684 psia (2)	≥ 1649.7 psia (2)
6. Containment Pressure - High	≤ 17.1 psia	≤ 17.4 psia
7. Steam Generator Pressure - Low	≥ ~~764~~ 662 psia (3)	≥ ~~749.9~~ 647.9 psia (3)
8. Steam Generator Level - Low	≥ 27.4% (4)	≥ 26.48% (4)
9. Local Power Density - High	≤ 21.0 kW/ft (5)	≤ 21.0 kW/ft (5)
10. DNBR - Low	≥ 1.26 (5)	≥ 1.26 (5)
11. Steam Generator Level - High	≤ 87.7% (4)	≤ 88.62% (4)
12. Reactor Protection System Logic	Not Applicable	Not Applicable
13. Reactor Trip Breakers	Not Applicable	Not Applicable
14. Core Protection Calculators	Not Applicable	Not Applicable
15. CEA Calculators	Not Applicable	Not Applicable
16. Reactor Coolant Flow - Low	≥ 19.00 psid (7)	≥ 18.47 psid (7)

REACTIVITY CONTROL SYSTEMS

BORATED WATER SOURCES - SHUTDOWN

LIMITING CONDITION FOR OPERATION

an indicated

3.1.2.7 *As a minimum, one of the following borated water sources shall be OPERABLE:*

a. One boric acid makeup tank with a boron concentration between ~~2.25~~ 4900 ppm and ~~3.50 weight percent~~ 6125 ppm and a minimum borated water volume of 36% indicated level.

b. The refueling water storage pool (RWSP) with:

1 A minimum contained borated water volume of 12% indicated level, and

2. A minimum boron concentration of 2050 ppm. indicated

APPLICABILITY: MODES 5 and 6.

ACTION:

With no borated water sources OPERABLE, suspend all operations involving CORE *ALTERATIONS or positive reactivity changes.* *

SURVEILLANCE REQUIREMENTS

4.1.2.7 The above required borated water source shall be demonstrated OPERABLE:

indicated

a. At least once per 24 hours when the Reactor Auxiliary Building air temperature is less than 55°F by verifying the boric acid makeup tank solution is greater than 55°F (when it is the source of borated water). indicated

b. At least once per 7 days by:

1. Verifying the boron concentration of the water, and

2. Verifying the contained borated water volume of the tank.

* Plant temperature changes are allowed provided the temperature change is accounted for in the calculated SHUTDOWN MARGIN.

BORATED WATER SOURCES - OPERATING

LIMITING CONDITION FOR OPERATION

3.1.2.8 Each of the following borated water sources shall be OPERABLE:

a. At least one of the following sources:

1) One boric acid makeup tank, with the tank contents in accordance with Figure 3.1-1, or

2) Two boric acid makeup tanks, with the combined contents of the tanks in accordance with Figure 3.1-~~1~~ 2, and

b. The refueling water storage pool with:

1. A minimum contained borated water volume of 475,500 gallons (83% of indicated level), and

2. A boron concentration of between 2050 and 2900 ppm of boron, and

3. A solution temperature between 55°F and 100°F.

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

ACTION:

a. With the above required boric acid makeup tank(s) inoperable, restore the tank(s) to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and borated to a SHUTDOWN MARGIN equivalent to the requirements of Specification 3.1.1.1 or 3.1.1.2, whichever is applicable; restore the above required boric acid makeup tank(s) to OPERABLE status within the next 7 days or be in COLD SHUTDOWN within the next 30 hours.

b. With the refueling water storage pool inoperable, restore the pool to OPERABLE status within 1 hour or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.1.2.8 Each borated water source shall be demonstrated OPERABLE:

a. At least once per 24 hours by verifying the RWSP temperature when the Reactor Auxiliary Building air temperature is less than 55°F or greater than 100°F.

b. At least once per 24 hours by verifying the BAMT temperature is above 55°F when the Reactor Auxiliary Building air temperature is less than 55°F.

c. At least once per 7 days by:

1. Verifying the boron concentration in the water, and

2. Verifying the contained borated water volume of the water source.

Replace with Insert Figure 3.1-1

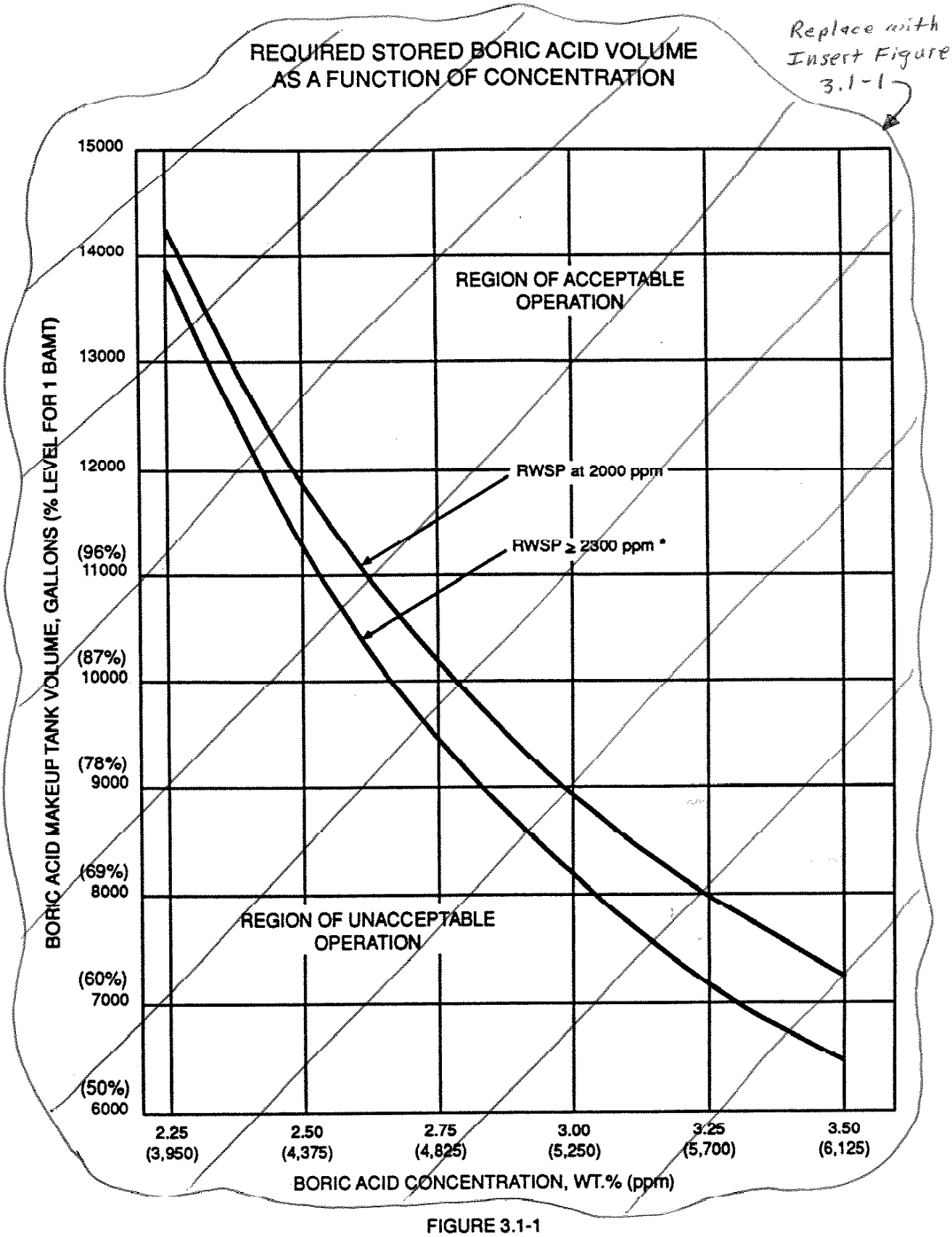
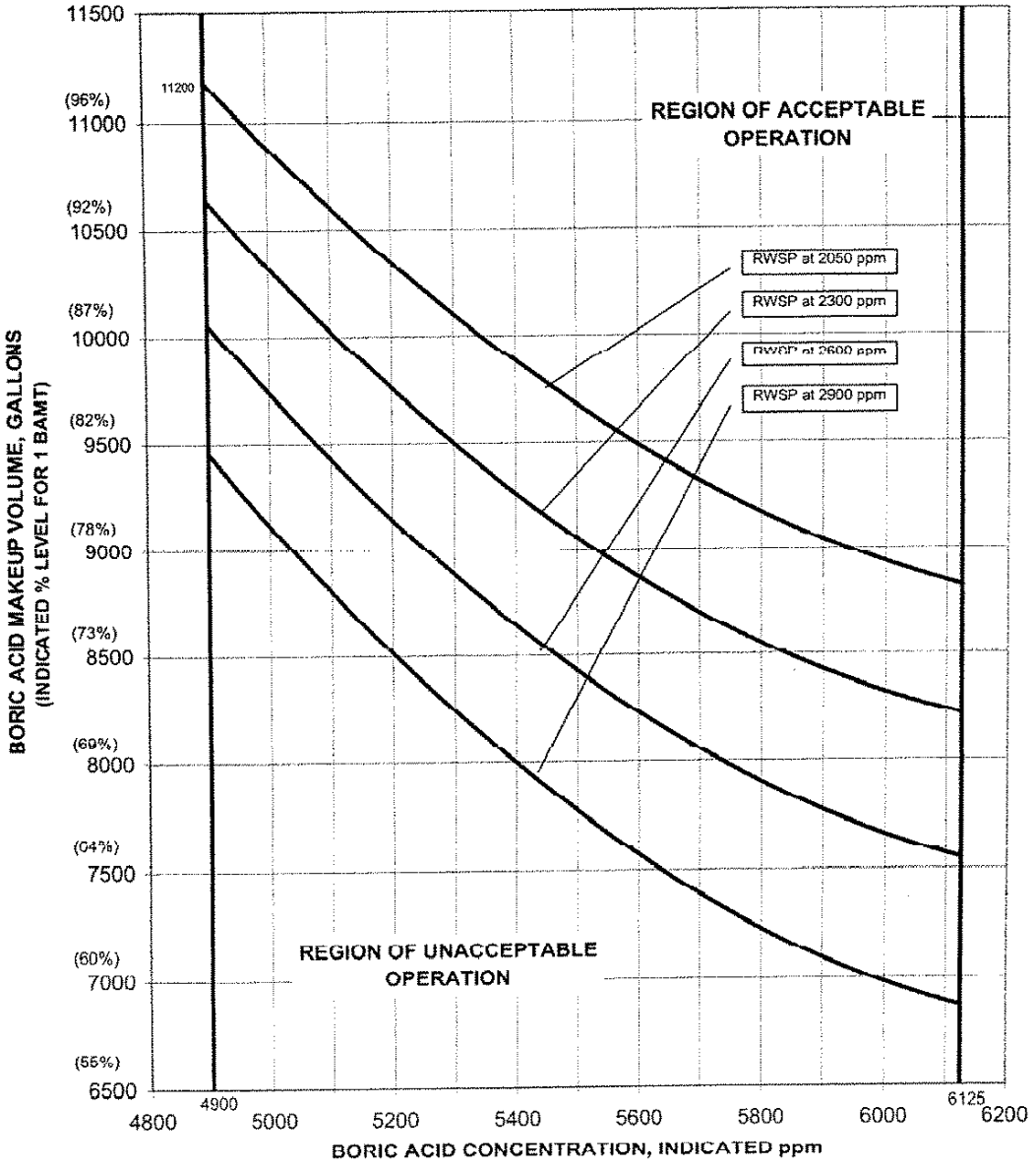


FIGURE 3.1-1

~~* This curve bounds RWSP concentrations ranging from 2300 ppm to 2900 ppm~~

Insert Figure 3.1-1

REQUIRED STORED BORIC ACID VOLUME
AS A FUNCTION OF CONCENTRATION
(VOLUME OF ONE BAMT)



New Figure 3.1-2

REQUIRED STORED BORIC ACID VOLUME
AS A FUNCTION OF CONCENTRATION
(COMBINED VOLUME OF TWO BAMT)

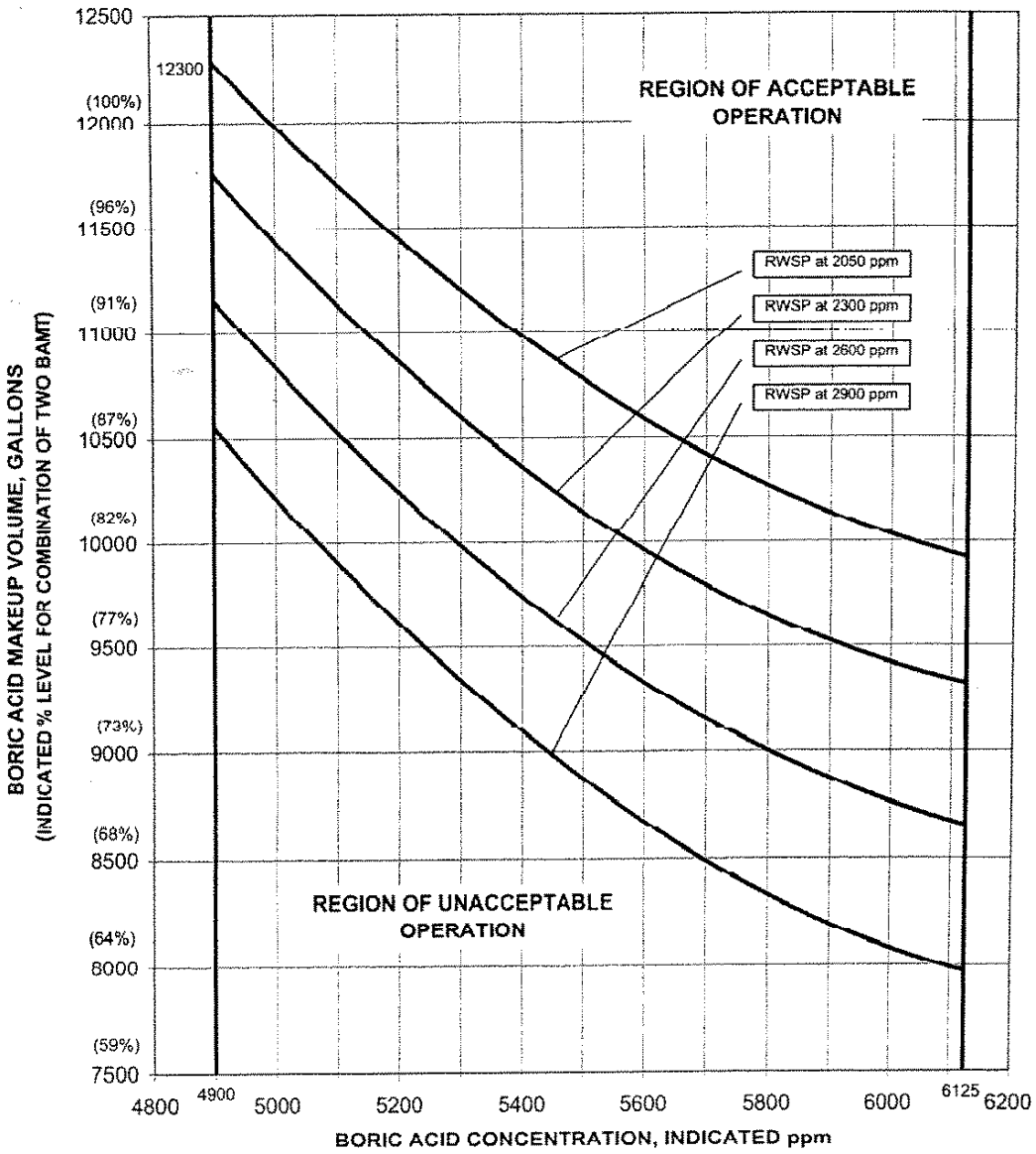


Figure 3.1-2

3/4.2.6 REACTOR COOLANT COLD LEG TEMPERATURE

LIMITING CONDITION FOR OPERATION

indicated

3.2.6 The reactor coolant cold leg temperature (T_c) shall be maintained between ~~541~~ 536°F and ~~558~~ 549°F.*

APPLICABILITY: MODE 1 above 30% of RATED THERMAL POWER.

ACTION:

With the reactor coolant cold leg temperature exceeding its limit, restore the temperature to within its limit within 2 hours or reduce THERMAL POWER to less than 30% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.6 The reactor coolant cold leg temperature shall be determined to be within its limit at least once per 12 hours.

*Following a reactor power cutback in which (1) Regulating Groups 5 and/or 6 are dropped or (2) Regulating Groups 5 and/or 6 are dropped and the remaining Regulating Groups (Groups 1, 2, 3, and 4) are sequentially inserted, the upper limit on T_c may increase to ~~568~~ 559°F indicated for up to 30 minutes.

3/4.2.8 PRESSURIZER PRESSURE

LIMITING CONDITION FOR OPERATION

3.2.8 The indicated steady-state pressurizer pressure shall be maintained between ~~2025~~ 2125 psia and 2275 psia.

APPLICABILITY: MODE 1

ACTION:

With the steady-state pressurizer pressure outside its above limits, restore the pressure to within its limit within 2 hours or reduce THERMAL POWER to less than 5% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.8 The steady-state pressurizer pressure shall be determined to be within its limit at least once per 12 hours.

TABLE 3.3-4

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP VALUES

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. SAFETY INJECTION (SIAS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Containment Pressure - High	≤ 17.1 psia	≤ 17.4 psia
c. Pressurizer Pressure - Low	≥ 1684 psia[1]	≥ 1649.7 psia[1]
d. Automatic Actuation Logic	Not Applicable	Not Applicable
2. CONTAINMENT SPRAY (CSAS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Containment Pressure -- High-High	≤ 17.7 psia	≤ 18.0 psia
c. Automatic Actuation Logic	Not Applicable	Not Applicable
3. CONTAINMENT ISOLATION (CIAS)		
a. Manual CIAS (Trip Buttons)	Not Applicable	Not Applicable
b. Containment Pressure - High	≤ 17.1 psia	≤ 17.4 psia
c. Pressurizer Pressure - Low	≥ 1684 psia[1]	≥ 1649.7 psia[1]
d. Automatic Actuation Logic	Not Applicable	Not Applicable
4. MAIN STEAM LINE ISOLATION		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Steam Generator Pressure - Low	≥ ~~764~~ 662 psia[2]	≥ ~~749.9~~ 647.9 psia[2]
c. Containment Pressure - High	≤ 17.1 psia	≤ 17.4 psia
d. Automatic Actuation Logic	Not Applicable	Not Applicable

TABLE 3-4 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP VALUES

FUNCTIONAL UNIT	TRIP VALUE	ALLOWABLE VALUES
5. SAFETY INJECTION SYSTEM SUMP RECIRCULATION (RAS)		
a. Manual RAS (Trip Buttons)	Not Applicable	Not Applicable
b. Refueling Water Storage Pool - Low	10.0% (57,967 gallons)	9.08% (52,634 gallons)
c. Automatic Actuation Logic	Not Applicable	Not Applicable
6. LOSS OF POWER		
a. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage)	≥ 3245 volts	≥ 3245 volts
b. 480 V Emergency Bus Undervoltage	≥ 372 volts	≥ 354 volts
c. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)	≥ 3875 volts	≥ 3860 volts
7. EMERGENCY FEEDWATER (EFAS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Steam Generator (1&2) Level - Low	≥ 27.4%(3) (4)	≥ 26.48%(3) (4)
c. Steam Generator ΔP - High (SG-1 > SG-2)	≤ 123 psid	≤ 134 psid
d. Steam Generator ΔP - High (SG-2 > SG-1)	≤ 123 psid	≤ 134 psid
e. Steam Generator (1&2) Pressure - Low	≥ 764 psia(2) 662	≥ 749.9 psia(2) 647.9
f. Automatic Actuation Logic	Not Applicable	Not Applicable
g. Control Valve Logic (Wide Range SG Level - Low)	≥ 36.3%(3) (5)	≥ 35.3%(3) (5)

REACTOR COOLANT SYSTEM

OPERATIONAL LEAKAGE

LIMITING CONDITION FOR OPERATION

3.4.5.2 Reactor Coolant System leakage shall be limited to:

a. No PRESSURE BOUNDARY LEAKAGE,

b. 1 gpm UNIDENTIFIED LEAKAGE,

0.75

c. 1 gpm total primary-to-secondary leakage through all steam generators and 720 gallons per day through any one steam generator,

540

d. 10 gpm IDENTIFIED LEAKAGE from the Reactor Coolant System, and

e. 1 gpm leakage at a Reactor Coolant System pressure of 2250 ± 20 psia from any Reactor Coolant System pressure isolation valve specified in Table 3.4-1.

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

ACTION:

a. With any PRESSURE BOUNDARY LEAKAGE, be in at least HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With any Reactor Coolant System leakage greater than any one of the limits, excluding PRESSURE BOUNDARY LEAKAGE and leakage from Reactor Coolant System pressure isolation valves, reduce the leakage rate to within limits within 4 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

c. With any Reactor Coolant System pressure isolation valve leakage greater than the above limit, isolate the high pressure portion of the affected system from the low pressure portion within 4 hours by use of at least one closed manual or deactivated automatic valve, or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.4.5.2.1 Reactor Coolant System leakages shall be demonstrated to be within each of the above limits by:

a. Commencing an RCS inventory balance within 1 hour to determine the leak rate when RCS leakage is alarmed and confirmed in a flow path with no flow rate indication.

b. Monitoring the containment atmosphere gaseous and particulate radioactivity monitor at least once per 12 hours.

c. Monitoring the containment sump inventory and discharge at least once per 12 hours.

REACTOR COOLANT SYSTEM

PRESSURIZER HEATUP/COOLDOWN

LIMITING CONDITION FOR OPERATION

3.4.8.2 The pressurizer shall be limited to:

a. A maximum heatup rate of 200°F per hour, and

b. A maximum cooldown rate of 200°F per hour, and

c. A maximum spray nozzle usage factor of 0.65.

APPLICABILITY: At all times.

ACTION:

a. With the pressurizer temperature limits in excess of any of the above limits, restore the temperature to within the limits within 30 minutes; perform an engineering evaluation to determine the effects of the out-of-limit condition on the structural integrity of the pressurizer; determine that the pressurizer remains acceptable for continued operation or be in at least HOT STANDBY within the next 6 hours and reduce the pressurizer pressure to less than 500 psig within the following 30 hours.

b. With the spray nozzle usage factor > 0.65, comply with requirements of Table 5.7-1.

SURVEILLANCE REQUIREMENTS

4.4.8.2.1 The pressurizer temperatures shall be determined to be within the limits at least once per 30 minutes during system heatup or cooldown.

4.4.8.2.2 The spray water temperature differential shall be determined to be within the limit at least once per 12 hours during auxiliary spray operation.

4.4.8.2.3 Each spray cycle and the corresponding ΔT (water temperature differential) shall be recorded whenever main spray is initiated with a ΔT (water temperature differential) of > 130°F and whenever auxiliary spray is initiated with a ΔT (water temperature differential) of > 140°F.

3/4.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3/4.5.1 SAFETY INJECTION TANKS

LIMITING CONDITION FOR OPERATION

3.5.1 Each Reactor Coolant System safety injection tank shall be OPERABLE with:

a. The isolation valve open,

b. A contained borated water volume of between 926 (40%) and 1807 (83.8%) cubic feet,

c. Between 2050 and 2900 ppm of boron, and

d. A nitrogen cover-pressure of between 600 and 670 psig.

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

ACTION: MODES 1, 2, 3 and 4 with pressurizer pressure greater than or equal to 1750 psia.

a. With one of the required safety injection tanks inoperable due to boron concentration not within limits, restore the boron concentration to within limits within 72 hours or be in at least HOT STANDBY within the next 6 hours and reduce pressurizer pressure to less than 1750 psia within the following 6 hours.

b. With one of the required safety injection tanks inoperable due to inability to verify level or pressure, restore the tank to OPERABLE status within 72 hours, or be in at least HOT STANDBY within the next 6 hours and reduce pressurizer pressure to less than 1750 psia within the following 6 hours.

c. With one of the required safety injection tanks inoperable for reasons other than ACTION a or b, restore the tank to OPERABLE status within 24 hours, or be in HOT STANDBY within the next 6 hours and reduce pressurizer pressure to less than 1750 psia within the following 6 hours.

---

* With pressurizer pressure greater than or equal to 1750 psia. When pressurizer pressure is less than 1750 psia, at least three safety injection tanks must be OPERABLE, each with a minimum pressure of 235 psig and a maximum pressure of 670 psig and a contained borated water volume of between 1332 (61%) and 1807 (83.8%) cubic feet. With all four safety injection tanks OPERABLE, each tank shall have a minimum pressure of 235 psig and a maximum pressure of 670 psig, a boron concentration of between 2050 and 2900 ppm boron, and a contained borated water volume of between 888 (39%) and 1807 (83.8%) cubic feet. In MODE 4 with pressurizer pressure less than 392 psia (700 psia for remote shutdown from LCP-43), the safety injection tanks may be isolated.

3/4.5.4 REFUELING WATER STORAGE POOL

LIMITING CONDITION FOR OPERATION

3.5.4 The refueling water storage pool shall be OPERABLE with:

a. A minimum contained borated water volume of 475,500 gallons (83% indicated level);

b. Between 2050 and 2900 ppm of boron, and

c. A solution temperature of between 55°F and 100°F.

indicated

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

ACTION:

With the refueling water storage pool inoperable, restore the pool to OPERABLE status within 1 hour or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.5.4 The RWSP shall be demonstrated OPERABLE:

a. At least once per 7 days by:

1. Verifying the contained borated water volume in the pool, and

2. Verifying the boron concentration of the water.

b. At least once per 24 hours by verifying the RWSP temperature when the RAB air temperature is less than 55°F or greater than 100°F.

indicated

CONTAINMENT SYSTEMS

AIR TEMPERATURE

LIMITING CONDITION FOR OPERATION

3.6.1.5 Primary containment average air temperature shall be ≥ 90°F* and ≤ ~~not exceed~~ 120 °F indicated.

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

ACTION:

With the containment average air temperature outside the limits ~~greater than 120 °F~~, restore ~~reduce~~ the average air temperature to within the limits within 8 hours, or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.5 The primary containment average air temperature shall be the arithmetical average of the temperatures at any three of the following locations and shall be determined at least once per 24 hours:

Location

a. Containment Fan Cooler No. 1A Air Intake

b. Containment Fan Cooler No. 1B Air Intake

c. Containment Fan Cooler No. 1C Air Intake

d. Containment Fan Cooler No. 1D Air Intake

* The minimum containment average air temperature limit is only applicable at greater than 70% RATED THERMAL POWER.

3/4.7 PLANT SYSTEMS

3/4.7.1 TURBINE CYCLE

SAFETY VALVES

LIMITING CONDITION FOR OPERATION

3.7.1.1 All main steam line code safety valves shall be OPERABLE with lift settings as specified in Table 3.7-1.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

a. ~~With both reactor coolant loops and associated steam generators in operation and with one or more main steam line code safety valves inoperable, operation in MODES 1, 2 and 3 may proceed provided, that within 4 hours, either the inoperable valve is restored to OPERABLE status or the Linear Power Level-High trip setpoint is reduced per Table 3.7-2; otherwise, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.~~

b. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.1.1 Verify each required main steam line code safety valve lift setpoint per Table 3.7-1 in accordance with Specification 4.0.5. Following testing, lift settings shall be within ± 1%.

With one or more main steam line code safety valve inoperable, within 4 hours reduce indicated power to less than or equal to the applicable percent RATED THERMAL POWER listed in Table 3.7-2 and within 12 hours reduce the Linear Power Level – High trip setpoint in accordance with Table 3.7-2, otherwise, be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 12 hours.

No changes are being made to this page. Page included for ease of review.

TABLE 3.7-1

STEAM LINE SAFETY VALVES PER LOOP

	VALVE NUMBER		LIFT SETTING (± 3%)*
	Line No. 1	Line No. 2	
a.	2MS-R613A (MS-106A)	2MS-R619B (MS-106B)	1070 psig
b.	2MS-R614A (MS-108A)	2MS-R620B (MS-108B)	1085 psig
c.	2MS-R615A (MS-110A)	2MS-R621B (MS-110B)	1100 psig
d.	2MS-R616A (MS-112A)	2MS-R622B (MS-112B)	1115 psig
e.	2MS-R617A (MS-113A)	2MS-R623B (MS-113B)	1125 psig
f.	2MS-R618A (MS-114A)	2MS-R624B (MS-114B)	1135 psig

*The lift setting pressure shall correspond to ambient conditions of the valve at nominal operating temperature and pressure.

POWER AND

TABLE 3.7-2

MAXIMUM ALLOWABLE LINEAR POWER LEVEL-HIGH TRIP SETPOINT WITH INOPERABLE STEAM LINE SAFETY VALVES DURING OPERATION WITH BOTH STEAM GENERATORS

MAXIMUM NUMBER OF INOPERABLE SAFETY VALVES ON ANY OPERATING STEAM GENERATOR	~~MAXIMUM ALLOWABLE LINEAR POWER LEVEL-HIGH TRIP SETPOINT (PERCENT OF RATED THERMAL POWER)~~
1	~~86.8~~
2	~~69.4~~

Replace with Insert Table 3.7-2.

Insert Table 3.7-2

MAXIMUM ALLOWABLE POWER (% RTP INDICATED)	LINEAR POWER LEVEL – HIGH TRIP SETPOINT (% RTP)
85.3	≤ 93.3
66.7	≤ 74.7

CONDENSATE STORAGE POOL

LIMITING CONDITION FOR OPERATION

3.7.1.3 The condensate storage pool (CSP) shall be OPERABLE with ~~a minimum contained volume of at least 91% indicated level.*~~

a. A minimum water volume of 92% indicated level.*

b. A water temperature of between 55°F and 100°F indicated.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

In MODES 1, 2, and 3:

With the condensate storage pool inoperable, within 4 hours restore the CSP to OPERABLE status or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

In MODE 4:

With the condensate storage pool inoperable, within 4 hours restore the CSP to OPERABLE status or be in at least COLD SHUTDOWN within the next 24 hours.

SURVEILLANCE REQUIREMENTS

4.7.1.3.1 The condensate storage pool shall be demonstrated OPERABLE ~~at least once per 12 hours by verifying the contained water volume is within its limits.~~

a. At least once per 12 hours by verifying the contained water volume is within its limits.

b. At least once per 24 hours by verifying CSP temperature when the indicated RAB air temperature is less than 55°F or greater than 100°F.

*In MODE 4, the CSP shall be OPERABLE with a minimum contained volume of at least 11% indicated level.

MAIN STEAM LINE ISOLATION VALVES (MSIVs)

LIMITING CONDITION FOR OPERATION

3.7.1.5 Two MSIVs shall be OPERABLE.

APPLICABILITY: MODE 1, and
MODES 2, 3, and 4, except when all MSIVs are closed and deactivated.

ACTION:

MODE 1

With one MSIV inoperable, restore the valve to OPERABLE status within 8 hours or be in STARTUP within the next 6 hours.

MODES 2, 3 and 4

With one MSIV inoperable, close the valve within 8 hours and verify the valve is closed once per 7 days. Otherwise, be in HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

Note: Required to be performed for entry into MODES 1 and 2 only.

4.7.1.5 Each MSIV shall be demonstrated OPERABLE:

a. By verifying full closure within ~~4.0~~ 8.0 seconds when tested pursuant to the Inservice Testing Program.

b. By verifying each MSIV actuates to the isolation position on an actual or simulated actuation signal at least once per 18 months.

MAIN FEEDWATER ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

3.7.1.6 Each Main Feedwater Isolation Valve (MFIV) shall be OPERABLE.

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

ACTION:

Note: Separate Condition entry is allowed for each valve.

With one or more MFIV inoperable, close and deactivate, or isolate the inoperable valve within 72 hours and verify inoperable valve closed and deactivated or isolated once every 7 days; otherwise, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

The provisions of Specification 3.0.4 do not apply.

SURVEILLANCE REQUIREMENTS

4.7.1.6 Each main feedwater isolation valve shall be demonstrated OPERABLE:

a. By verifying isolation ≤ 5.0 seconds when tested pursuant to the Inservice Testing Program. within 6.0

b. By verifying actuation to the isolation position on an actual or simulated actuation signal at least once per 18 months.

New TS

3/4.7.1.7 ATMOSPHERIC DUMP VALVES

LIMITING CONDITION FOR OPERATION

3.7.1.7 Each Atmospheric Dump Valve (ADV) shall be OPERABLE*.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTION:

a. With the automatic actuation channel for one ADV inoperable, restore the inoperable ADV to OPERABLE status within 72 hours or reduce power to less than or equal to 70% indicated RATED THERMAL POWER within the next 6 hours.

b. With the automatic actuation channels for both ADVs inoperable, restore one ADV to OPERABLE status within 1 hour or reduce power to less than or equal to 70% indicated RATED THERMAL POWER within the next 6 hours.

c. With one ADV inoperable, for reasons other than above, restore the ADV to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

The provisions of Specification 3.0.4 are not applicable provided one ADV is OPERABLE.

SURVEILLANCE REQUIREMENTS

4.7.1.7 The ADVs shall be demonstrated OPERABLE:

a. By performing a CHANNEL CHECK of each ADV automatic actuation channel at least once per 12 hours when the automatic actuation channels are required to be OPERABLE.

b. By verifying one complete cycle of each ADV when tested pursuant to the Inservice Testing Program.

c. By performing a CHANNEL CALIBRATION of each ADV automatic actuation channel at least once per 18 months.

d. By verifying actuation of each ADV to the open position on an actual or simulated automatic actuation signal at least once per 18 months.

---

* ADV automatic actuation channels (one per ADV, in automatic with a setpoint of less than or equal to 1000 psia) are not required to be OPERABLE when less than or equal to 70% RATED THERMAL POWER for greater than 6 hours.

5.0 DESIGN FEATURES

5.1 SITE

EXCLUSION AREA

5.1.1 The exclusion area shall be as shown in Figure 5.1-1.

LOW POPULATION ZONE

5.1.2 The low population zone shall be as shown in Figure 5.1-2.

MAP DEFINING UNRESTRICTED AREAS FOR RADIOACTIVE GASEOUS AND LIQUID EFFLUENTS

5.1.3 Information regarding radioactive gaseous and liquid effluents, which will allow identification of structures and release points as well as definition of UNRESTRICTED AREAS within the SITE BOUNDARY that are accessible to MEMBERS OF THE PUBLIC, shall be as shown in Figure 5.1-3.

The definition of UNRESTRICTED AREA used in implementing these Technical Specifications has been expanded over that in 10 CFR 20.1003. The UNRESTRICTED AREA boundary may coincide with the Exclusion (fenced) Area boundary, as defined in 10 CFR 100.3(a), but the UNRESTRICTED AREA does not include areas over water bodies. For calculations performed pursuant to 10 CFR 50.36a, the concept of UNRESTRICTED AREAS, established at or beyond the SITE BOUNDARY, is utilized in the Controls to keep levels of radioactive materials in liquid and gaseous effluents as low as is reasonably achievable.

5.2 [illegible]EM NOT USED

CON[illegible]ON

5.2.1 The reactor building is a steel containment vessel surrounded by a reinforced concrete shield building.

5.2.1.1 The containment vessel is a cylindrical vessel with a hemispherical dome and an ellipsoidal bottom and having the following design features:

a. Nominal inside diameter - 140 feet.
b. Nominal inside height = 240 feet 4.75 inches.
c. Nominal thickness of cylindrical wall = 1.903 inches.
d. Nominal thickness of hemispherical dome = 0.95 inch.
e. Nominal thickness of ellipsoidal bottom = 2.25 inches.
f. Net free volume = 2,680,000 cubic feet.

5.2.1.2 The shield building is a cylindrical structure with a shallow dome roof and having the following design features:

a. Nominal outside diameter = 154 feet.
b. Nominal outside height (from base slab) = 249.5 feet.
c. Nominal thickness of cylindrical wall = 3 feet.
d. Nominal thickness of dome roof = 2.5 feet.
e. Nominal inside radius of dome roof = 112 feet.
f. Nominal annular space = 4 feet.

DESIGN PRESSURE AND TEMPERATURE

5.2.2 The reactor containment building is designed and shall be maintained for a maximum internal pressure of 44 psig and a temperature of 263°F.

5.3 REACTOR CORE

FUEL ASSEMBLIES

5.3.1 The reactor core shall contain 217 fuel assemblies with each fuel assembly containing a maximum of 236 fuel rods clad with Zircaloy-4. Each fuel rod shall have a nominal active fuel length of 150 inches and contain a nominal total weight of 1830 grams uranium. The initial core loading shall have a maximum enrichment of 2.91 weight percent U-235. Reload fuel shall be similar in physical design to the initial core loading. Assemblies shall have a maximum nominal enrichment of 5.0 weight percent U-235 and meet the final storage requirements described in Section 5.6.

CONTROL ELEMENT ASSEMBLIES

5.3.2 The reactor core shall contain 87 control element assemblies.

5.4 NOT USED

5.5 METEOROLOGICAL TOWERS LOCATION

5.5.1 The primary and backup meteorological towers shall be located as shown on Figure 5.1-1.

5.6 FUEL STORAGE

CRITICALITY

5.6.1 The spent fuel storage racks are designed and shall be maintained with:

a. A normal k_{eff} of less that or equal to 0.95 when flooded with unborated water, which includes a conservative allowance for uncertainties.

b. A nominal 10.185 inch center-to-center distance between fuel assemblies placed in Region 1 (cask storage pit) spent fuel storage racks.

c. A nominal 8.692 inch center-to-center distance between fuel assemblies in the Region 2 (spent fuel pool and refueling canal) racks, except for the four southern-most racks in the spent fuel pool which have an increased N-S center-to-center nominal distance of 8.892 inches.

d. New or partially spent fuel assemblies may be allowed unrestricted storage in Region 1 racks.

e. New fuel assemblies may be stored in the Region 2 racks provided that they are stored in a "checkerboard pattern" as illustrated in Figure 5.6-1.

f. Partially spent fuel assemblies with a discharge burnup in the "acceptable range" of Figure 5.6-2 may be allowed unrestricted storage in the Region 2 racks.

g. Partially spent fuel assemblies with a discharge burnup in the "unacceptable range" of Figure 5.6-2 may be stored in the Region 2 racks provided that they are stored in a "checkerboard pattern", as illustrated in Figure 5.6-1, with spent fuel in the "acceptable range" of Figure 5.6-3.

5.6.2 The k_{eff} for new fuel stored in the new fuel storage racks shall be less than or equal to 0.95 when flooded with unborated water and shall not exceed 0.98 when aqueous foam moderation is assumed.

DRAINAGE

5.6.3 The spent fuel pool is designed and shall be maintained to prevent inadvertent draining of the pool below elevation +40.0 MSL. When fuel is being stored in the cask storage pit and/or the refueling canal, these areas will also be maintained at +40.0 MSL.

CAPACITY

5.6.4 The spent fuel pool is designed and shall be maintained with a storage capacity limited to no more than 1849 fuel assemblies in the main pool, 255 fuel assemblies in the cask storage pit and after permanent plant shutdown 294 fuel assemblies in the refueling canal. The heat load from spent fuel stored in the refueling canal racks shall not exceed 1.72x10E6 BTU/Hr. Fuel shall not be stored in the spent fuel racks in the cask storage pit or the refueling canal unless all of the racks are installed in each respective area per the design.

5.7 COMPONENT CYCLIC OR TRANSIENT LIMITS

NOT USED

5.7.1 The components identified in Table 5.7-1 are designed and shall be maintained within the cyclic or transient limits of Table 5.7-1.

TABLE 5.7-1

COMPONENT CYCLIC OR TRANSIENT LIMITS

COMPONENT	CYCLIC OR TRANSIENT LIMIT	DESIGN CYCLE OR TRANSIENT
Reactor Coolant System	500 system heatup cycles and 500 cooldown cycles at rates ≤ 100°F/h.	Heatup cycle - T_{avg} from ≤ 70°F to ≥ 545°F; cooldown cycle - T_{avg} from ≥ 545°F to ≤ 70°F.
	500 pressurizer heatup and cooldown cycles at rates ≤ 200°F/h.	Heatup cycle - Pressurizer temperature from < 70°F to > 653°F; cooldown cycle ≥ 653°F to ≤ 70°F
	10 hydrostatic testing cycles.	RCS pressurized to 3125 psia with RCS temperature ≥ 60°F above the most limiting components' NDTT value.
	200 leak testing cycles.	RCS pressurized to 2250 psia with RCS temperature greater than minimum for hydrostatic testing, but less than 400°F.
	200 seismic stress cycles.	Subjection to a seismic event equal to the operating basis earthquake (OBE).
	480 cycles (any combination) of reactor trip, turbine trip, or complete loss of forced reactor coolant flow	Trip from 100% of RATED THERMAL POWER; Turbine trip (total load rejection from 100% of RATED THERMAL POWER followed by resulting reactor trip; simultaneous loss of all reactor coolant pumps at 100% of RATED THERMAL POWER
	5 complete loss of secondary pressure cycles.	Loss of secondary pressure from either steam generator while in MODE 1, 2, or 3.

T_{cold}

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TABLE 5.7-1 (Continued)

COMPONENT	CYCLIC OR TRANSIENT LIMIT	DESIGN CYCLE OR TRANSIENT
Pressurizer Spray Nozzle	Unlimited number of cycles	Main spray (4 pumps operating). Main spray (less than 4 pumps operating) with $\Delta T_m \leq 130°F$ Auxiliary spray with $\Delta T_a \leq 140°F$
	Calculate usage factor as indicated below:	Main spray (Less than 4 pumps operating) with $\Delta T_m > 130°F$ Auxiliary spray with $\Delta T_a > 140°F$

Calculational Method:

1. The spray cycle is defined as the opening and closing of a spray valve, either by main spray or auxiliary spray.

2. If the difference between pressurizer water temperature and the spray water temperature exceeds 130°F for main spray or 140°F for auxiliary spray, each spray cycle and the corresponding temperature difference is logged.

3. The spray nozzle usage factor shall be calculated as follows::

   A. Fill in Column "N" above.

   B. Calculate "N/N_A" (Divide N and N_A).

   C. Add Column "N/N_A" to find $\Sigma N/N_A$.

   D. Add $\Sigma N/N_A$ for both main and auxiliary spray. This total is the cumulative usage factor.

4. A. If the cumulative usage factor is equal to or less than 0.65 no further action is required.

   B. If the cumulative usage factor exceeds 0.65, subsequent pressurizer spray operation shall continue to be monitored and an engineering evaluation of nozzle fatigue shall be performed within 90 days. The evaluation shall determine that the nozzle remains acceptable for additional service beyond the 90-day period or subsequent spray operation shall be restricted so that the difference between the pressurizer water temperature and the spray water temperature shall be limited to less than or equal to 130°F for main spray and 140°F for auxiliary spray.

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TABLE 5.7-1 (Continued)

PRESSURIZER SPRAY NOZZLE USAGE FACTOR

MAIN SPRAY				AUXILIARY SPRAY			
ΔT_m	N_A	N	N/N_A	ΔT_a	N_A	N	N/N_A
130-180	7900			140-190	50000		
181-230	4500			191-240	2200		
231-280	2900			241-290	1300		
281-330	1900			291-340	850		
331-380	1200			341-390	550		
381-430	850			391-440	375		
431-480	555			441-490	225		
				491-540	150		
			$\Sigma N/N_A$= _____				$\Sigma N/N_A$= _____

Cumulative Usage Factor

$\Sigma N/N_A$ (Main Spray) _____

$\Sigma N/N_A$ (Aux. Spray) _____

Total _____ (Cumulative Usage Factor)

WHERE:

ΔT_a = Temperature Difference between pressurizer and auxiliary spray (charging line)

ΔT_m = Temperature Difference between pressurizer and main spray

N_A = Allowable number of spray cycles

N = Number of cycles in ΔT range indicated

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CORE OPERATING LIMITS REPORT COLR (Continued)

6) "CESEC - Digital Simulation for a Combustion Engineering Nuclear Steam Supply System," CENPD-107. (Methodology for Specification 3.1.1.1 and 3.1.1.2 for Shutdown Margins, 3.1.1.3 for MTC, 3.1.3.1 for Movable Control Assemblies - CEA Position, 3.1.3.6 for Regulating and group P CEA Insertion Limits, and 3.2.3 for Azimuthal Power Tilt).

7) "Qualification of Reactor Physics Methods for the Pressurized Water Reactors of the Entergy System," ENEAD-01-P. (Methodology for Specifications 3.1.1.1 and 3.1.1.2 for Shutdown Margins, 3.1.1.3 for MTC, 3.1.3.6 for Regulating and group P CEA Insertion Limits, 3.1.2.9 Boron Dilution (Calculation of CBC & IBW), and 3.9.1 Boron Concentration).

8) "Fuel Rod Maximum Allowable Gas Pressure," CEN-372-P-A. (Methodology for Specification 3.2.1, Linear Heat Rate).

6.9.1.11.2 The core operating limits shall be determined such that all applicable limits (e.g., fuel thermal limits, core thermal-hydraulic limits, ECCS limits, nuclear limits such as shutdown margin, and transient and accident analysis limits) of the safety analysis are met.

6.9.1.11.3 The CORE OPERATING LIMITS REPORT, including any mid-cycle revisions or supplements thereto, shall be provided upon issuance, for each reload cycle, to the NRC Document Control Desk with copies to the Regional Administrator and Resident Inspector.

SPECIAL REPORTS

6.9.2 Special reports shall be submitted in accordance with 10 CFR 50.4 within the time period specified for each report.

6.10 Not Used

TS 6.9.1.11.1 Insert

TS 6.9.1.11.1 Insert

9) "Technical Manual for the CENTS Code," CENPD-282-P-A. (Methodology for Specification 3.1.1.1 and 3.1.1.2 for Shutdown Margins, 3.1.1.3 for MTC, 3.1.3.1 for Movable Control Assemblies - CEA Position, 3.1.3.6 for Regulating and group P CEA Insertion Limits, and 3.2.3 for Azimuthal Power Tilt).

10) "Calculative Methods for the CE Nuclear Power Large Break LOCA Evaluation Model," CENPD-132, Supplement 4-P-A. (Methodology for Specification 3.1.1.3 for MTC, 3.2.1 for Linear Heat Rate, 3.2.3 for Azimuthal Power Tilt and 3.2.7 for ASI).

Attachment 3

W3F1-2003-0074

Changes to Technical Specification Bases Pages
For Information Only

• (DRN 03-524, Ch. 23)

If a Surveillance is not completed within the allowed delay period, then the equipment is considered inoperable or the variable is considered outside the specified limits and the allowed outage times of the required actions for the applicable LCO begin immediately upon expiration of the delay period. If a Surveillance is failed within the delay period, then the equipment is inoperable, or the variable is outside the specified limits and the allowed outage times of the required actions for the applicable LCO begin immediately upon the failure of the Surveillance.

Satisfactory completion of the Surveillance within the delay period allowed by this Specification, or within the allowed outage time of the actions, restores compliance with Specification 4.0.1.

• (DRN 03-524, Ch. 23)

Surveillance Requirements do not have to be performed on inoperable equipment because the ACTION requirements define the remedial measures that apply. However, the Surveillance Requirements have to be met to demonstrate that inoperable equipment has been restored to OPERABLE status.

Specification 4.0.4 establishes the requirement that all applicable surveillance must be met before entry into an OPERATIONAL MODE or other condition of operation specified in the Applicability statement. The purpose of this specification is to ensure that system and component OPERABILITY requirements or parameter limits are met before entry into a MODE or condition for which these systems and components ensure safe operation of the facility. This provision applies to changes in OPERATIONAL MODES or other specified conditions associated with plant shutdown as well as startup.

Under the provisions of this specification, the applicable Surveillance Requirements must be performed within the specified surveillance interval to ensure that the Limiting Condition for Operation are met during initial plant startup or following a plant outage.

When a shutdown is required to comply with ACTION requirements, the provisions of Specification 4.0.4 do not apply because this would delay placing the facility in a lower MODE of operation.

• (DRN 03-1807, Ch. 30)

Bases 3/4.0-1 Insert

• (DRN 03-1807, Ch. 30)

Bases 3/4.0-1 Insert

Table B 3/4.0-1 lists both the analytical and indicated values for various specifications. Technical Specifications ensure that the plant is operated within the analyzed envelop for which analyses have demonstrated acceptable plant response to postulated events. In so doing, Technical Specifications provide operational restrictions and limitations on equipment, setpoints, and initial plant conditions assumed in the safety analysis. The Technical Specifications contain a mixture of analytical and indicated plant values based on various factors (e.g., safety setpoint, sensitivity of safety analysis to value, etc.) Choosing an indicated value or an analytical value for a limit depends on which value is judged most appropriate in each particular instance. For most initial conditions, the analytical value equals the indicated value. For more sensitive parameters, the indicated value varies from the analytical value to explicitly account for instrument inaccuracies and other process requirements thus providing increased assurance that expected automatic action occurs at or before the specified limit is reached. To highlight the association between indicated and analytical values, Table B3/4.0-1 presents both values for limits specified in the Technical Specifications.

TABLE B 3/4.0-1
ANALYTICAL/INDICATED VALUES

TS	Parameter	Analytical Value	Indicated / Plant Value	Comments
1.24	RATED THERMAL POWER	3735 MWt	3716 MWt	
Table 2.2-1	#2 Linear Power Level High	115%	≤108%	
Table 2.2-1	#3 Logarithmic Power Level High	4.4%	≤0.257%	
Table 2.2-1	#4 Pressurizer Pressure High	2422 psia	≤2350 psia	
Table 2.2-1	#5 Pressurizer Pressure Low	1560 psia	≥1684 psia	
Table 2.2-1	#6 Containment Pressure High	19.7 psia	≤17.1 psia	
Table 2.2-1	#7 Steam Generator Pressure Low	576 psia	≥662 psia	
Table 2.2-1	#8 Steam Generator Level Low	5%NR	≥27.4%NR	
Table 2.2-1	#9 Local Power Density High	21kW/ft	≤21kW/ft	
Table 2.2-1	#10 DNBR Low	1.26	≥1.26	
Table 2.2-1	#11 Steam Generator Level High	90% (NR)	≤87.7% (NR)	
Table 2.2-1	#16 Reactor Coolant Flow Low	60% flow	≥19.00 psid	Analysis utilizes units in % flow while indications are in psid
3.1.2.7	BAMT Boron Concentration	≥4551 ppm ≤6187 ppm	≥4900 ppm ≤6125 ppm	
3.1.2.7	RWSP Volume	NA	≥12% level	Modes 5 & 6
3.1.2.7	RWSP Boron Concentration	2029 ppm	≥2050 ppm	
4.1.2.7	RAB Air Temperature	50°F	≥55°F	
4.1.2.7	BAMT Solution Temperature	50°F	≥55°F	
3.1.2.8	RWSP Volume	383,000 gal.	≥83% level	Analysis utilizes units in gallons while indications are in %.
3.1.2.8	RWSP Boron Concentration	≥2029 ppm ≤2929 ppm	≥2050 ppm ≤2900 ppm	

TABLE B 3/4.0-1
ANALYTICAL/INDICATED VALUES

TS	Parameter	Analytical Value	Indicated / Plant Value	Comments
3.1.2.8	RWSP Solution Temperature	≥50°F/≥55°F ≤100°F	≥55°F ≤100°F	ECCS Analysis / Inadvertent Cntmt Spray
4.1.2.8	RAB Air Temperature	≥50°F ≤100°F	≥55°F ≤100°F	
4.1.2.8	BAMT Solution Temperature	50°F	≥ 55°F	
3.2.6	RCS Cold Leg Temperature	≥533°F ≤552°F	≥536°F ≤549°F	
3.2.8	Pressurizer Pressure	≥2090 psia ≤2310 psia	≥2125 psia ≤2275 psia	
Table 3.3-4	#1.b, 3.b & 4.c Containment Pressure High	19.7 psia	≤17.1 psia	
Table 3.3-4	#1.c & 3.c Pressurizer Pressure Low	1560 psia	≥1684 psia	@ NOP
Table 3.3-4	#2.b Containment Pressure High High	19.7 psia	≤17.7 psia	
Table 3.3-4	#1.b & 7.e Steam Generator Pressure Low	576 psia	≥662 psia	@NOP
Table 3.3-4	#5.b RWSP Level for RAS	28,843 gal.	≥10% level	Analysis utilizes units in gallons while indications are in %.
Table 3.3-4	#6.a 4.16 kV 1E Bus Undervoltage (Loss of Voltage)	3245 volts	≥3245 volts	
Table 3.3-4	#6.b 480 V 1E Bus Undervoltage	354 volts	≥372 volts	
Table 3.3-4	#6.c 4.16 kV 1E Bus Undervoltage (Degraded Voltage)	3860 volts	≥3875 volts	
Table 3.3-4	#7.b Steam Generator Level Low	5% (NR)	≥27.4% (NR)	
Table 3.3-4	#7.c & 7.d Steam Generator Delta Pressure High	230 psid	≤123 psid	
Table 3.3-4	#7.g Control Valve Logic (WR SG Level Low)	21.3% level	≥36.3% level	

TABLE B 3/4.0-1
ANALYTICAL/INDICATED VALUES

TS	Parameter	Analytical Value	Indicated / Plant Value	Comments
3.4.5.2	Primary – Secondary Leakage	0.75 gpm 540 gpd	≤0.75 gpm ≤540 gpd	All SGs One SG
3.4.8.2	Pressurizer Heatup & Cooldown Rate	200˚F	≤200˚F	
3.5.1	SIT Borated Water Volume	≥40%/926 ft^3 ≤77.8%/1686 ft^3	≥44% level ≤73.8% level	Analysis utilizes units in ft^3 while indications are in %.
3.5.1	SIT Boron Concentration	≥2029 ppm ≤2929 ppm	≥2050 ppm ≤2900 ppm	
3.5.1	SIT Pressure	≥570 psig ≤700 psig	≥600 psig ≤670 psig	
3.5.4	RWSP Volume	383,000 gal	≥83% level	Analysis utilizes units in gallons while indications are in %.
3.5.4	RWSP Boron Concentration	≥2029 ppm ≤2929 ppm	≥2050 ppm ≤2900 ppm	
3.5.4	RWSP Solution Temperature	≥50˚F/≥55˚F ≤100˚F	≥55˚F ≤100˚F	ECCS Analysis / Inadvertent Cntmt Spray
4.5.4	RAB Air Temperature	≥50˚F ≤100˚F	≥55˚F ≤100˚F	
3.6.1.4	Containment Pressure	≥14.275 psia ≤27" w.g.	≥14.275 psia ≤27" w.g.	
3.6.1.5	Containment Average Air Temperature	≥90˚F ≤120˚F	≥90˚F ≤120˚F	
Table 3.7-2	Maximum Allowable Power with MSSVs Inoperable	87.3% 69.9%	≤85.3% ≤66.7%	w/1 MSSV Inop w/2 MSSVs Inop
Table 3.7-2	Linear Power Level – High Trip Setpoint	NA NA	≤93.3% ≤74.7%	Not credited for loss of condenser vacuum event.
3.7.1.3	CSP Volume	170,000 gal.	≥92% level	Analysis utilizes units in gallons while indications are in %.
3.7.1.3	CSP Water Temperature	≥50˚F ≤100˚F	≥55˚F ≤100˚F	
4.7.1.5	MSIV Closure Time	8.0 sec	4.0 sec	Static test
4.7.1.6	MFIV Closure Time	6.0 sec	6.6 sec	Test with only one of two accumulators
3.7.1.7	ADV Setpoint	1000 psia	≤985 psia	

3/4.1.2 BORATION SYSTEMS

The boron injection system ensures that negative reactivity control is available during each mode of facility operation. The components required to perform this function include (1) borated water sources, (2) charging pumps, (3) separate flow paths, (4) boric acid makeup pumps, (5) associated heat tracing systems, and (6) an emergency power supply from OPERABLE diesel generators.

and

With the RCS average temperature above 200°F, a minimum of two separate and redundant boron injection systems are provided to ensure single functional capability in the event an assumed failure renders one of the systems inoperable. Allowable out-of-service periods ensure that minor component repair or corrective action may be completed without undue risk to overall facility safety from injection system failures during the repair period.

The boration capability of either system is sufficient to provide a SHUTDOWN MARGIN from expected operating conditions of 2.0% delta k/k after xenon decay and cooldown to 200°F. The maximum expected boration capability requirement occurs at EOL from full power equilibrium xenon conditions assuming the most reactive CEA stuck out of the core and requires boric acid solution from the boric acid makeup tanks in the allowable concentrations and volumes of Specification 3.1.2.8 plus approximately 19,000 gallons of 2050 ppm borated water from the refueling water storage pool or approximately 58,000 gallons of 2050 ppm borated water from the refueling water storage pool alone. The higher limit of 447,100 gallons is specified to be consistent with Specification 3.5.4 in order to meet the ECCS requirements.

5.15

10,064

with xenon-free conditions, RCS temperature greater than 200°F, and let down secured.

83% indicated

→(DRN 03-375, Ch.19)

With the RCS temperature below 200°F one injection system is acceptable without single failure consideration on the basis of the stable reactivity condition of the reactor and the additional restrictions prohibiting CORE ALTERATIONS and positive reactivity changes in the event the single injection system becomes inoperable. Temperature changes in the RCS impose reactivity changes by means of the moderator temperature coefficient. Plant temperature changes are allowed provided the temperature change is accounted for in the calculated SDM. This will require a new SDM calculation be performed if the current SDM calculation does not bound the temperature change. Small changes in RCS temperature are unavoidable and so long as the required SDM is maintained during these changes, any positive reactivity additions will be limited to acceptable levels. Introduction of temperature changes must be evaluated to ensure they do not result in a loss of required SDM.

←(DRN 03-375, Ch. 19)

The boron capability required below 200°F is based upon providing a 2% delta k/k SHUTDOWN MARGIN after xenon decay and cooldown from 200°F to 140°F. This condition requires either 5,465 gallons of 2050 ppm borated water from the refueling water storage pool or boric acid solution from the boric acid makeup tanks in accordance with the requirements of Specification 3.1.2.7.

1,727

BORATION SYSTEMS (Continued)

The contained water volume limits include allowance for water not available because of discharge line location, instrument tolerances, and other physical characteristics. Bases 3/4.1.2 Insert Here

The OPERABILITY of one boron injection system during REFUELING ensures that this system is available for reactivity control while in MODE 6.

The lower limit on the contained water volume, the specified boron concentration, and the physical size (approximately 600,000 gallons) of the RWSP also ensure a pH value of between 7.0 and 11.0 for the solution recirculated within containment after a LOCA. This pH band minimizes the evolution of iodine and minimizes the effect of chloride and caustic stress corrosion on mechanical systems and components.

The maximum limit on the RWSP temperature ensures that the assumptions used in the containment pressure analysis under design base accident conditions remain valid and avoids the possibility of containment overpressure. The minimum limit on the RWSP temperature is required to prevent freezing and/or boron precipitation in the RWSP.

3/4.1.2.9 BORON DILUTION

This specification is provided to prevent a boron dilution event, and to prevent a loss of SHUTDOWN MARGIN should an inadvertent boron dilution event occur. Due to boron concentration requirements for the RWSP and boric acid makeup tanks, the only possible boron dilution that would remain undetected by the operator occurs from the primary makeup water through the CVCS system. Isolating this potential dilution path or the OPERABILITY of the startup channel high neutron flux alarms, which alert the operator with sufficient time available to take corrective action, ensures that no loss of SHUTDOWN MARGIN and unanticipated criticality occur.

The ACTION requirements specified in the event startup channel high neutron flux alarms are inoperable provide an alternate means to detect boron dilution by monitoring the RCS boron concentration to detect any changes. The frequencies specified in the COLR provide the operator sufficient time to recognize a decrease in boron concentration and take appropriate corrective action without loss of SHUTDOWN MARGIN. More frequent checks are required with more charging pumps in operation due to the higher potential boron dilution rate.

The surveillance requirements specified provide assurance that the startup channel high neutron flux alarms remain OPERABLE and that required valve and electrical lineups remain in effect.

3/4.1.3 MOVABLE CONTROL ASSEMBLIES

The specifications of this section ensure that (1) acceptable power distribution limits are maintained, (2) the minimum SHUTDOWN MARGIN is

Bases 3/4.1.2 Insert

The volume of water not available when using one Boric Acid Makeup Tank is less than the volume of water not available when using two Boric Acid Makeup Tanks. Consequently, Figures 3.1-1 and 3.1-2 are provided for using one or two Boric Acid Makeup Tanks to satisfy the requirements of TS 3.1.2.8, respectively.

DNBR MARGIN (Continued)

A DNBR penalty factor has been included in the COLSS and CPC DNBR calculations to accommodate the effects of rod bow. The amount of rod bow in each assembly is dependent upon the average burnup experienced by that assembly. Fuel assemblies that incur higher average burnup will experience a greater magnitude of rod bow. Conversely, lower burnup assemblies will experience less rod bow. In design calculations, the penalty for each batch required to compensate for rod bow is determined from a batch's maximum average assembly burnup applied to the batch's maximum integrated planar-radial power peak. A single net penalty for COLSS and CPC is then determined from the penalties associated with each batch, accounting for the offsetting margins due to the lower radial power peaks in the higher burnup batches.

3/4.2.5 RCS FLOW RATE

This specification is provided to ensure that the actual RCS total flow rate is maintained at or above the minimum value used in the LOCA safety analyses, and that the DNBR is maintained within the safety limit for Anticipated Operational Occurrences (AOO).

3/4.2.6 REACTOR COOLANT COLD LEG TEMPERATURE

This specification is provided to ensure that the actual value of reactor coolant cold leg temperature is maintained within the range of values used in the safety analyses, with adjustment for instrument accuracy of ±2°F, and that the peak linear heat generation rate and the moderator temperature coefficient effects are validated.

±3°F

Bases 3/4.2.6 Insert

3/4.2.7 AXIAL SHAPE INDEX

→ **(DRN 02-458)**

This specification is provided to ensure that the actual value of AXIAL SHAPE INDEX is maintained within the range of values used in the safety analyses, to ensure that the peak fuel centerline temperature and DNBR remain within the safety limits for Anticipated Operational Occurrences (AOO).

← **(DRN 02-458)**

3/4.2.8 PRESSURIZER PRESSURE

uncertainty

35

This specification is provided to ensure that the actual value of pressurizer pressure is maintained within the range of values used in the safety analyses. The inputs to CPCs and COLSS are the most limiting. The values are adjusted for an instrument accuracy of ±25 psi. The sensitive events are SGTR, LOCA, FWLB and loss of condenser vacuum to initial high pressure, and MSLB to initial low pressure.

Bases 3/4.2.8 Insert

Bases 3/4.2.6 Insert

The safety analysis assumes that cold leg temperature is maintained between 553°F and 552°F or indicated temperatures of 556°F and 549°F.

Bases 3/4.2.8 Insert

The safety analysis assumes that pressurizer pressure is maintained between 2090 psia and 2310 psia or indicated pressurizer pressures of 2125 psia and 2275 psia.

STEAM GENERATORS (Continued)

based on a modification of Regulatory Guide 1.83, Revision 1. Inservice inspection of steam generator tubing is essential in order to maintain surveillance of the conditions of the tubes in the event that there is evidence of mechanical damage or progressive degradation due to design, manufacturing errors, or inservice conditions that lead to corrosion. Inservice inspection of steam generator tubing also provides a means of characterizing the nature and cause of any tube degradation so that corrective measures can be taken.

The plant is expected to be operated in a manner such that the secondary coolant will be maintained within those chemistry limits found to result in negligible corrosion of the steam generator tubes. If the secondary coolant chemistry is not maintained within these limits, localized corrosion may likely result in stress corrosion cracking. The extent of cracking during plant operation would be limited by the limitation of steam generator tube leakage between the primary coolant system and the secondary coolant system (primary-to-secondary leakage = 0.5 gpm per steam generator). Cracks having a primary-to-secondary leakage less than this limit during operation will have an adequate margin of safety to withstand the loads imposed during normal operation and by postulated accidents. Operating plants have demonstrated that primary-to-secondary leakage of 0.5 gpm per steam generator can readily be detected by radiation monitors of steam generator blowdown. Leakage in excess of this limit will require plant shutdown and an unscheduled inspection, during which the leakage tubes will be located and plugged or repaired. 0.375

Wastage-type defects are unlikely with proper chemistry treatment of the secondary coolant. However, even if a defect should develop in service, it will be found during scheduled inservice steam generator tube examinations. Plugging or sleeving will be required for all tubes with imperfections exceeding the plugging or repair limit as defined in Surveillance Requirement 4.4.4.4. Defective tubes may be repaired by sleeving in accordance with CENS Report CEN-605-P, "Waterford 3 Steam Generator Tube Repair Using Leak Tight Sleeves," Revision 00-P, dated December 1992. Steam generator tube inspections of operating plants have demonstrated the capability to reliably detect degradation that has penetrated 20% of the original tube wall thickness. Sleeved tubes will be included in the periodic tube inspections for the inservice inspection program.

Whenever the results of any steam generator tubing inservice inspection fall into Category C-3, these results will be promptly reported to the Commission pursuant to Specification 6.9.1 prior the resumption of plant operation. Such cases will be considered by the Commission on a case-by-case basis and may result in a requirement for analysis, laboratory examinations, tests, additional eddy-current inspection, and revision of the Technical Specifications, if necessary.

3/4.4.5 REACTOR COOLANT SYSTEM LEAKAGE

3/4.4.5.1 LEAKAGE DETECTION SYSTEMS

The RCS leakage detection systems required by this specification are provided to monitor and detect leakage from the Reactor Coolant Pressure Boundary. These detection systems are consistent with the recommendations of Regulatory Guide 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems," May 1973.

If one of the required systems becomes inoperable, 30 days are permitted for restoration since two diverse and redundant RCS leakage detection systems remain OPERABLE. If, however, the inoperable system is the containment gaseous or particulate monitoring system, grab samples are also performed as a backup to the single remaining atmospheric monitoring system.

3/4.4.5.2 OPERATIONAL LEAKAGE

Industry experience has shown that while a limited amount of leakage is expected from the RCS, the unidentified portion of this leakage can be reduced to a threshold value of less than 1 gpm. This threshold value is sufficiently low to ensure early detection of additional leakage.

The 10 gpm IDENTIFIED LEAKAGE limitation provides allowances for a limited amount of leakage from known sources whose presence will not interfere with the detection of UNIDENTIFIED LEAKAGE by the leakage detection systems.

The Surveillance Requirements for RCS pressure isolation valves provide added assurance of valve integrity thereby reducing the probability of gross valve failure and consequent intersystem LOCA. Leakage from the RCS pressure isolation valves is IDENTIFIED LEAKAGE and will be considered as a portion of the allowable limit.

The total steam generator tube leakage limit of 1 gpm for all steam generators ensures that the dosage contribution from the tube leakage will be limited to a small fraction of Part 100 limits in the event of either a steam generator tube rupture or steam line break. The 1 gpm limit is consistent with the assumptions used in the analysis of these accidents. The 0.5 gpm leakage limit per steam generator (720 gal/day) ensures that steam generator tube integrity is maintained in the event of a main steam line rupture or under LOCA conditions.

PRESSURE BOUNDARY LEAKAGE of any magnitude is unacceptable since it may be indicative of an impending gross failure of the pressure boundary. Therefore, the presence of any PRESSURE BOUNDARY LEAKAGE requires the unit to be promptly placed in COLD SHUTDOWN.

3/4.4.6 CHEMISTRY

The limitations on Reactor Coolant System chemistry ensure that corrosion of the Reactor Coolant System is minimized and reduces the potential for Reactor Coolant System leakage or failure due to stress corrosion. Maintaining

PRESSURE/TEMPERATURE LIMITS (Continued)

The maximum RT_{NDT} for all Reactor Coolant System pressure-retaining materials, with the exception of the reactor pressure vessel, has been determined to be 90°F. The Lowest Service Temperature limit line shown on Figures 3.4-2 and 3.4-3 is based upon this RT_{NDT} since Article NB-2332 of Section III of the ASME Boiler and Pressure Vessel Code requires the Lowest Service Temperature to be RT_{NDT} + 100°F for piping, pumps, and valves. Below this temperature, the system pressure must be limited to a maximum of 20% of the system's hydrostatic test pressure of 3125 psia (as corrected for elevation and instrument error).

The limitations imposed on the pressurizer heatup and cooldown rates and spray water temperature differential are provided to assure that the pressurizer is operated within the design criteria assumed for the fatigue analysis performed in accordance with the ASME Code requirements.

The OPERABILITY of the shutdown cooling system relief valve or an RCS vent opening of greater than 5.6 square inches ensures that the RCS will be protected from pressure transients which could exceed the limits of Appendix G to 10 CFR Part 50 when one or more of the RCS cold legs are less than or equal to 272°F. Each shutdown cooling system relief valve has adequate relieving capability to protect the RCS from overpressurization when the transient is either (1) the start of an idle RCP with the secondary water temperature of the steam generator less than or equal to 100°F above the RCS cold leg temperatures or (2) inadvertent safety injection actuation with injection into a water-solid RCS. The limiting transient includes simultaneous, inadvertent operation of three HPSI pumps, three charging pumps, and all pressurizer backup heaters in operation. Since SIAS starts only two HPSI pumps, a 20% margin is realized.

The restrictions on starting a reactor coolant pump in MODE 4 and with the reactor coolant loops filled in MODE 5, with one or more RCS cold legs less than or equal to 272°F, are provided in Specification 3.4.1.3 and 3.4.1.4 to prevent RCS pressure transients caused by energy additions from the secondary system which could exceed the limits of Appendix G to 10 CFR Part 50. The RCS will be protected against overpressure transients and will not exceed the limits of Appendix G by restricting starting of the RCPs to when the secondary water temperature of each steam generator is less than 100°F above each of the RCS cold leg temperatures. Maintaining the steam generator less than 100°F above each of the Reactor Coolant System cold leg temperatures (even with the RCS filled solid) or maintaining a large surge volume in the pressurizer ensures that this transient is less severe than the limiting transient considered above.

BASES

except for a SBLOCA above 70% RATED THERMAL POWER.

3/4.5.2 and 3/4.5.3 ECCS SUBSYSTEMS

The OPERABILITY of two separate and independent ECCS subsystems ensures that sufficient emergency core cooling capability will be available in the event of a LOCA assuming the loss of one subsystem through any single failure consideration. Either subsystem operating in conjunction with the safety injection tanks is capable of supplying sufficient core cooling to limit the peak cladding temperatures within acceptable limits for all postulated break sizes ranging from the double-ended break of the largest RCS cold leg pipe downward. In addition, each ECCS subsystem provides long-term core cooling capability in the recirculation mode during the accident recovery period.

Bases 3.5.2 Insert Here

Each subsystem includes the piping, instruments, and controls to ensure the availability of an OPERABLE flowpath capable of taking suction from the RWSP on a SIAS and automatically transferring suction to the containment sump upon a recirculation actuation signal (RAS). The flowpath for each subsystem must maintain its designed independence to ensure that no single failure can disable both ECCS subsystems.

An ECCS subsystem is inoperable if it is not capable of delivering the design flow to the RCS. The individual components are inoperable if they are not capable of performing their automatic design function, or if supporting systems are not available.

The LCO requires the OPERABILITY of a number of independent trains. Due to the redundancy of trains and the diversity of trains, the inoperability of one component in a train does not render the ECCS incapable of performing its function. Neither does the inoperability of two different components, each in a different train, necessarily result in a loss of function for the ECCS. The intent of these ACTIONs is to maintain a combination of OPERABLE equipment such that 100% of the ECCS flow equivalent to a single OPERABLE subsystem remains available.

100% of the ECCS flow equivalent to a single OPERABLE ECCS subsystem exists when the equivalent of one HPSI train, one LPSI train, and a suction flow path as described in the LCO are OPERABLE. The OPERABLE components may be in opposite subsystems. The HPSI component of the 100% ECCS flow equivalent may be composed of any combination of OPERABLE HPSI components such that flow is available to all four RCS loops. The LPSI component of the 100% ECCS flow equivalent may be composed of any combination of OPERABLE LPSI components such that flow is available to any two RCS loops. This allows increased flexibility in plant operations when components in opposite subsystems are inoperable.

Bases 3.5.2 Insert

For the SBLOCA above 70% RATED THERMAL POWER, the Atmospheric Dump Valves (ADVs) along with the high-pressure safety injection trains are credited to ensure sufficient emergency core cooling capability assuming any single failure consideration. At greater than 70% RATED THERMAL POWER, two high-pressure safety injection trains or one high-pressure safety injection train and one ADV, in automatic, are required to mitigate the SBLOCA event.

The minimum contained borated

3/4.5.4 REFUELING WATER STORAGE POOL (RWSP)

The OPERABILITY of the refueling water storage pool (RWSP) as part of the ECCS also ensures that a sufficient supply of borated water is available for injection by the ECCS in the event of a LOCA. The limits on RWSP minimum volume and boron concentration ensure that (1) sufficient water is available within containment to permit recirculation cooling flow to the core, and (2) the reactor will remain subcritical in the cold condition following mixing of the RWSP and the RCS water volumes with all CEAs inserted except for the most reactive control assembly. These assumptions are consistent with the LOCA analyses.

The contained water volume limit, 83% indicated, includes an allowance for water not usable because of pool discharge line location or other physical characteristics.

The lower limit on contained water volume, the specific boron concentration and the physical size (approximately 600,000 gallons) of the RWSP also ensure a pH value of between 7.0 and 11.0 for the solution recirculated within containment after a LOCA. This pH band minimizes the evolution of iodine and minimizes the effect of chloride and caustic stress corrosion on mechanical systems and components.

The maximum limit on the RWSP temperature ensures that the assumptions used in the containment pressure analysis under design base accident conditions remain valid and avoids the possibility of containment overpressure. The minimum limit on the RWSP temperature is required to prevent freezing and/or boron precipitation in the RWSP.

, and instrument uncertainty. The safety analysis assumes an available volume of 383,000 gallons which is bounded by the 83% level indicated.

3/4.6.1.4 INTERNAL PRESSURE

The limitations on containment internal pressure ensure that (1) the containment structure is prevented from exceeding its design negative pressure differential with respect to the annulus atmosphere of 0.65 psid, (2) the containment peak pressure does not exceed the design pressure of 44 psig during either LOCA or steam line break conditions, and (3) the minimum pressure of the ECCS performance analysis (BTP CSB 61) is satisfied.

The limit of +27 inches water (approximately 1.0 psig) for initial positive containment pressure is consistent with the limiting containment pressure and temperature response analyses inputs and assumptions.

The limit of 14.275 psia for initial negative containment pressure ensures that the minimum containment pressure is consistent with the ECCS performance analysis ensuring core reflood under LOCA conditions, thus ensuring peak cladding temperature and cladding oxidation remain within limits. The 14.275 psia limit also ensures the containment pressure will not exceed the containment design negative pressure differential with respect to the annulus atmosphere in the event of an inadvertent actuation of the containment spray system.

3/4.6.1.5 AIR TEMPERATURE

Bases 3/4.6.1.5 Insert Here

The limit of 120°F on high average containment temperature is consistent with the limiting containment pressure and temperature response analyses inputs and assumptions. The limits currently adopted by Waterford 3 are 269.3°F during LOCA conditions and 413.5°F during MSLB conditions.

90°F minimum and indicated are

→ (DRN 02-1904)

The 120°F maximum value specified in the TS is the value used in the accident analysis and does not contain any allowance for temperature measurement instrument uncertainty. Instrument uncertainty is addressed in the surveillance procedure.

← (DRN 02-1904)

3/4.6.1.6 CONTAINMENT VESSEL STRUCTURAL INTEGRITY

This limitation ensures that the structural integrity of the containment steel vessel will be maintained comparable to the original design standards for the life of the facility. Structural integrity is required to ensure that the containment vessel will withstand the maximum pressure resulting from the design basis LOCA and main steam line break accident. A visual inspection in conjunction with Type A leakage test is sufficient to demonstrate this capability.

3/4.6.1.7 CONTAINMENT VENTILATION SYSTEM

The use of the containment purge valves is restricted to 90 hours per year in accordance with Standard Review Plan 6.2.4 for plants with the Safety Evaluation Report for the Construction License issued prior to July 1, 1975. The purge valves have been modified to limit the opening to approximately 52° to ensure the valves will close during a LOCA or MSLB;and therefore, the SITE BOUNDARY doses are maintained within the guidelines of 10 CFR Part 100. The purge valves, as modified, comply with all provisions of BTP CSB 6-4 except for the recommended size of the purge line for systems to be used during plant operation.

Bases 3/4.6.1.5 Insert

The limitation on containment minimum average air temperature ensures that the ECCS is capable of maintaining a peak clad temperature (PCT) less than or equal to 2200°F under LOCA conditions. A lower containment average air temperature results in a lower post accident containment pressure, a lower reflood rate, and therefore a higher PCT. The containment minimum average air temperature limit is only applicable above 70% rated thermal power. At power levels of 70% or below and a containment minimum average air temperature of less than 90°F, ECCS is capable of maintaining the peak clad temperature (PCT) less than or equal to 2200°F under LOCA conditions

3/4.7.1 TURBINE CYCLE

3/4.7.1.1 SAFETY VALVES

The OPERABILITY of the main steam line code safety valves ensures that the secondary system pressure will be limited to within 110% (1210 psia) of its design pressure of 1100 psia during the most severe anticipated system operational transient. The maximum relieving capacity is associated with a turbine trip from 100% RATED THERMAL POWER coincident with an assumed loss of condenser heat sink (i.e., no steam bypass to the condenser).

1085 psig

Bases 3/4.7.1.1 Insert #1

The specified valve lift settings and relieving capacities are in accordance with the requirements of Section III of the ASME Boiler and Pressure Vessel Code, 1974 Edition. The MSSVs rated capacity passes the full steam flow at 102% RATED THERMAL POWER (100% + 2% for instrument error) with valves open. A minimum of 2 OPERABLE safety valves per steam generator ensures that sufficient relieving capacity is available for removing decay heat. All the MSSVs have an orifice size of 28.27 in².

~~STARTUP and/or POWER OPERATION is allowable with safety valves inoperable within the limitations of the ACTION requirements on the basis of the reduction in secondary system steam flow and THERMAL POWER required by the reduced reactor trip settings of the Power Level-High channels. The reactor trip setpoint reductions are derived on the following bases: An analysis of a loss of condenser vacuum event initiated at the reduced power levels listed in Table 3.7-2 that shows peak steam generator pressures are maintained below 1210 psia.~~

THERMAL POWER

Bases 3/4.7.1.1 Insert #2

Bases 3/4.7.1.1 Insert #1

An alternative to restoring the inoperable MSSV(s) to OPERABLE status is to reduce THERMAL POWER so that the available MSSV relieving capacity meets Code requirements for the power level. Operation may continue provided the allowable THERMAL POWER is less than or equal to the maximum allowable power as listed in Table 3.7-2 and the Linear Power Level – High trip setpoint is less than or equal to that listed in Table 3.7-2.

The 4 hour completion time is a reasonable time period to reduce power level and is based on the low probability of an event occurring during this period that would require activation of the MSSVs. An additional 8 hours is allowed to reduce the setpoints. This completion time is based on the time required to perform the power reduction, operating experience in resetting all channels of a protective function, and on the low probability of the occurrence of a transient that could result in steam generator overpressure during this period.

Bases 3/4.7.1.1 Insert #2

110% of system design pressure. The maximum allowable power limitations listed in Table 3.7-2 are reduced from the analytical values used in the analysis by at least 2% to account for power measurement uncertainties.

The reactor trip setpoint reductions are determined by adding 8% to the maximum THERMAL POWER limit derived from the analysis of condenser vacuum event. The 8% margin is consistent with margin between the normal Linear Power Level – High trip setpoint and 100% RATED THERMAL POWER. The 8% difference provides sufficient margin to avoid an inadvertent trip. The Linear Power Level – High trip is not credited in the analysis of the loss of condenser vacuum event but is reduced to reinforce the requirement to remain at the reduced power levels for extended periods of time.

3/4.7.1.2 EMERGENCY FEEDWATER SYSTEM (Continued)

Surveillance Requirements (Continued)

This SR is modified to indicate that the SR should be deferred until suitable test conditions have been established. This deferral is required because there is an insufficient steam pressure to perform post maintenance activities which may need to be completed prior to performing the required turbine-driven pump SR. This deferral allows the unit to transition from MODE 4 to MODE 3 prior to the performance of the SR and provides a 24 hour period once a steam generator pressure of 750 psig is reached to complete the required post maintenance activities and SR. If this SR is not completed within the 24 hour period or fails, then the appropriate ACTION must be entered. The twenty-five percent grace period allowed by TS 4.0.2 can not be applied to the 24 hour period.

d. The SR for flow testing ensures that the EFW system is aligned properly by verifying the flow paths from the condensate storage pool (CSP) to each steam generator before entering MODE 2 operation after being in MODE 4, 5, 6, or defueled, for 30 days or longer, or whenever feedwater line cleaning through the emergency feedwater line has been performed. Various combinations of pumps and valves may be used such that all flow paths (and flow legs) are tested at least once during the Surveillance.

OPERABILITY of EFW flow paths must be verified before sufficient core heat is generated that would require the operation of the EFW System during a subsequent shutdown. The frequency is reasonable, based on engineering judgment, and other administrative controls to ensure that flow paths remain OPERABLE. To further ensure EFW system alignment, the OPERABILITY of the flow paths is verified following extended outages to determine that no misalignment of valves has occurred. This SR ensures that the flow paths from the CSP to the steam generators are properly aligned.

3/4.7.1.3 CONDENSATE STORAGE POOL

The OPERABILITY of the condensate storage pool (CSP) with the minimum water volume of 173,500 gallons (170,000 gallons for EFW system usage and 3,500 gallons for CCW makeup system usage), plus makeup from one Wet Cooling Tower (WCT) basin, ensures that sufficient water is available to cool the Reactor Coolant System to shutdown cooling entry conditions following any design basis accident. This makeup water includes the capability to maintain HOT STANDBY for at least an additional 2 hours prior to initiating shutdown cooling.

The combined capacity (CSP and one WCT) provides sufficient cooling for ~~24~~ 32 hours until shutdown cooling is initiated in the event the ultimate heat sink sustains tornado damage concurrent with the tornado event.

3/4.7.1.3 CONDENSATE STORAGE POOL (Continued)

If natural circulation is required, the combined capacity (CSP and one WCT) is sufficient to maintain the plant at HOT STANDBY for 4 hours, followed by a cooldown to shutdown cooling entry conditions assuming the availability of only onsite or only offsite power, and the worst single failure (loss of a diesel generator or atmospheric dump valve). This requires approximately 303,000 gallons of EFW and complies with BTP RSB 5-1.

209,000

The CSP contained water volume limit (91% indicated in MODES 1, 2, and 3) includes an allowance for water not usable because of vortexing and instrumentation uncertainties. This provides an assurance that a minimum of 170,000 gallons is available for the EFW system and that 3,500 gallons is available for the CCW makeup system. The CSP contained water volume limit (11% indicated in MODE 4) also includes an allowance for water not usable because of vortexing and instrumentation uncertainties. This provides an assurance that minimum of 3,500 gallons is available in the CSP for the CCW makeup system.

92

The maximum limit on CSP temperature ensures that the assumptions used in design bases accidents with EFW flow remain valid. The minimum limit on CSP temperature ensures that the assumptions used in the MSLB return to power event remain valid.

3/4.7.1.4 ACTIVITY

0.75

The limitations on secondary system specific activity ensure that the resultant offsite radiation dose will be limited to a small fraction of 10 CFR Part 100 limits in the event of a steam line rupture. This dose also includes the effects of a coincident 1 gpm primary to secondary tube leak in the steam generator of the affected steam line and a concurrent loss-of-offsite electrical power. These values are consistent with the assumptions used in the safety analyses.

3/4.7.1.5 MAIN STEAM LINE ISOLATION VALVE

A

The OPERABILITY of the main steam line isolation valves ensures that no more than one steam generator will blow down in the event of a steam line rupture. This restriction is required to (1) minimize the positive reactivity effects of the Reactor Coolant System cooldown associated with the blowdown, and (2) limit the pressure rise within containment in the event the steam line rupture occurs within containment. The OPERABILITY of the main steam isolation valves within the closure times of the Surveillance Requirements are consistent with the assumptions used in the safety analyses. The Surveillance Requirement to verify isolation in less than or equal to 4 seconds is based on static testing. The static test using 4 seconds demonstrates the ability of the MSIVs to close in less than or equal to the 7 second required closure time under design basis accident conditions. The 8 second required closure time includes a 1 second allowance for instrument response time.

8

3/4.7.1.6 MAIN FEEDWATER ISOLATION VALVES

The Main Feedwater Isolation Valves (MFIVs) isolate main feedwater (MFW) flow to the secondary side of the steam generators following a high energy line break (HELB). Closure of the MFIVs terminates flow to both steam generators, mitigating the consequences for feedwater line breaks (FWLBs). Closure of the MFIVs effectively terminates the addition of main feedwater to an affected steam generator, limiting the mass and energy release for Main Steam Line Breaks (MSLBs) or FWLBs inside containment, and reducing the cooldown effects for MSLBs.

The MFIVs isolate the non-safety related feedwater supply from the safety related portion of the system. In the event of a secondary side pipe rupture inside containment, the valves limit the quantity of high energy fluid that enters containment through the break, and provide a pressure boundary for the controlled addition of Emergency Feedwater (EFW) to the intact steam generator.

One MFIV is located on each MFW line, outside, but close to, containment. The MFIVs are located upstream of the EFW injection point so that EFW may be supplied to a steam generator following MFIV closure. The piping volume from the valve to the steam generator must be accounted for in calculating mass and energy releases, and refilled prior to EFW reaching the steam generator following either a MSLB or FWLB.

A static test, utilizing the accumulated pressure in one of the two accumulators, using 6.6 seconds

3/4.7.1.6 MAIN FEEDWATER ISOLATION VALVES (con't)

The TS is annotated with a 3.0.4 exemption, allowing entry into the applicable MODES to be made with an inoperable MFIV closed or isolated as required by the ACTIONS. The ACTIONS allow separate condition entry for each valve by using "With one or more MFIV...". This prevents immediate entry into TS 3.0.3 if both MFIVs are declared inoperable.

Start new ¶

The Surveillance Requirement to verify isolation in less than or equal to 5 seconds is based on the time assumed in the accident and containment analyses. The static test demonstrates the ability of the MFIVs to close in less than or equal to 5 seconds under design basis accident conditions. The MFIVs should not be tested at power since even a partial stroke exercise increases the risk of a valve closure with the plant generating power and would create added cyclic stresses. The Surveillance to verify each MFIV can close on an actual or simulated actuation signal is normally performed when the plant is returning to operation following a refueling outage. Verification of valve closure on an actuation signal is not required until entry into Mode 3 consistent with TS 3.3.2. The 18 month frequency is based on the refueling cycle. Verification of closure time is performed per TS 4.0.5. This frequency is acceptable from a reliability standpoint and is in accordance with the Inservice Testing Program.

The 6 second required closure time includes a 1 second allowance for instrument response time.

→(DRN 02-1684)

Credited Non-Safety Related Support Systems for MFIV Operability

Reactor Trip Override (RTO) and the Auxiliary Feedwater (AFW) Pump High Discharge Pressure Trip (HDPT) are credited for rapid closure of the Main Feedwater Isolation Valves (MFIVs) during main steam and feedwater line breaks. Crediting of these non-safety features was submitted to the NRC as a USQ and approved. (Reference letter dated September 5, 2000 from the NRC to Charles M. Dugger, "Waterford 3 Steam Electric Station, Unit 3 - Issuance of Amendment RE: Addition of Main Feedwater Isolation Valves to Technical Specifications and Request for NRC Staff Review of an Unreviewed Safety Question.")

The feature of RTO that is credited for MFIV closure is the rapid SGFP speed reduction upon reactor trip initiation. This feature reduces the differential pressure across the valve disc at closure, thus allowing rapid valve closure. Therefore, the RTO feature must be able to decrease SGFP speed to minimum on a reactor trip during SGFP operation for OPERABILITY of the MFIVs.

The AFW Pump HDPT reduces the differential pressure across the valve disc at closure during AFW Pump operation. Therefore, this feature must be functional during AFW Pump operation for OPERABILITY of the MFIVs. When the AFW pump is not running, this trip is not required.

In MODES 1, 2, 3, and 4, the MFIVs are required to be OPERABLE. Because the MFIVs are required to be OPERABLE in MODES 1, 2, 3, and 4, RTO must be able to decrease SGFP

←(DRN 02-1684)

New TS Bases

3/4.7.1.7 ATMOSPHERIC DUMP VALVES (ADVs)

Two ADVs are provided, one per steam generator. The ADVs are provided with upstream block valves to permit their being tested at power, and to provide an alternate means of isolation. The ADVs are equipped with pneumatic controllers to permit control of the cooldown rate. The ADVs are provided with a pressurized nitrogen gas supply that, on a loss of pressure in the normal instrument air supply, automatically supplies nitrogen to operate the ADVs. The ADVs can also be operated manually once the nitrogen gas supply is depleted.

The ADVs provide a safety grade method for cooling the unit to Shutdown Cooling (SDC) System entry conditions, should the preferred heat sink via the Steam Bypass System to the condenser not be available, as discussed in the FSAR, Section 10.3. This is done in conjunction with the Emergency Feedwater System providing cooling water from the condensate storage pool (CSP) to meet Branch Technical Position (BTP) RSB 5-1.

The automatic operation of the ADVs to open is assumed in the Small Break LOCA (SBLOCA) analysis at power levels above 70% RATED THERMAL POWER. ADV's are credited for SBLOCA analysis to lower steam generator secondary side pressures, compared to crediting only MSSVs, and thus provide increased cooling of the RCS. This results in a lower calculated peak cladding temperature (PCT) for SBLOCA ECCS analysis.

Analysis has shown that automatic operation of the ADV is not required when the unit is at or below 70% RATED THERMAL POWER for greater than six hours because, based on decay heat load, one high-pressure safety injection train is capable of mitigating the SBLOCA event. At greater than 70% RATED THERMAL POWER, two high-pressure safety injection trains or one high-pressure safety injection train and one ADV, in automatic, are required to mitigate the SBLOCA event. Therefore, the ADVs, in automatic, are required at greater than 70% RATED THERMAL POWER and for six hours after reducing power to less than or equal to 70% RATED THERMAL POWER to address a single failure of a high-pressure safety injection train.

Limiting Condition for Operation

The LCO requires that each ADV be OPERABLE.

The ADV manual controls must be OPERABLE in MODES 1, 2, 3, and 4 to allow operator action needed for decay heat removal and safe shutdown in accordance with BTP RSB 5-1.

The LCO is modified by a footnote requiring that ADV automatic actuation controls be OPERABLE (i.e., ADVs in automatic and capable of automatic actuation at less than or equal to 1000 psia (985 psia indicated)) when operating at greater than 70% RATED THERMAL POWER and for six hours after reducing power to less than or equal to 70% RATED THERMAL POWER for mitigation of the SBLOCA.

3/4.7.1.7 ATMOSPHERIC DUMP VALVES (Continued)

The ADVs are containment isolation valves and must be capable of manual isolation of the ADV lines in MODE 1, 2, 3, and 4 in order to be considered OPERABLE. Because the OPERABILITY of the ADVs is controlled by this Technical Specification, Technical Specification 3.6.3, "Containment Isolation Valves," does not apply to the ADVs.

ACTIONs

The ACTIONs are modified by a note indicating that the provisions of Specification 3.0.4 are not applicable provided one ADV is OPERABLE. This allows for MODE changes with one ADV inoperable provided the appropriate ACTION is entered upon entry into the applicability MODEs.

ACTIONs (a) and (b) would be entered only when the automatic actuation channels are required to be OPERABLE per the LCO footnote.

a. This ACTION addresses the condition when one ADV is incapable of automatic actuation. This condition includes:
   - A malfunctioning automatic actuation channel, or
   - When the automatic actuation controls for one ADV have been placed in manual.

   A 72 hour allowed outage time is provided to restore the ADV to an OPERABLE status. The 72 hour allowed outage time takes into account the capability afforded by the remaining OPERABLE ADV and is consistent with the allowed outage time of an inoperable high-pressure safety injection train.

   If the ADV can not be restored to an OPERABLE status within the allowed outage time, the unit must be placed in a status in which the LCO does not apply. To achieve this status, power must be reduced to less than or equal to 70% RATED THERMAL POWER within the next 6 hours. The LCO will no longer apply once the unit has been at less than or equal to 70% RATED THERMAL POWER for greater than six hours

b. This ACTION addresses the condition when both ADVs are incapable of automatic actuation. This condition includes:
   - Malfunctioning of both ADVs automatic actuation channel,
   - When the automatic actuation controls for both ADVs have been placed in manual, or
   - A combination of the above such that both ADVs are incapable of automatic operation.

   In this condition, the SBLOCA can not be mitigated by one high-pressure safety injection train alone. Therefore, one of the ADVs must be restored to OPERABLE status within 1 hour or power must be reduced to less than or equal to 70% RATED THERMAL POWER within the next six hours. The LCO will no longer apply once the unit has been at less than or equal to 70% RATED THERMAL POWER for greater than six hours.

New TS Bases

3/4.7.1.7 ATMOSPHERIC DUMP VALVES (Continued)

c. This ACTION address the condition when one ADV is inoperable for reasons other than those addressed in ACTIONs (a) and (b) above. This condition includes:
   - The inability to operate the ADV manually, or
   - An inoperable nitrogen accumulator.

   A 72 hour allowed outage time is provided to restore the ADV to an OPERABLE status. The 72 hour allowed outage time takes into account the capability afforded by the remaining OPERABLE ADV, a nonsafety grade backup in the Steam Bypass System and MSSVs, the closed system inside containment, and the backup isolation capability of the block valve.

   If the ADV can not be restored to an OPERABLE status within the allowed outage time, the unit must be placed in a status in which the LCO does not apply. To achieve this status, the unit must be placed in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

The following conditions are not addressed by the ACTION statements:
- The automatic actuation channel for one ADV is inoperable and the other ADV is inoperable for other reasons.
- Both ADVs are inoperable for reasons other than the automatic actuation channels.

For these conditions, Specification 3.0.3 is entered.

Surveillance Requirements

a. To mitigate the SBLOCA event, the ADVs must automatically open at a pressure of less than or equal to 1000 psia (985 psia indicated.) This CHANNEL CHECK provides assurance that the steam line pressure input to the automatic actuation channel behavior is reasonable for the existing plant conditions. This Surveillance Requirement (SR) need not be performed when the ADV automatic actuation channels are not required to be OPERABLE per the LCO footnote

b. To perform a controlled cooldown of the reactor coolant system, the ADVs must be able to be opened and throttled through their full range. Additionally, the ADV must be capable of being closed to fulfill its secondary function of containment isolation. This SR ensures the ADVs are tested through a full control cycle. Performance of inservice testing or use of an ADV during a unit cooldown may satisfy this requirement. The test interval is in accordance with the Inservice Testing Program.

c. The SR to calibrate the ADV automatic actuation channels ensures that the system will generate an actuation signal at 1000 psia (985 psia indicated) as assumed for the SBLOCA.

New TS Bases

3/4.7.1.7 ATMOSPHERIC DUMP VALVES (Continued)

d. The SR for actuation testing ensures that the ADV will automatically open on a high steam pressure signal as assumed for the SBLOCA. Credit may be taken for an actual or simulated actuation signal.

3/4.7.4 ULTIMATE HEAT SINK

The limitations on the ultimate heat sink level, temperature, and number of fans ensure that sufficient cooling capacity is available to either (1) provide normal cooldown of the facility, or (2) to mitigate the effects of accident conditions within acceptable limits.

The UHS consists of two dry cooling towers (DCTs), two wet cooling towers (WCTs), and water stored in WCT basins. Each of two 100 percent capacity loops employs a dry and wet cooling tower.

Each DCT consists of five separate cells. Cooling air for each cell is provided by 3 fans, for a total of 15 per DCT. The cooling coils on three cells of each DCT (i.e. 60%) are protected from tornado missiles by grating located above the coils and capable of withstanding tornado missile impact. With a Tornado Watch in effect and the number of fans OPERABLE within the missile protected area of a DCT less than that required by Table 3.7-3, ACTION c requires the restoration of inoperable fans within 1 hour or plant shutdown as specified. This ACTION is based on FSAR analysis (subsection 9.2.5.3.3) that assumes the worst case single failure as, 1 emergency diesel generator coincident with a loss of offsite power. This failure occurs subsequent to a tornado strike and 60% cooling capacity of a DCT is assumed available.

Bases 3/4.7.4 Insert

Each WCT has a basin which is capable of storing sufficient water to bring the plant to safe shutdown under all design basis accident conditions. Item a of LCO 3/4.7.4 requires a minimum water level in each WCT basin of 97% (-9.86 ft MSL). ~~The bases for this elevation is WCT water evaporation and drift loss calculations, which concluded that during a LOCA 164,389 gallons (218,155 gallons with the non-essential load of spent fuel cooling) would be consumed from one WCT basin. When the WCT basin water level is maintained at -9.86 ft MSL, each basin has a minimum capacity of 174,000 gallons. The WCT basin is also credited as a source of Emergency Feedwater (EFW). However, the above LOCA water usage bounds the amount of EFW required from the WCT basin for all design basis accident conditions.~~ Each WCT consists of two cells, each cell is serviced by 4 induced draft fans, for a total of 8 per WCT. There is a concrete partition between the cells that prevents air recirculation between the fans of each cell. Covers are required on fans declared out-of-service to prevent air recirculation between fans within a cell. The WCT minimum capacity 5.

Table 3.7-3 specifies increased or decreased fan OPERABILITY requirements based on outside air temperature and humidity. The table provides the cooling tower fan OPERABILITY requirements that may vary with outside ambient conditions. Fan OPERABILITY requirements are specified for each controlling parameter (i.e., dry bulb temperatures for DCT fans and wet bulb temperatures for WCT fans). The calculated temperature values (EC-M95-009) associated

Bases 3/4.7.4 Insert

This minimum WCT basin capacity contains enough volume to account for water evaporation and drift losses expected during a LOCA. Additional volume is needed from the second WCT basin to handle the non-essential load of fuel pool cooling during the LOCA. (The WCTs can be manually interconnected through a Seismic Category I line.)

3/4.7.4 ULTIMATE HEAT SINK (Continued)

with DCT and WCT fan requirements have been rounded in the conservative direction and lowered at least one full degree to account for minor inaccuracies. Failure to meet the OPERABILITY requirements of Table 3.7-3 requires entry into the applicable action. Because temperature and humidity are subject to change during the day, ACTION d requires periodic temperature readings to verify compliance with Table 3.7-3 when any cooling tower fan is inoperable.

The limitations on minimum water level and maximum temperature are based on providing a 30-day cooling water supply to ~~safety-related~~ essential equipment without exceeding their design basis temperature and is consistent with the recommendations of Regulatory Guide 1.27, "Ultimate Heat Sink for Nuclear Plants," March 1974.

3/4.8.1, 3/4.8.2, and 3/4.8.3 A.C. SOURCES, D.C SOURCES, AND ONSITE POWER DISTRIBUTION SYSTEMS

The OPERABILITY of the A.C. and D.C. power sources and associated distribution systems during operation ensures that sufficient power will be available to supply the safety-related equipment required for (1) the safe shutdown of the facility and (2) the mitigation and control of accident conditions within the facility. The minimum specified independent and redundant A.C. and D.C. power sources and distribution systems satisfy the requirements of General Design Criterion 17 of Appendix A to 10 CFR Part 50.

Bases 3.8.1 Insert

The Limiting Condition for Operation (LCO) ensures that each diesel generator storage tank contains fuel oil of a sufficient volume to operate each diesel generator for a period of 7 days. The minimum required volume is based on the time-dependent loads of the diesel generator following a loss of offsite power and a design bases accident and includes the capacity to power the engineered safety features in conformance with Regulatory Guide 1.137 October 1979. The minimum onsite stored fuel oil is sufficient to operate the diesel generator for a period longer than the time to replenish the onsite supply from the outside sources discussed in FSAR 9.5.4.2.

An additional provision is included in the LCO which allow the diesel generators to remain operable when their 7 day fuel oil supply is not available. This provision is acceptable on the basis that replacement fuel oil is onsite within the first 48 hours after falling below the 7 day supply.

The ACTION requirements specified for the levels of degradation of the power sources provide restriction upon continued facility operation commensurate with the level of degradation. The OPERABILITY of the power sources are consistent with the initial condition assumptions of the safety analyses and are based upon maintaining at least one redundant set of onsite A.C. and D.C. power sources and associated distribution systems OPERABLE during accident conditions coincident with an assumed loss-of-offsite power and single failure of the other onsite A.C. source. When one diesel generator is inoperable to perform either preplanned maintenance (both preventive and corrective) or unplanned corrective maintenance work, the allowed-outage-time (AOT) can be extended from 72 hours to 10 days, if a temporary emergency diesel generator (TEDG) is verified available and aligned for backup operation to the permanent plant EDG removed from service. The TEDG will be available prior to removing the permanent plant EDG from service for the extended preplanned maintenance work or prior to exceeding the 72-hour AOT for the extended unplanned corrective maintenance work. A Configuration Risk Management Program (CRMP) is implemented to assess risk of this activity when applying this ACTION. The TEDG availability is verified by: (1) starting the TEDG and verifying proper operation; (2) verifying 24 hour onsite fuel supply; and (3) ensuring the TEDG is aligned to supply power through a 4.16 kV non-safety bus to the 4.16kV safety bus. A status check for TEDG availability will also be performed at least once every 72 hours following the initial TEDG availability verification. The status check shall consists of: (1) verifying the TEDG equipment is mechanically and electrically ready for manual operation; (2) verifying 24 hour onsite fuel supply; and (3) ensuring the TEDG is aligned to supply power through a 4.16 kV non-safety bus to the 4.16 kV safety bus. If the TEDG becomes unavailable during the 10 day AOT and cannot be restored to available status, the EDG AOT reverts back to 72-hours. The

Bases 3.8.1 Insert

This 7-day minimum required volume of fuel oil is bounded by the combined LCO required fuel oil volumes for the fuel oil storage tank and fuel oil feed (day) tank for each diesel generator.

Attachment 4

W3F1-2003-0074

Changes to Technical Requirements Manual
For Information Only

TABLE 3.3-2

REACTOR PROTECTIVE INSTRUMENTATION RESPONSE TIMES

FUNCTIONAL UNIT	RESPONSE TIME
1. Manual Reactor Trip	Not Applicable
2. Linear Power Level - High	≤ 0.40 second*
3. Logarithmic Power Level - High	≤ 0.40 second*
4. Pressurizer Pressure - High	≤ 0.90 second
5. Pressurizer Pressure - Low	≤ 0.90 second
6. Containment Pressure - High	≤ 1.70 seconds
7. Steam Generator Pressure - Low	≤ 0.90 second
8. Steam Generator Level - Low	≤ 0.90 second
9. Local Power Density - High	
a. Neutron Flux Power from Excore Neutron Detectors	≤ 0.429 second*
b. CEA Positions	≤ 0.424 second**
c. CEA Positions: CEAC Penalty Factor	≤ 0.379 second
10. DNBR - Low	
a. Neutron Flux Power from Excore Neutron Detectors	≤ 0.429 second *
b. CEA Positions	≤ 0.424 second**
c. Cold Leg Temperature	≤ 0.300 second#
d. Hot leg Temperature	≤ 0.429 second#
e. Primary Coolant Pump Shaft Speed	≤ 0.237 second**
f. Reactor Coolant Pressure from Pressurizer	≤ 0.429 second##
g. CEA Positions: CEAC Penalty Factor	≤ 0.379 second

Replace with TRM TABLE 3.3-2 INSERT 9

Replace with TRM TABLE 3.3-2 INSERT 10

TRM TABLE 3.3-2 INSERT 9

a.	Neutron Flux Power from Excore Neutron Detectors		≤ 0.191 second*
b.	CEA Positions		≤ 0.186 second**
c.	CEA Positions: CEAC Penalty Factor #1	Channel A	≤ 0.271 second
		Channel B	≤ 0.236 second
		Channel C	≤ 0.236 second
		Channel D	≤ 0.236 second
d.	CEA Positions: CEAC Penalty Factor #2	Channel A	≤ 0.236 second
		Channel B	≤ 0.236 second
		Channel C	≤ 0.236 second
		Channel D	≤ 0.271 second

TRM TABLE 3.3-2 INSERT 10

a.	Neutron Flux Power from Excore Neutron Detectors		≤ 0.191 second*
b.	CEA Positions		≤ 0.186 second**
c.	Cold Leg Temperature		≤ 0.285 second#
d.	Hot Leg Temperature		≤ 0.285 second#
e.	Primary Coolant Pump Shaft Speed		≤ 0.185 second**
f.	Reactor Coolant Pressure from Pressurizer		≤ 0.186 second##
g.	CEA Positions: CEAC Penalty Factor #1	Channel A	≤ 0.271 second
		Channel B	≤ 0.236 second
		Channel C	≤ 0.236 second
		Channel D	≤ 0.236 second
h.	CEA Positions: CEAC Penalty Factor #2	Channel A	≤ 0.236 second
		Channel B	≤ 0.236 second
		Channel C	≤ 0.236 second
		Channel D	≤ 0.271 second

TABLE 3.3-2 (Continued)

REACTOR PROTECTIVE INSTRUMENTATION RESPONSE TIMES

FUNCTIONAL UNIT	RESPONSE TIME
11. Steam Generator Level - High	Not Applicable
12. Reactor Protection System Logic	Not Applicable
13. Reactor Trip Breakers	Not Applicable
14. Core Protection Calculators	Not Applicable
15. CEA Calculators	Not Applicable
16. Reactor Coolant Flow - Low	0.70 second

No changes on this page. This page is included for completeness to assist in the review.

*Neutron detectors are exempt from response time testing. Response time of the neutron flux signal portion of the channel shall be measured from detector output or input of first electronic component in channel.

**Response time shall be measured from the time the CPC/CEAC receives an input signal until the electrical power is interrupted to the CEA drive mechanism.

#Response time shall be measured from the output of the sensor. RTD response time for all the RTDs shall be measured at least once per 18 months. The measured P_t of the slowest RTD shall be less than or equal to 8 seconds (P_t assumed in the safety analysis).

##Response time shall be measured from the output of the pressure transmitter. The transmitter response time shall be less than or equal to 0.70 second.

3/4.3.1 and 3/4.3.2 REACTOR PROTECTIVE AND ENGINEERING SAFETY FEATURES ACTUATION SYSTEMS INSTRUMENTATION

Items 9 and 10 in Table 3.3-2 provide the surveillance test acceptance criteria for Core Protection Calculator (CPC) response times consisting of:

- CPC system hardware, plus
- reactor trip matrix, plus
- time to interrupt power to the CEA holding coils.

These are the maximum times allowed in surveillance procedures. With the sum of these measured response times less than the times shown in Table 3.3-2, the CPC system hardware, the reactor trip matrix and time to interrupt power to the CEA drive mechanism are demonstrated to be functioning to specification and will support the response times assumed in safety analyses.

Having established the functioning of the CPC hardware, the creditable trip times are based upon fixed execution time and sequences of the various CPC system software modules.

The CPC delay times for these functional units that are acceptable to assume in accident and transient analysis corresponding to Table 3.3-2 instrumentation response times are listed below. The times include reactor trip matrix time, and time to interrupt power to the CEA holding coils, but omit detector response times.

	Functional Unit	Delay Time (second(s))
9.	Local Power Density – High	
	a. Neutron Flux Power From Excore Detectors	0.2748
	b. CEA Positions	1.3039
	c. CEA Positions: CEAC Penalty Factor #1	0.4631
	d. CEA Positions: CEAC Penalty Factor #2	0.4631
10.	DNBR – Low	
	a. Neutron Flux Power From Excore Detectors	0.2748
	b. CEA Positions	1.3422
	c. Cold Leg Temperature	0.3693[1]
	d. Hot Leg Temperature	N/A [2]
	e. Primary Coolant Pump Shaft Speed	0.2315
	f. Reactor Coolant Pressure from Pressurizer	0.2693
	g. CEA Positions: CEAC Penalty Factor #1	0.5014
	h. CEA Positions: CEAC Penalty Factor #2	0.5014

[1] Also applicable to CPC Auxiliary Trip on Differential Cold Leg Temperature
[2] No Direct Trip on Hot Leg Temperature.

3/4.3.1 and 3/4.3.2 REACTOR PROTECTIVE AND ENGINEERING SAFETY FEATURES ACTUATION SYSTEMS INSTRUMENTATION (Continued)

The time delays acceptable to assume in accident and transient analysis for module based CPC trip delay times for trips based on CPC logic include:

Hot Leg Saturation trip:	2.744 seconds
Low Quality Margin trip:	0.370 second
Differential Cold Leg Temperature trip:	0.370 second
Axial Shape Index trip:	0.275 second
Integrated Radial Peaking trip:	1.521 seconds
Variable Over Power trip (VOPT):	0.370 second [1]
Low DNBR Trip for Excess Load with Loss of A/C:	0.332 second [2]

[1] A 0.370 second response time is generally the minimum time assumption, where both temperature and neutron flux inputs to VOPT are considered.

[2] A 0.332 second response time applies for this event, based on detection of a decrease of reactor coolant flow from conditions assumed to be at the power operating limit.

The time delay for the module based trips for DNBR-Low and LPD-High can vary dependent upon the dynamics of the various parameters which are input to the algorithms.

TABLE 3.3-5 (Continued)

ENGINEERED SAFETY FEATURES RESPONSE TIMES

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
2. Pressurizer Pressure-Low	
a. Safety Injection (ECCS)	
(1) High Pressure Safety Injection	≤ ~~30.0~~ 27.0*/18.5**
(2) Low Pressure Safety Injection	≤ ~~45.5~~ 42.5*/34.0**
b. Containment Isolation	≤ 23.5*/12.0**
c. Containment Cooling	≤ 31.0*/19.5**
3. Containment Pressure-High	
a. Safety Injection (ECCS)	
(1) High Pressure Safety Injection	≤ ~~30.0~~ 27.0*/18.5**
(2) Low Pressure Safety Injection	≤ ~~45.5~~ 42.5*/34.0**
b. Containment Isolation	≤ 23.5*/12.0**
c. Main Steam Isolation	≤ 8.0*/8.0**
d. Main Feedwater Isolation ###	≤ 6.0*/6.0**
e. Containment Cooling	≤ 31.0*/19.5**
4. Containment Pressure--High-High	
a. Containment Spray Pump	≤ 15.2*/4.6**
b. Containment Spray Valves	≤ 10.4*/10.4**
c. CCW to RCP Valves	≤ 23.5*/12.0**
5. Containment Area Radiation-High #	
Containment Purge Valves Isolation	≤ 6.2*/6.2**
6. Steam Generator Pressure-Low	
a. Main Steam Isolation	≤ 8.0*/8.0**
b. Main Feedwater Isolation ###	≤ 6.0*/6.0**
7. Refueling Water Storage Pool-Low	
Safety Injection Sump	≤ 50.0##
Recirculation Valves Open	
8. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage)	
Loss of Power (0 volts)	≤ 2***
9. 480V Emergency Bus Undervoltage (Loss of Voltage)	
Loss of Power (0 volts)	N.A.
10. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)	
Loss of Power	≤ 14***

AMENDMENT NO. ~~25, 39, 41~~

3/4.4 REACTOR COOLANT SYSTEM

New TRM

3/4.4.3 PRESSURIZER HEATERS

LIMITING CONDITION FOR OPERATION

3.4.3.1 The pressurizer heaters shall be OPERABLE with at least 650 kW of nominal heater capacity available in addition to the heater capacity specified in Technical Specification 3.4.3.1b.

APPLICABILITY: MODE 1

ACTION:

With less than the above heater capacity available, restore the required capacity within 72 hours or initiate a Condition Report which requires the performance of an evaluation justifying continued plant operation. The evaluation should be completed within the following 6 hours and should be approved by the General Manager Plant Operations (GMPO) or his designee (e.g., the duty plant manager).

SURVEILLANCE REQUIREMENTS

4.4.3.1 The specified heater capacity shall be verified at least once each refueling outage.

New TRM Bases

3/4.4 REACTOR COOLANT SYSTEM

BASES

3/4.4.3 PRESSURIZER

The heater capacity cited in requirement 3.4.3.1 is sufficient, in conjunction with the heater capacity required by Technical Specification 3.4.3.1b, to bound the capacity credited in the analysis of the CEA Withdrawal within Deadband event. The additional heater capacity cited in requirement 3.4.3.1 can be heaters powered from any combination of Class 1E or non-class 1E buses.

3/4.6 CONTAINMENT SYSTEMS

3/4.6.1.5 AIR TEMPERATURE

LIMITING CONDITION FOR OPERATION

3.6.1.5 Primary containment average temperature shall be greater than or equal to 90°F.

APPLICABILITY: MODE 1 when THERMAL POWER is greater than 70 percent RATED THERMAL POWER.

ACTION:

→ (DRN 02-1571)
With the containment average air temperature less than 90°F, restore the average air temperature to within the limit within 8 hours, or insert a 0.2 kW/ft Peak Linear Heat Rate penalty into COLSS for every 10°F below the 90°F limit within the next 6 hours.
← (DRN 02-1571)

SURVEILLANCE REQUIREMENTS

4.6.1.5 The primary containment average air temperature shall be the arithmetical average of the temperatures at any three of the following locations and shall be determined at least once per 24 hours:

Location

a. Containment Fan Cooler No. 1A Air Intake

b. Containment Fan Cooler No. 1B Air Intake

c. Containment Fan Cooler No. 1C Air Intake

d. Containment Fan Cooler No. 1D Air Intake

THIS PAGE NOT USED

3/4.6.1 PRIMARY CONTAINMENT

Primary CONTAINMENT INTEGRITY ensures that the release of radioactive materials from the containment atmosphere will be restricted to those leakage paths and associated leak rates assumed in the safety analyses. This restriction, in conjunction with the leakage rate limitation, will limit the SITE BOUNDARY radiation doses to within the limits of 10 CFR Part 100 during accident conditions.

3/4.6.1.2 CONTAINMENT LEAKAGE

The limitations on containment leakage rates ensure that the total containment leakage volume will not exceed the value assumed in the safety analyses at the peak accident pressure, P_a. As an added conservatism, the measured overall integrated leakage rate is further limited to less than or equal to 0.75 L_a or less than or equal to 0.75 L_t as applicable during performance of the periodic tests to account for possible degradation of the containment leakage barriers between leakage tests.

The surveillance requirements for measuring leakage rates are consistent with the requirements of Appendix J of 10 CFR Part 50. A one time extension of the test interval is allowed for the third Type A test of the first 10-year service period, as required by Surveillance Requirement 4.6.1.2.a and by Section III.D.(a) of Appendix J to 10 CFR Part 50, provided the performance of the Type A test occurs prior to unit restart following Refuel 7.

3/4.6.1.5 AIR TEMPERATURE

→ (DRN 02-1571)

The limitation on containment minimum average air temperature ensures that the ECCS is capable of maintaining a Peak Clad Temperature (PCT) less than or equal to 2200°F under LOCA conditions. A lower containment average air temperature results in a lower post accident containment pressure, a lower reflood rate, and therefore a higher PCT. Lowering the Peak Linear Heat Rate setpoint in COLSS by 0.2 kW/ft. for every 10°F below the minimum containment temperature limit of 90°F will ensure the resulting PCT remains bounded by the UFSAR accident analyses. The value of 0.2 kW/ft. was calculated in a sensitivity analysis performed by ABB and the results are documented in the ABB letter to J.B. Holman dated June 29, 1993 (Letter number L 93 026).

← (DRN 02-1571)

The 90°F minimum value specified in the TRM is the value used in the accident analysis and does not contain any allowance for temperature measurement instrument uncertainty. Instrument uncertainty is addressed in the surveillance procedure.

3/4.6.3 CONTAINMENT ISOLATION VALVES

The OPERABILITY of the containment isolation valves ensures that the containment atmosphere will be isolated from the outside environment in the event of a release of radioactive material to the containment atmosphere or pressurization of the containment and is consistent with the requirements of GDC 54 through GDC 57 of Appendix A to 10 CFR Part 50. Containment isolation within the time limits specified for those isolation valves designed to close automatically ensures that the release of radioactive material to the environment will be consistent with the assumptions used in the analyses for a LOCA.

→ (DRN 02-1794)

3/4.7 PLANT SYSTEMS

3/4.7.1.7 ATMOSPHERIC DUMP VALVES (ADVs)

LIMITING CONDITION FOR OPERATION

3.7.1.7 Two Atmospheric Dump Valves (ADVs) shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTION:

a. With one ADV inoperable, enter TS 3.6.3 and restore the required ADV to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

→ (DRN 02-1923)

b. With two Atmospheric Dump Valves inoperable, enter TS 3.6.3 and restore one ADV to OPERABLE status within 1 hour or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

← (DRN 02-1923)

The provisions of Specification 3.0.4 are not applicable provided one Atmospheric Dump Valve is OPERABLE.

SURVEILLANCE REQUIREMENTS

4.7.1.7 The Atmospheric Dump Valves shall be demonstrated OPERABLE by verifying one complete cycle of each valve in accordance with Specification 4.0.5.

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3/4.7.1.7 ATMOSPHERIC DUMP VALVES

The ADVs have two safety functions 1) to close for containment isolation and 2) to open in order to provide for cooldown capability during isolation conditions. The ADV close safety function is addressed in Technical Requirements Manual (TRM) Table 3.6-2, "Containment Isolation Valves," as containment isolation valves and is applicable to TS 3.6.3 ACTION statements. This section addresses the open safety function of the valves.

The open safety function of the ADVs provide a safety grade method for cooling the unit to Shutdown Cooling (SDC) System entry conditions, should the preferred heat sink via the Steam Bypass System to the condenser not be available, as discussed in the FSAR, Section 10.3. This safety grade cooldown function is performed in conjunction with the Emergency Feedwater System providing cooling water from the condensate storage pool (CSP).

Two ADVs, one per steam generator, are provided. Each ADV flow path consists of an ADV and an associated block valve. The ADVs are provided within upstream block valves to permit their being tested at power, to provide an alternate means of isolation should the ADV not close on demand, and to allow maintenance of the valves with the steam headers pressurized. The ADVs are equipped with pneumatic controllers to permit control of the steam release rate and associated cooldown rate. The controllers provide both automatic and manual ADV operating modes. The ADVs are normally operated using the plant non-safety instrument air supply. Separate safety-related nitrogen accumulators are provided as backups to each of the ADVs in the event of a loss of instrument air.

The ADVs are one of the systems required to meet Branch Technical Position (BTP) RSB 5-1, Design Requirements of the Residual Heat Removal System, and 10 CFR 50, Appendix R for taking the plant from normal operating conditions to cold shutdown. A cooldown analysis was performed assuming loss of offsite power and the failure of one ADV to open. The analysis determined that shutdown cooling entry conditions would be reached in approximately ten hours. The Safety Class 3, Seismic Category I accumulators provide a ten hour minimum backup supply of motive gas for the ADV actuators to assure the valves remain operable from the control room until shutdown cooling entry conditions are satisfied. This is based on the time needed to reach shutdown cooling (SDC) conditions when both hot leg temperatures are reduced to 400°F. This temperature is the design temperature for the shutdown cooling system (SDCS) components.

The ADVs are used during normal plant startups and for cooldowns when either a vacuum in the condenser or the Steam Bypass Control System (SBCS) is not available. The ADVs are capable of being operated remotely from either the Control Room or the Remote Shutdown Panel (LCP-43), and locally from the local pneumatic panel or with manual handwheels.

In the accident analysis presented in the FSAR, the ADVs are assumed to be used by the operator to cooldown the plant to SDC System entry conditions for accidents accompanied by a loss of offsite power. Prior to the operator action, the main steam safety valves (MSSVs) are used to maintain steam generator pressure and temperature at the MSSV setpoint. Operator action is assumed to be 30 minutes following the initiation of an event. The limiting events are those that render one steam generator unavailable for RCS heat removal, with a coincident loss of offsite power. Typical initiating events falling into this category are a main steam line break (MSLB) between the main steam isolation valves and the steam generators, a feedwater line break (FWLB), and a steam generator tube rupture (SGTR).

← (DRN 02-1794)

3/4.7.1.7 ATMOSPHERIC DUMP VALVES (Continued)

One ADV is required to be OPERABLE on each steam generator to ensure that one ADV is OPERABLE to conduct a plant cooldown following an event in which one steam generator and the condenser become unavailable. An ADV is considered OPERABLE if it can be stroked through a complete cycle in accordance with Specification 4.0.5. Failure to meet the LCO can result in the inability to cool the plant to shutdown cooling entry conditions following an event in which the condenser is unavailable. The ADVs are required to be OPERABLE in MODES 1, 2, 3, and 4. In these MODES the ADVs provide the safety grade cooldown for the RCS to shutdown cooling entry conditions.

→ (DRN 02-1923)

If one ADV is inoperable, 72 hours is provided to return it to an OPERABLE status. The 72 hour allowed outage time takes into account the capability afforded by the remaining OPERABLE ADV and a non-safety backup in the SBCS and MSSVs. If both ADVs are inoperable, 1 hour is provided to return one ADV to an OPERABLE status. If the ADVs cannot be restored to OPERABLE status within the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours and in COLD SHUTDOWN within the following 30 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 safety systems.
← (DRN 02-1923)

The TRM is annotated with a 3.0.4 exemption, allowing entry into the applicable MODES to be made with an inoperable ADV.

To perform a controlled cooldown of the RCS, the ADVs must be able to be opened and throttled through their full range. The surveillance requirements ensure the ADVs are tested through a full cycle in accordance with Specification 4.0.5.

← (DRN 02-1794)

TABLE 3.6-2
CONTAINMENT ISOLATION VALVES

VALVE NUMBER	FUNCTION	Penetration Number	ACTUATION SIGNALS(1) CIAS	CPIS	Manual / Remote Manual	Check Valve	SIAS	MSIS	CSAS	EFAS	RAS	HDP	CADP
LRT MVAAA109	ILRT Connection	63			X								
LRT MVAAA110	ILRT Connection	63			X								
LRT MVAAA201	ILRT Test Connection	65			X								
LRT MVAAA2011	ILRT Test Connection	65			X								
LRT MVAAA202	ILRT Test Connection	65			X								
LRT MVAAA203	ILRT Test Connection	65			X								
LRT MVAAA2031	ILRT Test Connection	65			X								
LRT MVAAA204	ILRT Test Connection	65			X								
LRT MVAAA400	LLRT Test Connection	53			X								
~~MS MVAAA116A~~	~~Atmospheric Dump Valve~~	~~1~~			~~X(4)~~								
~~MS MVAAA116B~~	~~Atmospheric Steam Dump~~	~~2~~			~~X(4)~~								
MS MVAAA119A	Main Steam Drain	1	X										
MS MVAAA119B	Main Steam Drain	2	X										
MS MVAAA120A	Main Steam Drain	1	X										
MS MVAAA120B	Main Steam Drain	2	X										
MS MVAAA1244A	MSIV Bypass	1			X								
MS MVAAA1244B	MSIV Bypass	2			X								
→(DRN 03-1738, Am. 81)													
←(DRN 03-1738, Am. 81)													
MS MVAAA401A	Steam to Emergency Steam Generator Feed Pump Turbine	1			X (4)					X (open)			
MS MVAAA401B	Steam to Emergency Steam Generator Feed Pump Turbine	2			X (4)					X (open)			

Attachment 5

W3F1-2003-0074

Waterford 3 Extended Power Uprate Report

November 5, 2003

Waterford 3
Extended Power Uprate

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EXECUTIVE SUMMARY

The core power of Waterford Steam Electric Station, Unit 3 (Waterford 3) is being increased in an extended power uprate (EPU) from 3441 megawatts thermal (MWt) to 3716 MWt to increase the facility's electrical power output. The EPU will be implemented in Cycle 14 in Spring 2005. This Power Uprate Report (PUR) demonstrates acceptable facility operation at the increased power level. This PUR closely follows the guidance of NRC draft Review Standard RS-001, "Review Standard for Extended Power Uprates," December 2002. All items in the review standard and all acceptance criteria have been addressed to the extent they are consistent with the Waterford 3 licensing basis.

Plant modifications planned for implementation to support the power uprate include:

- The high pressure turbine will be upgraded.
- The generator will be rewound and associated auxiliaries will be provided.
- Higher capacity main generator output circuit breakers, disconnect switches, and bus work will be installed.
- Control valves for the heater drain system may be upgraded/replaced as necessary.
- Atmospheric Dump Valve (ADV) controllers will be replaced with more accurate controllers.
- Main transformer modifications may be performed as necessary.
- Instrument and control changes (e.g., lower steam generator pressure trip setpoint) will be made as necessary.
- The reheat system safety valves will be modified as required to provide adequate capacity.
- Condenser modifications will be performed as required to prevent potential condenser tube vibration.

Methodology changes employed for the EPU include:

- The CENTS computer code was used rather than CESEC for non-LOCA safety analyses.
- The 1999 Combustion Engineering Nuclear Power Large-Break Emergency Core Cooling System Evaluation Model was used rather than the June 1985 version of the Evaluation Model.
- Previously approved leak-before-break (LBB) methodology was applied to eliminate consideration of mechanical (dynamic) effects of Reactor Coolant System pipe breaks.

Other methodology and plant changes are identified in the PUR Introduction.

To ensure protection of the health and safety of plant personnel and the public following power uprate, the Waterford 3 design basis and accident analyses were reviewed with respect to changes to plant operating conditions and characteristics. The analyses and evaluations performed to support the uprate are described in this report. Evaluations of structural integrity and functional performance of plant components and systems demonstrate acceptable performance at uprate conditions. LOCA analyses credit automatic operation of the safety grade ADVs to mitigate the consequences of the small break LOCA. The LOCA analyses

demonstrate conformance to the Emergency Core Cooling System (ECCS) acceptance criteria for light water nuclear power reactors, 10CFR50.46, for Waterford 3 at uprate conditions. Evaluation of the non-LOCA safety analyses in Final Safety Analysis Report (FSAR) Chapter 15 demonstrates conformance with applicable acceptance criteria at power uprate conditions.

Proposed revisions to the Operating License and Technical Specifications required by power uprate are presented in attachments to this submittal. In addition, Technical Requirements Manual (TRM) revisions are provided for information. The Technical Specifications include a new specification to address automatic actuation of the atmospheric dump valves for small break LOCA mitigation. Other Technical Specification revisions include minor, typical changes to selected plant protection system setpoints and component and system parameter limits associated with increased power. The proposed Operating License and Technical Specification revisions ensure proper control of unit operation and equipment configuration under power uprate conditions.

Evaluations performed consistent with the proposed Technical Specification changes and documented in this PUR demonstrate that the facility meets applicable acceptance criteria at the EPU power level.

ACRONYMS & ABBREVIATIONS

1-D	one-dimensional
3-D	three-dimensional
AC	alternating current
ACCWS	Auxiliary Component Cooling Water System
ADV	Atmospheric Dump Valve
ALARA	As-Low-As-Reasonably-Achievable
ANO-2	Arkansas Nuclear One, Unit 2
AOO	anticipated operational occurrence
AOR	Analysis of Record
AOV	air-operated valve
ARI	all rods in
ASI	Axial Shape Index
ASGT	asymmetric steam generator transient
ASIU	axial shape index units
ASME	American Society of Mechanical Engineers
ASN	Analysis Section Number
ATWS	anticipated transient without scram
B&PV	boiler and pressure vessel
BAMT	boric acid makeup tank
BLPB	branch line pipe break
BMS	Boron Management System
BOC	beginning of cycle
BOP	balance of plant
BTP	Branch Technical Position
CAP	containment atmosphere purge
CARS	Containment Atmosphere Release System
CCDP	conditional core damage probability
CCF	common cause failure
CCS	Containment Cooling System
CCW	component cooling water
CCWS	Component Cooling Water System
CD	Condensate System
CDF	core damage frequency
CE	Combustion Engineering, Inc.
CE-1	Combustion Engineering Departure from Nucleate Boiling Correlation - 1
CEA	control element assembly
CEAW	control element assembly withdrawal
CEDM	control element drive mechanism
CEDMCS	Control Element Drive Mechanism Control System
CENPD	Combustion Engineering Nuclear Power Department
CENTS	Combustion Engineering Nuclear Transient Simulator
CESEC	Combustion Engineering System Excursion Code
CET	containment event tree

ACRONYMS & ABBREVIATIONS (cont.)

CFR	Code of Federal Regulations
CFWS	Condensate and Feedwater System
CHF	critical heat flux
CHLR	closure head lift rig
COLR	Core Operating Limits Report
COLSS	Core Operating Limits Supervisory System
CPCS	Core Protection Calculator System
CR	control room
CRH	control room habitability
CS	containment spray
CSB	core support barrel
CSP	core support plate
CSS	Containment Spray System
CST	condensate storage tank
CTM	core thermal margin
CTMT	containment
CUF	cumulative usage factor
CVAS	Controlled Ventilation System
CVCS	Chemical and Volume Control System
CWS	Circulating Water System
DBA	design basis accident
DBE	design basis event
DC	direct current
DCH	direct containment heating
DCT	dry cooling tower
DE	dose equivalent
DEFAS	diverse emergency feedwater actuation signal
DEG/PD	double-ended guillotine/pump discharge
DF	decalibration factor
DNB	departure from nucleate boiling
DNBR	departure from nucleate boiling ratio
DWt	deadweight
EAB	exclusion area boundary
ECCS	Emergency Core Cooling System
ECT	eddy current testing
EDG	emergency diesel generator
EFAS	emergency feedwater actuation signal
EFPD	effective full-power day
EFPH	effective full-power hours
EFPT	emergency feedwater pump turbine
EFPY	effective full-power year
EFS	Emergency Feedwater System
EFW	emergency feedwater

ACRONYMS & ABBREVIATIONS (cont.)

EFWA	emergency feedwater flow activation
EM	Evaluation Model
EMF	electromagnetic field
EOC	end of cycle
EOL	end of life
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
EPU	extended power uprate
EQ	environmental qualification
ER	Environmental Report
ESF	Engineered Safety Feature
ESFAS	Engineered Safety Features Actuation System
FAC	flow-accelerated corrosion
FAP	fuel alignment plate
FES	Final Environmental Statement
FF	fluence factor
FFBT	failure to fast bus transfer
FHA	fuel-handling accident
FHB	Fuel-Handling Building
FIV	flow-induced vibration
FIVE	Fire-Induced Vulnerability Evaluation
FLECHT	Full Length Emergency Cooling Heat Transfer
FrT	Radial Peak Including Tilt
FSAR	Final Safety Analysis Report
FW	feedwater
FWCS	Feedwater Control System
FWIV	feedwater isolation valve
FWLB	feedwater line break
FWP	feedwater pump
FWS	Feedwater System
GDC	General Design Criteria
GEIS	Generic Environmental Impact Statement
GIS	generated iodine spike
GL	(NRC) Generic Letter
GWd/MTU	gigawatt-day per metric ton of uranium
GWMS	Gaseous Waste Management System
H&V	heating and ventilation
HBD	heat balance diagram
HELB	high-energy line break
HEPA	high-efficiency particulate air (filter)
HDR	heater drain
HFE	human failure event
HFP	hot full power

ACRONYMS & ABBREVIATIONS (cont.)

HOV	hydraulic-operated valve
HP	high pressure
HPME	high-pressure melt injection
HPP	high-pressurizer pressure
HPPT	high-pressurizer pressure trip
HPSI	high-pressure safety injection
HRA	human reliability analysis
HTC	heat transfer coefficient
HTR	heater
HVAC	heating, ventilation and air conditioning
HVC	Control Room Heating, Ventilation and Air Conditioning System
HVT	Turbine Building HVAC System
HX	heat exchanger
HZP	hot zero power
I&C	instrumentation and control
IC	inside containment
ICI	in-core instrumentation, in-core instruments
IEF	initiating event frequency
IOSGADV	inadvertent opening of a steam generator atmospheric dump valve
IPB	Iso-Phase bus
IPE	Individual Plant Evaluation
IPEEE	Individual Plant Evaluation for External Event
ISI	in-service inspection
ITP	iodine, tritium, and particulates
LBB	leak before break
LBLOCA	large-break loss-of-coolant accident
LCO	limiting conditions for operation
LDE	dose to eye lens
LDEQ	Louisiana Department of Environmental Quality
LER	Licensee Event Report
LERF	large early release frequency
LHGR	linear heat generation rate
LHR	linear heat rate
LOAC	loss of AC
LOCA	loss-of-coolant accident
LOCA/MSLB	loss-of-coolant accident/main steam line break
LOCV	loss of condenser vacuum
LOF	loss of flow
LOOP	loss-of-offsite power
LP	low pressure
LPD	low-power density
LPDES	Louisiana Pollutant Discharge Elimination System
LPSI	low-pressure safety injection

ACRONYMS & ABBREVIATIONS (cont.)

LPZ	low-population zone
LR	long radius
LSGL	low steam generator level
LSGP	low steam generator pressure
LSS	lower support structure
LTC	long-term cooling
LTOP	low-pressure overpressure protection
LWR	light-water reactor
MCES	Main Condenser Evacuation System
MCL	main coolant loop
MCLB	main coolant loop break
MDNBR	minimum departure from nucleate boiling ratio
MEDP	maximum expected differential pressure
MFIV	main feedwater isolation valve
MFP	main feedwater pump
MFW	main feedwater
MOV	motor-operated valve
mrad	millirad
mrem	millirem
MS	main steam
MSCU	Modified Statistical Combination of Uncertainties
MSIS	main steam isolation signal
MSIV	main steam isolation valve
MSL	main steam line
MSLB	main steamline break
MSR	moisture separator reheater
MSSS	Main Steam Supply System
MSSV	main steam safety valve
MTC	moderator temperature coefficient
MTU	metric ton uranium
MWD/MTU	megawatt-day per metric ton of uranium
MWt	megawatts thermal
NEI	Nuclear Energy Institute
NEM	nodal expansion difference solution
NEMA	National Electric Manufacturer’s Association
NPSH	net positive suction head
NR	narrow range
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
NSSS	Nuclear Steam Supply System
NUMARC	Nuclear Management and Resources Council
NUREG	U.S. Nuclear Regulatory Commission Document
OBE	operating basis earthquake

ACRONYMS & ABBREVIATIONS (cont.)

OC	outside containment
OD	outside diameter
OPM	overpower margin
PASS	Post-Accident Sampling System
PCT	peak cladding temperature
PD	pump discharge
PID	proportional integral derivative
PIS	pre-existing iodine spike
PLCS	Pressurizer Level Control System
PLHGR	peak linear heat generation rate
PMC	plant monitoring computer
POL	power operating limit
PPCS	Pressurizer Pressure Control System
PPLS	Pressurizer Level Control System
PPS	Plant Protection System
PSA	Probabilistic Safety Analysis
PSV	pressurizer safety valve
P-T	pressure-temperature
PTS	pressurized thermal shock
PU	power upgrade
PULR	Power Uprate Licensing Amendment Request
PUR	Power Uprate Report
PWR	pressurized-water reactor
PWSCC	pressurized water stress corrosion cracking
PZR	pressurizer
QSPDS	Qualified Safety Parameter Display System
RAB	Reactor Auxiliary Building
RAI	Request for Additional Information
RAS	recirculation actuation signal
RC	reactor coolant
RCP	reactor coolant pump
RCPB	reactor coolant pressure boundary
RCPSSS	Reactor Coolant Pump Shaft Speed Sensor System
RCS	Reactor Coolant System
RF	refueling outage
RG	Regulatory Guide
RIR	reactivity insertion rate
RMS	root mean square
ROCS	Reactor Operation and Control Simulator
ROPM	required overpower margin
RPCS	Reactor Power Cutback System
RPS	Reactor Protection System
RRS	Reactor Regulating System

ACRONYMS & ABBREVIATIONS (cont.)

RS	Review Standard
RSB	Reactor Systems Branch
RSS	Reheat Steam System
RSS	root sum squared
RTD	resistance temperature detector
RT_{NDT}	reference temperature – nil ductility temperature
$RT_{NDT(u)}$	reference temperature – nil ductility temperature (unirradiated)
RTP	rated thermal power
RT_{PTS}	reference temperature-pressurized thermal shock
RTSG	reactor trip switchgear
RV	reactor vessel
RVI	reactor vessel internal
RWSP	refueling water storage pool
RWST	refueling water storage tank
S2M	Supplement 2 Model
SAF	single action failure
SAFDL	specified acceptable fuel design limit
SAM	seismic response time history anchor motion
SAR	Safety Analysis Report
SB	site boundary
SBCS	Steam Bypass Control System
SBLOCA	small-break loss-of-coolant accident
SBO	station blackout
SBS	Steam Bypass System
SBVS	Shield Building Ventilation System
SCC	stress corrosion cracking
scfm	standard cubic feet per minute
SCS	Shutdown Cooling System
SCU	statistical combination of uncertainties
SDC	shutdown cooling line
SDCF	skin dose conversion factor
SDCS	Shutdown Cooling System
SER	Safety Evaluation Report
SES	Steam Electric Station
SF	service factor
SFP	spent fuel pool
SG	steam generator
SGBS	Steam Generator Blowdown System
SGTP	steam generator tube plugging
SGTR	steam generator tube rupture
SHPO	State Historic Preservation Office
SI	safety injection
SI	stress intensity

ACRONYMS & ABBREVIATIONS (cont.)

SIAS	safety injection actuation signal
SIS	Safety Injection System
SIT	safety injection tank
SL	surge line
SLB	steam line break
SMA	seismic margins assessment
SOPP	Shutdown Operations Protection Plan
SR	short radius
SRP	Standard Review Plan
SRV	safety relief valve
SSC	structure, system, and component
SSE	safe shutdown earthquake
SSEL	Safe Shutdown Equipment List
SUPS	static uninterruptible power supplies
SUT	startup transformer
TAD	time of annulus downflow
TAM	thermal anchor movement
TAV	turbine admission valve
TBCCWS	Turbine Building Closed Cooling Water System
TBS	Turbine Bypass System
TEDE	total effective dose equivalent
TGB	Turbine Generator Building
TH	thermal expansion
TIG	tungsten inert gas
TODE	total organ dose equivalent
TRM	Technical Requirements Manual
TS	Technical Specification
UGS	upper guide structure
UGSSP	upper guide structure support plate
UHS	ultimate heat sink
USE	upper shelf energy
v/o	volume percent
VOPT	variable overpower trip
Waterford 3	Waterford Steam Electric Station, Unit 3
WCT	wet cooling tower
w/o	weight percent
WR	wide range
WT	wall thickness

1.0 INTRODUCTION

1.1 APPLICATION

Entergy Operations, Inc. (Entergy) requests changes to Facility Operating License NPF-38 and Technical Specifications for Waterford Steam Electric Station, Unit 3 (Waterford 3), Docket No. 50-382, to increase the rated thermal power from 3441 megawatts thermal (MWt) to 3716 MWt.

1.2 BACKGROUND

Waterford 3 is a pressurized water reactor (PWR) plant of the Combustion Engineering (CE) design. The Nuclear Steam Supply System (NSSS) configuration is typical of that design. It includes two steam generators (SGs) with each generator connected to the reactor vessel by one hot leg and two cold legs. Each cold leg contains a reactor coolant pump. The pressurizer is connected to one of the hot legs. The design of the unit includes no special or unique features.

The Nuclear Regulatory Commission (NRC) originally licensed Waterford 3 on March 16, 1985, for operation at a reactor core power not to exceed 3390 MWt. By Amendment No. 183 dated March 29, 2002, the NRC granted a power uprate allowing Waterford 3 to operate at a rated thermal power not to exceed 3441 MWt. Therefore, this extended power uprate (EPU) would result in an increase of approximately 9.6 percent over the originally licensed power level and approximately 8.0 percent over the current licensed power level.

The increase in licensed power from 3390 MWt to 3441 MWt was supported by a reduction in the power measurement uncertainty at full power from 2% to less than 0.5% using ultrasonic flow measurement equipment for feedwater flow. The reduced uncertainty remains valid at the power level of 3716 MWt.

Waterford 3 was originally designed with a Reactor Coolant System (RCS) temperature program where nominal T_{cold} increased from 545°F at hot zero power (HZP) to 553°F at hot full power (HFP). The corresponding T_{hot} value was 611°F, based on the minimum Technical Specification RCS flow of 148E6 lb/hr. This value was used as the nominal value of T_{hot} during initial design for a variety of analyses.

Waterford 3 chose to revise its RCS T_{cold} program in 1992 to a constant T_{cold} program, with a constant nominal T_{cold} of 545°F.

This T_{cold} program was not changed as part of implementation of the Appendix K Margin Recovery Power Uprate implemented for Cycle 12 in 2002. Nominal T_{hot} is 600.2°F for operation at current rated thermal power of 3441 MWt.

For the EPU to 3716 MWt, Waterford 3 chose to develop its power uprate operating point to correspond to a nominal HFP T_{hot} value of 601°F, which is approximately the same as for current licensed conditions. The 601°F T_{hot} value is chosen to avoid impact on steam generator tube materials as well as avoid impact on Alloy 600 components. For 3716 MWt operations, the

planned programmed T_{cold} is increased from 541°F at HZP to 543°F at HFP. Nominal temperature conditions are based upon a nominal RCS flow of 110% of the minimum design flow. Reviews of RCS flow data conducted in association with implementation of the 2002 Appendix K Power Uprate demonstrated that best estimate RCS flow was 110% of design; previously nominal flow was assumed to be 107%.

1.3 EPU APPROACH

This EPU application closely follows the guidance of the Office of Nuclear Reactor Regulation (NRR) draft RS-001, "Review Standard for Extended Power Uprates," December 2002, to the extent that the review standard is consistent with the Waterford 3 licensing basis. FSAR sections that discuss Waterford 3 features addressed in this PUR are identified. In addition, the Arkansas Nuclear One, Unit 2 (ANO-2) EPU application, including Requests for Additional Information (RAIs) and associated responses, were reviewed for guidance. ANO-2 is also a CE NSSS design plant, and the approximate 7.5 % ANO-2 power uprate compares closely to the approximate 8 % uprate requested for Waterford 3. The ANO-2 application was approved by the NRC's *Safety Evaluation Report* (SER) dated April 24, 2002.

Entergy plans to implement the Waterford 3 EPU in one increment. Completion of plant modifications necessary to implement the EPU is planned prior to the end of refueling outage 13 in spring 2005. The plant will be operated at 3716 MWt starting in cycle 14.

1.4 PLANT MODIFICATIONS

Among the plant modifications planned for implementation prior to the end of refueling outage 13 to permit implementing the EPU in cycle 14 are:

- The high pressure turbine will be upgraded.
- The generator will be rewound and associated auxiliaries will be provided.
- Higher capacity main generator output circuit breakers, disconnect switches, and bus work will be installed.
- Control valves for the heater drain system may be upgraded/replaced as necessary.
- Atmospheric dump valve controllers will be replaced with more accurate controllers.
- Main transformer modifications may be performed as necessary.
- Instrument and control changes (e.g., lower steam generator pressure trip setpoint) will be made as necessary.
- The reheat system safety valves will be modified as required to provide adequate capacity.
- Condenser modifications will be performed as required to prevent potential condenser tube vibration.

Evaluations of these modifications are provided in Section 2.0 of this report

Methodology and Analysis Changes

CENTS (non-LOCA transient analysis code) was used to perform non-LOCA safety analyses for the EPU, whereas CESEC was used previously for those analyses. Use of CENTS for these analyses is described in Section 2.13 of this PUR. The same methodology change was used for the non-LOCA safety analyses performed for the ANO-2 EPU.

The 1999 CE Nuclear Power Large-Break Emergency Core Cooling System (ECCS) Evaluation Model was used for large-break LOCA (LBLOCA) analyses rather than the June 1985 version of the CE Nuclear Power LBLOCA ECCS Evaluation Model. Use of the 1999 evaluation model is addressed in Section 2.12 of this PUR. The same methodology change was used for the LBLOCA analyses performed for the ANO-2 EPU.

Previously approved leak-before-break (LBB) methodology was used to eliminate consideration of mechanical (dynamic) effects of RCS pipe breaks. Application of LBB methodology is described in Section 2.1.6 of this PUR. The same application of LBB was used for the ANO-2 EPU.

Various analysis changes for the EPU relative to analyses of record are shown in Table 1-1.

Table 1-2 compares the current and EPU operating point parameters.

Table 1-1
Summary of Analysis Changes

Parameter	EPU Value	Current Value	Section Reference(s)
RCS Cold Leg Temperature Range (TS 3.2.6)	536 – 549°F	541 – 558°F	2.13.0.2
T_{cold} Program	541 – 543°F ramp	545°F constant	2.13.0.2
Normal Turbine Valve Operation	Single	Sequential	2.4.2
SG Low Pressure Setpoint (TS Tables 2-1 and 3.3-4)	662 psia	764 psia	2.13.0.2
Core Protection Calculator System (CPCS) Differential Cold Leg Temperature Trip Setpoint	11°F	18°F	2.13.0, 2.13.9.1.1
Minimum Boric Acid Makeup Tank (BAMT) Boron Concentration (TS 3.1.2.7 and TS Figure 3.1-1)	4900 ppm	3950 ppm	2.1.11
Minimum Pressurizer Pressure (TS 3.2.8)	2125 psia	2025 psia	2.13.0.2
Safety Injection Tank (SIT) Level Maximum Level (TS 3.5.1)	77.8%	83.8%	2.6.8, 2.12.3
Primary-to-Secondary Leak Rate (TS 3.4.5.2)	0.75 gpm	1 gpm	2.1.9, 2.12.3, 2.13.0.2.h
# SG Tube Plugging Limit	1000 per SG	500 per SG	2.13.0.2
Atmospheric Dump Valve (ADV) credited for Small-Break LOCA (SBLOCA) (TS 3.7.1.7)	Yes	No	2.12.4
Charging Credited in SBLOCA analysis	No	Yes	2.12.4
Long-Term Cooling (LTC) Approach Changes	2 ADVs credited, lower plenum not credited in mixing volume	1 ADV credited, lower plenum credited in mixing volume	2.12.5
Statistical Convolution for Fuel Failure	Yes	Yes for selected events	2.13.0
Fuel Failure for Return to Power Main Steamline Break (MSLB)	Yes	No	2.13.1.3.1

Table 1-1 (cont.)
Summary of Analysis Changes

Parameter	EPU Value	Current Value	Section Reference(s)
Fuel Failures Back Calculated from Regulatory Limits	Yes	No	2.13.0
Bounding Radiological Event for SAR 15.2 Infrequent Events	Excess main steam flow with single active failure	Inadvertent opening of an ADV with single active failure	2.13.0
Atmospheric Dispersion Factors	New	Original license	2.13.0.5
Dynamic Analysis for RCS Primary Loop and Attached Branch Lines	Yes	No	2.2.1
Limiting RCS Pressure Boundary Break - Branch Line Breaks	Yes	No	2.1.6
Code for SG Flow Profile	ATHOS	N/A	2.2.2.1.4.6.1
Code for Control Element Drive Mechanism (CEDM) Analysis	ANSYS	STRUDL	2.2.2.1.4.7
Code Used for Non-LOCA Transient Analyses	CENTS	CESEC	2.13.0
Code Used for Reactor Coolant Pump (RCP) Coastdown	CENTS	COAST	2.13.0
LBLOCA Evaluation Model (EM)	1999 EM	1985 EM	2.12
Reactor Coolant Radioisotopic Concentration	ANSI N18.1	ANSI N237	2.7.1

Table 1-2
Operating Point Parameters
(Nominal Values)

Parameter	EPU Value	Current Value
Reactor Power	3716 MWt	3441 MWt
Hot Leg Temperature	601°F	600.2°F
Cold Leg Temperature	543°F	545°F
RCS Pressure	2250 psia	2250 psia
RCS Flow	45,808 lbm/sec	44,522.4 lbm/sec
SG Pressure	810.2 psia	831.5 psia
Steam Flow	2301.4 lbm/sec/SG	2118.4 lbm/sec/SG
Final Feedwater Temperature	449.7°F	442.7°F

2.0 EVALUATION

2.1 MATERIALS AND CHEMICAL ENGINEERING

2.1.1 Reactor Vessel Materials Surveillance Program

Description of Analysis

The Waterford 3 reactor vessel materials surveillance program includes six surveillance capsules originally installed in the reactor vessel, of which three were scheduled for withdrawal during the 40-year design lifetime. The first surveillance capsule was withdrawn at the end of Cycle 4. The second reactor vessel surveillance capsule was withdrawn in 2002 (end of Cycle 11) for analysis. Analysis of this capsule as documented in WCAP-16002 (Reference 2.1.1-1) reported a revised fast neutron fluence calculated following the guidance of Regulatory Guide (RG) 1.190. The revised neutron fluence projection at the pressure vessel clad/base metal interface of 2.48×10^{19} n/cm^2 is less than the original design basis projection of 3.69×10^{19} n/cm^2 such that no modification of the surveillance capsule withdrawal schedule was considered necessary. The measurements from the second surveillance capsule were consistent with predictions and continued to demonstrate a low rate of embrittlement. The next surveillance capsule is scheduled for removal and evaluation after approximately 26 effective full-power years (EFPYs) such that it will reflect any changes resulting from the Cycle 14 EPU. Three additional surveillance capsules in the vessel are available if needed to evaluate other changes in the future.

Conclusions

The current projections of neutron fluence are conservatively based on the guidance of RG 1.190 and the measurements on the irradiated surveillance materials demonstrate a low rate of embrittlement. One additional capsule is scheduled for withdrawal after 26 EFPY. Three additional capsules are in the vessel and available if needed in the future. The updated neutron fluence projection demonstrates that no modification of the surveillance capsule withdrawal schedule is needed. The current withdrawal schedule continues to support compliance with the requirements of General Design Criteria (GDC) 4, GDC 31, 10CFR50 Appendix H, and 10CFR50.60 following implementation of the EPU.

References

2.1.1-1 WCAP-16002-NP, *Analysis of Capsule 263 from the Entergy Operations Waterford Unit 3 Reactor Vessel Radiation Surveillance Program*, Revision 0, March 2003. (Submitted to the NRC by Entergy letter dated March 28, 2003.)

2.1.2 Pressure-Temperature Limits and Upper-Shelf Energy

Description of Analysis

As reported in the analysis of the second reactor vessel surveillance capsule, WCAP-16002 (Reference 2.1.2-1), a revised fast neutron fluence was calculated following the guidance of RG 1.190. The neutron fluence projections were based on the power uprate to 3441 MWt at the beginning of Cycle 12 and the EPU at the beginning of Cycle 14. Using the analysis of the surveillance capsule, the pressure-temperature (P-T) Limits and Upper Shelf Energy screening criteria were updated in accordance with 10CFR50, Appendix G. The updated analyses are used as the basis of a technical specification change request submitted to the NRC on October 22, 2003. This change request includes new P-T curves based on the surveillance capsule evaluation and the projected fluence. The new P-T curves ensure the structural integrity of the ferritic components of the reactor coolant pressure boundary during any condition of normal operation, including operational occurrences and hydrostatic tests.

The current P-T curves in the technical specifications are applicable through 16 EFPY as stated in Technical Specification Figures 3.4-2 and 3.4-3. Evaluations reported in the analysis of the surveillance capsule, WCAP-16002 (Reference 2.1.2-1), demonstrate that the projected fluence for beginning of Cycle 14, including the Cycle 12 power uprate to 3441 MWt, is less than the fluence assumed for the current P-T curves. The updated P-T curves also account for the fluence increase due to the Cycle 14 EPU.

The updated projections of upper shelf energy (USE) for the reactor vessel beltline materials were done in accordance with NRC RG 1.99, Revision 2. All of the Waterford 3 beltline materials are projected to meet the 50 ft-lb screening criteria of 10CFR50, Appendix G with a substantial margin after 32 EFPY as well as after 48 EFPY. The lowest projected upper shelf energy after 32 EFPY is 71 ft-lbs. The projections to 32 EFPY for each of the reactor vessel beltline plates and welds are provided in Table 2.1-1.

Conclusions

As discussed above, updated projections of neutron fluence were calculated following the guidance of RG 1.190 and were found to be conservative relative to the fluence assumed for the current P-T limits. The updated P-T curves that were submitted on October 22, 2003 were generated in accordance with 10CFR50, Appendix G and account for changes including the Cycle 14 EPU. All of the Waterford 3 beltline materials are projected to meet, with a substantial margin, the 50 ft-lb upper shelf energy screening criteria of 10CFR50, Appendix G. The updated P-T limits meet the requirements of GDC 14, GDC 31, 10CFR50 Appendix G and 10CFR50.60 following implementation of the EPU.

References

2.1.2-1 WCAP-16002-NP, *Analysis of Capsule 263 from the Entergy Operations Waterford Unit 3 Reactor Vessel Radiation Surveillance Program*, Revision 0, March 2003. (Submitted to the NRC by Entergy letter dated March 28, 2003.)

2.1.2-2 Entergy Letter W3F1-2003-0075, *License Amendment Request NPF-38-250, Revision to Pressure/Temperature and Low Temperature Overpressure Protection Limits for 32 Effective Full Power Years*, October 22, 2003.

Table 2.1-1
USE Predictions for Waterford Unit 3 Beltline Region Materials at 32 EFPY

Material	Neutron Fluence[a] At ¼T	Copper Content, %	Initial USE (ft-lb)	32 EFPY USE (ft-lb)
M-1003-1	1.48E19	0.02	94[b]	74
M-1003-2	1.48E19	0.02	97[b]	77
M-1003-3	1.48E19	0.02	90[b]	71
M-1004-1	1.48E19	0.03	106[b]	84
M-1004-2	1.48E19	0.03	141[c]	121[d]
M-1004-3	1.48E19	0.03	94[b]	74
101-124 A	1.48E19	0.02	106	84
101-124 B,C	1.48E19	0.02	131	104
101-142 A,B,C	1.48E19	0.03	129	102
101-171	1.48E19	0.05	156[c]	141[d]

Notes:

a) The fluence, f, was taken from the peak azimuthal location (n/cm^2, E>1.0 MeV) from analysis of surveillance data in WCAP-16002-NP.

b) Initial transverse USE based on 65% of longitudinal Charpy impact data.

c) Initial transverse USE based on surveillance plate and weld Charpy impact data.

d) Projection of irradiated USE based on RG 1.99, Revision 02, Position 2.2.

2.1.3 Pressurized Thermal Shock

Description of Analysis

In the pressurized thermal shock (PTS) rule, 10CFR50.61, the NRC identified an acceptable risk with respect to contribution of vessel failure to core melt and used that risk in the basis for the PTS screening criteria. The screening criteria were expressed in 10CFR50.61 as values of Reference Temperature – PTS (RT_{PTS}) that reflected a vessel material reference temperature adjusted for the effect of neutron irradiation embrittlement. The screening criteria in 10CFR50.61 are 270ºF for an assumed axial flaw and 300ºF for an assumed circumferential flaw. The RT_{PTS} values were determined using materials data corresponding to the unirradiated and irradiated conditions (Reference 2.1.3-1). The projected RT_{PTS} values at the end of the current license for each of the Waterford 3 beltline materials are summarized in Table 2.1-2. The highest RT_{PTS} value for the Waterford 3 reactor pressure vessel at the end of the current license, 32 EFPY, was determined to be 53°F and is associated with lower shell course plate M-1004-2. The RT_{PTS} values ranged from -30°F to 53°F for the reactor vessel beltline plates and welds. These values are well below the PTS screening criterion of 270°F for an assumed axial flaw. They are based on vessel fluence calculations (Reference 2.1.3-2) that reflect the Cycle 12 power uprate to 3441 MWt and the Cycle 14 EPU. The fluence calculations were done following the guidance of RG 1.190. Therefore, the effect of EPU is negligible with respect to the PTS screening criterion.

Conclusions

Updated projections of neutron fluence were calculated following the guidance of Regulatory Guide 1.190 and were found to be conservative relative to the fluence assumed for the current RT_{PTS} projections. The updated RT_{PTS} projections were generated in accordance with 10CFR50.61 and account for the changes including the Cycle 14 EPU. All of the Waterford 3 beltline materials are projected to meet, with a substantial margin, the screening criteria of 10CFR50.61. The updated RT_{PTS} projections demonstrate that the requirements of GDC 14, GDC 31, 10CFR50 Appendix G and 10CFR50.60 continue to be satisfied following implementation of the EPU.

References

2.1.3-1 WCAP-16088-NP, *Waterford Unit 3 Reactor Vessel Heatup and Cooldown Limit Curves for Normal Operation*, July 2003. (To be included with P-T limit Technical Specification change submitted to the NRC by the end of 2003.)

2.1.3-2 WCAP-16002-NP, *Analysis of Capsule 263 from the Entergy Operations Waterford Unit 3 Reactor Vessel Radiation Surveillance Program*, Revision 0, March 2003. (Submitted to the NRC by Entergy letter dated March 28, 2003.)

Table 2.1-2
RT_{PTS} Predictions for Waterford Unit 3 Beltline Region Materials at 32 EFPY

Material	Neutron Fluence[a]	Fluence Factor, FF[b]	Chemistry Factor, CF	ΔRT_{PTS} (°F) [d]	Margin (°F) [e]	$RT_{NDT(U)}$ (°F) [f]	RT_{PTS} (°F) [g]
M-1003-1	2.48E19	1.244	20	24.9	24.9	-30	20
M-1003-2	2.48E19	1.244	20	24.9	24.9	-50	0
M-1003-3	2.48E19	1.244	20	24.9	24.9	-42	8
M-1004-1	2.47E19	1.243	20	24.9	24.9	-15	35
M-1004-2	2.47E19	1.243	12.4[c]	15.4	15.4	22	53
M-1004-3	2.47E19	1.243	20	24.9	24.9	-10	40
101-124 A,B,C	2.48E19	1.244	27	33.6	33.6	-60	7
101-142 A,B,C	2.47E19	1.243	35	43.5	43.5	-80	7
101-171	2.47E19	1.243	16.2[c]	20.1	20.1	-70	-30

Notes:

(a) The fluence, f, was taken from the peak azimuthal location (n/cm^2, E>1.0 MeV) from analysis of surveillance data in WCAP-16002-NP.

(b) $FF = f^{(.28 - 0.1*\log f)}$; where f is the clad/base metal interface fluence.

(c) Chemistry factor is taken from analysis of credible surveillance data in WCAP-16002-NP.

(d) $\Delta RT_{PTS} = CF * FF$

(e) Margin = $2*(\sigma_u^2 + \sigma_\Delta^2)^{1/2}$ where $\sigma_u = 0$ (see Note f).

(f) Initial RT_{NDT} values are measured values for plates and welds.

(g) $RT_{PTS} = RT_{NDT(U)} + \Delta RT_{PTS}$ + Margin (°F)

RT_{NDT} – Reference temperature – nil ductility temperature
$RT_{NDT(u)}$ – Reference temperature – nil ductility temperature (unirradiated)

2.1.4 Reactor Internals and Core Support Materials

Description of Analysis

During service, reactor vessel internal (RVI) and core support component materials are exposed to a high temperature aqueous environment, fast neutron irradiation and applied loads. Prolonged exposures to these conditions will result in changes to the mechanical and corrosion properties of the RVI component materials and may result in age related degradation of the materials. The Cycle 14 EPU will not result in an increase in the nominal primary coolant temperature. The neutron fluence and gamma heating received by the RVI components is actually decreased relative to the original design given the use of low leakage fuel management early in the life of Waterford 3.

An evaluation was performed to assess the effect of these condition changes on the potential for additional degradation of the RVI component materials. The RVI components are fabricated from several grades of wrought austenitic stainless steel, cast austenitic stainless steel, wrought martensitic stainless steel and precipitation hardened stainless steel. The predominant grade of material is Type 304 stainless steel. Much of the RVI components were fabricated using welding. Controls placed on the fabrication and processing of the reactor vessel internal and core support component materials are described in the Waterford 3 FSAR, Chapter 4, Section 4.5.2.

The evaluation addressed age-related degradation mechanisms that could be affected by the reactor coolant temperature and the decrease in neutron and gamma irradiation flux. Stress corrosion cracking (SCC) of stainless steel is very sensitive to reactor coolant temperature. However, the use of annealed austenitic stainless steel with fabrication controls, primary chemistry controls on the reactor coolant, and low operational stresses will continue to ensure that SCC potential remains low during future operation with the EPU. Stress relaxation is also very sensitive to reactor coolant temperature, but the lack of a temperature increase will not have an effect on thermal relaxation, and the reduction in gamma and neutron flux will reduce irradiation induced stress relaxation. The decrease in neutron and gamma irradiation flux with the planned EPU will ensure that the susceptibility to irradiation embrittlement and irradiation assisted stress corrosion cracking will remain low. The EPU will have no effect on corrosion, flow-assisted corrosion, creep or mechanical wear of the reactor vessel internal and core support component materials.

Conclusions

An evaluation was performed to assess the effect of the proposed Cycle 14 EPU on the susceptibility of reactor vessel internal and core support component materials to known degradation mechanisms. There is no increase in the nominal reactor coolant temperature (hot leg) associated with the EPU. The neutron and gamma flux are lower than considered in the original design. Therefore, there is no change to the susceptibility of the RVI materials to the age-related degradation mechanisms. All of the RVI and core support component materials are expected to meet their intended function, including the requirements of GDC 1 and 10CFR50.55a.

2.1.5 Reactor Coolant Pressure Boundary Materials

Description of Analysis

During service, the reactor coolant pressure boundary (RCPB) materials are exposed to a high temperature aqueous environment and applied loads. Prolonged exposures to these conditions may result in changes to the mechanical and corrosion properties of the component materials and may result in age-related degradation of the materials. The Cycle 14 EPU for Waterford 3 will result in a minimal increase in the nominal hot leg temperature and a 2.0°F decrease in the cold leg temperature. The ferritic materials were originally procured and tested in accordance with 10CFR50, Appendix G. The lack of anticipated changes from the planned EPU will have no effect for the hot leg components and are beneficial for the cold leg components with respect to pressurized water stress corrosion cracking (PWSCC) of dissimilar weld joints or thermal aging of cast austenitic stainless steel components.

Conclusions

Based on the above considerations, the changes associated with EPU are not expected to affect the structural integrity of the RCPB components. All of the RCPB materials will continue to meet the requirements of GDC 1, GDC 4, GDC 14, GDC 31, 10CFR50 Appendix G, and 10CFR50.55a following implementation of the EPU.

2.1.5.1 Alloy 600 Primary Water Stress Corrosion Cracking

Description of Evaluation

PWSCC of Alloy 600 components is a major materials issue currently confronting all PWR owners. Alloy 600 nozzles and associated weld metals (Alloy 182 and 82) are used throughout the primary system at most CE-designed PWRs, including Waterford 3. When highly stressed and exposed to primary coolant at elevated temperatures, Alloy 600 has displayed a propensity for intergranular stress corrosion cracking. Cracking has been predominantly in Alloy 600 nozzles, but there has been cracking in the weld metals, also. Waterford 3 has experienced PWSCC in Alloy 600 nozzles in pressurizer and hot leg piping applications.

At Waterford 3, Alloy 600 is used in various applications including pressurizer instrumentation nozzles and heater sleeves, hot and cold leg piping resistance temperature detector (RTD) and pressure measurement/sampling nozzles, reactor vessel head, control element drive mechanism (CEDM) and in-core instrumentation (ICI) nozzles and vent line, steam generator instrument nozzles and steam generator tubes. Alloy 600 type weld metals (Alloys 182 and 82) were used to make the partial penetration welds joining the various nozzle type applications to the components. In addition, there are various bimetallic weld joints in the primary piping, pressurizer and CEDM motor housings that have Alloy 182 weld metal.

EPU at Waterford 3 will result in changes in primary coolant temperatures. PWSCC is a thermally activated mechanism; thus, temperature changes could impact the timing and severity (extent) of PWSCC. EPU will result in minimal increase in nominal T_{hot} and a decrease (545.0 to 543.0°F) in T_{cold} at Waterford 3. The potential for PWSCC was assessed, including the effects of temperature changes as a result of the power uprate.

The pressurizer will continue to operate at the same temperature as before uprate; thus, the potential for PWSCC of pressurizer instrument nozzles and heater sleeves will not change.

The temperature experienced by the cold leg Alloy 600 instrument and sampling line nozzles will decrease slightly as a result of power uprate. Thus, the PWSCC susceptibility of these nozzles, their welds and safe end welds on the reactor coolant pump suction and discharge will not be adversely affected by the EPU.

There is minimal impact in susceptibility of hot leg instrument nozzles due to the slight increase in nominal hot leg temperature due to EPU. The Alloy 600 program will continue to monitor for potential leakage and repair as necessary.

The susceptibility of the reactor vessel head CEDM and ICI nozzles to PWSCC remains unchanged since the hot leg temperature remains below the presently analyzed value. Waterford 3 is ranked as a high susceptibility plant based on the criteria in the recent NRC order on interim inspection requirements. Waterford 3 is complying with the inspection requirements as stated in the NRC order.

The Waterford 3 steam generator heat transfer tubes are Alloy 600. Since the power uprate will not result in a significant temperature increase, and since PWSCC is a thermally activated process, the uprate is not expected to increase susceptibility to PWSCC. The steam generator tubes at Waterford 3 are inspected by eddy current testing (ECT) on an established periodic basis. Those areas most susceptible to development of PWSCC (small radius u-bends and tubesheet expansion transitions) are inspected with equipment and procedures that have been demonstrated to be capable of detecting axial and circumferential PWSCC. The scope of the examination is dictated by inspection findings and expanded as necessary.

Conclusions

In summary, the planned EPU will have a slight adverse effect on Alloy 600 nozzles, Alloy 182/82 weld metals and steam generator tubes at Waterford 3. Ongoing Alloy 600 aging degradation management programs and compliance with the inspection requirements as stated in the NRC order address the Alloy 600 issues.

2.1.6 Leak-Before-Break Evaluation

The evaluations documented in Topical Report CEN-367-A, *Leak Before Break Evaluation of Primary Coolant Piping in Combustion Engineering Designed Nuclear Steam Supply Systems,* are applicable considering the revised normal operation loads due to power uprate. This evaluation confirms that the dynamic effects of postulated main loop pipe breaks can be excluded from the design basis of main loop components, internals, fuel, supports, attachments and appurtenances, and attached piping systems under EPU conditions. Branch line pipe breaks (BLPBs) are required to be considered.

Elimination of postulated primary loop pipe ruptures from the design basis is permitted by the revised GDC 4 of Appendix A to 10CFR50. The revised rule is based on the development of advanced fracture mechanics technology using the LBB concept. The revised rule was published (52FR41288) on October 27, 1987. The criteria for evaluation of compliance with GDC 4 are defined in Chapter 5 of US Nuclear Regulatory Commission Document

(NUREG)-1061, Volume 3. The criteria address loading criteria, degradation of piping resulting from stress corrosion cracking, fatigue or waterhammer, materials properties, postulated through wall flaws and leak detection capability, margin in terms of applied loads, and margin between the leakage-size flaw and the critical size flaw.

The use of Topical Report CEN-367-A requires leakage detection systems to meet the guidelines of RG 1.45, *Reactor Coolant Pressure Boundary Leakage Detection Systems*. Waterford 3 leakage detection systems that meet RG 1.45 requirements are in place.

2.1.6.1 Methodology Used for this Evaluation

Each of the criteria for evaluation of compliance with the revised GDC 4 was reviewed for impacts due to power uprate. The loads calculated for the RCS with EPU were evaluated by comparing them to the loads used in the original LBB evaluation.

2.1.6.2 Evaluation Results

The six LBB compliance criteria from NUREG-1061 Volume III, which were considered and were met in Topical Report CEN-367-A, are met for EPU. These six criteria are summarized below:

(1) Loads are considered at locations of highest stress and weakest materials.

(2) The piping system is shown to be resistant to stress corrosion cracking, fatigue and waterhammer.

(3) Material data from base metal, weldments and safe ends are considered.

(4) A through-wall flaw is postulated at the highest stressed locations determined from criteria 1.

(5) The postulated leakage flaw is shown to be stable under (normal plus safe shutdown earthquake [SSE]) loads with a margin of 1.4.

(6) The postulated leakage flaw is shown to be stable under 2 x (normal plus SSE) loads.

Compliance with all criteria was found to be unaffected by EPU. All piping load revisions were found to be within the envelope loads employed in the CEN-367-A evaluation. Therefore, the evaluations of the CEN-367-A for Criteria (1), (5), and (6) are applicable for Waterford 3 following power uprate. Criteria (2) and (3) are not impacted by EPU because there is no impact on stress corrosion, water hammer or fatigue of the main loop piping and because there is no change in materials.

Criterion (4) is addressed as follows. Power uprate does not impact the leakage detection systems employed at Waterford 3. Since the evaluation in the CEN-367-A conservatively employed a pressure only loading in the determination of initial flaw size, the evaluation remains enveloping. The flow rate correlation for leakage through a flaw is not impacted by EPU. Therefore, the Criterion 4 evaluations remain applicable to Waterford 3 following EPU.

Through application of LBB technology, the need to consider the mechanical (dynamic) effects of main coolant loop breaks (MCLBs) was eliminated. The next limiting set of pipe breaks (with respect to dynamic effects on the RCS) consisted of all primary and secondary side BLPBs interfacing with the RCS. Of these, the controlling breaks with respect to RCS response are breaks in the largest tributary pipes:

a) Main steam line (MSL)
b) Feedwater line (FW)
c) Surge line (SL)
d) Safety injection line (SI)
e) Shutdown cooling line (SDC)

Further review was performed during the RCS pipe break analytical process to determine the locations and loadings associated with postulated breaks in these piping systems that would have the maximum effect on RCS response. The final set of BLPB cases analyzed is given in Section 2.2.

The structural integrity of the Waterford 3 RCS has been verified for EPU conditions to 3716 MWt. Section 2.2 describes the analyses and assessments of RCS components for power uprate.

2.1.7 Protective Coating Systems (Paints) – Organic Materials

FSAR Section 6.1.2, “Organic Materials,” provides a discussion of organic materials, including protective coatings, used inside the Waterford 3 containment.

Waterford 3 Service Level 1 coatings were selected and tested to meet design basis accident (DBA) and normal conditions. These coatings meet the requirements of ANSI Standards N5.12, *Protective Coatings (Paints) for the Nuclear Industry*, dated June 20, 1974 and N101.2, *Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities*, dated May 30, 1972. The Quality Assurance during manufacturing, transportation and storage is in compliance with ANSI Standard N101.4, *Quality Assurance for Protective Coating Applied to Nuclear Facilities* dated November 1972, in conjunction with the general quality assurance requirements of N45.2, *Quality Assurance Program Requirements for Nuclear Power Plants*.

Programs exist at Waterford 3 that provide controls for the procurement, application, and maintenance of Service Level 1 protective coatings used inside the containment in a manner that is consistent with the Waterford 3 licensing basis and regulatory requirements. The requirements of 10CFR50 Appendix B are implemented through specification and procedures that delineate appropriate technical and quality requirements for the Service Level 1 coatings program that includes ongoing maintenance activities. Adequate assurance that the applicable requirements for the procurement, application, inspection, and maintenance are implemented is provided by the procedures and programmatic controls, approved under the Waterford 3 Quality Assurance Program.

The EPU conditions that can affect the qualification of the Service Level 1 in containment coatings are changes in pressure, temperature, radiation, and chemistry.

The impact of the EPU on these parameters is evaluated in the following sections of this report:

Section No.	Title
2.1.12	Water Chemistry Evaluation
2.3.1	Environmental Qualification of Electrical Equipment
2.5.2	Containment Review Considerations
2.7.1	Source Terms for Radwaste Systems Analysis

Conclusions

The changes in pressure, radiation, and chemistry for DBA and normal conditions for EPU are bounded by current existing DBA and normal conditions for these parameters. The current existing environment qualification for temperature following a DBA LOCA that is used to qualify protective coatings in containment bounds the EPU conditions. Consequently, the protective coatings remain qualified for EPU conditions.

2.1.8 Flow-Accelerated Corrosion

An evaluation was performed using Electric Power Research Institute's (EPRI's) CHECWORKS code to estimate the effects that EPU would have on components determined to be susceptible to flow-accelerated corrosion (FAC), and modeled by the CHECWORKS code at Waterford 3. CHECWORKS is able to model piping greater than 2 inches in diameter. The EPU Heat Balance Diagram (HBD) reflected increased flow rates, changes in steam quality, temperatures, and pressures. The changes to the plant operating parameters were used to determine the CHECWORKS-predicted effects of EPU on FAC wear rates.

Evaluation

Prior to performing this study, an extensive review and update of the existing Waterford Unit 3 CHECWORKS model was performed. This effort included updating the current model and establishing the EPU operating conditions for all modeled FAC susceptible systems. The updated model incorporates all inspection data for calibration of predicted wear rates.

This study compared the current predicted wear rates and the post-EPU predicted wear rates of all modeled components in the FAC program. The modeled systems are feedwater, blowdown, heater drains, extraction steam, miscellaneous drains, and condensate drains. A summary of the most significant increases in wear rate is shown in Table 2.1-3 (wear rates are in mils per year).

Conclusion

The CHECWORKS analysis of the effects of the EPU on FAC susceptible systems at Waterford 3 using the EPU HBD, predicted that the post-uprate FAC wear rates will increase by a low to moderate amount. During each outage however, inspections are performed based on an aggressive program to identify piping in need of replacement. Repairs are performed to preclude falling below minimum wall thickness. The increase in post uprate FAC wear rate and consequent reduction in pipe wall thickness is monitored via the Waterford 3 FAC inspection

program. The program requires that if the measured wall thickness at the current refueling outage, and/or the projected wall thickness at the next refueling outage falls below the code allowable wall thickness, the piping should be replaced with like for like or with corrosion resistant material. This applies to both large bore and small bore piping.

Table 2.1-3
Projected Wear Rates

CHECWORKS Run Name	Ave % Change in Wear Rate	Max % Change in Wear Rate	Min % Change in Wear Rate	Ave EPU Wear Rate
CD01-HTR 5 to HTR 4	15%	19%	14%	6.07
CD02-HTR 4 to HTR 3	12%	17%	12%	9.55
CD03-HTR 3 to HTR 2	8%	12%	7%	10.12
CD04-HTR 2 to HDR	7%	11%	7%	8.04
CD05-HDR to FWP	5%	8%	4%	7.08
FW01-FWP to HTR 1	11%	14%	11%	4.58
FW02-HTR 1 to SG	11%	14%	11%	4.95

HTR – heater
HDR – heater drain
FWP – feedwater pump

2.1.9 Steam Generator Tube Inservice Inspection and Other Uprate Considerations

Waterford 3 has implemented the requirements of Nuclear Energy Institute's (NEI) 97-06 *Steam Generator Program Guidelines*. These guidelines provide the framework for structuring and strengthening steam generator programs. The elements of the program incorporate a balance of prevention, inspection, evaluation, repair and leakage monitoring. Utilizing these elements brings consistency in application to managing steam generator programs. The program is based on the American Society of Mechanical Engineers (ASME) code for structural integrity.

The power uprate project for Waterford 3 will result in higher feedwater flow, temperature changes, and potentially higher sludge loading to the steam generators. To address these issues, the program elements require that both the identified and potential damage mechanisms be addressed in the degradation assessment. The degradation assessment is performed prior to the inspections so that the scope and techniques used will address both the identified and potential degradation mechanisms. The changes in physical parameters that will result from the power uprate can potentially cause an increase in growth rates and initiation of cracking in the steam generator tubing. It is not anticipated that a "new" form of degradation will result from the uprate. It is anticipated that increased wear at the anti-vibration supports could result from changes in the thermal-hydraulics from increased flow.

A second requirement of the program is to perform an operational assessment to evaluate the end-of-cycle (EOC) conditions. This evaluation accounts for the expected upcoming cycle

parameters. Therefore, the evaluation prior to Cycle 14 will account for the changes in temperature on crack initiation and growth and the reduction (i.e., 1.0 gpm to 0.75 gpm) of the allowed primary-to-secondary leakage rate proposed for Technical Specification Section 3.4.5.2, “Operational Leakage.” Utilizing this information with the inspection results will determine EOC conditions which are compared to the performance criteria for burst and leakage. This will determine if the plant can operate full cycle or will be limited based on the projected degradation.

Implementation of the NEI 97-06 program ensures that changes in the conditions of the steam generator tubing that are the result of power uprate will be identified and addressed.

Repair techniques (e.g., plugs, sleeves, etc.) are addressed in Section 2.2.2.1.4.6.2 of this report.

Conclusions

Steam generator tube integrity will continue to be maintained in accordance with NEI 97-06 following the EPU.

2.1.10 Steam Generator Blowdown System

The Steam Generator Blowdown System (SGBS) is described in FSAR Section 10.4.8.

The SGBS is designed to fulfill the following requirements:

a) To maintain the steam generator shell side water chemistry by maintaining continuous blowdown during normal plant operating conditions.

b) To direct the blowdown to the blowdown demineralizers for further treatment.

c) To achieve and maintain the chemistry requirements of the water inventory in the Condensate and Feedwater Systems (CFWSs) prior to introduction of feedwater into the steam generators during plant start-up and operation.

The EPU review examined the effect of the higher feedwater flow rate on the SGBS.

Evaluation

Typical operational blowdown rates during normal operation are approximately 1% of current feedwater flow. The blowdown system is sized to handle 2% of the original rated flow or 650 gpm. Although the feedwater flow will be increasing as a result of EPU, the capacity of the SGBS under EPU conditions will still be adequate to maintain chemistry in the secondary system.

Conclusion

There are no design basis changes in the SGBS. The system will continue to meet the requirements of GDC 14 (secondary water chemistry), and satisfactorily perform the functions listed above under EPU conditions.

2.1.11 Chemical and Volume Control System

The Chemical and Volume Control System (CVCS) is described in FSAR Section 9.3.4. The CVCS consists of four basic subsystems as follows:

- Letdown
- Charging
- Boron addition
- Reactor makeup water

Each of these subsystems consists of various valves, tanks, pumps, and instrumentation that perform the functions of the CVCS. Its primary design function is to maintain reactor coolant system inventory and control RCS chemistry. Other RCS support functions include serving as a part of the RCS pressure boundary, aiding in containment isolation, providing auxiliary pressurizer spray and providing for RCP seal bleedoff flow. The CVCS functions were evaluated for performance under EPU conditions and were verified to be capable of being performed without system modifications. The requirements for the boric acid makeup tank (BAMT) volume and concentration will change.

The CVCS is designed to perform the following functions:

a) Maintain the chemistry and purity of the reactor coolant during normal operation and during shutdowns.
b) Maintain the required volume of water in the RCS compensating for reactor coolant contraction or expansion resulting from changes in reactor coolant temperature and for other coolant losses or additions.
c) Provide a controlled path for discharging reactor coolant to the Boron Management System (BMS) and venting gas to the Gaseous Waste Management System (GWMS).
d) Control the boron concentration in the RCS to obtain optimum control element assembly (CEA) positioning, to compensate for reactivity changes associated with major changes in reactor coolant temperature, core burnup, and xenon variations, and to provide shutdown margin for maintenance and refueling operations.
e) Provide auxiliary pressurizer spray for operator control of pressure during the final stages of shutdown and to allow pressurizer cooling.
f) Collect the controlled bleedoff from the reactor coolant pump seals.
g) Inject concentrated boric acid into the RCS upon a safety injection actuation signal (SIAS).

Evaluation

The chemistry and purity of the RCS will be maintained under the EPU conditions. Although the EPU will cause an increase in the generation of activity in the RCS, this change is considered to be negligible. The higher power level may necessitate changes to the RCS chemistry requirements, but any changes will be well within the capabilities of the CVCS. Primary chemistry is discussed in Section 2.1.12 of this report.

The ability of the CVCS to provide the required shutdown margin has been evaluated and found to be adequate for EPU, with exception to the operating limits of the BAMT. FSAR Section 9.3.4.3.1 explains that CVCS letdown is not required to achieve cold shutdown. In this situation (a cooldown without letdown), the total makeup that can be added to the RCS is limited by the total RCS shrink during cooldown. Because of the core design for EPU, the minimum required boron concentration in the BAMT will need to be increased. This has necessitated changes to Technical Specifications.

The other key functions and design criteria of the CVCS have been reviewed and are not impacted by the EPU. No system modifications are required to accommodate the EPU.

Conclusion

The analyses related to the effects of the proposed EPU on the CVCS have been reviewed. The effects of changes in the temperature of the reactor coolant and their effects on the CVCS due to the proposed EPU have been adequately addressed and it has been demonstrated that the CVCS will maintain its design function. Based on this, it is concluded that the CVCS will continue to be acceptable and will continue to meet the requirements of GDC 14 and GDC 29 following implementation of the proposed EPU.

2.1.12 Water Chemistry Evaluation

Water chemistry is discussed in Waterford 3 FSAR in Section 9.3.4 (primary chemistry) and Section 10.3.5 (secondary chemistry). These sections do not need to be modified as a result of EPU.

The Waterford 3 primary chemistry and secondary chemistry programs are governed by the Waterford 3 Strategic Primary Water Chemistry Plan and Strategic Secondary Water Chemistry Plan, as required by NEI 97-06, *Steam Generator Program Guidelines*. The Strategic Water Chemistry Plans have been evaluated for the EPU, and were found to be adequate for EPU conditions. No revisions to the Waterford 3 Strategic Water Chemistry Plans are required as a result of the EPU. The Waterford 3 program to control primary water pH with lithium to buffer boric acid does not need to be changed in light of the EPU. The Waterford 3 FAC program takes input from the secondary chemistry program to update the FAC model, as required. The secondary water chemistry program as described in the Strategic Secondary Water Chemistry Plan is adequate to provide this input to the FAC program, and does not need to be changed in light of the EPU.

In addition, the currently existing Analysis of Record (AOR) for the mass of trisodium phosphate dodecahydrate required in the containment sump for post-LOCA pH control remains valid – the boric acid inventory assumed in that reference analysis continues to bound the boric acid inventory after the power uprate.

Water chemistry at Waterford 3 is adequate for EPU.

2.2 MECHANICAL AND CIVIL ENGINEERING

The structural integrity analyses assessed the impact of the design condition changes by making comparisons to quantifiable limits. For example, structural analyses of normal operation and pipe break conditions produced loads on the major components, nozzles and supports of the RCS. Due to the elimination of main coolant loop pipe breaks (MCLBs) via leak-before-break (LBB), the pipe breaks analyzed under power uprate conditions were branch line pipe breaks (BLPBs), as listed in Section 2.2.1.1. Since EPU does not cause changes to either the RCS structure or the seismic excitation, seismic loads on the Reactor Coolant System (RCS) that were previously calculated for pre-uprate conditions remain applicable to the power uprate conditions. The normal operation, seismic and BLPB loads were combined according to regulatory guidelines and were used to calculate stresses. The stresses were then compared to the American Society of Mechanical Engineers (ASME) Code stress limits to demonstrate that the structural integrity of the components was maintained. Therefore, the results were system loads, and the limits were allowable stresses. The new design basis analyses employed are summarized below.

Section 2.2.2 discusses the main coolant loop, the pressurizer and the surge line. Included in the main coolant loop is the main coolant piping itself, reactor vessel (RV), the steam generators (SGs), the reactor coolant pumps (RCPs) and RCP motors, and supports for the RV, the SGs, and the RCPs. Section 2.2.3 discusses RVI and fuel design qualifications.

2.2.1 Reactor Coolant System Pipe Break Analysis

The purpose of this analysis was to determine the dynamic response of the RCS to postulated pipe breaks. Evaluations were performed for system operating parameters consistent with the uprate core power level, so that the results are applicable to EPU.

The dynamic response of the RCS to pipe breaks was determined, and response loads, motions and spectra at pre-determined interface locations were provided as input to specifications and to downstream structural analyses. Response loads and motions from the RCS analysis were provided as input to the Nuclear Steam Supply System (NSSS) component specifications and balance of plant piping evaluations.

Hot leg response motions and spectra due to pipe breaks other than surge line breaks were provided as input to the surge line analysis. The response of the surge line to these excitations was also determined, and response loads at pre-determined surge line pipe, nozzle, and support locations were provided as input to the NSSS component piping specification.

2.2.1.1 Regulatory Basis

Per General Design Criterion (GDC) 4, Waterford 3 safety systems are required to be designed to withstand the consequences of postulated pipe breaks so as not to compromise safe shutdown. The RCS, its components, supports, appurtenances, reactor vessel internals and connected tributary piping, including the surge line, are designed to faulted loading conditions, which include loads resulting from postulated pipe breaks.

The original version of GDC 4, the mechanical design basis for the original Waterford 3 RCS configuration included postulated breaks in all high energy piping above 1 inch in diameter. Through application of LBB technology, which was subsequently allowed by revisions to GDC 4, the need to consider the mechanical (dynamic) effects of MCLBs was eliminated. Following the application of LBB, the remaining pipe breaks in the mechanical design basis of the RCS are all primary and secondary side BLPBs interfacing with the RCS. Of these, the limiting breaks with respect to RCS structural considerations are breaks in the largest tributary pipes:

- Main steam line (MSL)
- Feedwater line (FW)
- Surge line (SL)
- Safety injection line (SI)
- Shutdown cooling line (SDC)

A review of pipe stresses and fatigue usage factors (where appropriate) for the as-built configurations of these piping systems eliminated many intermediate breaks in these branch lines. The final intermediate breaks in all these piping systems except the surge line were each represented by an envelope set of loads at its RCS nozzle interface. Due to the asymmetry of the Waterford 3 “A” and “B” loops, SI breaks were postulated off both “A” and “B” loops. All non-negligible intermediate surge line breaks were maintained as separate break cases. The final set of BLPBs postulated and analyzed for RCS response for the EPU consisted of 19 BLPBs, as listed in Table 2.2-1.

The response of branch lines to 19 cases of BLPBs was evaluated. See Sections 2.2.1.2 and 2.2.1.3 of this document.

2.2.1.2 Evaluation Methodology

There are differences between the pipe break analysis for the RCS under pre-uprate conditions vs. the RCS under EPU conditions. The original dynamic pipe break analysis of the RV and its supports was performed using non-linear time history methods only for the RV response. The mathematical model was defined using the STRUDL computer code representation of the RV, RV internals, RV columns and hot legs, and the non-linear time history analyses were performed using the CEDAGS computer code. The model was analyzed for MCLBs that were most significant to RV response, i.e., terminal end guillotines at the RV inlet and outlet nozzles and at the SG primary inlet nozzle. Break opening times greater than 1 millisecond that were used for flow area calculations were determined on mechanistic breaks from Topical CENPD-168-A, which was approved by the NRC. Mass-stiffness (α-β) damping of not more than 3% at significant modes of vibration was used in the time history analyses of the RV. The remainder of the RCS was analyzed statically for the set of MCLBs in the original mechanical design basis. The SGs, RCPs and RCS piping were analyzed dynamically using separate mathematical models to account for dynamic effects of gaps at component restraints and at pipe stops.

Table 2.2-1
Branch Line Pipe Breaks Analyzed for RCS Response

	Case #	Description of Break Location
1	fw 1n	Feedwater guillotine at SG1 terminal end
2	fw 1i	Feedwater intermediate break
3	ms 2n	Main steam guillotine at SG1 terminal end
4	ms 2i	Main steam intermediate break
5	sl 3n	Surge line guillotine at hot leg 1 terminal end
6	sl 3a	Surge line intermediate guillotine at 1st surge line elbow
7	sl 3b	Surge line intermediate slot at 1st surge line elbow
8	sl 3c	Surge line intermediate guillotine at 2nd surge line elbow
9	sl 3d	Surge line intermediate guillotine at 3rd surge line elbow
10	sl 3e	Surge line intermediate slot at 3rd surge line elbow
11	sl 3f	Surge line intermediate slot at 3rd surge line elbow
12	sl 3g	Surge line intermediate guillotine at 3rd surge line elbow
13	sl 3h	Surge line intermediate guillotine at 5th surge line elbow
14	si 4nr	Safety injection guillotine at 1A RCP discharge leg terminal end
15	si 4lr	1A loop safety injection line intermediate slot
16	si 5nr	Safety injection line guillotine at 1B RCP discharge leg terminal end
17	si 5lr	1B loop safety injection line intermediate slot
18	sc 6n1	Shutdown cooling line guillotine at hot leg 1 terminal end
19	sc 6n2	Shutdown cooling line guillotine at hot leg 2 terminal end

For the RCS under EPU conditions, non-linear response time history analyses were performed to calculate the RCS response for all the limiting BLPBs. These BLPBs replaced the MCLBs in the mechanical design basis, following elimination of the MCLBs via LBB evaluation. For the BLPB analyses of the RCS for EPU, a three-dimensional ANSYS model of the entire RCS was developed for Waterford 3 plant-specific boundary conditions, SG, RV and RCP supports, current fuel and updated closure head lift rig (CHLR) and control element drive mechanism (CEDM) configurations. The response of the entire RCS to BLPBs was calculated using non-linear response time history analysis. The ANSYS computer code was used to perform the dynamic transient time history BLPB analyses, using the modal superposition method with 3% damping applied at each mode.

For the pipe break model, gapped and preloaded RCS supports were used. Directional spring supports gaps and preloads at full power were included for all pipe break analyses.

As in the original pipe break analysis, a reduced model of the RVI was included in the RCS model for blowdown load inputs and internals-to-RV shell interaction effects. This RVI model included hydro-mass and coupling terms, as well as nodes for RV blowdown input loadings, and was based on the detailed models used for the analysis of the RVI due to pipe break. The RVI snubbers between the core support barrel (CSB) and the inside of the RV lower head were modeled as gapped springs.

The non-linear parameters used in the analysis are the gaps and preloads from two-way gapped supports and one-way preloaded supports between the major components of the reactor coolant system and the building. All gaps and preloads are modeled at full power as follows:

- Two-way (plus and minus) horizontal gapped supports were modeled at the upper and lower support keys of the SG in the direction perpendicular to the hot leg axis.
- Two-way gaps, representing the mechanical deadband in the SG and RCP snubbers prior to actuating, were used.
- Two-way gaps at each horizontal support of the RV, all tangential to the RV circumference were used.
- One-way supports at each of four vertical support pads at each SG and at the RV were used. At full power, all four RV vertical supports and three of the four SG supports are preloaded with loads due to dead weight (DWt) plus RCS thermal expansion. The SG vertical supports closest to the RV are modeled with a downward gap instead of a preload, because the thermal expansion of the RCS lifts the SGs off those supports (as they did under pre-uprate conditions).
- Stops and RCS pipe whip restraints that are currently in place at Waterford 3 to mitigate the consequences of MCLBs, were not expected to engage due to BLPBs and were not modeled as gapped supports in the BLPB analyses. This was confirmed by the analysis.

Input loadings applied to the RCS included thrust at the break locations, jet impingement loadings at and away from the break locations, RV blowdown loadings for the primary side BLPBs, and asymmetric pressurization loads on the SG and RCPs for all pipe breaks except the MSLB (which does not cause SG subcompartment pressurization). Jet targets and jet impingement loadings were based on cone jets or fan jets, depending on the break type and break scenario. After elimination of main coolant loop breaks by application of LBB, none of the limiting BLPBs for Waterford 3 causes asymmetric pressurization to occur between the RV cavity and the RV shell.

The results of the detailed RVI loads analysis are given in Section 2.2.3 of the EPU Report.

To account for depressurization blowdown loadings inside the RV in the RCS BLPB analysis, a simpler RVI model was built. The basis for this simpler model is the detailed RVI model that is later used in the RVI loads analysis. The simplified RVI model contains fewer nodes and fewer dynamic degrees of freedom than the detailed RVI model, but it maintains the total mass, center of gravity, structural properties, natural frequencies, and hydrodynamic mass couplings of the detailed model. Since the simpler model has fewer loading points for the blowdown loads than the detailed model, some of the blowdown loadings are combined for the RCS analysis. This RVI model and sets of blowdown load time histories were used for the RCS primary side BLPB analyses.

This methodology is the same as previously used for RCS asymmetric loads analysis which was approved by the NRC for main coolant loop breaks.

2.2.1.3 Analysis Results

RCS component and support loads were maximized over the response time history for each BLPB analyzed. These loads were used in the evaluations of the SG, RCP, and RV nozzles and their supports, as well as main coolant loop (MCL) piping and the RCP motor. Response displacement and acceleration time histories and acceleration response spectra were generated at the surge line nozzle interface, branch line RCS nozzle interfaces and the RV shell (at the upper head, closure flange and CSB snubber elevations). Response displacements maximized over time for each pipe break case were also determined. These results were used in the evaluations of tributary piping and RCS components. All results were acceptable as discussed in the following sections.

The subsequent tributary line analyses included the effects of the BLPB nozzle interface displacements provided above. These analyses, in turn, provided interface nozzle loads due to BLPB, with which the RCS tributary nozzles were evaluated and found to be acceptable (see Section 2.2.2.1.4.5.3 of this document).

2.2.2 Pressure-Retaining Components and Component Supports

2.2.2.1 Nuclear Steam Supply System Piping, Components, and Supports

2.2.2.1.1 Effect of RCS Transients on RCS Component Stresses and Cumulative Usage Factors

Power uprate resulted in minor changes to as-calculated normal operation transients. A detailed evaluation of the changes in stresses and fatigue levels in the RCS system due to these transients was performed to demonstrate that the originally specified design transients for Waterford 3 remain applicable under EPU conditions. This was accomplished by demonstrating that transients affected by EPU have no significant effect on the stresses or cumulative usage factors (CUFs) of the limiting RCS components. The transients affected by power uprate with potential to affect RCS components are:

- Reactor Trip
- Loss of Load
- Plant Loading
- Plant Unloading
- Plant Heat-up and Cooldown

The evaluations performed demonstrated that:

- The transients originally specified for design for Waterford 3 remain applicable for EPU to 3716 MWt.

2.2.2.1.2 RCS Dead Weight and Thermal Expansion Loads Analyses

This section describes the mechanical and thermal analyses performed to determine the response of the RCS when subjected to the effects of DWt and normal operation loads. The effect of power uprate on the existing design basis DWt and thermal expansion (TH) structural loads for the RCS were assessed, and where required, new design loads consistent with power uprate were produced and evaluated.

This section addresses RCS structural components needed for maintaining the reactor coolant pressure boundary (RCPB). This includes the MCL, pressurizer, and surge line. Tributary piping is addressed in Section 2.2.2.2 of this report.

The MCL is defined as:

- Reactor vessel (RV)
- Reactor coolant pumps (RCPs)
- Steam generators (SGs)
- Hot and cold leg piping
- RV, RCP, and SG supports

Although the RCP motors are outside of the RCPB, their mass and stiffness effects are included in the RCS analysis, as are the effects of the RV internals and RV head area components. The pressurizer is unaffected by EPU. However, the pressurizer surge and spray nozzles are qualified for EPU piping loads. RV internals are addressed in Section 2.2.3 of this report.

Normal operation loads are defined as the loads resulting from the signed addition of the DWt and TH loads for the full power condition. The original DWt and normal operation analyses performed for the RCS and surge line used system operating parameters consistent with the original core power level. The gross effects caused by EPU include slight increases in a limited number of RCS locations. These locations include the RCP upper lateral support links, the RCP suction nozzles, casings and motor mounts, the SG vertical side support pads, the RV inlet and SG outlet nozzles, and the suction leg piping. The changes are largely due to improved mathematical models of the RCS and the analytical codes used. Changes in loads due to the change in setpoint temperatures for EPU are minimal because the ΔT between the hot leg and cold leg is the same as used in the pre-uprate thermal expansion analysis.

The new sets of DWt and normal operation loads for the RCS and surge line are a combination of unmodified and modified design values. It was demonstrated through analysis that the original DWt and thermal movement design values at interface locations bound those due to EPU and, therefore were not modified.

2.2.2.1.2.1 Regulatory Basis

The MCL major components and their supports and the piping were evaluated for DWt and TH effects to determine loads due to normal operation loading conditions. The RCS was required to be designed with sufficient margin to assure that the design conditions of the RCPB were

not exceeded during any condition of normal operation including anticipated operational occurrences (AOOs). The process of assuring the integrity of the RCPB determines that normal operation structural loads are within allowable limits and remain so for power uprate conditions.

Normal operating limits were established for steady state and transient plant operations. The normal operating limits were selected so that adequate margin exists between them and the design (allowable) limits. The structural analyses described herein only considered the gross effects of the specified plant transients, e.g., the magnitude and direction of friction forces at the SG sliding base vertical pads during plant heat-up and cooldown.

RCS components were also analyzed for BLPB effects. The results of each of the individual analyses were used as inputs to the structural integrity analysis of the RCS, in which stress analyses were performed in accordance with the rules of Section III of the ASME Code.

The surge line was also evaluated for DWt and thermal expansion effects due to power uprate, the results of which were also used as input to ASME Code, Section III, stress analyses. In addition to DWt and thermal expansion effects, thermal transients were considered in the surge line analysis.

Thermal stratification is the controlling transient event for the surge line. The most significant stratification transients occur during plant heat-up and cooldown. Less significant thermal stratification events that occur during normal plant operation were also considered. Since the temperatures during heat-up and cooldown did not change for the RCS at uprated conditions, there was no impact on the stratification transients and the previous design basis transient results remained valid.

However, since the previous evaluations were performed using more limiting loads than applicable to Waterford 3, the reanalysis used plant-specific geometry for the surge line and, rather than using a full plastic analysis approach, benefited from a linear elastic-plastic analysis approach according to the ASME requirements.

Thermal anchor movement (TAM) data were part of the input to the thermal stratification analysis. As previously stated above, the original design basis TAMs were unmodified for EPU.

2.2.2.1.2.2 Methodologies Used for this Evaluation

The original design basis analysis for DWt and normal operation loads employed a three-dimensional mathematical model of the RCS. DWt and normal operation analyses of the RCS for power uprate were performed using the ANSYS model of the RCS, and results were reconciled to the original design basis loads and thermal movements.

The surge line was analyzed separately from the rest of the RCS. The surge line was modeled using the ANSYS computer code. The model contained three active dead weight hanger supports. Since it was known that the surge line would contact pipe whip restraints during the more severe thermal stratification events, these situations were properly evaluated by activating supports representing the contacted whip restraints for these events only.

2.2.2.1.2.3 Power Uprate Effects

The design and operating temperatures of the pressurizer, and therefore its thermal movements, were not affected by EPU. The TAMs on the hot leg piping did not change. Furthermore, and as discussed above, the hot leg surge line nozzle DWt and normal operation loads were not affected by EPU. Therefore, the surge line DWt and normal operation loads from the original design basis remained valid.

With respect to the pressurizer, the changes in the cold leg temperature due to EPU did not change the TAMs either at the hot leg/surge line interface, or along the surge line up to the surge line/pressurizer nozzle interface. Also, building thermal growths at the base of the pressurizer were unchanged, and design temperature conditions (653°F) affecting thermal expansion of the pressurizer enveloped the current conditions. Since the controlling transient conditions (including surge line thermal stratification effects) were unchanged from the original design basis, the original thermal analyses remained bounding. Therefore, the original design basis pressurizer loads and motions remained valid for EPU.

2.2.2.1.2.4 Results

The results of this evaluation consisted of:

- The RCS major component and component support design loads
- The RCS tributary nozzle design loads
- The surge line design loads
- The RCS piping tributary nozzle TAMs

Final design loads are found in the individual component and component support specifications. These loads were subsequently used as input to stress analyses and structural integrity assessments of the RCS and surge line for the EPU conditions.

The loads and thermal movement results documented herein pertain to external interface locations. These locations are at the component support interfaces and the tributary nozzle terminal ends.

2.2.2.1.3 RCS Seismic Analysis

The seismic loads previously calculated and evaluated for the RCS under pre-uprate conditions are unaffected by, and therefore are applicable to, EPU conditions.

2.2.2.1.3.1 Regulatory Basis

The regulatory bases for the seismic evaluation of the RCS are contained in GDC 1, 2, and 14. Statements of conformance to these GDCs are contained in FSAR Section 3.1, for the original plant configuration, which continues to be the licensing basis for the EPU. Per Section 3.2.1 and Table 3.2-2 of the FSAR, the design of these components conforms to RG 1.29 and sections of the ASME code pertaining to Seismic Category I components.

2.2.2.1.3.2 Evaluation Results

The seismic design loads for the pre-uprate condition are fully applicable to EPU and are used in combination with the updated normal operation and BLBP loads for the evaluation of RCS components. The seismic response time histories, anchor motions (SAMs) and response spectra at RCS interfaces from the pre-uprate analyses also remain applicable to EPU conditions and are used in the EPU evaluations of the RVI, RV head area components and tributary piping.

2.2.2.1.4 NSSS Component Evaluations

2.2.2.1.4.1 Reactor Vessel

2.2.2.1.4.1.1 RV Ledge

The Design Specification for the RV was revised for EPU to include new faulted loads on the RV ledge that include BLPB loads. These new faulted loads were evaluated following the methodology in the Analysis of Record (AOR). The maximum stress intensity resulting from local primary membrane stresses due to Faulted condition loads is 21.87 ksi, which is less than the allowable of 84.0 ksi. The maximum local primary membrane plus bending stress is 46.05 ksi, which is less than the allowable of 84.0 ksi.

2.2.2.1.4.1.2 RV Inlet Nozzle

The Design Specification provided revised normal operating loads (due to RCS thermal expansion) and new faulted loads that include BLPB loads on the RV inlet nozzles.

The RV inlet nozzle was evaluated for the revised normal operation loads. The maximum primary local plus bending stress intensity in the nozzles is 18.54 ksi which is less than the allowable of 26.9 ksi. The maximum primary local plus bending stress intensity in the RV wall is 34.47 ksi which is less than the allowable of 40.1 ksi.

The new faulted loads that include BLPB loads were found to be smaller than the existing faulted loads that were evaluated in the AOR, which included MCL pipe breaks. Therefore, the existing faulted condition evaluation is valid for EPU. The stress range and fatigue usage factor calculations for the inlet nozzle were found to remain valid for power uprate.

2.2.2.1.4.1.3 RV Outlet Nozzle

The only change in the Design Specification with respect to the RV outlet nozzles were new faulted condition loads that included BLPB loads. However, the existing faulted condition loads bound the new loads. Therefore, the stress evaluations in the AOR remain valid for EPU.

2.2.2.1.4.1.4 RV Supports

Loads for RV supports and support bearings for power uprate are bounded by those evaluated in the AOR. Therefore, the stress evaluations in the AOR remain valid for EPU.

2.2.2.1.4.1.5 CEDM Nozzles

The CEDMs were analyzed for EPU, and this evaluation is presented in Section 2.2.2.1.4.7 of this report. The results for the evaluation of the CEDM nozzles for EPU are summarized in the following Table 2.2-2.

Table 2.2-2
CEDM Nozzle Evaluation Results

	Calculated Value	Allowable Value
Design Conditions		
Primary General Membrane SI	16.92 ksi	23.3 ksi
General Membrane + Bending SI	17.83 ksi	34.95 ksi
Faulted Conditions		
Primary General Membrane SI	42.96 ksi	51.1 ksi
General Membrane + Bending SI	48.90 ksi	76.65 ksi
J Weld		
Shear Stress	2.67 ksi	2.74 ksi
Fatigue Evaluation		
Fatigue Usage Factor	0.0006	1.0

2.2.2.1.4.2 Steam Generator Components

2.2.2.1.4.2.1 SG Primary Inlet Nozzles

Normal operation temperatures and loads on the SG primary inlet nozzles for power uprate are bounded by loads for pre-uprate conditions, and the reactor coolant pressure is unchanged. The specified loads in the pre-uprate AOR bound those calculated for power uprate. Therefore, AOR remains applicable for the SG primary inlet nozzles for EPU.

2.2.2.1.4.2.2 SG Primary Outlet Nozzles

Normal operation loads on the primary outlet nozzles increased above the specified loads in the pre-uprate AOR due to increases in thermal expansion loads. The revised loads were found to be acceptable.

2.2.2.1.4.2.3 Steam Outlet Nozzles

The secondary pressure for EPU is lower than that for pre-uprate. The normal operation loads on the steam outlet nozzle are bounded by the original design loads and the seismic loads on the nozzle do not change for EPU. However, the nozzle loads due to pipe break were revised, and the nozzle was evaluated for the Faulted condition using the revised pipe break loads and were found to be acceptable.

2.2.2.1.4.2.4 Feedwater Nozzles

The secondary pressure for EPU is lower than that for pre-uprate. The normal operation and pipe break loads on the feedwater nozzle increased due to EPU, and the seismic loads on the nozzle do not change. An evaluation of the increased loads demonstrated that the feedwater nozzle was acceptable for EPU.

2.2.2.1.4.2.5 Small SG Nozzles

The AOR for the bottom blowdown nozzle and the 3/4-inch primary instrument nozzle is not affected by the lower secondary side pressure or lower secondary side temperature for the 3716 MWt EPU. The RCS pressure remains the same for the 3716 MWt EPU. SG seismic anchor motions are unchanged for EPU, and the SG anchor motions due to pipe breaks are equal to or less than the pre-uprate displacements. Therefore, the AOR remains applicable for these nozzles.

2.2.2.1.4.2.6 SG Support Skirt

For EPU there are a lower secondary side pressure, a lower secondary side temperature and a lower reactor coolant temperature. The reactor coolant pressure remains the same. However, there are new specified Faulted loads on the SG support skirt for EPU due to revised loads from RCS thermal expansion and new loads due to BLBP. The SG support skirt was evaluated for these new Faulted load cases.

For the skirt itself, the membrane stresses calculated in the pre-uprate evaluations bound the calculated stresses for the new cases. The previously calculated maximum anchor bolt load of 238 kips bounds the maximum bolt load of 76.8 kips from the new cases. The stress intensity and shear stresses in the flange were also found to be acceptable. Therefore, the EPU effects are acceptable.

2.2.2.1.4.2.7 SG Sliding Base and Sliding Base Bearings

The loads on the SG sliding base due to EPU are all less than the as-designed loads in the AOR. Therefore, the AOR remains applicable for power uprate.

Socket head screws hold the sockets to the sliding base. Attachment screws attach the expansion plate to the shim plates. The AOR for all these screws remains applicable for power uprate since the loads due to EPU are less than the as-designed loads.

The sliding base bearings consist of slides and sockets. The upset and faulted condition loads on the SG sliding base bearings due to EPU are less than the as-designed loads. Therefore the AOR for the sliding base bearings remains applicable for EPU.

2.2.2.1.4.2.8 Upper Support Lugs and Upper Supports

The loads on the SG upper support lugs and upper supports, including the snubber and snubber lever, do not increase for EPU conditions. Therefore, the AORs remain applicable for the upper support lugs and upper supports.

2.2.2.1.4.3 SG Internals

2.2.2.1.4.3.1 Baffle and Baffle Supports

The baffle and baffle support evaluation for pre-uprate is not affected by the lower secondary side pressure or the lower secondary side temperature for EPU. Therefore, the previous analysis of the baffle and baffle supports is fully applicable to EPU.

2.2.2.1.4.3.2 Feedwater Sparger and Support Bracket

The pre-uprate evaluations of the feedwater sparger and support bracket were determined to be controlling when compared to EPU conditions. Therefore, the previous analyses of the feedwater sparger and support bracket remain applicable for EPU.

2.2.2.1.4.3.3 Steam Dryer Supports

The steam dryer support evaluation for the pre-uprate is not affected by the lower secondary side pressure or the lower secondary side temperature for EPU. In the AOR for the steam generator internals, flow loads were not considered. However, review of a similar calculation for another plant with the same internal configuration shows that full load conditions result in stresses approximately 20% higher than no-load conditions.

Assuming the 10% increase in steam flow for the EPU results in a 20% increase in the ΔP across the dryers, a conservative estimate of the full load stresses on the dryer supports is that they would be 50% higher than currently reported in the AOR. However, the AOR shows the limiting stress condition occurs on the plate during the operating basis earthquake (OBE). For this condition, the calculated stress is 8 ksi with an allowable value of 27.4 ksi. Even if the stress is increased by 50%, the resulting value (12 ksi) is still less than one-half the allowable. The dryer supports are acceptable for the EPU.

2.2.2.1.4.3.4 Flow Deflector

The pressure drop in the pre-uprate analysis across the deflector is 1.92 psi. The pressure drop is dependent on velocity, density and the pressure shock coefficient. The maximum stress

for pre-uprate was 5.5 ksi vs. an allowable of 29.1 ksi. The uprate will increase the ΔP across the deflector plate by approximately 20%. Since the stress on the plate is directly proportional to the ΔP, the stresses will also increase approximately 20% to a value of 6.6 ksi. However, this stress is well below the Code limit of 29.1 ksi. Thus, the flow deflector is acceptable for the EPU.

2.2.2.1.4.3.5 Bottom Blowdown Pipe

The bottom blowdown pipe evaluation for pre-uprate is not affected by the lower secondary side pressure or the lower secondary side temperature for power uprate. Therefore, the previous analysis of the bottom blowdown pipe is fully applicable to EPU.

2.2.2.1.4.3.6 Tube and Tube Supports

The pre-uprate evaluations of the tube and tube supports are based on design parameters that do not change for EPU. Parameters that affect the interaction between the tubes and the vertical grid supports are the coefficient of thermal expansion and the average temperatures between the reactor coolant fluid within the tube and the external steam temperature. Because the T_{hot} temperature for power uprate is lower than the temperature used in the AOR for pre-uprate, and the steam temperature remains the same, it is concluded that the pre-uprate conditions bound the EPU conditions.

2.2.2.1.4.3.7 Tube and Tubesheet Weld

The variables used in the calculation of stresses in this component are:

(1) The differential primary pressure-to-secondary pressure
(2) The mean tubesheet temperature-to-primary temperature

The change in temperature for EPU represents a very small change in the mean tubesheet temperature and therefore an insignificant change in stress. The changes in primary-to-secondary pressure, however, were evaluated in detail for EPU for the following loadings:

A) Design

B) Primary leak test

C) Primary hydro

D) Secondary hydro

E) Secondary leak test

F) Normal operation

For EPU conditions, only loading conditions A and F change. Using a conservative multiplier of 1.147, which is based on the maximum ratio of power uprate to pre-uprate delta between primary and secondary pressures and is applied to the maximum stress for loadings A and F

above, the maximum for loadings A and F for EPU is: 1.147 x 17.29 ksi = 19.83 ksi. This does not represent a new bounding stress.

The stress range was also evaluated. Stress ranges do not change for primary or secondary leak tests. A review of stress ranges for the other loading conditions showed that the pre-uprate maximum stress range of 58.23 ksi remained the bounding stress range under EPU conditions. The maximum CUF for pre-uprate was 0.0047, and this value will not increase significantly for EPU, thereby remaining well below the acceptance criterion of 1.0.

2.2.2.1.4.3.8 Can Deck

The stress values for the AOR for the can deck were small and within Code allowables. Seismic and pipe rupture loads are unaffected by EPU. Normal operation loads increase a small amount but this is negligible compared to existing margins. Therefore, can deck integrity is maintained under EPU conditions.

2.2.2.1.4.3.9 Egg Crates, Tie Rods, and Supports

The stress values for the AOR for the egg crates, tie rods, and supports were small and within Code allowables. Normal operating loads increase a small amount but this is negligible compared to existing margins. Therefore, the integrity of these components is maintained under EPU conditions.

2.2.2.1.4.4 Reactor Coolant Pump and Motor

2.2.2.1.4.4.1 RCP Casing

The components of the RCP casing are affected by increases in loads due to RCS thermal expansion under EPU conditions. For the primary-plus-secondary membrane stress intensity range, there were critical components of the RCP casing in the areas of the volute, boss, lower flange and upper flange elements. For pre-uprate conditions, the elastic-plastic criteria of NB-3228.3 were met to disposition these critical elements. This methodology was followed again for the EPU evaluation. These components were all shown to have margin with respect to Code allowables under EPU conditions by conservatively increasing the calculated SI range due to thermal expansion and comparing the revised range of primary-plus-secondary membrane plus bending stress intensity (SI), excluding the thermal bending stresses, to 3 Sm, per Section NB-3228.3 of the ASME Code. The results of the critical components evaluation for the RCP casing are given in Table 2.2-3.

Table 2.2-3
Stress Results for RCP Casing Components

Critical RCP Casing Element	SI (ksi)	Allowable SI (ksi)
Volute	52.577	58.050
Boss Area	54.341	58.050
Lower Flange Area	57.700	58.050
Upper Flange Area	37.325	58.050

All critical components under upset conditions were shown to meet allowables for EPU by demonstrating that the set of upset (normal operation plus OBE) loads that had previously been specified for pre-uprate conditions and used in the RCP Case AOR envelop the Upset loads for EPU. This is because the previously specified OBE loads contain a large margin over as-calculated OBE loads for Waterford 3.

The faulted condition load combinations used in the AOR for pre-uprate conditions envelope the applicable faulted condition loads for power uprate, because the AOR evaluated the RCP case for specified MCLB loads, which contain margin on the BLPB loads calculated for EPU, and for specified SSE loads, which contain margin on the Waterford 3 as-calculated safe shutdown earthquake (SSE) loads.

The effect of EPU on the limiting CUF margins for the RCP case is insignificant.

2.2.2.1.4.4.2 RCP Closure

The components of the RCP closure were affected by increases in loads due to RCS TH for EPU conditions and by the inclusion of BLPB loads in the faulted load condition. Minimum stress margins on closure parts for normal operation occur almost entirely due to thermal transients, not due to RCS thermal expansion. Increases in loads due to RCS thermal expansion for EPU do not reduce these stress margins significantly, and the critical RCP closure components are shown to have margin with respect to Code allowables, shown in Table 2.2-4.

Table 2.2-4
Stress Results for RCP Closure Components

Critical RCP Closure Element	SI (ksi)	Allowable SI (ksi)
Shear Key	Pm = 15.1	1.2 Sm = 20.8
Shear Key Slot	PL+Pb = 24.2	1.5 Sm = 31.2
Bolts	Pm (average) = 45.8	2.0 Sm = 67.7

Faulted condition loads used in the AOR to evaluate the closure parts under pre-uprate conditions envelop most applicable faulted condition loads for power uprate, because most of

the specified SSE loads contain enough margin on the plant-specific SSE loads such that they envelop the root-sum-squared (RSS) combination of the as-calculated SSE-BLPB loads for EPU. Where the revised faulted loads exceed the previously specified Faulted loads, adequate margin on Code allowables continues to exist.

The effect of EPU on the limiting CUF margins for the RCP closure parts is insignificant.

2.2.2.1.4.4.3 RCP Heat Exchanger

The significant stress conditions within the heat exchanger are from thermal conditions and design pressure. The design pressure and specified thermal transients have not changed due to EPU, and the heat exchanger is not affected by RCS thermal expansion. Therefore, the results of the RCP heat exchanger (HX) AOR are applicable to EPU.

2.2.2.1.4.4.4 RCP Motor and Motor Flywheel

The specified loads on the RCP motor are unchanged due to EPU. Therefore, the AOR for the RCP motor is applicable to EPU.

2.2.2.1.4.4.5 RCP Supports

RCP supports were evaluated for EPU for changes in loads due to RCS thermal expansion and BLPB. The results for shearing, compressive and tensile stresses for the RCP support limiting components were evaluated and found to be less than the AOR and, therefore, are acceptable for EPU.

2.2.2.1.4.5 RCS Main Coolant Loop Piping

2.2.2.1.4.5.1 Hot Leg and Cold Leg Piping

A comparison of the piping specification loads to the loads used in the AOR for RCS piping indicated that the loads due to thermal expansion have increased in all suction legs. Also, accident loads at all RCS piping assemblies, which now include BLPB loads, in combination with normal operation and SSE loads, are not bounded by the original accident loads, which did not contain loads due to pipe breaks. Therefore, the following main loop piping components were re-evaluated:

- Hot leg pipe (end A) for design and faulted conditions
- Hot leg elbow (end B) for design and faulted conditions
- Cold leg pipe (end A) for faulted conditions
- Cold leg elbow (end B) for faulted conditions

The following primary stress results were determined as shown in Table 2.2-5.

Table 2.2-5
Primary Loop Piping, Primary Membrane Plus Bending Stresses

Condition	Component	Stress (ksi)	Allowable (ksi)
Design	Hot Leg Pipe	10.05	27.6
Design	Hot Leg Elbow	18.63	27.6
Faulted	Hot Leg Pipe	12.34	55.90
Faulted	Hot Leg Elbow	24.30	55.90
Faulted	Cold Leg Pipe	18.56	59.24
Faulted	Cold Leg Elbow	40.96	59.24

The fatigue evaluation of the hot leg and cold leg piping was originally performed for three major piping components - the hot leg piping, the hot leg elbow, and the cold leg elbow. Each of these components was re-evaluated.

For the hot leg piping, the normal operation loads for power uprate exceeded the AOR normal operation loads; the OBE loads remain the same. An assessment showed no change in the AOR CUF of 0.382, which accounts for the installation of a mechanical nozzle seal assembly on the hot leg straight pipe, and the subsequent reduction in the pipe thickness. For the hot leg elbow, the normal operation loads for EPU are lower than those evaluated in the AOR; the OBE loads remain the same. Therefore, the AOR CUF factor of 0.020 remains valid for power uprate. For the cold leg elbow, the normal operation and OBE loads remain the same. Therefore, the AOR CUF remains at 0.052 for EPU.

2.2.2.1.4.5.2 RCP Safe Ends

A comparison of the AOR to the piping specification loads shows that all DWt, seismic and normal operation loads for the pertinent cold leg piping assemblies on the suction side and on the discharge side have not changed for EPU conditions. However, inclusion of BLPB loads in the current evaluation necessitated a reanalysis of the safe end primary stresses for Faulted conditions. The resulting increased P_B value of 17.5 ksi remained well below the allowable of 57.9 ksi.

The AOR fatigue evaluation was unaffected by EPU. Therefore, the CUF for the RCP safe ends remains essentially at 0.0.

2.2.2.1.4.5.3 RCS Tributary Nozzle Reconciliation

According to Section 2.2.2.1.1 of this document, the current NSSS plant design transients remain unchanged for the EPU. However, a set of revised charging inlet nozzle transients were analyzed as part of the power uprate. The reactor coolant operating pressure (2,250 psia) for power uprate conditions remains the same as originally specified.

Therefore, with the exception of the charging inlet nozzle transients, the only tributary nozzle load changes examined in this evaluation were in the mechanical loads on piping tributary nozzles, as defined in the Piping Specification. Changes in the currently specified loads for EPU conditions resulted from a comparison of the EPU analysis results to the currently specified loads. The tributary nozzle stress evaluations considered load contributions from both the nozzle ends and the pipe runs.

The main loop piping tributary nozzles are:

- Safety injection nozzle
- Charging inlet nozzle
- Hot leg drain nozzle
- Cold leg letdown/drain nozzle
- Surge nozzle
- Shutdown cooling outlet nozzle
- Spray nozzle
- Partial penetration nozzles (e.g., RTD thermowells)

Evaluations for design and normal operation (including fatigue) conditions were performed for those nozzles using the EPU design loads. Seismic piping loads did not change for EPU conditions; however, faulted loads included the effects of BLPB. Primary stresses resulting from faulted conditions were determined for the above tributary nozzles. The results of these evaluations were compared to the appropriate allowables in accordance with the ASME Code.

Stresses were calculated using classical methods and the guidance of Paragraph NB-3200 of Section III of the ASME Code, or by using the more conservative approach of Paragraph NB-3600 of the Code. In cases where elastic or simplified elastic-plastic methodologies did not produce an adequate fatigue analysis result, elastic-plastic finite element analysis was performed. This occurred in the case of the charging inlet nozzle, which was reanalyzed for updated charging system transients. The revised loss of letdown and loss of charging transients reflect cooldown in the lines to ambient and increased cycle numbers based on actual operating experience. The ANSYS computer code was used to perform this analysis. The fatigue analysis of record for the safety injection nozzle is also an ANSYS finite element analysis with plasticity modeled. That particular result was updated for EPU conditions by using conservative factors, and therefore did not require reanalysis using finite element methods.

The results of these evaluations demonstrated compliance with the original design requirements of the *ASME Boiler and Pressure Vessel Code*, Section III, 1971 Edition up to and including Winter 1971 Addenda. These results are summarized in Tables 2.2-6 and 2.2-7.

2.2.2.1.4.6 Steam Generators

In addition to evaluating structural integrity, evaluations of SG thermal-hydraulic performance and mechanical hardware have been performed to address operation of the generators at 3716-MWt EPU conditions.

Table 2.2-6
Critical Stresses and Total Usage Factors for Design Conditions

Component	Location	Stress Int. (ksi) or Usage Factor	Allowable (ksi) or 1.0 for Usage
Safety Injection Nozzle	Nozzle Body	31.06	33.2
	Nozzle-Pipe Juncture	27.3	27.6
	Usage Factor (Bi-Metallic Weld)	0.49*	1.0
Charging Inlet Nozzle	Nozzle Body	10.90	24.9
	Nozzle-Pipe Juncture	24.7	26.1
	Usage Factor (Bi-Metallic Weld)	0.54*	1.0
Cold Leg Letdown/Drain Nozzle	Nozzle-Pipe Juncture	19.0	26.1
	Bi-Metallic Weld	7.2	24.9
	Usage Factor (Bi-Metallic Weld)	0.89**	1.0
Hot Leg Drain Nozzle	Nozzle-Pipe Juncture	18.5	26.1
	Bi-Metallic Weld	7.5	25.1
	Usage Factor (Bi-Metallic Weld)	0.39**	1.0
Surge Nozzle	Nozzle-Pipe Juncture	16.5	17.4
	Usage Factor (Bi-Metallic Weld)	0.709*	1.0
Shutdown Cooling Outlet Nozzle	Nozzle-Pipe Juncture	19.5	26.1
	Bi-Metallic Weld	8.4	26.1
	Usage Factor (Bi-Metallic Weld)	0.26*	1.0
Spray Nozzle	Nozzle-Pipe Juncture	23.4	26.1
	Bi-Metallic Weld	9.9	24.9
	Usage Factor (Bi-Metallic Weld)	0.42*	1.0
Partial Penetration Nozzles:			
RTD Hot Leg	Weld Boundary Region	4.9	23.3
RTD Cold Leg	Weld Boundary Region	6.9	23.3
Pressure & Sampling Hot Leg	Weld Boundary Region	5.5	23.3

* Based on 60-year plant life
** Based on 40-year plant life

Table 2.2-7
Critical Stresses for Faulted Conditions

Component	Location	Stress Int. (ksi) or Usage Factor	Allowable (ksi) or 1.0 for Usage
Safety Injection Nozzle	Nozzle Body	32.0	73.5
	Nozzle-Pipe Juncture	32.0	70.4
	Maximum Moment Criteria	53.4	73.5
Charging Inlet Nozzle	Nozzle Body	17.4	62.8
	Nozzle-Pipe Juncture	26.2	78.8
	Maximum Moment Criteria	25.4	78.8
Cold Leg Letdown/Drain Nozzle	Nozzle-Pipe Juncture	28.3	52.2
	Bi-Metallic Weld	26.1	50.2
	Maximum Moment Criteria	33.6	55.8
Hot Leg Drain Nozzle	Nozzle-Pipe Juncture	21.6	52.2
	Bi-Metallic Weld	14.8	50.2
	Maximum Moment Criteria	24.1	53.4
Surge Nozzle	Nozzle Body	36.6	63.8
	Nozzle-Pipe Juncture	16.7	42.5
	Maximum Moment Criteria	36.5	63.8
Shutdown Cooling Outlet Nozzle	Nozzle-Pipe Juncture	29.2	52.2
	Bi-Metallic Weld	14.8	52.2
	Maximum Moment Criteria	61.5	64.1
Spray Nozzle	Nozzle-Pipe Juncture	35.8	52.2
	Bi-Metallic Weld	14.5	49.8
	Maximum Moment Criteria	41.4	55.8
Partial Penetration Nozzles:			
RTD Hot Leg	Weld Boundary Region	8.3	55.9
RTD Cold Leg	Weld Boundary Region	14.2	55.9
Pressure & Sampling Hot Leg	Weld Boundary Region	9.0	55.9

The Code and Code edition used for this evaluation is *ASME Boiler and Pressure Vessel Code* (B&PV), 1971, Section III, “Nuclear Vessels,” up to and including the 1971 Winter Addenda. This is the Code of Record.

2.2.2.1.4.6.1 Thermal-Hydraulic Evaluation

The thermal-hydraulic evaluations of the Waterford 3 SG focused on changes to secondary-side operating characteristics at the proposed EPU conditions. The evaluations discussed in this section were performed to confirm the acceptability of the steam generator secondary-side parameters and to provide input to the flow-induced vibration analysis of the tubes. All calculations performed herein are best estimates of the SG performance.

As of Cycle 12, the Waterford 3 steam generators had 444 plugged tubes in SG 1 and 434 plugged tubes in SG 2. The tube plug locations for Lines 88 through 175 in SG 1 were utilized for Cycle 12 benchmark evaluations. The 3716 MWt EPU ATHOS3 analysis is performed assuming 500 plugged tubes. The additional tube plug locations were randomly selected to maintain the average tube length. The Waterford 3 SG operating conditions were also necessary for design input. The benchmarking of the SG performance was evaluated with the Cycle 12 operating conditions.

Methodology

The thermal-hydraulic analysis of the Waterford 3 SG was performed using the ATHOS and ATHOSGPP Version 3 Mod 01 computer codes (Reference 2.2.2.1.4.6-1).

ATHOS3 (Analysis of the Thermal-Hydraulic Of Steam Generators) is a three-dimensional, two-phase, steady state and transient computer code for thermal-hydraulic analysis of recirculating U-tube and once-through SGs. It was developed by updating earlier versions of the same code for the EPRI and has become the standard method for all major SG vendors to evaluate secondary side thermal-hydraulic performance. Earlier versions of the code have been validated against small-scale experimental data and operational SG thermal-hydraulic performance. The code is also recommended by EPRI for PWR SG thermal-hydraulic analysis and has been used in uprates including Arkansas Nuclear One, Unit 2 (ANO-2). The ATHOS3 Mod 01 computer codes have been verified and validated in accordance with the applicable Westinghouse quality assurance procedures.

Thermal-hydraulic analysis of the Waterford 3 SGs for both the Cycle 12 (benchmark evaluation) and 3716 MWt EPU operating conditions was performed using the algebraic slip flow option and the EPRI-78 correlations for heat transfer coefficients and friction. The converged ATHOS3 solution includes:

- Mixture velocity components in three directions
- Vapor and liquid phase axial velocities
- Secondary side void fraction, steam quality, temperature, and mixture density
- Primary side temperature distribution

The ATHOS3 output also includes tube metal temperature, secondary fluid pressure, heat transfer coefficients, etc. The gap velocities, used for the flow-induced vibration (FIV) evaluations at the specified tube locations, are calculated from nodal velocities and flow areas.

Results

A summary of the steam generator thermal-hydraulic parameters at 3390 MWt (pre-Appendix K uprate) and at 3716 EPU conditions is presented in Table 2.2-8. Both analyses were performed with the algebraic slip option of the ATHOS3 code. With power uprate conditions, the calculated primary hot leg temperature increases from 598.6°F for the Cycle 12 operating conditions to 601.0°F.

The overall, hot side and cold side circulation ratios are lower at 3716 MWt power. This is because the steam flow rate is approximately twelve percent higher while the total flow rate through the steam generator is approximately the same, 24.72 x 10^6 vs. 24.85 x 10^6 lb/hr. The three circulation ratios are defined as a ratio of the total (water + steam) flow divided by the steam flow rate at the separator deck.

With power uprate conditions, both the secondary fluid qualities and the velocities are higher. This is as expected since both the steam flow (7.43 x 10^6 vs. 8.30 x 10^6 lb/hr) and heat transfer rate (5794.5 x 10^6 vs. 6371.8 x 10^6 Btu/hr) are higher for the same size tube bundle. The maximum quality in the tube bundle increases from 63.71 percent for Cycle 12 to 69.21% for power uprate conditions.

Since both the fluid qualities and velocities are higher under power uprate conditions, both the maximum value of the deposit parameter (24.82 vs. 38.74) and the tube bundle regions with “higher” deposit potential are larger.

Conclusion

The results of the thermal-hydraulic evaluations are summarized in Tables 2.2-8 and 2.2-9. Based on these evaluations, the Waterford 3 SGs will operate satisfactorily at 3716 MWt EPU conditions.

2.2.2.1.4.6.2 Evaluations for Repair Hardware

The Waterford 3 steam generators have over 800 mechanical tube plugs installed at various locations in the tube bundle. Most of the tube plugs are CE-designed rolled mechanical plugs while others are Westinghouse-designed ribbed mechanical plugs. In addition to mechanical plugs, the Waterford 3 SGs also have both long and short tube stabilizers installed at various locations. Although there are currently no sleeves installed, the Waterford 3 steam generators are licensed to install tungsten-inert gas (TIG)-welded sleeves. Hence, an evaluation was also performed to ensure these sleeves could be installed following the power uprate.

Table 2.2-8
Thermal-Hydraulic Characteristics of Waterford 3 Steam Generators

	3390 MWt Cycle 12[3]	3716 MWt EPU
INPUT DATA		
1. Number of Tubes Total/Plugged	9350/445	9350/500
2. Heat Transfer Area, ft^2	99,751	99,152
3. Reactor Power, %	99.637	100.00
4. Steam Pressure, psia	840.5	803.0
5. Steam Flow Rate, Mlb/hr	7.4328	8.2996
6. Quality at Steam Outlet Nozzle	0.998	0.998
7. Carry-under, %	0.75	0.75
8. Feedwater Temperature, °F	438.05	449.74
9. Primary Flow Rate, Mlb/hr	82.332	82.454
10. Primary Pressure, psia	2246.3	2250
11. Primary Hot Leg Temperature, °F	598.20[1]	601[1]
12. Fouling Resistance, hr-ft^2-°F/BTU	7.495E-05	7.495E-05
13. Downcomer Water Level Above Tube Sheet, In.	438.6	438.6
OVERALL PERFORMANCE – ATHOS3 RESULTS		
1. Calculated Heat Transfer Rate, MWt/SG	1698.2	1867.4
2. Primary Hot Leg Temperature, °F	598.6	601.0
3. Primary Cold Leg Temperature , °F	545.0	542.0
4. Hot Side Downcomer Flow Rate, Mlb/hr	12.44	12.50
5. Cold Side Downcomer Flow Rate, Mlb/hr	12.28	12.35
6. Circulation Ratio – Overall	3.28	2.96
7. Circulation Ratio – Hot Side	2.34	1.97
8. Circulation Ratio – Cold Side	4.76	4.53
9. Maximum Quality, %	63.71 (1,7,31)[2]	69.21 (1,7,31)
10. Maximum Axial Velocity in the Tube Bundle, fps	17.41 (1,7,24)	19.88 (1,7,24)
11. Maximum Radial Velocity (Gap), fps	11.33 (9,14,2)	11.36 (9,14,2)
12. Maximum Deposit Parameter (|V|/(1.0-X)	24.82 (3,8,24)	38.74 (3,11,30)

Notes: (1) ATHO3 code calculates T_{hot}/T_{cold} using the initial guess for T_{hot}
(2) Location in the ATHOS3 output (IX, IY, IZ)
(3) pre Appendix K uprate

Table 2.2-9
Waterford 3 SG: Separator Loading and Carryover Performance

	3390 MWt Cycle 12[(1)]	**3716 MWt EPU**
1. Number of Separators	212	212
2. Steam Flow Rate at Separator Deck, lb/hr	$7{,}547.23 \times 10^3$	$8{,}406.96 \times 10^3$
3. Water Flow Rate at Separator Deck, lb/hr	$17{,}169.98 \times 10^3$	$16{,}443.26 \times 10^3$
4. Total Flow Rate at Separator Deck, lb/hr	$24{,}717.21 \times 10^3$	$24{,}850.22 \times 10^3$
5. Avg. Steam Flow Rate per Separator, lb/hr	35.61×10^3	39.66×10^3
6. Max. Steam Flow Rate per Separator, lb/hr	51.96×10^3	57.76×10^3
7. Min. Steam Flow Rate per Separator, lb/hr	19.39×10^3	21.52×10^3
8. Avg. Water Flow Rate per Separator, lb/hr	80.99×10^3	77.57×10^3
9. Max. Water Flow Rate Separator, lb/hr	136.33×10^3	143.57×10^3
10. Min. Water Flow Rate Separator, lb/hr	34.42×10^3	19.10×10^3
11. Calculated Carryover Flow Rate, lb/hr (Water Level = 16 Inches)	11.10×10^3	18.56×10^3
12. Calculated Carryover, % (Water Level = 16 Inches)	0.147	0.220
13. Calculated Carryover Flow Rate, lb/hr (Water Level = 2 Inches)	7.30×10^3	13.08×10^3
14. Calculated Carryover, % (Water Level = 2 Inches)	0.097	0.155

(1) Pre-Appendix K uprate

Rolled Mechanical Tube Plugs

CE-designed rolled mechanical tube plugs were qualified for use in the Waterford 3 SGs with a comprehensive test program. The test program addressed a wide range of diameters and wall thickness parameters of the tubing for CE designed steam generators. Westinghouse has concluded that the testing is applicable and the rolled mechanical tube plug is qualified for use in the Waterford 3 SGs under EPU conditions. The basis for this conclusion is summarized below.

Testing was performed on 0.75-inch OD tubes with a nominal wall thickness of 0.048 inches. The tubes were expanded into tubesheet mockups with bore diameters that bounded the nominal diameters in the Waterford 3 tubesheet (0.758 ± 0.002 inches). As a result, the test program was performed on mockups that had tube inside diameters in the range of 0.657 to 0.678 inches. Since the range of tube diameters in the Waterford 3 SGs is with in this range, the testing is directly applicable.

An analysis specific to the mechanical tube plugs made from a bar product for application in a CE-design SGs is directly applicable to the Waterford 3 SGs and evaluates the plug for stresses from both primary and secondary design pressures. Additionally, a fatigue evaluation was performed to evaluate the plug for alternating stresses.

In addition to including a range of tube diameters, tests also evaluated different tube plug wall thicknesses and a wide variation of torque values ranging from a low of 102 in-lbs to 182 in-lbs. It should be noted that Westinghouse's standard installation techniques require detailed torque traces for each plug installation that would identify any anomalies with the installation of the plug. All tests met the applicable qualification criterion with a minimum safety factor of 4. Many samples had significantly higher safety margins, but results varied depending on the applicable combination of test parameters. Specifically, these tube plugs were designed for the following conditions shown in Table 2.2-10.

Table 2.2-10
Tube Plug Design Conditions

Parameter	Test Value	Waterford 3 Power Uprate
Primary side design pressure	2500 psia	2500 psia
Secondary side design pressure	1100 psia	1100 psia
Primary side operating pressure	2250 psia	2250 psia
Secondary side operating pressure	900 psia	805 psia
Secondary side operating pressure (conservative lower bound)	815 psia	750 psia
Primary-to-secondary operating ΔP (normal)	1435 psi	1445 psi
Primary-to-secondary operating ΔP (design)	1400 psi	1500 psi

Based on the above conditions, the tube plugs were tested at a primary pressure approximately equal to 3 times the normal operating ΔP or 4300 psia. Twelve tube plugs were also tested at a secondary pressure equal to 1.5 times the maximum accident secondary to primary ΔP or 1400 psia. The results were no plug movement or plug leakage. This test

pressure bounds the largest secondary side accident ΔP for the Waterford 3 SGs, which would be no more than 1.5 times 805 psi or 1208 psi.

In addition to the standard pressure tests described above, 12 tube plugs were tested to failure (6 each for primary and secondary pressure tests) to determine safety factors. In the primary pressure test, six tube plugs were exposed to 10,000 psi with no leakage or movement. One plug moved at 9000 psi but did not leak. Thus, there is a safety factor of approximately 6 during normal operation. In the secondary side pressure tests to failure, 6 tube plugs were also tested with plug movement noted at approximately 6000 psi at the low range and other plugs testing as high as 9000 psi. This pressure (6000 psi) results in a safety factor of approximately 5 for those accidents that result in a secondary to primary ΔP.

Both the test program and the Waterford 3 SGs have nominal 0.750-inch diameter heat transfer tubes with 0.048-inch average wall thickness. Qualification of plugs is based on Alloy 600 tubing, which is directly applicable to the Alloy 600 tubes in the Waterford 3 SGs. That is, the parameters that could potentially affect the rolled joint (e.g., tube material hardness, coefficient of thermal expansion, tubesheet material, etc.) are the same. Thus, it is concluded that the tube plugs are qualified for repairs to the Waterford 3 SG tubes under EPU conditions.

In addition to Westinghouse-designed rolled mechanical tube plugs, the Waterford 3 SGs also have Framatome-designed rolled mechanical tube plugs installed at various locations. These tube plugs have been qualified in a manner similar to the Westinghouse plugs except they are not designed to be leak-tight. The small increase in primary-to-secondary pressure differential from the power uprate will result in a small increase in the overall leakage from these plugs. However, this increase is negligible with respect to allowable values and these tube plugs are acceptable for use for EPU conditions.

Ribbed Mechanical Tube Plugs

Both the “long” and “short” ribbed mechanical tube plugs are qualified for installation in the 3/4-inch OD Alloy 600 tubes with 0.048-inch walls in the SGs of Waterford 3 based on the following analytical results and conclusions.

Considering the specified normal operation, hot standby, upset transients, emergency and test conditions, the overall limiting plug retention condition occurs for the primary side hydrostatic pressure test in which the ΔP across the plug is 3125 psi. As a result of the calculated tubesheet bowing deformations (including the effects of the channel head and main cylinder), plugs installed in the outer most tubes would experience the maximum reduction in the initial preload (the radial contact pressure at the plug lands upon installation). For this limiting load at the most limiting location in the tubesheet and for a conservatively estimated 43.2 ksi initial preload contact pressure at the lands, the calculated maximum coefficient of friction required to retain the plug is 0.106. The actual “friction coefficient” available at the plug lands is expected to be much higher (on the order of one or more) since the plug lands plastically press into the tubes at installation. Therefore, substantial plug retention margin is available, even for the most limiting retention conditions. It should also be noted that the primary side hydrostatic tests at 3125 psi are not repeated after the SGs are placed in service.

Table 2.2-11 summarizes the calculated primary stress margins for the maximum design, emergency and test condition primary-to-secondary pressure differential (ΔP) loads. In all cases, the ratio of calculated stress intensity to the ASME Code allowable stress intensities is

Table 2.2-11
Summary of Maximum Primary Stress Intensity Evaluation
3/4 inch Tapered Mechanical Plug Shell Wall in the
Expander Parking Region Above the Top Land

All calculated stresses and the ASME Code allowable are in ksi.

Analysis Section Number (ASN) 1 is midway between the top land and the plug end cap.
ASN 2 is just above the top land.
ASN 3 is just below the plug end cap.

Design Condition: P_p = 2500 psia

ASN	P_m	Allowable	Ratio	P_L+P_b	Allowable	Ratio
1	13.8	23.3	0.59	16.3	34.95	0.47
2	12.6	23.3	0.54	15.1	34.95	0.43
3	4.94	23.3	0.21	11.2	34.95	0.32

Maximum Emergency Condition: P_p = 2350 psi

ASN	P_m	Allowable	Ratio	P_L+P_b	Allowable	Ratio
1	13.1	27.96	0.47	15.4	41.94	0.37
2	12.0	27.96	0.43	14.3	41.94	0.34
3	4.7	27.96	0.17	10.6	41.94	0.25

Maximum Test Condition (Primary Hydro): P_p = 3125 psi

ASN	P_m	Allowable 400°F	Ratio	P_L+P_b	Allowable 400°F	Ratio
1	17.4	25.8	0.67	20.5	38.7	0.53
2	15.9	25.8	0.62	19.0	38.7	0.49
3	6.2	25.8	0.24	14.0	38.7	0.36

less than unity which indicates that all primary stress limits are satisfied for all analysis sections of the plug shell wall between the top land and the plug end cap. The plug satisfies ASME Code limits for fatigue, based on meeting the six ASME Code conditions for exemption from an explicit fatigue analysis given in NB-3222.4 (d) of Section III.

The overall maximum external pressure on the plug shell is 1375 psi during the secondary side hydrostatic test conducted at 100°F. The allowable external pressure is assumed to be 80% of the lower bound collapse pressure calculated assuming an ovality (out-of-roundness) of 2%. The resulting allowable external pressure is 5019 psi at 100°F, which is well above the applied pressures, and it concluded that the plug shell is stable for the maximum specified external loads. It should be noted that the assumed 2% ovality is very conservative since the plug shell is held round by the expander, tube, and tubesheet at the lands at the bottom end and by the plug end cap at the top end.

Thus, it is concluded that ribbed mechanical tube plugs will perform satisfactorily in the Waterford 3 SGs at EPU conditions.

Steam Generator Tube Stabilizers

Steam generator tube stabilizers function to retain severed tubes, to dampen vibration and to mitigate additional wear on plugged SG tubes. The tube stabilizer is fabricated from 0.5 inch diameter 6 x 19 Type 304 stainless steel wire rope. It has a lower end fitting that allows it to be installed with a typical probe pusher. The upper end of the stabilizer is capped with a welded bullet nose to ease installation.

The major parameters that affect the tube/stabilizer assembly are secondary fluid properties, tube support geometry and design of the stabilizer. Since only the secondary fluid properties are affected by the power uprate, there is no need to address either the tube support geometry or the stabilizer design.

The effective fluid velocity is directly proportional to the secondary fluid velocity and density. The maximum gap velocity in the radial direction is 11.4 ft/sec and the density of the downcomer fluid is 49.0 lbs/ft^3. Based on these values, the mass flow (ρV) at the downcomer entrance to the tube bundle is 558.8 lbs/ft^2-sec for the power uprate condition. For the design power condition, the maximum gap velocity is 10.5 ft/sec and the fluid density is 48.7 lbs/ft^3. From these values, the mass flow (ρV) at the downcomer entrance to the tube bundle is 511.35 lbs/ft^2-sec for the design condition. Thus, there is a 9.3% increase in the mass flow at the downcomer entrance.

Since the critical velocity is not significantly affected by the fluid conditions (i.e., it is mainly a function of geometry), the stability ratio will increase in proportion to the change in mass flow. Thus, it is expected that the power uprate will result in an increase in the stability ratio equal to 0.29 x 1.093 or 0.317. Since this value is well below the acceptance criterion of 1.0, the existing stabilizers are acceptable for use following the EPU.

The Waterford 3 SGs also have long stabilizers installed near the stay cylinder region of the tube bundle. The function of these stabilizers is to provide an “infinite” mass of material to prevent the diagonal bars (batwings) from severing the tubes. Since these stabilizers are installed only to provide a wear volume, they are unaffected by the EPU.

Steam Generator Sleeves

Existing evaluations of maximum sleeve loads from accident conditions assume a maximum pressure of 2520 psia for main steam line break and 2850 psia for a feedwater line break. In both cases the loads are well below the acceptance criterion and have safety factor in excess of 4. A review of these accidents for the uprated condition shows that the feedwater line break is limiting and results in a maximum primary pressure less than 2850 psia. Loads resulting from a LOCA are based on secondary side design pressure and zero primary pressure and are less than those from normal operation. Hence, the calculated faulted loads remain bounding for the EPU condition.

The maximum axial load on the tube/sleeve assembly results from differential thermal expansion during normal operation. Calculation of the load assumed a primary temperature (T_{hot}) of 611°F and a secondary temperature of 506°F. From the most recent thermal-hydraulic analysis, T_{hot} is 601°F and the secondary temperature is 499.3°F. Thus, the existing analysis used a higher ΔT between the primary and secondary system. As a result, the existing calculated axial loads bound those that would occur after EPU.

The structural analysis of the sleeve weld is based on design conditions and SG transients defined by the design specification. There are no changes to these conditions. Evaluation of the lower rolled joint is based on qualification testing that bounds the uprate condition. Thus, it is concluded that the TIG-welded sleeves will perform satisfactorily in the Waterford 3 SGs following EPU.

2.2.2.1.4.6.3 Tube Vibration

Fluid-Elastic Instability

The fluid-elastic and turbulence response of the Waterford 3 SG tubes was determined using 1% damping and Beta (K) of 3.3.

The most limiting fluid-elastic stability ratio has been found to be 0.80. This value is less than the limit of 1.0, hence fluid-elastic instability is not predicted. Note that for this particular tube, the pre-uprate fluid-elastic instability value was found to be 0.75. The ratio of post-uprate to pre-uprate fluid-elastic instability values was found to be 1.07, which indicates that although there is a larger potential for fluid-elastic instability, the increase is relatively small (~7%) and that the tube remains stable while operating at the EPU operating conditions.

Turbulence Response

Although each tube was evaluated using 1% damping, the actual tube response is a function of specific values of damping for that particular tube. These values can be dependent upon various factors including the response of the tube in question (i.e., frequency).

The largest root mean square (RMS) displacement has been found to be ~7.2 mils. Peak values of displacement can be reasonably estimated by multiplying the RMS value by 3.5. This results in a maximum peak displacement of ~25 mils. This value is less than the tube-to-tube gap of 0.25 inch (250 mils), hence tube-to-tube contact is not predicted. In addition, the peak displacement value is also less than ½ of the tube gap, therefore, should two adjacent tubes

simultaneously displace toward each other at a particular level of displacement, tube-to-tube contact would still not occur. Note that for this particular tube, the pre-uprate displacement value was found to be 6.8 mils. The ratio of post-uprate to pre-uprate displacements for the limiting condition was found to be 1.06, which indicates that although there is a larger potential for turbulence induced displacement, the increase is relatively small (~6%) and the tubes will not contact each other during operation at the EPU operating conditions.

Tube Stress

Turbulence induced bending stresses on the limiting tube are calculated based on nodal forces and moments. The limiting tube was selected based upon the tube that had the largest turbulence induced displacements.

The maximum bending moment was identified and the stress calculated. Since the stress would be a RMS stress and peak stresses would be of interest with respect to fatigue, peak bending stresses were estimated by applying a factor of 3.5 to the RMS values. The two peak bending moments (local X-X and Y-Y axis) were then combined using the square root of the sum of the squares to obtain a total peak bending stress. (Note that the axial forces were very small and were neglected in the calculation.) The following is a summary of the resulting stress:

0.57 ksi – Peak bending stress for Cycle 12 (pre-uprate)
0.61 ksi – Peak bending stress for uprated operating conditions

As can be observed, the peak bending stress will increase during uprate by approximately 7%. These values are well below the endurance limit of the Nickel Alloy 600 tube material; hence, tubes stresses and high cycle fatigue are of no concern under EPU conditions.

2.2.2.1.4.6.4 References

2.2.2.1.4.6-1 Singhal, A. K. et al., *ATHOS3 Mod. 01: A Computer Program for Thermal-Hydraulic Analysis of Steam Generators, Volumes 1 - 3*, EPRI-NP-4604-CCML, September 1990.

2.2.2.1.4.7 CEDM Evaluation

Control element drive mechanism (CEDM) structural integrity depends on the characteristics of the CEDMs as well as those components comprising the adjacent support structures. Notably, the redesign of the Waterford 3 closure head lift rig (CHLR) created the possibility of interaction between the CEDMs and the CHLR under pipe break conditions. The CEDMs are also affected by the reactor coolant pressure, the vessel outlet temperature, and the NSSS design transients.

The controlling transient conditions are unchanged from the original design basis. In addition, the reactor coolant pressure (2250 psia) for power uprate conditions remains the same as originally specified for the CEDMs. The vessel outlet temperature for power uprate conditions is 601°F, which is below the operating temperature value of 611°F analyzed in the AOR. This same relationship exists between the pre-uprate, uprate, and AOR RV head operating temperatures in the vicinity of the CEDM nozzles. Therefore, no additional assessments of the

impact of pressure and thermal loads on the CEDMs and CEDM nozzles was required to account for EPU conditions.

For the re-analysis, the CEDM model was converted from STRUDL to ANSYS. The new CEDM model was benchmarked by comparing the ANSYS model frequencies to the frequencies of the STRUDL model used in the AOR. This comparison verified correctness of operation of the new model. The CHLR model was also available in ANSYS, and was coupled to the CEDMs to reflect the appropriate system stiffnesses. The re-analysis focused on the determination of CEDM response to BLPB excitations with the interaction between the CEDMs and the CHLR. These results were determined using the ANSYS computer code and response spectrum techniques.

Faulted condition stresses for all CEDM locations were calculated as required. They are summarized below, along with any design condition results that have increased due to power uprate conditions. The locations described in the table are shown in Figure 2.2-1. Results for the CEDM nozzles are tabulated in Table 2.2-12.

Table 2.2-12
CEDM Stresses for Power Uprate Conditions

CEDM Component	Calculated Stress (psi)	Stress Allowable (psi)
Shroud – Design Conditions		
Membrane Stress Intensity	8,980	S_m = 16,200
Membrane Plus Bending Stress Intensity	8,980	1.5 S_m = 24,300
Shroud – Faulted Conditions		
Membrane Stress Intensity	19,520	Greater of 1.5 S_m/1.2 S_y = 24,300
Membrane Plus Bending Stress Intensity	19,520	1.5 times the above value = 36,450
Upper Pressure Housing – Section II – Faulted Conditions		
Membrane Stress Intensity	31,800	Smaller of 2.4 S_m/0.7 S_u = 40,510
Membrane Plus Bending Stress Intensity	31,800	1.5 times the above value = 60,765
Motor Housing – Section III – Faulted Conditions		
Membrane Stress Intensity	17,670	Smaller of 2.4 S_m/0.7 S_u = 55,920
Membrane Plus Bending Stress Intensity	17,670	1.5 times the above value = 83,880

Table 2.2-12 (cont.)
CEDM Stresses for Power Uprate Conditions

CEDM Component	Calculated Stress (psi)	Stress Allowable (psi)
Motor Housing – Section IV – Faulted Conditions		
Membrane Stress Intensity	46,200	Smaller of 2.4 S_m/0.7 S_u = 63,820
Membrane Plus Bending Stress Intensity	46,200	1.5 times the above value = 95,730
Motor Housing – Section V – Faulted Conditions		
Membrane Stress Intensity	14,210	Smaller of 2.4 S_m/0.7 S_u = 55,920
Membrane Plus Bending Stress Intensity	14,210	1.5 times the above value = 83,880
Screw Threads (Location 3)		
Maximum Shear Stress	3,910	1.44 S_m = 33,550
Screw Threads (Location 4)		
Maximum Shear Stress	2,270	1.44 S_m = 33,550
Motor Bearing Stress	8,050	S_y = 66,500
Stability Under Compressive Load		
Maximum Axial Load	5060 lbs	Limit load = 12,210 lbs
Reed Switch Position Transmitter Tube		
Membrane Stress Intensity	25,860	Smaller of 2.4 S_m/0.7 S_u = 39,840
Membrane Plus Bending Stress Intensity	27,810	1.5 times the above value = 59,760
Maximum Shear	16,250	0.42 S_u = 27,300
Maximum Acceleration	25.32 Gs	34.1 Gs*

* This is a Qualification Test value.

The Code and Code edition used for this evaluation is *ASME Boiler and Pressure Vessel Code* (B&PV), 1971, Section III, “Nuclear Vessels,” up to and including the 1973 Summer Addenda. This is the Code of Record.

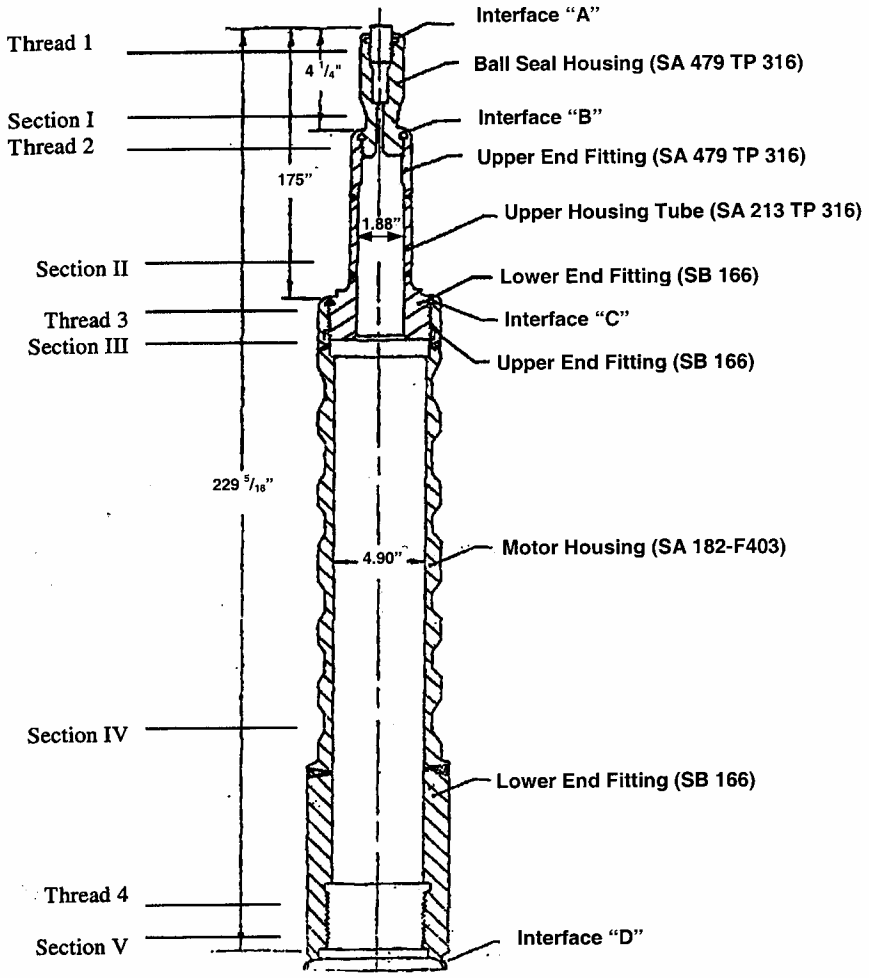


Figure 2.2-1
CEDM Pressure Housing

2.2.2.2 Balance of Plant Piping, Components and Supports

As part of the Waterford 3 EPU, all essential plant piping systems were evaluated to assess the impact of the various changes due to uprate and/or due to new branch line pipe break (BLPB) LOCA, thermal stratification, and new transient loadings for the Chemical and Volume Control System (CVCS) charging and letdown lines. Besides the Reactor Coolant System (RCS) piping on the primary side the four safety injection, the two shutdown cooling, the surge, one pressurizer spray, and the CVCS charging/letdown/auxiliary spray piping runs were evaluated. Two main steam and two feedwater piping runs on the secondary side were also evaluated.

Design Changes

The EPU effort for Waterford 3 resulted in a nominal T_{hot} of 601°F and a nominal T_{cold} of 543°F. In addition, thermal stratification transients were applied, and BLPB dynamic loads were considered in the analyses of the major branchlines of the RCS. Several CVCS piping systems were evaluated for new transient cases. The following are the changes considered:

- New nominal hot leg and nominal cold leg temperatures
- Addition of thermal stratification effects
- Fatigue analyses to reflect load changes
- New thermal transient cases (CVCS charging, letdown, and auxiliary spray lines)
- Dynamic effects of BLPBs

Summary of Results

This document summarizes the reanalysis results for piping systems in accordance with the *ASME Boiler and Pressure Vessel Code*, Section III allowables. Specifically, the following aspects of the structural integrity of these systems were examined:

- Pipe stress code compliance – Class 1 components
- Pipe stress code compliance – Class 2 components
- Nozzle load summary and qualification
- Penetration load summary and qualification
- Penetration displacement clearance check
- Whip restraint clearance check
- Valve acceleration check
- Pipe displacement check
- Pipe break qualification
- Recommended in-service inspection (ISI) regions
- Pipe support load/displacement summary
- Flange joint qualification

Whereas the individual analysis documents address all the above issues, the emphasis in this document is to demonstrate ASME Code compliance for all systems. As to the remaining evaluations, it can be stated that pipe support acceptability, pipe displacements, valve accelerations, Class 2 components, nozzles, penetrations, flanges, pipe whip restraints, etc., all meet the stipulated acceptance criteria. No new pipe break locations were created.

Class 1 Code Compliance

Safety Injection Loop 1A

Table 2.2-13 summarizes calculated maximum stresses in the piping system in compliance to ASME Code Class 1.

Table 2.2-13
Safety Injection Loop 1A Stress Summary

ASME Equation	Component	Stress (psi)	Allowable (psi)	Ratio
9 (Design)	8 inch × 3 inch Reducing Tee	21,616	24,300	0.89
9 (Faulted)	Weldolet	29,277	48,450	0.60
10	Elbow (Butt Weld)	69,315	54,300	1.28(1)
12	Elbow (Butt Weld)	14,098	54,300	0.26
13	Elbow (Butt Weld)	34,556	54,300	0.64
CUF	Elbow (Butt Weld)	---	---	0.043

Note 1: ASME Code requirement is that Equation 10 may be exceeded provided that Equation 12 and 13 are met. In this case Equations 12 and 13 are met.

Safety Injection Loop 1B

Table 2.2-14 summarizes calculated maximum stresses in the piping system in compliance to ASME Code Class 1.

Table 2.2-14
Safety Injection Loop 1B Stress Summary

ASME Equation	Component	Stress (psi)	Allowable (psi)	Ratio
9 (Design)	8 inch × 3 inch Branch Conn.	20,334	24,225	0.84
9 (Faulted)	Branch Connection	30,225	48,450	0.62
10	Tangent (Butt Weld)	55,976	54,150	1.03(1)
12	Tangent (Butt Weld)	1,601	54,150	0.03
13	Tangent (Butt Weld)	33,200	54,150	0.61
CUF	8×3 inch Branch Conn.	---	---	0.02
Note 1: ASME Code requirement is that Equation 10 may be exceeded provided that Equation 12 and 13 are met. In this case Equations 12 and 13 are met.				

Safety Injection Loop 2A

Table 2.2-15 summarizes calculated maximum stresses in the piping system in compliance to ASME Code Class 1.

Table 2.2-15
Safety Injection Loop 2A Stress Summary

ASME Equation	Component	Stress (psi)	Allowable (psi)	Ratio
9 (Design)	8 inch Sch 160 Long Radius (LR) Elbow	20,232	24,225	0.84
9 (Faulted)	8 inch Sch 160 LR Elbow	28,239	48,450	0.58
10	12 inch Pipe 1.09 inch WT	51,118	50,610	1.01(1)
12	12 inch Pipe 1.09 inch WT	10,803	50,610	0.21
13	12 inch Pipe 1.09 inch WT	34,077	50,610	0.67
CUF	2 inch Weldolet	---	---	0.01
Note 1: ASME Code requirement is that Equation 10 may be exceeded provided that Equations 12 and 13 are met. In this case Equations 12 and 13 are met.				

Safety Injection Loop 2B

Table 2.2-16 summarizes calculated maximum stresses in the piping system in compliance to ASME Code Class 1.

Table 2.2-16
Safety Injection Loop 2B Stress Summary

ASME Equation	Component	Stress (psi)	Allowable (psi)	Ratio
9 (Design)	8 inch × 3 inch Branch Conn.	22,596	24,225	0.93
9 (Faulted)	8 inch × 3 inch Branch Conn.	28,713	48,450	0.59
10	8 inch × 3 inch Branch Conn.	63,376	56,100	1.13(1)
12	8 inch × 3 inch Branch Conn.	38,569	56,100	0.69
13	8 inch × 3 inch Branch Conn.	29,746	56,100	0.53
CUF	8 inch × 3 inch Branch Conn.	---	---	0.02
Note 1: ASME Code requirement is that Equation 10 may be exceeded provided that Equations 12 and 13 are met. In this case Equations 12 and 13 are met.				

Shut Down Cooling Line 1

Table 2.2-17 summarizes calculated maximum stresses in the piping system in compliance to ASME Code Class 1.

Table 2.2-17
Shut Down Cooling Line 1 Stress Summary

Equation	Component	Stress (psi)	Allowable Stress (psi)	Stress Ratio
9 (Design)	14 inch Butt Elbow	23,735	24,225	0.98
9 (Faulted)	14 inch Butt Elbow	30,546	48,450	0.63
10	1 inch Weldolet	53,863(2)	49,035	1.10(2)
12	1 inch Weldolet	9,298	49,035	0.19
13	1 inch Weldolet	33,831	49,035	0.69
CUF	3 inch x 3 inch x 3 inch Welding Tee	---	---	0.03
Note 1: Small bore lines are exempted from LOCA consideration.				
Note 2: Equation 10 may be exceeded if Equations 12 and 13 are met.				

Shut Down Cooling Line 2

Table 2.2-18 summarizes calculated maximum stresses in the piping system in compliance to ASME Code Class 1.

Table 2.2-18
Shut Down Cooling Line 2 Stress Summary

Equation	Component	Stress (psi)	Allowable Stress (psi)	Stress Ratio
9 (Design)	3 inch Sweepolet	20,780	24,225	0.86
9 (Faulted)	14 inch elbow	25,795	48,450	0.53
10	Tangent	48,874	50,966	0.96
12(1)	NA	NA	NA	NA
13(1)	NA	NA	NA	NA
CUF	1 inch Weldolet	---	---	0.04
Note 1: Equations 12 and 13 not needed if Equation 10 is met.				

Charging and Letdown Piping System

Table 2.2-19 summarizes calculated maximum stresses in the piping system in compliance to ASME Code Class 1.

Table 2.2-19
Charging and Letdown Piping Stress Summary

Equation	Component	Stress (psi)	Allowable Stress (psi)	Stress Ratio
9 (Design)	LR Elbow	20,018	24,150	0.83
9 (Faulted)	LR Elbow	31,724	48,300	0.66
10 (Case 112)	Tangent	40,807	50,610	0.81
10 (Fatigue)	Tangent	54,048	50,610	1.07(1)
12 (Fatigue)	Tangent	2,617	50,610	0.05
13 (Fatigue)	Tangent	39,660	50,610	0.78
Component			**Cumulative Usage Factor**	
2 inch Pipe to valve Weld, Run 2			0.02 (Charging Tr. Set)	
2 inch Pipe to Valve, Run 8			0.02 (Letdown Tr. Set)	
Note 1: Equations 12 and 13 needed if Equation 10 is not met.				

Auxiliary Spray and Charging System Piping

Table 2.2-20 summarizes calculated maximum stresses in the piping system in compliance to ASME Code Class 1.

Table 2.2-20
Auxiliary Spray and Charging Piping Stress Summary

Equation	Component	Stress (psi)	Allowable Stress (psi)	Stress Ratio
9 (Design)	Short Radius (SR) Elbow	20,262	24,150	0.84
9 (Faulted)	SR Elbow	30,586	48,300	0.63
10 (Case 112)	LR Elbow Connection	43,860	48,300	0.91
10 (Fatigue)	LR Elbow Connection	44,433	48,300	0.92
12(1)	NA	NA	NA	NA
13(1)	NA	NA	NA	NA
Component			**Cumulative Usage Factor**	
2 inch Tee, Run 6 Branch of Run 1			0.01	
Note 1: Equations 12 and 13 not needed if Equation 10 is met.				

Surge Line

Table 2.2-21 summarizes the calculated maximum stress results in the critical surge line elbow.

Table 2.2-21
Surge Line Stress Summary

Equation	Component	Stress Ratio/Fatigue Usage
9 (Design)	PZR Elbow	0.31
9 (Faulted)	PZR Elbow	0.87
Fatigue Usage	PZR Elbow	0.39

Note, the Surge Line Fatigue Analysis was based on an Elastic-Plastic Analysis and the Fatigue Usage factor is given for a 40-year plant life.

Pressurizer Spray Piping

Table 2.2-22 summarizes calculated maximum stresses in the piping system in compliance to ASME Code Class 1.

Table 2.2-22
Pressurizer Spray Piping Stress Summary

Equation	Component	Stress (psi)	Allowable Stress (psi)	Stress Ratio
9 (Design)	Connection to RC Piping	23210	26100	0.89
9 (Faulted)	LR Elbow	35247	52200	0.68
10	LR Elbow	65230	52000	1.25
12(1)	LR Elbow	50800	52200	0.97
13(1)	LR Elbow	43330	52200	0.83
CUF	LR Elbow	---	---	0.65
Note 1: ASME Code requirement is that Equation 10 may be exceeded provided that Equations 12 and 13 are met. In this case Equations 12 and 13 are met.				

Class 2 Code Compliance

Main Steam Line A

Table 2.2-23 summarizes maximum calculated stresses in the piping system in compliance to ASME Code Class 2.

Table 2.2-23
Main Steam Line A Stress Summary

ASME Equation	Component	Stress (psi)	Allowable (psi)	Ratio
8	Pipe at Containment (CTMT) Penetration	8031	17500	0.46
9 (Upset)	Pipe at CTMT Penetration	12137	21000	0.58
9 (Faulted)	Reducer	14208	42000	0.34
10	LR Elbow	10156	26250	0.39
11(1)	---	---	---	---
Note 1: ASME Code requirement is that Equation 11 need not be evaluated if Equation 10 is met. In above case Equation 10 is met.				

Main Steam Line B

Table 2.2-24 summarizes maximum calculated stresses in the piping system in compliance to ASME Code Class 2.

Table 2.2-24
Main Steam Line B Stress Summary

ASME Equation	Component	Stress (psi)	Allowable (psi)	Ratio
8	Pipe at CTMT Penetration	7946	17500	0.45
9 (Upset)	Pipe at CTMT Penetration	12190	21000	0.58
9 (Faulted)	Reducer	14596	42000	0.30
10	LR Elbow	9805	26250	0.35
11(1)	---	---	---	---
Note 1: ASME Code requirement is that Equation 11 need not be evaluated if Equation 10 is met. In above case Equation 10 is met.				

Main Feedwater Line A

Table 2.2-25 summarizes maximum calculated stresses in the piping system in compliance to ASME Code Class 2.

Table 2.2-25
Main Feedwater Line A Stress Summary

ASME Equation	Component	Stress (psi)	Allowable (psi)	Ratio
8	CTMT Penetration Conn.	5849	17500	0.33
9 (Upset)	LR Elbow	8606	21000	0.41
9 (Faulted)	SG Nozzle	14603	42000	0.35
10	LR Elbow	5994	26250	0.23
11(1)	---	---	---	---
Note 1: ASME Code requirement is that Equation 11 need not be evaluated if Equation 10 is met. In above case Equation 10 is met.				

Main Feedwater Line B

Table 2.2-26 summarizes maximum calculated stresses in the piping system in compliance to ASME Code Class 2.

Table 2.2-26
Main Feedwater Line B Stress Summary

ASME Equation	Component	Stress (psi)	Allowable (psi)	Ratio
8	SG Nozzle(2)	6238	17500	0.36
9 (Upset)	LR Elbow	8605	21000	0.41
9 (Faulted)	SG Nozzle	15375	42000	0.37
10	LR Elbow	6010	26250	0.23
11(1)	---	---	---	---

Note 1: ASME Code requirement is that Equation 11 need not be evaluated if Equation 10 is met. In above case Equation 10 is met.

Note 2: Maximum stress occurs at the penetration for Main Feedwater Line A, and at the steam generator nozzle for Main Feedwater Line B.

The preceding data pertains to main steam and main feedwater piping inside containment. For all other ASME Class 2 lines affected by changes in pressure, temperature and/or fluid flows due to power uprate, the piping, components, and supports will continue to comply with the current qualification requirements including loading, load combinations, acceptance criteria, and ASME code requirements. Systems that fail to meet the current design requirements in their current configuration as a result of changes in input parameters will be redesigned and physically modified, as required, to meet the current design requirements.

Class 3 Code Compliance

Evaluation of the balance-of-plant (BOP) piping and components utilizes the same design basis loadings and load combinations as the original design, including compliance to ASME code versions and editions under EPU conditions.

EPU affects only the design input parameters associated with loadings used in the qualification of BOP piping, components and supports. Other design aspects such as seismic requirements, design loading combinations, acceptance criteria, etc. are not affected by EPU. Consequently, evaluation of changes in input parameters, primarily pressure, temperature and in some cases fluid flow need to be considered.

Seismic input and qualification requirements are not affected by EPU. However, seismic loading is considered in conjunction with other operating loads that may be impacted by EPU. Consequently, seismic loading is included in the evaluations associated with EPU.

Environmental conditions can have impact on qualification of piping, components and supports. It has been determined that environmental conditions are not adversely affected by EPU, therefore, BOP piping, components and supports are not adversely affected.

The primary design input parameters associated with qualification of BOP piping, components and supports that are affected by EPU include pressure, temperature and in certain cases fluid flows. Piping, components and supports will continue to comply with the current qualification requirements including loading, load combinations, acceptance criteria and ASME code requirements. Systems that fail to meet the current design requirements in their current configuration as a result of changes in input parameters will be redesigned and physically modified, as required to meet the current design requirements.

Piping qualification does not specifically evaluate for effects of vibration due to equipment or fluid flow. To ensure that changes resulting from EPU do not cause excessive vibration that could be detrimental to system performance, vibration monitoring will be performed following EPU to identify sources of vibrations and appropriate corrective actions will be taken to eliminate or minimize these vibrations.

Conclusion

Structural integrity of the pressure-retaining piping, components and associated supports is not adversely affected as a result of EPU. Consequently, the BOP piping, components, and their supports will continue to meet the requirements of GDCs 1, 2, 4, 14, 15; and 10CFR50.55a, following implementation of the EPU.

2.2.3 Reactor Vessel Internals and Fuel Assemblies

The reactor vessel internals addressed in this section comprise both core support and internal structures. These structures are illustrated in Figure 2.2-2. Core support structures, which provide direct support/restraint of the reactor core, include the lower support structure (LSS), core support barrel (CSB) and upper guide structure (UGS) components. Internal structures, which do not provide direct support/restraint of the reactor core, include the core shroud assembly, the in-core instrument supports, the alignment keys and the holddown ring. The reactor vessel internals support and orient the reactor core within the reactor vessel (RV), provide a uniform distribution of coolant among the fuel assemblies, maintain the reactor core in a coolable geometry, provide and maintain a free path for the insertion of control element assemblies (CEAs) into the reactor core, and protect the CEAs and in-core instrument hardware from coolant crossflow. The reactor vessel internals are designed to safely withstand loads due to deadweight, handling, flow impingement, vibration, pressure differentials, temperature differentials, seismic excitation and LOCAs; under normal operating, upset and faulted design loading conditions.

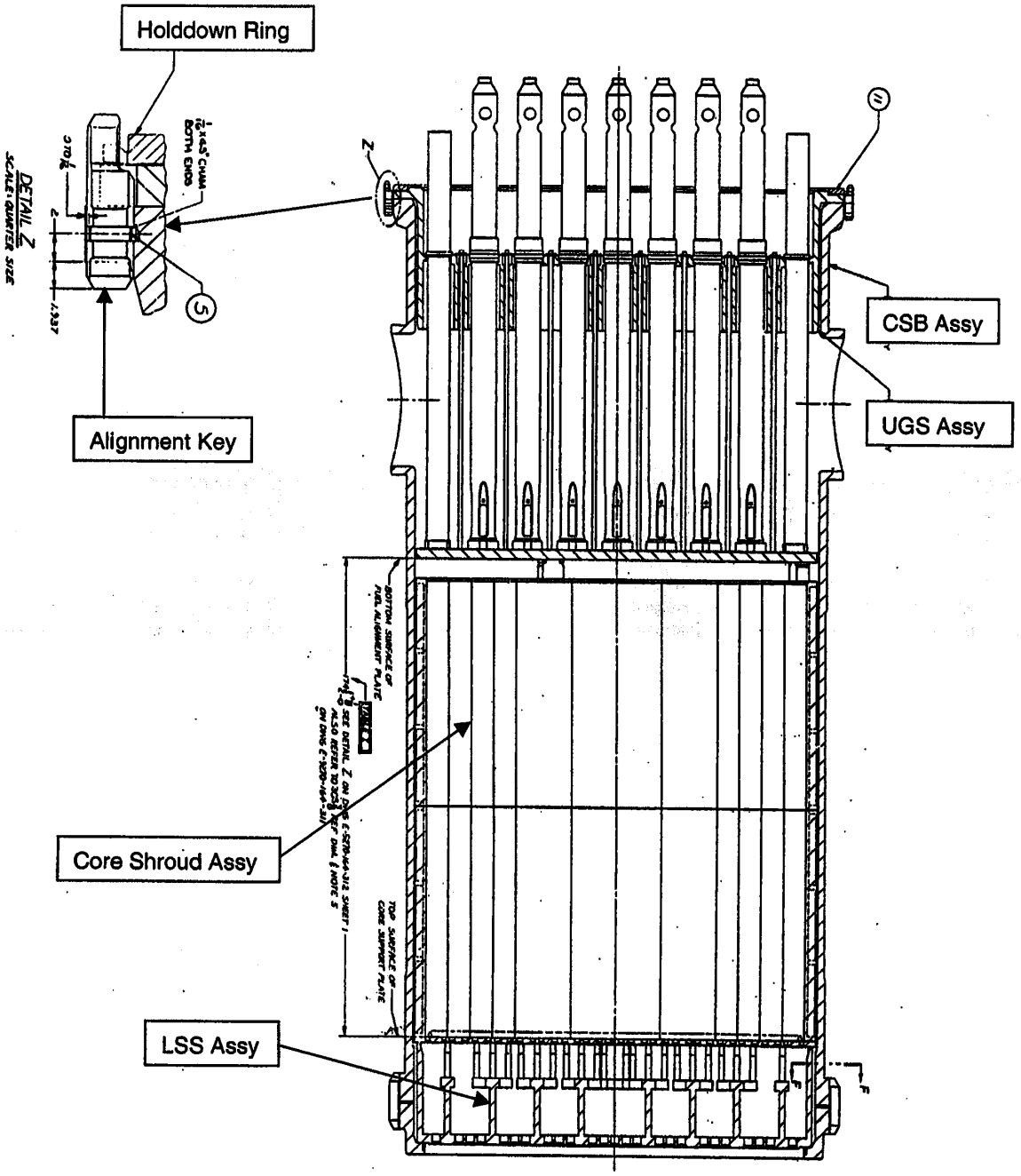


Figure 2.2-2
Reactor Vessel Internals Assembly

2.2.3.1 Introduction

This section evaluates the impact of revised thermal, hydraulic, mechanical and pipe break input data due to power uprate on the Level A+B (normal operating plus upset condition) and Level D (faulted condition) structural evaluations of reactor vessel internal (RVI) components documented in the AOR. The impact of the revised mechanical and hydraulic input data on the ability of the holddown ring to provide adequate RVI hold down force was also evaluated. Seismic loading of the RVI components, as evaluated in the AOR, is not affected by the extended power uprate (EPU).

The revised thermal input, in the form of linearized and local temperature gradients, reflects changes in temperature distribution associated with the EPU. The revised hydraulic input, in the form of hydraulic loads, moments and pressure differentials, reflects the current fuel assembly design. The revised mechanical input, in the form of weights, fuel spring loads and holddown ring loads, also reflect the current fuel assembly design. The revised pipe break input, comprising loads and moments on RVI components, reflects the design basis replacement of main loop pipe breaks with branch line pipe breaks, and again reflects the current fuel assembly design. Vertical pipe break loads used in the AOR included normal operating, steady-state mechanical and hydraulic components. Revised vertical pipe break loads reflect dynamic LOCA excitation only, and do not include these steady-state components. This was done so that the revised steady-state mechanical and hydraulic loads (described above) could be combined with the revised dynamic pipe break loads and the existing SSE loads per the faulted condition design basis.

Design bases, design loading conditions, and design loading categories for the RVI components under both normal operating plus upset and faulted design conditions are defined in Sections 3.9.5.4.1, 3.9.5.2, and 3.9.5.3 of the Waterford 3 FSAR.

2.2.3.2 Methodology Used for Evaluation

All RVI components, both core support structures and internal structures, were evaluated as core support structures in accordance with the criteria described above.

Critical Level A+B stress intensities in the RVI components were obtained from the AOR. The revised thermal, hydraulic and mechanical input data was compared with that used in the AOR. For those components where the revised input data is encompassed by the AOR input data, the AOR stresses were generally left as is. For those components where the revised input data is more limiting than the AOR input data, stresses were recalculated using the AOR methodology in combination with the revised input data. In some cases, AOR methodology was enhanced to address input data that was previously unavailable (e.g., for the calculation of thermal stresses as discussed below).

At the time of the AOR, detailed information on thermal loading of RVI components was limited, and thermal stresses were calculated using simplified methodology. For Waterford 3 power uprate, detailed thermal loadings on the RVI components were calculated. To facilitate incorporation of the new information using AOR methodology, these detailed thermal loadings were generated in the form of linearized and local temperature gradients, from which total secondary stress values are calculated. This approach to generating thermal stresses is

appropriate if the product of the modulus of elasticity and the coefficient of thermal expansion is reasonably constant over the range of temperatures being considered, as is the case for this evaluation.

All Level A+B stress intensities were evaluated against criteria defined in Section III, Subsection NG of the *ASME Boiler and Pressure Vessel Code* (introduced in the Winter 1973 Addendum), per Section 3.9.5.4.1 and Table 3.9-13 of the Waterford 3 FSAR. These criteria include limitations on primary membrane, primary membrane plus bending, and primary plus secondary stress intensities of $n \times 1 \times S_m$, $n \times 1.5 \times S_m$, and $3 \times S_m$, respectively, where S_m represents the design stress intensity and n represents the weld quality factor, if applicable.

A fatigue evaluation of the RVI components was performed by demonstrating that the peak alternating stress required to achieve maximum allowable fatigue usage was greater than that calculated for any of the RVI components. This evaluation utilized the appropriate fatigue curve provided in Section III, Appendix I of the ASME Code, 1971 edition with addenda through Winter 1973, which is considered to be the ASME Code edition-of-record for the RVI. Fatigue curves in this edition of the Code were limited to 10^6 cycles. The calculation of high-cycle ($> 10^6$ cycles) fatigue usage, normally associated with flow-induced vibration, was therefore not required for this evaluation. However, the dynamic hydraulic loads that cause flow-induced vibration are included in the revised hydraulic input described above, and are thus accounted for in the Level A+B stress evaluation.

Critical Level D stress intensities in the RVI components were obtained from the AOR. The revised hydraulic, mechanical and pipe break loads were compared with those used in the AOR. For those components where the revised input data is encompassed by the AOR input data, the AOR stresses were left as-is. For those components where the revised input data is more limiting than the AOR input data, stresses were recalculated using the AOR methodology in combination with the revised input data.

All Level D stress intensities were evaluated against criteria defined in Section III, Appendix F of the *ASME Boiler and Pressure Vessel Code* (introduced in the Winter 1972 Addendum), per Section 3.9.5.4.1 and Table 3.9-13 of the Waterford 3 FSAR. These criteria include limitations on primary membrane and primary membrane plus bending stress intensities of $n \times 2.4 \times S_m$ and $n \times 3.6 \times S_m$, respectively.

The holddown ring exerts a downward force on the CSB and UGS upper flanges; maintaining them in a clamped configuration to prevent rocking and sliding of the CSB and UGS assemblies relative to one another and to the reactor vessel. Sliding margin is defined as the ratio of the lateral (frictional) component of the net hold down load over the applied lateral hydraulic load. The net hold down load is calculated using the holddown ring, dead weight, fuel spring and the vertical hydraulic loads. Rocking margin is defined as the ratio of the moment generated by the net hold down load over the applied hydraulic moment. The derivation of allowable rocking and sliding margins is not based on any regulatory or design basis document. The allowable margin values used in the rocking and sliding evaluations are based on good engineering practice and operating experience with numerous plants. As defined above, rocking and sliding margin is defined as the ratio of holddown load or moment to the applied load or moment. Any ratio greater than 1 is acceptable. To provide conservatism, the analysis uses a factor of 2 for normal operation and 1.5 for plant transients. Plant transients occur a much smaller percentage of operating life and therefore a lower safety factor is

appropriate. For this evaluation, rocking and sliding margins were calculated using the revised mechanical and hydraulic inputs, loads and moments described above.

2.2.3.3 Results of Evaluation

The results of the RVI stress evaluation are presented in Table 2.2-27. Stress intensities in the RVI components resulting from the incorporation of revised input loads associated with EPU were shown to satisfy design criteria for both normal operating-plus-upset and faulted design conditions. Cumulative fatigue usage was shown to be < 1.0 for all of the RVI components. The reactor internals therefore maintain a free path for CEA insertability.

Rocking and sliding margins resulting from the incorporation of revised input loads associated with power uprate were shown to be acceptable for both the normal operating configuration and for plant transients.

Table 2.2-27
Stress Evaluation Results for RVI Components

	Normal Operation + Upset Condition			Faulted Condition		
LSS Components	**Stress (psi)**	**Allowable (psi)**	**Margin (%)**	**Stress (psi)**	**Allowable (psi)**	**Margin (%)**
Core Support Plate (CSP) (mb)	8,834	24,150	63	26,423	57,960	54
CSP (mbQ)	41,752	48,300	14	*	*	*
Beams (mb)	3,292	10,740	69	11,494	21,480	46
Columns (m)	2,433	12,880	81	8,396	30,912	73
Columns (mbQ)	45,090	48,300	7	*	*	*
CSP to Cylinder Weld (m)	2,400	7,245	67	3,717	17,388	79
CSP to Core Shroud Weld (m)	4,900	14,490	66	10,491	34,776	70
Insert Pin to Beam (br)	2,700	17,900	85	*	*	*
Insert Pin (mb)	**	**	**	1.565	57,960	97

CSB Components	**Stress (psi)**	**Allowable (psi)**	**Margin (%)**	**Stress (psi)**	**Allowable (psi)**	**Margin (%)**
Upper Flange to Barrel Weld (mb)	13,287	24,150	45	34,652	57,960	40
Upper Flange to Barrel Weld (mbQ)	32,378	48,300	33	*	*	*
Lower Flange to Barrel Weld (mb)	10,428	24,150	57	34,138	57,960	41
Lower Flange to Barrel Weld (mbQ)	23,150	48,300	52	*	*	*
CSB to Lower Support Structure (LSS) Flexure Weld (m)	8,865	14,490	39	28,279	34,776	19
CSB to LSS Flexure away from Weld (m)	7,459	16,100	54	**	**	**

Table 2.2-27 (cont.)
Stress Evaluation Results for RVI Components

	Normal Operation + Upset Condition			Faulted Condition		
CSB Components (cont.)	**Stress (psi)**	**Allowable (psi)**	**Margin (%)**	**Stress (psi)**	**Allowable (psi)**	**Margin (%)**
Inlet Impingement Area (m)	4,409	16,100	73	20,467	38,640	47
Outlet Nozzle (m)	4,617	11,270	59	9,445	27,048	65
Outlet Nozzle (mbQ)	42,321	48,300	12	*	*	*
Center Cylinder Upper Transition (mb)	**	**	**	39,129	57,960	32
Center Cylinder Upper Transition (mbQ)	44,080	48,300	9	*	*	*
Lower Cylinder to Snubber Weld (mb)	13,195	21,735	39	43,276	52,164	17
UGS Components	**Stress (psi)**	**Allowable (psi)**	**Margin (%)**	**Stress (psi)**	**Allowable (psi)**	**Margin (%)**
CEA Shroud Upper Guide Structure Support Plate (UGSSP) End @ Threads (mb)	9,579	24,150	60	23,428	57,960	60
CEA Shroud UGSSP End @ Threads (mbQ)	25,467	48,300	47	*	*	*
Modified CEA Shroud @ UGSSP Weld (mb)	9,430	13,283	29	22,807	31,878	28
Modified CEA Shroud @ UGSSP Weld (mbQ)	22,716	48,300	53	*	*	*
CEA Shroud @ flow channels (mb)	8,387	24,150	65	19,010	57,960	67
Modified Shroud @ flow by-pass (mb)	9,029	24,150	63	20,454	57,960	65
CEA Shroud Cap Screw (m)	**	**	**	29,727	86,600	66
CEA Shroud Cap Screw (mbQ)	53,143	72,900	27	*	*	*
UGS Flange to Cylinder Weld (mb)	10,273	24,150	57	48,389	57,960	17
UGS Flange Top (mb)	**	**	**	21,273	57,960	63
UGS Flange Top (mbQ)	41,171	48,300	15	*	*	*
Grid Beam Bottom (mb)	2,405	24,150	90	7,149	57,960	88
Grid Beam Bottom (mbQ)	14,398	48,300	70	*	*	*
Fuel Alignment Plate (FAP) (mb)	1,421	24,150	94	6,624	57,960	89
FAP (mbQ)	18,810	48,300	61	*	*	*
Extension Shaft Guide Assembly (mb)	994	10,868	91	49,421	57,960	15

Table 2.2-27 (cont.)
Stress Evaluation Results for RVI Components

	Normal Operation + Upset Condition			Faulted Condition		
Internal Structures	**Stress (psi)**	**Allowable (psi)**	**Margin (%)**	**Stress (psi)**	**Allowable (psi)**	**Margin (%)**
Core Shroud (m)	11,656	14,600	20	12,439	35,040	65
Core Shroud (mb)	12,094	21,900	45	19,735	52,560	62
Core Shroud (mbQ)	42,746	43,800	2	*	*	*
Core Shroud Guide Lug (mb)	5,944	24,150	75	44,020	57,960	24
Instrument Tube Support (mb)	21,450	21,735	1	29,193	52,164	44
Instrument Tube Support (mbQ)	47,914	48,300	1	*	*	*
Water Level Monitoring Support (mb)	12,809	21,735	41	48,736	52,164	7
Water Level Monitoring Support (mbQ)	42,263	48,300	12	*	*	*
Alignment Key to CSB Keyway (br)	14,330	17,900	20	*	*	*
Alignment Key (mb)	19,225	64,950	70	57,287	155,880	63
Flow Channel Extension (mb)	2,935	24,150	88	14,326	57,960	75

The following abbreviations are used in this table:

m Primary membrane stress intensity
mb Primary membrane plus bending stress intensity
mbQ Primary plus secondary membrane plus bending stress intensity
br Bearing stress

* The evaluation of mbQ and br (as defined above) is not required for the faulted design condition
** Not a critical stress intensity for this component

2.2.3.4 Fuel Assembly Structural Evaluation

This section provides a summary of the assessment performed to evaluate the impact of the EPU conditions, including new LOCA loads, on the structural components of the fuel assemblies.

2.2.3.4.1 Structural Performance of the Fuel Designs under Seismic and LOCA Conditions

The overall objective of the assessment was to perform an evaluation of the impact of loadings developed as a result of EPU conditions upon the fuel assembly structural components. The existing fuel assembly seismic and LOCA condition structural evaluations that support the fuel designs were utilized during the assessment to compare loading conditions. The fuel assembly structural performance during seismic and LOCA conditions was evaluated based on current fuel assembly designs.

The criteria that determine acceptable fuel assembly performance for licensing are identified in Section 4.2 of the Waterford 3 FSAR. The criteria and their application remain unchanged for this seismic/LOCA assessment as part of the EPU.

The seismic loadings remained unchanged for EPU. The LOCA loadings were identified as changed primarily as a result of the application of leak-before-break (LBB), and were noted as resulting in reduced LOCA loadings. The coolant temperature changes were also factored into the assessment.

Existing analyses were used to identify the applicable previous loading conditions and resultant stress levels and to aid in the development of a comparison with the current EPU loadings.

2.2.3.4.2 Methodology Used for Evaluation

The assessment utilized comparisons of overall fuel assembly response to the seismic and LOCA events in order to evaluate whether earlier analytical results remain applicable for all assembly components. The evaluation method used for the earlier work is described in CE Topical Report CENPD-178-P, Rev. 1-P. No changes to the methods were made as part of the assessment.

For all fuel structural components, comparisons were made between the loadings evaluated by the existing analyses and the combination of unchanged seismic and new LOCA load conditions. Existing analyses were utilized to show compliance of components for the current fuel designs. New design load inputs for this assessment were obtained from the reactor vessel internals seismic and reactor vessel internals pipe break analyses. The new design load inputs were compared to those utilized in previous analyses. As identified above, no methodology changes have been introduced for these evaluations.

2.2.3.4.3 Results of the Evaluation

The assessment acknowledged that, due to the seismic loads being unchanged, and as a result of the implementation of LBB, the new LOCA loads transmitted in conjunction with the Waterford 3 power uprate effort are considerably less severe than the LOCA loads previously transmitted. Therefore it was concluded that existing analyses that support the structural design of the current fuel designs conservatively bound the EPU loading conditions. Therefore the fuel assembly design is structurally adequate and control rod insertion will not be impaired for EPU.

2.2.4 Safety-Related Valves and Pumps

The safety-related pumps and valves were evaluated for the conditions associated with EPU to 3716 MWt.

The evaluation focused on the effects of the proposed EPU on the required functional performance of the valves and pumps. The evaluation also looked for any impacts that the proposed EPU may have on the Waterford 3 motor-operated valve (MOV) programs related to GL 89-10, GL 96-05, and GL 95-07. The evaluation also considered lessons learned from the MOV program and the application of those lessons learned to other safety-related power-operated valves.

Evaluation

The safety-related pumps were evaluated for impact due to EPU conditions. This evaluation included Safety Class 1, 2, and 3 pumps as listed in the FSAR (Table 3.2-1). These are:

Class 1	Reactor coolant pumps (RCPs)
Class 2	Low-pressure safety injection (LPSI) pumps High-pressure safety injection (HPSI) pumps Charging pumps Containment spray pumps
Class 3	Boric acid pumps Equipment drain tank pump Reactor drain tank pump Component cooling water pumps Component cooling water makeup pumps Emergency feedwater (EFW) pumps Auxiliary component cooling water pumps Chilled water pumps Diesel lube oil pumps Fuel pool pumps Diesel oil transfer pumps Emergency diesel generator (EDG) motor drive jacket water pump

Minimum performance requirements did not increase due to EPU. Therefore, EPU has no effect on the functionality of the pumps. The safety analyses confirmed that these minimum requirements are sufficient for the pumps to perform their intended function (Section 2.12 and

2.13 of this report describe the safety analyses for EPU). EPU does not affect the ability of the pumps to meet their technical specification requirements.

As stated in Section 2.5.5.5 of this document, the EFW pumps are adequate for EPU. Although decay heat will increase for the EPU, no change to the EFW pump flow rate is needed. It was demonstrated that the EFW pumps can provide the minimum flow rate necessary to support the safety analysis flow rate assumptions.

No changes are necessary for the high-pressure injection pumps or the low-pressure injection pumps to support the Emergency Core Cooling System (ECCS) analyses.

Similarly, detailed system evaluations or qualitative evaluations in support of the EPU conclude that performance requirements are not changing the remainder of the listed pumps.

The safety-related MOVs, air-operated valves (AOVs), and hydraulic-operated valves (HOVs) were evaluated for the pressures expected for the EPU. For systems not affected by power uprate (no increase in differential pressure), the valves were considered acceptable without further evaluation.

The safety-related AOVs were evaluated and found to be acceptable for EPU conditions. AOVs were evaluated for the proper pressure rating for the expected conditions. This included an evaluation of the expected differential pressure that will be experienced by the valve under EPU conditions.

The safety-related HOVs were evaluated and found to be acceptable for EPU conditions. The HOVs were evaluated against the expected differential pressure conditions that will be experienced by the valves under EPU conditions.

The valves in the MOV program were evaluated for impact due to EPU conditions. Expected system pressures were compared with the pressures listed in MOV maximum expected differential pressure calculations.

Safety-related MOVs were determined to be acceptable for EPU conditions. The MOVs, including the GL 89-10 MOVs, were evaluated for any differential pressure increases expected for EPU. The pressures were reviewed with respect to each MOVs' design function to stroke. As part of this review, applicable maximum expected differential pressure (MEDP) calculations were examined for potential impact from EPU. Based on this evaluation, no physical changes to MOVs are expected for EPU conditions. Also, pressure locking and thermal binding assumptions were reviewed to determine if impacted by EPU. No changes to the programs related to GL 89-10, GL 96-05 or GL 95-07 are required.

The lessons learned associated with the periodic inspection and testing of safety-related pumps and valves are continuously being reviewed in accordance with Waterford 3 procedures and updated as necessary. Likewise, industry experience is also continuously factored into these programs.

In support of the EPU, specific credit is being taken for the Atmospheric Dump Valves (ADVs). The ADVs are now credited in the SBLOCA analysis. This function has been evaluated and it is concluded that these valves are adequate to support the SBLOCA assumptions.

Conclusion

The functional performance of safety-related valves and pumps has been reviewed and it is concluded that the effects of the EPU on them have been adequately addressed. The effects of the EPU on MOV programs related to GL 89-10, GL 96-05, and GL 95-07, and application of the lessons learned from those programs to other safety-related power-operated valves have been evaluated and these programs are adequate for the EPU. Based on this, it is concluded that the safety-related valves and pumps will continue to meet the requirements of GDC 1, GDC 37, GDC 40, GDC 43, GDC 46, GDC 54, and 10CFR50.55a(f) following implementation of the EPU.

2.2.5 Seismic and Dynamic Qualification of Mechanical and Electrical Equipment

FSAR Section 3.7, “Seismic Design,” provides the general requirements for seismic design. Appendices 3.9A, 3.9B, and 3.9C provide additional discussions on seismic qualification. FSAR Section 3.9.2 includes discussions regarding dynamic system analysis and testing. FSAR Section 3.10 provides details regarding seismic qualification of electrical equipment.

Seismic design is not impacted by EPU since seismic requirements remain unchanged. Dynamic qualification can be impacted if equipment operating conditions such as pressure, temperature and fluid flow change as a result of EPU. Additionally, ability of the equipment to withstand effects of pipe-whip, jet impingement, internal, and external missiles may also be affected as a result of EPU impact on systems in physical proximity of essential equipment.

Evaluation

Seismic input and qualification requirements for essential equipment are not affected by EPU. Similarly, quality assurance requirements related to Appendix B to 10CFR50 are not affected. Effects of adverse changes in pressure, temperature and fluid flow on equipment have been found to be within the rated capacity of the equipment or have been evaluated by the original equipment supplier, and found to comply with the appropriate qualification requirements.

Essential equipment within the reactor coolant pressure boundary (RCPB) have been evaluated for effects of the EPU, such as changes in temperature, pressure, flow, and effects of LOCA. They have been determined to be within the specified acceptance limits.

Dynamic effects of internally and externally generated missiles under EPU have been evaluated, and are addressed in Section 2.5.1.2 of this document. Dynamic effects of pipe-whip and jet impingement under uprate conditions have been evaluated, and are addressed in Sections 2.2.1 and 2.5.1.3 of this document. Based on these evaluations, EPU will have no adverse impact on essential equipment as a result of pipe whip, jet impingement, internal, and external missiles.

Conclusion

Seismic and dynamic qualification of mechanical and electrical equipment is not adversely affected as a result of EPU. Consequently, the equipment will continue to meet the requirements of GDCs 1, 2, 4, 14, 30; 10CFR100, Appendix A; and 10CFR50, Appendix B, following implementation of the EPU.

2.3 ELECTRICAL ENGINEERING

2.3.1 Environmental Qualification of Electrical Equipment

Waterford 3 FSAR Section 3.11 discusses environmental qualification.

Impact to the Environmental Qualification (EQ) Program from the extended power uprate (EPU) includes potential changes in the containment loss-of-coolant accident/main steamline break (LOCA/MSLB) temperature and pressure EQ profile, containment radiological conditions (both normal and accident), auxiliary building radiological conditions during accident conditions, and high-energy line breaks (HELBs).

Evaluation

Containment Accident Conditions

The current plant accident profile for electrical EQ equipment located in containment will change for the EPU conditions. While the peak pressures and temperatures at the EPU conditions are bounded by the current pressure and temperature EQ plant accident profile, the time at elevated temperatures at EPU conditions is slightly longer. Analysis performed demonstrates the electrical EQ equipment located inside containment remains qualified. There will be no changes to the containment spray chemical content for uprate.

The total integrated radiation dose used for qualification of safety-related electrical equipment inside the containment is the sum of the 40-year normal plus the radiation associated with the most severe DBE during and following which the equipment must remain functional. To evaluate the impact of power uprate on normal doses, a series of calculations was performed that compared the normal operating doses from contained sources due to power uprate source terms with doses resulting from current design basis source terms. In all cases evaluated, the doses calculated using the power uprate source terms were bounded by the doses using the current design basis source terms. The reduction in dose rates is primarily due to use of the newer standard ANSI 18.1 for the source term in place of ANSI N237, and use of the updated ANSI 6.1.1 1991 flux-to-dose conversion factors in place of the older 1977 version of that standard. The post-accident containment doses are due to contributions from airborne and plateout radioactivity, contained sources, and radioactivity deposited in the sump. The post-accident doses from these sources, based on the power uprate source terms, were compared with the doses based on the current design basis source terms. For all cases evaluated, the doses calculated using the power uprate source terms were bounded by the doses using the current design basis source terms.

The containment flood level was not changed. The submergence level remains the same and as such the EQ components at the lower levels, as they are addressed by the current evaluation, will also remain the same. Therefore, they are not affected by the EPU.

High-Energy Line Breaks (HELBs)

Per FSAR Section 3.6A.2.3, Environmental Effects: “The high energy piping systems located in the Reactor Auxiliary Building are given in Subsection 3.6A.2. Since the main steam and

feedwater systems are located outside of the structure, the environmental conditions produced by the pipe breaks in these systems will not affect any safety-related equipment or components." The response to NUREG 588 justifies that there are no HELBs outside containment that need to be evaluated at Waterford 3. The EPU does not invalidate these results.

Radiological Conditions – General Auxiliary Building

The normal 40-year total integrated dose for qualification of safety-related electrical equipment was evaluated by comparing the contained source dose based on the power uprate normal operating source terms with the dose resulting from use of the design basis normal source term or that specified for EQ zones. For all cases evaluated, the power uprate case was bounded by the design basis case. The reduction in dose rates is primarily due to use of the newer standard ANSI 18.1 for the source term in place of ANSI N237, and use of the updated ANSI 6.1.1 flux-to-dose conversion factors in place of the older 1977 version of that standard.

Post-accident radiological conditions in the Reactor Auxiliary Building were also evaluated for power uprate. The dose from recirculating fluid and airborne radionuclides was specifically addressed. The dose due to reactor building shine was not re-evaluated for power uprate since the existing design basis calculations have shown that this is a minor contributor to the equipment qualification dose. Likewise, the doses from Engineered Safety Feature (ESF) filters were not specifically re-evaluated since the power uprate source term for iodines, the primary contributors for filter doses, is less than the current design basis values. For contained recirculating fluids, a series of evaluations was performed which demonstrated that the doses resulting from power uprate source terms were bounded by the current design basis source terms. The airborne dose in the Reactor Auxiliary Building is due to containment leakage and Engineered Safety Feature (ESF) leakage. The 120-day post-accident dose from these sources using the power uprate core inventory was compared with the dose using the current design basis core source term. The evaluation showed that the total airborne dose using the power uprate source term was bounded by the airborne dose using the design basis source term.

Conclusion

The existing equipment qualification documentation was evaluated against the containment and auxiliary building environmental conditions postulated for the EPU (radiological, containment flooding, temperature, pressure, submergence, and chemical spray). The result is that EQ equipment remains qualified and will continue to meet the requirements of 10CFR50.49 for power uprate.

2.3.2 Offsite Power System

2.3.2.1 Grid Stability

The transmission system in the vicinity of the Waterford 3 switchyard was analyzed for single contingency (loss of Waterford 3, loss of largest generating unit, or loss of the most critical transmission line) including the rewound generator characteristics, to ensure that the grid system remains stable for the uprated generation level at Waterford 3. Increasing the generation level does not result in instability of the Waterford 3 unit for the disturbances (faults

or other single contingency events) expected on the transmission system. Offsite power systems will return to equilibrium without cascading trips of additional transmission lines, generators or other transmission equipment after these disturbances. Additionally, during such disturbances the offsite system will continue to supply the safety related buses with acceptable voltage levels (per National Electric Manufacturer's Association [NEMA] standards) so motors can start and perform their required safety function.

Entergy performed a grid system analysis to support the proposed power increase. The steady state analysis confirmed that the Waterford 3 switchyard voltage levels during summer peak conditions following a loss of Waterford 3, the most critical transmission line, or any large surrounding generating unit are acceptable. A generated output for the station was assumed that bounds the Waterford 3 power uprate. The dynamic analysis indicated that a three-phase fault near the Waterford 3 230-kV switchyard results in the Waterford 3 unit and the system remaining stable for both existing and power uprate generation levels. The analysis resulted in the conclusion that there is insignificant impact on grid stability and reliability for the power uprate. Additionally, the Waterford 3 power uprate will not adversely impact the availability of the offsite power source for Waterford 3 house loads in the event of a unit trip.

Conclusion

Grid stability studies have demonstrated that for power uprate the transmission grid remains stable. Safety-related buses will be acceptably supplied by the offsite power sources following postulated transmission system disturbances. Waterford 3 continues to be in conformance with GDC 17 for the power uprated electrical conditions.

2.3.2.2 Offsite Power System Components

Main Generator

The main generator is discussed in FSAR Section 8.2.1.5.1. The function of the main generator is to provide a controllable means of converting the mechanical energy of the main turbine into a regulated and usable supply of electricity. The generator delivers 60 Hz power at 25kV to the main and auxiliary transformers using the isolated phase bus. The instrumentation, controls, interconnections and associated support systems allow parallel operation of the generator within the utility power grid to meet the demands of the system. Additionally, the main generator, through the unit auxiliary transformer, furnishes electric energy to unit auxiliary loads under normal plant operating conditions.

Evaluation

The main generator is being rewound to restore its 1333-MVa rating prior to implementing the EPU.

Conclusion

The main generator will be acceptable for EPU conditions after being rewound.

Transformers

Main Transformers

The main transformers are discussed in FSAR Section 8.2.1.6.3. The function of the main transformers A and B is to provide a means to transmit the electrical output of the main generator to the switchyard by stepping up the main generator voltage of 25kV to the switchyard voltage of 230kV. The Waterford 3 main transformers consist of 2 three-phase units, each rated at 600 MVa (with 4 of 5 cooling pump/fan units in service), and 798 MVa (with additional external cooling connected) connected in parallel to the main generator output.

Evaluation

The equipment has been evaluated for EPU conditions. At this time it is expected that additional cooling for both transformers, and replacement or rewind of the main transformer A may be required in order to support EPU.

Unit Auxiliary Transformers

The unit auxiliary transformers are discussed in FSAR Section 8.2.1.6.3. The function of the two unit auxiliary transformers is to provide power from the main generator output stepped down to 4.16kV and 6.9kV to the AC electrical distribution system during normal power operations. The unit auxiliary transformers are three phase transformers having an overall capacity of 52 MVa with a capacity of 32 MVa on the 6900-volt winding, and a capacity of 20 MVa on the 4160-volt winding.

Evaluation

The equipment has been evaluated for EPU conditions. The unit auxiliary transformer loading assumed in plant load and degraded voltage relay setpoint evaluations bounds anticipated load increases due to EPU.

Startup Transformers

Startup transformers (SUTs) are discussed in FSAR Section 8.2.1.6.3. The function of the two startup transformers is to supply offsite power stepped down to 4.16kV and 6.9kV to the AC electrical distribution system during plant startup and shutdown when the main generator is not available. The SUTs are the preferred source of power for accident mitigation. The two SUTs are three-phase transformers having an overall capacity of 56 MVa with the 6900-volt winding rated at 36 MVa, and the 4160-volt winding rated at 20 MVa.

Evaluation

The equipment has been evaluated for EPU conditions. The SUT loading assumed in plant load and degraded voltage relay setpoint evaluations bounds anticipated load increases due to the EPU.

Conclusion for Transformers

There are no accident load increases at any voltage level due to the EPU. The 6900- and 4160-volt motor load increases are minor in nature and are bounded by existing calculation assumptions. The unit auxiliary transformers and startup transformers are acceptable under EPU conditions. Plant modifications will be made as necessary to upgrade the main transformers to support EPU.

House Load Changes for Power Uprate Evaluation

Normal loads are supplied via the unit auxiliary and startup transformers. These loads are classified by voltage levels: 6900-, 4160-, and 480-volts. An alkalizer skid will be added as part of the main generator rewind project to address main generator stator cooling water chemistry concerns. This skid and plant modification for the main transformers will add load to the non-vital portion of the 480-VAC system and will be addressed within the modification process. No other new loads at these voltage levels will be installed for the EPU, this evaluation examined whether existing motor loads would increase due to EPU conditions.

The evaluation determined that there are minor increases in the 6900-volt motor loads due to increased demands on the condensate pumps and the reactor coolant pumps (due to a lower average coolant temperature). Additionally, the 4160-volt motor loads will increase due to heater drain pump performance requirements. These increases are well within transformer capabilities. No load increases other than those identified above are anticipated on the 480-volt system due to power uprate.

The increased loading due to the condensate pumps, reactor coolant pumps, and heater drain pumps is bounded by the load values assumed in plant load and degraded voltage relay setpoint evaluations. These load increases exist for normal operation only.

Iso-Phase Bus and Bus Duct

The function of the iso-phase bus (IPB) is to conduct power from the main generator to the main and unit auxiliary transformers. The buses are individually enclosed in isolated phase bus ducts and routed to the main and unit auxiliary transformers. The buses are highly conductive hollow aluminum conductors, insulated and enclosed within an isolating duct, which utilize a forced air cooling system.

Evaluation

The EPU will increase IPB current and result in more heat generated from the bus due to increased I^2R losses. The IPB and bus duct were evaluated for EPU conditions and found to be within the system's existing capacity.

Conclusion

Based on the evaluation, the current IPB supports the EPU.

Generator Output Breakers

The generator output breakers are discussed in FSAR Section 8.2.1. The main generator output breakers consist of three individual phase breakers, operated as a single breaker, located in the switching station. The function of these breakers is to electrically connect the output of the main transformers to the 230-kV switchyard.

Evaluation

Due to the EPU, the existing breakers' continuous load and short circuit interrupting ratings will be exceeded, as well as the associated mechanical disconnect switches on either side of each breaker. New breakers and disconnects are required to meet 1333 MVa and will be installed over RF12 and RF13.

Conclusion

Installation of the new breakers will support implementation of the EPU.

2.3.2.3 Offsite Power System Conclusion

The offsite power system with implementation of the identified modifications will support EPU and continue to meet the requirements of GDC 17.

2.3.3 AC Onsite Power System

The AC onsite power system is discussed in FSAR Section 8.3.1. The safety-related buses associated with the AC onsite power system provide reliable power for safe shutdown of the plant during normal and emergency conditions when preferred power is unavailable in either 'A' or 'B' division. This system is supplied via the emergency diesel generators (EDGs) to enable safe shutdown of the plant. The safety-related functions are performed through Division A and Division B of this system. Additionally, this system powers selected non-safety related loads during start-up, normal, and emergency operation of the plant.

Evaluation

The EPU will result in negligible changes in 4160-volt motor loads. The sequencing of the safety loads is unchanged. No load increases are anticipated on the 480-volt or 208/120-volt safety-related low voltage distribution systems due to power uprate.

Conclusion

There are negligible load changes to the safety related buses and EDGs due to the EPU. The onsite power system will continue to meet the requirements of GDC 17.

2.3.4 DC Onsite Power System

The safety-related function of the DC onsite power system is to provide reliable continuous 125 VDC power to the Plant Protection System (PPS) and other loads for safe operation of the

reactor. This system also furnishes power for a safe shutdown of the plant during normal and emergency conditions. Should an accident occur and preferred power be lost in either or both divisions, this system acts as a source of power for safety related DC loads and static uninterruptible power supplies (SUPSs) until emergency power is available.

The non-safety related function of the system is to power the non-safety related loads required to ensure instrumentation and control capability to monitor and maintain the plant status during startup, shutdown, normal, and emergency plant operation. Loads which are sensitive to voltage loss/fluctuations and/or frequency fluctuations are served by the DC or SUPS systems. Examples include computer, communications, and security equipment. In addition, loads which are critical upon loss of offsite power, such as turbine bearing lube oil pumps, are fed from these systems.

Evaluation

The 125-VDC distribution system is discussed in FSAR Section 8.3.2, and was evaluated for the EPU. A plant modification associated with the atmospheric dump valve controls required for the EPU will result in a slight change in DC system loading. No other changes are expected to component operation or battery duty cycles due to the EPU.

Conclusion

The 125-VDC distribution system will continue to function as designed. Adequate separation exists, and the system has the capability to continue to supply adequate power to both safety and non-safety equipment. The system will continue to meet the requirements of GDC 17 following implementation of the EPU.

2.3.5 Station Blackout

The station blackout evaluation is discussed in FSAR Section 8.1A.

Station blackout encompasses the complete loss-of-offsite electric power concurrent with a turbine trip and failure of the onsite emergency AC power system. Plant equipment power from the DC onsite power system and steam from the SGs will be used to remove decay heat from the reactor core.

Evaluation

The turbine-driven Emergency Feedwater System (EFS) pump, the atmospheric dump valves, and DC electric power from Class 1E batteries are available for reactor core decay heat removal during the 4-hour event. The turbine-driven pump draws water from the condensate storage pool and pumps it into the SGs. Steam from the SGs is used for operating the pump's turbine. The batteries provide electric power to the steam supply valves and the EFS flow control valves. The suction lines to the turbine-driven pump are aligned to the condensate storage pool.

The atmospheric dump valves (ADVs) are used for bleeding steam from the SGs. Decay heat from the reactor core is removed by feeding and bleeding the SGs. Approximately 82,200 gallons of water is needed to remove decay heat for 4 hours in accordance with

Nuclear Management and Resources Council (NUMARC) methodology. The condensate storage pool has a technical specification limit of 170,000 gallons of water dedicated for EFS usage. The turbine-driven EFS pump has the capability of pumping the required flow to the two SGs during station blackout.

The Class 1E batteries have sufficient power to meet station blackout needs for 4 hours.

Air-operated valves needed to control EFS flow to the SGs are provided with backup nitrogen accumulators. The accumulators have sufficient gas capacity for 10 hours of operation.

The ambient air temperature for the turbine-driven EFS pump area is not expected to rise above 90°F for station blackout. This temperature is below the threshold value of 120°F for dominant areas of concern requiring equipment operability analysis.

Conclusions

The EFS, in conjunction with the ADVs and Class 1E batteries following EPU, are capable of maintaining the RCS in a hot standby condition and removing the decay heat during the 4 hours of station blackout. The EFS and supporting system and components will continue to meet the requirements of 10CFR50.63.

2.4 INSTRUMENTATION AND CONTROLS

2.4.1 Reactor Protection, Safety Features Actuation, and Control Systems

The Plant Protection System (PPS) is composed of two sub-systems: the Reactor Protection System (RPS) and the Engineered Safety Features Actuation System (ESFAS).

The RPS is designed to trip the reactor by de-energizing the control element drive mechanism (CEDM) coils whenever any monitored condition reaches a trip setpoint. For each measured variable, the RPS uses a 2 of 4 channel logic arrangement, with each channel electrically and physically separated to ensure no loss of functionality with a single failure. The RPS is designed to protect the reactor core and the reactor pressure boundary during defined anticipated operational occurrences, and to assist in mitigating the consequences of certain design basis accidents. The RPS also includes the Core Protection Calculator System (CPCs), the reactor trip switchgear (RTSG) and the Reactor Coolant Pump Shaft Speed Sensor System (RCPSSSS). The RPS is discussed in FSAR Section 7.2.

The ESFAS is designed to initiate safety features whenever any monitored condition reaches a trip setpoint. Like the RPS, the ESFAS uses a 2-of-4 channel logic arrangement, with each channel electrically and physically separated to ensure no loss of functionality with a single failure. The ESFAS is designed to mitigate the consequences of certain design basis accidents (DBAs), particularly by protecting the containment building integrity. The ESFAS is discussed in FSAR Section 7.3.

Systems required for safe shutdown are described in FSAR Section 7.4. Instrumentation required to monitor, control, and provide interlocks for these systems is described in FSAR Sections 7.4, 7.5, and 7.6. The EPU affects the process ranges of some of the instrumentation described in these sections.

The EPU also affects the atmospheric dump valve (ADV) controllers. The existing ADV analog controllers are being replaced with more accurate digital controllers.

Waterford 3 provides anticipated transient without scram (ATWS) mitigation systems required by 10CFR50.62 as described in FSAR Section 7.8.

2.4.1.1 Evaluation

The PPS is affected by EPU. The low steam generator pressure trip setpoint has decreased. The maximum allowable linear power level – high trip setpoints with inoperable steam line safety valves are adjusted accordingly for EPU conditions. No other setpoints affecting the PPS will change due to EPU.

The EPU redefines 100% power level, affecting changes to the neutron flux to percent power correlation of the ex-core nuclear instruments. The ex-core nuclear instruments provide signals to the PPS for high linear power level and high logarithmic power level reactor trips. The correlation is achieved by frequent secondary calorimetric calibrations, which normalize the flux signals to calorimetric power.

Power uprate will result in different operating conditions in the SGs, which affects the calibration of the SG level instruments. The SG low and high level limits will remain protected.

The core protection calculators (CPCs) receive input signals, including neutron flux from the ex-core instruments, and calculate local power density (LPD) and departure from nucleate boiling ratio (DNBR). Power uprate will affect the ex-core signals as addressed above, but changes to the neutron flux to power correlation will be corrected by the calorimetrics. As part of EPU, the CPC differential cold leg temperature trip setpoint was reduced to compensate for more negative MTC and the higher EPU power level, as discussed in Section 2.13.9.1.1. As part of EPU, CPC response times have been clarified in the Technical Requirements Manual (TRM).

The changes to ranges on instrumentation supporting safe shutdown will not change the instrument functions as described in FSAR Sections 7.4 and 7.5. The setpoints for shutdown system interlocks and plant processes having significant impact on plant safety described in FSAR Sections 7.4 and 7.6 are not affected by the EPU.

The change to digital ADV controllers for improved accuracy will not change their functions as described in FSAR Section 7.4.

The EPU does not change the design of ATWS mitigation systems as described in FSAR Section 7.8. However, because the EPU lowers steam generator and main steam operating pressures, the diverse emergency feedwater actuation signal (DEFAS) permissive setpoint will be lowered; this change ensures that the configuration for the Emergency Feedwater System (EFS) actuation described in Section 7.8 is maintained under EPU conditions. Additionally, other actuation setpoints remain such that ATWS mitigation systems will not be actuated before initiation of the PPS.

The EPU does not change the separation, redundancy, or diversity of the above instrumentation and controls as described in the applicable sections of the FSAR.

2.4.1.2 Conclusion

The EPU configuration has been analyzed to a lower SG pressure. Changes to the Plant Protection System due to lower SG pressure will be implemented for EPU.

No setpoint changes to safe shutdown interlocks or alarms are required.

CPC constants will be updated to be consistent with the new definition of 100% power and other requirements of the EPU and cycle-specific analysis.

The EPU does not change the safety functions or design such as separation, redundancy, and diversity of the instrumentation as described in FSAR Sections 7.2, 7.3, 7.4, 7.5, 7.6, and 7.8. The changes resulting from the EPU are, therefore, consistent with the licensing basis and comply with acceptance criteria related to 10CFR49, 10CFR50.55a, 10CFR62, 10CFR50 App. A GDCs 1, 2, 3, 4, 10, 12, 13, 19, 20, 21, 22, 23, 24, 25, 29 and 10CFR50 App. R.

2.4.2 Additional Instrumentation and Control Systems

FSAR Sections 7.5A and 7.7 discuss various control and instrumentation systems that are not required to perform safety functions. Changes for EPU applicable to these systems are discussed in the sections below.

2.4.2.1 Evaluation

NSSS Operational Control Systems

The performance of the basic Nuclear Steam Supply System (NSSS) operational control systems (Pressurizer Level Control System [PLCS], Feedwater Control System [FWCS], Steam Bypass Control System [SBCS] and Reactor Power Cutback System) was evaluated for steady state operation and design basis control system maneuvering transients under the new operating conditions associated with power uprate. This evaluation concluded that certain changes to the NSSS control systems would ensure proper NSSS dynamic performance such that the probability for reactor trips is minimized for the load maneuvering transients and certain equipment malfunctions, and also confirmed post-trip responses are acceptable.

The EPU requires adjustments to NSSS control systems setpoints and parameters to provide proper control system performance for the EPU operating conditions. With respect to plant safety, the NSSS response to load maneuvering transients and equipment malfunctions is bounded by the plant safety analyses.

Boron Control System

The Boron Control System is described in FSAR Section 7.7.1.1. The EPU does not affect any components described in this system.

Main Turbine Controls

The main turbine controls are described in FSAR Section 7.7.1.4. The EPU does change the high-pressure (HP) turbine control scheme from sequential to single valve control. However, the control system as described in FSAR Section 7.7 is not changed.

Turbine Trip Signals

Turbine trip signals are described in FSAR Section 7.7.1.4. EPU does not affect any of the turbine trips described in this section. The impact of the EPU on the NSSS control systems responding to turbine trip (SBCS and reactor power cutback) has been evaluated. As previously discussed, response to load maneuvering transients and equipment malfunctions is bounded by the plant safety analysis.

Core Operating Limit Supervisory System (COLSS)

COLSS is described in FSAR Section 7.7.1.5 and consists of process instrumentation and algorithms implemented on the plant monitoring computer (PMC). COLSS continually monitors the Technical Specifications limiting conditions for operations (LCOs) on the following:

a) Linear heat rate (LHR)
b) Margin to DNBR

c) Total core power

d) Azimuthal tilt

e) Axial shape index

COLSS database constants are updated during each refueling outage to account for the reload core design. The COLSS constants that are based on the reactor thermal power and instrumentation uncertainties will be modified as necessary. These constants will be calculated and implemented as part of the reload fuel design process.

The functions of COLSS as described in FSAR Sections 7.7.1.5 and 7.5A after implementing the EPU changes are preserved and bounded.

Plant Computer

The plant computer (also referred to as the “plant monitoring computer,” or PMC) is described in FSAR Section 7.5A. The EPU affects the ranges of many of the instrument loops that input into the plant computer. However, the plant computer functions as described in FSAR Section 7.5A will not change as a result of the EPU.

Incore Instrumentation

The in-core instrumentation is described in FSAR Section 7.7.1.7. The EPU will result in higher neutron flux within the reactor core. The in-core instrumentation inputs to COLSS and CECOR for radial and axial power distribution calculations. This function is not affected by the increased neutron flux.

Ex-core Neutron Flux Monitoring System

The ex-core neutron flux monitoring system is described in FSAR Section 7.7.1.8. The four safety channels are addressed in Section 2.4.1 of this evaluation. The EPU will increase neutron flux within the reactor core. However, the external neutron flux will not increase significantly due to the reactor core configuration. The ex-core instrumentation will, therefore, function as described in FSAR Section 7.7.1.8.

2.4.2.2 Conclusion

The instrument functions as described in FSAR Sections 7.5A and 7.7 are not changed. The EPU does not affect the functions of this instrumentation in a manner such that its failure will affect safety functions. The design of this instrumentation complies, where applicable, with GDCs 1, 13, and 19.

2.5 PLANT SYSTEMS

2.5.1 Internal Hazards

2.5.1.1 Flooding

The maximum flood level from breaks/cracks in the piping, tanks, and vessels inside and outside of containment is considered at Waterford 3. The results of external flooding from natural phenomena is not affected by this EPU. The measures taken to prevent external flooding from natural phenomena are discussed in FSAR Section 3.4. FSAR Section 3.6A.6 discusses the measures taken to deal with internal flooding.

Evaluation

The maximum post-LOCA flood level inside of containment is not adversely affected by the EPU. The water inventory added to the containment floor from the refueling water storage pool, boric acid makeup tanks (BAMTs), safety injection tanks (SITs), pressurizer, charging pumps, safety injection piping, and Reactor Coolant System (RCS) is not adversely affected. The RCS temperature that results in the highest containment flood level prior to EPU is not adversely impacted for the EPU. Further, the range of containment atmosphere and sump water temperatures considered in the flood level analysis performed under pre-EPU conditions bounds the post-LOCA containment temperatures determined under EPU conditions.

Flooding outside of containment caused by cracks in moderate energy lines, breaks in high energy lines and activation of fire protection sprinklers is evaluated at Waterford 3. The period of time at which the flood level will reach the height of the safety-related equipment closest to the floor is determined. The flooding caused by the moderate energy line cracks and high-energy line breaks (HELBs) is conservatively calculated assuming the flow rate from the cracks/breaks is obtained from an infinite reservoir and assuming the floor drains are 100% clogged. The flooding caused by activation of the fire protection sprinkler system conservatively assumes that half of the sprinkler heads in each room are activated. If the time required to reach the flood level from these sources is greater than 30 minutes, it is assumed that operator action can be taken to mitigate the consequences of the rising flood level. If the flooding period is less than 30 minutes, one of the following actions are taken to remedy the flooding condition:

- Redundant system components are identified
- Eliminate the need to postulate cracks in any moderate energy lines in which the pipe stress is less than the ASME Section III allowable stress
- Qualify the equipment to the flooding conditions

Because the normal operating temperature and pressure for the moderate and high energy lines are not changing significantly, there is a negligible impact to the flow rate through cracks and breaks in the moderate and high energy lines. In addition, the classification of the lines that are considered moderate or high energy is not impacted. The number of fire protection

sprinkler heads in each of the rooms is also not impacted by the EPU. Therefore, the time to reach the flood level in each of the rooms and the remedies used for the rooms in which the flooding period is less than 30 minutes are not affected by the EPU.

Conclusion

After reviewing the fluid volumes in tanks and vessels as well as system operating conditions, it was determined that the flood levels inside and outside of containment are not impacted by the EPU. Therefore, the structures, systems, and components (SSCs) important to safety will continue to be protected from flooding, and will continue to meet the requirements of GDC 2.

2.5.1.2 Missile Protection

Internally Generated Missiles

Safety-related and seismic Category I equipment at Waterford 3 is protected against internally generated missiles from sources inside and outside of containment. These missiles are generated by failures in the high energy systems and overspeed of rotating components. FSAR Section 3.5 discusses the measures taken to protect the safety related and seismic Category I equipment at Waterford 3 against internally generated missiles.

Evaluation

Internally Generated Missiles Outside Containment

Missiles generated from the high energy systems in the turbine building are prevented from causing damage to safety-related equipment by the large separation between these high energy systems and the safety related components. Missiles generated from valve stems, valve bonnets and safety relief valves are not postulated because either there are sufficient restraints, adequate separation from safety related equipment or limited stresses in the bolting material restraining the components. The stored energy in nuts, bolts and nut/stud combinations is small and, therefore, missiles from these components are not postulated. The missiles generated from thermowells installed in the piping outside of containment were shown not to impinge on any safety-related equipment required for safe shutdown. Compressed air/gas bottles in the Reactor Auxiliary Building (RAB) are not postulated as missiles since the bottles are stored using seismic restraints. In addition, prior to transporting the bottles, caps are procedurally installed on the bottles. The few valves that need to be replaced to support the EPU will employ the same measures that have been taken for the existing valves to prevent missile generation.

Overspeed protection is provided on the emergency feedwater (EFW) pump turbine, diesel generators, main feedwater pump turbines, and main turbine by mechanical and electric trip setpoints. Missiles from the EFW pump turbine and the diesel generators are not postulated since the components are designed to withstand 125% overspeed and since the components normally are not operated. Missiles from the main feedwater pump turbines are contained by the RAB wall that separates these turbines from adjacent safety related equipment. Additional details regarding missiles generated by the main turbine are provided below. Missiles from motor-operated pumps and fans are not postulated because the pumps and fans located near safety-related equipment have casings that will prevent the release of missiles.

Neither the operating speed nor the overspeed protection circuits for the EFW pump turbine or the diesel generators will be impacted by the EPU. The speed of the main feedwater pump turbines will increase as a result of the increased feedwater flow rate. However, the speed of the main feedwater pump turbines is still within its normal operating range and the turbine speed is much less than the setpoint at which the turbines are tripped for overspeed. Further, the RAB wall will still protect the safety-related equipment adjacent to the main feedwater pump turbines. The pump and fan casings will still adequately restrain any missiles generated from the pumps and fans located near safety-related equipment.

Internally Generated Missiles Inside Containment

Since the operating pressure for the systems that could generate missiles inside containment is not adversely impacted by the EPU, the missile protection measures within containment are not impacted by the EPU.

Conclusion

The SSCs important to safety will still be adequately protected from internally generated missiles resulting from the changing system pressures and components (e.g., valve replacement) required for the EPU. The requirements of GDC 4 will continue to be met under EPU conditions; therefore, the EPU is acceptable with respect to internally generated missiles.

Turbine Generator Missiles

Failures of the main turbine have the potential to produce large, high-energy missiles. The potential for damage to safety-related SSCs due to a turbine failure is evaluated at Waterford 3. FSAR Section 3.5 discusses the measures taken to protect the safety-related and seismic Category I equipment against turbine generator missiles.

Evaluation

No setpoint changes are currently identified for the turbine control system to support the power uprate. Minor adjustments to the turbine control system may be required. The 0.25-second closure times listed in the FSAR for the turbine steam valves upon a detection of an overspeed condition is not impacted by the power uprate. Further, the maximum expected turbine overspeed under EPU conditions considering the new high-pressure steam turbine will remain within the original turbine overspeed design limit (120% of turbine-rated speed).

The low-pressure (LP) turbine will not be modified as a result of the uprate. Since the disc exit temperatures under uprate conditions are less than or equal to the disc temperatures used in the original design of the rotors, the missile generation probability for the LP turbine is not adversely impacted by the EPU.

Conclusion

The effects of the changes to plant operating conditions on turbine overspeed has been evaluated. The turbine generator will continue to provide adequate turbine overspeed protection to minimize the probability of generating turbine missiles, and will continue to meet the requirements of GDC 4 under power uprate conditions. Therefore, the EPU will be acceptable with respect to turbine generator missiles.

2.5.1.3 Pipe Failures

The high-energy lines outside of containment consist of lines in the main steam, main feedwater, steam generator blowdown, and chemical and volume control systems. All the systems outside containment in which the normal operating pressure is less than 275 psig and the normal operating temperature is less than 200°F are considered moderate energy systems. Systems that exceed 200°F and 275 psig for less than 2% of the system operating time (not considering testing) are also considered moderate energy. The classification of which lines are considered moderate or high energy is not impacted by the EPU.

Evaluation

The impact of the EPU on pipe whip, jet impingements, environmental conditions, subcompartment pressurization, and flooding caused by the failure of high-energy lines outside of containment was evaluated. The impact of the EPU on the environmental conditions and flooding caused by breaks in the moderate energy lines was also evaluated.

Pipe Whip

The design basis requirements associated with high energy pipe whip will not be impacted by the EPU. Systems that are considered high energy, and the protective measures taken to mitigate the effect of high-energy line whip, will also not be impacted by the EPU. In addition, the postulated high-energy break locations will not be impacted by the EPU.

The operating conditions for the steam generator blowdown and the CVCS prior to the EPU bound the operating conditions following EPU; therefore, the pipe whip from these lines is not impacted by the EPU.

Jet Impingement

Jet impingement from breaks in the MS and FW lines will not affect any essential components/systems or any safety-related structures because the lines are routed outside on top of the RAB roof.

The CVCS letdown and charging lines are routed through a chase from the containment penetrations to the letdown heat exchanger and the charging pump rooms. The letdown heat exchanger and the charging pumps are located in individual compartments. The fluid jets from CVCS pipe breaks will be contained in these rooms and thus safety-related equipment will not be affected by jet impingement loads. In addition, the current operating temperature and pressure for the CVCS bounds the EPU operating conditions.

Jet impingement from breaks in the Steam Generator Blowdown System (SGBS) is not impacted by the EPU because the operating conditions for the SGBS under EPU are bounded by current operating conditions.

Environmental Effects

Breaks in the high-energy lines outside of containment under EPU conditions will not affect the environmental conditions to which safety-related systems are subjected. The personnel operating safety related equipment required for post-accident operations will not be affected.

Failure of the FW and MS piping will not affect any safety-related equipment because these systems are located outside of the RAB. The CVCS letdown and charging lines are routed in a chase and thus the environmental conditions produced by the piping failure are minimized. The environmental effects from breaks in the SGBS are not impacted by the EPU because the operating conditions for the SGBS under EPU are bounded by current operation conditions.

The effect of moderate-energy line breaks on the environmental conditions to which safety-related systems are subjected and the personnel operating safety-related equipment required for post-accident operations will not be impacted by the EPU since there will be no significant changes to the operating conditions for the portions of these systems outside containment.

Subcompartment Pressurization

Pressurization of subcompartments within the RAB due to breaks in the main steam and feedwater lines is not possible since these lines are located outside on top of the RAB roof. The environmental effects from breaks in the SGBS are not impacted by the EPU because the operating conditions for the SGBS under EPU conditions are bounded by current operation conditions.

The maximum internal pressure build-up and structural integrity of the pipe chase through which the CVCS letdown and charging lines are run (from the containment penetrations to the letdown heat exchanger and charging pump rooms) is not impacted by the EPU because the operating conditions for the CVCS under EPU are bounded by the current operating conditions.

Flooding

It was concluded in the flooding evaluation section of this document (Section 2.5.1.1) that the adverse effects from flooding caused by moderate and high-energy line breaks (HELBs) should not be impacted by this EPU.

Control Room Habitability

The main control room is protected against whipping pipe by the whip restraints at the postulated MS and FW break locations. Jet impingement does not impact the control room habitability requirements because breaks in the MS and FW lines will not impinge on the main control room.

Conclusions

The SSCs that are important to safety will continue to be protected from jet impingement loads, environmental effects, subcompartment pressurization and flooding caused by pipe failures outside of containment. Pipe whip from the steam generator blowdown and chemical and volume control systems is also not adversely impacted by the EPU. Therefore, the requirements of GDC 4 will continue to be met following the EPU.

2.5.1.4 Fire Protection

The Waterford 3 Fire Protection Program includes classical industrial-type fire protection features and nuclear specific fire protection features. The classical features include fire pumps

and a water distribution system, fire detection systems, fire suppression systems, fire walls, and administrative implementation programs.

Evaluation

Classical fire protection features are not impacted by the power uprate project because their requirements are derived from insurer and regulatory requirements to eliminate or at least limit the risk due to fire. The power uprate program does not introduce new industrial-type fire hazards. The nuclear-specific fire protection features (such as cable protection, train separation, and circuit protection) are provided to ensure that at least one safe shutdown train is available to achieve and maintain post-fire safe shutdown and to mitigate fire-induced release of radioactivity to the public. It should be noted that regulatory requirements preclude consideration of a simultaneous plant accident (Chapter 15) and a fire unless the accident is an initiator of a fire.

Waterford 3 maintains a post-fire safe shutdown analysis that identified all components and cables, by fire area, credited for post-fire safe shutdown. The performance goals for post-fire safe shutdown are reactivity control, reactor coolant makeup, reactor heat removal, process monitoring and support functions associated with electrical power, cooling water, heating, ventilation and air conditioning (HVAC), etc., as necessary to permit credited equipment operation. The power uprate project does not change the credited equipment necessary for post-fire safe shutdown nor does it reroute essential cables or relocate essential components/equipment credited for post-fire safe shutdown.

The fire analysis also included a functional time line analysis that addressed the ability of operator response to various plant transients such as a spuriously opened normal spray valve, spurious closure of a volume control tank isolation valve, spurious actuation of an atmospheric dump valve (ADV) and inadvertent containment spray actuation. The power uprate project does not impact credited manual operator actions, the post-fire safe shutdown analysis, or thermal-hydraulic parameters that could impact the feasibility of time-sensitive credited post-fire operator actions. Existing administrative controls related to the fire protection (and safe shutdown) program include a screening process that requires the review of all changes that could impact fire protection and safe shutdown. This screening process considers Waterford 3 License Condition 2.c.9, which allows changes to the fire protection program as long as those changes do not impact the ability to achieve and maintain post-fire safe shutdown. Plant changes associated with the EPU are subject to this process and receive the necessary review prior to implementation.

Conclusion

Waterford 3 fire protection supports EPU and will continue to be in compliance with 10CFR50.48, 10CFR50, Appendix R, and GDC 3.

2.5.2 Containment Review Considerations

2.5.2.1 Primary Containment Functional Design

Background

Waterford 3 FSAR Section 6.2 discusses the containment response to design basis loss-of-coolant accident (LOCA) and main steam line break (MSLB) accident. Both LOCA and MSLB result in the addition of mass and energy to the containment building. These accidents have been analyzed at EPU conditions to ensure the containment pressure and temperature results are within the acceptable limits.

Containment response to LOCA and MSLB events was analyzed using GOTHIC to support License Amendment 165. The mass and energy release data for LOCA were generated based on EPU conditions. The mass and energy release data for EPU conditions were determined to bound the pre-uprate mass and energy release data. The mass and energy release data for MSLB however were generated based on the pre-uprate power level conditions. Amendment 165 was approved by the NRC in a safety evaluation dated July 6, 2000. Use of GOTHIC computer code for containment analyses at Waterford 3 was also approved by the NRC in Amendment 165.

Evaluation

For the EPU, MSLB events were analyzed using GOTHIC and utilizing the mass and energy release data generated for the EPU conditions. The limiting LOCA cases (peak pressure case and peak pressure at 24-hour case) were re-analyzed using GOTHIC with minor input changes to the current LOCA licensing basis calculation and utilizing the mass and energy release data generated for the EPU conditions.

The LOCA pressure and temperature response analyses were performed assuming loss of offsite power and a worst single failure (loss of one emergency diesel generator [EDG]) i.e., loss of one containment cooling train. Only one containment fan cooler per train (there are two fan coolers per train) is assumed operable per Technical Specification Section 3.6.2.2. For the MSLB event, the availability of offsite power is more limiting than the loss of offsite power for mass and energy release generation. Therefore the containment response to MSLB event is analyzed assuming availability of offsite power. For MSLB events three separate single failures are considered:

- Loss of one containment cooling train (i.e., one train of containment spray and one train of containment fan coolers)
- Failure of one main feedwater isolation valve to close on main steam isolation signal (MSIS)
- Failure of one main steam isolation valve (MSIV) to close on MSIS

The MSLB from hot-full power conditions with failure of one containment cooling train, i.e., only one containment spray and one containment fan cooler operable, was found to be the most limiting event for both peak pressure and peak temperature cases.

Consistent with the existing Waterford 3 licensing basis, instrument measurement uncertainty is implicitly considered in accordance with the graded approach in the containment pressure and temperature response analyses.

Values of selected parameters used in the containment pressure and temperature response analyses are shown in Table 2.5-1.

Table 2.5-1
Parameter Values for Containment Pressure/Temperature Response Analyses

Parameter	Values Used in the Analyses
Initial Containment Temperature	120°F
Component Cooling Water Temperature	115°F
Component Cooling Water Flow	1100 gpm
Initial Containment Spray Riser Level	149.5 ft.
Initial Containment Pressure	15.7 psia
Refueling Water Storage Pool Temperature	100°F

The containment peak pressure and temperature results for limiting LOCA and MSLB and the acceptance criteria for these parameters are provided in Table 2.5-2.

Table 2.5-2
Containment Peak Pressure and Temperature Results

	LOCA	MSLB
Peak Pressure (psig)	35.16*	41.83
Peak Temperature (°F)	254.4	394.4
Pressure at 24 hours	15.94**	N/A

Acceptance Limits

	LOCA	MSLB
Peak Pressure (psig)	44	44
Peak Temperature (°F)	269.3	413.5
Pressure at 24 hours	½ the calculated peak	N/A

* The maximum containment pressure occurs during the blowdown phase of a hot leg break.
** The peak pressure for the LOCA that results in the maximum 24 hour pressure (reactor coolant pump discharge leg break) is 33.23 psig. One half of this peak pressure is 16.62 psig.

Conclusion

Per GDC 38, the LOCA and MSLB analyses have been performed with the most limiting condition of offsite power and the worst single failure. The above results demonstrate that the

resultant containment peak pressure and temperature are within acceptable limits. Also the pressure at 24 hours is less than half of the peak pressure and therefore is also acceptable.

2.5.2.2 Subcompartment Analyses

The steam generator (SG), reactor vessel cavity, and pressurizer subcompartments are subjected to pressure transient forces caused by the mass and energy releases from postulated high energy pipe ruptures within the subcompartments. FSAR Section 6.2.1.2 discusses the design of the subcompartments.

Evaluation

The Reactor Coolant System (RCS) mass and energy release data discussed in Section 2.5.2.3 of this report was used to evaluate the structural integrity of the subcompartments due to the pressure transient under EPU conditions. The peak pressure for all breaks occurs early in the transient, typically at 0.1 seconds following the break.

Over the period of time in which the peak subcompartment pressurization occurs, the mass and energy release rates from breaks that are evaluated in the RCS pump suction legs, RCS hot legs and the pressurizer surge line for EPU conditions are lower than mass and energy release rates described in FSAR Section 6.2 for the pre-EPU RCS conditions. During a circumferential break in the RCS discharge legs, the mass and energy release rates determined under EPU conditions are higher than the mass and energy release rates described in the FSAR for the pre-EPU conditions. Prior to the EPU, the discharge leg break was the most limiting break affecting the post-LOCA pressurization of the reactor cavity. Prior to the EPU, the peak pressure load on the reactor cavity wall was calculated to be 130.3 psid. The design wall loading for the reactor cavity is 240 psid. Under EPU conditions, the peak pressure load was determined to increase by ≤5.8%, corresponding to ≤138 psid. Thus, there is still significant structural margin within the reactor cavity walls following the slight increase in mass and energy release rates.

Subcompartment Conclusion

The impact of the system conditions and the mass and energy release rates under EPU conditions on subcompartment pressurization was reviewed. The SSCs important to safety will continue to be protected from the dynamic effects that would result from pipe breaks, and the subcompartments will continue to prevent fracture of the structure due the pressure difference across the walls. Waterford 3 will continue to meet the requirements of GDCs 4 and 50 for the proposed EPU. Therefore, the subcompartments will continue to provide their safety function.

2.5.2.3 Mass and Energy Release

FSAR Section 6.2.1 discusses the containment response to design basis accidents. Both the LOCA and the MSLB result in the addition of mass and energy to the containment building. These accidents have been analyzed at EPU conditions to ensure that the structural integrity of the containment is maintained. Additionally, the mass and energy releases resulting from the mechanistic breaks in the RCS main piping and tributary lines are used to evaluate the structural integrity of the subcompartments due to pressure transients. Consistent with the

original design analyses, the mass and energy released into containment during these events have been calculated in accordance with the standards and requirements mandated by the NRC in the Standard Review Plan (SRP). The mass and energy release information was then used for the calculation of the transient containment pressure-temperature (P-T) response and the evaluation of the subcompartment structural integrity due to pressure transients.

Input and Assumptions

The LOCA containment analysis is performed in two parts. The CEFLASH-4A and FLOOD3 computer codes generated the mass and energy discharged from the RCS into the containment. Additionally, the CONTRANS computer code was used to calculate post-LOCA long-term energy input. This information was then used to calculate the containment response using the GOTHIC computer code. FSAR Section 6.2.1.3 provides both an overview of the analysis methodology and a summary of the important analysis assumptions and inputs utilized in the calculations of the LOCA mass and energy release data.

Similar to the LOCA, the MSLB containment analysis is performed in two parts. The SGNIII computer code was used to determine the mass and energy discharged from the ruptured steam line into the containment. This information was then used to determine the containment response using the GOTHIC computer code. FSAR Section 6.2.1.4 provides both an overview of the analysis methodology and a summary of the important analysis assumptions and inputs utilized in the calculations of the MSLB mass and energy release data.

Additionally, the mass and energy releases due to mechanistic breaks in the RCS main piping and tributary lines were generated using the CEFLASH-4A computer code. FSAR Section 6.2.1.2.3 provides an overview of the analysis methodology and a summary of the important analysis assumptions and inputs utilized in the calculations of the mass and energy release data.

Results of Analysis

The results of the LOCA and MSLB mass and energy analyses were provided as input to the calculation of the transient containment pressure/temperature response. Additionally, the mass and energy releases resulting from the mechanistic breaks in the RCS main piping and tributary lines were provided as input to the evaluation of the subcompartment structural integrity.

Conclusions

The LOCA and MSLB mass and energy release data at the EPU conditions were generated in accordance with the requirements of the SRP and GDC 50. Additionally, the mass and energy release analyses for postulated LOCAs have appropriately accounted for the sources of energy identified in 10CFR50, Appendix K. Therefore, the mass and energy release analyses meet the requirements in GDC 50 for ensuring that the analyses are conservative.

2.5.2.4 Combustible Gas Control in Containment

Evaluation

Entergy has followed the development of the rule change to revise 10CFR50.44 to eliminate the requirements for hydrogen recombiners and hydrogen purge systems, and relax the requirements for hydrogen and oxygen monitoring equipment. The final rule, effective October 16, 2003, eliminates the hydrogen release associated with a design-basis LOCA and the associated requirements that necessitated the need for the hydrogen recombiners and the backup hydrogen vent and purge systems. Based on this rule change to 10CFR50.44, Entergy will be submitting a separate license amendment request to eliminate the Waterford 3 Technical Specification requirements for combustible gas control in containment. This license amendment request will be submitted by the end of 2003.

Conclusion

Therefore, with NRC approval of the proposed license amendment, no reanalysis of the combustible gas control system is necessary for the EPU.

2.5.2.5 Containment Heat Removal Systems

The containment heat removal systems are discussed in FSAR Section 6.2.2.

The containment heat removal systems consist of the Containment Cooling System (CCS) and the Containment Spray System (CSS). These systems perform the following:

- Remove heat from the containment atmosphere and from the water in the safety injection (SI) sump.
- Limit offsite radiation by reducing the pressure differential between containment and the external environment (including scrubbing the containment atmosphere) following a LOCA so that offsite doses and control room doses are within the guidelines of 10CFR100 and GDC 19.

Evaluation

The CCS consists of four containment fan cooler units, a common ductwork system that acts as an air distribution system, and associated instrumentation and controls. The four fan coolers are arranged as two redundant, safety trains. Each fan cooler consists of a vane axial fan and two cooling coils.

The CCS is started and the emergency discharge dampers are opened after receiving a safety injection actuation signal (SIAS). The fan coolers operate in a low-speed mode during the postulated accident.

The CSS consists of two redundant trains of pumps, piping lines, valves, heat exchangers and associated instrumentation and controls. During initial operation of the system (i.e., the injection mode), the CSS pumps take suction from the refueling water storage pool (RWSP) and spray borated water into containment.

The CSS is started after receiving a containment spray actuation signal. The RWSP is used as the water source during the initial injection mode. The water source is transferred from the RWSP to the SI sump when a recirculation actuation signal is generated.

The heat removing capabilities of one fan cooler and one spray system are considered in the containment temperature and pressure analyses. Fan cooler performance parameters developed by the cooler's manufacturer are used as inputs to the containment analyses. The current containment spray system flow rates and water temperatures are used as inputs for the containment analyses. These parameters are incorporated into the containment and dose analyses to demonstrate acceptable performance.

Conclusion

The safety function of the CCS and CSS following EPU continue to comply with the requirements described in GDC 38.

2.5.2.6 Pressure Analysis for Emergency Core Cooling System (ECCS) Performance Capability

The containment pressure impacts the hydraulic response following a large-break LOCA (LBLOCA). As such, this analysis is integral with the ECCS performance analysis for LBLOCA, which is discussed in Section 2.12.3 of this report.

2.5.2.7 Pressure Relief Tank (Quench Tank)

The pressurizer relief tank is referred to as the quench tank. It is a pressure vessel provided to condense and cool the discharge from the pressurizer safety and relief valves. The quench tank is not safety-related and is not designed to accept a continuous discharge from the pressurizer. The FSAR specifies that the quench tank is sized based on a loss of load followed by a rod withdrawal incident as the plant returns to power.

Evaluation

Individual anticipated operational occurrences were analyzed to determine that the size of the quench tank is within the capacity of the tank to receive discharges without functioning of the rupture disc. Multiple events resulting in repeated lifts of the relief valves are not considered credible. In addition, the rupture disc will function satisfactorily under conditions that require actuation for events that are beyond the expected events.

Conclusion

Based on the evaluation in support of EPU, and the conservatism of the design basis sizing of the quench tank, it is considered to be satisfactory without modification to support EPU. The quench tank has been reviewed relative to the increase in pressurizer discharge as a result of the proposed EPU and it is concluded that: (1) the quench tank will operate in a manner consistent with transient analyses of related systems and (2) safety-related SSCs will continue to be protected against failure of the quench tank consistent with GDCs 2 and 4.

2.5.3 Habitability, Filtration, and Fission Product Control

2.5.3.1 Control Room Habitability System

Entergy is familiar with the ongoing discussions on control room habitability (CRH) between the industry and the NRC and has been an active participant in the development of the industry's CRH assessment guidance. In response to Generic Letter 2003-01, *Control Room Habitability*, Entergy has committed to complete the requested evaluation prior to the end of September 2004. This evaluation will include a validation of the inleakage assumptions made in the dose consequence analyses. The results of this evaluation will determine further appropriate actions, if any, that must be taken to resolve this issue.

Power uprate does not affect normal ambient conditions inside the control room. Nor does it impact control room conditions during non-radiological events. Therefore, the only CRH issue associated with a power uprate is the dose consequences associated with accidents at Waterford 3.

Control room doses have been analyzed, at EPU conditions, for the LOCA and Fuel Handling Accident consistent with the current licensing basis. These analyses are presented in Section 2.13 of this report. Control room doses, for these and other events, are planned to be addressed, as necessary, in conjunction with the resolution of Generic Letter 2003-01.

2.5.3.2 Engineered Safety Feature (ESF) Atmosphere Cleanup

The ESF Atmosphere Cleanup/Filter Systems are discussed in FSAR Section 6.5.1. The specific systems discussed are the Control Room Heating, Ventilation and Air Conditioning System (HVC), the Controlled Ventilation Area System (CVAS), and the Shield Building Ventilation System (SBVS). Each of these systems has been evaluated under EPU conditions with no identified uprate impact resulting in a design or licensing basis revision.

The Fuel-Handling Building Ventilation System at Waterford 3 is no longer classified as an ESF cleanup system as discussed in License Amendment 176. The analysis to support the Technical Specification change showed that the control room and offsite doses resulting from a fuel-handling accident (FHA) without high-efficiency particulate air (HEPA) filtration or charcoal adsorption remained well within the regulatory guidelines. This analysis will not be impacted by EPU operation because the analysis was performed for a power level of 3,844.3 MWt, which is bounding for the EPU power level including an allowance for measurement uncertainties.

Control Room Air Conditioning System

The HVC is described in FSAR Sections 6.5.1 and 9.4.1, and is designed to fulfill the following functions:

a) Remove the heat from the control room following a design basis accident (DBA).
b) Provide filtered outside air following a MSLB or LOCA to maintain the control room under positive pressure to prevent infiltration of airborne radiation.
c) To maintain the control room air quality to an acceptable limit following LOCA/MSLB.

d) To monitor airborne radiation at the control room main outdoor air intake for detection and isolation of the control room envelope.
e) To maintain the control room envelope at an acceptable temperature level during normal operation.
f) To monitor infiltration of toxic gases at the control room's main outside air intake for detection and isolation of the control room envelope.

Evaluation

The temperature control and hazardous gas isolation functions (functions a, e, and f) of the HVC are evaluated in Section 2.5.4.

The LOCA dose fuel source terms will increase for EPU operation as described in Section 2.13.6.3.3 of this report. Based on data from Section 2.13.6.3.3, the HEPA filtration and charcoal adsorption capabilities will remain acceptable to maintain control room doses below the guidelines of 10CFR50, Appendix A, GDC 19.

The current analysis shows that charcoal heating due to radioactive decay and charcoal oxidation is insignificant in the Control Room Emergency Filtration System. The increased fuel source terms will result in a small increase in the amount of radioactive material that collects in the charcoal filters. The heat loading is so small that the additional radioactive material will not impact the existing analysis and no additional ventilation is required during idle periods. The charcoal filtration system will not be impacted by the EPU operating conditions.

The EPU will not introduce any additional failure modes or operational hazards, therefore the system will continue to meet its existing design basis requirements. This includes operation following a DBA coincident with a single active failure and a loss-of-offsite power (LOOP); operation following a safe shutdown earthquake (SSE); realignment and operation following a toxic chemical accident; and 30-day continuous operation following a DBA.

The EPU will have no impact on control room parameters that affect the operation of the air conditioning system. The heating and cooling loads will not change and the required air flow rates will remain adequate to ensure the required positive pressure is maintained in the control room.

Controlled Ventilation Area System

The CVAS system is described in FSAR Section 6.5.1 and is designed to fulfill the following safety-related functions:

a) Provide high efficiency particulate filtration and iodine adsorption for air exhausted from the controlled ventilation area and the post-accident sampling cabinets (via pipe penetration areas exhaust) following a DBA (LOCA), such that the CVAS, in conjunction with other ESF systems, limit the post-accident radiological releases below the guidelines of 10CFR100.
b) Exhaust air from the controlled ventilation areas following a DBA (LOCA) at a rate required to create and maintain a negative pressure below 0.25 inch water gauge (inwg) relative to surrounding areas.

c) Perform its function assuming the maximum possible post-accident leakage in the controlled ventilation area from ECCS equipment (pump seals, valve stems, etc., outlined in FSAR Section 6.3.3.8).

Evaluation

The LOCA dose fuel source terms will increase for EPU operation as described in Section 2.13.6.3.3. This will result in slightly higher control room and offsite doses, however, the increased doses will remain within regulatory requirements. Based on this, the HEPA filtration and charcoal adsorption capabilities will remain acceptable to maintain doses below the guidelines of 10CFR100 and 10CFR50, Appendix A, GDC 19. The filter loading and heating will increase slightly for the uprated conditions, however the existing system design margin is sufficient to account for this increase. The current cross flow is designed with sufficient margin to account for the small increase and will be adequate to ensure the charcoal in the idle train does not overheat. Therefore, the filter loading and heat-up will be slightly impacted by EPU conditions, but the current cross flow will be adequate to ensure the charcoal in the idle train does not overheat.

The EPU will not introduce any additional failure modes or operational hazards, therefore the system will continue to meet its existing design basis requirements. This includes operation following a DBA coincident with a single active failure and a LOOP; operation following an SSE; and 30 day continuous operation following a DBA.

The EPU will have no impact on CVAS operational parameters, therefore the exhaust air flow rate will remain adequate to ensure the required negative pressure is achieved.

Shield Building Ventilation System

The SBVS is described in FSAR Section 6.5.1 and is designed to fulfill the following functions:

a) Maintain the annulus pressure below atmospheric during and following a LOCA inside containment.
b) Adequately mix, dilute, holdup, and filter radioactive materials in the annulus atmosphere prior to environmental discharge to ensure that 10CFR100 offsite dose exposures are not exceeded.

Evaluation

The LOCA dose fuel source terms will increase for EPU operation as discussed in Section 2.13.6.3.3. This will result in slightly higher filter loading and bypass, however, the offsite and control room doses will remain within regulatory requirements. The current shield building ventilation system analysis was performed for a power level of 3,865 MWt, which is above the EPU power level. Based on this, the HEPA filtration and charcoal adsorption capabilities will remain acceptable to maintain post accident doses below the guidelines of 10CFR100. The existing shield building analysis for charcoal mass loading and heating was performed at a power level that bounds the EPU power level. The filter loading and heat-up for EPU conditions are bounded by the existing analyses, and the current cross flow will be adequate to ensure the charcoal in the idle train does not overheat.

The EPU will have no impact on SBVS operational parameters. The exhaust air flow rate will remain adequate to ensure the required negative pressure is maintained. Also, the recirculation mode of operation will remain adequate to ensure proper mixing, dilution, holdup, and filtration of all airborne radioactive material that leaks into the Shield Building annulus.

The EPU will not introduce any additional failure modes or operational hazards, therefore the system will continue to meet its existing design basis requirements. This includes operation following a DBA coincident with a single active failure and a LOOP; operation following a safe shutdown earthquake; 30-day continuous operation following a DBA.

Conclusion

The HVC, CVAS, and SBVS are adequate to support EPU operation. Environmental and fission product issues have been addressed, and the ESF Atmosphere Cleanup Systems are adequate for EPU conditions. GDC requirements of 19, 41, 61, and 64 will continue to be met.

2.5.3.3 Fission Product Control Systems and Structures

The fission product control systems and structures are discussed in FSAR Section 6.5.3. The fission product control structures provided for Waterford 3 are the containment vessel and the Shield Building. The fission product control systems operate post accident in conjunction with the ESF Systems.

Primary containment vessel structure consists of a cylindrical steel pressure vessel with hemispherical dome forming a continuous leak tight free standing steel shell. It is completely enclosed by the reinforced concrete Shield Building having a cylindrical shape with shallow dome roof. An annular space is provided between the primary containment vessel and the Shield Building and clearance is also provided between the containment vessel and the Shield Building dome.

The long and short-term containment response to the design basis accident is discussed in FSAR Section 6.2.1. The operation of the CSS to reduce iodine concentrations and containment atmosphere temperature and pressure is discussed in FSAR Sections 6.5.2 and 6.2.2

The Containment Atmosphere Release System (CARS) is provided to purge containment at low containment atmosphere pressure. Its operation following a DBA allows fission products to be released to the Shield Building annulus for fission product removal by the SBVS.

The Containment Atmosphere Purge System is not used following a DBA. The containment vacuum relief system is used to prevent excess external pressure on the primary containment steel shell. This system is described in FSAR Section 3.8.2.3.

Secondary Containment – Additional fission product control is achieved following a design basis accident by the maintenance of a negative pressure inside the Shield Building annulus by the SBVS. A partial vacuum inside the annulus prevents outleakage through the concrete structure and thus provides control over the release of fission products to the outside environment.

The cleanup of fission products in the annulus is accomplished by the SBVS which is described in FSAR Sections 6.2.3 and 6.5.1

The time sequence of events for the annulus transient and for performing the dose estimates are described in the FSAR Section 6.2.3 and Appendix 15B.

Fission product control is also provided by the CVAS. The CVAS maintains a portion of the RAB at a negative pressure following a design basis accident and provides filtration.

During normal operation, the annulus is maintained at negative pressure by the Annulus Negative Pressure System, which is discussed in the FSAR Section 9.4.

Evaluation

The operation of the CSS has been evaluated and found to be adequate to support the EPU to reduce iodine concentrations and containment atmosphere temperature and pressure as a function of fission product control system.

The CARS is operated following a DBA when containment pressure has reduced sufficiently to allow fission products to be released to the Shield Building annulus for fission product removal by the SBVS.

The CARS, the SBVS, and the CVRS are described in the FSAR Sections 6.2.5.2.3 and 3.8.2.3, respectively. These systems have been evaluated and found to be adequate to support the EPU.

The Containment Atmosphere Purge (CAP) System has been evaluated and found to be adequate to support the EPU in reducing the level of radioactive contamination in the containment atmosphere below the limits of 10CFR20 to allow personnel access to the containment.

Containment structures are maintained intact since the calculated containment pressures following a LOCA and MSLB for EPU conditions are within the design pressure.

Conclusion

The fission product control systems and structures have been evaluated and it is determined that these systems are acceptable for the EPU. These systems will continue to provide adequate fission product removal in post accident environments following implementation of the EPU.

2.5.3.4 Main Condenser Evacuation System

The Main Condenser Evacuation System (MCES) is discussed in FSAR Section 10.4.2. The system is designed to remove non-condensable gases and in-leaking air from the steam space of three condenser shells during plant startup, cooldown, and normal operation.

The MCES is designed to remove air from the three condenser shells to create a vacuum in the condenser during plant start up.

Evaluation

The existing MCES design includes 3 vacuum pump units providing a total gas removal capacity of 105 scfm. Two pumps have a capacity of 40 scfm and the third has a capacity of 25 scfm.

The EPU will not affect the design requirements of the MCES during plant start up because EPU does not change the startup operation of the plant. Therefore the existing mechanical vacuum pumps and accessories utilized during plant startup are acceptable.

During normal plant operation, mechanical vacuum pump assemblies are used for evacuation of water vapor mixture and non-condensable gases from the main condenser. The industry-standard air removal system sizing criteria, when applied to the main condenser under EPU operating conditions, recommends a system with a capacity of at least 75 scfm. This is well within the capability of the existing system. Therefore, no modifications to the existing MCES are required to support the EPU.

Since the requirements of the vacuum pumps will not change, the seal water equipment design capacity is adequate.

The non-condensable gases, vapor mixture and condensed water discharged from the MCES will continue to be monitored for radioactivity prior to being discharged to the atmosphere and from the industrial waste sump under EPU conditions.

Conclusion

Based on the above evaluation, the MCES will meet operational requirements under EPU conditions. Therefore, the system will continue to maintain its ability to control and provide monitoring for releases of radioactive material to the environment consistent with regulatory requirements.

2.5.3.5 Turbine Gland Sealing System

The Turbine Gland Sealing System is discussed in FSAR Section 10.4.3. The system provides sealing of the turbine generator shaft and the main feedwater pump turbine shafts against leakage of air into the turbine casings and the escape of steam into the turbine building.

Evaluation

The EPU will increase gland steam flow, however, the velocity of gland seal steam will remain under the existing velocity limit.

Non-condensable gases from the gland steam condenser are routed to the main condenser air evacuation system exhaust and therefore continue to be monitored for radioactivity.

Conclusion

Based on the above evaluation, the Turbine Gland Sealing System and its components will meet system operational requirements under EPU conditions. Therefore, the system will

continue to maintain its ability to control and provide monitoring for releases of radioactive material to the environment consistent with regulatory requirements.

2.5.4 Ventilation Systems

The Waterford 3 ventilation systems required to be addressed for the EPU are discussed in FSAR Section 9.4. The specific systems are the HVC, the EDG Ventilation System; the RAB Heating and Ventilation Equipment Room Ventilation System; the RAB safety-related fan coolers; the RAB Cable Vault and Switchgear Areas Ventilation System; the Fuel-Handling Building (FHB) Ventilation System; and the RAB Normal Supply and Exhaust Systems.

Each of these systems has been evaluated with no identified EPU impact resulting in a design or licensing basis revision.

Control Room Air Conditioning System

The HVC is described in FSAR Sections 6.5.1 and 9.4.1, and is designed to fulfill the following functions:

a) Remove the heat from the control room following a DBA.
b) Provide filtered outside air following a MSLB or LOCA to maintain the control room under positive pressure to prevent infiltration of airborne radiation.
c) Maintain the control room air quality to an acceptable limit following LOCA/MSLB.
d) Monitor airborne radiation at the control room main outdoor air intake for detection and isolation of the control room envelope.
e) Maintain the control room envelope at an acceptable temperature level during normal operation.
f) Monitor infiltration of toxic gases at the control room's main outside air intake for detection and isolation of the control room envelope.

The emergency radiological isolation, pressurization, and filtration functions (functions b, c, and d) of the HVC are evaluated in Section 2.5.3.1 of this report.

Evaluation

The EPU operating conditions do not increase the cooling or heating loads within the control room envelope. The existing cooling coils and their associated flow rates are adequate to maintain the required environmental conditions and pressurization requirements, and the current electrical and instrumentation and controls requirements including instrument setpoints will not be affected. The independent trains of equipment provide redundant capacity to assure the safety functions of HVC following a single failure.

The EPU will not introduce any additional failure modes or operational hazards. The current system design for toxic chemical isolation, withstanding seismic events, and withstanding a single active failure will continue to meet the design basis requirements following implementation of the EPU.

The control room HVAC System can adequately support the EPU. The EPU will not change system operating parameters, introduce additional failure modes, or introduce additional operational hazards; therefore the system will continue to meet its existing design basis requirements.

Emergency Diesel Generator Ventilation System

The purpose of the EDG Room Ventilation System is to remove the heat generated in the EDG A and B rooms during operation of the emergency diesel generators. The system is described in FSAR Section 9.4.3.3 and is designed to maintain the temperature in the diesel generator rooms at a maximum of 120°F whenever the EDGs are in operation.

Evaluation

The EDG Room Ventilation System will not be impacted by operation at EPU conditions. The EPU operating conditions are not adding additional electrical loading above the design loading of the EDGs. The ventilation system was designed to remove the heat from both diesels operating continuously at 110% load (4,840 kW), and the installed fans have additional air flow margin above this requirement. Therefore, the ventilation system as currently designed has sufficient margin to meet its functional requirements at the expected EPU operating conditions.

The EPU will not introduce any additional failure modes or operational hazards, therefore the system will continue to meet its existing design basis requirements. This includes operation following a DBA coincident with a single active failure and a LOOP, and operation following a SSE.

There is no impact on the existing licensing basis of the EDG Room Ventilation System due to the conservative design of the existing system. No equipment changes are required to this safety-related system as a result of the EPU. Therefore the ventilation system as currently designed has sufficient margin to meet its functional requirements at the expected EPU operating conditions.

RAB Heating and Ventilation Equipment Room Ventilation System

The purpose of the RAB heating and ventilation (H&V) Equipment Room Ventilation System is to remove the heat generated in the RAB +46.00’ elevation during normal and post accident operation. The system is described in FSAR Section 9.4.3.4 and is designed to maintain suitable temperatures in the RAB H&V equipment room at elevation +46.00’ MSL during normal or accident conditions.

Evaluation

The heat generated by the additional radioactive loading of the SBVS and CVAS charcoal filters is insignificant and therefore will have negligible impact for EPU conditions. The largest post-accident heat contributor to the H&V equipment room will be the SBVS ductwork and components operating to recirculate, filter, and exhaust the annulus atmosphere. The post-accident containment temperature profile from operation at EPU conditions will not increase, therefore the post-accident shield building temperature will not increase above current values. Based on this, the EPU operating conditions will have an insignificant effect on the heat load

contributors in the RAB H&V equipment room, and the RAB H&V Equipment Room Ventilation System will not be impacted by operation at EPU conditions.

The existing system will maintain the equipment room temperature within acceptable values. The EPU will not introduce any additional failure modes or operational hazards. Therefore, the ventilation system as currently designed has sufficient margin to meet its functional requirements at the expected EPU operating conditions.

RAB Safety-Related Fan Coolers

This section evaluates the EPU impact on the safety-related fan coolers associated with the following RAB areas:

- Component cooling water (CCW) heat exchangers
- CCW pumps
- Safeguard pumps
- Shutdown heat exchangers
- EFW pumps
- Charging pumps

The safety-related fan coolers are required to operate during an accident condition to maintain an acceptable operating environment for the engineered safety features equipment located in each area. The fan coolers are described in FSAR Section 9.4.3.8 and are designed to maintain a suitable operating environment for equipment during accident conditions.

Evaluation

There is no expected increase in cooling loads within the areas served by these air handling units, with the exception of the shutdown cooling heat exchanger rooms. The increased decay heat for EPU conditions during normal shutdown will increase the shutdown cooling heat exchanger Component Cooling Water System (CCWS) outlet temperature, which will increase the CCWS piping contribution to the room heat load. As stated in Section 2.5.5.3, the impact of this higher heat load on the shutdown cooling heat exchanger room cooler will be evaluated. The process piping systems in the RAB areas will not experience increases in fluid temperatures during normal and post-accident operation as a result of EPU (see CCWS discussion in Section 2.5.5.3). The heat loads removed include electrical switchgear, pump case and motor heat, and instrumentation heat losses to the ambient air. These loads are not affected by EPU. The RAB safety-related fan coolers are supplied by the Essential Chilled Water System that will not be impacted by EPU operating conditions. The existing cooling coils and their associated flow rates will remain adequate to maintain the required environmental conditions.

The cooling coils are designed with two independent trains that provide redundant capacity to assure the safety functions of maintaining adequate environmental conditions to ensure proper equipment operation. The EPU will not introduce any additional failure modes or operational hazards, therefore the system will continue to meet its existing design basis requirements. The electrical and instrumentation and control (I&C) requirements including instrument setpoints will not be affected by the EPU.

The RAB safety related fan coolers (with the exception of the shutdown cooling heat exchanger room coolers, which will be evaluated) will adequately support operation at EPU conditions. The EPU will not change system design parameters, introduce additional failure modes, or introduce additional operational hazards, therefore the fan coolers as currently designed have sufficient margin to meet their functional requirements at the expected EPU operating conditions.

RAB Cable Vault and Switchgear Areas Ventilation System

The purpose of the RAB Cable Vault and Switchgear Area HVAC System is to maintain a suitable operating environment for electrical equipment, battery, and cable areas during normal plant operations and accident conditions. The RAB Cable Vault and Switchgear Areas Ventilation System is described in FSAR Section 9.4.3.5 and is designed to fulfill the following functions:

a) Maintain a suitable operating environment for all electrical equipment during normal and accident conditions.
b) Prevent the accumulation of a combustible concentration of hydrogen in the battery rooms during normal and accident conditions.

Evaluation

The RAB Cable Vault and Switchgear Area Ventilation System will not be adversely impacted by the proposed increase in reactor thermal power. There is no expected increase in cooling loads within the areas served by these air handling units. These areas do not contain hot fluid process piping, and the electrical equipment loads are based on the design rating. These loads are not increased by the EPU. In addition, battery hydrogen generation will not increase because the battery loads are not increasing. This means that the existing battery room exhaust flow rate and margin will not require revision. The existing exhaust fan and cooling coils along with their associated flow rates will remain adequate to maintain the required environmental conditions, and the current electrical and instrumentation and controls requirements including instrument setpoints will not be affected. The system is designed with two independent trains that provide redundant capacity to assure the safety functions of maintaining adequate environmental conditions and hydrogen removal.

The RAB Cable Vault and Switchgear Area Ventilation System will adequately support operation at EPU conditions. The EPU will not change system operating parameters, introduce additional failure modes, or introduce additional operational hazards, therefore the ventilation system as currently designed has sufficient margin to meet its functional requirements at the expected EPU operating conditions.

Fuel-Handling Building Ventilation System

The Fuel-Handling Ventilation System is described in FSAR Section 9.4.2 and is designed to fulfill the following functions:

a) Provide high efficiency particulate filtration and iodine adsorption for air exhausted form the FHB.
b) Exhaust air from the FHB areas following a FHA at a rate required to create and maintain a negative pressure below 0.50 inch water gauge (inwg) relative to the outside atmosphere.

c) Provide a suitable environment for personnel, equipment and controls in the FHB during normal operation

d) Direct airflow from areas of low potential airborne contamination to areas of progressively higher potential airborne contamination.

Evaluation

The FHB Ventilation System is designed to maintain the FHB areas at a negative pressure during emergency operation, and to provide filtration and charcoal adsorption for the air exhausted from the area assuming a single active failure coincident with a LOOP. The system is also designed to maintain the space temperature in the FHB between 50°F and 104°F to ensure proper functioning of instrumentation and controls during normal operating conditions.

The FHB Ventilation System equipment and operational modes will not be adversely impacted by the proposed increase in reactor thermal power. The analysis of record shows that the system isolation and filtration/adsorption functions are not needed to mitigate the radiological consequences of a fuel-handling accident (FHA) in the FHB. This analysis was performed using a radioactive source term which bounds EPU conditions. The system design inputs used to determine electrical and I&C requirements (including instrument setpoints), system flow rates, filtration requirements, and negative pressure setpoints will not change as a result of operation at the EPU level. The existing exhaust fans, filter trains, and their associated control components will remain adequate to maintain the required environmental conditions and pressurization requirements.

The EPU will not adversely impact the FHB Ventilation System due to the conservative parameters utilized to establish the building heat loads and to determine the required air flows. The existing system analysis has been reviewed and bounds the anticipated EPU operating conditions.

A review of the overall system design shows that the system is capable of meeting its design pressurization and filtration requirements for the proposed EPU. The existing equipment will perform within the existing design basis requirements at the proposed EPU operating conditions. The EPU will not introduce any additional failure modes or operational hazards, therefore the system will continue to meet its existing design basis requirements.

RAB Normal Supply and Exhaust Systems

The RAB Normal Ventilation System is described in FSAR Section 9.4.3.1 and is designed to fulfill the following non-safety related functions:

a) Maintain a suitable operating environment for all equipment and personnel during normal operation.

b) Maintain air flow from areas of low potential radioactivity to areas of progressively higher potential radioactivity.

c) Limit concentrations of airborne radioactivity by circulating sufficient volumes of purging air.

d) Minimize airborne fission product releases from the building exhaust during normal operation.

e) Monitor ventilation system discharge to detect and prevent excessive release of airborne radioactivity.

f) Provide means for filtering containment purge air.

g) Provide automatic shutdown upon a toxic chemical event.

Evaluation

The RAB Normal Ventilation System is not required to operate following a DBA and, therefore, is not designed to safety or seismic requirements. The RAB Normal Ventilation System will not be adversely impacted by operation at the proposed increase in reactor thermal power. There is no expected increase in cooling or heating loads within the RAB areas cooled by the normal ventilation system, therefore the existing electrical and I&C requirements, including instrument setpoints will not be affected by the EPU. The existing cooling coil and its associated flow rates will remain adequate to maintain the required environmental conditions and pressurization requirements. The major components provide operating margin to assure the functions of cooling to maintain space temperatures and pressurization to maintain proper air flow. The RAB normal exhaust charcoal filtration unit has significant margin given the expected leakage and normal operation source terms. The current RAB dose calculations will bound the doses under EPU conditions. In addition, the expected releases from the RAB areas during normal operation are small, and any EPU changes will remain within the regulatory requirements. Based on this, the existing charcoal filtration system flow rate, charcoal filter residence time, and filter loading is adequate to maintain radiological design parameters well within design basis requirements.

There is no impact on the existing licensing basis of the RAB Normal Ventilation System due to the conservative design of the existing system. The EPU will not introduce any additional failure modes or operational hazards, therefore the system will continue to meet its existing design basis requirements. A review of the overall system design along with the interaction of support systems (supplemental service chiller water) shows that the system is capable of meeting its design cooling, pressurization, and filtration requirements for EPU operation.

Turbine Building Ventilation Systems

The purpose of the Turbine Building HVAC (HVT) System is to provide a satisfactory environment for equipment and personnel in the turbine building during all operating modes. The HVT System is required for reliable production of electricity but is not require for safe shutdown of the plant. The system is designated non-safety and non-seismic.

Evaluation

The EPU will have no impact on the design and operation of the HVT System. Conservative parameters were used for establishing the heat loads generated in the building and the air flow rates needed to remove the heat. The conservative parameters bound the heat loads anticipated for the EPU.

Conclusion

The Waterford 3 Ventilation Systems are adequate to support operation at EPU conditions. These systems continue to meet the requirements of GDC 4, 17, 19, 60, and 61 as applicable.

2.5.5 Component Cooling and Decay Heat Removal

2.5.5.1 Spent Fuel Pool Cooling and Cleanup System

The Spent Fuel Pool (SFP) Cooling and Cleanup System is described in FSAR Section 9.1.3. The system is designed to fulfill the following requirements:

a) Remove the decay heat produced in the fuel from a full core offload placed in the spent fuel pool after reactor shutdown. With two spent fuel cooling pumps operating, the maximum SFP temperature will not exceed 155°F.

b) Remove the decay heat produced in the spent fuel from a partial core offload placed in the SFP after reactor shutdown. With one spent fuel cooling pump operating, the maximum SFP water temperature will not exceed 140°F.

c) Remove soluble and insoluble foreign matter from the SFP water and dust from the pool surface.

d) Minimize the continuous radiation dose levels in working areas around the fuel pool less than 2.5 mrem/hr by maintaining at least 23 feet of water over the stored fuel assemblies.

Evaluation

Evaluations of the SFP Cooling System performance under EPU conditions demonstrate that the maximum bulk pool temperature limit of 140°F for a normal refueling outage (partial core offload of 108 assemblies and up to 2,116 previously discharged assemblies) will not be exceeded. The evaluations also show that the maximum bulk pool temperature limit of 155°F for a full core offload (full core offload of 217 assemblies with up to 2,116 previously discharged assemblies) will not be exceeded.

The EPU has no impact on the hydraulic portions of the purification sub-system. No equipment changes in the purification loop are required to support the uprate. A possible impact on the purification system is an increase in the frequency of resin replacement in the ion exchanger due to mathematically predicted higher levels of fission products in the pool cooling water due to the core power change. Any significant increase in fission product inventory in the primary coolant system due solely to the change in core power level will be mitigated by RCS cleanup systems prior to transmission to the SFP.

Radiation dose limits for the EPU are bounded by the radiological and shielding analyses previously performed for the reracking of the SFP. The analysis was based on a peak core power of 3844.3 MWt. Fuel enrichment levels up to 5.5% were considered in the analysis. This is conservative relative to the 5% maximum enrichment permitted by the plant Technical Specifications. A peak rod average burnup limit of 70 GWD/MTU was considered in the analysis. The peak rod average burnup limit for the EPU is 60 GWD/MTU.

Conclusion

The existing SFP Cooling System can handle the decay heat loads associated with the EPU. No component changes are required in the system. The maximum bulk pool temperature limit

of 140°F for a normal refueling outage will not be exceeded. The maximum bulk pool temperature limit of 155°F for a full core offload will not be exceeded.

The EPU requires no equipment changes to the purification system. Mathematically generated fission product level increases in the primary coolant could be carried over to the SFP during refueling operations. This increase in fission products in the SFP will result in a potential increase in the load on the ion exchanger. This will result in an increase in the resin depletion rate and the frequency of the resin regeneration and/or replacement. This is an operational issue and does not require any design changes to the existing system.

The SFP Cooling and Cleanup System will continue to provide sufficient cooling capacity to cool the SFP and will continue to meet the requirements of GDCs 44 and 61.

2.5.5.2 Turbine Building Closed Cooling Water System (TCCWS)

Waterford 3 does not have a Service Water System. Instead, Waterford 3 has two safety-related cooling water systems designated as the Component Cooling Water System (CCWS) and the Auxiliary Component Cooling Water System (ACCWS). The non-safety cooling water system is designated as the Turbine Building Closed Cooling Water System (TCCWS).

The TCCWS provides cooling water to the turbine building equipment such as the turbine generator and auxiliary equipment. The system removes excess heat from the turbine generator and auxiliary equipment via equipment coolers. The heat is then transferred to the Circulating Water System by the TCCWS heat exchangers. The TCCWS is discussed in FSAR Section 9.2.7.

Evaluation

Excess heat from the turbine generator and auxiliary equipment is transferred to the TCCWS by equipment coolers. The TCCWS rejects the heat (via the TCCWS heat exchangers) to the Circulating Water System. The actual heat loads for the generator coolers and isolated phase bus cooler will increase for the EPU, but remain bounded by the design heat loads originally established for the equipment. The heat loads for the remaining coolers (i.e., lube oil coolers, hydraulic oil coolers, air compressor coolers, sample coolers, seal water cooler) will not increase for the EPU. Control valves provide flexibility for cooling water flow rates. Pump flow rates are adequate for EPU conditions.

Conclusions

The EPU will have no adverse effect on the design or operation of the TCCWS. The EPU will increase the actual heat loads transferred from the main generator and isophase bus cooler to the TCCWS, but this increase is relatively small when compared to the total heat loads handled by the system. The actual heat loads (including the increased heat loads from the refurbished generator) are bounded by the original design heat loads identified in equipment specifications. System flow rates and pump capacities are not affected by the EPU.

2.5.5.3 Reactor Auxiliary Cooling Water Systems

The Component Cooling Water System (CCWS) and ACCWS are described in FSAR Section 9.2.2, and are designed to fulfill the following requirements:

a) To supply sufficient cooling water to remove heat from the safety-related reactor auxiliaries and non-safety-related auxiliaries where the potential for radioactive leakage exists and to transfer it to the cooling towers during normal reactor operation.
b) To supply sufficient cooling water to the components required for normal unit shutdown.
c) To supply sufficient cooling water to components required for refueling.
d) To supply sufficient cooling water to the components required for safe shutdown, and to mitigate a design basis accident assuming a single active component failure coincident with a LOOP.
e) To provide a radiation monitored intermediate barrier between the reactor auxiliaries and the evaporative wet towers (ACCWS) during normal operation.

The EPU review examined the effect of revised heat loads on the CCWS and the ACCWS.

Evaluation

The maximum heat load on the CCWS and ACCWS systems occurs during a DBA LOCA. Under EPU conditions, the maximum heat load from containment during a LOCA is lower than the maximum heat load considered on the CCWS and ACCWS systems under pre-EPU conditions. The containment heat load under EPU conditions was determined using a more detailed evaluation of the containment heat loads than was performed previously under pre-EPU conditions. Therefore, the heat load on the CCWS and ACCWS systems following the EPU is bounded by heat loads that were considered in the design of these systems for the pre-EPU conditions.

Although the maximum heat load on the CCWS and ACCWS systems is bounded by the heat load that was considered under the pre-EPU conditions, the heat load on these systems is higher during normal shutdown. The heat load during normal shutdown is higher due to the higher decay heat from the fuel in the reactor vessel and the spent fuel pool. These higher heat loads increase the temperature of the CCWS return flow in some of the CCWS piping sections. The impact of these higher temperatures for the CCW piping, supports, and components will be evaluated. Also, the impact of these higher temperatures on the shutdown cooling heat exchanger room cooler will be evaluated. Appropriate actions will be taken as necessary based on the results of this evaluation.

Prior to the EPU, the potential for boiling of the CCW in the containment fan coolers during a LOCA with a concurrent LOOP (Generic Letter [GL] 96-06) was evaluated at Waterford 3. When the CCWS pumps are restarted with power from the EDGs, any steam voids in the coolers would collapse and possibly cause waterhammer loads. This issue was addressed by demonstrating that the maximum temperature that the CCW could reach during this event is lower than the saturation temperature. The containment atmospheric conditions used to evaluate GL96-06 bounds the containment atmospheric conditions under EPU. The same justification for the CCW not reaching saturated conditions therefore applies under EPU conditions.

Waterford 3 complies with GL 89-13 in that Waterford 3 has a program to evaluate the performance of the service water heat exchangers. At Waterford 3, the ACCW fulfills the role of service water with respect to GL 89-13. The Waterford 3 design process ensures that the required changes to the GL 89-13 program are made with respect to the EPU.

Conclusion

With the exception of the slightly higher CCWS piping temperatures, it has been demonstrated that the CCWS and ACCWS can accommodate the plant heat loads under EPU conditions. The impact of these slightly higher temperatures on the CCW return piping (including pipe supports and system components) and the RAB safety-related room/area coolers is still being evaluated. These systems will also be protected from the dynamic effects associated with flow instabilities as discussed in GL 96-06 and will provide sufficient cooling to the SSCs important to safety. Therefore, the CCWS and ACCWS will continue to meet the requirements of GDCs 4 and 44.

2.5.5.4 Ultimate Heat Sink

The plant Ultimate Heat Sink (UHS) System is described in FSAR Section 9.2.5, and is designed to:

a) Provide a reliable rejection of heat loads from the CCWS and ACCWS to the atmosphere during normal, shutdown, and refueling operations.
b) Provide a reliable 30 day post-LOCA shutdown cooling capability for reactor and auxiliaries following a DBA.
c) Provide a sufficient capacity to dissipate CCWS and ACCWS heat to permit a safe shutdown of the unit coincident with a LOOP, multiple tornado missiles and single active failure.
d) Perform following a DBA, the above functions assuming a single active failure coincident with a LOOP and the historically worst combination meteorological conditions.

The UHS provides the safety-related cooling medium required to dissipate the heat removed from the reactor and its auxiliaries during normal operation, during refueling operations, or following a DBA. The UHS consists of dry cooling towers (DCTs) and wet cooling towers (WCTs) and the volume of water stored in the basins of the WCTs. The wet cooling towers remove heat from the CCWS via the ACCWS. The ACCWS is an intermediate cooling water loop that circulates through the shell of the CCWS heat exchangers and is returned to the basins of the wet cooling towers via spray nozzles.

The EPU will not introduce any additional failure modes or operational hazards, therefore the system will continue to meet its existing design basis requirements. This includes operation following a DBA coincident with a single active failure and a LOOP; operation following an SSE; design basis tornado event; and 30-day continuous operation following a DBA. The existing system has sufficient margin in heat removal capacity and stored water volume to perform the design basis functions under EPU operating conditions.

Evaluation

The UHS System heat removal requirements result from primary system releases to the containment environment and auxiliary heat loads from other ESF systems. The peak total heat load for the UHS at EPU operating conditions decreases from the pre-EPU peak heat load due to a more detailed evaluation of CCWS heat loads. The DCT is designed to operate at full load, while the WCT picks up the excess load above the DCT capacity.

The UHS is designed to provide sufficient post-DBA cooling for 30 days or longer. It is also designed to permit safe shutdown and cool down of the plant and maintain the plant in a safe shutdown condition. The post-DBA heat load (for each independent UHS division) consists of the following essential plant equipment: one EDG, one essential services water chiller, two containment fan coolers, one high-pressure safety injection pump, one low-pressure safety injection pump, one containment spray pump and one shutdown cooling heat exchanger. The WCT basins contain sufficient water for post-accident UHS operation without makeup. To minimize evaporative water losses from the WCT, the system is designed so that the DCTs are operating at full capacity post-accident. The maximum CCWS heat load under EPU conditions will be lower due to a more detailed evaluation of post-accident heat loads that resulted in lower peak containment heat loads, therefore, the peak heat removal requirements for the UHS will decrease. The total mass and thermal energy released for the accident duration will be slightly larger for EPU operation, therefore the long-term heat removal by the UHS will slightly increase. The EPU UHS analysis shows that the dry and wet cooling towers have sufficient capacity to accommodate the post-LOCA CCWS and ACCWS heat loads for power uprate operation. The analysis also shows that for the LOCA event, the UHS has sufficient water volume in one basin to meet the 30-day heat removal requirements for the essential loads without makeup from an external source of water.

The UHS heat removal requirements for normal shutdown cooling and refueling operations will increase for the EPU due to the increased decay heat loads. The heat loads for normal cool down and refueling operations have been evaluated. It has been determined that the UHS can dissipate the EPU heat load. The EPU UHS analysis also shows that the UHS can dissipate the bounding LOCA heat loads. This accident scenario uses only a single DCT and a single WCT as the UHS. Meteorological conditions limit the performance of the cooling towers. The DCT performance is dependent on dry bulb temperature and the WCT performance is dependent on wet bulb temperature. The DCT and the WCT design meteorological conditions have been evaluated and bound the recent recorded meteorological data.

The tornado event is the most limiting event for WCT water consumption. The WCT is a source of water supply for the Emergency Feedwater System (EFS) during recovery from a design basis tornado event (with a LOOP and failure of one diesel generator). The UHS is required to operate a minimum of 30 days following the tornado event. The analysis has shown that there is sufficient UHS water volume to supply the EFS and provide heat removal to the essential plant auxiliary equipment.

Conclusion

The UHS has the capacity to handle the EPU containment heat loads and plant auxiliary heat loads for the bounding LBLOCA. The EPU peak accident heat load and the total integrated accident heat load by the UHS are within the UHS heat removal capability. The dry and wet cooling towers will meet the design basis heat removal and water usage requirements at the

EPU operating conditions. The UHS also can dissipate the EPU heat loads for normal cooldown and refueling operations.

The EPU condition does not introduce any new hazards or failure modes, therefore it will not affect the existing general design criteria requirements and acceptance criteria. The design ambient environmental conditions are based on historical maximum values that include a review of recent recorded meteorological data. The UHS has been analyzed to these conditions and will continue to meet the design heat removal requirements for EPU operation and the requirements of GDC 44.

2.5.5.5 Emergency Feedwater System

The EFS is described in FSAR Section 10.4.9. The functions of the system and design bases are provided below.

a) The function of EFS is to ensure a sufficient supply of cooling water to the steam generators to provide cooldown of the RCS to the temperature and pressure at which the Shutdown Cooling System (SDCS) can be placed in operation.
b) EFS supplies sufficient cooling water following loss of normal FW to one or both steam generators.
c) The system delivers feedwater against a steam generator pressure corresponding to the first main steam safety valve set pressure plus operating tolerances.
d) Seismic Category I water storage for EFS contains as a minimum, sufficient water to hold the reactor at hot shutdown for 2 hours, followed by an orderly cooldown until the SDCS may be initiated.
e) The system is designed to operate for 4 hours with complete loss of either onsite and/or offsite AC power.
f) Redundant pumping capacity is provided by either two AC powered motor-driven pumps or one DC power controlled steam turbine-driven EFS pump to ensure system performance with multiple and diverse power sources.

Evaluation

The design parameters and criteria for the EFS have been evaluated for the EPU.

Although EPU will cause an increase in decay heat, engineering evaluations for the EPU determined that no change to the EFS performance (flow rate and delivery pressure) is required. Analyses demonstrate that the EFS pumps can provide the minimum flow rate necessary to support the safety analysis flow rate assumptions. Also, since there is no change in system performance requirements and no change in physical system arrangements, the proposed EPU will have no change in the likelihood of creating fluid flow instabilities (e.g., waterhammer) during operation. Thus, there is no change in the susceptibility of the system to waterhammer events.

The condensate storage pool provides the initial source of water to the EFS pumps' suction. The wet cooling tower basins provide the Seismic Category I backup source. The increased demand for condensate requirements for cooldown as the result of EPU can be met with the current system configuration and operation. No physical changes are necessary to the system.

The sources of EFS have been evaluated and have adequate capacity for power uprate conditions.

Conclusion

The current design of the Emergency Feedwater System and Condensate Storage Pool system will support Waterford 3 EPU. The design functions of the EFS as described in the FSAR have been evaluated and are unaffected by EPU. The increase in core decay heat and other changes in plant conditions due to the EPU will not affect the ability of the EFS to supply adequate water to the steam generators to ensure adequate cooling of the core. It is concluded that the EFS will continue to meet its design functions following implementation of the proposed EPU. It is further concluded that the EFS will continue to meet the requirements of GDCs 4, 19, 34, and 44.

2.5.6 Balance-of-Plant Systems

2.5.6.1 Main Steam Supply System

The Main Steam Supply System (MSSS) is described in FSAR Section 10.3. The MSSS performs the following safety-related functions:

a) Isolate the SG from the non-safety portions of the MSSS during emergency conditions by the use of the MSIVs.

b) Dissipate heat generated and accumulated in the NSSS to the atmosphere during emergency conditions by the use of the ADVs and pressure code safety relief valves until shutdown cooling can be initiated.

c) Provide over pressure protection for the MSSS and the SGs.

d) Provide a flow path for steam to the emergency feedwater pump turbine (EFPT).

In addition, the MSSS performs the following non-safety related functions:

e) Deliver steam for power generation from the SGs to the turbine generator set at the required flow rate and steam conditions.

f) Dissipate heat generated by the NSSS in the event the turbine generator is not in service during non-emergency conditions such as turbine load reductions, by use of steam bypass to the condenser.

g) Provide steam for the turbine gland seals, moisture separator reheaters (MSRs), SG feedwater pump turbines (during low load), and other plant auxiliary components.

The Reheat Steam System (RSS) including the MSRs is a non-safety related system that performs the following functions:

a) Removes the moisture from the HP turbine exhaust steam to prevent excessive wear on the LP turbine blades.

b) Superheats the HP turbine exhaust to improve the thermodynamic efficiency of the steam cycle using the MSSS as the heat source.

c) Limits the steam flow to the LP turbine following a load rejection thereby protecting the main turbine from an overspeed condition.

The EPU review examined the effects of extended power uprate (most notably increased steam mass flow) on the system's capability to transport steam to the power conversion system, provide heat sink capacity, supply steam to drive the EFPT, and withstand adverse dynamic loads. Overpressure protection capabilities were also reviewed with respect to new power uprate conditions.

Evaluation

The design temperatures and pressures of the MSSS are not impacted by the EPU. Operating temperatures and pressures for the MSSS from the SG to the turbine have been reduced at normal operating power levels, while steam mass flow has been increased (which results in a higher steam velocity). MSSS flow at normal operating power levels has increased by approximately 8.6%. In order to accept the higher MSSS flows for EPU, the HP turbine steam path will be replaced. Pressures and temperatures at some intermediate points in the power cycle (most notably extraction steam) have increased slightly due to lower pressure losses and improved turbine efficiencies. The MSSS piping has been evaluated and has been shown to be acceptable in its current configuration. Lines with increased velocities above design guidelines are infrequently operated or have been recommended for inclusion in the Flow Accelerated Corrosion Program. The MSSS piping has been evaluated for increased LOCA movements at SG nozzles and transient loading as a result of a turbine trip. The results indicate both piping and nozzles are acceptable.

Closure times for MSIVs have been evaluated and have been determined to be unaffected by the EPU.

The ADVs are required to maintain reactor coolant temperature during LOOP, and are also credited for the small-break LOCA (SBLOCA) event. ADV capacities are incorporated into the accident and transient analyses. These analyses indicate that sufficient heat rejection capability exists. The ADV opening setpoint is being lowered to less than or equal to 1000 psia.

The main steam safety relief valve capacity has been reviewed and has been found to be sufficient to pass the maximum rated plant steam flow at set pressure plus accumulation (3%). The main steam safety relief valves, therefore, have sufficient capacity at EPU conditions to perform their design basis function.

Hot-zero power (HZP) steam pressures are reduced slightly by the EPU, however, no changes to EFW pump flowrates or operating conditions are required, nor are any EFW turbine operating conditions adversely affected. Decay heat has increased, increasing the EFW volume required, however, the flow rate is within the design capacity of the EFW pumps.

The MSSS provides steam for the feedwater pump turbines during startup. The EPU requires that the feedwater flow (and thus steam flow to the feedwater pump turbines) be increased to meet the new steam flow requirements. No modifications are required to the turbine since the rated horsepower of the turbine exceeds the calculated horsepower requirements (to deliver

the required feedwater flow) at EPU conditions. The Feedwater Control System setpoints will be modified slightly to increase pump speed at a lower demand. The remaining current Feedwater Control System setpoints were used in the evaluation and were found to be acceptable at EPU conditions.

The MSSS design bases are described in FSAR Section 10.3.1. EPU conditions do not affect the existing design basis of the MSSS or alter the method in which it performs these functions. An additional safety related function has been added, in that the ADVs are credited for secondary pressure control during the small break LOCA event. The sizing of these valves is adequate for EPU conditions.

The MSSS has been evaluated with respect to 10CFR50, Appendix A, GDC 34, *Residual Heat Removal*. The MSSS is capable of providing heat sink capacity and pressure relief capability and supplying steam to the steam-driven EFW pump at EPU conditions.

No additional internally generated missiles or pipe break locations are identified in the MSSS as a result of evaluation at EPU conditions, nor have any additional effects from natural phenomena such as tornadoes, earthquakes, or hurricanes been postulated. Evaluation of missile generation and protection is addressed in Section 2.5.1.2 of this report. The MSSS piping analysis incorporates the effects of dynamic loads due to LOCA and sudden turbine stop valve closure. Based upon the above, continued compliance with 10CFR50, Appendix A, GDC 2, *Design Bases for Protection Against Natural Phenomena* and GDC 4, *Environmental and Missile Design Bases* is assured.

With the exception of the MSR safety valves in the RS, the MSR and other system piping and components are not adversely impacted by the EPU. The MSR safety valves are undersized for the EPU conditions and will be modified as required to provide adequate capacity.

The turbine steam valve closure time following the detection of a turbine overspeed condition as described in FSAR Section 10.2.2.2.9 is not impacted by the EPU.

The Steam Bypass System (SBS) is discussed in Section 2.5.6.3.

Conclusion

Safety-related and non-safety related components and sub-systems in the MSSS as described in the Waterford 3 FSAR are adequately sized and designed (with ADV setpoint/controls modifications and MSR safety valve replacement) to perform their intended function at EPU conditions for normal, transient, and accident conditions. The MSSS will maintain its ability to transport steam to the power conversion system, provide heat sink capacity, supply steam to steam-driven safety pumps, and withstand steam hammer. The system continues to comply with the requirements of GDCs 2, 4 and 34.

2.5.6.2 Main Condenser

The main condenser is discussed in FSAR Section 10.4.1 and FSAR Table 10.4-1. The three-shell, single-pressure, main condenser provides a continuous heat sink for the exhaust from the three tandem-compound LP turbines and for miscellaneous flows, drains, and vents during normal plant operation.

The main condenser also provides a heat sink for the SBS in the initial phase of reactor cooldown after plant shutdown.

The main condenser is designed to:

a) Condense the main steam flow bypassed directly to the condenser by the SBS. This condition could occur in case of a sudden load rejection by the turbine generator, a turbine trip, or during start-up and shutdown.

b) Provided for removal of non-condensable gases from the condensing steam through the Main Condenser Evacuation System.

c) Deaerate the condensate before it leaves the condenser hotwell.

Evaluation

Power uprate will increase the total mass flow of steam in the main condenser. Potential tube vibration exists when operating the existing condenser at higher than original design loads.

Evaluation of the condenser indicated that condenser performance thermal ratings and the steam bypass lines capacity are adequate for the proposed EPU. However, a tube vibration analysis indicated that the existing support plate spacing may be inadequate for the uprate conditions. Measures will be implemented as necessary to prevent potential condenser tube vibration under power uprate conditions.

A motor-operated, fail-as-is gate valve is provided on each main condenser shell and is used to break vacuum during normal shutdown, and in the event of an emergency that dictates decreasing main turbine coastdown time. These valves have been evaluated for EPU and found to be adequately sized and will be able to perform their functions under the EPU conditions.

Conclusion

The main condenser, modified as necessary to prevent tube vibration, will perform acceptably under EPU conditions. The system will continue to maintain its ability to withstand the blowdown effects of the steam from the SBS and therefore, continue to meet the regulatory requirements for prevention of the consequences of failures of the system.

2.5.6.3 Steam Bypass System

The SBS is composed of six turbine bypass valves and associated instrumentation and controls that function to position the valves to draw steam energy from the NSSS and deliver it directly to the main condenser in situations where NSSS output exceeds turbine demand. As part of the SBS, the Steam Bypass Control System (SBCS) allows avoidance of a reactor trip following large load rejections or turbine trips without challenging RCS or MSSSs. The SBS is discussed in Sections 7.7.1.4.1 and 10.4.4 of the FSAR.

The SBS monitors steam header pressure, and maintains it within programmed limits by opening any or all of the six bypass valves. The valves are automatically controlled in the slow-opening modulate mode in cases of small load rejections and in the quick-opening mode for larger load rejections, such as a turbine trip at high power. Additionally, for larger load

rejections, the SBS will provide cutback signals to the Reactor Power Cutback System to rapidly reduce reactor power, bringing it within the limitations of the SBS flow capabilities. The SBS is also used to control RCS temperature during cooldown operations and to control reactor power during startup operations prior to loading the turbine.

The inadvertent opening of a SBS valve is bounded by the inadvertent opening of an ADV, evaluated in Section 2.13.1.

Evaluation

The SBS control setpoints and programming will require changes as indicated in paragraph 2.4.2.1 to conform to the new operating point under EPU conditions. The mechanical portions of the system have sufficient margin to operate under EPU conditions. Transient response has been evaluated, and found to require several changes to ensure the SBS functions to avoid unnecessary plant trips as it responds to load rejections. The bypass valve capacities (steam flows) are modeled as they currently exist, and no valve modifications are required, thus the increase in power level results in a reduction in the capacity of the SBCS (as a percentage of full power steam flow rate).

Conclusion

The piping and mechanical portions of the SBS are not affected by EPU.

2.5.6.4 Condensate and Feedwater, Extraction Steam, Heater Drain, and Heater Vent Systems

The Condensate and Feedwater Systems (CFWS) are described in FSAR Section 10.4.7. These systems are designed to supply full load feedwater flow plus steam generator blowdown (maximum of two percent of the rated flow) at the expected steam pressures. In addition, these systems provide the proper flow to the steam generators during transient conditions which include the following:

a) Required plant load changes

b) Simultaneous turbine and reactor trip with normal operation of the Steam Bypass System (SBS) to dissipate heat

c) Complete loss of load without coincident reactor trip and with the failure of the SBS to operate. The main steam safety valves are assumed to open and credit is taken for a trip by the Reactor Protection System (RPS)

The CFWSs are designed to maintain unit operation when the system is needed to operate under abnormal conditions due to one SG FW pump, or one condensate pump, or all heater drain pumps, or one string of heaters, being out of service.

The FW safety-related function to provide containment isolation is provided by the feedwater isolation valves. The main and backup FW-regulating valves backup the FW isolation valves.

The Extraction Steam, Heater Drain, and Heater Vent Systems are described in FSAR Sections 10.2.2.2.6 and 10.4.7. These systems that support the CFWS provide the following functions:

a) The Extraction Steam System provides a means for recovering heat from the steam plant cycle to maximize the thermodynamic efficiency of the system cycle and to limit the thermal shock caused by the FW entering the SGs.

b) The Heater Drain System provides a means for recovering heat from the drainage in the feedwater heater shell to maximize the thermodynamic efficiency of the system cycle and to limit the thermal shock caused by the FW entering the SGs.

c) The FW heater vents continuously remove non-condensable gases from the FW heater shells to prevent high rates of corrosion within the heaters and to prevent a reduction in the efficiency of the steam cycle.

Evaluation

The hydraulic and thermodynamic effects on the CFWS, Extraction Steam, Heater Drain, and Heater Vent Systems from the EPU have been evaluated by considering Waterford 3's original design requirements and its operating history. A heat and mass balance of Waterford 3's Steam and Power Conversion Systems was performed at the EPU level (3716 MWt) and 102% of the EPU level (3811 MWt). Most of the hydraulic evaluation for the CFWS was conservatively performed at 102% of the EPU power level.

The required total developed head and flow, horsepower, and net positive suction head (NPSH) available versus NPSH required for the CFWS pumps were evaluated at 102% of the EPU power level. This evaluation demonstrated that the condensate and feedwater equipment is adequate for EPU conditions without modification.

Under EPU conditions, the velocity in some of the CFWS piping segments will increase. The flow-accelerated corrosion (FAC) analysis performed with increased flow rate indicates that the post uprate FAC wear rate will increase by a low to moderate amount.

The system flow rates considered in the FW waterhammer analysis bounds the feedwater system flow rates under EPU conditions. Therefore, the FW System and related components are qualified to handle the waterhammer loads under EPU conditions.

The main and startup FW regulating valves are adequately sized to pass the higher flow rate required for the EPU.

The FW isolation valves (FWIVs) will continue to meet the containment isolation requirements for the FW System. The main and startup FW regulating valves still adequately backup the FWIVs.

The effect of the power uprate on the FW heater operating pressure, tube-side pressure drop, tube velocity, and nozzle velocity was evaluated. In addition, the FW heater vibrations and the shell/tube-side relief valve capacities were evaluated. These evaluations determined that the FW heaters are adequately sized for EPU conditions.

Under EPU conditions, the velocity in some of the extraction steam piping segments will increase. The FAC analysis performed with increased flow rate indicates that the post-uprate FAC wear rate will increase by a low to moderate amount.

The heater drain pumps are adequately sized to meet the total developed head, flow, horsepower, and NPSH requirements under EPU conditions. The level control valves that control the drain flow may be replaced or modified to increase the flow capacity as necessary. These changes to the control valves will not affect any safety-related functions at Waterford 3.

The FW Heater Vent System will adequately support the EPU conditions.

Conclusion

The effects of the EPU operating conditions on the CFWS, Extraction Steam, Heater Drain, and Heater Vent Systems were evaluated. These systems will continue to satisfy the FW requirements for normal operation and shutdown, withstand waterhammer, maintain isolation capability in order to preserve the system safety function, and not cause the failure of safety-related SSCs. The non-safety-related level control valves within the Heater Drain System may require replacement or modification to support the EPU. These systems meet the requirements of GDCs 4 and 44.

2.5.7 Waste Management Systems

An evaluation of the impact of the power uprate on liquid and gaseous releases from the Plant Waste Management System is made based on current effluent releases (References 2.5.7-1, 2.5.7-2, and 2.5.7-3) and the projected change in releases due to the power uprate. The projected change in liquid and gaseous effluent releases is evaluated with the PWRGALE (Reference 2.5.7-4) code and the associated change in offsite doses is evaluated with the GASPAR code (Reference 2.5.7-5).

2.5.7.1 Gaseous Waste Management

The Waterford 3 Gaseous Waste Treatment System is designed to collect, process, and dispose of radioactive gaseous waste in accordance with the requirements outlined in 10CFR20 and Appendix I to 10CFR50. This radioactive waste treatment system is discussed in the Final Environmental Statement (FES). The EPU will not affect the environmental monitoring of this waste stream or the radiological monitoring requirements contained in licensing basis documents. The EPU does not result in any changes in operation or design of the equipment in the Gaseous Waste Treatment Systems. The EPU will not introduce new or different radiological release pathways and consequently will not increase the probability of an operator error or equipment malfunction that will result in an uncontrolled radioactive release. Changes in the gaseous and liquid waste streams and their radiological environmental impact due to EPU are summarized in the following two sections.

Evaluation

During normal operation, the Gaseous Effluent Systems control the release of gaseous radioactive effluents to the site environment, including small quantities of noble gases, halogens, particulates, and tritium. Routine offsite releases from plant operation remain below the limits outlined in 10CFR20 and Appendix I to 10CFR50 (10CFR20 includes the requirements of 40CFR190). The Gaseous Waste Management Systems (GWMSs) include the off-gas system and various building ventilation systems. Based on PWRGALE estimates of the increase in gaseous releases and GASPAR estimates of the increase in offsite doses associated with the power uprate, the impact of the power uprate on offsite doses due to gaseous releases is conservatively estimated to be less that 15%. This conservative estimate is well within the current variation of annual gaseous doses. Thus, the estimated increase in the offsite dose due to EPU will be very small with no significant impact on human health and be below Appendix I requirements. Using the average data for year 2000 through 2002, the estimated average dose due to the EPU is summarized in Table 2.5-3.

Table 2.5-3
Gaseous Doses

	Gamma (mrad)	Beta (mrad)	Iodine, Tritium & Particulates (mrem)
2000	5.0E-02	1.5E-01	1.7E-01
2001	8.0E-03	2.3E-02	8.0E-02
2002	7.6E-02	2.45E-01	5.28E-01
Average	4.47E-02	1.39E-01	2.59E-01
Projected Average Due to Power Uprate	5.10E-02	1.60E-01	2.98E-01

Conclusion

Based on the results listed in Table 2.5-3, the current conclusions provided in the FES will remain valid under EPU conditions. The projected average dose due to EPU on gamma in air and beta in air results in 5.10E-02 and 1.60E-01 millirad per year (mrad/yr), respectively.

Comparing the EPU dose rates to same type dose rates in FES Table J-4, the following conclusions are drawn:

- Waterford 3 EPU results are far below the RM-50-2[1] design objective values of 10 and 20 mrad/yr for gamma and beta,
- The annual EPU doses for gamma and beta are about 50 times lower than the gamma (2.6 mrad/yr) and beta (8.1 mrad/yr) doses listed in the FES Table J-4.

[1] Guides on Design Objectives proposed by the NRC staff on February 20, 1974; considers dose to individuals from all units onsite. From *Concluding Statement of Position of the Regulatory Staff*, Docket No. RM-50-2. Feb. 20, 1974, pp. 25-30, U.S. Atomic Energy Commission, Washington, D. C.

Similarly, based on the 3-year average, the projected EPU dose for iodine, tritium, and particulates (ITP) is 2.98E-01 millirem per year (mrem/yr). Comparing the EPU dose rates to same type dose in FES Table J-4, it can be concluded that the Waterford 3 power uprate ITP dose results are far below the RM-50-2 design objective dose rate of 15 mrem/yr and also about 18 times lower in dose consequence than the 5.5 mrem/yr calculated dose for ITP in the FES Table J-5.

Therefore, based on past performance, it can be clearly demonstrated that Waterford 3 will maintain the low exposure to the public due to gaseous effluent releases following EPU.

2.5.7.2 Liquid Waste Management

The Waterford 3 Liquid Waste Treatment System is designed to collect, process, and dispose of radioactive liquid waste in accordance with the requirements outlined in 10CFR20 and Appendix I to 10CFR50. This Radioactive Waste Treatment System is discussed in the FES. The EPU will not affect the environmental monitoring of this waste stream or the radiological monitoring requirements contained in licensing basis documents. The EPU does not result in any changes in operation or design of the equipment in the Liquid Waste System. The EPU will not introduce new or different radiological release pathways and consequently will not increase the probability of an operator error or equipment malfunction that will result in an uncontrolled radioactive release. Changes in the liquid waste streams and their radiological environmental impact due to the EPU are summarized in the following two subsections.

Evaluation

The Liquid Radwaste System is designed to process and recycle, to the extent practicable, the liquid waste collected during the normal plant operation. PWRGALE estimates of the change in liquid releases due to EPU show a negligible change in radionuclide releases. However, the impact on radionuclide releases is still conservatively estimated by increasing current annual radiation doses by 9.6%.[2] Annual radiation doses to individuals from Liquid Radwaste System are maintained below the guidelines in 10CFR20 and 10CFR50, Appendix I. There will be no change in the release policy as a result of the EPU.

Table 2.5-4 summarizes the activities released to the environment over the past 3 years.

[2] This increase is based on the change in power level from 3390 to 3716 MWt.

Table 2.5-4
Liquid Releases

	Fission & Activation (Curies)	Tritium (Curies)	Gases (Curies)	Gross Alpha (Curies)
2000	2.89E-01	6.64E+02	2.40E+00	0
2001	1.94E-01	3.40E+02	3.12E-02	0
2002	6.01E-02	8.66E+02	1.24E+00	0
Average	1.81E-01	6.23E+02	1.22E+00	0
Projected Average Due to Power Uprate	1.97E-01	6.79E+02	1.33E+00	0

The EPU conditions will not result in significant increases in the volume of fluid from other sources flowing into the Liquid Radwaste System due to the following reasons:

- The reactor will continue to be operated within its present pressure control band.
- Valve packing leakage volume into the Liquid Radwaste System is not expected to increase.
- There will be no changes in RCP seal flow or the flow of any other normal equipment drain path.

In addition, there will be no impact on the dirty radwaste or chemical waste subsystems of the Liquid Radwaste System as a result of the EPU since the operation and the inputs to these subsystems are independent of the EPU. No significant dose increase in the liquid pathway will result from the EPU.

Annual offsite doses from liquid effluent during the period from 2000 to 2002 are presented in Table 2.5-5.

Table 2.5-5
Annual Offsite Doses Due to Liquid Effluent

	Whole Body (mrem)	Critical Organ (mrem)
2000	1.0E-02	1.0E-2
2001	3.0E-03	6.0E-3
2002	3.0E-03	5.0E-3
Average	5.3E-03	7.0E-3
Projected Average Due to Power Uprate	5.8E-03	7.7E-3

Assuming that the activities in the liquid waste system increase linearly due to power uprate, the projected uprate average dose from liquid effluent will be 5.8E-3 mrem to the whole body and 7.7E-3 mrem to the critical organ. These values are still well below any of the Waterford 3 reporting limits. This is lower than the 1.0E-1 mrem whole body and 1.2E-1 mrem critical organ doses reported in the original FES for Waterford 3.

Conclusion

The EPU conditions will not result in significant increases in the volume of fluid from other sources flowing into the Liquid Radwaste System. Annual doses from liquid effluent due to the EPU will remain well below the original FES, and well below the 10CFR50 Appendix I limits.

2.5.7.3 Solid Waste Management Systems

The Waterford 3 Solid Waste Treatment System is designed to collect, process, and dispose of radioactive solid waste in accordance with the requirements outlined in 10CFR20 and Appendix I to 10CFR50. This radioactive waste treatment system is discussed in the FES. The EPU will not affect the environmental monitoring of this waste stream or the radiological monitoring requirements contained in licensing basis documents. The EPU does not result in any changes in operation or design of the equipment in the solid waste systems. The EPU will not introduce new or different radiological release pathways and consequently will not increase the probability of an operator error or equipment malfunction that will result in an uncontrolled radioactive release. Changes in the solid waste streams and their radiological environmental impact due to the EPU are summarized in the following two subsections.

Evaluation

The Solid Radioactive Waste System collects, monitors, processes, packages, and provides temporary storage facilities for radioactive solid wastes prior to offsite shipment and permanent disposal. Waterford 3 has implemented procedures to assure that the processing and packaging of wet and dry solid radioactive waste and irradiated reactor components are accomplished in compliance with regulatory requirements. Entergy continually tracks the volume of solid radioactive waste generated at the site. From 1998 through 2002, Waterford 3 generated approximately 22,520 ft^3 of low level radioactive waste for an average of about 4,504 ft^3 per year. In 2002, Waterford 3 generated a peak volume of 6,737 ft^3 of low-level radioactive waste. The majority of the waste was generated as a result of the Waterford 3 refueling outage.

Wet Waste – The typical contributors to radioactive solid wet waste is low specific activity spent secondary and primary resin and filters and oil and sludge from various contaminated systems. Historically, this has accounted around a 50:50 split of the total volume of wet radioactive waste generated annually. The EPU will not change either reactor water cleanup flow rates or filter performance. Therefore, implementation of the EPU will not have a significant impact on the volume or activity of wet radioactive solid waste at Waterford 3.

Dry Waste – Dry waste consists primarily of air filters, contaminated paper products and rags, contaminated clothing, tools and equipment parts that cannot be effectively decontaminated, and solid laboratory wastes. The activity of much of this waste is low enough to permit manual handling. Dry waste is collected in containers located throughout the plant, packaged and removed to a controlled area for temporary storage. Because of its low activity, dry waste can

be stored until enough is accumulated to permit economical transportation to an offsite processing facility for volume reduction or a burial ground for final disposal.

Irradiated Reactor Components – Irradiated reactor components such as in-core detectors and fuel assemblies, must be disposed of after the life of the component. The volume and activity of waste generated from spent control element assemblies and in-core detectors may increase slightly under the higher flux conditions associated with EPU conditions.

The EPU core design allows up to 104 new assemblies per reload. However, representative core designs for the transition and equilibrium designs call for typically 92 fresh assemblies per reload. This is 4 bundles more than required for the current refueling cycle. This may result in a slight increase in spent fuel discharge to the spent fuel pool.

Conclusion

In light of Waterford 3's continuing efforts to reduce radioactive wastes, any projected increase in solid waste generation under power uprate conditions described above is not significant, and is not sufficient to change the continuing downward trend in the production and activity of solid wastes.

2.5.7.4 References

2.5.7-1 *Annual Radioactive Effluent Release Report*, January 1, 2000 – December 31, 2000, Waterford 3 SES, Entergy Operations, Inc.

2.5.7-2 *Annual Radioactive Effluent Release Report*, January 1, 2001 – December 31, 2001, Waterford 3 SES, Entergy Operations, Inc.

2.5.7-3 *Annual Radioactive Effluent Release Report*, January 1, 2002 – December 31, 2002, Waterford 3 SES, Entergy Operations, Inc.

2.5.7-4 NUREG-0017, Rev. 1, *Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Light Water Reactors* – PWR GALE Code, April 1985.

2.5.7-5 NUREG/CR-4653, *GASPAR II Technical Reference and User Guide*, March 1987.

2.5.8 Additional Considerations

2.5.8.1 Emergency Diesel Engine Fuel Oil Storage and Transfer System

The EDG Fuel Oil Storage and Transfer System is discussed in FSAR Section 9.5.4. The system is designed to provide oil storage capacity in each storage tank for 7 days operation of one diesel generator to meet the engineered safety feature load requirements following a LOOP and a DBA.

The Emergency Diesel Engine Fuel Oil Storage and Transfer System provides adequate storage of diesel fuel oil and supplies to the two emergency diesel engines. Diesel fuel oil storage for each diesel engine is separate and independent of the other.

Two completely redundant trains are provided, each consisting of a diesel oil storage tank, transfer pump, diesel oil feed tank, interconnecting piping, valves, and instrumentation and controls. Train A normally serves emergency diesel engine A, and train B normally serves emergency diesel engine B. All necessary electrical power for the operation of each train is supplied from the associated EDG bus.

The system is also designed for missile protection and protection against dynamic effects associated with the postulated rupture of piping.

Evaluation

The fuel oil inventory required to support the EDGs has been evaluated. The operating duration of certain components will increase, due to the increased decay heat level under EPU conditions.

The electrical load during accident conditions will continue to be within the design rating of the EDG. A time-dependent load profile was developed based on the expected power requirement and run time of each component powered by the EDG under accident conditions. This evaluation considered the ECCS performance and containment design analyses, along with engineering judgement for the long-term portion of the event and for components not modeled in those analyses. Note that consistent with the change to 10CFR50.44, the hydrogen recombiner load was not included in the profile. (See Section 2.5.2.4 for more information on the rule change.)

The load profile was used to determine the total diesel fuel oil inventory required. The fuel oil consumption rates were based on actual measured rates rather than on the vendor-supplied rates determined when the EDGs were new. The consumption rates used in the evaluation were less than the vendor-supplied rates used in the Analysis of Record, but greater than the measured rates. Additional testing will be performed to reconfirm the acceptability of the fuel oil consumption rates used in the fuel oil inventory calculation prior to implementing the EPU. The evaluation shows that the on-site capacity of the diesel fuel storage tank and the diesel oil feed tank, at their current Technical Specification limits, is sufficient to allow the associate EDG to meet the required loads for seven days.

The independence and redundancy features of the system will not be impacted by EPU, and the design for missile protection and protection against the dynamic effects associated with the postulated rupture of piping will be maintained.

Conclusion

Based on the above evaluation, the existing EDG Fuel Oil Storage and Transfer System is adequate to support EDG operation to meet onsite power requirements for the proposed EPU.

2.5.8.2 Light Load Handling System

The Light Load Handling System is described in FSAR Section 9.1.4.

The Fuel Handling System is designed to store and handle new fuel, spent fuel, and control element assemblies (CEAs). All spent fuel transfer and storage operations are designed to be conducted underwater to ensure adequate shielding during refueling and to permit visual control of the operation at all times. The Fuel Handling System also provides for disassembly, handling and re-assembly of the reactor vessel closure head.

a) The design of the fuel handling equipment ensures that no failure will result in a release of radioactivity in excess of that assumed in the design basis FHA. Offsite releases from a design basis refueling FHA have been determined to be within the guideline values of 10CFR100.
b) Although Fuel Handling System components are not required to function following an SSE, critical components of the fuel handling system are designed to Seismic Category I requirements to preclude failure in a manner which results in unacceptable consequences such as fuel damage or damage to safety-related equipment.

Plant documents were reviewed for the impact of the EPU to confirm that no alterations were made to design or operations to cause system malfunctions or failures that could result in a criticality accident or a release of radioactivity or an increased exposure to plant personnel.

Evaluation

The EPU will not have any effect on the operation of the Fuel Handling System since the system will handle the same length, overall dimensions and weight assemblies as prior to the EPU. The analysis performed on the new fuel and spent fuel racks at 5.0% is the highest enrichment currently allowed by Technical Specification 5.3.1. Therefore, the current fuel storage requirements with the enriched fuel assemblies for power uprate will be bounded by the current criticality analysis.

Since the EPU does not require a higher enrichment for each fuel assembly, the radiological doses in the surrounding environment are not expected to increase while fuel handling operation is in progress. The offsite and control room doses due to a FHA in the FHB were evaluated. The inputs used in the evaluation are consistent with Waterford 3 EPU conditions. The results indicated that the radiological consequences are within the NRC acceptance criteria.

Conclusion

Review of the Light Load Handling System documentation determined that the EPU did not alter the fuel handling equipment/system. The fuel handling equipment and methods have not changed from pre-EPU operations. The criticality analysis based on 5.0% enriched fuel is bounding for the EPU fuel. Thus, Waterford 3 continues to meet GDCs 2, 61, and 62 requirements.

2.6 REACTOR SYSTEMS

2.6.1 Fuel System Design

The fuel cladding is designed to prevent fuel element damage under steady state and transient operating conditions. The fuel rod design accounts for external pressure, differential expansion of the fuel and clad, fuel swelling, clad creep, fission and other gas releases, internal helium pressure, thermal stress, pressure and temperature cycling, and flow-induced vibrations (FIVs).

The purpose of the fuel system design evaluations was to review the fuel rod design to determine the acceptability of operating Waterford 3 at the 3716-MWt extended power uprate (EPU) conditions.

The fuel system design evaluations for Waterford 3 3716-MWt EPU are based on the use of the same fuel assembly designs currently employed at Waterford 3. These assemblies, fabricated at both the Hematite and Columbia facilities, have the Guardian™ grid feature with either an HID-1L/Zr-4 top spacer grid or an Inconel top spacer grid.

The fuel rod mechanical design and performance is discussed in FSAR Section 4.2.1.

2.6.1.1 Description of Analyses, Acceptance Criteria, and Results

An evaluation was performed for the 3716-MWt power uprate conditions of the impact of the performance parameters in Table 2.6-1 on the ability to satisfy fuel rod design criteria for Waterford 3. The evaluation accounted for the impact of cladding oxidation during the stress and collapse evaluations.

The parameters used in the fuel rod design criteria evaluation for the 3716-MWt EPU condition are summarized in Table 2.6-1.

The following sections summarize the impact of the Waterford 3 3716-MWt EPU conditions on key fuel rod design criteria relative to their corresponding acceptance limits and assess the resulting impact on anticipated design margin. The key criteria considered include rod cladding collapse, clad fatigue, clad stress and strain, rod maximum internal pressure, clad corrosion, and plenum spring seizure. Other fuel rod design criteria are not significantly impacted by the proposed 3716 MWt EPU conditions.

2.6.1.2 Rod Cladding Collapse

Design Basis

The fuel rod will not collapse under operating compressive differential pressures for the specified residence time of the fuel.

Table 2.6-1
Waterford 3 3716-MWt EPU
Summary of Parameters Analyzed in Fuel Rod Design Evaluation

Parameter	Current Condition	Uprated Condition
Maximum Fuel Rod Axially Averaged Fluence (10^{21} n/cm^2, E > 0.821 MeV)	13.7	13.7
Nominal Core Inlet Temperature (°F)	545.0	543.0
Minimum Flow Rate (10^6 lbm/hr)	148.0	148.0
Nominal System Pressure (psia)	2250	2250
Peak Rod Axially-Averaged Burnup (MWD/MTU)	60,000*	60,000*
Maximum Residence Time (EFPH)	41,200	41,200
Fuel Designs Considered	Batches J through U	Batches P through Z
Peak Linear Heat Rate (kW/ft)	13.5	Rods ≤ 50 MWD/kgU 13.2 Rods > 50 MWD/kgU 12.9

* A higher analytical burnup value was conservatively used as input to calculations that support Sections 2.6.1.2 through 2.6.1.6. In all cases, the applicability of the analyses remains limited to the 60,000 MWD/MTU licensed burnup limit.

Acceptance Limit

The minimum collapse time for any fuel rod in the reactor will be greater than or equal to the target value of residence time specified in Table 2.6-1.

Design Evaluation

Margin to the fuel rod clad collapse limit is impacted by changes in the core power rating because higher power levels result in higher fuel operating temperatures and the resulting increase in oxide thickness levels. The NRC-approved collapse performance methodology and computer program CEPAN, References 2.6.1-1 and 2.6.1-2, were used to evaluate rod collapse as a function of residence time. The results of this Waterford 3 3716-MWt EPU evaluation confirmed that rod collapse limits can be satisfied for the assumed residence time under 3716-MWt EPU conditions.

2.6.1.3 Clad Fatigue

Design Basis

The fuel system will not be damaged due to excessive fatigue from normal operating and upset transient conditions.

Acceptance Limit

The fuel rod clad cumulative fatigue damage at end of life (EOL) must be less than 0.8 for normal operating and upset condition transients of startup/shutdown and plant variations due to normal power changes and reactor trips from 100% power.

Design Evaluation

Margin to the fuel rod clad and end cap weld fatigue limit is impacted by changes in the core power rating because higher power levels result in higher fuel operating temperatures and the resulting increase in cyclic strain levels. The fatigue analysis evaluated rod and end cap weld fatigue as a function of burnup. The results of this Waterford 3 3716-MWt EPU evaluation confirmed that rod fatigue limits can be satisfied for core designs having the end-of-cycle (EOC) burnup listed in Table 2.6-1.

2.6.1.4 Clad Stress

Design Basis

The fuel system will not be damaged due to excessive fuel clad stress.

Acceptance Limits

The maximum tensile stress in the clad and in the end cap welds will not exceed two-thirds of the minimum unirradiated yield strength of the material at the applicable temperature.

The maximum compressive stress in the clad and in the end cap welds will not exceed the minimum unirradiated yield strength of the material at the applicable temperature.

Design Evaluation

Approved models and methodology were used to evaluate clad stress limits. The local power duty during anticipated operational occurrences (AOOs) is a key factor in evaluating margin to clad stress limits. The results of this evaluation show that the core power uprate will not impact the fuel's capability to meet clad stress limits for the 3716-MWt uprated power conditions.

2.6.1.5 Clad Strain

Design Basis

The fuel system will not be damaged due to excessive fuel clad strain.

Acceptance Limit

Net unrecoverable circumferential strain in the fuel rod clad shall not exceed 1% as predicted by computations considering clad creep, pellet swelling, and pellet/clad differential thermal expansion under normal operating conditions.

The total circumferential strain in the fuel rod clad for rods having axially-averaged burnups greater than or equal to 52,000 MWD/MTU shall not exceed 1% under normal operating conditions.

Design Evaluation

Approved models and methodology were used to evaluate clad strain limits. The local power duty during AOO events is a key factor in evaluating margin to clad strain limits. The results of this evaluation show that the core power uprate will not impact the fuel's capability to meet clad strain limits for the 3716-MWt uprated power conditions.

2.6.1.6 Plenum Spring Seizure

Design Basis

The fuel system will not be damaged due to excessive deflection of the plenum spring.

Acceptance Limit

Deflection of the plenum spring at any point in the fuel lifetime must not cause it to seize within the cladding tube inside diameter.

Design Evaluation

Approved models and methodology were used to evaluate diametral clearance in the fuel rod over the design life. The results of this evaluation show that the plenum spring will not seize within the cladding tube for the 3716-MWt uprated power conditions.

2.6.1.7 Rod Maximum Internal Pressure

The thermal performance of erbia and UO_2 composite fuel rods for Waterford 3 3716-MWt power uprate cycles has been evaluated using the FATES3B version of the Westinghouse CENP fuel evaluation model (References 2.6.1-3, 2.6.1-4, 2.6.1-5, and 2.6.1-6). This analysis used a power history that enveloped the power and burnup levels representative of the peak fuel at each burnup interval, from beginning of cycle to end of cycle burnups.

The maximum predicted fuel rod internal pressure for the Waterford 3 3716 MWt EPU cycles is below the no-clad-liftoff pressure (Reference 2.6.1-7). These results support a peak linear heat rate of 13.2 kW/ft to a peak rod average burnup of 50 GWD/MTU, and 12.9 kW/ft at higher burnups.

2.6.1.8 Cladding Waterside Corrosion

In accordance with Reference 2.6.1-8, an evaluation of waterside corrosion of Westinghouse CENP fuel in Waterford 3 was completed under 3716 MWt EPU conditions. This analysis was performed with fuel management guidelines and limits, including a recommended oxide thickness corrosion guideline of 100 microns.

Maximum oxide thickness levels which will accumulate as a result of operation in the Waterford 3 plant at 3716 MWt are expected to be bounded by the waterside corrosion levels described for the highest burnup oxide data of References 2.6.1-8, 2.6.1-9, and 2.6.1-10. Therefore, the impact on thermal and mechanical performance will be acceptably described by these topical reports and related safety analyses for those aspects dependent on the maximum oxide thickness.

However, predicted maximum oxide thicknesses and fuel duty spalling indexes for some operating high duty fuel cycles at Westinghouse CENP plants and for certain postulated EPU core designs are close to recommended guidelines. Therefore, consideration of these guidelines will, as is currently performed, be factored into determining the final fuel management designs for the uprated Waterford 3 reload cores, beginning with Cycle 14. Note that fuel rod corrosion evaluations are already performed as part of the current core design process for Waterford 3 to ensure that upcoming cycles conform with fuel management guidelines and limits.

2.6.1.9 Conclusions

The fuel rod design criteria most impacted by a change in core power rating have been analyzed with respect to the available margin to support the Waterford 3 3716-MWt EPU.

Although some design criteria are impacted, as stated above, the uprated conditions listed in Table 2.6-1 are supported. These analyses support the conclusions that:

(1) The fuel system will not be damaged as a result of normal operation and anticipated operational occurrences.

(2) The fuel system damage will never be so severe as to prevent control rod insertion when it is required.

(3) The number of fuel rod failures will not be underestimated for postulated accidents.

(4) Coolability will always be maintained.

Finally, as in the past, cycle-specific fuel performance will continue to be evaluated for each fuel cycle to confirm that this assessment, and all fuel rod design criteria, are satisfied for the operating conditions specified for each cycle of operation. These evaluations support the reload safety evaluation that is performed for each cycle of operation.

2.6.1.10 Fuel System Design References

2.6.1-1 CENPD-187-P-A, *CEPAN, Method of Analyzing Creep Collapse of Oval Cladding*, March 1976.

2.6.1-2 EPRI NP-3966-CCM, *CEPAN Method of Analyzing Creep Collapse of Oval Cladding*, Volume 5, April 1985.

2.6.1-3 CEN-161(B)-P, Supplement 1-P-A, *Improvements to Fuel Evaluation Model*, Combustion Engineering, Inc., January 1992.

2.6.1-4 CENPD-139-P-A, *CE Fuel Evaluation Model Topical Report*, Combustion Engineering, Inc., July 1974.

2.6.1-5 CEN-161(B)-P-A, *Improvements to Fuel Evaluation Model*, August 1989.

2.6.1-6 CENPD-382-P-A, *Methodology for Core Designs Containing Erbium Burnable Absorbers*, ABB Combustion Engineering Nuclear Fuel, August 1993.

2.6.1-7 CEN-372-P-A, *Fuel Rod Maximum Allowable Gas Pressure*, ABB Combustion Engineering Nuclear Power, May 1990.

2.6.1-8 CEN-386-P-A, *Verification of the Acceptability of a 1-Pin Burnup Limit of 60 MWD/kgU for Combustion Engineering 16x16 PWR Fuel*, ABB Combustion Engineering, Inc., August 1992.

2.6.1-9 CENPD-384-P, *Report on the Continued Applicability of 60 MWD/kgU for ABB Combustion Engineering PWR Fuel*, ABB Combustion Engineering, Inc., September 1995.

2.6.1-10 CENPD-388-P, *Extension of the 1-Pin Burnup Limit to 65 MWd/kgU for ABB PWR Fuel with OPTIN Cladding*, CEOG Combustion Engineering Owners Group, February 1998.

2.6.2 Nuclear Design

Nuclear design analyses were performed to determine the impact on key safety parameters of Waterford 3 Power Uprate operation at 3716 MWt. These parameters include core power distribution, reactivity coefficients, reactivity control requirements and control provisions, control rod patterns and reactivity worths, criticality, burnup, and vessel irradiation.

The nuclear design analyses for Waterford 3 3716-MWt EPU are based on the use of the same fuel assembly designs currently employed at Waterford 3. These assemblies, fabricated at both the Hematite and Columbia facilities, have the Guardian™ grid feature with either an HID-1L/Zr-4 top spacer grid or an Inconel top spacer grid.

Key safety parameters are used as input to the Safety Analysis Report (SAR) Chapter 15 accident analyses.

2.6.2.1 Description of Analyses and Evaluations

The nuclear design analyses employed a core power level of 3716 MWt. The core designs considered for EPU utilized typical values for the mechanical and thermal hydraulics data. The values of these parameters and others (enrichment, moderator temperature coefficient [MTC], maximum burnup, etc.) were within the current licensed limits.

Finally, as in the past, the cycle-specific reload process utilizing approved methodologies will determine the final parameter values so as to confirm whether this assessment is satisfied for the operating conditions specified for each cycle of operation.

Fuel management patterns representative of Waterford 3 3716-MWt EPU operation were constructed based on typical fuel loadings. The safety parameters were then evaluated such that the expected future range of potential fuel managements would be accommodated.

The methods and models have been used for other Waterford 3 reload designs. No changes to the nuclear design philosophy, methods, or models are necessary due to the 3716-MWt EPU.

The philosophy for the generation of physics data is to provide parameter values to the safety analyses that bound those actually expected within a given cycle. This includes items such as power distributions, fuel rod power histories, power peaking factors, reactivity coefficients, control rod worths, shutdown boron concentrations, neutron kinetics parameters, and neutron detector response.

All physics data for the Waterford 3 3716-MWt EPU have been evaluated and verified to be acceptable for a range of fuel managements. The parameter values used in the safety analyses bound the values expected in future core designs.

2.6.2.2 Conclusions

In summary, the key physics parameters for the Waterford 3 3716-MWt EPU have been analyzed for a range of fuel managements. These nuclear design analyses, along with the discussions of Sections 2.6.1, 2.6.3, and 2.13 support the conclusion that the fuel design limits will not be exceeded during normal or anticipated operational transients, and that the effects of postulated reactivity accidents will not cause significant damage to the reactor coolant pressure boundary or impair the capability to cool the core.

2.6.3 Thermal and Hydraulic Design

The primary objective of the thermal and hydraulic design of the reactor is the assurance that the core can meet normal steady state and transient performance requirements (i.e., without exceeding the design bases). For the Waterford 3 3716-MWt EPU, the thermal margins for the uprate cycle core designs were evaluated to ensure that the design bases have been met.

The thermal and hydraulic design analyses for Waterford 3 3716-MWt EPU are based on the use of the same fuel assembly designs currently employed at Waterford 3. These assemblies, fabricated at both the Hematite and Columbia facilities, have the Guardian™ Grid feature with either an HID-1L/Zr-4 top spacer grid or an Inconel top spacer grid.

Table 2.6-2 presents a comparison of the reference Cycle (Cycle 2), Cycle 12, and the 3716-MWt EPU cycle parameters of interest for thermal-hydraulic design.

FSAR Section 4.4 discusses the reactor thermal and hydraulic design. No changes to the FSAR methodology were made in the evaluation of the thermal-hydraulic design under 3716 MWt EPU conditions.

2.6.3.1 Description of Analyses and Evaluations

2.6.3.1.1 Thermal Margin Analysis

Avoidance of thermally induced fuel damage during normal steady-state operation and during AOOs is the principal thermal-hydraulic design basis.

Steady state departure from nucleate boiling ratio (DNBR) analyses for Waterford 3 at the rated power level of 3716 MWt have been performed using the TORC computer code described in Reference 2.6.3-1, the CE-1 critical heat flux (CHF) correlation described in References 2.6.3-2 and 2.6.3-3, the simplified TORC modeling methods described in Reference 2.6.3-4, and the CETOP code described in Reference 2.6.3-5. The screening methodology for determining the limiting fuel assembly(ies) for this analysis is outlined in Reference 2.6.3-6.

Table 2.6-2 presents a comparison of the pertinent thermal hydraulic design parameters for the 3716-MWt EPU cycle, the reference Cycle (Cycle 2), and Cycle 12.

Table 2.6-2
Waterford 3 EPU
Thermal-Hydraulic Parameters at Full Power

Parameter	Units	Reference Cycle 2	Cycle 12	EPU
Total Heat Output (Core Only)	MWt 10^6 Btu/hr	3390 11570	3441 11740	3716 12680
Fraction of Heat Generated in the Fuel Rod	none	0.975	0.975	0.975
Primary System Pressure (Nominal)	psia	2250	2250	2250
Inlet Temperature (Nominal)	°F	553.0	545.0	543.0
Total Reactor Coolant Flow (Minimum Steady State)	10^6 lbm/hr	148.0	148.0	148.0
Minimum Coolant Flow through Core	10^6 lbm/hr	144.2	144.2	144.2
Hydraulic Diameter (Nominal Channel)	feet	0.039	0.039	0.039
Average Mass Flux	10^6 lbm/hr-ft^2	2.64	2.63	2.63
Pressure Drop across Core(1)	psi	15.4	17.1	17.3
Total Pressure Drop across Vessel(2)	psi	41.5	42.7	43.2
Core Average Heat Flux(3)	Btu/hr-ft^2	182,700(4)	179,172(9)	193,870(5)
Total Heat Transfer Area(6)	ft^2	61,700(4)	63,892(9)	63,767(5)

Table 2.6-2 (cont.)
Waterford 3 EPU
Thermal-Hydraulic Parameters at Full Power

Parameter	Units	Reference Cycle 2	Cycle 12	EPU
Film Coefficient (Nominal Conditions)	Btu/hr-ft^2-°F	6200	6300	6300
Average Film Temperature Difference	°F	29.3(4)	28.6(9)	30.8(5)
Average Linear Heat Rate of Undensified Fuel Rod(7)	kW/ft	5.34(4)	5.24(9)	5.67(5)
Average Core Enthalpy Rise	Btu/lbm	80.3	81.5	88.0
Maximum Clad Surface Temperature	°F	656.7	659.7	656.8
Engineering Heat Flux Factor(8)	none	1.03	1.03	1.03
Engineering Factor on Hot Channel Heat Input (8)	none	1.03	1.03	1.03
Rod Pitch, Bowing, and Clad Diameter Factor(8)	none	1.05	1.05	1.05
Fuel Densification Factor (Axial)	none	1.002	1.002	1.002

Notes for Table 2.6-2:
(1) Minimum steady state flow irreversible dP over entire fuel assembly.
(2) Based on nominal dimensions and minimum steady state flow.
(3) Accounts for fraction of heat generated in the fuel rod and axial densification factor.
(4) Based on 1728 B_4C rods.
(5) Conservatively based on the use of up to 100 non-fuel rods.
(6) Accounts for axial fuel densification factor.
(7) Accounts for fraction of heat generated in fuel rod.
(8) These factors have been statistically combined with other uncertainty factors at 95/95 probability/confidence levels to define a new design limit on the CE-1 minimum DNBR when iterating on power as discussed in Reference 2.6.3-7.
(9) Cycle 12 core does not contain non-fuel rods.

The Modified Statistical Combination of Uncertainties (MSCU) methodology presented in Reference 2.6.3-7 was applied with Waterford 3-specific data using the parameters presented in Table 2.6-2 and other uncertainty factors at 95/95 probability/confidence levels to validate the design limit on minimum DNBR.

Effects of fuel rod bowing on DNBR margin have been incorporated in the safety and setpoint analyses in the manner discussed in Reference 2.6.3-6. A penalty of 2.2% on minimum DNBR is valid for bundle burnups up to 33,000 MWD/MTU. For assemblies with burnup greater than 33,000 MWD/MTU, sufficient margin exists to offset rod bow penalties due to the lower radial peaks in these higher burnup fuel batches. Hence, the rod bow penalty based upon Reference 2.6.3-6 for 33,000 MWD/MTU is applicable for all assembly burnups expected for the 3716 MWt EPU.

2.6.3.1.2 Coolant Flow Rate and Distribution

The lower limit on the total reactor coolant flow (minimum steady-state, given in Table 2.6-2) is utilized for all thermal margin analyses to assure that the core is adequately cooled. Uncertainties in system resistance, pump head, and core bypass flow are assumed to be in the adverse direction.

2.6.3.1.3 CEA and ICI Cooling

Cooling of control element assemblies (CEAs) and in-core instruments (ICIs) in the core region has been evaluated at the Waterford 3 EPU to 3716 MWt. It is concluded that the available flow in CEA guide tubes is greater than the required flow to preclude bulk boiling in guide tube coolant during CEA insertions. Maximum temperatures for B_4C and AgInCd remain below the design limits. Flow in ICI guide tubes provides adequate cooling to ICIs, and is sufficient to preclude bulk boiling in guide tube coolant.

2.6.3.1.4 Fuel Rod and Assembly Uplift Force

Thermal-hydraulic effects on fuel rod and assembly uplift forces have been analyzed for Waterford 3 at the conditions associated with the EPU to 3716 MWt and were shown to meet the relevant design criteria.

2.6.3.2 Conclusions

The thermal and hydraulic design of the Waterford 3 reactor was analyzed under 3716-MWt EPU conditions. These analyses, performed using accepted analytical methods, have verified that the EPU core can meet normal steady state and transient performance requirements without exceeding the design bases and support the conclusions that the thermal and hydraulic design:

(a) Is a justified extrapolation from proven designs.

(b) Provides acceptable margins of safety from conditions that would lead to fuel damage during normal reactor operation and anticipated operational occurrences.

(c) Is not susceptible to thermal-hydraulic instability.

(d) Meets GDC 10 requirements.

2.6.3.3 Thermal and Hydraulic Design References

2.6.3-1 CENPD-161-P-A, TORC Code, *A Computer Code for Determining the Thermal Margin of a Reactor Core*, April 1986.

2.6.3-2 CENPD-162-P-A, *Critical Heat Flux Correlation for CE Fuel Assemblies with Standard Spacer Grids, Part 1, Uniform Axial Power Distribution*, September 1976.

2.6.3-3 CENPD-207-P-A, *Critical Heat Flux Correlation for CE Fuel Assemblies with Standard Spacer Grids, Part 2, Non-uniform Axial Power Distribution*, December 1984.

2.6.3-4 CENPD-206-P-A, *TORC Code, Verification and Simplified Modeling Methods*, June 1981.

2.6.3-5 CEN-160(S)-P, Rev. 1-P, *CETOP Code Structure and Modeling Methods for San Onofre Nuclear Generating Station Units 2 and 3*, September 1981.

2.6.3-6 CENPD-225-P-A, *Fuel and Poison Rod Bowing*, June 1983.

2.6.3-7 CEN-356(V)-P-A, Rev. 01-P-A, *Modified Statistical Combination of Uncertainties*, May 1988.

2.6.4 <u>Emergency Systems</u>

2.6.4.1 Functional Design of the Control Element Drive System

CEA motion control is discussed in FSAR Section 7.7.1.1. The Control Element Drive Mechanism Control System (CEDMCS) receives automatic direction and speed signals from the Reactor Regulating System (RRS) or manual motion signals from the CEDMCS control panel. The CEDMCS converts the motion demand signals into pulses that are transmitted to the control element drive mechanism (CEDM) coils to cause CEA motion.

The CEDMs are cooled by a forced air cooling system called the Control Element Drive Mechanism Cooling System. The system consists of four exhaust fans and associated ductwork, dampers and coolers. The exhaust fans draw air into the shrouded area enclosing the reactor head and CEDMs. The cool air flows across each of the drive mechanisms, thereby limiting their temperature. The heated air is then drawn into a collection plenum and across water-cooled heat exchangers. The heat exchangers transfer the heat from the air to the Component Cooling Water System (CCWS). The cooled air is returned to the containment atmosphere via the exhaust fans. CEDM cooling is discussed in FSAR Section 9.4.5.

Evaluation

The Reactor Protection System (RPS) initiates reactor trip to mitigate the consequences of anticipated operational occurrences and accidents. The RRS and CEDMCS are not relied upon for these functions, or for any aspect of achieving safe shutdown. CEA related events caused by postulated control system failures are evaluated in Section 2.13.4, and are shown to meet acceptance criteria under EPU conditions.

The Control Element Drive Mechanism Cooling System design incorporates four air-to-water coolers and two redundant trains of exhaust fans. During normal plant operation, two fans draw air into the shrouded area from the containment atmosphere. Isolation dampers, located in each of the fan inlet lines, isolate the standby fans from the collection plenum. The temperature of the containment atmosphere (i.e., the air entering the shroud) is limited to a maximum of 120°F by Technical Specification.

The air flow through the shrouded area has been modeled in several calculations. The calculations verify the air flow across each drive mechanism is within the established limits and the drive mechanisms are maintained at a temperature less than 350°F. The calculations also verify that the cooling fans are capable of providing the necessary air flow rate and static pressure. The calculated air flow and static pressure losses are based on a recently developed plant modification that redesigned the shroud and air flow inlets.

The amount of heat added to the cool air as it passes through the shrouded area and across the drive mechanisms has been calculated. The computed heat load is bounded by the design heat load established for the coolers. Trending data recorded after installation of the new shroud design indicates that the environmental conditions inside the shrouded area are less than 142°F.

The EPU will not increase the temperature of the reactor vessel or the heat generated in the shrouded area. Air flow and static pressure losses will remain unchanged because the shroud design is not being modified for power uprate. Heat loads transferred to the CCWS will be bounded by current design parameters. In addition, containment air temperature will remain unchanged for power uprate. Since these parameters remain constant, CEDM cooling will not be affected by power uprate conditions.

Conclusions

The EPU will have no adverse effect on the design or operation of the RRS or CEDMCS. These systems perform no safety-related functions. Analyses demonstrate that the results of CEA-related events caused by postulated failures in these systems are acceptable under EPU conditions. Evaluations demonstrate that EPU conditions do not affect fan flow rates, static air pressures, heat loads, and air flow patterns in the shrouded area surrounding the CEDMs, so CEDMCS design requirements will continue to be met following implementation of the proposed EPU.

Consequently, the CEDMCS, RRS and CEDM Cooling System will continue to meet the requirements of GDCs 4, 23, 25, 26, 27, and 29 following implementation of the proposed EPU.

2.6.4.2 Overpressure Protection During Power Operation

FSAR Section 5.2.2, and Appendix 5.2A present the report on overpressure protection as required by the ASME Code, Section III.

Evaluation

The specific overpressure protection requirements of the ASME Code were evaluated for EPU. All general requirements and component requirements for the pressurizer safety valves and the main steam safety valves were found to be in compliance with the Code.

Conclusion

Analysis of bounding reactor and steam plant anticipated operational occurrences causing pressure excursions has been conducted. These transients were evaluated to ensure both peak primary and secondary pressure did not exceed 110% of design pressure per ASME Code requirements. Based on this, it is concluded that the overpressure protection features will continue to provide adequate protection to meet GDC 15 and GDC 31 following implementation of the proposed EPU.

2.6.4.3 Overpressure Protection During Low Temperature Operation

Low-temperature overpressure protection (LTOP) is described in FSAR Appendix 5.2B. LTOP is a combination of measures that ensure that brittle fracture limits of the reactor vessel will not be exceeded during startup and shutdown operations in the case of a pressure transient. LTOP conditions exist when the RCS T_{cold} is less than the LTOP enable temperature and the RCS is capable of being pressurized.

Relief valves located in the Shutdown Cooling System (SDCS) suction lines provide overpressure protection of the Reactor Coolant System (RCS) during low temperature conditions. This protection precludes any pressurization transient from exceeding the pressure-temperature (P-T) operating limits provided in the Technical Specifications. The most limiting transients were determined by conservative analyses to be mass and energy additions into a water-solid RCS as a function of time. The transients are:

a) An inadvertent safety injection actuation (mass input).
b) An RCP start when a positive steam generator (SG) to reactor vessel ΔT exists (energy input).

Evaluation

The analysis of the LTOP was revised as part of the effort for EPU to 3716 MWt. The update accounted for changes resulting from the EPU to 3716 MWt. The ASME Appendix G P-T limits applicable for the EPU to 3716 MWt were also evaluated.

The resulting peak pressures in the limiting transients determine which P-T limits (i.e., for which heatup or cooldown rates) are protected by the LTOP System over specific RCS temperature ranges. Based on the results of the mass addition and energy addition analyses, and the limits

of pressure and temperature for the EPU to 3716 MWt, the RCS is protected during LTOP as the result of the analyzed transients.

Conclusion

The analyses of the effects of the proposed EPU on the overpressure protection capability of the plant during low temperature operation have been reviewed. The effects of the proposed EPU on pressurization events and overpressure protection features have been adequately evaluated and it has been demonstrated that the plant will continue to have sufficient pressure relief capacity to ensure that pressure limits are not exceeded. Based on this, it is concluded that the low temperature overpressure protection features will continue to provide adequate protection to meet GDC 15 and GDC 31 following implementation of the proposed EPU.

2.6.4.4 Shutdown Cooling System

The SDCS is described in FSAR Section 9.3.6. The SDCS consists of two heat exchangers, two pumps, and associated valves and piping. The system components are shared with the Safety Injection System (SIS) and Containment Spray System (CSS).

The SDCS is used in conjunction with the Main Steam Supply System (MSSS) and Main Feedwater System (FWS) to reduce the temperature of the RCS in post-shutdown periods from normal operating temperature to the refueling temperature. The initial phase of the cooldown is accomplished by heat rejection from the steam generators to the condenser or atmosphere. After the reactor coolant temperature and pressure have been reduced to approximately 350°F and 377 psig, the SDCS is put into operation to reduce the reactor coolant temperature to the refueling temperature and to maintain this temperature during refueling.

Evaluation

The ability of the SDCS to achieve cold shutdown has been verified. System performance was evaluated to support the performance as described in the FSAR, and the system's capability to achieve cold shutdown conditions for Reactor Systems Branch Technical Position RSB BTP 5-1, Natural Circulation Cooldown. Also, performance with regard to support of Technical Specifications limitations for time based reduced system flow was confirmed. These evaluations for the EPU condition demonstrate acceptable capability to achieve each of the performance conditions without modification.

The SDCS remains adequate to maintain refueling temperatures and a uniform boron concentration in the RCS. The SDCS functions have been reviewed and are either not impacted by the EPU, or are acceptable based upon specific analysis or by qualitative evaluation. No system modifications are required to accommodate the EPU. The results of the performance evaluation as described in the FSAR conclude that while the cooldown capability is achieved, the duration of each condition evaluated may be extended, depending on actual operating conditions. The system's capability to achieve cold shutdown conditions for RSB BTP 5-1 natural circulation cooldown, when combined with the atmospheric dump valve (ADV) and Emergency Feedwater System (EFS), conclude that cooldown to cold shutdown conditions is achieved within 36 hours of shutdown. With regard to the Technical Specifications limitations, the current limiting conditions for operation (LCO) limitations for time based reduced flow rate are acceptable at EPU condition.

Conclusions

It is concluded that the SDCS will continue to meet the requirements of GDCs 4, 19, and 34 following implementation of the proposed EPU. Therefore, the proposed EPU is acceptable with respect to the SDCS.

2.6.5 Accident and Transient Analyses

In this report, LOCA analyses are presented in Section 2.12, and non-LOCA transient analyses are presented in Section 2.13. Using separate sections facilitates organizing and presenting the analyses in a manner consistent with their presentation in the FSAR, particularly the non-LOCA analyses addressed in FSAR Chapter 15.

2.6.6 Fuel Storage

2.6.6.1 New Fuel Storage

The fuel assembly designs that will be employed for the EPU cycles are of the same designs as those currently employed at Waterford 3. These assemblies, fabricated at both the Hematite and Columbia facilities, have the Guardian™ grid feature with either an HID-1L/Zr-4 top spacer grid or an Inconel top spacer grid.

The current Waterford 3 limits on uranium loading, burnable poison concentration, and other characteristics related to new fuel storage criticality are unchanged for EPU. Therefore, it is concluded that the 3716 MWt EPU will have no impact on the ability of the new fuel storage facility to maintain new fuel in a subcritical array during all credible storage conditions at Waterford 3.

2.6.6.2 Spent Fuel Storage

The fuel assembly designs that will be employed for the EPU cycles are of the same designs as those currently employed at Waterford 3. These assemblies, fabricated at both the Hematite and Columbia facilities, have the Guardian™ GRID feature with either an HID-1L/Zr-4 top spacer grid or an Inconel top spacer grid.

While cycle-specific data relevant to criticality analyses may change slightly with the EPU to 3716 MWt, these parameters will still be bounded by the current limits on uranium loading, burnable poison concentration, and other characteristics related to spent fuel storage criticality, which themselves are not being changed for EPU. Therefore, it is concluded that the 3716 MWt EPU will have no impact on the ability of the Waterford 3 spent fuel pool (SFP) design to ensure an acceptable degree of subcriticality.

The effects of the Waterford 3 3716 MWt EPU on spent fuel storage temperatures are addressed in Section 2.5.5.1 of this document.

2.6.7 Reactor Coolant System

The RCS is described in FSAR Section 5.1. The RCS is a two-loop PWR with U-tube SGs and four RCPs.

The key functions of the RCS are as follows:

a) Act in conjunction with other systems to provide sufficient cooling of the core during all normal plant evolutions and anticipated operational occurrences to preclude significant core damage.
b) Transfer heat generated in the core to the MSSS via the SGs.
c) Transfer heat via the SDCS during shutdown conditions.
d) Provide a barrier against fission product release to the environment, including during low-temperature conditions.
e) Enhance the fission process by functioning as a neutron moderator.
f) Serve as a medium for boric acid, which functions as a neutron poison for reactivity control.
g) Allow for natural circulation flow following a loss of RCP flow, including adequate RCP coastdown characteristics.
h) Maintain subcooled conditions by controlling pressurizer pressure via heaters and spray flow.

Evaluation

RCS operating pressure will remain the same as in previous cycles. RCS flow rate will be the same as current Technical Specifications limits for minimum flow. Based upon plant RCS flow measurements, a nominal RCS flowrate of 110% is assumed.

The EPU will result in higher neutron flux and different RCS temperatures. The limiting component for the effects of higher flux is the reactor vessel. Section 2.1.2 of this report addresses the effects of neutron fluence on the vessel pressure-temperature limits.

The loop coolant temperatures associated with the EPU remain within the bounds of the original design temperatures for the RCS and the pressurizer. For the EPU power of 3716 MWt, the nominal T_{hot} of 601°F is within design temperature and less that the operating temperature identified in the FSAR.

Sufficient core cooling under EPU conditions is verified by various plant transient and safety analyses discussed in other sections of this report, as is the general acceptability of EPU changes for the RCS. The acceptability of the EPU changes for normal operating transients is verified by the review of the Nuclear Steam Supply System (NSSS) control systems described in Section 2.4 of this report.

The natural circulation capacity of the RCS is acceptable for EPU conditions. The ability to perform a natural circulation cooldown without drawing a steam bubble in the reactor vessel head has been evaluated for EPU conditions. The analysis demonstrated that such a cooldown can be accomplished within the criteria established by RSB BTP 5-1. The EFS provides the heat sink during natural circulation conditions, followed by the SDCS to cold shutdown

conditions. The effect of the EPU on EFS is discussed in Section 2.5.5.5 of this report. The SDCS is discussed in Section 2.6.4.4 of this report.

The most limiting transients for LTOP that are described in Appendix 5.2B of the FSAR were re-analyzed. Results of the re-analysis indicated that existing LTOP relief valves provide sufficient pressure relief capacity to mitigate the most limiting LTOP events identified. Section 2.6.4.3 summarizes the results of the evaluation of LTOP.

The other key functions of the RCS are not affected by the EPU. No system modifications were required to accommodate the EPU.

The quench tank, described in FSAR Section 5.4.11, is designed to receive and condense the discharges from the pressurizer safety valves during anticipated operational occurrences and prevent the discharge from being released to the containment. The sizing of the quench tank and its operational limits were verified to be acceptable for EPU conditions as described in Section 2.5.2.7 of this report.

Conclusion

Based on the preceding description, and supporting content elsewhere in this report, it is concluded that the RCS will continue to meet the design requirements as described in the FSAR and those of GDCs 2, 4, 14, 15, 30, 31 and 32 following implementation of the proposed EPU. Therefore, the proposed EPU is acceptable with respect to the RCS.

2.6.8 Emergency Core Cooling System

The Emergency Core Cooling System (ECCS), or Safety Injection System (SIS), is described in FSAR Section 6.3, “Emergency Core Cooling System.”

The SIS consists of two active subsystems and one passive subsystem:

a) The high-pressure safety injection (HPSI) system (active)
b) The low-pressure safety injection (LPSI) system (active)
c) The safety injection tanks (SITs) (passive)

The components of the high-pressure and low-pressure subsystems are arranged in two separate and redundant trains, each of which is capable of performing 100% of the required system design functions. There are three HPSI pumps, two LPSI pumps, and four SITs and associated valves and piping. One HPSI pump is capable of being aligned to either train. One SIT is connected to each RCS cold leg. In the event of a LBLOCA, the SITs function to reflood the core following blowdown and to provide cooling until the active subsystems begin to inject cooling water.

The system is designed to provide core cooling in the unlikely event of a LOCA. In addition, the SIS functions to inject borated water into the RCS to add negative reactivity to the core in the unlikely event of a steam line rupture. Safety injection is also initiated in the event of a steam generator tube rupture (SGTR) or a CEA-ejection incident. The system is actuated

automatically. The accidents and transients for which the required protection includes the ECCS are discussed in FSAR Chapter 15.

The ECCS is designed to take suction from the refueling water storage pool (RWSP) during the injection mode of operation following a design basis accident (DBA). ECCS pump suction is automatically realigned to take suction from the safety injection sump when the inventory in the RWSP is depleted. The suction switchover occurs when the tank water level drops to approximately 10% of the indicated span and a recirculation actuation signal (RAS) is generated. The RAS signal secures the LPSI pumps and opens the SIS sump isolation valves. As outlined in FSAR Section 6.3.2.9, operator action completes the line-up for recirculation.

Evaluation

The system performance requirements are not changing from the current cycle to the EPU condition, except for a decrease in the maximum liquid volume requirements of the SIT and a decrease in the ECCS pump response times. No system modifications are required for EPU.

The adequacy of the SIS is verified by the various safety analyses performed in support of the EPU. In support of the LOCA analyses, the SIT maximum liquid level requirement is being revised. While this change provides improved tank performance for LOCA, the change has no effect on the tanks' design. Excess conservatism in assumed ECCS pump response times are also removed. The ability of the system to perform its design function during sump recirculation has been verified for EPU conditions. A more detailed discussion of the ECCS performance analyses is presented in Section 2.12 of this report.

The RWSP volume requirements for the EPU have been evaluated and minimum volume requirements continue to be acceptable for EPU.

Conlusion

Based on the preceding description, and supporting content elsewhere in this report, it is concluded that the SIS will continue to meet the requirements of the GDCs 2, 4, 17, 27, 35, 36, and 37 following implementation of the proposed EPU. Therefore, the proposed EPU is acceptable with respect to the SIS.

2.6.9 NSSS Design Transients

This section describes the NSSS fluid transients that are used for the structural design of the SG, reactor vessel, RCS main coolant piping and nozzles, pressurizer, and RCPs. This set of NSSS transients is comprised of the NSSS response to plant heatup, plant cooldown, plant loading, reactor trips, and other evolutions.

2.6.9.1 Introduction

The design transients are classified into four categories based on how often the transient is expected to occur: normal condition, upset condition, emergency condition, and faulted condition. The basis for these transients and the number of occurrences assumed was

intended to provide a system/component design which will not be limited by expected cyclic operation over the life of the plant.

The specified design transients represent conservative estimates for design purposes and do not purport to be accurate representations of actual transients, nor do they necessarily reflect actual operating conditions. The entire set of design transients is input into the structural integrity analysis and the SG component analysis.

The primary reason for evaluating these transients is to account for any impacts of the Waterford 3 EPU. This power uprate will result in some changes to the normal operating conditions such as T_{cold}. Such changes may impact the stress and fatigue levels in the RCS components. The stress and fatigue evaluations are based on design specifications that define the pressure and temperature limits of expected transients and the number of times the plant may experience a specific transient (cycles). This report evaluates the effect the uprate and changes to the normal operating conditions may have on the pressure and temperature limits of expected transients. The number of cycles assumed for each transient is consistent with original design assumptions.

2.6.9.2 Regulatory Basis

The methodology for defining the NSSS design transients ensures that they bound both normal and abnormal (AOOs) plant operations. The number of occurrences of any given transient selected for design purposes exceeds the expected number over the life of the plant. The intent is to ensure that no reactor coolant system component is stressed above the allowable limit as described in the ASME Code - Section III. The transients are classified into four categories (normal, upset, emergency, and faulted) which are consistent with the ASME Code classification. Again, the design transients are conservative estimates for design purposes and are not necessarily a representation of actual transients or reflective of actual operating conditions. However, in developing the design transients, actual operating conditions, expected operating transients and selected non-LOCA transients are used as a basis.

The NSSS transients are defined in accordance with the ASME Code requirements for Class 1 components in that each condition to which a component may be subjected shall be described in the design specification. The set of NSSS transients defined herein form the basis of the design specifications.

10CFR50.55a, Codes & Standards, requires that systems and components meet the requirements of the ASME B&PV Code. Since the design transients are input into the ASME B&PV Code Stress Analysis, this section describes some of the steps needed to meet 10CFR50.55a.

2.6.9.3 Methodology Used for Evaluation

This section defines a set of thermal-hydraulic conditions and thermal-hydraulic transients which can affect the stress level of components. The range of pressures and temperatures to which a component is subjected during a particular transient and the number of cycles for this same transient influence the stress levels for a component. The NSSS transients were based on conservative estimates of the NSSS response to normal plant operations and upset events.

These conservative estimates were provided as input to the structural integrity analyses of Section 2.2 of this report.

The bulk of the thermal design transients fall within the two categories of normal conditions and upset conditions. Level A (normal conditions) and Level B (upset conditions) transients were based upon expected normal plant operating conditions. Consistent with normal plant operating conditions, non-safety grade plant control systems have been assumed operational. This is consistent with the ASME B&PV Code description of Level A and B categories.

Level C (emergency) and Level D (faulted) transients are rare occurrences. These events are not considered in structural fatigue analysis but are considered in primary stress calculations.

The frequency of occurrence for design basis events is intended for design purposes only. The frequency of occurrence used in the design transient analyses is expected to exceed the actual number of occurrences over the life of the plant.

Conservatism in the thermal-hydraulic responses was provided in several ways. The number of occurrences selected exceeds the expected number. Conservative methods of predicting the range of pressure and temperature for the transients were used. A composite transient was defined with the most severe portion of the transient derived from a group of transients.

The normal maneuvering transients were simulated using the CENTS code with Waterford 3 plant specific data.

2.6.9.4 Results of Evaluation

For the following equipment, the expected normal operating point data (Table 1-2 of this report) was used to determine the initial conditions for the transients:

a) Reactor vessel (RV)
b) RCPs
c) Pressurizer
d) Reactor coolant piping and fittings
e) SG primary side
f) SG secondary side

A. <u>Thermal Design Transients for Normal Conditions</u>

Table 2.6-3 provides the number of occurrences assumed for the different transients that are qualified as normal condition transients. Evaluation of the current pressure and temperature criteria is as follows:

a) Plant heatup and plant cooldown transients are not affected by the power uprate. The existing pressure and temperature limitations remain applicable for the Waterford 3 uprate to 3716 MWt.
b) Plant loading and unloading conditions apply between 15% to 100% power. The plant loading and unloading remains at a rate of 5% full power per minute. The existing RCS

temperature changes remain bounded by the current design temperature assumptions. The existing pressure and temperature limitations, which are related to the coolant density changes, remain applicable for the Waterford 3 uprate to 3716 MWt.

c) The current pressure and temperature criteria for a 10% step change provide significant margin and remain applicable for the Waterford 3 uprate to 3716 MWt.

d) The current pressure and temperature criteria for normal plant variation provide significant margin and remain applicable for the Waterford 3 uprate to 3716 MWt.

e) A RCP start-up (or shutdown) transient is not affected by the power uprate. The existing pressure and temperature limitations remain applicable for the Waterford 3 uprate to 3716 MWt.

f) Adding cold feedwater while in hot standby is not affected by the power uprate. The existing pressure and temperature limitations remain applicable for the Waterford 3 uprate to 3716 MWt.

B. Thermal Design Transients for Upset Conditions

Table 2.6-4 provides the number of occurrences expected for the different transients that are categorized as upset condition transients. Bounding composite pressure and temperature plots were developed for the reactor trip, loss of reactor coolant flow, and loss of load upset condition because these transients exhibit similar characteristics. These three transients were rerun for the Waterford 3 plant based on the uprate initial conditions. Evaluation of the current pressure and temperature criteria is as follows:

a) The cold leg will experience a temperature increase of nearly 16°F during a loss-of-load event. The composite design criterion allows for a 10°F increase. This difference was considered in the fatigue evaluation in Section 2.2 of this document.

b) The pressurizer surge line will experience a temperature change of 114°F following a reactor trip event, plant loading events and plant unloading events. This represents a 4°F difference from the current temperature change of 110°F. This difference was related to the revised no-load temperature and considered in the fatigue evaluation in Section 2.2 of this document.

Assumptions used to establish the criteria for Operating Basis Earthquake (OBE) are not affected by the EPU. The existing OBE remains applicable for the EPU.

C. Thermal Design Transients for Emergency Conditions

Table 2.6-5 provides the number of occurrences expected for the different transients defined as emergency condition transients. The no-load and full-load loss-of-secondary pressure control transients were rerun for the Waterford 3 plant based on the uprate initial conditions. The no-load loss-of-secondary pressure transient remains the limiting case. Evaluation of the pressure and temperature plots indicated an increase in the expected cooldown criteria should be applied as follows:

a) The hot leg could experience a cooldown of as much as 210°F.

b) The pressurizer side of the surge line could experience a cooldown of as much as 305°F.

c) The hot leg side of the surge line could experience a cooldown of as much as 322°F.

The loss-of-secondary pressure event is only rated for 5 cycles and will not affect current fatigue calculations.

The design assumptions used to address Loss of Feedwater Flow remain applicable for the EPU.

D. Thermal Design Transients for Faulted Conditions

Table 2.6-6 provides the number of occurrences assumed for the different transients defined as faulted condition transients. Assumptions used to establish the criteria for faulted conditions are not affected by the power uprate. The existing faulted condtion criteria remain applicable for the Waterford 3 EPU.

E. Testing

Table 2.6-7 presents transient lifetime occurrences for test conditions. Plant conditions during testing are not affected by the power uprate. The existing pressure and temperature limitations remain applicable for the Waterford 3 EPU.

2.6.9.5 Summary of Results

The NSSS fluid transients for the RV, RCS main piping, pressurizer, RCPs, and SGs have been evaluated for the revised operating conditions related to the Waterford 3 EPU. The existing pressure and temperature limitations remain applicable for the Waterford 3 EPU with the following differences between the current design transient limitations and expected uprate transient responses are as follows:

A) The cold leg temperature will experience a temperature increase of nearly 16°F during a loss-of-load event. (Related to the power uprate and change in the temperature program.)

B) The pressurizer surge line temperature change during plant trips, loading and unloading needs to be revised from 110°F to 114°F to accommodate the 543°F no-load RCS temperature.

The effects of these differences on fatigue life of the subject components were incorporated into the evaluation in Section 2.2 of this report.

Table 2.6-3
Assumed Transient Lifetime Occurrences for Normal Conditions

Transient	Reactor Vessel	Reactor Coolant Pump	Pressurizer	Reactor Coolant Pipe and Fittings	Steam Generator
Plant heatup, 100°F/hr	500	500	500(1)	500	500(3)
Plant cooldown, 100°F/hr (pzr. 200°F/hr)	500	500	500(2)	500	500(3)
Plant loading, 5%/min	15,000	15,000	10^6	15,000	15,000
Plant unloading, 5%/min	15,000	15,000	10^6	15,000	15,000
10% step load increase	10^6	10^6	$10^{6`}$	10^6	10^6
10% step load decrease					
Normal plant variation					
Pump starting and stopping	NA	NA	NA	NA	4000
Cold feedwater following hot standby	NA	NA	NA	NA	15,000

Notes:

(1) The pressurizer heatup rate is 200°F/hr.
(2) The pressurizer cooldown rate is 200°F/hr and includes flooding during cooldown.
(3) The steam generator manway studs are designed for 200 cycles.

Table 2.6-4
Assumed Transient Lifetime Occurrences for Upset Conditions

Transient	Reactor Vessel	Reactor Coolant Pump	Pressurizer	Reactor Coolant Pipe and Fittings	Steam Generator
Reactor trip Loss of reactor coolant flow Loss of load	400 40 40	480	480	480	480
Operating basis earthquake	200	200	200	200	200

Table 2.6-5
Assumed Transient Lifetime Occurrences for Emergency Conditions

Transient	Reactor Vessel	Reactor Coolant Pump	Pressurizer	Reactor Coolant Pipe and Fittings	Steam Generator
Loss of secondary pressure	5	5	5	5	5
Loss of feedwater flow	NA	NA	NA	NA	20

Table 2.6-6
Assumed Transient Lifetime Occurrences for Faulted Conditions

Transient	Reactor Vessel	Reactor Coolant Pump	Pressurizer	Reactor Coolant Pipe and Fittings	Steam Generator
Design Basis Earthquake + Normal Operation	1	1	1	1	1
Design Basis Earthquake + Normal Operation + RCS Pipe Rupture	1	1	1	1	1

Table 2.6-7
Assumed Transient Lifetime Occurrences for Test Conditions

Test Conditions	Reactor Vessel	Reactor Coolant Pump	Pressurizer	Reactor Coolant Pipe and Fittings	Steam Generator
Hydrostatic test, 3125 psia 100°F - 400°F	10	10	10	10(1)	10
Secondary Hydrostatic test	NA	NA	NA	NA	10
Leak test, 2250 psia 100°F - 400°F	200	200	200	200(1)	200
Secondary Leak test, 820 psia to design pressure.	NA	NA	NA	NA	200
Safety Injection Check Valve Test	NA	NA	NA	160	NA

Notes: (1) 160°F to 400°F

2.7 SOURCE TERMS AND RADIOLOGICAL CONSEQUENCES ANALYSES

2.7.1 Source Terms for Radwaste Systems Analysis

Reactor coolant activity concentrations impact the liquid and Gaseous Waste Management Systems (GWMS). The radiological source terms in the coolant are a function of the core power level, leakage from the fuel, radioactive decay and removal by coolant purification systems. As part of the extended power uprate (EPU), a re-evaluation of the radiosotopic concentrations in the reactor coolant was performed. In addition, the source terms for LOCA conditions were also re-evaluated. The results of the re-evaluation and comparison with the Waterford 3 previous design basis are described in subsequent sections.

2.7.1.1 Description of Analyses and Evaluations

The source terms for normal operation, anticipated operational and accident conditions have an impact on dose rates to people and equipment throughout the plant as well as offsite. Maximum reactor coolant radioisotopic concentration assuming 1% failed fuel, expected reactor coolant radioisotopic concentrations based on ANSI 18.1, and circulating crud were re-evaluated for the higher power level. The maximum reactor coolant radioisotopic concentration due to power uprate was compared to the original Waterford 3 FSAR design basis reactor coolant radioisotopic concentration. Loss-of-coolant accident (LOCA) source terms for their use in accident dose and EQ dose evaluations were regenerated for the higher power level. The LOCA source terms regenerated for the higher power level were also compared to the original design basis LOCA source terms. Selective dose rate evaluations were performed to further quantify the changes in estimated dose rates to plant personnel and to safety related equipment due to the power uprate.

Maximum fission product activity in the primary coolant due to the power uprate was calculated assuming 1% failed fuel. The mathematical models of production and transport of radioisotopes from pellet to coolant are outlined in Section 11.1.1.1 of the Waterford 3 FSAR. The reactor coolant activity concentrations were determined at a core inventory from 3735 MWt and for 590 effective full-power days (EFPD). Fission product escape coefficients, purification flow rate, and ion exchange removal efficiency are unchanged from the original Waterford 3 design basis as specified in Section 11.1. The estimated reactor-coolant-specific activities due to power uprate and original FSAR values are summarized in Table 2.7-1.

Average fission product activity in the primary coolant for the EPU was estimated using ANSI 18.1 methodology. The Waterford 3 design basis average coolant activity was originally based on ANSI N237 methodology. Radioisotopic coolant inventories calculated based on the ANSI methodology are typically used to compute dose rates for normal operations and anticipated occurrences. A comparison of the average primary coolant activities for the EPU and for the original Waterford 3 design basis is summarized in Table 2.7-2.

Circulating crud activities were also calculated using the methodology outlined in Section 11.1.2 of the Waterford 3 FSAR. A comparison of the results shows that a slight increase in crud activities is expected due to the EPU. This may result in a slight increase in

the dose rates from the purification filter tanks. A comparison of circulating crud activities for the EPU and for the original Waterford 3 design basis is summarized in Table 2.7-3.

2.7.1.2 Source Terms for Radioactive Liquid and Gaseous Effluents

The source terms from the processed liquid and gaseous releases of the radwaste management system have an impact on offsite doses. The Waterford 3 liquid and gaseous effluent source terms were re-evaluated with the PWRGALE code. The influence of EPU was determined by comparing the results for the original licensed power level of 3390 MWt with the EPU level of 3716 MWt. The results of the PWRGALE analysis for the annual liquid and gaseous radioisotope releases are shown in Tables 2.7-4 and 2.7-5 respectively.

Table 2.7-1
Comparison of Maximum Reactor Coolant Radionuclide Concentrations
Based on 1% Failed Fuel

Radionuclide	EPU (µCi/cc)	FSAR (µCi/cc)	% Difference*
Ba-140	7.70E-03	1.27E-02	39.37%
Br-84	2.10E-02	3.97E-02	47.10%
Ce-144	8.50E-04	7.82E-03	89.13%
Cs-134	5.20E-01	1.53E-01	-239.87%
Cs-136	9.80E-02	2.64E-02	-271.21%
Cs-137	7.90E-01	6.20E-01	-27.42%
I-131	4.80E+00	4.67E+00	-2.78%
I-132	9.50E-01	1.32E+00	28.03%
I-133	5.60E+00	5.88E+00	4.76%
I-134	4.80E-01	5.73E-01	16.23%
I-135	2.70E+00	2.58E+00	-4.65%
Kr-85	5.50E+00	5.13E+00	-7.21%
Kr-85M	1.10E+00	2.35E+00	53.19%
Kr-87	8.70E-01	1.26E+00	30.95%
Kr-88	2.40E+00	4.08E+00	41.18%
La-140	3.30E-03	1.23E-02	73.17%
Mo-99	5.10E-01	2.24E+00	77.23%
Pr-143	1.00E-03	1.13E-02	91.15%
Rb-88	2.40E+00	4.06E+00	40.89%
Ru-103	3.70E-04	8.58E-03	95.69%
Ru-106	1.70E-04	5.12E-04	66.80%
Sr-89	5.90E-03	1.07E-02	44.86%
Sr-90	3.70E-04	5.79E-04	36.10%
Y-91	6.40E-03	4.84E-02	86.78%
Te-129	1.10E-02	4.98E-02	77.91%
Te-132	3.60E-01	6.48E-01	44.44%
Xe-131M	5.40E+00	2.39E+00	-125.94%
Xe-133	3.30E+02	3.34E+02	1.20%
Xe-135	7.40E+00	9.24E+00	19.91%
Xe-135M	6.80E-01	1.10E+00	38.18%
Xe-138	5.70E-01	5.58E-01	-2.15%
Y-90	1.30E-04	1.42E-03	90.85%
Sr-91	8.80E-04	6.15E-03	85.69%
Y-91M	3.80E-03	3.85E-03	1.30%
Zr-95	9.80E-04	1.15E-02	91.48%

$$* \text{ \% Difference} = \frac{\text{FSAR} - \text{EPU}}{\text{FSAR}} \cdot 100\%$$

Table 2.7-2
Comparison of Average Reactor Coolant Radionuclide Concentrations

Radionuclide	FSAR (μCi/cc)	EPU (μCi/cc)	% Difference*
Ba-137m	2.02E-02	---	NA
Br-83	6.45E-03	---	NA
Co-58	3.05E-02	1.3E-02	56.44%
Co-60	3.83E-03	1.5E-03	59.63%
Cr-51	3.61E-03	8.8E-03	-144.20%
Cs-134	4.47E-02	8.6E-05	99.81%
Cs-136	2.27E-02	1.9E-03	91.58%
Cs-137	3.22E-02	1.2E-04	99.62%
Fe-55	3.06E-03	3.5E-03	-14.35%
Fe-59	1.90E-03	8.6E-04	54.67%
H-3	1.00E+00	1.0E+00	0.00%
I-130	3.24E-03	---	NA
I-131	5.07E-01	5.4E-03	98.93%
I-132	1.34E-01	7.4E-02	45.05%
I-133	6.19E-01	4.9E-02	92.11%
I-134	6.09E-02	1.1E-01	-87.67%
I-135	2.75E-01	7.9E-02	71.21%
Kr-83m	2.65E-02	---	NA
Kr-85	2.90E-01	8.5E-02	70.67%
Kr-85m	1.39E-01	1.7E-02	87.83%
Kr-87	7.58E-02	1.8E-02	75.82%
Kr-88	2.53E-01	1.9E-02	92.39%
Kr-89	6.31E-03	---	NA
Mn-54	5.93E-04	4.7E-03	-685.51%
Mo-99	8.02E-01	1.5E-02	98.11%
Np-239	2.12E-03	5.1E-03	-139.71%
Rb-86	1.50E-04	---	NA
Sr-89	6.67E-04	4.0E-04	39.62%
Tc-99m	5.44E-01	6.6E-03	98.78%
Te-127	1.27E-03	---	NA
Te-127m	5.35E-04	---	NA
Te-129	2.09E-03	2.8E-02	-1232.82%
Te-129m	2.66E-03	5.4E-04	79.60%
Te-131m	4.19E-03	3.0E-03	27.25%
Te-132	4.65E-02	4.1E-03	91.12%
Xe-131m	1.53E-01	3.6E-01	-131.85%
Xe-133	2.39E+01	1.9E-02	99.92%

Table 2.7-2 (cont.)
Comparison of Average Reactor Coolant Radionuclide Concentrations

Radionuclide	FSAR (µCi/cc)	EPU (µCi/cc)	% Difference*
Xe-133m	2.84E-01	5.9E-02	79.27%
Xe-135	4.44E-01	6.9E-02	84.43%
Xe-135m	1.64E-02	1.4E-01	-759.05%
Xe-137	1.14E-02	3.7E-02	-224.83%
Xe-138	5.56E-02	6.6E-02	-19.12%
Y-91	3.81E-03	1.5E-05	99.61%

$$* \text{ \% Difference} = \frac{\text{FSAR} - \text{EPU}}{\text{FSAR}} \cdot 100\%$$

Table 2.7-3
Comparison of Circulating CRUD Activities

Radionuclide	FSAR (µCi/cm^3)	EPU (µCi/cm^3)	% Difference*
Co-60	2.50E-04	2.66E-04	-6.58%
Co-58	1.00E-02	1.15E-02	-15.29%
Mn-54	1.00E-04	1.24E-04	-23.81%
Cr-51	3.40E-03	3.52E-03	-3.61%
Fe-59	4.70E-05	4.76E-05	-1.34%
Zr-95	9.00E-05	9.66E-05	-7.37%

$$* \text{ \% Difference} = \frac{\text{FSAR} - \text{EPU}}{\text{FSAR}} \cdot 100\%$$

Table 2.7-4
GALE Liquid Results (Curies)

Isotope	Original Basis (3390 Mwt)	EPU (3716 Mwt)	% Difference*
Na-24	3.2E-03	3.3E-03	3.12%
P-32	1.8E-04	1.8E-04	0.00%
Cr-51	5.3E-03	5.3E-03	0.00%
Mn-54	4.1E-03	4.1E-03	0.00%
Fe-55	7.5E-03	7.5E-03	0.00%
Fe-59	2.3E-03	2.3E-03	0.00%
Co-58	8.9E-03	8.9E-03	0.00%
Co-60	1.4E-02	1.4E-02	0.00%
Ni-63	1.7E-03	1.7E-03	0.00%
Zn-65	1.1E-04	1.1E-04	0.00%
W-187	2.4E-04	2.4E-04	0.00%
Np-239	3.0E-04	3.0E-04	0.00%
Sr-89	1.2E-04	1.2E-04	0.00%
Sr-90	2.0E-05	2.0E-05	0.00%
Sr-91	5.0E-05	5.0E-05	0.00%
Y-91M	3.0E-05	3.0E-05	0.00%
Y-91	8.0E-05	8.0E-05	0.00%
Y-93	2.0E-04	2.1E-04	5.00%
Zr-95	1.2E-03	1.2E-03	0.00%
Nb-95	2.0E-03	2.0E-03	0.00%
Mo-99	9.9E-04	9.9E-04	0.00%
Tc-99M	6.0E-04	6.1E-04	1.67%
Ru-103	1.8E-03	1.8E-03	0.00%
Rh-103M	1.5E-03	1.5E-03	0.00%
Ru-106	2.8E-02	2.8E-02	0.00%
Rh-106	1.9E-02	1.9E-02	0.00%
Ag-110M	1.5E-03	1.5E-03	0.00%

$$* \text{ \% Difference} = \frac{\text{EPU} - \text{FSAR}}{\text{FSAR}} 100\%$$

Table 2.7-4 (cont.)
GALE Liquid Results (Curies)

Isotope	Original Basis (3390 Mwt)	EPU (3716 Mwt)	% Difference*
Ag-110	4.0E-05	4.0E-05	0.00%
Sb-124	4.3E-04	4.3E-04	0.00%
Te-129M	4.0E-05	4.0E-05	0.00%
Te-129	4.0E-05	4.0E-05	0.00%
Te-131M	1.6E-04	1.6E-04	0.00%
Te-131	3.0E-05	3.0E-05	0.00%
I-131	3.2E-02	3.2E-02	0.00%
Te-132	2.5E-04	2.5E-04	0.00%
I-132	3.5E-03	3.6E-03	2.86%
I-133	4.0E-02	4.0E-02	0.00%
I-134	3.5E-04	3.5E-04	0.00%
Cs-134	1.5E-02	1.5E-02	0.00%
I-135	2.4E-02	2.4E-02	0.00%
Cs-136	7.8E-04	7.8E-04	0.00%
Cs-137	2.2E-02	2.2E-02	0.00%
Ba-137M	5.4E-03	5.4E-03	0.00%
Ba-140	3.3E-03	3.3E-03	0.00%
La-140	3.5E-03	3.6E-03	2.86%
Ce-141	2.6E-04	2.6E-04	0.00%
Ce-143	3.1E-04	3.1E-04	0.00%
Pr-143	1.0E-05	1.0E-05	0.00%
Ce-144	4.7E-03	4.7E-03	0.00%
Pr-144	8.2E-04	8.2E-04	0.00%
ALL OTHERS	0	0	0.0%
Total (except Tritium)	0.26	0.26	0.0%
TRITIUM RELEASE	370	370	0.0%

$$* \text{ \% Difference} = \frac{\text{EPU} - \text{FSAR}}{\text{FSAR}} 100\%$$

Table 2.7-5
GALE Gaseous Results (Curies)

Isotope	Original Basis (3390 Mwt)	EPU (3716 Mwt)	% Difference*
I-131	3.1E-02	3.3E-02	6.45%
I-133	8.1E-02	8.9E-02	9.88%
Kr-85M	1.4E+01	1.4E+01	0.00%
Kr-85	2.4E+03	2.7E+03	12.50%
Kr-87	8.0E+00	8.0E+00	0.00%
Kr-88	1.8E+01	2.1E+01	16.67%
Xe-131M	1.3E+03	1.5E+03	15.38%
Xe-133M	4.3E+01	4.7E+01	9.30%
Xe-133	3.1E+03	3.4E+03	9.68%
Xe-135M	5.0E+00	6.0E+00	20.00%
Xe-135	1.2E+02	1.3E+02	8.33%
Xe-137	0.0E+00	0.0E+00	0.00%
Xe-138	4.0E+00	5.0E+00	25.00%
Cr-51	1.1E-04	1.1E-04	0.00%
Mn-54	6.1E-05	6.1E-05	0.00%
Co-57	8.5E-06	8.5E-06	0.00%
Co-58	5.0E-04	5.0E-04	0.00%
Co-60	1.3E-04	1.3E-04	0.00%
Fe-59	3.0E-05	3.0E-05	0.00%
Sr-89	2.0E-04	2.0E-04	0.00%
Sr-90	8.2E-05	8.2E-05	0.00%
Zr-95	1.5E-05	1.5E-05	0.00%
Nb-95	4.7E-05	4.7E-05	0.00%
Ru-103	2.1E-05	2.1E-05	0.00%
Ru-106	3.5E-06	3.5E-06	0.00%
Sb-125	6.1E-07	6.1E-07	0.00%
Cs-134	8.1E-05	8.1E-05	0.00%
Cs-136	3.9E-05	3.9E-05	0.00%
Cs-137	1.7E-04	1.7E-04	0.00%
Ba-140	2.7E-05	2.7E-05	0.00%
Ce-141	1.5E-05	1.5E-05	0.00%
H-3	980	1100	12.24%
C-14	7.3	7.3	0.00%
Ar-41	34	34	0.00%

$$* \text{ \% Difference} = \frac{\text{EPU} - \text{FSAR}}{\text{FSAR}} 100\%$$

2.7.1.3 Conclusions

The comparison of the maximum reactor coolant activities assuming 1% fuel failure between the EPU and the FSAR design basis indicate that the overall reactor coolant activities are lower for the power uprate compared to the original Waterford 3 design basis, with the exception of some of the cesium, iodine and xenon isotopes.

Since the current Waterford 3 technical specifications limit the actual reactor coolant concentrations to 1 μCi/gm dose equivalent (DE) ^{131}I, and this limit will still be in force for the Waterford 3 EPU, the assumption of 1% failed fuel in estimations of plant system dose rates is very conservative.

A comparison of the average or expected reactor coolant inventories based on ANSI N237 (the FSAR design basis) and ANSI 18.1 (the EPU basis) shows that, even though several isotopes increase, the radiologically significant isotopes are estimated to be lower using ANS 18.1. These include: Xe-133, I-131, I-133, Cs-134, Cs-136, and Cs-137. Thus, normal operation and anticipated occurrences dose rates due to EPU are bounded by the current FSAR design basis dose rates.

Dose rate evaluations from reactor coolant piping with maximum and average reactor coolant concentrations using EPU and Waterford 3 design basis source terms show a 10 to 20% reduction in dose rates using the EPU reactor coolant inventories compared to the original Waterford 3 design basis. Thus, the uprate source terms and resultant dose rates are bounded by the current FSAR design basis.

The EPU conditions result in a slight increase in the liquid effluent releases. The highest increase in liquid release was for Y-93, which increased by 5%. Based on this result, an evaluation of the EPU offsite dose impact due to liquid releases is unnecessary. From the liquid release results, it is concluded that the additional environmental consequences of EPU will be less than the percentage power increase (9.6%).

The increase in gaseous effluent releases was more for EPU. The largest increase was 25% for Xe-138. As a result, an evaluation of the offsite dose due to gaseous effluent release was performed. From the results of the analysis, it was concluded that the overall impact due to EPU on offsite doses is less than 13%. Assuming the offsite dose consequences increase by 15%, they would bound the environmental impact of the gaseous releases due to EPU. This increase is well within the annual variation of offsite doses as reported in the Waterford 3 effluent release reports.

2.7.2 Radiological Consequences of Main Steamline Failures Outside Containment

Radiological consequences of these failures are presented in Sections 2.13.1.3.1 and 2.13.1.3.3.

2.7.3 Radiological Consequences of a RCP Locked-Rotor Accident

Radiological consequences of this accident are presented in Section 2.13.3.3.1.

2.7.4 Radiological Consequences of a Control Rod Ejection Accident

Radiological consequences of this accident are presented in Section 2.13.4.3.2.

2.7.5 Radiological Consequences of the Failure of Small Lines Carrying Primary Coolant Outside Containment

Radiological consequences of these failures are presented in Section 2.13.6.3.1.

2.7.6 Radiological Consequences of SGTR

Radiological consequences of this accident are presented in Section 2.13.6.3.2.

2.7.7 Radiological Consequences of a Design-Basis LOCA

Radiological consequences of this accident are presented in Section 2.13.6.3.3.

2.7.8 Radiological Consequences of FHAs

Radiological consequences of these accidents are presented in Section 2.13.7.3.4.

2.7.9 Radiological Consequences of Spent Fuel Cask Drop Accidents

The spent fuel cask drop accident need not be analyzed for power uprate conditions as described in Section 2.13.7.3.5.

2.8 HEALTH PHYSICS

2.8.1 Occupational/Public Dose Impacts

In-plant and offsite radiation dose was evaluated as part of the environmental impacts due to the EPU.

2.8.1.1 Evaluation

In-Plant Radiation Evaluation

Increasing the rated power at Waterford 3 could increase the radiation levels in the reactor coolant system. However, plant programs and administrative controls, such as shielding, RCS chemistry, and the plant radiation protection programs will compensate for these potential increases. Occupational exposures due to in-plant radiation primarily occur during routine maintenance, special maintenance and refueling operations. These operations are more a function of time in radiation areas and less a function of the plant power level. Annual personnel exposures, based on electronic dosimeters, are presented in Table 2.8-1 for the period starting in 1998 through 2002 [References 2.8.1-1, 2.8.1-2, 2.8.1-3, 2.8.1-4, and 2.8.1-5]. The average for this five-year period is 80.3 man-rem/yr. Conservatively assuming a linear increase in the personnel exposure rate due to the EPU, the in-plant occupational exposure could increase to 88 man-rem/yr (a 9.6% increase), which is well below the 1300 man-rem/yr estimated in the Waterford 3 Final Environmental Statement (FES) Section 5.9.1.1.1.

Table 2.8-1
Annual Occupational Exposures
(Man-Rem)

1998	23.4
1999	118.0
2000	139.4
2001	7.5
2002	113.2
Average	80.3
Projected Average Due to Uprate[3]	88.0

The plant radiation protection program will be utilized to its maximum to maintain individual doses as low as possible to comply with as-low-as-reasonably-achievable (ALARA) requirements and well below the 10CFR20 limits. Routine plant radiation surveys required by the radiation protection program will identify increased radiation levels in accessible areas of

[3] Based on a power uprate ratio of 3716 MWt/3390 MWt = 1.096.

the plant and radiation zone postings and job planning will be adjusted if necessary to minimize the exposure. Time spent in the radiation areas is monitored and controlled under the radiation protection program. Administrative limits are set for occupational dose that are at levels well below the limits given in the Code of Federal Regulations (10CFR20). The administrative limits for occupational doses are summarized in Table 2.8-2.

Table 2.8-2
Occupational Dose Limits

2,000 mrem/year*	Whole Body Dose (total effective dose equivalent [TEDE])
40,000 mrem/year	Organ Dose (total organ dose equivalent [TODE])
40,000 mrem/year	Dose to Skin of Whole Body
40,000 mrem/year	Dose to Extremities
12,000 mrem/year	Dose to Lens of Eye (LDE)

* TEDE administrative control may be extended up to 4500 mrem/year with appropriate management approval.

These administrative limits provide a significant margin of safety compared to regulatory dose limits under normal operating and outage conditions. The current administrative dose limits were not exceeded under present power conditions.

Offsite Dose Evaluation

An evaluation to study the impact of the power uprate on liquid and gaseous releases from the plant waste management systems is made based on current effluent releases [References 2.8.1-6, 2.8.1-7, and 2.8.1-8] and the projected change in releases due to the power uprate. The projected change in liquid and gaseous effluent releases is evaluated with the PWRGALE [Reference 2.8.1-9] code and the associated change in offsite doses is evaluated with the GASPAR code [Reference 2.8.1-10]. A slight increase in normal operational gaseous activity levels under the EPU will not affect the large margin to the offsite dose limits established by 10CFR20. In addition, the current low doses from liquid effluents will remain low under the EPU conditions.

The Waterford 3 Technical Specifications implement the guidelines provided in 10CFR50, Appendix I. These guidelines are within the 10CFR20 limits. The calculated annual offsite doses using the data from Waterford 3 Annual Radioactive Effluent Release Reports for year 2000 through 2002 [References 2.8.1-6, 2.8.1-7, and 2.8.1-8] are summarized in Table 2.8-3. Adjusting the average values for the estimated EPU increases in liquid and gaseous effluents, the average offsite doses from different activities will increase to:

a) 5.8E-03 mrem from liquid activity
b) 5.10E-02 mrads from gaseous gamma activity
c) 1.60E-01 mrad from noble gas beta activity

Appendix I limits for liquid activity, gaseous gamma activity and noble gas beta activity are 3 mrem, 10 mrads, and 20 mrads, respectively. The offsite dose will continue to be within the Technical Specification dose limits.

The EPU will not significantly increase offsite dose from noble gases, airborne particulates, iodine, or tritium. As stated in the Waterford 3 Radiological Environmental Monitoring Program, the radiation from shine is not a significant exposure pathway, therefore it will not be significantly affected by the EPU.

Table 2.8-3
Annual Offsite Whole Body Doses

	Liquid (mrem)	Gaseous	
		Gamma (mrad)	Beta (mrad)
2000	1.0E-02	5.0E-02	1.5E-01
2001	3.0E-03	8.0E-03	2.3E-02
2002	3.0E-03	7.6E-02	2.45E-01
Average	5.3E-03	4.47E-02	1.39E-01
Projected Average Due to Uprate	5.8E-03	5.10E-02	1.60E-01

The estimated doses from both the liquid and gaseous release pathways resulting from EPU conditions are within the design requirements specified in 10CFR50, Appendix I, and 10CFR20 limits.

2.8.1.2 Conclusion

Under EPU conditions, the plant radiation protection program will be used to maintain individual occupational doses within ALARA policies, and well below the 10CFR20 limits. In addition, as stated in the Waterford 3 Radiological Environmental Monitoring Program, since radiation from shine is not a significant exposure pathway, it will not be significantly affected by the EPU. Offsite doses will not involve significant increases from noble gases, airborne particulates, iodine, or tritium.

2.8.1.3 References

2.8.1-1 *1998 Personnel Monitoring Annual Reports, Worker Job Function Exposure Tabulation End of Year 1998 Report*.

2.8.1-2 *1999 Personnel Monitoring Annual Reports, Worker Job Function Exposure Tabulation End of Year 1999 Report*.

2.8.1-3 *2000 Personnel Monitoring Annual Reports, Worker Job Function Exposure Tabulation End of Year 2000 Report*.

2.8.1-4 *2001 Personnel Monitoring Annual Reports, Worker Job Function Exposure Tabulation End of Year 2001 Report*.

2.8.1-5 *2002 Personnel Monitoring Annual Reports, Worker Job Function Exposure Tabulation End of Year 2002 Report*.

2.8.1-6 *Annual Radioactive Effluent Release Report*, January 1, 2000 – December 31, 2000, Waterford 3 SES, Entergy Operations, Inc.

2.8.1-7 *Annual Radioactive Effluent Release Report*, January 1, 2001 – December 31, 2001, Waterford 3 SES, Entergy Operations, Inc.

2.8.1-8 *Annual Radioactive Effluent Release Report*, January 1, 2002 – December 31, 2002, Waterford 3 SES, Entergy Operations, Inc.

2.8.1-9 NUREG-0017, Rev. 1, Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Light Water Reactors – PWRGALE Code, April 1985.

2.8.1-10 NUREG/CR-4653, GASPAR II Technical Reference and User Guide, March 1987.

2.9 HUMAN PERFORMANCE

2.9.1 Changes in Emergency and Abnormal Operating Procedures

Existing procedures will adequately cover emergency scenarios, abnormal occurrences, or normal operations. New procedures are not expected to be required. No new operator actions, as a result of the proposed EPU, are anticipated.

Setpoints that are mentioned in emergency operating procedures or off normals will be changed to new uprate values.

Specific, non-setpoint, changes to existing steps in emergency and off-normal operating procedures for power uprate follow:

The time window to establish simultaneous hot and cold leg injection in the loss-of-coolant accident (LOCA) emergency operating procedure will be changed from 2 to 4 hours to 2 to 3 hours.

As discussed in Section 2.5.2.4, Entergy is submitting a separate license amendment request to eliminate the Technical Specification requirements for combustible gas control in containment. Resulting Emergency Operating Procedures (EOP) changes, regarding operation of the combustible gas control system, will be made during the implementation phase following approval and issuance of the associated amendment.

Conclusion

The change in the hot/cold leg injection window between 2-3 hours provides no challenge to operator performance and will be satisfactorily implemented by the procedure change process and operator training.

2.9.2 Changes to Operator Actions Sensitive to Power Uprate

The Atmospheric Dump Valve (ADV) controllers are being changed to digital controllers and will have a Technical Specification-mandated automatic setpoint. Operators will be required to perform channel checks once per 12 hours to ensure ADV automatic actuation operability when operating above 70% rated thermal power (RTD).

Conclusion

These channel checks will have no impact on operator response times.

2.9.3 Changes to Control Room Controls, Displays and Alarms

The instrument loops affected by the extended power uprate (EPU) are listed in Table 2.9-1 below. The associated changes to the control room controls, displays, and alarms affected by the EPU are described in the table below.

Operators have been involved in the conceptual design, detailed design, and review of the modification packages making the indicated changes. Multiple layers of operator involvement are in place to assure and reinforce operator cognizance of these changes.

This applies also to the ADV modification that upgrades each of the ADV controllers from an analog to a digital self-contained digital proportional integral derivative (PID) unit. These controllers will be changed to improve the accuracy of setting the ADV control setpoint.

Conclusion

See the conclusion to 2.9.4.

2.9.4 Changes to the Qualified Safety Parameter Display System

Planned changes to the Qualified Safety Parameter Display System (QSPDS) are summarized in Table 2.9-1 below. As discussed in Section 2.9.3 above, multiple layers of operator involvement are in place to assure and reinforce operator cognizance of these changes.

Table 2.9-1
Summary of Changes

Description	Before EPU	After EPU
RPS Channel Trip SG Pressure	Alarm Setpoint: 764 psia	Alarm Setpoint: 662 psia
Feedwater Mass Flow	Indicated Range: 0 – 8.0 MPPH	Indicated Range: 0 – 9.0 MPPH
Main Steam Mass Flow	Indicated Range: 0 – 8.0 MPPH	Indicated Range: 0 – 9.0 MPPH
ADV Control	Analog with setpoint adjustment resolution of 60 psi. Setpoint: 1050 psig	Digital with setpoint adjustment resolution of 1 psi. Setpoint: 970 psig
SBCS Controller Process Range	Indicated Range: 800 – 1050 psia	Indicated Range: 750 – 1050 psia
QSPDS Cold Leg Temperature	Alarm Setpoint: 558°F	Alarm Setpoint: 562°F

Color banding will change for the following indicated parameters:

a) Pressurizer pressure narrow range
b) Pressurizer pressure wide range
c) RCS cold leg temperature
d) RCS hot leg temperature
e) SIT levels

Conclusion

The changes summarized in Table 2.9-1 will provide the control room operator the information required to achieve and maintain safe shutdown of the reactor during normal and accident conditions. Training and testing of the operators regarding the use of the changed displays is addressed in Section 2.9.5 of this report ensuring that control room operators will use the instrumentation reliably. The control room configuration after implementation of the EPU will therefore remain consistent with GDC 19, and SRP Section 18.

2.9.5 Changes to the Operator Training Program and the Control Room Simulator

2.9.5.1 Operation Training

The training staff will provide training as determined by the Operations Training Review Group. Prior to EPU implementation, the simulator will be upgraded to provide operator training at EPU conditions. Operators will receive training using the systematic approach to training process. This training will cover procedure changes, new or revised technical specifications/safety analysis, and equipment modifications for the EPU. The topics will include items such as high pressure turbine upgrade, new atmospheric dump valve controllers, and instrument range/alarm changes. Classroom training/testing and simulator training/testing with the new equipment/instrument changes installed will ensure the operators understand the changes to plant systems.

Startup training will be conducted prior to the conclusion of the outage for the operations crews with emphasis on core reload, positive moderator temperature coefficient, reactor engineering interface, and teamwork skills.

2.9.5.2 Simulator Modification

Plant modifications including the power uprate modifications and refueling outage plant modifications are reviewed for impact on the simulator. Plant modifications that affect the primary, secondary, control systems logic or dynamic response are incorporated into the simulator. Hardware control board changes that affect the simulator physical fidelity are incorporated into the simulator. Plant computer and display changes are updated on the simulator. New or modified instructor station malfunction, remote functions, and overrides along with panel and piping graphics are updated to reflect the modifications.

Verification and validation testing is performed on the simulator modifications. After the process model modifications are implemented and core reload parameters are installed, simulator initial conditions are established at various power levels and core life. Simulator testing occurs after the 100% power initial conditions have been established.

2.9.5.3 Simulator Pre-Outage Data

The EPU simulator modification, design, analysis, and test data will be evaluated based on, but not limited to, the following:

a) Engineering report modification packages
b) Design and analysis data including heat balance, balance-of-plant (BOP) flow changes, and plant systems set point changes
c) Updated plant and physics data book
d) Engineering reports on system response and new accident analyses
e) Best-estimate data

2.9.5.4 Simulator Post-Outage Data

The simulator will be compared to actual plant data. Data collection will be conducted by the simulator support and training staff for validation of the simulator performance. The new data will supplement the baseline data for simulator response when conducting ANSI/ANS 3.5 testing.

Conclusion

Updating the simulator and training the operators prior to EPU implementation will ensure that operators understand changes to plant systems and the associated effects on operation of the plant.

2.10 POWER ASCENSION TESTING

Approach to EPU Power Level and Test Plan

The power ascension test program for Cycle 14 is expected to be similar to previous cycle test programs with the exception of the additional tests to address specific aspects of the power uprate.

The final design modifications required to support the EPU are scheduled to be installed during the refueling outage prior to Cycle 14. The startup test program following that outage will include many of the same tests performed for Cycle 13 with data collection extended to the new uprated power level. These tests include vibration measurements of secondary systems inside containment, RCS flow measurements, core power distribution and reactivity checks, critical cooling systems, and secondary plant performance. Pre-operational tests will be performed to demonstrate appropriate performance of new modifications.

Cycle 14 Test Program Description

Pre-Critical Tests

a) Comparison of Plant Protection System (PPS), core protection calculators, and process computer input

Low Power Physics Tests

b) Isothermal temperature coefficient
c) Boron worth
d) Critical configuration boron concentrations

Power Range Tests

e) Power uprate data collection/design prediction test (includes secondary plant parameter and performance testing [includes pre-refuel 13 data collection at 100% MWt] and Nuclear Steam Supply System (NSSS) data collection)
f) Steady-state core performance
g) Variable T_{avg} (isothermal temperature coefficient and power coefficient)
h) Reactor Coolant System (RCS) flowrate determination
i) Comparison of PPS, core protection calculators, and process computer inputs
j) Verification of core protection calculator power distribution-related constants
k) Steam generator moisture carryover test (includes pre-refuel 13 test that has been completed)
l) Main generator rewind test (includes generator output breaker replacement and electrical protective relaying)

m) Turbine valve and digital electro-hydraulic testing

n) RP survey at new 100% power level (normal accessible areas)

The Waterford 3 Extended Power Uprate Startup Testing Program will be based on a review of the Final Safety Analysis Report (FSAR), the scope of modifications performed, the scope of testing completed following power uprate projects by other licensees, and industry experience from startup testing. During power ascension, data shall be taken at 2.5% increments from 3441 MWt (previous rated full power), which equates to approximately 92.5% reactor power to 100% reactor power. Steady state data shall be collected at the 92.5% (previous rated full power) plateau so that operating performance parameters can be projected for uprated power before the previous full power rate is exceeded. Steady state data shall be evaluated against design predictions and any identified discrepancies shall be resolved prior to proceeding with power ascension. A test working group, made up of Waterford 3 management and experienced testing personnel, shall review all significant test deficiencies and anomalies identified at each power plateau before recommending ascension to the next plateau.

Waterford 3 will make projections based upon actual plant data from the current 100% power of 3441 MWt to the new 100% power of 3716 MWt. These projections will support our power uprate design and form the basis for the acceptance criteria at each power plateau level specified, (~92.5%, 95%, 97.5%, and 100% of rated power).

Most of the control system design changes that support power uprate will be completed and tested during refueling outage 13. These will require steady state control system monitoring/testing to be performed at ~ 92.5%, 95%, 97.5% and 100% of uprated conditions.

The control system performance criteria that will be used for Cycle 14 are similar to the original power ascension tests, but not exactly the same. The high-level performance criteria (e.g., not causing trips or safety system actuations) have remained the same. Some system-specific performance criteria requirements have changed since the original startup because of physical changes to the plant control systems and operating methods.

2.11 RISK EVALUATION

2.11.1 Background

This section describes the risk assessment of the extended power uprate (EPU). The full 9.6% power increase from the originally licensed power of 3390 MWt to the new power of 3716 MWt is evaluated. The risk evaluation addresses the following risk areas:

1) Impact of EPU on:
   a) Level 1 internal events initiating event frequencies, component failure rates, success criteria, operator actions, and loss-of-offsite power (LOOP) recovery
   b) Level 1 external events fire, seismic, and other events
   c) Level 2 internal and external events
2) Quality of the Probability Safety Analysis (PSA) model
3) Shutdown risk

The evaluation of these risk areas is described in the following subsections. Although the extended power uprate is not a risk informed application, this risk evaluation is provided for information.

2.11.2 Level 1 Internal Events Evaluation

2.11.2.1 Initiating Event Frequencies

The following initiating events are modeled in the Level 1 Internal Events PSA. The underlying contributors to these initiating events were reviewed to determine the potential effects of the power uprate on the initiating event frequencies, with the following results:

Loss-of-Coolant Accidents (LOCA)

LOCA initiators include the small break (0.0005 to 0.05 sq-ft), medium break (0.05 to 0.1 sq-ft), and large break (above 0.1 sq-ft). LOCA frequency is dictated by the potential for passive pipe failures, which is independent of power level. EPU changes do not have an impact on the LOCA initiator frequency.

Steam Generator Tube Rupture (SGTR)

The SGTR initiating event frequency (IEF) used in the Waterford 3 PSA is a generic value based on industry experience. This generic IEF is applicable to Waterford 3 and remains so under EPU conditions.

Loss-of-Offsite Power (LOOP)

LOOP IEF is dictated by the reliability of the switchyard and grid, which are not degraded by the power uprate (Section 2.3.2).

Transient Initiators

Waterford 3 Reactor Protection System (RPS) setpoint methodology assures that the trip setpoint values are sufficiently different from normal operating conditions to account for instrumentation uncertainties and drift. This methodology was used for all trip setpoints affected by power uprate, and the calculations demonstrated that the appropriate acceptance criteria for trip avoidance were met.

Feedwater Control System (FWCS), Pressurizer Level Control System (PLCS) and Steam Bypass Control System (SBCS) setpoints were assessed and adjusted as necessary to ensure proper plant response to certain transients and plant maneuvers (load changes, heatup, and cooldown).

Other sections of this document discuss the hardware changes and setpoint modifications made to maintain margin on trip setpoints at the uprated power level and maintain equipment operation within design constraints. For example, the following changes (in addition to setpoint changes) were made to assure reliability of balance-of-plant (BOP) systems:

a) Replace high-pressure (HP) turbine steam path, replace main generator oil circuit breakers, rewind main generator (these ensure the turbine trip frequency is unaffected by power uprate).
b) Replace selected feedwater (FW) heater level control valves as necessary (ensures the loss of feedwater frequency is unaffected).

These modifications and setpoint changes mitigate the potential for increase of the frequency of transient initiators. Therefore, the power uprate will not increase the frequency of these transient initiators.

Transient Initiators – Support Systems

Support systems that may initiate a transient, such as DC power, AC power and component cooling water (CCW), are not adversely affected by changes in power. These systems have been reviewed for any small changes in loads and requirements and verified to be within the design capacities of the systems.

Anticipated Transients without Scram (ATWS)

ATWS sequence initiation occurs under the same primary system conditions as existed prior to the power uprate. Since there is no change in the transient initiator frequency, the potential for ATWS is also unchanged.

In conclusion, the power uprate will have no adverse effect on Level 1 internal events PSA initiator frequencies. Any future deviations in initiating event frequencies can be identified via existing monitoring processes, such as the licensee event report, condition reporting, and

industry events databases. Also, safety system actuations are trended under the Maintenance Rule as an indicator of unnecessary challenges of safety-related equipment.

2.11.2.2 Component Failure Rates

Comprehensive reviews of all plant systems and associated equipment with the potential to be affected by power uprate are discussed in other sections of this document. Changes in equipment service conditions and process changes, if any, were identified. Modifications were made to ensure the performance of certain equipment and systems under uprated conditions. Thus, plant systems and equipment will continue to be operated within design constraints and component failure rates will not change with the power uprate.

Existing component monitoring programs (e.g., preventive maintenance, vibration analysis, thermography, oil analysis, environmental qualification, flow-accelerated corrosion, and maintenance rule), can account for any additional wear as a result of power uprate. While the power uprate may result in some components being refurbished or replaced more frequently, the functionality and reliability of components can be maintained to the current standards. These monitoring programs will also identify any future deviations in component failure rates. An example of specific power uprate affected components and the associated monitoring programs follows.

As described in Section 2.5.6.4 of this report, the Condensate and Feedwater Systems (CFWS) are affected by EPU. The speed of the turbine-driven FW pumps will be higher, the flow rate through the piping will be higher, the pump suction pressure will be lower, and the pump total developed head will be higher. The CFWS, Steam Supply, Extraction and Drain Systems' velocity changes and pressure drops are within acceptable ranges. However, the increased pump speed, increased flow rate, and pressure changes could cause specific components to wear out more quickly. This wear will be apparent due to various aspects of maintenance, as described below:

a) Maintenance Rule Program: The CFWSs are included in the Maintenance Rule Program, with FW designated as a risk significant system so that functional failures and availability are trended.
b) Vibration Program: The FW pumps, the FW pump turbine drivers, the FW pump lube oil pumps, the FW heater drain pump motors, and the condensate pumps and motors are included in the Vibration Program. The FW pump turbine drivers are monitored by proximity probes or shaft riders at the inboard and outboard bearings and alarmed in the control room. The remaining components are not continuously monitored, but are observed during normal walkdowns.
c) Flow-Accelerated Corrosion (FAC) Program: The CFWS and Main Steam System (MSS) are included in the FAC program, so increases in wear rates due to increased flow rates for power uprate will be monitored.
d) Predictive Maintenance Program: Equipment condition is monitored in order to predict component life and replace components before failure.
e) Preventive Maintenance Program: The Preventive Maintenance Program includes periodic inspections, tests, calibrations, measurements, adjustments, cleaning, sampling/analysis, lubrication, and the replacement of limited life parts or components. Preventive maintenance also includes any scheduled maintenance activity required to

avoid in-service failures to systems or components. These activities are performed to keep equipment in good operating condition and to detect and correct conditions that require component repair, replacement or rebuild.)

In conclusion, the power uprate will have no adverse effect on Level 1 Internal events PSA component failure rates. Existing monitoring processes, including preventive maintenance, vibration analysis, thermography, oil analysis, environmental qualification, FAC, and the Maintenance Rule Program, can be used to identify any future deviations in component failure rates.

2.11.2.3 Plant Modifications

Plant hardware modifications related to power uprate were reviewed; none of the plant modifications required changes to the existing Waterford 3 PSA Level 1 internal events model. The power uprate modifications are identified in Section 1.4. These modifications either affect systems not modeled in the PSA, or did not affect the components as modeled in the PSA.

2.11.2.4 Success Criteria

A detailed review was performed to identify the effect of the increase in Waterford 3 thermal power level on the system success criteria credited in the Waterford 3 PSA Level 1 internal events model. These success criteria specify the requirements of the plant systems to address critical safety functions. These safety functions are as follows:

a) Reactivity control
b) RCS pressure control
c) RCS Pressure boundary integrity
d) RCS and core heat removal
e) RCS inventory control
f) Long-term RCS inventory control and heat removal

Thermal-hydraulic analyses using the CENTS code were used to confirm the success criteria for transient and SGTR sequences and the small end of the small LOCA sequences. The larger small LOCA and medium LOCA success criteria were confirmed using the CEFLASH code. These analyses determined that there is no impact of power uprate on the success criteria for these sequences. Although licensing basis analysis indicates that the Atmospheric Dump Valves (ADVs) are required for small LOCA, the best estimate thermal-hydraulic analysis performed for the PSA show that the ADVs are not required for preventing core damage; thus, the PSA success criteria for small LOCA are not affected by this licensing basis change. Large LOCA success criteria are based on the LOCA/Emergency Core Cooling System (ECCS) licensing analysis, which showed no change related to PSA success criteria.

2.11.2.5 Operator Actions and LOOP Recovery

Thermal-Hydraulic Analyses

A detailed assessment was performed to account for the effect of the increase in the Waterford 3 thermal power level on the probability of operator failure and offsite power non-recovery. The analysis involved the development of realistic available times for post-initiator operator actions and recovery of offsite power using the Waterford 3 CENTS model (and CEFLASH for small and medium LOCA) to simulate a variety of accident conditions. The CENTS and CEFLASH calculations were performed for uprated power levels. These analyses produced revised power uprate times to core uncovery, which were used to update the human reliability analysis (HRA) and LOOP models.

Operator Actions (HRA)

Power uprate has the general effect of reducing the time available for the operators to complete recovery actions, because of the higher decay heat level after EPU implementation. Reduced time available can increase the probability of operator failure. The available times from the thermal-hydraulic analyses were input into the Waterford 3 PSA HRA model to assess the effect of the power uprate on the operator actions used in the model. A comprehensive list of the post-initiator operator actions whose available times (and possibly their error probabilities) changed as a result of the power uprate are listed on Table 2.11-1. The table provides the operator failure event or human failure event (HFE), its description, and the times available to core uncovery from the current Waterford 3 PSA and for power uprate.

It should be noted that other operator failures occur in the model. These operator failures include pre-initiator operator failure events (e.g., “failure to restore after maintenance”) which are not time-dependent—and thus not affected by the power uprate-related changes in sequence timing—and post-initiator operator failures which did not change as a result of the power uprate.

Since the CENTS analyses performed in support of the PSA model for EPU were more realistic than much of the thermal-hydraulic analyses supporting the current model, many of the power uprate times available are longer than in the current model; in other words, the operator failure probabilities calculated for the EPU condition are lower than the probabilities in the current PSA. A realistic assessment of the change in operator failure probabilities from before and after power uprate would require that the power uprate thermal-hydraulic analyses (using CENTS and CEFLASH) be repeated for the pre-power uprate condition. Quantification of the power uprate PSA model shows, however, that only changes in the LOOP non-recovery probabilities have a significant effect on the overall core damage frequency (CDF). Specifically, revision of the current PSA model to incorporate the available times in Table 2.11-1 changed the CDF by only 3E-9, while incorporating the LOOP non-recovery probabilities changed the CDF by over 8E-7. Therefore, the pre-power uprate CDF was estimated by changing only the LOOP non-recovery probabilities, as described below.

Table 2.11-1
Impact of EPU on HRA Time Available

Event Name	Description	Existing Time Available	EPU Time Available
EHFALPABMP	Failure to energize bus 3AB3-S from bus opposite initial supply	40 min	2.83* min
EHFALPABSP	Failure to energize bus 3AB3-S from bus opposite initial supply	60 min	14 min
EHFMANTRNP	Failure to transfer loads to startup transformers when auto transfer fails	50 min	68.3 min
EHFMTRNLTP	Failure to transfer loads to startup transformers when auto transfer fails, with long time available	9 hr	14 hr
EHF-TEDG-P	Failure to start/align/load	50 min	68.3 min
HHFALNABMP	Failure to align high-pressure safety injection (HPSI) pump AB to replace pump A or B following medium LOCA	40 min	2.83* min
HHFALNABSP	Failure to align HPSI pump AB to replace pump A or B following small LOCA or SGTR	60 min	14 min
IHFSTCOMPP	Failure to restart instrument air compressor after fast transfer failure	50 min	68.3 min
NHFCDMKUPP	Failure to make up to condenser hotwell from condensate storage tank (CST) when automatic makeup fails	50 min	68.3 min
OHFCONDSTP	Failure to attempt to restore feed to SGs via condensate pumps	50 min	68.3 min
OHFRELTFWP	Failure to attempt to restore feedwater (e.g., via auxiliary FW) after late loss of EFW	9 hr	14 hr
OHFRESTFWP	Failure to attempt to restore feedwater (e.g., via auxiliary FW)	50 min	68.3 min
PHFMFIVOPP	Failure to unisolate main feedwater (MFW) to allow feeding SGs after main steam isolation signal (MSIS)	50 min	68.3 min
PHFSGTRBDP	Failure to blow down SGs to prevent overfilling affected generator	60 min	>24 hr
QHFCSPEMPP	Failure to align makeup to core support plate (CSP) during EFW operation	9 hr	9.33 hr

Note:
* The 2.83 minutes time available does not include the effect of the safety injection tanks, which would extend this time.

Table 2.11-1 (cont.)
Impact of EPU on HRA Time Available

Event Name	Description	Existing Time Available	EPU Time Available
QHFCSPWCTP	Failure to align suction to EFW from wet cooling tower (WCT) after CSP depletion	9 hr	14 hr
RHFSTCVCPP	Failure to start charging pumps to provide backup injection following SGTR	60 min	3 hr (assumed)

LOOP Recovery

Since the LOOP initiating event is the dominant core damage initiator for the Waterford 3 PSA model, it is important to account for the likelihood of recovering offsite power prior to core damage. This is done using a LOOP recovery analysis. The products of this analysis are LOOP non-recovery factors which are applied to the PSA cut sets initiated by the LOOP initiator.

The LOOP recovery analysis uses a convolution approach which consists of integrating (or convoluting) the product of the failure rates for run failures in a given cut set with the offsite power non-recovery probability. The convolution integral equals the mean probability that offsite power is not recovered in time to prevent core damage for the given cut set. In a broad sense, the convolution process may be viewed as a time-averaging approach to determining the probability that offsite power is not recovered before core damage, accounting for the fact that the equipment failures that lead to core damage (e.g., emergency diesel generator [EDG] or turbine-driven emergency feedwater (EFW) pump run failures) could occur many hours into a LOOP event, when the probability of recovery of offsite power is high.

The times available to recovery before core uncovery were determined using the CENTS code. For the power uprate condition, the CENTS analyses that supported the power uprate HRA, described above, were used. The pre-power uprate times available for recovering offsite power were determined by running CENTS for the specific LOOP scenarios, shown in Table 2.11-2, below.

Table 2.11-2
LOOP Recovery Times

Scenario	Time Available	
	Pre-Power Uprate	Post-Power Uprate
Recover Feedwater for Early Loss of FW	82.6 min	68.3 min
Recover Feedwater for Late Loss of FW (battery depletion)	5.1 hr	4.1 hr
Recover Feedwater for Late Loss of FW (CSP depletion)	12.32 hr	11.33 hr

The LOOP non-recovery factors (recovery events added to the LOOP cut sets) were calculated with the LOOP convolution method using these available times.

2.11.2.6 Level 1 Internal Events Results

The Level 1 internal events risk assessment of the Waterford 3 power uprate was performed via the revision and quantification of the existing Waterford 3 PSA Model to account for the above-noted changes in operator failure and LOOP non-recovery probabilities. Two Waterford 3 PSA models were used in the assessment of the risk impact of the power uprate:

EPU Model — The power uprate operator failure and LOOP non-recovery probabilities were used to update the current PSA model to create the EPU model.

Pre-EPU Model — The EPU model was modified to use the pre-EPU LOOP non-recovery probabilities; differences in operator failure probabilities between pre-EPU and EPU are not significant and are neglected.

Both models were quantified and their results compared in order to assess the effect of the power uprate on the internal events Level 1 risk. As a result of this assessment, the effect of the Waterford 3 power uprate from 3390 MWt to 3716 MWt was to increase the internal events CDF from 5.52E-6 to 5.87E-6, an increase of 3.5E-7 (6.3%). Table 2.11-3 provides the effect of the power uprate on the CDF results by accident sequence.

Table 2.11-3
Level 1 Internal Events Sequence Results

Sequence	Description	Pre-EPU CDF	EPU CDF	Change in CDF	% Change*
ATWS	Anticipated Transient Without Scram	1.35E-07	1.35E-07	0.00E+00	0.0
AU	Large LOCA with SI Failure in Injection	1.96E-08	1.96E-08	0.00E+00	0.0
AX	Large LOCA with SI Failure in Recirc	1.57E-09	1.57E-09	0.00E+00	0.0
ISLOCA	Interfacing System LOCA	3.13E-07	3.13E-07	0.00E+00	0.0
MU	Medium LOCA with HPSI Failure in Injection	6.08E-09	6.08E-09	0.00E+00	0.0
MX	Medium LOCA with HPSI Failure in Recirc	1.32E-07	1.32E-07	0.00E+00	0.0
RB	SGTR with Failure of Normal FW and EFW Failure	1.77E-08	1.77E-08	0.00E+00	0.0
RU	SGTR with Failure of RCS Injection	4.03E-08	4.03E-08	0.00E+00	0.0
RX	SGTR with Failure to Depressurize	2.86E-07	2.86E-07	0.00E+00	0.0
SB	Small LOCA with Failure of Normal FW and EFW Failure	4.67E-10	4.67E-10	0.00E+00	0.0

Table 2.11-3 (cont.)
Level 1 Internal Events Sequence Results

Sequence	Description	Pre-EPU CDF	EPU CDF	Change in CDF	% Change*
SBO	Station Blackout (SBO) with EFW AB Failure or Battery Depletion	1.41E-06	1.65E-06	2.42E-07	4.37
SBORCP	Station Blackout with RCP Seal Failure	0	1.08E-10	1.08E-10	0.0
SU	Small LOCA with HPSI Failure in Injection	9.76E-08	9.76E-08	0.00E+00	0.0
SX	Small LOCA with HPSI Failure in Recirc	1.61E-07	1.61E-07	0.00E+00	0.0
TB	Loss of Normal Feedwater with EFW Failure	2.56E-06	2.67E-06	1.06E-07	1.91
TPQB	Stuck Open Safety Relief Valve (SRV) LOCA with Failure of Normal FW and EFW Failure	5.49E-10	5.49E-10	0.00E+00	0.0
TPQU	Stuck Open SRV LOCA with HPSI Failure in Injection	2.44E-08	2.44E-08	0.00E+00	0.0
TPQX	Stuck Open SRV LOCA with HPSI Failure in Recirc	3.95E-08	3.95E-08	0.00E+00	0.0
TQB	RCP Seal LOCA with Failure of Normal FW and EFW Failure	1.04E-08	1.17E-08	1.35E-09	0.02
TQU	RCP Seal LOCA with HPSI Failure in Injection	5.23E-09	5.23E-09	0.00E+00	0.0
TQX	RCP Seal LOCA with HPSI Failure in Recirc	7.01E-09	7.21E-09	1.95E-10	0.0
V	Reactor Vessel Rupture	2.70E-07	2.70E-07	0.00E+00	0.0

*Calculated as percent of total pre-EPU CDF.

2.11.2.7 Level 1 Internal Events Conclusion

The power uprate will have no adverse effect on Level 1 internal events PSA initiator frequencies. Any future deviations in initiating event frequencies can be identified via existing monitoring processes, such as the Licensee Event Report (LER), condition reporting, and industry events databases. Also, safety system actuations are trended under Maintenance Rule as an indicator of unnecessary challenges of safety-related equipment.

The power uprate will have no adverse effect on Level 1 internal events PSA component failure rates. Existing monitoring processes, including preventive maintenance, vibration analysis, thermography, oil analysis, environmental qualification, flow accelerated corrosion, and the maintenance rule program, can be used to identify any future deviations in component failure rates.

The estimated increase in internal events CDF of 3.5E-7 per year as a result of the power uprate is small. Although this license amendment is not being requested as a risk-informed change, this risk increase meets the acceptance criterion of Regulatory Guide (RG) 1.174 (Reference 2.11-11) of 1E-6 for CDF. Therefore, the requested extended power uprate poses a small and acceptable risk.

2.11.3 Level 1 Internal Fire Evaluation

Background

The Waterford 3 *Individual Plant Evaluation for External Events (IPEEE) Fire Analysis* (Reference 2.11-1) was performed using EPRI's *Fire-Induced Vulnerability Evaluation* (FIVE, Reference 2.11-6). In this method, for each fire area a fire initiating frequency was combined with a conditional core damage probability (CCDP) to determine the CDF.

The CCDP for each fire area was calculated using a fire CDF model derived from the Level 1 internal events Individual Plant Evaluation (IPE) model. This was accomplished by setting the basic events for all fire susceptible equipment in the area to 'true' and solving the model. If the CDF obtained by combining this CCDP value with the area's fire initiating frequency was less than 1.0E-06 the area was screened from further analysis. Areas that did not screen on the first pass were evaluated using more realistic fire initiator frequencies and fire damage scenarios.

Evaluation

Since the CCDP is calculated using a model that is similar to the Level 1 internal events PSA, the IPEEE fire analysis attributes that could potentially be affected by the proposed power uprate are the same as those for the Level 1 internal events PSA: initiating event frequencies, component failure rates, success criteria, operator actions, LOOP recoveries. Each of these attributes is discussed below.

Initiating Event Frequencies

The fire initiating frequency for each area is dictated by combustible loading within the area and is, therefore, not affected by the power uprate.

Component Failure Rates

Since the discussion on the Level 1 internal events PSA concluded that the power uprate will have no adverse effect on component failure rates, this attribute will also not be affected for the IPEEE fire analysis.

Success Criteria

Since the discussion on the Level 1 internal events PSA concluded that the power uprate will have no adverse effect on success criteria, this attribute will also not be affected for the IPEEE fire analysis.

Operator Actions

Since the time available to perform operator actions may decrease with the increase in power, the operator recovery actions applied in the analysis may be affected. For example, most of the recoveries applied in the IPEEE fire analysis have an available time based on the time it takes to begin uncovering the core after core cooling is lost.

An available time of 50 minutes was used in the IPEEE fire analysis. However, recent CENTS calculations show that this time is 82.6 minutes before power uprate and that it is 68.3 minutes after power uprate.

Since the fire risk is dominated by the unscreened areas, only the unscreened areas were evaluated for power uprate. The screened areas were treated very conservatively in the IPEEE fire analysis and realistically are much lower in risk than the unscreened areas. In this analysis, the CENTS-calculated available times were factored into the recoveries applied to the unscreened areas and new pre- and post-power uprate CDF values were calculated using the original IPEEE cut set files.

LOOP Recovery

External LOOP is not assumed, since the initiator is a fire within the plant. LOOPs due to fire damage to offsite power-related cables and switchgear within the plant are included in the analysis, with no recovery credited. Therefore, the LOOP recovery (convolution) analysis described in the internal events section—which is dependent on available time—is not applicable to the fire analysis.

Core Damage Probability

The Waterford 3 power uprate increases the CDF contribution of the unscreened areas in the IPEEE Fire Analysis as shown in the following table. The total increase in fire CDF is 6.7E-10. The increase is due to the decreased time available to recover from fire-induced and random loss of FW (normal and emergency). Table 2.11-4 shows the CDF results by fire area for the unscreened areas.

Table 2.11-4
CDF Results for IPEEE Fire Unscreened Zones

Fire Area	Description	Pre-EPU CDF	Post-EPU CDF	Change in CDF	% Change*
RAB 1A	Control Room	1.952E-06	1.952E-06	0.0E+00	0.0
RAB 1E	Cable Spreading Room	9.920E-08	9.920E-08	0.0E+00	0.0
RAB 2	H&V Mechanical Room	1.940E-06	1.940E-06	0.0E+00	0.0
RAB 6	Elec. Penetration Area A	4.392E-07	4.392E-07	0.0E+00	0.0
RAB 7	Relay Room Envelope	1.642E-07	1.642E-07	0.0E+00	0.0
RAB 8	Switchgear Room	1.467E-06	1.467E-06	0.0E+00	0.0
RAB 15	EDG B	5.733E-07	5.733E-07	0.0E+00	0.0
RAB 31	-4 Corridor and Passageways	5.580E-08	5.580E-08	0.0E+00	0.0
RAB 39	-35 and -4 General Areas	1.905E-08	1.920E-08	1.5E-10	1.8E-03
TGB	Turbine Generator Building	1.437E-06	1.437E-06	5.2E-10	6.4E-03
	Total	8.147E-06	8.147E-06	6.7E-10	8.2E-03

* Calculated as percent of total pre-EPU CDF.

Conclusion

In conclusion, the EPU negligibly increases the CDF contribution of the unscreened areas in the IPEEE fire analysis. This increase is due to the decreased time available to recover from loss of core cooling. However, no new vulnerabilities or insights were noted. Thus, the power uprate will have negligible adverse impact on the IPEEE internal fire analysis.

2.11.4 Level 1 External Events Evaluation

2.11.4.1 IPEEE Seismic Analysis

Background

Waterford 3 is classified as a reduced scope plant as defined in NUREG-1407 (Reference 2.11-2) based on the low seismicity. Therefore, for the original IPEEE seismic evaluation, a seismic review of the plant was performed to the plant's original design basis. This was accomplished by performing a seismic margins assessment (SMA) of the safe shutdown equipment list (SSEL) with plant walkdowns in accordance with the guidelines and procedures documented in EPRI NP-6041-SL (Reference 2.11-3).

Safe shutdown success paths were developed to identify the systems that must function to successfully shutdown and cool the reactor following the occurrence of a safe shutdown

earthquake (SSE). A safe shutdown success path is a string of systems which is used to accomplish all of the required safe shutdown functions.

No seismic vulnerabilities were identified. The walkdowns resulted in no outliers that are operability issues at the plant.

Evaluation

As discussed previously, existing component monitoring programs can account for any additional wear as a result of power uprate. While the power uprate may result in some components being refurbished or replaced more frequently, the functionality and reliability of components can be maintained to the current standard. Thus, the increase in power level is not expected to affect equipment survivability nor equipment response during an earthquake. Also, the power uprate does not modify the safe shutdown pathway assumed in the SMA. Thus, the SMA is not impacted by the power increase.

Conclusion

Based on the above arguments, the power uprate will have no adverse effect on the IPEEE seismic evaluation.

2.11.4.2 IPEEE Other External Events Analysis

Background

The IPEEE Other Events Analysis Screening for Waterford 3 (Reference 2.11-1) used the IPEEE screening approach described in Reference 2.11-4. Waterford 3 searched for significant changes in the probability for high winds, floods, or offsite industrial facility accidents. The focus of this part of the IPEEE submittal was on reviewing the plant design for consistency with the acceptance criteria in the 1975 Standard Review Plan (SRP) (Reference 2.11-5) in terms of high winds, onsite storage of hazardous materials, and offsite developments. The original licensing action for Waterford 3 used the 1975 SRP as a basis for finding Waterford 3 acceptable in terms of external hazards with a few exceptions that the NRC reviewed and accepted. The exceptions were technical rather than substantive, e.g., the SRP recommended technique for calculating tornado loading on the shield building was not appropriate given the shallow dome roof of the shield building.

The IPEEE found no high winds, floods, or offsite industrial facility accidents that significantly altered the Waterford 3 estimate of either the core damage frequency, or the distribution of containment release categories. The IPEEE concluded that the plant is in conformance with the 1975 SRP that pertains to high winds, onsite storage of hazardous materials, and offsite developments.

Evaluation

Power uprate only involves small impacts on internal event sequence timing. It does not affect high wind, flood, or offsite industrial accident frequencies, nor does it affect associated protective features, such as missile and flood barriers and toxic chemical monitors.

Conclusion

Power uprate will have a no effect on the IPEEE Other External Events Analysis.

2.11.5 Level 2 Internal And External Events Evaluation

A simplified, conservative method was used to calculate the large early release frequency (LERF). This LERF calculation was a simplification of NUREG/CR-6595 (Reference 2.11-7). Four elements were considered:

a) HP core damage sequence leading to HP melt ejection (HPME)/direct containment heating (DCH)

b) Core damage with failure of containment isolation

c) Containment bypass sequences

d) Thermally induced SGTR

Note that several questions in the containment event tree (CET) (Reference 2.11-7, Figure 2-1) were ignored in the present calculation, which is equivalent to not crediting the LERF-reducing effects of the phenomena under question. First, recovery after core damage but before vessel breach was ignored, i.e., no recovery was credited. Second, no credit is taken for sequence timing that could allow offsite protective actions before containment failure (i.e., to make a release late).

The power uprate Level 2 evaluation calculates the LERF associated with the pre-EPU to post-EPU CDF change by sequence; sequence CDF results were used in order to bin the results into the appropriate LERF categories (e.g., HP sequences, bypass sequences).

Table 2.11-5 shows the pre-EPU and EPU LERF, and the change in LERF, by Level 1 sequence, for internal events; the total internal events LERF increase is 6.84E-8. This is a very conservative estimate. The 2 dominant LER scenarios are 1) HPME/DCH and 2) thermally induced SGTR. For HP core melt sequences (assumed to include small LOCAs), the probability of early containment failure is assumed to be 0.1, even though current Level 2 knowledge indicates that this failure mode is unlikely for large, dry containments like Waterford 3. For thermally induced SGTR, scenarios with high primary pressure and a depressurized, dry secondary are assumed to result in an induced SGTR with a probability of 1.0.

Table 2.11-5
LERF Results by Level 1 Internal Events Sequence

Sequence	Description	Pre-EPU	EPU	Delta-LERF
ATWS	ATWS	2.65E-08	2.65E-08	0.00E+00
AU	Large LOCA with SI Failure in Injection	2.15E-10	2.15E-10	0.00E+00
AX	Large LOCA with SI Failure in Recirc	1.73E-11	1.73E-11	0.00E+00
ISLOCA	Interfacing System LOCA	3.13E-07	3.13E-07	0.00E+00
MU	Medium LOCA with HPSI Failure in Injection	6.69E-11	6.69E-11	0.00E+00
MX	Medium LOCA with HPSI Failure in Recirc	1.45E-09	1.45E-09	0.00E+00
RB	SGTR with Failure of Normal FW and EFW Failure	1.77E-08	1.77E-08	0.00E+00
RU	SGTR with Failure of RCS Injection	4.03E-08	4.03E-08	0.00E+00
RX	SGTR with Failure to Depressurize	2.86E-07	2.86E-07	0.00E+00
SB	Small LOCA with Failure of Normal FW and EFW Failure	9.14E-11	9.14E-11	0.00E+00
SBO	Station Blackout with EFW AB Failure or Battery Depletion	2.76E-07	3.24E-07	4.73E-08
SBORCP	Station Blackout with RCP Seal Failure	0.00E+00	2.11E-11	2.11E-11
SU	Small LOCA with HPSI Failure in Injection	9.86E-09	9.86E-09	0.00E+00
SX	Small LOCA with HPSI Failure in Recirc	1.63E-08	1.63E-08	0.00E+00
TB	Loss of Normal Feedwater with EFW Failure	5.01E-07	5.22E-07	2.07E-08
TPQB	Stuck-Open Safety Relief Valve (SRV) LOCA with Failure of Normal FW and EFW Failure	1.07E-10	1.07E-10	0.00E+00
TPQU	Stuck-Open SRV LOCA with HPSI Failure in Injection	2.46E-09	2.46E-09	0.00E+00
TPQX	Stuck-Open SRV LOCA with HPSI Failure in Recirc	3.99E-09	3.99E-09	0.00E+00
TQB	RCP Seal LOCA with Failure of Normal FW and EFW Failure	2.03E-09	2.30E-09	2.65E-10
TQU	RCP Seal LOCA with HPSI Failure in Injection	5.28E-10	5.28E-10	0.00E+00
TQX	RCP Seal LOCA with HPSI Failure in Recirc	7.08E-10	7.28E-10	1.97E-11
V	Reactor Vessel Rupture	2.97E-09	2.97E-09	0.00E+00
	Total	1.50E-06	1.57E-06	6.84E-08

For fire, the CDF increase for all unscreened fire areas was assumed to be totally HP scenarios, producing a LERF increase of 7E-11.

Conclusion

The estimated increase in internal events large early release (LERF) of 6.84E-8 per yr as a result of the power uprate is small. (Fire LERF is 3 orders of magnitude lower and negligible.) Although this license amendment is not being requested as a risk-informed change, this risk increase meets the acceptance criterion of RG 1.174 (Reference 2.11-11) of 1E-7 for LERF. Therefore, the requested extended power uprate poses a small and acceptable risk.

2.11.6 Evaluation of PSA Model Quality

The Waterford 3 Level 1 PSA Model was initially developed in response to NRC Generic Letter 88-20 (the Individual Plant Examination, or IPE; Reference 2.11-8). A peer review of the IPE results was performed. Since its submittal to the staff (Reference 2.11-9), this model has been updated several times to maintain it consistent with the as-built, as-operated plant. In addition, the most recent update involved extensive revision of the HRA, common cause failure (CCF) analysis, data analysis (generic and plant-specific failure rates and maintenance unavailabilities), and loss of offsite power analysis in order to bring the PSA model up to current PSA standards, including the new ASME PSA standard (Category II). Weaknesses in the Level 1 IPE model identified in the IPE Staff Evaluation Report (Reference 2.11-10) have been addressed by this update. Weaknesses identified in the Level 2 IPE model are not applicable because the Level 2 model is not used in the power uprate analysis; rather, a simplified, conservative method based on NUREG/CR-6595 is used, as described previously. Furthermore, the vast majority of industry peer review comments (e.g., 15 of 19 A-level and 60 of 80 B-level) have been addressed. Remaining open peer review comments include documentation and Level 2 comments, comments that are partially addressed, and minor model limitations; these open comments do not affect the ability of the model to estimate the risk impact of power uprate. Finally, engineering calculations document the development of all major elements of the initial and updated versions of the model. These calculations have been independently reviewed and are retained as quality records.

2.11.7 Shutdown Risk

Background

Shutdown risk impacts were examined in a qualitative manner by answering the four questions posed by SRP 19 to determine if impacts on shutdown risk would be important. A discussion of these four points follows.

Evaluation

1. Will these changes affect shutdown schedule?

   The Shutdown Cooling System (SDCS) performance evaluation indicates that the ability of the SDCS to achieve cold shutdown (less than 200°F) in a reasonable time frame has been verified. The evaluation is comparable to that described in FSAR Section 9.3.6 with considerations for the effects of the power uprate and system changes since the original

evaluation. The SDCS remains adequate to maintain refueling temperatures and a uniform boron concentration in the RCS.

Since the decay heat levels are expected to be slightly higher at power uprate conditions, it may take a few hours longer to achieve cold shutdown. This will cause very little change in the shutdown schedule, and has no direct safety impacts on the schedule.

2. Will these changes affect operator ability to respond?

The following shutdown safety functions are typically tracked during an outage:

a) Decay heat removal
b) RCS
c) Vital power control (AC and DC)
d) Reactivity control
e) Containment closure

The possible initiating events during shutdown are generally defined as loss of the shutdown safety functions. The power uprate does not increase the frequency of these initiators, but may impact the operators' ability to respond to loss of shutdown safety functions.

Decay Heat Removal

The SDCS performance evaluation notes that the SDCS remains adequate to maintain refueling temperatures and a uniform boron concentration in the RCS. Section 2.5.5.1 notes that, with the increase in decay heat due to power uprate, the spent fuel pool (SFP) temperature is still kept within allowable limits for a full core discharge. The increase in temperature and the increase in decay heat will decrease the time for operators to respond to a loss of shutdown cooling or spent fuel pool cooling.

Maintaining an adequate defense-in-depth for this safety function, at all times, via the Shutdown Operations Protection Plan (SOPP) minimizes the impact of this decreased response time. The SOPP is prepared according to the guidance of the planned outages procedure. The current revision of this procedure includes requirements that:

a) At least three of the following seven heat sinks shall be available: 2 wet cooling towers (WCTs), 2 dry cooling towers (DCTs), reactor head removed and refueling water level as required by Technical Specification 3.9.8.1 (i.e., the large mass of water), or 2 steam generators with associated reactor coolant pumps (RCPs).
b) Both SDC trains shall be available during reduced inventory operations.
c) Additional restrictions in place when in reduced inventory conditions.

Inventory Control

The increase in RCS temperature and the increase in decay heat will decrease the time for operators to respond to a loss of RCS inventory control. Maintaining an adequate defense-in-depth for this safety function, at all times, via the SOPP minimizes the impact of this

decreased response time. The SOPP is prepared according to the guidance of the planned outages procedure. The current revision of this procedure includes requirements that:

a) In addition to the SDCS requirements described above, 2 HPSI pumps with a flow path to the RCS are required during reduced inventory.
b) Mid-loop operations shall be minimized.

Vital Power – AC & DC

The increase in RCS temperature and the increase in decay heat will decrease the time for operators to respond to a loss of electrical systems, since the electrical systems support the systems required for the other safety functions. Maintaining an adequate defense-in-depth for this safety function, at all times, via the SOPP minimizes the impact of this decreased response time. For example, in addition to the requirements for the other safety functions, the current revision of the planned outages procedure includes the requirements that:

a) With an EDG out of service and two SDC trains required, 2 independent trains of offsite power are required. At least 1 EDG shall be operable.
b) For the protected train, the associated DC bus shall be energized and the 4160V AC safety bus shall be energized from offsite power with its EDG available. For the non-protected train, if its associated SDC train is required, the associated DC bus shall be energized and the 4160V AC safety bus shall be energized from offsite power, i.e., work on the non-protected EDG is allowed. Waterford 3 currently performs major EDG maintenance on-line, so the unavailability of the EDGs during outage conditions when the non-protected SDC train is not affected by EPU.

Reactivity Control

The non-LOCA safety analysis section of this report describes the analysis of the uncontrolled boron dilution incident for power uprate conditions. The increase in rated power was found to have a negligible impact on the results of the boron dilution event. The analysis showed that for dilution during refueling, dilution during cold shutdown with the RCS filled, and dilution during cold shutdown with the RCS partially drained the operator is alerted to the event with more than the minimum response time available.

Containment Closure

The containment closure safety function assures the capability to close the containment following a loss of another safety function. Thus, the response time for this safety function is decreased by the decreased response time for the other safety functions. Maintaining an adequate defense-in-depth for this safety function, at all times, via the SOPP minimizes the impact of this decreased response time.

3. Will changes affect shutdown equipment reliability?

As discussed previously, existing component monitoring programs can account for any additional wear as a result of power uprate. While the power uprate may result in some

components being refurbished or replaced more frequently, the functionality and reliability of components can be maintained to the current standard.

4. Will changes affect availability of equipment or instrumentation used for contingency plans?

   As discussed previously, existing component monitoring programs can account for any additional wear as a result of power uprate. While the power uprate may result in some components being refurbished or replaced more frequently, the functionality and reliability of components can be maintained to the current standard.

Conclusion

The increase in decay heat will result in a small decrease in the time available for operator actions during shutdown. However, maintaining an adequate defense-in-depth for the shutdown safety functions at all times, via the SOPP, minimizes the impact of this decreased response time. In conclusion, the power uprate will have no unique or significant impacts on shutdown risk.

2.11.8 Overall Risk Assessment Conclusions

The Waterford 3 power uprate will have no adverse effect on Level 1 internal events PSA initiator frequencies or component failure rates. The power uprate negligibly affects the CDF contribution of the unscreened areas that dominate the IPEEE fire analysis. No new fire vulnerabilities or insights were noted. Finally, the power uprate will have no adverse effect on the IPEEE other external events analysis.

The increase in decay heat will result in a small decrease in the time available for operator actions during shutdown. However, maintaining an adequate defense-in-depth for the shutdown safety functions at all times, via the SOPP, minimizes the impact of this decreased response time. Therefore, the power uprate will have no unique or significant impacts on shutdown risk.

The power uprate increases the Waterford 3 internal events CDF by 3.5E-7 per yr (an increase of about 6%), for a power increase from the original 3390 MWt to 3716 MWt. The increase in internal events LERF is 6.84E-8. These increases are small. Although this license amendment is not being requested as a risk-informed change, these risk increases meet the acceptance criteria of RG 1.174 (Reference 2.11-11) of 1E-6 for delta-CDF and 1E-7 for delta-LERF. Therefore, the requested extended power uprate poses a small and acceptable risk.

The risk assessment also shows that the Waterford 3 power uprate does not create the “special circumstances” described in Appendix D of SRP Chapter 19 (Reference 2.11-12). The power uprate risk impact is small, and thus does not meet the “special circumstances” definition of undue risk. Appendix D of SRP Chapter 19 gives as an example of a license amendment request that creates “special circumstances:” a power uprate request that would increase power “well beyond the levels approved in previous uprates and introduce or substantially increase the frequency of risk-significant core damage sequences”. Since the Waterford 3 power uprate is similar to previous uprates and involves only a small increase in risk, the power uprate is acceptable with respect to Appendix D of SRP Chapter 19.

The Waterford 3 PSA has been updated to keep it consistent with the as-built, as-operated plant and to address IPE review comments and most industry peer review comments. The model is sufficient for estimating the risk impact of power uprate.

2.11.9 References

2.11-1 W3F1-95-0117, A4.05, Letter, R. F. Burski to NRC, *Response to Generic Letter 88-20, Supplement 4, 'Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities'*, July 28, 1995.

2.11-2 NUREG-1407, *Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities*, NRC, June 1991.

2.11-3 EPRI NP-6041-SL, *A Methodology for Assessment of Nuclear Power Plant Seismic Margin*, Rev. 1, August 1991.

2.11-4 Generic Letter 88-20, Supplement 4, *Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities*, NRC, June 28, 1991.

2.11-5 NUREG-75/087, *Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plans—LWR Edition*, NRC, December 1975.

2.11-6 *Fire-Induced Vulnerability Evaluation (FIVE),* EPRI TR-100370 Project 3000-41, April 1992.

2.11-7 NUREG/CR-6595, *An Approach for Estimating the Frequencies of Various Containment Failure Modes and Bypass Events*, NRC.

2.11-8 Generic Letter No. 88-20, *Individual Plant Examination for Severe Accident Vulnerabilities - 10CFR50.54(f),* NRC, November 23, 1988.

2.11-9 W3F192-0311, Letter, R. F. Burski to USNRC, *Response to Generic Letter 88-20, 'Individual Plant Examination for Severe Accident Vulnerabilities – 10CFR50.54(f)'*, August 28, 1991.

2.11-10 C. P. Patel (NRC) to C. M. Dugger (Entergy), *Review of Waterford Steam Electric Station, Unit 3, Individual Plant Examination Submittal – Internal Review (TAC. No. M77487)*, March 4, 1997.

2.11-11 Regulatory Guide 1.174, *An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis*, Rev. 1, November 2002.

2.11-12 NUREG-0800, *Standard Review Plan*, Chapter 19, *Use of Probabilistic Risk Assessment in Plant-Specific, Risk-Informed Decisionmaking: General Guidance*, NRC, November 2002.

2.12 ECCS PERFORMANCE ANALYSIS

An Emergency Core Cooling System (ECCS) performance analysis demonstrated conformance to the ECCS acceptance criteria for light water nuclear power reactors, 10CFR50.46 (Reference 2.12-1), for Waterford 3 at the power uprate rated core power of 3716 MWt (3735 MWt including a 0.5% power measurement uncertainty). Analyses were performed for a spectrum of large-break and small-break loss-of-coolant accidents (LOCAs). FSAR Sections 6.3.3 and 15.6.3.3 describe the ECCS performance analysis for Waterford 3.

Section 2.12.1 of this report describes the objective of the ECCS performance analysis. Section 2.12.2 identifies the regulatory basis of the analysis. Sections 2.12.3 through 2.12.5 summarize the large-break LOCA (LBLOCA), small-break LOCA (SBLOCA), and the long-term ECCS performance analyses. The summaries include a description of the methodology, the plant design data, and the results of the analyses. Section 2.12.6 summarizes an evaluation of the inadvertent opening of a pressurizer safety valve. The conclusions of the ECCS performance analysis are presented in Section 2.12.7 in this document.

2.12.1 Objective

The objective of the ECCS performance analysis is to demonstrate conformance to the ECCS acceptance criteria of 10CFR50.46(b):

Criterion 1: Peak Cladding Temperature (PCT): The calculated maximum fuel element cladding temperature shall not exceed 2200°F.

Criterion 2: Maximum Cladding Oxidation: The calculated total oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation.

Criterion 3: Maximum Hydrogen Generation: The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam shall not exceed 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react.

Criterion 4: Coolable Geometry: Calculated changes in core geometry shall be such that the core remains amenable to cooling.

Criterion 5: Long-Term Cooling: After any calculated successful initial operation of the ECCS, the calculated core temperature shall be maintained at an acceptably low value and decay heat shall be removed for the extended period of time required by the long-lived radioactivity remaining in the core.

2.12.2 Regulatory Basis

As required by 10CFR50.46(a)(1)(i), the ECCS performance analysis must conform to the ECCS acceptance criteria identified in Section 2.12.1 above. Additionally, the ECCS performance must be calculated in accordance with an acceptable evaluation model and must be calculated for a number of postulated LOCAs of different sizes, locations, and other

properties sufficient to provide assurance that the most severe postulated LOCAs are calculated. The evaluation model may either be a realistic evaluation model as described in 10CFR50.46(a)(1)(i) or must conform to the required and acceptable features of Appendix K ECCS Evaluation Models (Reference 2.12-2). The evaluation models used to perform the Waterford 3 EPU ECCS performance analysis are Appendix K evaluation models.

2.12.3 Large-Break LOCA (LBLOCA) Analysis

2.12.3.1 Methodology

The LBLOCA ECCS performance analysis used the 1999 Evaluation Model (EM) version of the Westinghouse LBLOCA evaluation model for Combustion Engineering (CE) PWRs. The current Waterford 3 LBLOCA ECCS performance analysis, described in Sections 6.3.3.2 and 15.6.3.3.3.1 of the Waterford 3 FSAR (Reference 2.12-3), employs the June 1985 version of the Westinghouse LBLOCA EM for CE PWRs (Reference 2.12-4), which is the version of the evaluation model upon which the 1999 EM is built.

Several computer codes are used in the 1999 EM. The computer codes are described in the references cited with additional descriptive information provided in the 1999 EM topical report (Reference 2.12-5). The CEFLASH-4A computer code (Reference 2.12-6) is used to perform the blowdown hydraulic analysis of the reactor coolant system (RCS) and the COMPERC-II computer code (Reference 2.12-7) is used to perform the RCS refill/reflood hydraulic analysis and to calculate the containment minimum pressure. It is also used in conjunction with the methodology described in Reference 2.12-8 to calculate the FLECHT-based reflood heat transfer coefficients used in the hot rod heatup analysis. The HCROSS (Reference 2.12-9) and PARCH (Reference 2.12-10) computer codes are used to calculate steam cooling heat transfer coefficients. The hot rod heatup analysis, which calculates the PCT and maximum cladding oxidation, is performed with the STRIKIN-II computer code (Reference 2.12-11). Core-wide cladding oxidation is calculated using the COMZIRC computer code (Appendix C of Supplement 1 of Reference 2.12-7). The initial steady state fuel rod conditions used in the analysis are determined using the FATES3B computer code (Reference 2.12-12).

The 1999 EM is described in the topical report (Reference 2.12-5) and it has been approved for LBLOCA analyses for the CE-designed PWRs as documented in the Safety Evaluation Report for the model (Reference 2.12-28). The 1999 EM as described in the topical report was used in the Waterford 3 extended power uprate LBLOCA ECCS performance analysis.

The 1999 EM is built on the June 1985 version of the Westinghouse LBLOCA evaluation model for the CE-designed PWRs. The Safety Evaluation Reports for the 1985 EM and computer codes are documented in References 2.12-13 through 2.12-19. The Safety Evaluation Reports (SERs) for the FATES3B computer code are documented in References 2.12-20 through 2.12-22.

In performing the LOCA calculations, conservative assumptions are made concerning the availability of safety injection (SI) flow. It is assumed that offsite power is lost and all pumps must await diesel startup before they can begin to deliver flow. (It is assumed, however, that offsite power is available for the Containment Spray System (CSS) and containment fan coolers). Also, it is assumed that all safety injection flow delivered to the broken cold leg is lost.

The limiting initial fuel rod conditions used in the LBLOCA analysis (i.e., the conditions that result in the highest calculated peak cladding temperature) were determined by performing burnup dependent calculations with STRIKIN-II using initial fuel rod conditions calculated by FATES3B. The calculations included the analysis of both UO_2 and erbia burnable absorber fuel rods.

A study was performed to determine the most limiting single failure of ECCS equipment under EPU conditions. The study analyzed no failure, failure of an emergency diesel generator, failure of a high-pressure safety injection (HPSI) pump, and a failure of a low-pressure safety injection (LPSI) pump consistent with approved topical reports. Maximum safety injection pump flow rates were used in the no failure case; minimum safety injection pump flow rates were used in the emergency diesel generator (EDG), HPSI and LPSI pump failure cases. The pumps were actuated on a safety injection actuation signal (SIAS) generated by low pressurizer pressure with a startup delay of greater than or equal to 27.0 seconds for HPSI and greater than or equal to 42.5 seconds for LPSI. Minimum refueling water storage pool temperature was used in all four cases as a result of a sensitivity study of the refueling water storage pool water temperature. The most limiting single failure (i.e., the failure that resulted in the highest calculated PCT) was no failure of ECCS equipment. This is the same limiting single failure described in the SAR for the current analysis. No failure is the worst condition because it maximizes the amount of safety injection that spills into the containment. This acts to minimize containment pressure which, in turn, minimizes the rate at which the core is reflooded. The failure of either an EDG or a HPSI or LPSI pump is not the most damaging failure because, in all cases, there is sufficient safety injection pump flow to keep the acceptable reflood rate. This maintains about the same reflood rate as for no failure, but results in less spillage into the containment. The study also investigated the impact of variation in safety injection tank (SIT) pressure, water temperature, and water volume on PCT. Minimum SIT pressure, minimum water temperature and maximum water volume were determined to result in the highest peak cladding temperature. The assumed maximum SIT water volume is 1686 ft^3, which is a 200 ft^3 reduction from the current Technical Specification. A Technical Specification change for maximum SIT water volume is included as part of this licensing amendment request.

A spectrum of guillotine breaks in the reactor coolant pump (RCP) discharge leg was analyzed. As described in Section 3.4 of Reference 2.12-5, the discharge leg is the most limiting break location and a guillotine break is more limiting than a slot break. In particular, the 0.6, 0.8, and 1.0 double-ended guillotine breaks in the reactor coolant pump discharge leg (DEG/PD) were analyzed. The 0.8 DEG/PD break was determined to be the limiting LBLOCA (i.e., the break that results in the highest calculated PCT). The same break was the limiting case in previous cycles also.

2.12.3.2 Plant Design Data

Important core, Reactor Coolant System (RCS), ECCS, and containment design data used in the LBLOCA analysis are listed in Tables 2.12-1 and 2.12-2. The listed fuel rod conditions are for rod average burnup of the hot rod that produced the highest calculated PCT. Plant design data for the containment (e.g., data for the containment initial conditions, containment volume, containment heat removal systems, and containment passive heat sinks) were selected to minimize the transient containment pressure. The core inlet temperature was the minimum RCS cold leg temperature at full power including uncertainty.

2.12.3.3 Results

Table 2.12-3 lists the peak cladding temperature and oxidation percentages for the spectrum of LBLOCAs. Times of interest are listed in Table 2.12-4. The variables listed in Table 2.12-5 are plotted as functions of time in Figures 2.12-1 through 2.12-8 for the 1.0 DEG/PD break. The variables listed in Tables 2.12-5 and 2.12-6 are plotted as functions of time for the 0.8 DEG/PD break, the limiting LBLOCA, in Figures 2.12-9 through 2.12-27. The variables listed in Table 2.12-5 are plotted for the 0.6 DEG/PD in Figures 2.12-28 through 2.12-35. The results for the extended power uprate demonstrate conformance to the ECCS acceptance criteria as summarized below. The results from the FSAR are provided for comparison.

Parameter	Criterion	EPU Results	Current FSAR
PCT	≤2200°F	2164°F	2177°F
Maximum Cladding Oxidation	≤17%	8.7%	8.6%
Maximum Core-Wide Oxidation	≤1%	<0.99%	<0.81%
Coolable Geometry	Yes	Yes	Yes

The results are applicable to Waterford 3 for a peak linear heat generation rate (PLHGR) of 13.2 kW/ft as specified in the Core Operating Limits Report (COLR) and a rated core power of 3716 MWt (3735 MWt including a 0.5% power measurement uncertainty).

Table 2.12-1
LBLOCA ECCS Performance Analysis
Core and Plant Design Data

Quantity	Value	Units
Reactor power level (100.5% of rated power)	3735	MWt
PLHGR of the hot rod*	13.2	kW/ft
PLHGR of the average rod in assembly with hot rod	12.38	kW/ft
Gap conductance at the PLHGR**	1661	BTU/hr-ft^2-^{o}F
Fuel centerline temperature at the PLHGR**	3371	°F
Fuel average temperature at the PLHGR**	2129	°F
Hot rod gas pressure**	1108	psia
Moderator temperature coefficient at 583°F, 2250 psia	$+0.0 \times 10^{-4}$	$\Delta\rho$/°F
RCS flow rate	148.0×10^6	lbm/hr
Core flow rate	144.15×10^6	lbm/hr
RCS pressure	2250	psia
Cold leg temperature	533.0	°F
Hot leg temperature	598.7	°F
Plugged tubes per steam generator	1000	---
Low pressurizer pressure SIAS setpoint	1560	psia
SIT pressure (min/max)	584.7/714.7	psia
SIT water volume (min/max)	926/1686	ft^3
LPSI pump flow rate (min, 1 pump/max, 2 pump)	4084/11300	gpm
HPSI pump flow rate (min, 1 pump/max, 2 pump)	762/1970	gpm
Containment pressure	14.025	psia
Containment temperature	90	°F
Containment humidity	100	%
Containment net free volume	2.684×10^6	ft^3
Containment spray pump flow rate	2250	gpm/pump
Refueling water storage pool temperature (min/max)	50/100	°F
Containment passive heat sinks	Table 2.12-2	---

* As specified in Core Operating Limits Report (COLR).
** These quantities correspond to the rod average burnup of the hot rod (1000 MWD/MTU) that yields the highest PCT.

Table 2.12-2
LBLOCA ECCS Performance Analysis
Containment Passive Heat Sink Data

Wall No.	Description	Material	Thickness(1) (ft)	Surface Area (ft^2)
1	Containment Primary Cylinder and Dome	Carbon Steel	0.118879	92819.00
2	Concrete Underwater (one side faces ground)	Concrete	11.463	15427.75
3	Concrete Underwater (all remaining)	Concrete	2.049	8553.69
4	Concrete in Air – less than 6 feet thick	Concrete	1.1025	47663.92
5	Concrete in Air – greater than or equal to 6 feet thick	Concrete	3.365	9913.15
6	Stainless Steel	Stainless Steel	0.003734	59114.40
7	Galvanized Steel (Zinc Coating on Carbon Steel)	Zinc Carbon Steel	0.000122 0.005628	192827.75
8	Structural and Miscellaneous Exposed Steel – less than 0.2-inch thick	Carbon Steel	0.008134	184549.18
9	Structural and Miscellaneous Exposed Steel – greater than or equal to 0.2-inch thick but less than 0.5-inch thick	Carbon Steel	0.03154	215234.76
10	Structural and Miscellaneous Exposed Steel – greater than 0.5-inch thick	Carbon Steel	0.065582	71308.76

(1) Thickness is effective thickness as a result of combining similar thickness walls.

Table 2.12-3
LBLOCA ECCS Performance Analysis Results

Break Size	PCT (°F)	Maximum Cladding Oxidation (%)	Maximum Core-Wide Cladding Oxidation (%)
1.0 DEG/PD	2133	8.3	<0.99
0.8 DEG/PD	2164	8.7	<0.99
0.6 DEG/PD	2149	8.3	<0.99

Table 2.12-4
LBLOCA ECCS Performance Analysis
Times of Interest (Seconds after Break)

Break Size	SITs On	End of Bypass	Start of Reflood	SITs Empty	SI Pumps on	Hot Rod Rupture
1.0 DEG/PD	10.5	21.7	43.1	114.6	49.7	43.6
0.8 DEG/PD	11.7	23.2	44.6	115.9	49.7	44.4
0.6 DEG/PD	13.8	25.6	47.0	118.2	49.8	45.8

Table 2.12-5
LBLOCA ECCS Performance Analysis
Each Break
Variables Plotted as a Function of Time

Variable
Core Power
Pressure in Center Hot Assembly Node
Leak Flow Rate
Hot Assembly Flow Rate (below and above hot spot)
Hot Assembly Quality
Containment Pressure
Mass Added to Core During Reflood
Peak Cladding Temperature

Table 2.12-6
LBLOCA ECCS Performance Analysis
Limiting Break
Variables Plotted as a Function of Time

Variable
Mid Annulus Flow Rate
Quality Above and Below the Core
Core Pressure Drop
Safety Injection Flow Rate into Intact Discharge Legs
Water Level in Downcomer During Reflood
Hot Spot Gap Conductance
Maximum Local Cladding Oxidation Percentage
Fuel Centerline, Fuel Average, Cladding, and Coolant Temperature at the Hot Spot
Hot Spot Heat Transfer Coefficient
Hot Pin Pressure
Core Bulk Channel Flow Rate

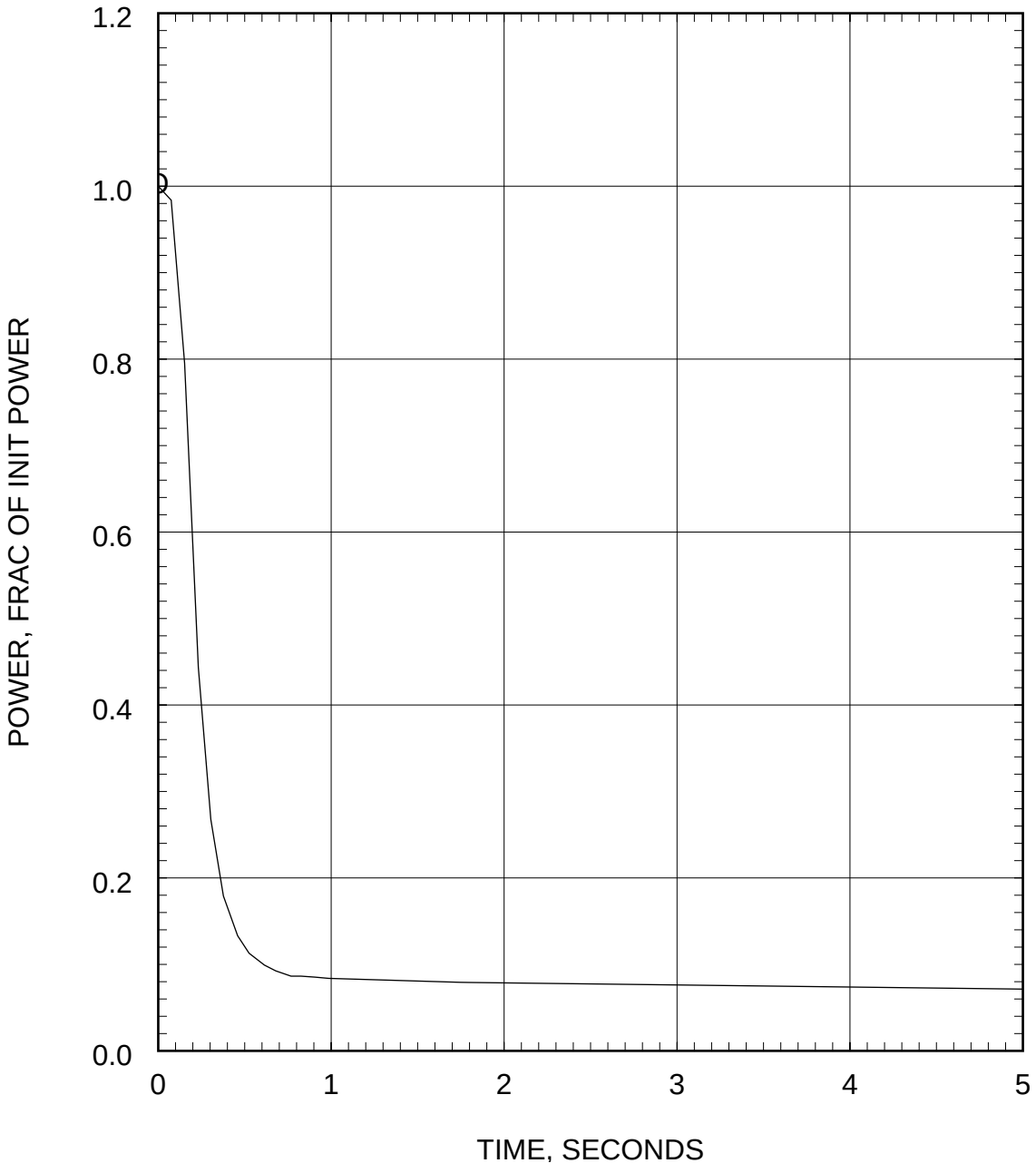


Figure 2.12-1
LBLOCA ECCS Performance Analysis
1.0 DEG/PD Break Core Power

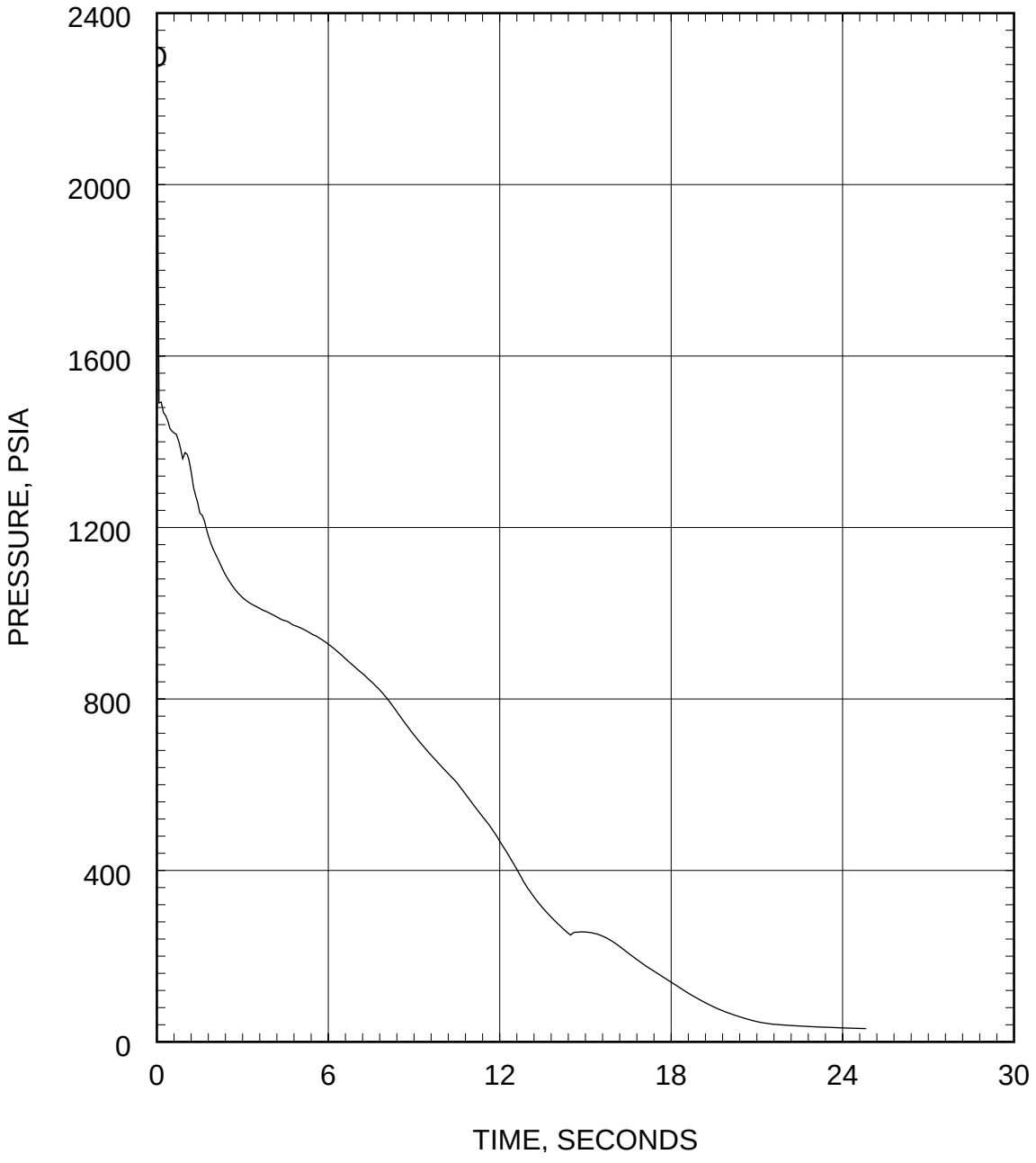


Figure 2.12-2
LBLOCA ECCS Performance Analysis
1.0 DEG/PD Break Pressure in Center Hot Assembly Node

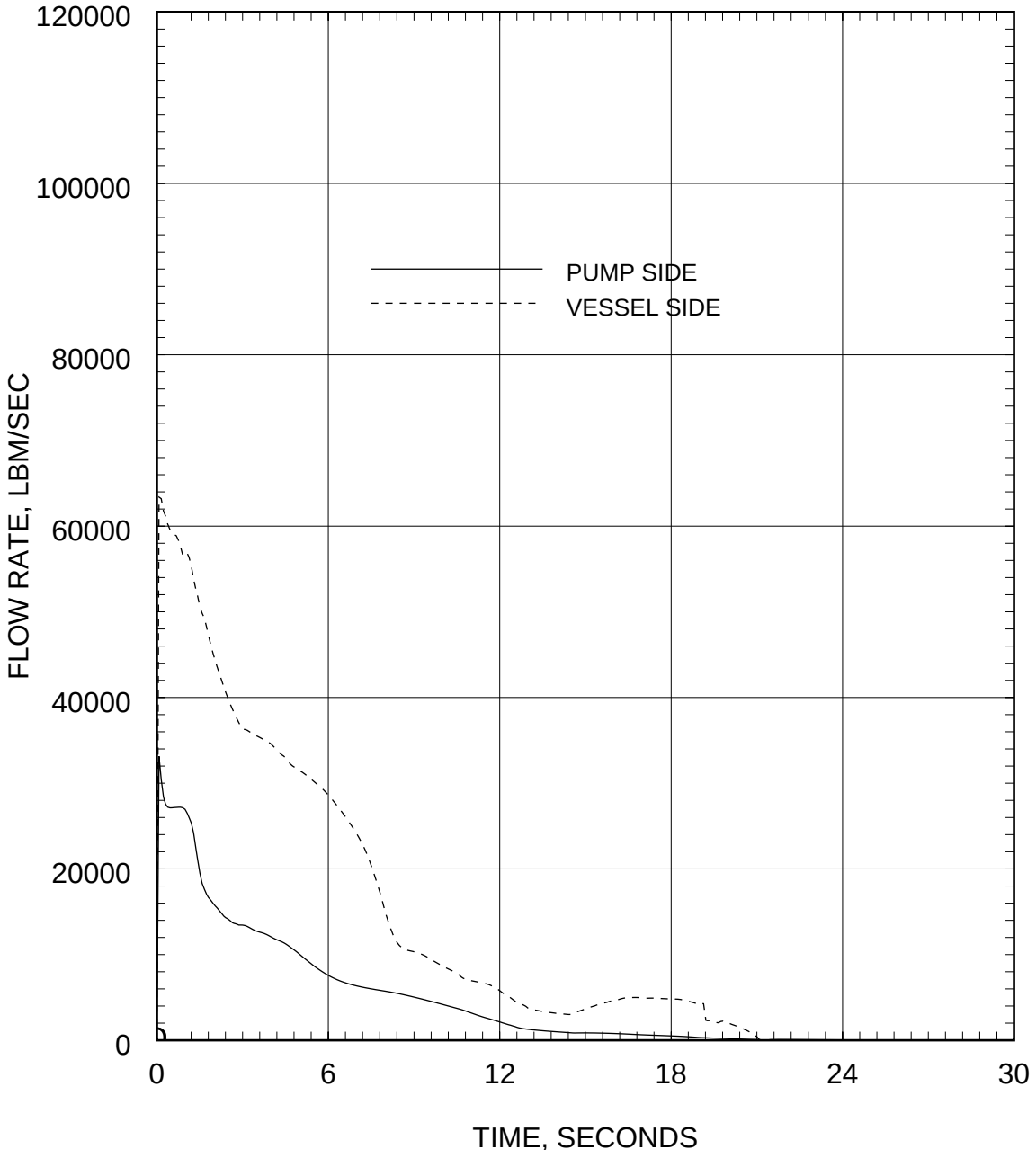


Figure 2.12-3
LBLOCA ECCS Performance Analysis
1.0 DEG/PD Break Leak Flow Rate

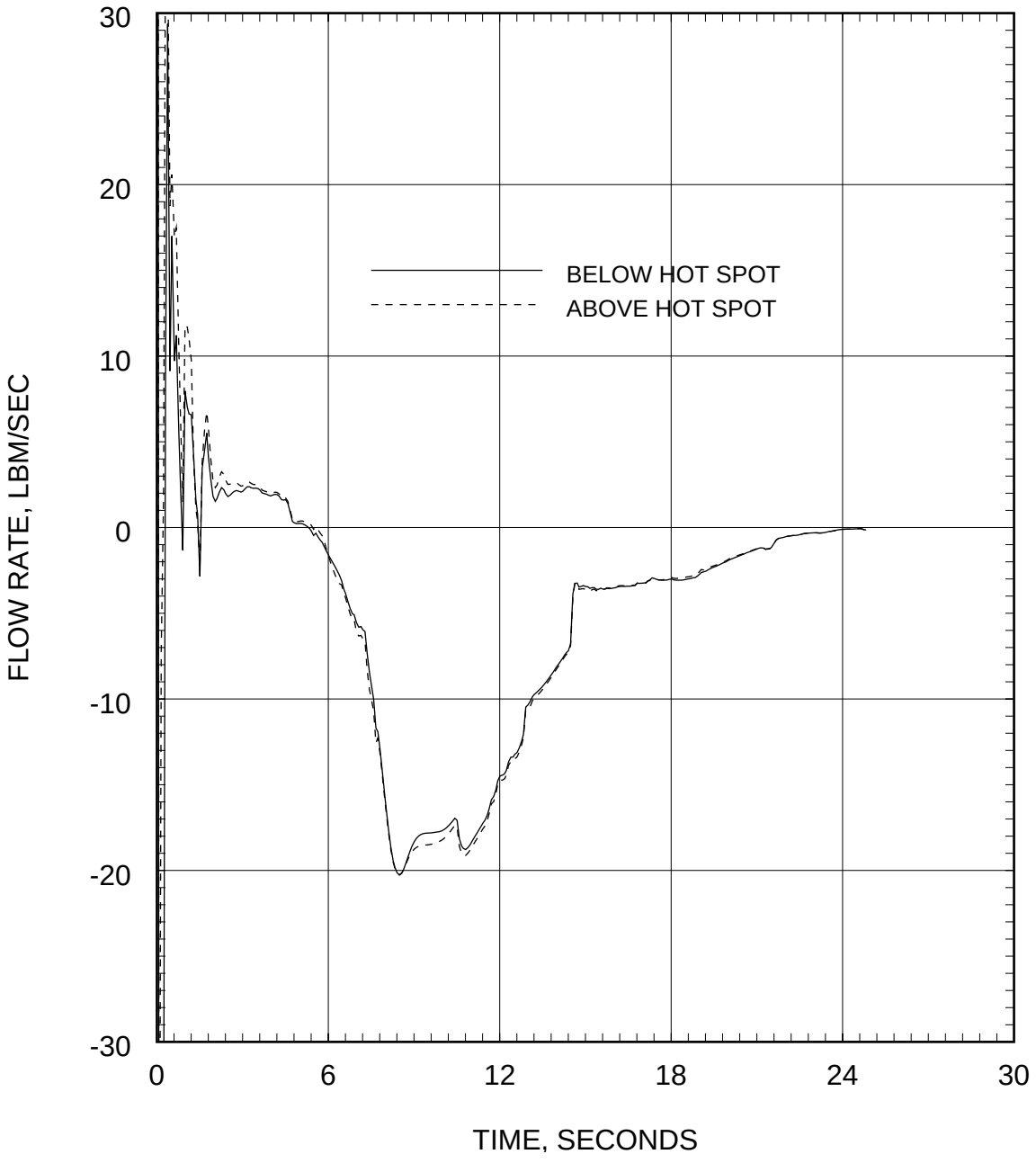


Figure 2.12-4
LBLOCA ECCS Performance Analysis
1.0 DEG/PD Break Hot Assembly Flow Rate (Below and Above Hot Spot)

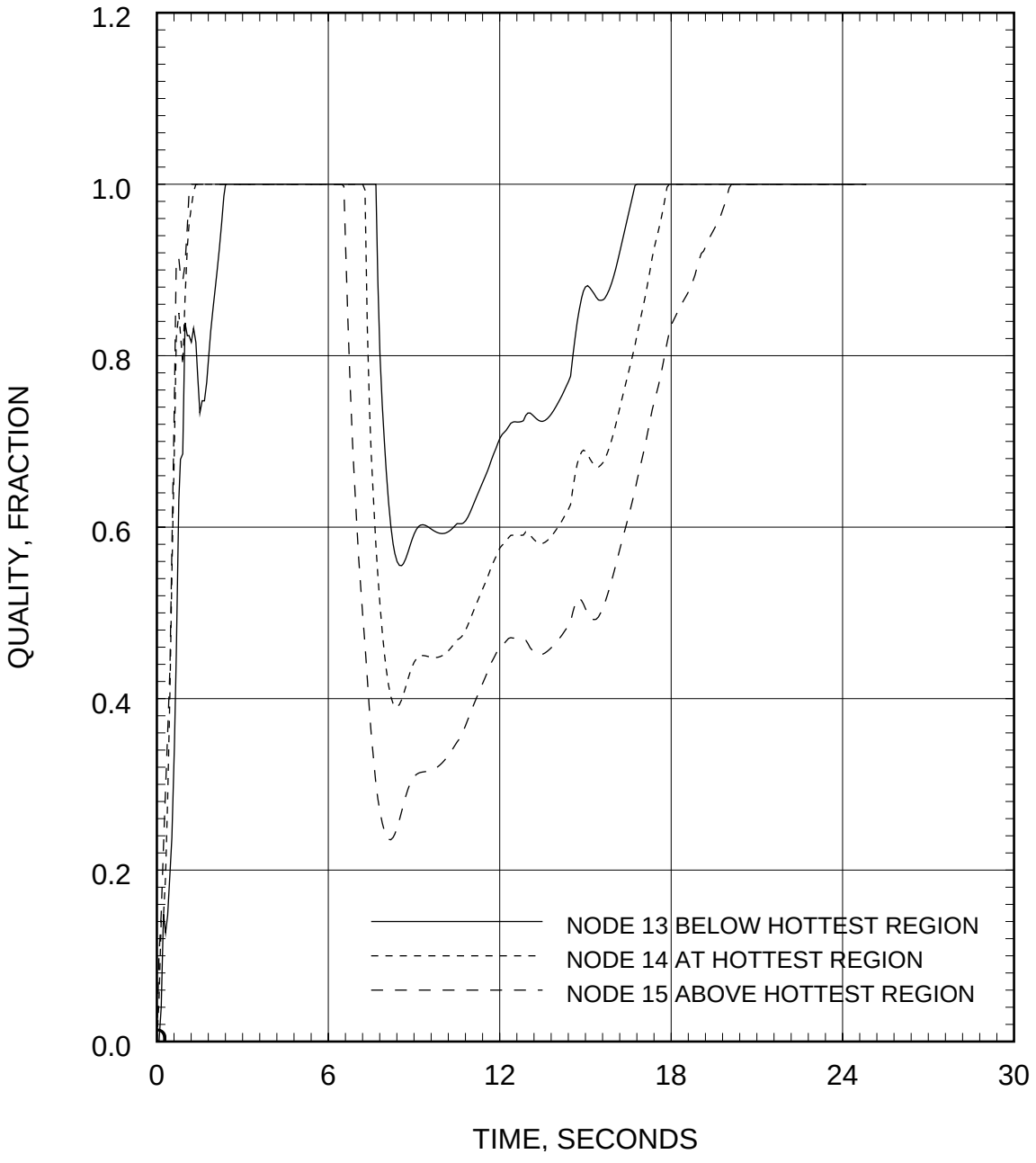


Figure 2.12-5
LBLOCA ECCS Performance Analysis
1.0 DEG/PD Break Hot Assembly Quality

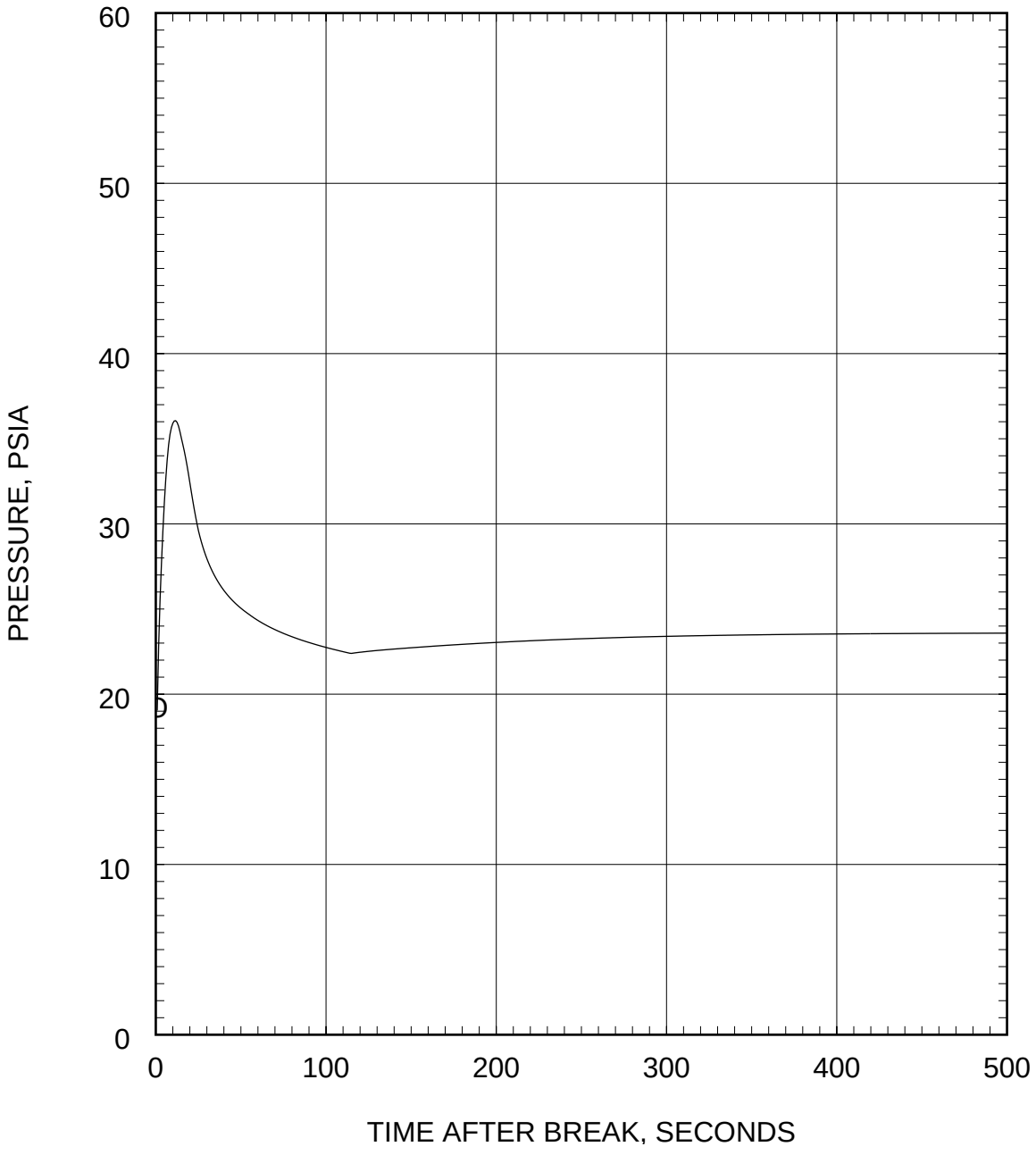


Figure 2.12-6
LBLOCA ECCS Performance Analysis
1.0 DEG/PD Break Containment Pressure

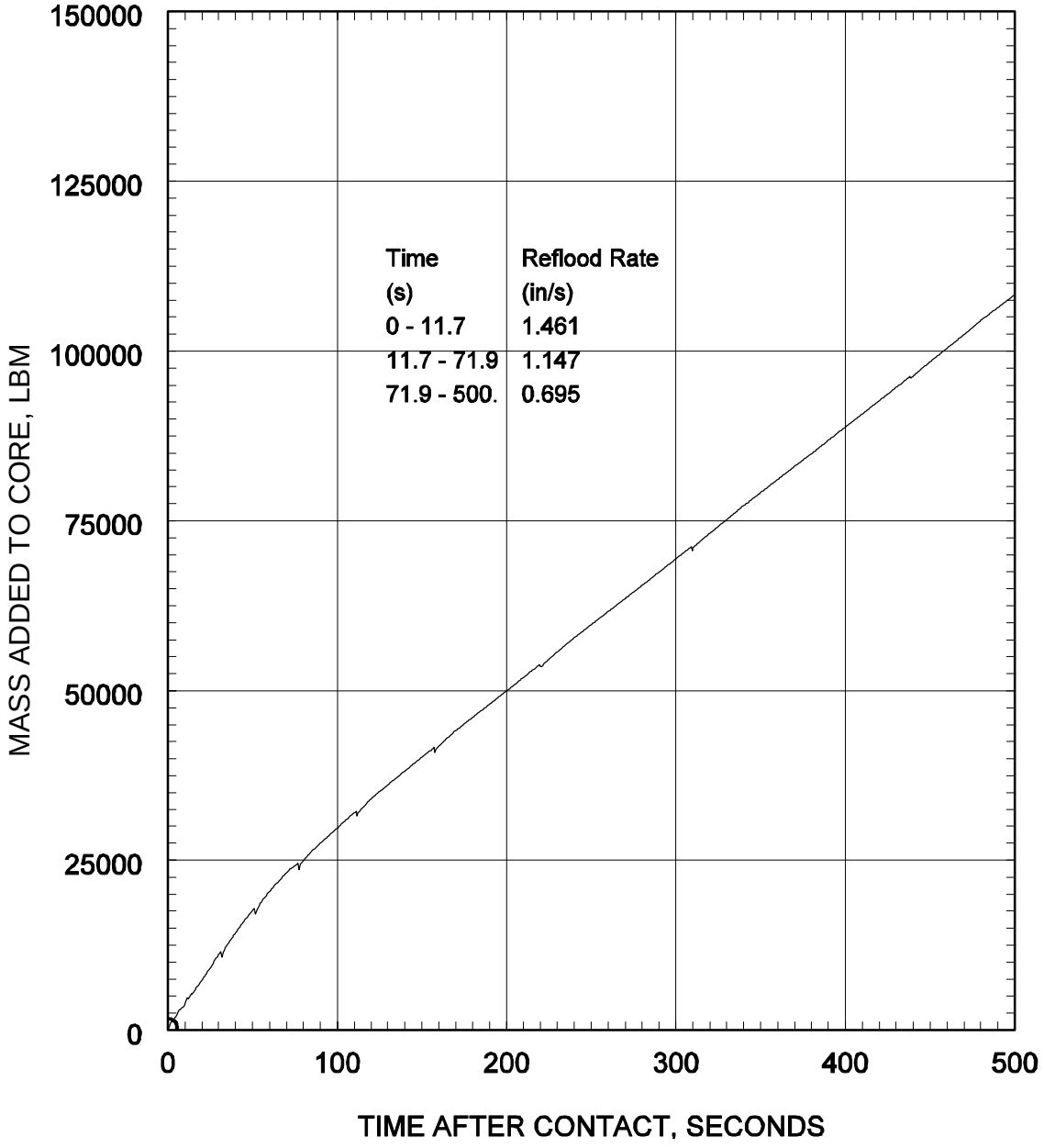


Figure 2.12-7
LBLOCA ECCS Performance Analysis
1.0 DEG/PD Break Mass Added to Core During Reflood

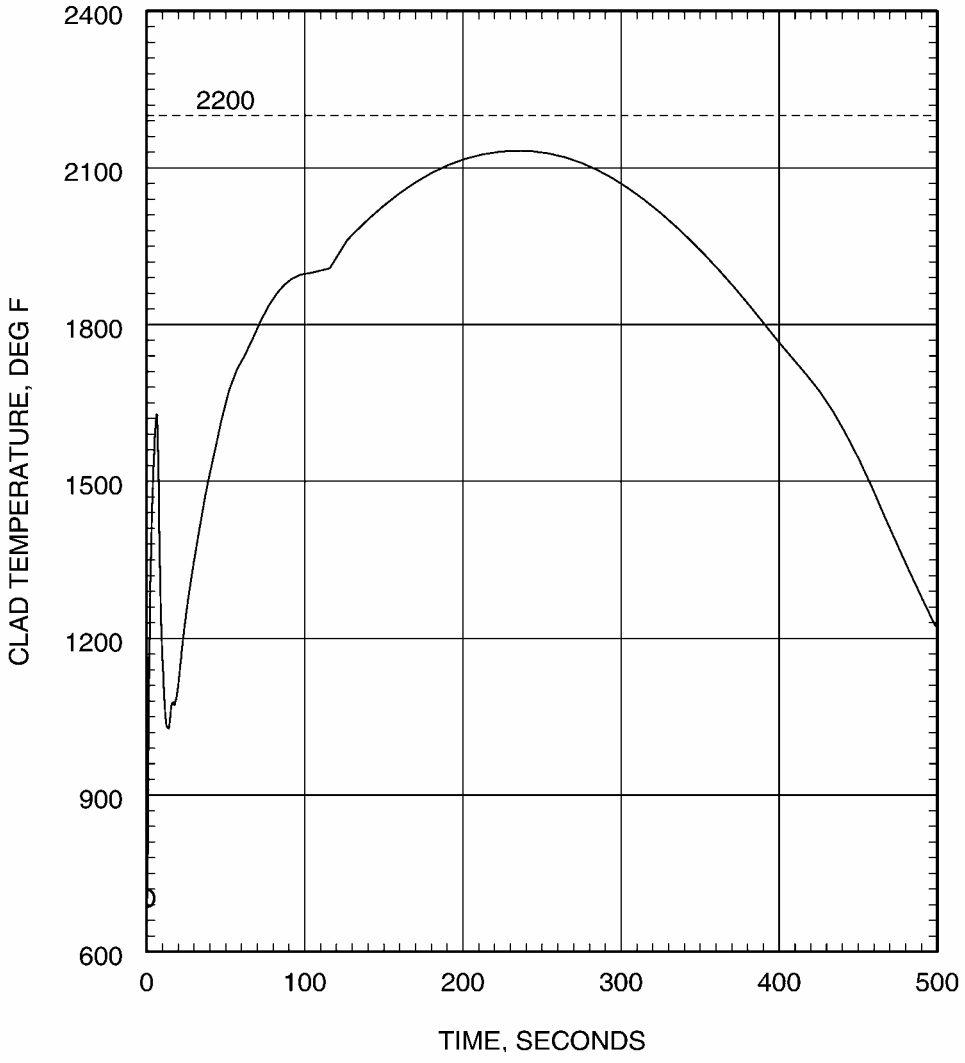


Figure 2.12-8
LBLOCA ECCS Performance Analysis
1.0 DEG/PD Break Peak Cladding Temperature

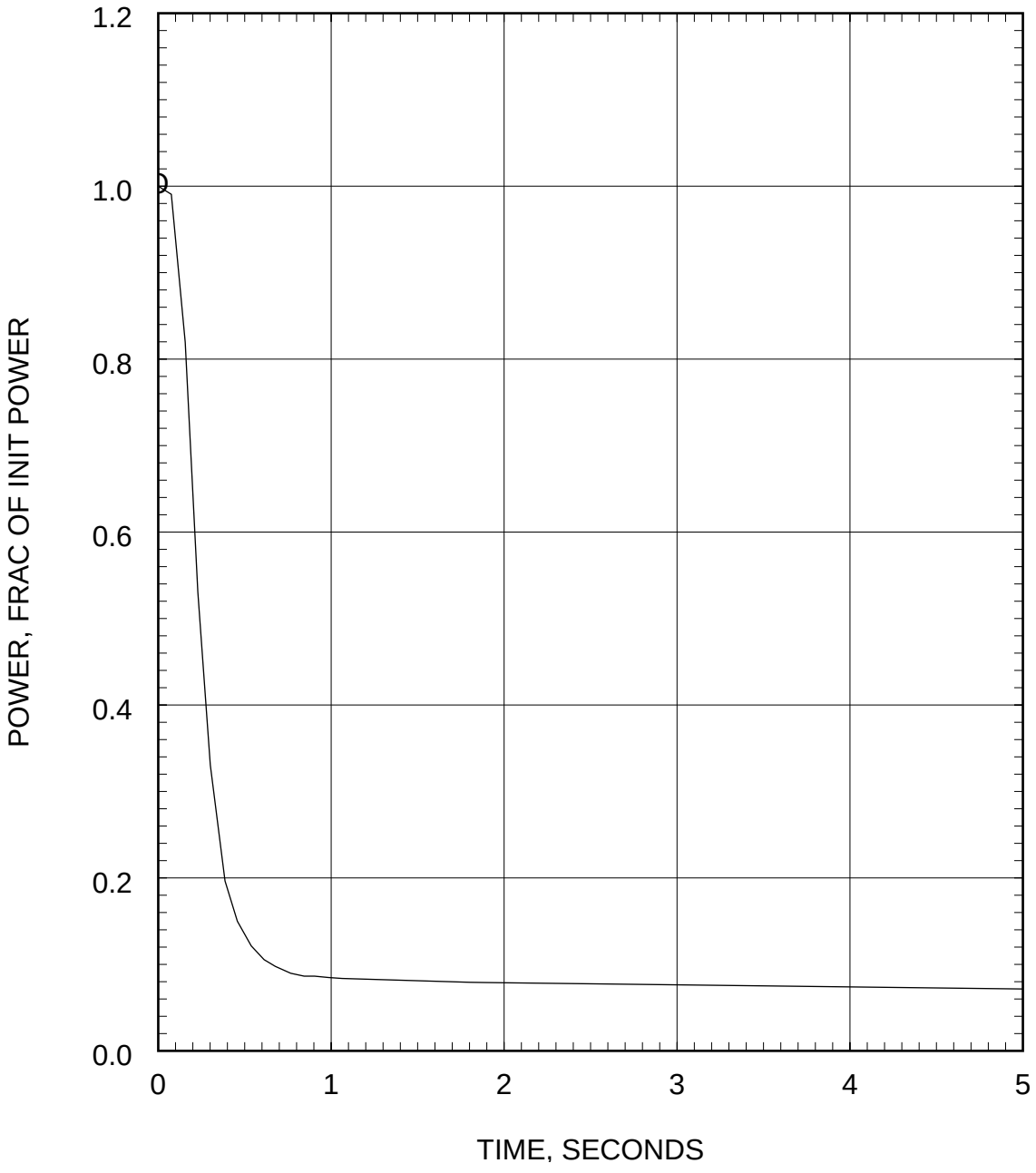


Figure 2.12-9
LBLOCA ECCS Performance Analysis
0.8 DEG/PD Break Core Power

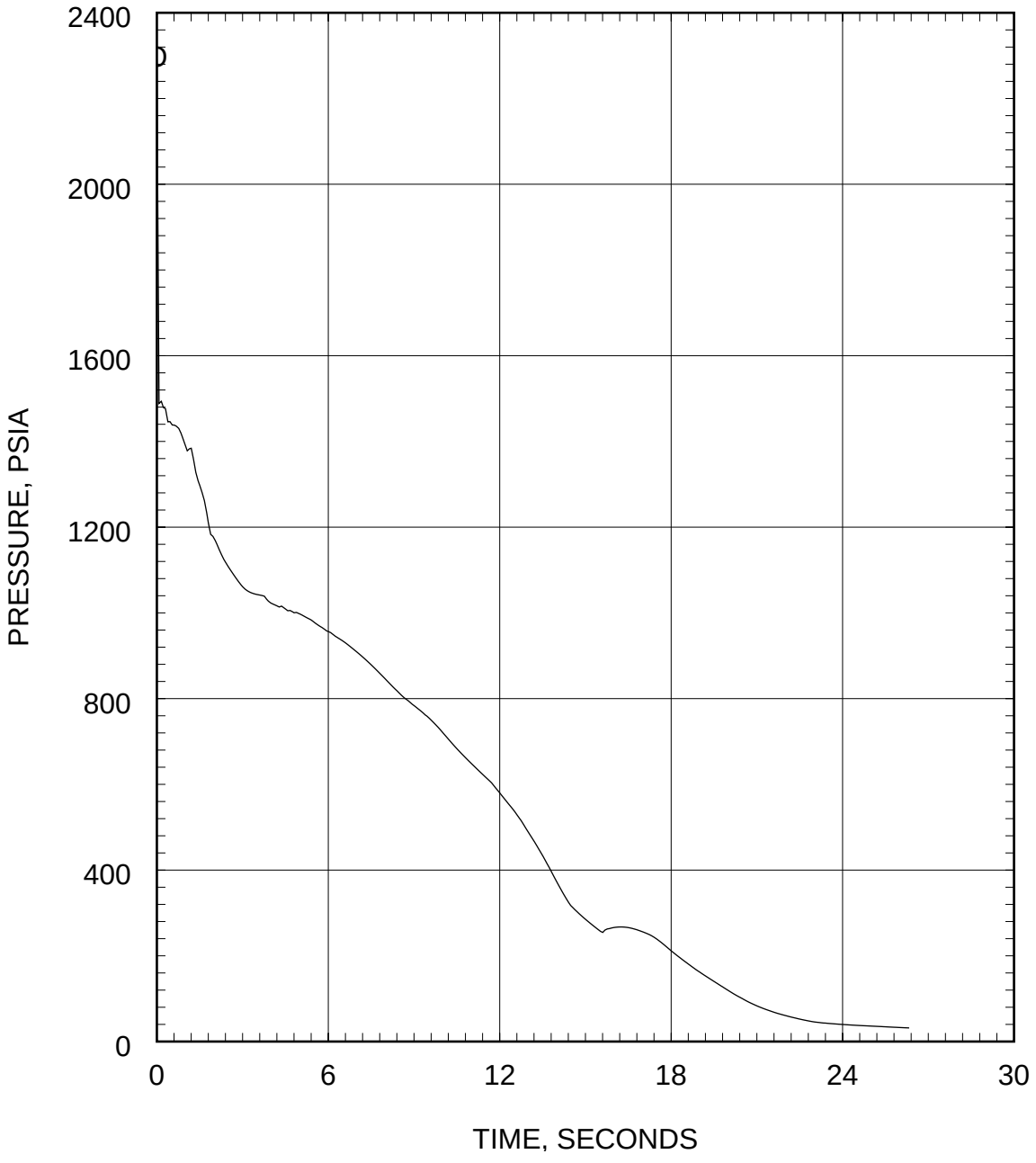


Figure 2.12-10
LBLOCA ECCS Performance Analysis
0.8 DEG/PD Break Pressure in Center Hot Assembly Node

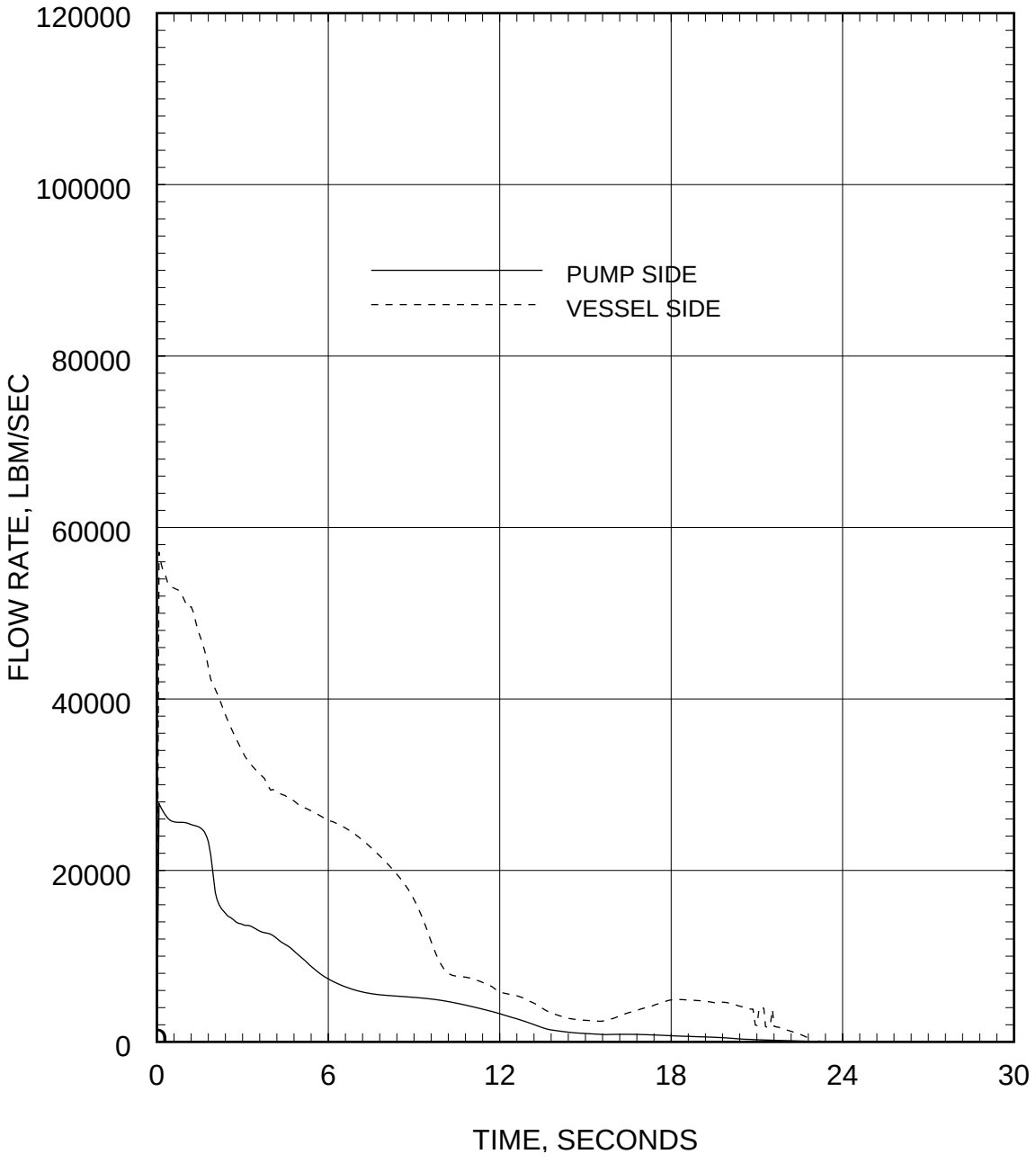


Figure 2.12-11
LBLOCA ECCS Performance Analysis
0.8 DEG/PD Break Leak Flow Rate

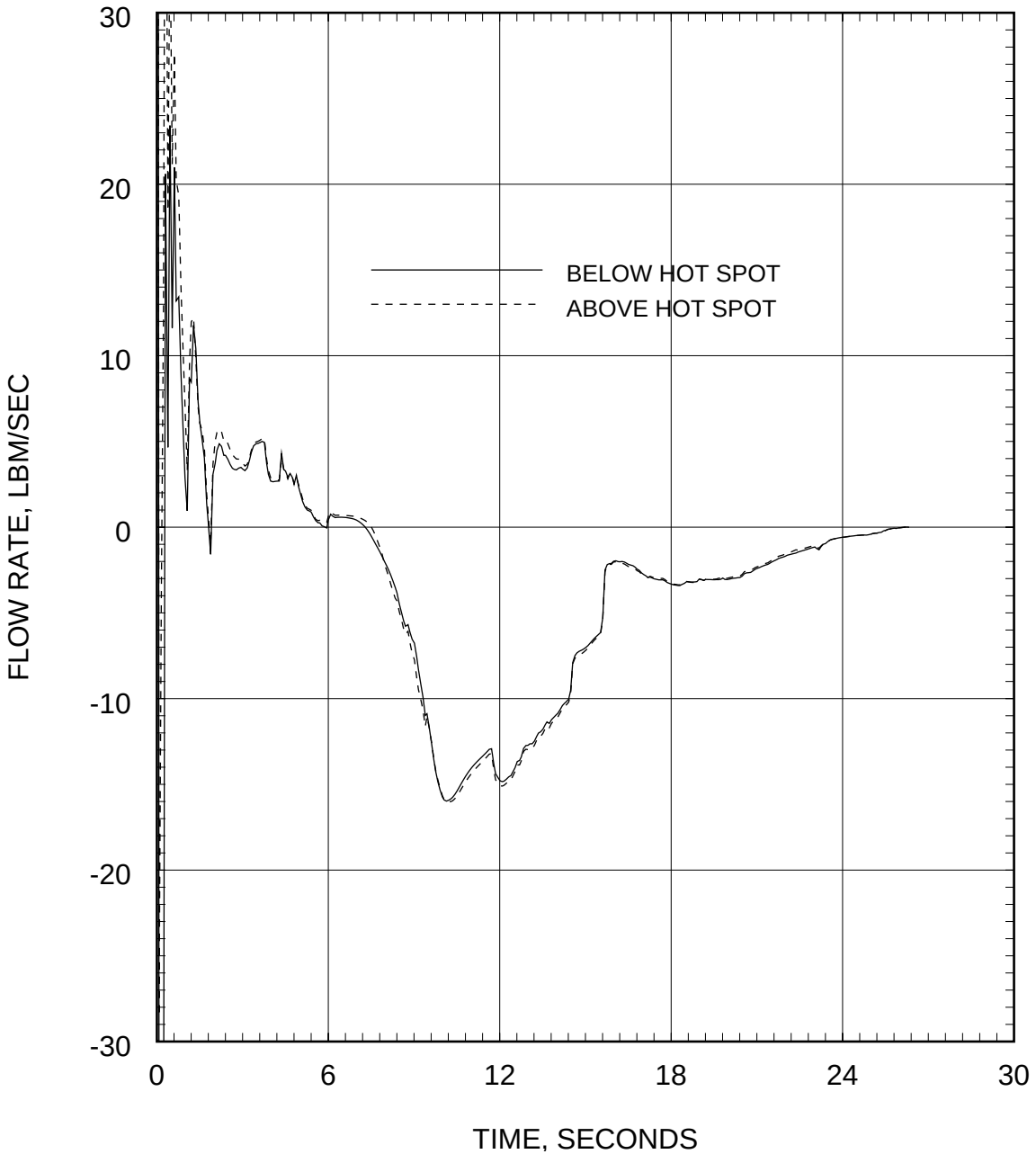


Figure 2.12-12
LBLOCA ECCS Performance Analysis
0.8 DEG/PD Break Hot Assembly Flow Rate (Above and Below Hot Spot)

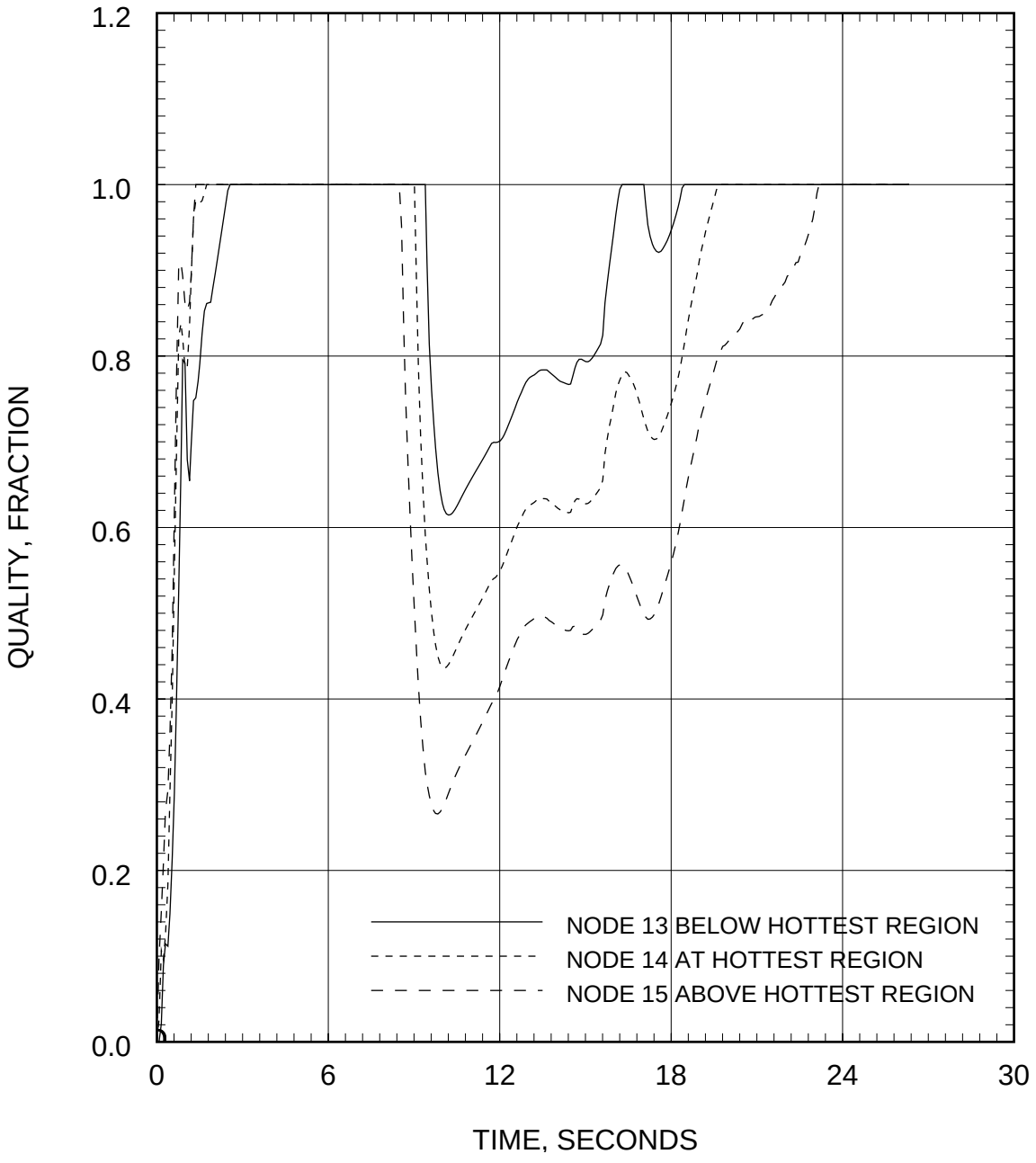


Figure 2.12-13
LBLOCA ECCS Performance Analysis
0.8 DEG/PD Break Hot Assembly Quality

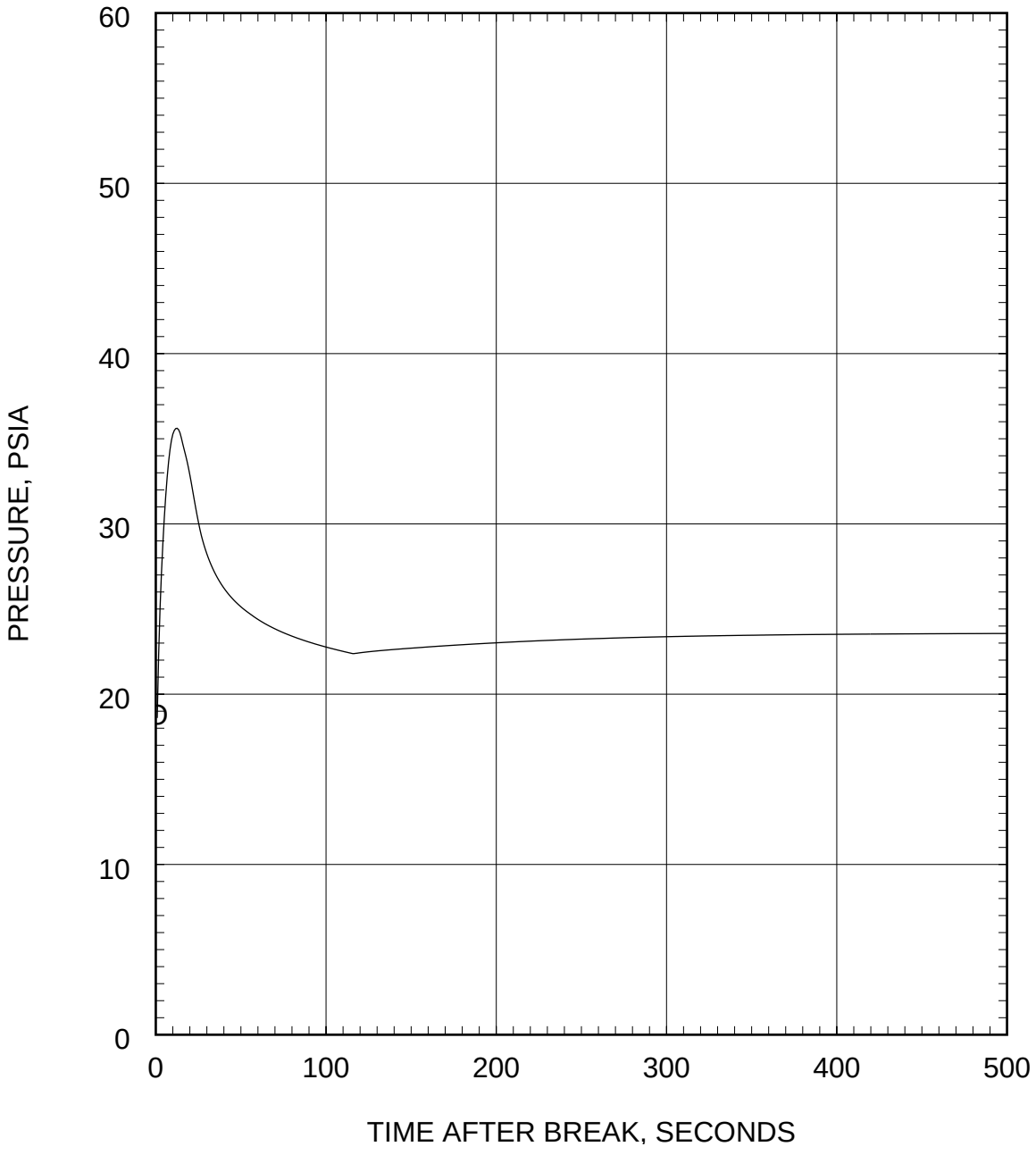


Figure 2.12-14
LBLOCA ECCS Performance Analysis
0.8 DEG/PD Break Containment Pressure

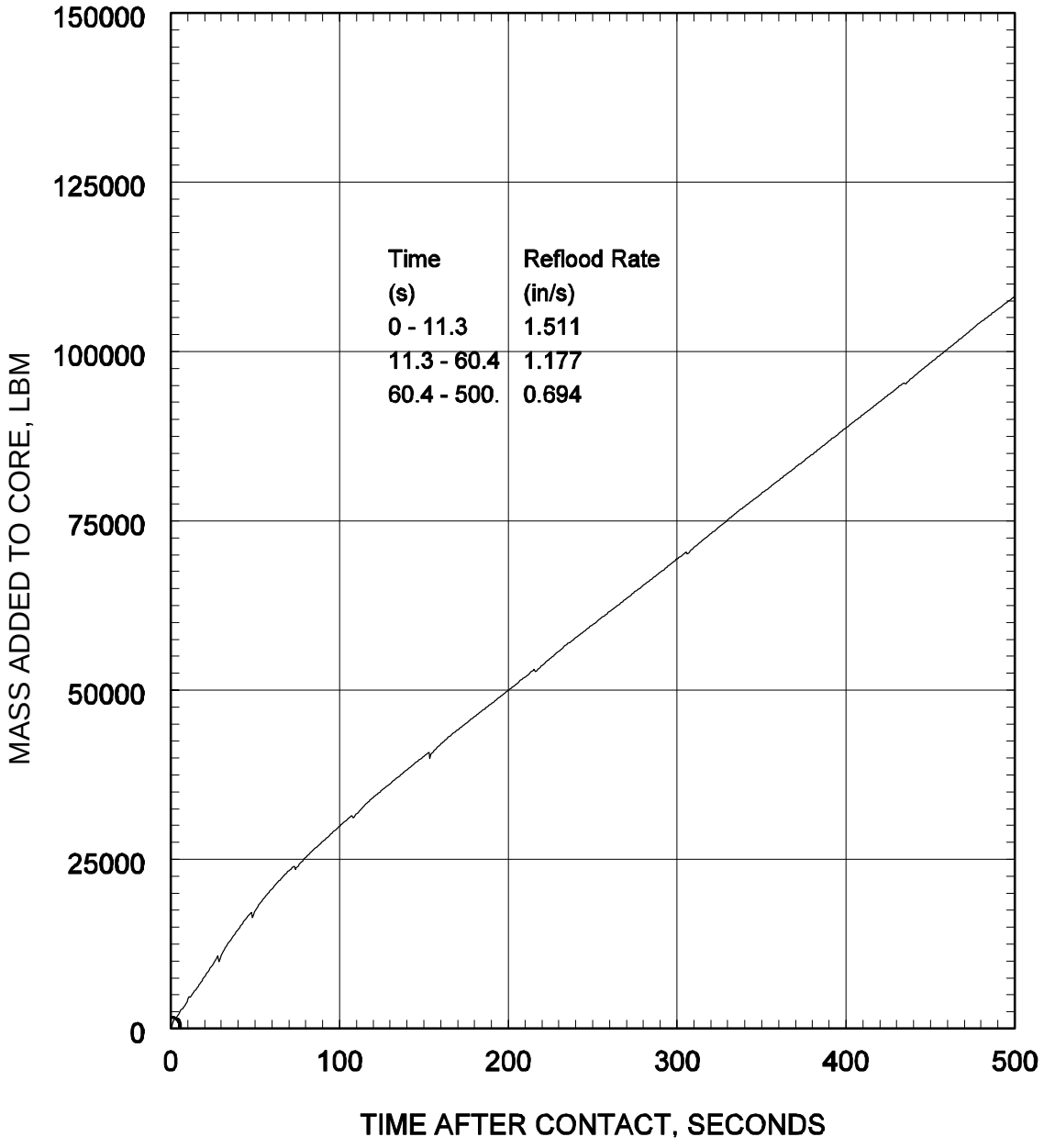


Figure 2.12-15
LBLOCA ECCS Performance Analysis
0.8 DEG/PD Break Mass Added to Core During Reflood

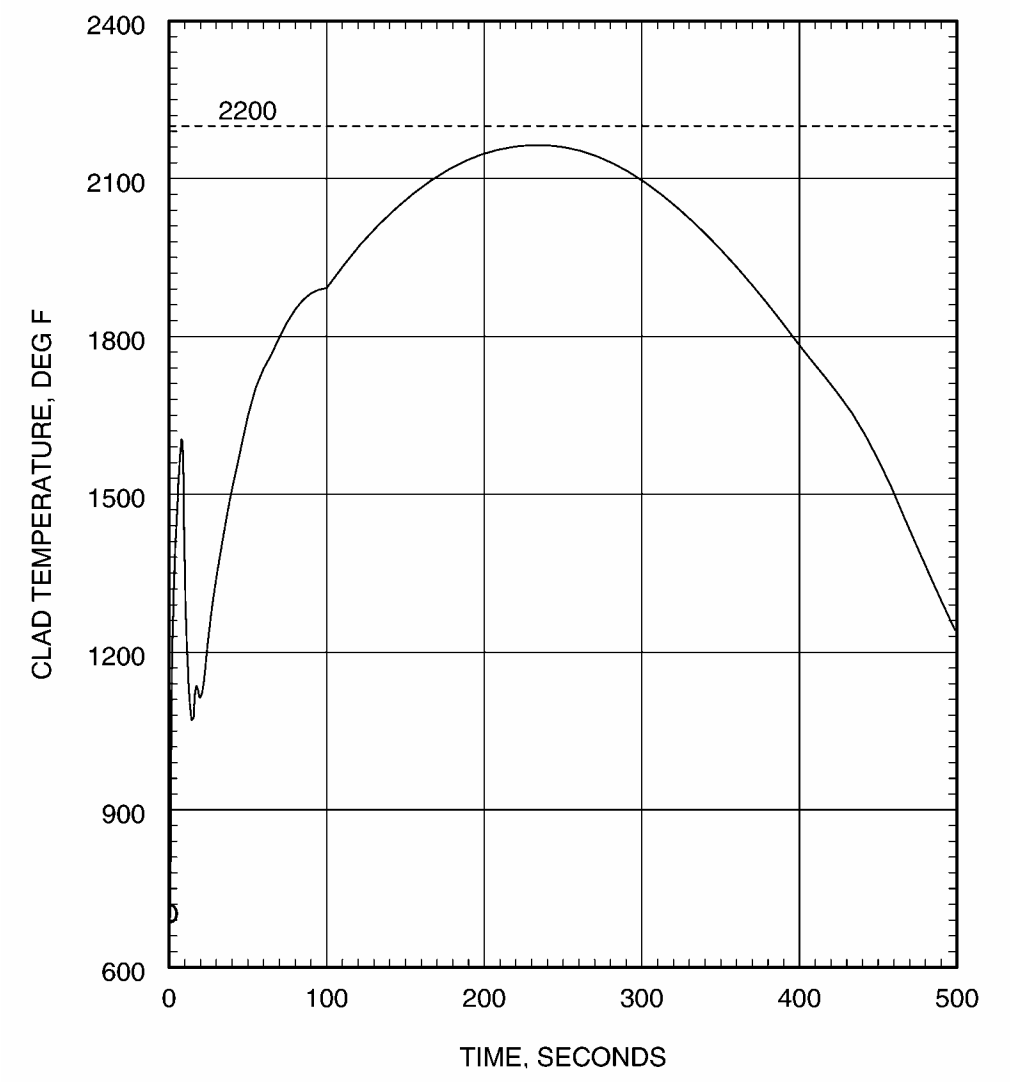


Figure 2.12-16
LBLOCA ECCS Performance Analysis
0.8 DEG/PD Break Peak Cladding Temperature

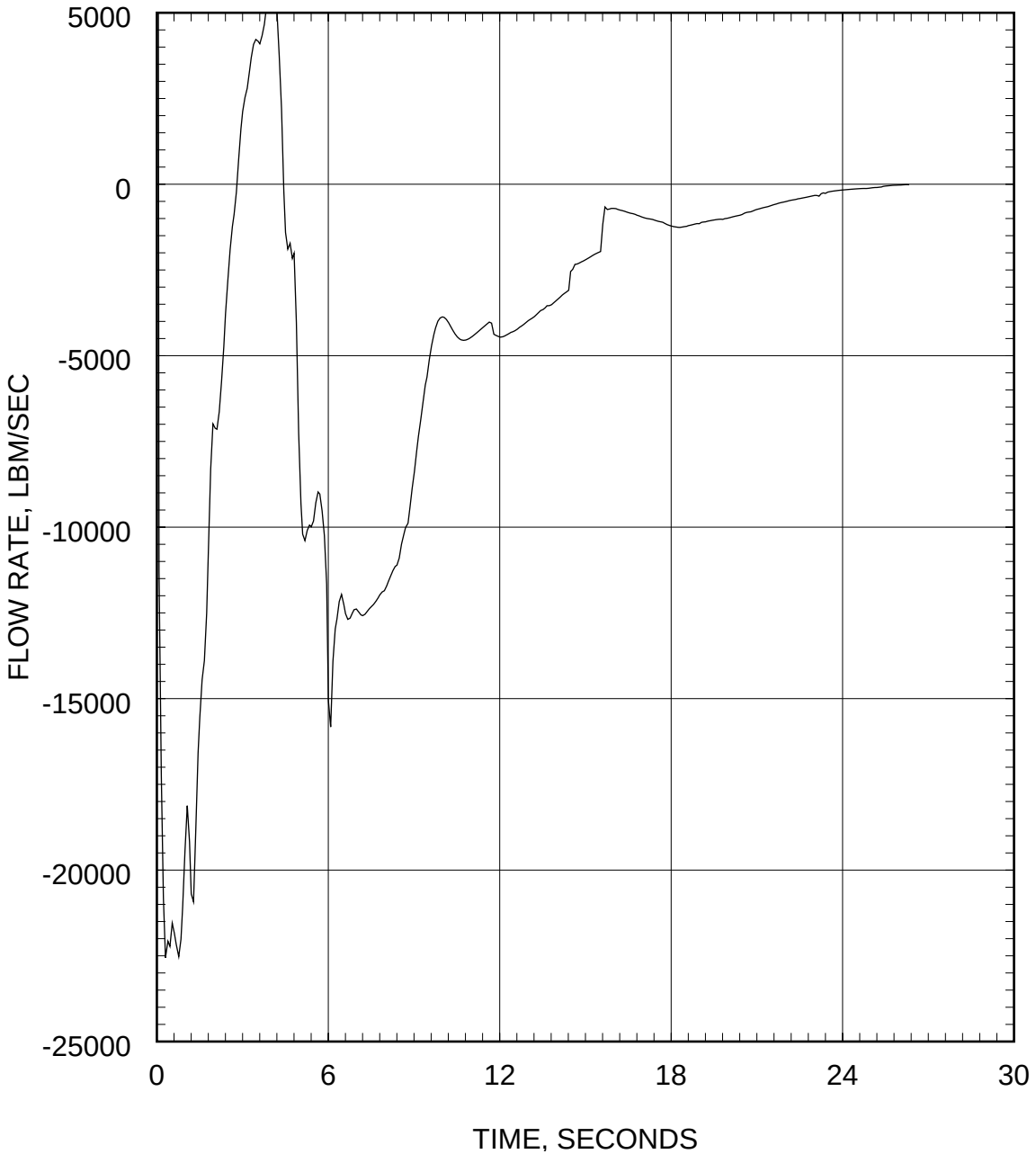


Figure 2.12-17
LBLOCA ECCS Performance Analysis
0.8 DEG/PD Break Mid Annulus Flow Rate

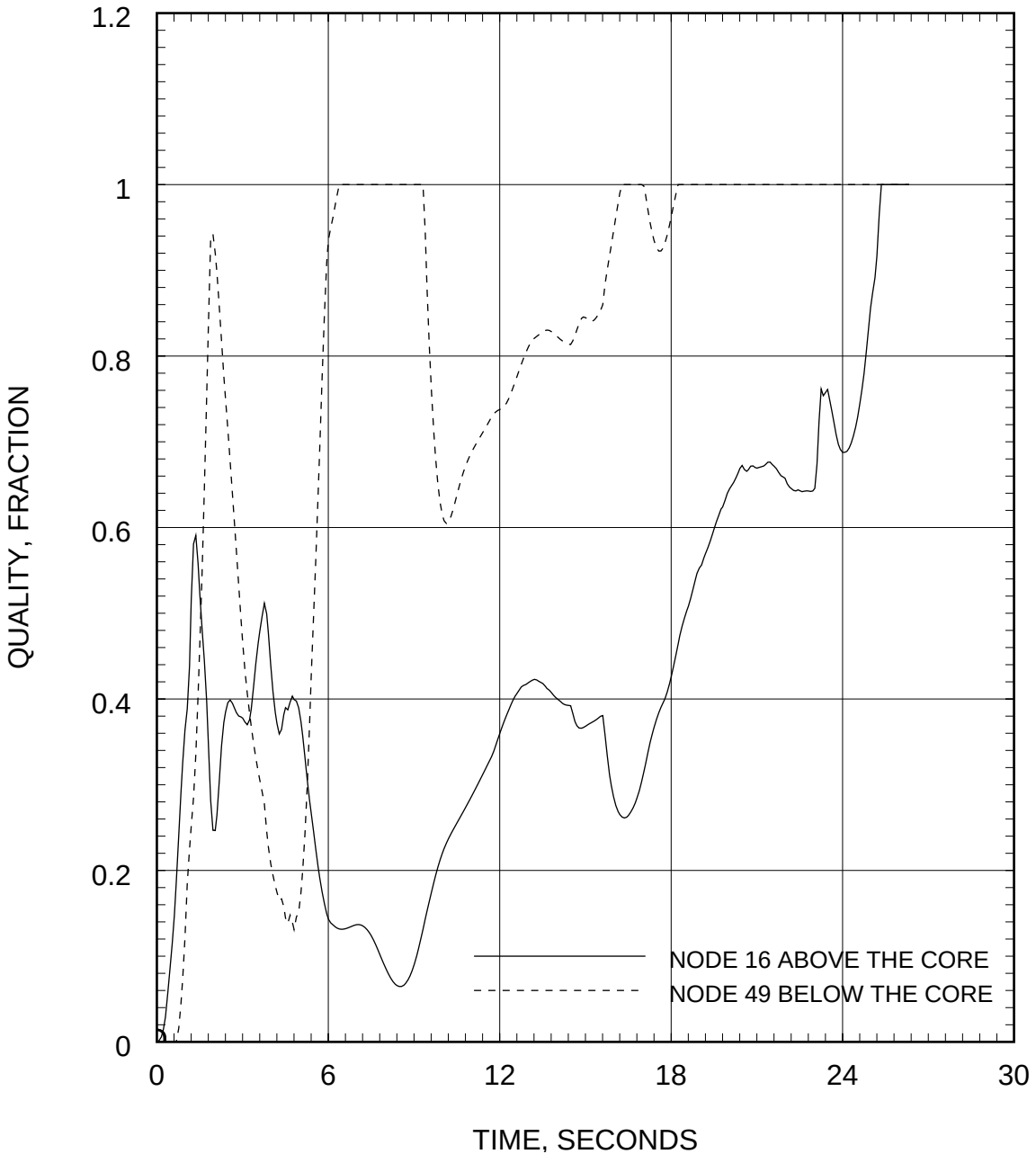


Figure 2.12-18
LBLOCA ECCS Performance Analysis
0.8 DEG/PD Break Quality Above and Below the Core

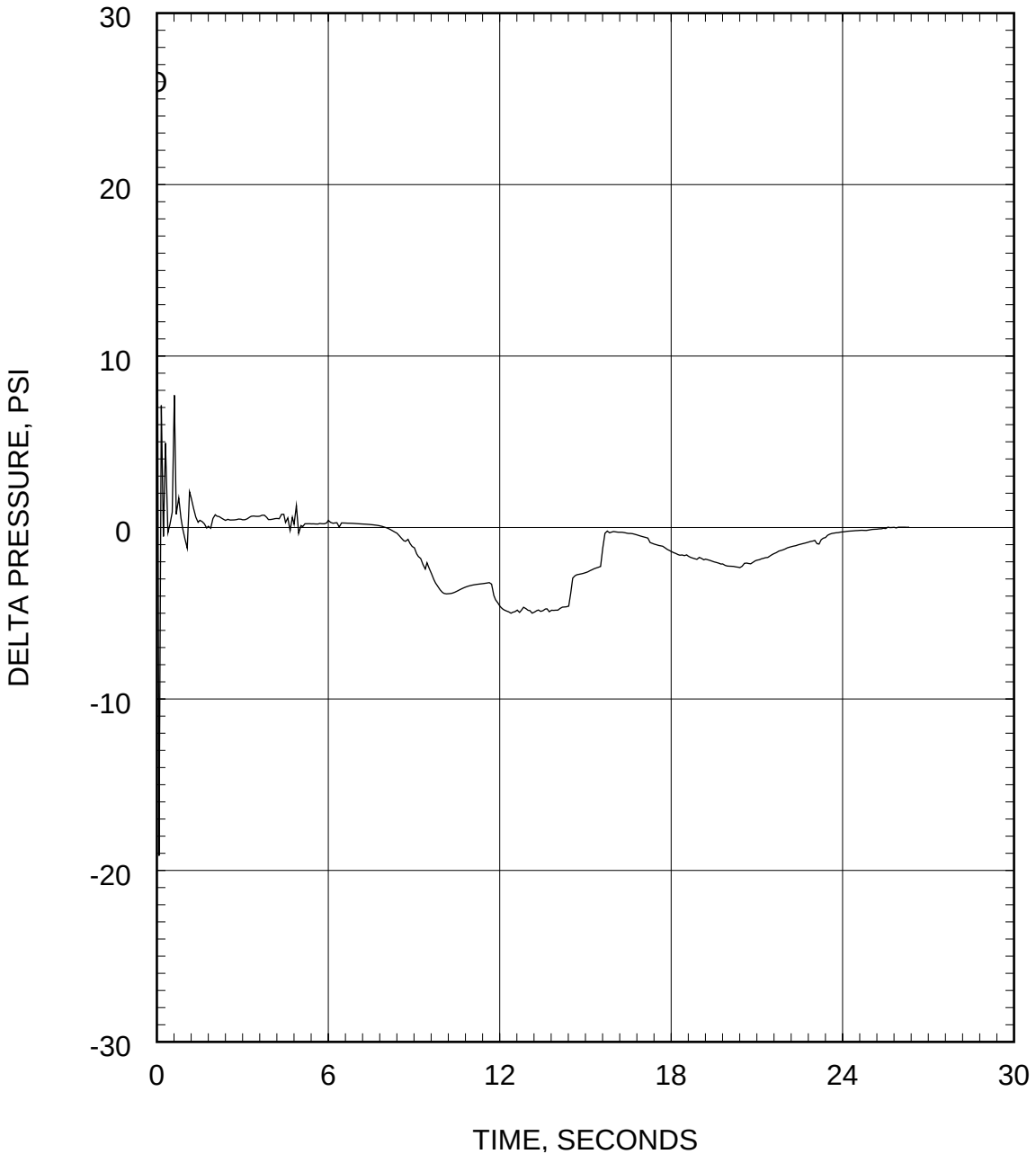


Figure 2.12-19
LBLOCA ECCS Performance Analysis
0.8 DEG/PD Break Core Pressure Drop

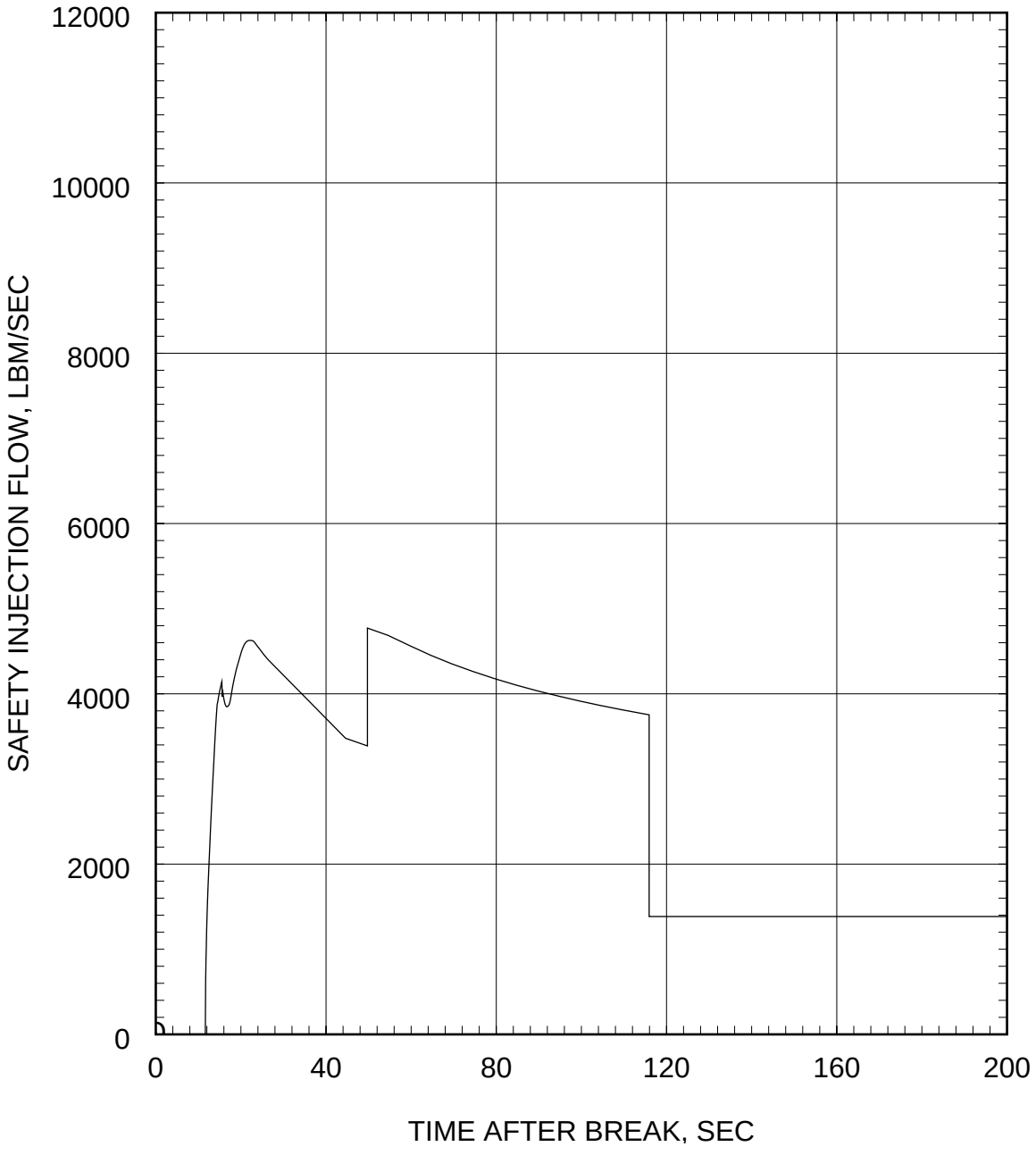


Figure 2.12-20
LBLOCA ECCS Performance Analysis
0.8 DEG/PD Break Safety Injection Flow Rate into Intact Discharge Legs

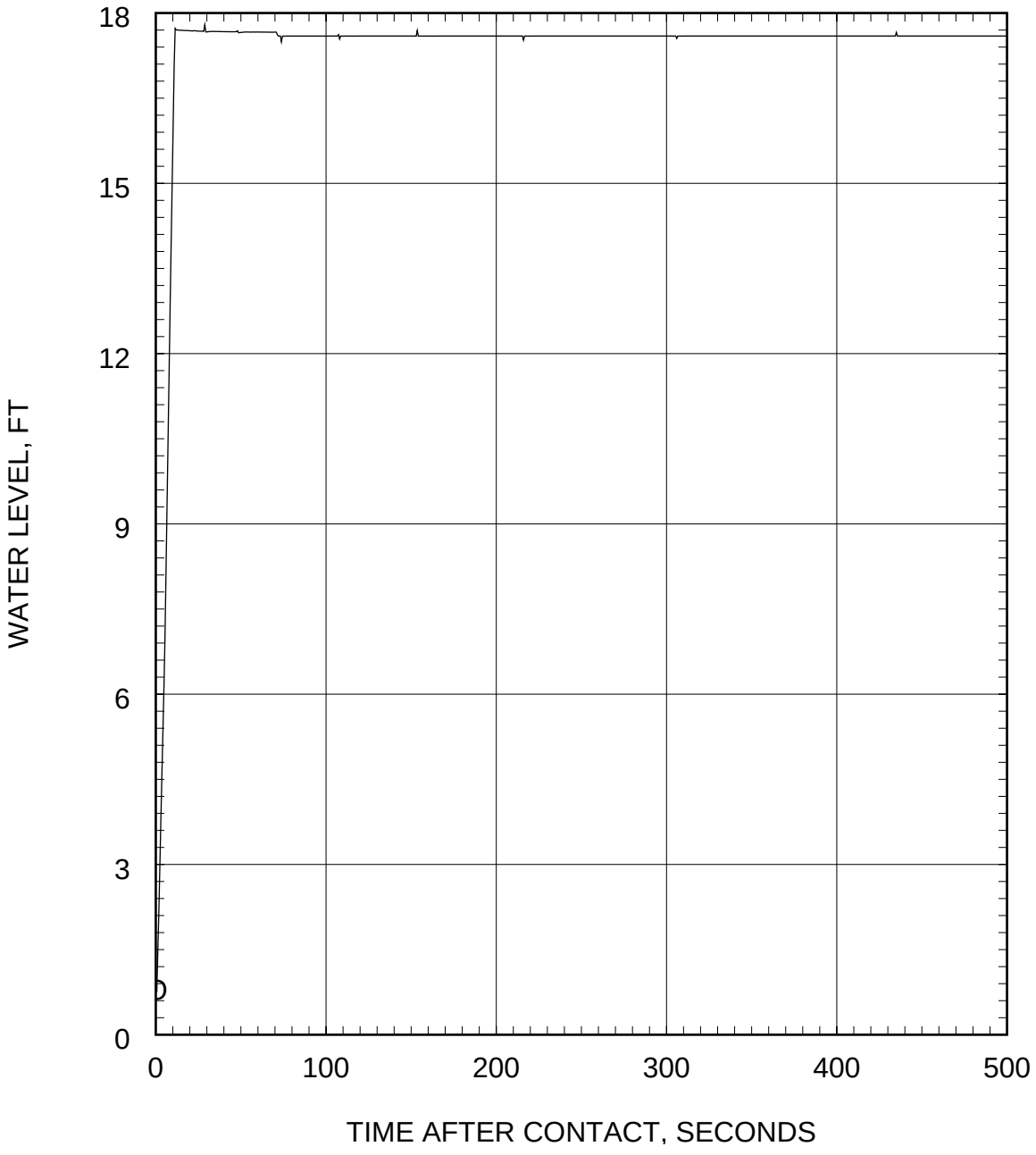


Figure 2.12-21
LBLOCA ECCS Performance Analysis
0.8 DEG/PD Break Water Level in Downcomer During Reflood

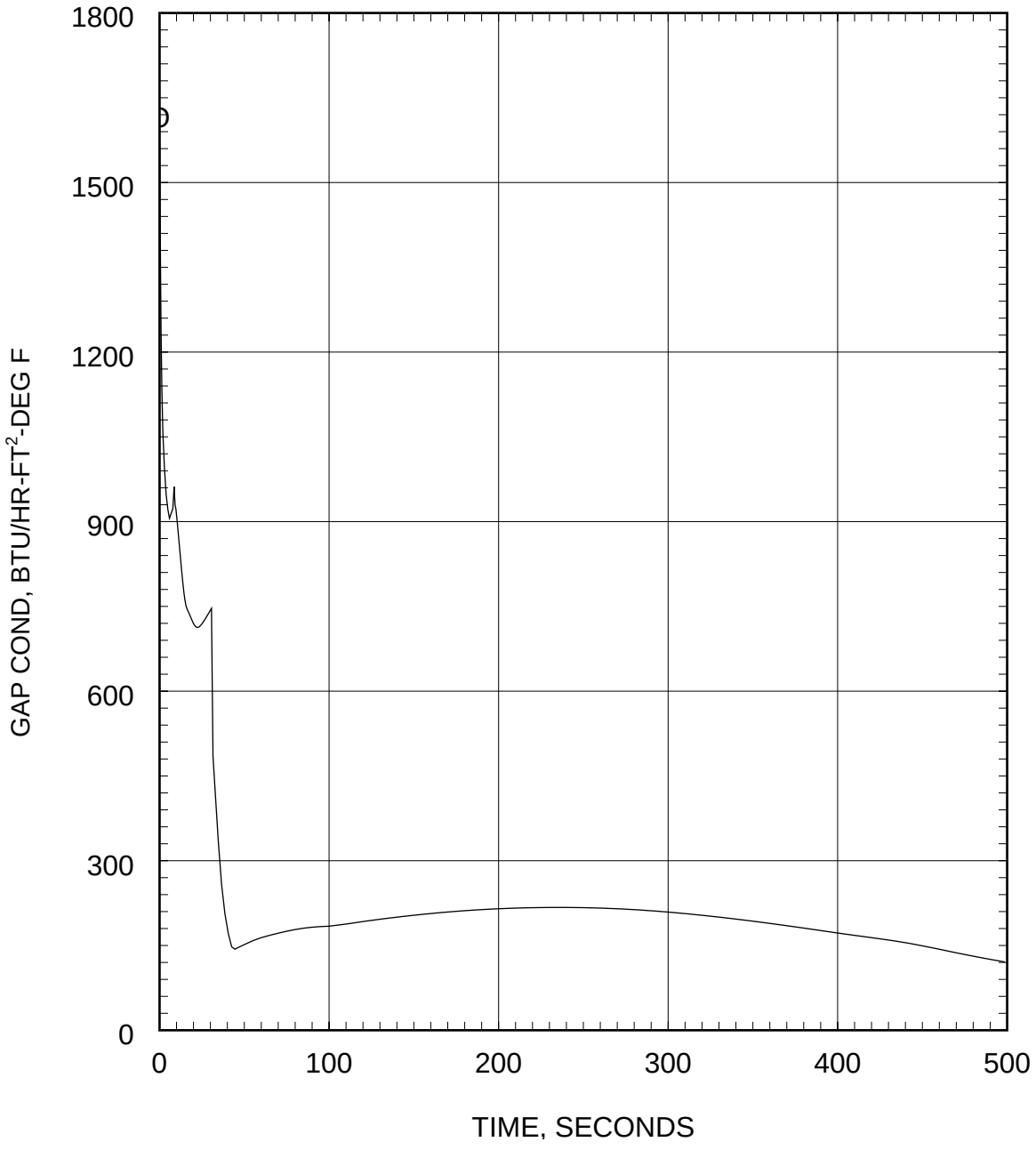


Figure 2.12-22
LBLOCA ECCS Performance Analysis
0.8 DEG/PD Break Hot Spot Gap Conductance

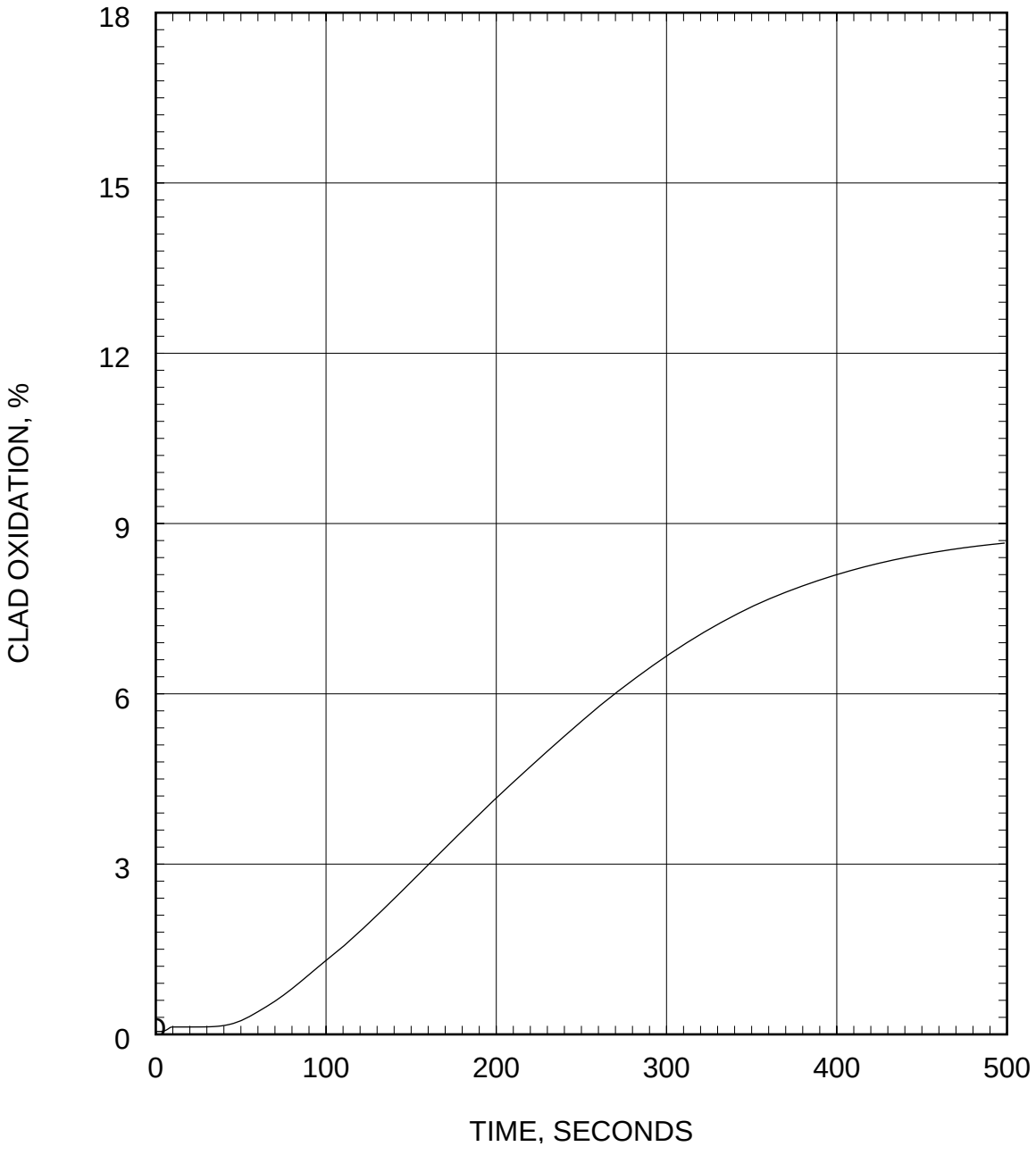


Figure 2.12-23
LBLOCA ECCS Performance Analysis
0.8 DEG/PD Break Maximum Local Cladding Oxidation Percentage

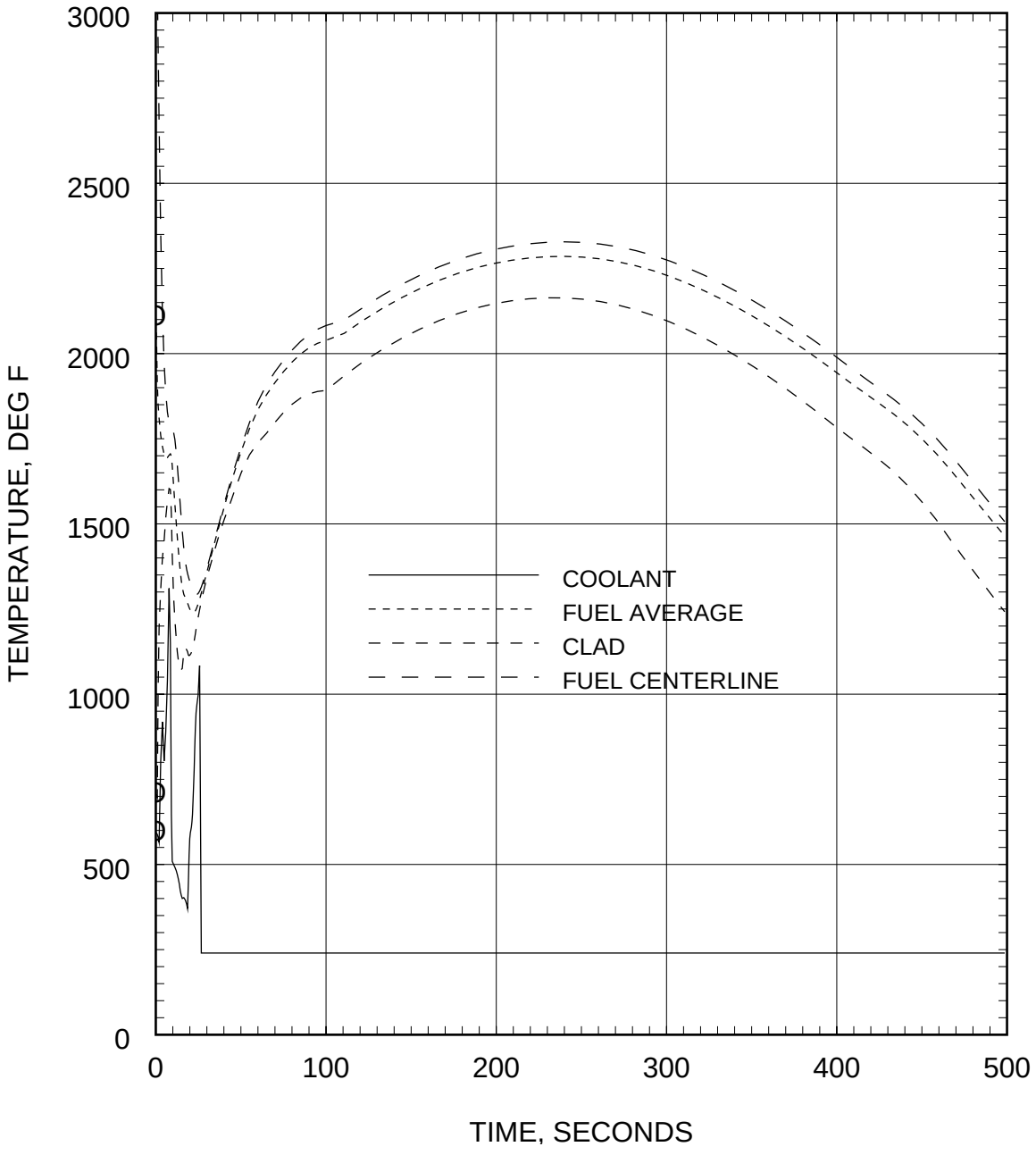


Figure 2.12-24
LBLOCA ECCS Performance Analysis
0.8 DEG/PD Break
Fuel Centerline, Fuel Average, Cladding, and Coolant Temperature at the Hot Spot

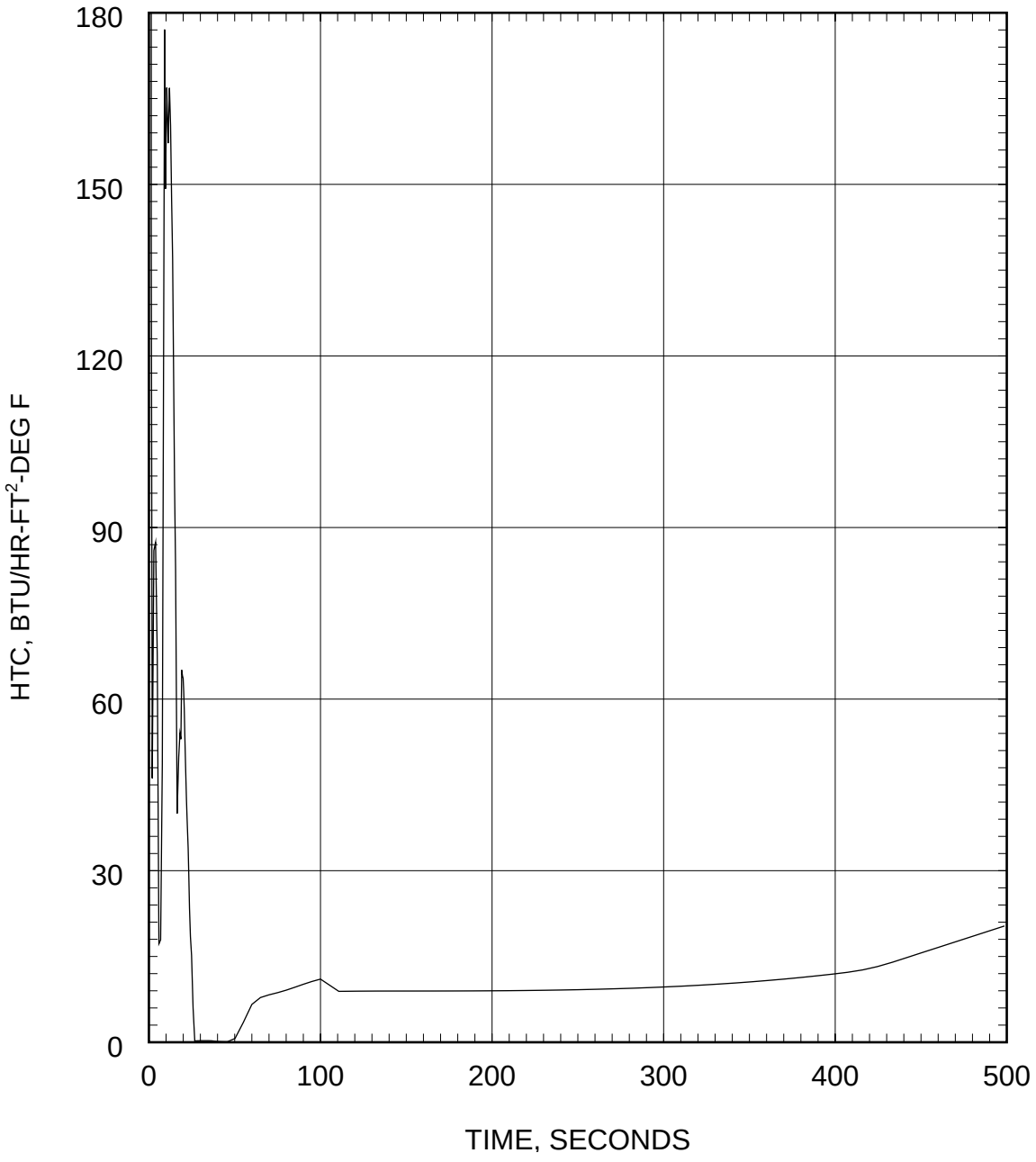


Figure 2.12-25
LBLOCA ECCS Performance Analysis
0.8 DEG/PD Break Hot Spot Heat Transfer Coefficient (HTC)

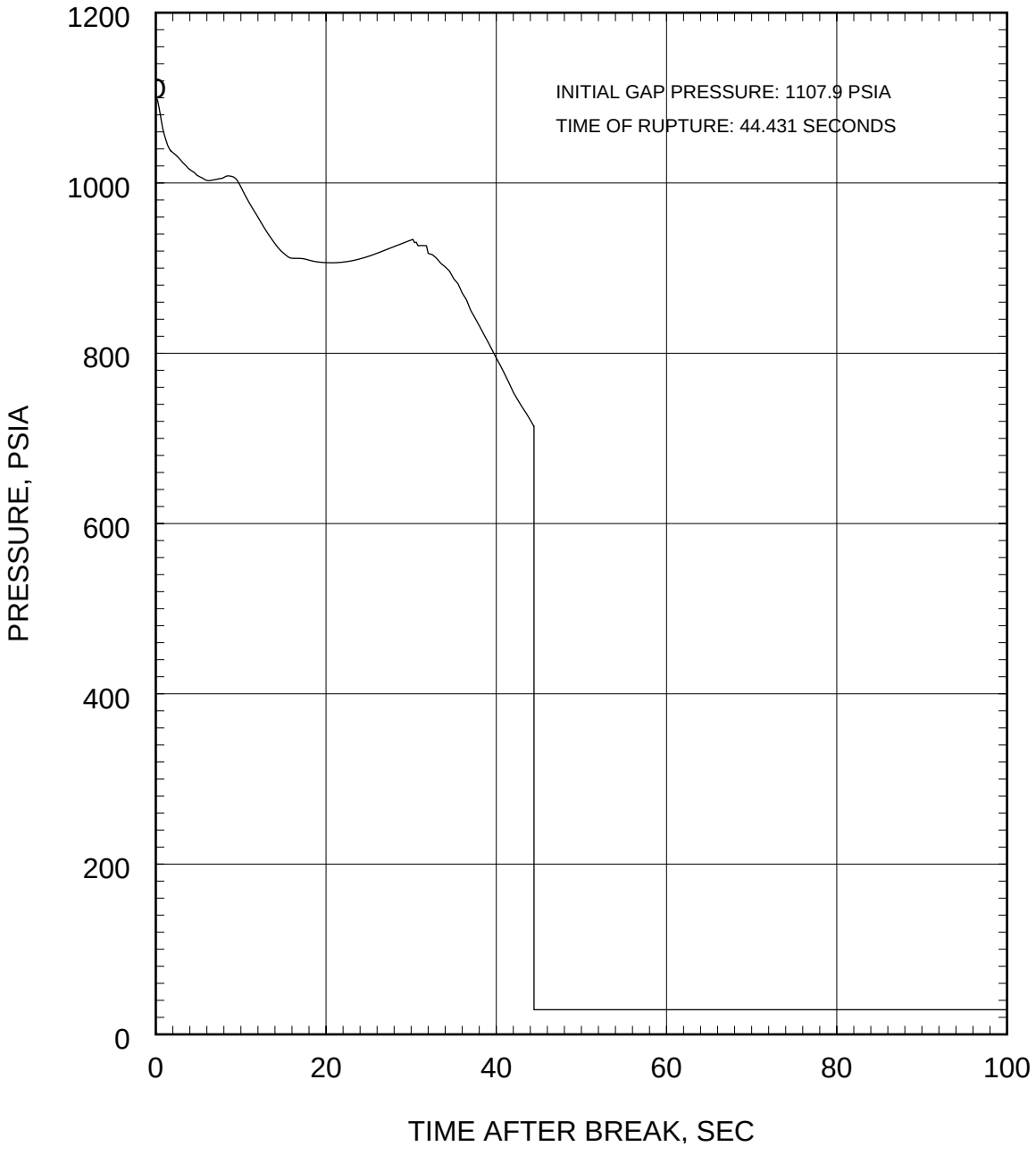


Figure 2.12-26
LBLOCA ECCS Performance Analysis
0.8 DEG/PD Break Hot Pin Pressure

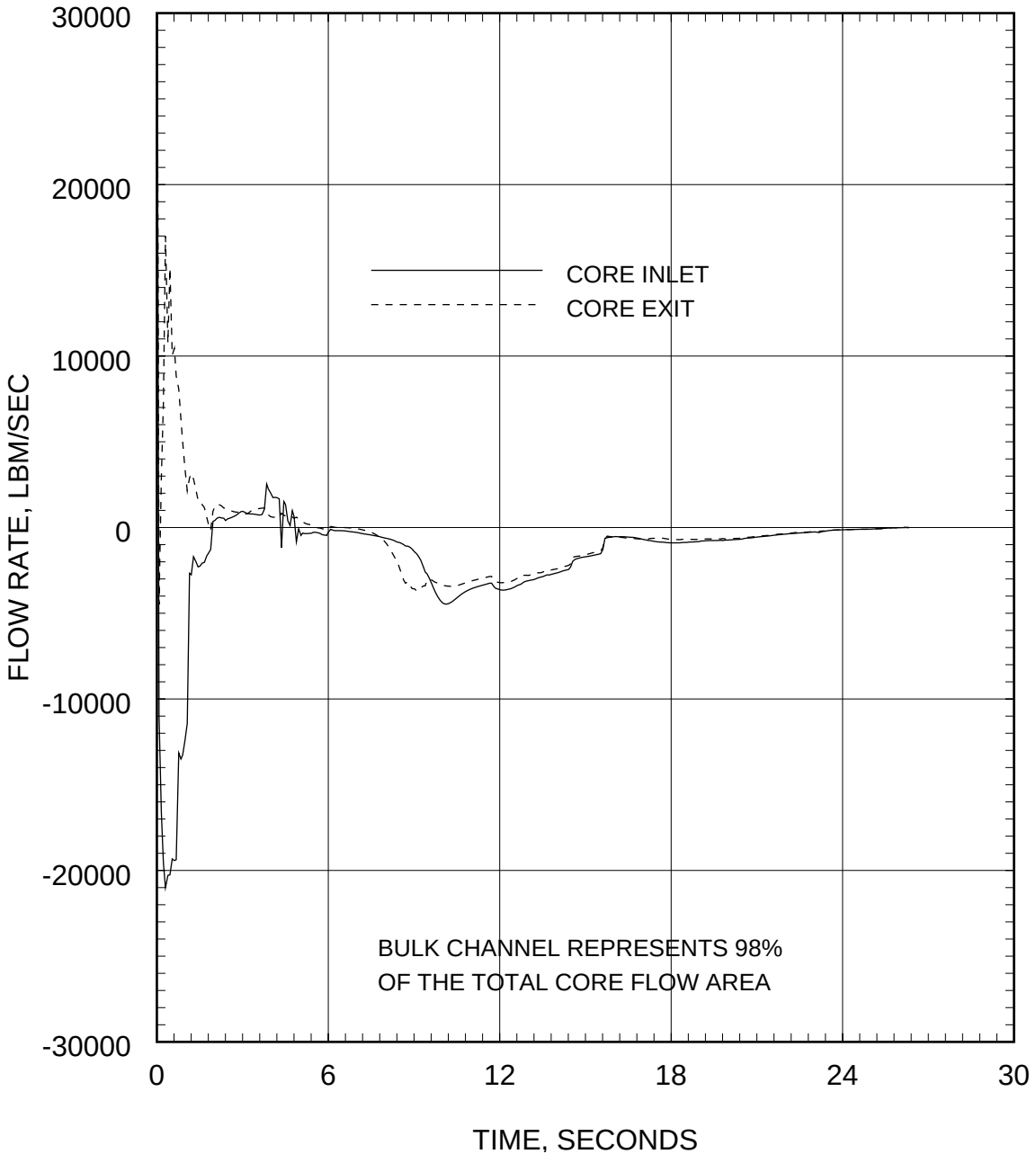


Figure 2.12-27
LBLOCA ECCS Performance Analysis
0.8 DEG/PD Break Core Bulk Channel Flow Rate

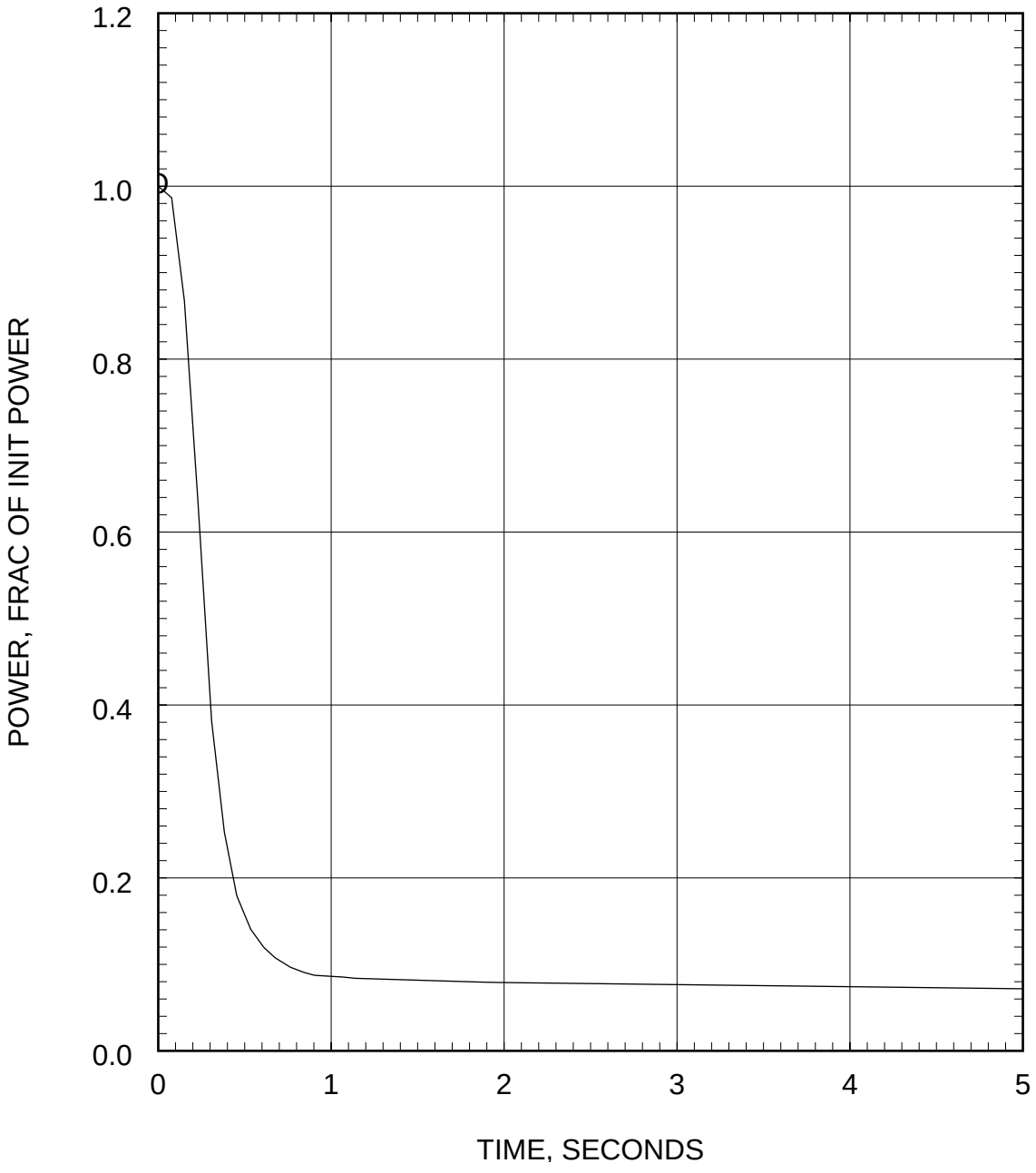


Figure 2.12-28
LBLOCA ECCS Performance Analysis
0.6 DEG/PD Break Core Power

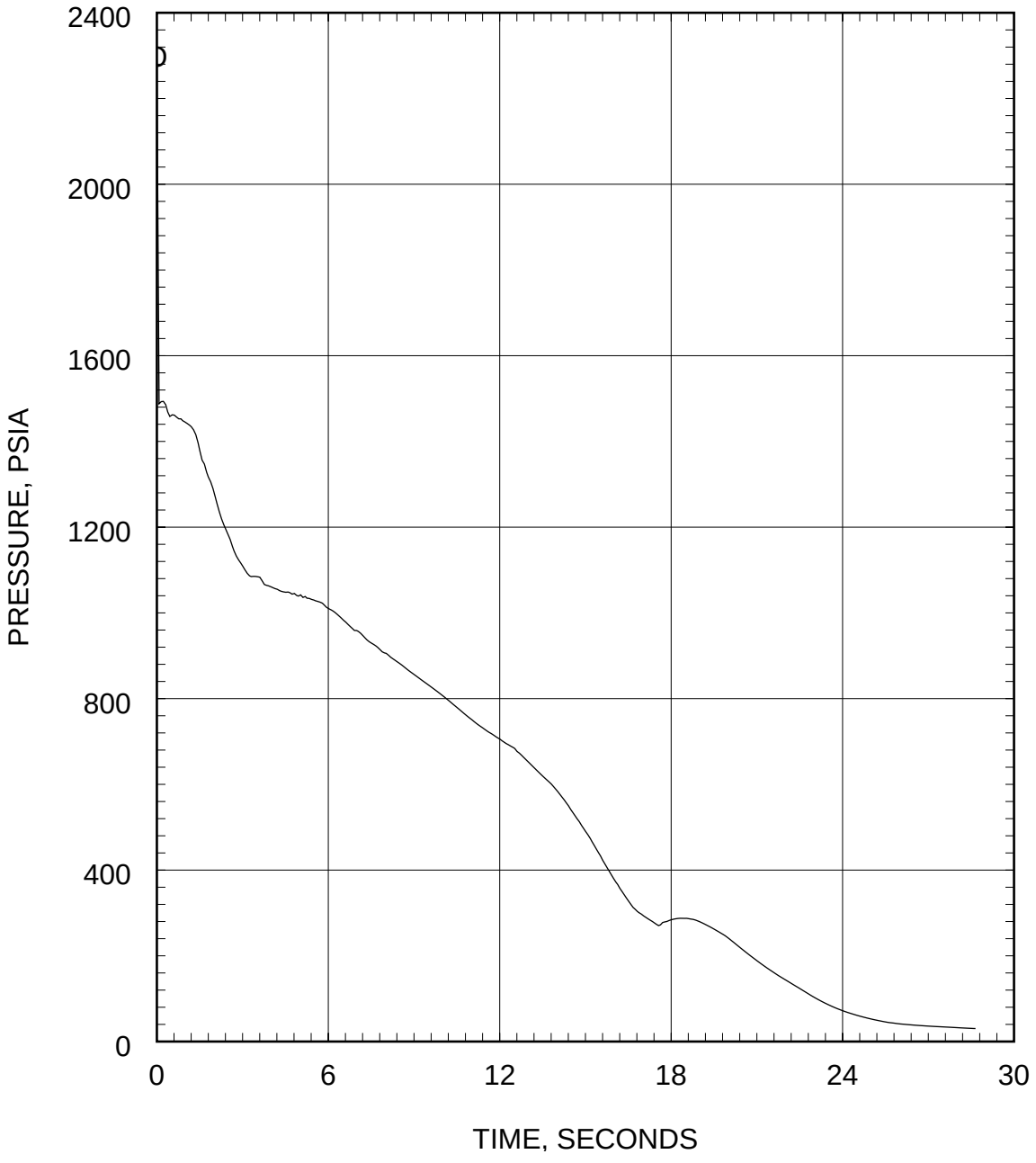


Figure 2.12-29
LBLOCA ECCS Performance Analysis
0.6 DEG/PD Break Pressure in Center Hot Assembly Node

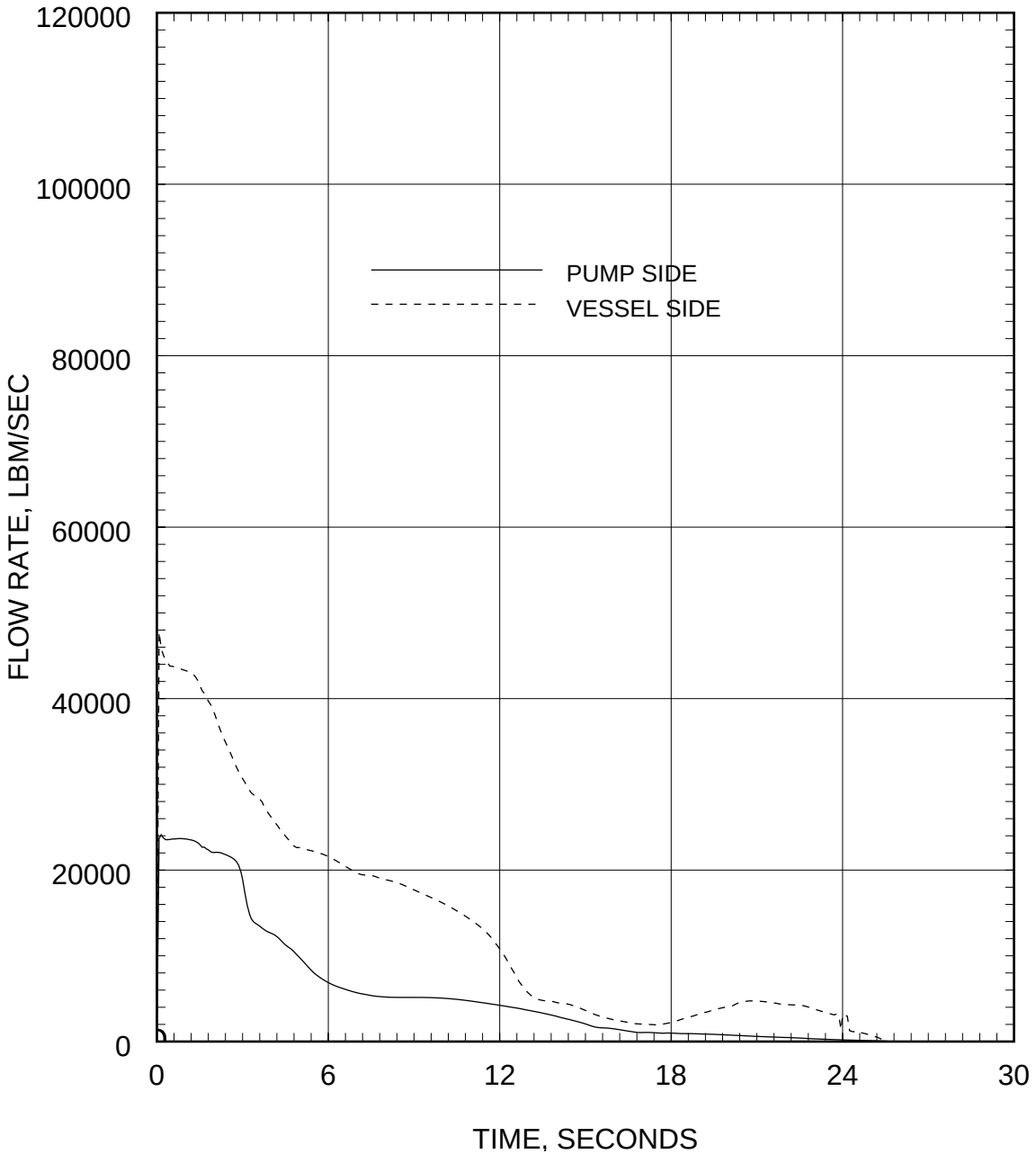


Figure 2.12-30
LBLOCA ECCS Performance Analysis
0.6 DEG/PD Break Leak Flow Rate

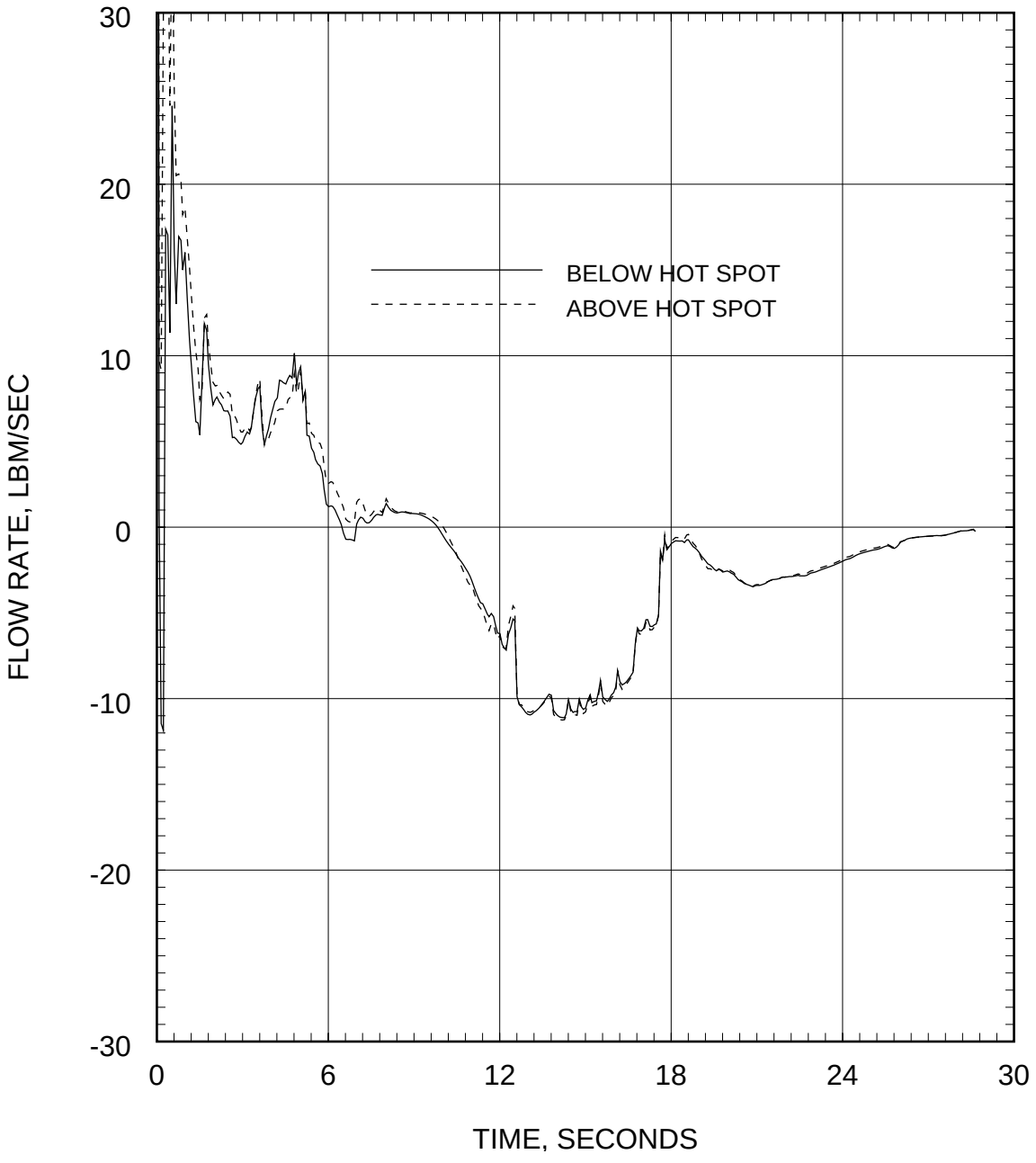


Figure 2.12-31
LBLOCA ECCS Performance Analysis
0.6 DEG/PD Break Hot Assembly Flow Rate (Above and Below Hot Spot)

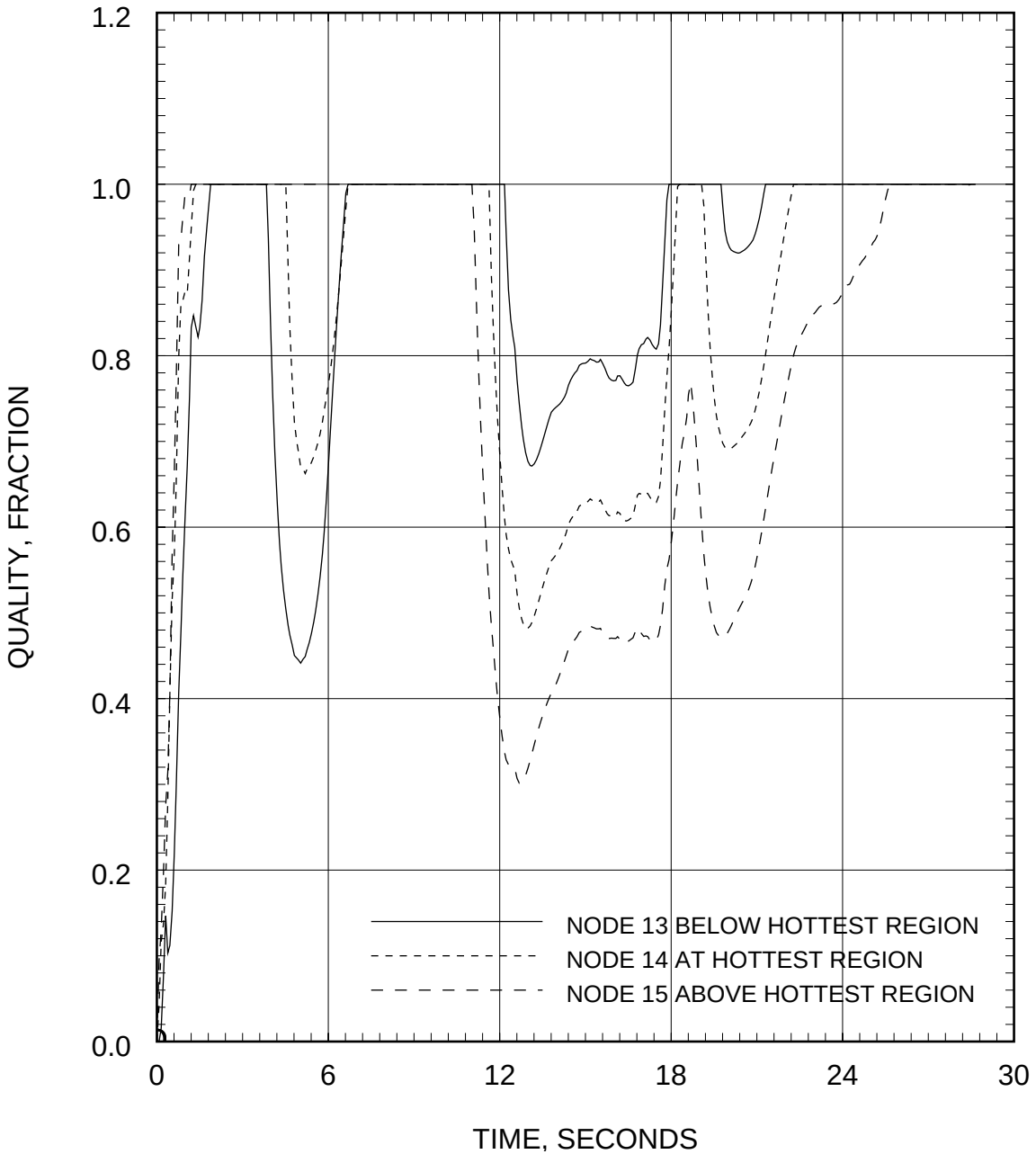


Figure 2.12-32
LBLOCA ECCS Performance Analysis
0.6 DEG/PD Break Hot Assembly Quality

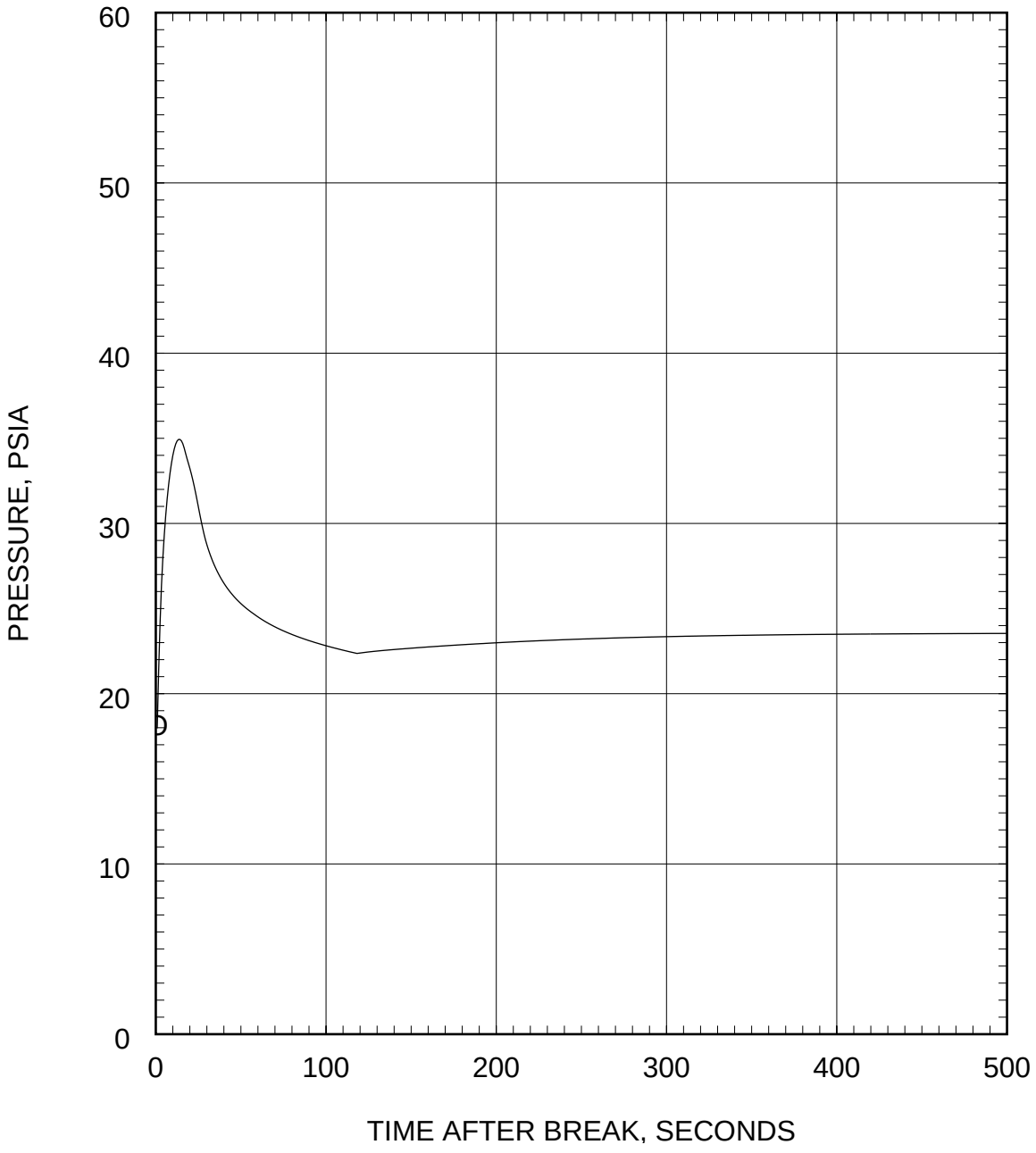


Figure 2.12-33
LBLOCA ECCS Performance Analysis
0.6 DEG/PD Break Containment Pressure

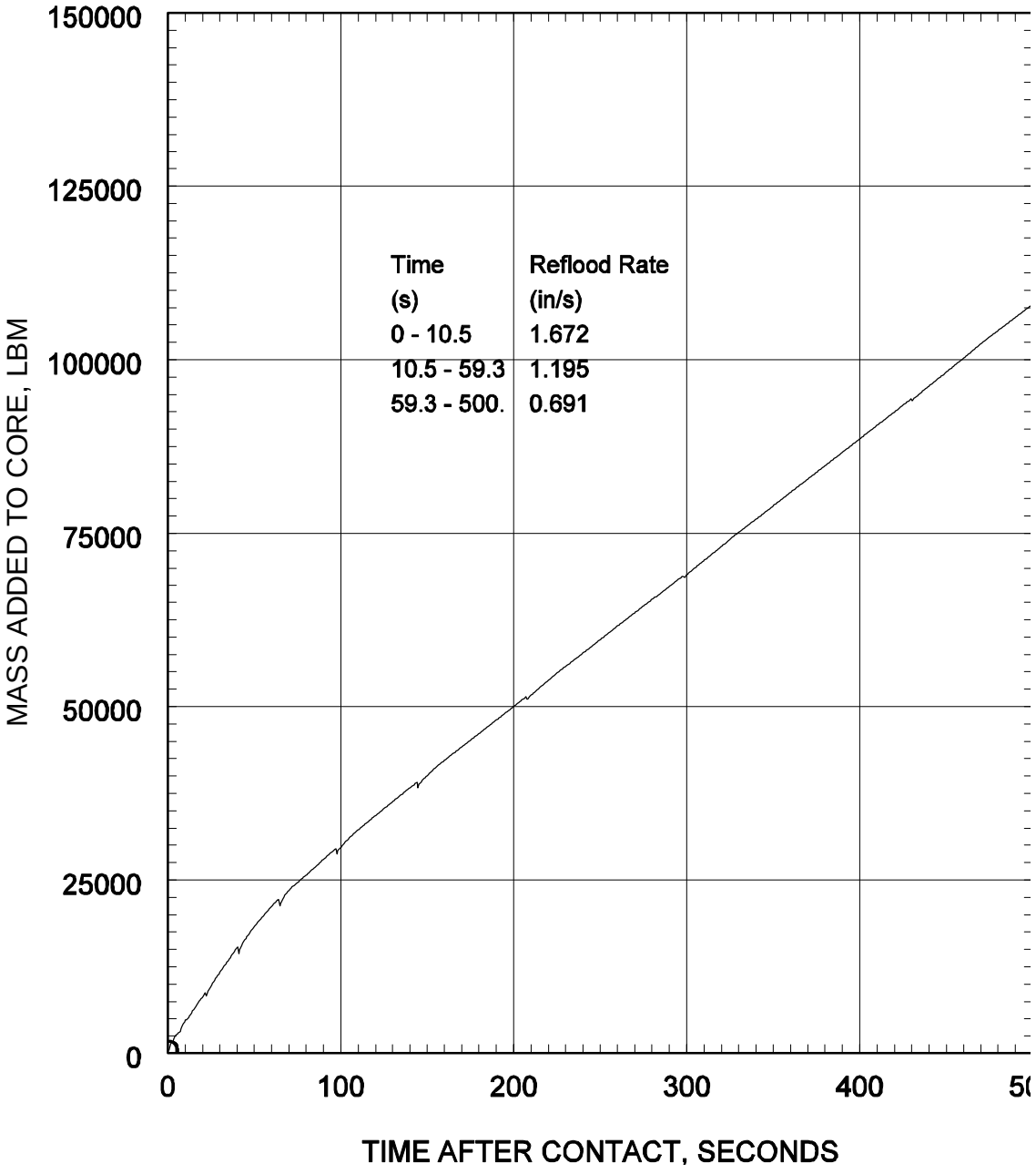


Figure 2.12-34
LBLOCA ECCS Performance Analysis
0.6 DEG/PD Break Mass Added to Core During Reflood

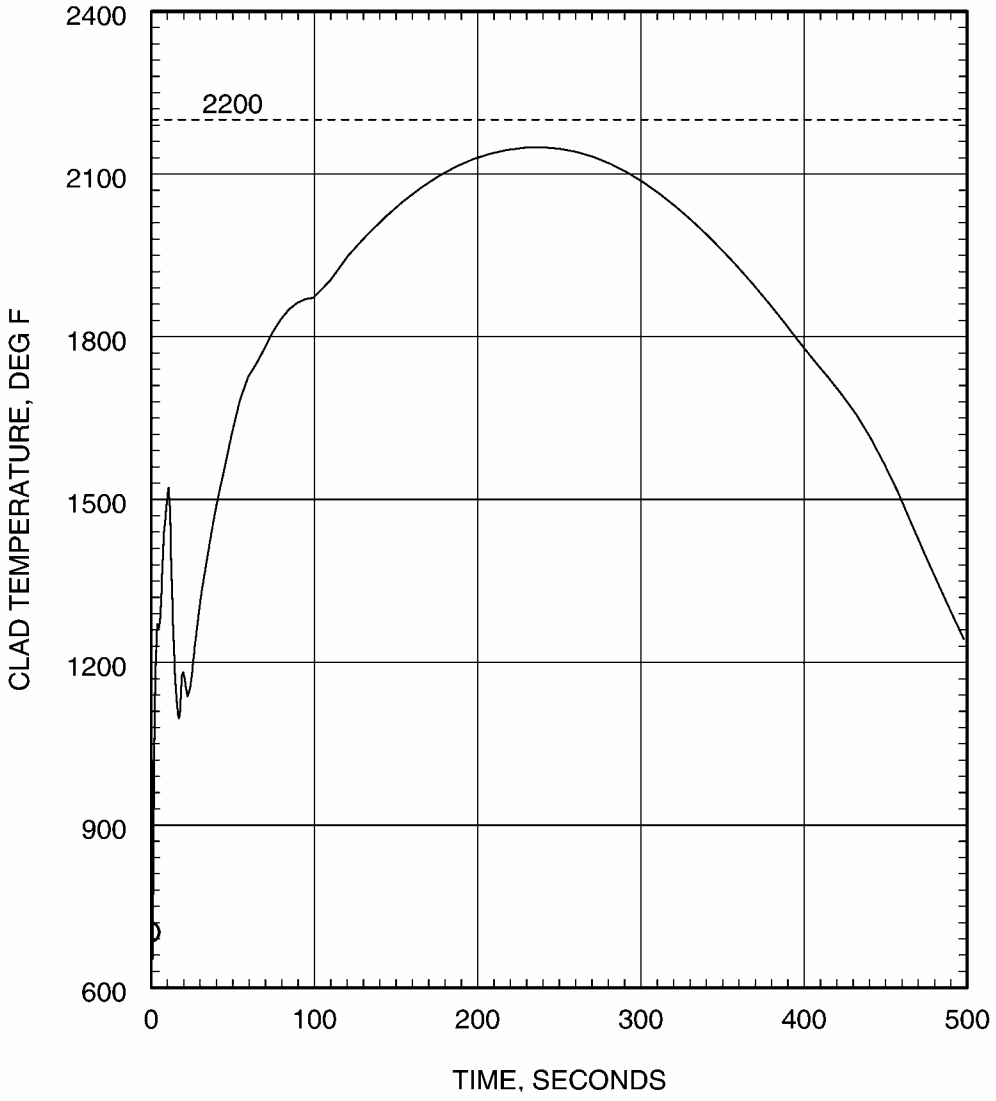


Figure 2.12-35
LBLOCA ECCS Performance Analysis
0.6 DEG/PD Break Peak Cladding Temperature

2.12.4 Small-Break LOCA (SBLOCA) Analysis

2.12.4.1 Methodology

The SBLOCA ECCS performance analysis used the Supplement 2 version (referred to as the S2M, or Supplement 2 Model) of the Westinghouse SBLOCA ECCS evaluation model for CE PWRs (Reference 2.12-23). This is the same methodology used in the current Waterford 3 SBLOCA ECCS performance analysis described in Sections 6.3.3.3 and 15.6.3.3.3.2 of the Waterford 3 FSAR (Reference 2.12-3). The Safety Evaluation Reports (SERs) documenting NRC acceptance of the S2M are contained in References 2.12-13, 2.12-24, and 2.12-25.

In the S2M evaluation model, the CEFLASH-4AS computer program (Reference 2.12-26) is used to perform the hydraulic analysis of the RCS until the time the safety injection tanks (SITs) begin to inject. After injection from the SITs begins, the COMPERC-II computer program (Reference 2.12-7) is used to perform the hydraulic analysis. However, COMPERC-II was not run in this analysis because the SITs did not begin injecting until after the peak cladding temperature (PCT) was calculated to occur for the limiting break size. The limiting break size was determined to be the largest small break for which the PCT occurred prior to the start of SIT injection. The hot rod cladding temperature and maximum cladding oxidation are calculated by the STRIKIN-II computer program (Reference 2.12-11) during the initial period of forced convection heat transfer and by the PARCH computer program (Reference 2.12-10) during the subsequent period of pool boiling heat transfer. Core-wide cladding oxidation is conservatively represented as the rod-average cladding oxidation of the hot rod. The initial steady state fuel rod conditions used in the analysis are determined using the FATES3B computer program (Reference 2.12-12). The SERs for the SBLOCA ECCS performance analysis computer codes are documented in References 2.12-13, 2.12-16 through 2.12-18 and 2.12-24. The SERs for the FATES3B computer code are documented in References 2.12-20 through 2.12-22.

The SBLOCA analysis was performed for the fuel rod conditions that result in the maximum initial stored energy in the fuel. Both UO_2 fuel rods and erbia burnable absorber fuel rods were analyzed.

The analysis was performed using the failure of an emergency diesel generator as the most limiting single failure of the ECCS. This is the same limiting failure as the current analysis. The emergency diesel generator failure causes the loss of a high-pressure safety injection (HPSI) pump and a low-pressure safety injection (LPSI) pump, and results in a minimum of safety injection water being available to cool the core. Based on this failure and the design of the Waterford 3 ECCS, 75% of the flow from one HPSI pump is credited in the SBLOCA analysis. The LPSI pumps are not explicitly credited in the SBLOCA analysis since the RCS pressure never decreases below the LPSI pump shutoff head during the portion of the transient that is analyzed. Charging flow, which had previously been credited, is not credited for the EPU SBLOCA analysis.

The analysis credits operation of the steam generator Atmospheric Dump Valves (ADVs). The ADVs are safety-grade equipment. They are modeled in automatic mode with an opening pressure of 1000 psia. The ADVs are credited in the analysis for control of secondary side pressure. The automatic operation of the ADVs with an opening pressure of 1000 psia results

in lower primary pressure compared to the previous assumption of crediting the main steam safety valves (MSSVs) for secondary pressure control. Analyses were conducted to confirm that the failure of an emergency diesel generator (i.e., failure of one HPSI pump) resulted in worse ECCS performance than failure of one ADV. The ADVs are required to be in automatic at power levels greater than 70% of the uprated power level. The ADVs are not required for small break ECCS performance for power levels below 70% of the uprated power level since, within 6 hours of operation at 70% of the uprated power, core decay heat is less than the decay heat associated with the pre-uprated power level and ADVs were not credited in the pre-uprate SBLOCA analysis.

A spectrum of three break sizes in the reactor coolant pump (RCP) discharge (PD) leg was analyzed: the 0.04, 0.05, and 0.06 ft^2/PD breaks. The RCP discharge leg is the limiting break location because it maximizes the amount of spillage from the ECCS. The limiting SBLOCA, the 0.05 ft^2/PD break, is the largest small break for which the hot rod cladding heatup transient is terminated solely by injection from a HPSI pump. The 0.04 ft^2/PD break was analyzed to demonstrate that break sizes smaller than the limiting break are too small to experience as much core uncovery and are therefore, less limiting. The 0.06 ft^2/PD break demonstrates that breaks larger than the limiting size break are sufficiently large to allow injection from the SITs, in conjunction with the injection from the HPSI pump, to recover the core and terminate the heatup of the cladding before the cladding temperature approaches the PCT of the limiting SBLOCA.

2.12.4.2 Plant Design Data

Important core, RCS, and ECCS design data used in the SBLOCA analysis are listed in Tables 2.12-7 and 2.12-8. The listed fuel rod conditions are for the hot rod burnup that produces the maximum initial stored energy.

2.12.4.3 Results

Table 2.12-9 lists the peak cladding temperature and oxidation percentages for the spectrum of SBLOCAs. Times of interest are listed in Table 2.12-10. The variables listed in Table 2.12-11 are plotted as a function of time for each break in Figures 2.12-36 through 2.12-59. The results for the 0.05 ft^2/PD break, the limiting SBLOCA, demonstrate conformance to the ECCS acceptance criteria as summarized below.

Parameter	Criterion	EPU Results	Current FSAR
PCT	≤2200°F	2016°F	1929°F
Maximum Cladding Oxidation	≤17%	7.50%	8.09%
Maximum Core-Wide Oxidation	≤1%	<0.99%	<0.58%
Coolable Geometry	Yes	Yes	Yes

The results are applicable to Waterford 3 for a PLHGR of 13.2 kW/ft and a rated core power of 3716 MWt (3735 MWt including a 0.5% power measurement uncertainty).

Table 2.12-7
SBLOCA ECCS Performance Analysis
Core and Plant Design Data

Quantity	Value	Units
Reactor power level (including uncertainty)	3735	MWt
PLHGR	13.2	kW/ft
Axial shape index	-0.25	---
Gap conductance at PLHGR(1)	1536	BTU/hr-ft^2-°F
Fuel centerline temperature at PLHGR(1)	3278	°F
Fuel average temperature at PLHGR(1)	2091	°F
Hot rod gas pressure(1)	1093	psia
Moderator temperature coefficient at initial density	0.0×10^{-4}	$\Delta\rho$/°F
RCS flow rate	148.0×10^6	lbm/hr
Core flow rate	144.15×10^6	lbm/hr
RCS pressure	2250	psia
Cold leg temperature	552.0	°F
Hot leg temperature	615.5	°F
Plugged tubes per steam generator	1000	count
MSSV first bank opening pressure	1117.2	psia
Low pressurizer pressure reactor trip setpoint	1560	psia
Low pressurizer pressure SIAS setpoint	1560	psia
HPSI Flow Rate	Table 2.12-8	gpm
SIT pressure	584.7	psia
ADV Opening Pressure	1000	psia

Note:
(1) These quantities correspond to the rod average burnup of the hot rod (1000 MWD/MTU) that yields the maximum initial stored energy.

Table 2.12-8
HPSI Pump Minimum Delivered Flow to RCS
(Assuming Failure of an EDG)

RCS Pressure, psia	Flow Rate, gpm
0.0	777.0
225.0	693.0
343.0	646.0
450.0	603.0
568.0	553.0
675.0	504.0
850.0	421.0
948.0	371.0
1019.0	330.0
1075.0	290.0
1203.0	197.0
1250.0	144.0
1303.0	100.0
1344.0	0.0

Notes:
1. The flow is assumed to be split equally to each of the 4 discharge legs.
2. The flow to the broken discharge leg is assumed to spill out the break.

Table 2.12-9
SBLOCA ECCS Performance Analysis Results

Break Size	PCT (°F)	Maximum Cladding Oxidation (%)	Maximum Core-Wide Cladding Oxidation (%)
0.04 ft^2/PD	1788	2.92	<0.99
0.05 ft^2/PD	2016	7.50	<0.99
0.06 ft^2/PD	1884	2.30	<0.99

Table 2.12-10
SBLOCA ECCS Performance Analysis
Times of Interest

Break Size	HPSI Flow Delivered to RCS (seconds after break)	LPSI Flow Delivered to RCS (seconds after break)	SIT Flow Delivered to RCS (seconds after break)	PCT (seconds after break)
0.04 ft^2/PD	193	(a)	(b)	2292
0.05 ft^2/PD	157	(a)	1880	1824
0.06 ft^2/PD	135	(a)	1451	1453

(a) Calculation completed before LPSI flow delivery to RCS begins.
(b) Calculation completed before SIT injection begins.

Table 2.12-11
SBLOCA ECCS Performance Analysis
Variables Plotted as a Function of Time for Each Break

Variable
Core Power
Inner Vessel Pressure
Break Flow Rate
Inner Vessel Inlet Flow Rate
Inner Vessel Two-Phase Mixture Level
Heat Transfer Coefficient at Hot Spot
Coolant Temperature at Hot Spot
Cladding Temperature at Hot Spot

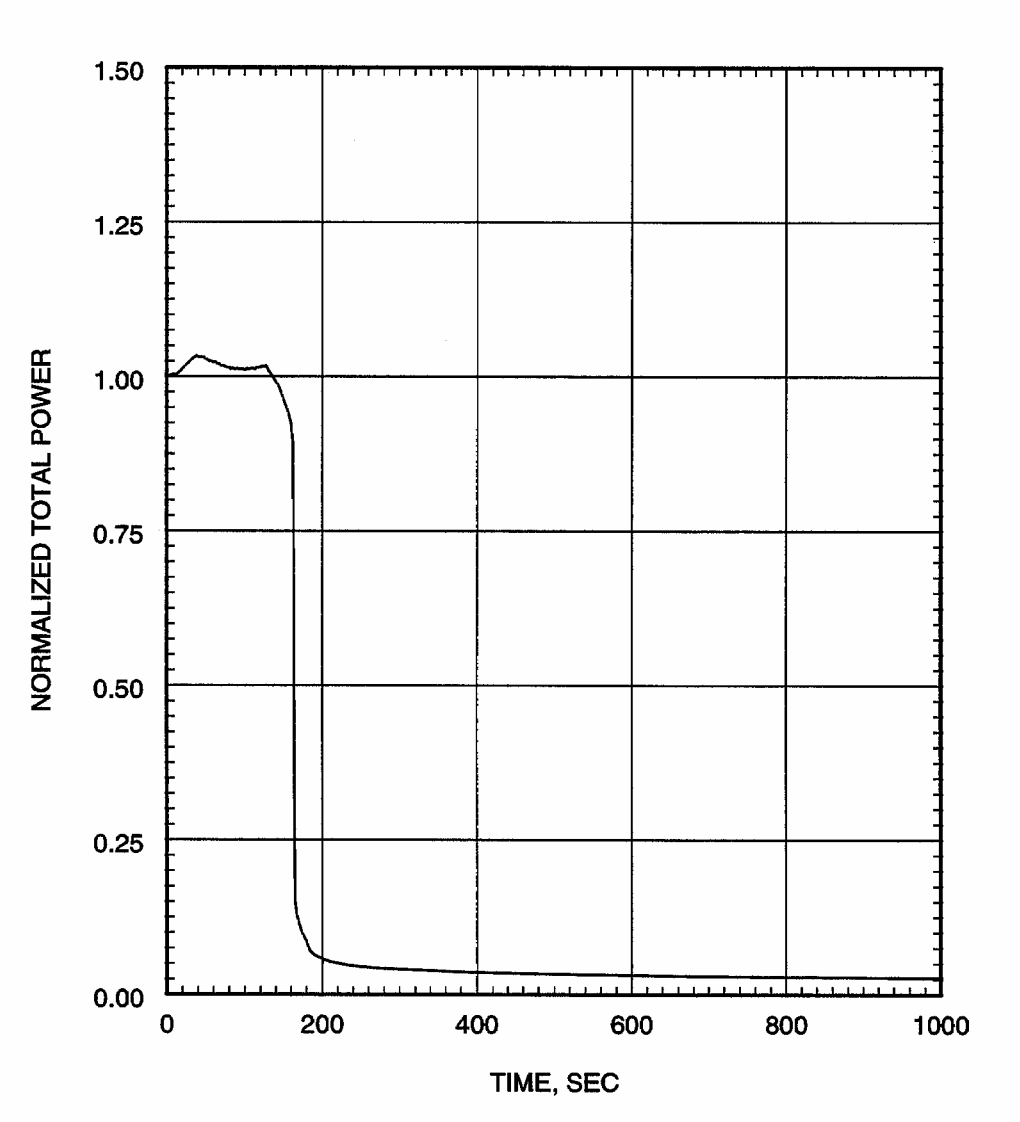


Figure 2.12-36
Waterford 3 SBLOCA ECCS Performance Analysis
0.04 ft^2/PD Break Core Power

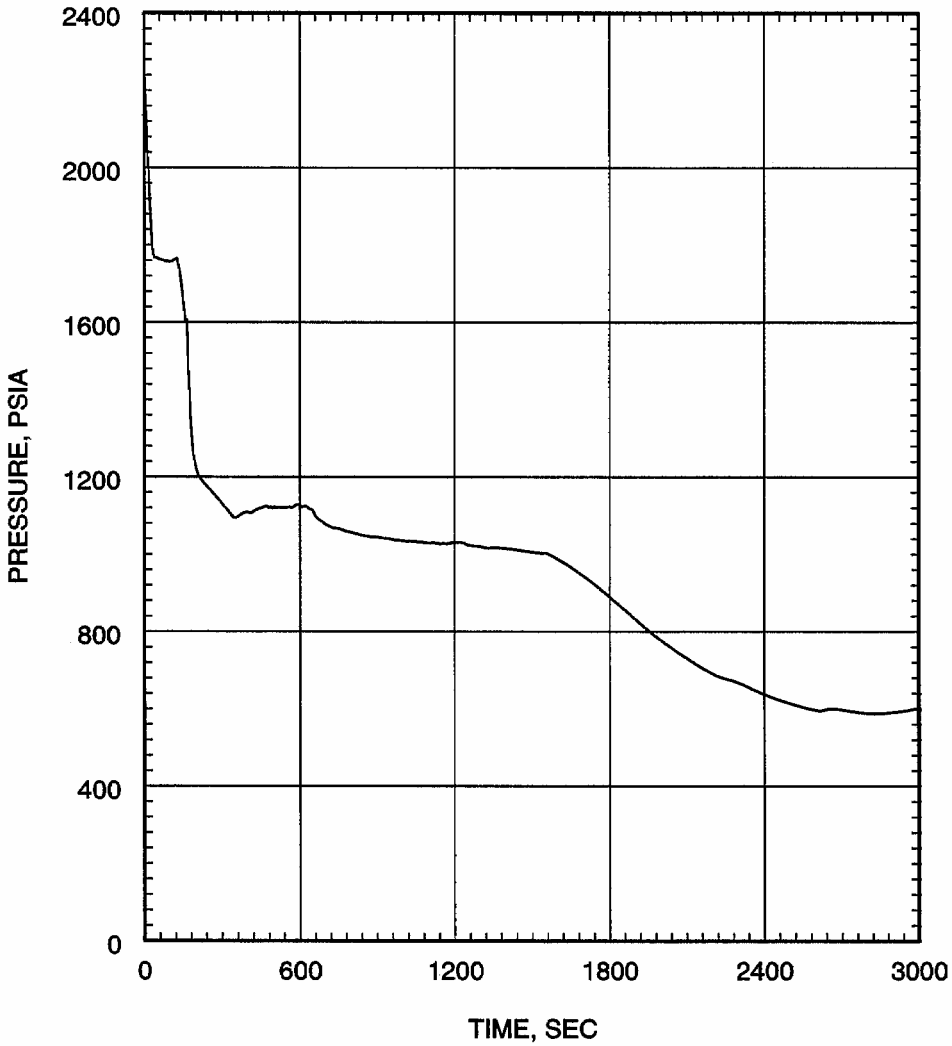


Figure 2.12-37
Waterford 3 SBLOCA ECCS Performance Analysis
0.04 ft^2/PD Break Inner Vessel Pressure

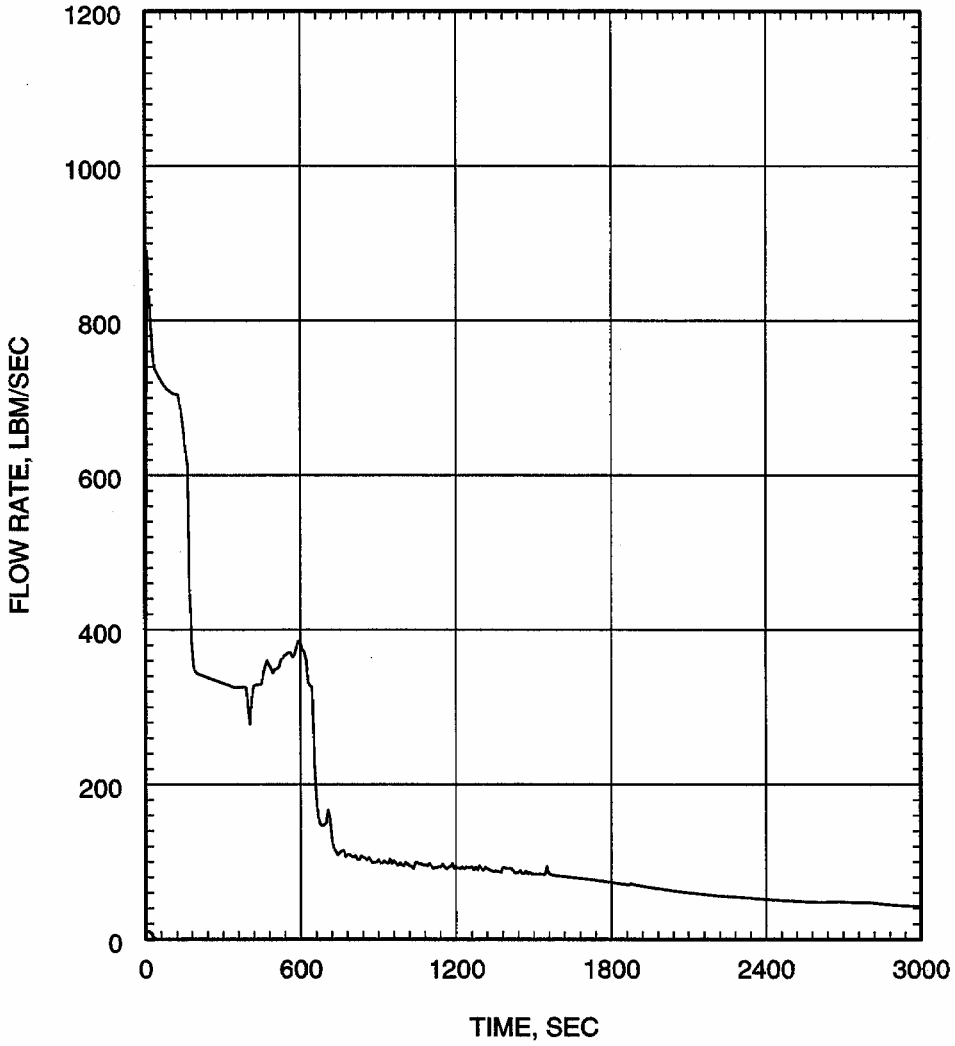


Figure 2.12-38
Waterford 3 SBLOCA ECCS Performance Analysis
0.04 ft^2/PD Break
Break Flow Rate

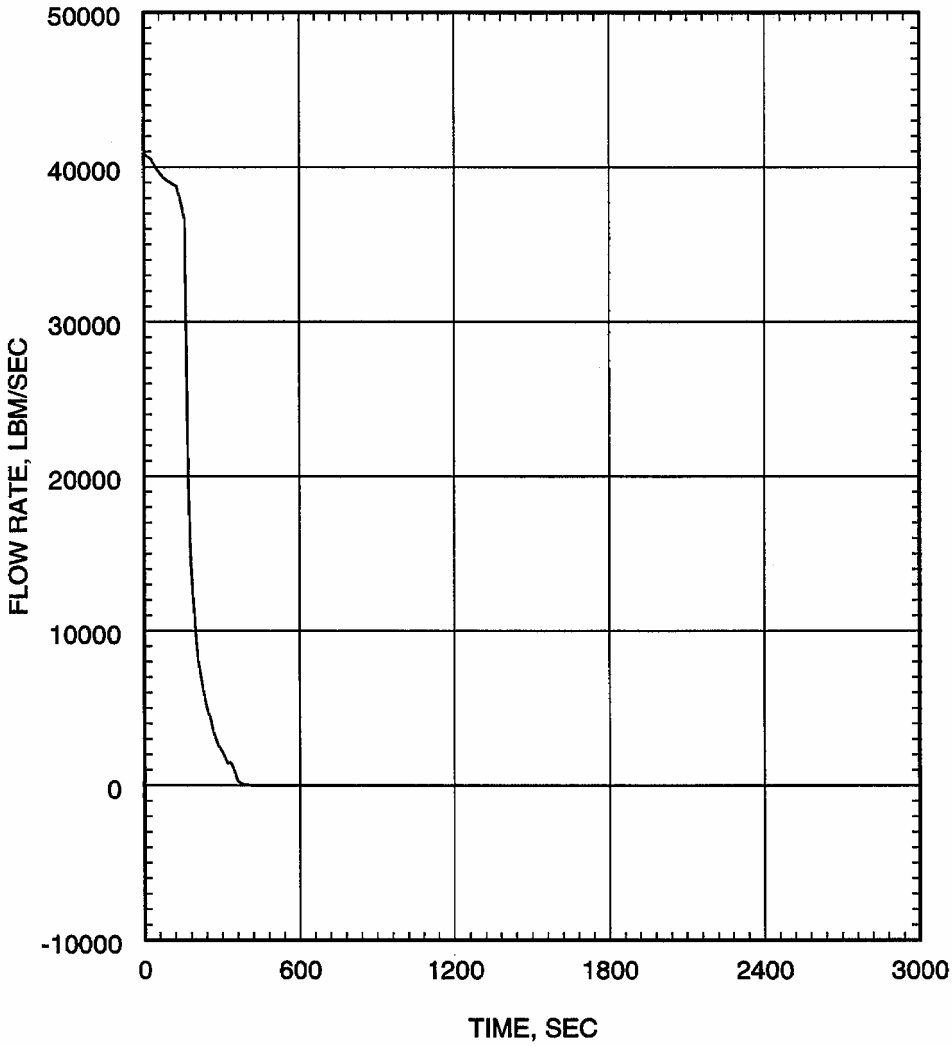


Figure 2.12-39
Waterford 3 SBLOCA ECCS Performance Analysis
0.04 ft^2/PD Break Inner Vessel Inlet Flow Rate

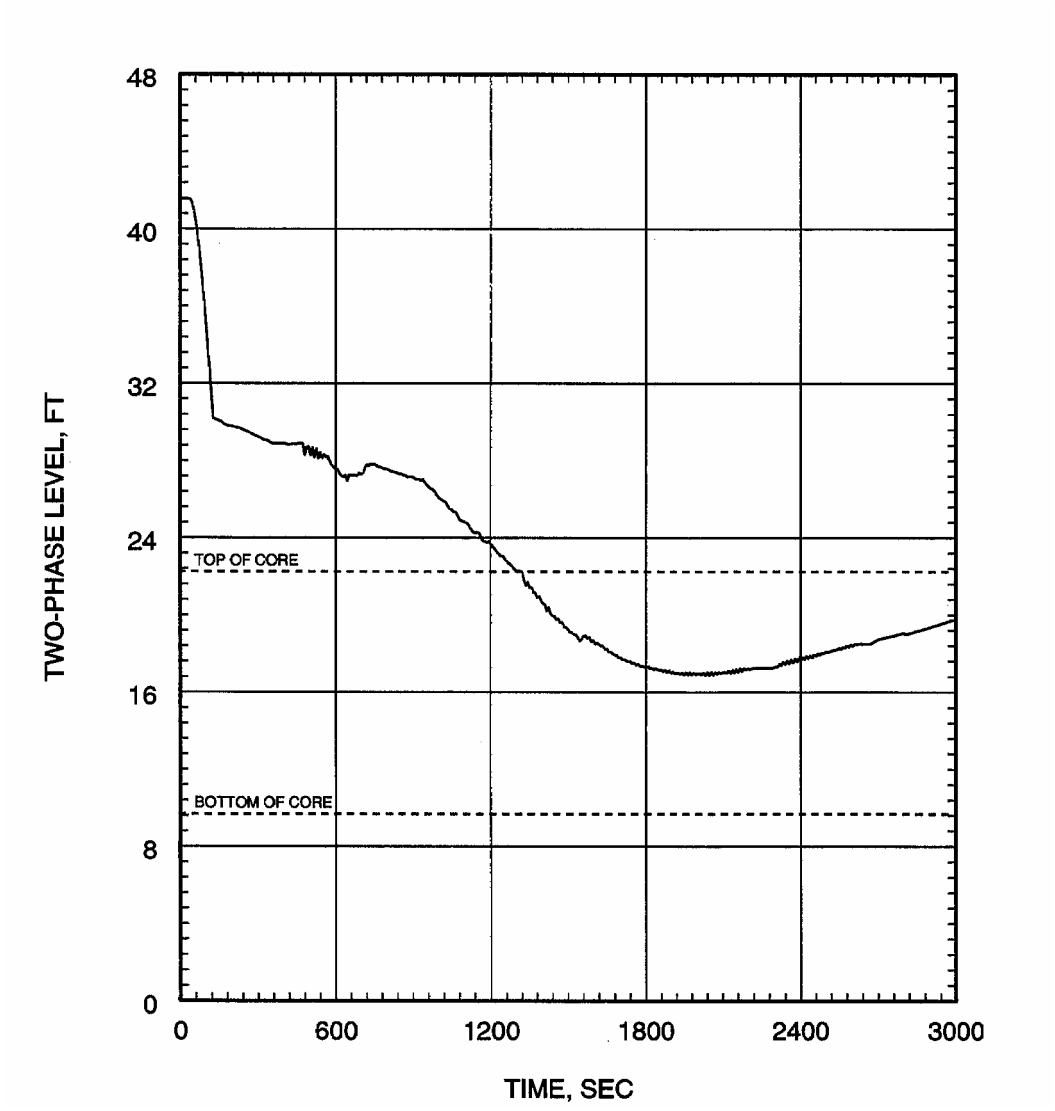


Figure 2.12-40
Waterford 3 SBLOCA ECCS Performance Analysis
0.04 ft^2/PD Break Inner Vessel Two-Phase Mixture Level

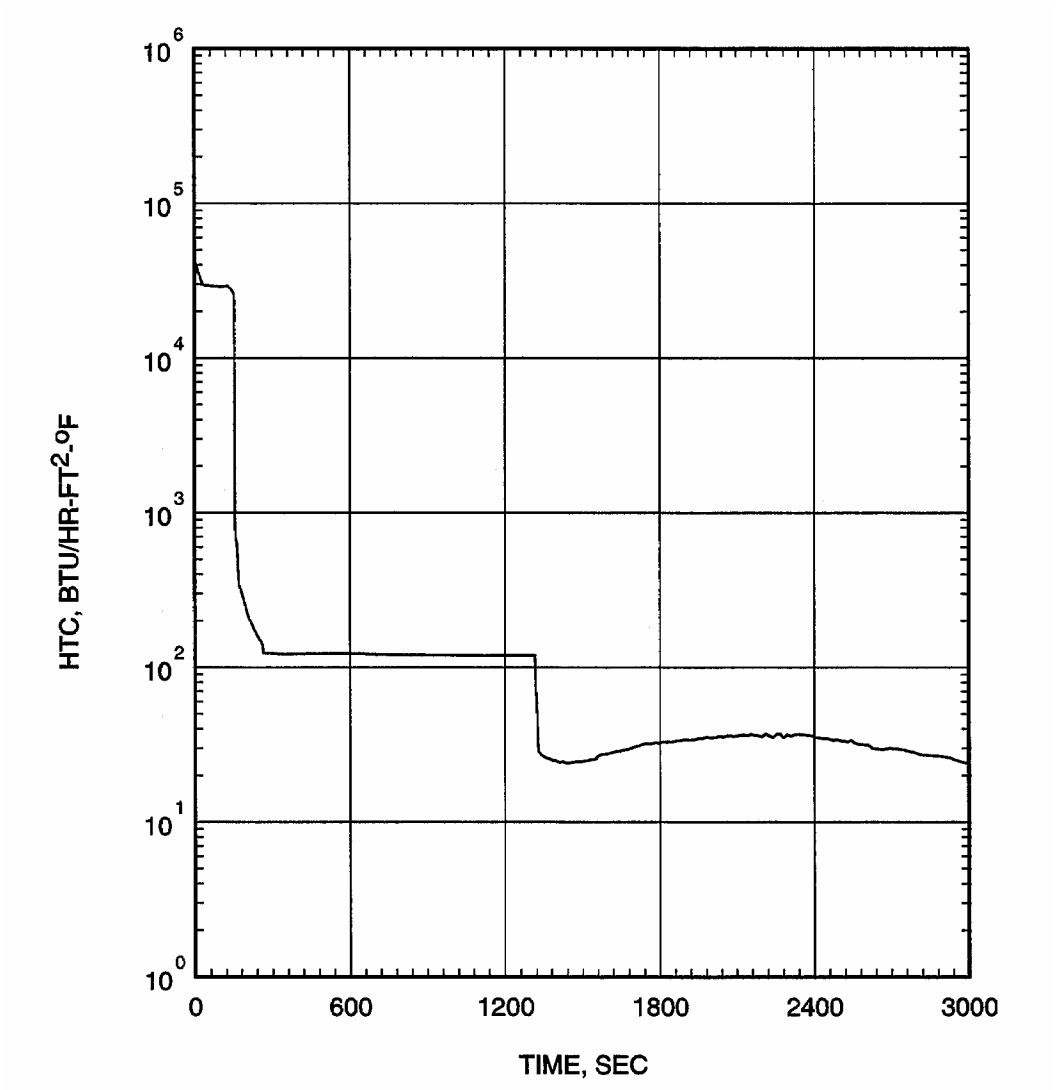


Figure 2.12-41
Waterford 3 SBLOCA ECCS Performance Analysis
0.04 ft^2/PD Break Heat Transfer Coefficient at Hot Spot

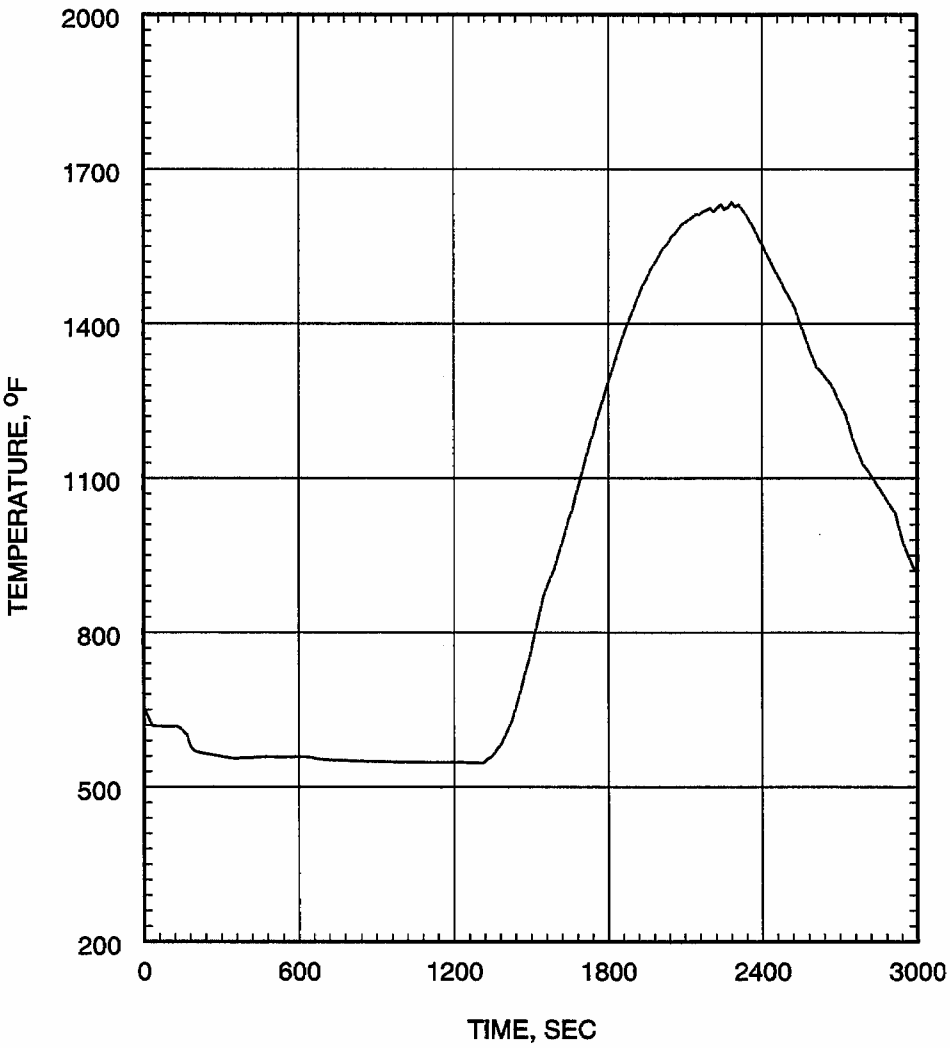


Figure 2.12-42
Waterford 3 SBLOCA ECCS Performance Analysis
0.04 ft^2/PD Break Coolant Temperature at Hot Spot

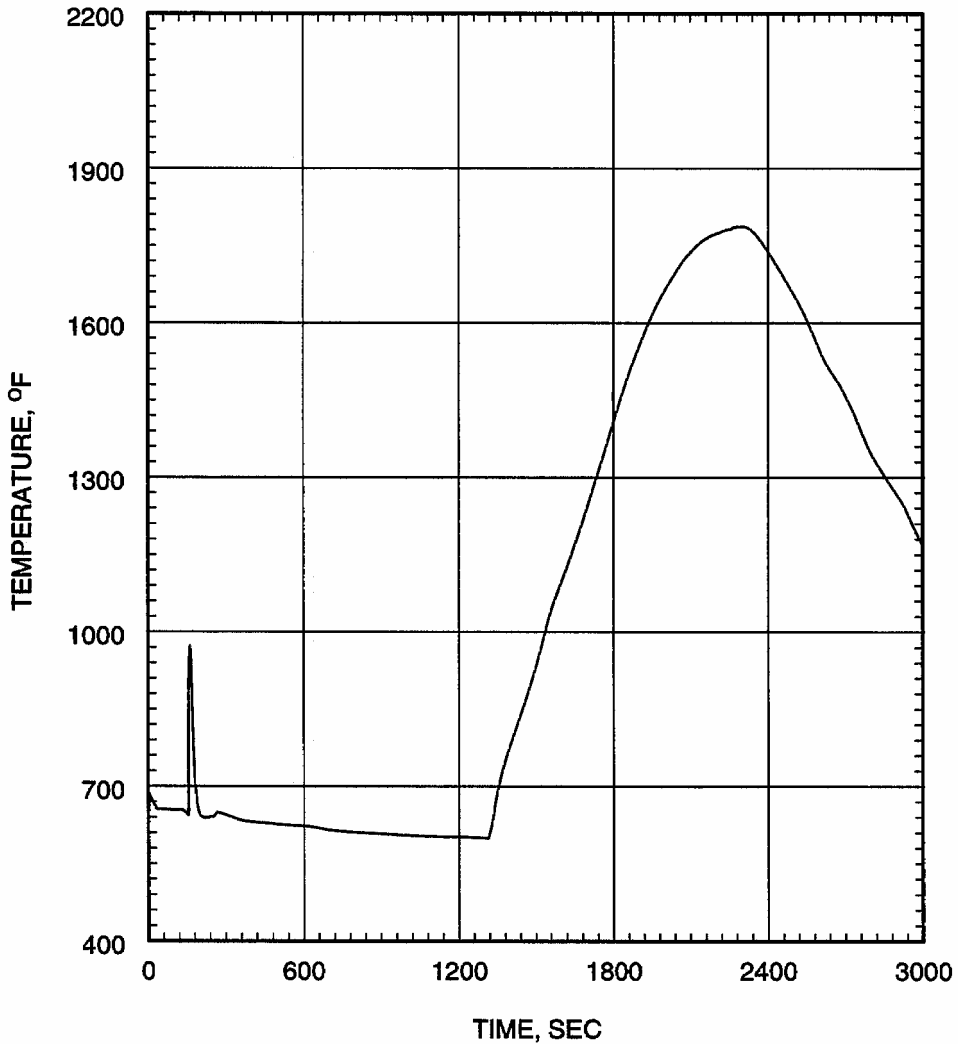


Figure 2.12-43
Waterford 3 SBLOCA ECCS Performance Analysis
0.04 ft^2/PD Break Cladding Temperature at Hot Spot

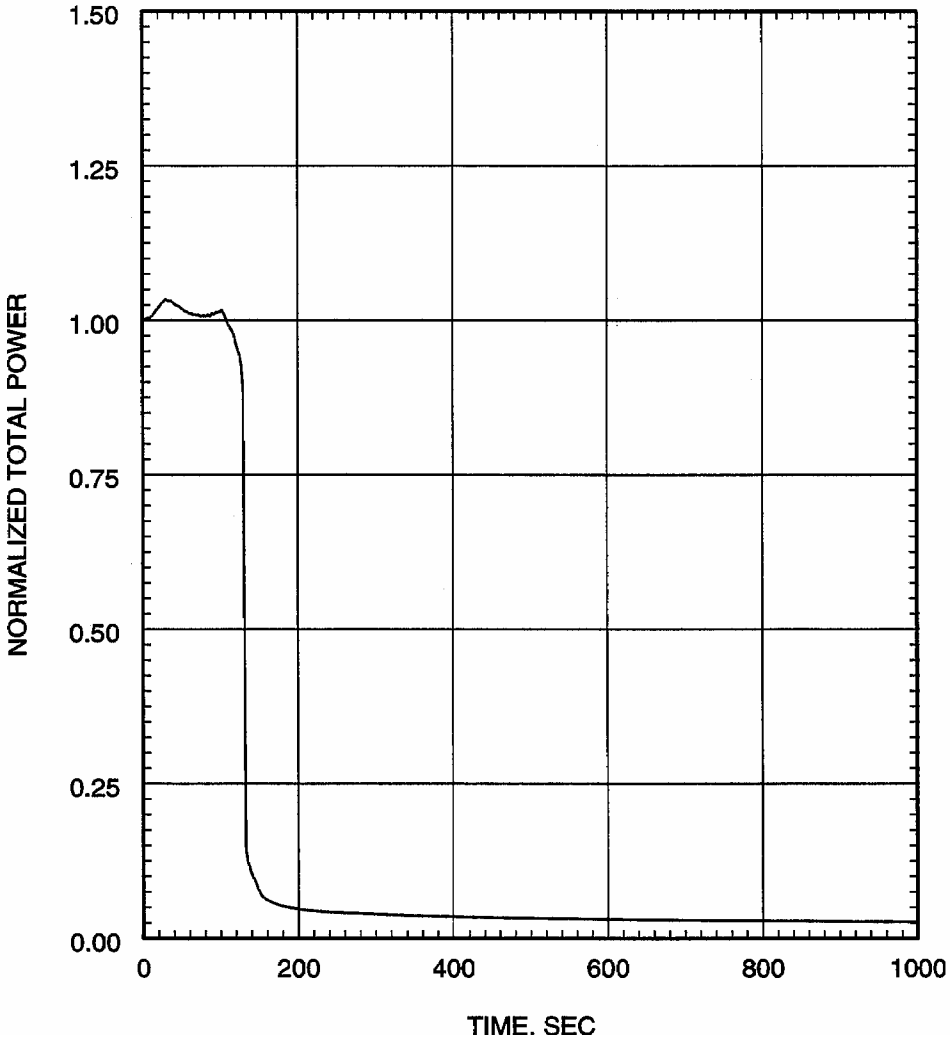


Figure 2.12-44
Waterford 3 SBLOCA ECCS Performance Analysis
0.05 ft^2/PD Break Core Power

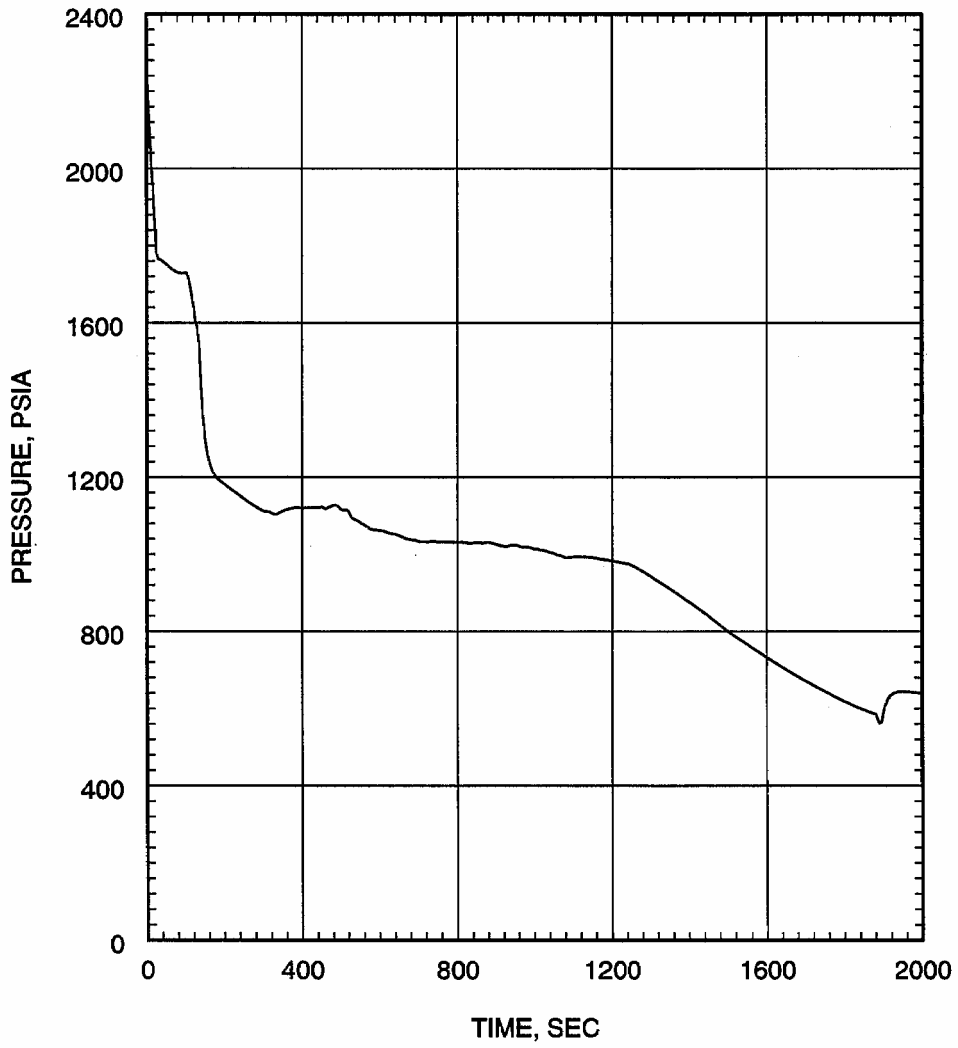


Figure 2.12-45
Waterford 3 SBLOCA ECCS Performance Analysis
0.05 ft^2/PD Break Inner Vessel Pressure

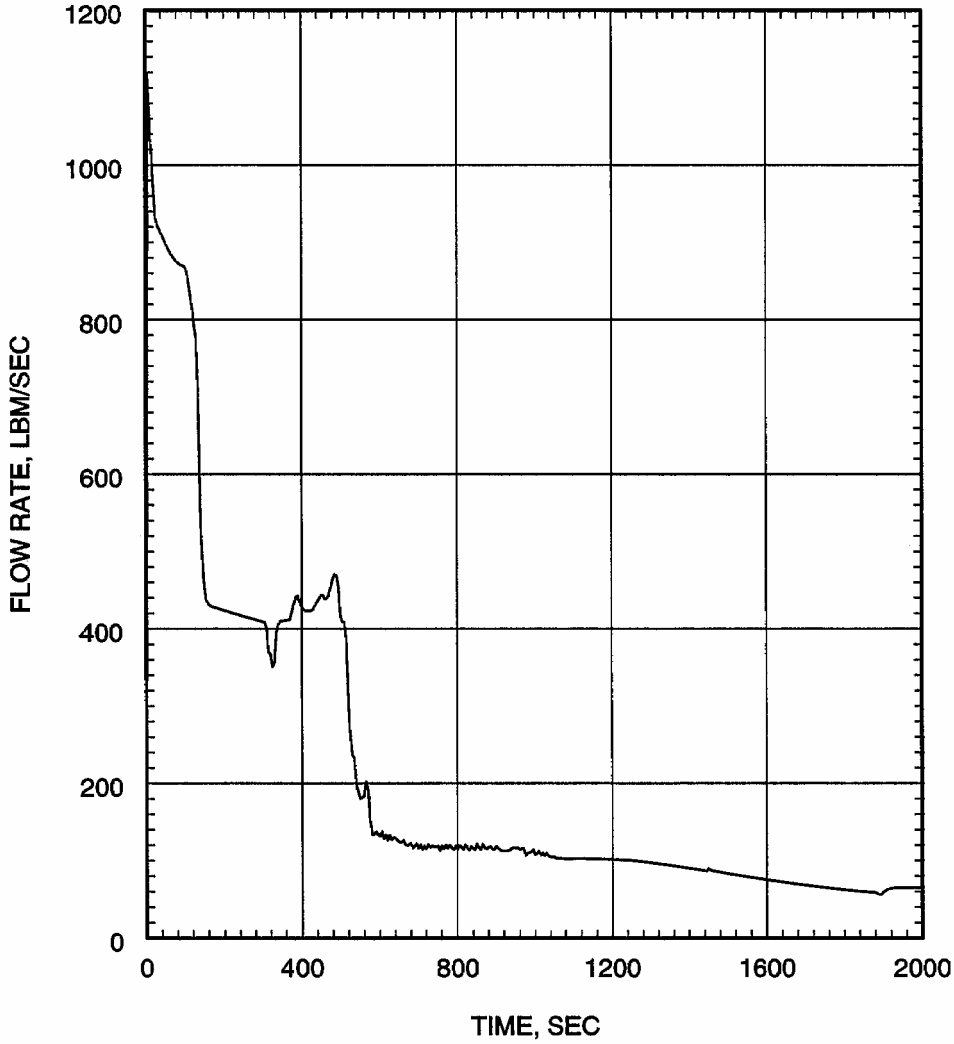


Figure 2.12-46
Waterford 3 SBLOCA ECCS Performance Analysis
0.05 ft^2/PD Break
Break Flow Rate

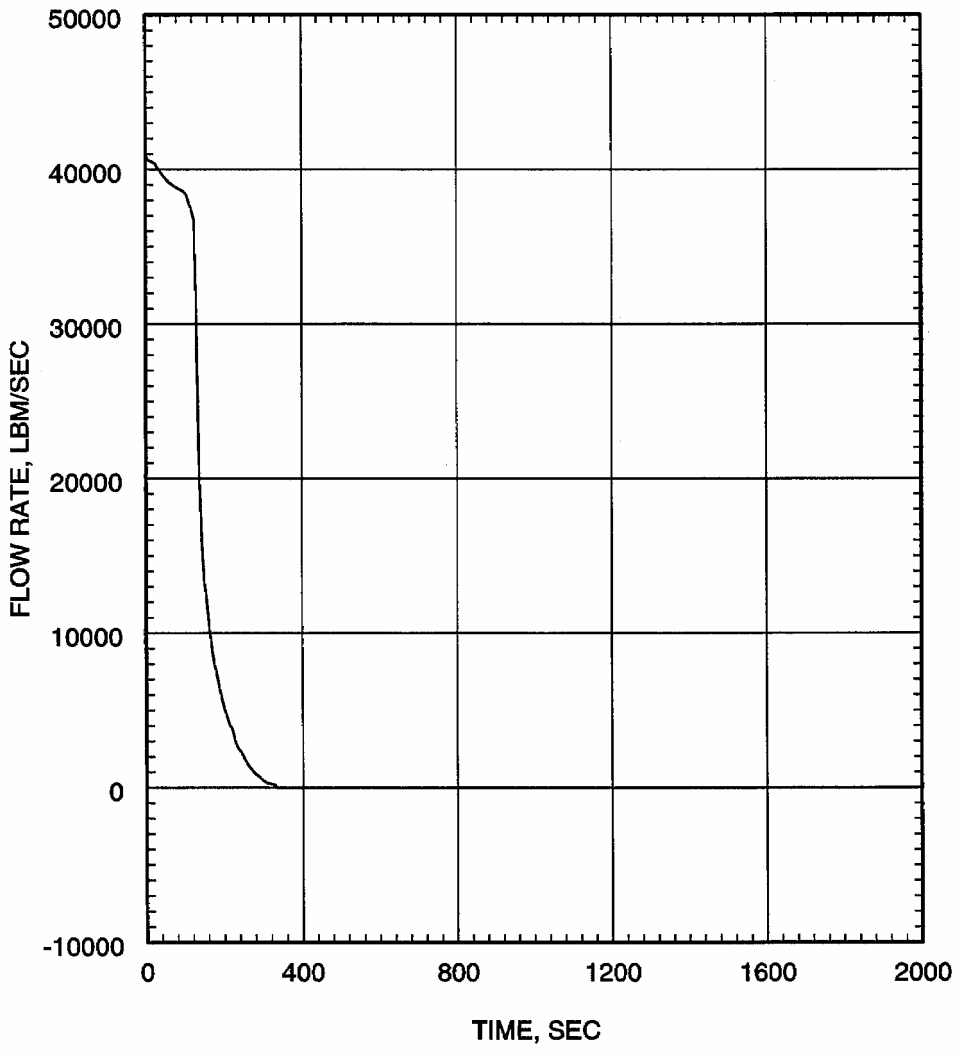


Figure 2.12-47
Waterford 3 SBLOCA ECCS Performance Analysis
0.05 ft^2/PD Break Inner Vessel Inlet Flow Rate

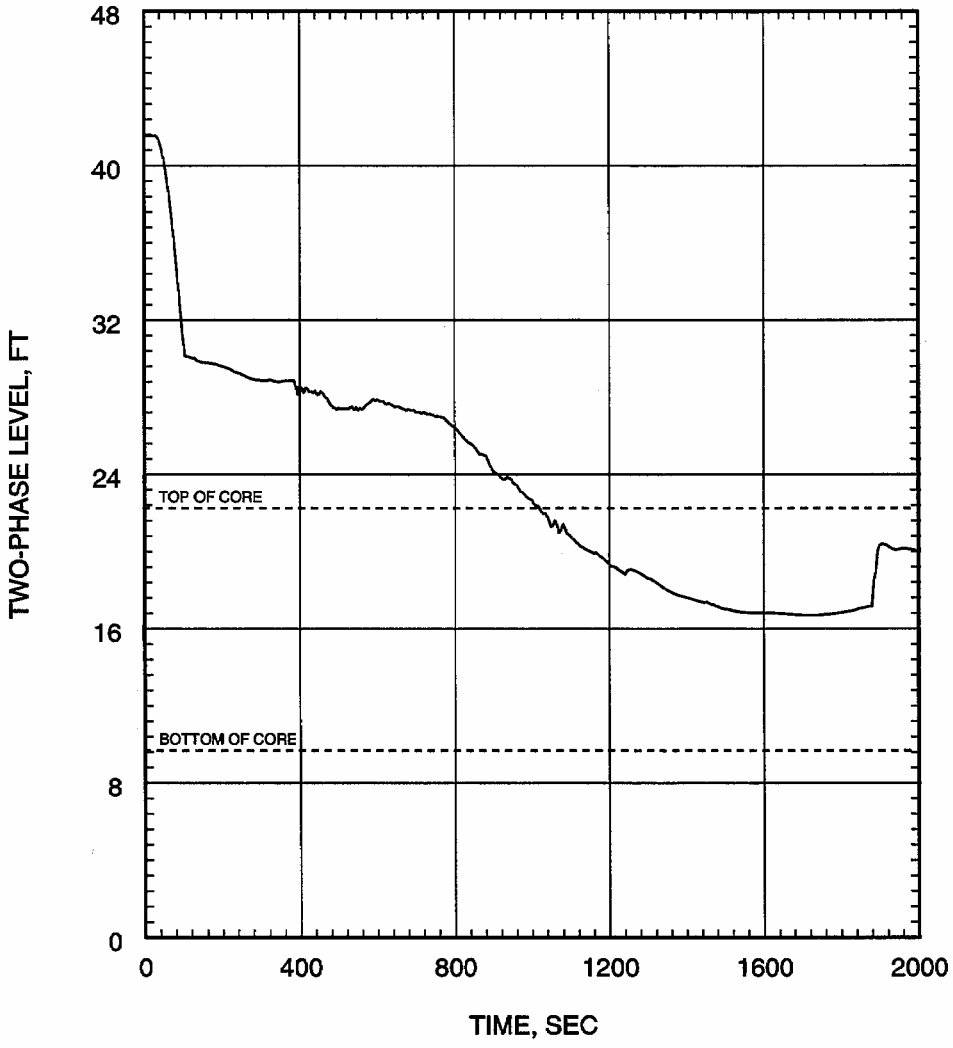


Figure 2.12-48
Waterford 3 SBLOCA ECCS Performance Analysis
0.05 ft^2/PD Break Inner Vessel Two-Phase Mixture Level

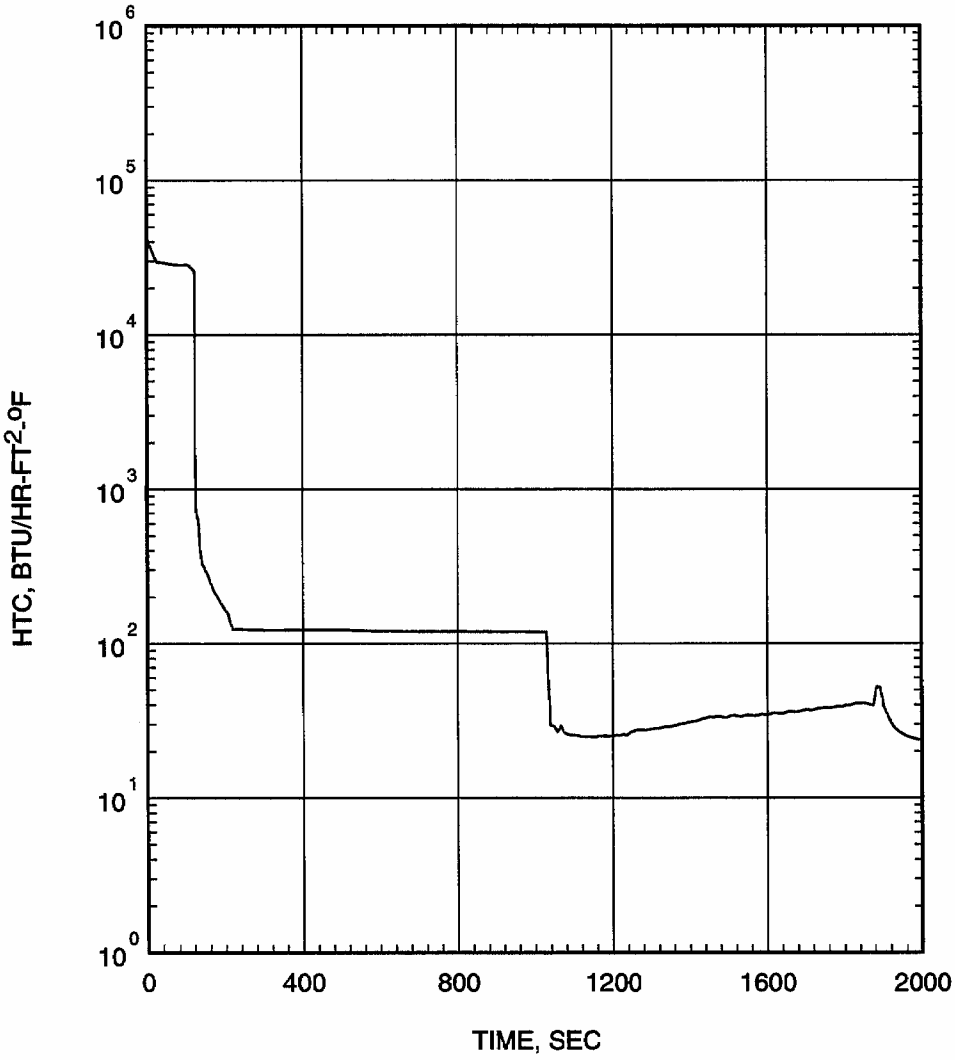


Figure 2.12-49
Waterford 3 SBLOCA ECCS Performance Analysis
0.05 ft^2/PD Break Heat Transfer Coefficient at Hot Spot

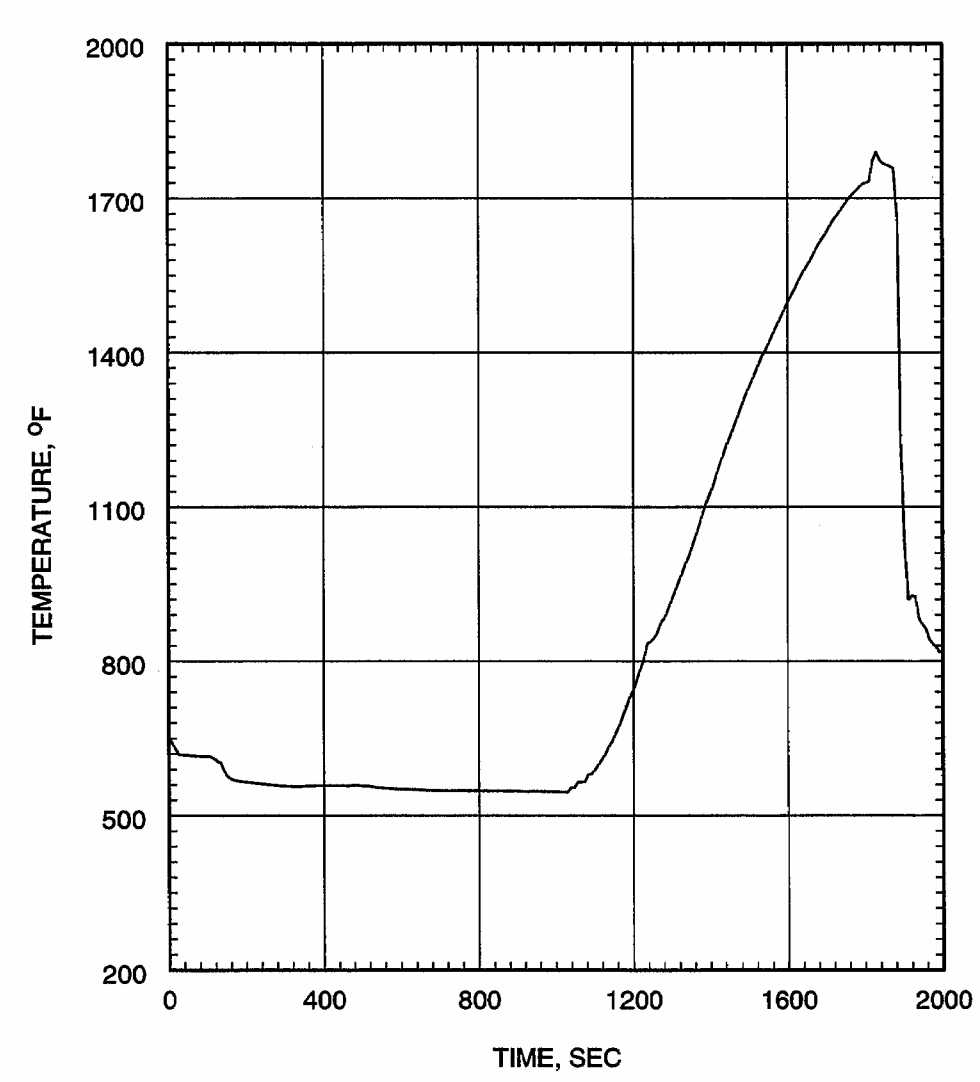


Figure 2.12-50
Waterford 3 SBLOCA ECCS Performance Analysis
0.05 ft^2/PD Break Coolant Temperature at Hot Spot

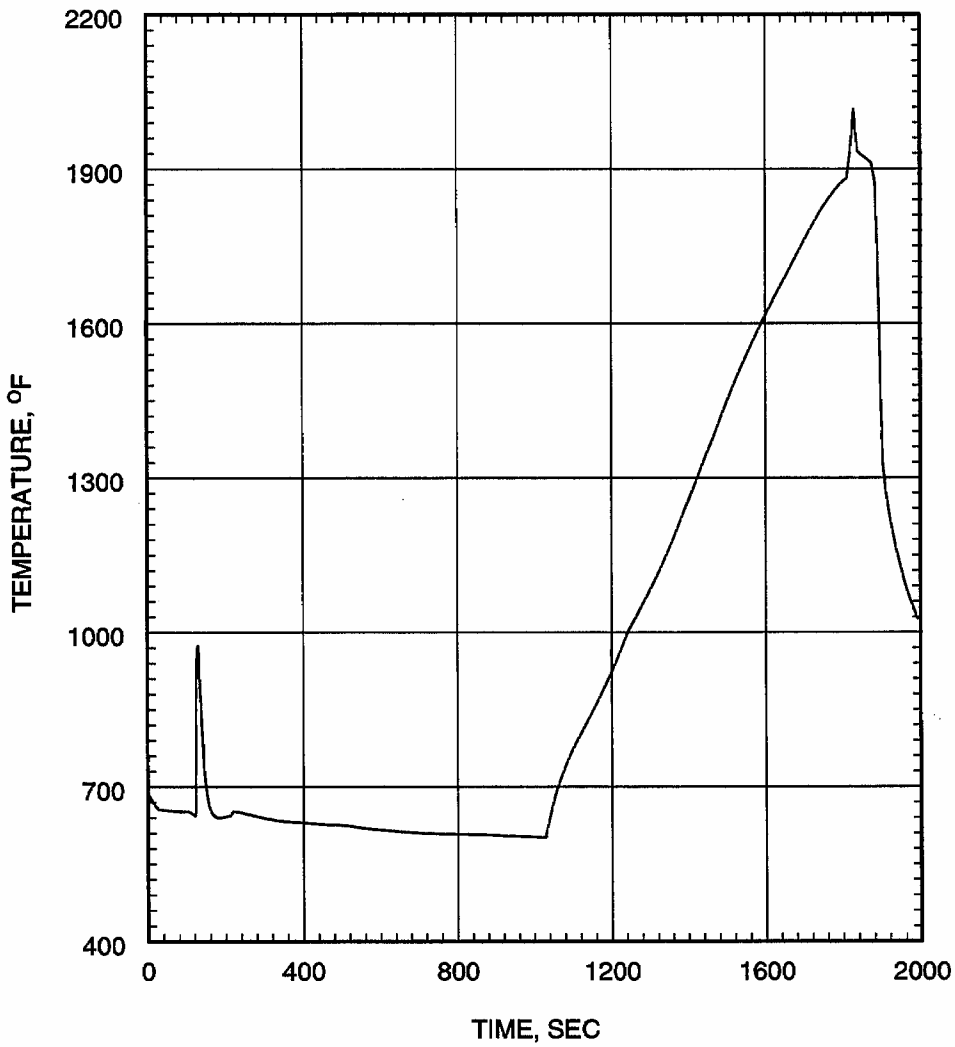


Figure 2.12-51
Waterford 3 SBLOCA ECCS Performance Analysis
0.05 ft^2/PD Break Cladding Temperature at Hot Spot

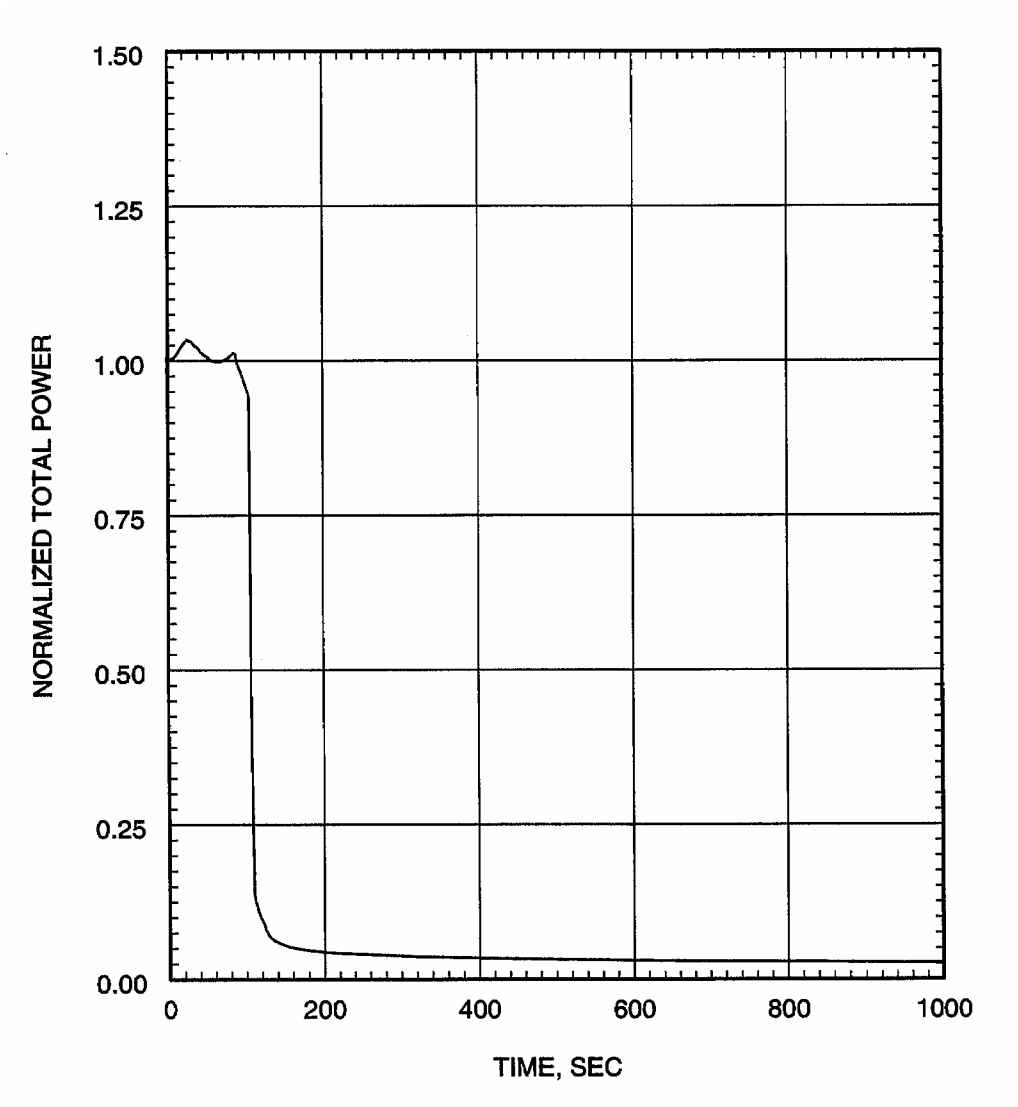


Figure 2.12-52
Waterford 3 SBLOCA ECCS Performance Analysis
0.06 ft^2/PD Break Core Power

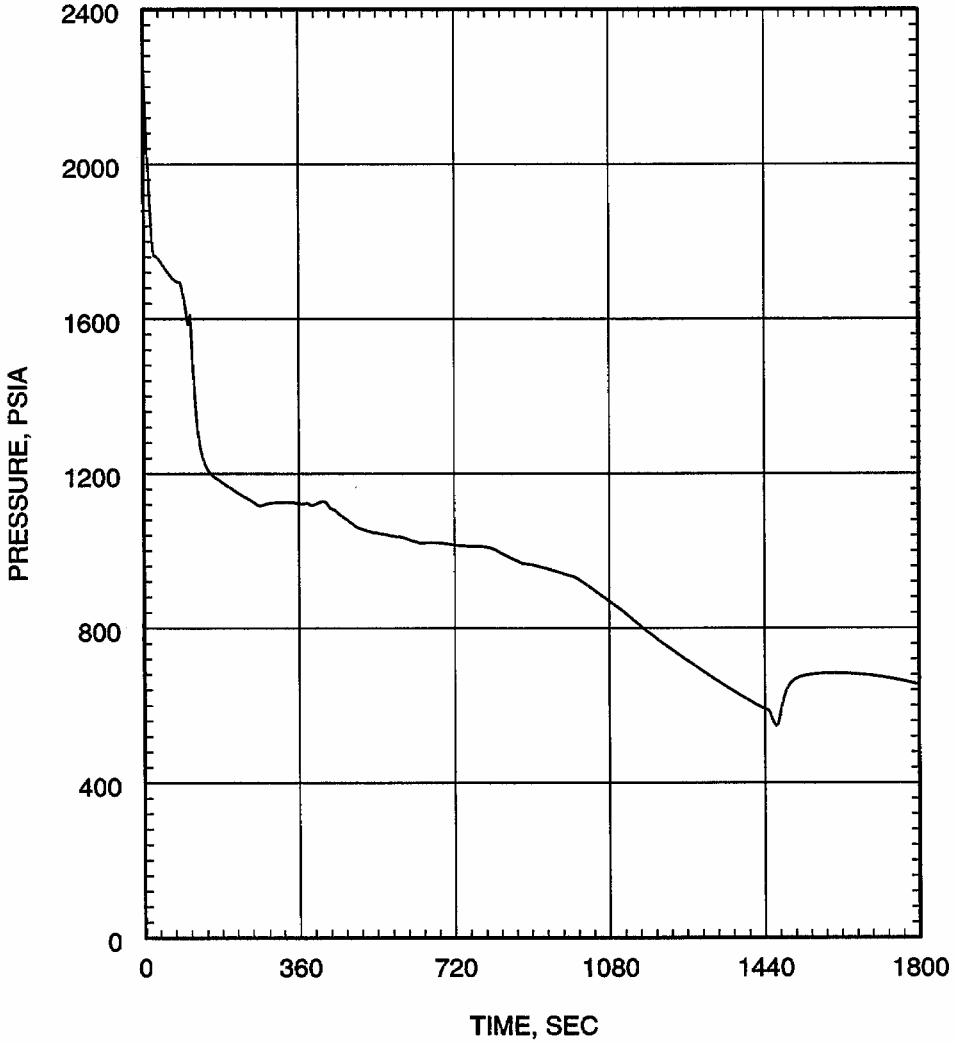


Figure 2.12-53
Waterford 3 SBLOCA ECCS Performance Analysis
0.06 ft^2/PD Break Inner Vessel Pressure

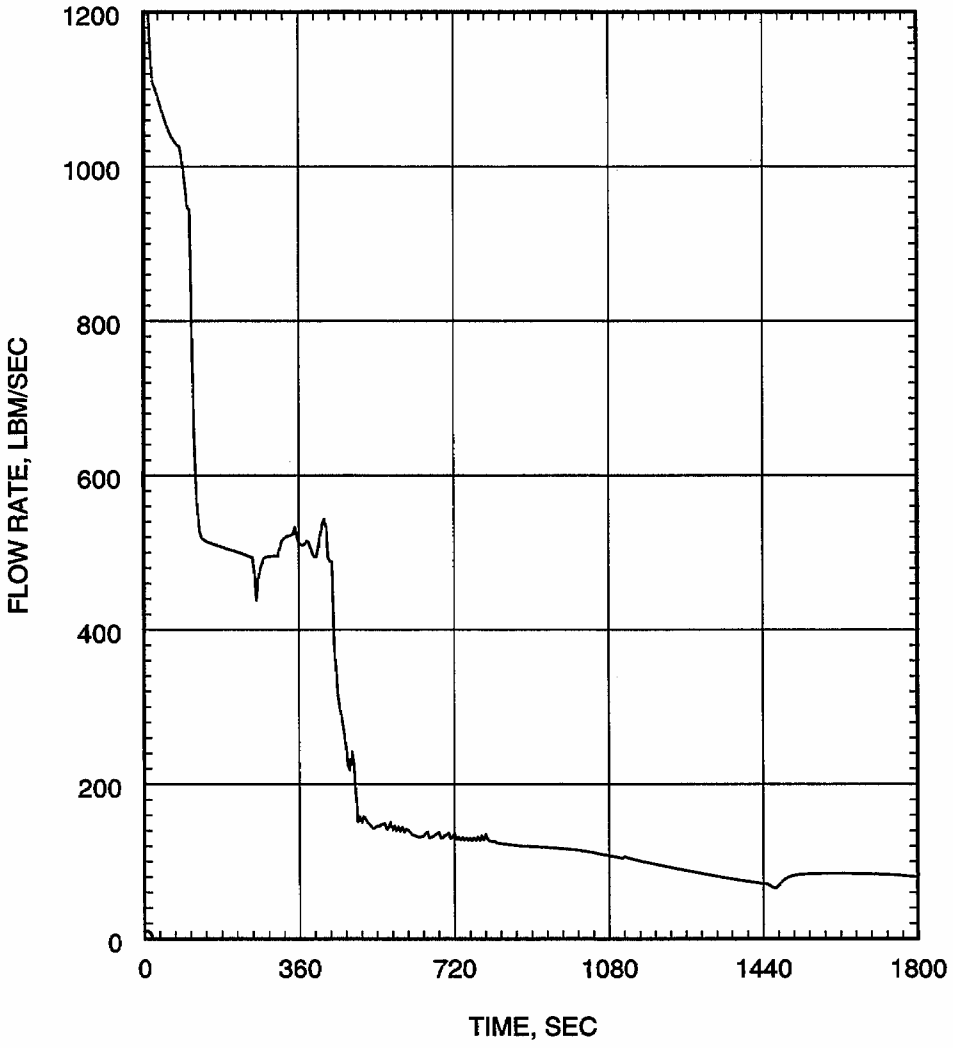


Figure 2.12-54
Waterford 3 SBLOCA ECCS Performance Analysis
0.06 ft^2/PD Break
Break Flow Rate

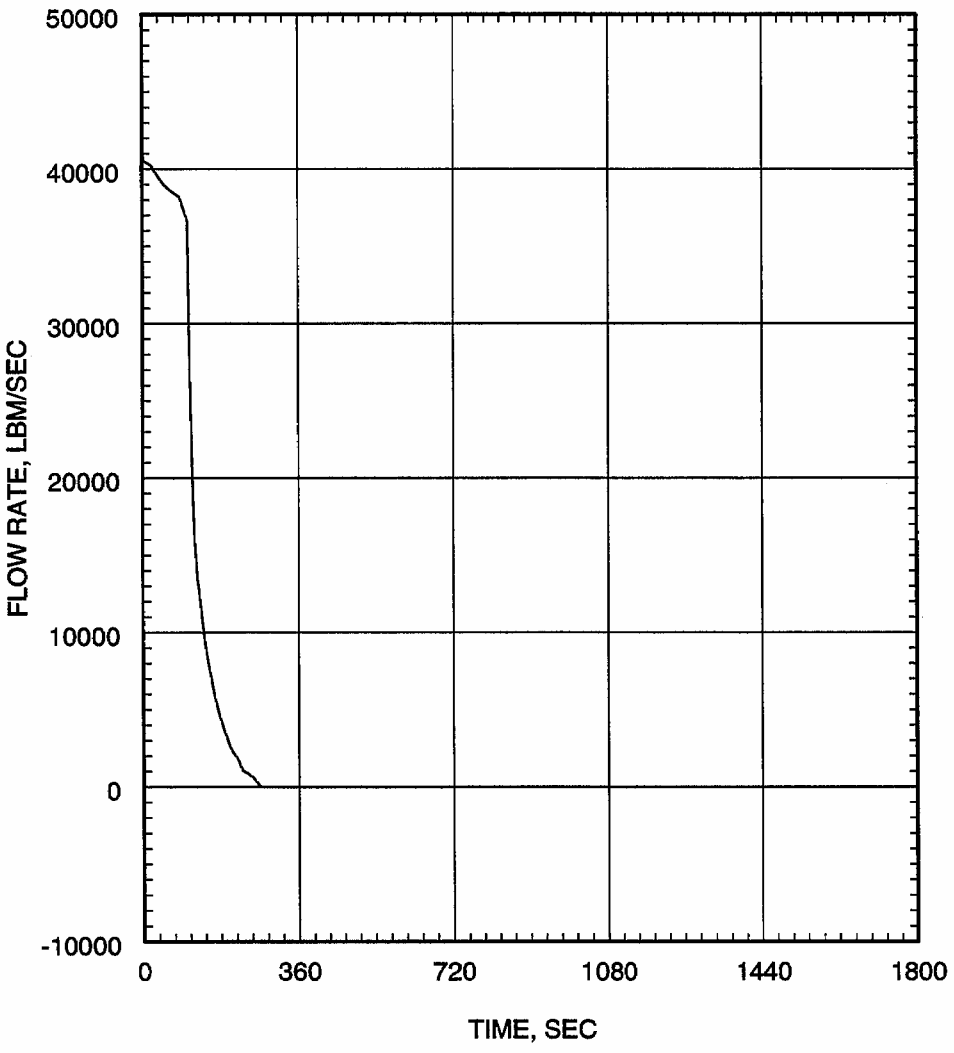


Figure 2.12-55
Waterford 3 SBLOCA ECCS Performance Analysis
0.06 ft^2/PD Break Inner Vessel Inlet Flow Rate

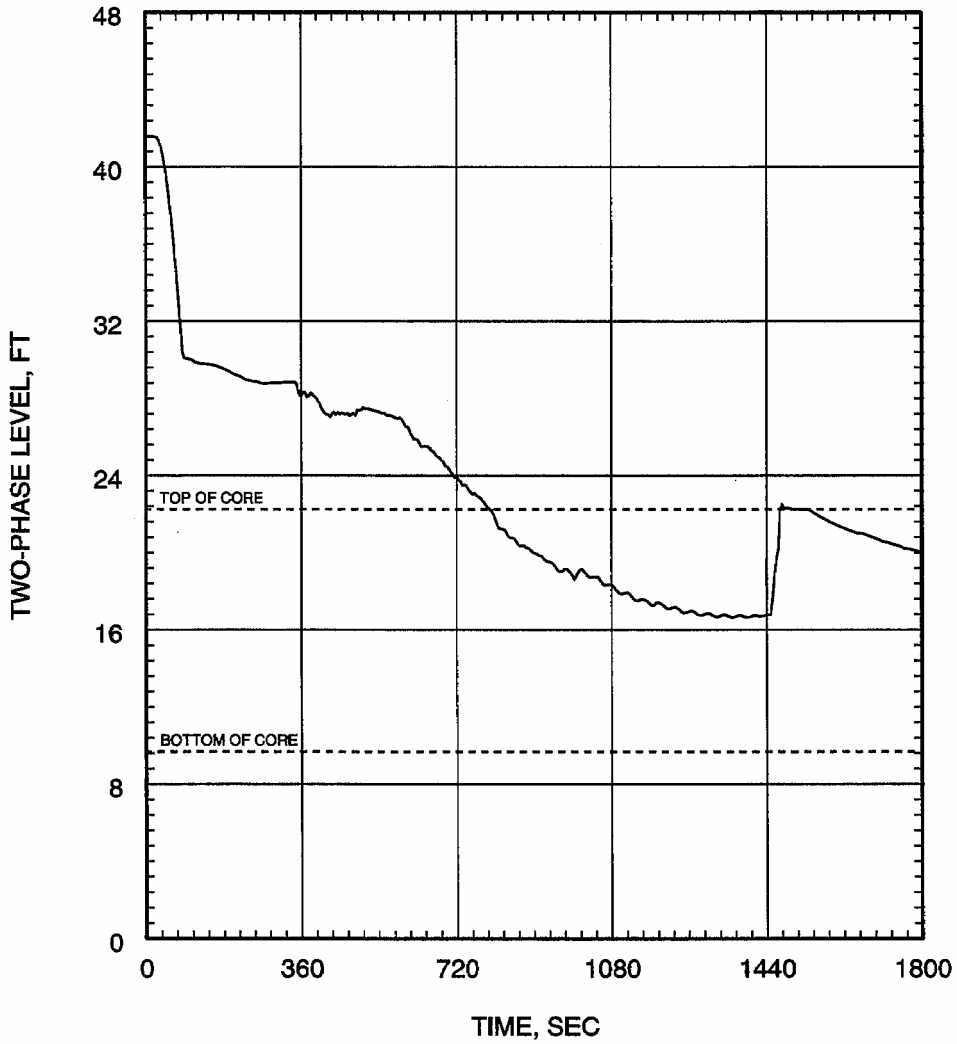


Figure 2.12-56
Waterford 3 SBLOCA ECCS Performance Analysis
0.06 ft^2/PD Break Inner Vessel Two-Phase Mixture Level

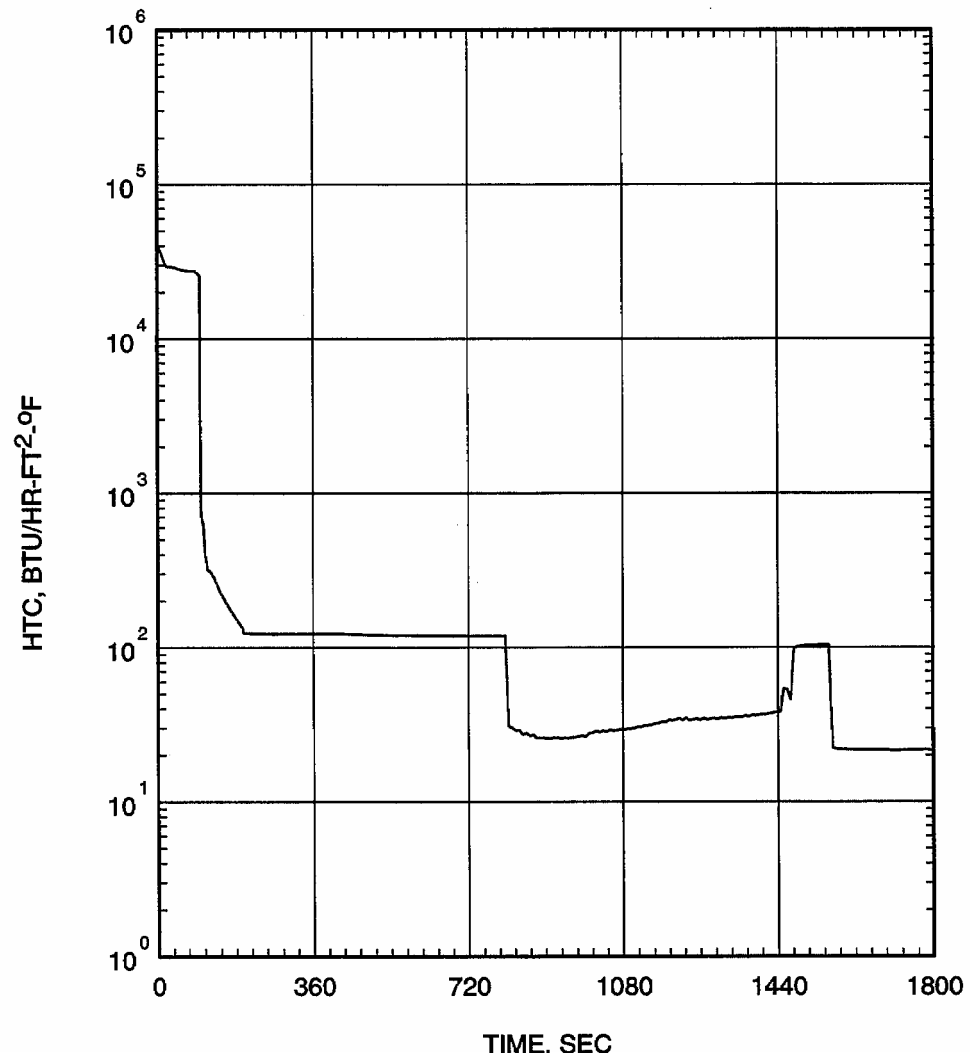


Figure 2.12-57
Waterford 3 SBLOCA ECCS Performance Analysis
0.06 ft^2/PD Break Heat Transfer Coefficient at Hot Spot

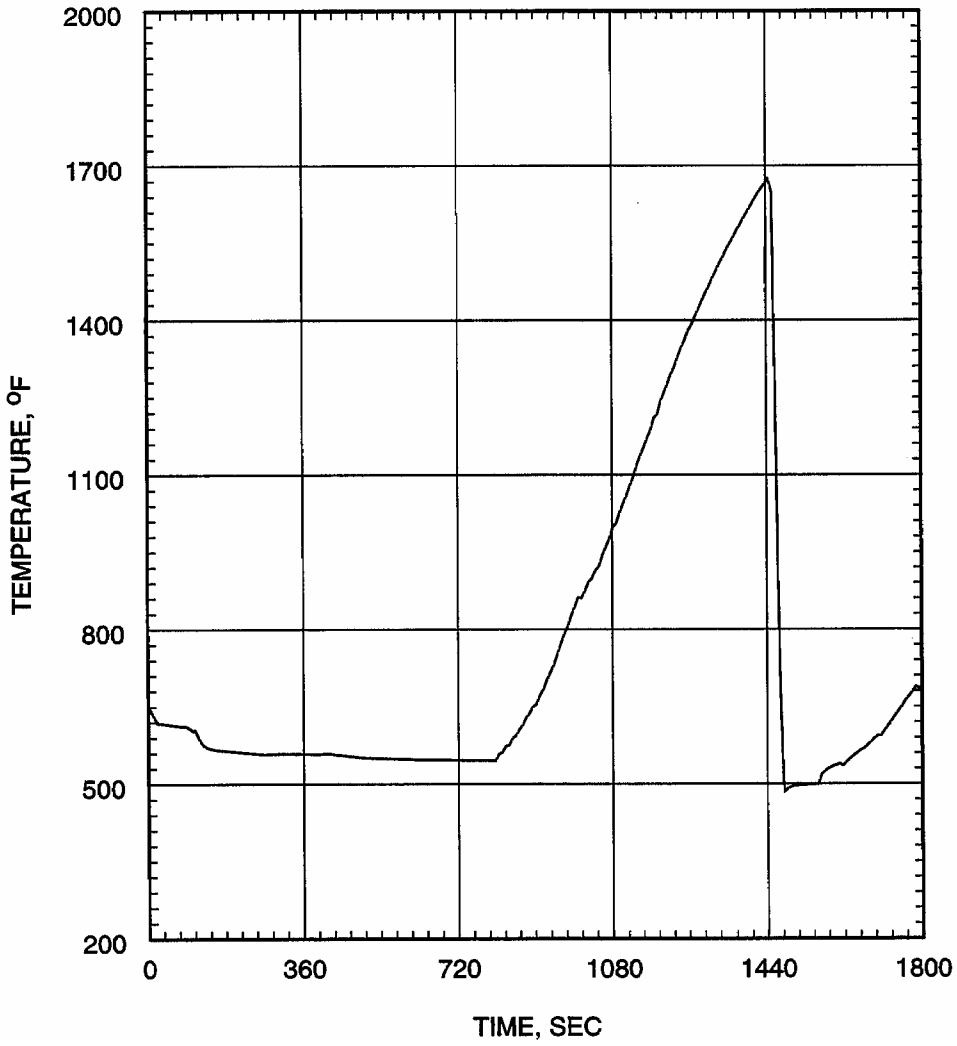


Figure 2.12-58
Waterford 3 SBLOCA ECCS Performance Analysis
0.06 ft^2/PD Break Coolant Temperature at Hot Spot

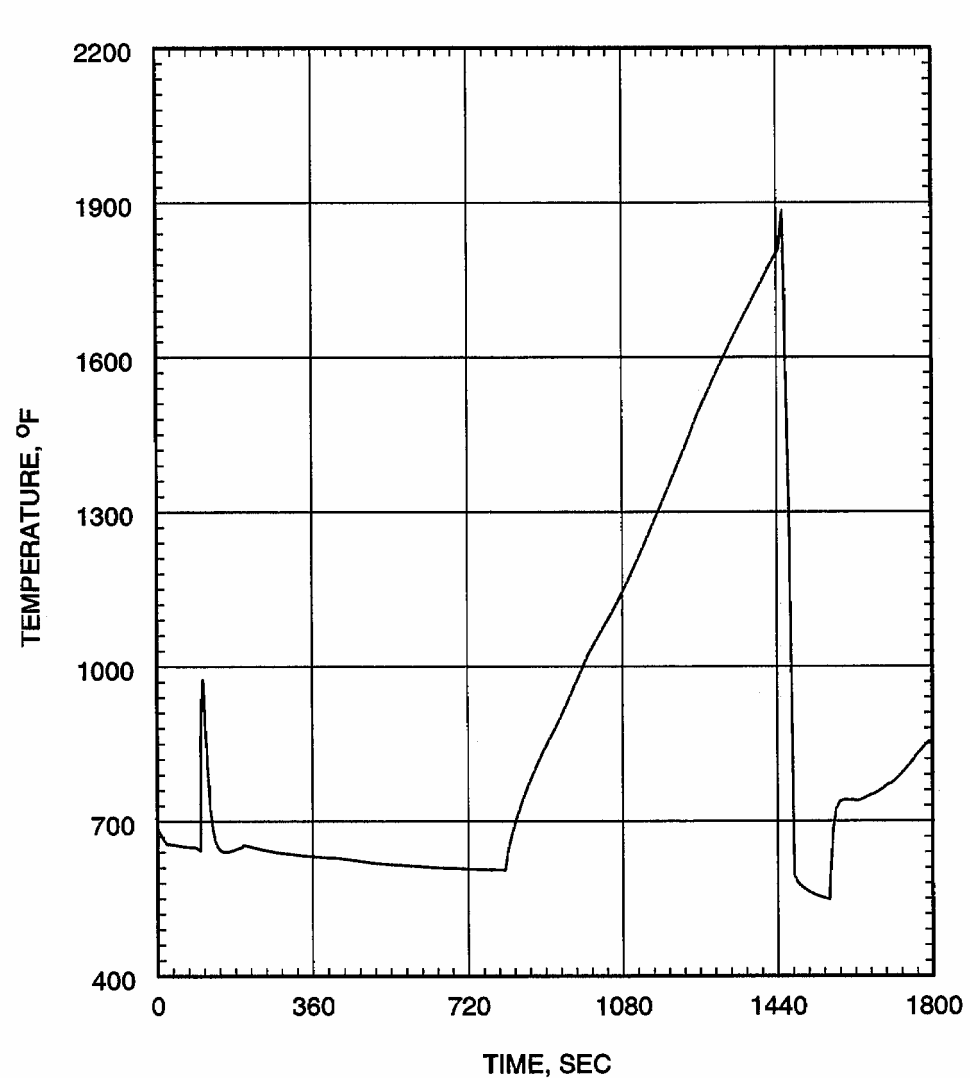


Figure 2.12-59
Waterford 3 SBLOCA ECCS Performance Analysis
0.06 ft^2/PD Break Cladding Temperature at Hot Spot

2.12.5 Long-Term ECCS Performance

2.12.5.1 Methodology

The post-LOCA long-term cooling analysis used the Westinghouse post-LOCA long-term cooling evaluation model for Combustion Engineering (CE) PWRs, CENPD-254-P-A (Reference 2.12-27). This is the same methodology used in the current Waterford 3 long-term cooling analysis described in Section 6.3.3.4 of the Waterford 3 FSAR (Reference 2.12-3). The Safety Evaluation Report (SER) documenting NRC acceptance of CENPD-254-P-A is contained in Reference 2.12-29.

The long-term cooling analysis consists of two separate analyses, namely, a boric acid precipitation analysis and a decay heat removal analysis. These two analyses are referred to as the large break analysis and the small break analysis in CENPD-254-P-A.

The purpose of the boric acid precipitation analysis is to demonstrate that the maximum boric acid concentration in the core remains below the solubility limit, thereby preventing the precipitation of boric acid in the core. If boric acid were to precipitate in the core region, the precipitate could prevent water from remaining in contact with the fuel cladding and, consequently, result in the core temperature not being maintained at an acceptably low value.

The boric acid precipitation analysis used a boric acid concentration of 27.6 w/o as the solubility limit of boric acid. This is the solubility limit of boric acid in saturated water at atmospheric pressure. Atmospheric pressure is a conservative minimum value for the core pressure following a LBLOCA.

The boric acid precipitation analysis was performed with the BORON computer code (Reference 2.12-27, Appendix C). An important parameter in the boric acid precipitation analysis is the volume within which the boric acid accumulates in the reactor vessel, i.e., the mixing volume. As stated in a footnote on page 20 of Amendment 1 to CENPD-254-P-A, the BORON code uses a constant, input specified value for the mixing volume that is conservatively determined. In the Waterford 3 boric acid precipitation analysis, the mixing volume consists of the volume from the top of the core support plate to the bottom elevation of the hot legs that is inside the core baffle and, above the core baffle, that is inside the core barrel.

The purpose of the decay heat removal analysis is to demonstrate that, regardless of break size, the core remains covered with two-phase liquid in the long-term, thereby ensuring that the core temperature is maintained at an acceptably low value. If the break is small enough for the RCS to refill, the RCS is cooled down via the steam generators to the shutdown cooling entry temperature and shutdown cooling is initiated. Decay heat is then removed by the shutdown cooling system. For breaks that are too large for the RCS to refill, the break flow is sufficient to remove decay heat from the RCS in the long-term.

The decay heat removal analysis was performed with the CELDA, NATFLOW, and CEPAC computer codes (Reference 2.12-27, Appendices A, B, and D).

2.12.5.2 Plant Design Data

Important plant design data used in the post-LOCA long-term cooling analysis are listed in Table 2.12-12.

2.12.5.3 Results

The post-LOCA boric acid precipitation analysis determined that a minimum flow rate of 372 gpm from a HPSI pump to both the hot and cold legs of the RCS, initiated between 2 and 3 hours post-LOCA, maintains the boric acid concentration in the core below the solubility limit of 27.6 w/o for the limiting break, i.e., a large cold leg break. The analysis also determined that the potential for entrainment of the hot leg injection by the steam flowing in the hot legs ends prior to 2 hours post-LOCA.

Figure 2.12-60 compares the core boiloff rate with the minimum simultaneous hot and cold leg injection flow rate of 372 gpm. It shows that the initiation of 372 gpm of hot and cold leg injection at 3 hours post-LOCA provides a substantial and time-increasing flushing flow through the core. Figure 2.12-61 presents the core boric acid concentration as a function of time for the limiting break. It shows that without simultaneous hot and cold leg injection, the boric acid concentration in the core exceeds the solubility limit at approximately 4.1 hours post-LOCA. When 372 gpm of simultaneous hot and cold leg injection is initiated at 3 hours post-LOCA, the maximum boric acid concentration in the core is 23.58 w/o, a margin of 4.02 w/o to the solubility limit of 27.6 w/o. Figure 2.12-61 also shows that a flushing flow rate of 25 gpm started by 3 hours post-LOCA is sufficient to prevent the core boric acid concentration from reaching the solubility limit.

Figure 2.12-62 presents the sequence of events and time schedule for the operator actions that comprise the Waterford 3 long-term cooling plan. The plan summarizes the key elements of the decay heat removal analysis as well as the boric acid precipitation analysis. The decay heat removal analysis shows that, regardless of break size, decay heat can be removed for the long-term and that in doing so, the core remains covered with two-phase liquid, thereby ensuring that core temperatures are maintained at acceptably low values. The analysis identified a decision time of 12 hours and a decision pressure of 140 psia. At the decision time, for breaks as large as 0.036 ft^2, the RCS has refilled and shutdown cooling may be used as the long-term decay heat removal method. For breaks as small as 0.012 ft^2, decay heat may be removed in the long-term by simultaneous hot and cold leg injection. The overlap in these two break ranges ensures that an appropriate long-term decay heat removal method is possible.

Figure 2.12-63 is a plot of break area versus RCS refill time. Figure 2.12-64 is a plot of RCS pressure at the decision time of 12 hours post-LOCA versus break area. Figure 2.12-65 tabulates break size and RCS pressure at the decision time. It also indicates the range of break sizes that are large breaks (i.e., simultaneous hot and cold leg injection is acceptable for long-term decay heat removal) and the range of break sizes that are small breaks (i.e., shutdown cooling is acceptable for long-term decay heat removal).

In summary, the results of the post-LOCA long-term cooling analysis demonstrate conformance to Criterion 5 of the ECCS acceptance criteria. The results are applicable to Waterford 3 for a rated core power of 3716 MWt (3735 MWt including the power measurement uncertainty).

Table 2.12-12
Post-LOCA Long-Term Cooling Analysis
Core and Plant Design Data

Quantity	Value	Units
Reactor power level (including uncertainty)	3735	MWt
Number of plugged tubes per SG	1000	---
SG/RCS cooldown rate	40	°F/hr
Shutdown cooling entry temperature	350	°F
RCS pressure measurement uncertainty	±40	psi
Number of ADVs	2	---
ADV flow rate, at 900 psia	675,000	lbm/hr/valve
Emergency feedwater flow requirement	259,000	gal
RCS liquid mass	480,000	lbm
Initial RCS boron concentration	2000	ppm
Boric acid makeup tanks (BAMTs)		
liquid volume, total	22,920	gal
boron concentration	6187	ppm
Refueling water storage pool (RWSP)		
liquid volume	548,016	gal
boron concentration	3000	ppm
SITs		
number	4	---
liquid volume per tank	1886	ft^3
boron concentration	3000	ppm
Charging pumps		
number	3	---
flow rate per pump	44	gpm
Flow rates for emptying the RWSP		
HPSI pump flow rate	770	gpm
LPSI pump flow rate	4084	gpm
CS pump flow rate	1750	gpm

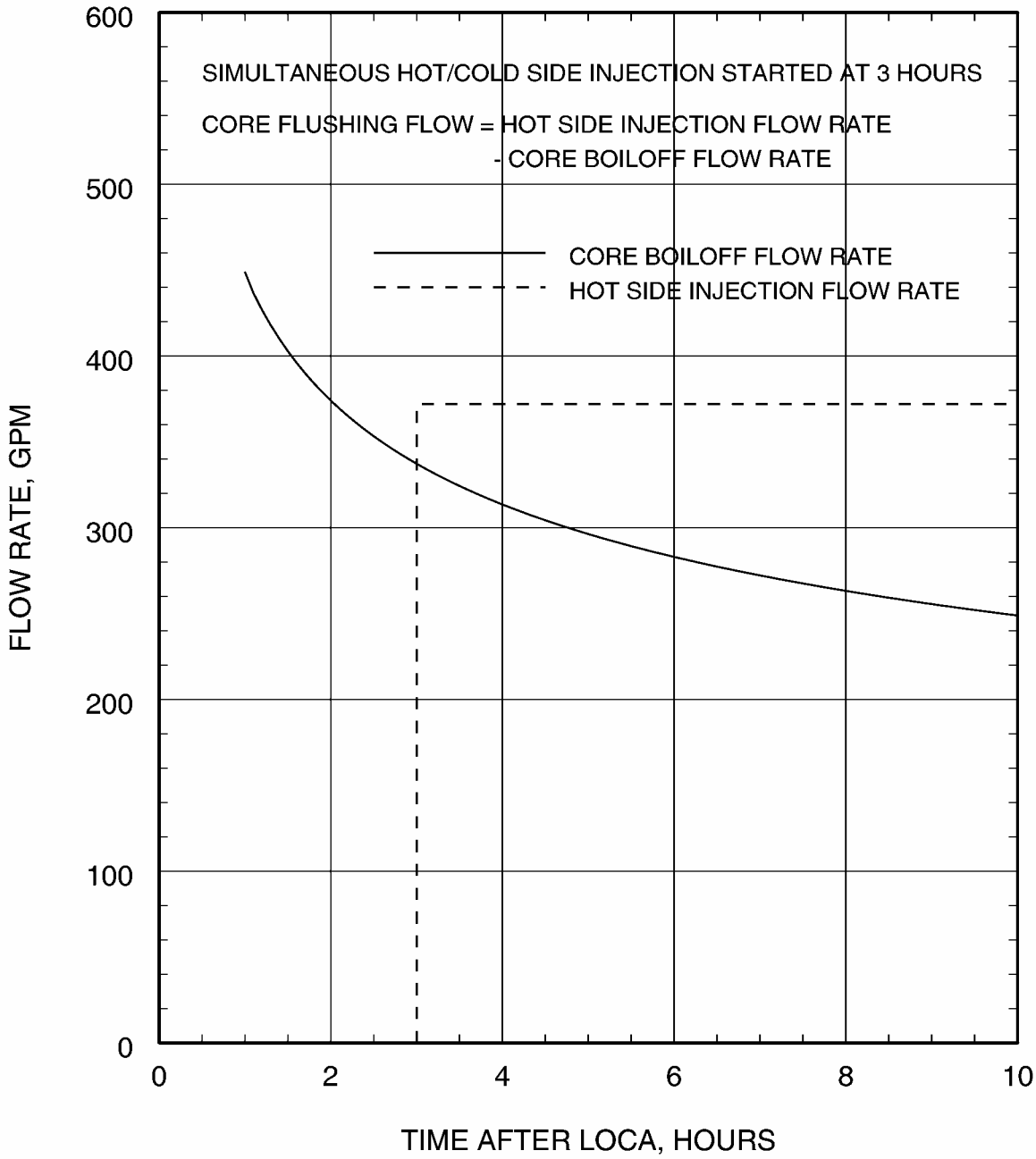


Figure 2.12-60
Post-LOCA Long-Term Cooling Analysis
Comparison of Core Boiloff Rate and Minimum
Simultaneous Hot and Cold Leg Injection Flow Rate

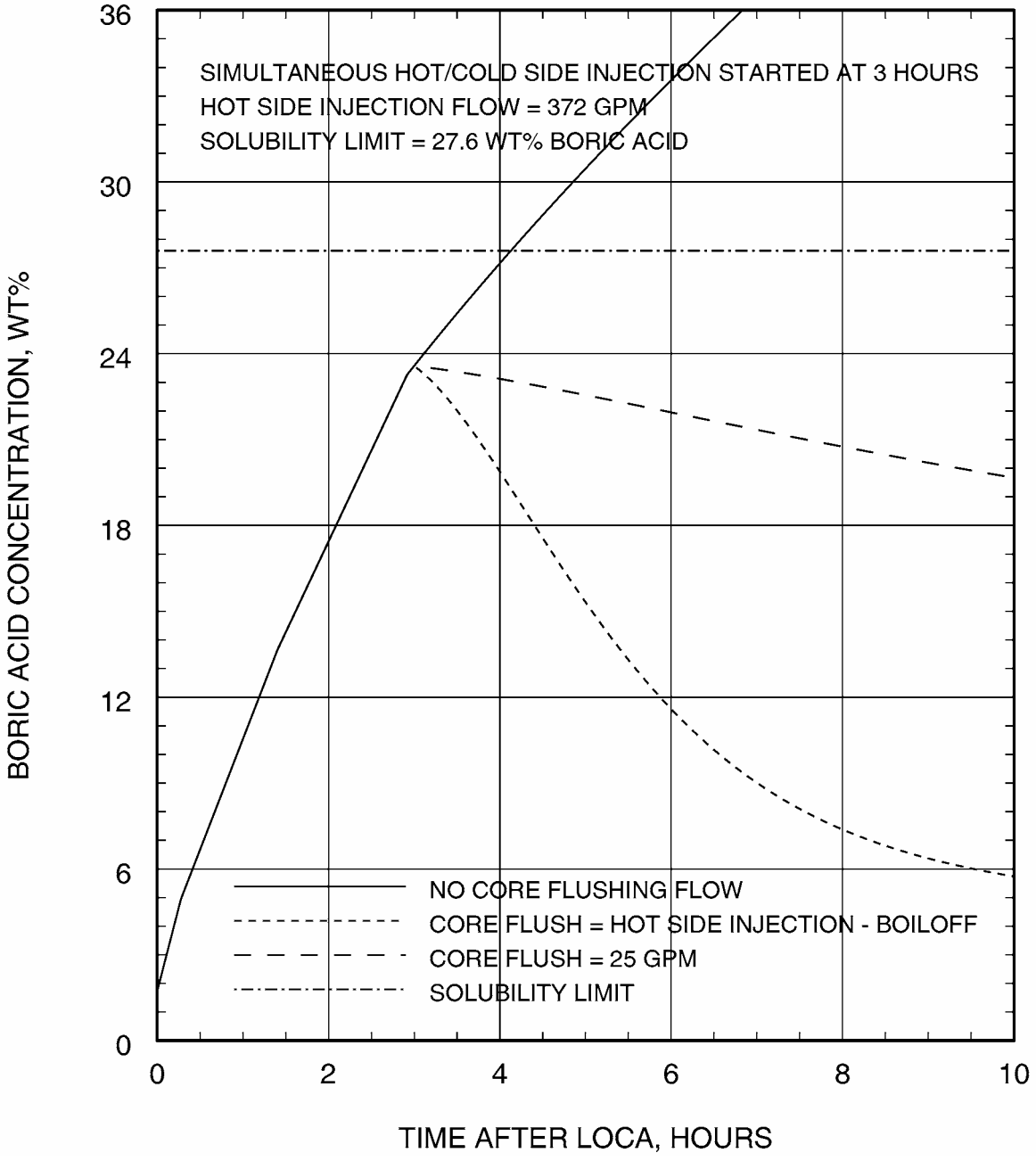
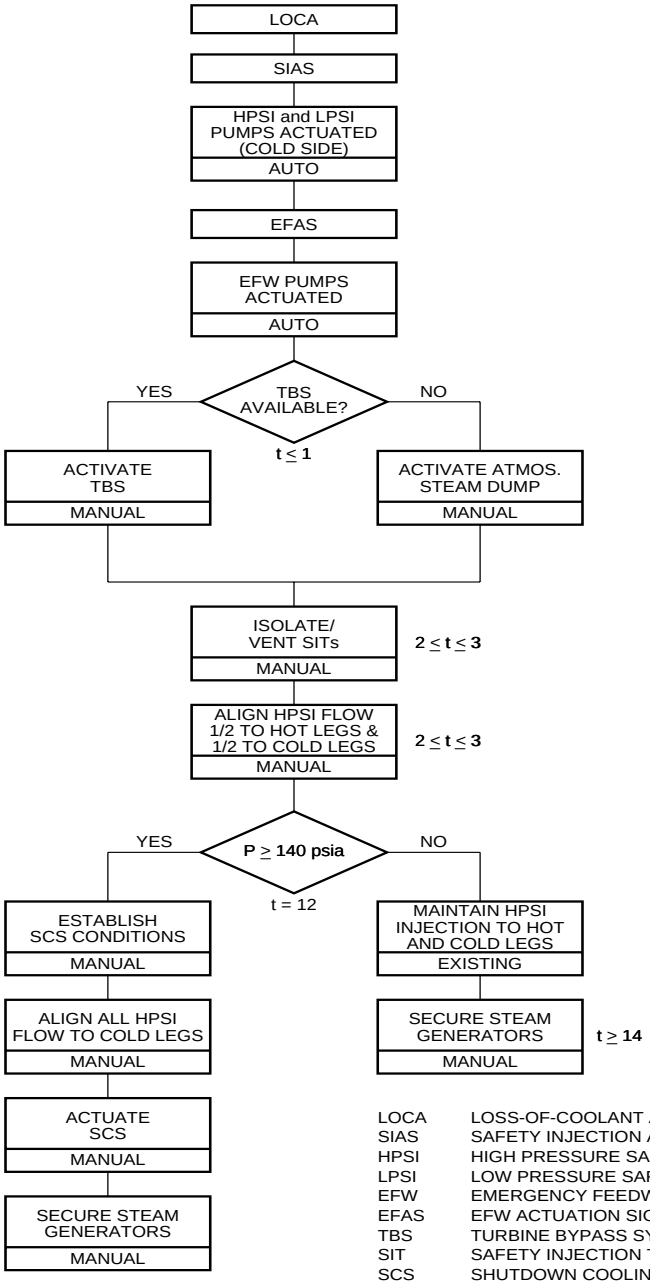


Figure 2.12-61
Post-LOCA Long-Term Cooling Analysis
Boric Acid Concentration in the Core Versus Time



LOCA	LOSS-OF-COOLANT ACCIDENT
SIAS	SAFETY INJECTION ACTUATION SIGNAL
HPSI	HIGH PRESSURE SAFETY INJECTION
LPSI	LOW PRESSURE SAFETY INJECTION
EFW	EMERGENCY FEEDWATER
EFAS	EFW ACTUATION SIGNAL
TBS	TURBINE BYPASS SYSTEM
SIT	SAFETY INJECTION TANK
SCS	SHUTDOWN COOLING SYSTEM
P	REACTOR COOLANT SYSTEM PRESSURE
t	TIME AFTER LOCA, HRS

Except for the time to initiate simultaneous hot and cold leg injection, the times assumed for analysis purposes in the LTC plan are not intended to correspond to required times for actions in plant procedures, but are appropriate values to assume to demonstrate acceptability for long-term cooling.

Figure 2.12-62
Post-LOCA Long-Term Cooling Analysis
Long-Term Cooling Plan

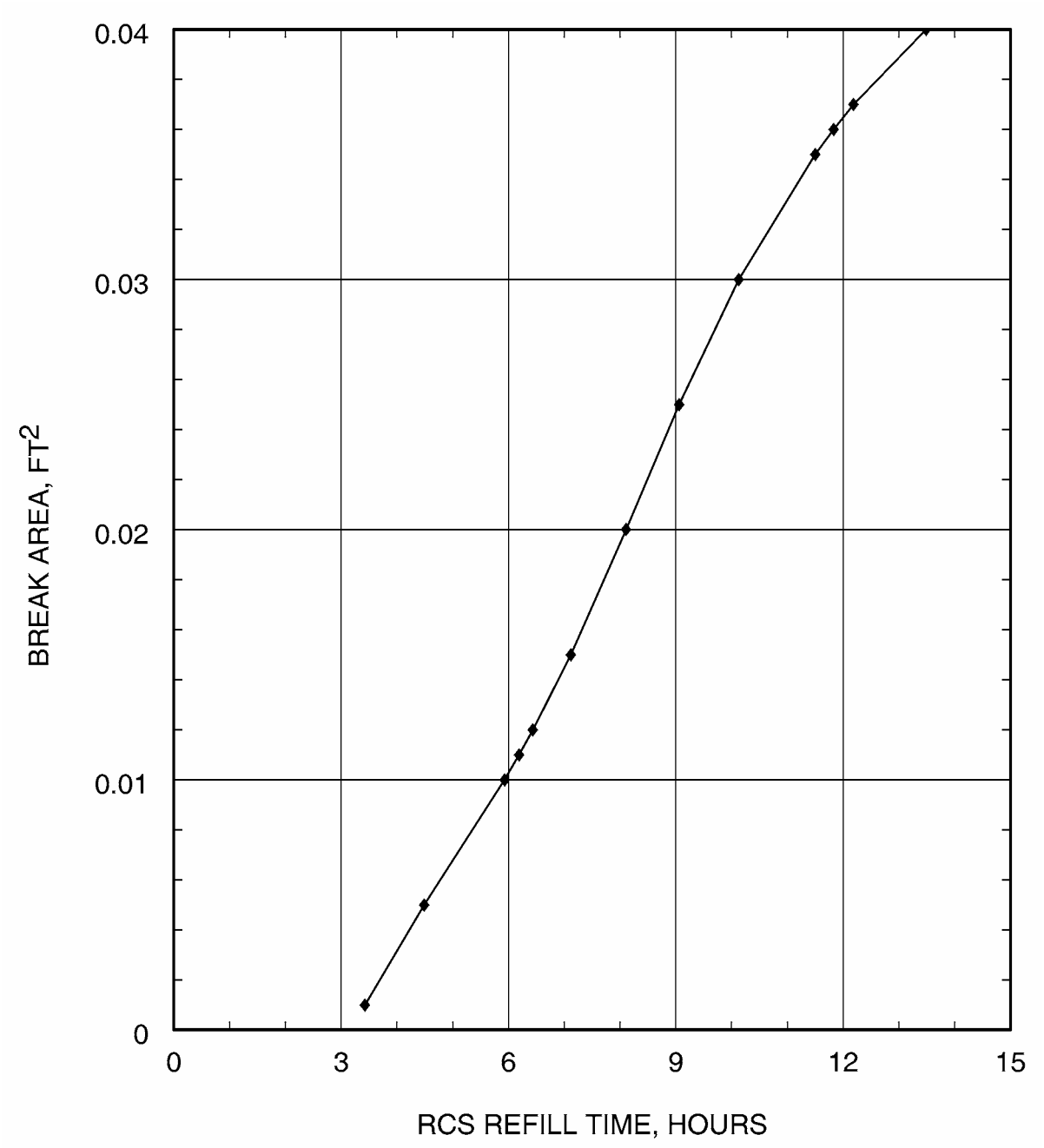


Figure 2.12-63
Post-LOCA Long-Term Cooling Analysis
Break Area Versus RCS Refill Time

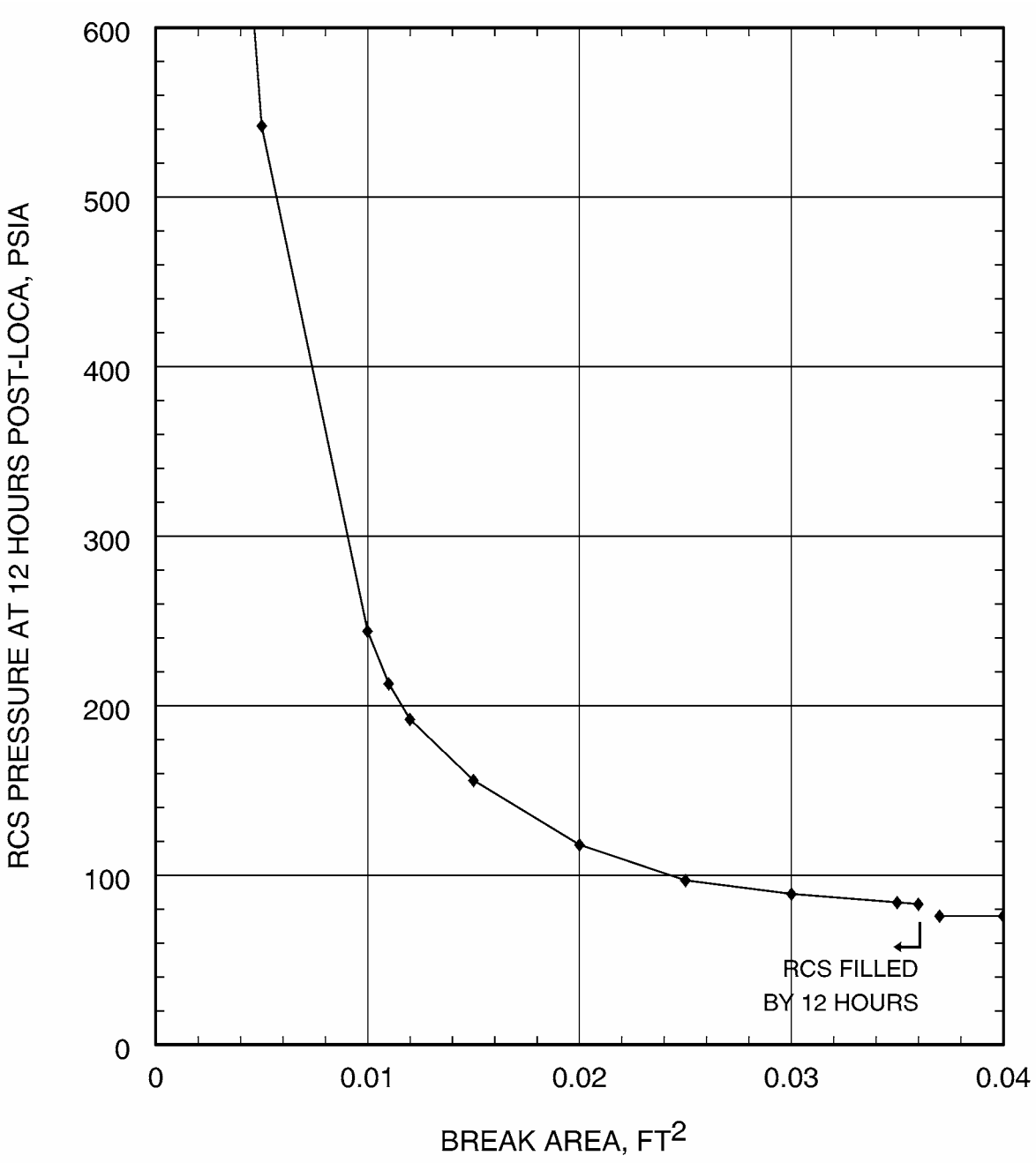


Figure 2.12-64
Post-LOCA Long-Term Cooling Analysis
RCS Pressure at Decision Time Versus Break Area

For break areas 0.012 ft^2 and larger, simultaneous hot/cold leg injection cools the core and flushes boric acid from the core.

For break areas 0.036 ft^2 and smaller, refill of the RCS disperses boric acid throughout the RCS and the SGs cool the RCS to the SDC entry temperature.

Break Size (ft^2)	RCS Pressure at 12 Hours Post-LOCA (psia)
0.040	76
0.037	76
0.036	83
0.035	84
0.030	89
0.025	97
0.020	118
0.015	156
0.012	192
0.011	213
0.010	244
0.005	542
0.001	1216

Figure 2.12-65
Post-LOCA Long-Term Cooling Analysis
Overlap of Acceptable Procedures in Terms of Break Size

2.12.6 Inadvertent Opening of a Pressurizer Safety Valve

An evaluation for the inadvertent opening of a pressurizer safety valve was performed for Waterford 3. The evaluation consisted of an assessment of the applicability of the FSAR analysis for inadvertent opening of a pressurizer safety valve to Waterford 3 with power uprate.

The FSAR ECCS performance analysis for an inadvertent opening of a pressurizer safety valve used the Supplement 1 version of the Westinghouse SBLOCA evaluation model for CE PWRs (Reference 2.12-23). The method and results of that analysis are documented in Section 15.6.3.4 of the Waterford 3 FSAR.

The FSAR analysis demonstrated that for an inadvertent opening of a pressurizer safety valve there is no core uncovery. The major reason for the core to remain covered is the location of the leak, i.e., the pressurizer safety valve is located at the top of the pressurizer. With this location for loss of coolant there is no loss of safety injection flow. The coolant inventory lost is steam, which is exceeded by the high-pressure safety injection (HPSI) flow.

The primary conclusion of the FSAR analysis is that the inadvertent opening of a pressurizer safety valve LOCA is bounded by a SBLOCA in the pump discharge leg. This FSAR analysis conclusion is independent of core power level.

The conclusion of this evaluation is that the inadvertent opening of a pressurizer safety valve LOCA is not as severe as a SBLOCA in the pump discharge leg (Section 2.12.4). This evaluation is applicable to Waterford 3 with a rated core power of 3716 MWt (3735 MWt including a 0.5% power measurement uncertainty).

2.12.7 Conclusions

An ECCS performance analysis was completed for Waterford 3 at the power uprate rated core power of 3716 MWt (3735 MWt, including a 0.5% power measurement uncertainty). The analysis included consideration of LBLOCA, SBLOCA, and post-LOCA long-term cooling. The limiting break size, i.e., the break size that resulted in the highest PCT, was determined to be the 0.8 DEG/PD break.

The results of the analysis demonstrate conformance to the ECCS acceptance criteria at a PLHGR of 13.2 kW/ft as follows:

Criterion 1: PCT: The calculated maximum fuel element cladding temperature shall not exceed 2200°F.

Result: The ECCS performance analysis calculated a PCT of 2164°F for the 0.8 DEG/PD break.

Criterion 2: Maximum Cladding Oxidation: The calculated total oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation.

Result: The ECCS performance analysis calculated a maximum cladding oxidation of 0.087 times the total cladding thickness before oxidation for the 0.8 DEG/PD break.

Criterion 3: Maximum Hydrogen Generation: The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam shall not exceed 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react.

Result: The ECCS performance analysis calculated a maximum hydrogen generation of less than 0.01 times the hypothetical amount for the 0.8 DEG/PD break.

Criterion 4: Coolable Geometry: Calculated changes in core geometry shall be such that the core remains amenable to cooling.

Result: The cladding swelling and rupture models used in the ECCS performance analysis account for the effects of changes in core geometry that would occur if cladding rupture is calculated to occur. Adequate core cooling was demonstrated for the changes in core geometry that were calculated to occur as a result of cladding rupture. In addition, the transient analysis was performed to a time when cladding temperatures were decreasing and the RCS was depressurized, thereby precluding any further cladding deformation. Therefore, a coolable geometry was demonstrated.

Criterion 5: Long-Term Cooling: After any calculated successful initial operation of the ECCS, the calculated core temperature shall be maintained at an acceptably low value and decay heat shall be removed for the extended period of time required by the long-lived radioactivity remaining in the core.

Result: The LBLOCA and SBLOCA ECCS performance analyses demonstrated that the Waterford 3 ECCS successfully maintains the fuel cladding temperature at an acceptably low value in the short term. Subsequently, for the extended period of time required by the long-lived radioactivity remaining in the core, the ECCS continues to supply sufficient cooling water from the refueling water storage pool and then from the sump to remove decay heat and maintain the core temperature at an acceptably low value. In addition, at the appropriate time, the operator realigns a HPSI pump for simultaneous hot and cold leg injection in order to maintain the core boric acid concentration below the solubility limit.

2.12.8 References

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2.13 NON-LOCA TRANSIENT ANALYSES

2.13.0 Introduction

All Final Safety Analysis Report (FSAR) Chapter 15 non-loss-of-coolant accident (LOCA) analyses were evaluated to demonstrate acceptability at operation at 3716-MWt extended power uprate (EPU) conditions. The design basis events (DBEs) presented in this section are categorized based on frequency of occurrence into three groups:

- Moderate frequency events
- Infrequent events
- Limiting faults

Table 2.13.0-1 lists the non-LOCA events by category and defines the level of evaluation included for extended power uprate. All FSAR, Reference 2.13-1, events received some level of evaluation to ensure acceptable consequences following EPU. The levels of evaluation are:

- The analysis remains bounded for EPU by a different FSAR event presented for EPU.
- The analysis has been reanalyzed as part of this submittal.
- The analysis has been evaluated for EPU, the FSAR results remain bounding, and a complete reanalysis was not required.

Table 2.13.0-1
Non-LOCA Transient Events

Section	Event	Category	Result
Increase in Heat Removal by the Secondary System (Turbine Plant)			
2.13.1.1.1	Decrease in Feedwater Temperature	Moderate Frequency	Bounded by 2.13.1.1.3
2.13.1.1.2	Increase in Feedwater Flow	Moderate Frequency	Bounded by 2.13.1.1.3
2.13.1.1.3	Increased Main Steam Flow	Moderate Frequency	EPU analysis provided
2.13.1.1.4	Inadvertent Opening of a Steam Generator Atmospheric Dump Valve (ADV) (IOSGADV)	Moderate Frequency	EPU analysis provided
2.13.1.2.1	Decrease in Feedwater Temperature with Single Active Failure (SAF)	Infrequent Event	Bounded by 2.13.1.2.3
2.13.1.2.2	Increase in Feedwater Flow with a SAF	Infrequent Event	Bounded by 2.13.1.2.3

Table 2.13.0-1 (cont.)
Non-LOCA Transient Events

Section	Event	Category	Result
2.13.1.2.3	Increased Main Steam Flow with Loss-of-offsite Power (LOOP)	Infrequent Event	EPU analysis provided
2.13.1.2.4	IOSGADV with LOOP	Infrequent Event	EPU analysis provided
2.13.1.3.1	Steam System Piping Failures Post-Trip Analysis	Limiting Fault	EPU analysis provided
2.13.1.3.2	Mode 3 and 4 All Rods In (ARI) Steam Line Break (SLB)	Limiting Fault	Event is bounded by current FSAR
2.13.1.3.3	Steam System Piping Failures Pre-Trip Power Excursion	Limiting Fault	EPU analysis provided
Decrease in Heat Removal by the Secondary System (Turbine Plant)			
2.13.2.1.1	Loss of External Load	Moderate Frequency	Event is bounded by 2.13.2.1.3
2.13.2.1.2	Turbine Trip	Moderate Frequency	Event is bounded by 2.13.2.1.3
2.13.2.1.3	Loss of Condenser Vacuum (LOCV)	Moderate Frequency	EPU analysis provided
2.13.2.1.4	LOOP	Moderate Frequency	Event is bounded by 2.13.2.1.3 and 2.13.3.2.1
2.13.2.1.5	Steam Pressure Regulator Failure	Moderate Frequency	Event is bounded by 2.13.2.1.3
2.13.2.2.1	Loss of External Load with SAF	Infrequent Event	Event is bounded by 2.13.2.2.3
2.13.2.2.2	Turbine Trip with SAF	Infrequent Event	Event is bounded by 2.13.2.2.3
2.13.2.2.3	LOCV with LOOP	Infrequent Event	Event with SAF is bounded by event with no SAF, 2.13.2.1.3
2.13.2.2.4	Loss-of-Normal AC Power with SAF	Infrequent Event	Event is bounded by 2.13.3.2.1
2.13.2.2.5	Loss-of-Normal Feedwater Flow	Infrequent Event	EPU analysis provided
2.13.2.3.1	Feedwater System Pipe Breaks	Limiting Fault	EPU analysis provided

Table 2.13.0-1 (cont.)
Non-LOCA Transient Events

Section	Event	Category	Result
2.13.2.3.2	Loss-of-Normal Feedwater Flow with SAF	Limiting Fault	EPU analysis provided
Decrease in Reactor Coolant Flow Rate			
2.13.3.1.1	Partial Loss of Forced Reactor Coolant Flow	Moderate Frequency	Event is bounded by 2.13.3.2.1
2.13.3.2.1	Total Loss of Forced Reactor Coolant Flow	Infrequent Event	EPU analysis provided
2.13.3.2.2	Partial Loss of Forced Reactor Coolant Flow with SAF	Infrequent Event	Events is bounded by 2.13.3.3.1
2.13.3.3.1	Single Reactor Coolant Pump (RCP) Shaft Seizure/Sheared Shaft	Limiting Fault	EPU analysis provided
Reactivity and Power Distribution Anomalies			
2.13.4.1.1	Uncontrolled Control Element Assembly (CEA) Withdrawal from Subcritical	Moderate Frequency	EPU analysis provided
2.13.4.1.2	Uncontrolled CEA Withdrawal from Low Power	Moderate Frequency	EPU analysis provided
2.13.4.1.3	Uncontrolled CEA Withdrawal at Power	Moderate Frequency	EPU analysis provided
2.13.4.1.4	CEA Misoperation	Moderate Frequency	EPU analysis provided
2.13.4.1.5	Inadvertent Boron Dilution	Moderate Frequency	Event is bounded by current FSAR
2.13.4.1.6	Startup of an Inactive RCP	Moderate Frequency	Event is bounded by current FSAR
2.13.4.1.7	CEAW Modes 3, 4, and 5 ARI	Moderate Frequency	Event is bounded by current FSAR
2.13.4.3.1	Inadvertent Loading of a Fuel Assembly into an Improper Position	Limiting Fault	EPU analysis provided
2.13.4.3.2	CEA Ejection	Limiting Fault	EPU analysis provided

Table 2.13.0-1 (cont.)
Non-LOCA Transient Events

Section	Event	Category	Result
Increase in Reactor Coolant Inventory			
2.13.5.1.1	Chemical and Volume Control System (CVCS) Malfunction	Moderate Frequency	Event is bounded by current FSAR
2.13.5.1.2	Inadvertent Emergency Core Cooling System (ECCS)	Moderate Frequency	Event is bounded by current FSAR
2.13.5.2.1	CVCS Malfunction with SAF	Infrequent Event	Event is bounded by current FSAR
Decrease in Reactor Coolant System (RCS) Inventory			
2.13.6.3.1	Small Primary Line Break Outside Containment	Limiting Fault	EPU analysis provided
2.13.6.3.2	Steam Generator Tube Rupture (SGTR)	Limiting Fault	EPU analysis provided
2.13.6.3.3	LOCA Radiological Consequences	Limiting Fault	EPU analysis provided
2.13.6.3.4	Pressurizer Safety Valve Lift	Limiting Fault	Bounded by Small-Break LOCA (SBLOCA), Section 2.12
Radioactive Release from a Subsystem or Component			
2.13.7.3.4	Fuel-Handling Accident (FHA)	Limiting Fault	Event is bounded by current FSAR
2.13.7.3.5	Spent Fuel Cask Drop Accidents	Limiting Fault	Event is bounded by current FSAR
Anticipated Transients Without Scram (ATWS)			
2.13.8	ATWS	Limiting Fault	Event is bounded by current FSAR
Miscellaneous			
2.13.9.1.1	Asymmetric Steam Generator	Moderate Frequency	EPU analysis provided

2.13.0.1 Methodology and Computer Codes

The transient analysis methodology used for EPU analyses is the same as the methodologies documented in the FSAR, except where noted. The transient simulation code CENTS (Reference 2.13-2) was employed for a majority of the Chapter 15 events. Transition to the CENTS code as the primary NSSS simulation tool has already been made on other CE digital plant designs: SONGS-2, SONGS-3, ANO-2, PVNGS-1, PVNGS-2 and PVNGS-3.

The CENTS model and solution methodology provides a realistic best estimate calculation. Conservatism required in non-LOCA analyses is provided by the selection of transient specific initial conditions and plant performance data. Where important, initial conditions are selected from the worst case conditions allowed by plant limiting conditions of operations (LCOs). Plant performance parameters such as trip response times, safety valve capacities, high-pressure safety injection (HPSI) pump capacities are conservative relative to actual best estimate. The CENTS point kinetics models is used in the non-LOCA analysis. This is combined with conservative nuclear characteristics of the power uprate cores.

The minimum departure from nucleate boiling ratio (DNBR) values and departure from nucleate boiling (DNB) thermal margin requirements were determined using the CETOP-D code (Reference 2-13-3).

The STRIKIN-II code (Reference 2.13-9) was employed to simulate fuel and cladding integrity for CEA ejection events.

The HERMITE code (Reference 2.13-4) was employed to simulate the core response to loss of RCS flow and single RCP sheared shaft events. The RCS flow coastdown experienced following a LOOP, single RCP sheared shaft, and single RCP seized rotor events was generated using the CENTS code.

The following methods/assumption changes have been applied to non-LOCA transient analyses:

a) The method of statistical convolution to predict the number of fuel pins experiencing DNB, Reference 2.13-5, is extended to include all fuel failure events except return-to-power MSLB.

b) A limited amount of specified acceptable fuel design limit (SAFDL) violation is predicted for the return-to-power MSLB events.

c) CENTS replaces CESEC as the primary Nuclear Steam Supply System (NSSS) simulation tool.

d) CENTS is used in lieu of COAST to calculate flow coastdown for reduced reactor coolant flow events.

e) Fuel failure limits for each event are calculated that result in the radiological consequences being at the regulatory acceptance criteria. Cycle-specific reload analyses of the uprate cores will verify that these limits will not be exceeded.

f) For EPU, radiological consequences for several infrequent events (e.g., Turbine Trip with a Concurrent Single Active Failure) and the Loss of Feedwater Flow with Single Active Failure are bounded by the radiological consequences of the Excess Main Steam Flow with LOOP. Note that fuel failure is allowed for the Excess Main Steam Flow with LOOP; NUREG-0800 permits limited violation of the SAFDLs for Infrequent Events provided that the dose consequences remain under a small fraction of 10CFR100 limits. The Waterford 3 FSAR currently reports these events as bounded by the inadvertent opening of an ADV with LOOP, for which there is no predicted fuel failure but which has a more adverse release path.

g) Use of PAVAN and ARCON96 for calculation of atmospheric dispersion factors for radiological consequence calculations.

h) The SGTR analysis assumed that a LOOP occurs three seconds following reactor trip. This assumption is consistent with SGTR with LOOP assumptions made on other CE NSSS plants.

2.13.0.2 Initial Conditions

The range of initial conditions evaluated in the non-LOCA transient analyses is listed in Table 2.13.0-2. Values beyond this range are used in certain analyses to provide additional margin.

The following changes have been made in association with 3716-MWt power uprate:

a) Maximum initial power levels are based on a rated power of 3716 MWt versus 3441 MWt. An unchanged 0.5% power measurement uncertainty is applied at full power conditions.

b) The most negative moderator temperature coefficient (MTC) has been increased from $-4.0*10^{-4}$ $\Delta\rho$ to $-4.2*10^{-4}$ $\Delta\rho$.

c) The assumed analysis range for T_{cold} has been revised to 533 to 552°F, to support the T_{cold} Technical Specification range of 536 to 549°F, with allowance for up to 3°F instrument uncertainty. Previous Technical Specification range was 541 to 558°F, with 2°F instrument uncertainty. The proposed range allows for adequate flexibility for operation about the nominal T_{cold} temperature program, which ranges linearly from 541°F at hot-zero power (HZP) to 543°F at hot-full power (HFP).

d) The assumed analysis range for pressurizer pressure has been revised to 2090 to 2310 psia to support the Technical Specification range of 2125 to 2275 psia, with allowance for up to 35 psia instrument uncertainty. The previous Technical Specification range was 2025 to 2275 psia, with 25 psia instrument uncertainty. The allowed range was reduced to gain additional analytical margin with no impact on operations.

e) Steam generator (SG) initial pressures are generally calculated by analysis codes based on initial RCS temperature and flow conditions. Because of the power uprate, steam generator initial pressures are typically reduced at full-power conditions compared to previous analyses.

f) Due to the reduction in operating point SG pressures, the setpoints for the low steam generator pressure (LSGP) trip and main steam isolation signal (MSIS) have been reduced. Analytical values have been reduced from 678 psia to 576 psia.

g) Allowance is made for a maximum of up to 1000 SG tubes plugged.

h) Assumed primary-to-secondary leakage is reduced from 720 gallons per day per SG to 540 gallons per day per SG to reduce radiological consequences.

i) Atmospheric dispersion values (χ/Qs) have been updated, as discussed in Section 2.13.0.5.

In accordance with the Standard Review Plan (SRP) (Reference 2.13-14), the transient analyses employ the most limiting combination of core characteristics (i.e., Doppler, MTC, power distribution, etc.). In some instances, this has been achieved by combining the most adverse value of each parameter, regardless of burnup. Other analyses used burnup

consistent sets of physics parameters, with the most adverse time in cycle combination being reported. A set of bounding core physics parameters, including control rod worths, was generated based on representative uprate core designs and utilized in the transient analyses. These physics parameters are verified for future core loading patterns following the reload design process in accordance with Waterford 3 procedures. Refer to the specific event section for a more detailed list of the core physics parameters for any given transient.

The CEA reactivity insertion curve assumed for the analyses remains the same as for previous cycles. The CEA reactivity insertion curve utilizes a 0.6-second holding coil delay time and a 3.0-second arithmetic average drop time to 90% inserted.

The consequences of a given transient may be insensitive to certain initial conditions. In these instances, a nominal value within the range specified in Table 2.13.0-2 was selected.

Before the transient event, non-safety grade control systems were selected to be in their most adverse configuration (i.e., manual or automatic) consistent with steady state plant operations. For example, letdown and charging flow will be determined by either an automatic response to the Pressurizer Level Control System (PLCS) or manually set to a constant and equal value. Initial system settings that are not consistent with steady state operation and introduce a system perturbation (i.e., minimum letdown along with maximum charging) were not considered. Non-safety grade control systems (i.e., Reactor Power Cutback System [RPCS], Steam Bypass Control System [SBCS], Reactor Regulating System [RRS]) that would act to mitigate the severity of transients were not credited.

The Core Operating Limits Supervisory System (COLSS) monitors various instruments and alerts operators on approach to many of the Technical Specification LCOs. In addition, COLSS preserves DNB and linear heat rate (LHR) margin that is important in maintaining the initial conditions assumed by the safety analyses. COLSS displays the available thermal margin via DNB-power operating limit (POL) and LHR-POL meters and alerts operators on approach to the prescribed POL. The transients were initiated from thermal margin conditions consistent with the minimum thermal margin preserved by COLSS for the power uprate cycles. Thus, COLSS ensures that the initial conditions of the safety analyses are not exceeded.

Table 2.13.0-2
Range of Initial Conditions Evaluated in the Non-LOCA Transient Analyses

Parameter	Units	Lower Limit	Upper Limit
Steady State Conditions			
Core Power	MWt	0	3735(1)
Core Inlet Temperature	°F	533(2)	552(2)
RCS Mass Flow Rate	10^6 Lbm/Hr	148.0	170.2
Pressurizer Pressure	psia	2090(3)	2310(3)
Pressurizer Level	%	21	67.5
SG Level	% Narrow Range	45	80
SG Tube Plugging	Tubes per SG	421	1000
Safety Valve Lift Setpoints			
Main Steam Safety Valve (MSSV) Setpoint Bank 1 Bank 2 Bank 3 Bank 4 Bank 5 Bank 6	psia	 1052.6 1067.2 1081.7 1096.3 1106.0 1115.7	 1116.8 1132.2 1147.7 1163.2 1173.5 1183.8
Pressurizer Safety Valve Setpoint	psia	2425	2575
Core Physics Conditions			
Axial Power Distribution >=50% RTP 20%>=RTP>50% <20% RTP	Axial Shape Index Unit (ASIU)	 -0.2 -0.3 -0.6	 +0.2 +0.3 +0.6
Azimuthal Tilt >20% RTP <=20% RTP	%	 3 10	 3 10
MTC HZP HFP	10-4Δρ/°F	 -4.2 -4.2	 0.5 -0.2
Fuel Temperature Coefficient	Δρ/√°K	End of Cycle (EOC) -0.00240	Beginning of Cycle (BOC) -0.00113

Table 2.13.0-2 (cont.)
Range of Initial Conditions Evaluated in the Non-LOCA Transient Analyses

Parameter	Units	Lower Limit	Upper Limit
Kinetics - β		EOC	BOC
Group 1		0.000122	0.000255
Group 2		0.000864	0.001617
Group 3		0.000765	0.001458
Group 4		0.001593	0.003113
Group 5		0.000621	0.001152
Group 6		0.000155	0.000284
Kinetics - λ		EOC	BOC
Group 1		0.0128	0.01276
Group 2		0.0314	0.03160
Group 3		0.1237	0.12070
Group 4		0.3276	0.32180
Group 5		1.4063	1.40000
Group 6		3.7844	3.84780
Prompt Neutron Lifetime	μSec	10	50
CEA Scram Worth			
N-1	%Δρ	-5.0 (HZP)	-6.0 (HFP)
N-2 (CEA Ejection)		-4.0 (HZP)	-5.0 (HFP)

Notes:
1. Includes 0.5% power measurement uncertainty.
2. Includes ±3°F temperature measurement uncertainty.
3. Includes 35 psi pressurizer pressure measurement uncertainty.

2.13.0.3 Reactor Protection Systems

The Reactor Protection System (RPS) provides the necessary reactor trips required to mitigate the consequences of non-LOCA transient events. Table 2.13.0-3 lists the analytical trip setpoints credited in the transient analyses. The analytical setpoints have been calculated for both normal and harsh environments. The analytical setpoints include instrument uncertainties that were applied to delay the response of the RPS.

The manner in which the RPS responds to each transient event is detailed in each event section. The Core Protection Calculator System (CPCS) calculates DNBR and local power density (LPD). DNBR and LPD trips assure that the SAFDLs on DNB and centerline fuel melting are not exceeded during AOOs and assist the Engineered Safety Features Actuation System (ESFAS) in limiting the consequences of certain postulated accidents. In addition to DNB and LPD trip functions, CPCs provide reactor trips generated on variable overpower trip (VOPT), low RCP shaft speed, hot leg saturation temperature, cold leg differential temperature, and various out-of-range trips.

As part of the power uprate, the response times for CPCS low DNBR and high LPD trips were reviewed and enhancements to clarify the time requirements were identified, which included reductions in some of the times required to be assumed in safety analyses. The Waterford 3 Technical Requirements Manual (TRM) is being revised to account for these improved values, and the times assumed in the power uprate analyses equal or exceed the required response times.

Table 2.13.0-3
RPS Analytical Setpoints Credited in the Transient Analysis

Parameter	Units	Analytical Setpoint	Response Time
High-Pressurizer Pressure	psia	2422	0.9 Sec
Low-Pressurizer Pressure	psia	1560	0.9 Sec
Low-Steam Generator Pressure	psia	576	0.9 Sec
Low-Steam Generator Level	% narrow range (NR)	5	0.9 Sec
Low RCS Flow (SG ΔP)	%Flow	60	0.7 Sec
High Logarithmic Power	%RTP	4.4	0.4 Sec(2)
Core Protection Calculator (CPC) Variable Overpower Trip (VOPT) Offset Floor Ceiling Rate	 %RTP %RTP %RTP %RTP\Min	 8 30 110 2	 0.370 Sec(1,2)
CPC Low DNBR	DNBR	1.26	0.332 Sec(1,2)
CPC Low RCP Speed	Frac	0.965	0.232 Sec
CPC Hot Leg Saturation	°F	13	2.744 Sec(1,2)
CPC Asymmetric Cold Leg Temp	°F	11	0.370 Sec(1,2)
CPC Pressure Out-of-Range	psia	1736	0.270 Sec

Notes:
1. Additionally an 8-second RTD response time is modeled.
2. Nuclear instrument response time must also be added.

2.13.0.4 Engineered Safety Features (ESFs)

The ESFAS provide automatic actions to mitigate the consequences of the transient events. Table 2.13.0-4 lists the ESF analytical setpoints credited in the transient analyses. The ESF responses to each transient event are detailed in the event sections.

Table 2.13.0-4
ESF Analytical Setpoints

Parameter	Units	Analytical Setpoint
Safety Injection Actuation Signal (SIAS) on Low Pressurizer Pressure	psia	1560
MSIS on Low SG Pressure	psia	576
Emergency Feedwater on Low SG Level	% narrow range (NR)	5
Emergency Feedwater Lock-Out on SG ΔP	psid	230

2.13.0.5 Radiological Consequences Calculation

The analysis of the design basis events for the 3716 MWt power uprate project included evaluation of the radiological consequences. The 2-hour EAB and 8-hour low-population zone (LPZ) doses were calculated for all non-LOCA events for the power uprate condition. Consistent with the current licensing basis, the control room doses from the LOCA and the fuel handling accidents were also evaluated for power uprate.

Important inputs to the radiological consequences calculation are provided in Tables 2.13.0-5 through 2.13.0-10. The dose conversion factors used are from ICRP 30, Reference 2.13-15, and are listed in Table 2.13.0-6.

New sets of offsite and control room atmospheric dispersion factors (χ/Qs) were calculated for Waterford 3 using the PAVAN and ARCON96 computer codes (References 2.13-19 and 2.13-20) and using five years of current (1997 through 2001) meteorological data. The meteorological data were obtained from the storage data module from each of the meteorological towers and were verified and validated to be of good quality. The control room χ/Q values for both (East and West) control room emergency intakes were calculated from the following potential release locations:

- MSSVs, east and west sides
- ADVs, east and west sides
- Plant stack
- Main steam lines, east and west sides
- Fuel Building, truck bay door and personnel door
- Containment equipment hatch
- Containment purge intake

The control room χ/Q calculation assumed a straight line from the release point to the control room intakes. This provides a conservative distance from the release points to the control room intakes. Also in all cases, intervening structures were ignored for calculational simplicity, thereby underestimating the true distance to the control room intakes. Release point height above grade was considered. The release point-intake directions were calculated relative to the plant north and were then converted to true north.

In the calculation of new base χ/Q values, for all the release paths, the release type is assumed to be a “ground level” release with zero vent flow and zero vent velocity. For the plant stack release, the vent velocity is also assumed to be zero in accordance with the R.G. 1.194. These new χ/Q values appear in Tables 2.13.0-7 and 2.13.0-8.

In the case of events which experience violation of the SAFDLs, the amount of fuel failure which results in doses equal to the regulatory acceptance limits were calculated based upon the release path applicable to the event scenario. Cycle-specific analyses performed during the reload core design process will ensure that these fuel failure limits are not exceeded.

Each of the design basis events in Section 2.13 of this report will either present the radiological consequences (or fuel failure limit) calculated for the event or identifies an event that a similar release path which provides bounding results for the event.

Table 2.13.0-9 contains the source term for non-LOCA radiological analyses, providing the maximum volatile fission product activities for each isotope. The values given in Table 2.13.0-9 are valid for enrichments up to 5.0 w/o U-235 and for fuel management such that the maximum burnup of any rod within 10% of the limiting radial peaking factor (Fr) is less than 40,000 MWD/MTU, and for the standard 16x16 pellet design. For a peak power pin, these values may be multiplied by the appropriate pin power peaking (Fr) required for the non-LOCA event analyzed.

Table 2.13.0-10 contains the source term for the FHA of Section 2.13.7.3.4 of this document. The table provides the maximum volatile fission product gas gap activities for each isotope. These values represent conservative results for a 72-hour decay following burnup to 70,000 MWD/MTU. The data is normalized to a radial peaking factor of 1.00. The analysis then increases the inventory of the pins which fail by a 1.8 radial peak.

LOCA source terms for fission product activities are discussed in Section 2.13.6.3.3 of this report.

Table 2.13.0-5
Parameters for Dose Calculations

Parameter	Units	Value
Containment Leak Rate(0 - 24 hours)	v/o per day	0.5
Containment Leak Rate (24 hours – 30 days)	v/o per day	0.25
Leakage from containment to areas of the RAB and filtered by Controlled Ventilation Area System (CVAS)	%	54
Direct containment leakage into the annulus, (Shield Building Ventilation System [SBVS])	%	40
Unfiltered Bypass	%	6
CVAS Filter Efficiencies	%	99
SBVS Filter Efficiencies	%	90
Breathing Rate (0 - 8 hours)	m^3/sec	3.47E-04
Control Room Volume	ft^3	220,000
Control Room Recirculation Flow	CFM	3,800
Control Room Pressurization Flow	CFM	200
Control Room Unfiltered Inleakage (LOCA)	CFM	50
Control Room Filtration Efficiency	%	99
Iodine Partition Factor for an Empty SG	---	1
Iodine Partition Factor for a Full SG	---	100
Steam Generator Tube Leakage	Gallons per day per SG	540

Table 2.13.0-6
Dose Conversion Factors

Isotope	Whole Body Dose Conversion Factors (rem-m^3/sec-Ci):	Skin Dose Conversion Factors (SDCFs): (rem/Ci inhaled):	Thyroid Dose Conversion Factors (rem/Ci inhaled):
Kr-83m	1.27E-05	---	---
Kr-85m	2.31E-02	4.97E-02	---
Kr-85	3.31E-04	4.84E-02	---
Kr-87	1.33E-01	3.36E-01	---
Kr-88	3.38E-01	7.76E-02	---
Kr-89	3.03E-01	3.47E-01	---
Xe-131m	1.25E-03	1.33E-02	---
Xe-133m	4.29E-03	2.96E-02	---
Xe-133	4.96E-03	9.67E-03	---
Xe-135m	6.37E-02	2.14E-02	---
Xe-135	3.59E-02	6.32E-02	---
Xe-137	2.83E-02	4.59E-01	---
Xe-138	1.87E-01	1.47E-01	---
I-129	3.02E-03	2.435E-02	5.542E+06
I-131	5.59E-02	3.07E-02	1.10E+06
I-132	3.55E-01	1.10E-01	6.30E+03
I-133	9.11E-02	8.90E-02	1.80E+05
I-134	4.11E-01	1.42E-01	1.10E+03
I-135	2.49E-01	7.86E-02	3.10E+04
I-136	6.786E-01	1.30E+00	---

Table 2.13.0-7
Control Room (CR) Atmospheric Dispersion Factors (χ/Q)
5% Probability – Level χ/Q Values (Sec/M^3)

	East MSSV		West MSSV		East ADV	
Time Period	**East CR Air Intake**	**West CR Air Intake**	**East CR Air Intake**	**West CR Air Intake**	**East CR Air Intake**	**West CR Air Intake**
0 to 2 hours	4.36E-02	1.37E-03	1.52E-03	7.40E-03	1.06E-01	1.23E-03
2 to 8 hours	3.08E-02	9.34E-04	9.44E-04	5.44E-03	7.45E-02	8.31E-04
8 to 24 hours	1.33E-02	4.48E-04	4.00E-04	2.46E-03	3.30E-02	4.00E-04
1 to 4 days	9.01E-03	2.99E-04	2.81E-04	1.92E-03	2.31E-02	2.63E-04
4 to 30 days	6.57E-03	2.10E-04	2.07E-04	1.50E-03	1.62E-02	1.85E-04

	West ADV		East MSL		West MSL	
Time Period	**East CR Air Intake**	**West CR Air Intake**	**East CR Air Intake**	**West CR Air Intake**	**East CR Air Intake**	**West CR Air Intake**
0 to 2 hours	1.36E-03	7.50E-03	5.09E-02	1.44E-03	1.54E-03	9.28E-03
2 to 8 hours	8.29E-04	5.62E-03	3.26E-02	9.78E-04	9.62E-04	6.84E-03
8 to 24 hours	3.55E-04	2.57E-03	1.39E-02	4.68E-04	4.11E-04	3.11E-03
1 to 4 days	2.48E-04	2.04E-03	8.81E-03	3.05E-04	2.89E-04	2.37E-03
4 to 30 days	1.85E-04	1.57E-03	6.87E-03	2.18E-04	2.15E-04	1.85E-03

	Plant Stack		FHB Truck Bay		FHB Personnel Door	
Time Period	**East CR Air Intake**	**West CR Air Intake**	**East CR Air Intake**	**West CR Air Intake**	**East CR Air Intake**	**West CR Air Intake**
0 to 2 hours	2.77E-03	2.06E-03	7.50E-04	7.63E-04	9.75E-04	1.05E-03
2 to 8 hours	1.78E-03	1.56E-03	6.15E-04	6.32E-04	7.74E-04	8.72E-04
8 to 24 hours	7.22E-04	7.16E-04	2.62E-04	2.95E-04	3.33E-04	4.02E-04
1 to 4 days	5.27E-04	5.49E-04	1.82E-04	2.27E-04	2.22E-04	3.08E-04
4 to 30 days	4.05E-04	4.32E-04	1.25E-04	1.70E-04	1.55E-04	2.29E-04

	Containment Hatch		Containment Purge	
Time Period	**East CR Air Intake**	**West CR Air Intake**	**East CR Air Intake**	**West CR Air Intake**
0 to 2 hours	1.22E-03	1.93E-03	1.55E-02	1.68E-03
2 to 8 hours	8.54E-04	1.60E-03	1.01E-02	1.20E-03
8 to 24 hours	3.64E-04	7.42E-04	4.18E-03	5.75E-04
1 to 4 days	2.43E-04	5.61E-04	2.72E-03	3.90E-04
4 to 30 days	1.86E-04	4.24E-04	2.13E-03	2.67E-04

Table 2.13.0-8
Offsite Atmospheric Dilution Factors (χ/Q)
5% Probability – Level χ/Q Values (Sec/M^3)

Duration		Distance (M)	
1 HR	(0 - 2 hr Exclusive Area Boundary [EAB])	914	4.31E-04
8 HR	(0 - 8 hrs Low Population Zone [LPZ])	3200	6.58E-05
16 HR	(8 - 24 hrs.)	3200	4.45E-05
3 DAYS	(24 - 96 hrs.)	3200	1.91E-05
26 DAYS	(96 - 720 hrs.)	3200	5.88E-06

Table 2.13.0-9
Waterford 3 3716-MWt Power Uprate
Maximum Fuel Rod Fission Product Activities
for Non-LOCA Transients

Isotope	Activity (Ci/Rod)
Kr-83m	3.29E+2
Kr-85	2.28E+1
Kr-85m	7.67E+2
Kr-87	1.55E+3
Kr-88	2.19E+3
I-131	2.04E+3
I-132	2.93E+3
I-133	4.15E+3
I-134	4.68E+3
I-135	3.86E+3
Xe-131M	2.29E+1
Xe-133	4.01E+3
Xe-133M	1.28E+2
Xe-135	1.21E+3
Xe-135M	8.14E+2
Xe-138	3.81E+3

Table 2.13.0-10
Waterford 3 3716-MWt Power Uprate
Radioisotopic Source Terms for the FHA
(60 failed fuel rods)

Isotope	Maximum Activity (Ci)
Kr-85	5.870E+02
Kr-85M	1.670E-01
Kr-87	7.090E-14
Kr-88	2.510E-04
I-129	8.010E-06
I-131	1.196E+02
I-132	9.661E+01
I-133	2.367E+01
I-134	2.300E-22
I-135	1.210E-01
Xe-131M	1.880E+02
Xe-133	2.020E+04
Xe-133M	4.500E+02
Xe-135	2.695E+02
Xe-135M	1.970E+00

2.13.1 Increase in Heat Removal by the Secondary System (Turbine Plant)

2.13.1.1 Moderate Frequency Incidents

2.13.1.1.1 Decrease in Feedwater Temperature

Event is bounded by increased main steam flow, Section 2.13.1.1.3 of this report.

2.13.1.1.2 Increase in Feedwater Flow

Event is bounded by increased main steam flow, Section 2.13.1.1.3 of this report.

2.13.1.1.3 Increased Main Steam Flow

The objective of the increased main steam flow event is to document the impact of the following changes:

- An increase in rated power
- A change to the CENTS code
- Application of a more negative MTC
- A reduction in CEA worth at trip
- Credit for the CPCS Variable Overpower Trip
- A decrease in the low steam generator pressure (LSGP) trip and MSIS setpoints

The impact of the above changes results in no violation to the DNB SAFDLs.

2.13.1.1.3.1 General Description of the Event

Increased main steam flow events can result from the malfunction of valve(s) within the Main Steam Safety System (MSSS).

The increase in heat removal by the SGs as a result of increased main steam flow is defined as any rapid increase in SG steam flow, other than a steam line rupture, without a turbine trip. Any one of the following events may cause an increase in steam flow:

a) Inadvertent opening of the turbine admission valves. This is assumed to result in approximately a 11% increase of the full power turbine flow rate.

b) Failure in the Steam Bypass System (SBS) that could result in an opening of one steam bypass valve. The flow rated of one valve is assumed to be approximately 12.3% of the full power turbine flow rate.

c) Inadvertent opening of an ADV or SG safety valve. Each dump valve can release approximately 5.3% of the full-power steam flow, and the safety valve can pass approximately 9.3% of full power steam flow.

The sudden opening of a Main Steam Safety System (MSSS) valve will cause an increase in steam flow rate. If the feedwater control system is in the automatic mode of operation, it will increase the feedwater flow rate to match the increased steam flow rate. This increases the rate of cooldown during the event. If the Feedwater Control System is in the manual mode of operation and depending on the magnitude of the increased steam flow rate, a low steam generator level trip may occur. In both cases, main feedwater is reduced to approximately 3% on turbine trip and is completely isolated after the MSIS is generated. The CPCS will terminate this transient on either a VOPT or low DNBR trip to protect against violating the SAFDLs.

Of the three types of valve malfunctions listed above that can initiate an increased main steam flow, the inadvertent opening of a steam bypass valve is the most adverse.

This analysis assumes the inadvertent opening of one steam bypass valve downstream of the MSIV associated with SG A. This analysis conservatively assumed 12.3% flow capacity for the steam bypass valve at the full-open position at EPU conditions.

The increased main steam flow events are mitigated by the CPCS low DNBR trip and the CPCS VOPT. However, the safety analyses do not explicitly credit the CPCS low DNBR/high LPD trip since some input values are cycle-specific (e.g., the power penalty factors). To make the event analysis cycle independent, the CPCS low DNBR and high LPD trips are not explicitly credited for the licensing analysis. Instead, other RPS and other CPCS trips (VOPT, ΔT_{cold}, and low RCP shaft speed) are used.

The analysis of the excess load event covers a spectrum of initial power levels, MTC values and load demands to ensure adequate initial thermal margin and acceptable trip response. Initial thermal hydraulic conditions for the analysis presented herein are selected to be the most adverse for tuning of the CPCS.

2.13.1.1.3.2 Purpose of Analysis and Acceptance Criteria

The purpose of this analysis is to determine that the increased main steam flow event does not violate fuel SAFDLs for DNBR and peak linear heat rate (LHR) and that the radiological doses are a small fraction of 10CFR100 limits.

The following criteria apply to the increased main steam flow event:

- DNBR > 1.26
- Fuel temperature < fuel melt temperature limit, demonstrated by peak LHR ≤ 21.0 kW/ft
- Radiological dose ≤ small fraction of 10CFR100 limits
- RCS pressures ≤ 110% of design

The increased main steam flow event is described in Chapter 15.1.1.3 of the FSAR (Reference 2.13-1).

2.13.1.1.3.3 Impact of Changes

The increase in rated power and associated decrease in steam generator pressure results in a little slower transient cooldown. Hence, the core power and heat flux increases are smaller.

The CPCS VOPT includes temperature compensation on measured power for decreasing core inlet temperature. The CPCS VOPT actuates on core power prior to the CPCS generating a low DNBR trip due to loss of thermal margin. There is no impact on initial thermal margin as the minimum thermal margin preserved by the LCOs is assumed for the DNBR calculation.

The increase in the most negative MTC value results in a faster transient cooldown. More rapid cooldown results in a larger addition of positive reactivity, which results in a faster increase in core power and heat flux. The faster transient power response presents a greater challenge to the CPCS response and a larger overshoot of core power and heat flux at the time of trip. This larger overshoot results in a more rapid approach to the SAFDLs after reactor trip.

The decrease in LSGP trip and MSIS setpoints to 576 psia resulted in an extension of the secondary and primary cooldown after reactor trip. This extends the time the pressurizer remains empty by approximately 100 seconds. Also, the minimum primary and secondary pressures are lower than the previous analyses. The lower secondary pressure results in the SG safety valves opening later after the MSIVs close.

This event is now analyzed with the CENTS code (Reference 2.13-2) versus the CESEC code. The CETOP code (Reference 2.13-3) was used to generate the minimum DNBR.

2.13.1.1.3.4 Analysis Overview

The methodology used in this analysis is similar to the methodology used in the current analysis of record, except that the CENTS code is used instead of the CESEC codes.

Input parameters from Table 2.13.1.1.3-1 and the bounding physics data from Section 2.13.0.2 of this report have been incorporated in this analysis:

a) The BOC Doppler coefficient was assumed.

b) A BOC delayed neutron fraction and neutron lifetime consistent with those defined in Section 2.13.0.2 were assumed.

c) The CEA insertion curve includes 0.6-second holding coil delay. A CEA worth of -6.0% $\Delta\rho$ was assumed.

d) The analysis is conservatively based on an inadvertent opening of a steam bypass valve with a flow capacity of approximately 12.3%.

e) The VOPT of the CPCS was employed in the analysis. A cold leg RTD response time of 8 seconds was included along with a CPC trip delay time of 0.50 seconds. This CPC trip delay is a conservative assumption with respect to the CPC delay times discussed in Section 2.13.0.3.

f) An initial core power of 3735 MWt, based on a rated power of 3716 MWt and a 0.5% uncertainty, was assumed.

g) The most negative MTC of –4.2 * 10-4 Δρ/°F was assumed. This results in the largest radial power distortion in the core due to the core temperature asymmetry.

h) MSIS is actuated on a low steam generator pressure setpoint of 576 PSIA. The MSIVs and main feedwater isolation valves (MFIVs) receive an MSIS signal to close. A response time of 8 seconds (which includes a 1-second MSIS response time) was assumed for the MSIVs. The MFIVs were assumed to close in 13 seconds.

2.13.1.1.3.5 Radiological Consequences

No SAFDL violation occurs during the increased main steam flow event. Source terms are therefore limited to the initial primary and secondary limits on coolant activity in the Technical Specifications. Doses for this event are bounded by the IOSGADV with LOOP event in Section 2.13.1.2.4. Both events have the same criteria (small fraction of 10CFR100 guidelines), and the inadvertent opening of a SG ADV event radiological dose assumptions are conservative for the increased main steam flow event.

2.13.1.1.3.6 Analysis Results

The impact of the steam bypass valve malfunction can cause an overcooling of the Reactor Coolant System (RCS) resulting from the decreasing cold leg inlet temperature. Core power also increases due to the reactivity feedback interaction caused by the lower cold leg inlet temperature. The CPCS VOPT terminates the transient.

The NSSS and RPS responses for the increased main steam flow event are shown in Table 2.13.1.1.3-2 and in Figures 2.13.1.1.3-1 through 2.13.1.1.3-11.

For the increased main steam flow, the minimum DNBR is greater than 1.26 and the peak LHR is less than 21 kW/ft. Thus, there is no violation of the SAFDLs.

The radiological consequences are ≤ a small fraction of 10CFR100 limits.

The RCS pressure undergoes a reduction during this event so the 110% criterion is not challenged.

Table 2.13.1.1.3-1
Assumptions for Increased Main Steam Flow Event

Parameter, units	Power Uprate Assumption	Current Power Level Assumption
Initial Core Power, MWt	3735	3478
Core Inlet Coolant Temperature, °F	554	560
RCS Flowrate, 10^6 lbm/hr	146.0	141.5
Pressurizer Pressure, psia	2310	2250
Pressurizer Level, %	67.5	---
SG pressure, psia	892	949
Total Nuclear Heat Flux Factor	2.5	2.71
MTC, 10^{-4} $\Delta\rho$/°F	-4.2	-4.0
Doppler Coefficient Multiplier	0.85	0.85
CEA worth for trip, 10^{-2} $\Delta\rho$	-6.0	-8.15
Steam Bypass System (SBS)	Fails	Fails
Feedwater Regulating System	Automatic	Automatic
Pressurizer Level Control System (PLCS)	Manual	Manual
Pressurizer Pressure Control System (PPCS)	Manual	Manual

Table 2.13.1.1.3-2
Sequence of Events for an Increased Main Steam Flow

EPU Time (seconds)	Current Power Level Time (seconds)	Event	EPU Setpoint/Value	Current Power Level Setpoint Value
0.0	0.0	A postulated spurious quick open signal generated by the SBCS, one of the steam bypass valves begins to open	---	---
1.0	1.0	The steam bypass valve is fully open	---	---
23.9	---	CPCS VOPT occurs, % of rated power	108.8	---
---	18.2	CPCS Low DNBR trip signal generated	---	1.19 projected
24.4	---	Trip breakers open	---	---
24.65	18.35	Turbine admission valves start to close	---	---
25.0	18.5	CEAs begin to drop into the core	---	---
25.0	18.75	Maximum core power occurs, % of rated power	109.6	110.0
25.1	18.95	Maximum core average heat flux occurs, % of full power average channel heat flux	109.1	108.0
25.2	18.95	Minimum DNBR occurs	1.533	1.19
42.4	38.35	Feedwater control valves fully closed, main feedwater reaches 3.5% of full flow	---	---
153.5	113.4	Pressurizer empties	---	---
347.1	255.2	MSIS and low SG pressure setpoint reached, psia	576.0	675.0
348.1	256.2	MSIS is generated	---	---
355.1	258.0	Minimum SG pressure occurs, psia	568.6	671.0
355.2	258.2	MSIVs closed	---	---
356.4	283.0	Minimum pressurizer pressure, psia	679.8	716.0
360.3	274.3	Feedwater isolations valves closed	---	---
367.5	525.0	Pressurizer begins to refill	---	---
>1000.	>1000	SG safety valves open, psia	1085	1085
1800.0	1800.0	Operator initiates plant cooldown procedures if the malfunction has not already been corrected	---	---

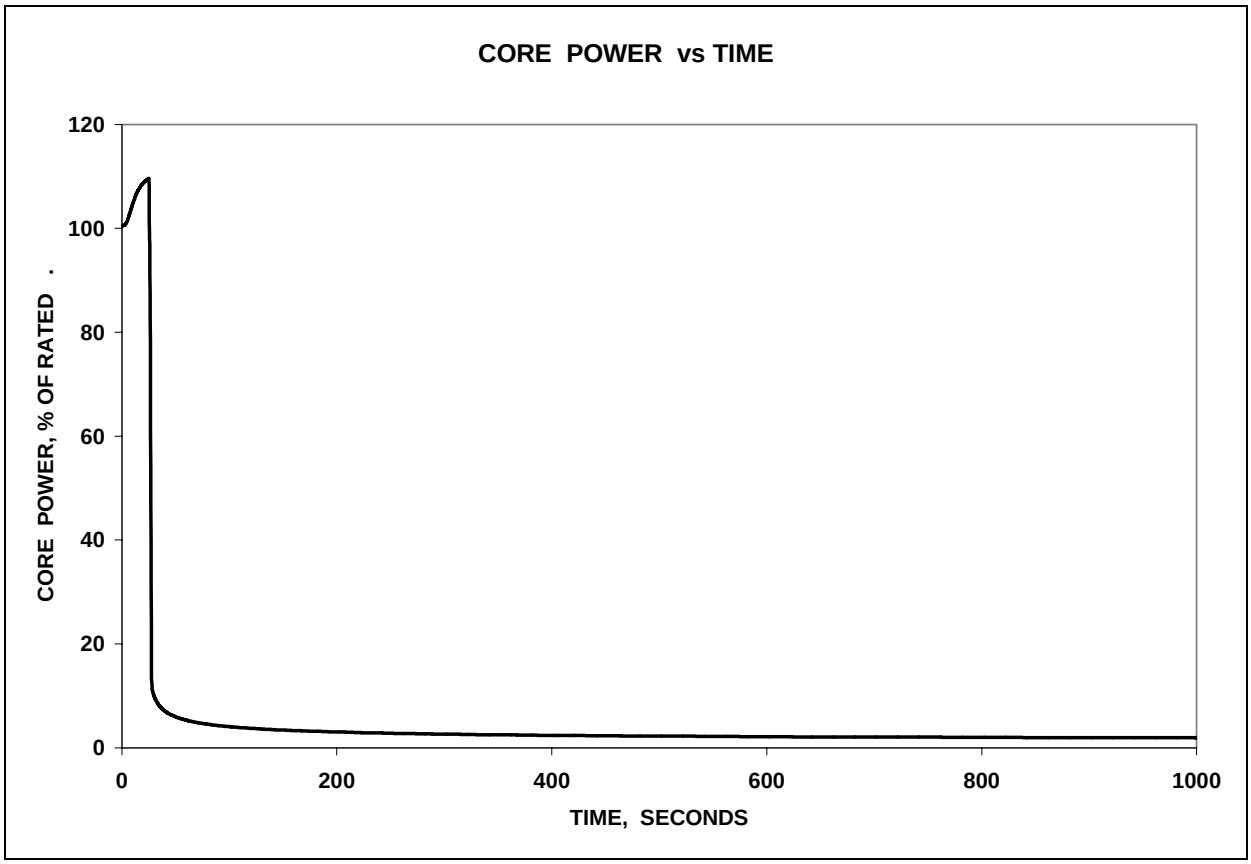

Figure 2.13.1.1.3-1
Increased Main Steam Flow
Core Power vs. Time

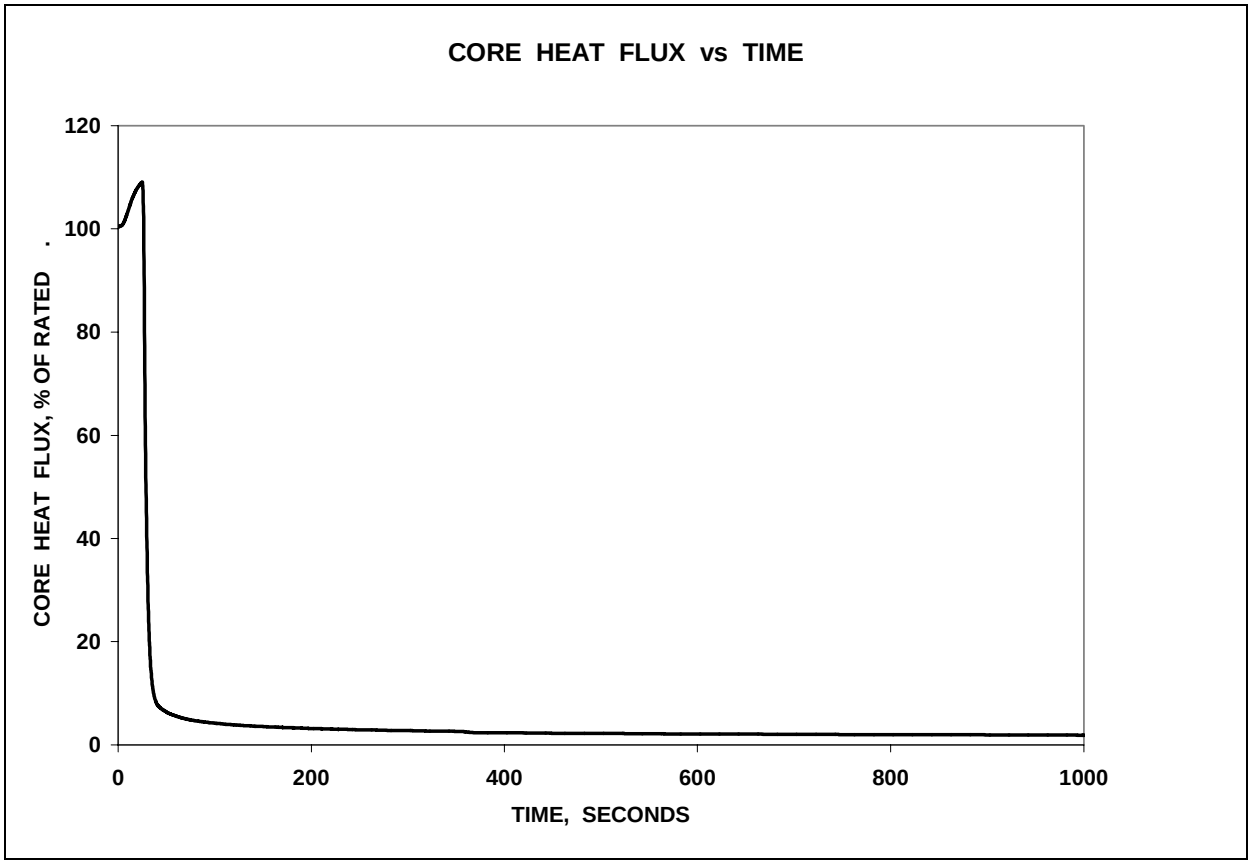

Figure 2.13.1.1.3-2
Increased Main Steam Flow
Core Average Heat Flux vs. Time

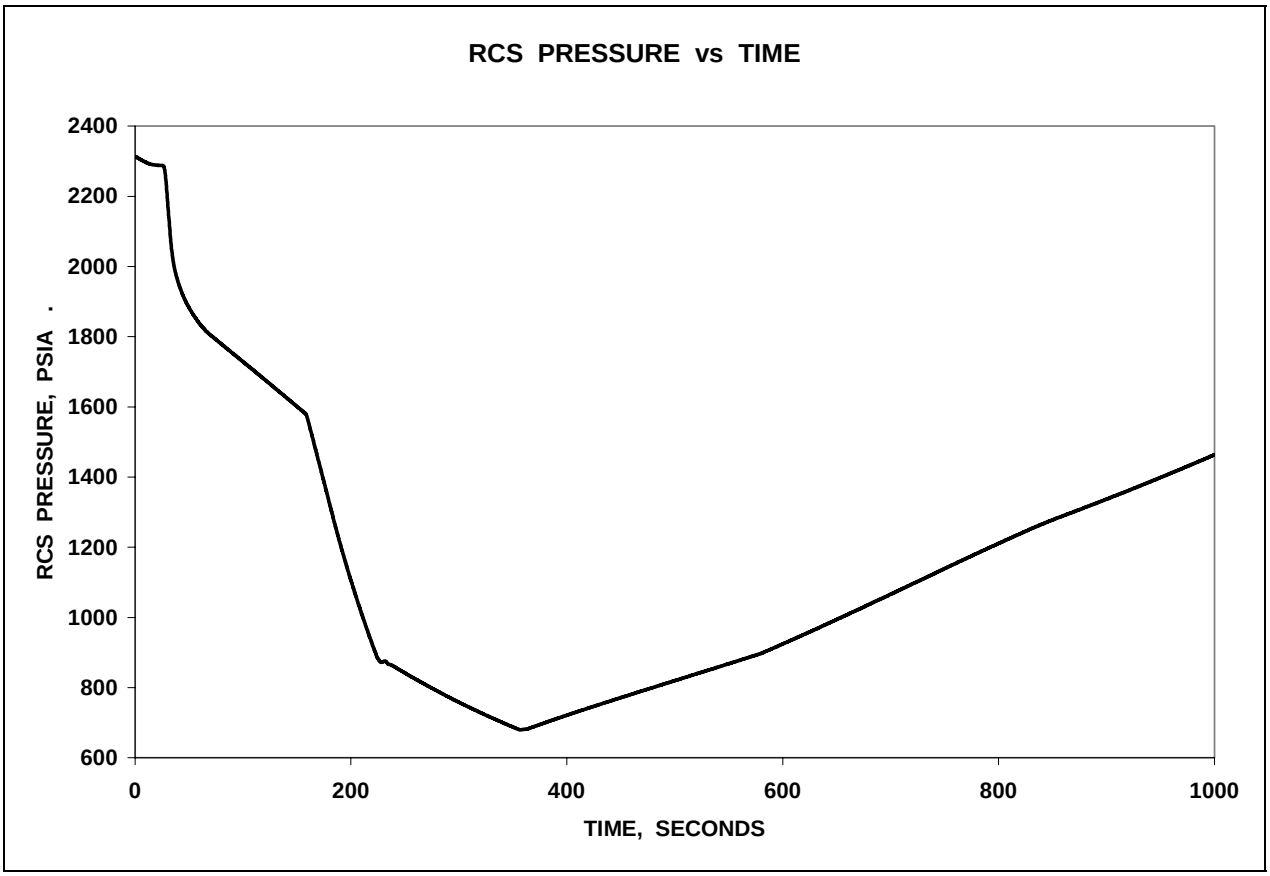

Figure 2.13.1.1.3-3
Increased Main Steam Flow
Pressurizer Pressure vs. Time

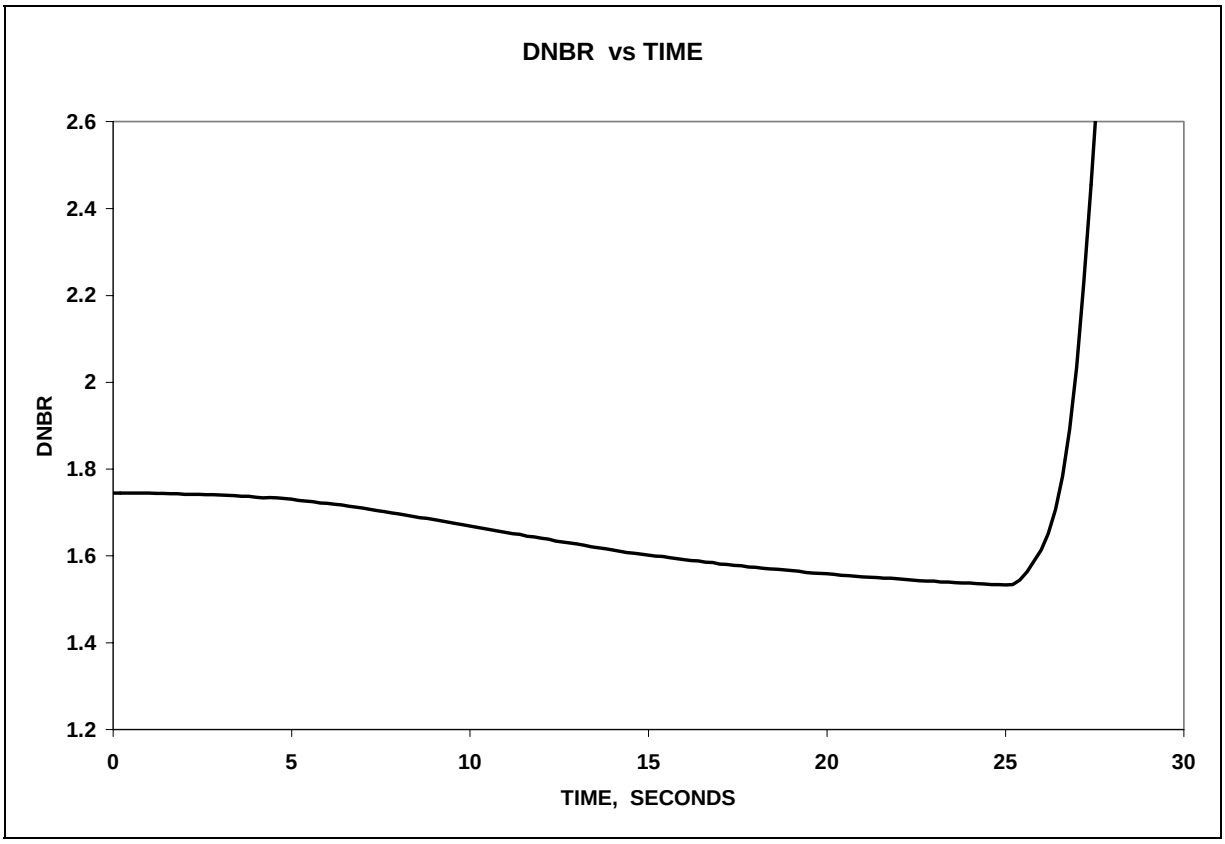

Figure 2.13.1.1.3-4
Increased Main Steam Flow
Minimum DNBR vs. Time

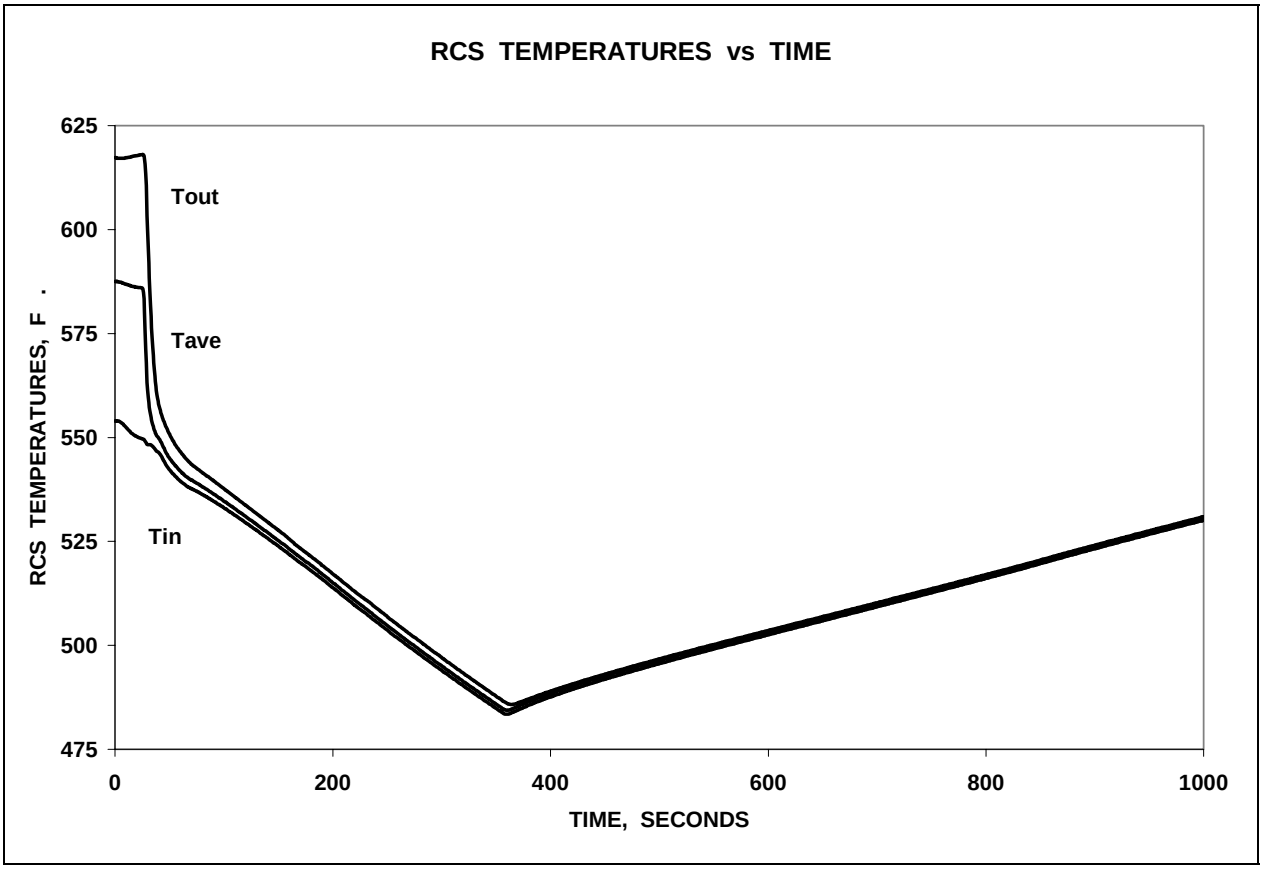

Figure 2.13.1.1.3-5
Increased Main Steam Flow
RCS Temperatures vs. Time

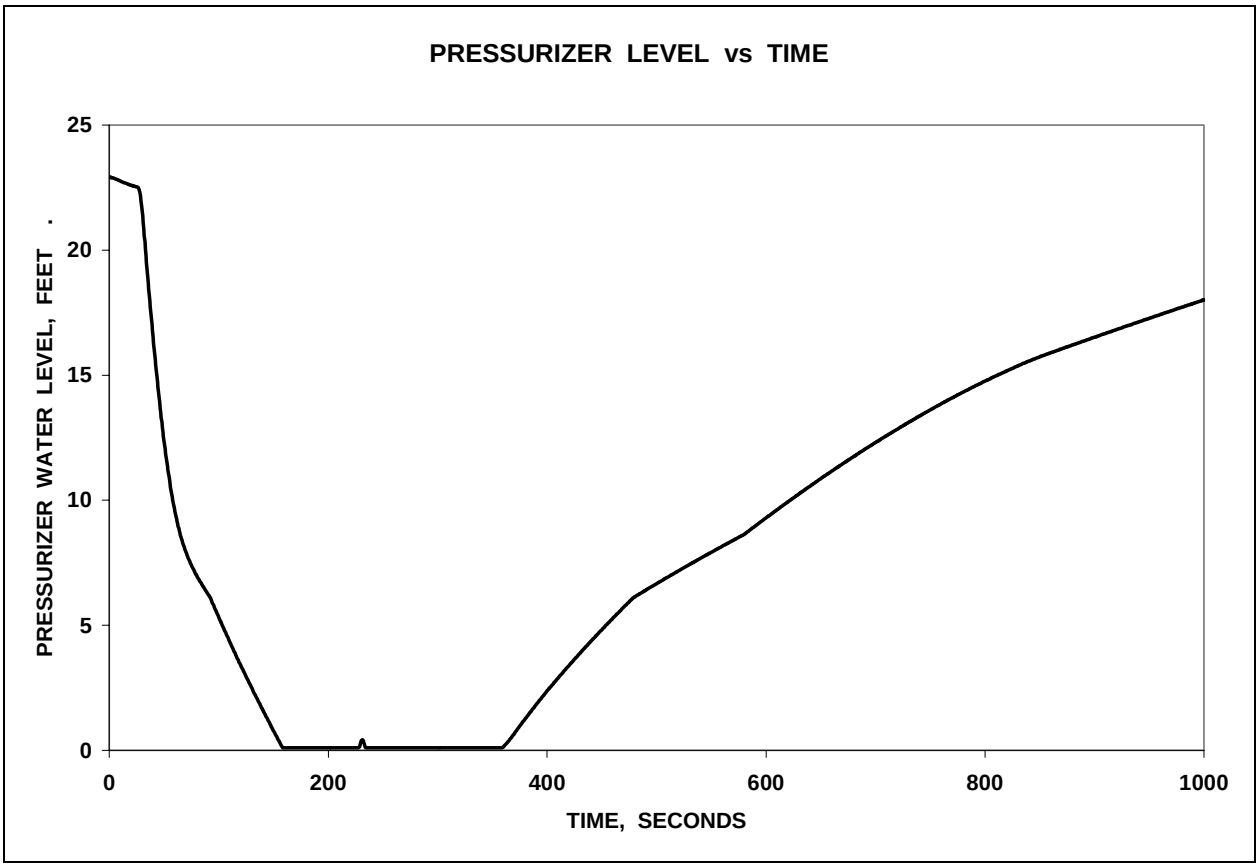

Figure 2.13.1.1.3-6
Increased Main Steam Flow
Pressurizer Level vs. Time

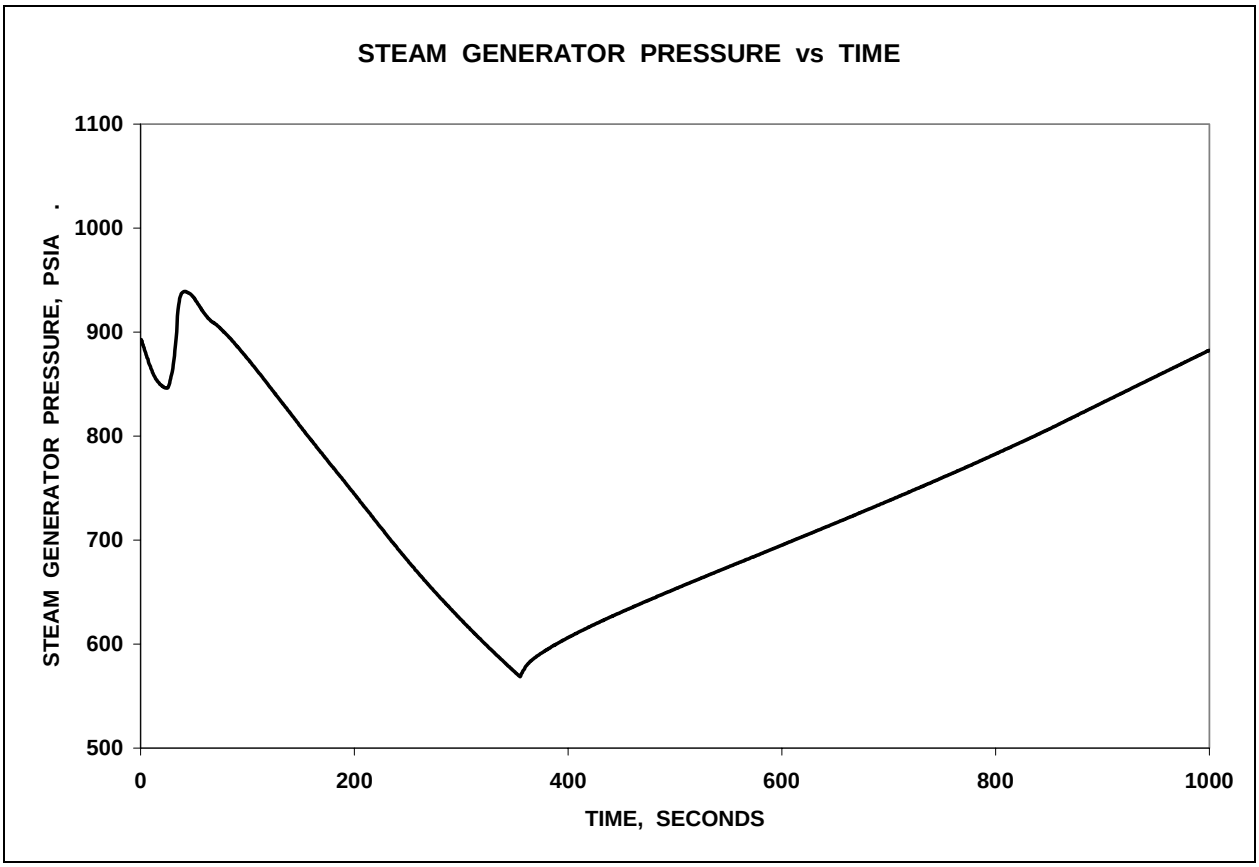

Figure 2.13.1.1.3-7
Increased Main Steam Flow
SG Pressure vs. Time

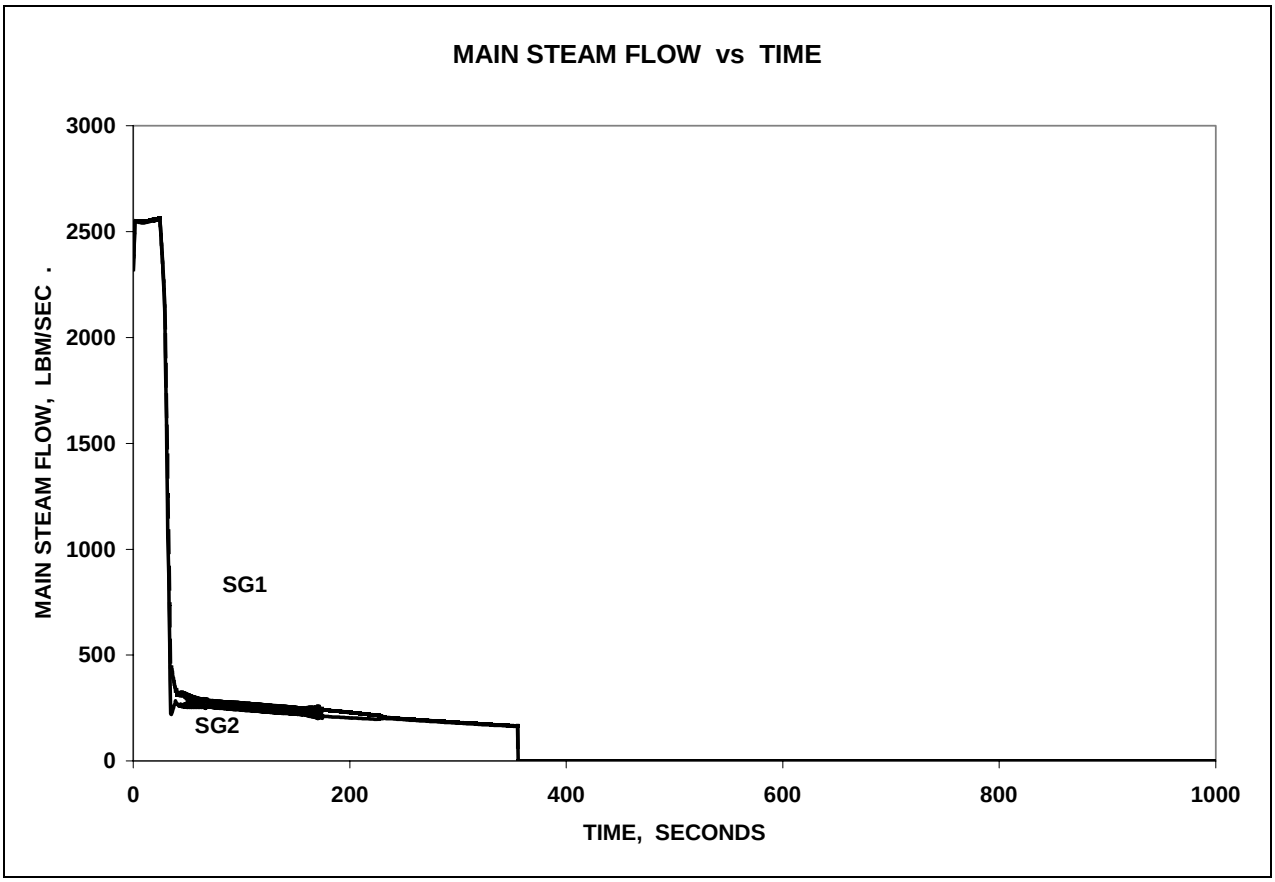

Figure 2.13.1.1.3-8
Increased Main Steam Flow
Total Steam Flow vs. Time

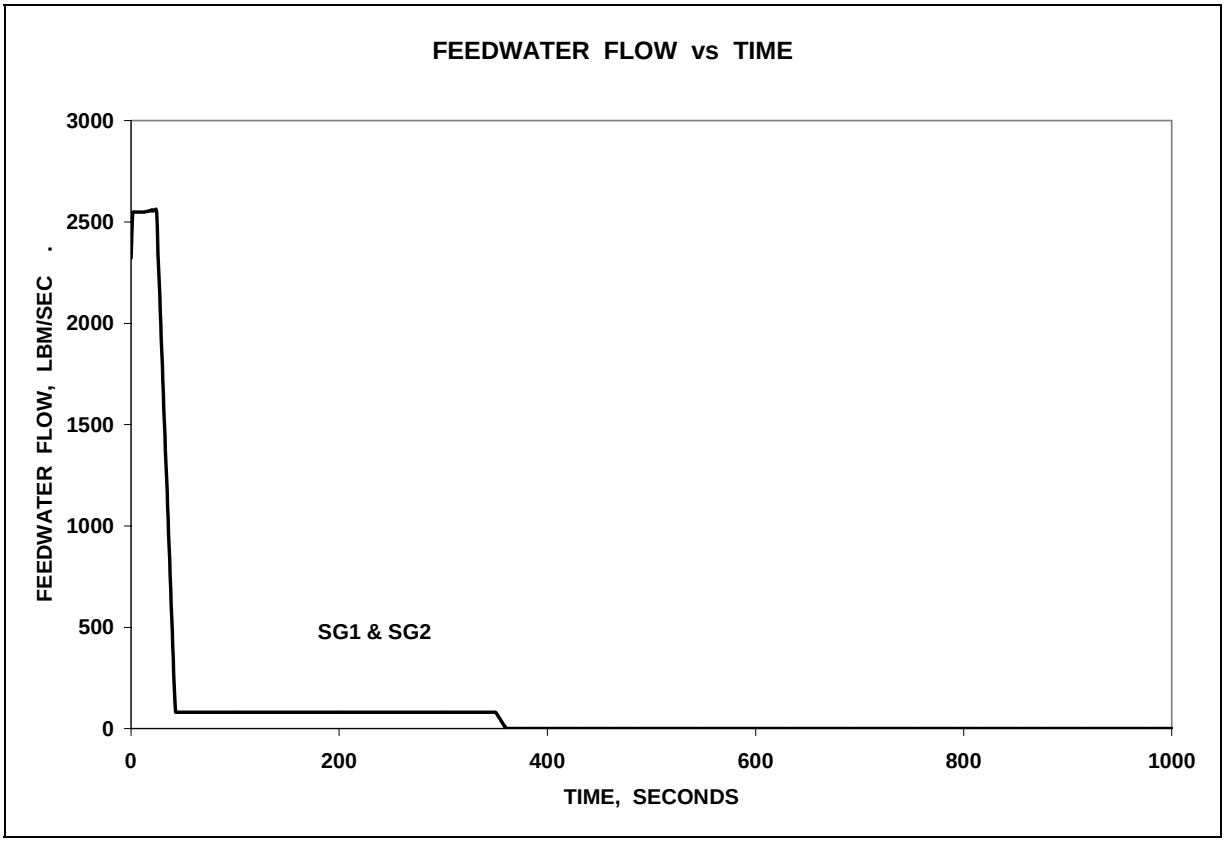

Figure 2.13.1.1.3-9
Increased Main Steam Flow
Feedwater Flow vs. Time

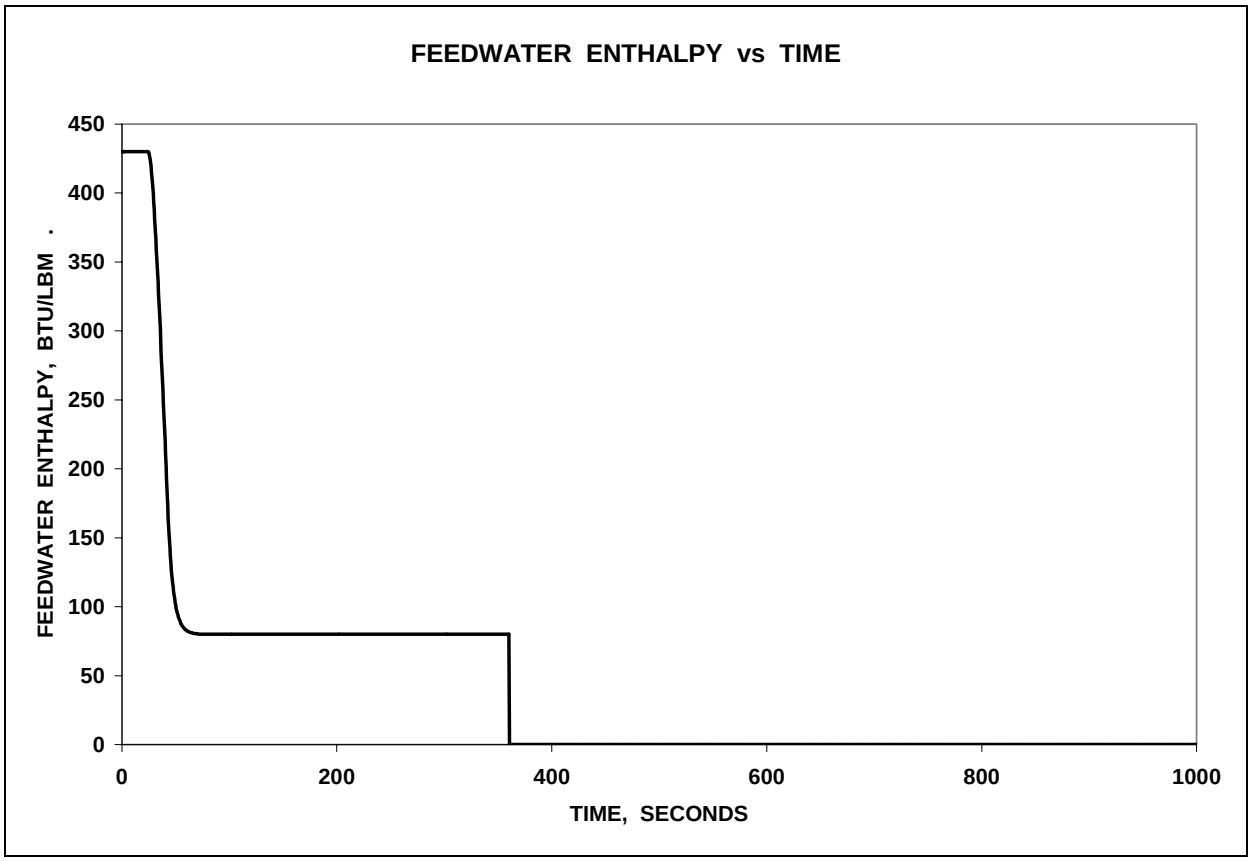

Figure 2.13.1.1.3-10
Increased Main Steam Flow
Feedwater Enthalpy vs. Time

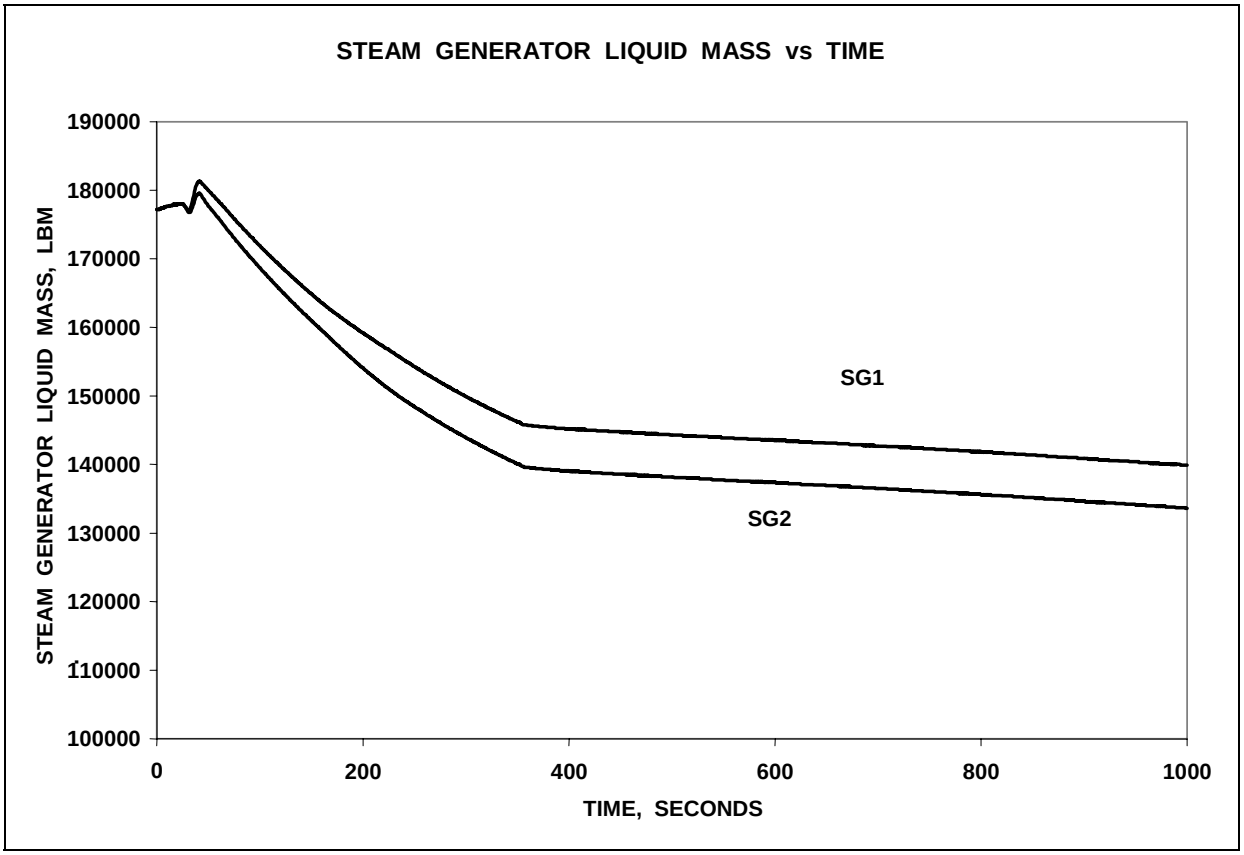

Figure 2.13.1.1.3-11
Increased Main Steam Flow
SG Liquid Mass vs. Time

2.13.1.1.4 Inadvertent Opening of a Steam Generator ADV (IOSGADV)

The objective of the inadvertent opening of an SG Atmospheric Dump Valve (IOSGADV) analysis is to document the impact of:

- The change in plant parameters due to the increase in rated power from 3441 MWt to 3716 MWt
- Using CENTS instead of CESEC as the NSSS simulation code
- The change in the most negative MTC from -4.0×10^{-4} $\Delta\rho/°F$ to -4.2×10^{-4} $\Delta\rho/°F$

The decrease in the most negative MTC has the potential to add more positive reactivity during the cooldown.

The impact of the above changes results in no violation of the specified acceptable fuel design limits (SAFDL).

2.13.1.1.4.1 General Description of the Event

The IOSGADV results in excessive heat removal from the SG. The mass released from the open valve is not made up by the feedwater, which is assumed to be in the manual mode. Therefore, the SG water level decreases. The decreasing pressure and temperature in the affected SG results in a greater temperature difference between the RCS and SG, resulting in greater heat transfer from the RCS. This lowers the RCS temperature and results in an increase in reactor power due to the most negative MTC. This increase in power results in the heatup of the RCS, since the heat entering the RCS is greater than that extracted by the steam generator. The pressurizer pressure and RCS temperature begin to increase. The increase in RCS temperature results in a greater RCS-to-SG temperature difference, resulting in more heat being transferred to the SG and causing the SG temperature and pressure to increase. As the power increases, the fuel temperature increases. Therefore, the Doppler reactivity contribution increases. This decreases the positive reactivity and decreases core power and heat flux. Eventually the affected SG water level reaches the low level trip setpoint and initiates a reactor trip. The RCS and SGs then cool at a faster rate because of the decrease in core power. At 1800 seconds, operator action is credited.

An ADV may be inadvertently opened due to operator error or due to a failure in the ADV control system.

2.13.1.1.4.2 Purpose of Analysis and Acceptance Criteria

The purpose of the analysis was to demonstrate that the fuel SAFDLs were not violated, and to maximize the release of steam in order to maximize radiological releases.

The following criteria apply to the IOSGADV event:

- DNBR > 1.26
- Fuel temperature < fuel melt temperature limit, demonstrated by peak LHR ≤ 21.0 kW/ft
- Radiological dose ≤ small fraction of 10CFR100 limits
- RCS pressures ≤ 110% of design.

The IOSGADV event is a cooldown event initiated from low power. Consequently, the peak RCS and SG pressure do not challenge the acceptance criteria, and are therefore not analyzed.

The IOSGADV event is described in Chapter 15.1.1.4 of the SAR (Reference 2.13-1).

2.13.1.1.4.3 Impact of Changes

The difference in initial SG liquid mass is due to more accurate SG modeling in CENTS. The CENTS model has 3 SG nodes, while the CESEC model has 1 SG node. Any additional differences are due to changes in initial conditions since Cycle 1.

The more detailed modeling of the SG heat transfer area vs. inventory in the CENTS models leads to the prediction of a later time of dryout of the affected unit.

The decrease in the most negative MTC has the potential for adding more positive reactivity to the core during the cooldown.

2.13.1.1.4.4 Analysis Overview

This analysis utilized the CENTS (Reference 2.13-2) computer code for the simulation of the transient. The minimum DNBR evaluation was performed using the CETOP code (Reference 2.13-3).

Input parameters from Table 2.13.1.1.4-1 and the core physics data from Section 2.13.0.2 of this report have been incorporated in this analysis with the following clarifications:

- The most negative Doppler curve in Figure 2.13.2-2 was assumed.
- A maximum delayed neutron fraction and neutron lifetime consistent with those defined in Section 2.13.0.2 of this report were assumed.
- A low SG level trip setpoint of 5.0% and a response time of 0.9 seconds were assumed in the analysis.
- An initial power level of 1 MWt was assumed.

2.13.1.1.4.5 Radiological Consequences

No SAFDL violation occurs during the IOSGADV event. Source terms for release therefore consist of the long-term limits on primary and secondary activity.

Following reactor trip, the unaffected SG is steamed through its ADV to achieve cooldown of the plant to shutdown cooling entry conditions. During the first 2 hours of the cooldown, 962,000 lbm of steam are discharged from the ADV to remove decay heat and commence the cooldown of the RCS. Even though shutdown cooling entry conditions are achieved in the 4-to-5 hour time frame, the radiological consequences calculation assume that the plant is being maintained via the ADV for the duration of the 8-hour dose calculation. A total of 2,303,000 lbm of steam are released to the atmosphere through the ADVs.

The radiological consequences, with the inclusion of a pre-existing iodine spike (PIS), resulting from the IOSGADV are:

	2-Hour EAB	**8-Hour LPZ**
Thyroid	< 30 rem	< 30 rem
Whole Body	< 2.5 rem	< 2.5 rem

2.13.1.1.4.6 Analysis Results

The total amount of steam released is 313,300 lbm in 1800 seconds. The peak linear heat rate was less than 21.0 kW/ft. The minimum DNBR was greater than 1.26. There was no violation of the fuel SAFDLs. The IOSGADV is a cooldown event resulting in depressurization of the RCS, the peak pressure criteria is therefore not challenged.

The NSSS and RPS responses to the IOSGADV are shown in Table 2.13.1.1.4-2 and in Figures 2.13.1.1.4-1 through 2.13.1.1.4-9.

Table 2.13.1.1.4-1
Assumptions for the IOSGADV

Parameter	3716-MWt Power Uprate Assumption	Current Power Level Assumption
Initial Core Power, MWt	1	1
Core Inlet Coolant Temperature, °F	552	544
RCS Flowrate, 10^6 lbm/hr	148	141.5
Pressurizer Pressure, psia	2090	2250
Pressurizer Level, %	21	---
SG level, %	90%	---
SG pressure, psia	1057	995
MTC 10^{-4} $\Delta\rho$	-4.2	-3.75
Doppler Coefficient Multiplier	0.85	0.85
CEA Worth for Trip, 10^{-2} $\Delta\rho$	-5.0	-4.45
SBS	Fails	Fails
Feedwater Regulating System	Manual	Manual
Turbine Control System	Manual	Manual
PLCS	Manual	Manual
PPCS	Manual	Manual

Table 2.13.1.1.4-2
Sequence of Events for the IOSGADV

3716-MWt EPU Time (sec)	Current Power Level Time (sec)	Event	3716-MWt EPU Setpoint/Value	Current Power Level Setpoint/Value
0.0	0.0	One ADV opens fully	---	---
53.0	56.0	Minimum pressurizer pressure, psia	2045	2196
72.7, 70.5	67.5	Minimum SG pressure, psia	956.8 affected SG 1056.3 intact SG	884.3 affected SG 980.0 intact SG
82.9	82.5	Maximum core power, % of rated power	5.73	14.6
85.1	85.0	Maximum average core heat flux, % of full power heat flux	5.69	14.4
161.3	103	Maximum pressurizer pressure, psia	2116	2294
188.3	175.8	Maximum pressure in affected SG, psia	968.9	945.7
200.9	240.5	Maximum pressure in intact SG, psia	1085.9	1044
607.0	618.0	Low SG level trip signal, feet above tube sheet	27 (5% narrow range)	27 (5% narrow range)
607.9	618.4	Trip breakers open	---	---
608.5	618.7	Shutdown CEAs begin to enter core	---	---
1800	1800	Operator takes control of plant	---	---
28,800	---	SDC initiated	---	---

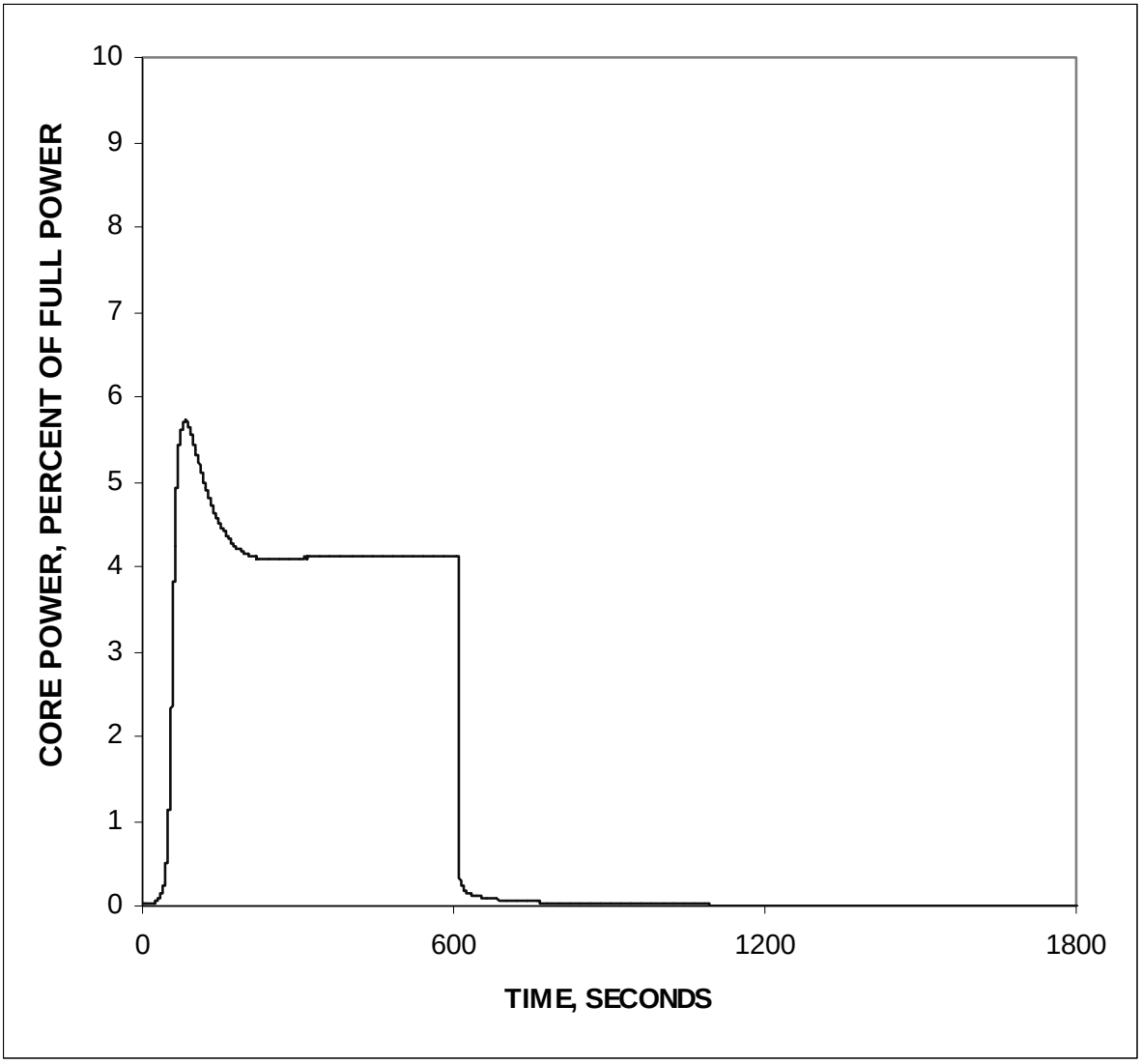

Figure 2.13.1.1.4-1
IOSGADV Core Power vs. Time

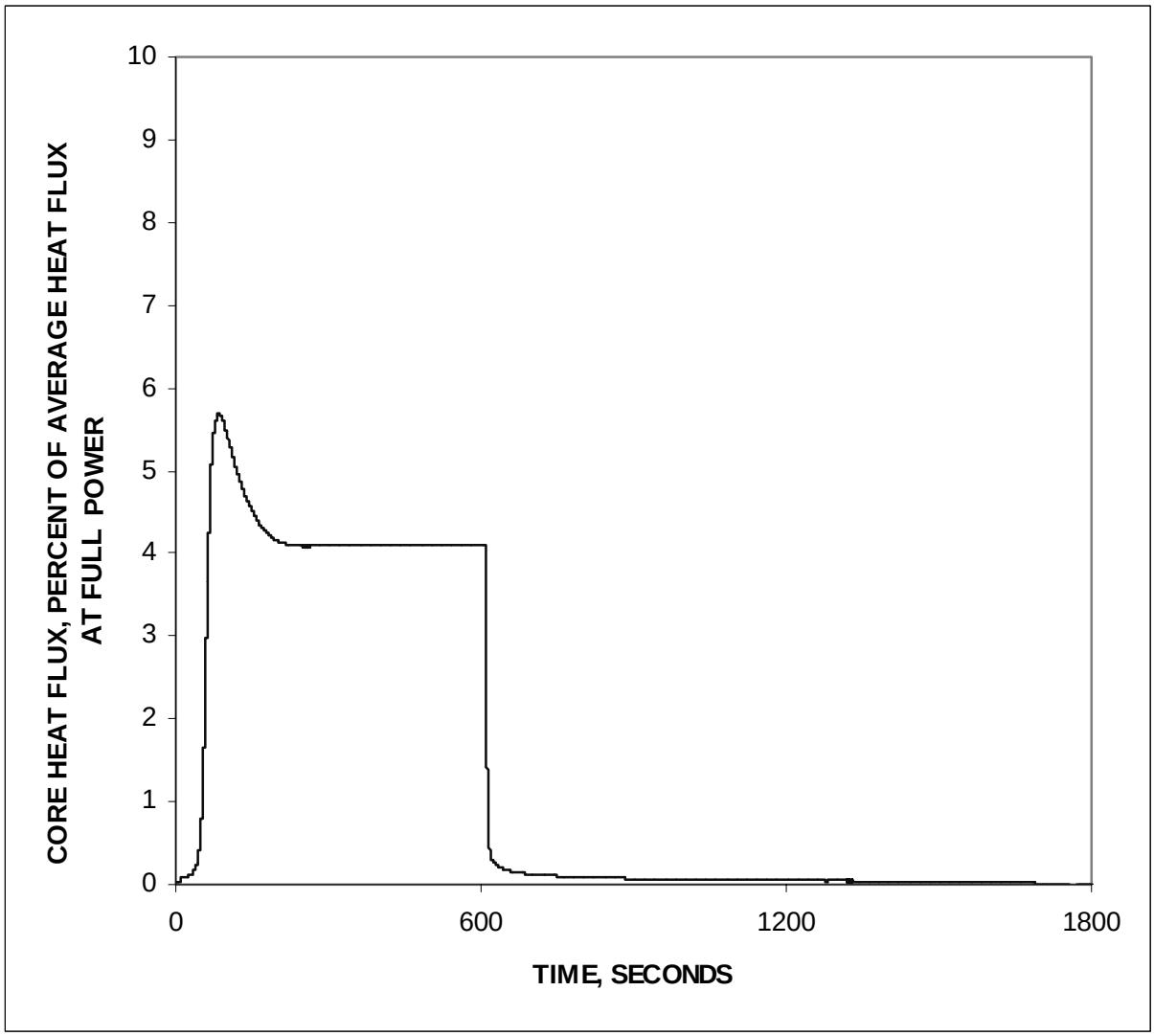

Figure 2.13.1.1.4-2
IOSGADV Core Heat Flux vs. Time

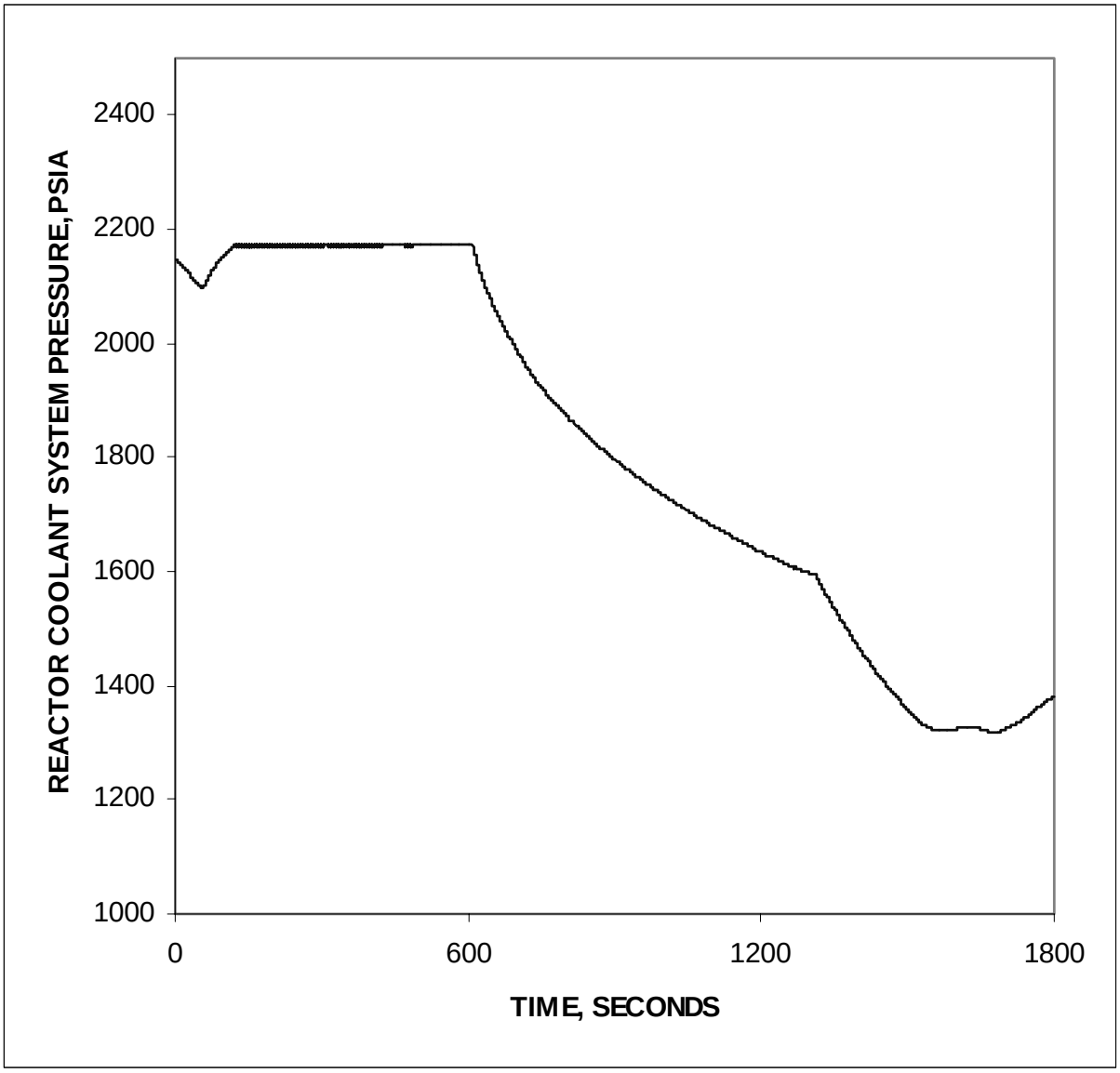

Figure 2.13.1.1.4-3
IOSGADV RCS Pressure vs. Time

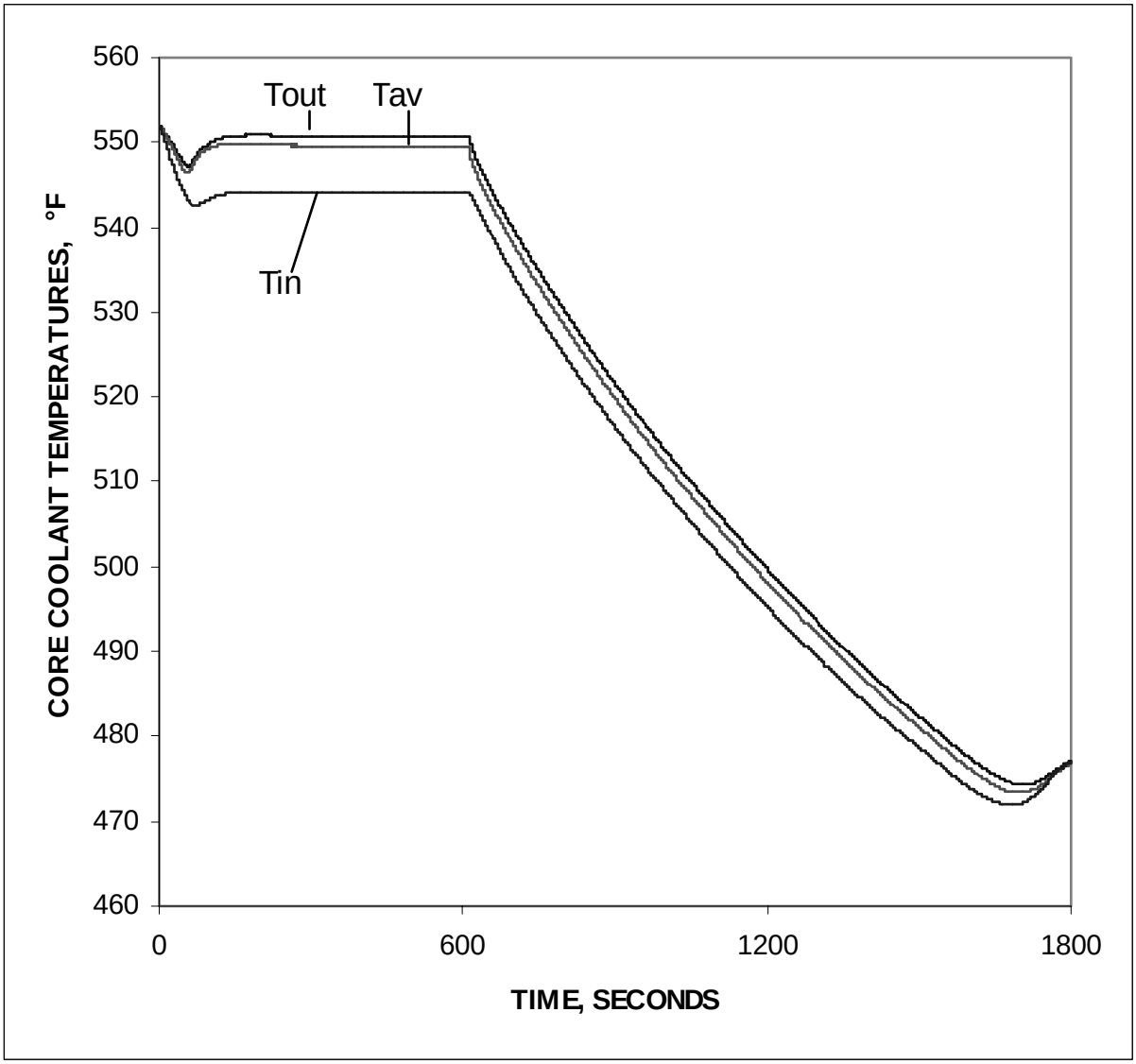

Figure 2.13.1.1.4-4
IOSGADV Reactor Coolant Temperature vs. Time

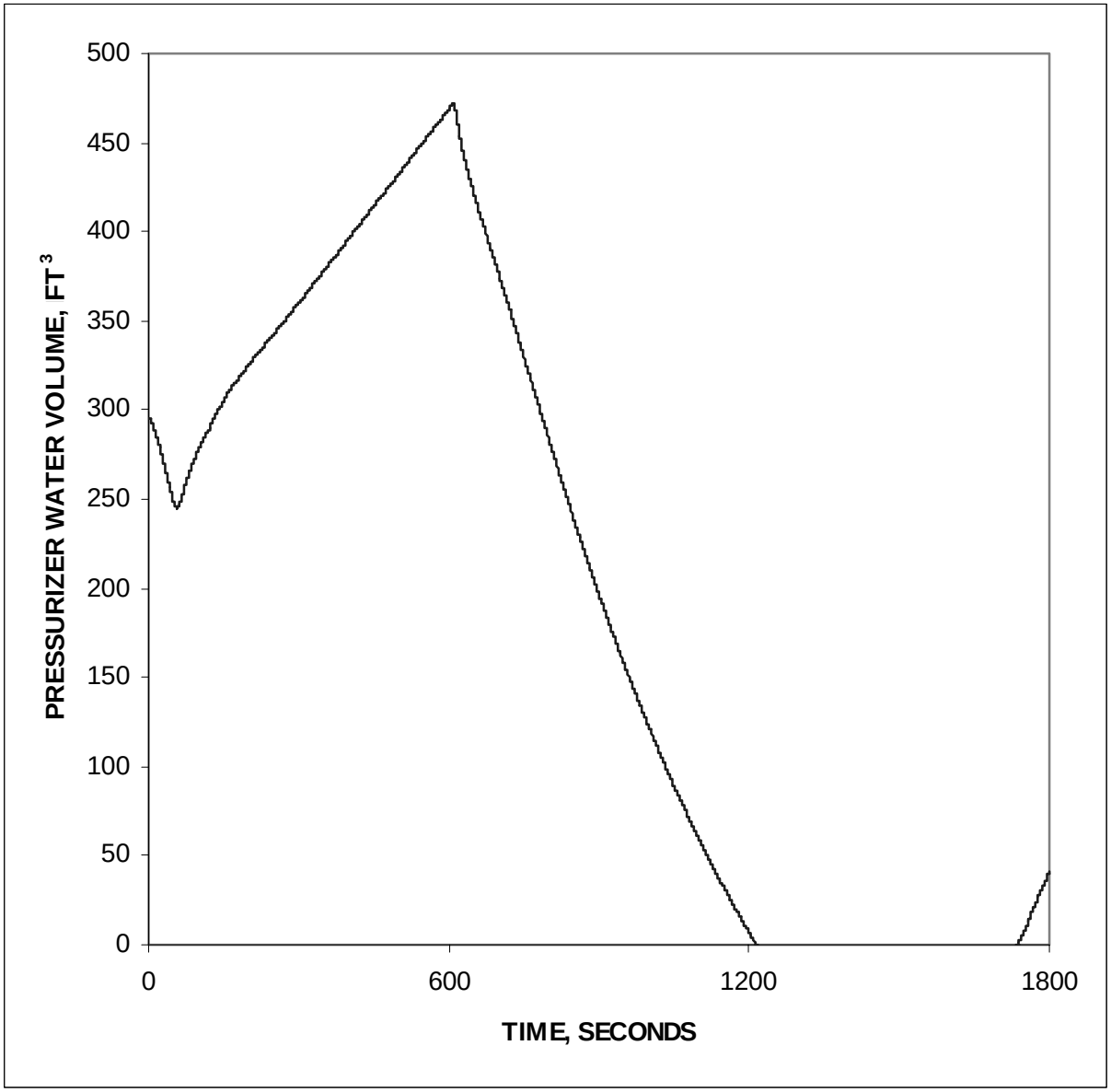

Figure 2.13.1.1.4-5
IOSGADV Pressurizer Water Volume vs. Time

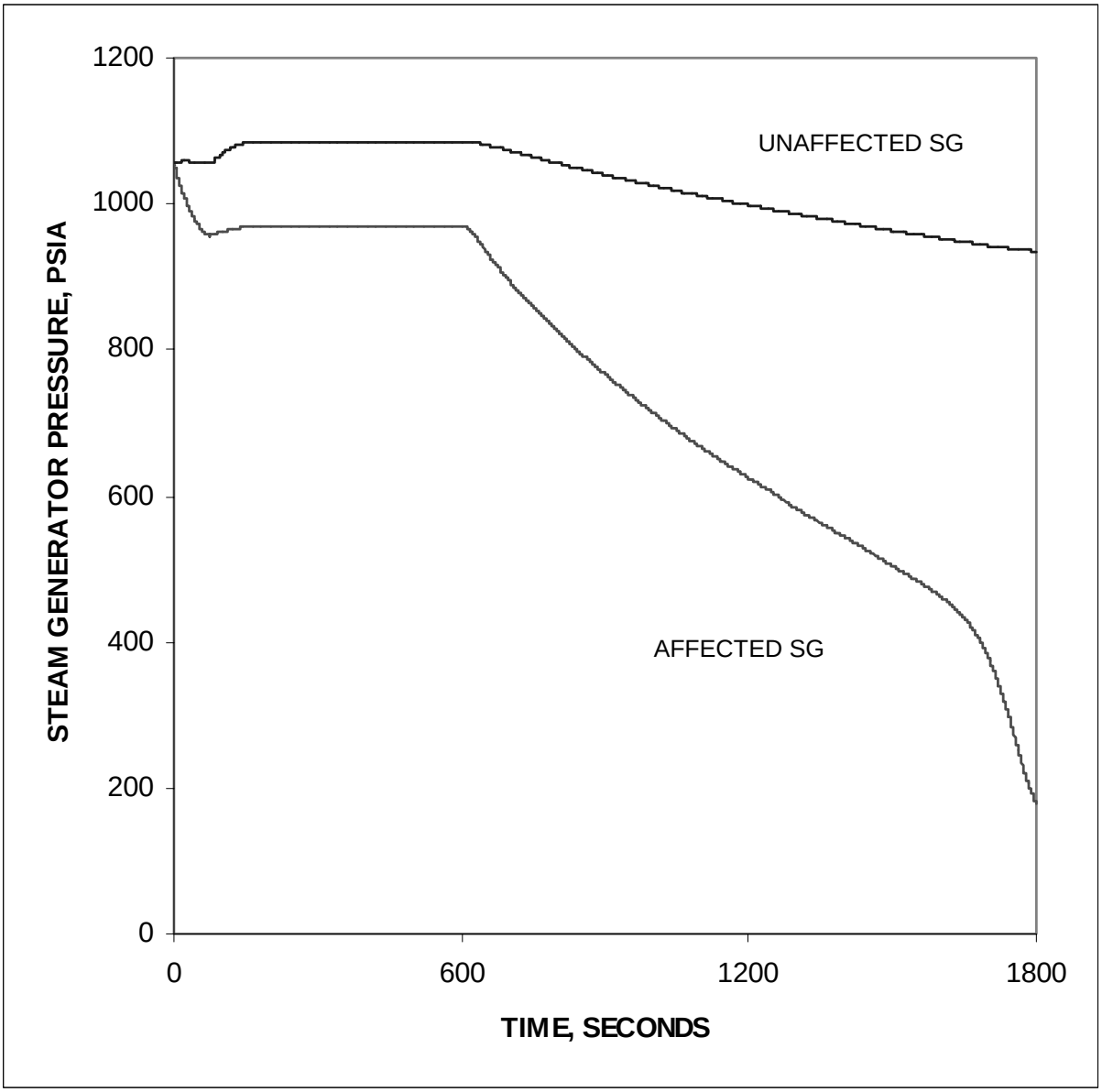

Figure 2.13.1.1.4-6
IOSGADV SG Pressure vs. Time

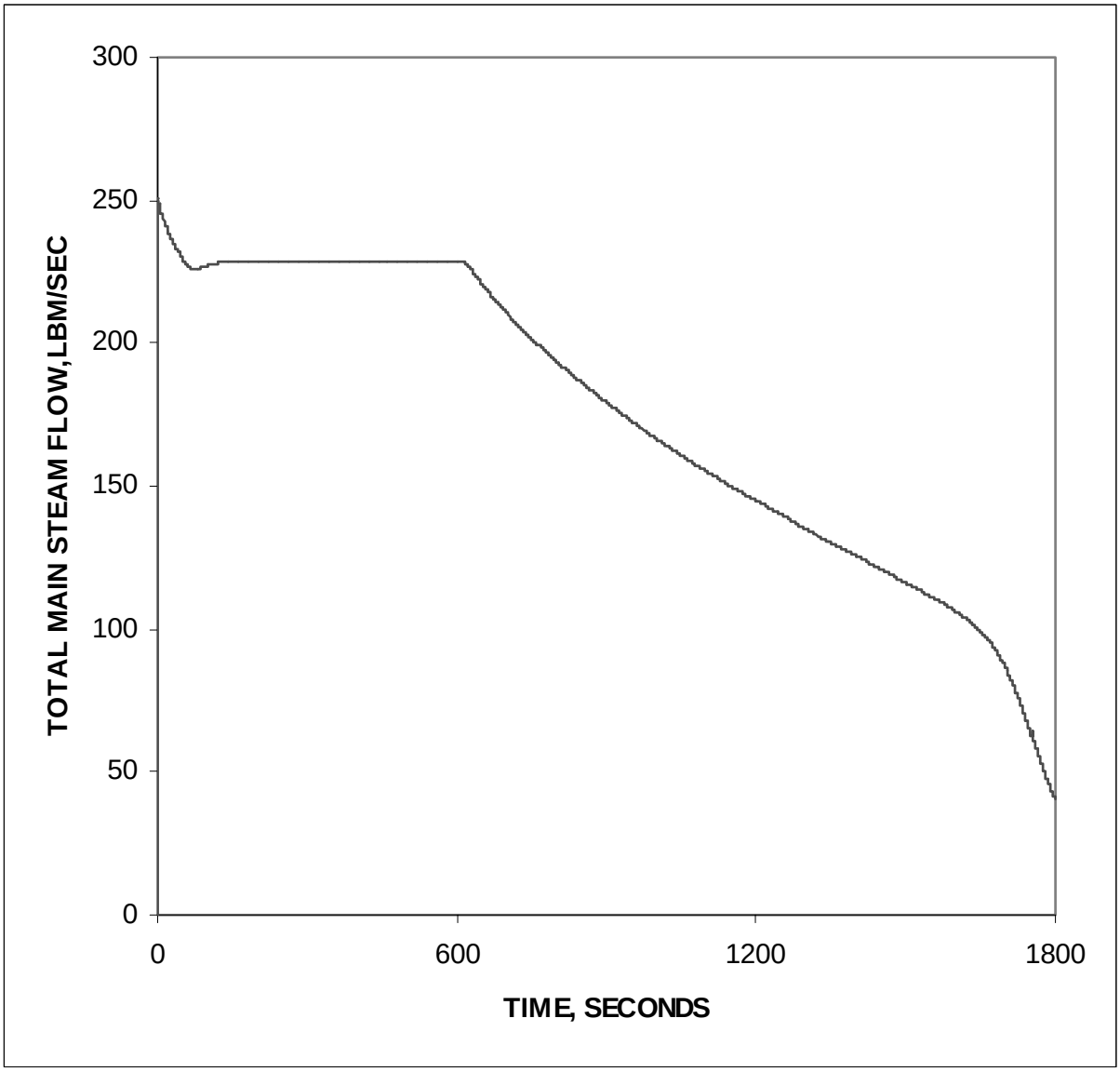

Figure 2.13.1.1.4-7
IOSGADV Total Main Steam Flow vs. Time

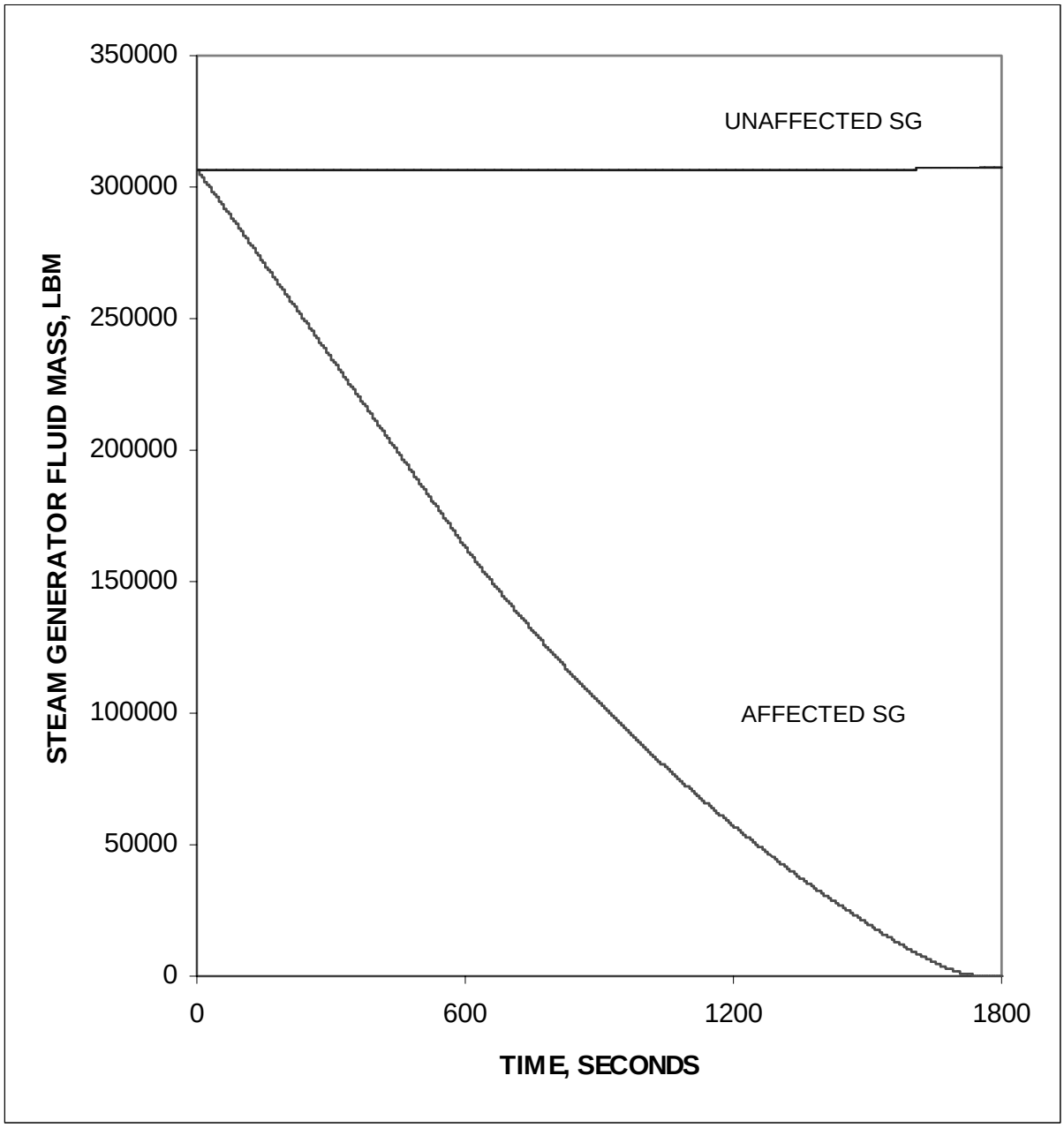

Figure 2.13.1.1.4-8
IOSGADV SG Fluid Mass vs. Time

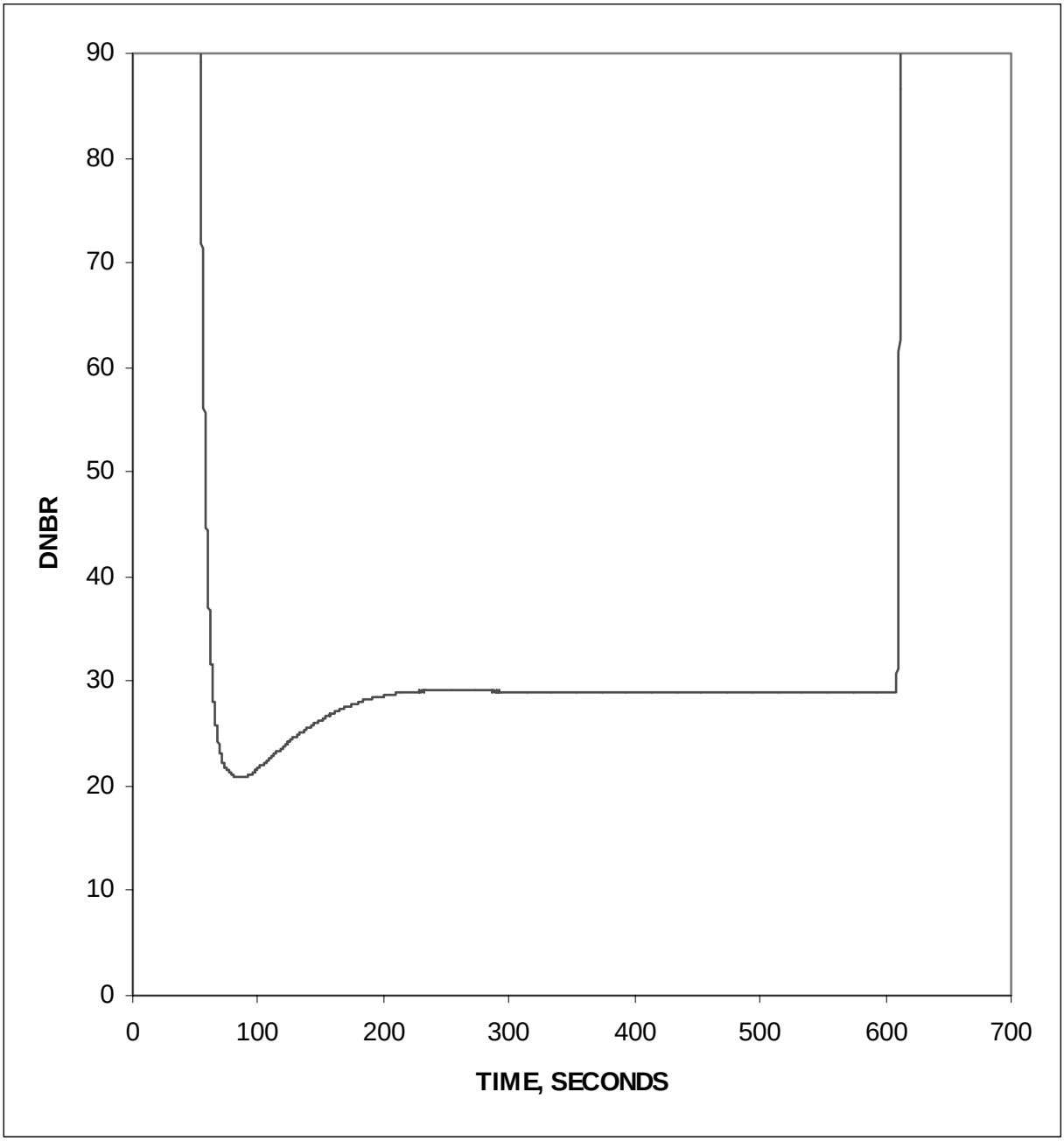

Figure 2.13.1.1.4-9
IOSGADV DNBR vs. Time

2.13.1.2 Infrequent Incidents

2.13.1.2.1 Decrease in Feedwater Temperature with a SAF

Event is bounded by increased main steam flow with LOOP, Section 2.13.1.2.3.

2.13.1.2.2 Increase in Feedwater Flow with a SAF

Event is bounded by increased main steam flow with LOOP, Section 2.13.1.2.3.

2.13.1.2.3 Increased Main Steam Flow with SAF

The increased main steam flow with LOOP is examined to evaluate the impact of:

- Increase in RTP to 3716 MWt
- The use of CENTS rather than the COAST code to generate the RCS flow coastdown curves which are inputs to the one-dimensional (1-D) HERMITE model for fuel performance evaluation.

This event is presented in FSAR Section 15.1.2.3.

2.13.1.2.3.1 General Description of Event

To simplify analysis of the increased main steam flow with single active failure event, it is assumed that a transient initially occurs that degrades all thermal margin preserved by COLSS and brings the hot channel to DNBR SAFDL conditions. This assumption is conservative since the AOOs are specifically analyzed to ensure that SAFDLs are not violated and the necessary thermal margin is preserved by plant LCOs. The most limiting single active failure with respect to DNBR degradation is a LOOP, which results in a coastdown of all 4 RCPs. Therefore, this event is functionally analyzed as a loss of flow (Reference 2.13-5) from DNBR SAFDL conditions (LOOP from SAFDL). This event has historically been analyzed for DNBR performance in this manner.

The most limiting AOOs with respect to peak LHR are the bank CEAW events presented in Sections 2.13.4.1.1 through 2.13.4.1.3. There are no single active failures (SAFs) or postulated operator errors, which in combination with these events would produce more severe consequences.

The details of the increased main steam flow with LOOP from SAFDL analysis are presented below.

2.13.1.2.3.2 Purpose of Analysis and Acceptance Criteria

As defined in the Standard Review Plan (Reference 2.13-14), the specific acceptance criteria for an infrequent event is:

- An incident of moderate frequency in combination with any single active component failure, or single operator error, should not result in loss of function of any barrier other than the fuel cladding. A limited number of fuel rod cladding perforation is acceptable.
- Offsite radiological consequences must be limited to a small fraction of 10CFR100 guidelines (i.e., 30 rem thyroid, 2.5 rem whole body).

2.13.1.2.3.3 Impact of Changes

The use of CENTS to generate the flow coastdown curve resulted in minor changes in the event. This is seen by the small difference in minimum DNBR between the power uprate analysis and the existing results. Excess conservatism in the CPC VOPT response time assumed in the analysis has been removed to reduce fuel failure. Because this event assumes the loss of offsite power occurs from SAFDL conditions, the impact of EPU is limited.

2.13.1.2.3.4 Analysis Overview

A set of initial conditions corresponding to the DNBR SAFDL was calculated with the CETOP-D (Reference 2.13-3) computer code. The core average and hot channel response to the loss of flow event from these initial conditions was simulated using the 1-D HERMITE computer program (Reference 2.13-4). The transient DNBR values were calculated using the CETOP-D computer program (Reference 2.13-3) which uses the CE-1 CHF correlation. Additionally, input parameters and initial conditions were selected to maximize the DNBR degradation.

The limiting AOO with single active failure is modeled as a loss of forced RCS flow from SAFDL conditions. An excess load event degrades all available COLSS margin and forces the hot channel DNBR to the SAFDL. At this point the limiting single failure, LOOP occurs and further degrades DNB.

This evaluation conservatively assumes a coincident turbine trip and LOOP. The RCP coastdown leads to a CPC low DNBR reactor trip. RCS flow coastdown degrades DNBR below the initial SAFDL conditions. DNBR degradation is terminated when the mitigating effects of scram CEA insertion dominate the flow coastdown, which is determined by the CENTS computer code.

Table 2.13.1.2.3-1 contains the initial conditions and assumptions used for the LOOP from SAFDL event.

2.13.1.2.3.5 Radiological Consequences

The radiological consequences for the LOOP from SAFDL were calculated assuming that the radioisotopes in the gas gap of the pins which experience DNB was immediately mixed with

the RCS for release. Releases for the site boundary doses were calculated accounting for the carry over of activity to the secondary system via SG tube leakage paths.

The allowed fuel failure limit for the LOOP from SAFDL was back-calculated to determine the extent of fuel failure that would result in the regulatory limit for the event. Cycle-specific fuel failure evaluations for power uprate cores will be performed to ensure that this fuel failure limit will not be exceeded. For the LOOP from SAFDL, the fuel failure limit was determined to be 8.0% of the fuel pins.

The radiological consequences resulting from these fuel failure results are:

	2-Hour EAB	**8-Hour LPZ**
Thyroid	< 30 rem	< 30 rem
Whole Body	< 2.5 rem	< 2.5 rem

2.13.1.2.3.6 Results

The limiting infrequent event (i.e., AOO with single failure) is simply modeled as a loss of forced flow from SAFDL conditions. This conservative modeling approach is intended to bound the DNBR degradation of all Infrequent AOOs. Core average and hot channel performance during the loss of flow (LOF) was modeled in HERMITE. The dynamic behavior of typical NSSS parameters are modeled as an increased main steam flow (excess load) with concurrent LOOP, when a reactor trip condition exists, is shown in Figures 2.13.1.2.3-1 through 2.13.1.2.3-12. CENTS (Reference 2.13-2) is used to simulate the transients.

A sequence of events for the increased main steam flow in combination with a LOOP for the worst DNB performance case is shown in Table 2.13.1.2.3-2. Additionally, a typical sequence of events of the increased main steam flow in combination with a LOOP is shown in Table 2.13.1.2.3-3.

Table 2.13.1.2.3-1
Increased Main Steam Flow with LOOP Assumption Table

Parameter	Power Uprate Assumption	Current Power Level Assumption
Initial Core Power, MWt	3735	3478
Core Inlet Temperature, ^{o}F	533	535
Pressurizer Pressure, psia	2310	2350
RCS Flowrate, 10^6 lbm/hr	177.6	182.3
Pressurizer Level, %	44	---
SG Pressure, psia	740	---
MTC, $x10^{-4}$ $\Delta\rho/^{o}$F	-1.05	-1.05
Doppler Coefficient Multiplier	0.85	0.85
Kinetics	Maximum β	Maximum β
CEA Worth for Trip, $\%\Delta\rho$	5.0	5.0

Table 2.13.1.2.3-2
Sequence of Events of the Increased Main Steam Flow with LOOP
(Worst DNB Performance Case)

EPU Time (sec)	Current Power Level Time (sec)	Event	EPU Setpoint/Value	Current Power Level Setpoint/Value
0.0	0.0	Malfunction of control system causes increased steam flow through the turbine or the steam bypass valves	---	---
ΔT	ΔT	Thermal margin initially preserved by COLSS depleted, the hottest fuel rod is just above the DNBR SAFDL of 1.26 as calculated by the CPCs. LOOP is assumed and the coastdown of the RCPs begins	---	---
ΔT+0.34	ΔT+0.35	Low DNBR trip generated by the CPCs, trip breakers open	1.26	1.26
ΔT+0.94	ΔT+0.95	CEAs begin to drop	---	---
ΔT+2.05	ΔT+2.10	Minimum DNBR occurs	1.057	1.076
ΔT+3.34	ΔT+3.429	Average CEA position 90% inserted	---	---
---	ΔT+6.0	SG safety valves open	1102	1070 psia
ΔT+117.7	ΔT+11.0	Maximum SG pressure	1102	1124 psia
1,800	1,800	Operator takes control of plant	---	---
28,800	28,800	Shutdown cooling initiated	---	---

Table 2.13.1.2.3-3
Sequence of Events for the Increased Main Steam Flow in Combination with a LOOP
(Typical NSSS Response)

EPU Time (sec)	Current Power Level Time (sec)	Event	Current Power Level Setpoint/Value	EPU Setpoint/Value
0.0	0.0	Malfunction of control system causes increased steam flow through the turbine or the steam bypass valves	---	---
1.0	1.0	Turbine or steam bypass valve fully opens	---	---
11.7	39.0	Low DNBR trip signal generated	---	---
11.9	39.2	Turbine admission valves start to close	---	---
11.8	39.7	Maximum core power, percent of rated core power	110	109
11.7	39.8	Loss of all offsite electrical power	---	---
11.8	39.8	Maximum average core heat flux, percent of full power heat flux	109	105
12.6	40.1	Shutdown CEAs begin to drop into core	109	---
13.8	41.45	Minimum DNBR	1.096	1.061
---	45.0	SG safety valves open, psia	1070	1102.1
129.4	50.0	Maximum SG pressure, psia	1124	1102
1,800	1,800	Operator takes control of plant	---	---
28,800	28,000	Shutdown cooling initiated	---	---

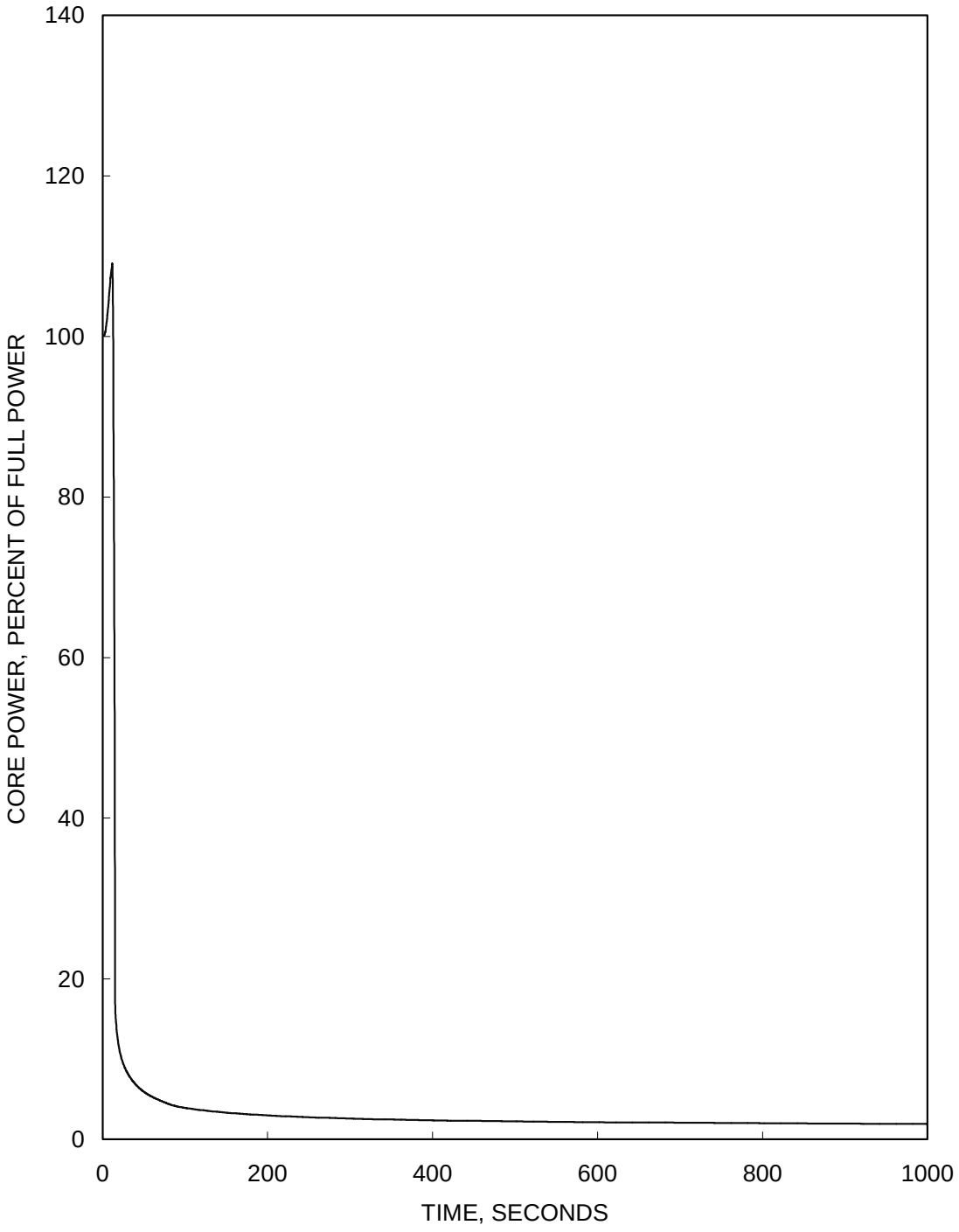

Figure 2.13.1.2.3-1
Increased Main Steam Flow with Concurrent Single Failure
Core Power vs. Time

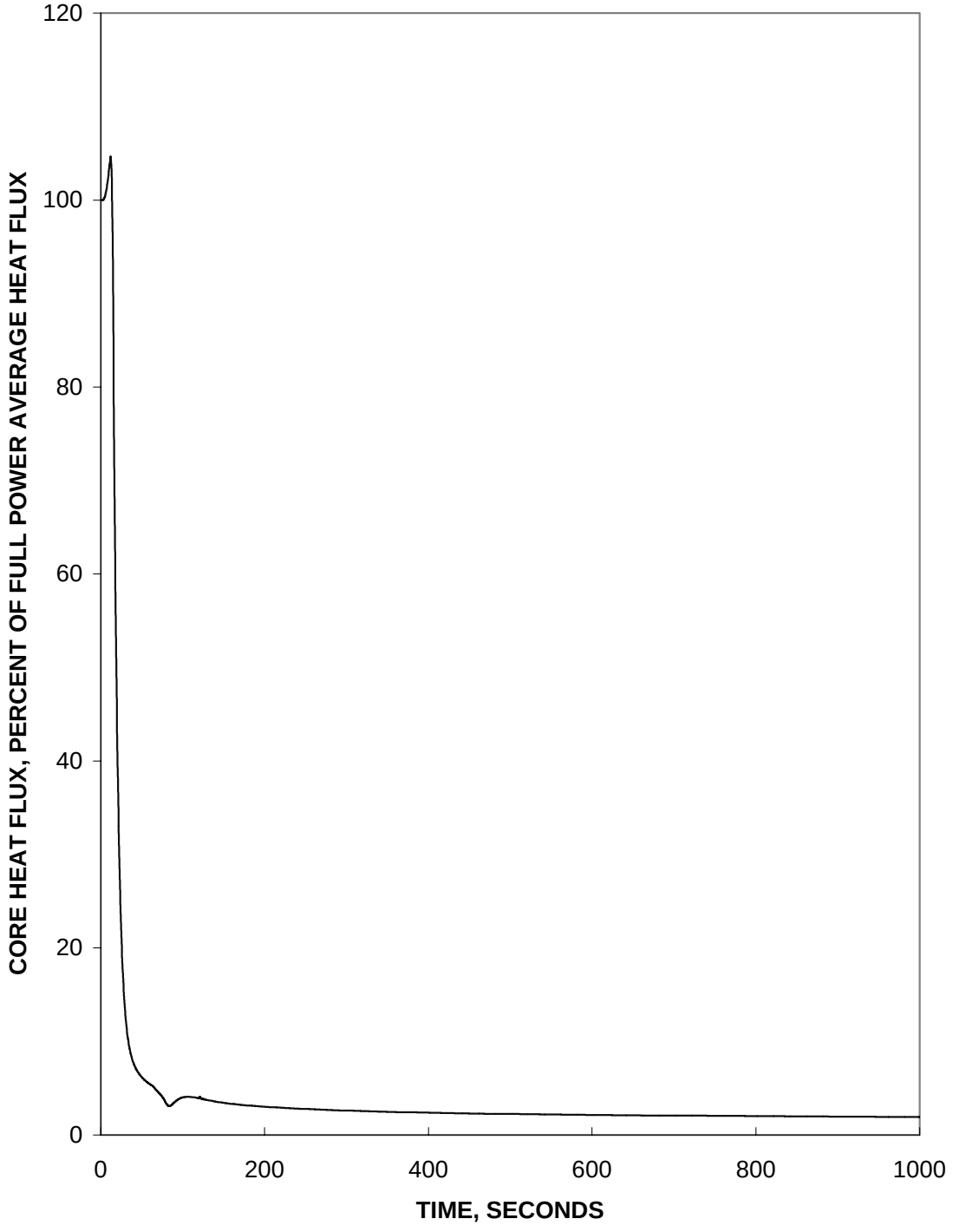

Figure 2.13.1.2.3-2
Increased Steam Flow with Concurrent Single Failure
Core Heat Flux vs. Time

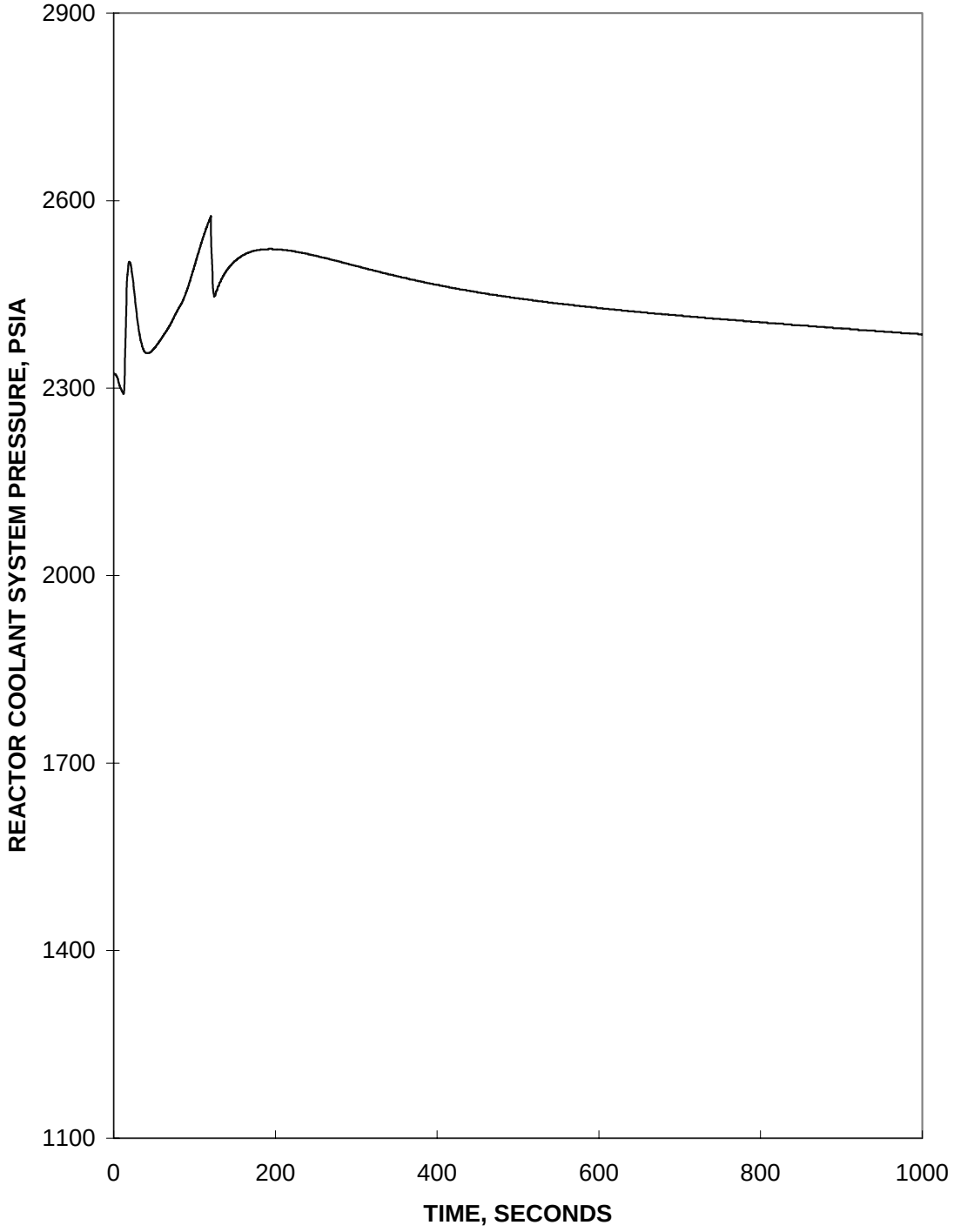

Figure 2.13.1.2.3-3
Increased Main Steam Flow with Concurrent Single Failure
RCS Pressure vs. Time

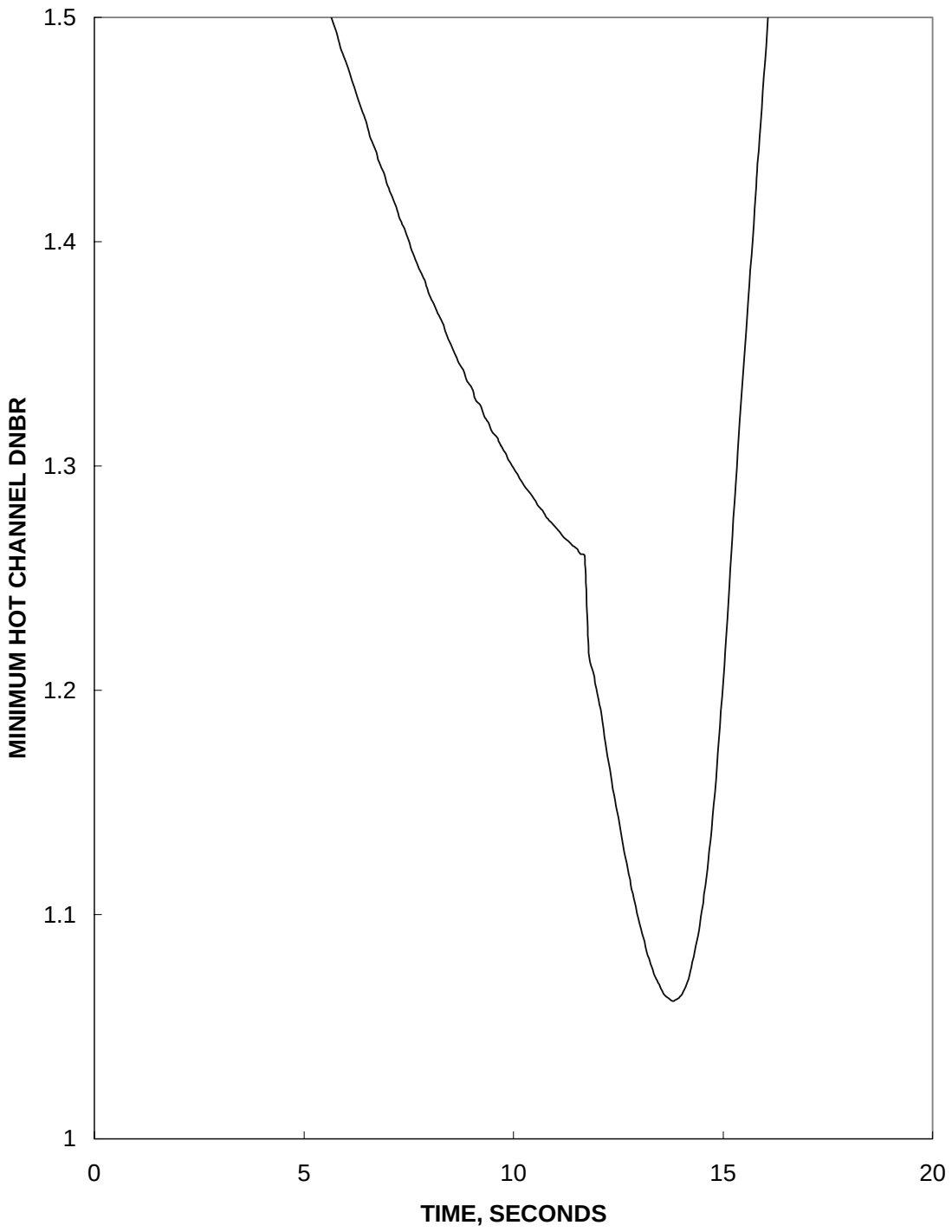

Figure 2.13.1.2.3-4
Increased Main Steam Flow with Concurrent Single Failure
Minimum Hot Channel DNBR vs. Time

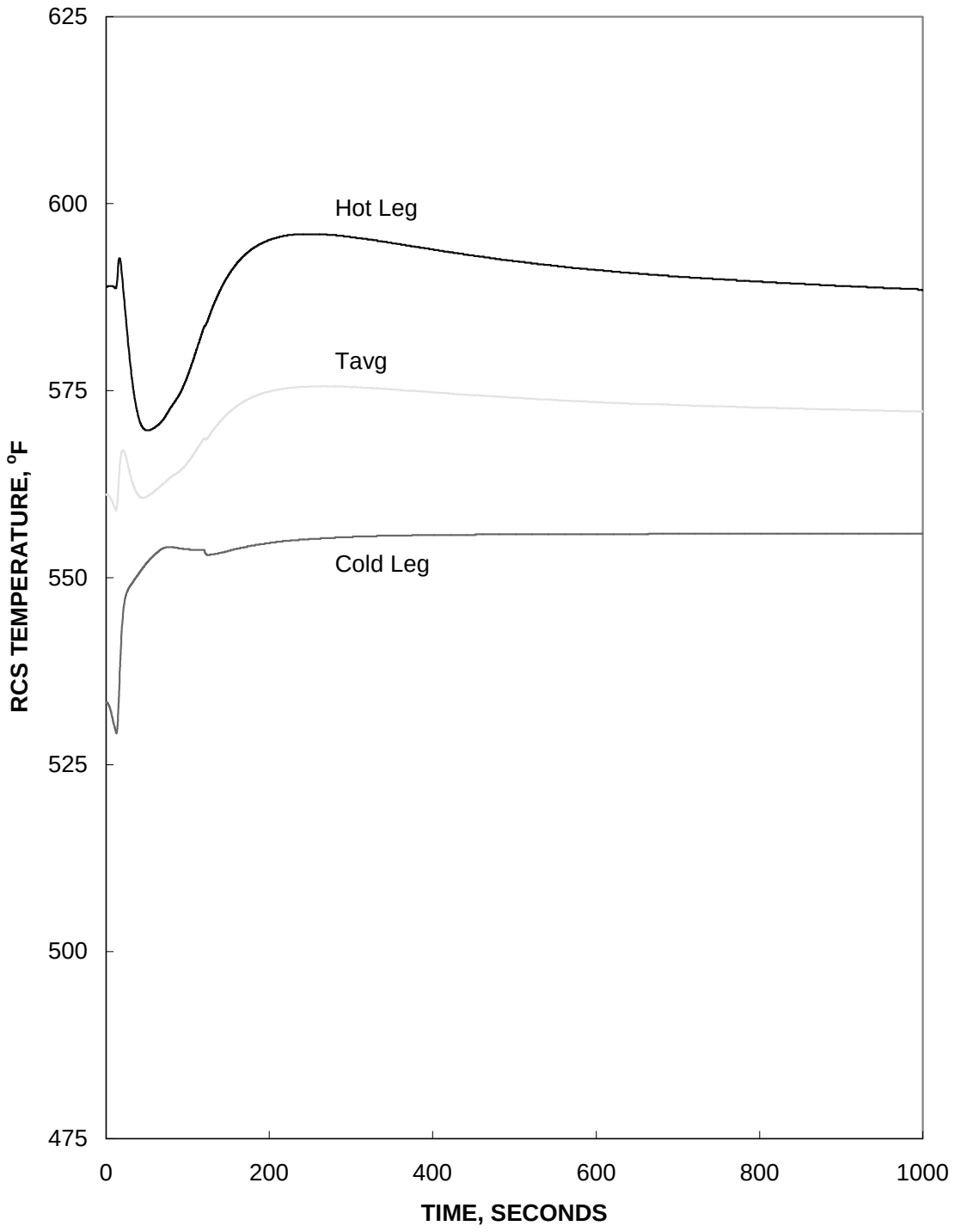

Figure 2.13.1.2.3-5
Increased Main Steam Flow with Concurrent Single Failure
Reactor Coolant Temperatures vs. Time

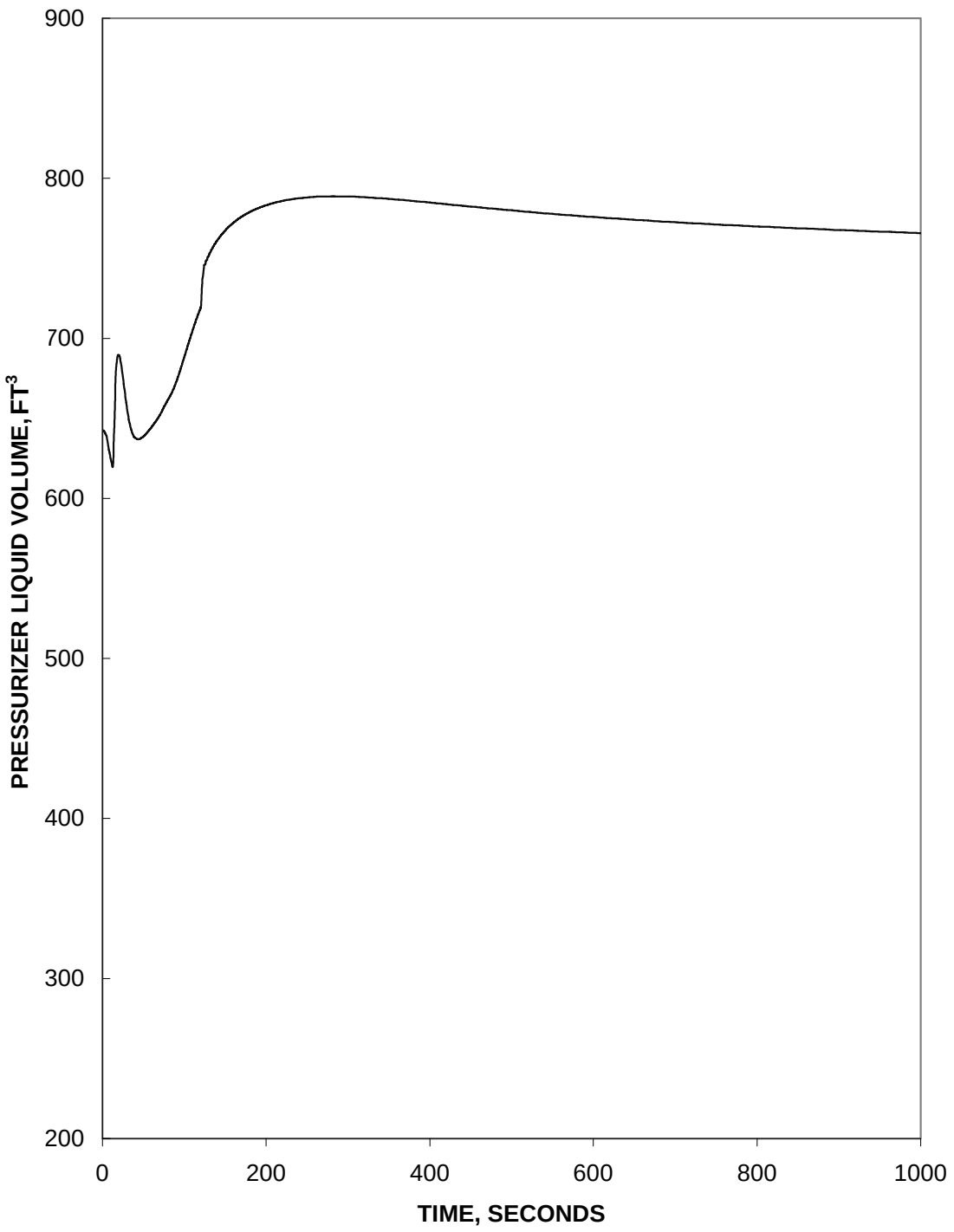

Figure 2.13.1.2.3-6
Increased Main Steam Flow with Concurrent Single Failure
Pressurizer Liquid Volume vs. Time

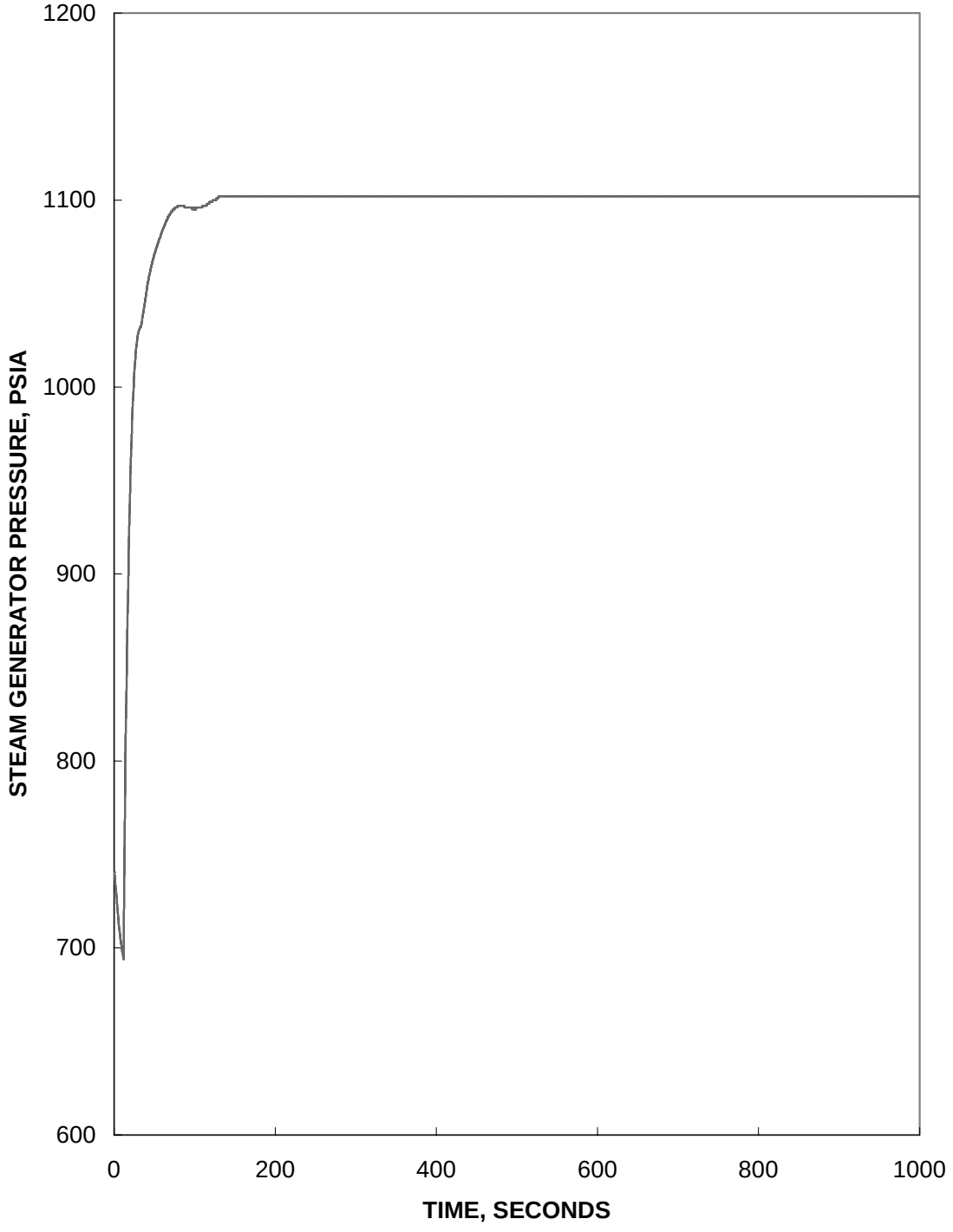

Figure 2.13.1.2.3-7
Increased Main Steam Flow with Concurrent Single Failure
SG Pressure vs. Time

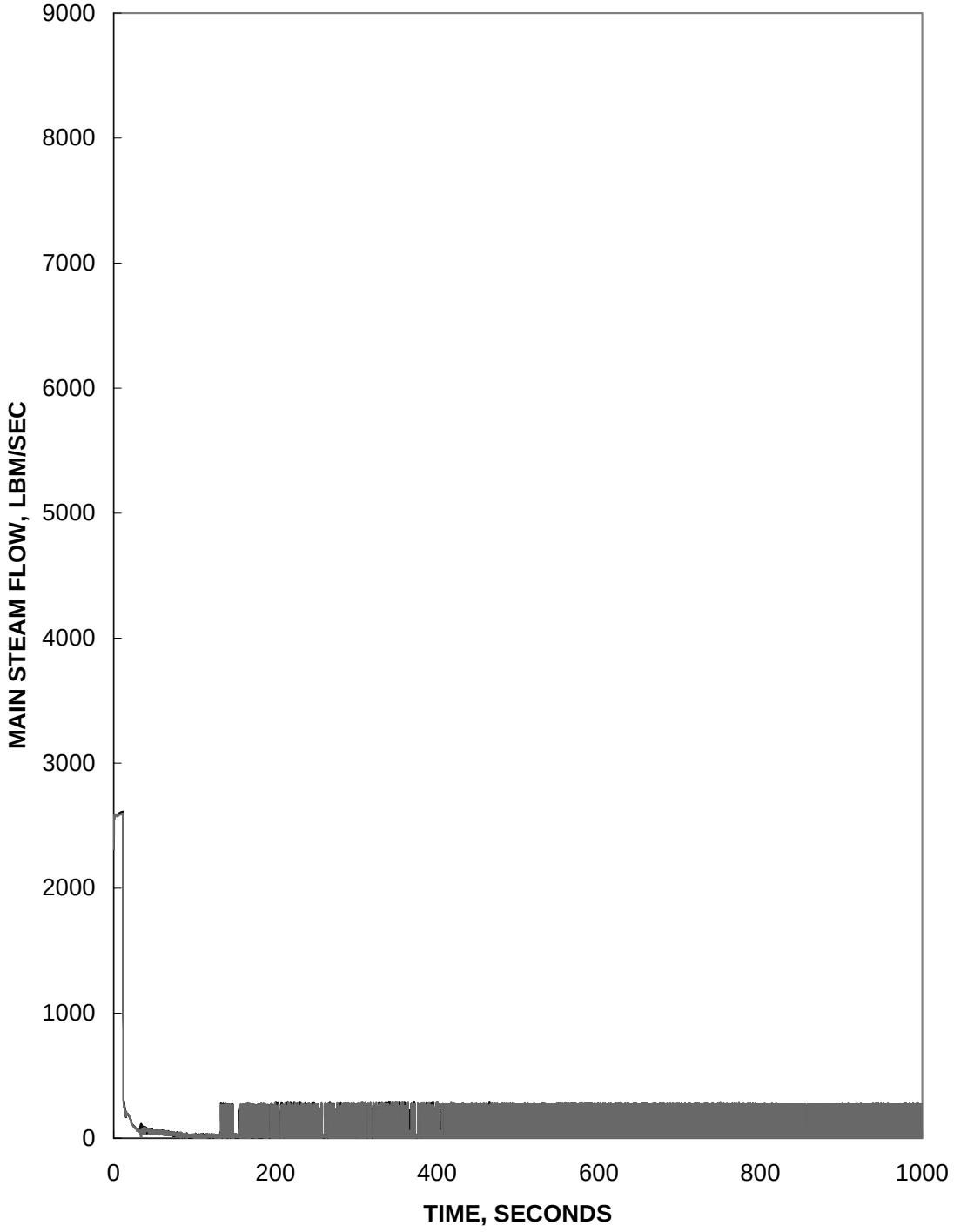

Figure 2.13.1.2.3-8
Increased Main Steam Flow with Concurrent Single Failure
Main Steam Flow vs. Time

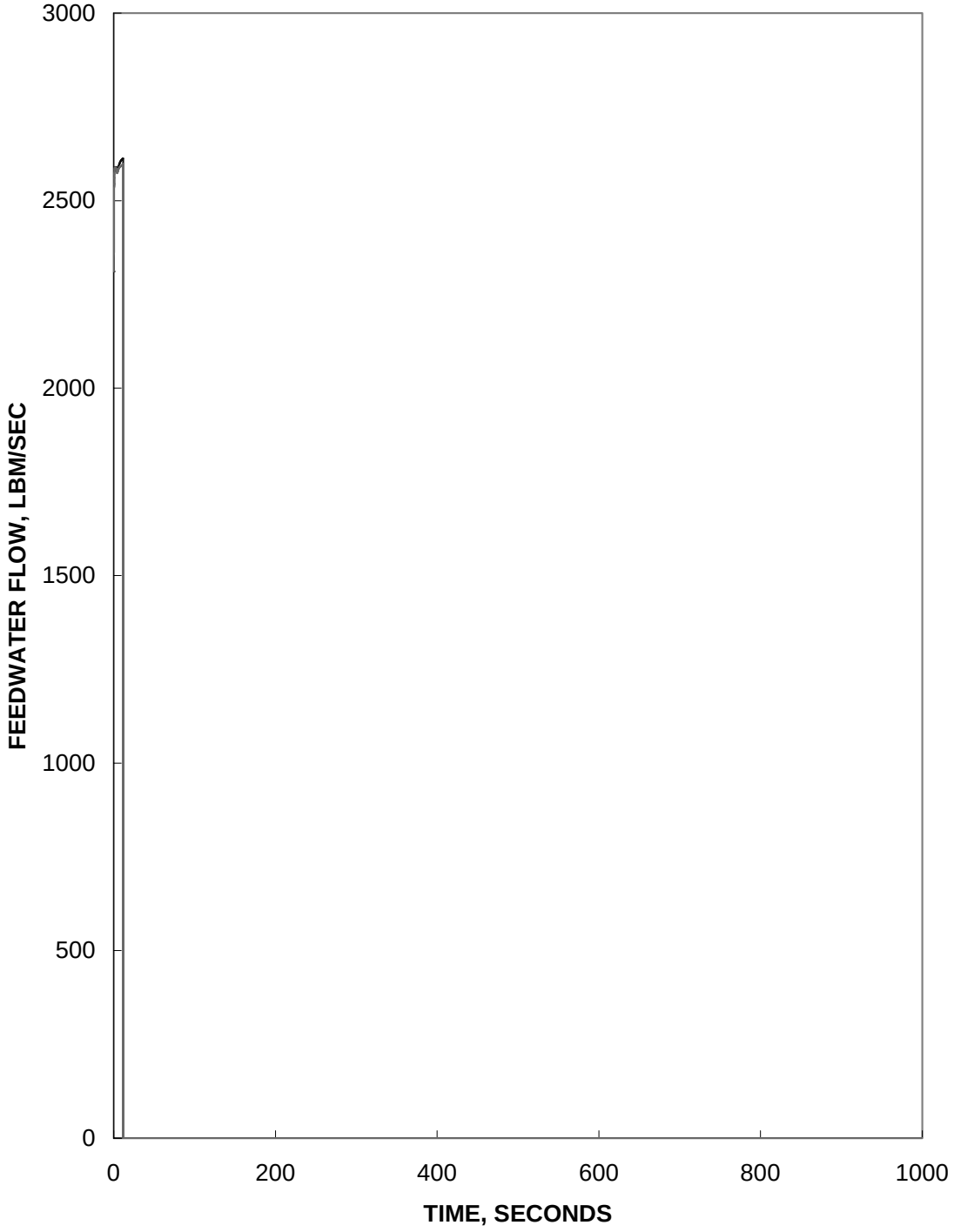

Figure 2.13.1.2.3-9
Increased Main Steam Flow with Concurrent Single Failure
Feedwater Flow vs. Time

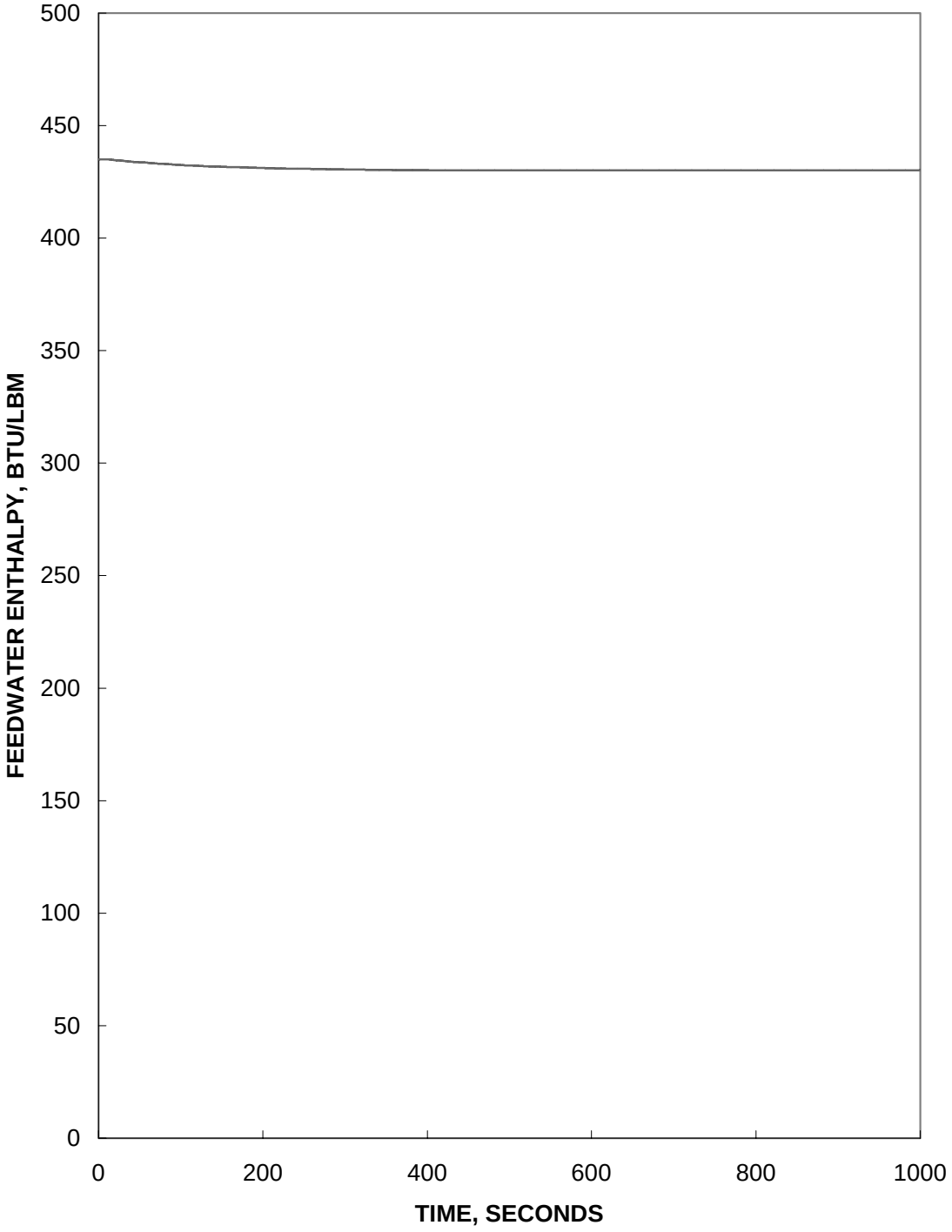

Figure 2.13.1.2.3-10
Increased Main Steam Flow with Concurrent Single Failure
Feedwater Enthalpy vs. Time

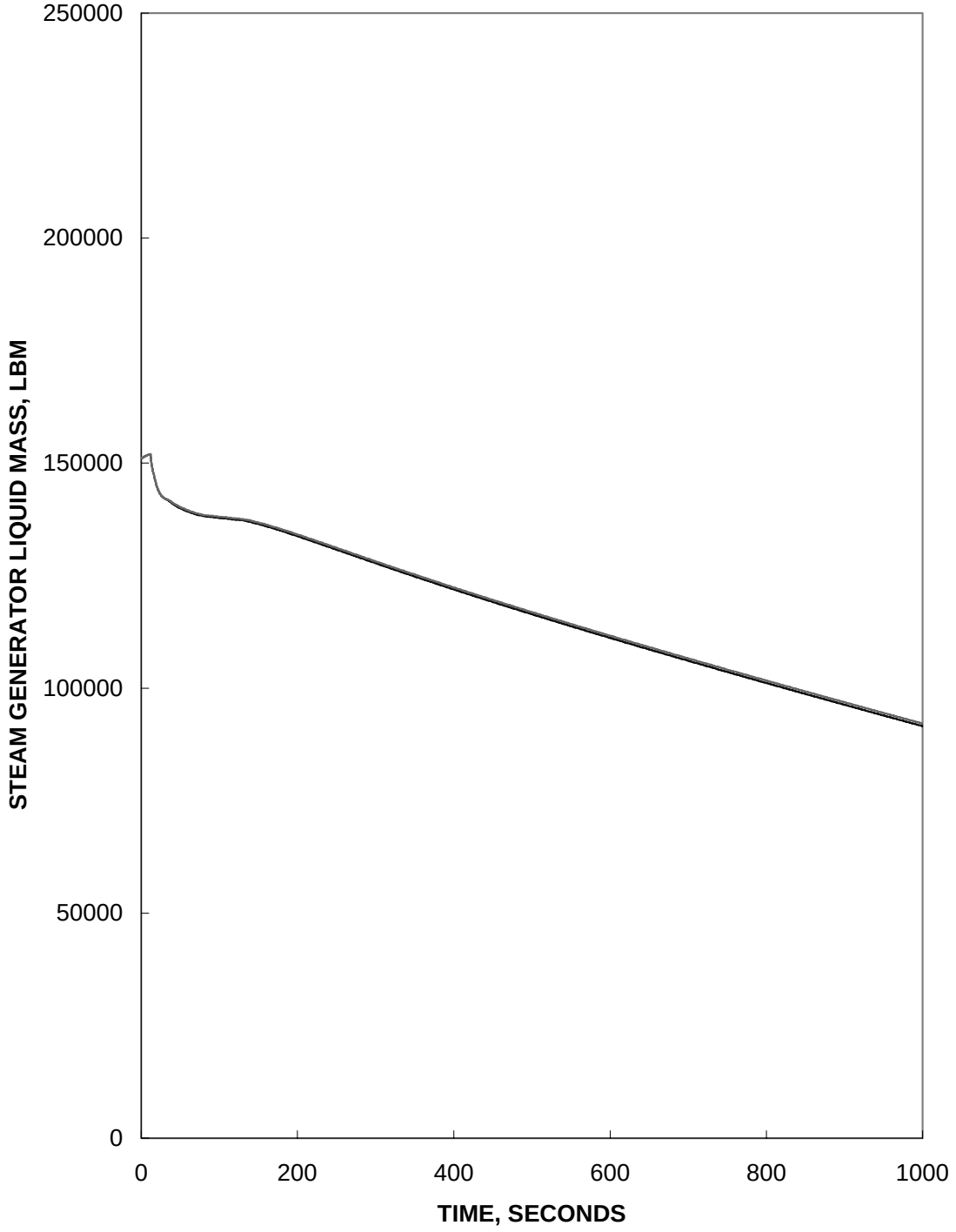

Figure 2.13.1.2.3-11
Increased Main Steam Flow with Concurrent Single Failure
SG Liquid Mass vs. Time

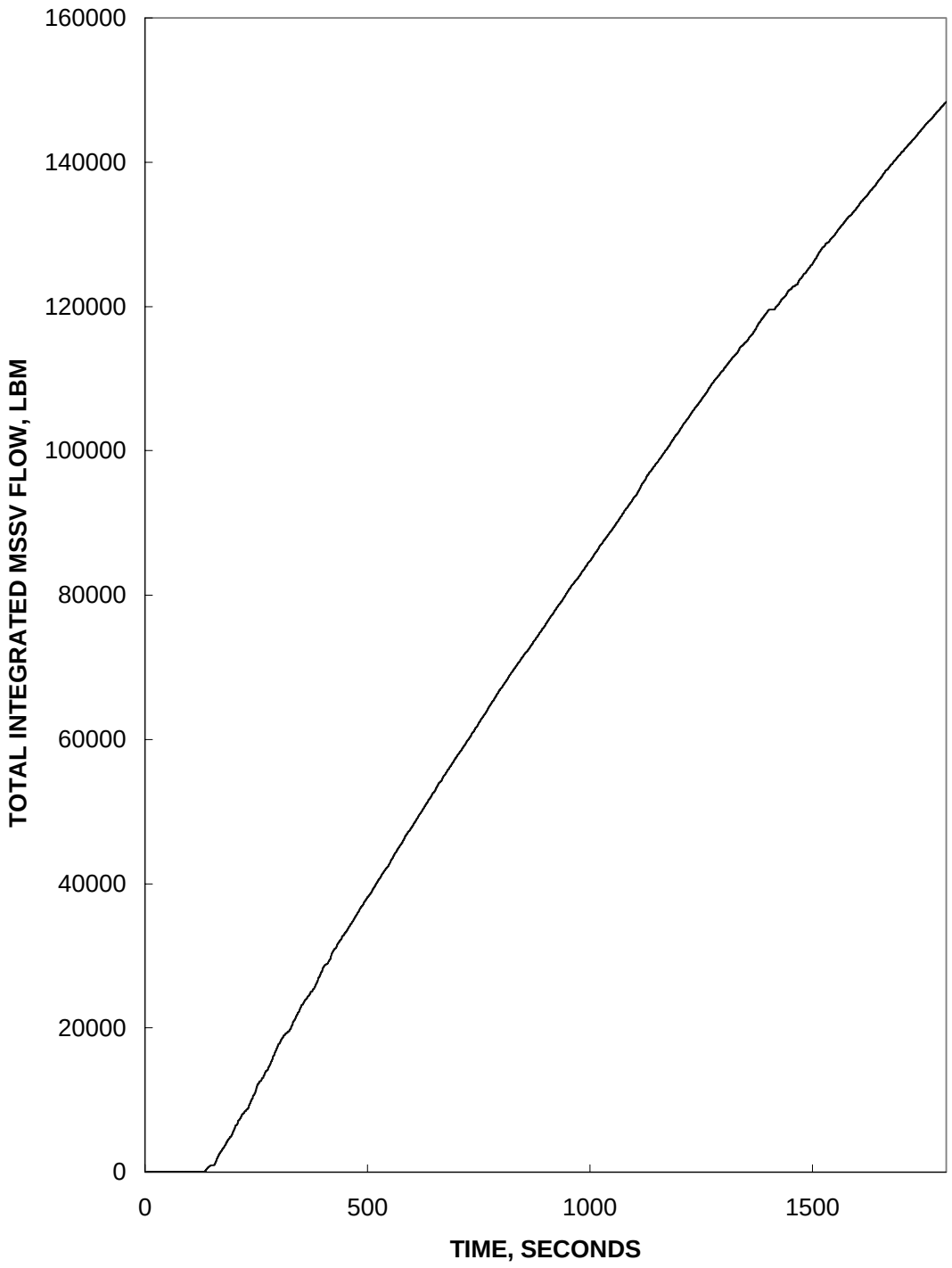

Figure 2.13.1.2.3-12
Increased Main Steam Flow with Concurrent Single Failure
Total Integrated Safety Valve Flow vs. Time

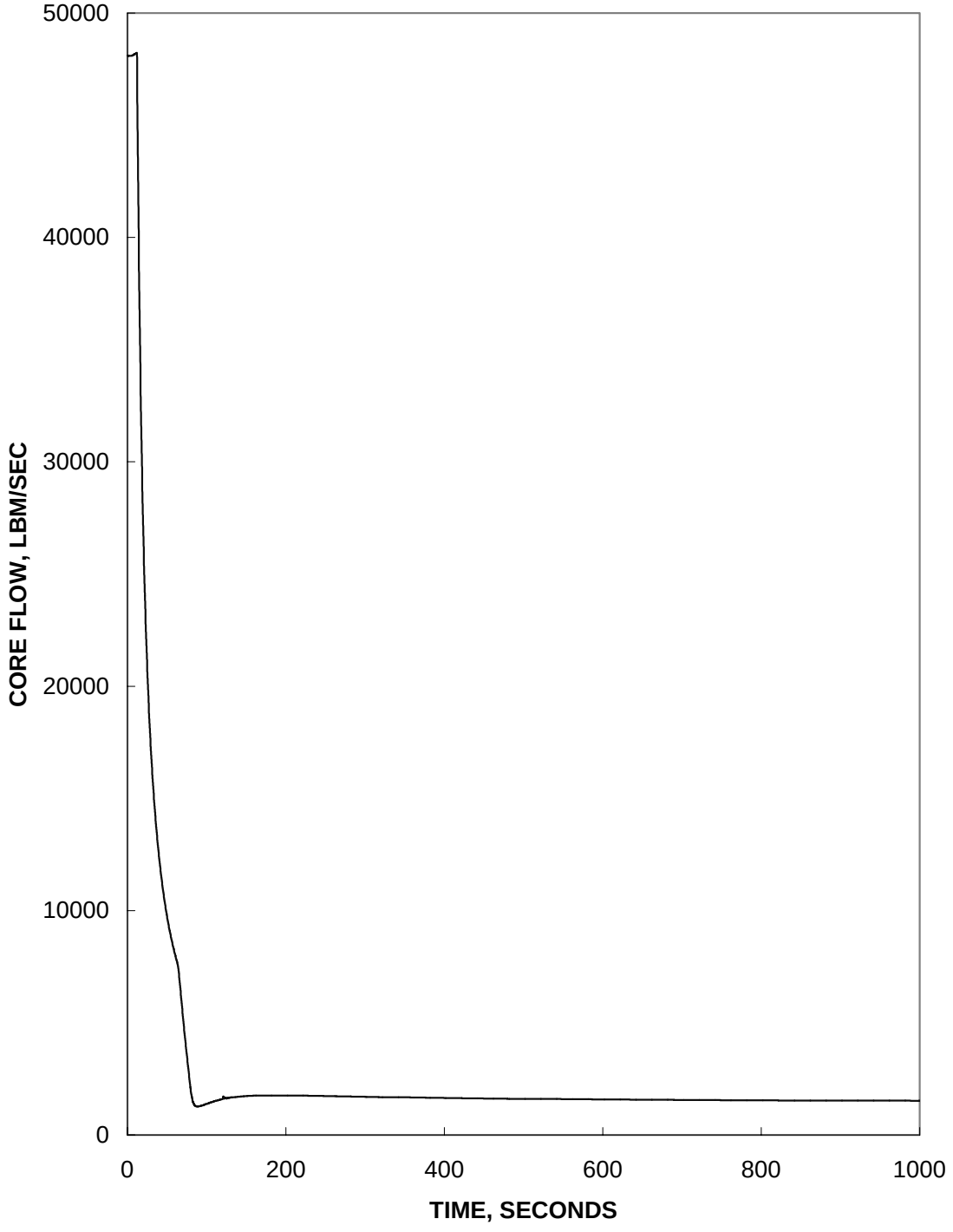

Figure 2.13.1.2.3-13
Increased Main Steam Flow with Concurrent Single Failure
Core Flow vs. Time

2.13.1.2.4 IOADV with LOOP

The inadvertent opening of a SG ADV (IOADV) with LOOP is examined to evaluate the impact of:

- Increase in RTP to 3716 MWt
- The use of CENTS rather than the COAST code to generate the RCS flow coastdown curves that are inputs to the 1-D HERMITE model for fuel performance evaluation.

This event is a special case of the increased main steam flow with LOOP and is presented in FSAR Section 15.1.2.4. This particular excess load is examined separately due to the more adverse release path associated with the stuck open ADV. Due to the more adverse release path, no SAFDL violation is allowed for this event.

2.13.1.2.4.1 General Description of Event

The initiating event for this section is the opening of a single ADV without a turbine trip at HFP. The opening of a single ADV results in a secondary side cooldown that increases core power to almost 107% of HFP. After reaching a quasi-steady state at a reduced thermal margin, a limiting single failure occurs. Note that the initiating event is different from that discussed in Section 2.13.1.2.3. There the initiating AOO was assumed to deplete the entire initial thermal margin, such that the single failure is initiated at the DNBR SAFDL. In this event the LOOP is initiated from the conditions resulting from the IOADV. The pump coastdown initiates a CPCS trip on low Reactor Coolant Pump speed (Reference 2.13-8, Section 4.1.1). The DNBR SAFDL is approached but not violated during the thermal margin degradation resulting from the IOADV with LOOP.

The details of the HFP IOADV with a concurrent LOOP analysis are presented below.

2.13.1.2.4.2 Purpose of Analysis and Acceptance Criteria

FSAR (Reference 2.13-1) Section 15.1.2.4.1 identifies the IOADV+LOOP event as an infrequent incident. Typical acceptance criteria for an infrequent event are as follows:

- An incident of moderate frequency in combination with any single active component failure, or single operator error, should not result in loss of function of any barrier other than the fuel cladding. A limited number of fuel rod cladding perforation is acceptable.
- Offsite radiological consequences must be limited to a small fraction of 10CFR100 guidelines (i.e., 30 rem thyroid, 2.5 rem whole body).

The Waterford 3 HFP IOADV with LOOP analysis is analyzed to a more restrictive ‘No DNBR SAFDL violation’ criterion.

2.13.1.2.4.3 Impact of Changes

The use of CENTS to generate the flow coastdown curve resulted in minor changes in the event. This is seen by the small difference in minimum DNBR between the power uprate analysis and the existing results.

The more negative MTC for EPU conditions is assumed for the analysis of NSSS response, including radiological releases. This, in conjunction with increased decay heat due to EPU, increases releases slightly.

2.13.1.2.4.4 Analysis Overview

The HFP IOADV event is modeled simply as a decrease in initial thermal margin. Accordingly, only the LOOP portion of the event is explicitly simulated. The core average and hot channel response to the loss of flow event resulting from the LOOP was simulated using the 1-D HERMITE computer program (Reference 2.13-4). The transient DNBR values were calculated using the CETOP-D computer program (Reference 2.13-3) that uses the CE-1 CHF correlation. Additionally, input parameters and initial conditions for the LOOP were selected to maximize the DNBR degradation.

The HFP IOADV with single active failure (SAF) is modeled as a loss of forced RCS flow from reduced thermal margin conditions. The roughly 7% core power increase resulting from an IOADV from HFP conditions degrades the operating margin. At this point the limiting single failure, a LOOP, occurs and further degrades DNBR.

Although a LOOP would not occur for at least 3 seconds following a turbine trip, this evaluation conservatively assumes a coincident turbine trip and LOOP. The RCP coastdown, which is determined using the CENTS computer code (Reference 2.13-2), leads to a CPCS low RCP speed reactor trip. The RCS flow coastdown degrades DNBR to slightly above the DNBR SAFDL. DNBR degradation is terminated when the mitigating effects of scram CEA insertion overwhelm the effects of the flow coastdown.

Table 2.13.1.2.4-1 contains the initial conditions and assumptions used for the LOOP from reduced thermal margin conditions.

2.13.1.2.4.5 Radiological Consequences

The HFP IOADV with LOOP does not result in SAFDL violation. Due to the open ADV, one SG is open to the atmosphere for 30 minutes until operator action. During this time, the initial iodine activity in the SG, and the iodine activity carried due to SG tube leakage in the affected unit is released with a decontamination factor (DF) of unity. No partition factor is applied to the noble gases.

The remainder of the releases is the result of steaming the intact SG to remove decay heat and cool down the plant. The activity in the intact SG is initially assumed to be at the LCO limit for the secondary system, and is gradually increased with the activity carried by the primary-to-secondary leakage with coolant at the LCOs for primary system activity. Iodine releases from

the intact generator use a DF of 100 based on the activity in the bulk secondary water during a given interval. No partition factor is applied to the noble gases.

The radiological consequences for the IOSGADV with LOOP, including the effect of a pre-existing iodine spike are:

	2-Hour EAB	8-Hour LPZ
Thyroid	≤ 30 rem	≤ 30 rem
Whole Body	≤ 2.5 rem	≤ 2.5 rem

2.13.1.2.4.6 Results

The HFP IOADV with LOOP does not result in SAFDL violation. Due to the open ADV, one SG is open to the atmosphere for 30 minutes until operator action. During this time, the initial iodine activity in the SG, and the iodine activity carried due to SG tube leakage in the affected unit is released with a DF of unity. No partition factor is applied to the noble gases.

The remainder of the releases is the result of steaming the intact SG to remove decay heat and cool down the plant. The activity in the intact SG is initially assumed to be at the limiting conditions of operation (LCO) limit for the secondary system, and is gradually increased with the activity carried by the primary-to-secondary leakage with coolant at the LCOs for primary system activity. Iodine releases from the intact generator use a DF of 100 based on the activity in the bulk secondary water during a given interval. No partition factor is applied to the noble gases.

Radiological consequences so released are bounded by those of the feedwater line break in which no isolation of the affected SG occurs.

A sequence of events for the worst DNB performance case is shown in Table 2.13.1.2.4-2. In addition, a typical sequence of events is shown in Table 2.13.1.2.4-3. The dynamic behavior of typical NSSS parameters is shown on Figures 2.13.1.2.4-1 through 2.13.1.2.4-13.

Table 2.13.1.2.4-1
Assumption Table for
the HFP IOADV with LOOP Event

Parameter	Power Uprate Assumption	Current Power Level Assumption
Initial Core Power, MWt	3735	3478
Core Inlet Temperature, ^{o}F	533	535
Pressurizer Pressure, psia	2310	2350
RCS Flowrate, 10^6 lbm/hr	170.2	182.3
Pressurizer Level, %	44	---
SG Level, ft/%narrow range***	36.4/67.2% (Nominal)	Nominal
SG Pressure, psia***	740.6	Not available
MTC, $x10^{-4}$ $\Delta\rho/^{o}$F	-1.05*	-1.05
Doppler Coefficient Multiplier	0.85	0.85
Kinetics	Maximum β	Maximum β
CEA Worth at Trip, %$\Delta\rho$	-5.0	-5.0
PPCS**	Auto	Not available
PPLS**	Auto	Not available

* This MTC is used in the HERMITE core simulation. For the NSSS response simulation (performed using CENTS), MTC = $-4.2x10^{-4}$ $\Delta\rho/^{o}$F is used. A more negative MTC is used to exacerbate the NSSS response. (Use of MTC = $-1.05x10^{-4}$ $\Delta\rho/^{o}$F would have increased the time to reach quasi-steady state after the IOADV.)

** The PPCS and PLCS are set to auto to maintain a steady-state prior to initiation of the event. These systems are shut off when the LOAC initiates.

*** This input is not used in the HERMITE core simulation. The specified value is taken from the CENTS NSSS response simulation.

Table 2.13.1.2.4-2
Sequence of Events for the HFP IOADV with LOOP Event
(Worst DNB Performance Case)

EPU Time (sec)	Current Power Level Time (sec)	Event	EPU Setpoint/Value	Current Power Level Setpoint/Value
0.0	0.0	Operator error or malfunction of control system causes increased steam flow through 1 ADV.	---	---
1.0	1.0	ADV fully opens	---	---
ΔT	ΔT	Thermal margin initially preserved by COLSS is partially depleted, a quasi-steady state is reached.	---	---
ΔT	ΔT	A LOOP occurs; coastdown of the RCPs begins.	---	---
ΔT+0.5	ΔT+0.622	CPCS low RCP shaft speed trip condition is reached.	0.965	0.965
ΔT+0.8	ΔT+0.922	CPCS trip due to low RCP shaft speed is generated; trip breakers open	---	---
ΔT+1.40	ΔT+1.522	CEAs begin to drop	---	---
ΔT+2.50	ΔT+2.60	Minimum DNBR occurs	1.2645	1.268
ΔT+3.80	ΔT+3.922	Average CEA position 90% inserted	---	---
ΔT+138.1	ΔT+6.00	SG safety valves open, psia	1117	1100
ΔT+138.1	ΔT+11.00	Maximum SG pressure, psia	1117	1139
1,800	1,800	Operator takes control of plant	---	---
28,800	---	Shutdown cooling initiated	---	---

Table 2.13.1.2.4-3
Sequence of Events for the HFP IOADV with LOOP Event
(Typical NSSS Response)

EPU Time (sec)	Current Power Level Time (sec)	Event	EPU Setpoint/Value	Current Power Level Setpoint/Value
0.0	0.0	Operator error or malfunction of control system causes increased steam flow through 1 ADV	---	---
1.0	1.0	ADV fully opens	---	---
21.2	---	Minimum pressurizer pressure, psia	2308	Not available
91.6	82.5	Maximum core power, % of rated power	106.0	108.2
95.0	---	Minimum SG pressure, psia	705.9	Not available
130.3	85.0	Maximum average core heat flux, percent of full power heat flux	106.0	108.2
150.0	105.0	Thermal margin initially preserved by COLSS is partially depleted, a quasi-steady state is reached.	---	---
150.0	105.0	A LOOP occurs; coastdown of the RCPs begins.	---	---
150.5	105.7	CPCS low RCP shaft speed trip condition is reached.	0.965	0.965
150.8	106.0	CPCS trip due to low RCP shaft speed is generated; trip breakers open	---	---
150.8	106.0	Turbine admission valves start to close	---	---
151.4	106.6	Shutdown CEAs begin to drop into core	---	---
152.5	107.6	Minimum DNBR	1.264	1.268
247.40	---	Maximum pressurizer pressure, psia	2575	Not available
247.40	---	Maximum RCS pressure, psia	2583	Not available
279.0	111.0	SG safety valves open, psia	1117	1100
279.0	116.0	Maximum SG pressure, psia	1117	1139
1,800	1,800	Operator takes control of plant	---	---
28,800	---	Shutdown cooling initiated	---	---

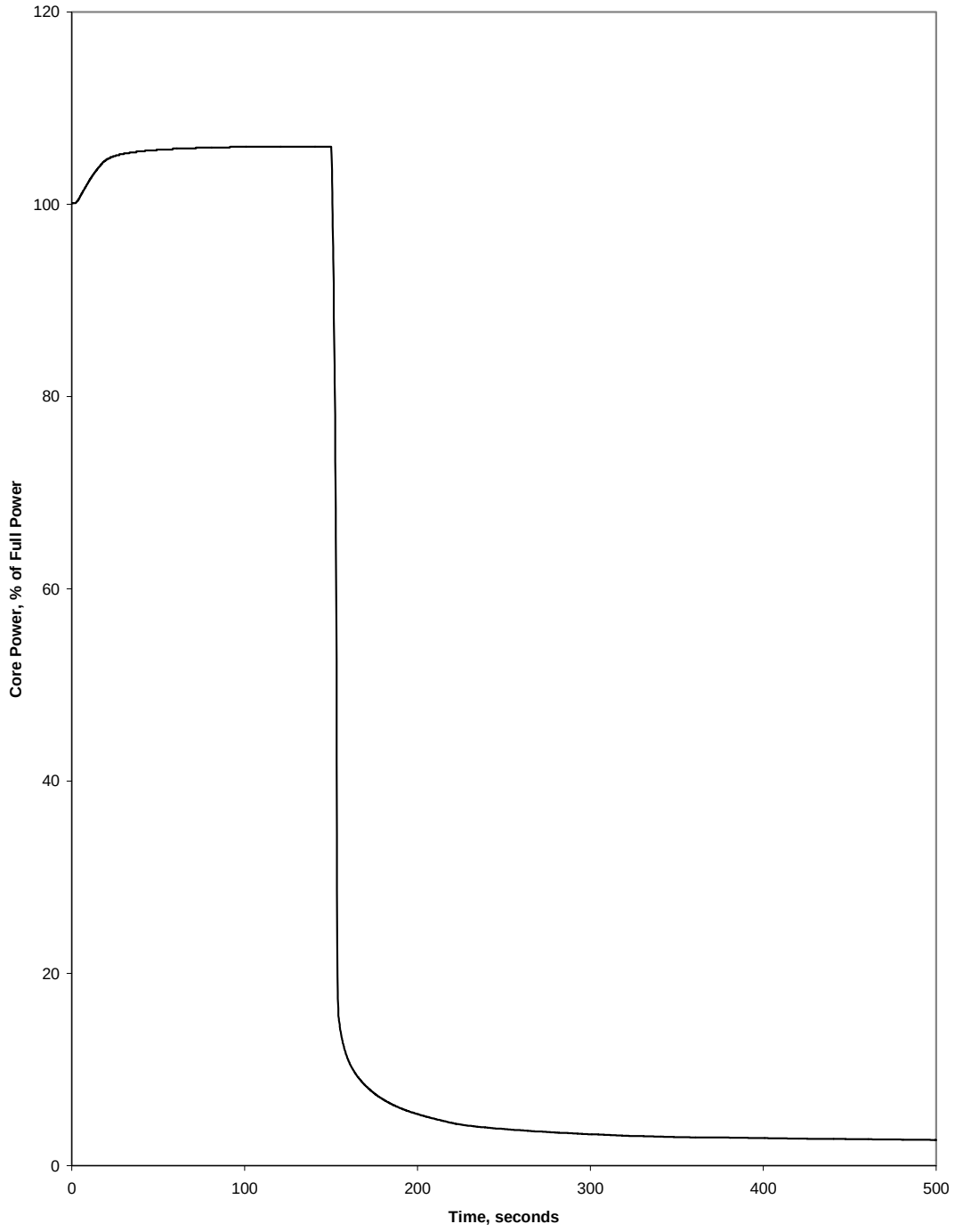

Figure 2.13.1.2.4-1
HFP IOADV with a Concurrent LOOP
Core Power vs. Time

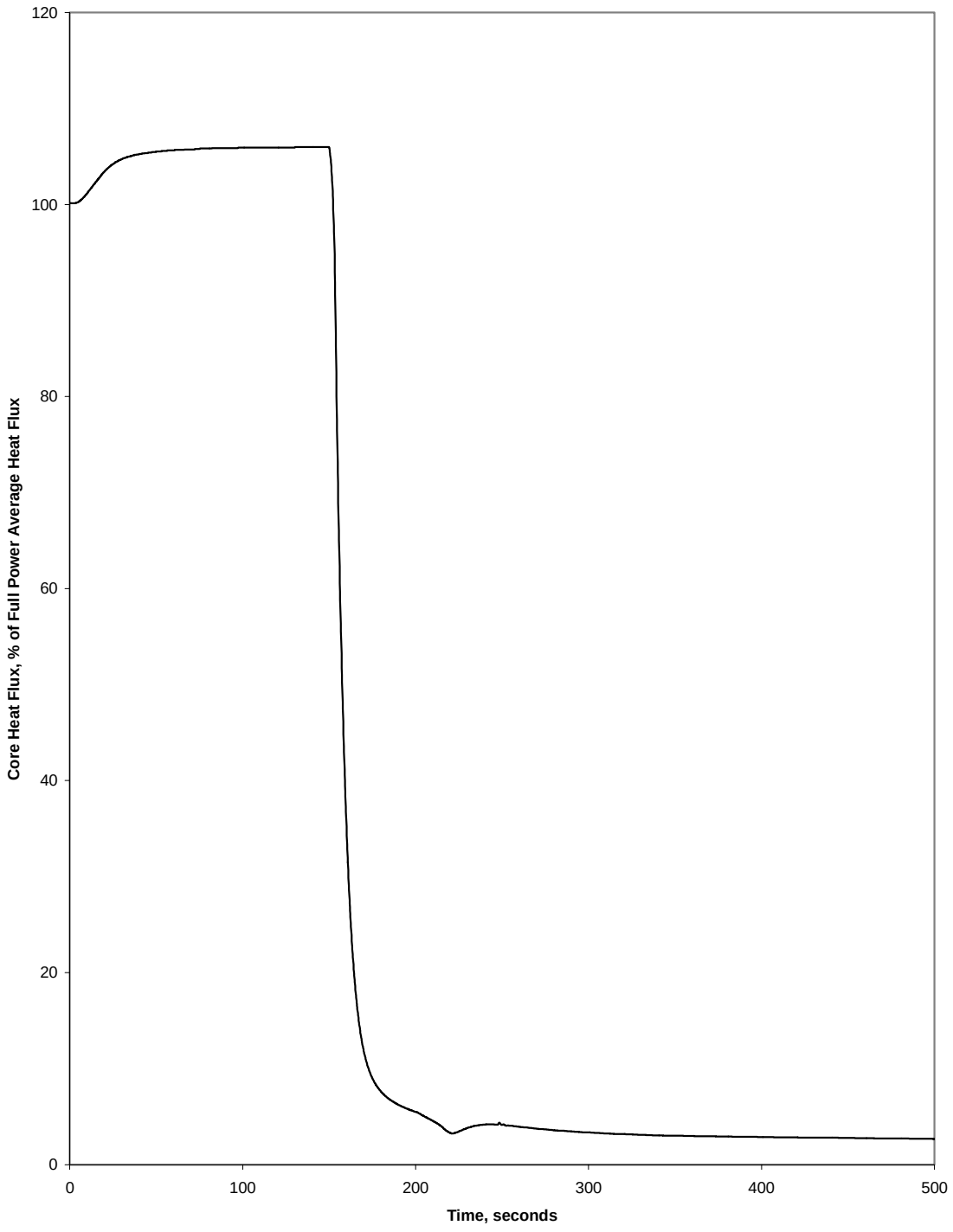

Figure 2.13.1.2.4-2
HFP IOADV with a Concurrent LOOP
Core Heat Flux vs. Time

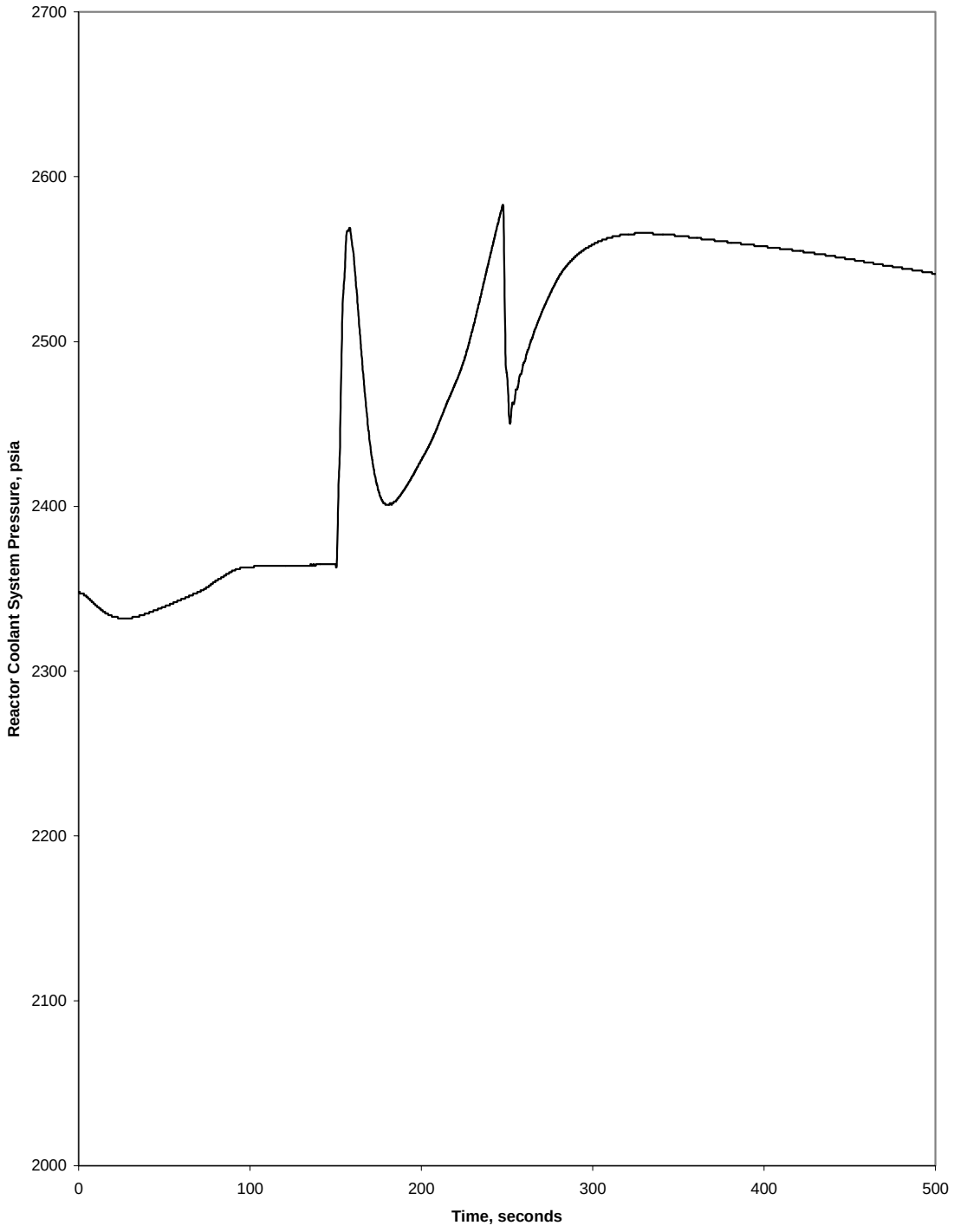

Figure 2.13.1.2.4-3
HFP IOADV with a Concurrent LOOP
RCS Pressure vs. Time

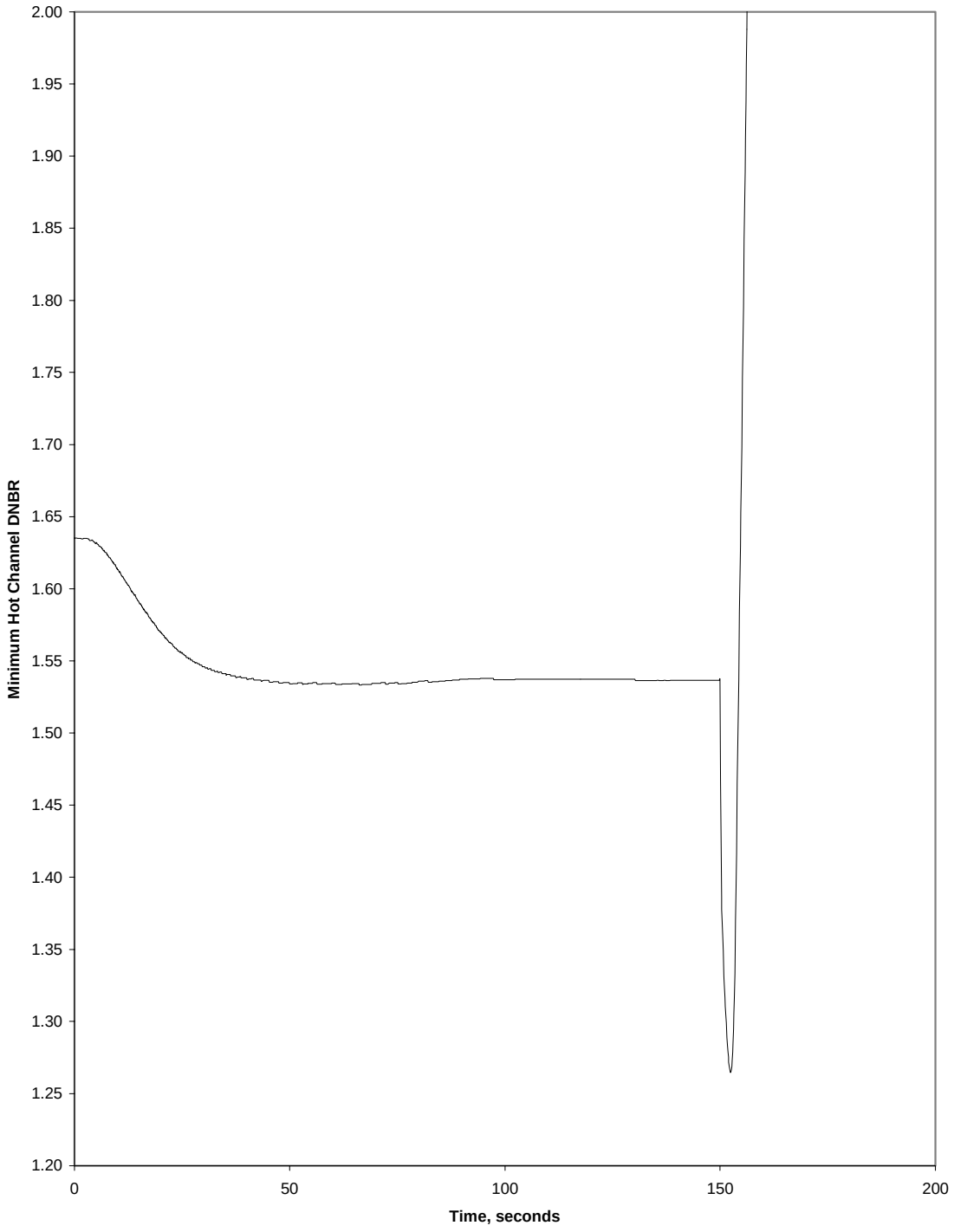

Figure 2.13.1.2.4-4
HFP IOADV with a Concurrent LOOP
Minimum Hot Channel DNBR vs. Time

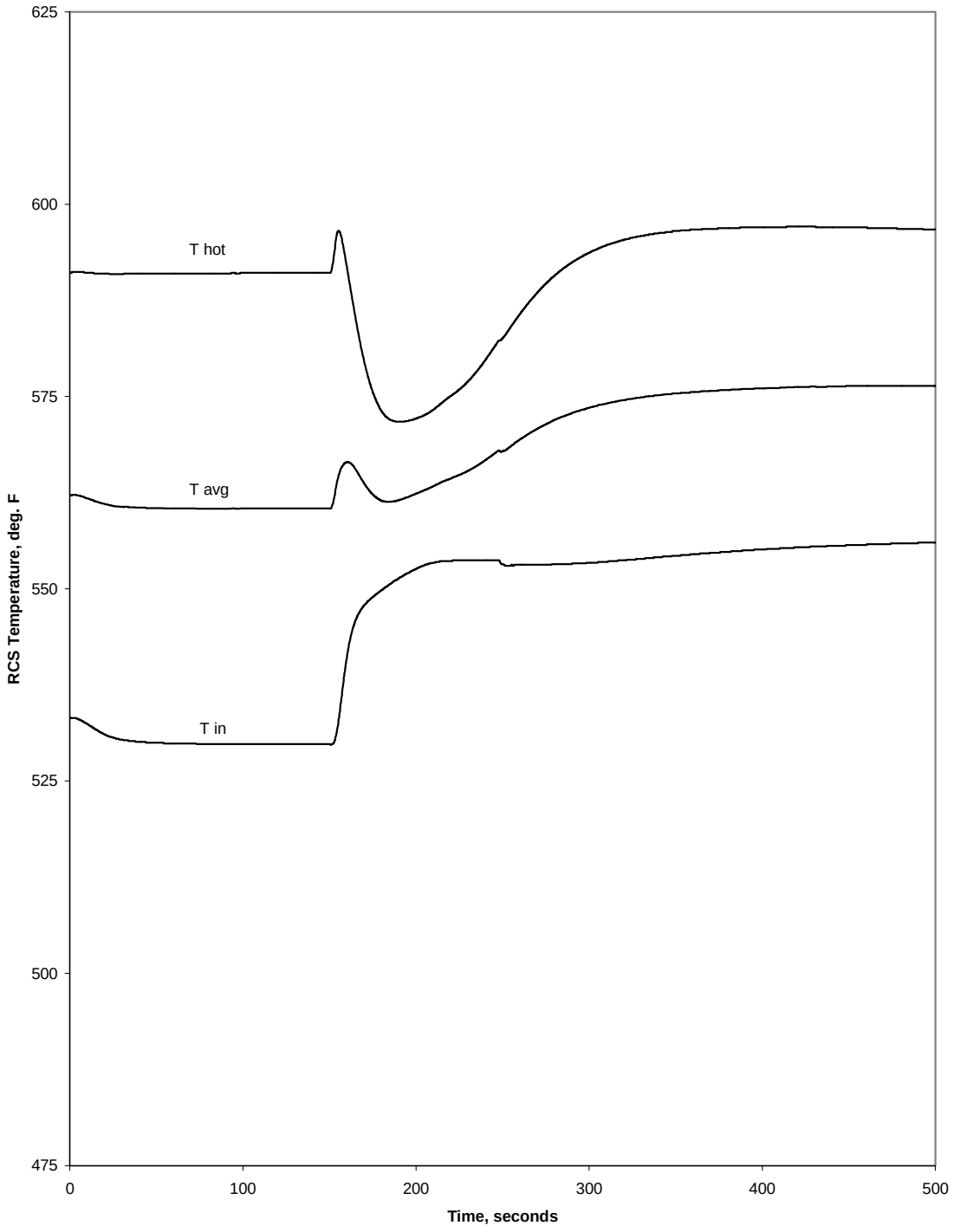

Figure 2.13.1.2.4-5
HFP IOADV with a Concurrent LOOP
Reactor Coolant Temperature vs. Time

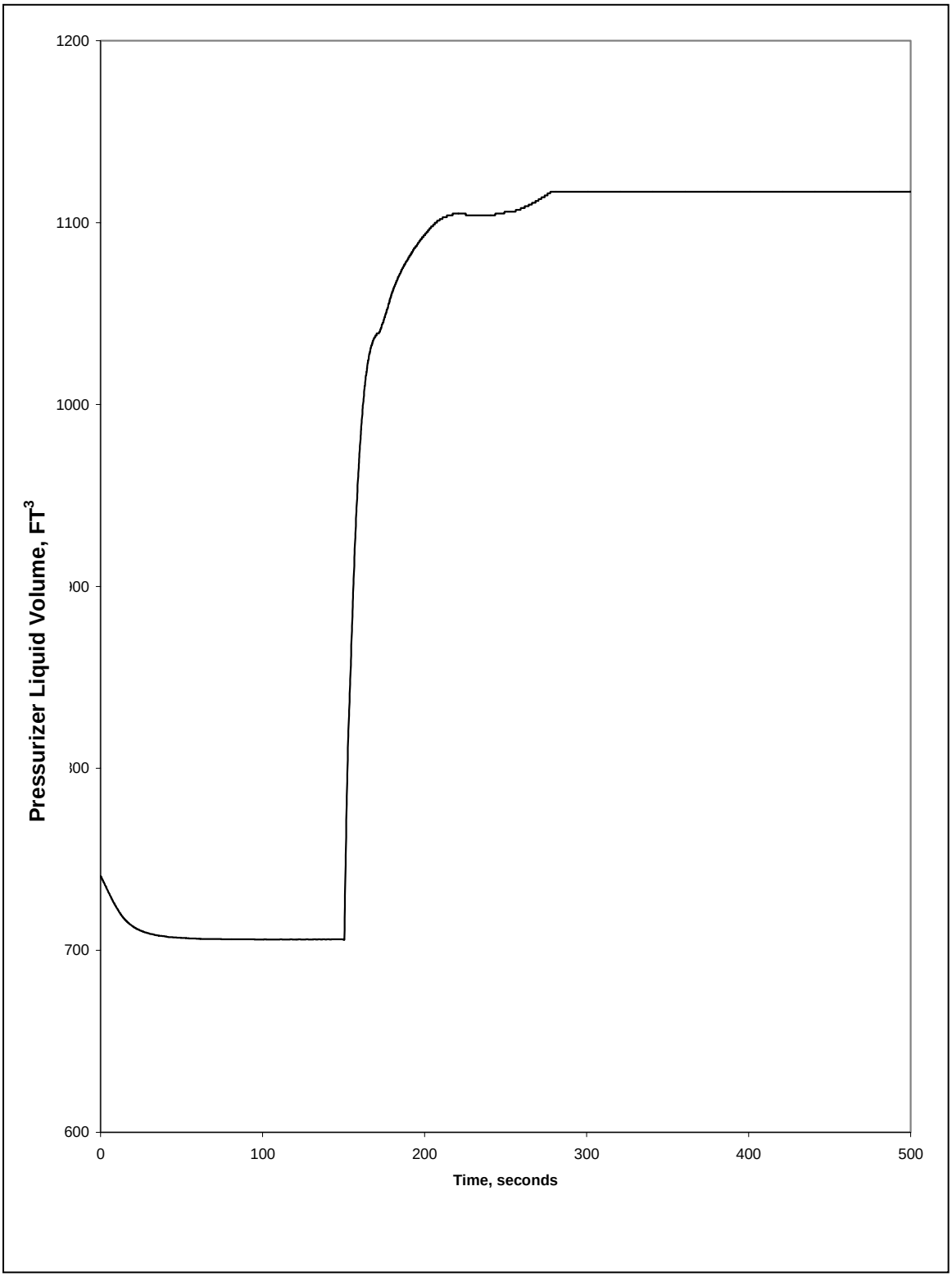

Figure 2.13.1.2.4-6
HFP IOADV with a Concurrent LOOP
Pressurizer Liquid Volume vs. Time

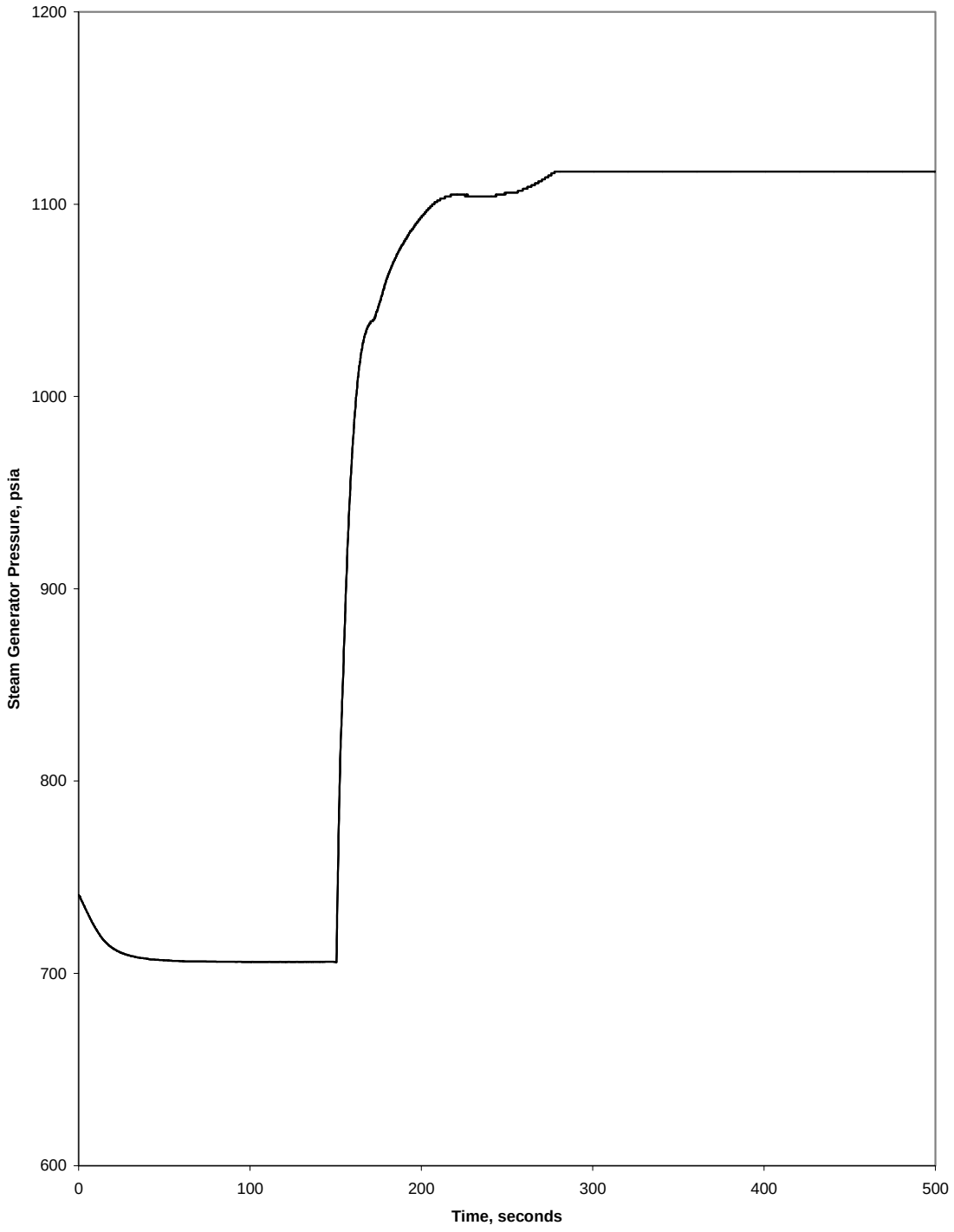

Figure 2.13.1.2.4-7
HFP IOADV with a Concurrent LOOP
Steam Generator Pressure vs. Time

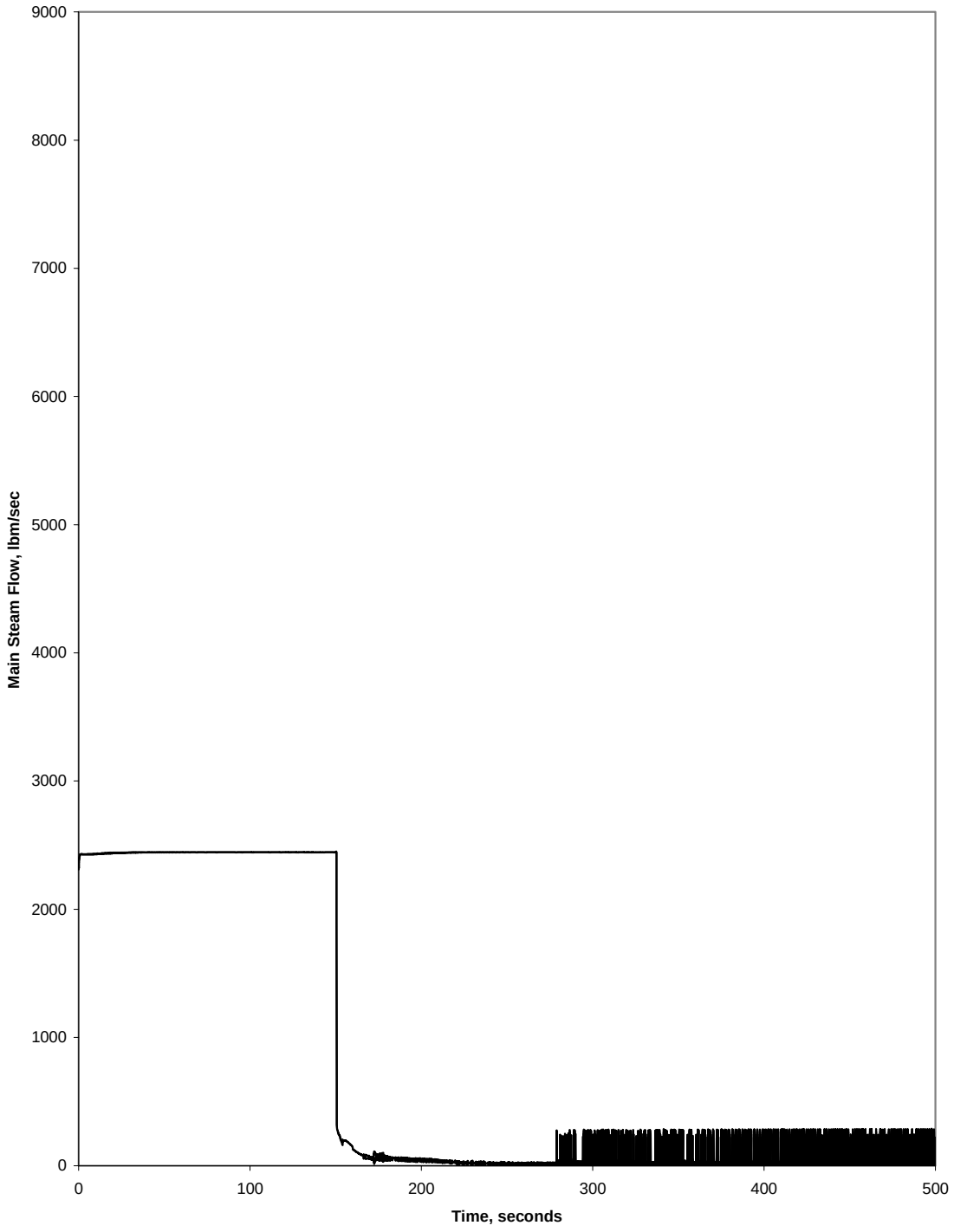

Figure 2.13.1.2.4-8
HFP IOADV with a Concurrent LOOP
Main Steam Flow vs. Time

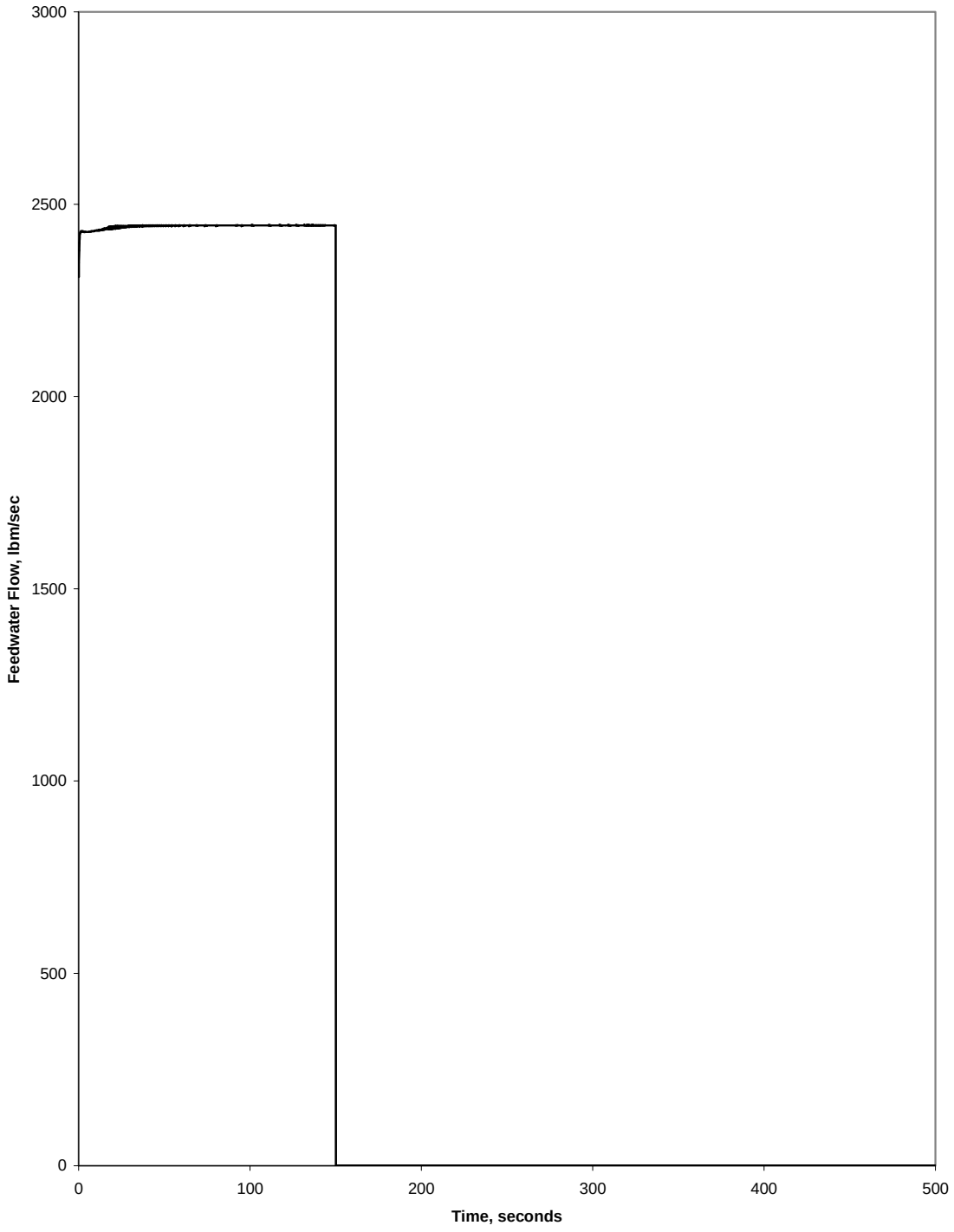

Figure 2.13.1.2.4-9
HFP IOADV with a Concurrent LOOP
Feedwater Flow vs. Time

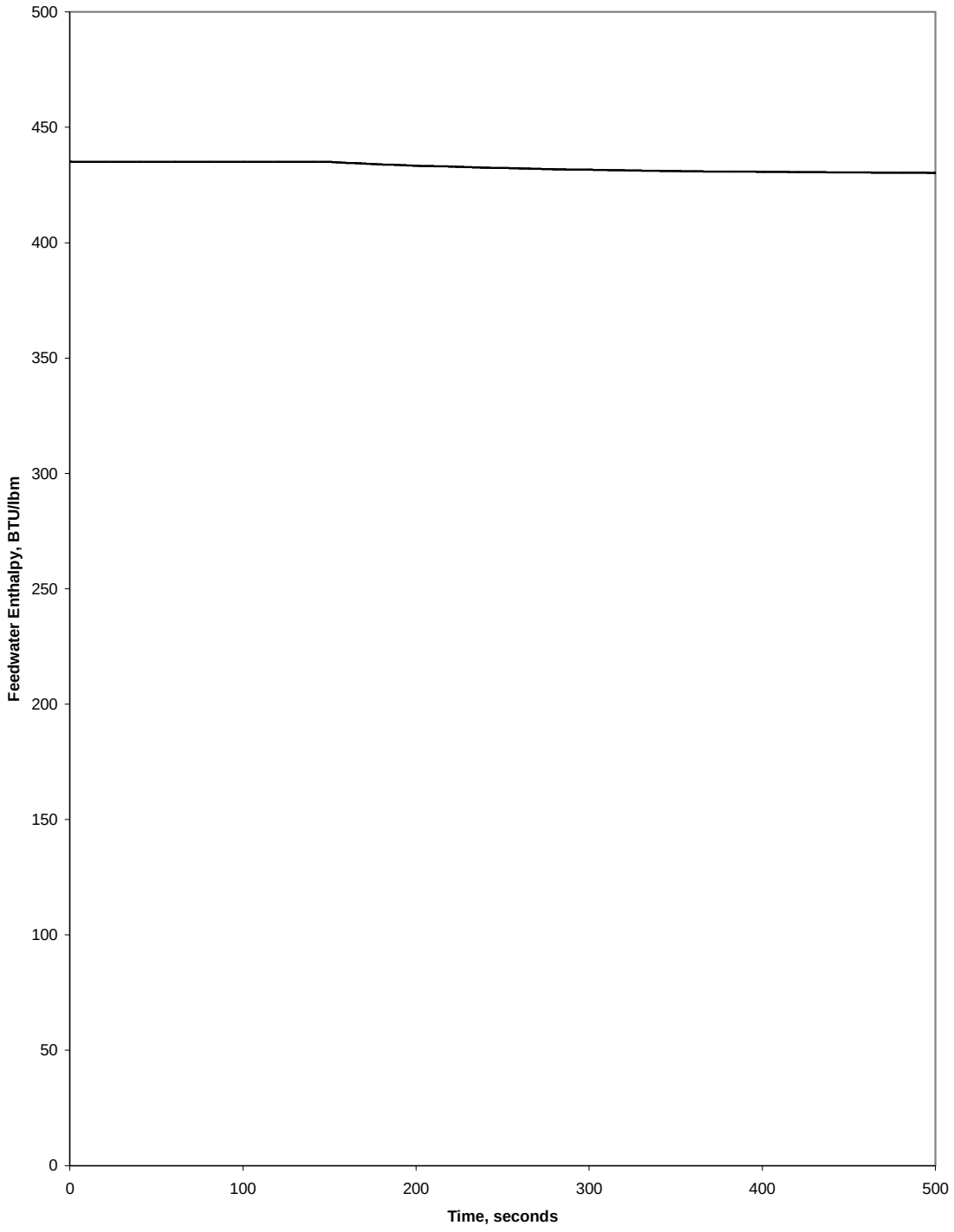

Figure 2.13.1.2.4-10
HFP IOADV with a Concurrent LOOP
Feedwater Enthalpy vs. Time

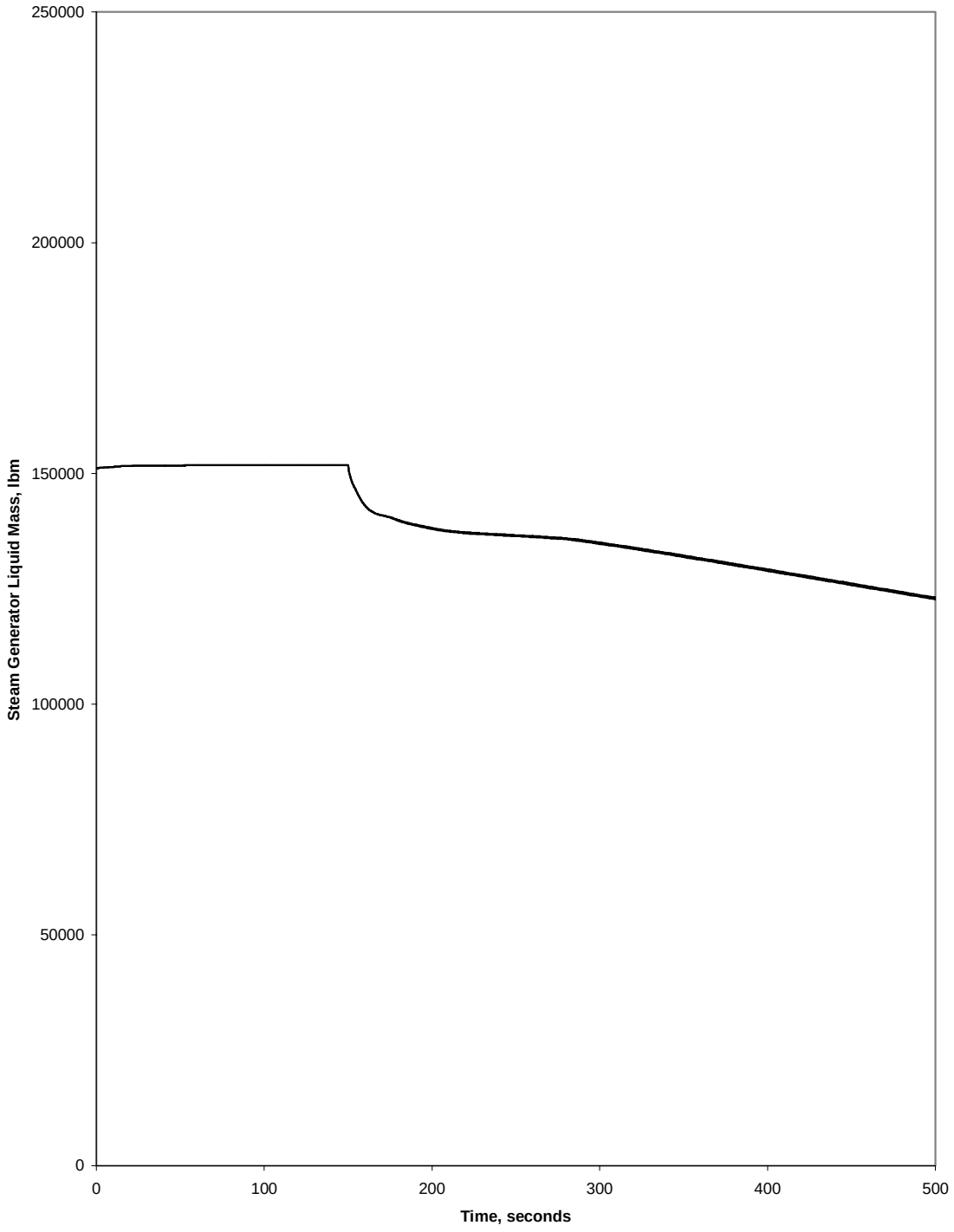

Figure 2.13.1.2.4-11
HFP IOADV with a Concurrent LOOP
SG Liquid Mass vs. Time

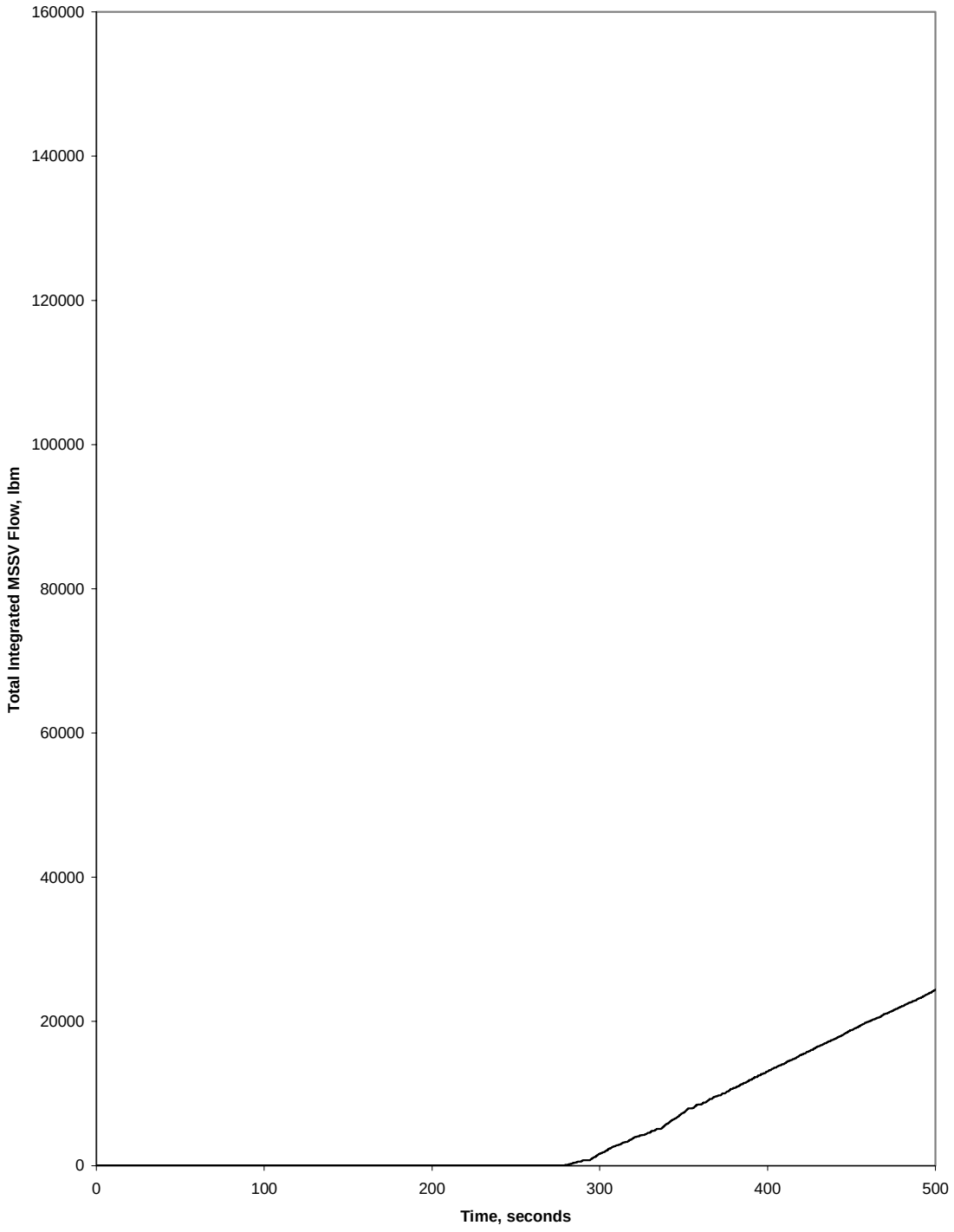

Figure 2.13.1.2.4-12
HFP IOADV with a Concurrent LOOP
Total Integrated Safety Valve Flow vs. Time

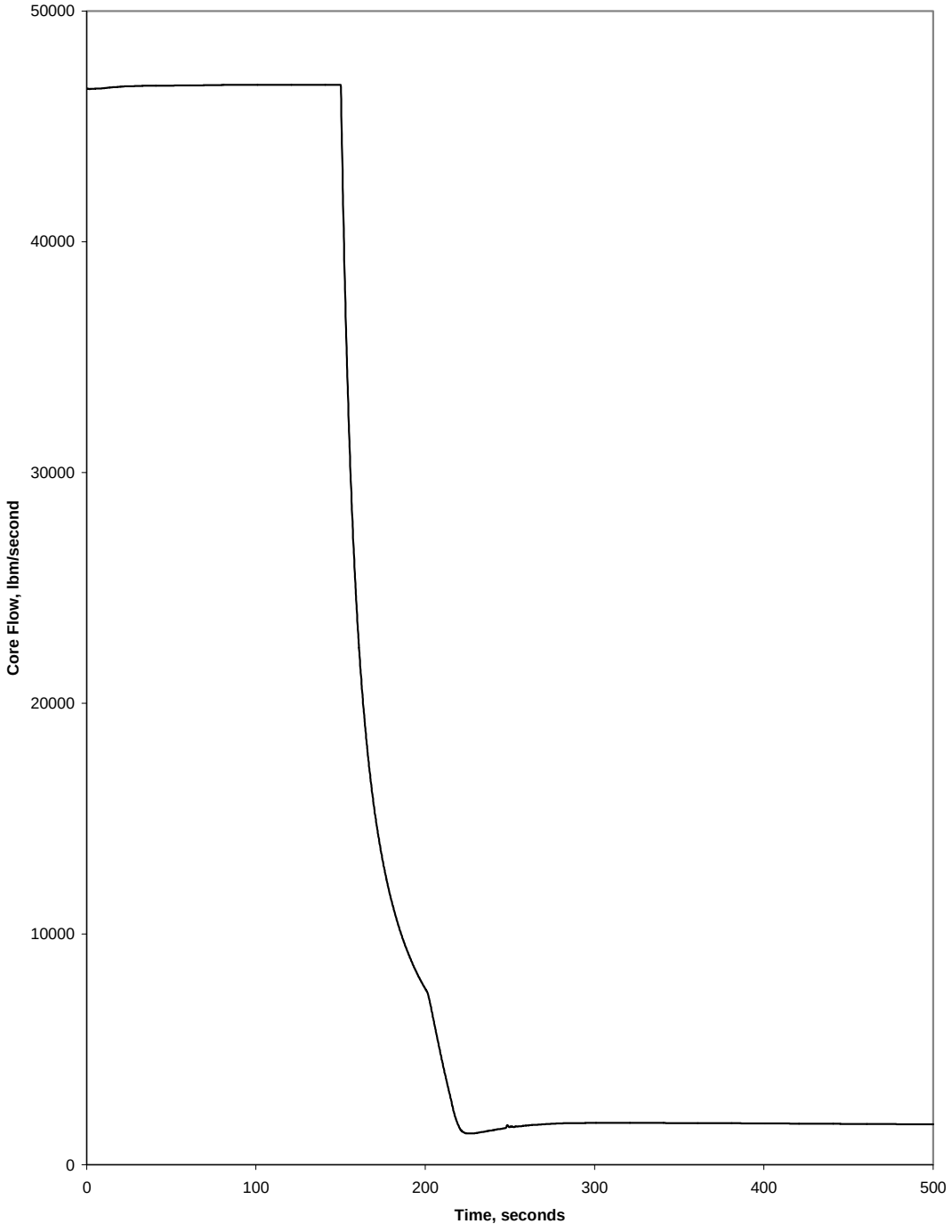

Figure 2.13.1.2.4-13
HFP IOADV with a Concurrent LOOP
Core Flow vs. Time

2.13.1.3 Limiting Faults

2.13.1.3.1 Steam System Piping Failures Post-Trip Analysis

The objective of the main steam line break (MSLB) with or without a concurrent LOOP event analysis is to document the impact of:

- An increase in rated power to 3716 MWt
- A decrease in the LSGP trip and MSIS actuation setpoints
- A reduction in CEA worth at trip
- Transition to the CENTS transient simulation code
- Change in most negative MTC from -4.0×10^{-4} $\Delta\rho/°F$ to -4.2×10^{-4} $\Delta\rho/°F$

The return to power MSLB analysis is presented in FSAR Section 15.1.3.1.

2.13.1.3.1.1 General Description

A MSLB is defined as a pipe break in the Main Steam Safety System (MSSS). The increased steam flow resulting from a pipe break in the MSSS causes an increased energy removal from the affected steam generator, which causes a decrease in the overall Reactor Coolant System (RCS) temperatures and RCS pressure.

In the presence of a negative moderator temperature coefficient (MTC), the cooldown causes positive reactivity to be added to the core. A highly negative MTC in conjunction with a large break size (guillotine breaks) can combine to degrade shutdown margin and result in a potential post-trip return to power.

With a loss-of-offsite power (LOOP) concurrent with the break, reactor coolant pumps (RCPs) begin to coast down and certain Engineered Safety Features (ESF) Systems are actuated.

In all guillotine break cases, the low steam generator pressure trip initiates a MSIS, which causes closure of the MSIVs and main feed isolation valves (MFIVs). The steam flow from the intact SG is terminated by the complete closure of the MSIVs. Since the pipe break is assumed to occur upstream of the MSIV, the steam flow from the affected SG is not terminated until the affected SG dries out. The large cooldown of the RCS results in the reduction of the RCS pressure, which will empty the pressurizer and initiate a safety injection actuation signal (SIAS). The emptying of the affected SG and the initiation of boron injection terminates the return to power and causes the core reactivity to decrease. The operator, via the appropriate emergency procedures, may initiate plant cooldown by manual control of ADVs anytime after reactor trip occurs. The plant is then cooled to the shutdown cooling temperature, at which time shutdown cooling can be initiated.

In the analysis of record (AOR), four MSLB events were chosen to maximize the potential for a post-trip return-to-power. The events were:

- A guillotine break MSLB at hot-full power (HFP) with LOOP
- A guillotine break MSLB at HFP with offsite power available
- A guillotine break MSLB at hot-zero power (HZP) with LOOP
- A guillotine break MSLB at HZP with offsite power available

In addition, the above combinations were analyzed for both inside containment (IC) and outside containment (OC) break locations. The outside containment break locations are in general more benign with the blowdown flow being limited by the inline venturi flow restrictors.

2.13.1.3.1.2 Purpose of Analysis and Acceptance Criteria

The purpose of the analysis is to determine that the radiological doses are within their respective limits and that a coolable geometry is maintained. This is accomplished by iterating on SCRAM worth to determine that which results in 2% fuel failure.

The criteria for the MSLB with and without LOOP events are the following:

- Maintain a coolable geometry
- Radiological Doses ≤ small fraction (10%) of 10CFR100 limits for an event generated iodine spike and no iodine spike, and
  ≤ 10CFR100 limits for a pre-existing iodine spike or fuel failure
- Control Room Doses ≤ 5 rem whole body
  ≤ 75 rem skin
  ≤ 30 rem thyroid

The MSLB with or without a concurrent LOOP event is described in Chapter 15.1.14.1 of the SAR (Reference 2.13-1).

2.13.1.3.1.3 Impact of Changes

The increase in rated power maximizes the amount of energy that is removed by the broken steam line and the cooldown effect on the RCS temperature.

The LSGP trip and MSIS actuation setpoints were decreased due to lower operating SG pressures. This delays somewhat the action of the MSIVs in stopping steam flow from the unaffected SG.

The more negative MTC results in the addition of additional positive reactivity by MTC effects during the cooldown.

The reduction in CEA worth at trip results in less negative reactivity to counteract the positive reactivity addition during the cooldown.

The impact of the above changes results in a small number of fuel pins predicted to experience SAFDL violation for inside containment (IC) break locations and no violation of SAFDLs for outside containment (OC) break locations. The radiological doses remain less than the 10CFR100 limits.

2.13.1.3.1.4 Analysis Overview

The methodology used in this analysis is the same as that used in the analysis of record.

This analysis utilized the CENTS computer code (Reference 2.13-2) for the transient analysis simulation. The minimum DNBR evaluation was determined using the HRISE code (Reference 2.13-10), which employed the MacBeth correlation. ROCS/HERMITE were used to assess reactivity feedback and core power distribution.

Input parameters for HFP and HZP from Table 2.13.1.3.1-1 and the bounding physics data from Section 2.13.0.2 have been incorporated in this analysis with the following clarifications:

- A double-ended IC guillotine break (7.88 ft^2) causes the greatest cooldown of the RCS and the most severe degradation of shutdown margin. Flow from the other SG was limited to the 3.14 ft^2 area of the inline flow restrictors.
- A break inside or outside the containment building, upstream of the MSIVs causes a non-isolatable condition in the affected SG.
- A SIAS is actuated when the pressurizer pressure drops below 1560 psia. Time delays associated with the safety injection pump acceleration and valve opening are taken into account. An 18.5-second HPSI response time was assumed for the offsite power available case while a 30-second delay (conservatively greater than the 27 seconds to be specified in the Technical Requirements Manual [TRM]) was assumed for the LOOP case. Additionally, the event was initiated from the highest pressure allowed by the Technical Specifications to delay the effect of the safety injection boron.
- The cooldown of the RCS is terminated when the affected steam generator blows dry. As the coolant temperatures begin increasing, positive reactivity insertion from moderator reactivity feedback decreases. The decrease in moderator reactivity combined with the negative reactivity inserted via boron injection cause the total reactivity to become more negative.
- CENTS is used to model the reactor coolant pump (RCP) coast down on a LOOP.
- Low SG pressure trip setpoint of 576 psia was assumed with a 0.9-second response time.
- MSIS is actuated on a LSGP setpoint of 576 psia. The MSIVs and Main Feedwater Isolation Valves (MFIVs) all receive an MSIS signal to close. A response time of 8.0 seconds was assumed for the MSIVs.
- The HERMITE code (Reference 2.13-4) was used to calculate the reactivity for the post-trip return to power portion of the analysis. This was done since the HERMITE code, which is a three-dimensional, coupled neutronics, open channel thermal hydraulics code, can more accurately model the effects of moderator temperature feedback on the power distribution and reactivity for the critical configuration existing during the return to power. The HERMITE results used in the Waterford 3 analysis were actually obtained from a parametric study

performed for Calvert Cliffs Unit 1 Cycle 7. Waterford 3-specific ROCS calculations were used to confirm the applicability of these parametric results to Waterford 3.

- Three-dimensional power distribution peaks (Fq) were determined with the ROCS and HERMITE evaluations mentioned above. Axial profiles consistent with these conservative power distribution peaks were utilized in the analysis.
- Reactor core thermal margin (DNBR) was simulated using the HRISE computer program, which employed the MacBeth critical heat flux (CHF) correlation and a 1.3 DNBR limit described in Reference 2.13-10. RCS conditions from CENTS (RCS temperature, pressure, flow, and power) are used in the HRISE thermal margin calculations.
- An EOC Doppler coefficients was assumed. This was based on the most negative fuel temperature coefficient (FTC). This FTC, in conjunction with the decreasing fuel temperatures, causes the greatest positive reactivity insertion during the steam line break event.
- The delayed neutron fraction assumed is the maximum value including uncertainties for EOC conditions (total delayed neutron fraction, β, 0.005662).
- A minimum initial RCS flow of 148,000,000 lbm/hr was assumed.
- A maximum initial RCS temperature results in the greatest increase in density of the coolant during the event. This maximizes the positive reactivity added by the moderator. The analytical value of 552°F was used in this analysis.

The conservative assumptions included in the HZP and HFP simulations are discussed below.

The MTC assumed in the analysis corresponds to the most negative value. This negative MTC results in the greatest positive reactivity addition during the RCS cooldown caused by the steam line break. Since the coefficient of reactivity associated with moderator feedback varies significantly over the range of moderator density covered in the analysis, a curve of reactivity insertion versus moderator density rather than a single value of MTC is assumed in the analysis. The moderator cooldown curve used in the analysis (Figure 2.13-1) was conservatively calculated assuming that on reactor trip, the highest worth control element assembly is stuck in the fully withdrawn position. The effect of uneven temperature distribution on the moderator reactivity is accounted for by assuming that the moderator reactivity is a function of the lowest cold leg temperature.

For conservatism, the full steam generator heat transfer surface area is assumed to always be covered by the 2-phase level until a steam generator becomes essentially empty.

Due to differences in the magnitudes of reactivity feedback mechanisms, the rates of heat removal associated with different break areas and LOOP assumptions, the minimum acceptable SCRAM worth would be different for each of the eight RTP steamline break (SLB) scenarios examined. These values are tabulated below. Restrictions will be incorporated in future reload core designs to ensure that the most limiting of the requirements are verified for actual power uprate core designs.

SCRAM Worth Resulting in Less than 2% Fuel Failure for
Inside Containment RTP SLB, 7.88 ft^2 Break Flow Area

	With LOOP	Without LOOP
HFP	5.7 %Δρ	6.08 %Δρ
HZP	3.1 %Δρ	3.6 %Δρ

SCRAM Worth Resulting in No SAFDL Violation for
Outside Containment RTP SLB, 3.14 ft^2 Break Flow Area

	With LOOP	Without LOOP
HFP	5.7 %Δρ	< 6.0 %Δρ
HZP	< 3.1 %Δρ	< 3.6 %Δρ

The HFP cases assume that feedwater delivery to the affected SG reached the capacity of the Main Feedwater (MFW) System until the MFIVs act to terminate MFW delivery.

2.13.1.3.1.5 Radiological Consequences

Based upon the required scram worths, the maximum fuel failure for the inside containment RTP MSLB is 2%; no fuel failure is allowed for the outside containment RTP main steamline break (MSLB). Similar limited fuel failure during the RTP SLB has been licensed for Calvert Cliffs and St Lucie 2. The radiological consequences and fuel failure limits of the RTP SLB scenario are combined with those of the pre-trip SLB scenario. Refer to Section 2.13.1.3.3.5 for the discussion.

2.13.1.3.1.6 Analysis Results

Two typical cases are presented, the HFP LOOP case and the HZP LOOP case. Table 2.13.1.3.1-1 and 2.13.1.3.1-2 present the assumptions on important core parameters used in these two scenarios.

The sequence of events for the two scenarios are seen in Tables 2.13.1.3.1-3 and 2.13.1.3.1-4. Figures 2.13.1.3.1-1 though 2.13.1.3.1-13 present the transient response of key parameters for the HFP LOOP case. The same parameters are plotted in Figures 2.13.1.3.1-14 through 2.13.1.3.1-26 for the HZP LOOP case.

It is seen that the response for the power uprate is slightly more adverse than the current power level. A limited extent of SAFDL violation is seen to occur for these inside containment steam line breaks.

Table 2.13.1.3.1-1
HFP, LOOP Assumption Table

Parameter	Power Uprate Assumption	Current Power Level Assumption
Initial Core Power, MWt	3735	3478
Core Inlet Coolant Temperature, °F	552	560
RCS Flowrate, $x10^6$ lbm\hr	148.0	148.0
Pressurizer Pressure, psia	2310	2300
Pressurizer Level, %	21	---
SG Pressure, psia	867	969
SG Level, % NR	90	---
Doppler Coefficient Multiplier	1.15 (EOC)	1.15 (EOC)
MTC, 10^{-4} $\Delta\rho$/°F	-4.2	-4.0
CEA Worth for Trip, $10^{-2}\Delta\rho$	-5.7	-6.65
SBCS	Inoperative	Inoperative
PPCS	Automatic	Automatic
High-Pressure Safety Injection Pumps	1 pump inoperative	1 pump inoperative
Blowdown Fluid	100% steam	100% steam
Break Area, ft^2	7.88	7.88

Table 2.13.1.3.1-2
HZP, LOOP Assumption Table

Parameter	Power Uprate Assumption	Current Power Level Assumption
Initial Core Power Level, MWt	37.16	34.78
Core Inlet Coolant Temperature, °F	552	551
RCS Flowrate, $x10^6$ lbm/hr	148.0	148.0
Pressurizer Pressure, psia	2310	2300
Pressurizer Level, %	21	---
SG Pressure, psia	1054	1044
SG Level, % NR	90	---
Doppler Coefficient Multiplier	1.15	1.15
MTC, 10^{-4} $\Delta\rho$/°F	-4.2	-4.0
CEA Worth for Trip, $10^{-2}\Delta\rho$	3.1	3.95
SBCS	Inoperative	Inoperative
PPCS	Automatic	Automatic
HPSI Pumps	1 pump inoperative	1 pump inoperative
Blowdown Fluid	100% steam	100% steam
Break Area, ft^2	7.88	7.88

Table 2.13.1.3.1-3
HFP, LOOP, Inside Containment Sequence of Events

EPU Time (sec)	Current Power Level Time (sec)	Event	EPU Setpoint/Value	Current Power Level Setpoint/Value
0.0	0.0	Steam line break upstream of MSIV, loss of power to RCPs	7.88 ft^2	7.88 ft^2
1.9	1.7	LSGP trip and MSIS setpoint reached	576 psia	675 psia
2.8	2.6	Trip breakers open	---	---
2.8	2.6	MSIVs begin to close	---	---
3.4	3.2	Shutdown CEAs begin dropping into the core	---	---
11.4	---	MSIVs closed	---	---
19.4	12.6	MFIVs closed	---	---
44.2	15.8	Pressurizer empties	---	---
50.4	19.8	Low RCS pressure initiates SIAS	1560 psia	1560 psia
69.5	---	Minimum pressurizer pressure, psia	873.3	---
80.4	49.8	HPSI pump reaches full speed	---	---
153.2	142.3	Maximum post-trip fission power	6.1% of 3716 MWt	5.2% of 3410 MWt
169.3	152.3	Minimum post-trip MacBeth DNBR	1.03	>1.30
183.8	143.5	Maximum post-trip reactivity	+.006%$\Delta\rho$	-.056%$\Delta\rho$
269.0	112.7	Affected SG empties	---	---
1800	1800	Plant cooldown initiated by manual control of the ADV associated with the intact SG	---	---
28,800	---	SDC initiated	---	---

Table 2.13.1.3.1-4
HZP, LOOP, Inside Containment Sequence of Events

EPU Time (sec)	Current Power Level Time (sec)	Event	EPU Setpoint/Value	Current Power Level Setpoint/Value
0.0	0.0	Steam line break upstream of MSIV, loss of power to RCPs	7.88 ft^2	7.88 ft^2
3.2	2.2	LSGP trip and MSIS setpoint reached	576 psia	675 psia
4.1	3.1	Trip breakers open	- - -	- - -
4.7	3.7	Shutdown CEAs begin dropping into the core	- - -	- - -
11.6	---	Pressurizer empties	---	---
12.2	11.6	Low RCS pressure initiates SIAS	1560 psia	1560 psia
12.2	13.1	MSIVs closed	---	---
19.8	---	MFIVs closed	---	---
40.0	94.5	Maximum post-trip reactivity	+0.19%$\Delta\rho$	+0.19%$\Delta\rho$
42.2	41.6	HPSI pump reaches full speed	---	---
123.6	---	Minimum RCS pressure, psia	580.1	---
226.1	229.6	Maximum post-trip fission power	4.4% of 3716 MWt	4.2% of 3478 MWt
228.0	249.4	Minimum post-trip DNBR	1.18	>1.30
>600	311.4	Affected SG empties	---	---
1800	1800	Plant cooldown initiated by manual control of the ADV associated with the intact SG	---	---
28,800	---	SDC initiated	---	---

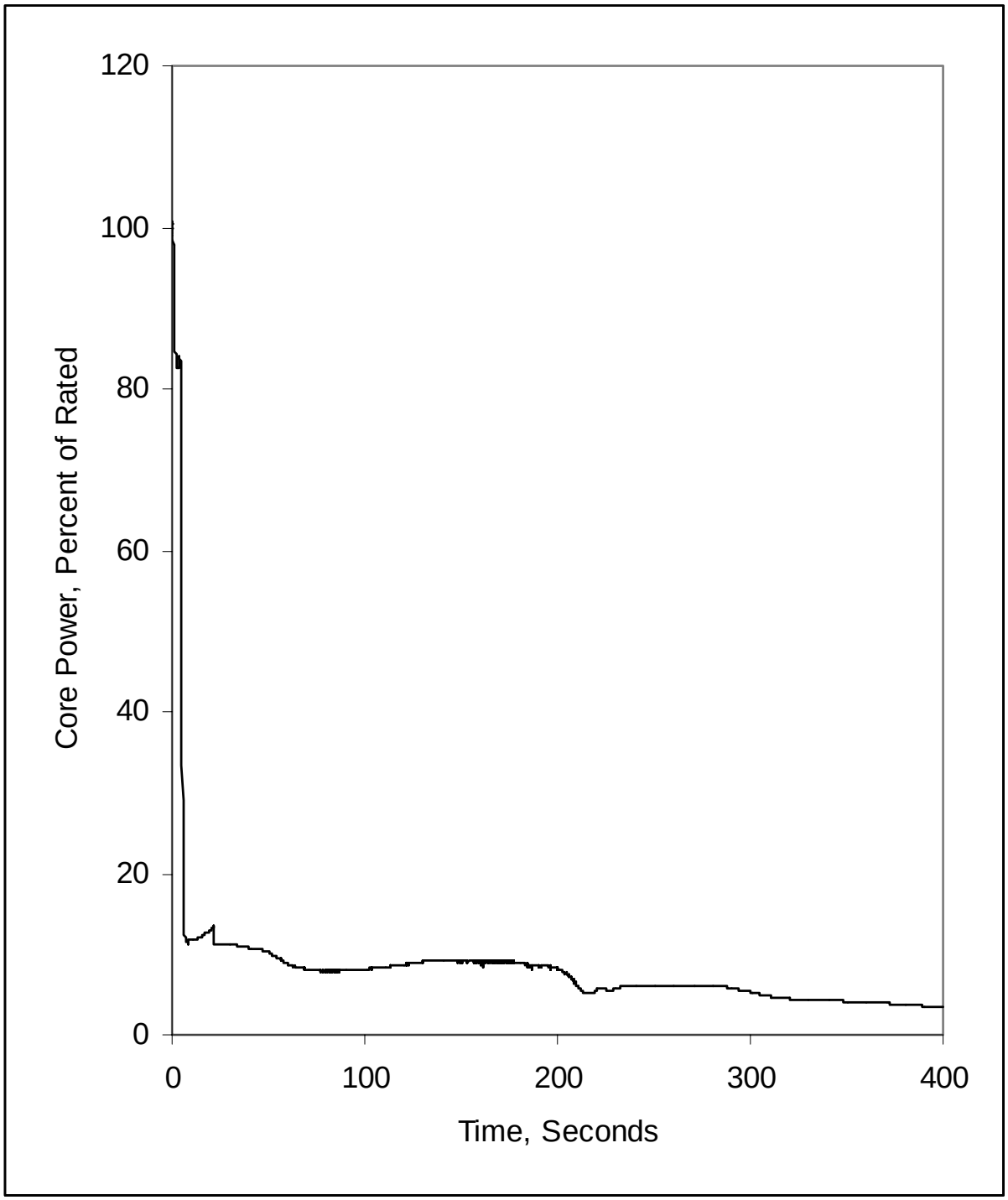

Figure 2.13.1.3.1-1
Inside Containment, HFP SLB with LOOP
Core Power vs. Time

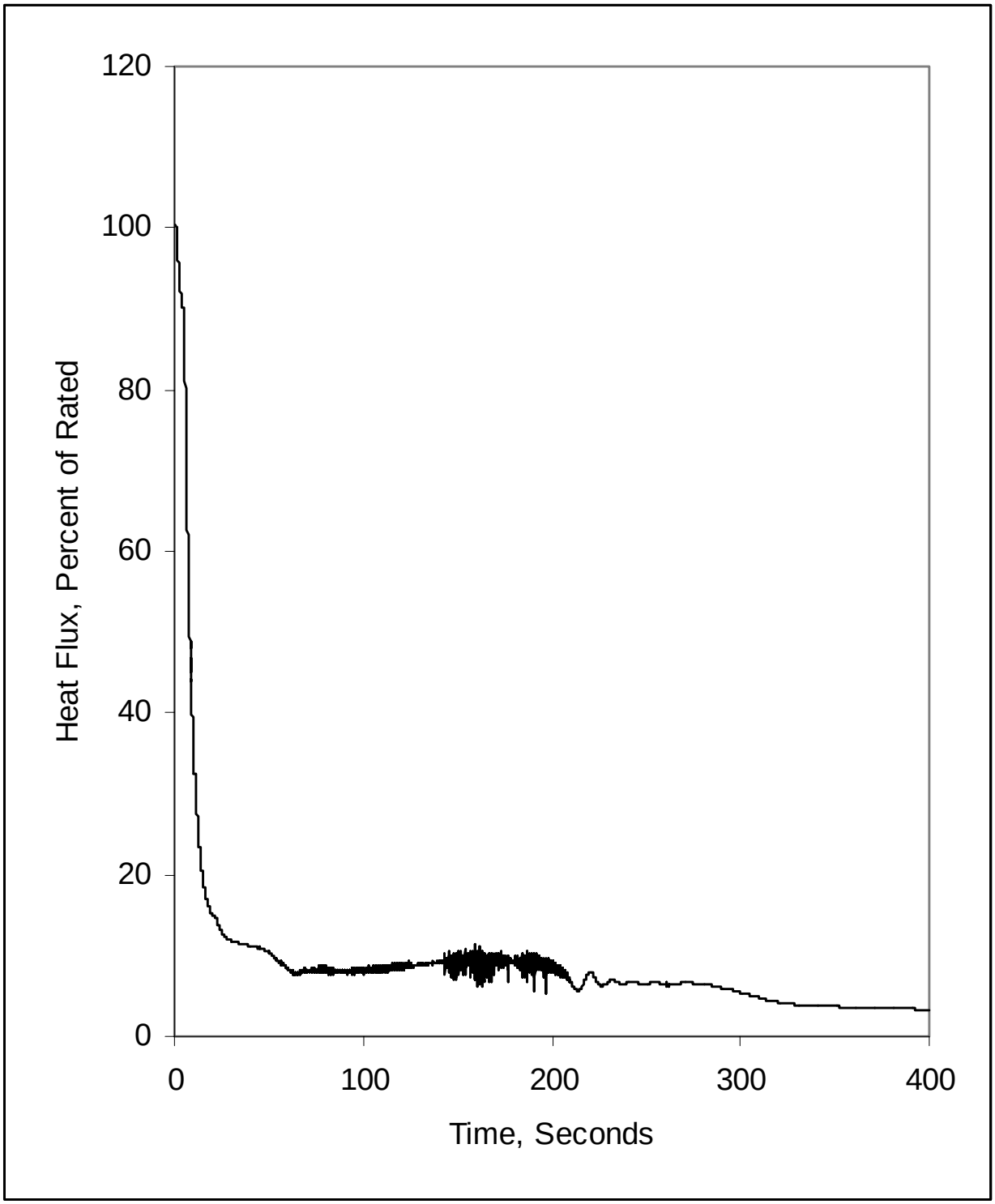

Figure 2.13.1.3.1-2
Inside Containment, HFP SLB with LOOP
Core Heat Flux vs. Time

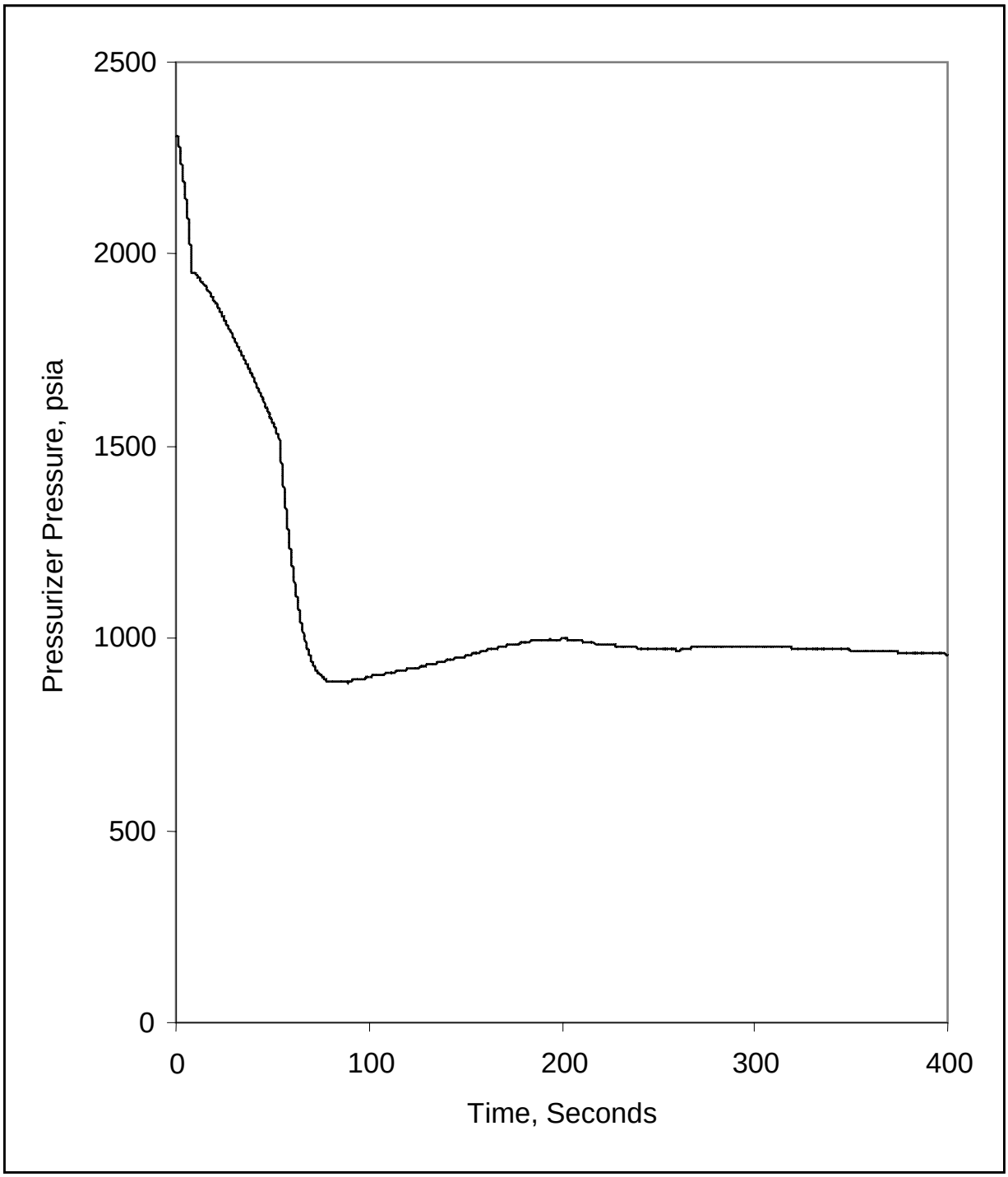

Figure 2.13.1.3.1-3
Inside Containment, HFP SLB with LOOP
Pressurizer Pressure vs. Time

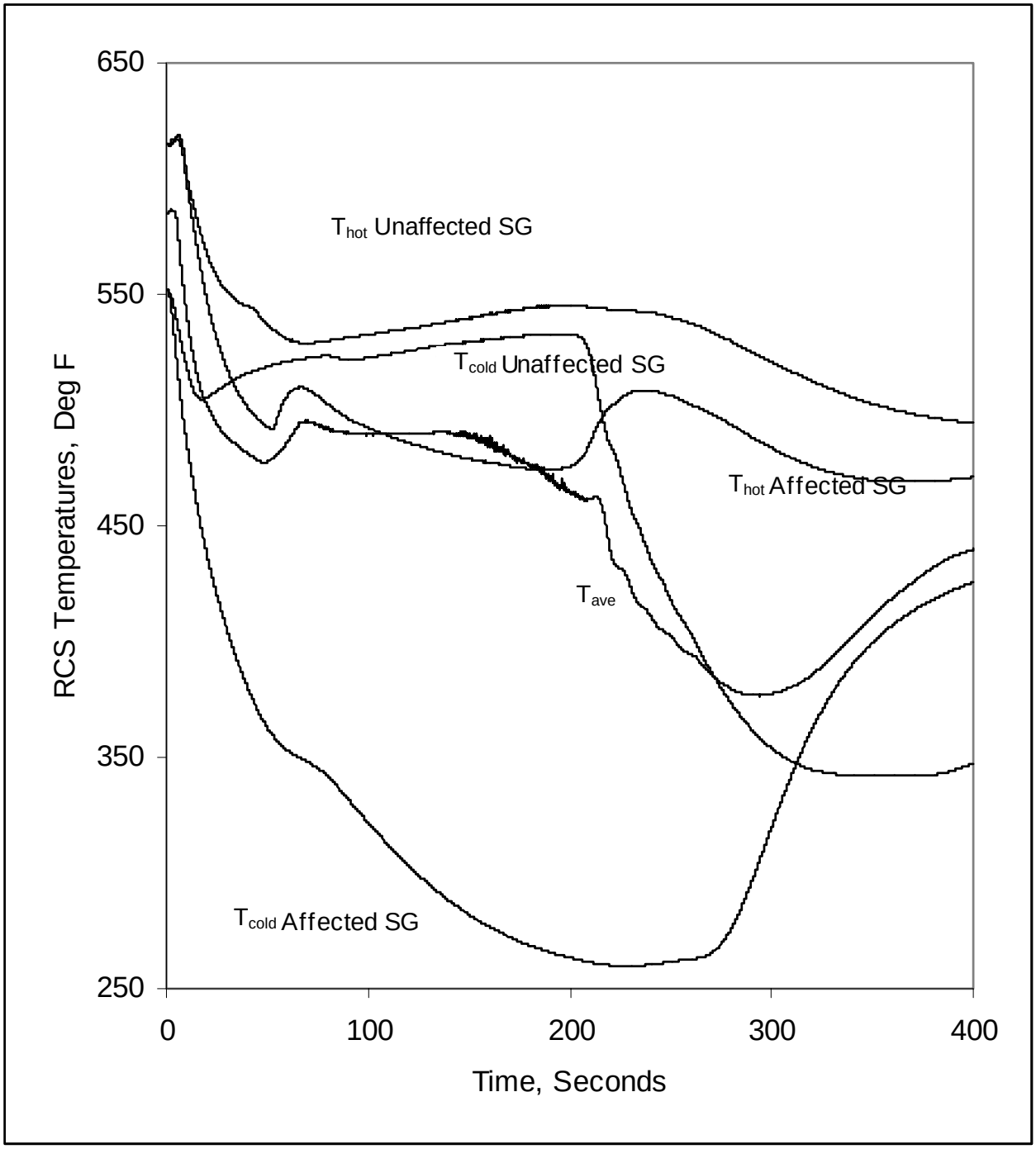

Figure 2.13.1.3.1-4
Inside Containment, HFP SLB with LOOP
RCS Temperatures vs. Time

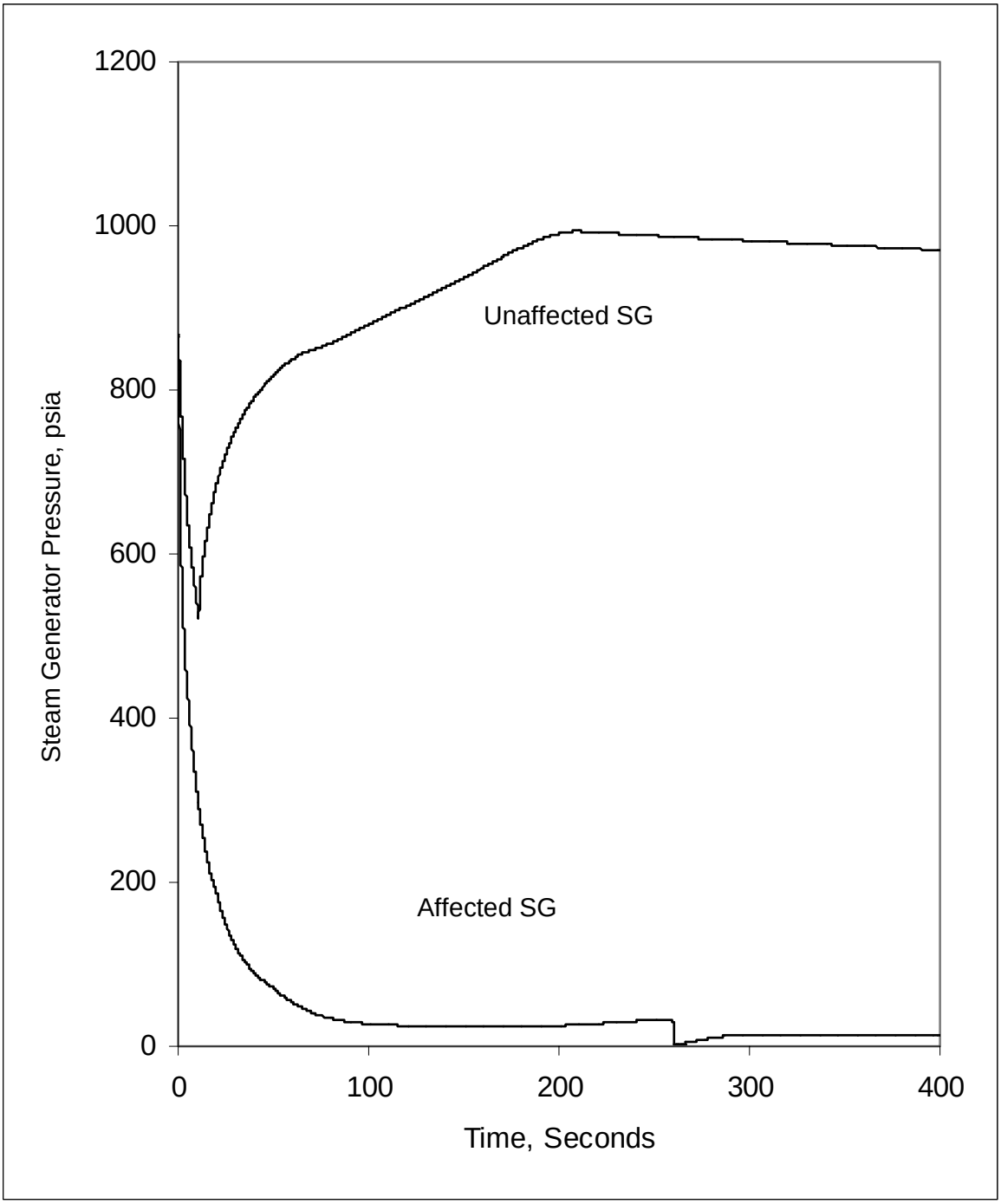

Figure 2.13.1.3.1-5
Inside Containment, HFP SLB with LOOP
SG Pressure vs. Time

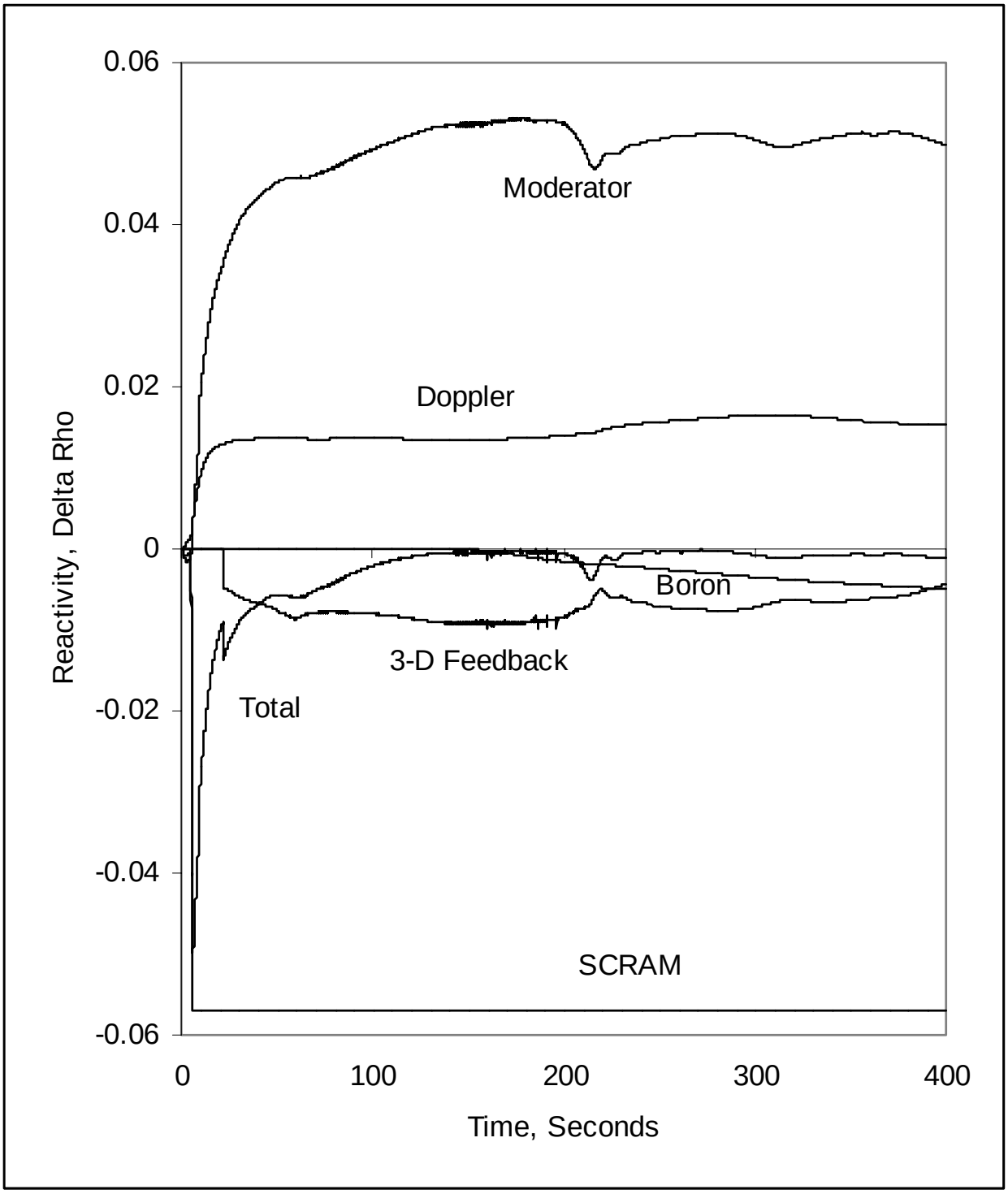

Figure 2.13.1.3.1-6
Inside Containment, HFP SLB with LOOP
Reactivity vs. Time

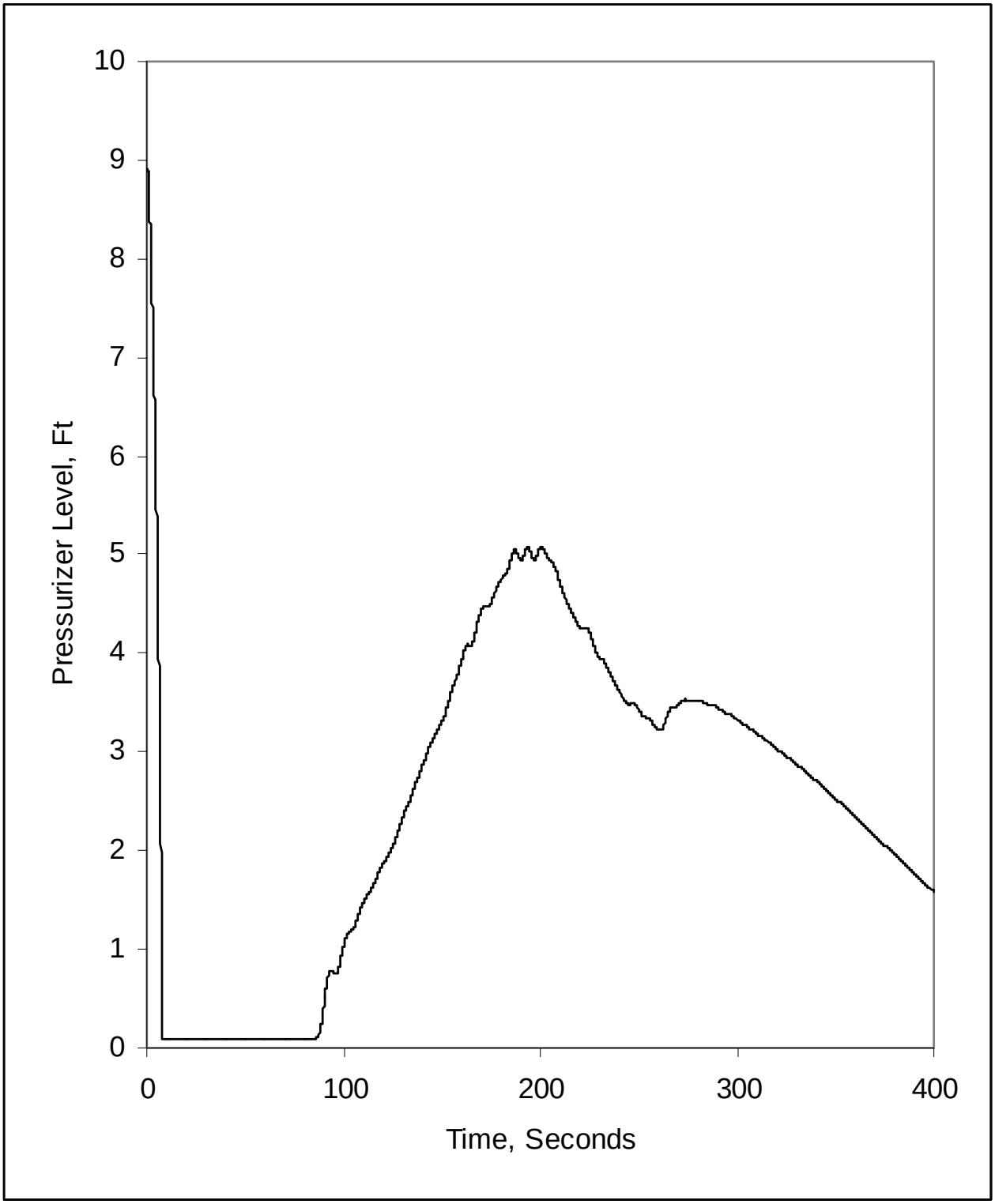

Figure 2.13.1.3.1-7
Inside Containment, HFP SLB with LOOP
Pressurizer Level vs. Time

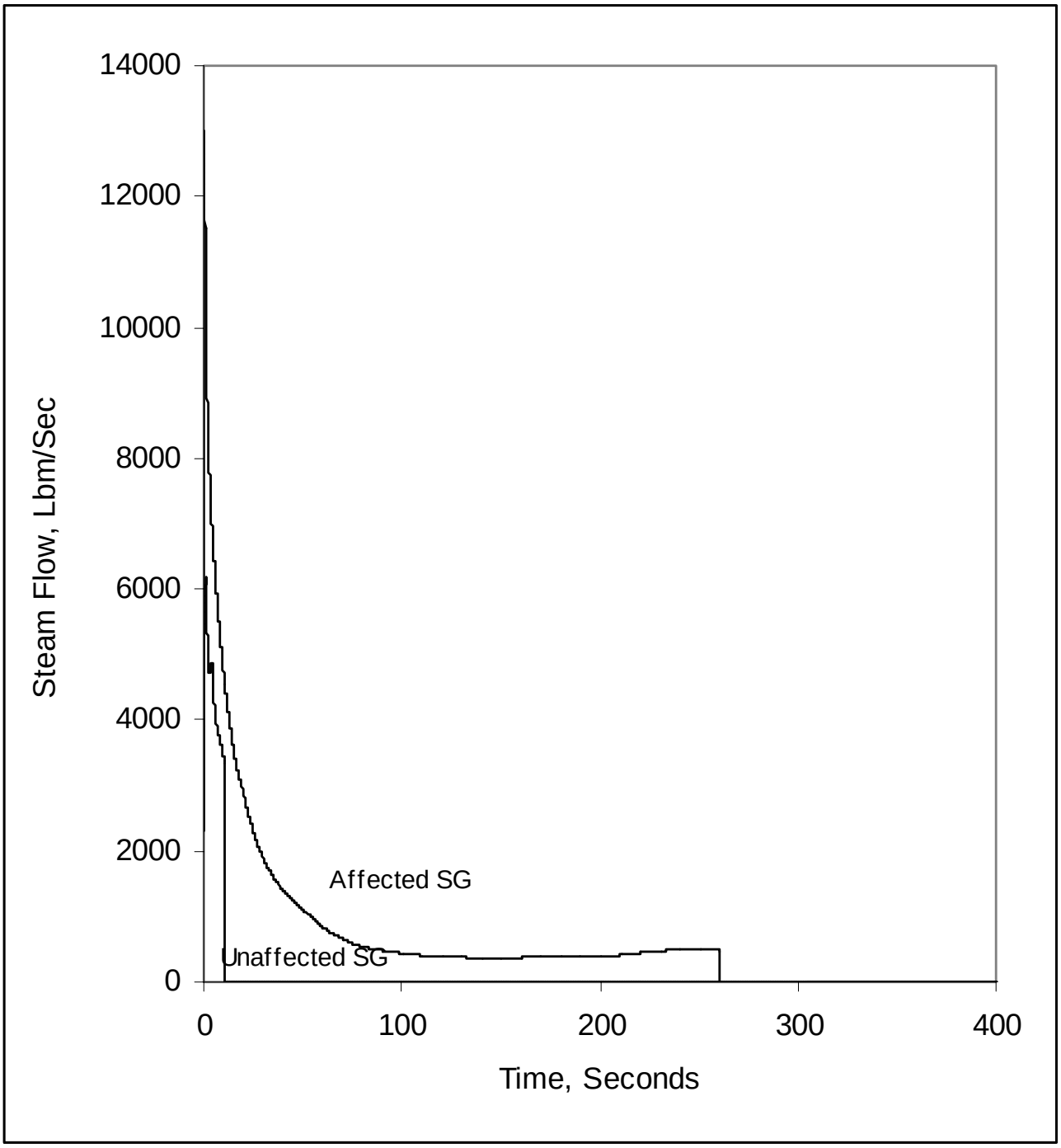

Figure 2.13.1.3.1-8
Inside Containment, HFP SLB with LOOP
Steam Flow vs. Time

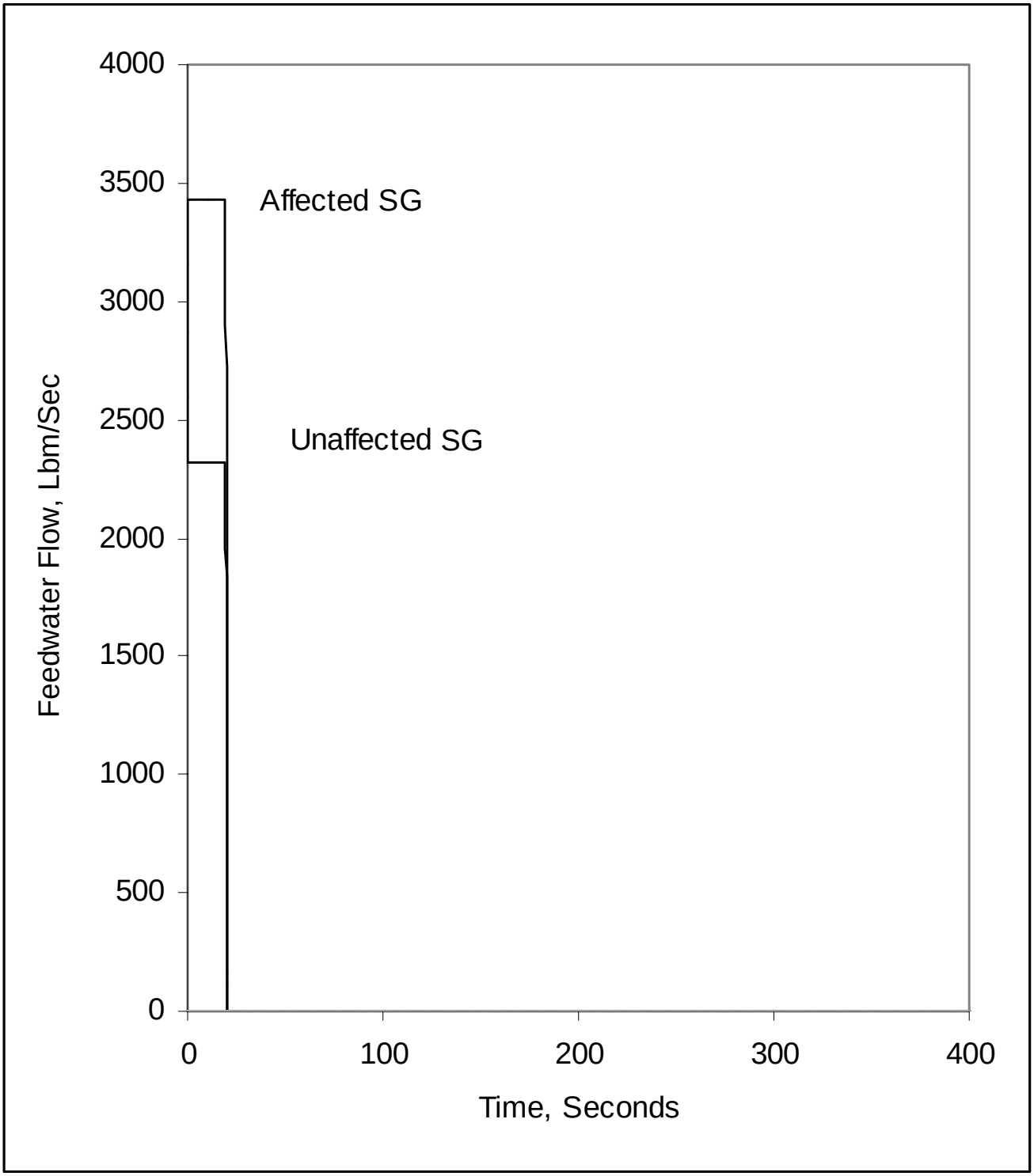

Figure 2.13.1.3.1-9
Inside Containment, HFP SLB with LOOP
Feedwater Flow vs. Time

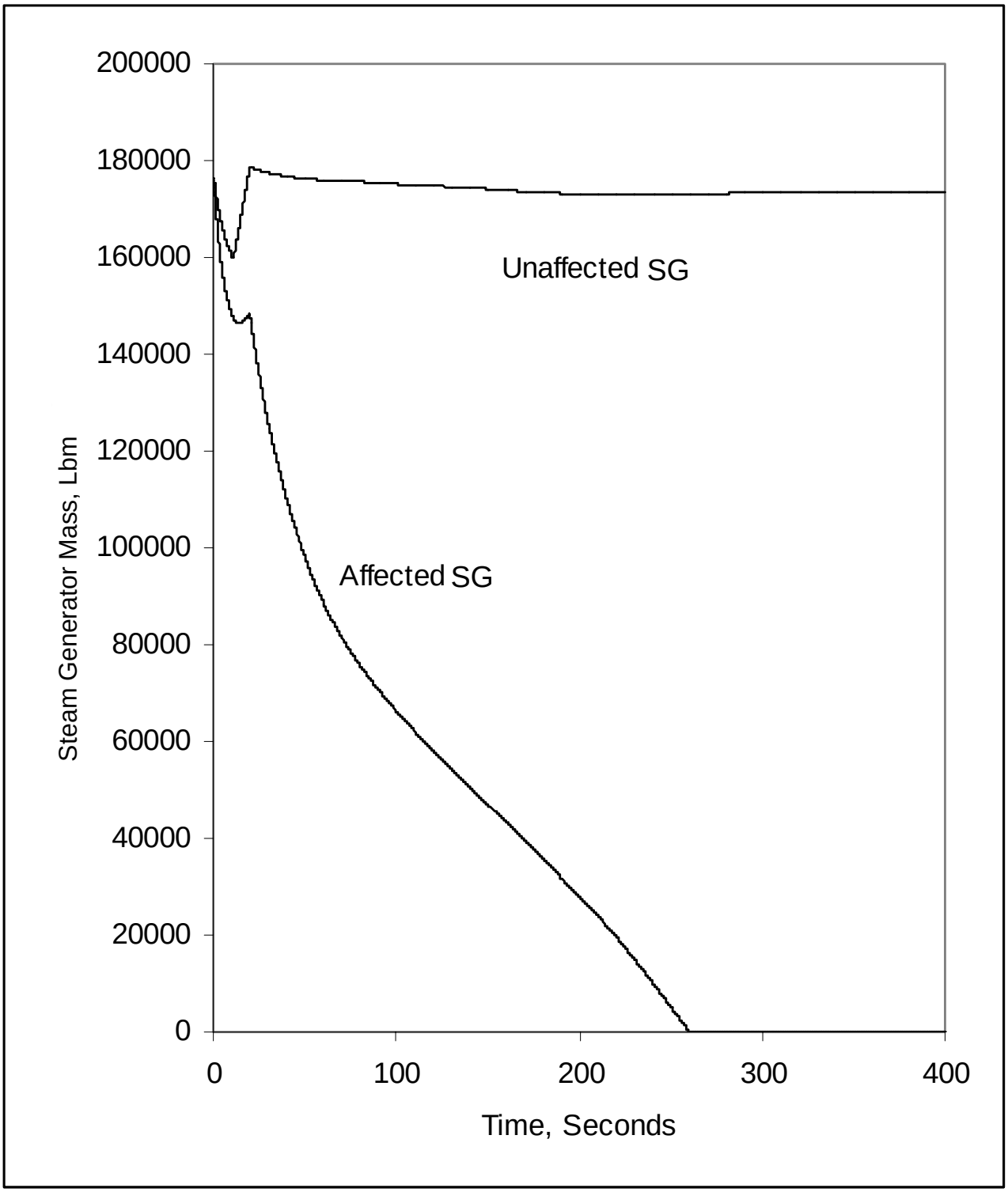

Figure 2.13.1.3.1-10
Inside Containment, HFP SLB with LOOP
SG Mass vs. Time

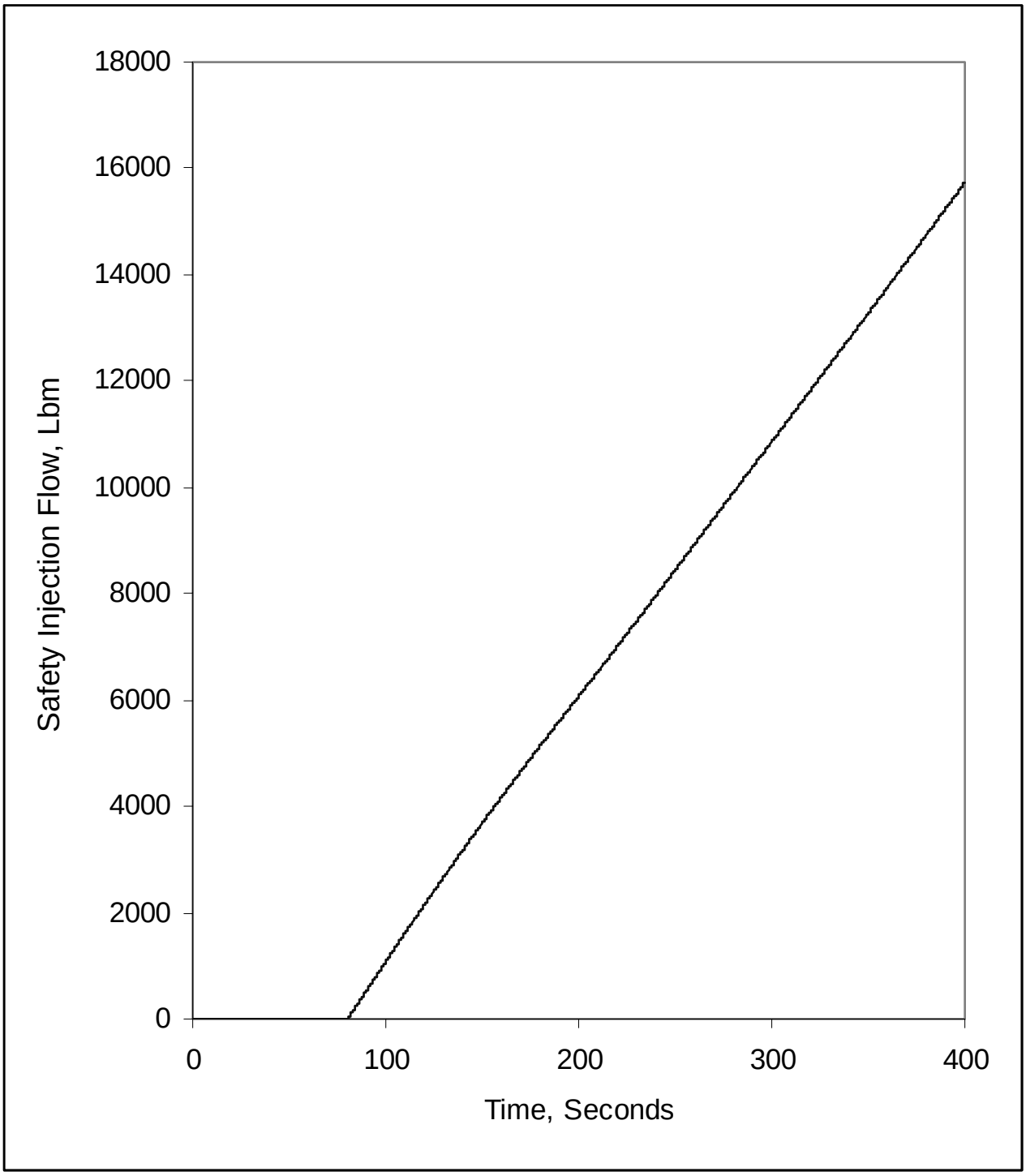

Figure 2.13.1.3.1-11
Inside Containment, HFP SLB with LOOP
Safety Injection Flow vs. Time

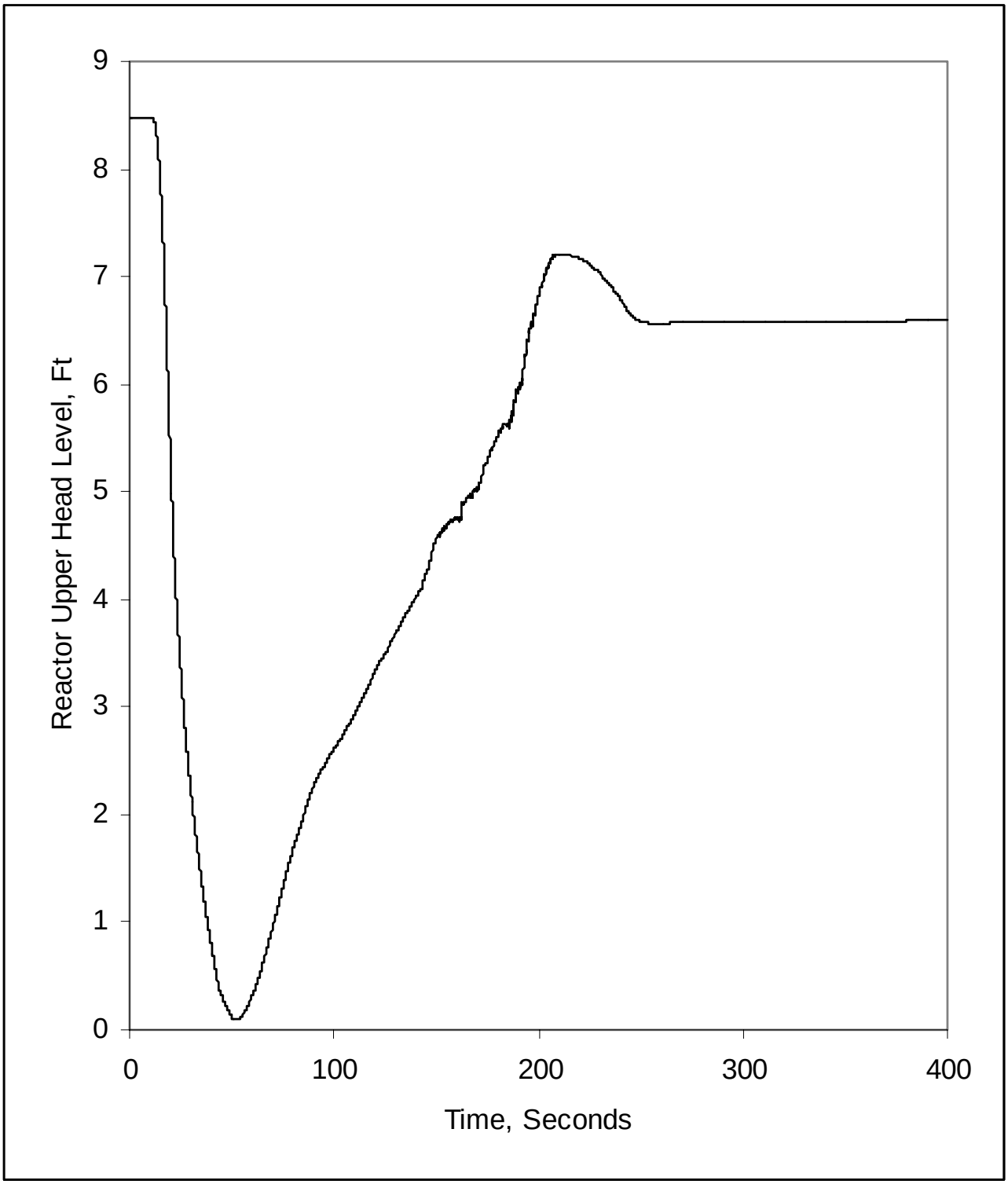

Figure 2.13.1.3.1-12
Inside Containment, HFP SLB with LOOP
Reactor Vessel Level vs. Time

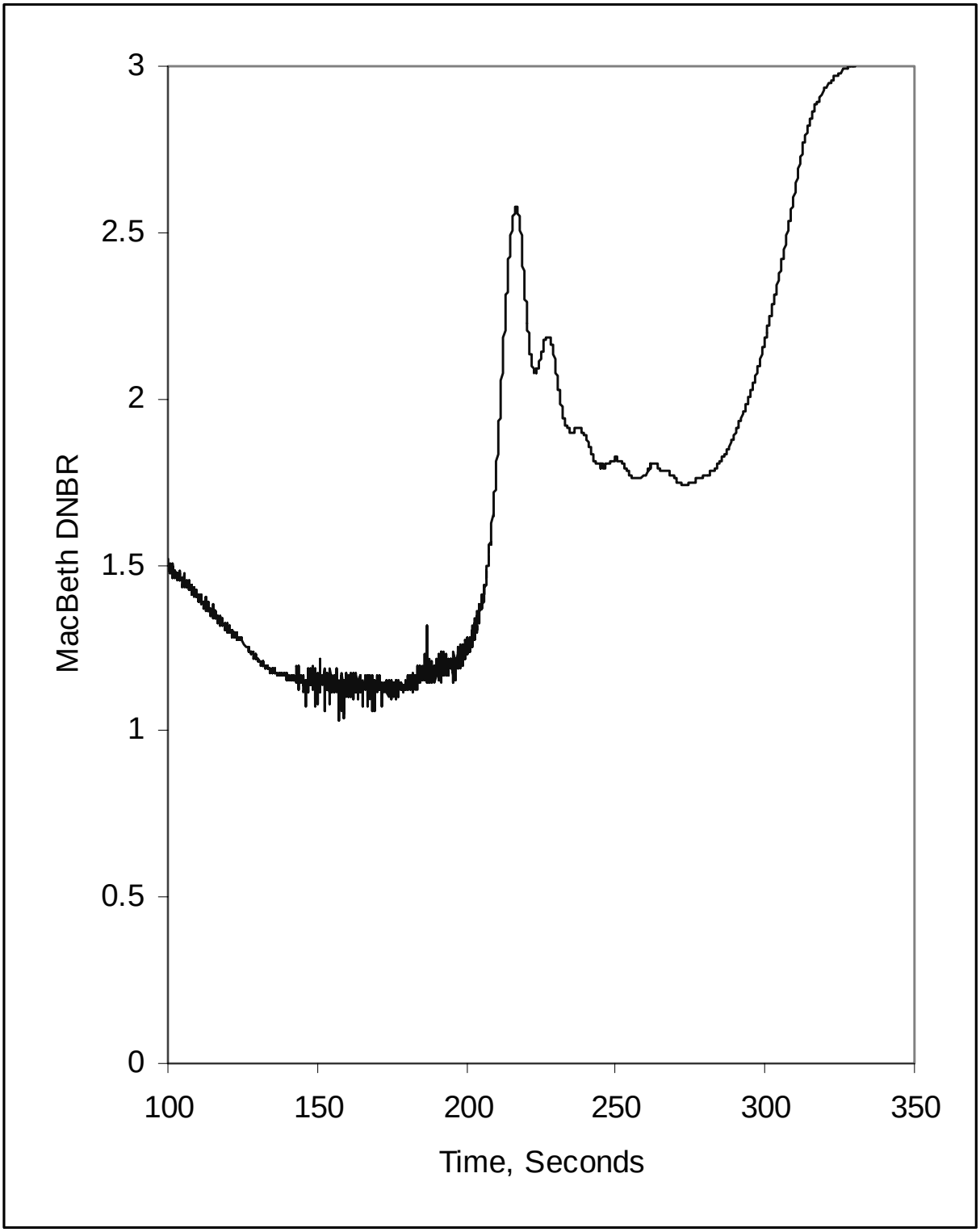

Figure 2.13.1.3.1-13
Inside Containment, HFP SLB with LOOP
DNBR vs. Time

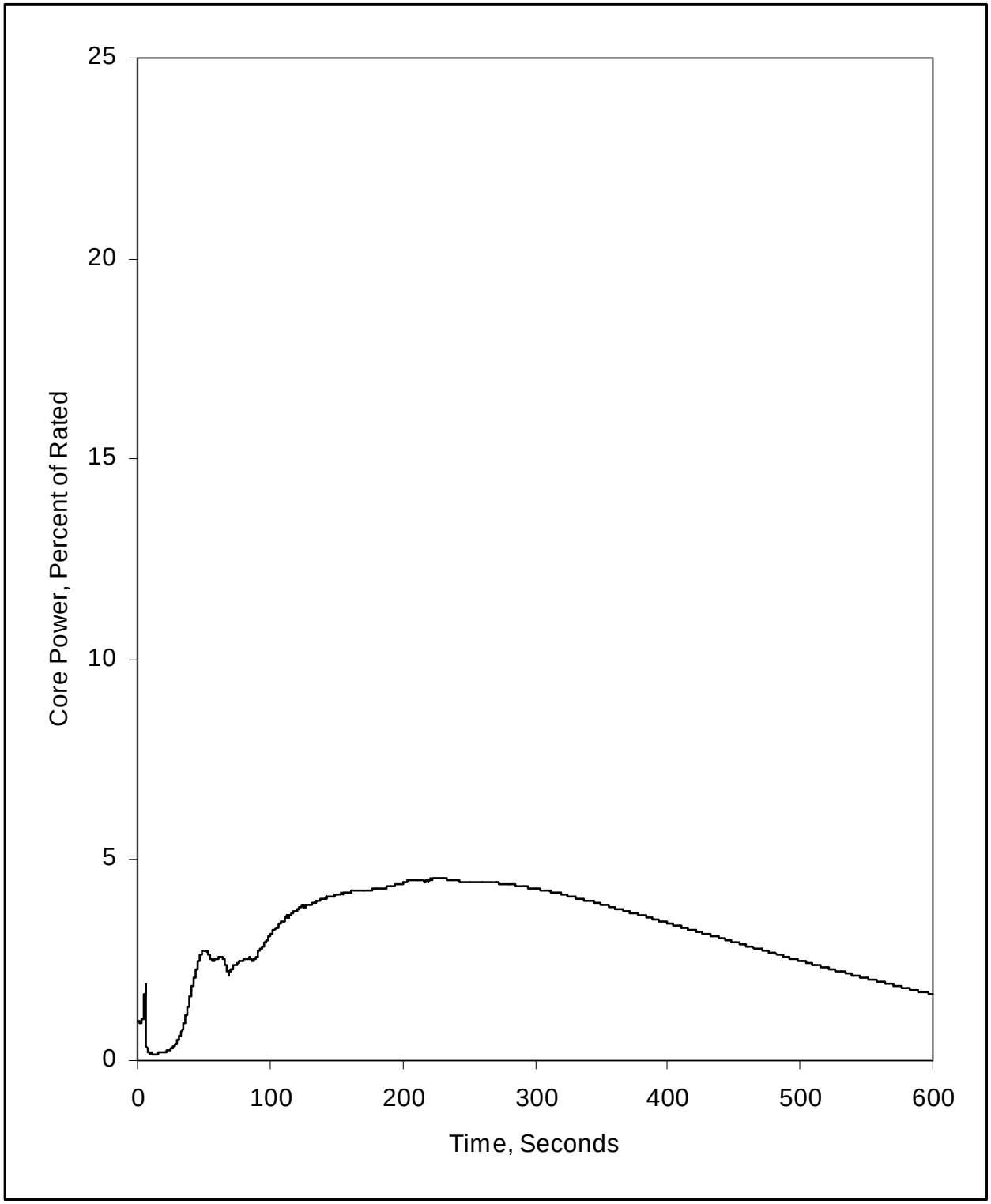

Figure 2.13.1.3.1-14
Inside Containment, HZP SLB with LOOP
Core Power vs. Time

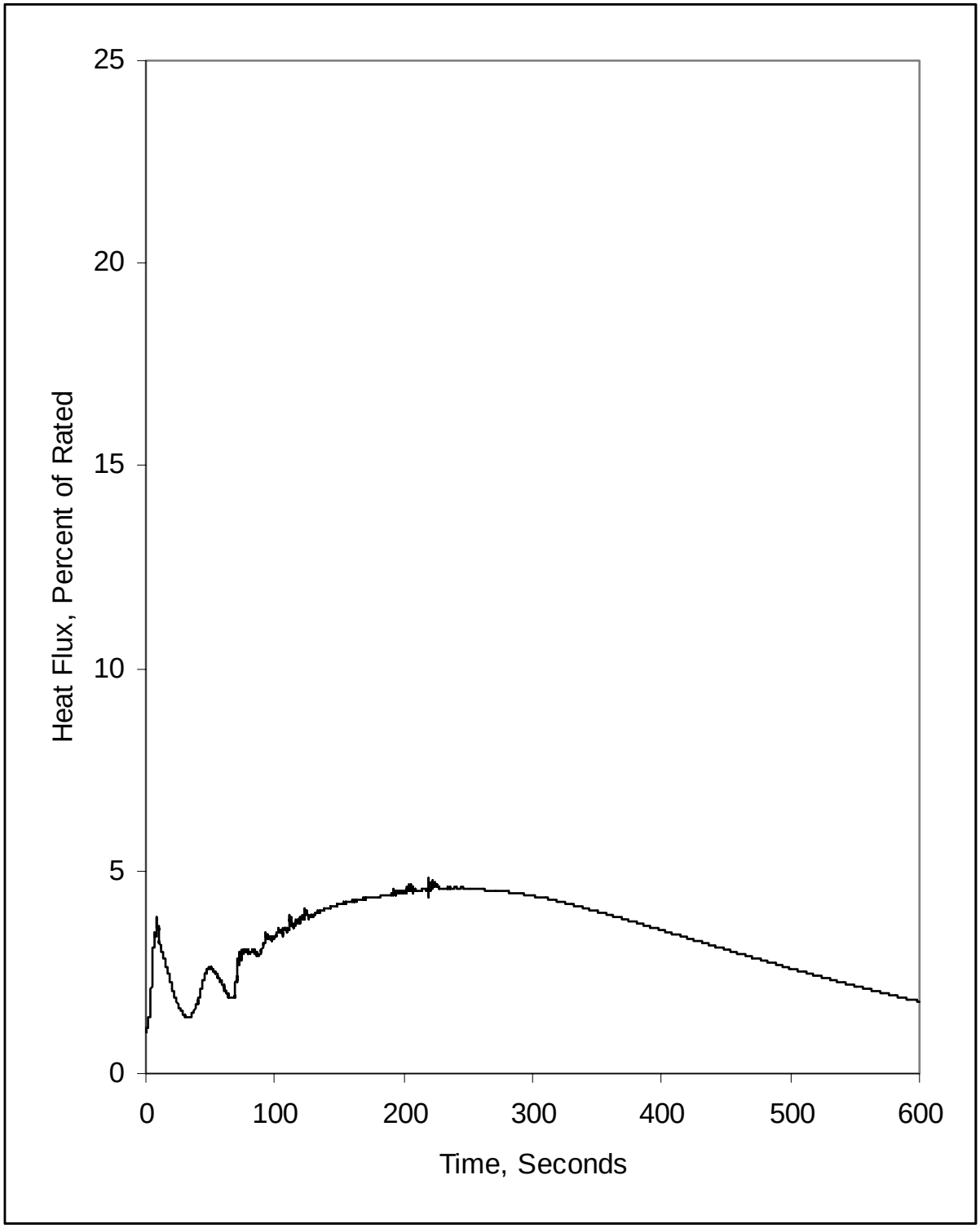

Figure 2.13.1.3.1-15
Inside Containment, HZP SLB with LOOP
Core Heat Flux vs. Time

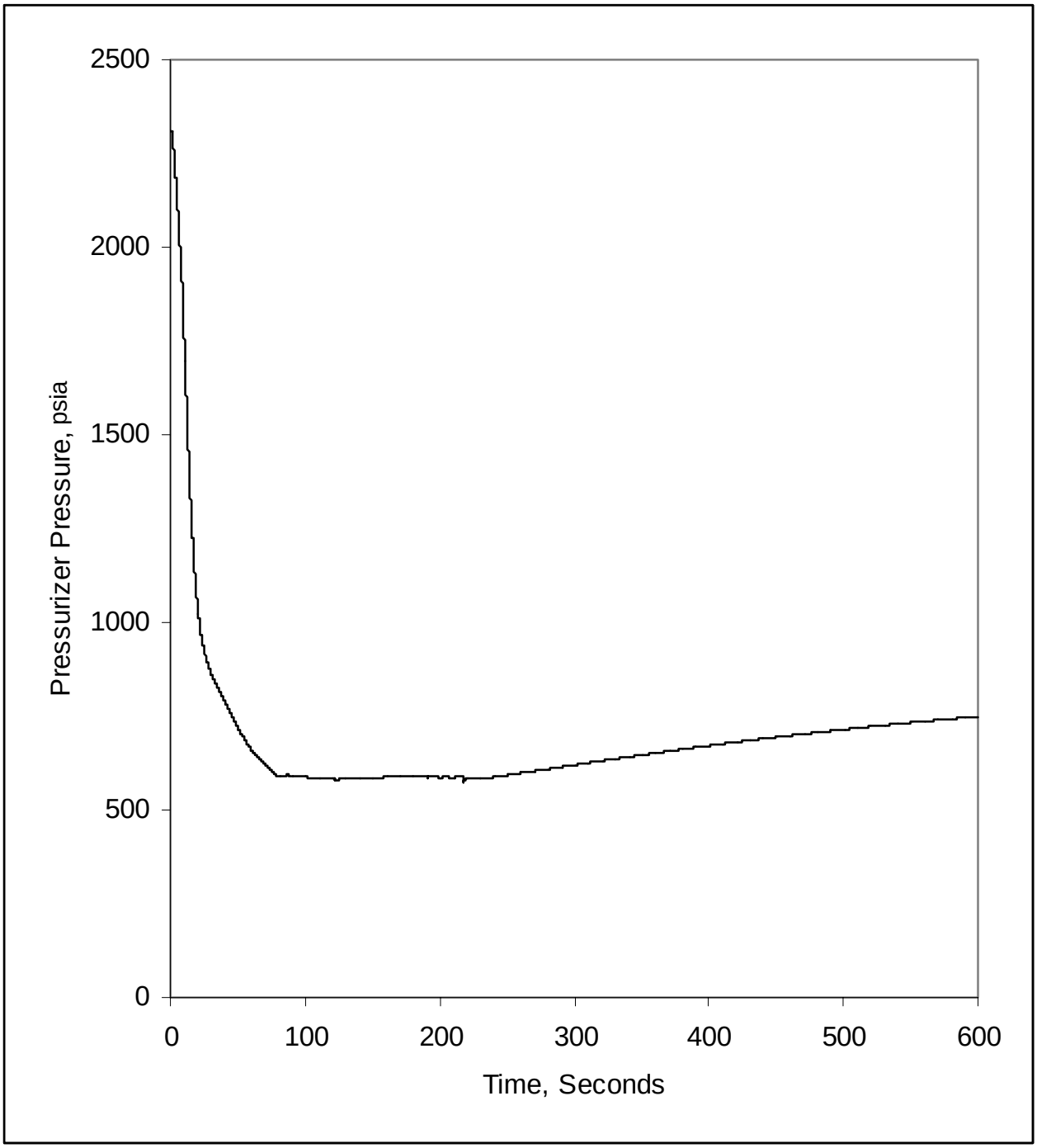

Figure 2.13.1.3.1-16
Inside Containment, HZP SLB with LOOP
Pressurizer Pressure vs. Time

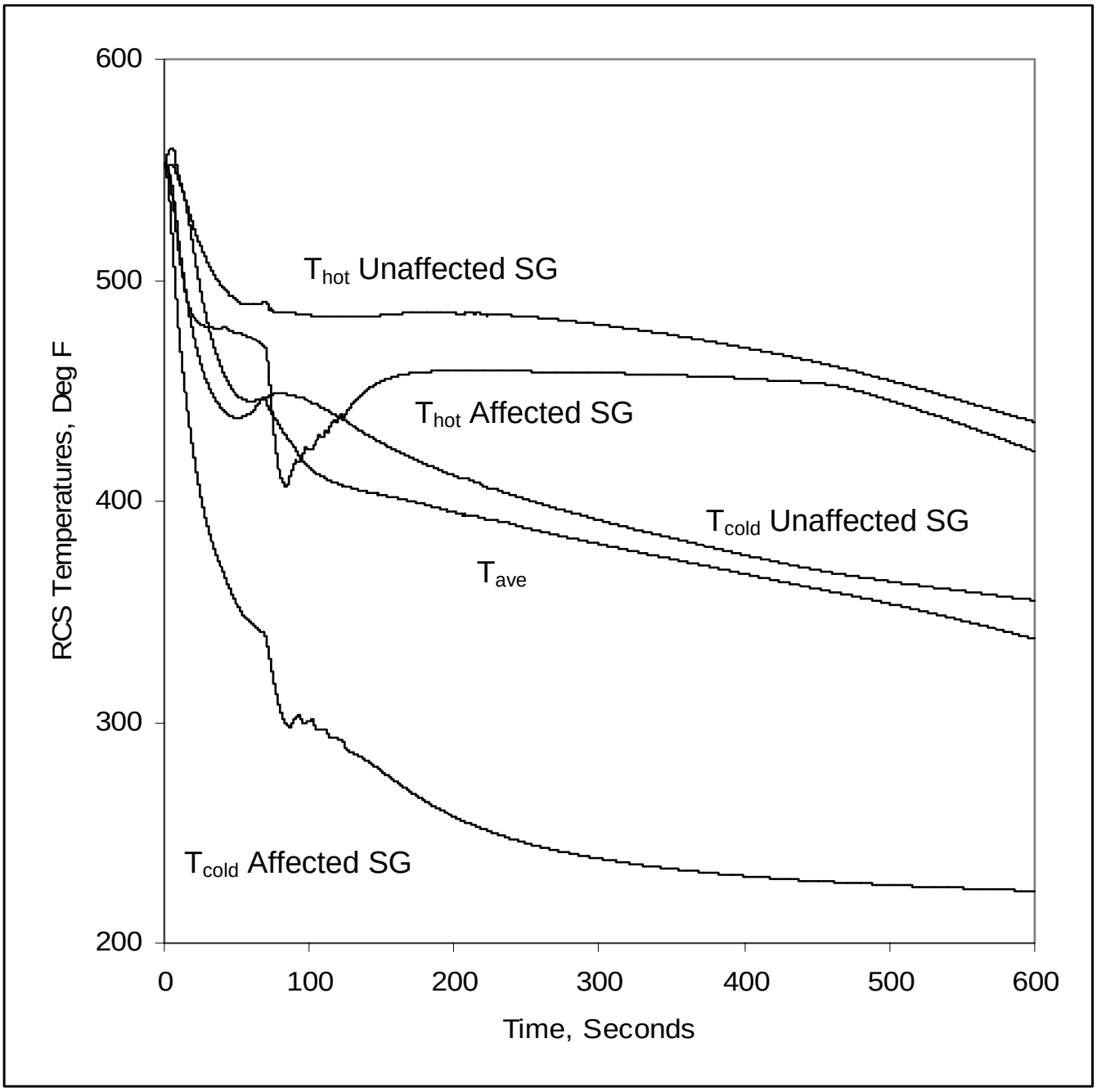

Figure 2.13.1.3.1-17
Inside Containment, HZP SLB with LOOP
RCS Temperature vs. Time

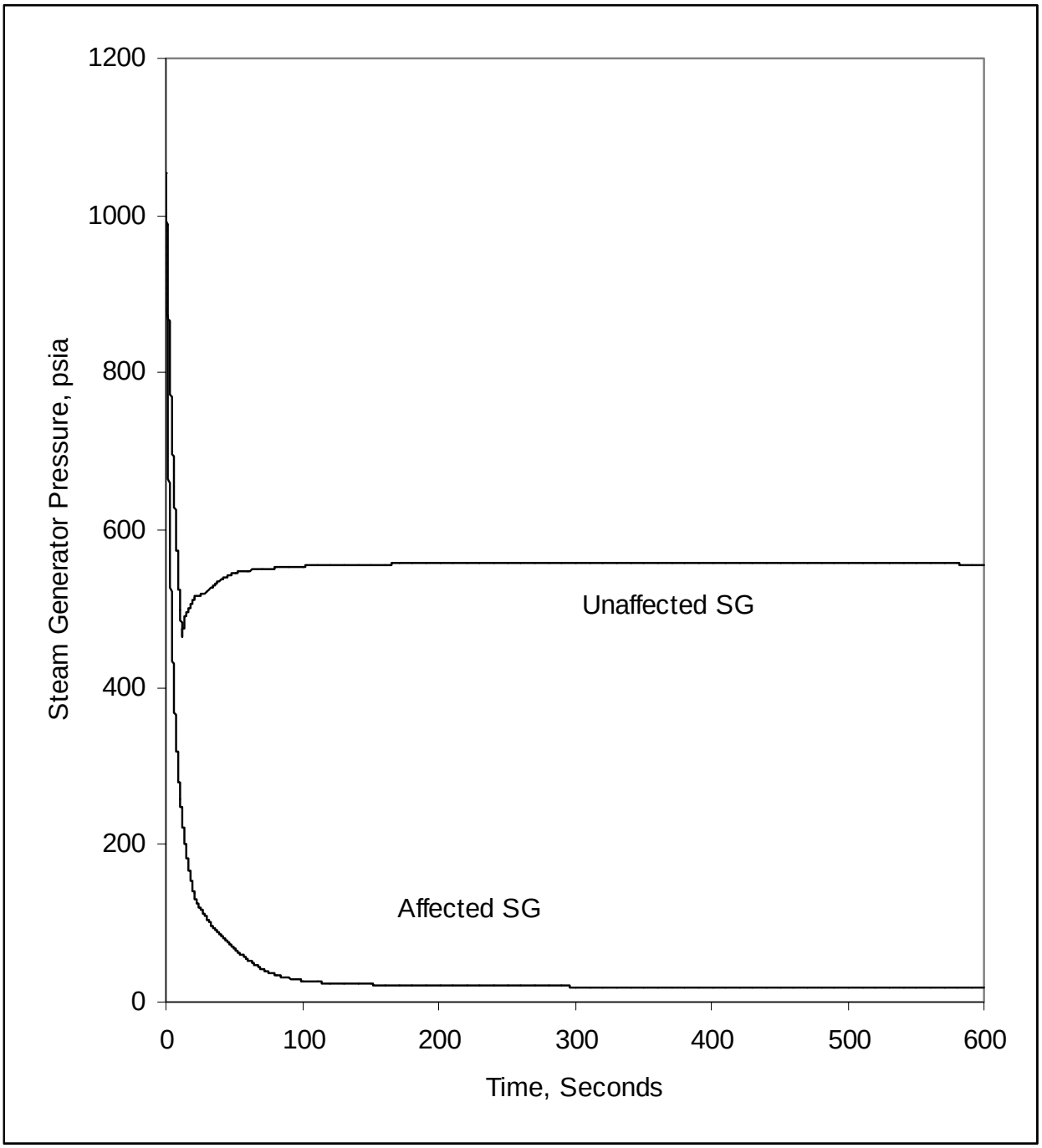

Figure 2.13.1.3.1-18
Inside Containment, HZP SLB with LOOP
SG Pressure vs. Time

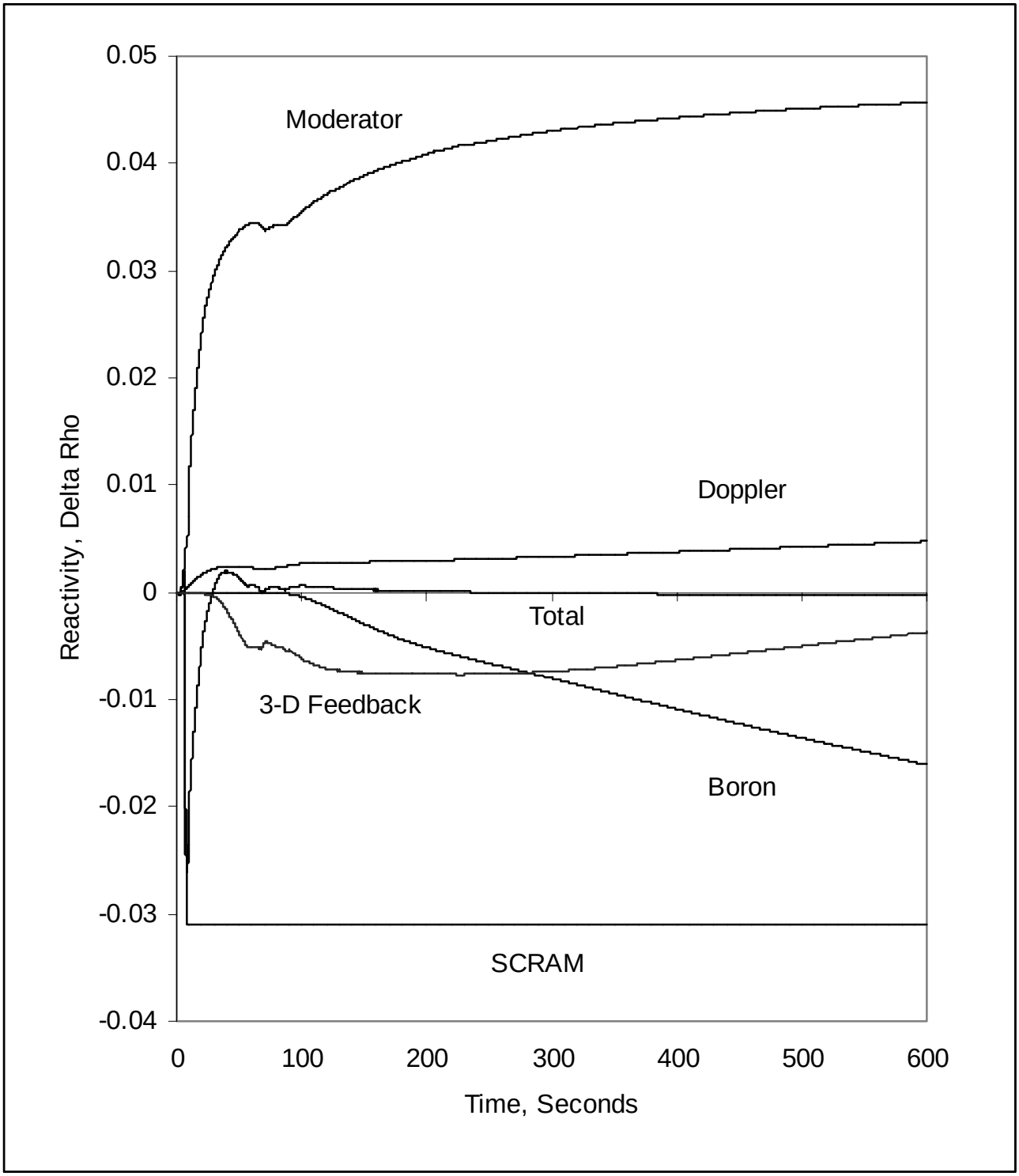

Figure 2.13.1.3.1-19
Inside Containment, HZP SLB with LOOP
Reactivity vs. Time

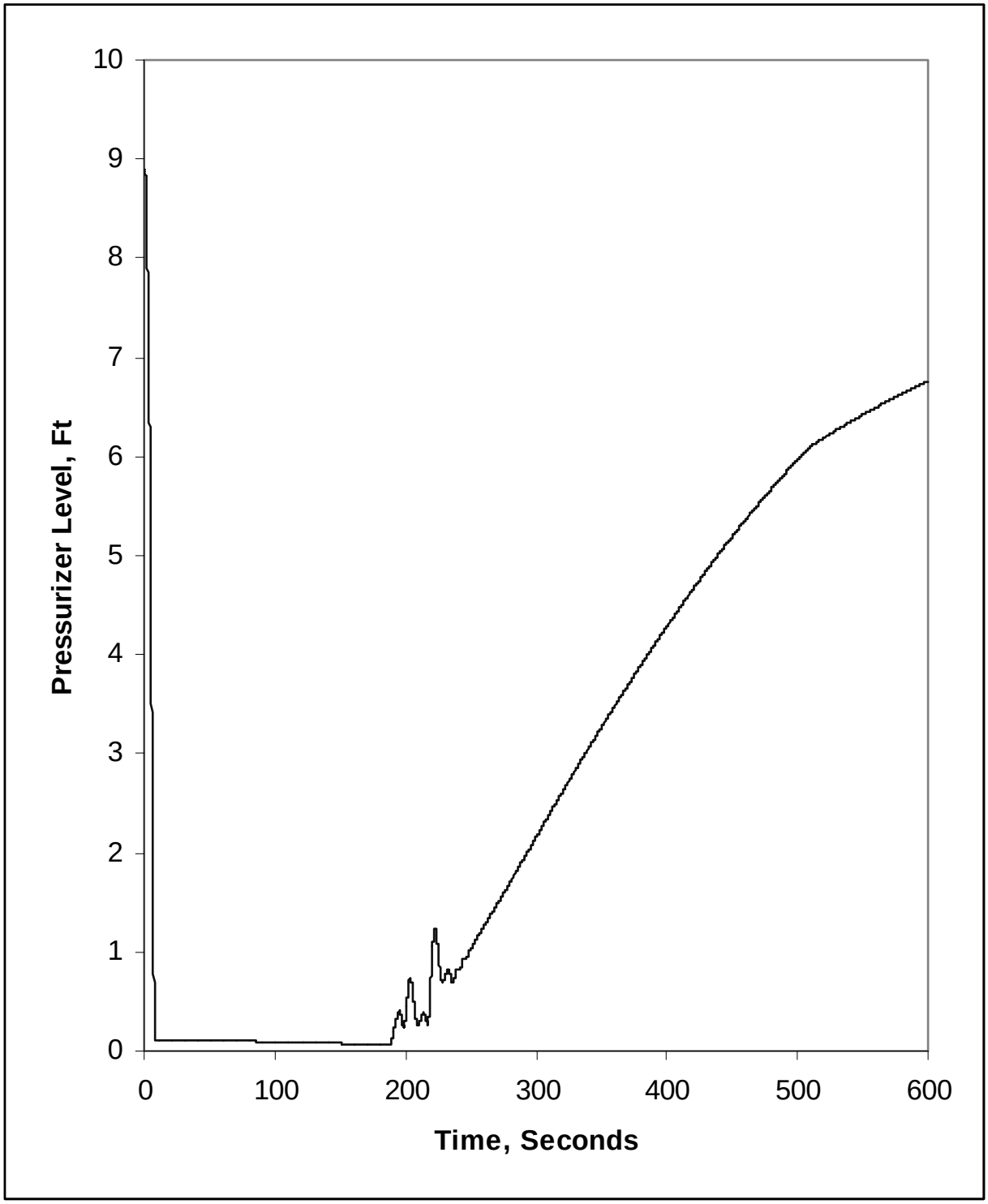

Figure 2.13.1.3.1-20
Inside Containment, HZP SLB with LOOP
Pressurizer Level vs. Time

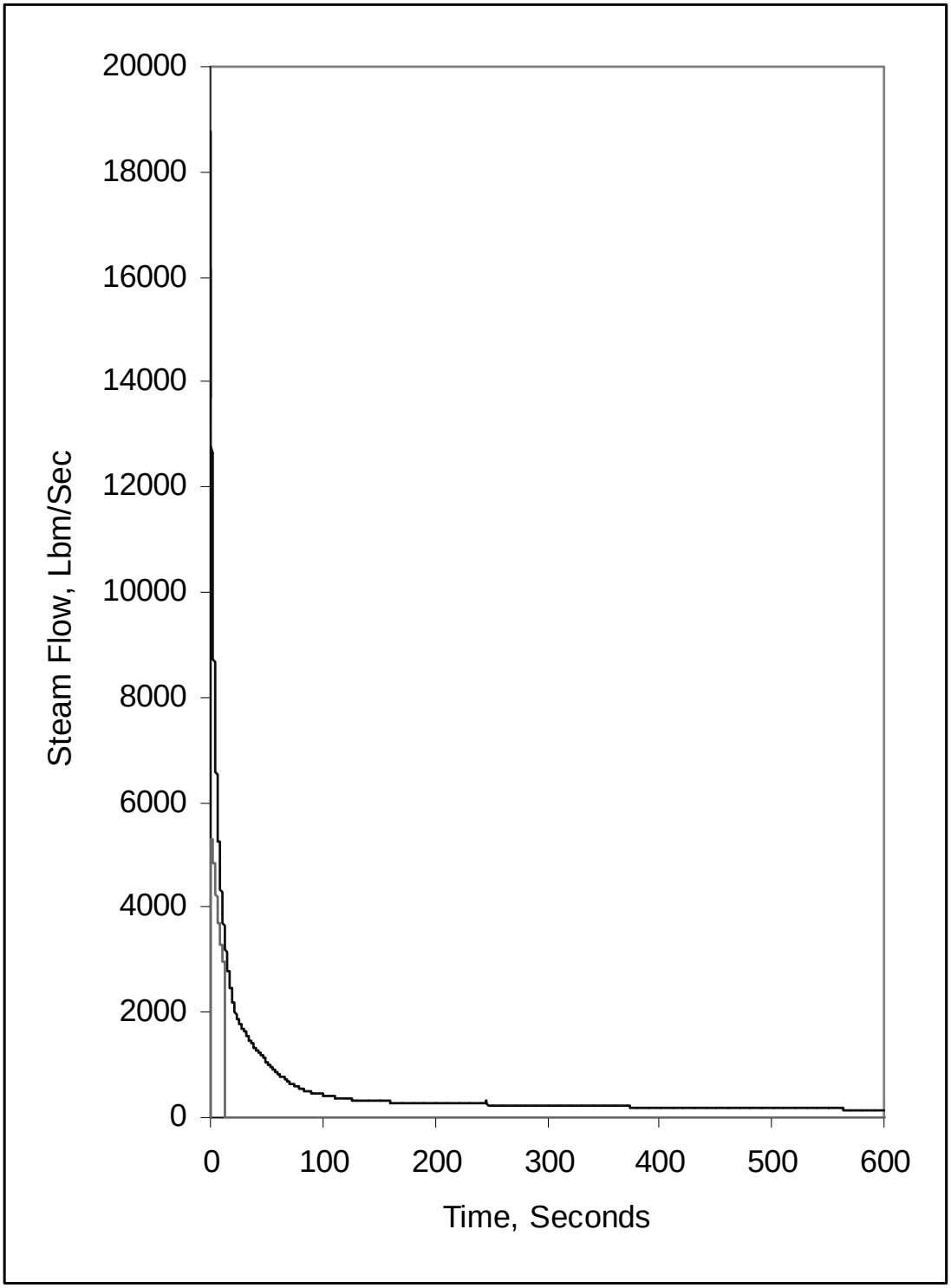

Figure 2.13.1.3.1-21
Inside Containment, HZP SLB with LOOP
Steam Flow vs. Time

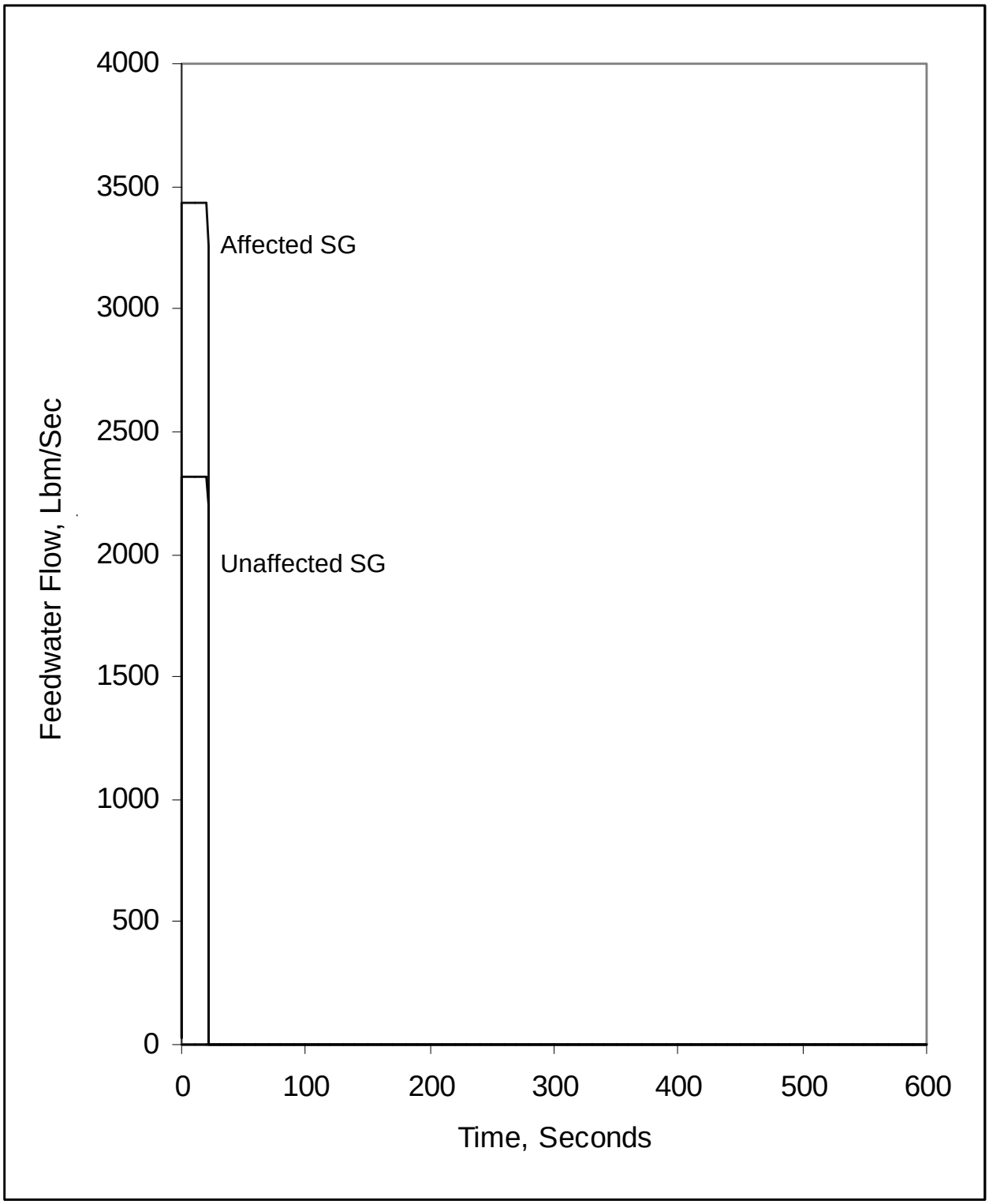

Figure 2.13.1.3.1-22
Inside Containment, HZP SLB with LOOP
Feedwater Flow vs. Time

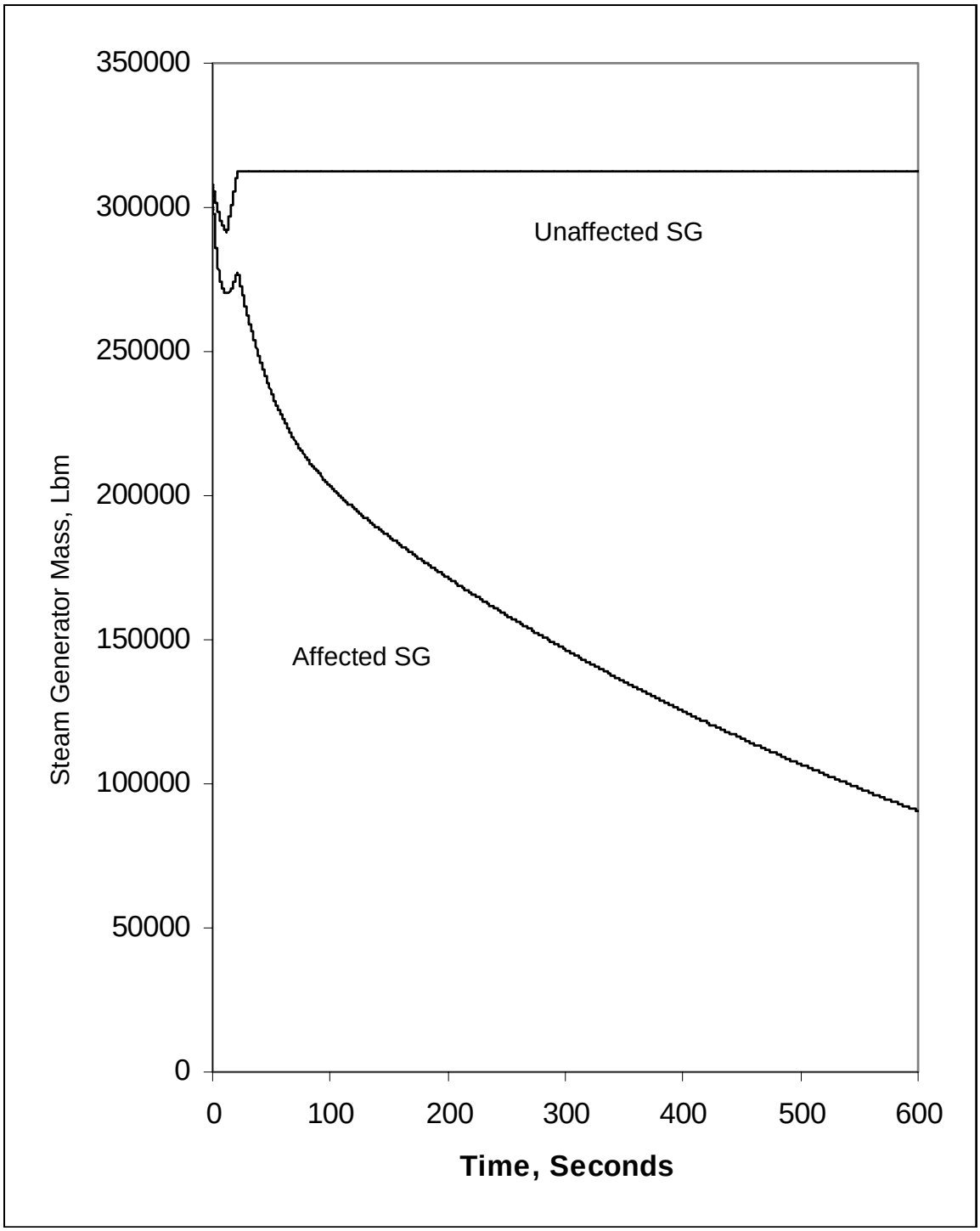

Figure 2.13.1.3.1-23
Inside Containment, HZP SLB with LOOP
SG Mass vs. Time

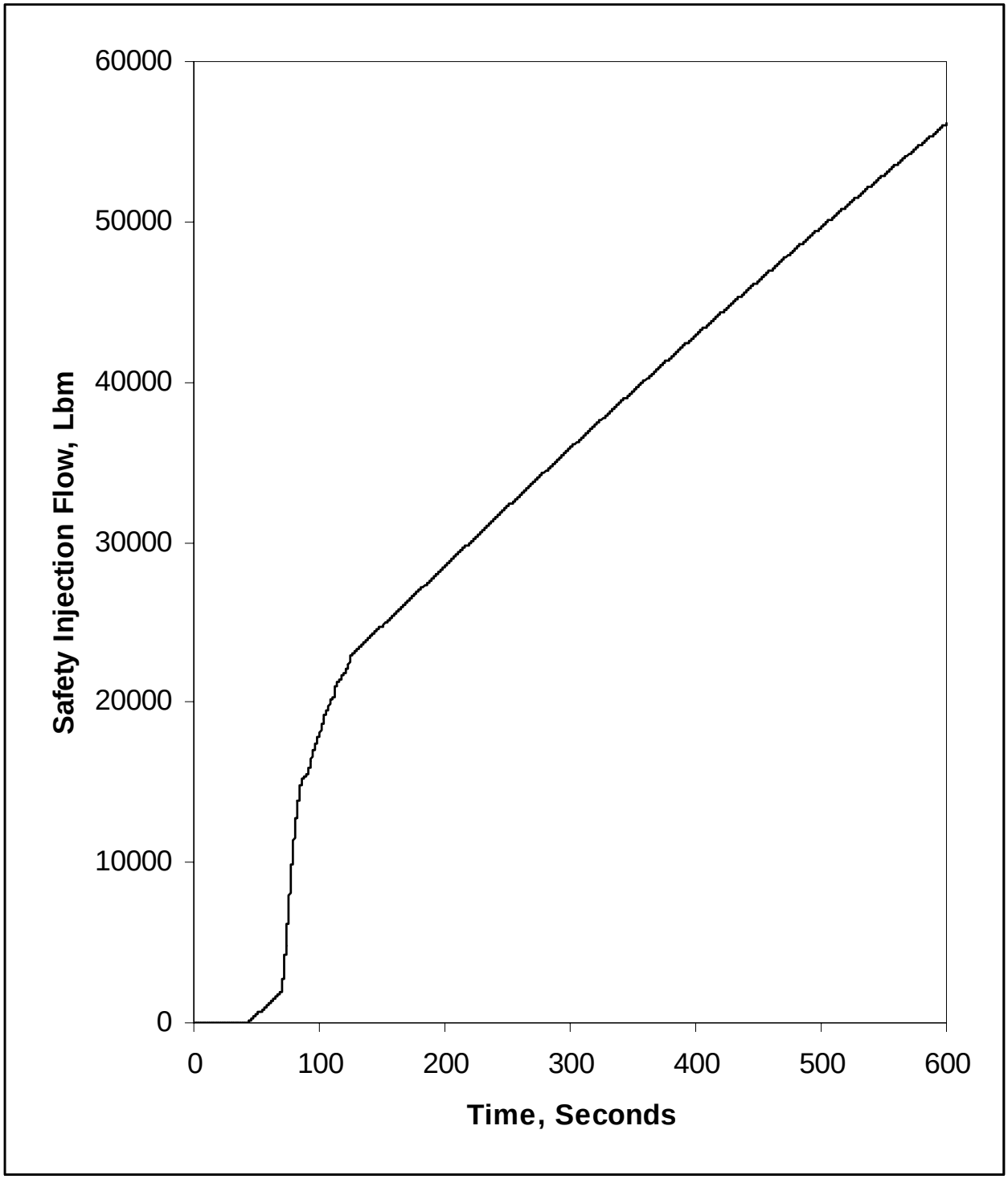

Figure 2.13.1.3.1-24
Inside Containment, HZP SLB with LOOP
Safety Injection Flow vs. Time

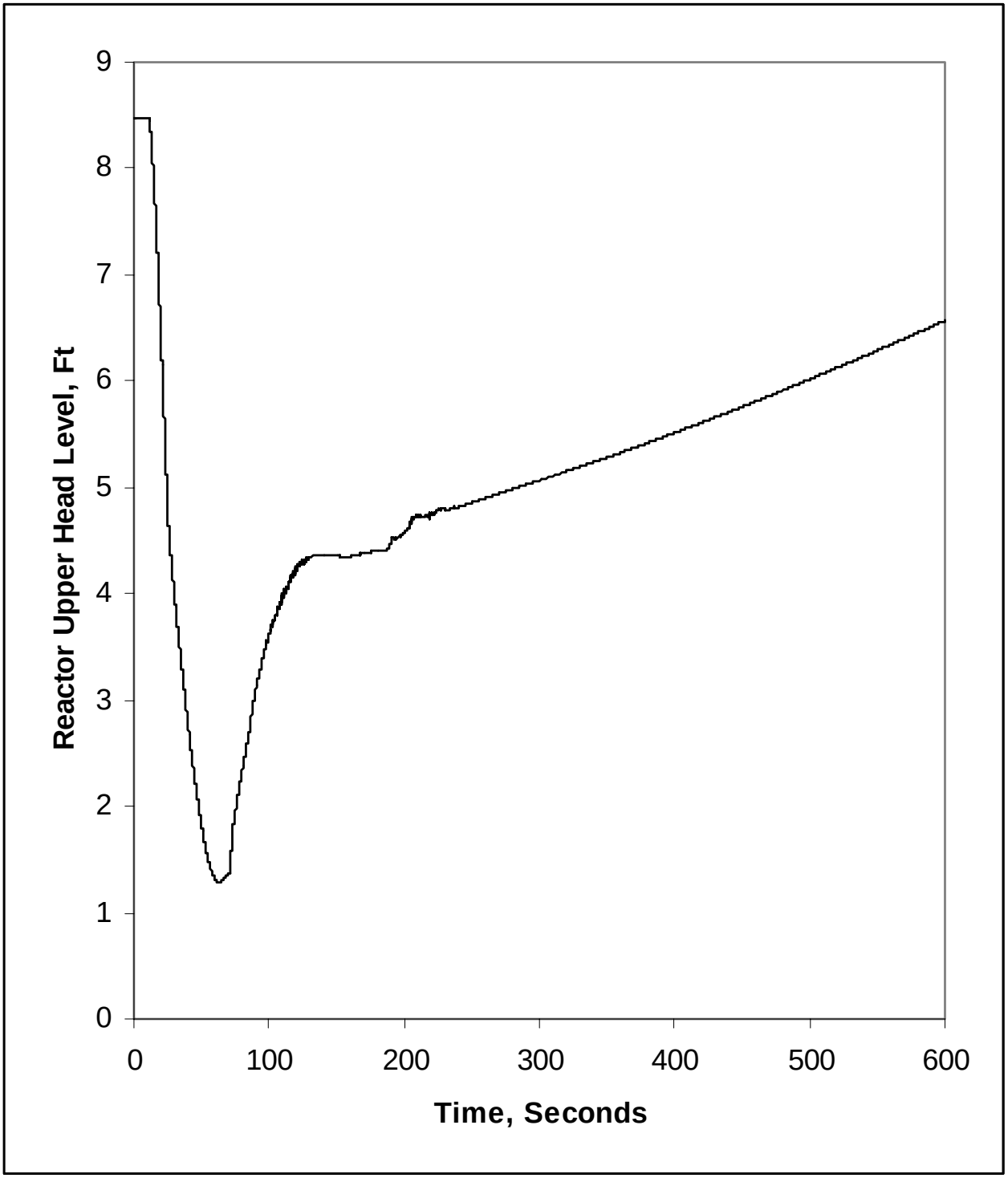

Figure 2.13.1.3.1-25
Inside Containment, HZP SLB with LOOP
Reactor Vessel Level vs. Time

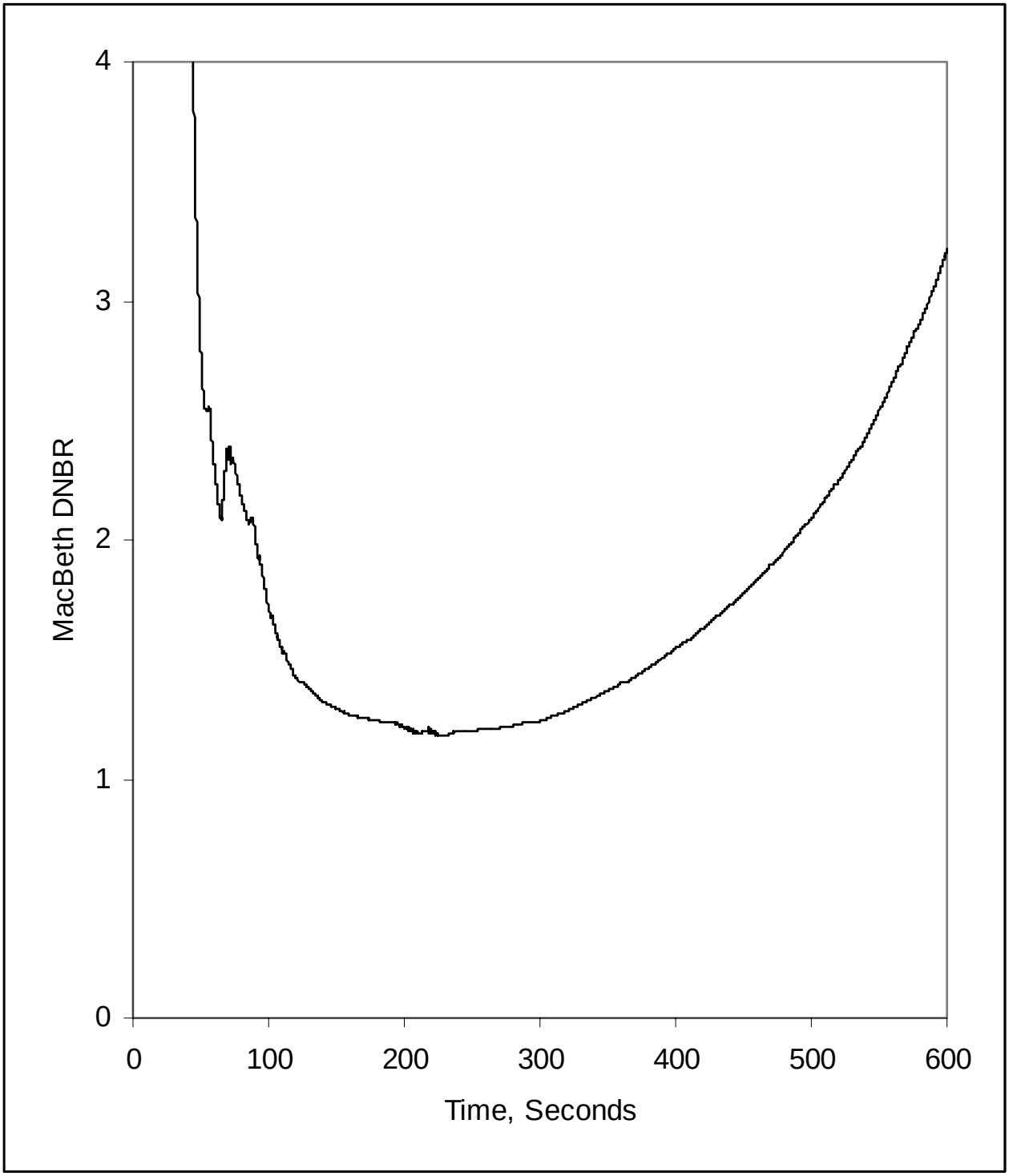

Figure 2.13.1.3.1-26
Inside Containment, HZP SLB with LOOP
DNBR vs. Time

2.13.1.3.2 Mode 3 and 4 All Rods In (ARI) (RTP) SLB

Event is bounded by current FSAR analysis.

2.13.1.3.3 Steam System Piping Failures Pre-Trip Power Excursion

The objective of the pre-trip SLB analysis is to document the impact of the following changes:

- The increase in rated power to 3716 MWt
- Using the CENTS code rather than the CESEC code as the NSSS simulation tool
- Change in most negative MTC from -4.0×10^{-4} $\Delta\rho/°F$ to -4.2×10^{-4} $\Delta\rho/°F$

2.13.1.3.3.1 General Description of the Event

The initiating event is the instantaneous break in a main steam line with the plant at power. The increased steam flow resulting from the break in the main steam system piping results in increased heat removal from the affected SG and causes a cooldown of the RCS. With an EOC (most negative) MTC, the core power rapidly increases, pressure decreases, and core heat flux increases, resulting in a decrease in DNBR. The CPCS VOPT produces a reactor trip when core power exceeds the VOPT setpoint. The insertion of the CEAs upon reactor trip terminates the DNBR excursion.

2.13.1.3.3.2 Purpose of Analysis and Acceptance Criteria

The purpose of this analysis is to examine the thermal margin degradation and fuel failure immediately before and after trip during a steam line break event. Longer term effects are discussed in the return to power SLB event. (Section 2.13.1.3.1) Two break locations were analyzed: an inside containment (IC) break and an outside containment (OC) break. The OC break, due to the smaller flow area, does not result in SAFDL violation. The IC break cases do allow some fuel failure. Should fuel failure occur, a radiological dose assessment is performed. If fuel failure does not occur, the radiological doses for return to power steam line break are bounding for this event.

The criteria for the pre-trip SLB are the following:

- Minimum DNBR ≥1.26 for no fuel failure (OC). If the IC minimum DNBR < 1.26 then a fuel failure analysis must be performed
- Radiological doses ≤ 10CFR100 limits
- Fuel temperature ≤ fuel centerline melt temperature, as demonstrated by peak LHR ≤ 21.0 kW/ft.

This event is described in Section 15.1.3.3 of the Safety Analysis Report (SAR) (Reference 2.13-1).

2.13.1.3.3.3 Impact of Changes

The increase in power could result in a small degradation of the thermal margin for the IC break.

The more negative MTC will tend to result in a faster power rise in response to a given break size.

The CENTS code is used in the same manner and with the same conservatisms (i.e., no moisture carryover) as the CESEC code has been.

2.13.1.3.3.4 Analysis Overview

The NSSS response is modeled using the CENTS code. (Reference 2.13-2) The minimum DNBR evaluation was determined using the CETOP code. (Reference 2.13-3)

The most adverse timing of the LOOP was obtained by varying the time of its occurrence around the time of reactor trip. The inside containment break LOOP occurred at 4.35 seconds. The outside-containment LOOP occurred at 4.16 seconds.

Input parameters from Tables 2.13.1.3.3-1 (IC) and 2.13.1.3.3-2 (OC) and the bounding physics data from Section 2.13.0.2 have been incorporated in this analysis with the following clarifications:

- The BOC Doppler was assumed. This maximizes the power increase prior to reactor trip.
- An EOC delayed neutron fraction and neutron lifetime consistent with those defined in Section 2.13.0.2 were assumed.
- The CEA insertion curve accounts for a 0.6-second holding coil delay. A CEA worth of -6.0% $\Delta\rho$ was assumed.
- The analysis is conservatively based on a guillotine SLB with an effective area of 3.14 ft^2 for the outside-containment break, and 5.5 ft^2 for the IC break.
- The VOPT of the CPCS was employed in the analysis. A cold leg RTD response time of 8 seconds was accounted for along with a CPCS trip delay time of 0.629 seconds, which is conservative and exceeds the expected delay time of 0.2669 seconds described in Section 2.13.3 of this report plus the full power nuclear instrument delay time of 5 milliseconds.
- An initial core power of 3735 MWt, based on a rated power of 3716 MWt and a 0.5% uncertainty, was assumed.
- The most negative MTC of $-4.2*10^{-4}$ $\Delta\rho/°F$ was assumed.

2.13.1.3.3.5 Radiological Consequences

With the release path resulting from inside containment SLB's, the fuel failure that would result in the 10CFR100 limits being reached is well in excess of 10% of the pins in DNB (MSLB with LOOP) and well in excess of 2% for pins with centerline melting violation.

The pre-trip SLB event with no LOOP does not result in violation of the DNBR SAFDL. The pre-trip SLB with LOOP, discussed in this section results in a limited violation of the DNBR SAFDL. The thermal hydraulic conditions present in the core at the time of minimum DNBR in this analysis will be evaluated in combination with the cycle-specific pin census each reload cycle. It will be verified that fewer than 8.0% of the fuel pins will be predicted to experience DNB via the method of statistical convolution.

Similarly, a limited amount of SAFDL violation will occur during the RTP SLB. The extent of this SAFDL violation will be confirmed each reload cycle. The no-LOOP RTP SLB will be limited to 2% of the pins in violation of the fuel melting SAFDL. The LOOP RTP SLB will be limited to less than 2% of the pins in violation of the MacBeth DNBR SAFDL.

The fuel pin census applicable to the Pre-Trip phase of the SLB is typical of the HFP power distribution. The fuel pin census applicable to the RTP phase of the SLB is governed by the power distribution that would be present in the core in the N-1 configuration. As these two power distributions are independent of each other, the total fuel failure associated with the SLB event is taken as the summation of the fuel failure for these two scenarios.

Thus for the SLB event with no LOOP, the total fuel failure is ≤2% of the pins in violation of the fuel melting SAFDL. These failures occur entirely due to the RTP phase of the no-LOOP phases of the SLB event.

For the SLB event with LOOP, the total fuel failure is ≤10.0% of the pins experiencing DNB. Of these, 8.0% are attributable to the pre-trip phase and 2% are attributable to the RTP phase.

The radiological consequences resulting from these fuel failure results are:

	2-Hour EAB	**8-Hour LPZ**
Thyroid	< 300 rem	< 300 rem
Whole Body	< 25 rem	< 25 rem

2.13.1.3.3.6 Analysis Results

The primary reactor trip for the pre-trip SLB event is the CPCS VOPT. The initial thermal margin was selected to ensure no fuel failure occurs for the OC breaks. This margin, in conjunction with the input parameters from Tables 2.13.1.3.3-1 and 2.13.1.3.3-2 and the physics data from Section 2.13.0.2 resulted in the lowest calculated DNBR.

Table 2.13.1.3.3-3 delineates the sequence of events for the pre-trip SLB IC event. A CPCS VOPT occurs at 3.63 seconds, which results in a minimum DNBR of 1.1602 at 6.7 seconds. Figures 2.13.1.3.3-1 through 2.13.1.3.3-7 illustrate the behavior of key parameters associated with the pre-trip SLB event.

As shown in Table 2.13.1.3.3-4 for the pre-trip SLB outside-containment event, a CPCS VOPT occurs at 3.73 seconds, which results in a minimum DNBR of 1.2879 at 6.7 seconds. The minimum DNBR remains greater than the SAFDL value of 1.26.

Table 2.13.1.3.3-1
Key Parameters Assumed for the Steam Piping Failures Event
IC Pre-Trip Power Excursions

Parameter	Power Uprate Assumption	Current Power Level Assumption
Initial Core Power, MWt	3735	3482
Core Inlet Temperature, °F	552	560
Pressurizer Pressure, psia	2310	2000
RCS Flowrate, 10^6 m/hr	148.0	137.0
Pressurizer Level, %	35.8	---
SG Pressure, psia	878	976
SG Level, % NR	65 (36.1 ft)	---
MTC, 10^{-4} $\Delta\rho$/°F	-4.2	-4.0
Doppler Coefficient Multiplier	0.85 (BOC)	0.85 (BOC)
Kinetics	Minimum β	Minimum β
CEA Worth at Trip, %$\Delta\rho$	-6.0	-6.0
Break Size ft^2	5.5	5.25

Table 2.13.1.3.3-2
Key Parameters Assumed for the Steam Piping Failures Event
OC Pre-Trip Power Excursions

Parameter	Power Uprate Assumption	Current Power Level Assumption
Initial Core Power, MWt	3735	3482
Core Inlet Temperature, °F	552	560
Pressurizer Pressure	2310	2000
RCS Flowrate, 10^6 lbm/hr	146	137
Pressurizer Level, %	35.8	---
SG Pressure, psia	878	976
SG Level, % WR	65 (36.1 ft)	---
MTC, 10^{-4} $\Delta\rho$/°F	-4.2	-4.0
Doppler Coefficient Multiplier	0.85 (BOC)	0.85 (BOC)
Kinetics	Minimum β	Minimum β
CEA Worth at Trip, %$\Delta\rho$	-6.0	-6.0
Break Size ft^2	3.14	3.14

Table 2.13.1.3.3-3
Sequence of Events for the Steam System Piping Failure Event
IC Pre-Trip Power Excursion with LOOP

3716 MWt EPU Time (sec)	Current Power Level Time (sec)	Event	3716 MWt EPU Setpoint/Value	Current Power Level Setpoint/Value
0.0	0.0	Failure in the MSSS Piping	5.5 ft^2	5.25 ft^2
3.63	4.57	CPCS VOPT trip occurs	113.63% of 3716 MWt	117.14% of 3482 MWt
4.06	5.2	Trip breakers open	---	---
4.35	6.0	LOOP occurs, RCPs begin coastdown	---	---
4.66	5.8	CEAs begin to drop	---	---
5.42	6.0	Maximum core power	136.06% of 3716 MWt	137.53% of 3482 MWt
5.96	6.35	Maximum core heat flux	119.73% of 3716 MWt	119.4% of 3482 MWt
6.7	6.9	Minimum DNBR	1.1602	1.1617

Table 2.13.1.3.3-4
Sequence of Events for the Steam System Piping Failure Event
OC Pre-Trip Power Excursion with LOOP

3716 MWt EPU Time (sec)	Current Power Level Time (sec)	Event	3716 MWt EPU Setpoint/Value	Current Power Level Setpoint/Value
0.0	0.0	Failure in the MSSS piping	3.14 ft^2	3.14 ft^2
3.73	5.4	CPCS VOPT trip occurs	114.31% of 3716 MWt	115% of 3482 MWt
4.16	6.1	Trip breakers open	---	---
4.16	6.1	LOOP occurs, RCPs begin coastdown	---	---
4.27	6.6	Maximum core power	121% of 3716 MWt	129% of 3482 MWt
4.75	7.0	Maximum core heat flux	110% of 3716 MWt	116% of 3482 MWt
4.76	6.5	CEAs begin to drop	---	---
6.3	7.2	Minimum DNBR	1.2754	1.23

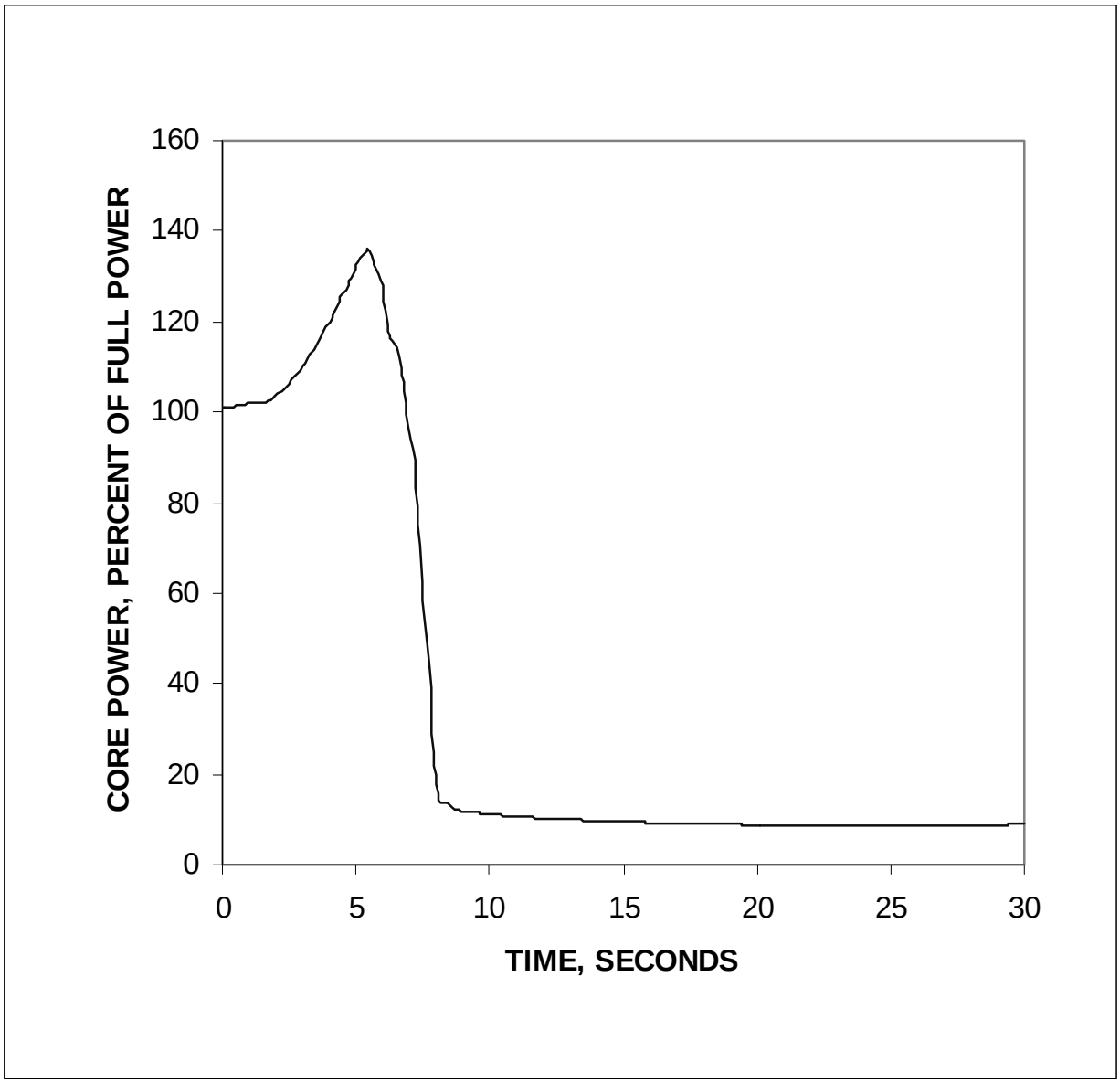

Figure 2.13.1.3.3-1
IC, SLB, Pre-Trip Power Excursions
Core Power vs. Time

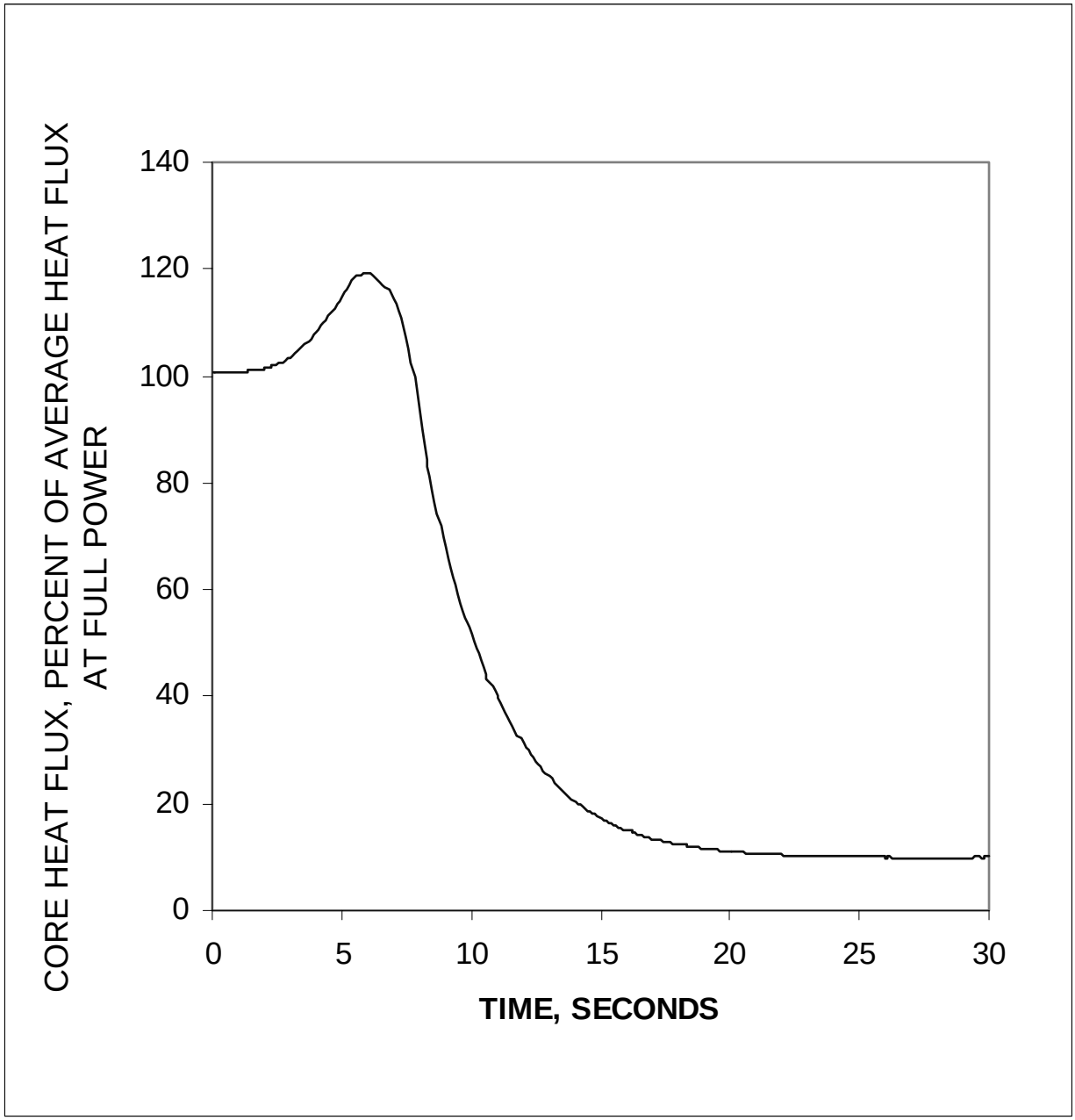

Figure 2.13.1.3.3-2
IC, SLB, Pre-Trip Power Excursions
Core Heat Flux vs. Time

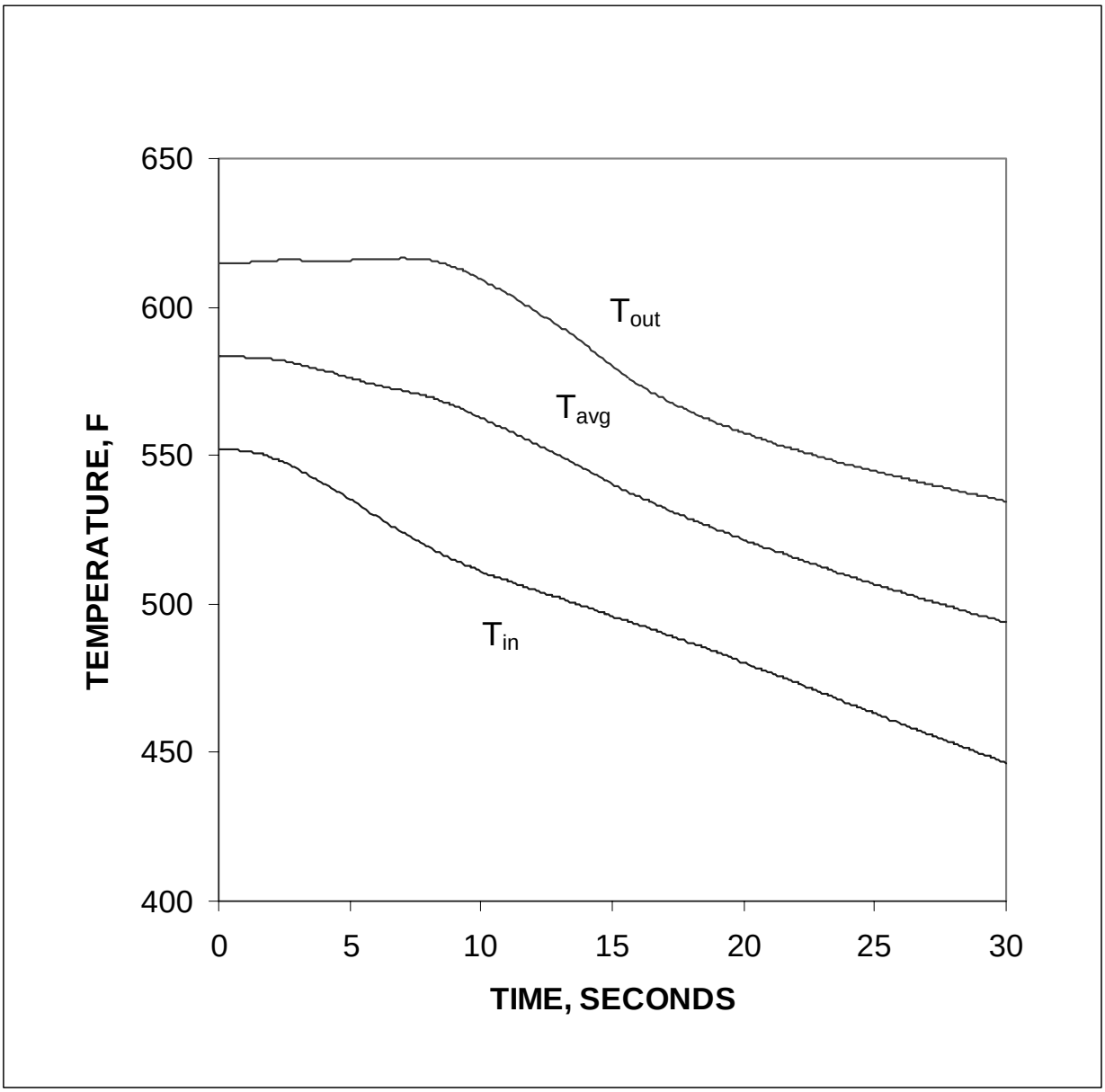

Figure 2.13.1.3.3-3
IC, SLB, Pre-Trip Power Excursions
RCS Temperature vs. Time

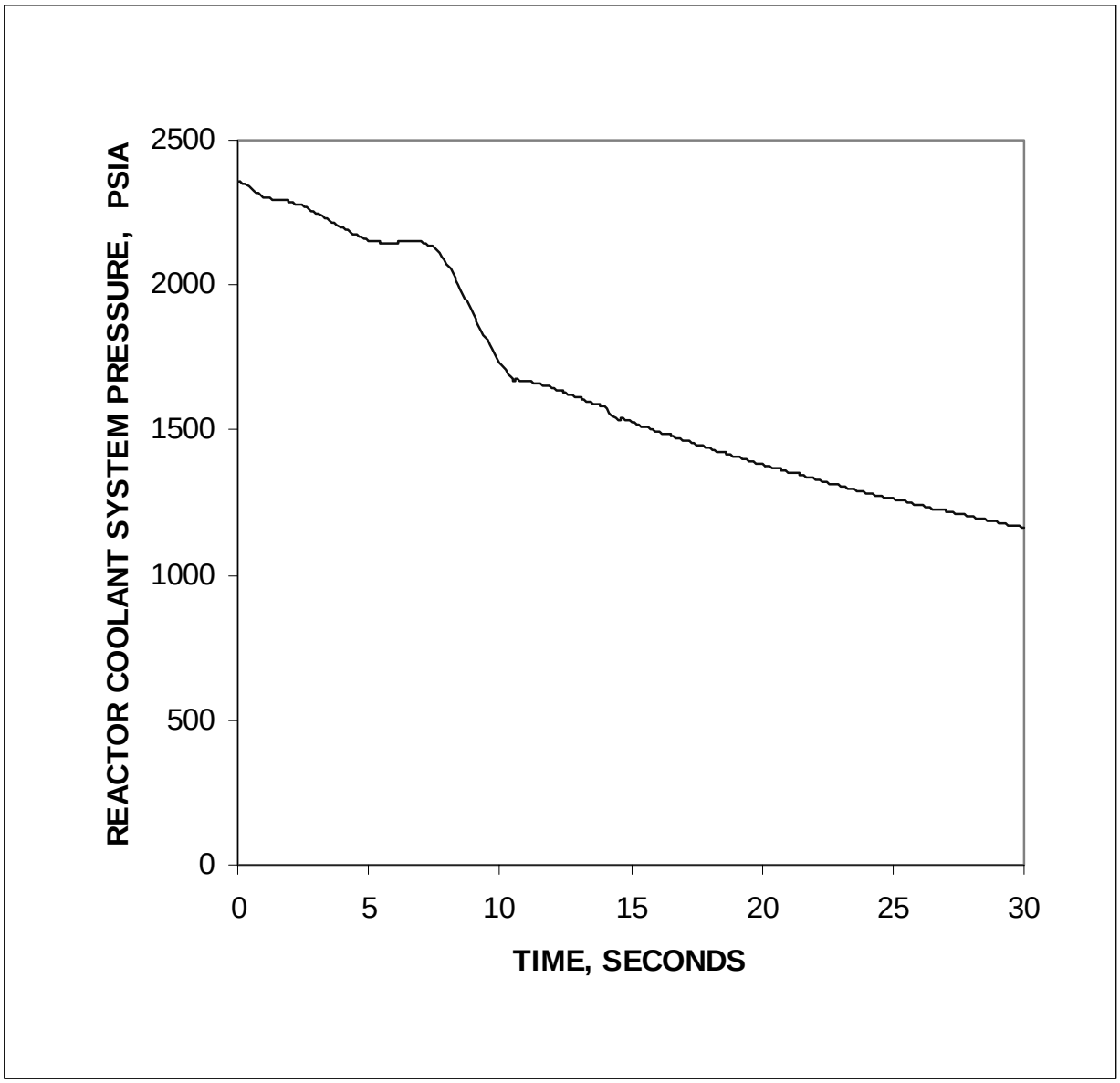

Figure 2.13.1.3.3-4
IC, SLB, Pre-Trip Power Excursions
RCS Pressure vs. Time

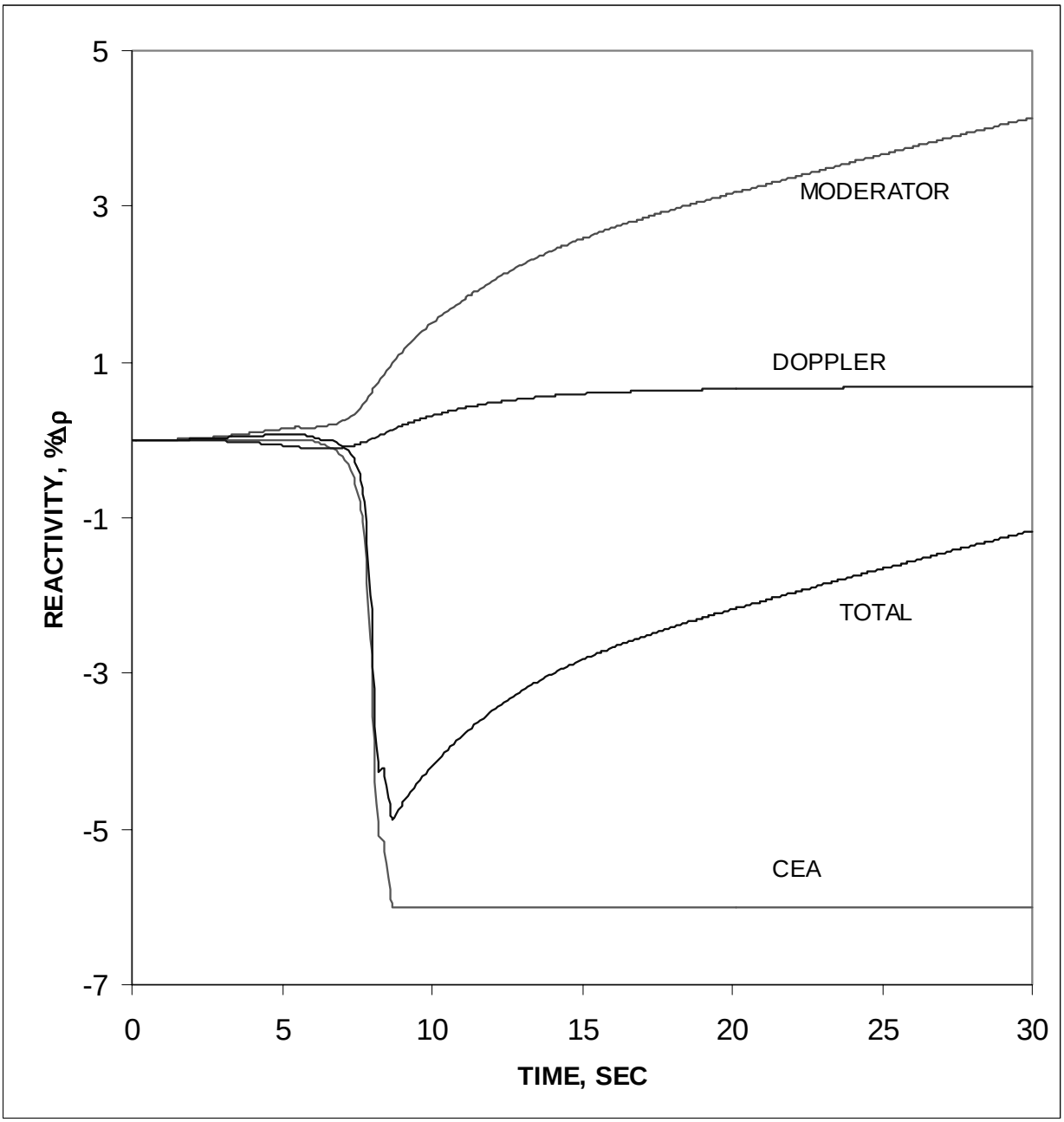

Figure 2.13.1.3.3-5
IC, SLB, Pre-Trip Power Excursions
Reactivity vs. Time

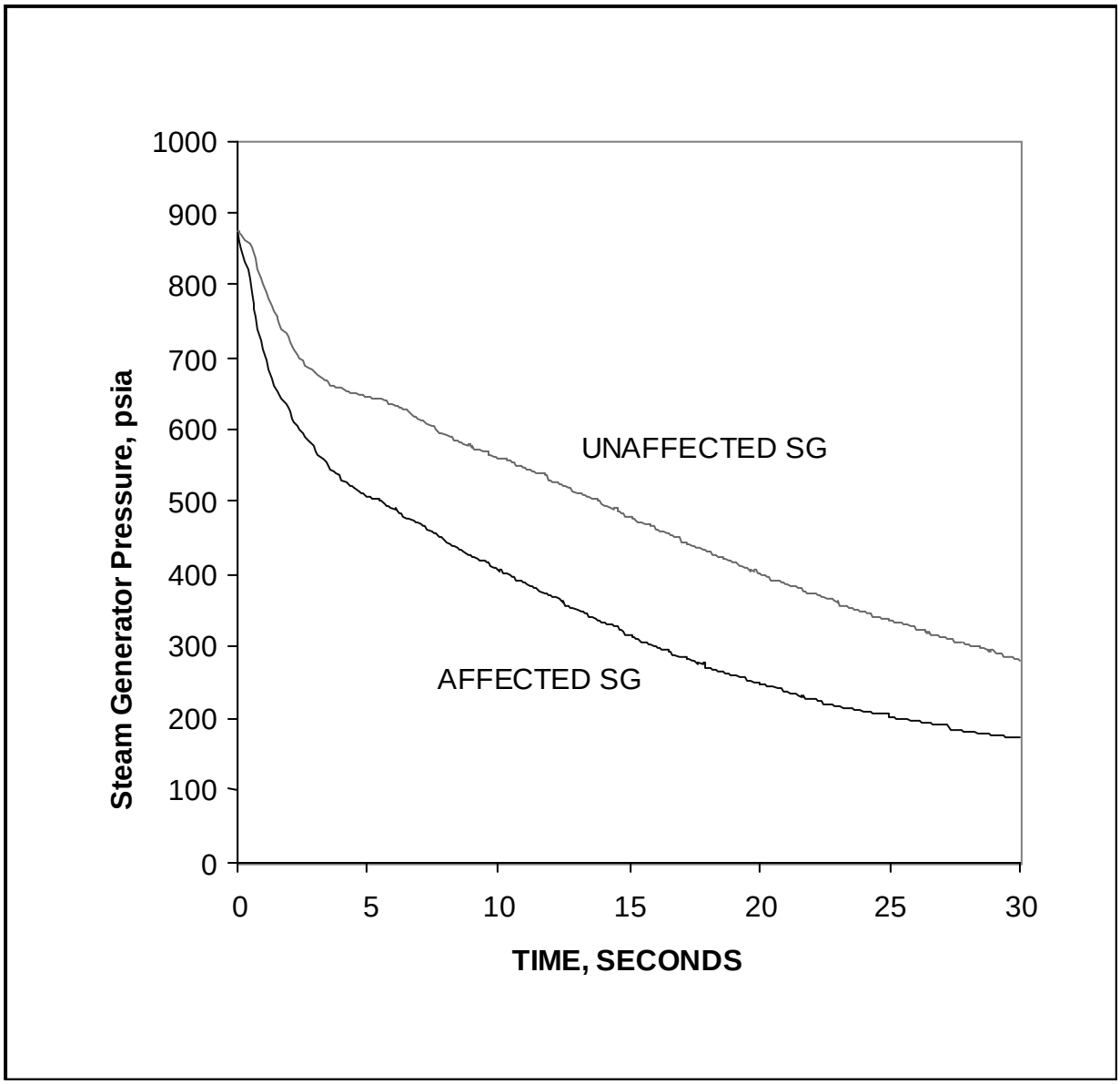

Figure 2.13.1.3.3-6
IC, SLB, Pre-Trip Power Excursions
SG Pressure vs. Time

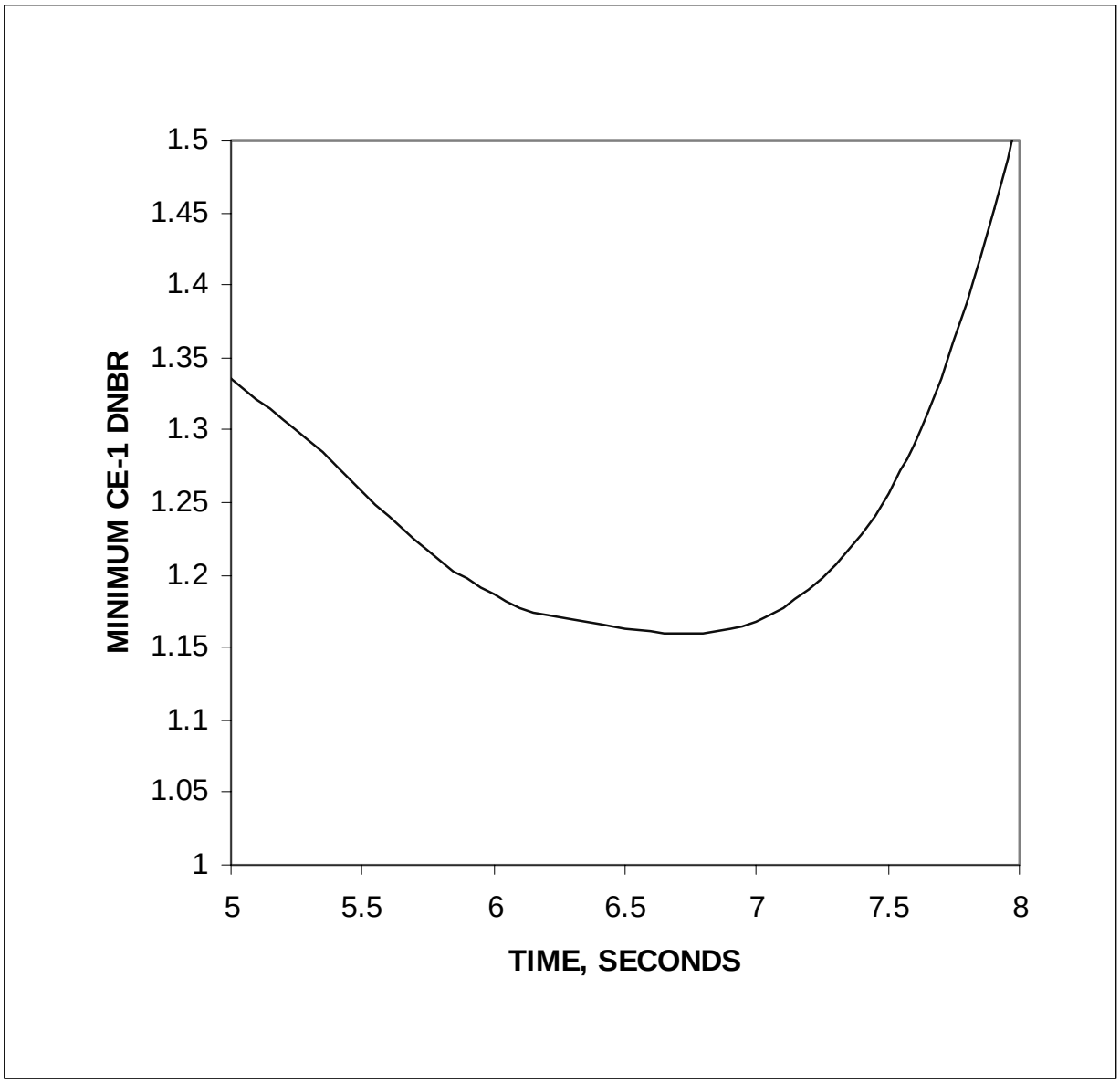

Figure 2.13.1.3.3-7
IC, SLB, Pre-Trip Power Excursions
DNBR vs. Time

2.13.2 Decrease in Heat Removal by the Secondary System (Turbine Plant)

2.13.2.1 Moderate Frequency Incidents

2.13.2.1.1 Loss of External Load

Event is bounded by loss of condenser vacuum (LOCV), Section 2.13.2.1.3 of this report.

2.13.2.1.2 Turbine Trip

Event is bounded by LOCV, Section 2.13.2.1.3 of this report.

2.13.2.1.3 Loss of Condenser Vacuum

The objective of LOCV event analysis was to document the impact of the following changes on the LOCV:

- Utilizing CENTS rather than CESEC as the NSSS simulation tool
- The increase in rated power to 3716 MWt
- The reduction in the RCS temperature

The LOCV is presented in FSAR Section 15.2.1.3.

2.13.2.1.3.1 General Description of Event

An LOCV could occur due to a failure of the circulating water system to supply cooling water, failure of the main condenser evacuation system to remove non-condensable gases, or excessive leakage of air through a turbine gland packing. The turbine generator trip that occurs due to the LOCV closes the turbine stop valves. The turbine trip is assumed to cause the feedwater pumps to trip on low suction pressure. Since no credit is taken for the SBCS, which is assumed to be in manual operation, the RCS pressurizes and reactor trip occur on high pressurizer pressure.

Closure of the turbine stop valves and coastdown of the main feedwater pumps causes the primary and secondary temperatures and pressures to increase. The pressure increase in the primary and secondary systems following reactor trip is limited by the pressurizer safety valves (PSVs) and the main steam safety valves (MSSVs), respectively. The operator may cool the NSSS by using manual operation of the Emergency Feedwater System (EFS) and the ADVs beginning 30 minutes after trip. Subsequent actions (occurring automatically or by the operator) to achieve safe shutdown after SG liquid recovery are not explicitly modeled in the analysis.

Because this event bounds the results of the event with any single active failure, the case with single active failure is also discussed in this section. The LOOP single failure was timed to occur at the time of the high-pressurizer pressure trip (HPPT).

2.13.2.1.3.2 Purpose of Analysis and Acceptance Criteria

The objective of this analysis is to demonstrate that the most limiting conditions for the LOCV event does not violate the acceptance criteria for peak pressure and fuel integrity for Waterford 3 at a thermal power output of 3716 MWt.

The following criteria apply to the LOCV event:

- DNBR > 1.26
- Fuel temperature < fuel melt temperature limit, demonstrated by peak LHR ≤ 21.0 kW/ft
- Radiological dose ≤ small fraction of 10CFR100 limits
- RCS pressures ≤ 110% of design

The LOCV event is described in Chapter 15.2.1.3 of the SAR (Reference 2.13-1). The LOCV with concurrent single failure event is described in Chapter 15.2.2.3 of the SAR.

2.13.2.1.3.3 Impact of Changes

The event is now analyzed with the CENTS code vs. the CESEC code. The CENTS code includes more detailed modeling of the main steam system piping. As a result, steam continues to flow from the SG after the initiation of the transient. The CESEC model resulted in a much more rapid termination of steam flow, and hence more rapid termination of heat removal after the turbine trip.

The increase in rated power resulted in greater energy transfer to the primary and secondary systems. The expected increase of the peak secondary system pressure from the increased power level is offset by the use of the CENTS code to model the transient.

For peak primary system pressure cases, the decrease in the initial coolant temperatures tends to add more initial mass to the primary system. The heatup, acting on a greater RCS mass tends to increase the peak primary system pressures reached. Again, this is offset by the use of the CENTS code.

2.13.2.1.3.4 Analysis Overview

This analysis utilized the CENTS computer code (Reference 2.13-2) for the transient analysis simulation. The minimum DNBR evaluation was determined using the CETOP code (Reference 2.13-3).

For the peak primary pressure analysis, input parameters from Table 2.13.2.1.3-1 and the bounding physics data from Section 2.13.0.2 of this document were incorporated with the following clarifications:

- The least negative (BOC) Doppler coefficient was assumed.
- A maximum (BOC) delayed neutron fraction and minimum neutron lifetime consistent with those defined in Section 2.13.0.2 were assumed.
- The CEA insertion curve assumed accounts for a 0.6 second holding coil delay. A CEA worth of -6.0% $\Delta\rho$ was conservatively assumed.
- An HPPT setpoint of 2422 psia and a response time of 0.9 seconds were assumed.
- An MSSV tolerance of +3% was applied
- An initial core power of 3735 MWt, based on a rated power of 3716 MWt and a 0.5% uncertainty, was assumed.
- A most positive/least negative MTC of $-0.2 * 10^{-4}$ $\Delta\rho/°F$ at hot full power (HFP) was used.
- The minimum HFP core inlet temperature of 533°F was assumed.
- A PSV tolerance of +3% was applied.
- Parametric analyses were performed on coolant flow, temperature, pressurizer level, and SG level. The most limiting conditions were maximum RCS flow, minimum inlet temperature, maximum pressurizer level, and minimum SG level.

A similar analysis was performed to determine a conservative peak secondary pressure, as the input assumptions described above and denoted in Table 2.13.2.1.3-1 ensure a peak primary pressure. This secondary system analysis is effectively the same as the peak primary analysis with the following differences:

- A low SG level trip of 5.0% was credited.
- The maximum HFP core inlet temperature of 552°F was assumed.
- Parametric analyses were performed on coolant flow, temperature, pressurizer level, and SG level. The most limiting conditions were minimum RCS flow, minimum inlet temperature, minimum pressurizer level, and maximum SG level.
- A minimum RCS flow of 148×10^6 lbm/hr was assumed.

For the inoperable MSSV analysis (one or two valves), the following assumptions either complement or replace the peak secondary system pressure case.

- An ESFAS low SG level actuation of 5% and a response time of 0.9 seconds were credited.
- Initial core powers were based on a HFP value of 3716 MWt. For one inoperable MSSV bank, an initial core power of 87.3% RTP was used. For two inoperable MSSV banks, an initial core power of 69.9% RTP was used.
- For the one or two inoperable MSSVs per steam line, the lowest opening valve(s) were assumed to be inoperable. This analysis is performed in support of Technical Specification Table 3.7-2.

The single failure considered was a LOOP simultaneous with reactor trip.

2.13.2.1.3.5 Radiological Consequences

No SAFDL violation occurs during the LOCV event. Source terms are therefore limited to the initial primary and secondary limits on coolant activity in the Technical Specifications. Doses for this event are bounded by the IOSGADV with LOOP discussed in Section 2.13.1.2.4.5. Both events have the same criteria (small fraction of 10CFR100 guidelines), and the IOSGADV with LOOP event radiological dose assumptions are conservative for the LOCV event.

2.13.2.1.3.6 Analysis Results

The peak RCS and SG pressures remained below their respective acceptance criteria of 2750 psia and 1210 psia. The peak RCS pressure case yielded a peak RCS pressure of 2732 psia. The peak SG pressure case showed a peak SG pressure of 1186 psia, including accounting for cases with 1 or 2 inoperable MSSVs.

The above cases were also run with a LOOP at the time of the HPPT. The peak RCS pressure case with a LOOP yielded a peak RCS pressure of 2731 psia. The peak SG pressure case with a LOOP had a peak SG pressure of 1177 psia. Thus, the LOCV with LOOP case is bounded by the LOCV case without LOOP.

The NSSS and RPS responses for the LOCV event are shown in Table 2.13.2.1.3-2 and in Figures 2.13.2.1.3-1 through 2.13.2.1.3-14.

Table 2.13.2.1.3-1
Assumptions for 3716-MWt LOCV

Parameter	Power Uprate Assumption	Current Power Level Assumption
Initial Core Power, MWt	3735	3478
Core Inlet Temperature, °F	533	548
RCS Flowrate, 10^6 lbm/hr	177.6	163.6
Pressurizer Pressure, psia	2090	2000
Pressurizer level, %	67.5	---
SG Level, % NR	5	---
SG Pressure, psia	736.5	860
MTC, 10^{-4} $\Delta\rho$/°F	-0.2	+0.0
Doppler Coefficient Multiplier	0.85	0.85
CEA Worth on Trip, %$\Delta\rho$	-6.0	-7.95
SBCS	Inoperative	Inoperative
PLCS	Inoperative*	Inoperative
PPCS	Inoperative*	Inoperative

* PLCS and PPCS are not assumed to operate for peak RCS Pressure case. PLCS and PPCS are assumed in automatic for the peak secondary pressure case.

Table 2.13.2.1.3-2
Sequence of Events for 3716-MWt LOCV

EPU Time (sec)	Current Power Level Time (sec)	Event	EPU Setpoint/Value	Current Power Level Setpoint/Value
0.0	0.0	Closure of turbine stop valves on turbine due to LOCV	---	---
0.0	0.0	Peak pressure case conservatively initiated at low SG water level trip signal	---	27.0 ft above tubesheet
0.2	---	Emergency feedwater actuation signal (EFAS) condition reached	5% NR	---
5.7	8.2	HPPT condition, psia	2422	2422
6.6	9.3	Trip breakers open	---	---
7.0	11.0	Maximum pressurizer pressure	2576	2551
7.1	9.2	PSVs begin to open, psia	2575	2525
7.2	9.9	CEAs begin to drop into core	---	---
8.3	10.6	Maximum RCS pressure, psia	2732	2708
12.5	13.0	PSV closed, psia	2525	2525
13.3	7.2	SG safety valves begin opening, psia	1117	1085
14.3	13.0	Maximum pressurizer liquid volume	1233	939
18.5	16.0	Maximum SG pressure, psia	1175*	1152
51.6	367.0	SG safety valves close, psia	1061	1042
60.2	122.0	EFW reaches SGs	---	---
900	1800	Operator opens atmospheric steam dump valves to begin plant cooldown to shutdown cooling	---	---

* Worst case value of 1186 psia for case of two MSSVs inoperable.

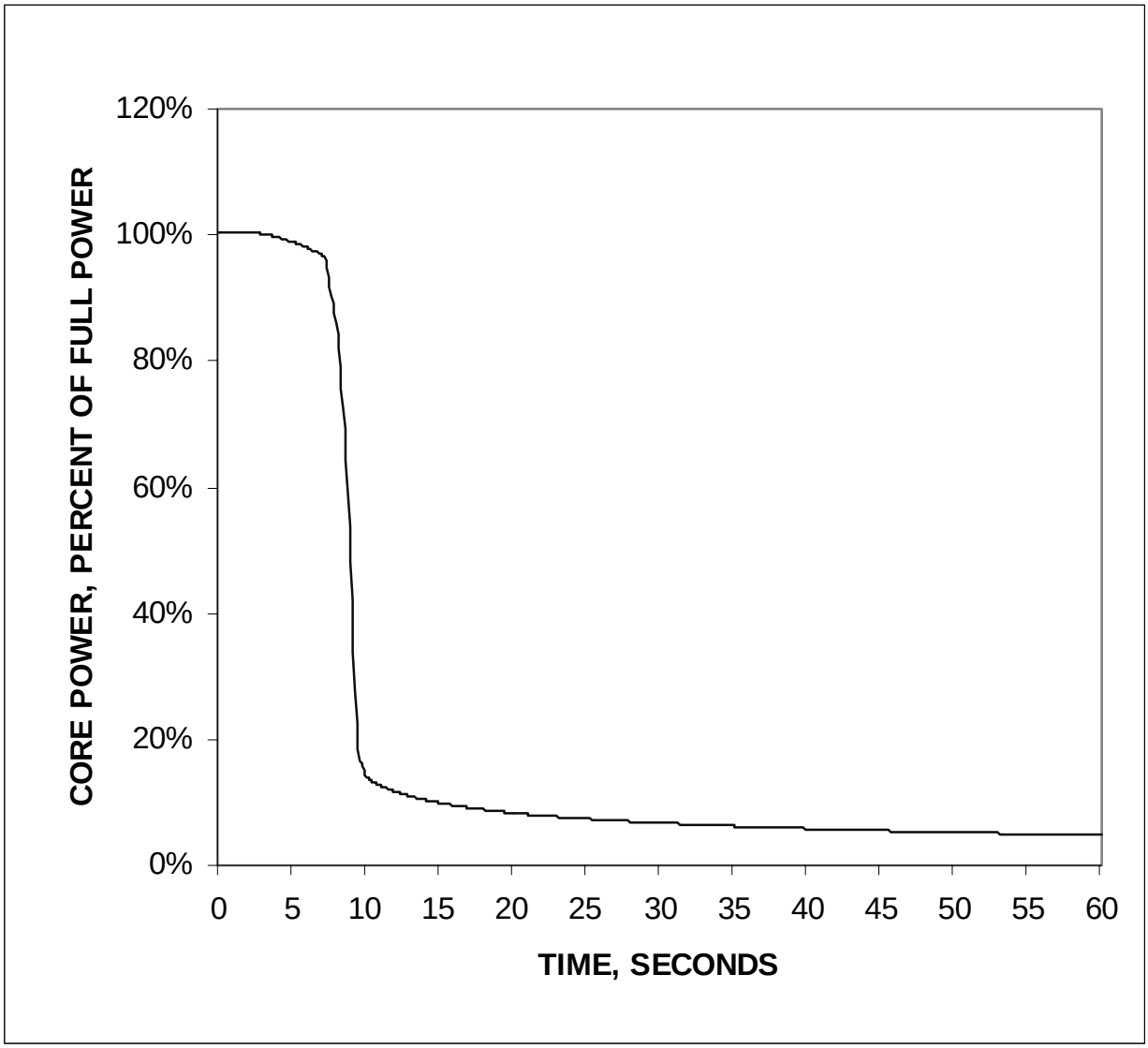

Figure 2.13.2.1.3-1
LOCV Neutron Power vs. Time

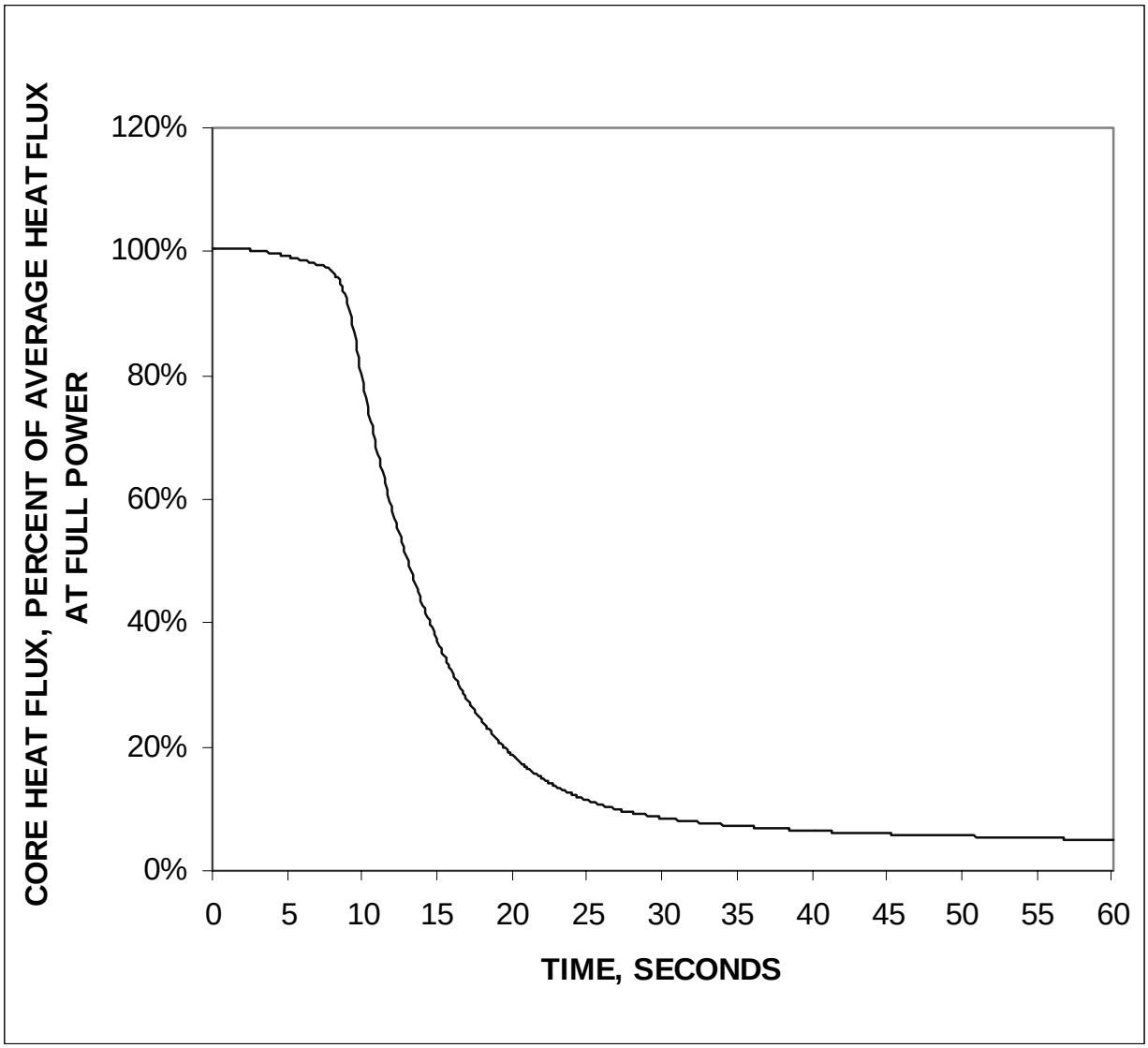

Figure 2.13.2.1.3-2
LOCV Core Average Heat Flux vs. Time

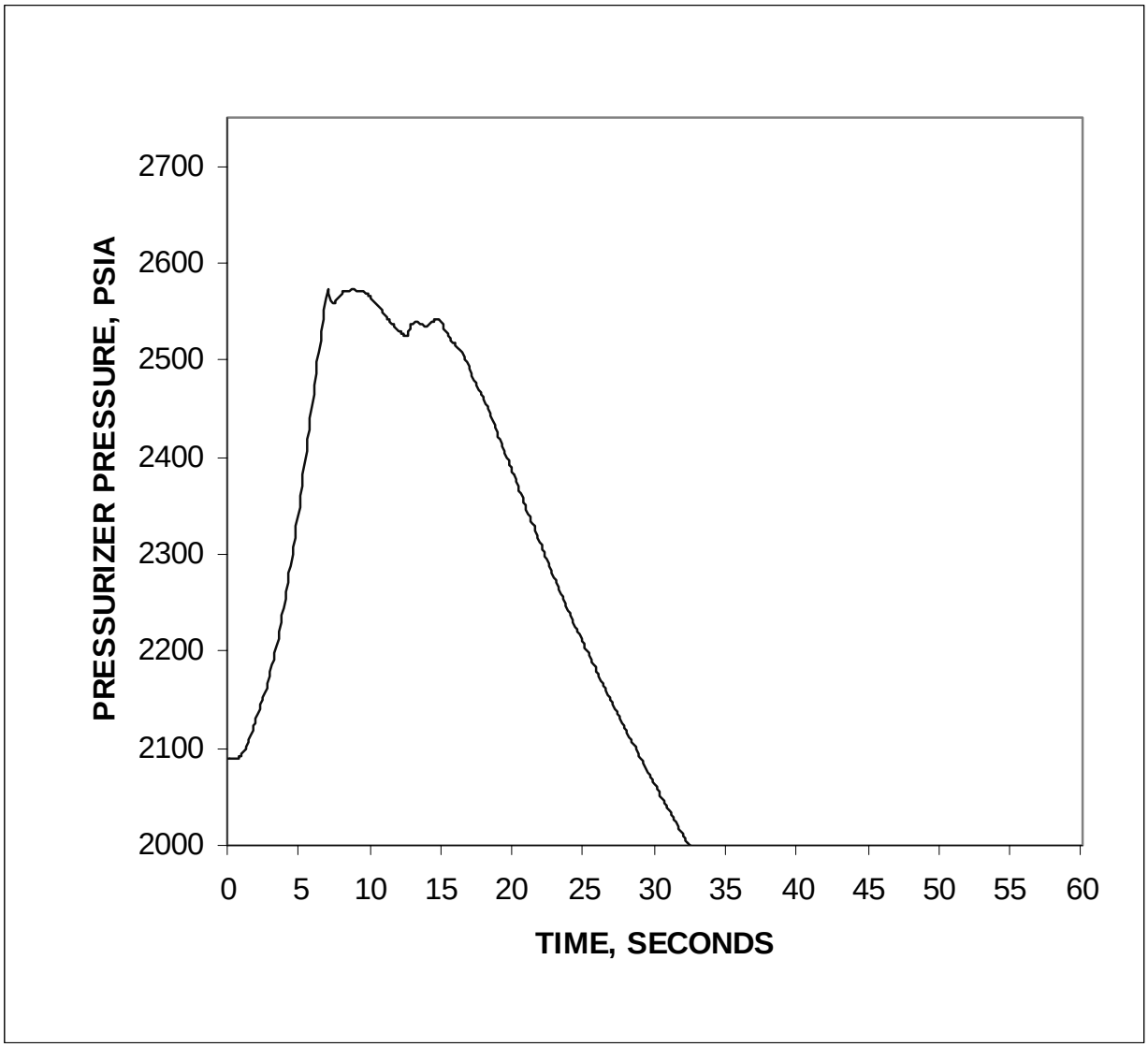

Figure 2.13.2.1.3-3
LOCV Pressurizer Pressure vs. Time

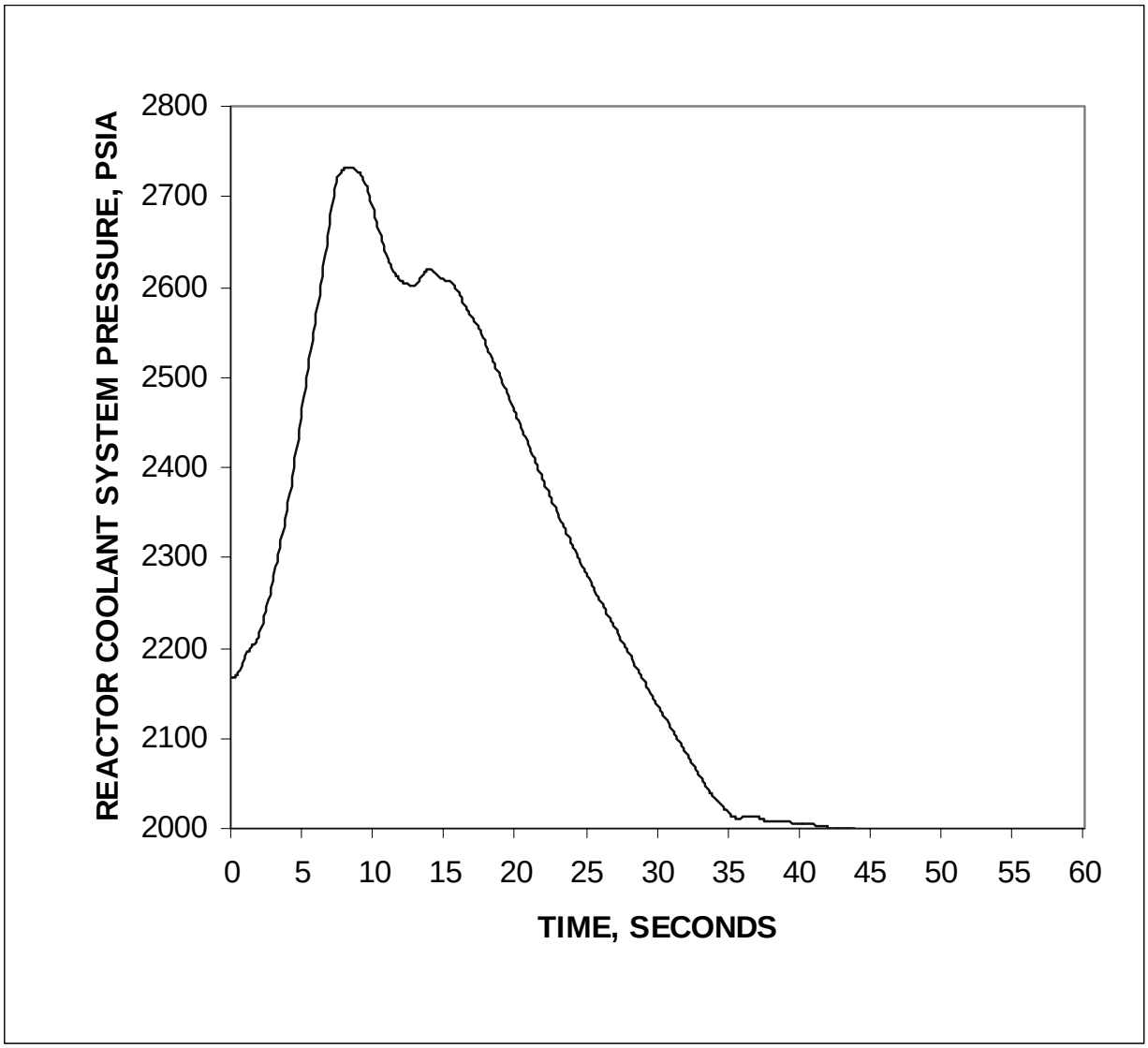

Figure 2.13.2.1.3-4
LOCV RCS Pressure vs. Time

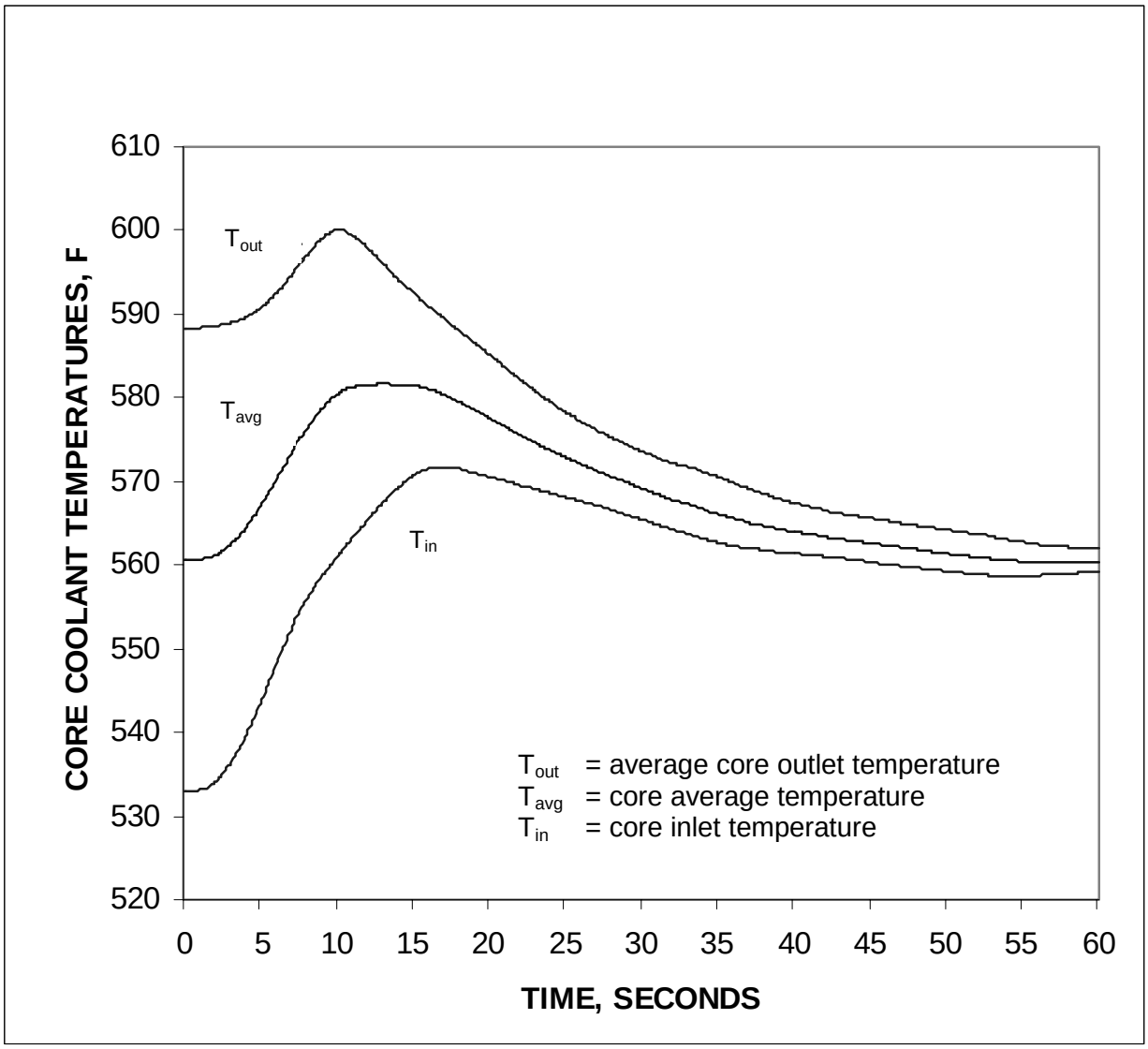

Figure 2.13.2.1.3-5
LOCV Core Coolant Temperatures vs. Time

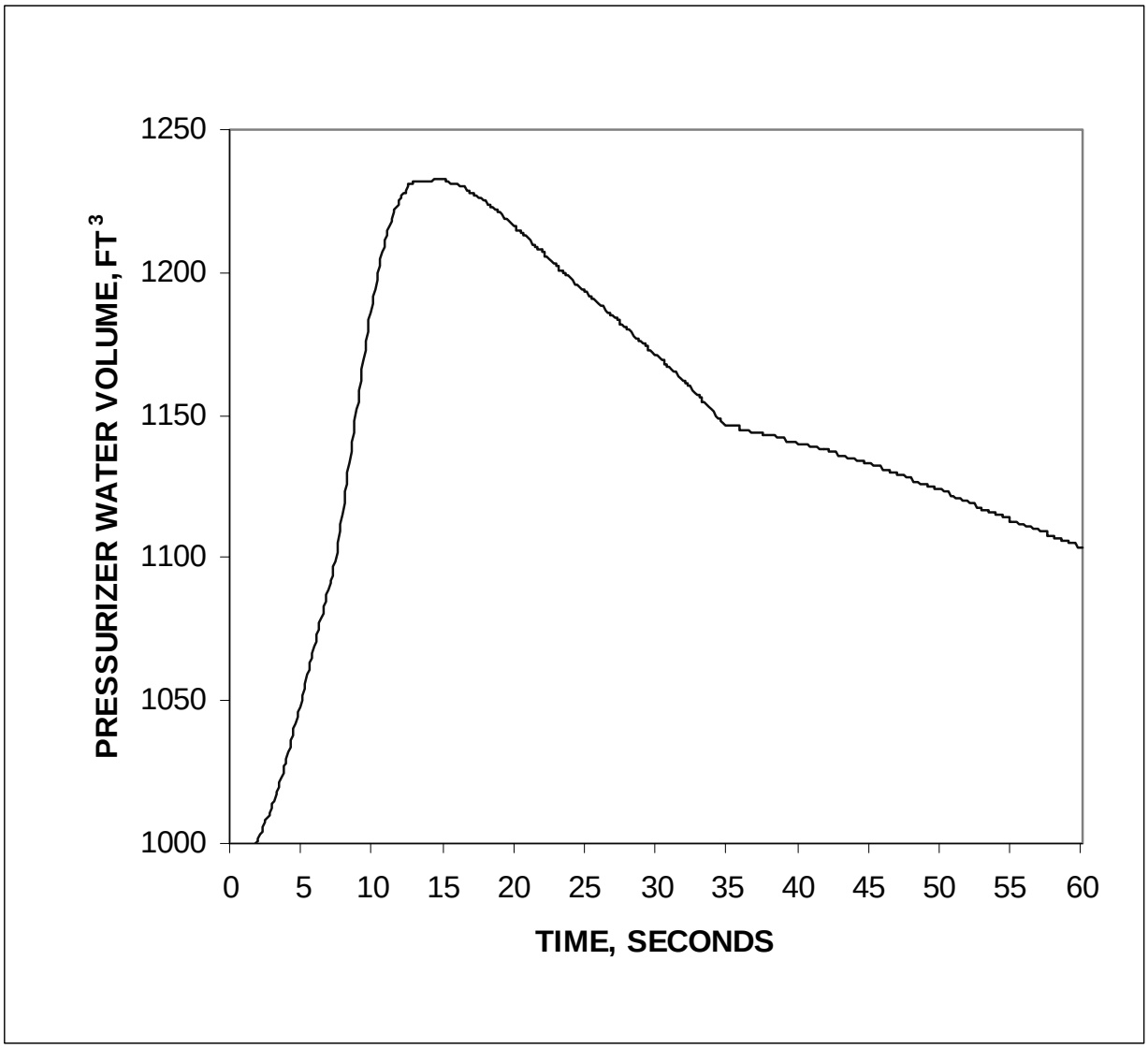

Figure 2.13.2.1.3-6
LOCV Pressurizer Water Volume vs. Time

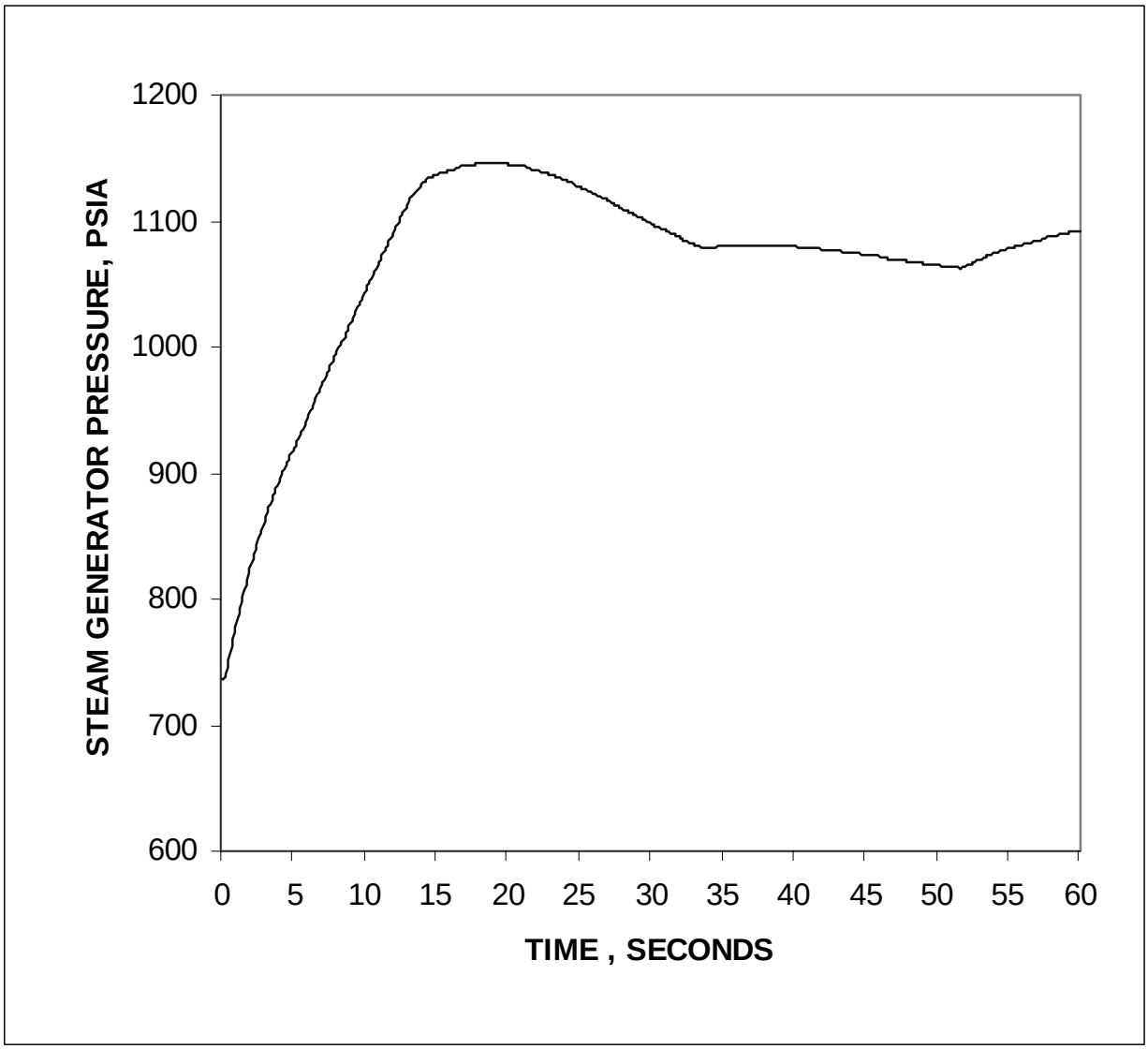

Figure 2.13.2.1.3-7
LOCV SG Pressure vs. Time

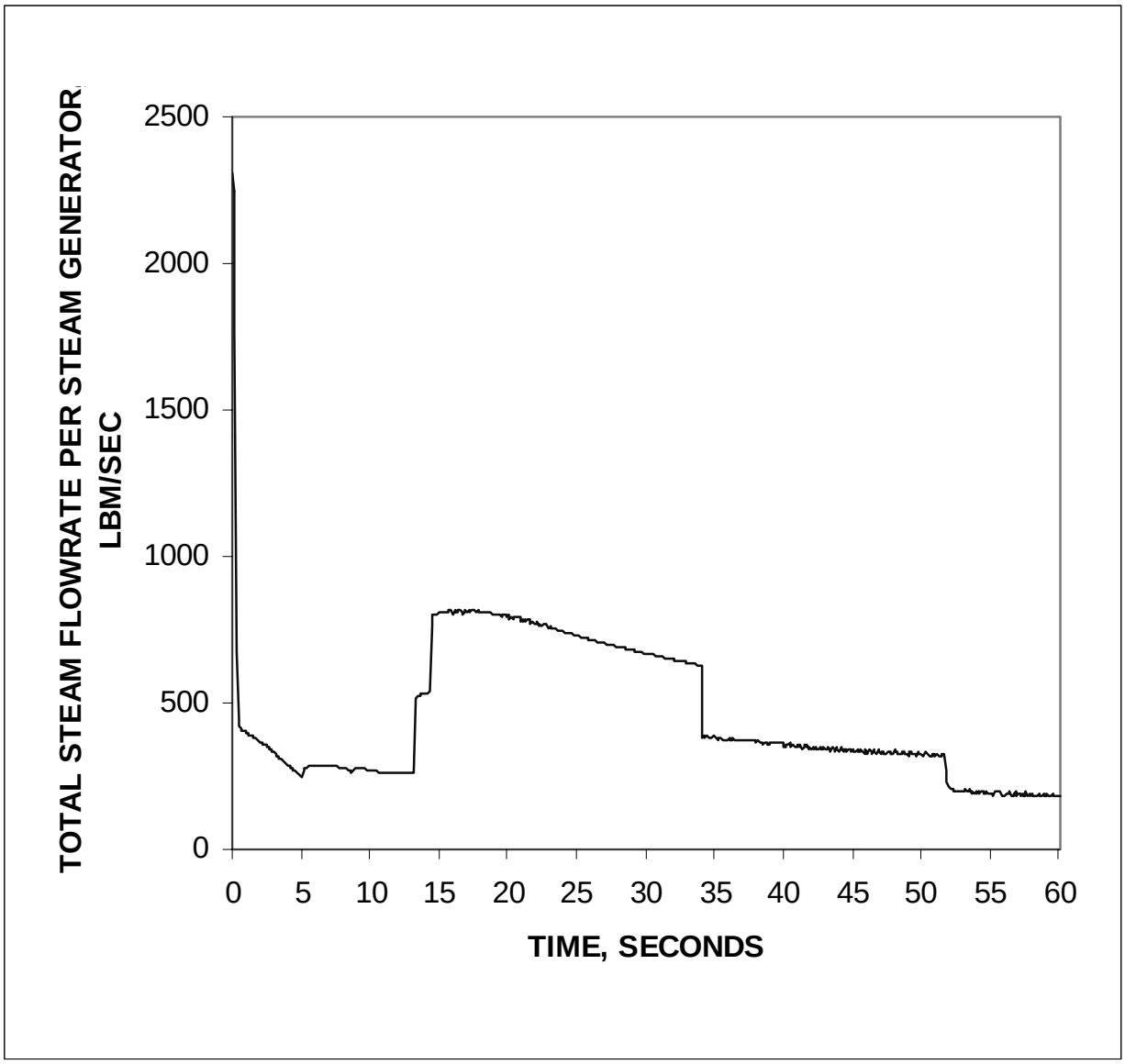

Figure 2.13.2.1.3-8
LOCV Total Steam Flowrate per SG vs. Time

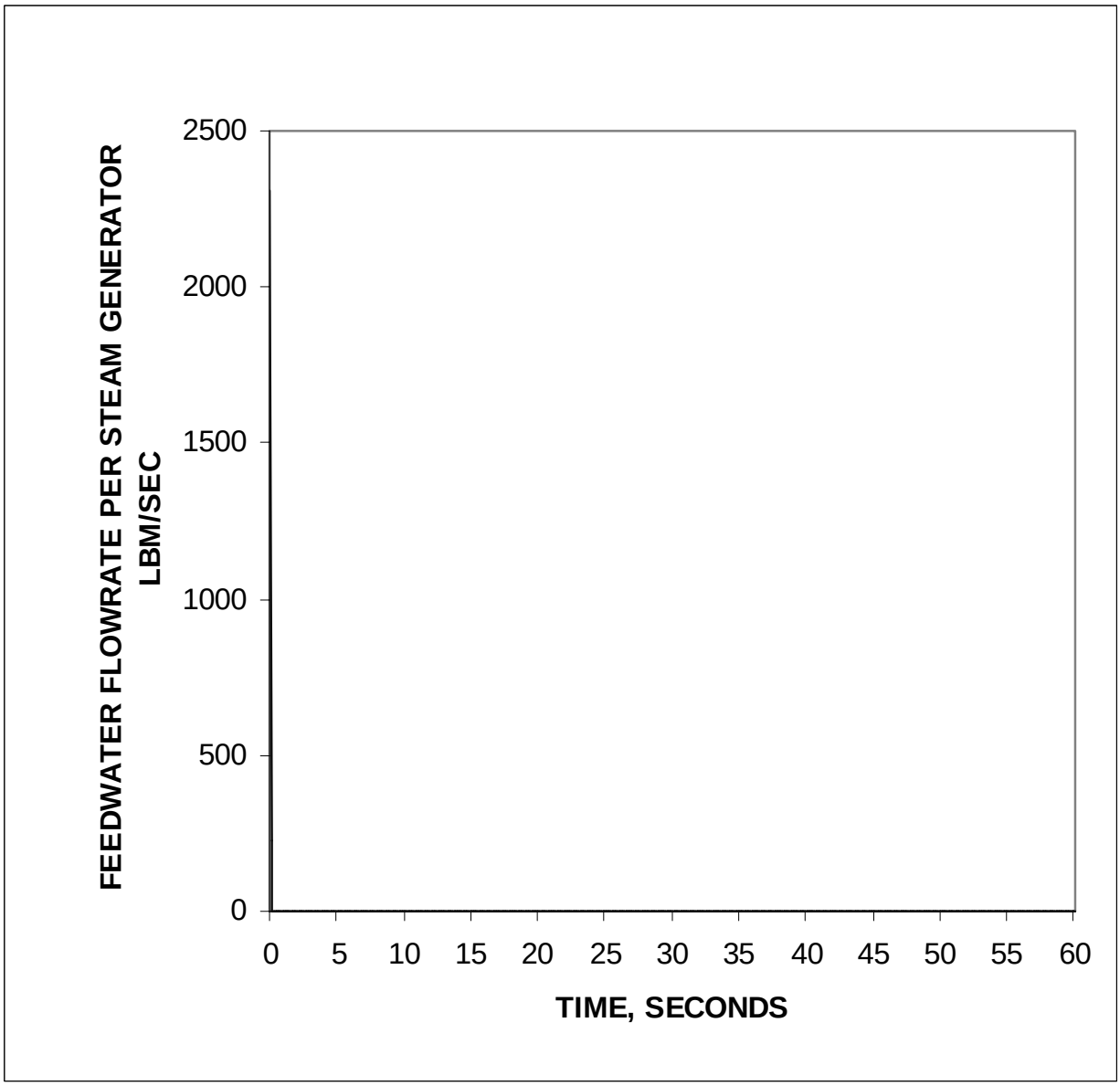

Figure 2.13.2.1.3-9
LOCV Feedwater Flowrate per SG vs. Time

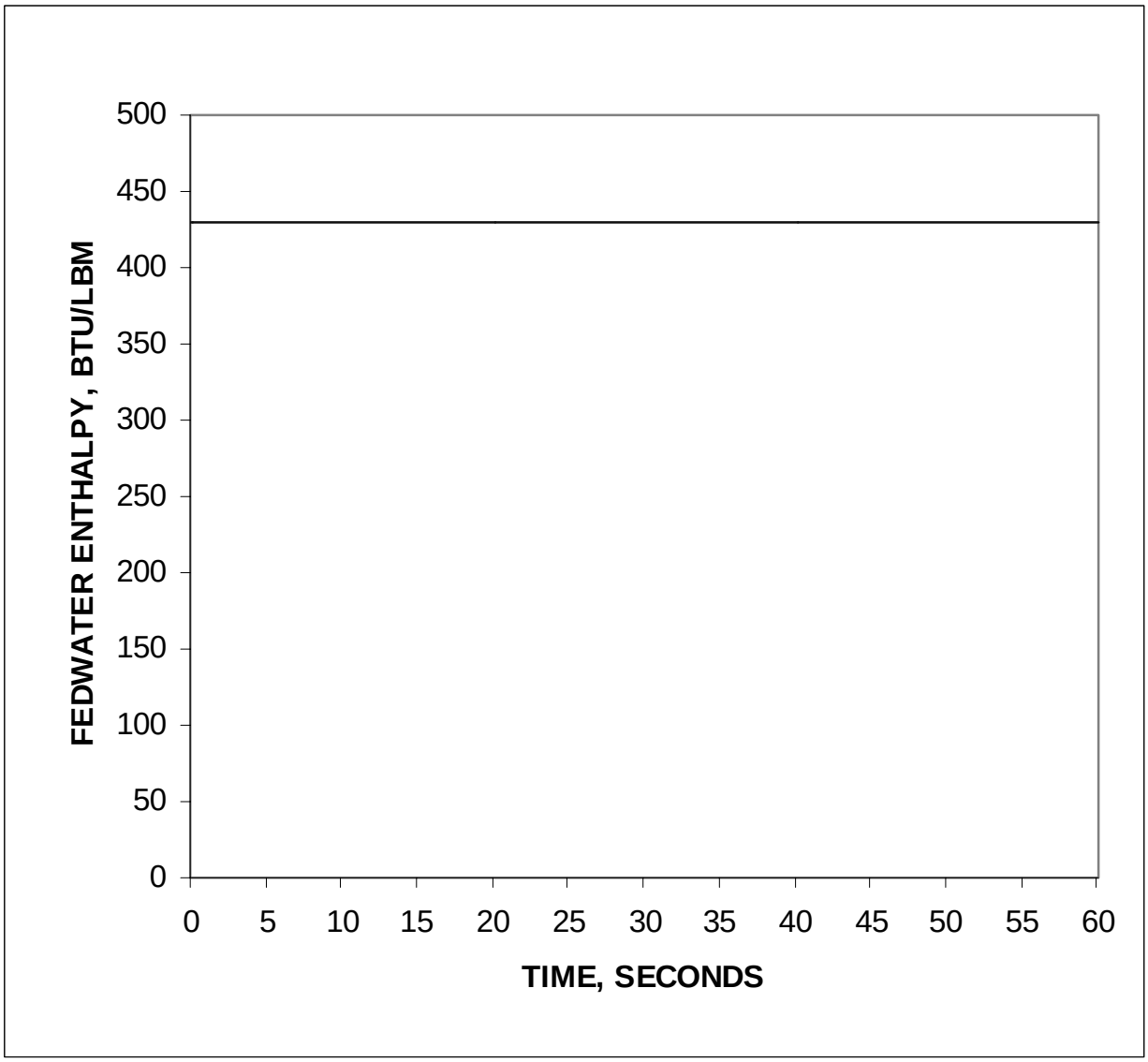

Figure 2.13.2.1.3-10
LOCV Feedwater Enthalpy vs. Time

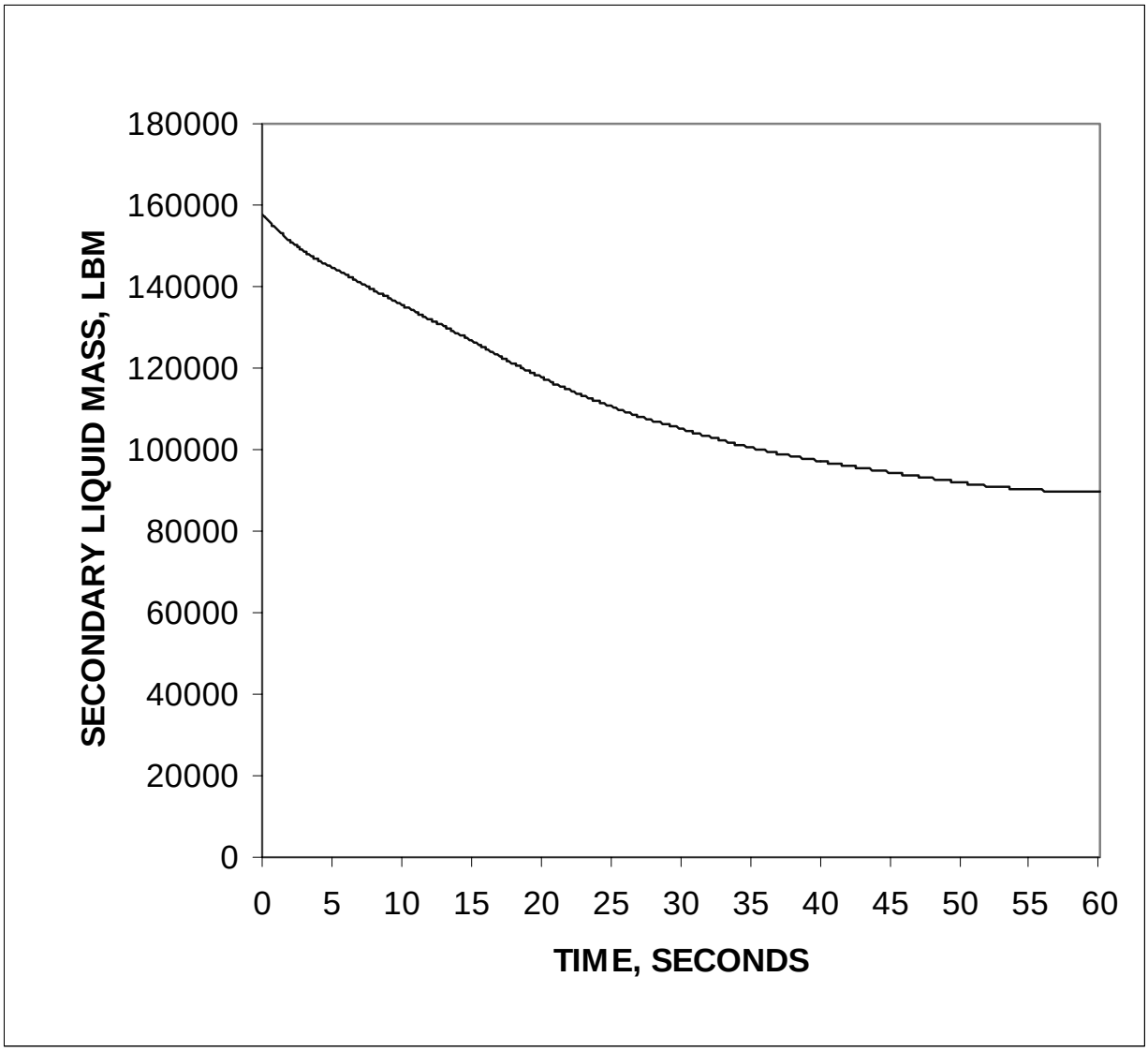

Figure 2.13.2.1.3-11
LOCV Secondary Liquid Mass vs. Time

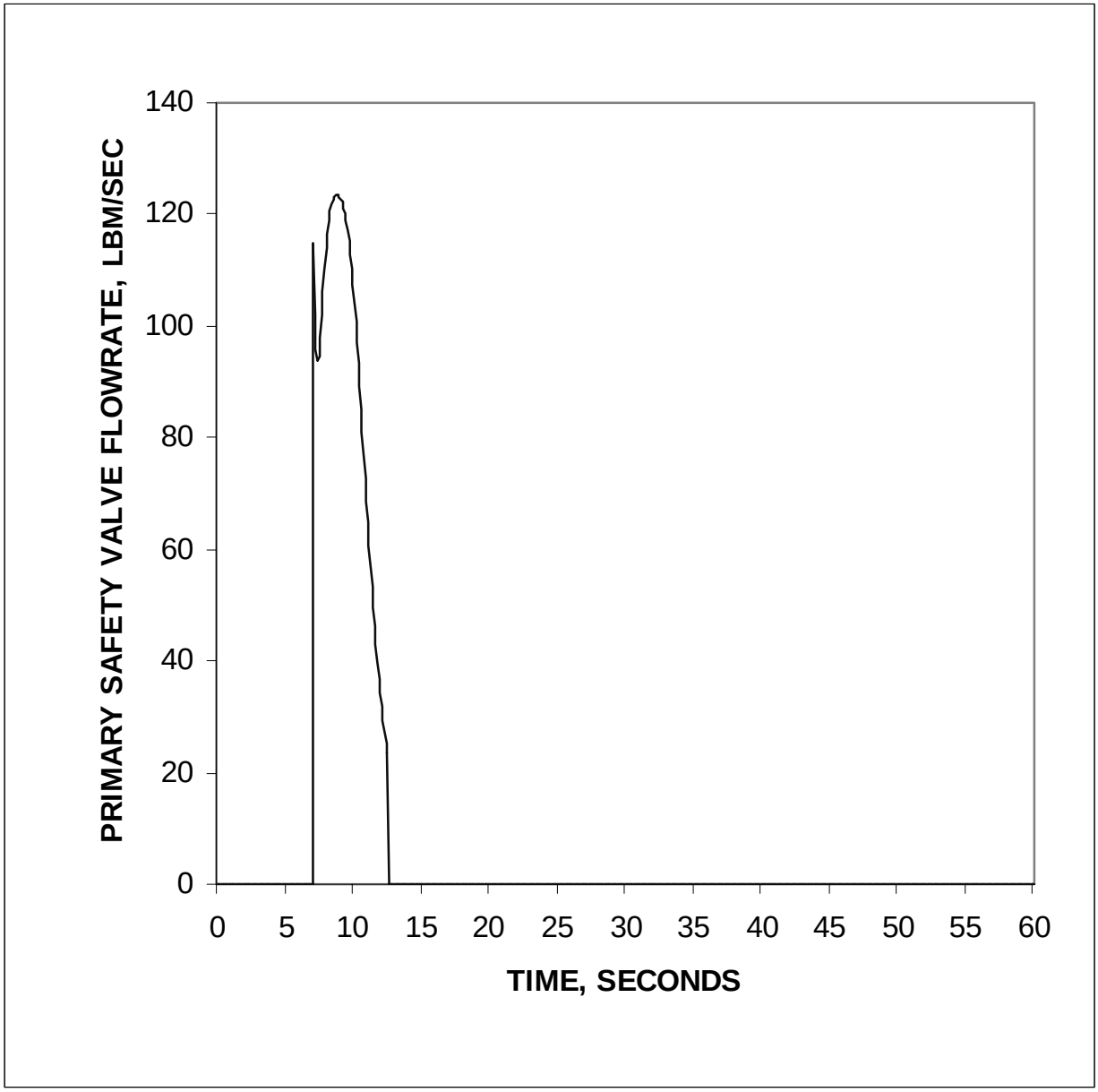

Figure 2.13.2.1.3-12
LOCV Primary Safety Valve Flowrate vs. Time

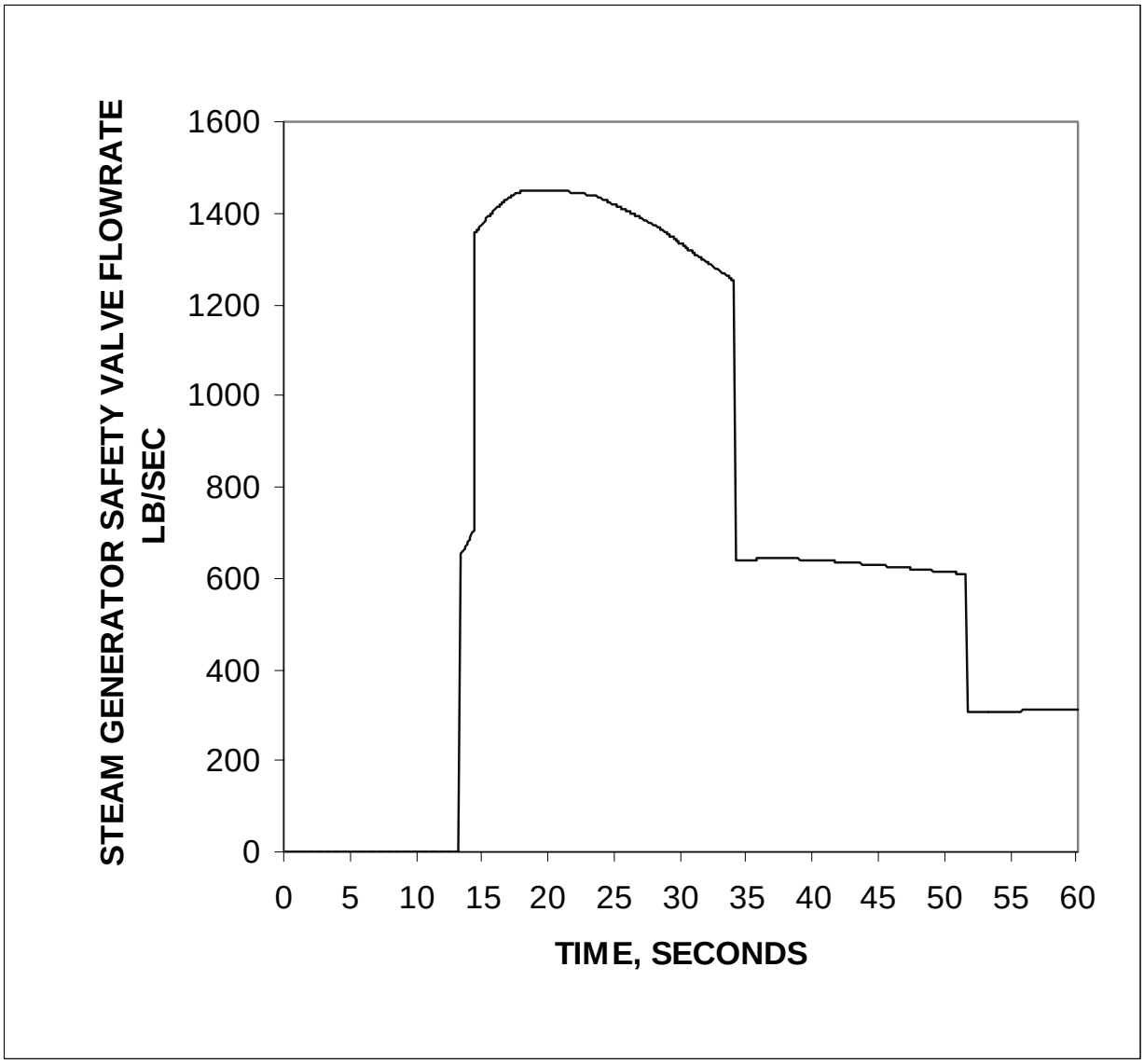

Figure 2.13.2.1.3-13
LOCV SG Safety Valve Flowrate vs. Time

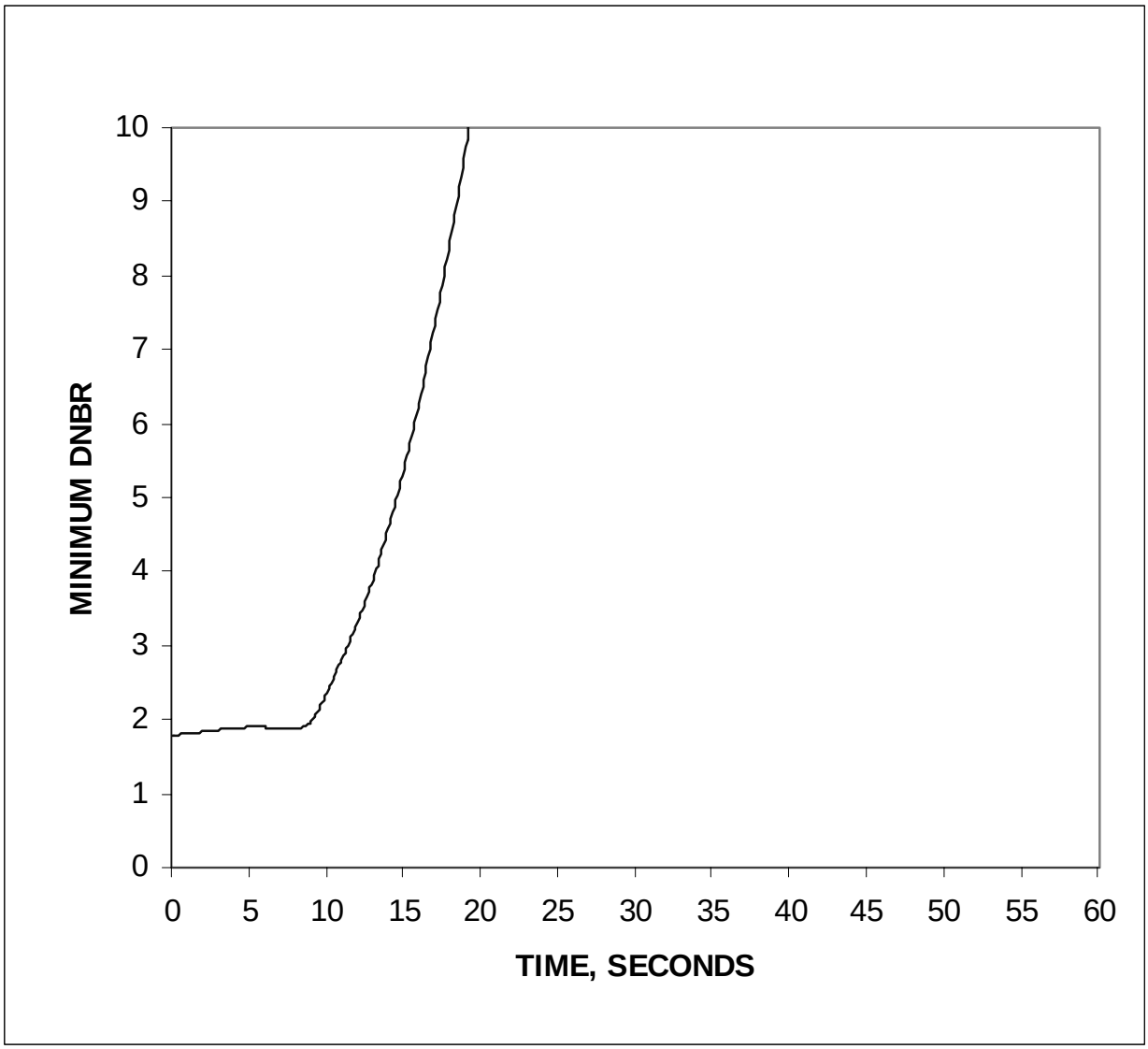

Figure 2.13.2.1.3-14
LOCV Minimum DNBR vs. Time

2.13.2.1.4 Loss-of-Normal AC Power

The thermal margin consequences of this event are bounded by the loss of flow, Section 2.13.3.2.1 of this report. The peak pressure consequences of this event are bounded by the LOCV, Section 2.13.2.1.3 of this report.

2.13.2.1.5 Steam Pressure Regulator Failure

This event is bounded by the LOCV, Section 2.13.2.1.3.

2.13.2.2 Infrequent Incidents

2.13.2.2.1 Loss of External Load with Single Active Failure (SAF)

This event is bounded by the LOCV, Section 2.13.2.1.3.

2.13.2.2.2 Turbine Trip with SAF

This event is bounded by the LOCV, Section 2.13.2.1.3.

2.13.2.2.3 Loss of Condenser Vacuum with SAF

This event is bounded by the LOCV, Section 2.13.2.1.3.

2.13.2.2.4 Loss-of-Normal AC Power with SAF

The DNBR/fuel performance aspects of this event is bounded by the loss of flow, Section 2.13.3.2.1. The peak pressure aspects of this event is bounded by the LOCV, Section 2.13.2.1.3.

2.13.2.2.5 Loss-of-Normal Feedwater Flow

The objective of the loss-of-normal feedwater flow analysis is to document the impact of the following changes:

- An increase in rated power
- A change to the CENTS code
- Reduction in steam generator pressure
- A reduction in CEA worth at trip

The impact of the power uprate results in no violation of SG heat removal capability for this Safety Analysis Report (SAR) event.

2.13.2.2.5.1 General Description of the Event

A loss-of-normal feedwater flow is defined as a reduction in feedwater flow to the steam generators when operating at power, without a corresponding reduction in steam flow from the SGs. This flow imbalance results in a reduction in the SG water inventory and a consequent heatup of the reactor coolant. The complete loss-of-normal feedwater case is analyzed since this condition requires the most rapid response from the Plant Protection System (PPS). A complete loss-of-normal feedwater flow can result from the loss of both main feedwater pumps or the loss of three condensate pumps or by a control system malfunction causing the feedwater control valves to close. Manually closing the feedwater control or isolation valves will also result in a complete loss-of-normal feedwater flow.

The complete loss-of-normal feedwater flow is analyzed by assuming an instantaneous stoppage of feedwater flow to both steam generators. The PPS provides protection against the loss of the secondary heat sink by the SG low water level trip and by automatic initiation of the Emergency Feedwater System (EFS). The EFS consists of one turbine-driven and two motor-driven emergency feedwater pumps. The HPPT provides protection in the event the RCS pressure limit is approached. The Steam Bypass Control System (SBCS) is assumed to be in the automatic mode, which maximizes the decrease in SG water inventory.

2.13.2.2.5.2 Purpose of Analysis and Acceptance Criteria

The purpose of the analysis was to determine that emergency feedwater flow is sufficient such that the SG heat removal capability is maintained.

The following criteria apply to the loss-of-feedwater flow event:

- DNBR > 1.26
- Fuel temperature < fuel melt temperature limit, demonstrated by peak LHR ≤ 21.0 kW/ft
- Radiological dose ≤ small fraction of 10CFR100 limits
- RCS pressures ≤ 110% of design

The loss-of-normal feedwater flow event is described in Chapter 15.2.2.5 of the FSAR (Reference 2.13-1).

2.13.2.2.5.3 Impact of Changes

The increase in rated power, and decrease in maximum core inlet temperature have the combined effect of decreasing the SG pressure. A decrease in SG pressure results in slower loss of SG inventory. A parametric study on MTC showed that the most negative MTC caused a larger depletion of the SG than most positive MTC .

This event is now analyzed with the CENTS code versus the CESEC code (Reference 2.13-2). The CENTS code is used in this analysis in exactly the same manner as CESEC was in the current analysis. In this case the substitution of one code for the other introduces no significant changes.

2.13.2.2.5.4 Analysis Overview

This analysis utilized the CENTS computer code for the transient analysis simulation.

The input parameters from Table 2.13.2.2.5-1 and the bounding physics data from Section 2.13.0.2 were incorporated with the following clarifications:

- The EOC Doppler curve was assumed with 1.3 multiplier.
- A BOC delayed neutron fraction and neutron lifetime consistent with those defined in Section 2.13.0.2 were assumed.
- The CEA insertion curve based on the limiting +0.3 ASI shape was assumed. This curve accounts for a 0.6 second holding coil delay. A CEA worth of -6.0% $\Delta\rho$ was conservatively assumed.
- An MSSV tolerance of -3% was applied.
- An initial core power of 3735 MWt, based on a rated power of 3716 MWt and a 0.5% uncertainty, was assumed.
- A most negative MTC of $-4.2 * 10^{-4}$ $\Delta\rho/°F$ was used for the no single failure case.

2.13.2.2.5.5 Radiological Consequences

No SAFDL violation occurs during the loss of feedwater flow event. Source terms are therefore limited to the initial primary and secondary limits on coolant activity in the Technical Specifications. Doses for this event are bounded by the increased main steam flow with LOOP Section 2.13.1.2.3.5. Both events have the same criteria (small fraction of 10CFR100 guidelines), and the increased main steam flow with LOOP event radiological dose assumptions are conservative for the loss-of-feedwater event.

2.13.2.2.5.6 Analysis Results

The loss-of-feedwater event did not result in SG dryout, and thus there is no loss of secondary heat sink. The NSSS, PPS, and EFS responses for the loss-of-feedwater event are shown in Table 2.13.2.2.5-2 and Figures 2.13.2.2.5-1 through 2.13.2.2.5-12.

Table 2.13.2.2.5-1
Assumptions for 3716-MWt Loss-of-Normal Feedwater Analysis

Parameter	Power Uprate Assumption	Current Power Level Assumption *
Initial Core Power, MWt	3735	3478
Core Inlet Temperature, °F	552	560
RCS Flowrate, 10^6 lbm/sec	148	141
Pressurizer Pressure, psia	2090	2000
Pressurizer Level, %	67.5	---
SG Pressure, psia	877	950
SG Level, %NR	90	---
MTC, 10^{-4} $\Delta\rho$/°F	-4.2	+0.5
Doppler Coefficient Multiplier	1.3	0.85
CEA Worth for Trip, 10^{-2} $\Delta\rho$	-6.0	-7.95
SBCS	Automatic	Automatic

Table 2.13.2.2.5-2
Sequence of Events for 3716-MWt Loss-of-Normal Feedwater Flow

EPU Time (sec)	Current Power Level Time (sec)	Event	EPU Setpoint/Value	Current Power Level Setpoint/Value
0.0	0.0	Termination of all feedwater flow	---	---
6.9	47.7	Maximum core power	100.9%	105%
33.0	46.9	Low SG water level trip signal (EFAS)	5% NR	5% NR
33.9	47.3	Reactor trip breakers open	---	---
34.5	47.6	CEAs begin to drop into core	---	---
38.1	49.9	Maximum RCS pressure	2280 psia	2321 psia
38.5	48.5	SG safety valves begin to open	1052.1 psia	1085 psia
39.7	51.9	Maximum SG pressure	1071.3 psia	1136 psia
47.5	62.6	SG safety valves close	999.5 psia	1042 psia
83.0	89.6	Emergency feedwater (3 pumps) reaches SGs	---	---
204.9	100.0	Minimum SG water inventory	34,240 lbm	18,100 lbm
244.1	136.6	Minimum RCS pressure	1676 psia	1451 psia
1,800	1800.	Operator begins cooldown	---	---

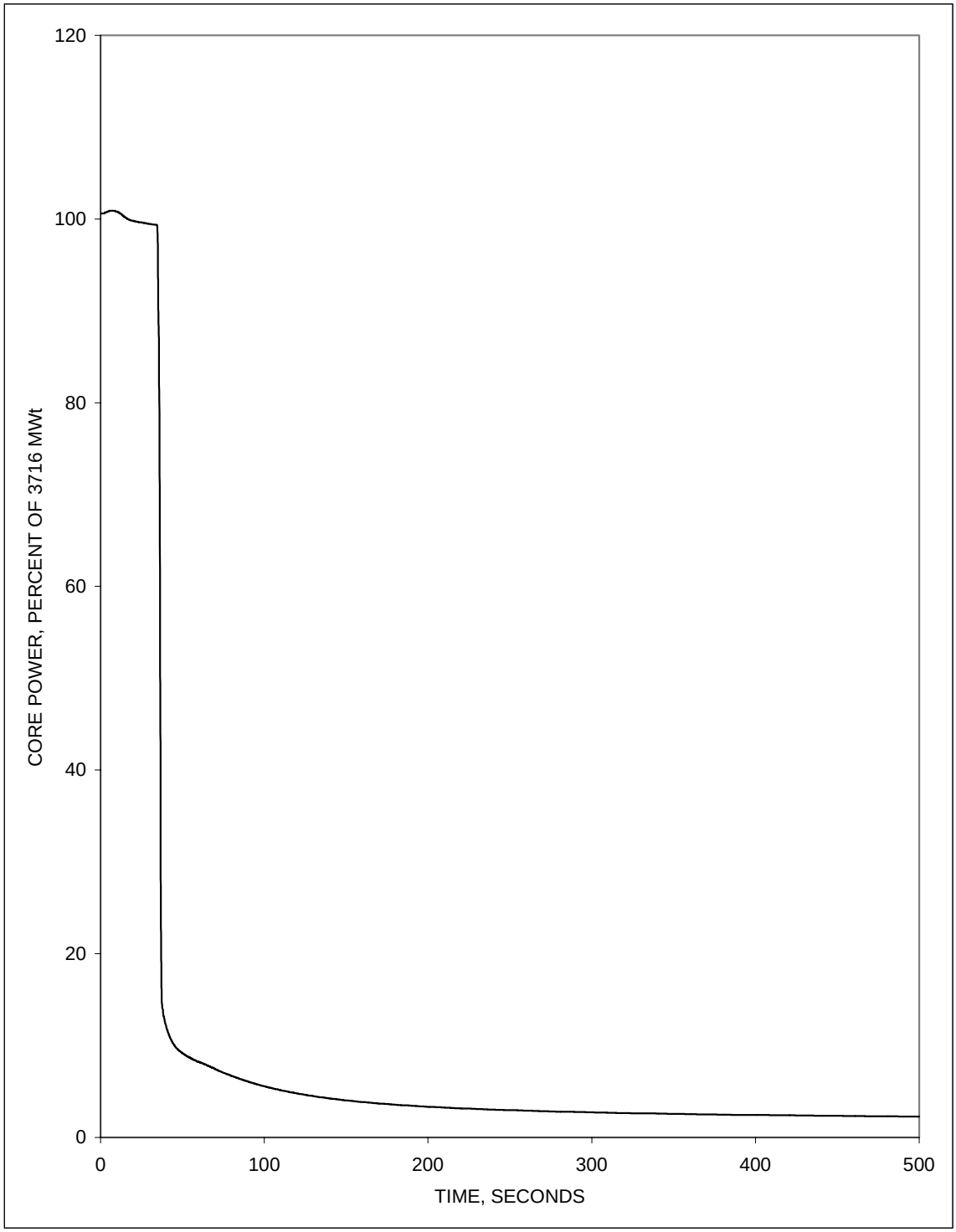

Figure 2.13.2.2.5-1
Loss-of-Normal Feedwater Flow
Core Power vs. Time

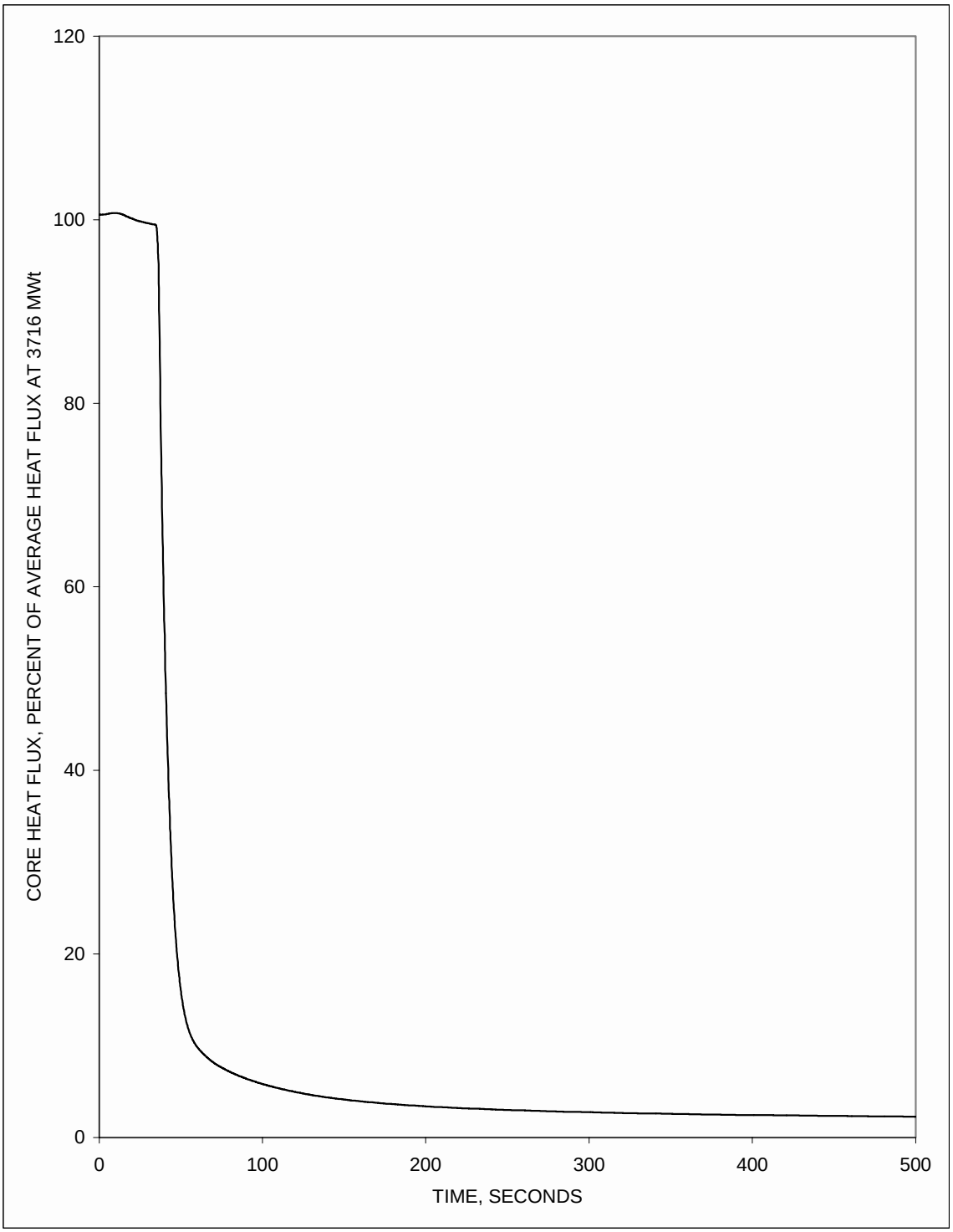

Figure 2.13.2.2.5-2
Loss-of-Normal Feedwater Flow
Core Heat Flux vs. Time

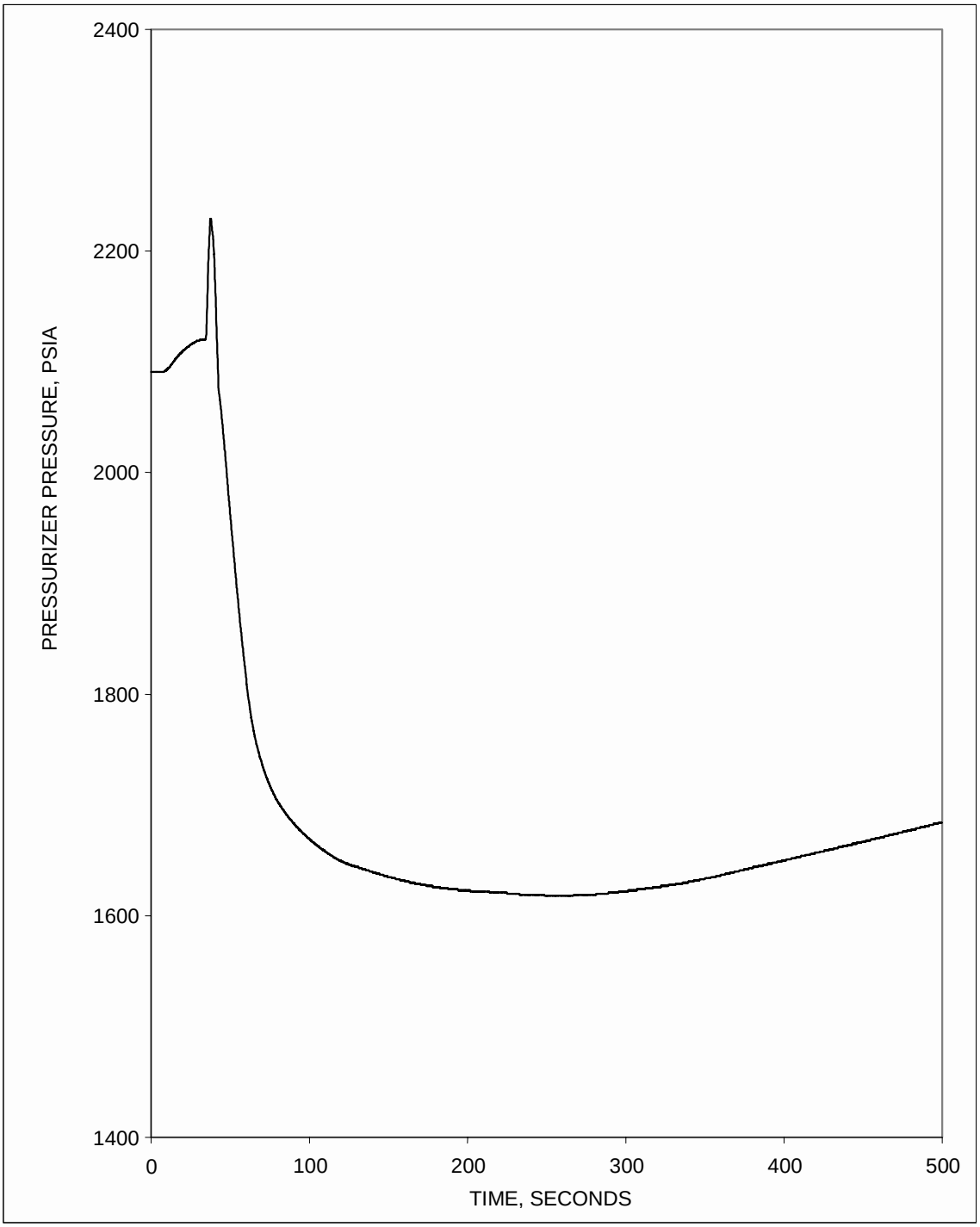

Figure 2.13.2.2.5-3
Loss-of-Normal Feedwater Flow
Pressurizer Pressure vs. Time

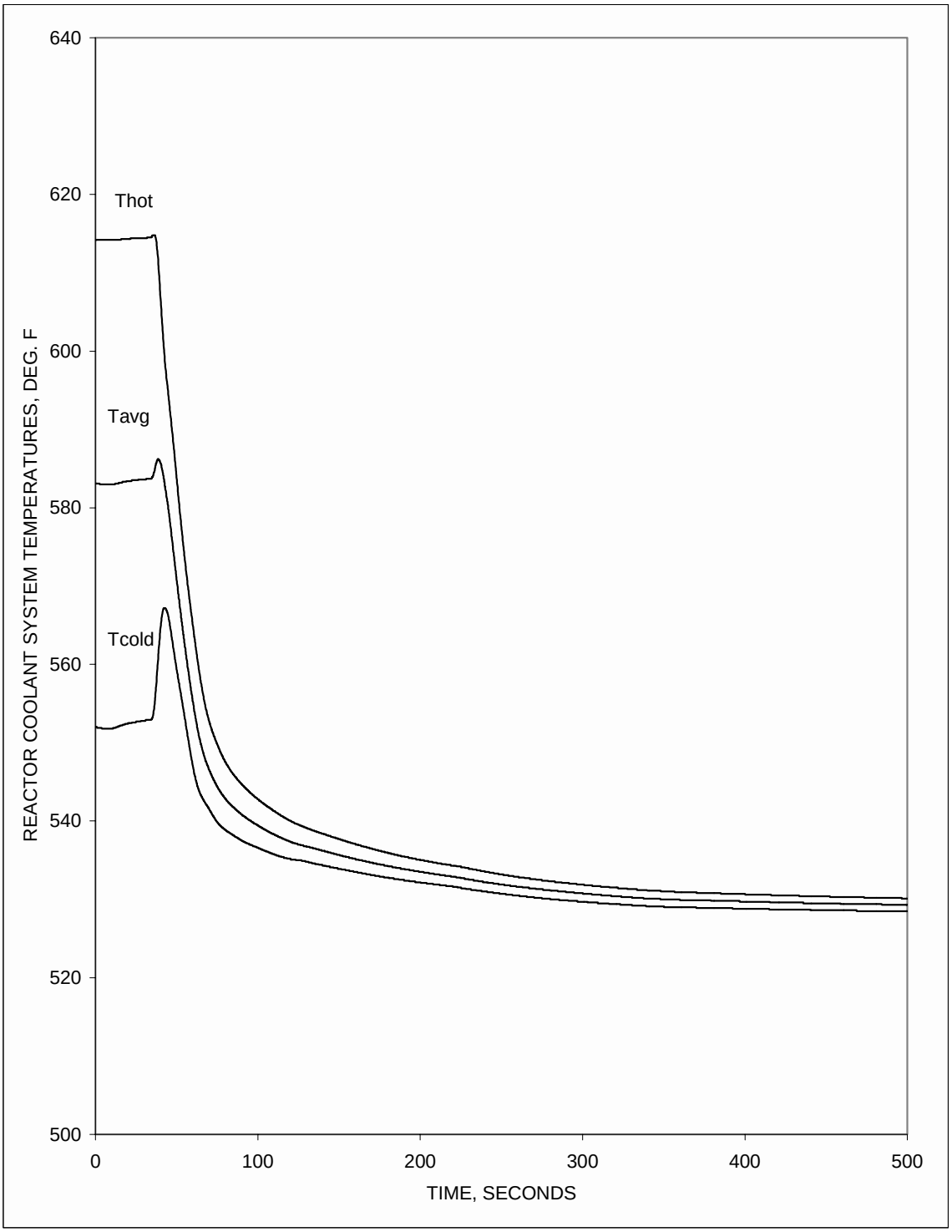

Figure 2.13.2.2.5-4
Loss-of-Normal Feedwater Flow
RCS Temperatures vs. Time

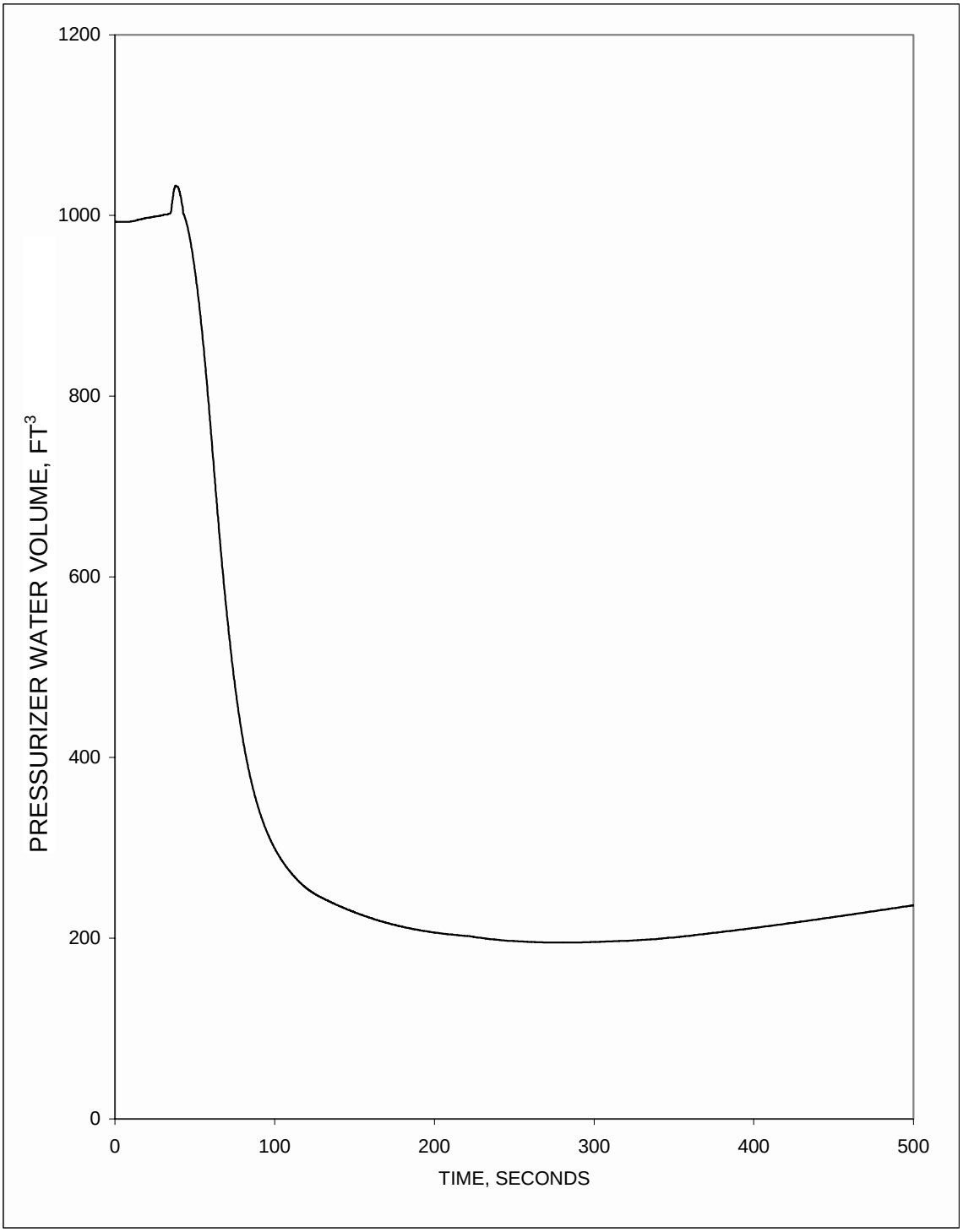

Figure 2.13.2.2.5-5
Loss-of-Normal Feedwater Flow
Pressurizer Water Volume vs. Time

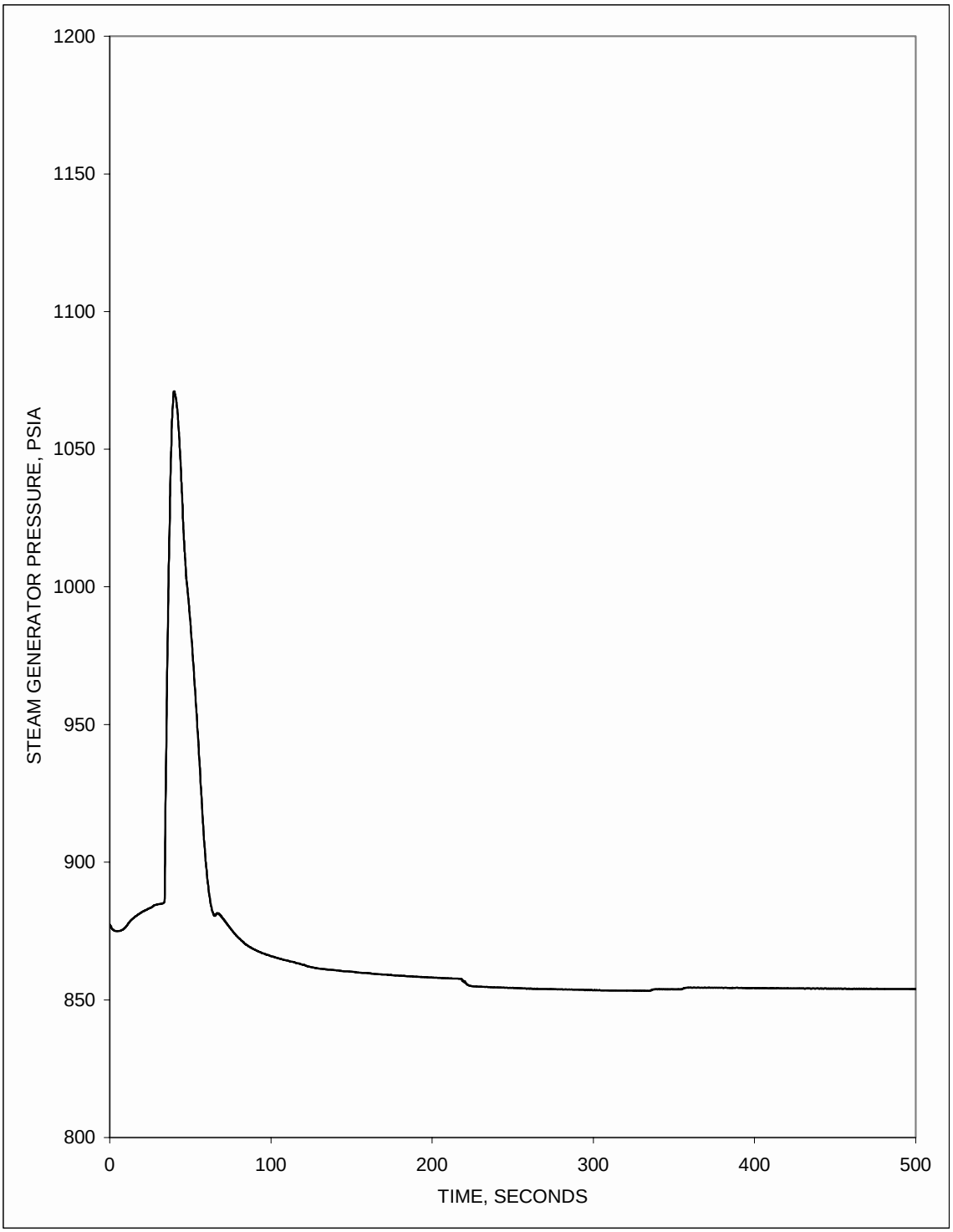

Figure 2.13.2.2.5-6
Loss-of-Normal Feedwater Flow
SG Pressure vs. Time

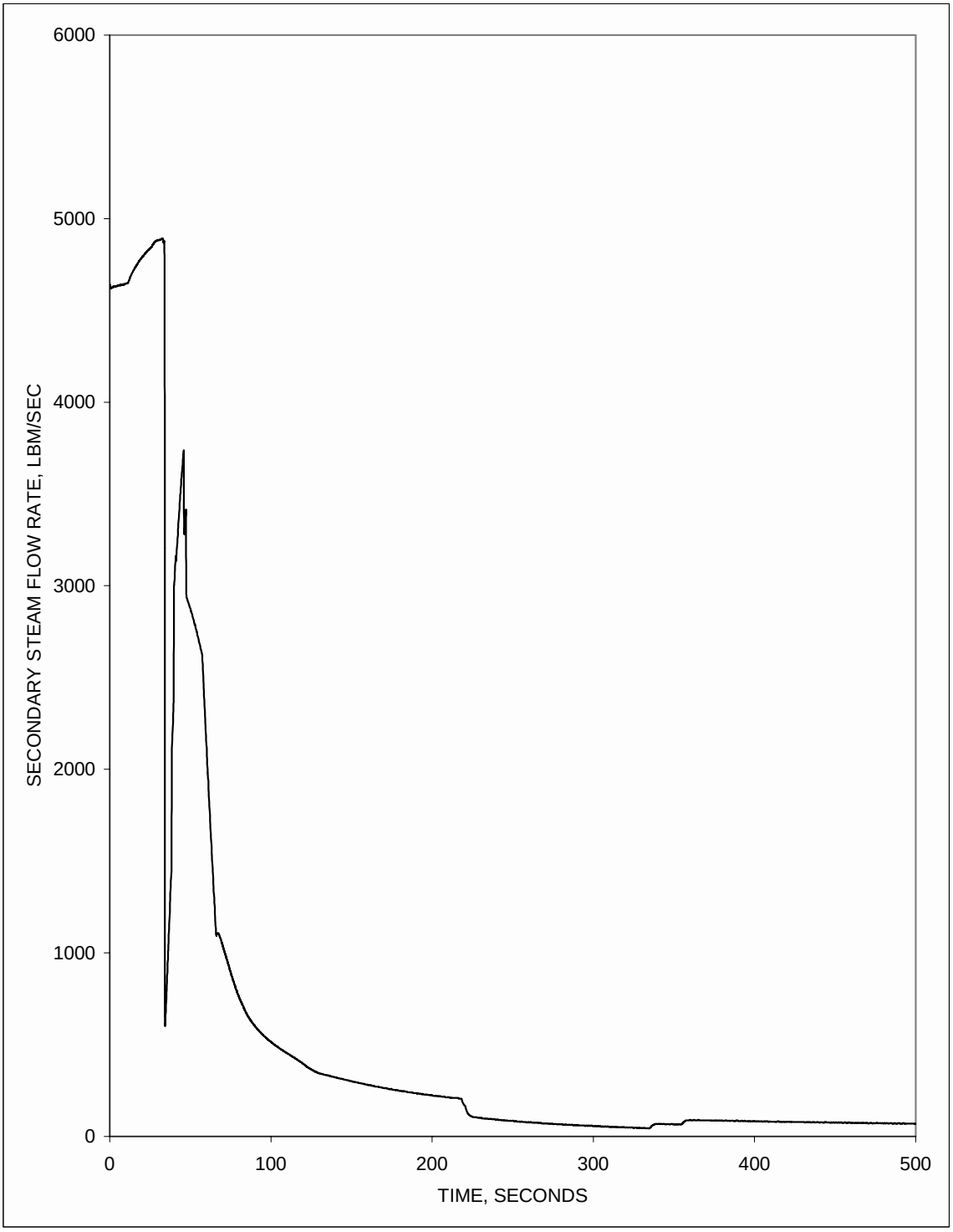

Figure 2.13.2.2.5-7
Loss-of-Normal Feedwater Flow
Secondary Steam Flowrate vs. Time

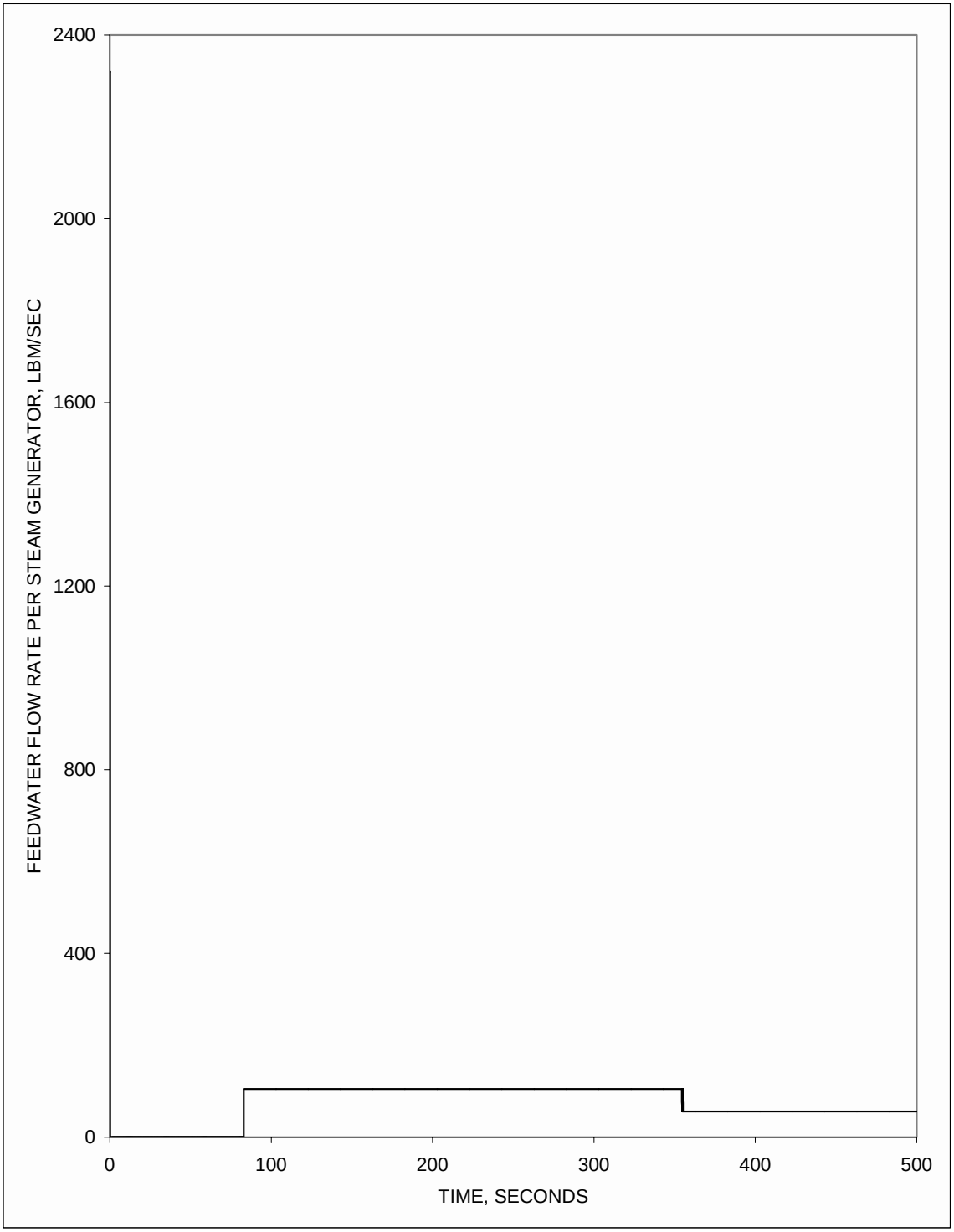

Figure 2.13.2.2.5-8
Loss-of-Normal Feedwater Flow
Emergency Feedwater Flowrate per SG vs. Time

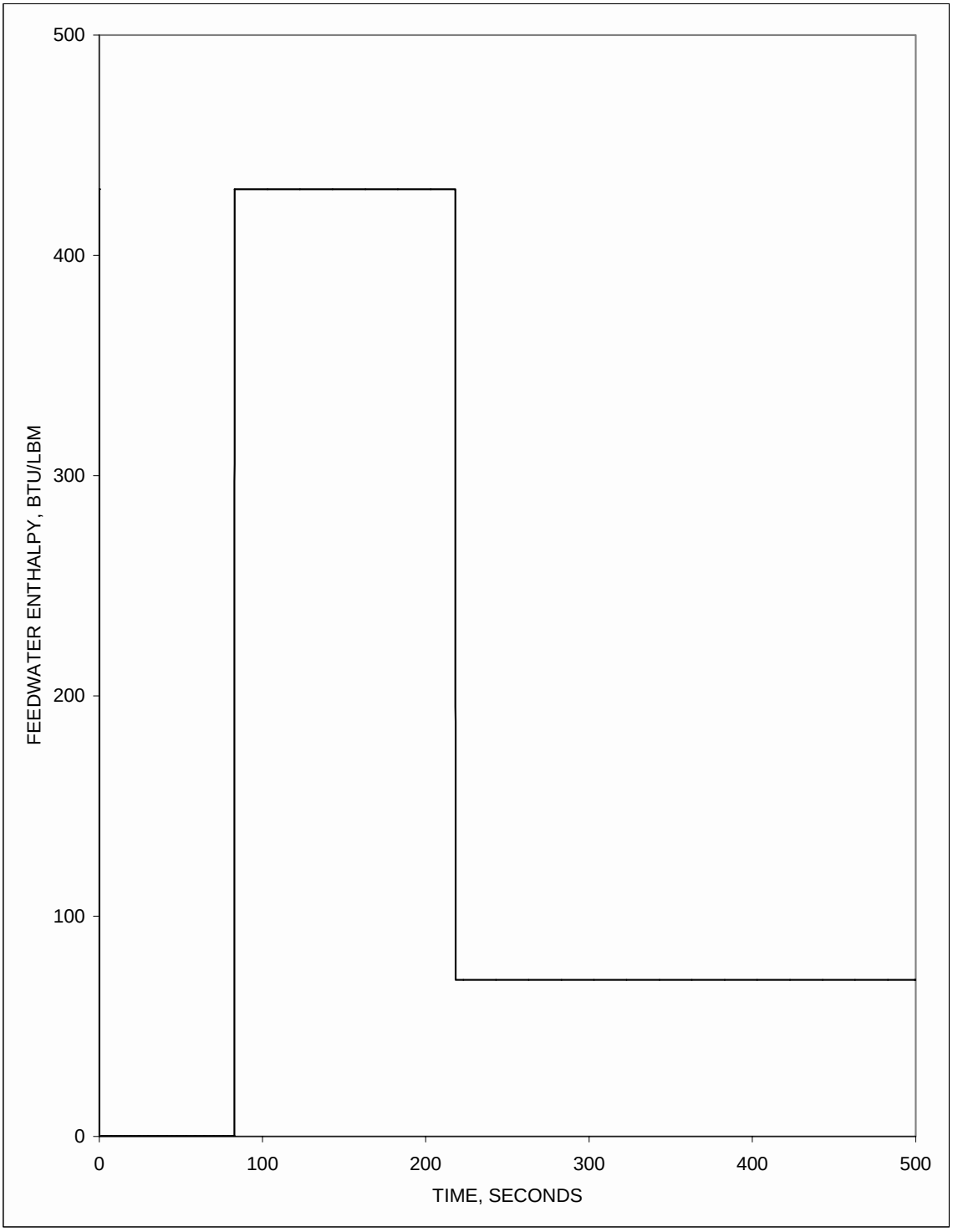

Figure 2.13.2.2.5-9
Loss-of-Normal Feedwater Flow
Feedwater Enthalpy vs. Time

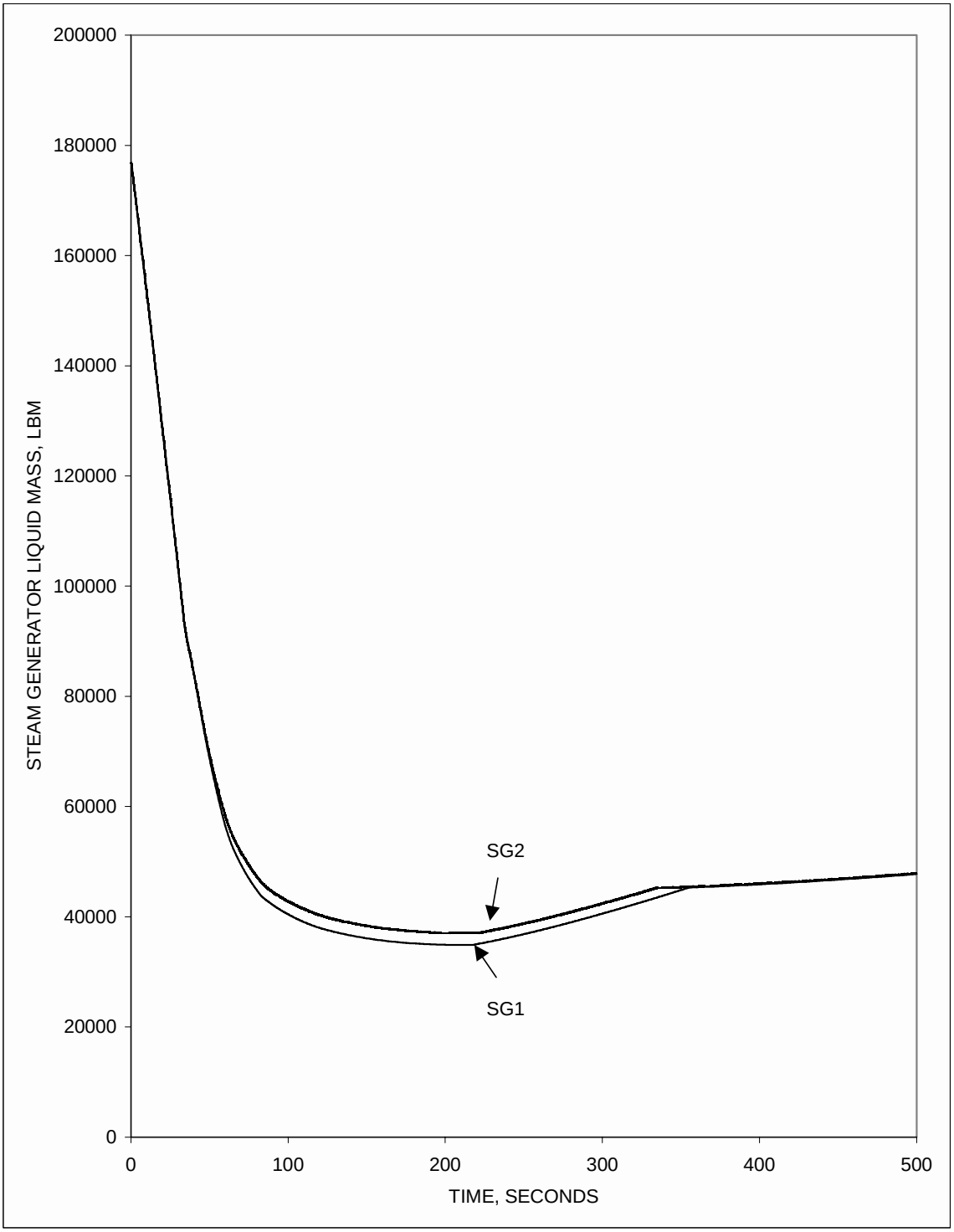

Figure 2.13.2.2.5-10
Loss-of-Normal Feedwater Flow
Secondary Liquid Mass vs. Time

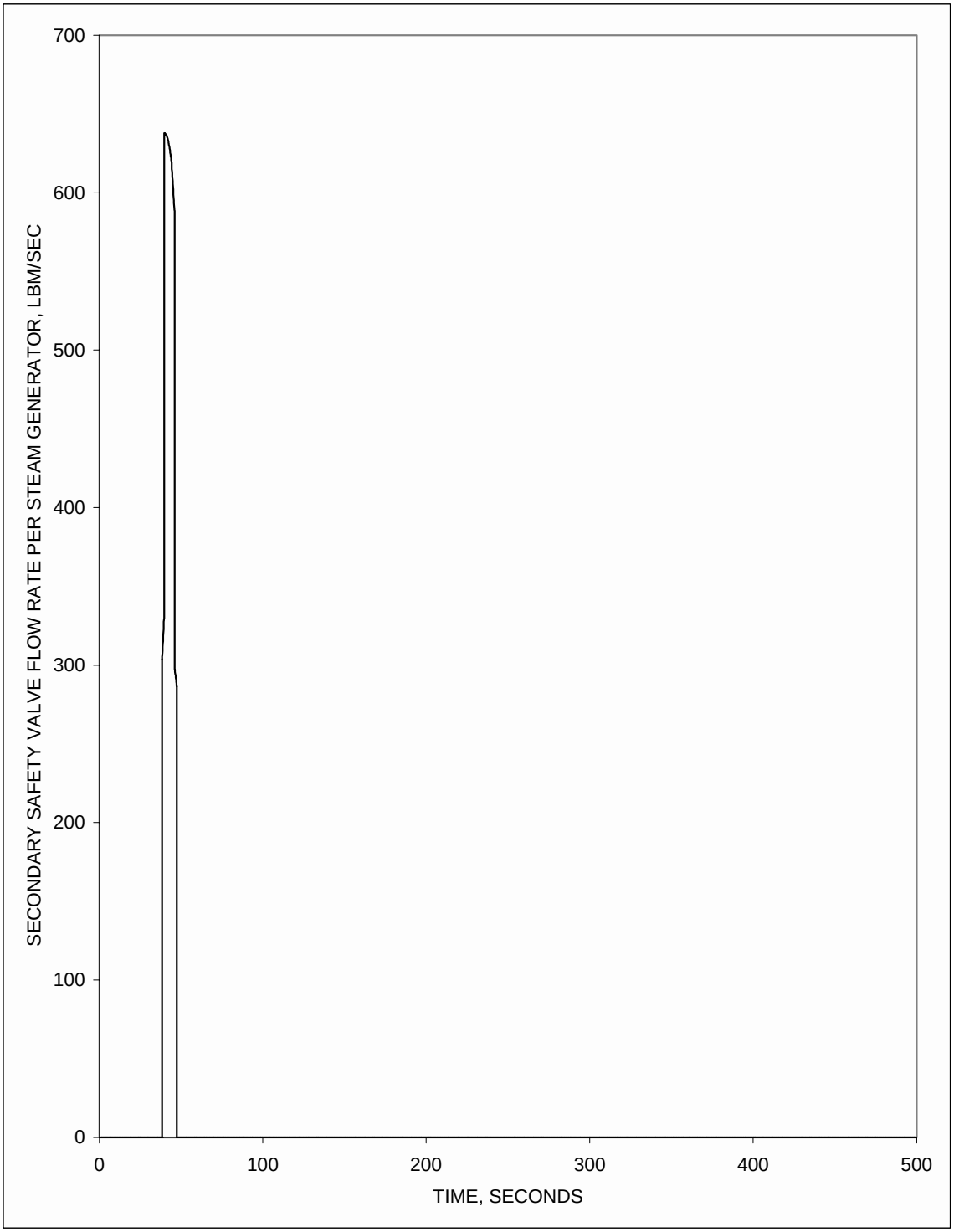

Figure 2.13.2.2.5-11
Loss-of-Normal Feedwater Flow
Safety Valve Flowrate per SG vs. Time

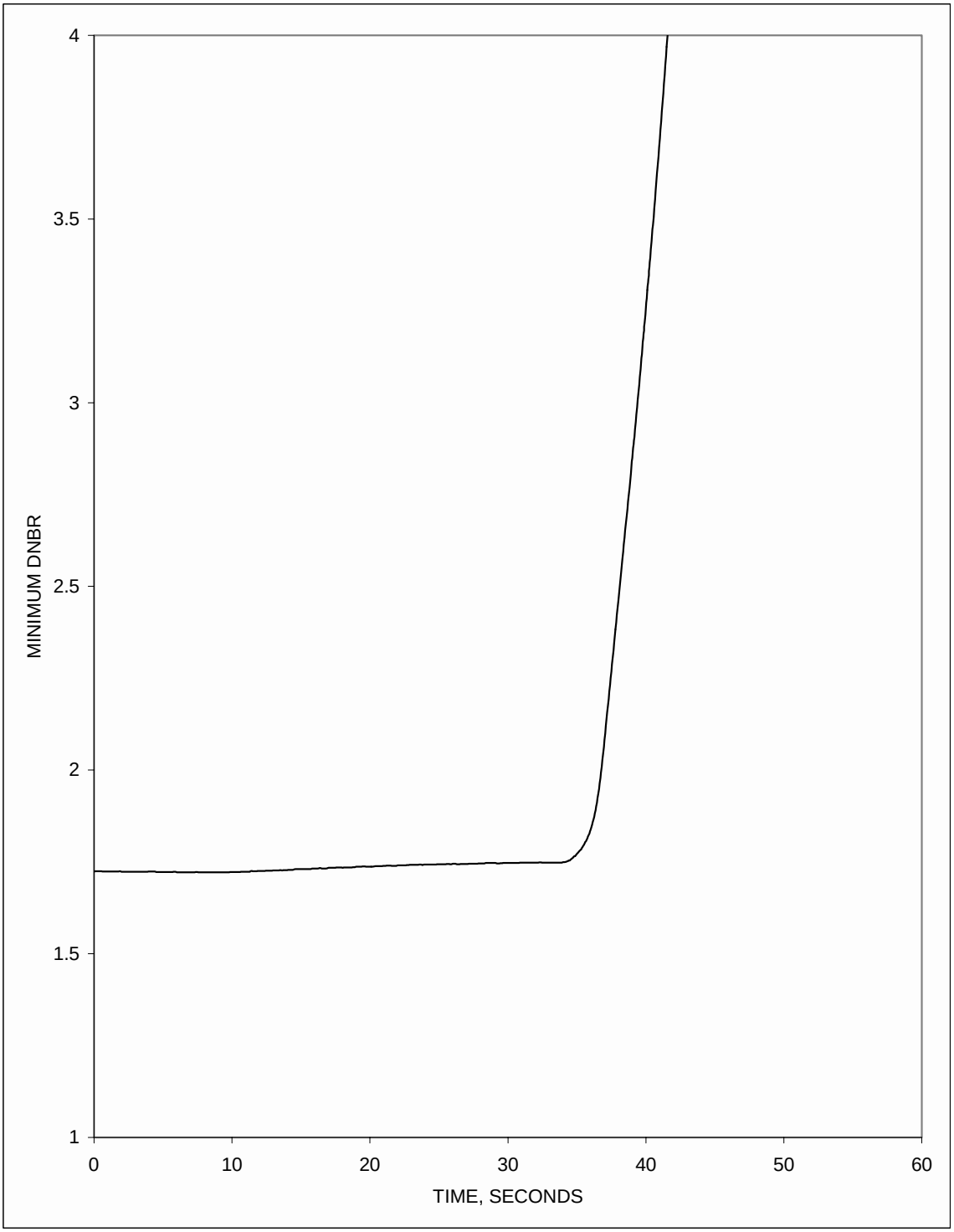

Figure 2.13.2.2.5-12
Loss-of-Normal Feedwater Flow
Minimum DNBR vs. Time

2.13.2.3 Limiting Faults

2.13.2.3.1 Feedwater System Pipe Breaks

2.13.2.3.1.1 Summary

The objective of the feedwater line break event is to document the impact of the following changes:

- An increase in rated power
- Use of the CENTS code in place of CESEC

2.13.2.3.1.2 General Description of the Event

A feedwater line break (FWLB) event is defined as the rupture of a main feedwater pipe during plant operation. If the FWLB is upstream of the feedwater check valves, SG blowdown is prevented by the closure of the check valves. If the break occurs between the steam generator and the check valves, blowdown of that SG continues until it empties. Blowdown of the unaffected SG is prevented by the action of the feed line check valves and, after main steam isolation signal (MSIS) actuation, by closure of the main steam isolation valves. In a postulated FWLB accident, a reactor trip occurs due to one of the following Reactor Protection System (RPS) signals:

- Low steam generator level (LSGL)
- High pressurizer pressure (HPP)
- Low steam generator pressure (LSGP)

Additional reactor trip signals that may respond to the transient are the CPCS low DNBR trip or the high containment pressure trip.

Large breaks are evaluated with LOOP. Small breaks (less than 0.2 ft^2) are analyzed with failure to fast bus transfer (FFBT) resulting in coastdown of two RCPs in accordance with the current licensing basis assumption.

The Engineered Safety Feature Actuation System (ESFAS) logic initiates emergency feedwater (EFW) to the intact steam generator upon receiving an emergency feedwater actuation signal (EFAS) after the appropriate time delay has been satisfied. Prior to the MSIS condition, EFW flow to the ruptured SG is assumed to flow directly out of the break. Because the EFW header is cross-tied to the SGs, complete EFW flow to the intact SG may not begin until the ruptured SG is isolated. The SGs are isolated after the MSIS signal. After the MSIS signal, EFW flow to the ruptured SG ceases and all available EFW flow is directed to the intact steam generator.

The opening of the pressurizer safety valves (PSVs) and the main steam safety valves (MSSVs) mitigates overpressurization of the Reactor Coolant System (RCS) and SGs.

SIAS during the FWLB event results in actuation of 2 charging pumps and isolation of the letdown. For these conditions, the event is run parametrical on break size to determine the most limiting time requirement to turn off the charging pumps to prevent filling the pressurizer.

The transient is run to determine the maximum RCS pressure during the event (large and small break peak pressure cases).

2.13.2.3.1.3 Purpose of the Analysis and Acceptance Criteria

The purpose of the FWLB analysis is to demonstrate that the FWLB event does not violate the following acceptable criteria for Waterford 3 with EPU at 3716 MWt.

The following criteria apply to the FWLB event:

- Radiological dose ≤ small fraction of 10CFR100 limits
- RCS pressures
  - Small FWLB without LOOP: The pressure in the RCS (primary) should be maintained below 110% of design pressure.
  - Large FWLB without LOOP, and FWLB (both large and small) with LOOP: The pressure in the RCS (primary) should be maintained below 120% of design pressure for all FWLBs.
- Secondary pressure criterion for all FWLB events: The pressure in the SG and MSSS should be maintained below 110% of the design pressure.

2.13.2.3.1.4 Impact of Changes

The increase in core power from 3478 MWt to 3716 MWt tends to increase the maximum RCS pressure and to increase the swelling of the fluid in the system, thus, decreasing the size of the steam bubble in the pressurizer during the FWLB event.

The event is now analyzed with the CENTS code vs. the CESEC code. The CENTS code includes modeling of the MSSS piping. As a result, termination of steam flow upon turbine trip and closure of the MSIVs is more gradual. This acts to compensate for some of the pressure increase that might be expected from the increase in core power.

2.13.2.3.1.5 Analysis Overview

Large Feedwater Line Break Analysis

Although the break is described as “large,” this part of methodology applies to the whole spectrum of FWLBs (small or large), occurring with LOOP assumed to result from a turbine trip and a limiting single failure. FWLB event with LOOP and a single failure is subject to ASME Service Level C pressure limit (120% of design pressure) defined in ASME Pressure Vessel

Code due to the very low probability of occurrence. The principal conservative assumptions and analytical methods utilized in the analysis of this event include:

a) Conservative estimation of the break flow and enthalpy, i.e., discharge of liquid from the downcomer until the SG is dry. Consistent with the pre-uprate licensing basis, the steam generator is considered dry when 9,000 lbm or less of liquid inventory is left. To establish this, the break is assumed to occur at the bottom of the SG, that is, at the tube sheet elevation.

b) Delay of heat transfer degradation in the affected steam generator until the liquid inventory is depleted. Consistent with the pre-uprate licensing basis analysis methodology, the heat transfer area is ramped from unity at 9,000 lbm liquid mass in the SG to zero at 2,000 lbm liquid mass in the SG.

c) Initializing key parameters such that a reactor trip occurs on high pressurizer pressure coincident with low SG level trip; further, the low SG level trip is delayed until liquid mass inventory in the affected SG is depleted. Parametric study shows that the coincident trips result in the most adverse results. Although depletion of the liquid mass inventory results in a low SG level trip much earlier, no credit is taken for the low SG level trip until the affected SG liquid mass inventory is depleted. Consistent with the pre-uprate licensing basis, the SG low level trip is activated when the SG liquid mass is less than 9,000 lbm.

d) Delaying the emergency feedwater actuation signal until liquid mass inventory in the affected SG is depleted (the SG liquid mass is less than 9,000 lbm).

A comparison of analysis assumptions for EPU versus the current power level is shown in Table 2.13.2.3.1-1. The transient is run as follows:

The FWLB is opened instantaneously and the feedwater to both generators is terminated to simulate a total loss-of-feedwater flow. The mismatch of the steam/feed flow inventory yields a reduction of the SG water inventory, pressurization of the secondary side, and a resulting heatup and pressurization of the primary side. Reactor trip occurs at the earliest of the high pressurizer pressure trip (HPPT) and the low SG level trip. The SG heat transfer capability is also modeled as lost at 9,000 lbm liquid mass in the SG. A turbine trip on reactor trip is generated followed by an instant closure of the turbine admission valve (TAV) to conservatively prevent any heat removal by the turbine. LOOP is assumed to occur at the time of turbine trip causing a trip of all RCPs. The HPPT is followed by the lifting of primary (PSV) and secondary (MSSV) safety valves, which are set at their most adverse lift and blowdown pressures. Primary and secondary cooldown is provided by the heat removal through the PSVs and MSSVs.

The transient is continued until the primary and secondary pressures, temperatures, and pressurizer level have turned around.

Small Feedwater Line Break (FWLB) Analysis

Small break is defined as the break sizes less than 0.2 ft^2. The probability of a small break occurring (with a single failure with offsite power available) is higher than the probability of FWLB (with LOOP). Therefore, the ASME Service Code C limits are not applicable to this event, so that the acceptable pressure is less than or equal to 110% of the design pressure. The principal conservative assumptions utilized in the analysis of this event include:

a) Conservative estimation of the break flow and enthalpy, i.e., discharge of liquid from the downcomer until the SG is dry. Consistent with the FSAR, the SG is considered dry for the analysis of small feed line breaks when 21,000 lbm or less of liquid inventory is left. To establish this, the break is assumed to occur at the bottom of the SG, which is at the tube sheet elevation.

b) Conservative delay in crediting a reactor trip generated from a low water level within the affected SG. For conservatism, the low SG level trip is delayed until the liquid mass inventory is at or below 21,000 lbm.

c) Delay of heat transfer degradation in the affected SG until the liquid inventory is depleted. Consistent with the FSAR small break analysis methodology, the heat transfer area is ramped from unity at 21,000 lbm liquid mass in the SG to zero at 2,000 lbm liquid mass in the SG.

d) Initializing key parameters such that a reactor trip occurs on high pressurizer pressure coincident with low SG level trip. The low SG level trip is delayed until liquid mass inventory in the affected SG is depleted. Parametric study shows that the coincident trips result in the most adverse results. Consistent with the pre-uprate licensing basis, the SG is assumed to be depleted when the SG liquid mass is less than 21,000 lbm.

e) Delaying the EFW actuation signal until liquid mass inventory in the affected SG is depleted (the SG liquid mass is less than 21,000 lbm).

A comparison of analysis assumptions for EPU versus the current power level is shown in Table 2.13.2.3.1-3.

The transient is analyzed as follows:

The FWLB is simulated by an instantaneous opening of the break and terminating the feedwater to both SGs to simulate a conservative total loss of feedwater flow. The mismatch of the steam/feed flow inventory yields a reduction of the steam generator water inventory, pressurization of the secondary side, and a resulting heatup and pressurization of the primary side. Reactor trip occurs at the earliest of the high pressurizer pressure trip (HPPT) and the low SG level trip corresponding to level when liquid mass inventory in the affected SG is depleted (21,000 lbm of liquid mass inventory). A turbine trip on reactor trip (when the breakers open) is generated followed by an instant closure of the TAV to conservatively prevent any heat removal by the turbine. FFBT results in two RCP in opposite loops to trip. If one of the fast transfer buses is blocked, fast bus transfer may result in LOOP which causes 4 RCP pumps to trip and loss of PLCS and PPCS but, two-pump coastdown is more limiting for the peak pressure case. Meanwhile, the steam generator heat transfer capability degrades when the SG liquid inventory decreases below 21,000 lbm, and is totally lost when the SG dries out (2,000 lbm SG liquid inventory). The HPPT is followed by the lifting of primary (PSV) and secondary (MSSV) safety

valves, which are set at their most adverse lift and blowdown pressures. Primary and secondary cooldown is provided by the heat removal through the PSVs and MSSVs.

The transient is continued until the primary and secondary pressures, temperatures, and pressurizer level have turned around and are decreasing.

2.13.2.3.1.6 Radiological Consequences

The FWLB does not result in SAFDL violation. Due to the rupture in the feedline, one SG is open to the atmosphere for the duration of the event. During this time, the initial iodine activity in the SG and the iodine activity carried due to SG tube leakage in the affected unit is released with a DF of unity. No partition factor is applied to the noble gases.

The remainder of the releases is the result of steaming the intact SG to remove decay heat and cool down the plant. The activity in the intact SG is initially at the LCO limit for the secondary system, and is gradually increased with the activity carried by the primary-to-secondary leakage with coolant at the LCOs for primary system activity. Iodine releases from the intact generator use a DF of 100 based on the activity in the bulk secondary water during a given interval. No partition factor is applied to the noble gases.

Radiological consequences, with the inclusion of a pre-existing iodine spike, are:

	2-Hour EAB	**8-Hour LPZ**
Thyroid	≤ 30 rem	≤ 30 rem
Whole Body	≤ 2.5 rem	≤ 2.5 rem

2.13.2.3.1.7 Analysis Results

<u>Large FWLB</u>

A comparison of the sequence of events for the limiting large FWLB for EPU versus the current power level is shown in Table 2.13.2.3.1-2.

The most adverse break size for large FWLB assumptions was determined by parametric analyses. Figure 2.13.2.3.1-1 shows the parametric study on maximum RCS pressure as a function of break area.

Figures 2.13.2.3.1-2 through 2.13.2.3.1-19 show the system response for the limiting large-break case. The peak pressure results for the limiting large FWLB event are as follows:

Large FWLB				
Limiting Break Size ft^2	**Maximum RCS Pressure psia**	**Maximum Pressurizer Liquid Volume ft^3**	**Maximum SG Pressure psia**	**Minimum DNBR**
0.12	2753	1321.4	1122	1.64

The limiting parameters satisfy the peak pressure acceptance criteria described above.

Small FWLB

A comparison of the sequence of events for the limiting small FWLB for EPU versus the current power level is shown in Table 2.13.2.3.1-4.

The most adverse break size for small FWLB assumptions was determined by parametric analyses. Figure 2.13.2.3.1-20 shows the parametric study on maximum RCS pressure as a function of break area.

Figures 2.13.2.3.1-21 through 2.13.2.3.1-38 show the system response for the limiting small break case. The limiting small break is the 0.17 ft^2 break. The peak pressure results for the limiting small break peak pressure FWLB event are as follows:

Small FWLB				
Limiting Break Size ft^2	**Maximum RCS Pressure psia**	**Maximum Pressurizer Liquid Volume ft^3**	**Maximum SG Pressure Psia**	**Minimum DNBR**
0.17	2670.8	1212.8	1129.1	1.73

The limiting parameters satisfy the peak pressure acceptance criteria described above.

The radiological consequences of the FWLB scenarios meet the acceptance criteria of ≤ a small fraction of 10CFR100.

An evaluation of the potential for pressurizer fill demonstrates that the operators must act to turn off the charging pumps by 12 minutes following SIAS to avoid filling of the pressurizer. This is greater than the 10 minutes allowed prior to the first operator action per NUREG-0800. Since this case is run to determine operator response times, less excess conservatism is used for some of the input assumptions to avoid an unrealistic conclusion.

Table 2.13.2.3.1-1
Comparison of Assumptions for the Large FWLB Event

Parameter	Power Uprate Assumption	Current Power Level Assumption
Initial core power, MWt	3735	3478*
Core inlet temperature, °F	552	560
RCS Flow rate, 10^6 lbm/hr	148	128.6
Pressurizer pressure, psia	2310	2225
SG pressure, psia	867	964
MTC, $10^{-4}\Delta\rho$/°F	-0.2	0.0
Doppler coefficient multiplier	0.85	0.85
CEA worth for trip, $10^{-2}\Delta\rho$	-6.0	-6.0
SBCS	Inoperative	Inoperative
PPCS	Inoperative	Inoperative
PLCS	Automatic	Inoperative
FWLB area, ft^2	0.12	0.2
Initial intact SG liquid inventory, lbm	98,280	100,000
Emergency feedwater flow,gpm	575	575

* Includes pump heat

Table 2.13.2.3.1-2
Comparison of the Sequence of Events for the Limiting Large FWLB Event

EPU Time (sec)	Current Power Level Time (sec) Reference 3, Table 15.2-8	Event	EPU Setpoint/ Value	Current Power Level Setpoint/Value Reference 3, Table 15.2-8
0.0	0.0	Break of main feedwater line. Complete loss of feed flow.	0.12 ft^2	0.2 ft^2
24.1	---	Low SG trip condition (SG liquid mass)	9000 lbm (2 ft)	5% NR
24.1	---	EFW actuation signal generated by low water level trip condition (SG liquid mass)	9000 lbm (2 ft)	5% NR
24.6	17.3	High pressurizer trip condition	2422 psia	2474 psia
25.0	18.2	Trip breakers open	---	---
25.0	18.2	Turbine trip	---	---
25.0	18.2	LOOP	---	---
25.01	18.2	Turbine admission valves closed	---	---
25.6	18.8	CEAs begin to drop	---	---
26.95	16.6	SG connected to the ruptured feed line empties	2000 lbm	---
27.0	18.7	PSVs open	2575 psia	2575 psia
27.85	20.7	Maximum, pressurizer surge line flow	1914 lbm/sec	1637 lbm/sec
28.2	21.3	Maximum RCS pressure	2753 psia	2750 psia
34.5	22.8	SG safety valves open	1117 psia	1117.6 psia
35.0	26.7	Maximum SG pressure	1122 psia	1165 psia
84.1	70.1	Emergency feedwater flow initiated*	---	---
100	26.0	Minimum pressurizer steam volume	225.2 ft^3	391 ft^3
1800	1800	Opertor takes control of plant	---	---
28,800	---	SDC initiated	---	---

*EFW flow is initially diverted to the break.

Table 2.13.2.3.1-3
Comparison of Assumptions for the Small FWLB Event

Parameter	Power Uprate Assumption	Current Power Level Assumption
Initial core power level, MWt	3735	3478*
Core inlet temperature, °F	552	560
Core mass flow rate, 10^6 lbm/hr	148	128.55
RCS pressure, psia	2310	2200
SG pressure, psia	867	964
MTC, $10^{-4}\Delta\rho$/°F	-0.2	0
Doppler coefficient multiplier	0.85	0.85
CEA worth for trip, $10^{-2}\Delta\rho$	-6	-6.0
SBCS	Inoperative	Inoperative
PPCS	Inoperative	Inoperative
PLCS	Automatic	Inoperative
FWLB area, ft^2	0.17	0.2
Initial intact SG liquid inventory, lbm	98.280	144,300
SG safety valve setpoint tolerance, percent	+3%	+3%
PSV setpoint tolerance, percent	+3%	+3%
EFW flow, gpm	575	700

* Includes pump heat

Table 2.13.2.3.1-4
Comparison of the Sequence of Events for the Limiting Small FWLB Event

EPU Time (sec)	Current Power Level Time (sec) Reference 3, Table 15.2-8	Event	EPU Setpoint/Value	Current Power Level Setpoint/Value Reference 3, Table 15C.1-3
0.0	0.0	Break of main feedwater line. Complete loss of feedwater flow	0.17 ft^2	0.20 ft^2
0.1	0.0	Initial break flow, lbm/sec	1922 lbm/sec	1940 lbm/sec
36.6	16	Low steam generator trip condition (SG liquid mass)	21,000 lbm (5 ft.)	21,000 lbm
36.6	16	EFW actuation signal generated by low water level trip condition (SG liquid mass)	21,000 lbm (5 ft)	21,000 lbm
36.6	15.4	High pressurizer trip condition	2422 psia	2474 psia
37.5	16.5	Trip breakers open	Trip signal + 0.9 sec	2474 psia
37.5	16.5	Turbine trip	Time of trip breakers open	---
37.5	16.5	FFBT – two RCPs coastdown	Time of turbine trip	---
37.51	16.5	Turbine admission valves closed	Time of turbine trip + 0.01 sec	---
38.1	17.2	CEAs begin to drop	Time of trip breakers open + 0.6 sec	---
39.9	15.9	PSVs open	2575 psia	2575 psia
39.95	---	Maximum pressurizer pressure	2578.9 psia	---
40.45	20	Maximum RCS pressure	2670.8 psia	2716.02 psia
40.85	18.6	Maximum, pressurizer surge line flow	1334 lbm/sec	1530 lbm/sec
42.95	30.8	SG connected to the ruptured feed line empties	2000 lbm	---

Table 2.13.2.3.1-4 (cont.)
Comparison of the Sequence of Events for the Limiting Small FWLB Event

EPU Time (sec)	Current Power Level Time (sec) Reference 3, Table 15.2-8	Event	EPU Setpoint/Value	Current Power Level Setpoint/Value Reference 3, Table 15C.1-3
44	28.1	SG safety valves open	1117.2 psia	1117.6 psia
46.05	30.5	Maximum SG pressure	1129.1 psia	1152.5 psia
51.8	35.8	Minimum pressurizer steam volume	345.4 ft^3	443.2 ft^3
86.6	---	EFW flow initiated	emergency feedwater flow activation (EFWA) + 60 sec	---
100.	---	End of analysis	100.0	---

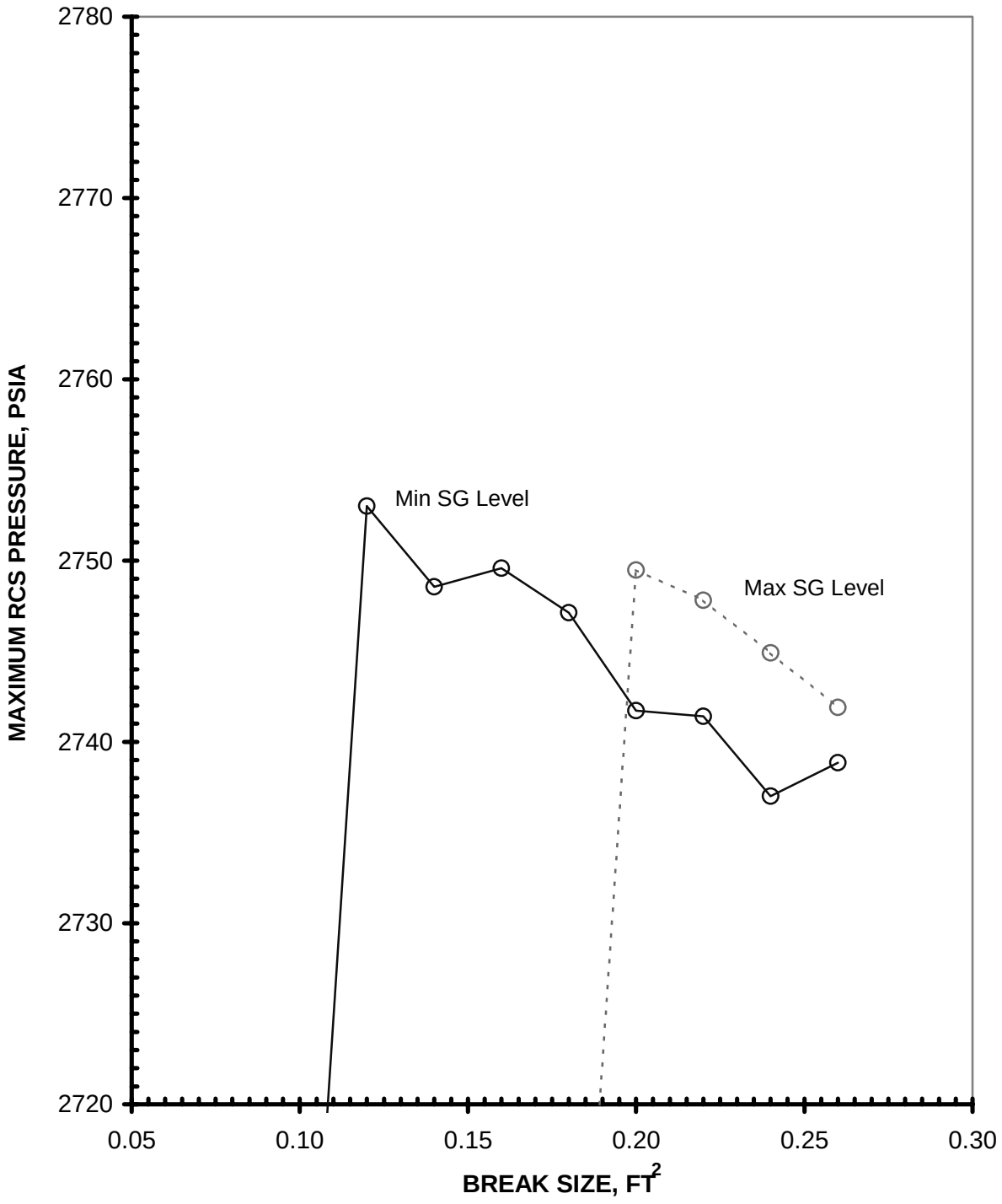

Figure 2.13.2.3.1-1
Feedwater System Pipe Break (Large)
RCS Pressure vs. Time

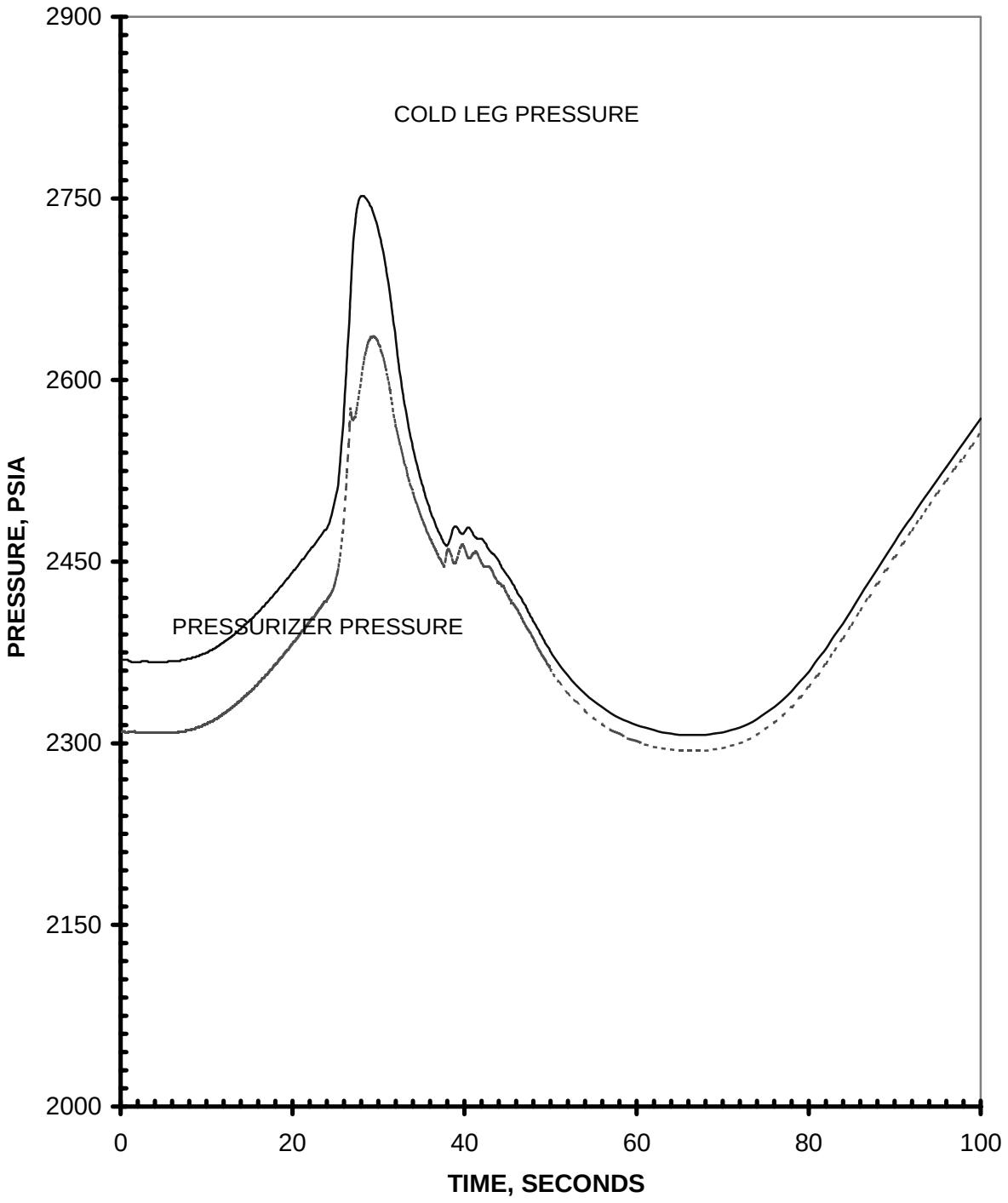

Figure 2.13.2.3.1-2
Feedwater System Pipe Break (Large)
RCS Pressure vs. Time

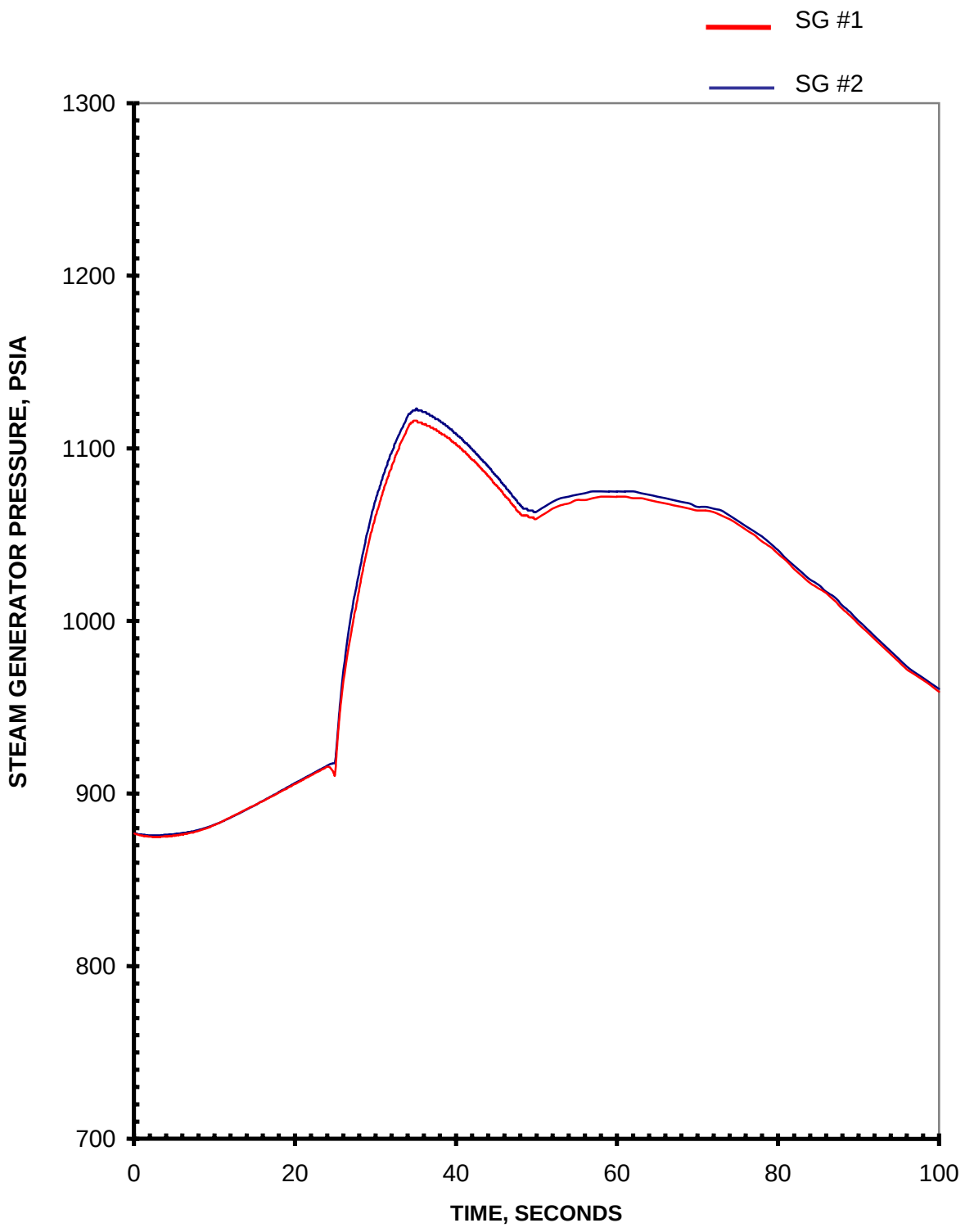

Figure 2.13.2.3.1-3
Feedwater System Pipe Break (Large)
SG Pressure vs. Time

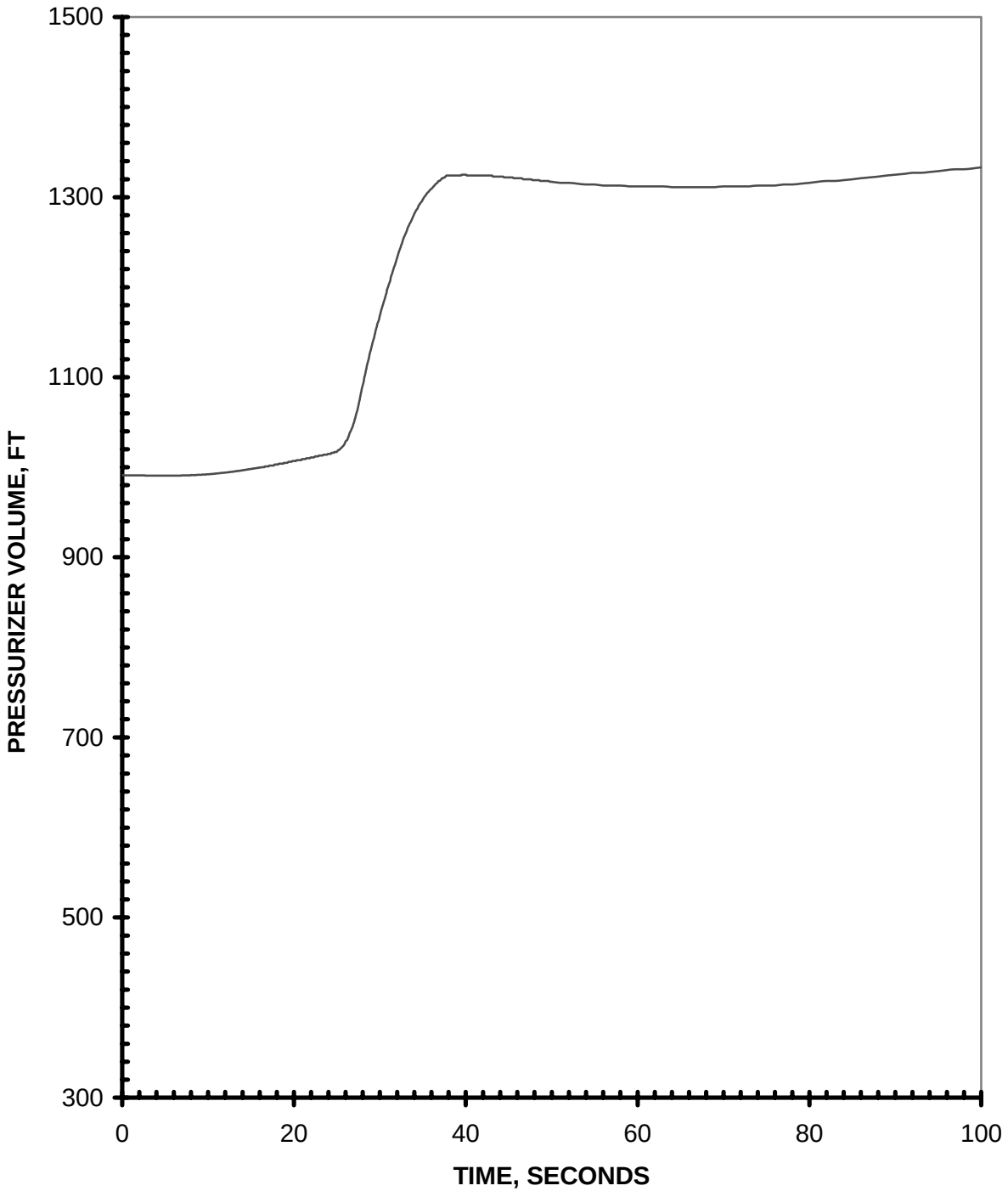

Figure 2.13.2.3.1-4
Feedwater System Pipe Break (Large)
Pressurizer Water Volume vs. Time

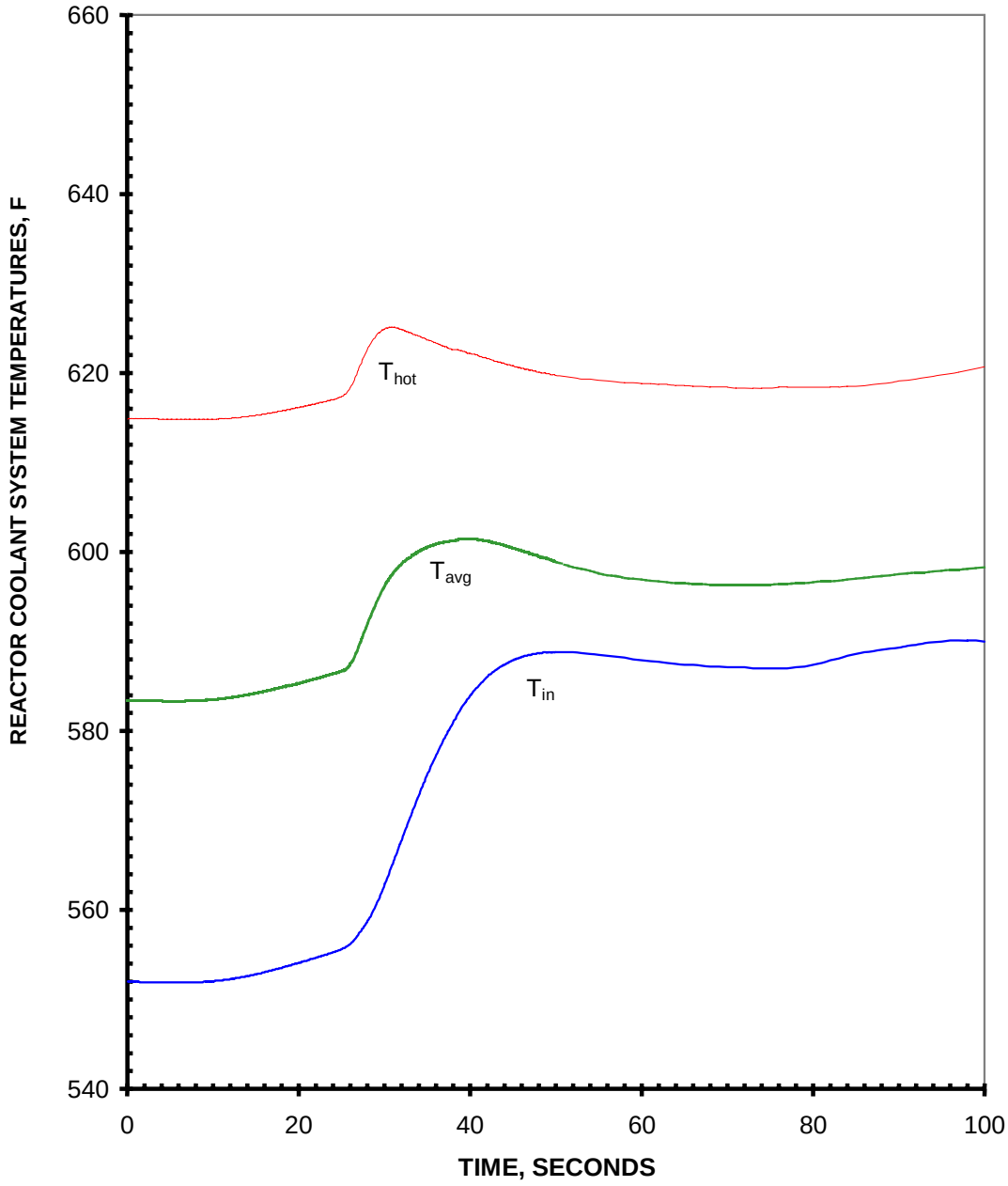

Figure 2.13.2.3.1-5
Feedwater System Pipe Break (Large)
RCS Temperatures vs. Time

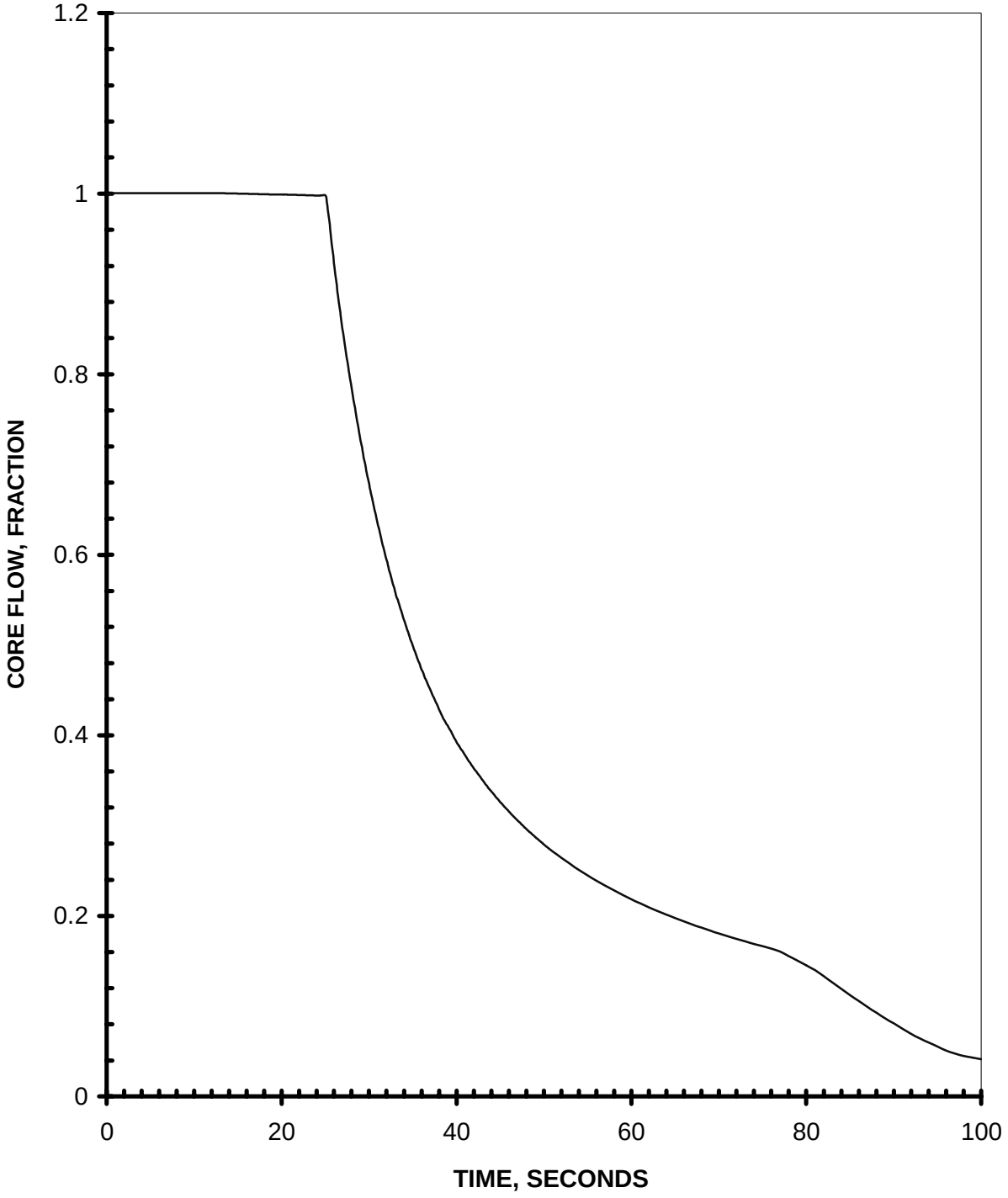

Figure 2.13.2.3.1-6
Feedwater System Pipe Break (Large)
Core Flow (Fraction) vs. Time

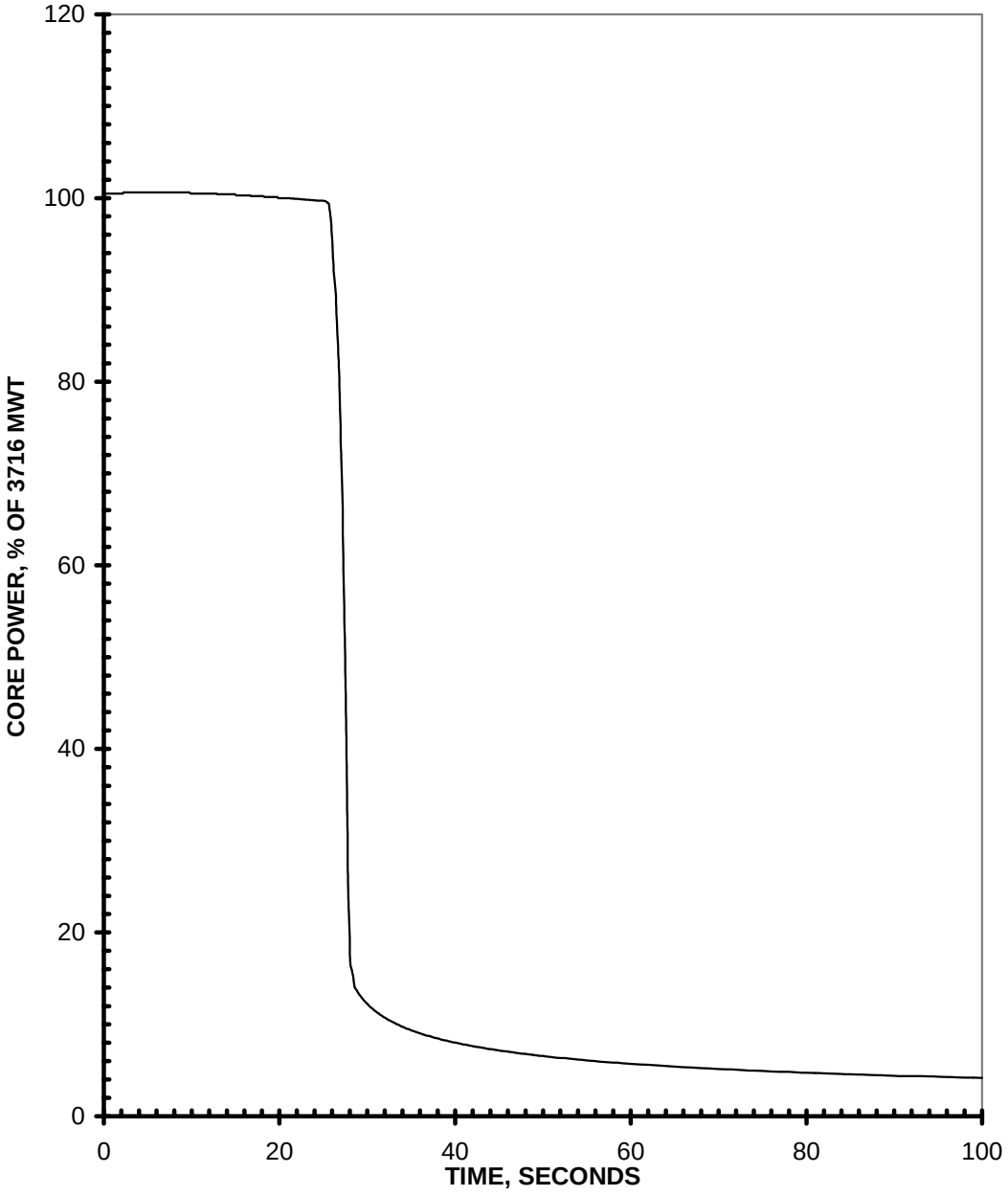

Figure 2.13.2.3.1-7
Feedwater System Pipe Break (Large)
Core Power vs. Time

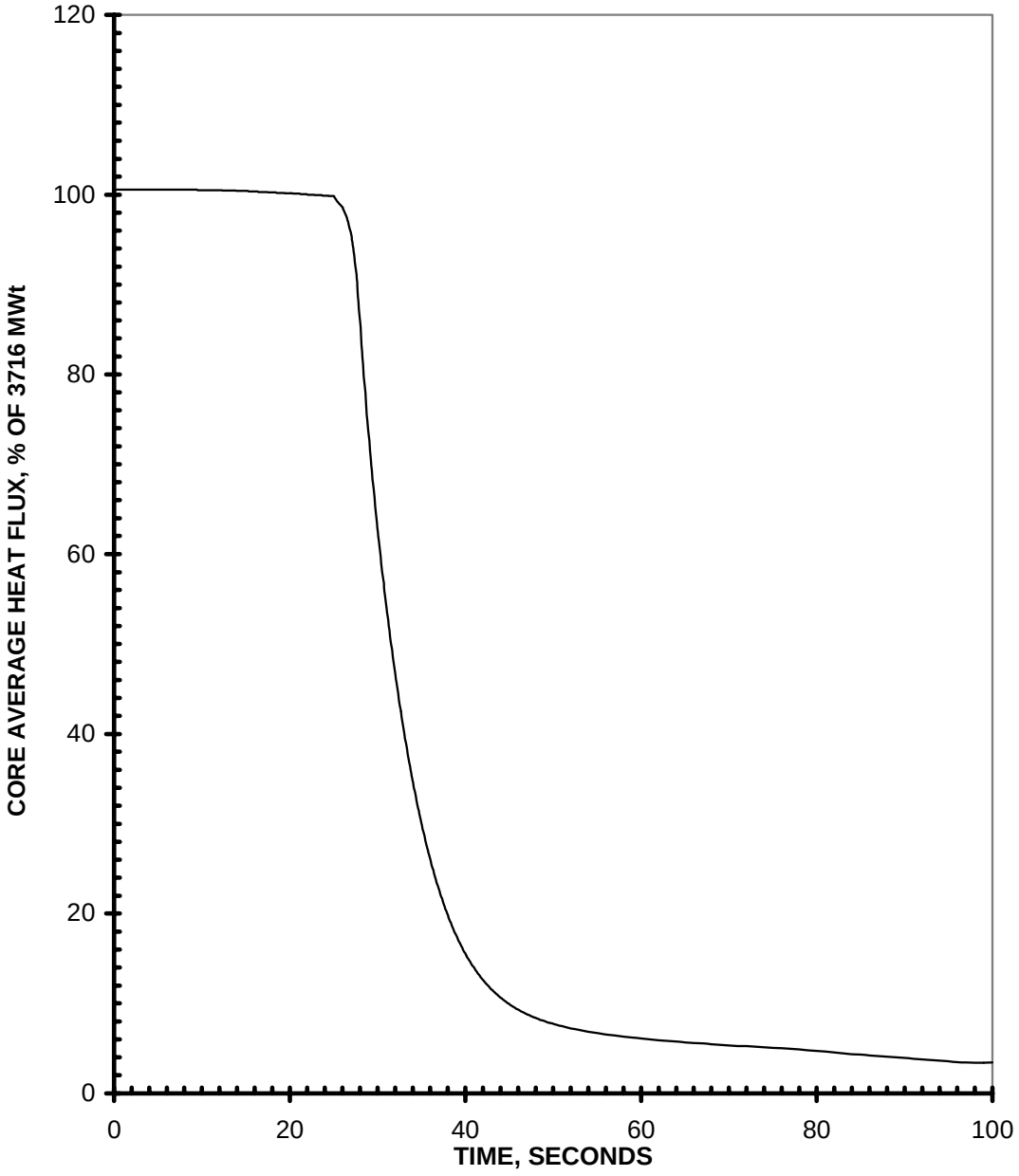

Figure 2.13.2.3.1-8
Feedwater System Pipe Break (Large)
Core Heat Flux vs. Time

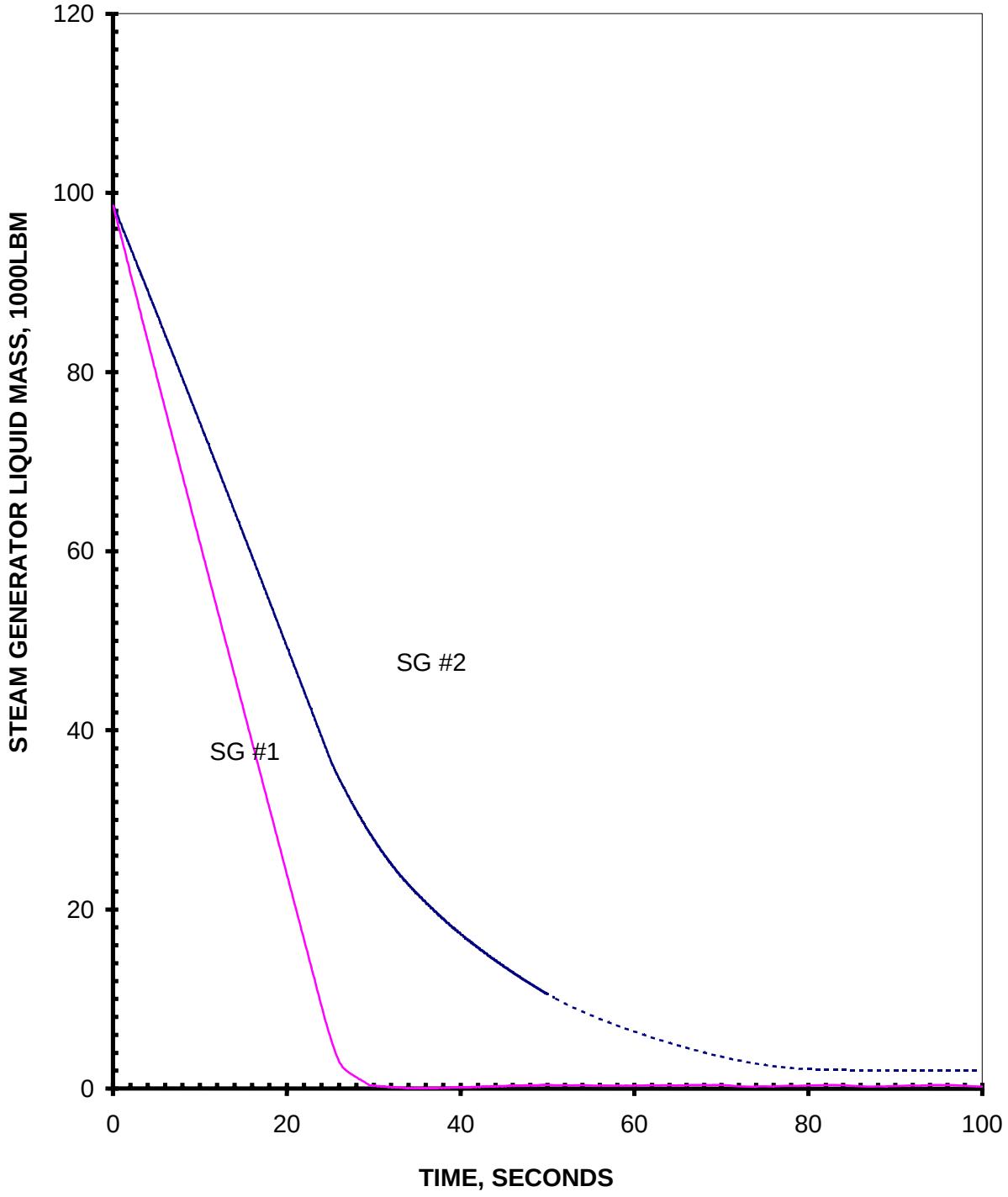

Figure 2.13.2.3.1-9
Feedwater System Pipe Break (Large)
SG Liquid Mass vs. Time

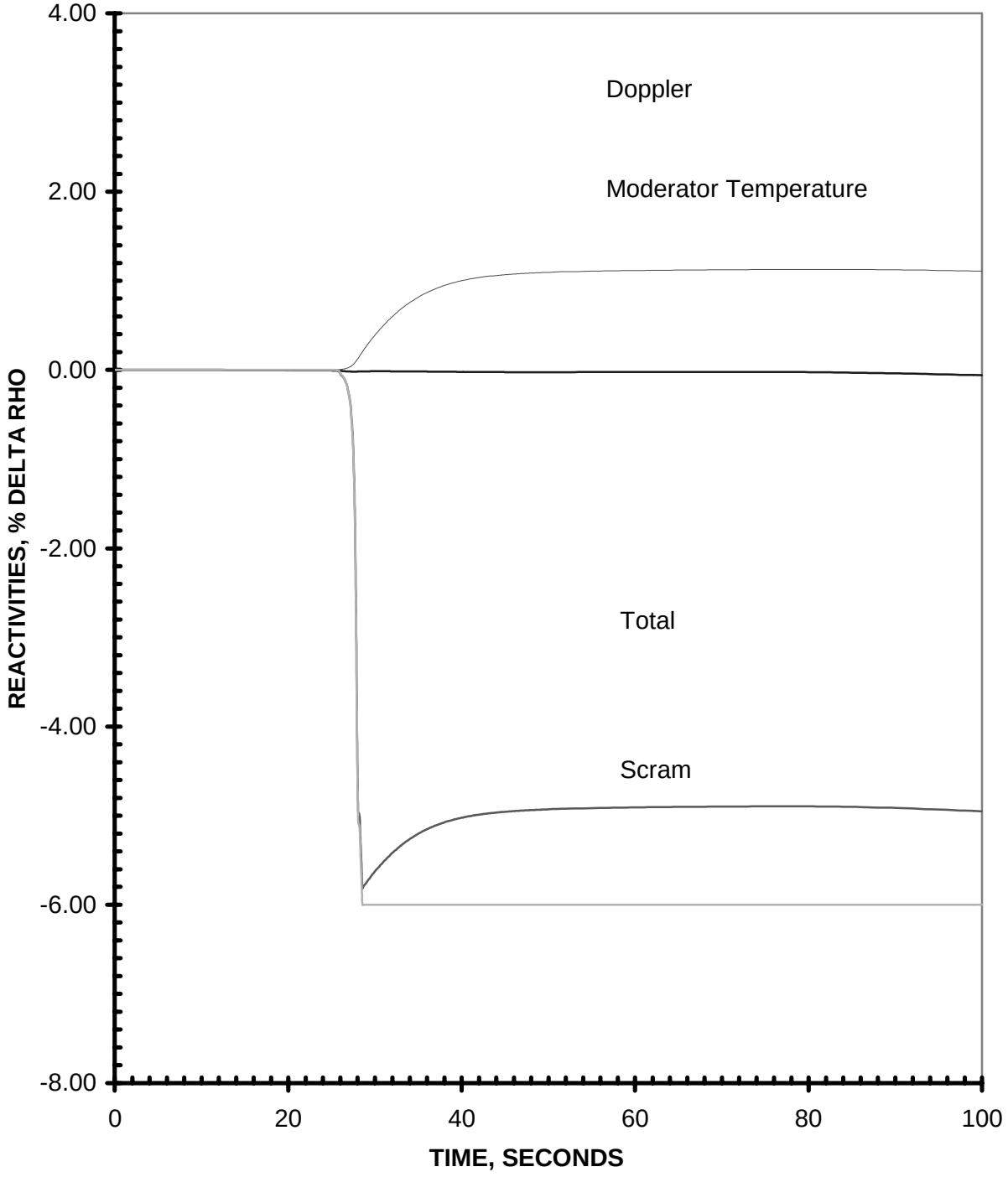

Figure 2.13.2.3.1-10
Feedwater System Pipe Break (Large)
Reactivity vs. Time

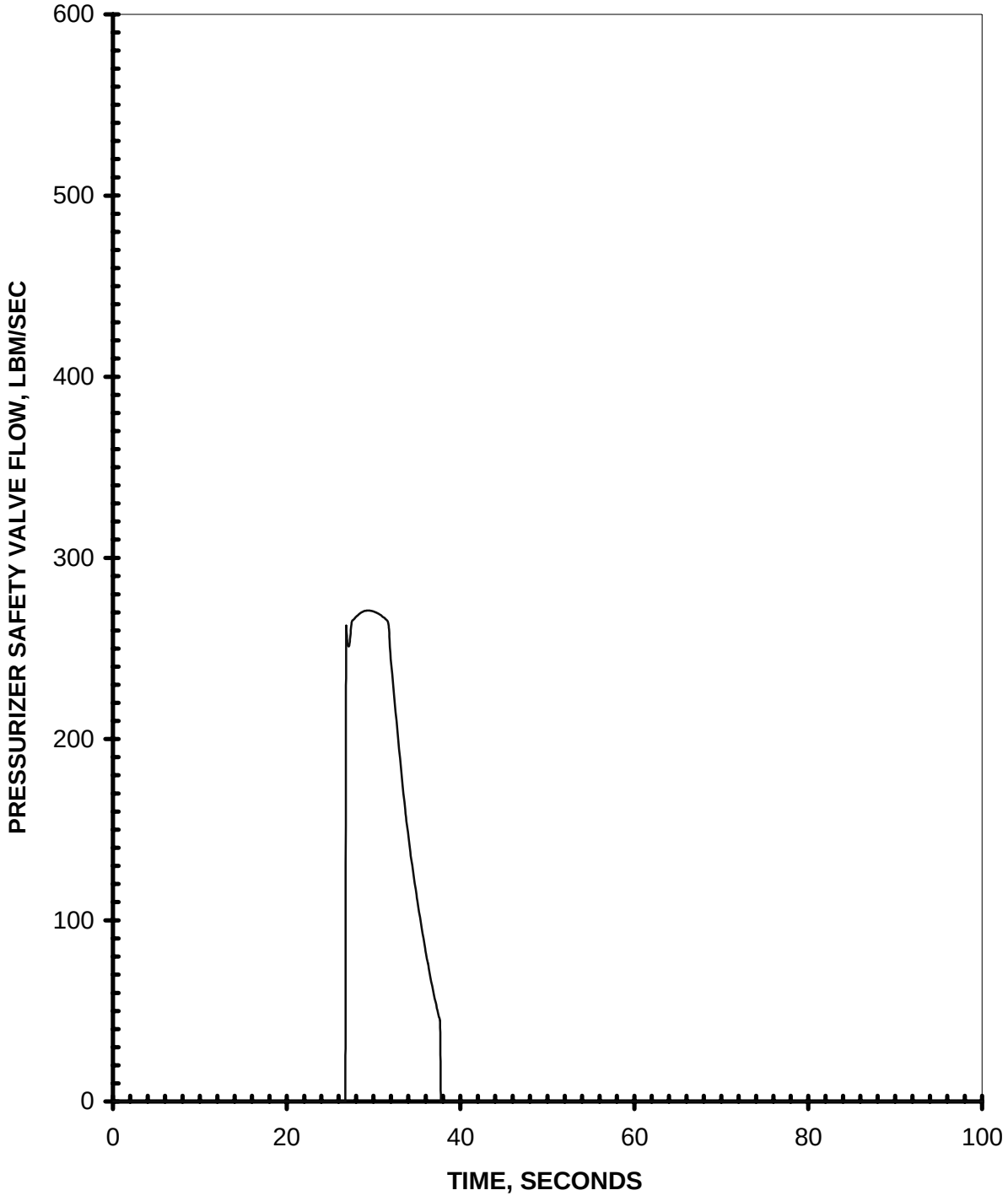

Figure 2.13.2.3.1-11
Feedwater System Pipe Break (Large)
Pressurizer Spray Flow vs. Time

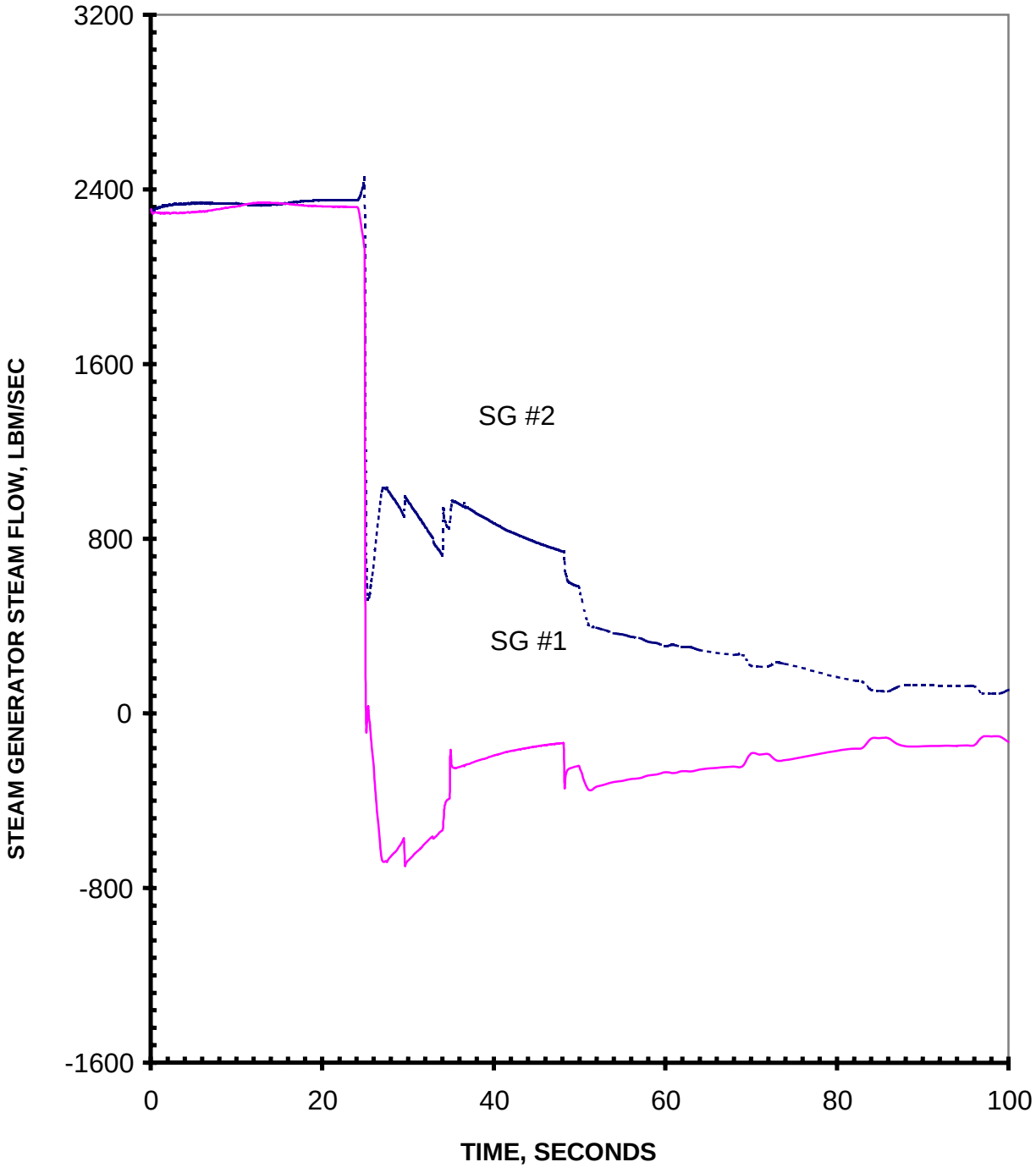

Figure 2.13.2.3.1-12
Feedwater System Pipe Break (Large)
Steam Flowrate vs. Time

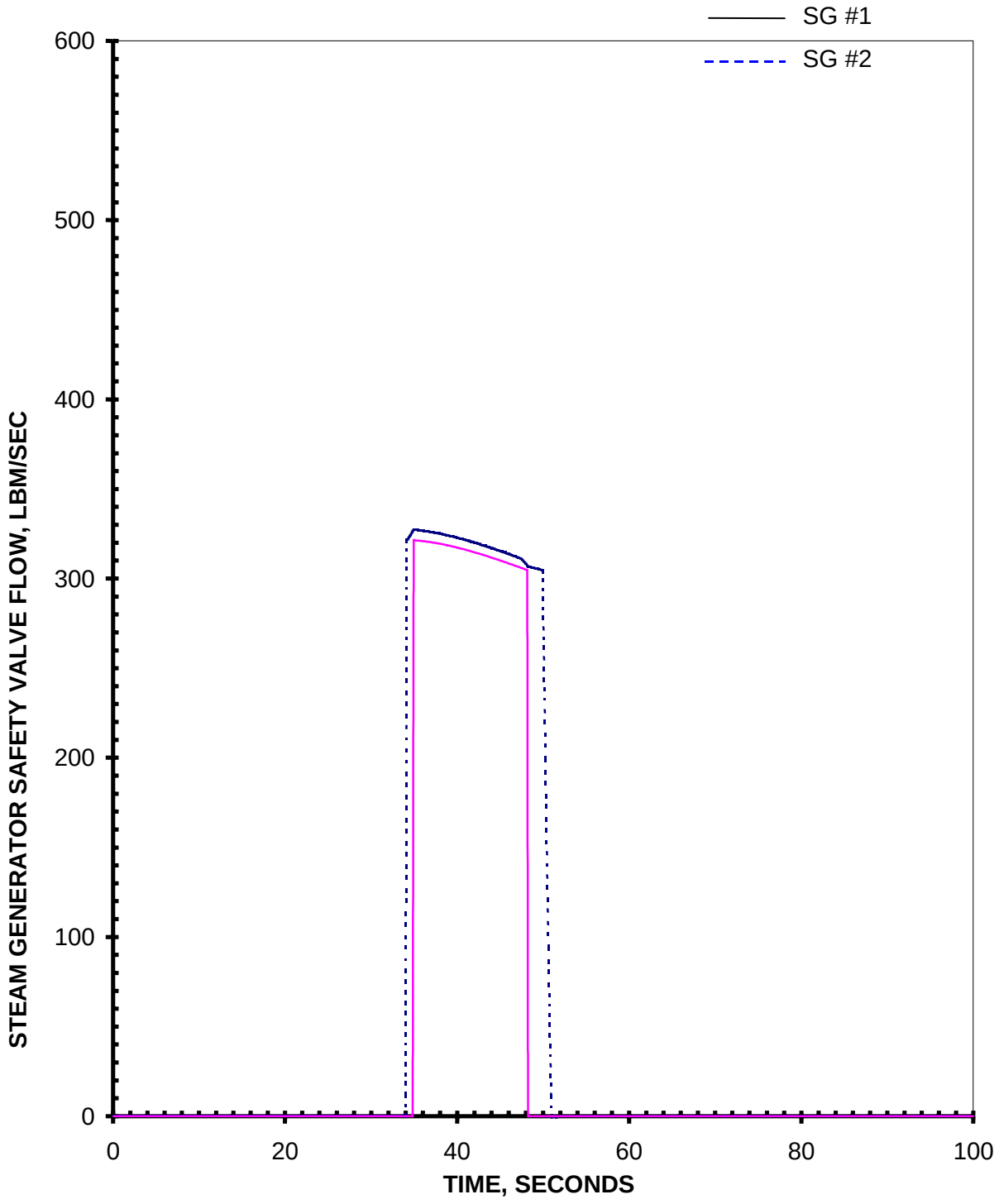

Figure 2.13.2.3.1-13
Feedwater System Pipe Break (Large)
Secondary Safety Valve Flowrate vs. Time

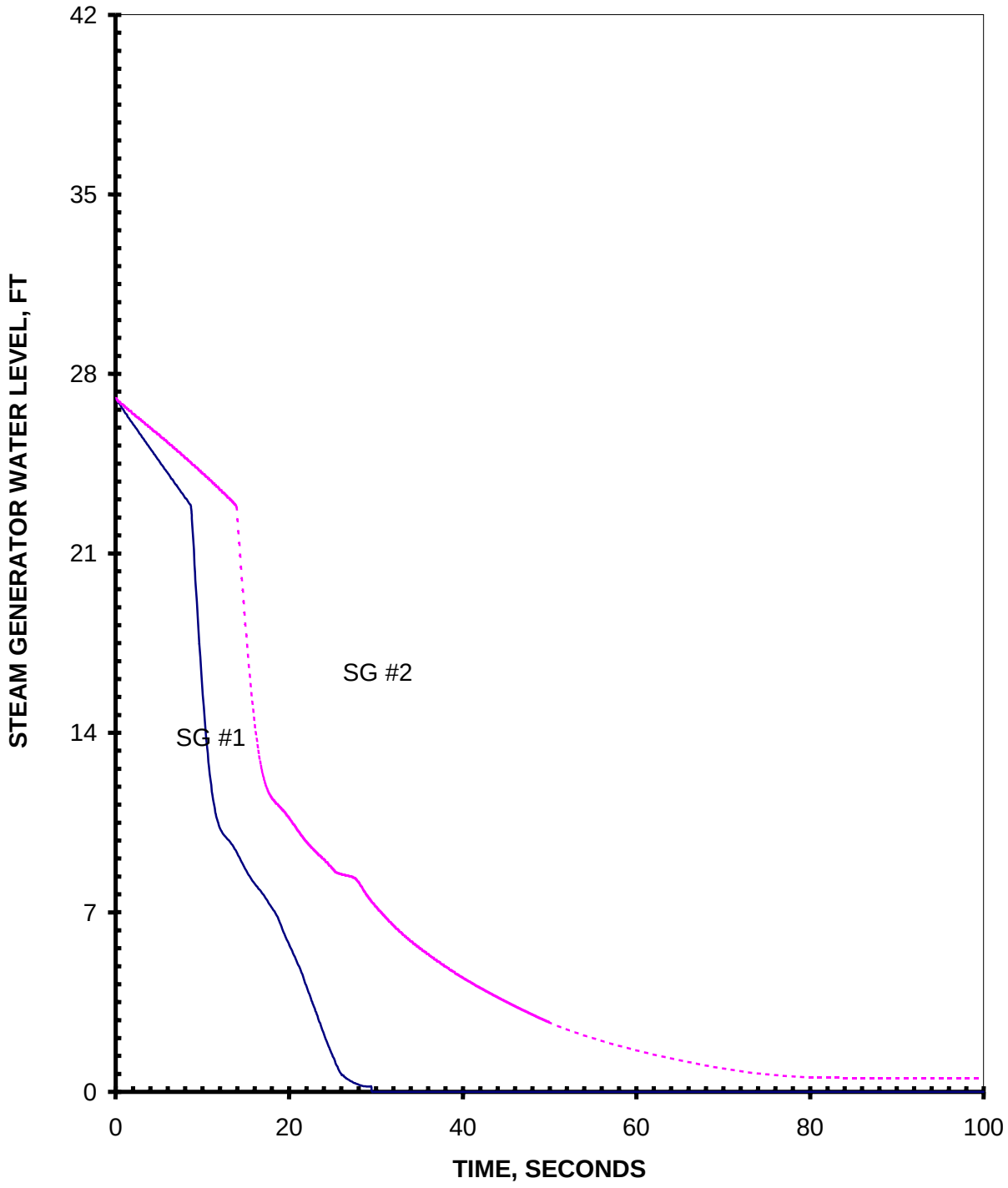

Figure 2.13.2.3.1-14
Feedwater System Pipe Break (Large)
SG Water Level vs. Time

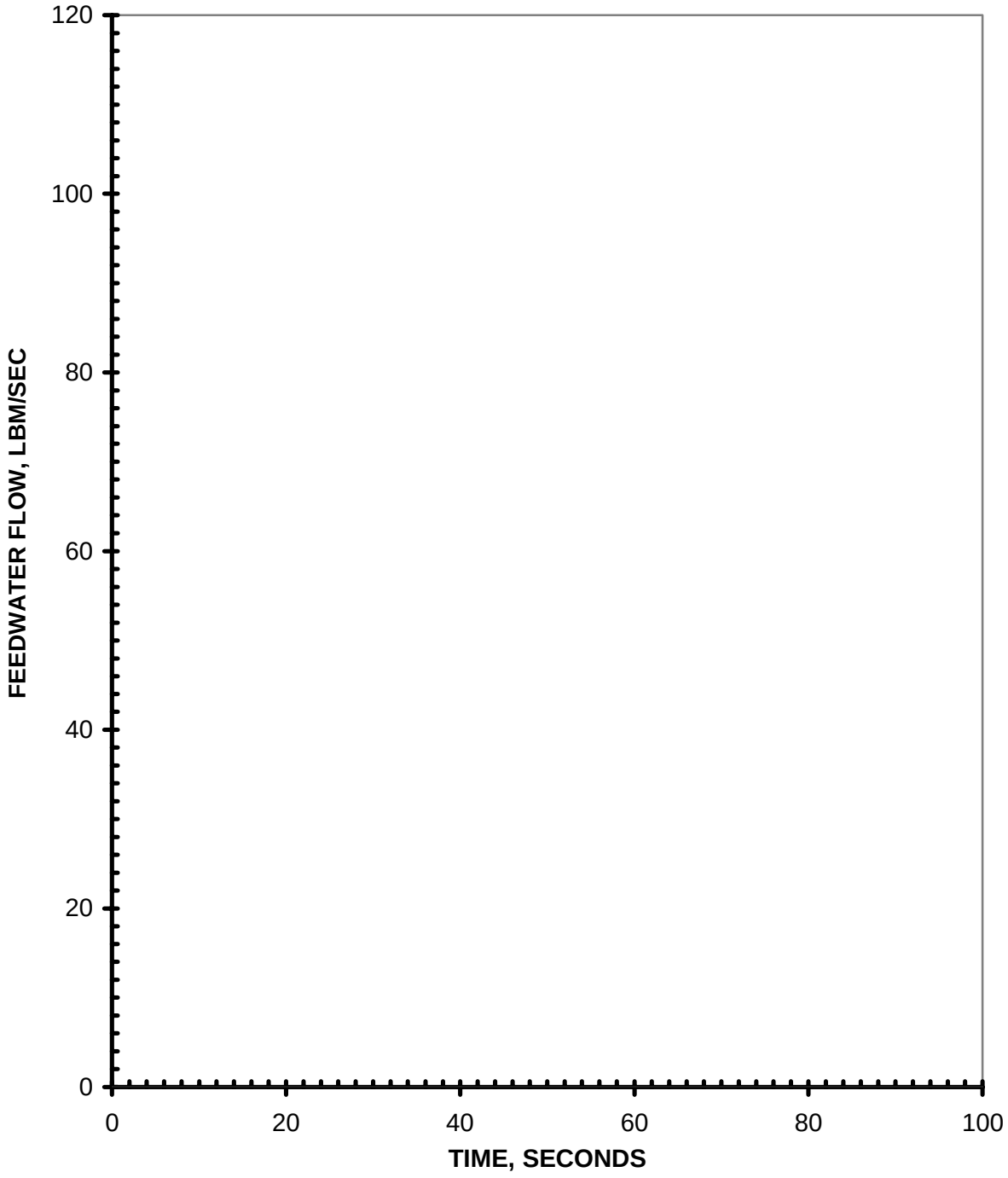

Figure 2.13.2.3.1-15
Feedwater System Pipe Break (Large)
Feedwater Flow (Intact Side) vs. Time

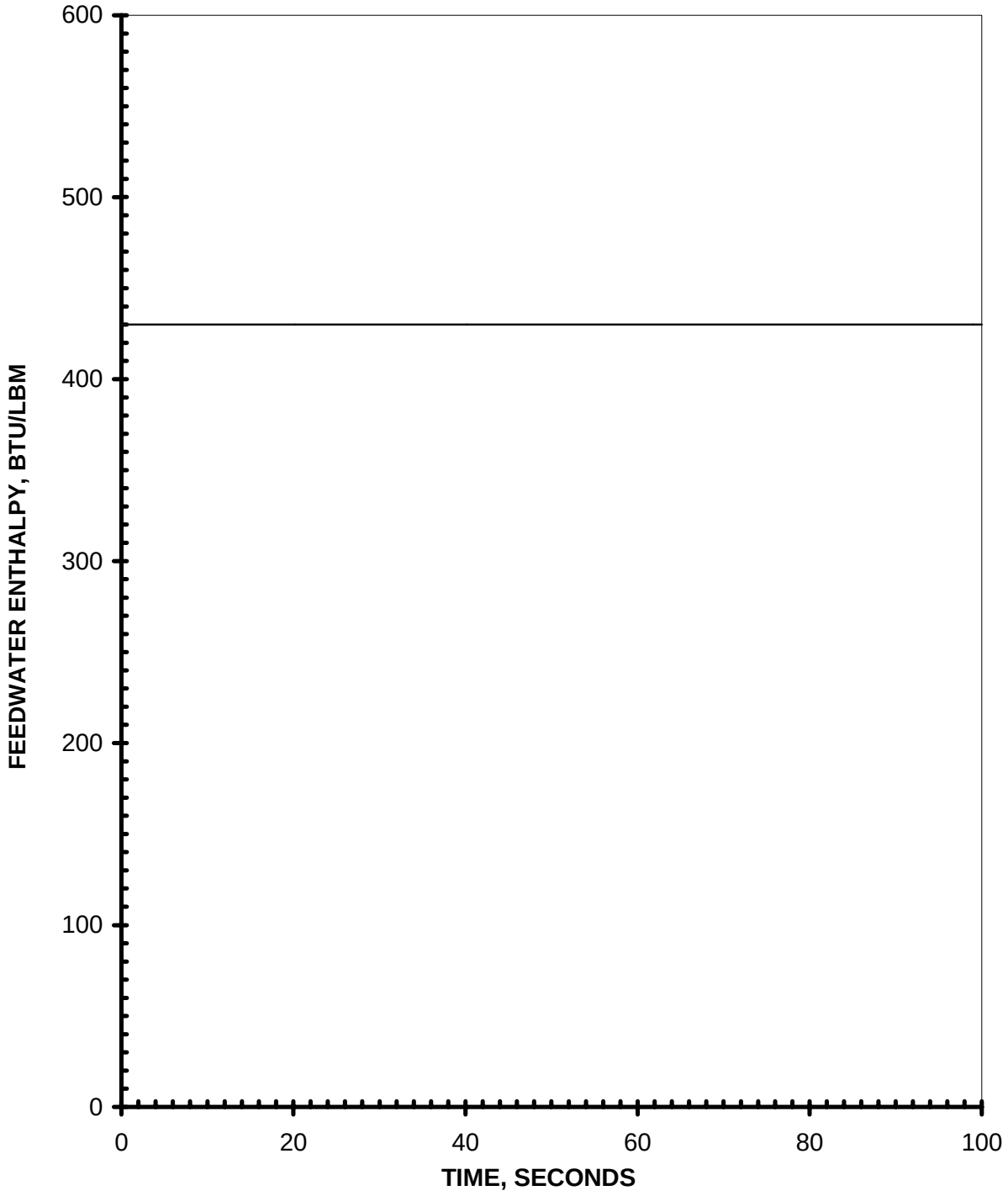

Figure 2.13.2.3.1-16
Feedwater System Pipe Break (Large)
Feedwater Enthalpy (Intact Side) vs. Time

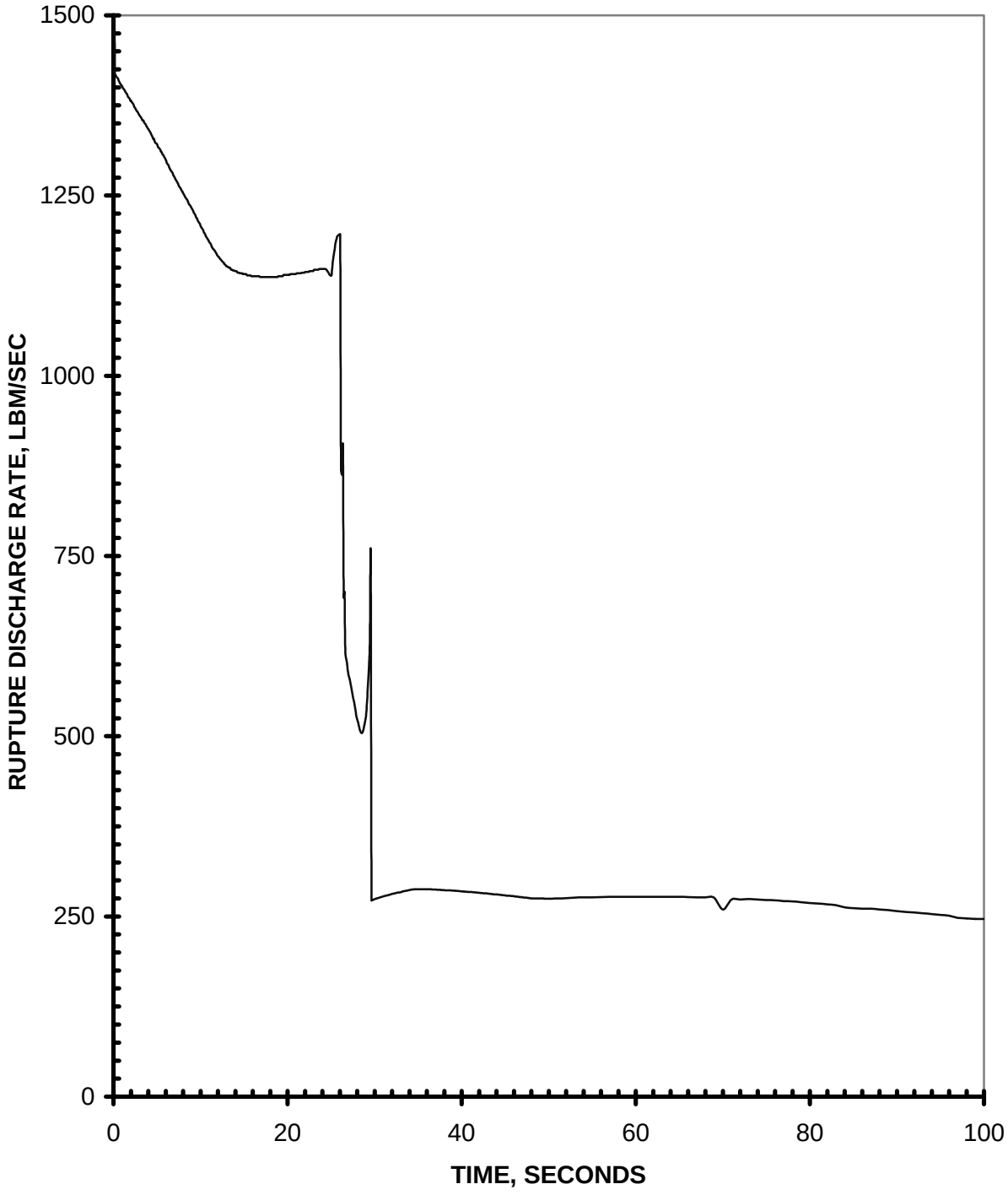

Figure 2.13.2.3.1-17
Feedwater System Pipe Break (Large)
Rupture Discharge Flowrate vs. Time

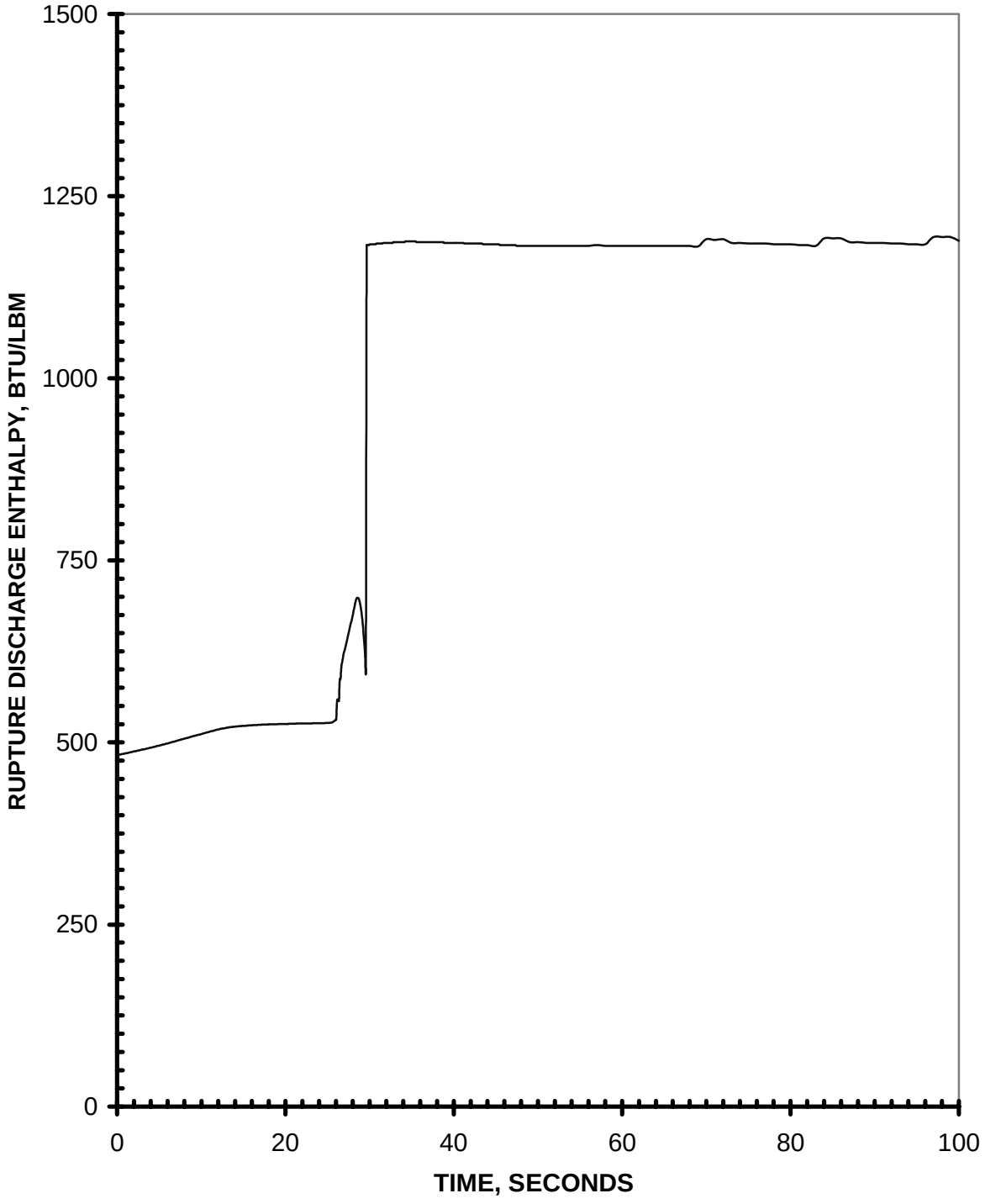

Figure 2.13.2.3.1-18
Feedwater System Pipe Break (Large)
Rupture Discharge Enthalpy vs. Time

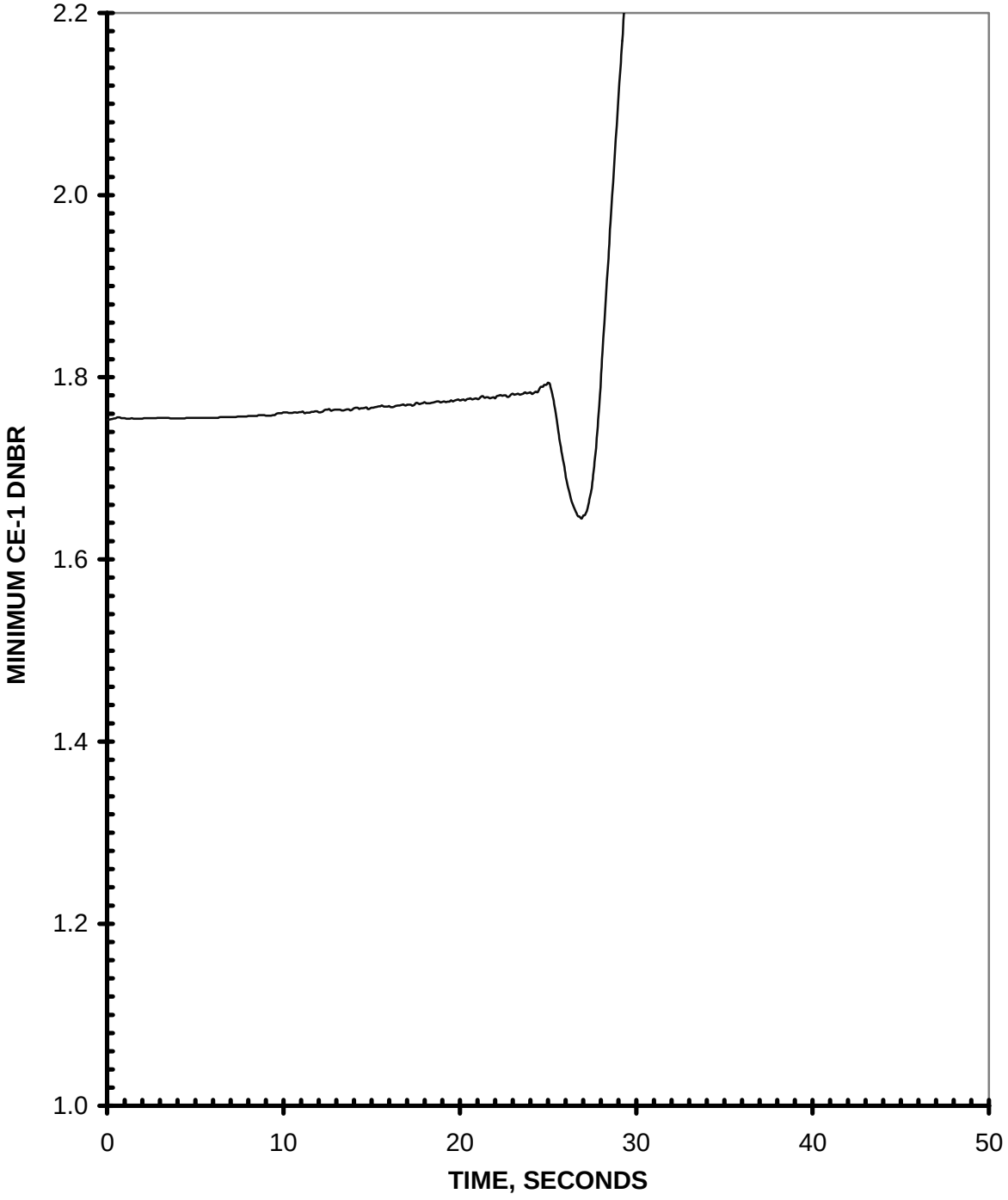

Figure 2.13.2.3.1-19
Feedwater System Pipe Break (Large)
Minimum DNBR vs. Time

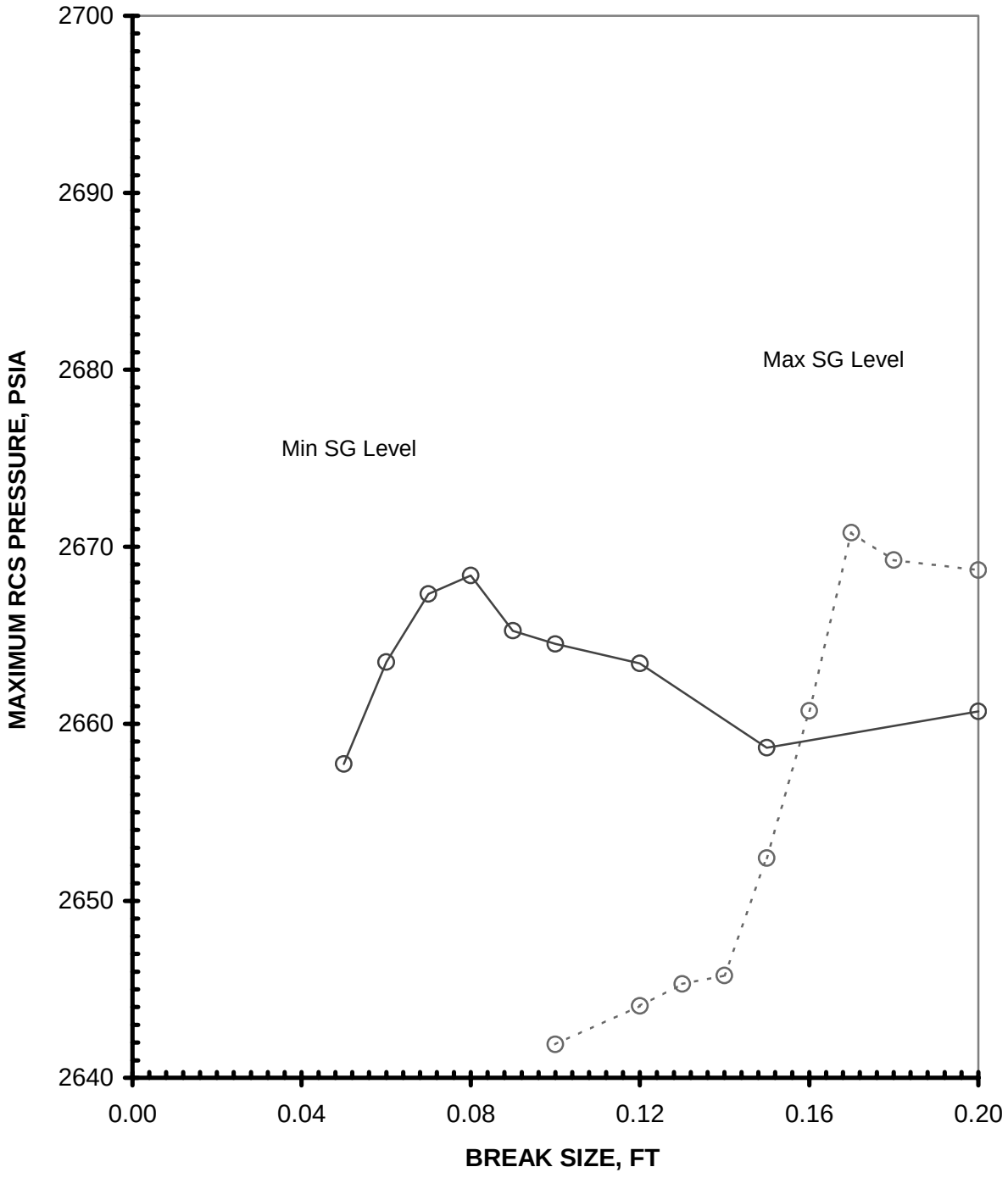

Figure 2.13.2.3.1-20
Feedwater System Pipe Break (Small)
RCS Pressure vs. Time

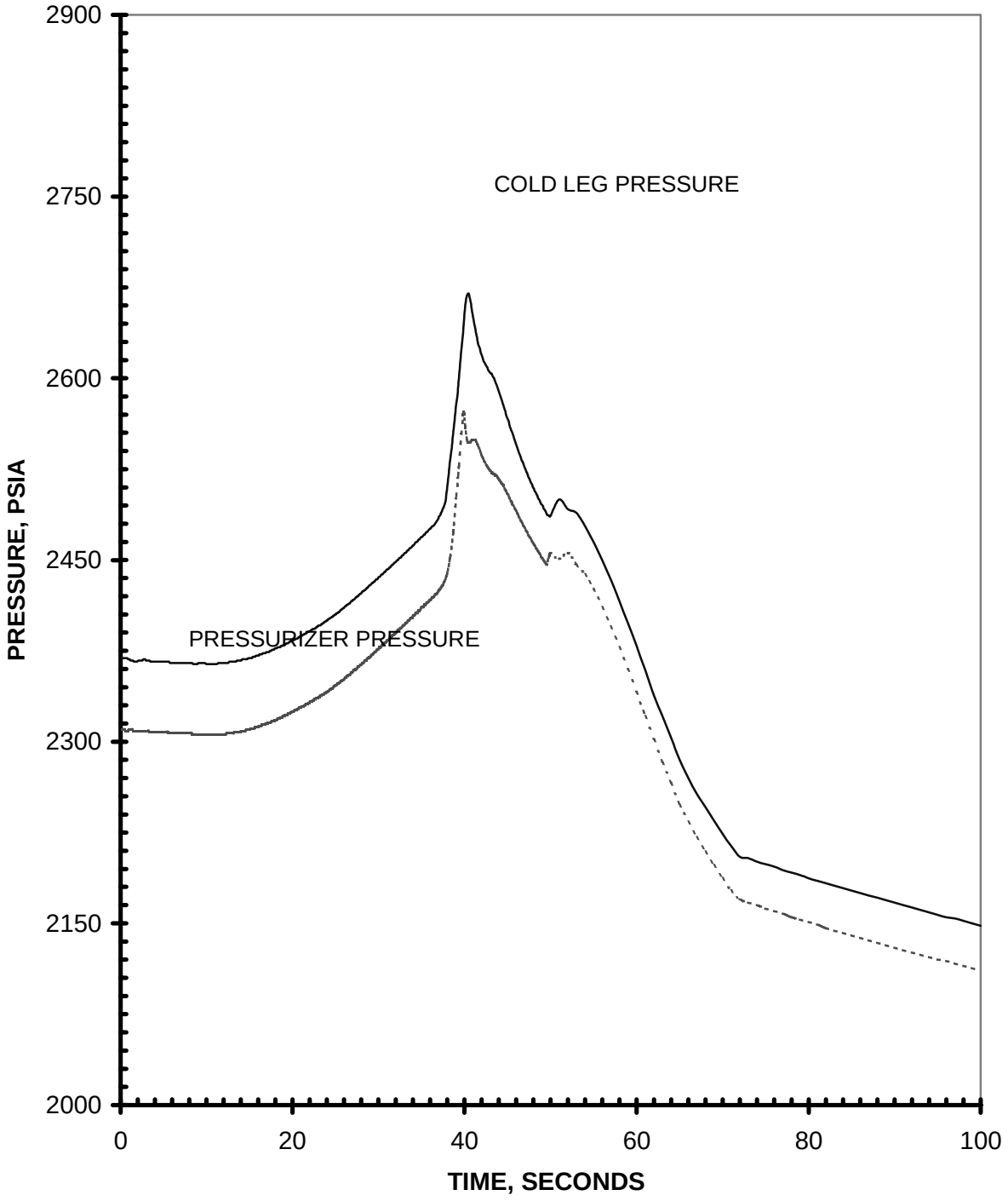

Figure 2.13.2.3.1-21
Feedwater System Pipe Break (Small)
RCS Pressure vs. Time

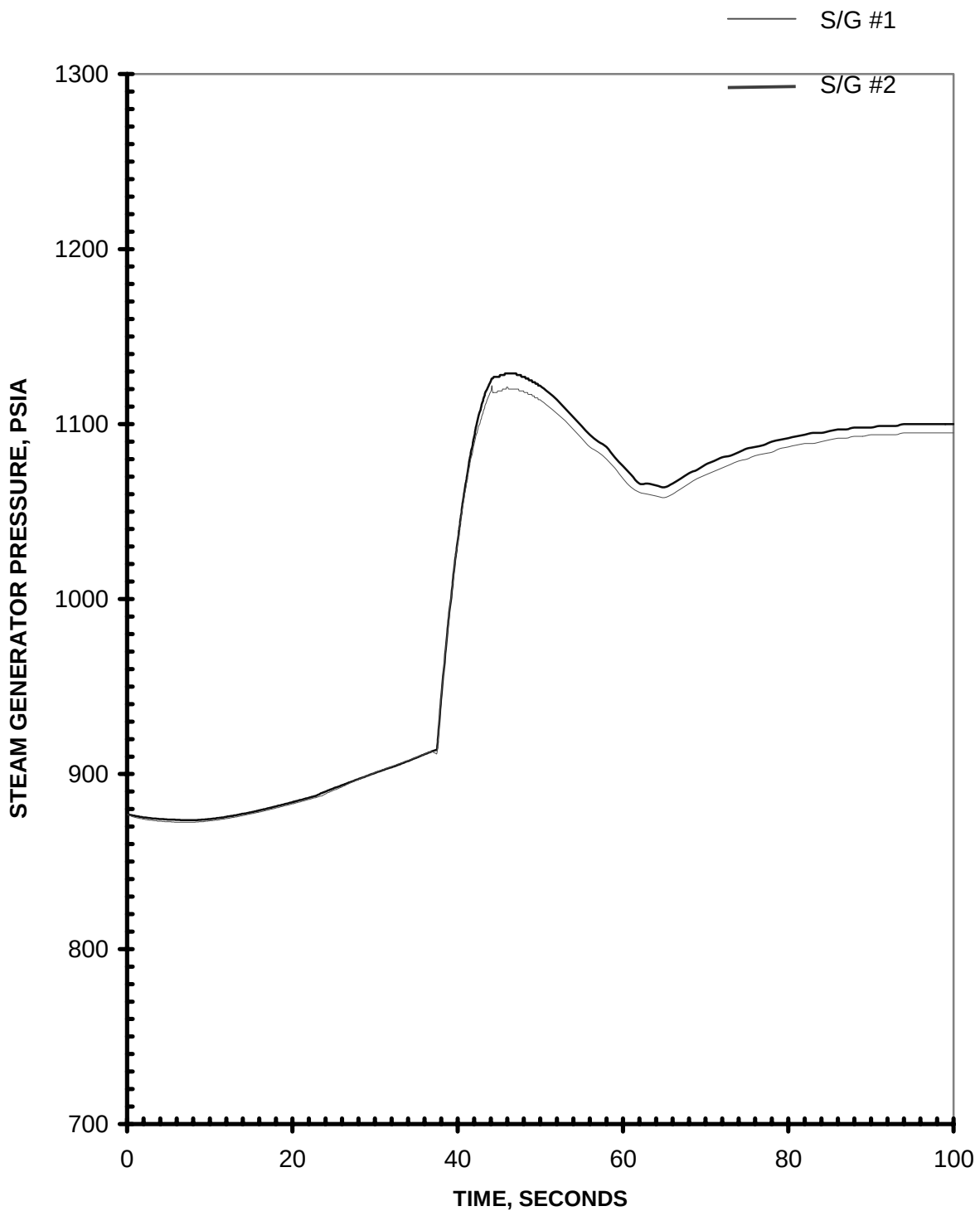

Figure 2.13.2.3.1-22
Feedwater System Pipe Break (Small)
SG Pressure vs. Time

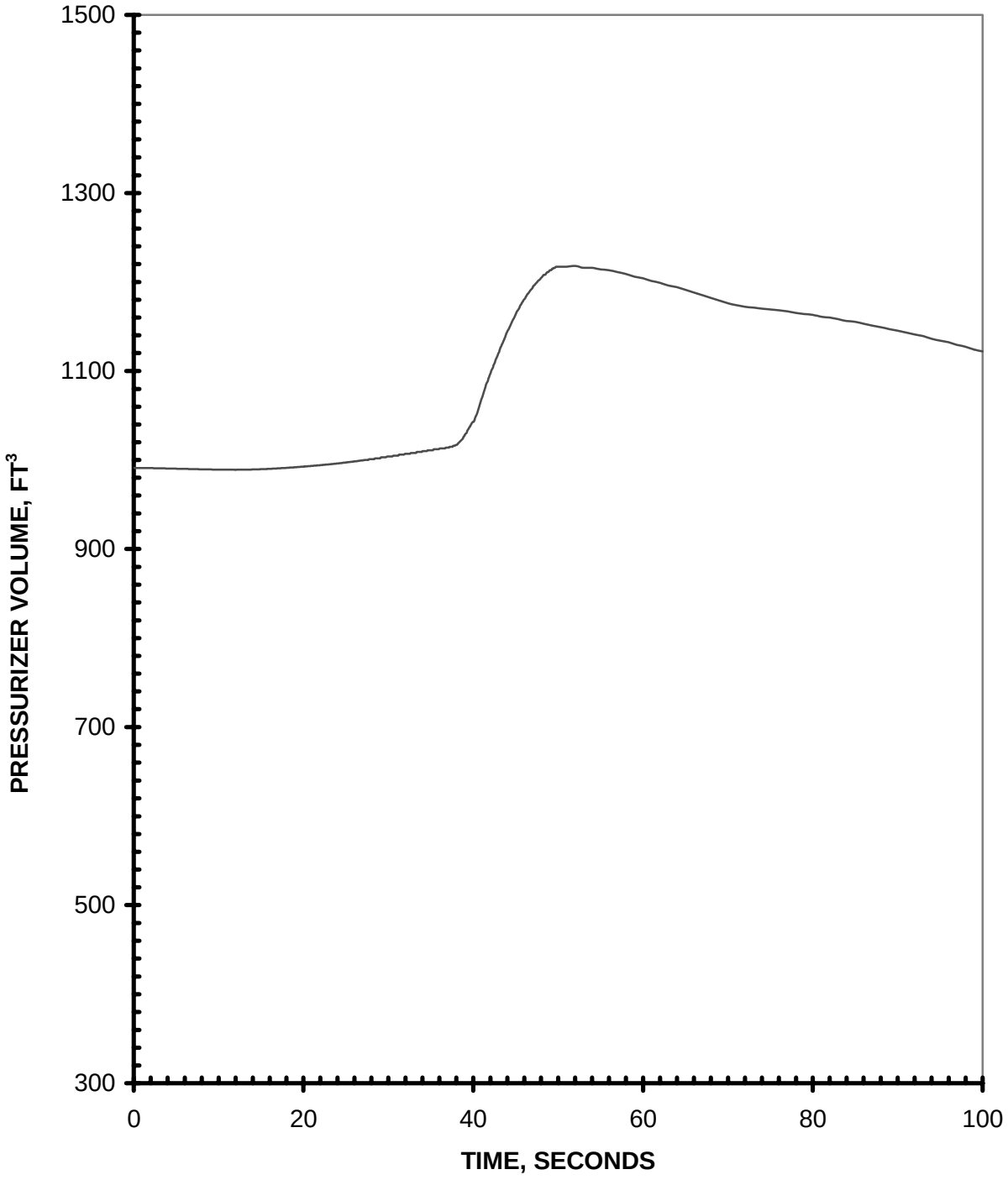

Figure 2.13.2.3.1-23
Feedwater System Pipe Break (Small)
Pressurizer Water Volume vs. Time

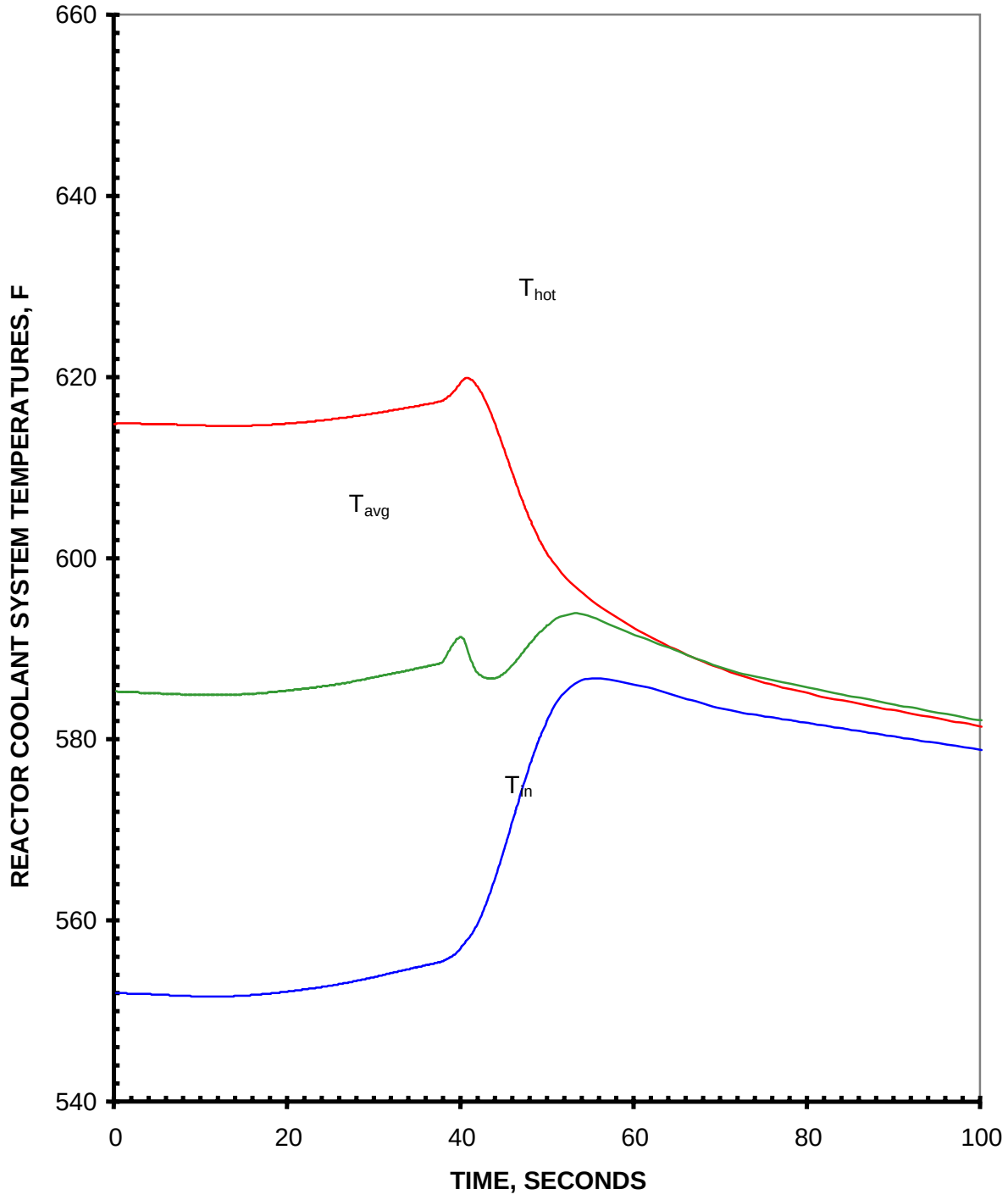

Figure 2.13.2.3.1-24
Feedwater System Pipe Break (Small)
RCS Temperatures vs. Time

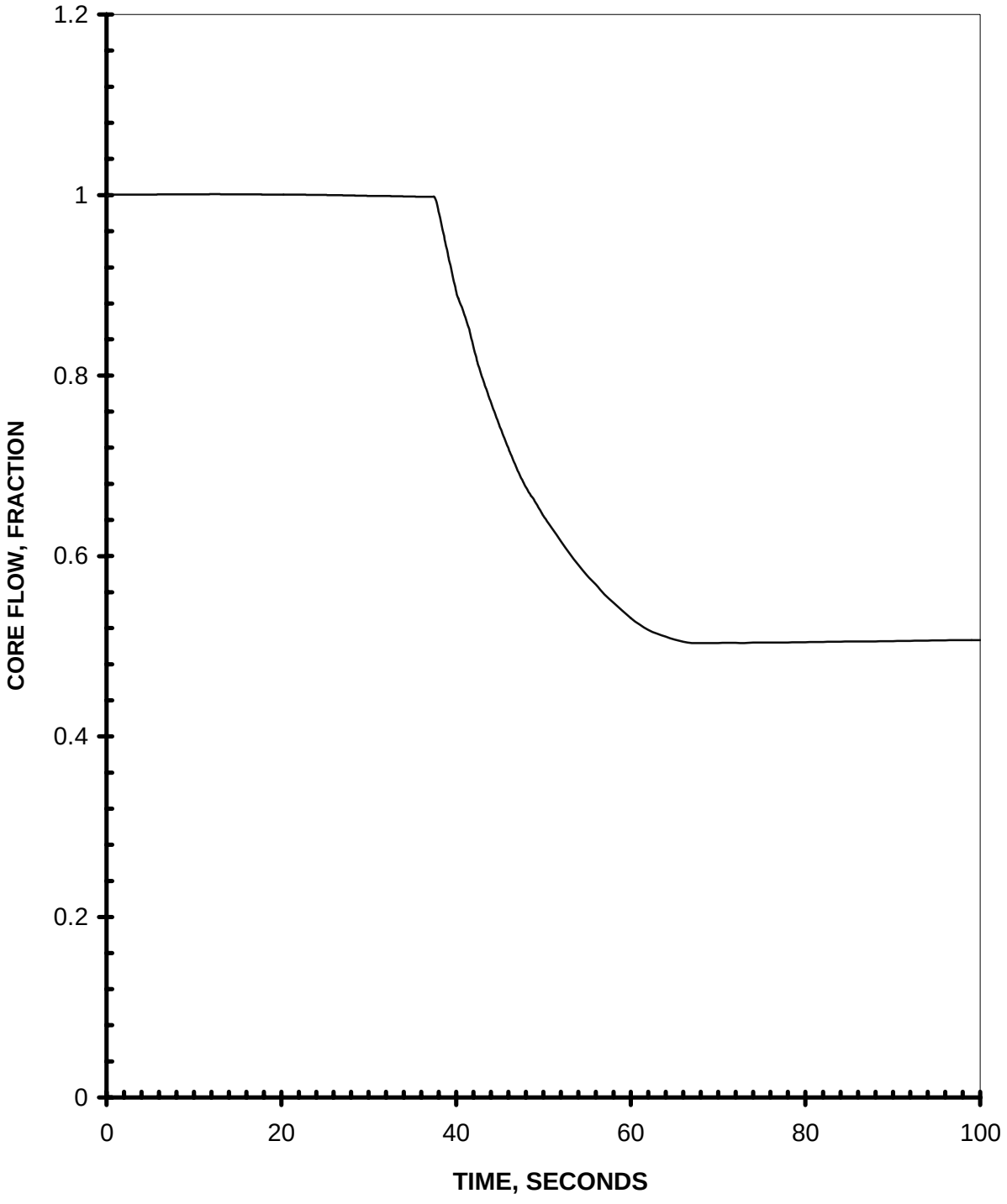

Figure 2.13.2.3.1-25
Feedwater System Pipe Break (Small)
Core Flow (Fraction) vs. Time

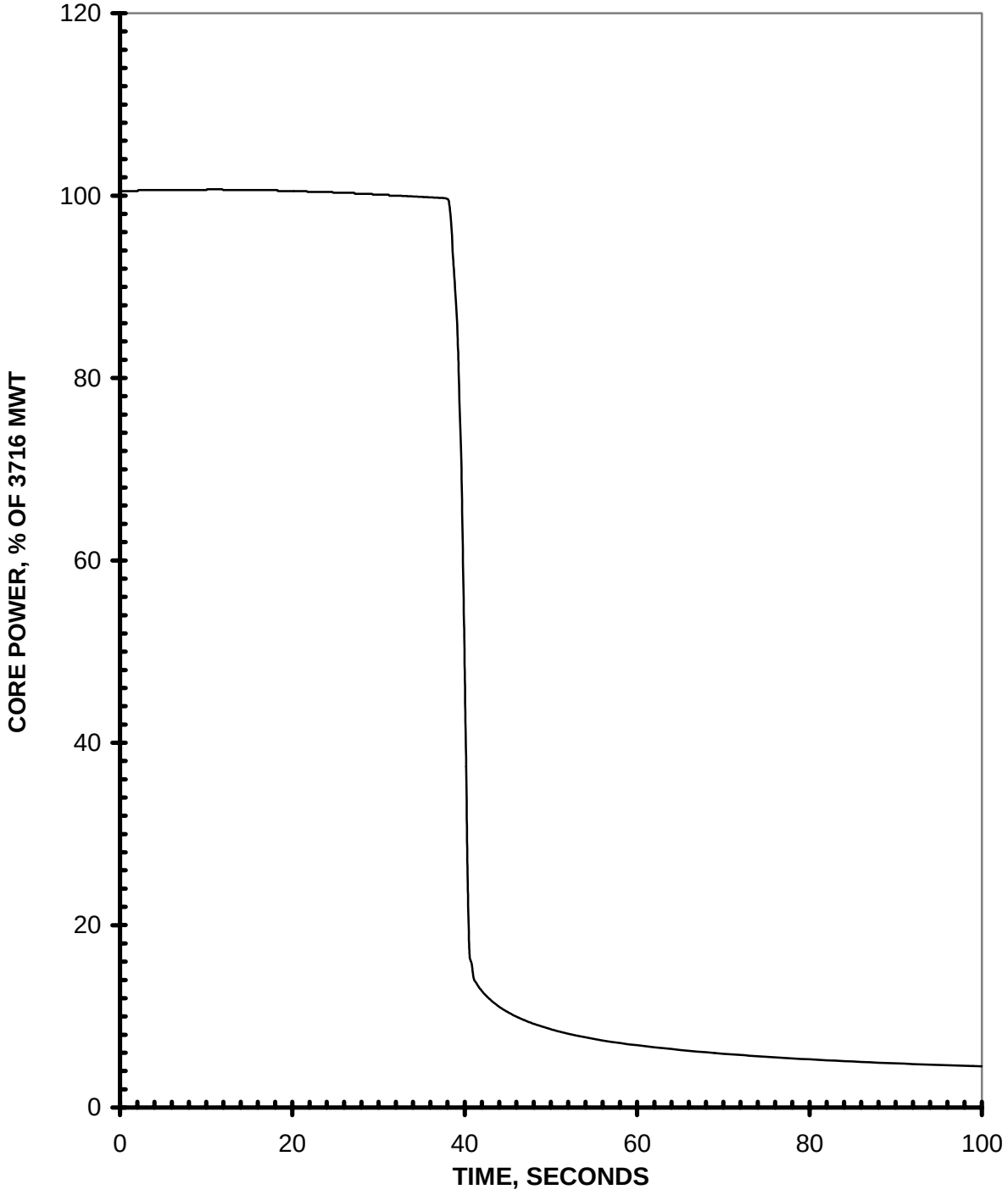

Figure 2.13.2.3.1-26
Feedwater System Pipe Break (Small)
Core Power vs. Time

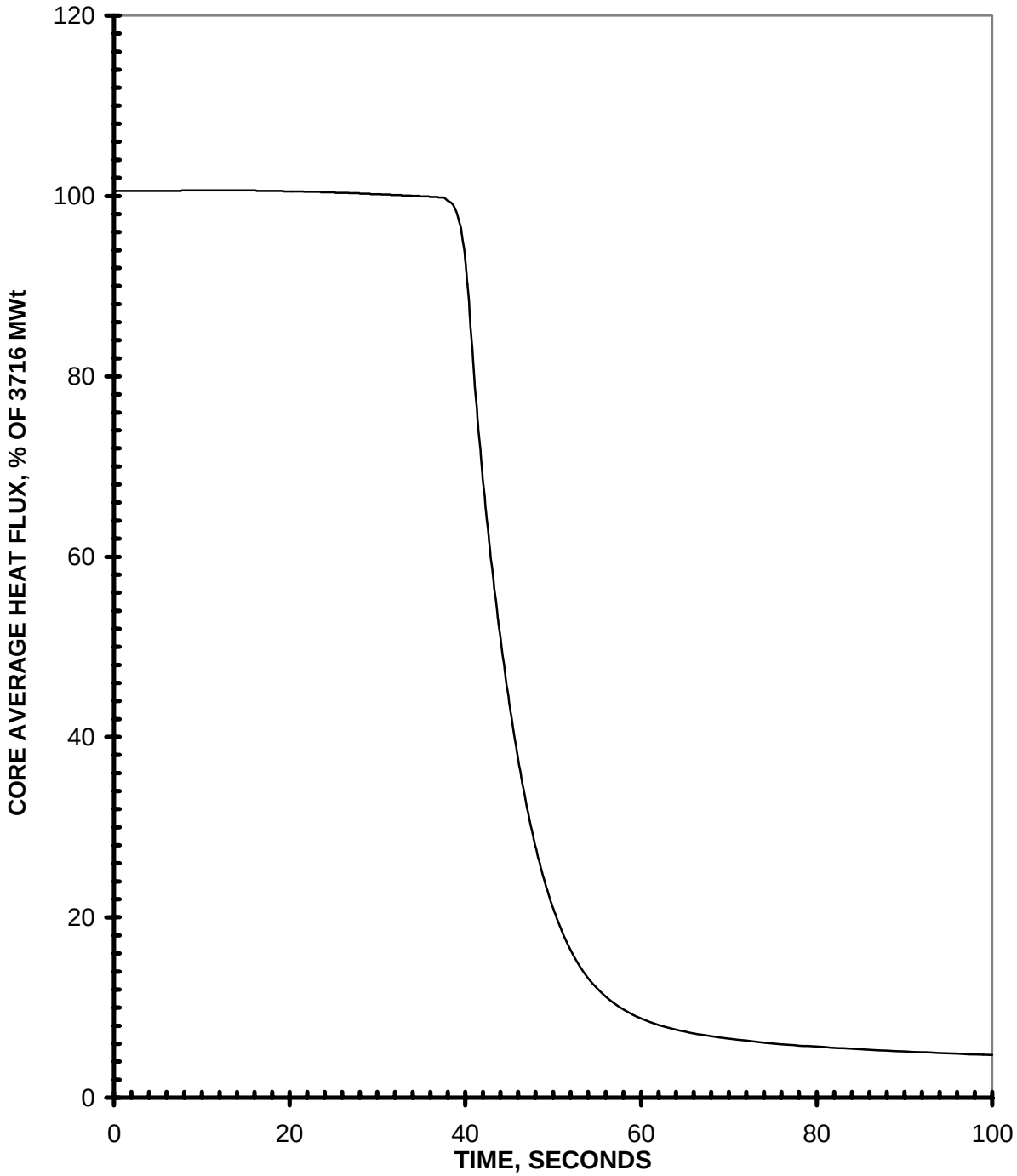

Figure 2.13.2.3.1-27
Feedwater System Pipe Break (Small)
Core Heat Flux vs. Time

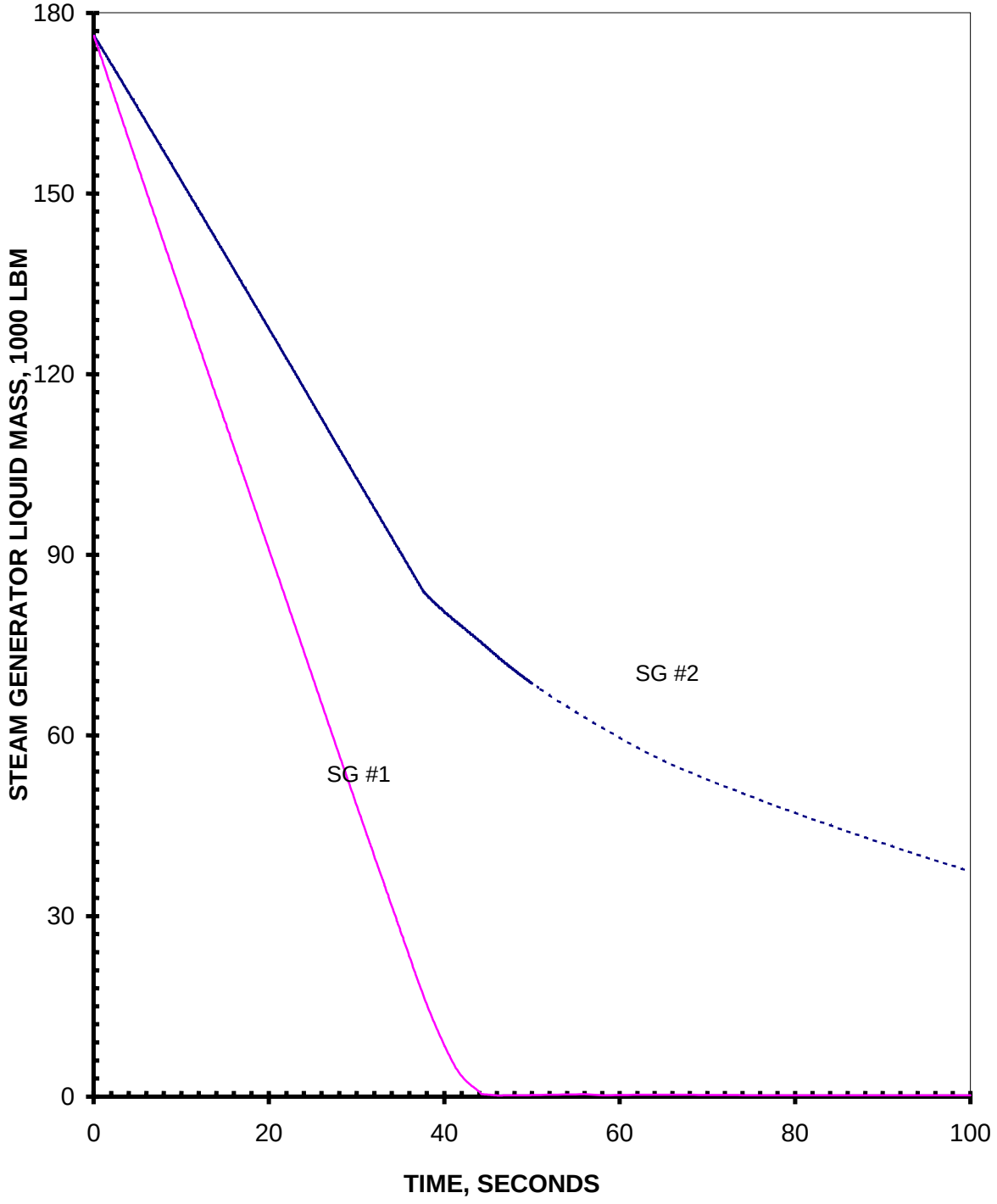

Figure 2.13.2.3.1-28
Feedwater System Pipe Break (Small)
SG Liquid Mass vs. Time

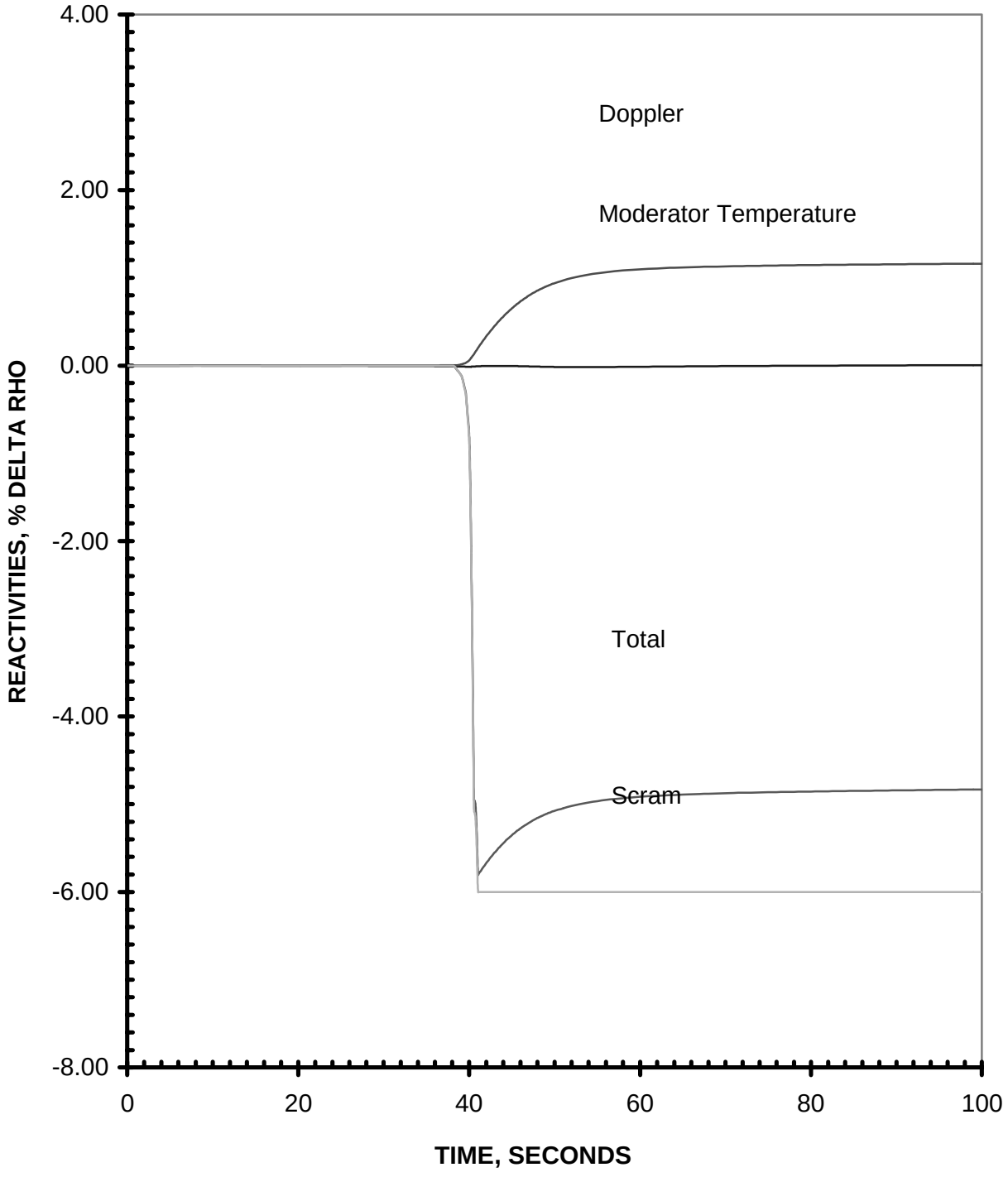

Figure 2.13.2.3.1-29
Feedwater System Pipe Break (Small)
Reactivity vs. Time

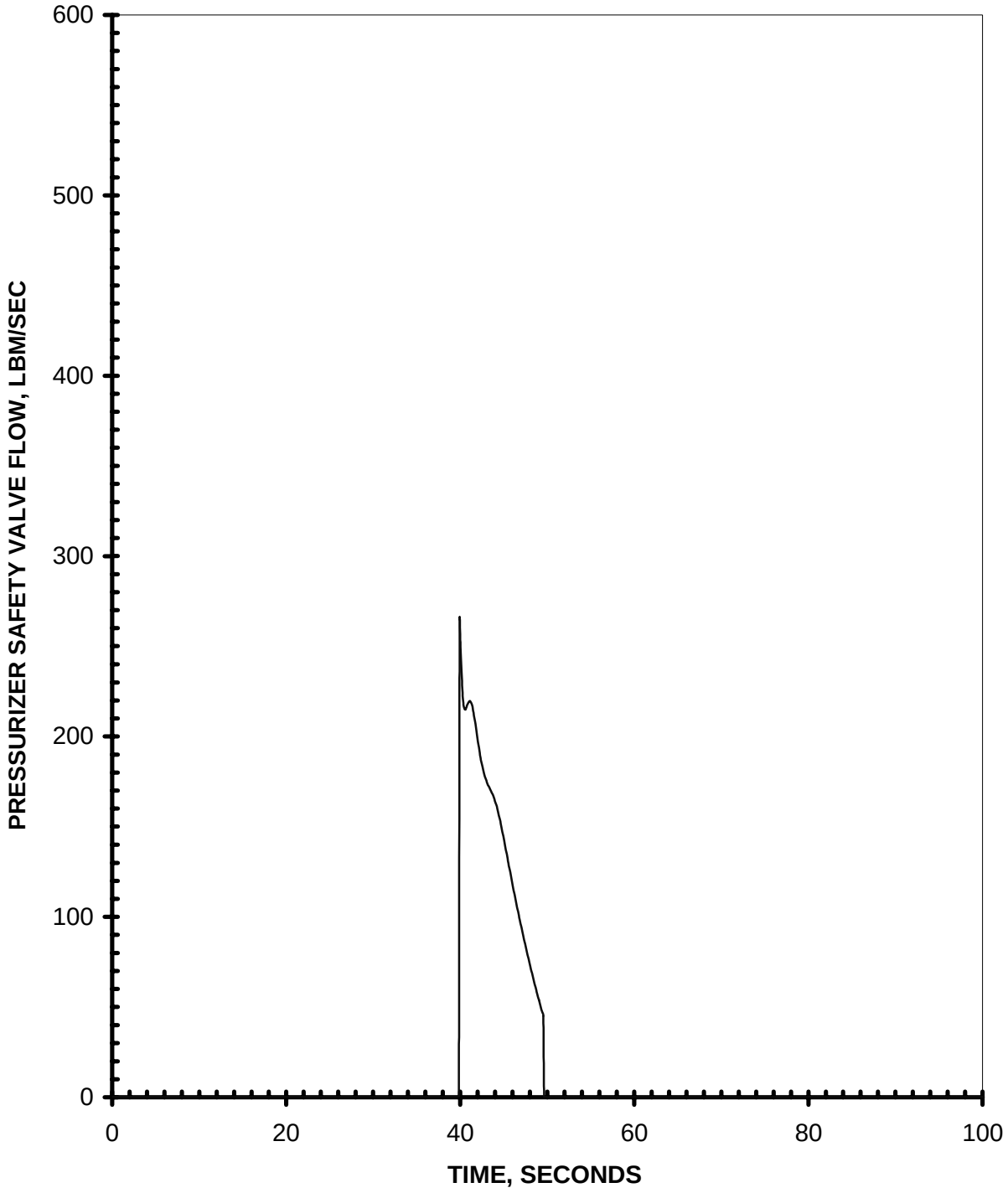

Figure 2.13.2.3.1-30
Feedwater System Pipe Break (Small)
Pressurizer Spray Flow vs. Time

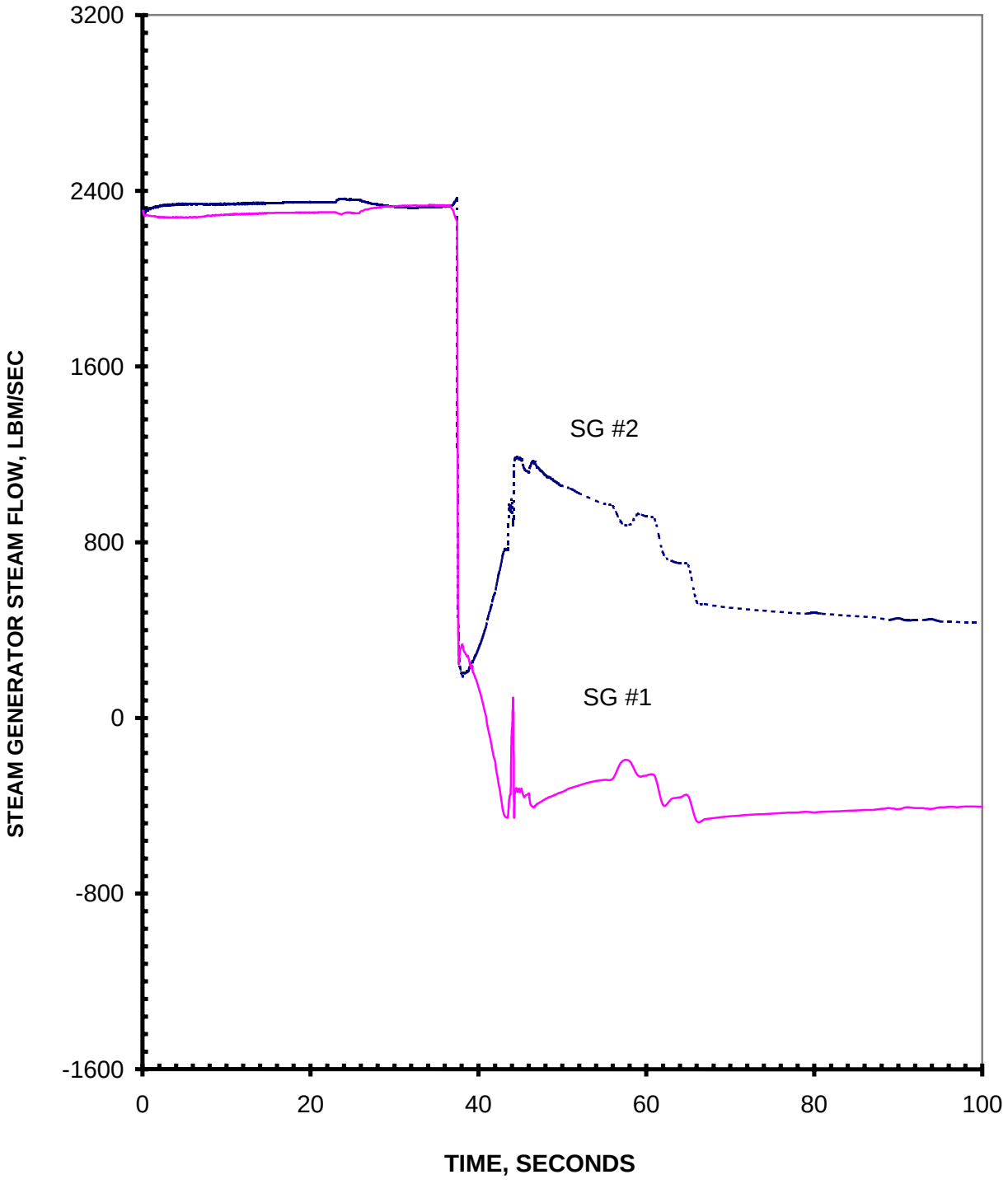

Figure 2.13.2.3.1-31
Feedwater System Pipe Break (Small)
Steam Flowrate vs. Time

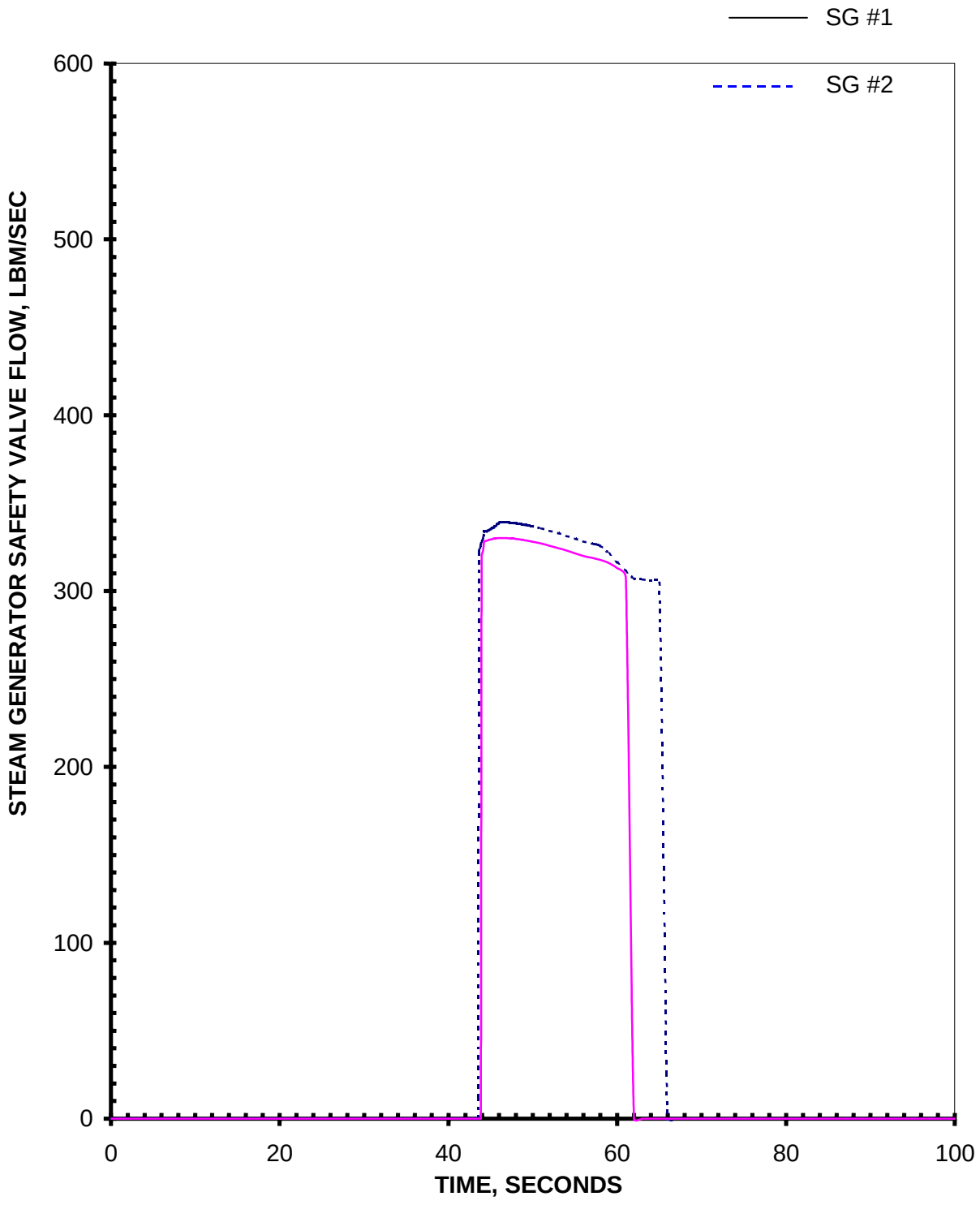

Figure 2.13.2.3.1-32
Feedwater System Pipe Break (Small)
Secondary Safety Valve Flowrate vs. Time

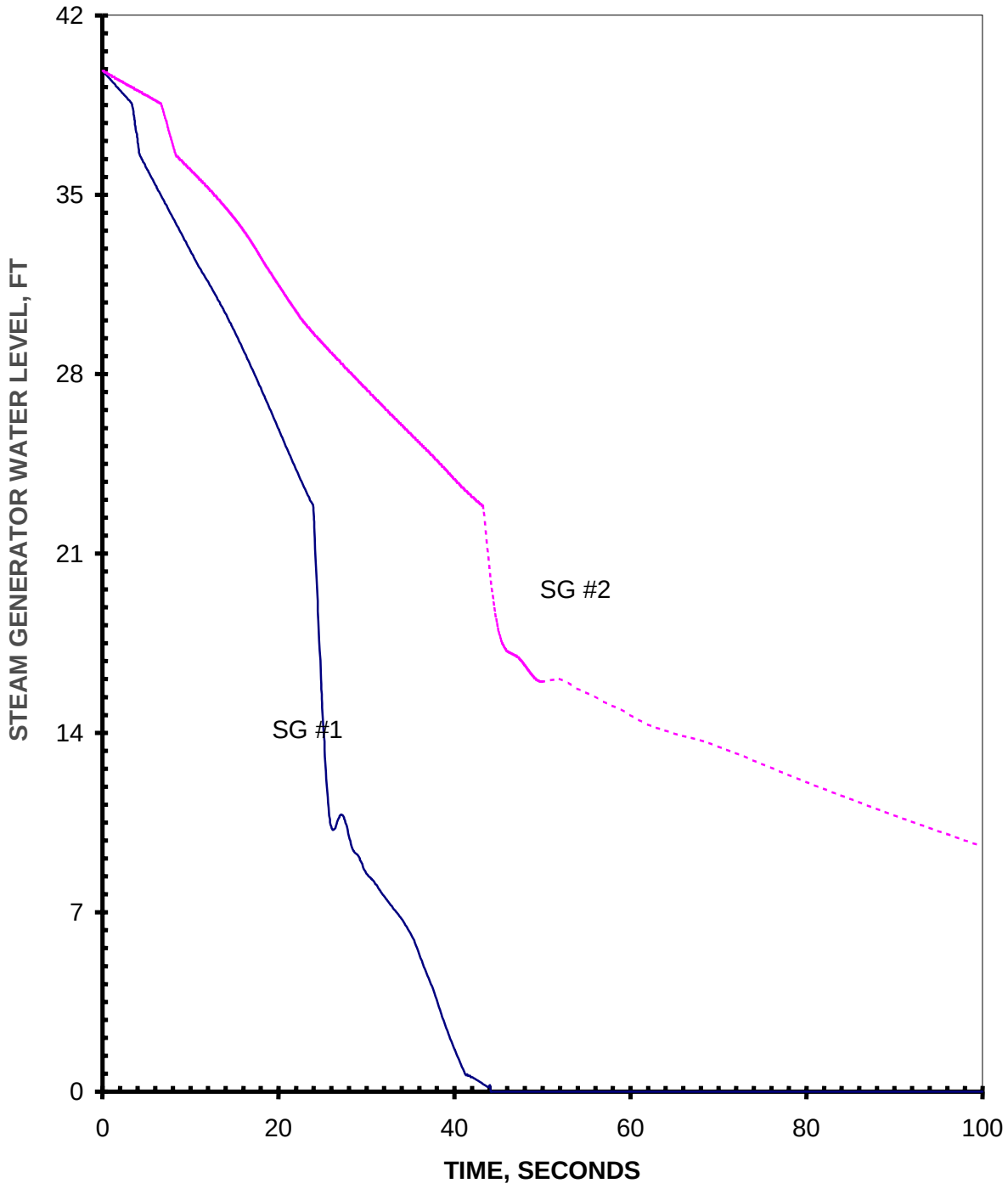

Figure 2.13.2.3.1-33
Feedwater System Pipe Break (Small)
SG Water Level vs. Time

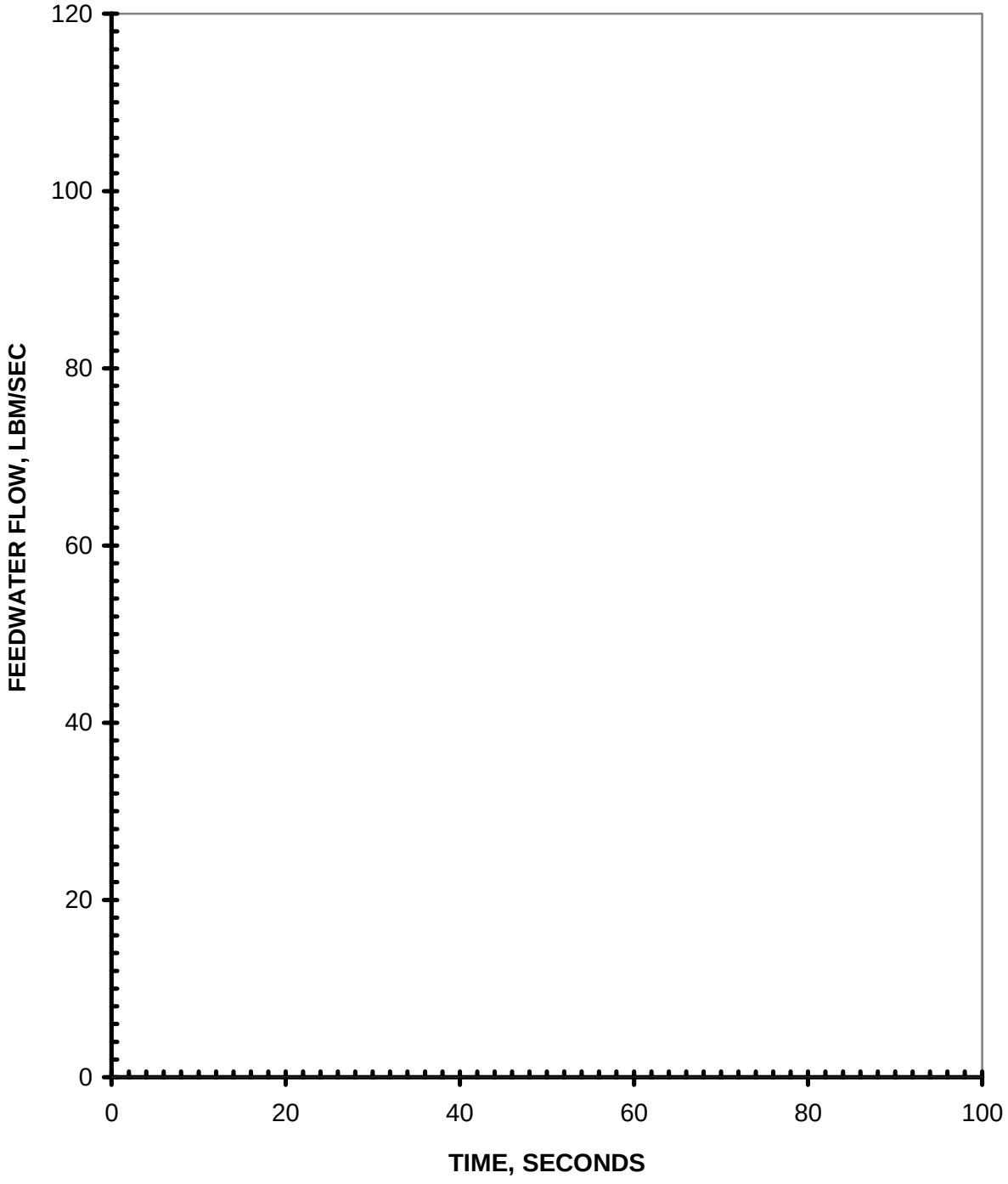

Figure 2.13.2.3.1-34
Feedwater System Pipe Break (Small)
Feedwater Flow (Intact Side) vs. Time

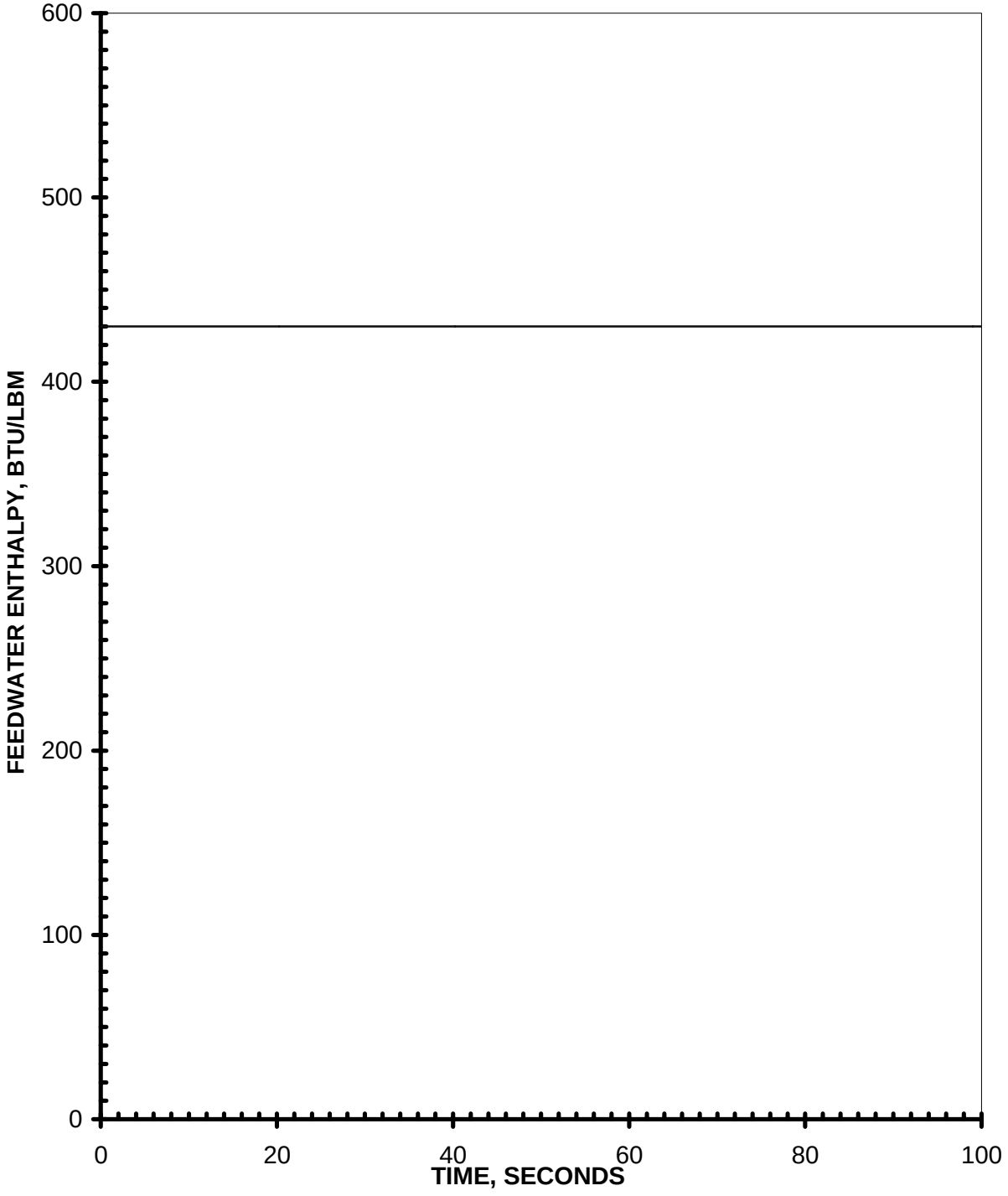

Figure 2.13.2.3.1-35
Feedwater System Pipe Break (Small)
Feedwater Enthalpy (Intact Side) vs. Time

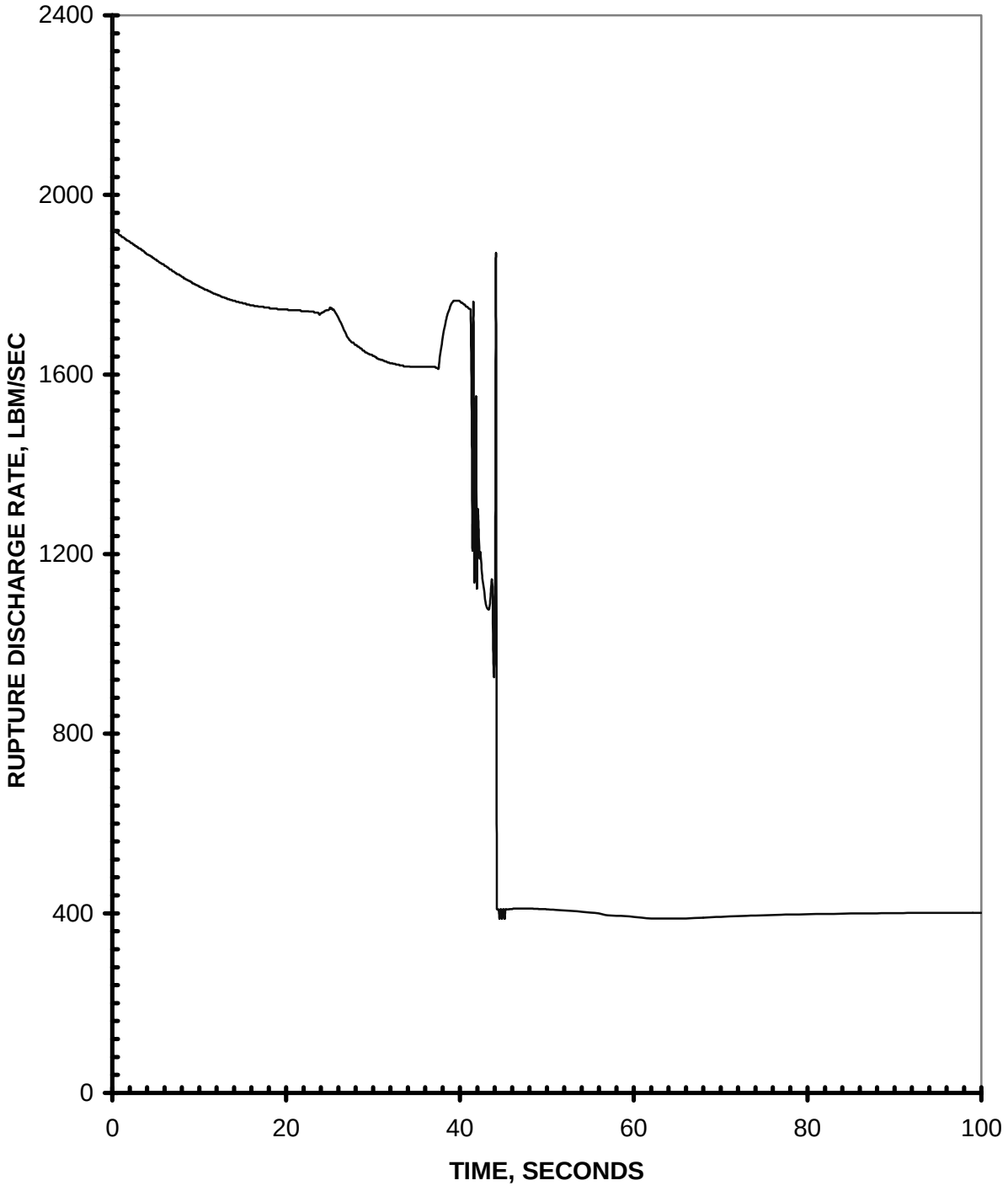

Figure 2.13.2.3.1-36
Feedwater System Pipe Break (Small)
Rupture Discharge Flowrate vs. Time

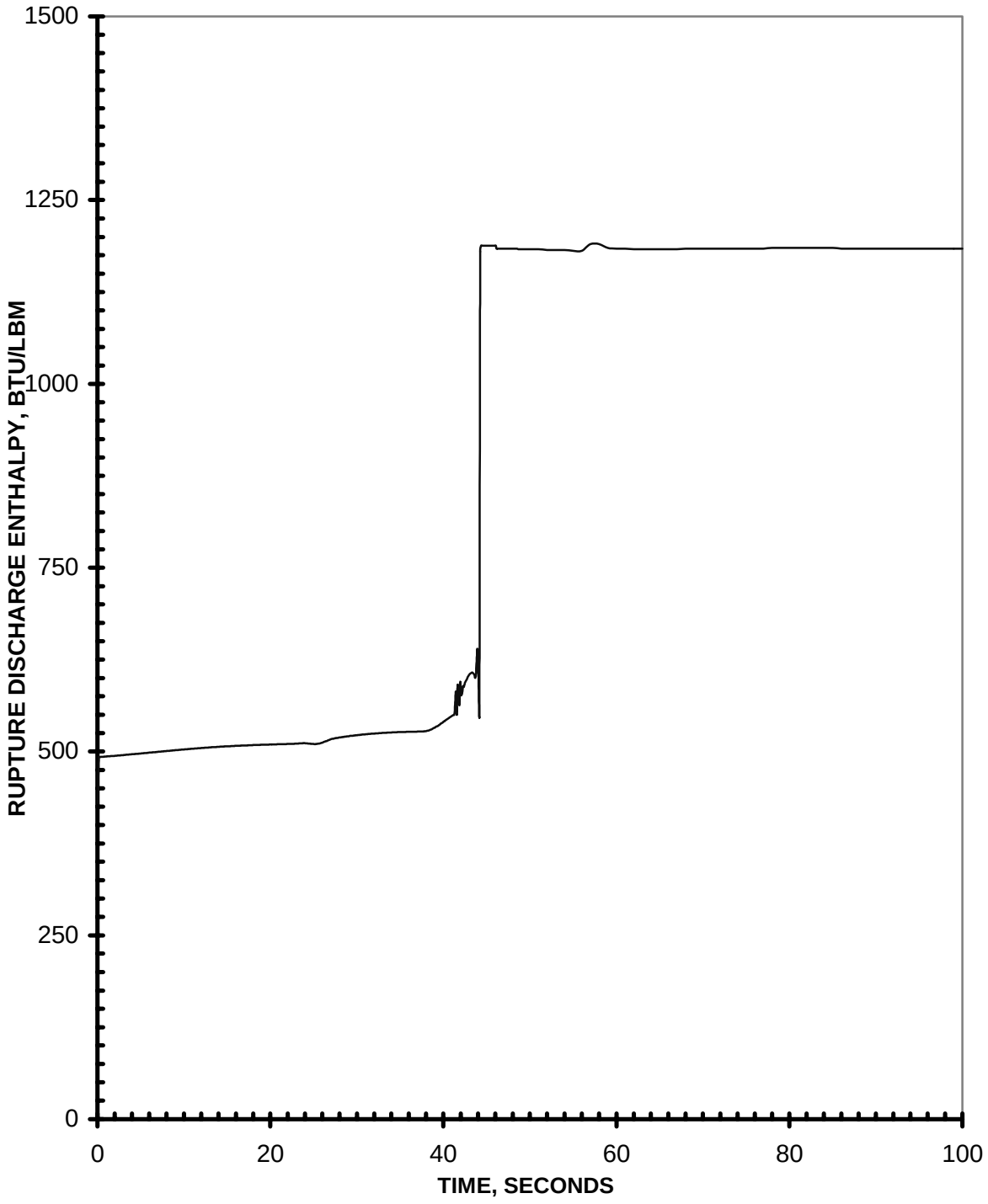

Figure 2.13.2.3.1-37
Feedwater System Pipe Break (Small)
Rupture Discharge Enthalpy vs. Time

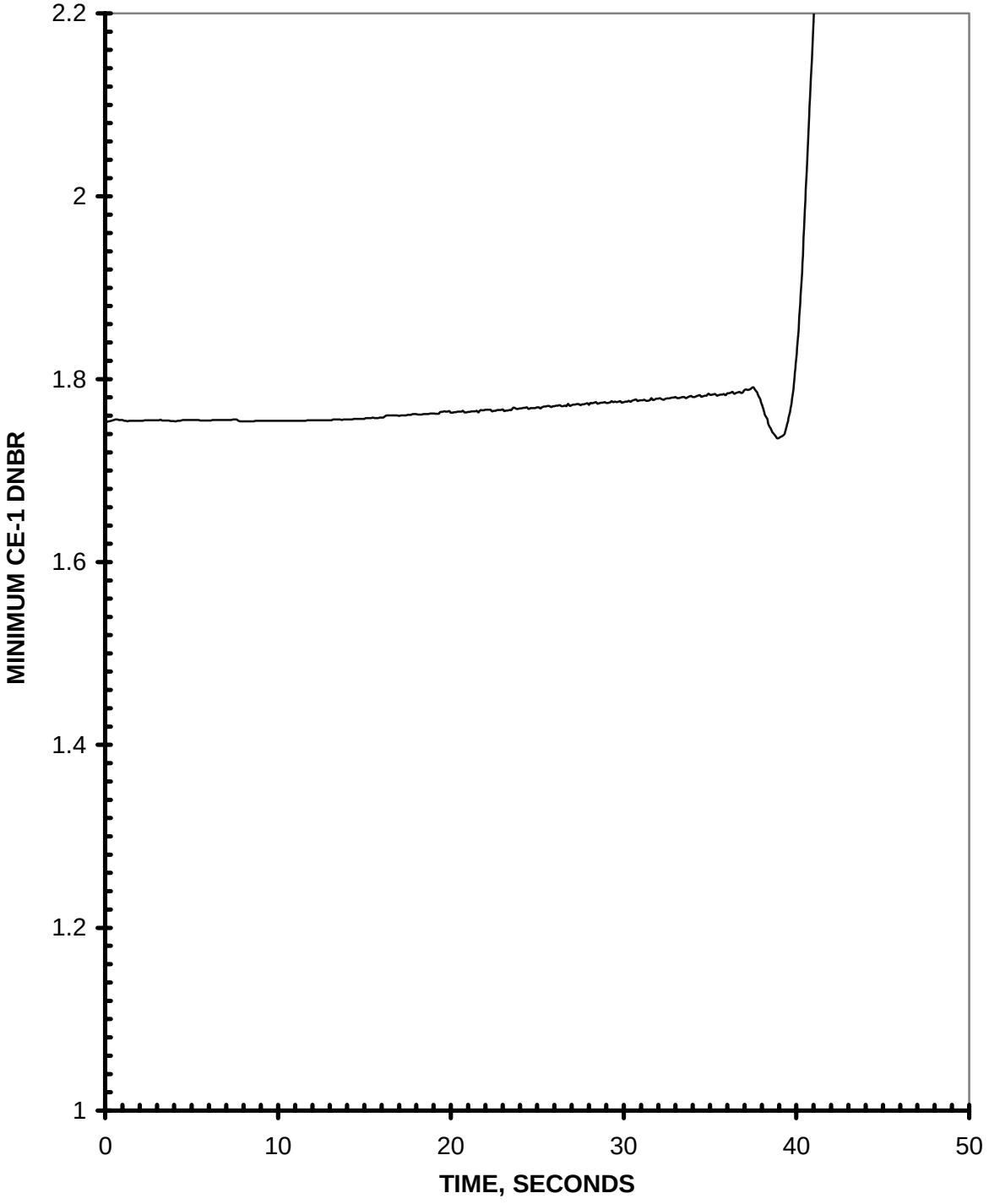

Figure 2.13.2.3.1-38
Feedwater System Pipe Break (Small)
Minimum DNBR vs. Time

2.13.2.3.2 Loss-of-Normal Feedwater Flow with SAF

2.13.2.3.2.1 Summary

The objective of loss-of-normal feedwater flow with an active failure in the Steam Bypass Control System (SBCS) analysis is to document the impact the following changes:

- An increase in rated thermal power to 3716 MWt
- A change to the CENTS code
- Application of a more negative MTC
- A decrease in the main steam isolation signal (MSIS) setpoints
- A reduction in SG pressure

The impact of the power uprate results in no violation of steam generator heat removal capability for this SAR event.

2.13.2.3.2.2 General Description of the Event

The causes of a loss-of-normal feedwater flow are discussed in Section 2.13.2.2.5 of this report. The same single active failure as in the current FSAR was assumed, i.e., failure of the SBCS (open).

The failure of the SBCS produces the minimum steam generator inventory in the shortest period of time following a loss-of-normal feedwater flow. This failure could be caused by an electrical malfunction providing a quick opening signal to all the steam bypass valves. It is assumed that the failure in the SBCS causes these valves to remain open, even in the presence of closure signals generated by the system due to adverse steam generator or condenser conditions (e.g., low pressure and low level) until a main steam isolation signal (MSIS) is generated.

The systems and reactor trip which operate following a loss-of-normal feedwater flow with failure of the SBCS open are the same as those described in Section 2.13.2.2.5, except for the operation of the SBCS and the generation of an MSIS. The MSIS is generated due to low SG pressure and provides protection against emptying the steam generators.

2.13.2.3.2.3 Purpose of Analysis and Acceptance Criteria

The purpose of the analysis was to determine that feedwater flow is sufficient such that the steam generator heat removal capability is maintained.

The loss-of-normal feedwater flow with an active failure in the SBCS event is described in Chapter 15.2.3.2 of the FSAR (Reference 2.13-1).

2.13.2.3.2.4 Impact of Changes

The CENTS code is used in this analysis in exactly the same manner as CESEC has been in the current analysis. In this case the substitution of one code for the other introduces no significant changes.

The lowering of the MSIS setpoint results in a somewhat longer period of continued steam flow through the steam bypass system. This tends to decrease the minimum inventory occurring in the SGs. This is both driven by and somewhat mitigated by the reduced SG pressure for EPU conditions.

The increase in rated thermal power also acts to increase the heat load to be removed by the SG inventory existing at the initiation of the event. This tends to exacerbate the reduction in minimum SG inventory during the event.

2.13.2.3.2.5 Analysis Overview

This analysis utilized the CENTS computer code (Reference 2.13-2) for the transient analysis simulation.

The input parameters from Table 2.13.2.3.2-1 and the bounding physics data from Section 2.13.0.2 were incorporated with the following clarifications:

- The EOC Doppler curve was assumed with 1.3 multiplier for uncertainty.
- A BOC delayed neutron fraction and neutron lifetime consistent with those defined in Section 2.13.0.2 were assumed.
- The CEA insertion curve based on the limiting +0.3 ASI shape was assumed. This curve accounts for a 0.6 second holding coil delay. A CEA worth of -6.0% $\Delta\rho$ was conservatively assumed.
- An MSSV tolerance of -3% was applied.
- An initial core power of 3735 MWt, based on a rated power of 3716 MWt and a 0.5% uncertainty, was assumed.
- A most negative MTC of $-4.2 * 10^{-4}$ $\Delta\rho/°F$ at hot-full power (HFP) was used for single failure case.
- Main steam isolation signal (MSIS) is actuated on a low SG pressure setpoint of 576 psia. The main steam isolation valves (MSIVs) receive an MSIS signal to close. A response time of 8 seconds (which includes a 1-second MSIS response time) was assumed for the MSIVs.
- Safety injection actuation signal (SIAS) setpoint of 1560 psia was used. However, no HPSI flow was initiated, since RCS pressure did not drop below HPSI shutoff head of 1300 psia.

2.13.2.3.2.6 Radiological Consequences

No SAFDL violation occurs during this event. Source terms are therefore limited to the initial primary and secondary limits on coolant activity in the Technical Specifications. Doses for this

event are bounded by the increased main steam flow with LOOP event in Section 2.13.1.2.3.5. Both events have the same criteria (small fraction of 10CFR100 guidelines), and the increased main steam flow with LOOP event radiological dose assumptions are conservative for the loss of feedwater plus SAF event.

2.13.2.3.2.7 Analysis Results

The loss-of-feedwater event did not result in steam generator dryout, thus there is no loss of secondary heat sink. The NSSS, PPS, and EFS responses for the loss-of-feedwater event are shown in Table 2.13.2.3.2-2 and Figures 2.13.2.3.2-1 through 2.13.2.3.2-11.

Table 2.13.2.3.2-1
Assumptions for 3716-MWt Loss-of-Normal Feedwater Flow with an Active Failure in the SBCS Analysis

Parameter	Power Uprate Assumption	Current Power Level Assumption
Initial Core Power, MWt	3735	3478
Core Inlet Temperature, °F	552	560
RCS Flowrate, 10^6 lbm/hr	148	141
Pressurizer Pressure, psia	2090	2000
Pressurizer Level, %	67.5	- - -
SG Pressure, psia	877	950
SG Level, %NR	90	- - -
MTC, 10^{-4} $\Delta\rho$/°F	-4.2	-2.0
Doppler Coefficient Multiplier	1.3 (EOC)	0.85 (BOC)
CEA Worth on Trip, 10^{-2} $\Delta\rho$	-6.0	-7.95
SBCS	Automatic	Automatic

Table 2.13.2.3.2-2
Sequence of Events for 3716-MWt
Loss-of-Normal Feedwater Flow with an Active Failure in the SBCS

EPU Time (sec)	Current Power Level Time (sec)	Event	EPU Setpoint/ Value	Current Power Level Setpoint/Value
0.0	0.0	Termination of all feedwater flow	---	---
11.3	9.8	Turbine steam bypass valves fully open	852 psia	950 psia
35.4	42.8	Maximum core power	126 %	131%
35.9	42.6	Low SG water level trip signal (EFAS)	5% NR	5% NR
36.8	43.0	Reactor trip breakers open	---	---
37.4	43.3	CEAs begin to drop into core	---	---
74.6	62.2	Low-pressurizer pressure SIAS (SIAS flow not initiated as minimum transient RCS pressure is above HPSI shutoff head)	1560 psia	1560 psia
76.5	77.3	MSIS	576 psia	675 psia
84.5	79.4	Minimum SG pressure	501.2 psia	633 psia
84.5	80.3	MSIVs fully closed	---	---
86.0	68.0	Pressurizer empties	1463 psia	1436 psia
100.9	85.3	EFW reaches SGs	---	---
115.0	90.0	Minimum SG water inventory	4,476 lbm	7,530 lbm
1800.0	1800.0	Operator begins cooldown	---	---

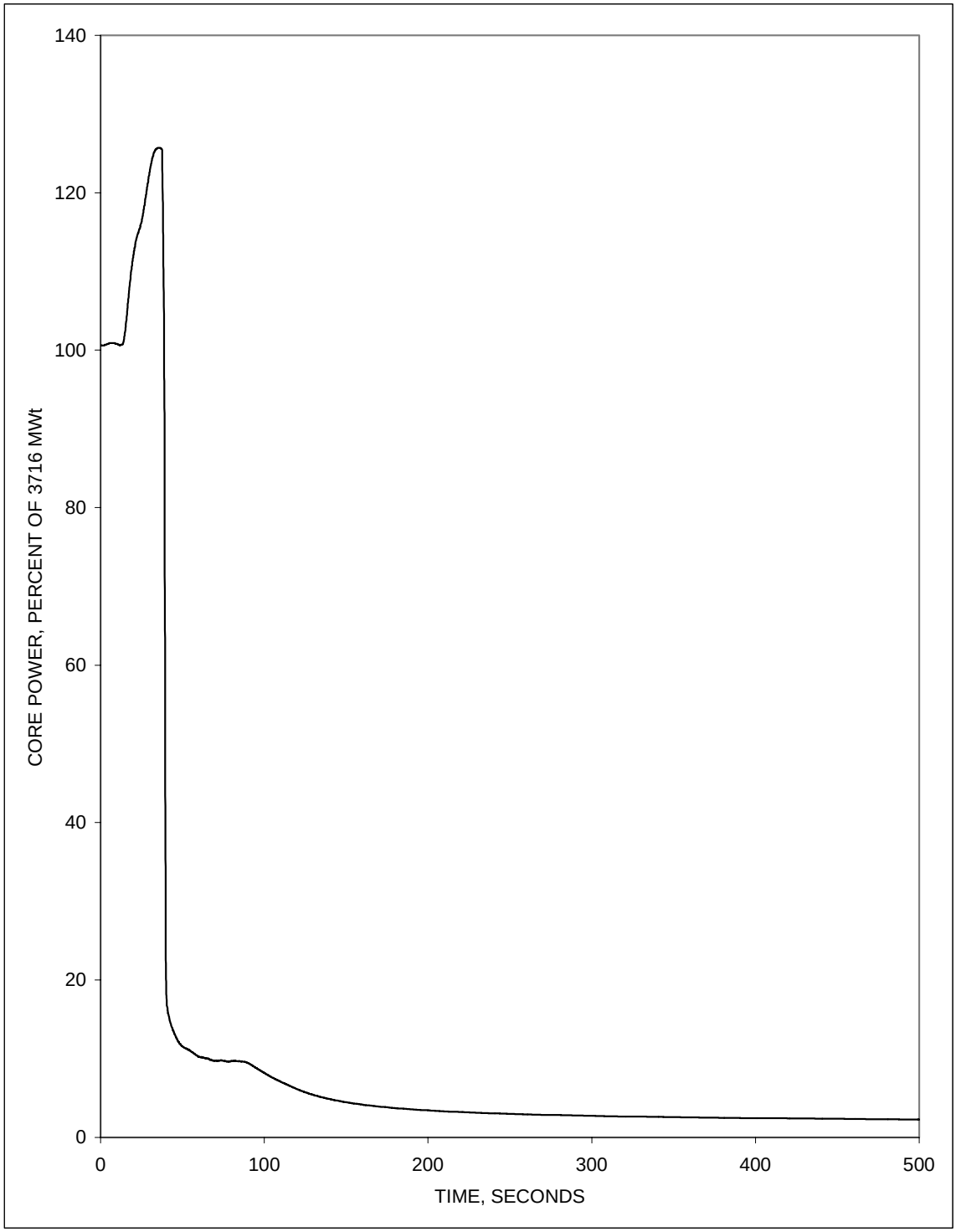

Figure 2.13.2.3.2-1
Loss-of-Normal Feedwater Flow with an Active Failure in the SBCS Core Power vs. Time

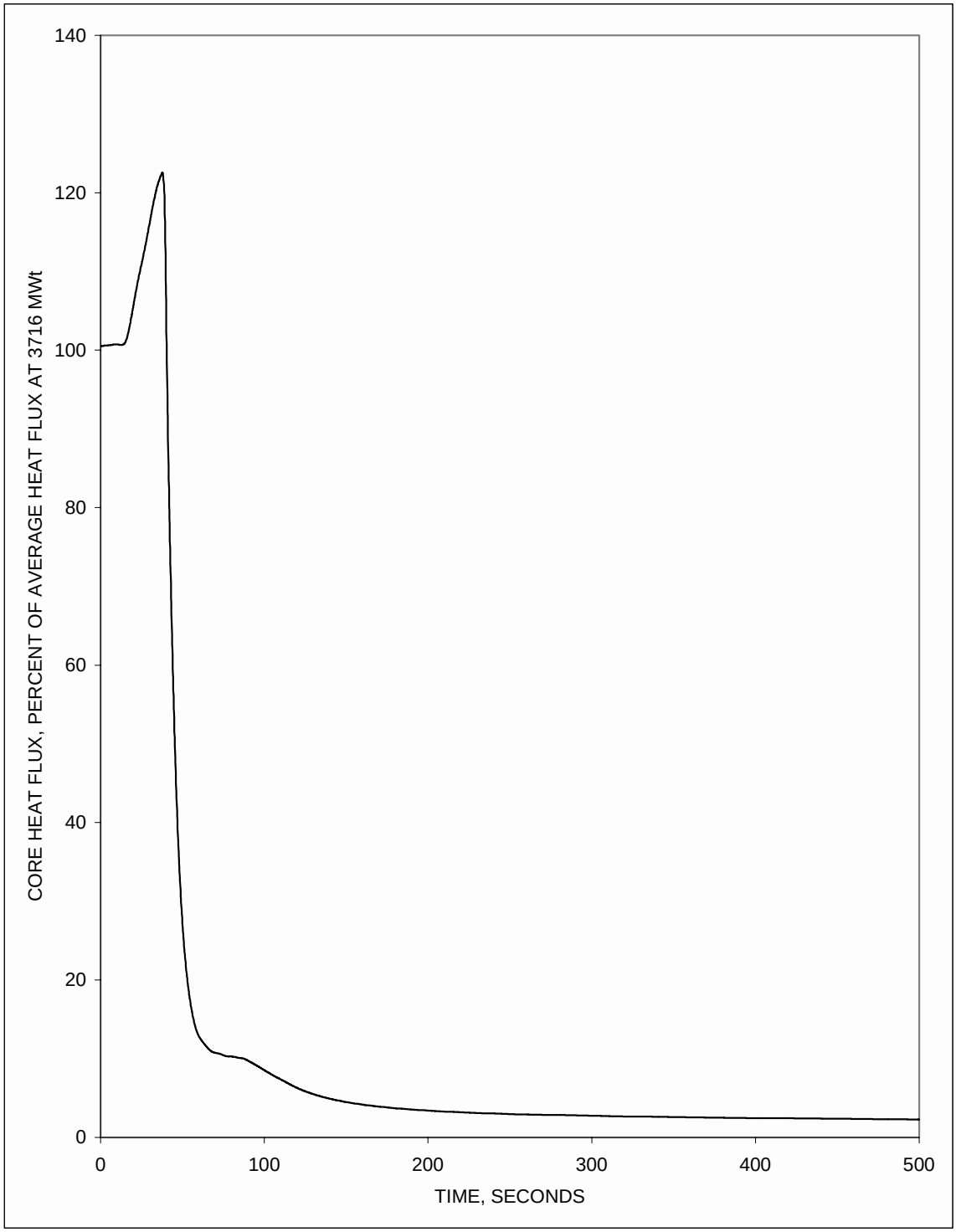

Figure 2.13.2.3.2-2
Loss-of-Normal Feedwater Flow with an Active Failure in the SBCS Core Heat Flux vs. Time

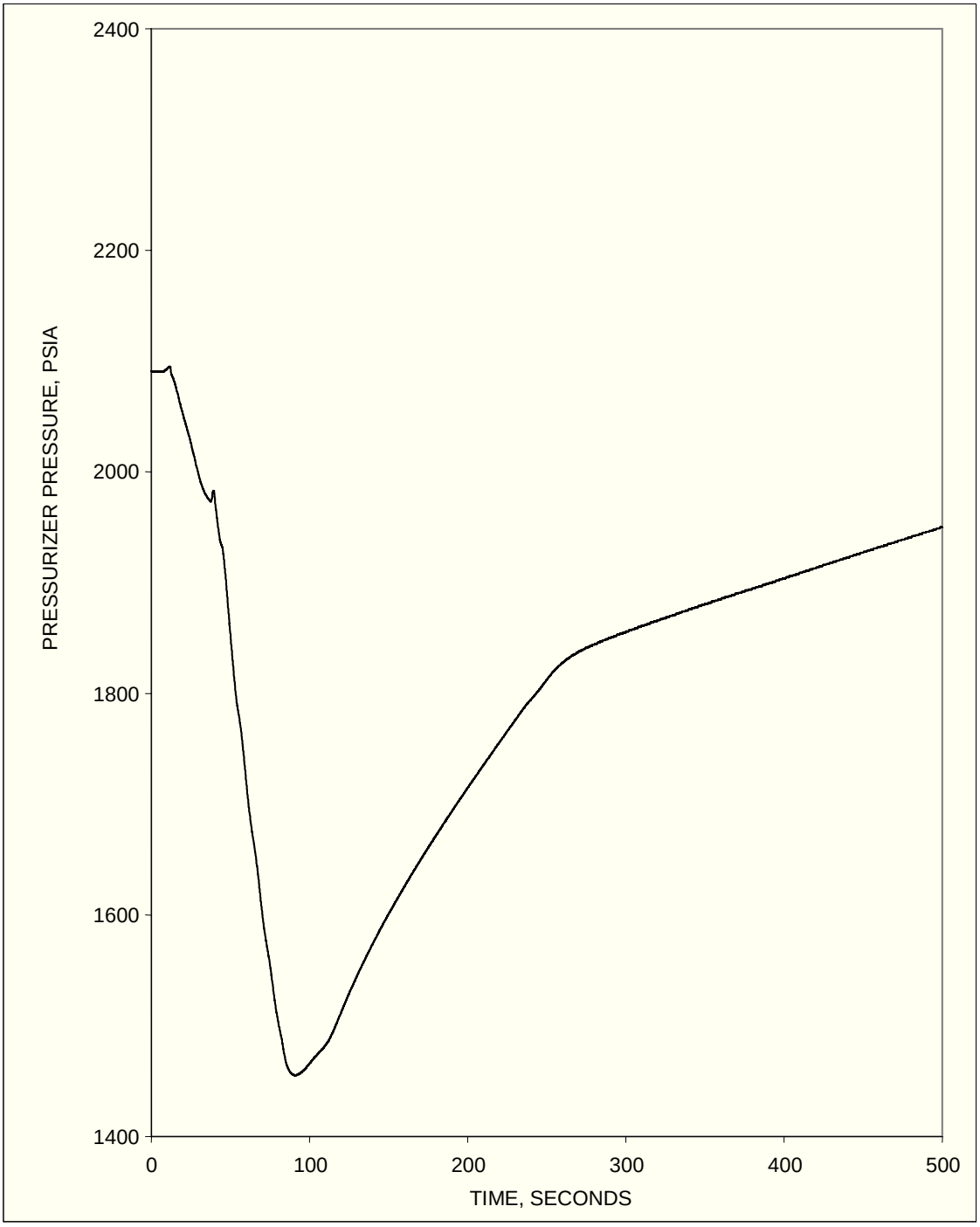

Figure 2.13.2.3.2-3
Loss-of-Normal Feedwater Flow with an Active Failure in the SBCS Pressurizer Pressure vs. Time

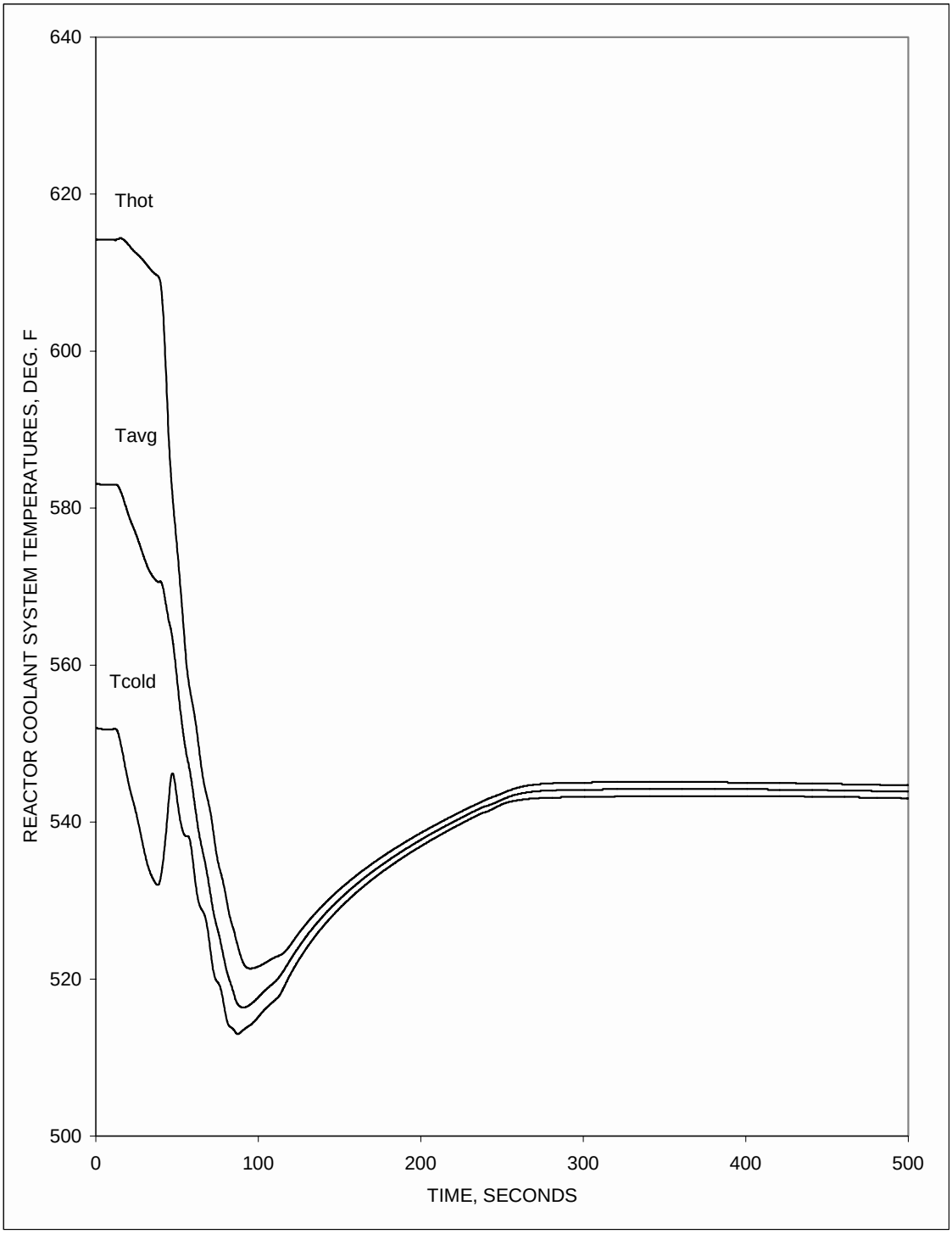

Figure 2.13.2.3.2-4
Loss-of-Normal Feedwater Flow with an Active Failure in the SBCS RCS Temperatures vs. Time

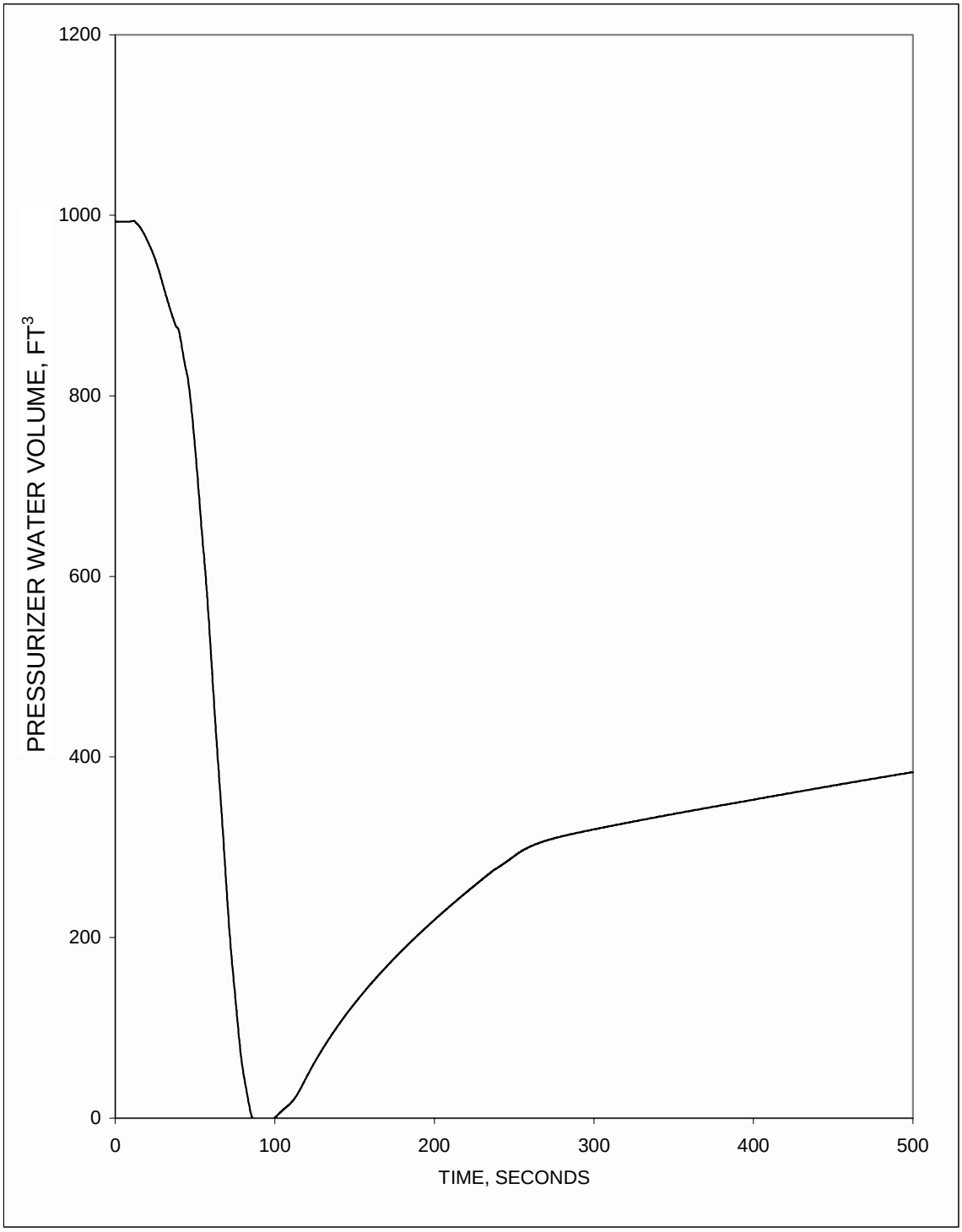

Figure 2.13.2.3.2-5
Loss-of-Normal Feedwater Flow with an Active Failure in the SBCS Pressurizer Water Volume vs. Time

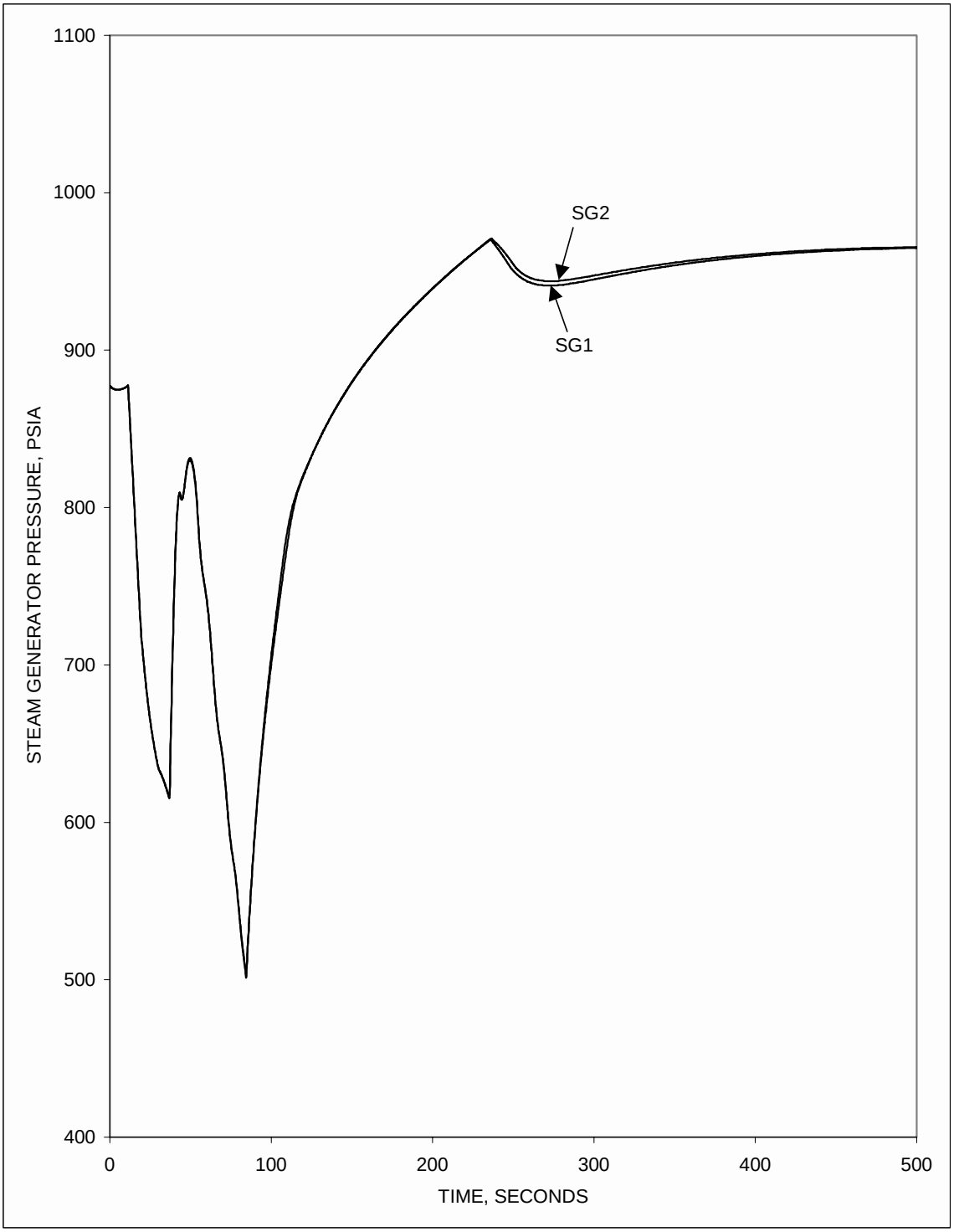

Figure 2.13.2.3.2-6
Loss-of-Normal Feedwater Flow with an Active Failure in the SBCS SG Pressure vs. Time

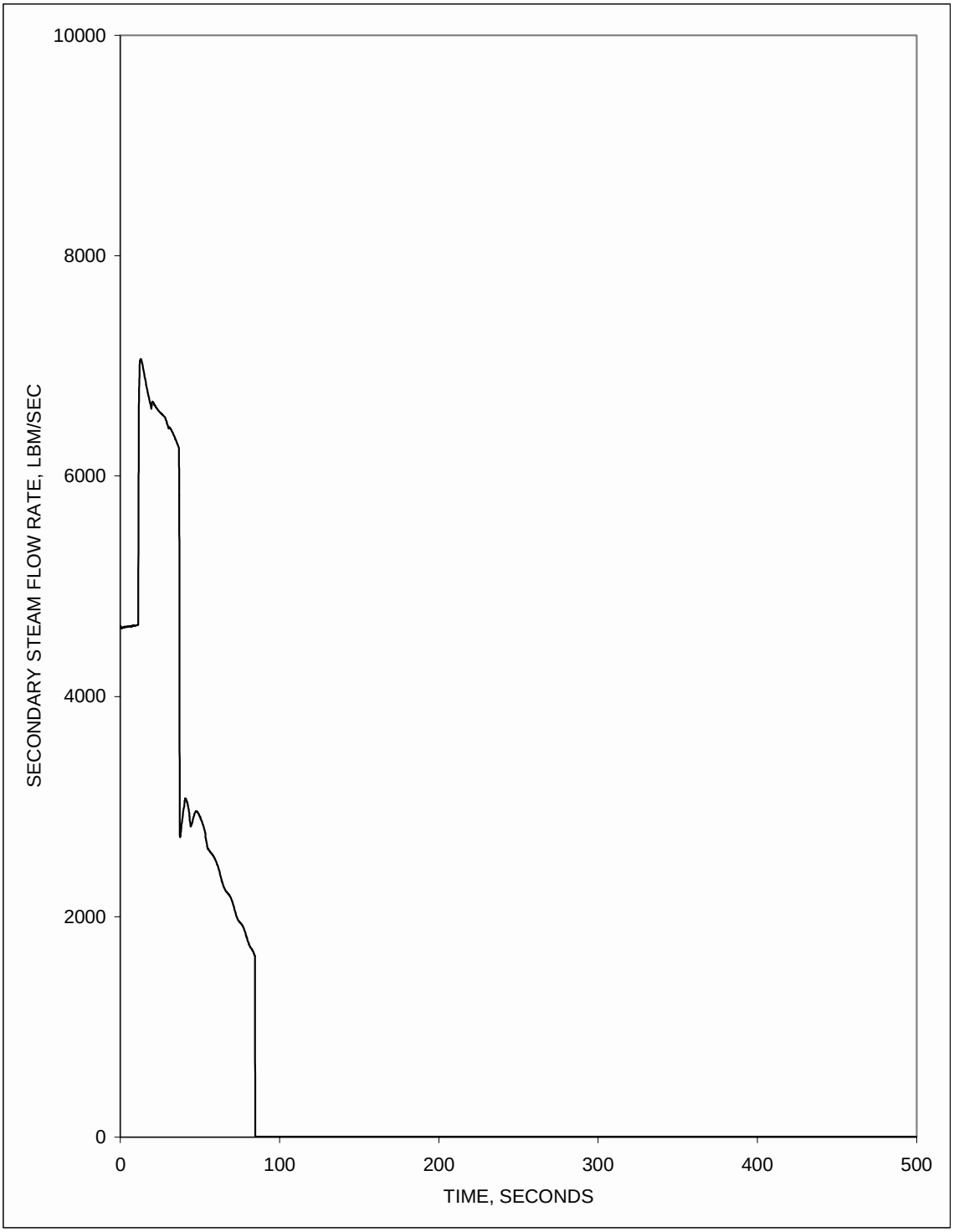

Figure 2.13.2.3.2-7
Loss-of-Normal Feedwater Flow with an Active Failure in the SBCS Secondary Steam Flowrate vs. Time

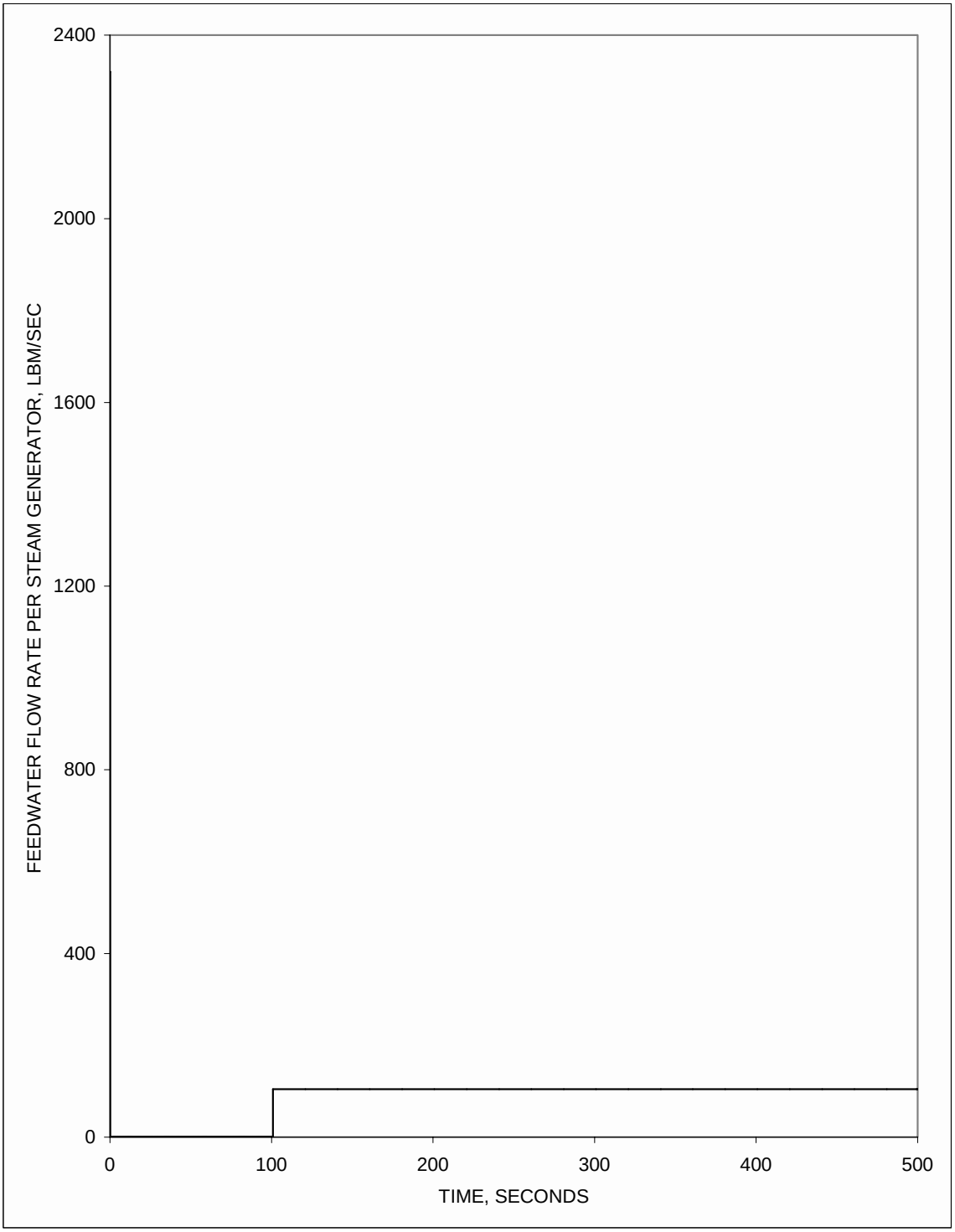

Figure 2.13.2.3.2-8
Loss-of-Normal Feedwater Flow with an Active Failure in the SBCS EFW Flowrate per SG vs. Time

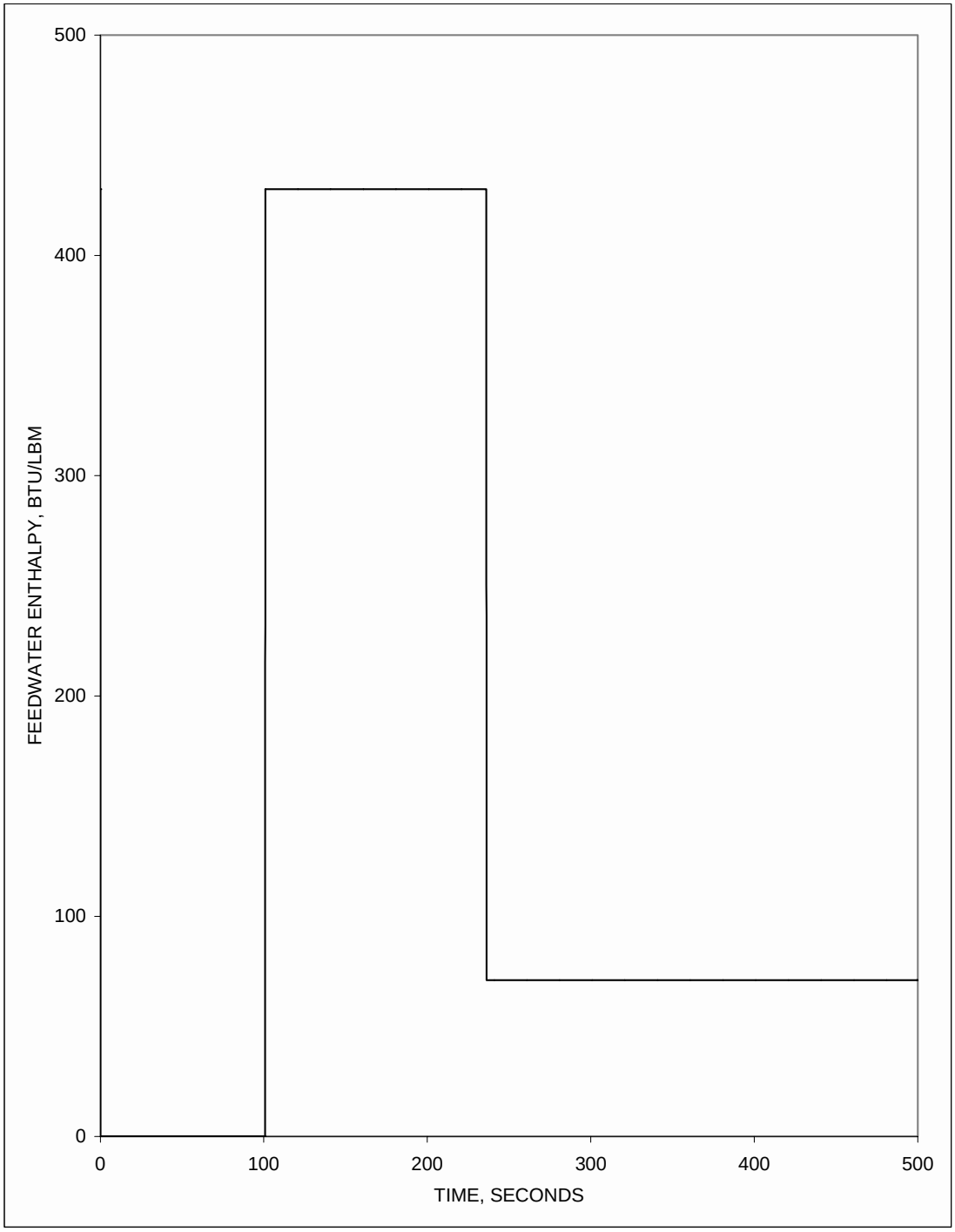

Figure 2.13.2.3.2-9
Loss-of-Normal Feedwater Flow with an Active Failure in the SBCS EFW Enthalpy vs. Time

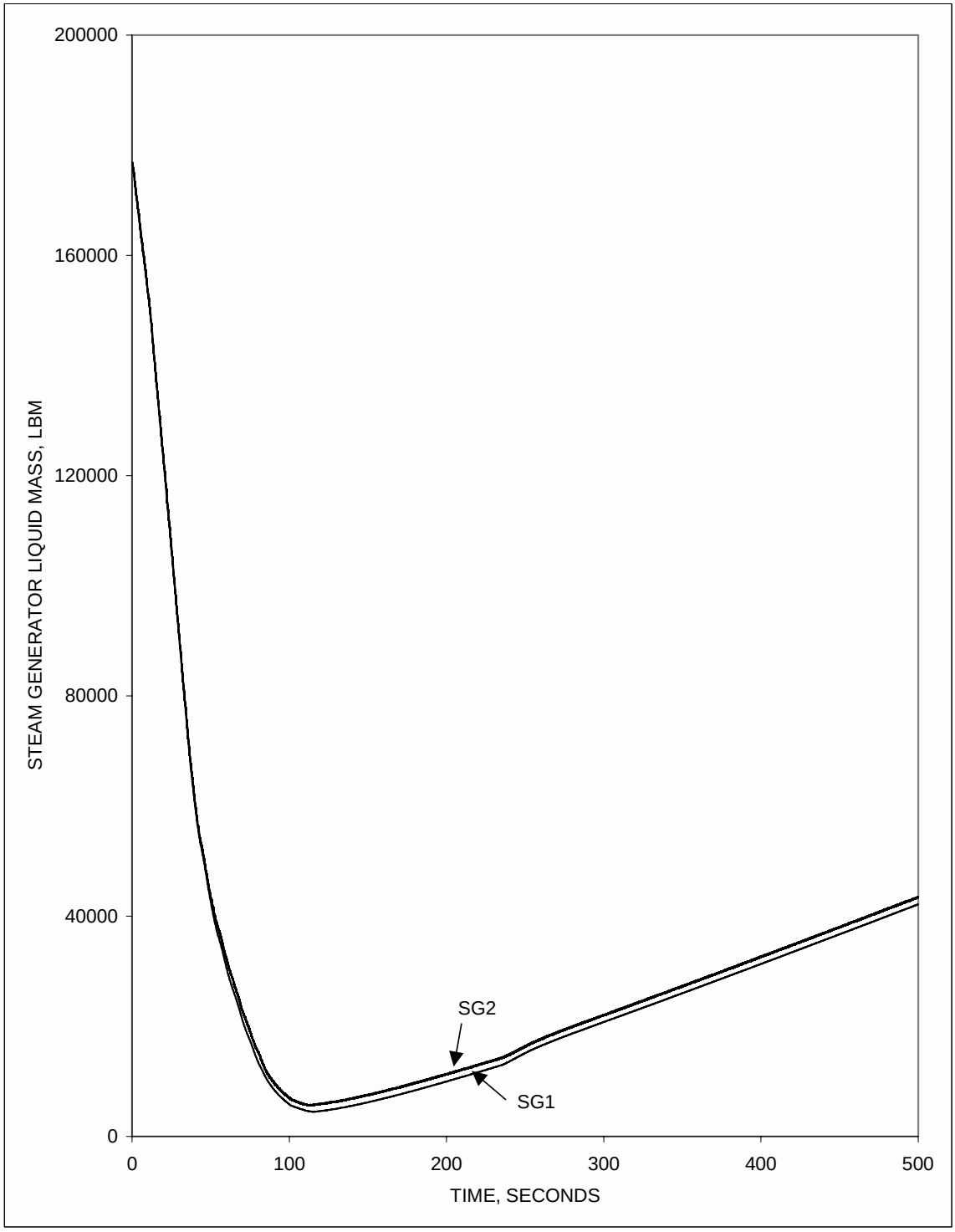

Figure 2.13.2.3.2-10
Loss-of-Normal Feedwater Flow with an Active Failure in the SBCS Secondary Liquid Mass vs. Time

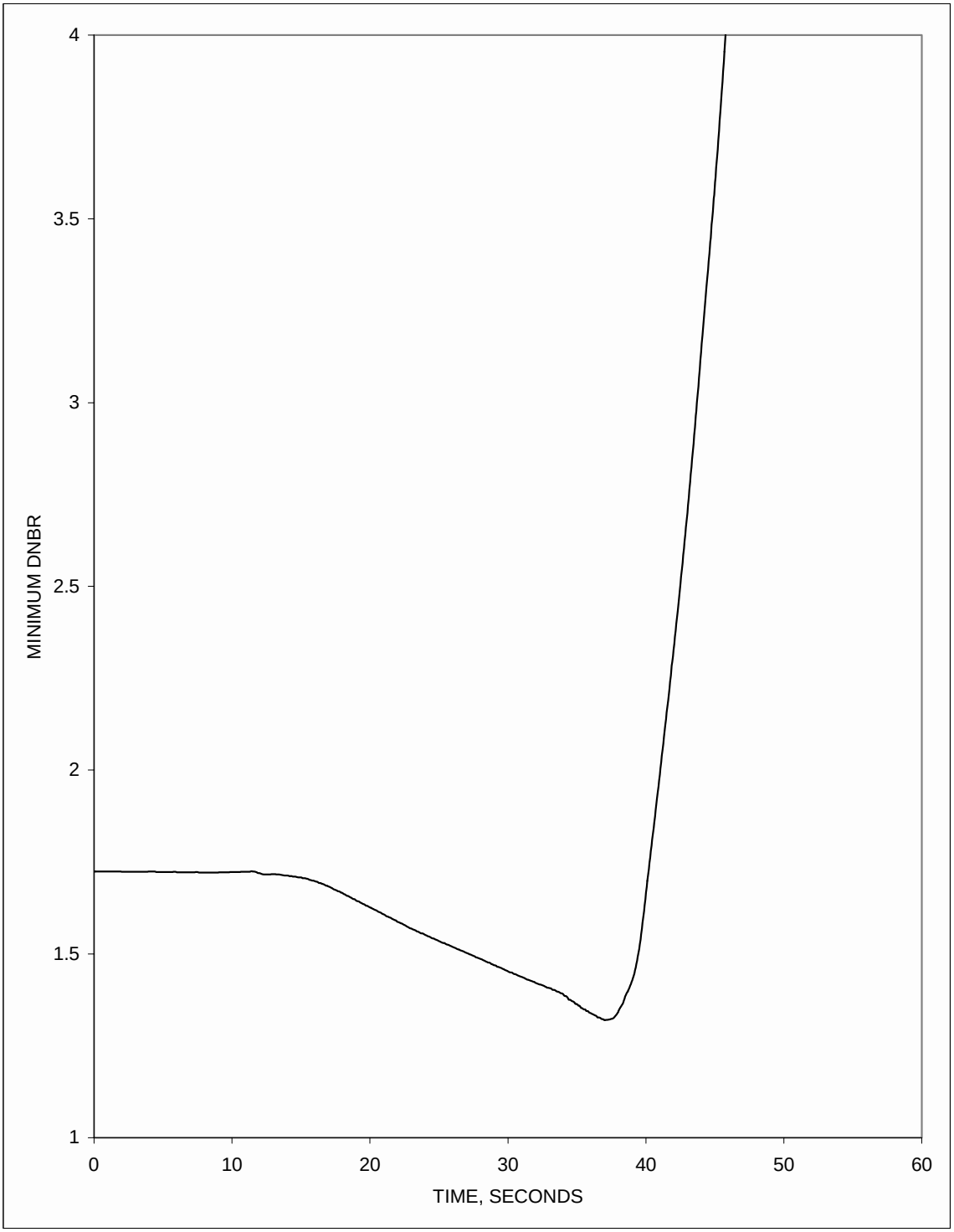

Figure 2.13.2.3.2-11
Loss-of-Normal Feedwater Flow with an Active Failure in the SBCS Minimum DNBR vs. Time

2.13.3 Decrease in Reactor Coolant Flow Rate

2.13.3.1 Moderate Frequency Events

2.13.3.1.1 Partial Loss of Forced Reactor Coolant Flow

This event is bounded by the total loss of forced reactor coolant flow, Section 2.13.3.2.1.

2.13.3.2 Infrequent Events

2.13.3.2.1 Total Loss of Forced Reactor Coolant Flow

The total loss of forced reactor coolant flow is analyzed for power uprate to evaluate the impact of the following changes:

- The increase in rated thermal power to 3716 MWt
- The decrease in core inlet temperature to 533°F
- The use of the CENTS code rather than the COAST code to generate the flow coastdown curves that are input into the 1-D HERMITE model for the fuel failure evaluation

2.13.3.2.1.1 General Description of Event

A total loss of forced reactor coolant will result from the simultaneous loss of electrical power to all reactor coolant pumps (RCPs). The only credible failure that can result in a simultaneous loss of power is a complete LOOP.

A total loss of forced reactor coolant flow will produce a minimum DNBR more adverse than any partial loss of forced reactor coolant flow.

For the loss of offsite power event, the minimum DNBR occurs during the first few seconds of the transient and the reactor is tripped by the CPCS on low RCP shaft speed. Therefore, any single failure that would result in a lower DNBR during the transient would have to affect at least one of the above parameters during the first few seconds of the event.

Following the total loss of reactor coolant flow, reactor heat removal takes place by means of natural circulation. The pressurizer assists in the control of RCS pressure and volume changes during the transient by compensating for the initial expansion of the RCS fluids. The combination of the loss of primary system heat sink (turbine stop valves close) with the reduction of reactor coolant flow results in an increase in RCS pressure that is limited by the primary safety valves.

The steam generators provide primary-to-secondary heat transfer.

The LOOP is assumed to produces a loss of load on the turbine that generates a turbine trip signal. The turbine stop valves are closed as a result of the trip. The SBCS becomes unavailable due to the LOOP and subsequent LOCV. In addition, because of the loss of condenser vacuum, main feedwater flow to the steam generators is lost. This sequence of events results in opening of the main steam safety valves (MSSVs) that limits secondary system pressure and removes heat stored in the core and the RCS. Once the flow parameters are stabilized, the operator initiates cooldown (assumed to be initiated 30 minutes after event initiation) utilizing the Emergency Feedwater System (EFW) and ADVs.

2.13.3.2.1.2 Acceptance Criteria

As defined in the SRP Section 15.3 (Reference 2.13-14), the specific acceptance criteria for a limiting moderate frequency event are:

The following criteria apply to the loss of flow event:

- DNBR > 1.26
- Fuel temperature < fuel melt temperature limit, demonstrated by peak LHR ≤ 21.0 kW/ft
- Radiological dose ≤ small fraction of 10CFR100 limits
- RCS pressures ≤ 110% of design

2.13.3.2.1.3 Impact of Changes

The methodology used to analyze this event for Waterford 3 demonstrates more adverse results when initiated at colder core inlet temperature conditions. Thus, the change in the low end of the inlet temperature LCO is adverse.

Only small differences between the flow coastdown between the CENTS and COAST codes were seen. The new coastdown was used in the HERMITE analysis performed herein.

2.13.3.2.1.4 Analysis Overview

The Nuclear Steam Supply System (NSSS) response to a total loss of reactor coolant flow was simulated using the CENTS computer code (Reference 2.13-2). The core average and hot channel response to the loss-of-flow event from these initial conditions was simulated using the 1-D HERMITE computer program (Reference 2.13-4). The transient DNBR values were calculated using the CETOP-D computer program (Reference 2.13-3) that uses the CE-1 CHF correlation. Additionally, input parameters and initial conditions were selected to maximize the DNBR degradation. The flow coastdown is determined using CENTS computer code (Reference 2.13-2).

The use of the 1-D HERMITE code to model the response of the core to the loss of flow allows an analytical credit to be determined for the effect of coolant density changes in the hot channel. To minimize the credit obtained, the initial conditions for the HERMITE simulation are selected to maximize corewide subcooling. Therefore, the reduction in the initial core inlet temperature will tend to further minimize this credit and make DNBR more adverse.

CENTS is initialized at 100.5% power and the most limiting initial parameters, i.e., RCS flow, cold leg temperatures, pressurizer pressure, moderator temperature, Doppler coefficients, SCRAM characteristics, and axial power distribution with respect to subcooled conditions in HERMITE.

At time equal to zero, the loss of flow is simulated by a LOOP, which results in a turbine trip, main feedwater ramping to zero and coastdown of all four RCPs. Reactor trip occurs on CPCS low RCP shaft speed trip.

Table 2.13.3.2.1-1 contains the initial conditions and assumptions used for the loss-of-flow event.

2.13.3.2.1.5 Radiological Consequences

No SAFDL violation occurs during the loss of flow event. Source terms are therefore limited to the initial primary and secondary limits on coolant activity in the Technical Specifications. Doses for this event are bounded by the IOSGADV with LOOP event in Section 2.13.1.2.4.5. Both events have the same criteria (small fraction of 10CFR100 guidelines), and the IOSGADV with LOOP event radiological dose assumptions are conservative for the loss-of-flow event.

2.13.3.2.1.6 Results

The DNBR degradation from the loss of flow event is modeled using the core average and hot channel properties from HERMITE. The dynamic behavior of typical NSSS parameters, which are modeled as loss of four RCPs with concurrent loop, is shown on Figures 2.13.3.2-1 through 2.13.3.2-9. Table 2.13.2.1-2 presents a sequence of events that occur following the loss of flow until the operator action is initiated.

Table 2.13.3.2.1-1
Loss of Flow Assumption Table

Parameter	Power Uprate Assumption	Current Power Level Assumption
Initial Core Power, MWt	3735	3478
Core Inlet Temperature, ^{o}F	533	560
Pressurizer Pressure, psia	2310	2350
RCS Flowrate, 10^6 lbm/hr	177.6	165.5
Pressurizer Level, %	44	---
SG Pressure, psia	741	949
SG Level, % NR	67.2	---
MTC, x10-4 $\Delta\rho$/°F	0.0	+0.5
Doppler Coefficient Multiplier	0.85	0.85
Kinetics	Maximum β	Maximum β
CEA Worth at Trip, %$\Delta\rho$	-5.0	-6.0

Table 2.13.3.2.1-2
Sequence of Events for the Loss of Flow

EPU Time (sec)	Current Power Level Time (sec)	Event	EPU Setpoint/Value	Current Power Level Setpoint/Value
0.0	0.0	Loss of power to all RCPs	---	---
0.48	0.622	Low RCP shaft speed trip condition	96.5% of initial shaft speed	96.5% of initial shaft speed
0.78	0.85	Reactor trip breakers open	---	---
1.38	1.45	CEAs begin to drop	---	---
2.60	2.20	Minimum DNBR	$\geq$ 1.26	$\geq$ 1.26
7.9	4.5	Maximum RCS pressure, psia	2395	2523
183.5*	15*	SG safety valves open, psia	1117	1100
183.5*	19*	Maximum SG pressure, psia	1117	1116
212.8*	24*	SG safety valves close, psia	1062	1056

* These are typical values for the loss-of-forced RCS flow event.

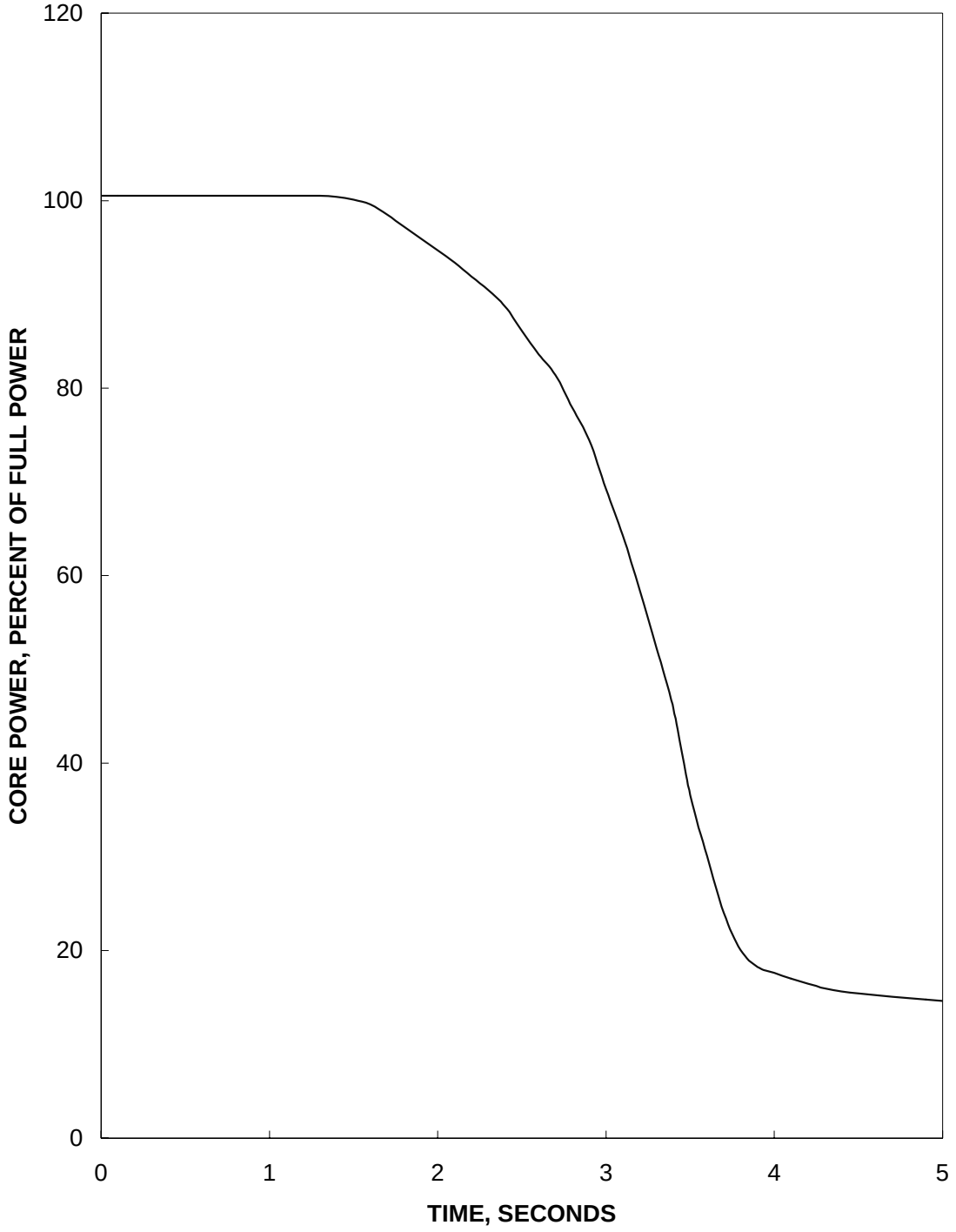

Figure 2.13.3.2.1-1
Total Loss of Forced Reactor Coolant Flow
Core Power vs. Time

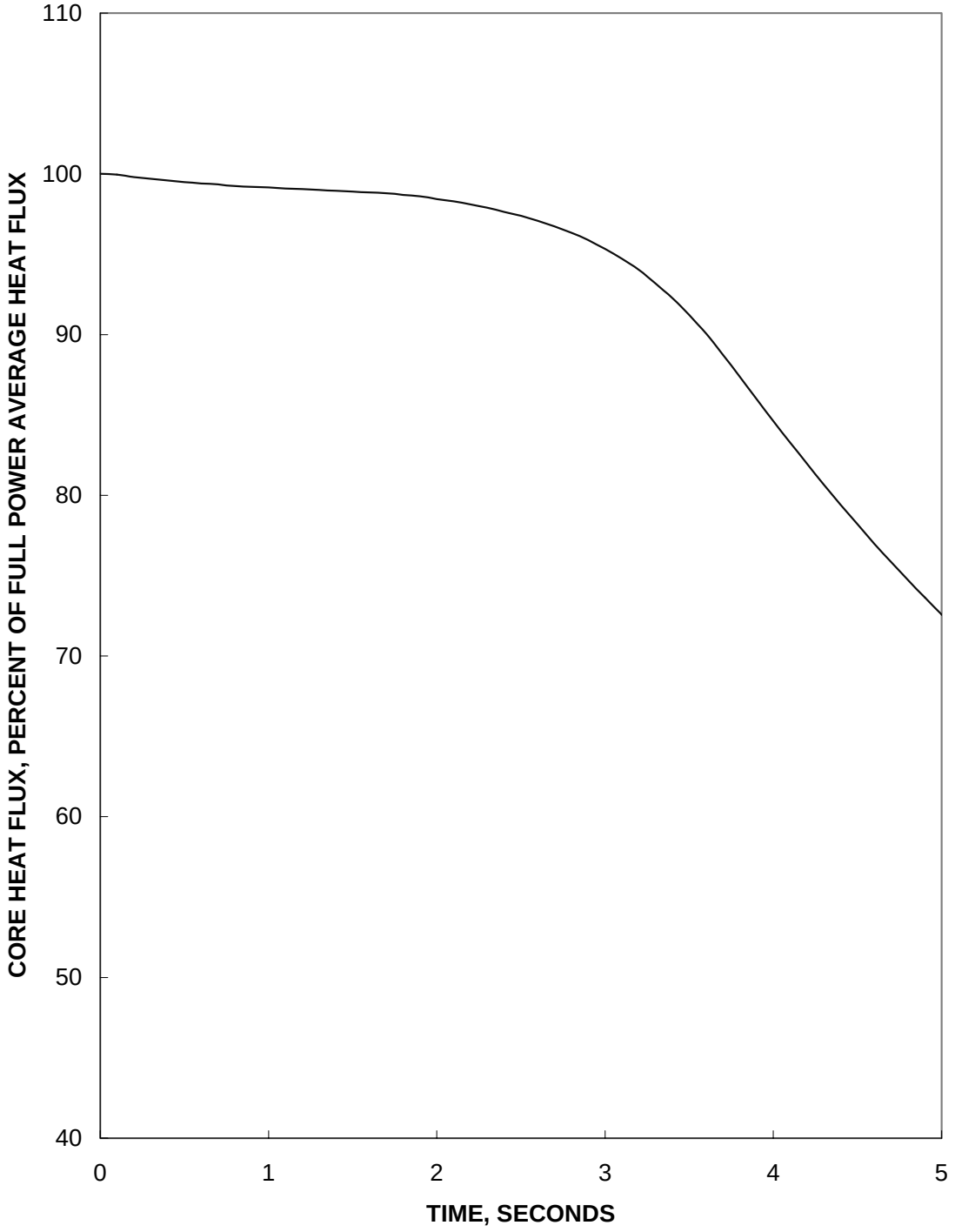

Figure 2.13.3.2.1-2
Total Loss of Forced Reactor Coolant Flow
Core Heat Flux vs. Time

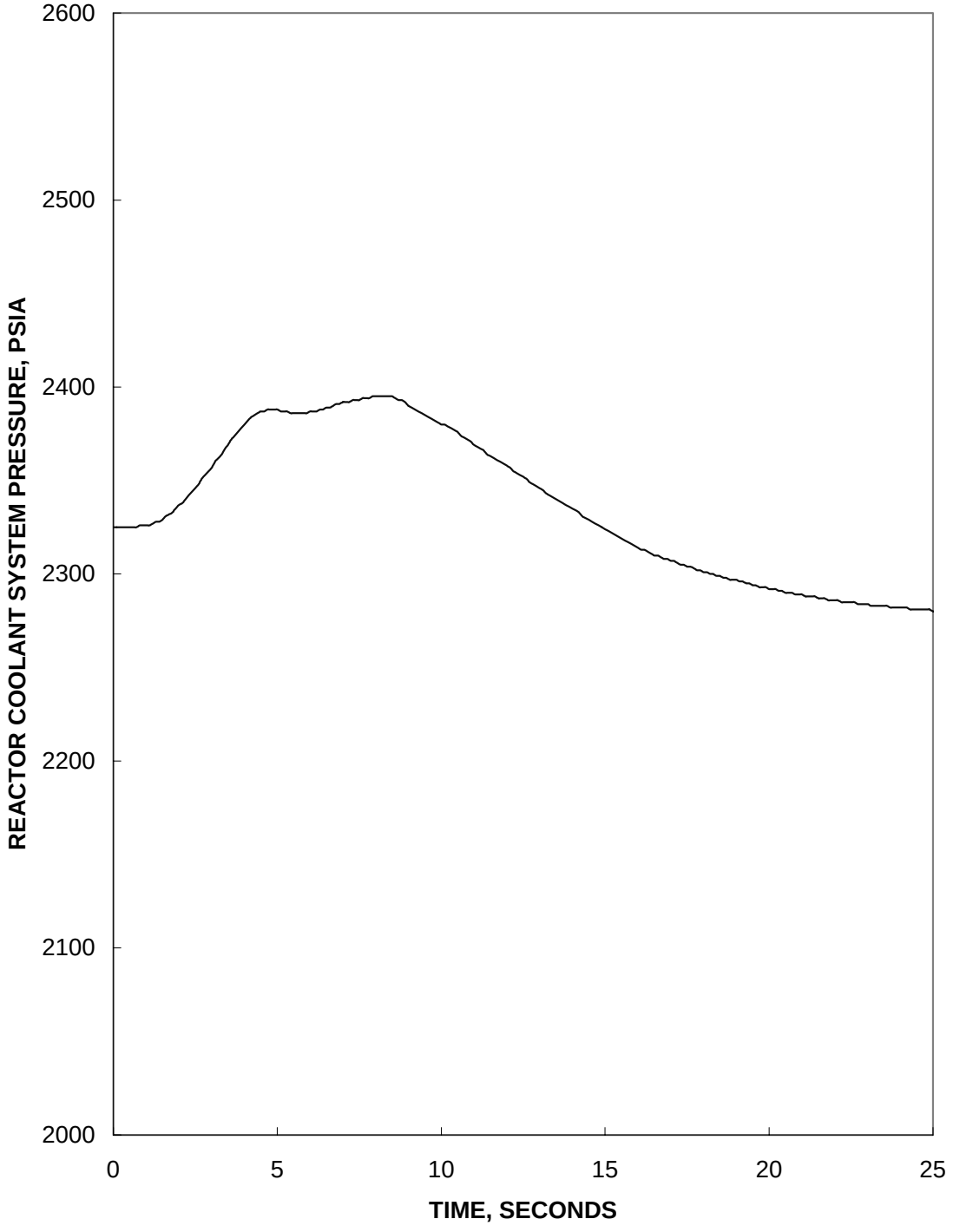

Figure 2.13.3.2.1-3
Total Loss of Forced Reactor Coolant Flow
RCS Pressure vs. Time

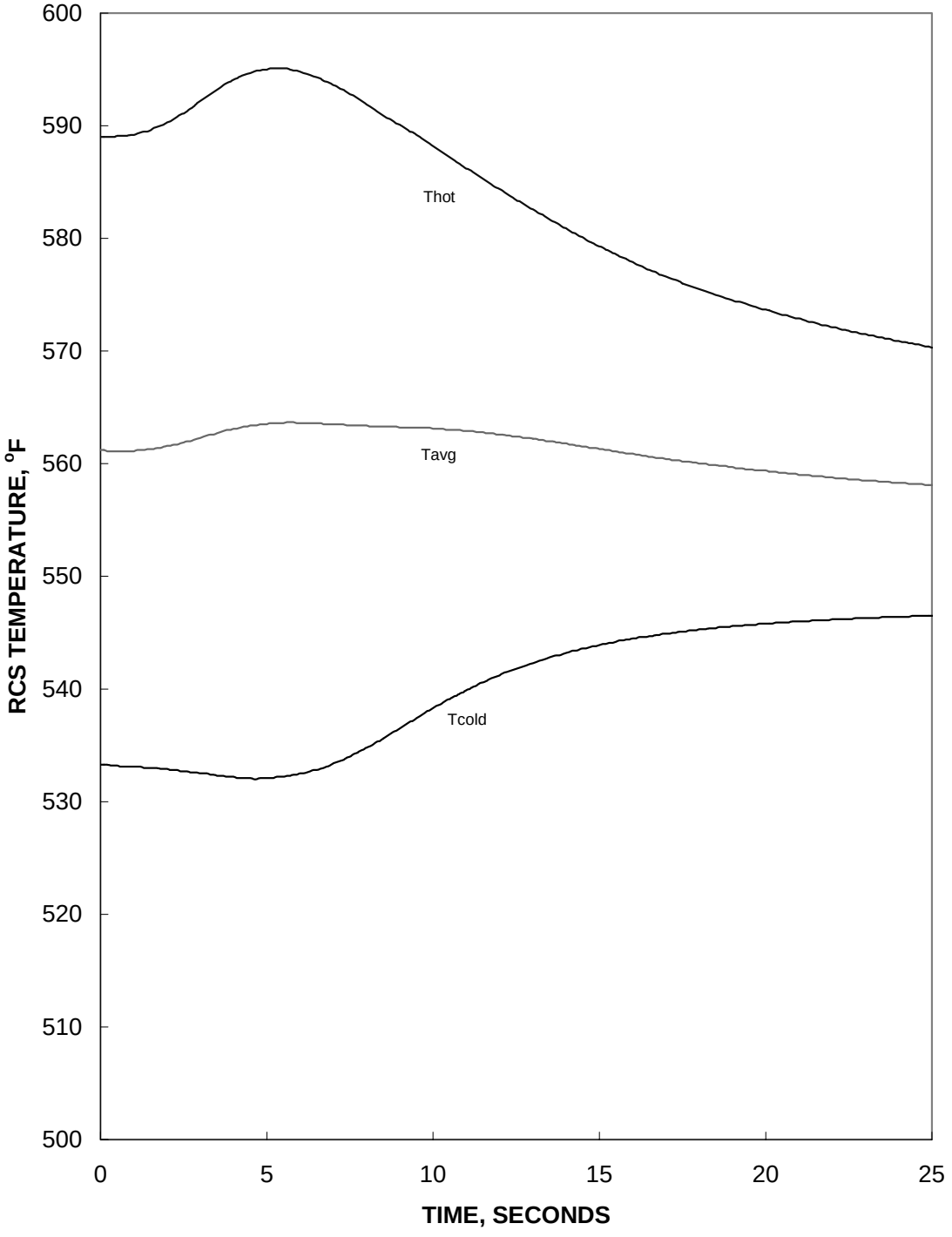

Figure 2.13.3.2.1-4
Total Loss of Forced Reactor Coolant Flow
Reactor Coolant Temperatures vs. Time

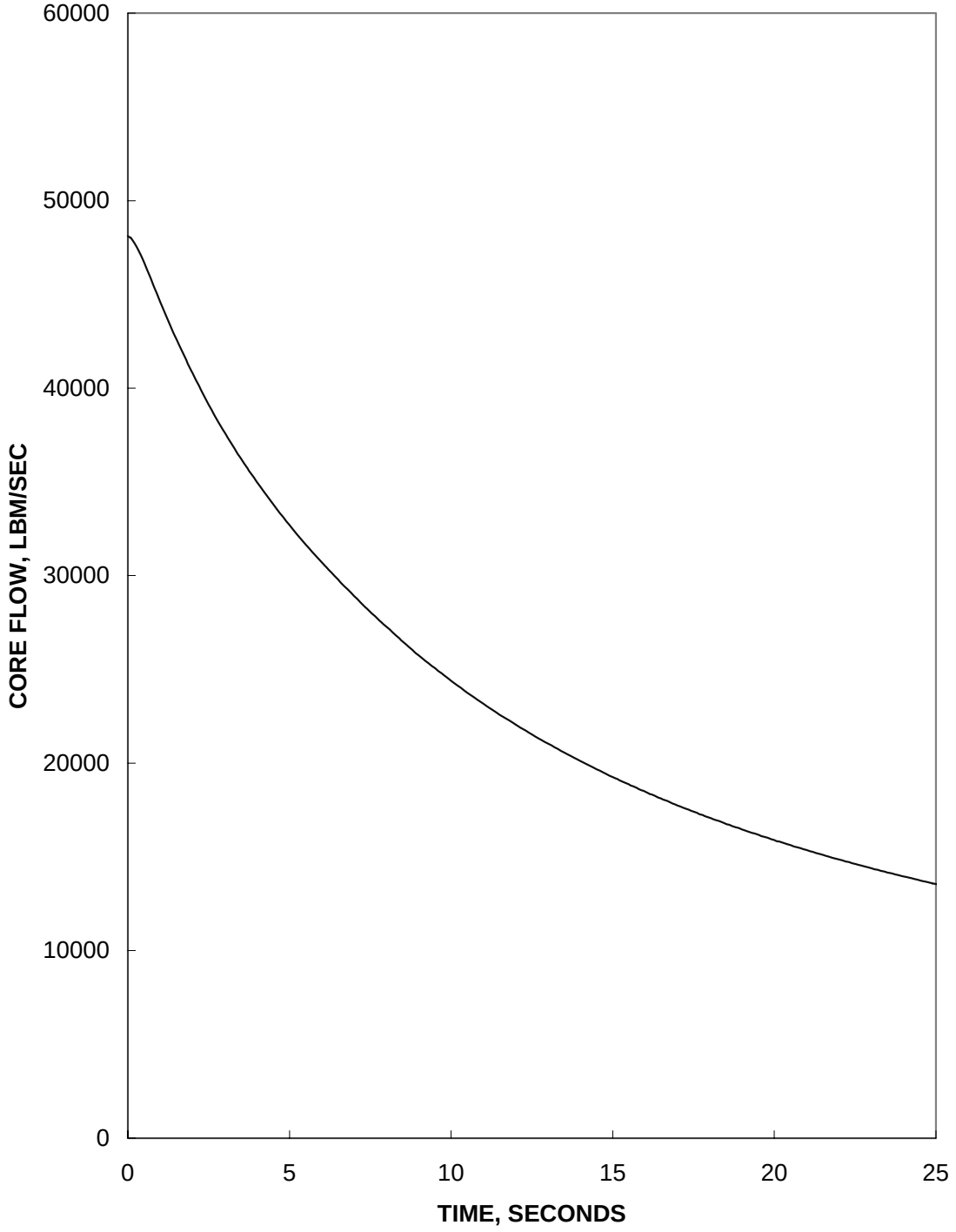

Figure 2.13.3.2.1-5
Total Loss of Forced Reactor Coolant Flow
Core Flow vs. Time

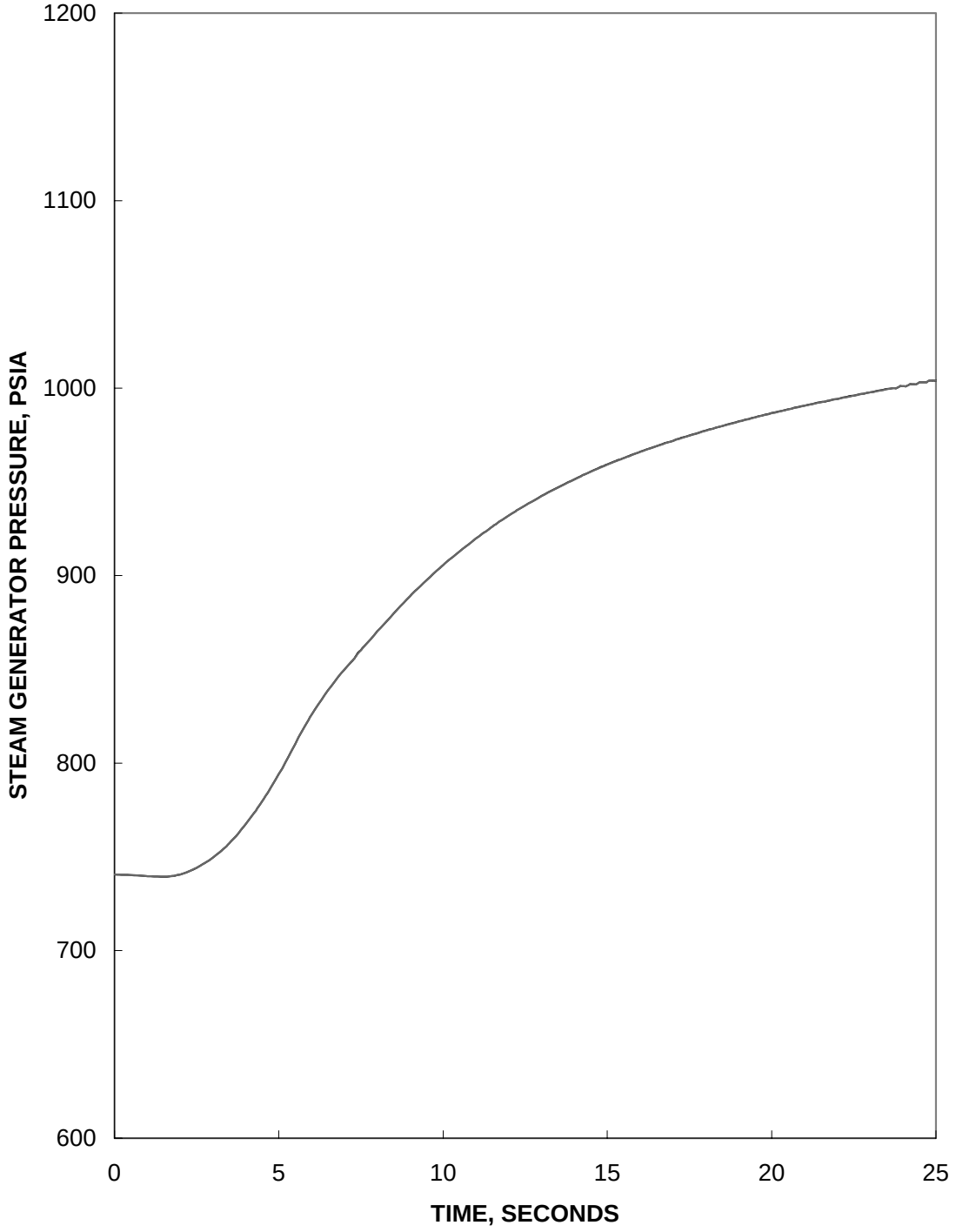

Figure 2.13.3.2.1-6
Total Loss of Forced Reactor Coolant Flow
SG Pressure vs. Time

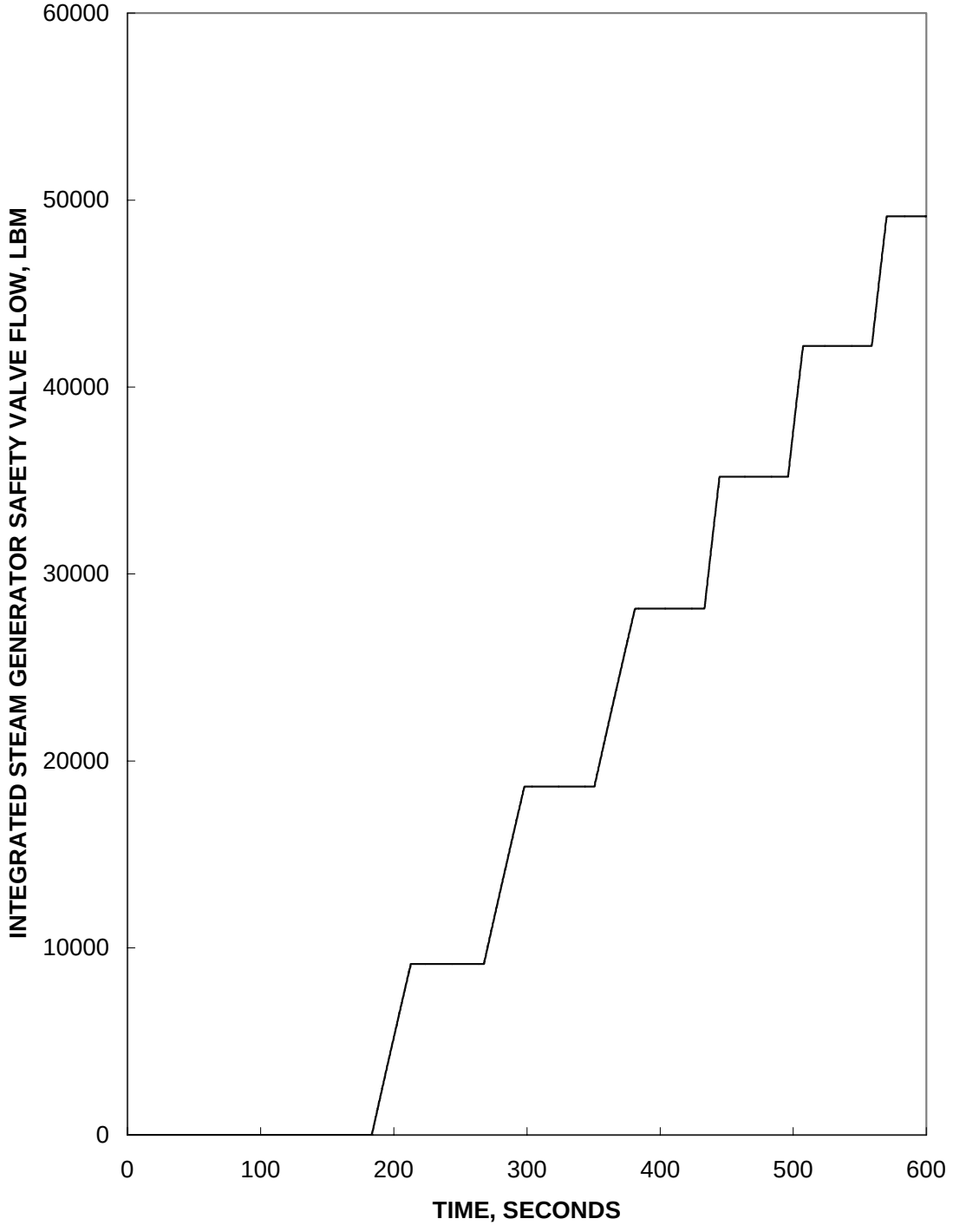

Figure 2.13.3.2.1-7
Total Loss of Forced Reactor Coolant Flow
Integrated SG Safety Valve Flow vs. Time

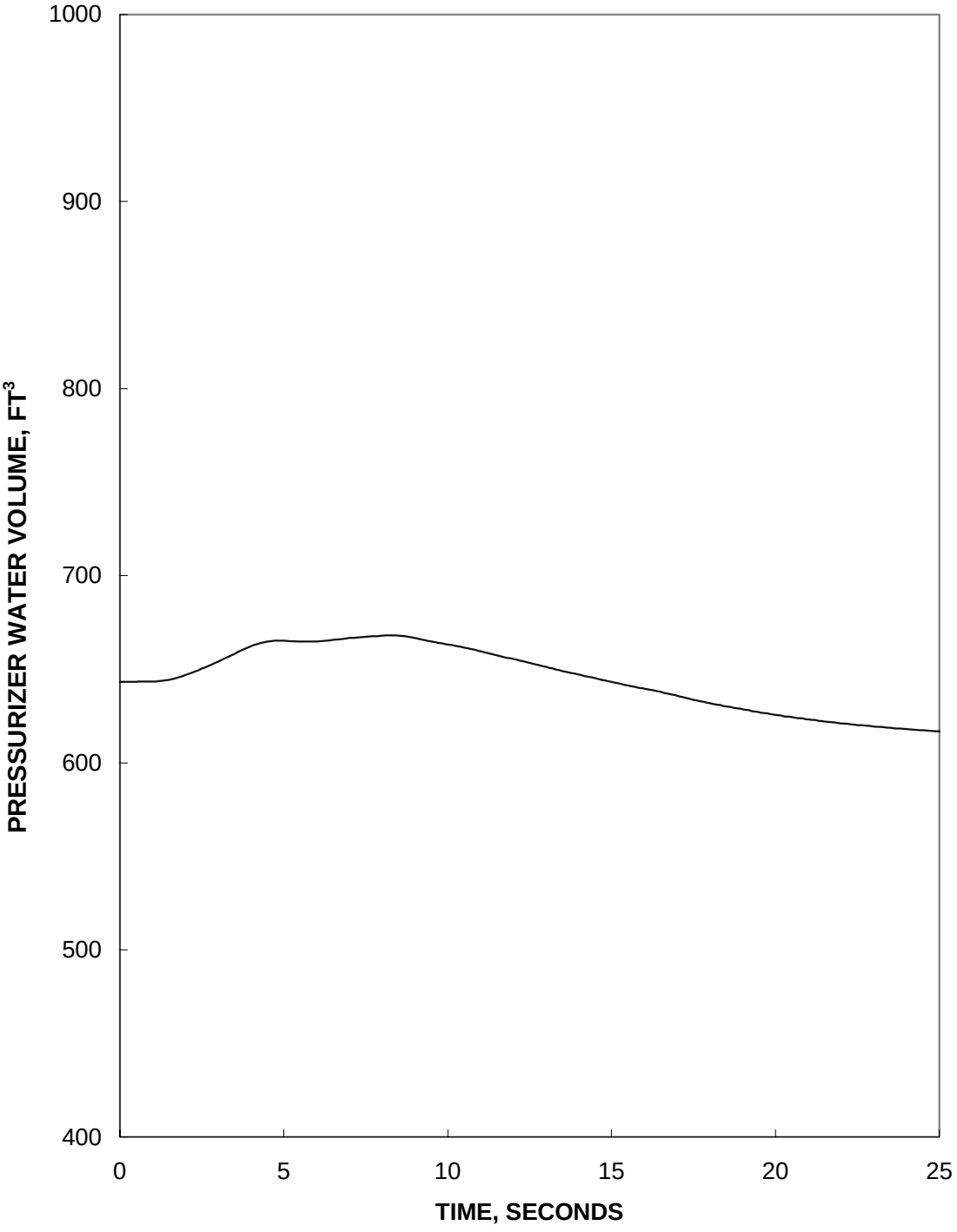

Figure 2.13.3.2.1-8
Total Loss of Forced Reactor Coolant Flow
Pressurizer Liquid Volume vs. Time

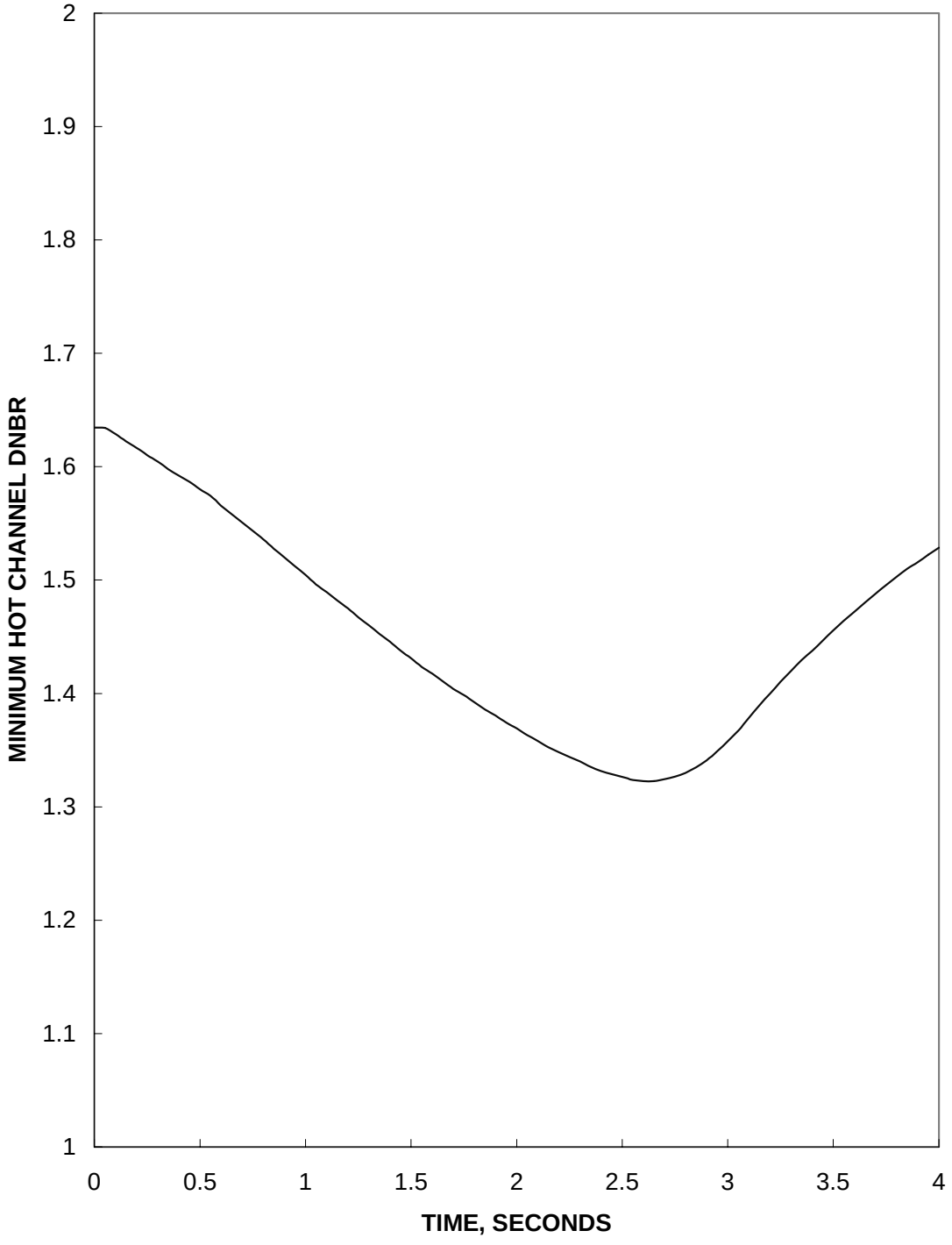

Figure 2.13.3.2.1-9
Total Loss of Forced Reactor Coolant Flow
Minimum Hot Channel DNBR vs. Time

2.13.3.2.2 Partial Loss of Forced Reactor Coolant Flow with Single Active Failure (SAF)

This event is bounded by the total loss of forced coolant flow, Section 2.13.3.2.1.

2.13.3.3 Limiting Faults

2.13.3.3.1 Single Reactor Coolant Pump (RCP) Shaft Seizure/Sheared Shaft

The total loss of forced reactor coolant flow is analyzed for power uprate to evaluate the impact of the following changes:

1. The increase in rated thermal power to 3716 MWt
2. The decrease in core inlet temperature to 533°F
3. The use of the CENTS code rather than the COAST code to generate to flow coastdown curves which are input into the 1-D HERMITE model for fuel failure evaluation

2.13.3.3.1.1 General Description of Event

The RCP shaft seizure and sheared shaft events with concurrent loss of all normal offsite power (LOOP) were reanalyzed for the Waterford 3 EPU. As noted in the FSAR (Reference 2.13-1), Section 15.3.3.1.1, the RCP shaft seizure and sheared shaft events are classified as limiting fault incidents. Re-analysis of both the shaft seizure and sheared shaft events and investigation of the timing of the LOOP indicate that the most limiting scenario for these events remains the RCP sheared shaft with a LOOP initiated concurrent with the time that a reactor trip is generated.

The details of the limiting RCP sheared shaft with LOOP analysis are presented below. Additional discussion for the RCP seized rotor with LOOP event is also present to illustrate the differences between the seized rotor and sheared shaft events.

2.13.3.3.1.2 Acceptance Criteria

As defined in the FSAR Section 15.1.1 (Reference 2.13-1), the specific acceptance criteria for a limiting fault incident are:

- A limiting fault incident should not result in loss of function of any barrier other than the fuel cladding. A limited number of fuel rod cladding perforation is acceptable.
- Offsite radiological consequences must be limited to a small fraction of 10CFR100 guidelines (i.e., 30 rem thyroid, 2.5 rem whole body).

2.13.3.3.1.3 Impact of Changes

The methodology used to analyze this event for Waterford 3 demonstrates more adverse results when initiated at colder core inlet temperature conditions. Thus the change in the low end of the inlet temperature LCO is adverse.

The change in the initial RCS temperature from highest to lowest and the change in RCS flow from lowest to highest did not occur for the power uprate analysis. It reflects a change which occurred previously during the application of the 1-D HERMITE methodology to the sheared shaft/seized rotor for Waterford 3.

Only small differences between the flow coastdown between the CENTS and COAST codes were seen. The new coastdown was used in the HERMITE analysis performed herein.

2.13.3.3.1.4 Analysis Overview

The use of the 1-D HERMITE code to model the response of the core to the sheared shaft/seized rotor allows an analytical credit to be determined for the effect of coolant density changes in the hot channel. To minimize the credit obtained, the initial conditions for the HERMITE simulation are selected to maximize corewide subcooling. Thus the reduction in the core inlet temperature will tend to further minimize this credit and make DNBR more adverse.

COLSS maintains a minimum initial margin to the DNBR SAFDL. A set of initial conditions corresponding to this minimum margin was calculated with the CETOP-D (Reference 2.13-3) computer code. The CENTS code (Reference 2.13-2) is used in lieu of the COAST code (Reference 2.13-6) to determine the flow coastdowns due to the seized rotor/sheared shaft events. Using these coastdowns and the above set of initial conditions, the core average and hot channel response to the seized rotor/sheared shaft event was simulated using the 1-D HERMITE computer program (Reference 2.13-4). Determination of the time of minimum DNBR, as well as an estimate of the transient DNBR values, were calculated using the CETOP-D computer program (Reference 2.13-3). CETOP-D uses the CE-1 CHF correlation. For reload analyses, a more accurate calculation of the minimum DNBR will be performed using the three-pump TORC computer program (Reference 2.13-7). The TORC program also uses the CE-1 CHF correlation. Long-term response of key NSSS parameters to the limiting RCP sheared shaft with LOOP case was simulated using the CENTS code (Reference 2.13-2).

The initiating event is a mechanical failure of a RCP shaft (i.e., rotor). This failure results in either an instantaneous seizure or the shearing of the RCP shaft. Mechanical failure of an RCP shaft only results from a manufacturing defect in the shaft itself. Following the shearing or seizing of the shaft, the core flow rate rapidly decreases to roughly the value that occurs when only 3 RCPs are operating. The reduction in coolant flow rate causes an increase in the average coolant temperature in the core, which may result in some fuel pins experiencing departure from nucleate boiling (DNB) and possibly fuel failure.

For an RCP shaft seizure, a reactor trip on low RCP shaft speed is generated via the Core Protection Calculator System (CPCS) described in Reference 2.13-9. For an RCP sheared shaft event, no CPCS trip is generated since the RCP shaft continues to spin and the CPCS perceives full flow. Instead, a reactor trip is generated for the RCP sheared shaft when the

rapid flow reduction causes the pressure difference (ΔP) across the affected loop steam generator (SG) to drop below the low flow differential pressure trip setpoint.

The reactor trip produces an automatic turbine trip. Following the turbine trip, there is an assumed failure to transfer to offsite power, thus a loss-of-non-emergency-offsite power (LOOP) is experienced. This results in a loss of power (LOOP) to the remaining RCPs, steam bypass valves (SBVs), the PPCS and the PLCS. The main impact is that the remaining 3 RCPs begin coastdown, resulting in further loss of flow at a time in which the core is already experiencing possible DNB. This makes the immediate DNB situation more adverse.

This evaluation conservatively analyzed LOOP occurring coincident with turbine trip. DNBR degradation is terminated when the mitigating effects of scram CEA insertion dominate the flow coastdown resulting from the combined effects of the initiating seized rotor/sheared shaft event and the subsequent LOOP.

Table 2.13.3.3.1-1 contains the initial conditions and assumptions used for RCP seized rotor/sheared shaft with LOOP event.

2.13.3.3.1.5 Radiological Consequences

The radiological consequences for the RCP seized rotor/sheared shaft were calculated assuming that the radioisotopes in the gas gap of the pins that experience DNB was immediately mixed with the RCS for release. Releases for site boundary doses were calculated accounting for the carry over of activity to the secondary system via SG tube leakage paths.

The allowed fuel failure limit for the RCP seized rotor/sheared shaft was back-calculated to determine the extent of fuel failure which would result in the regulatory limit for the event. Cycle-specific fuel failure evaluations for power uprate cores will be performed to ensure that this fuel failure limit will not be exceeded. For the RCP seized rotor/sheared shaft, the fuel failure limit to meet the SRP Guidance of a small fraction of 10CFR100 was determined to be 8.0% of the fuel pins.

The radiological consequences resulting from these fuel failure results are:

	2-Hour EAB	**8-Hour LPZ**
Thyroid	< 30 rem	< 30 rem
Whole Body	< 25 rem	< 25 rem

2.13.3.3.1.6 Results

The combined impact of a more adverse flow coastdown and a later time to reach the credited RPS trip condition results in the RCP sheared shaft event being more limiting than the RCP seized rotor event. LOOP occurring coincident with turbine trip was determined to be more limiting that an LOOP occurring shortly after turbine trip. Hence, the most limiting event for this analysis (i.e., resulting in more adverse DNBR degradation) is the RCP sheared shaft event with LOOP at time of trip. A sequence of events for this limiting case is shown in Table 2.13.3.3.1-2.

Based on the HERMITE transient simulation results, the DNBR response is calculated using CETOP-D. Since the HERMITE code only models the average and hot core channels, the dynamic behavior of NSSS parameters due to an RCP sheared shaft event with LOOP at time of trip is modeled using the CENTS code (Reference 2.13-2). Typical NSSS responses, including DNBR vs. time, are shown in Figures 2.13.3.3.1-1 through 2.13.3.3.1-9.

Table 2.13.3.3.1-1
RCP Seized/Sheared Shaft Assumption Table

Parameter	Power Uprate Assumption	Current Power Level Assumption
Initial Core Power, MWt	3735	3478
Core Inlet Temperature, ^{o}F	533	560
Pressurizer Pressure, psia	2098	2300
RCS Flowrate, 10^6 lbm/hr	170.2	141.7
Pressurizer Level, %	44	---
SG Pressure, psia	733	---
SG Level, % NR	68	---
MTC, $x10^{-4}$ $\Delta\rho$/°F	-0.20	+0.5
Doppler Coefficient Multiplier	0.85	0.85
Kinetics	Maximum β	Maximum β
CEA Worth at Trip, %$\Delta\rho$	-5.0	-8.55

Table 2.13.3.3.1-2
Sequence of Events for the RCP Sheared Shaft Event with a LOOP at Time of Trip

EPU Time (sec)	Current Power Level Time (sec)	Event	3716 MWt EPU Setpoint/Value	Current Power Level Setpoint/Value
0.0	0.0	Single RCP sheared shaft	---	---
0.80	0.874	Low RCS flow trip condition reached	0.6 of initial	0.6 of initial
1.50	1.574	Low RCS flow trip signal generated	---	---
1.50	1.574	Turbine generator trip; LOOP occurs	---	---
2.10	2.174	CEAs begin to drop into core	---	---
3.25	2.9	Minimum DNBR	1.0698	0.86
8.45	6.9*	RCS maximum pressure	2422	2490
113.6	6.4*	Unaffected loop SG safety valves open	1117	1100
113.6	6.7*	Affected loop SG safety valves open	1117	1100
113.6	11.3*	Maximum SG pressure	1117	1127
1800	1800	ADVs opened by operator to initiate plant cooldown	---	---
28,800	---	SDC initiated	---	---

Notes:

* These are typical values that would occur for the RCP sheared shaft with LOOP event at current power conditions. The event was only analyzed for the time of interest (i.e., minimum DNBR within 5 seconds after event initiation) in the current power level analysis of record. Thus, beyond this point, typical values are given.

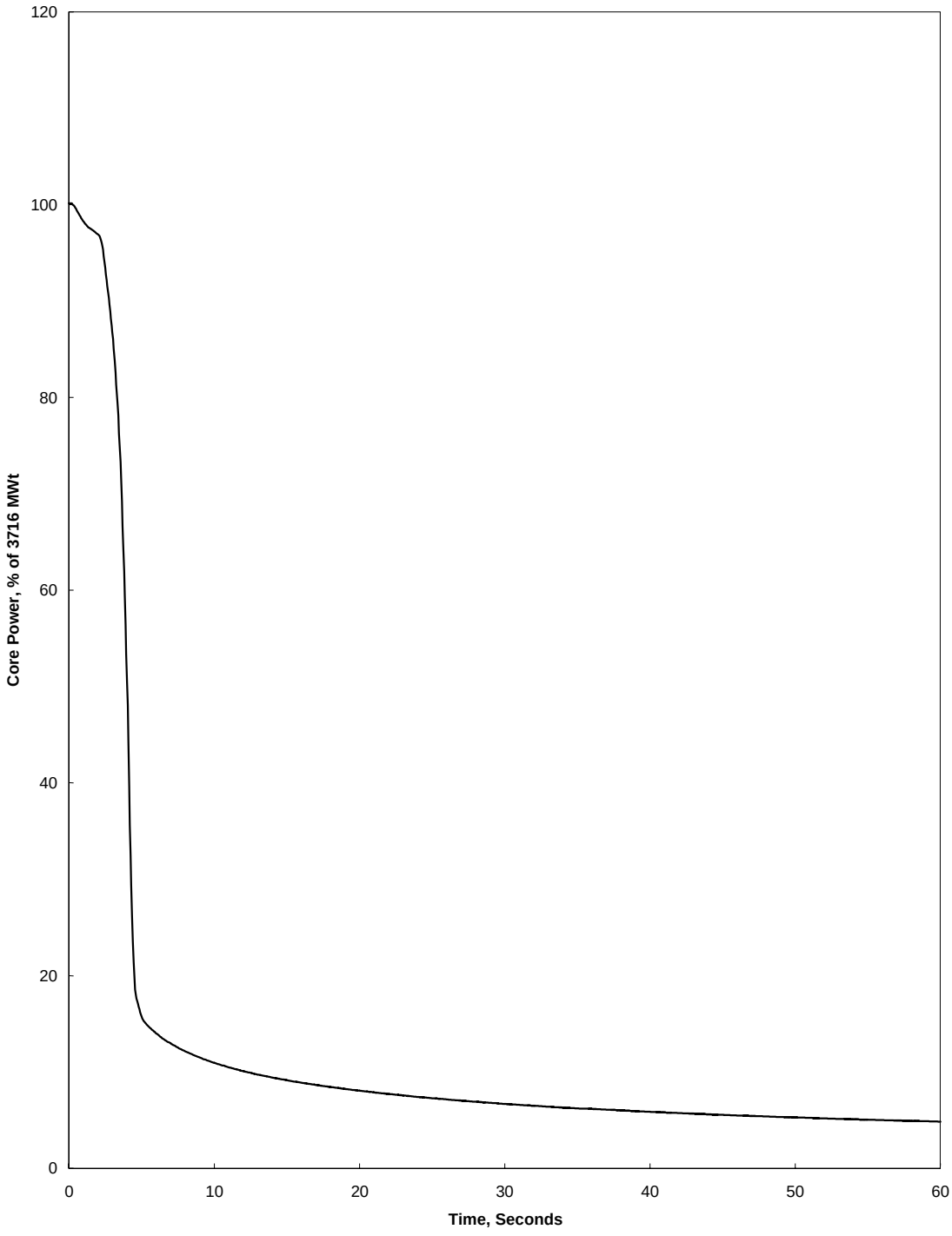

Figure 2.13.3.3.1-1
Sheared Shaft with LOOP
Core Power vs. Time

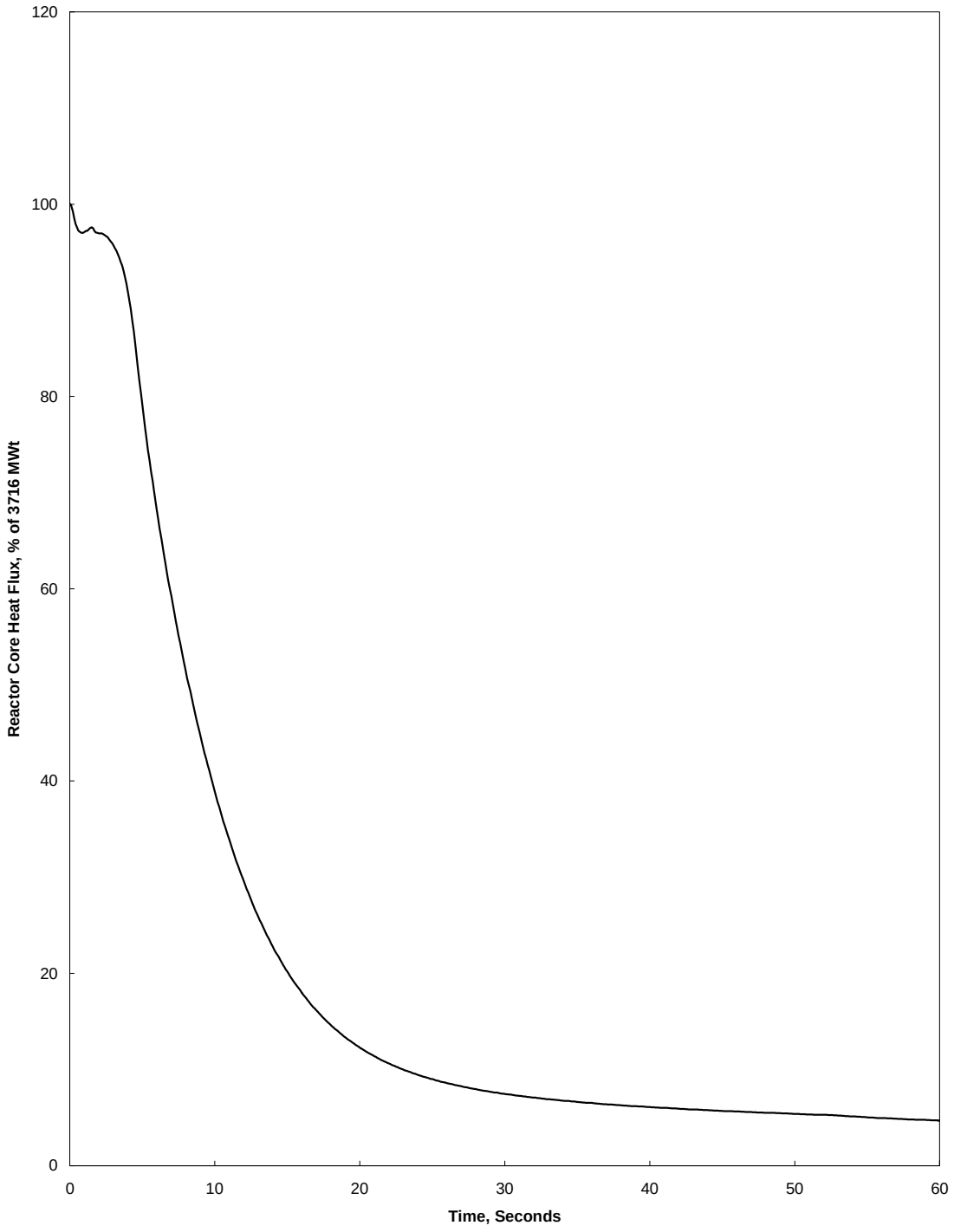

Figure 2.13.3.3.1-2
Sheared Shaft with LOOP
Core Heat Flux vs. Time

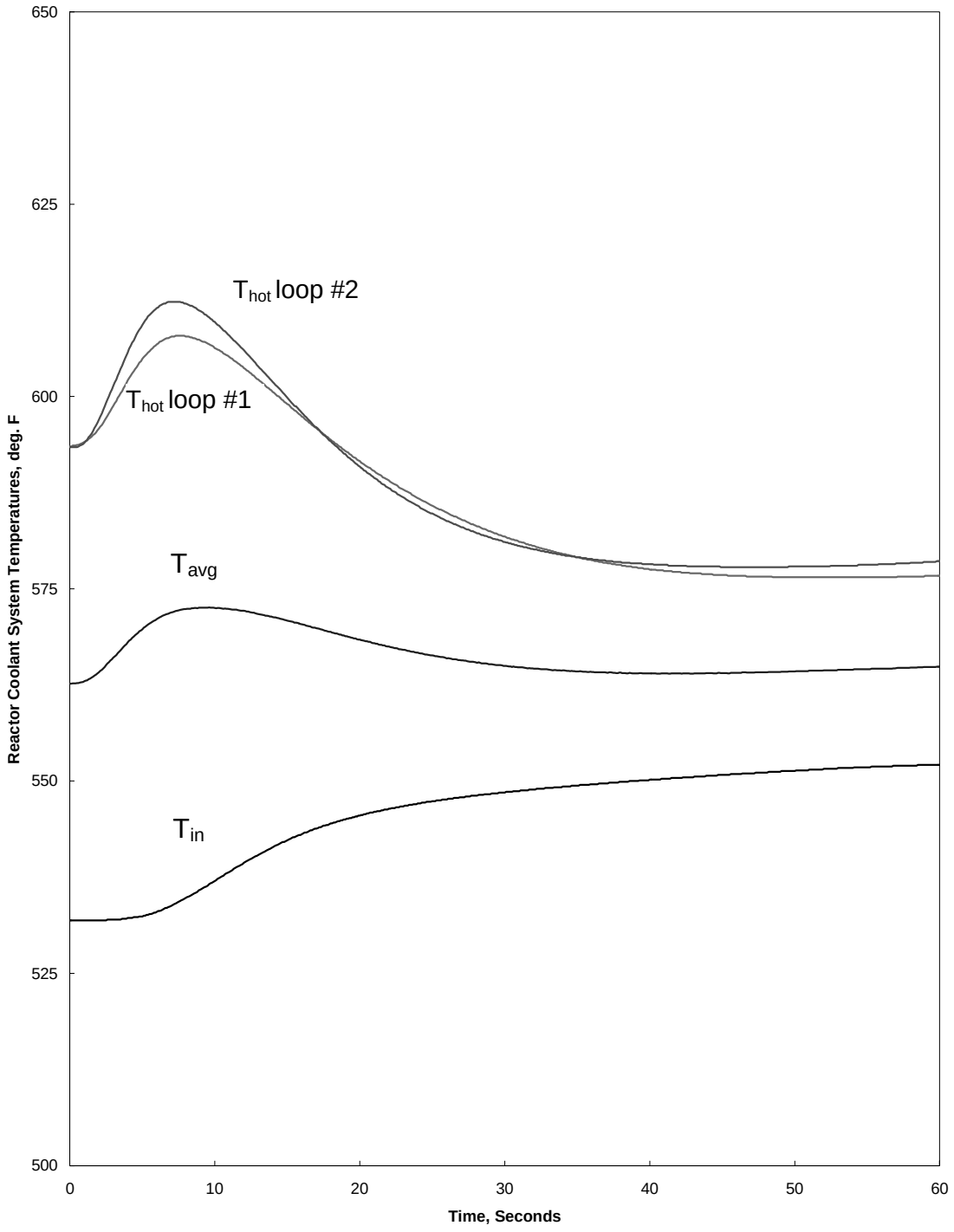

Figure 2.13.3.3.1-3
Sheared Shaft with LOOP RCS Temperatures vs. Time

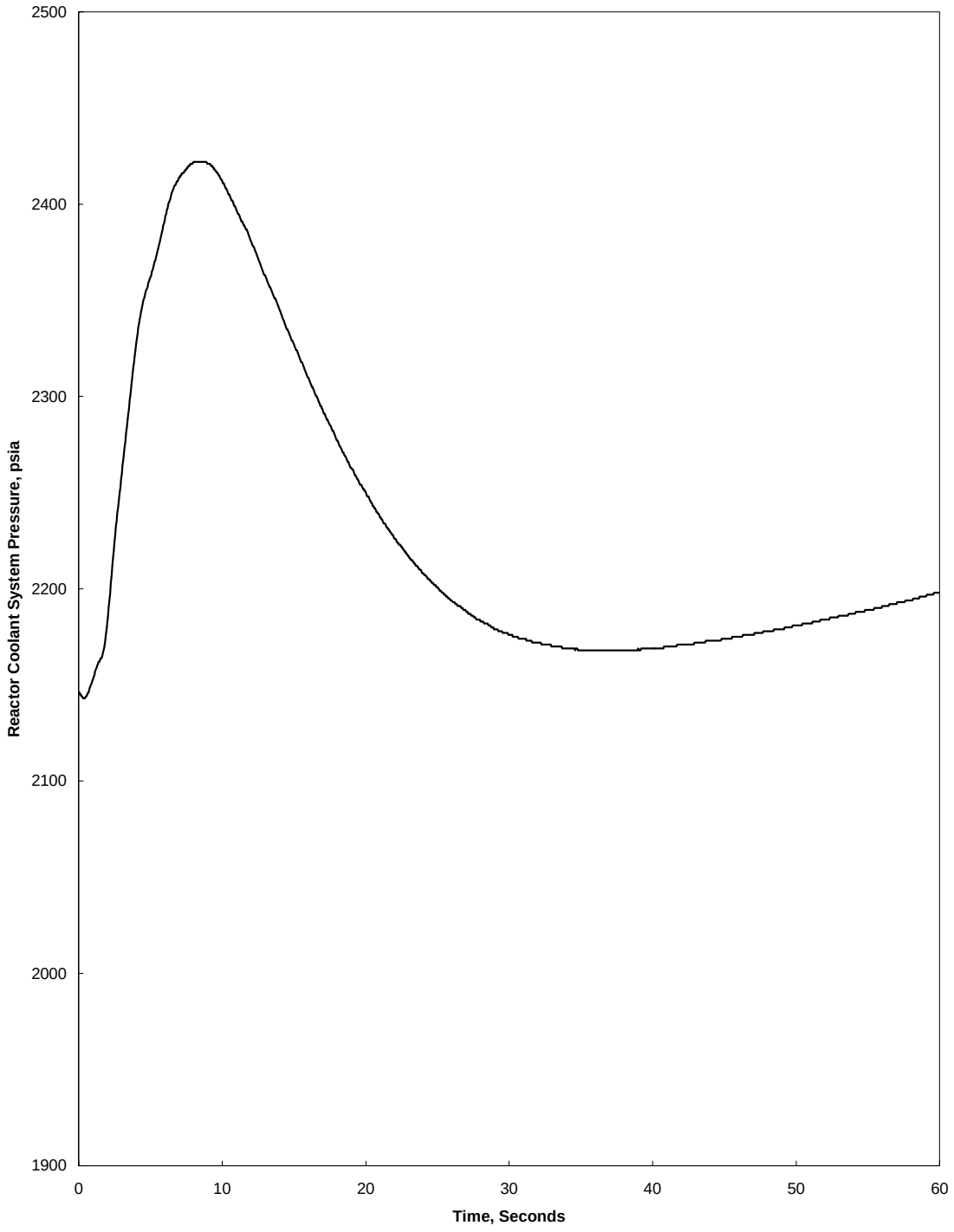

Figure 2.13.3.3.1-4
Sheared Shaft with LOOP RCS Pressure vs. Time

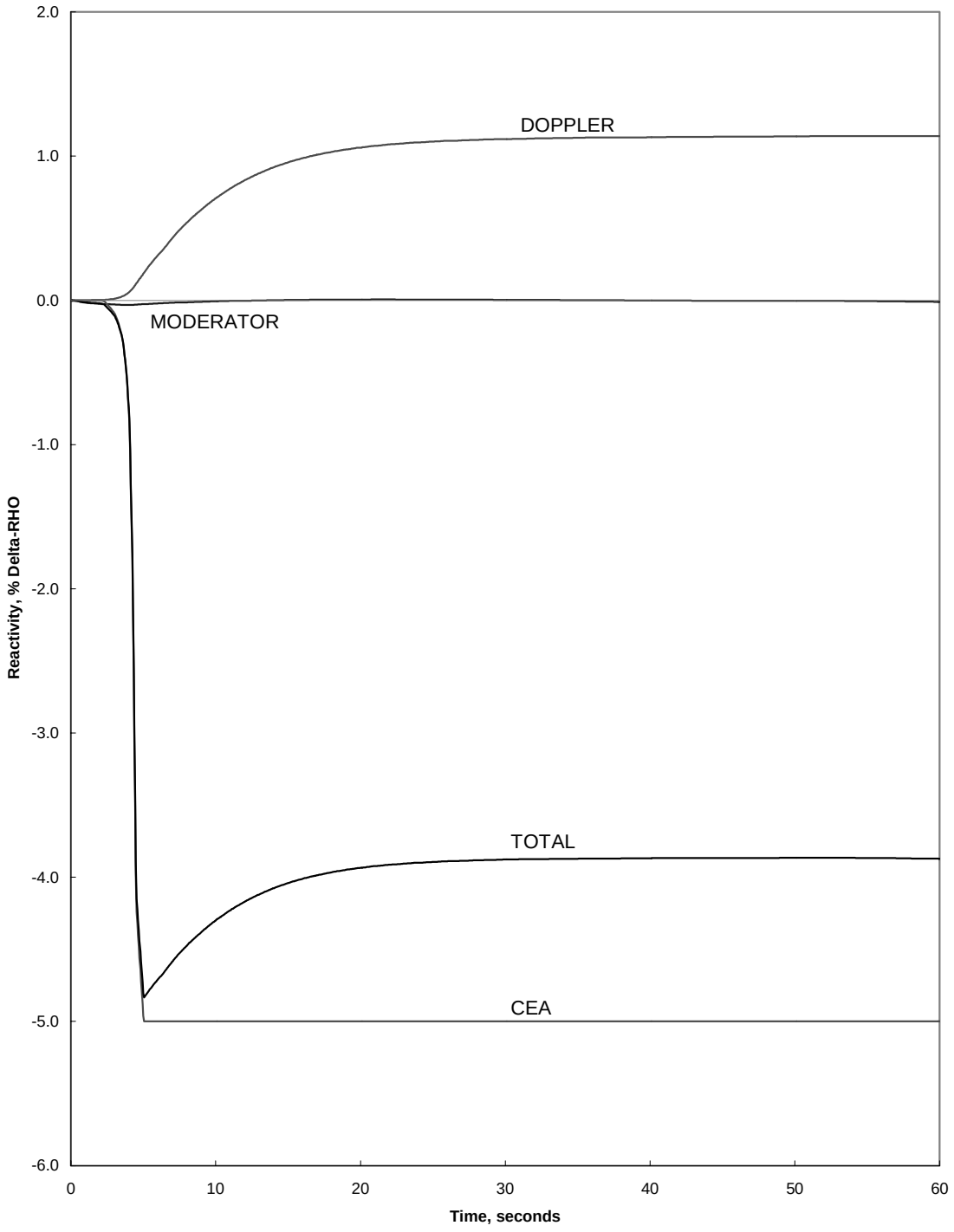

Figure 2.13.3.3.1-5
Sheared Shaft with LOOP Reactivity vs. Time

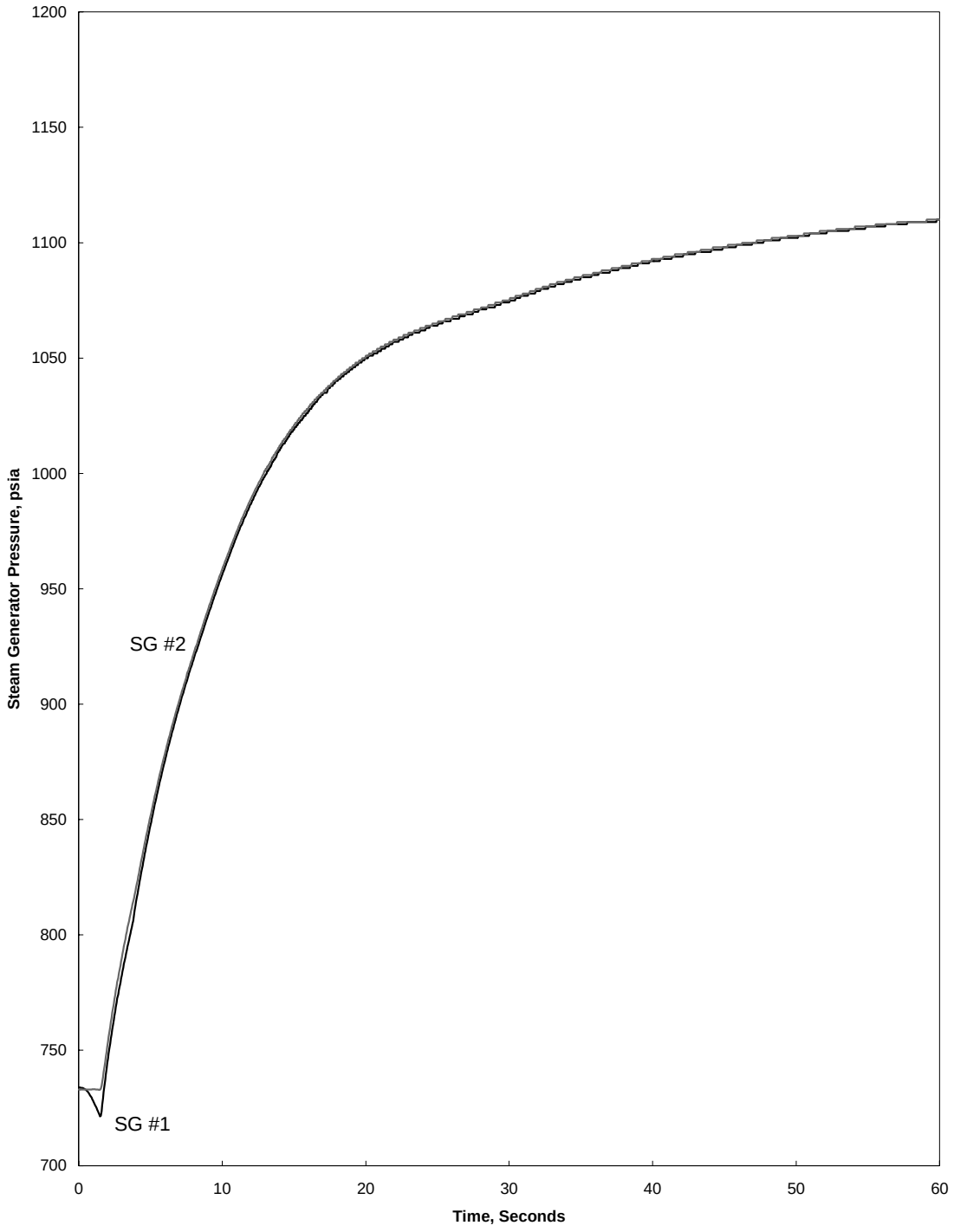

Figure 2.13.3.3.1-6
Sheared Shaft with LOOP SG Pressure vs. Time

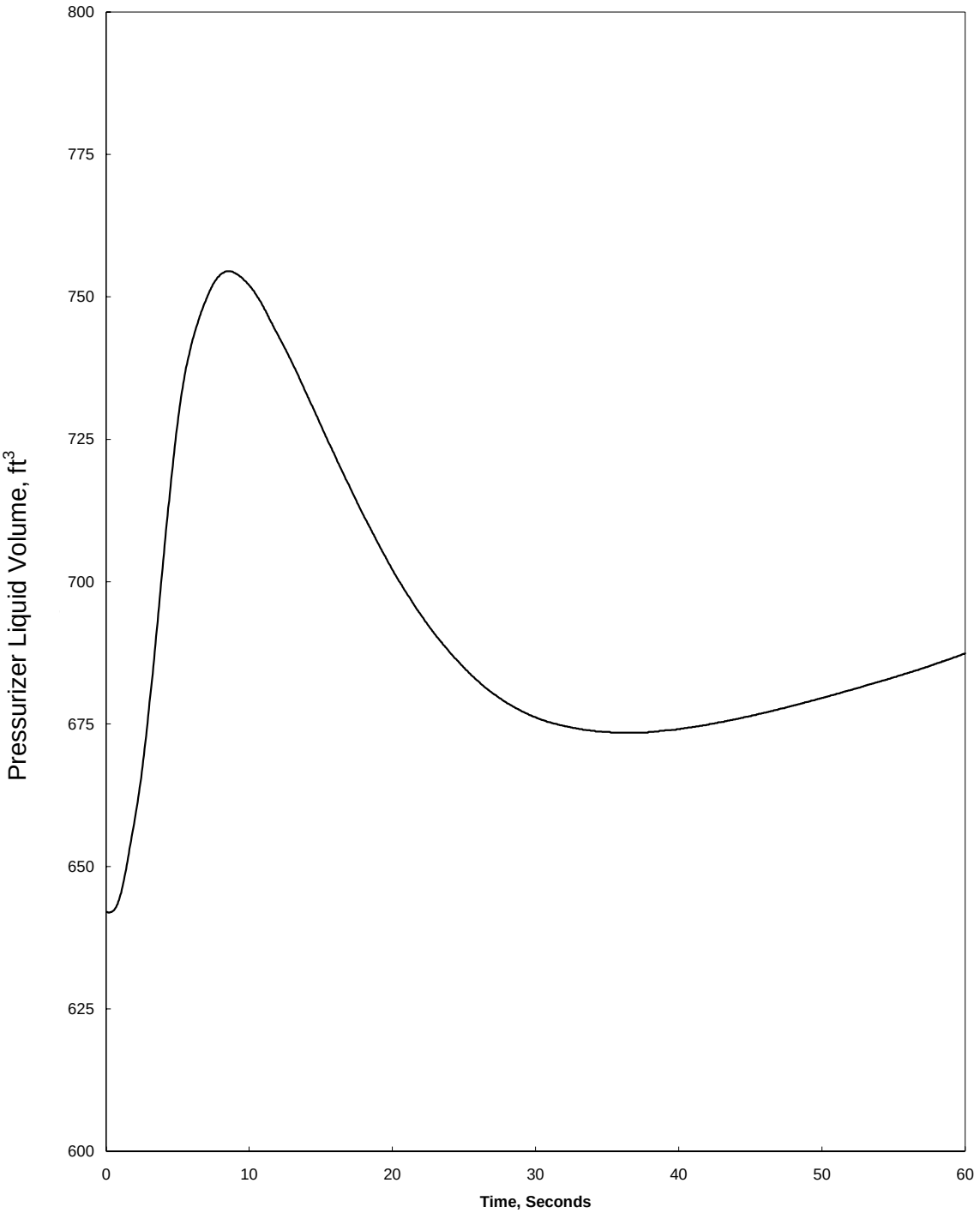

Figure 2.13.3.3.1-7
Sheared Shaft with LOOP Pressurizer Liquid Volume vs. Time

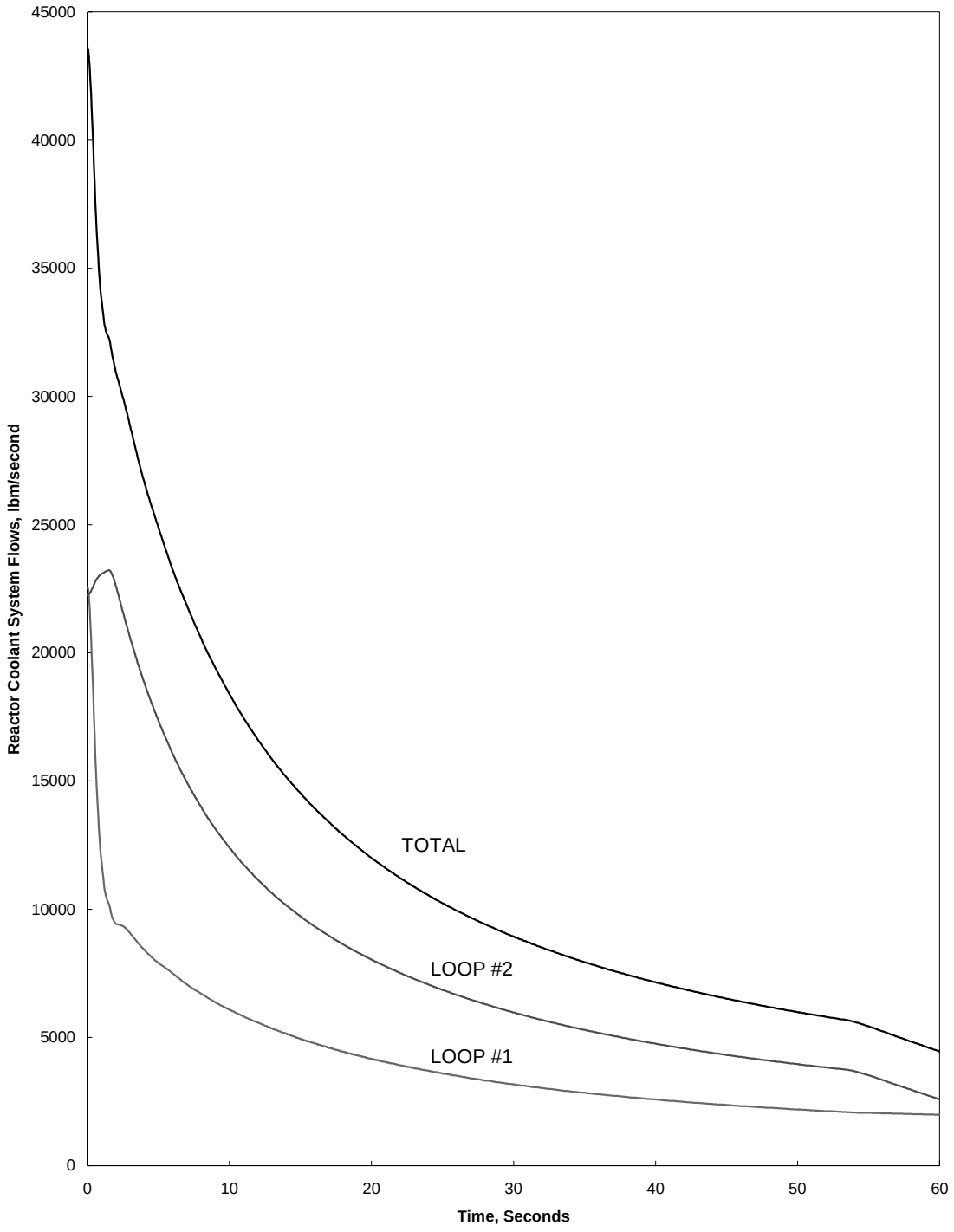

Figure 2.13.3.3.1-8
Sheared Shaft with LOOP RCS Flows vs. Time

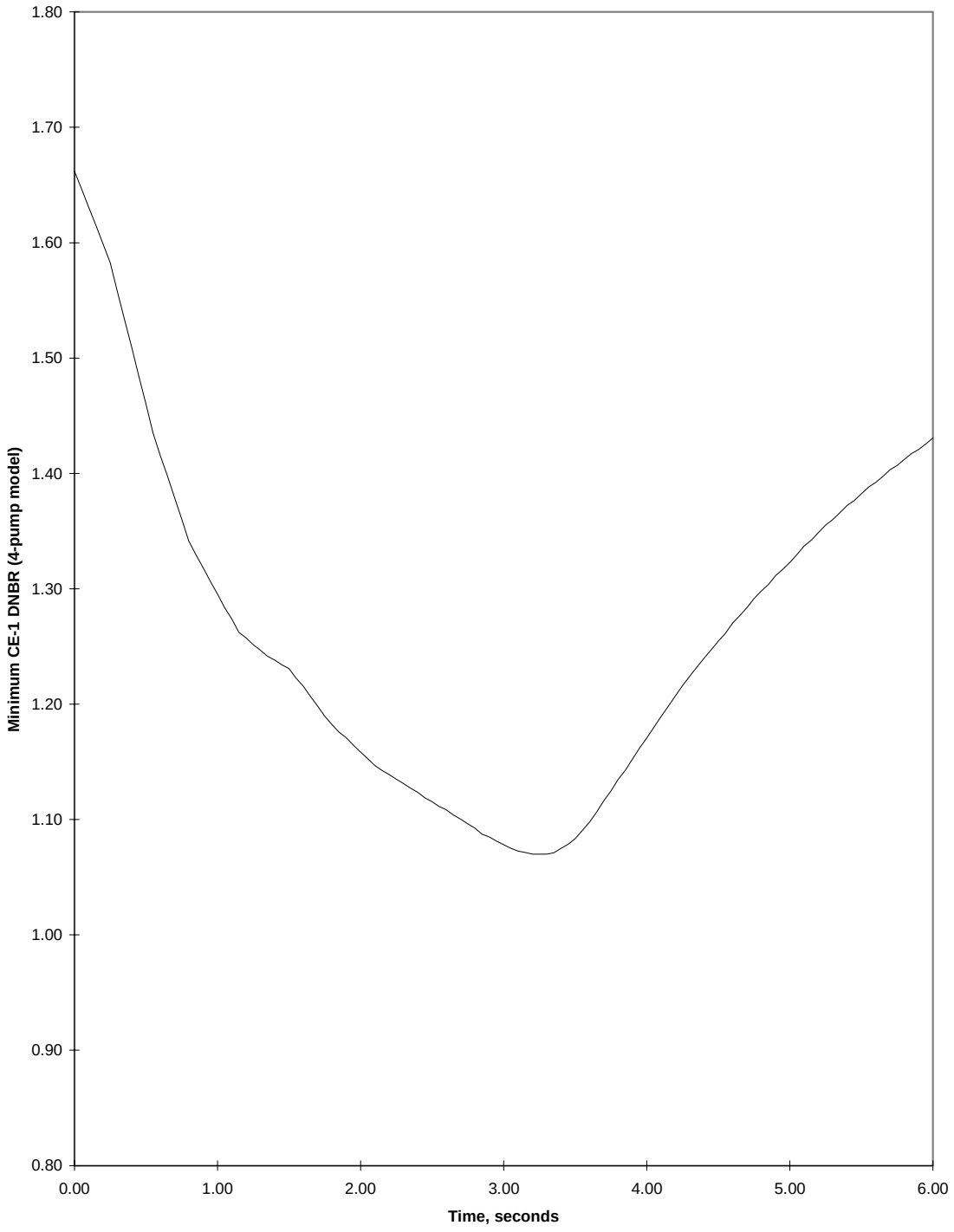

Figure 2.13.3.3.1-9
Sheared Shaft with LOOP Minimum Hot Channel DNBR vs. Time

2.13.4 Reactivity and Power Distribution Anomalies

2.13.4.1 Moderate Frequency Events

2.13.4.1.1 Uncontrolled CEA Withdrawal from Subcritical

The objective of the uncontrolled CEA withdrawal (CEAW) from subcritical conditions analysis is to document the impact of the increase in rated power from 3441 MWt to 3716 MWt, the impact of using CENTS instead of CESEC, and the impact of starting at 10% subcritical.

The impact of the above changes results in no violation of the specified acceptable fuel design limits (SAFDLs).

2.13.4.1.1.1 General Description of the Event

The withdrawal of CEAs from subcritical conditions adds positive reactivity to the reactor core, causing both the core power level and the core heat flux to increase. Since the transient is initiated at low power levels, the normal reactor feedback mechanisms (moderator feedback and Doppler feedback) do not occur until power generation in the core is large enough to cause changes in the fuel and moderator temperatures. The reactor protection system (RPS) is designed to prevent such a transient from resulting in a minimum DNBR less than 1.26 by initiating a high logarithmic power level reactor trip. The high pressurizer pressure trip (HPPT) is credited as a secondary trip for the protection of the reactor coolant pressure boundary.

The uncontrolled CEA bank withdrawal may be the result of a single failure in the control element drive mechanism (CEDM) or the Control Element Drive Mechanism Control System (CEDMCS). An uncontrolled CEA withdrawal may also be the result of operator error.

Startup of the reactor involves a planned sequence of events during which certain CEA groups are withdrawn at a controlled rate and in a prescribed order to increase the core reactivity gradually from subcritical to critical. To ensure that rapid shutdown by CEAs is always possible when the reactor is critical or near critical, Technical Specifications require that specified groups of CEAs be withdrawn before reaching criticality. These groups of assemblies combined with soluble boron concentration will have a total negative reactivity worth that is sufficient to provide at least the shutdown margin required by the technical specifications at the hot standby condition, with the most reactive CEA assumed to remain in the fully withdrawn position.

2.13.4.1.1.2 Purpose of Analysis and Acceptance Criteria

The purpose of the analysis was to determine that the fuel SAFDLs were not violated.

The following criteria apply to the subcritical CEAW event:

- DNBR > 1.26
- Fuel temperature < fuel melt temperature limit

- Radiological dose ≤ small fraction of 10CFR100 limits
- RCS pressures ≤ 110% of design.

The CEA bank withdrawal from subcritical event is described in Chapter 15.4.1.1 of the SAR (Reference 2.13-1).

2.13.4.1.1.3 Impact of Changes

The increase in rated power could result in a small degradation of the calculated thermal margin since the high logarithmic power level trip setpoint is based on the rated power.

This event is now analyzed with the CENTS code versus the CESEC code (Reference 2.13-2). The CENTS code is used in this analysis in exactly the same manner as CESEC was in the current analysis. In this case the substitution of one code for the other introduces no significant changes.

2.13.4.1.1.4 Analysis Overview

This analysis utilized the CENTS (Reference 2.13-2) computer code for the simulation of the transient. The minimum DNBR evaluation was determined using the CETOP code (Reference 2.13-3).

The reactivity addition rate used was consistent with the maximum addition rate of $1.75 \cdot 10^{-4}$ $\Delta\rho$/s expected for bank withdrawals near critical conditions. Only bank withdrawals that resulted in critical conditions were considered for this event. Procedural controls on CEA bank withdrawal sequences limited the potential inadvertent bank withdrawal that could result in critical core condition and ensured that greater than critical boron concentration are maintained whenever the CEDMCS are energized.

Input parameters from Table 2.13.4.1.1-1 and the core physics data from Section 2.13.0.2 of this report have been incorporated in this analysis with the following clarifications:

- The least negative Doppler was assumed.
- A minimum delayed neutron fraction and neutron lifetime consistent with those defined in Section 2.13.0.2 were assumed.
- A CEA coil decay time of 0.6 seconds was assumed followed by negative reactivity insertion proportional to the CEA position post trip. A stuck rod was assumed.
- A high logarithmic power level trip setpoint of 4.4% of rated power and a response time of 0.4 seconds were assumed in the analysis. This timing is a conservative assumption with respect to the CPC delay times discussed in Section 2.13.0.3 and nuclear instrumentation response times.
- An initial power fraction of 1×10^{-8} % of rated thermal power was assumed.
- A source strength of 1×10^{-11} of rated thermal power was assumed.

2.13.4.1.1.5 Radiological Consequences

No SAFDL violation occurs during the subcritical CEAW event. Source terms are, therefore, limited to the initial primary and secondary limits on coolant activity in the Technical Specifications. Doses for this event are bounded by the IOSGADV with LOOP event in Section 2.13.1.2.4.5. Both events have the same criteria (small fraction of 10CFR100 guidelines), and the IOSGADV with LOOP event radiological dose assumptions are conservative for the subcritical CEAW event.

2.13.4.1.1.6 Results

A subcritical CEA bank withdrawal results in a rapid core power increase. As core power increases, both RCS temperatures and pressures also increase. The action of the high logarithmic power level trip terminates the transient.

The current analysis used an initial K_{eff} of 0.99. The 3716-MWt power uprate analysis used a K_{eff} of 0.91. Using a smaller K_{eff} resulted in much later trip time.

The NSSS and RPS responses to a subcritical CEA bank withdrawal event are shown in Table 2.13.4.1.1-2 and in Figures 2.13.4.1.1-1 through 2.13.4.1.1-8.

For the limiting subcritical CEA bank withdrawal event, a deposited energy analysis shows that peak fuel temperature remains below the fuel melting temperature limit. The peak heat flux resulted in a minimum DNBR no less than 1.26. The peak RCS pressure produced by this event is well below 110% of the design limit.

Table 2.13.4.1.1-1
Assumptions for the Uncontrolled CEA Withdrawal from Subcritical Conditions

Parameter	3716 MWt Power Uprate Assumption	Current Power Level Assumption
Initial Core Power, Fraction	$1x10^{-10}$	$1.4x10^{-8}$
Core Inlet Temperature, F	552	551
RCS Flowrate, $x10^6$ lbm/hr	148	148
Pressurizer Pressure, psia	2090	2000
SG Pressure, psia	1056	---
MTC, 10^{-4} $\Delta\rho$/°F	+0.5	+0.5
Doppler coefficient multiplier	0.85	0.85
CEA Reactivity Addition Rate, 10^{-4} $\Delta\rho$/sec	1.75	1.75
CEA Worth on trip, %$\Delta\rho$	-5.25	-4.0
One Pin Radial Peaking Factor, with Uncertainty	4.15	4.36

Table 2.13.4.1.1-2
Sequence of Events for the Uncontrolled CEA Withdrawal from Subcritical Conditions

3716 MWt EPU Time (sec)	Current Power Level Time (sec)	Event	3716 MWt EPU Setpoint/Value	Current Power Level Setpoint/Value
0.0	0.0	Initiation of CEA bank withdrawal	---	---
571.5	45.3	Reactor reaches criticality	---	---
593.0	70.9	High logarithmic power level trip condition, % of rated thermal power	4.4 %	4.4%
593.4	71.4	Trip breakers open, and rod withdrawal stops	---	---
594.0	72.0	CEAs begin to drop	---	---
594.0	72.0	Maximum core power, % of rated thermal power	58.9	86
594.15	72.1	Maximum core heat flux, % of rated thermal power	17.3	29
594.15	72.2	Minimum CE-1 DNBR	≥ 1.26	≥ 1.26

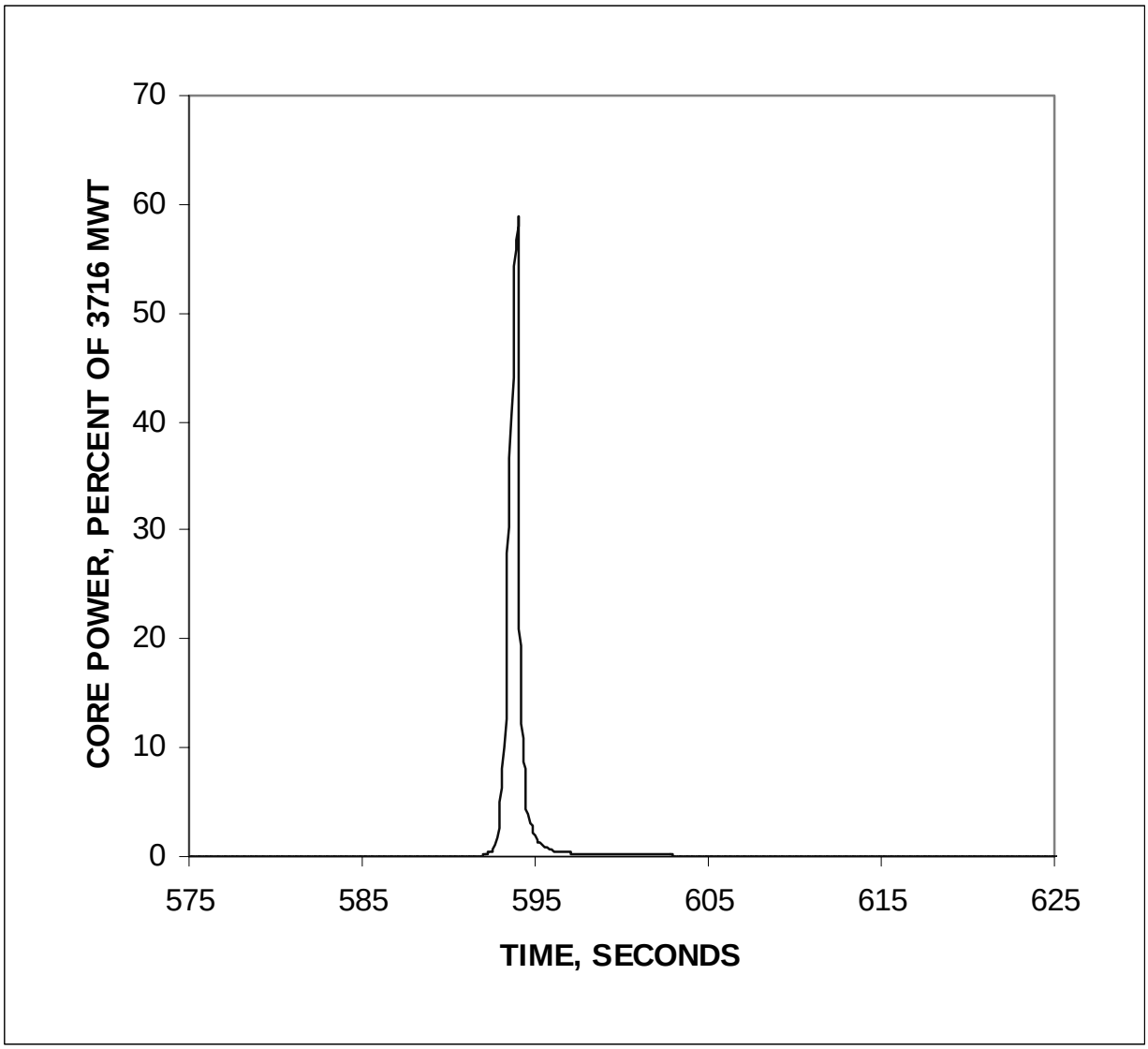

Figure 2.13.4.1.1-1
CEAW from Subcritical
Core Power vs. Time

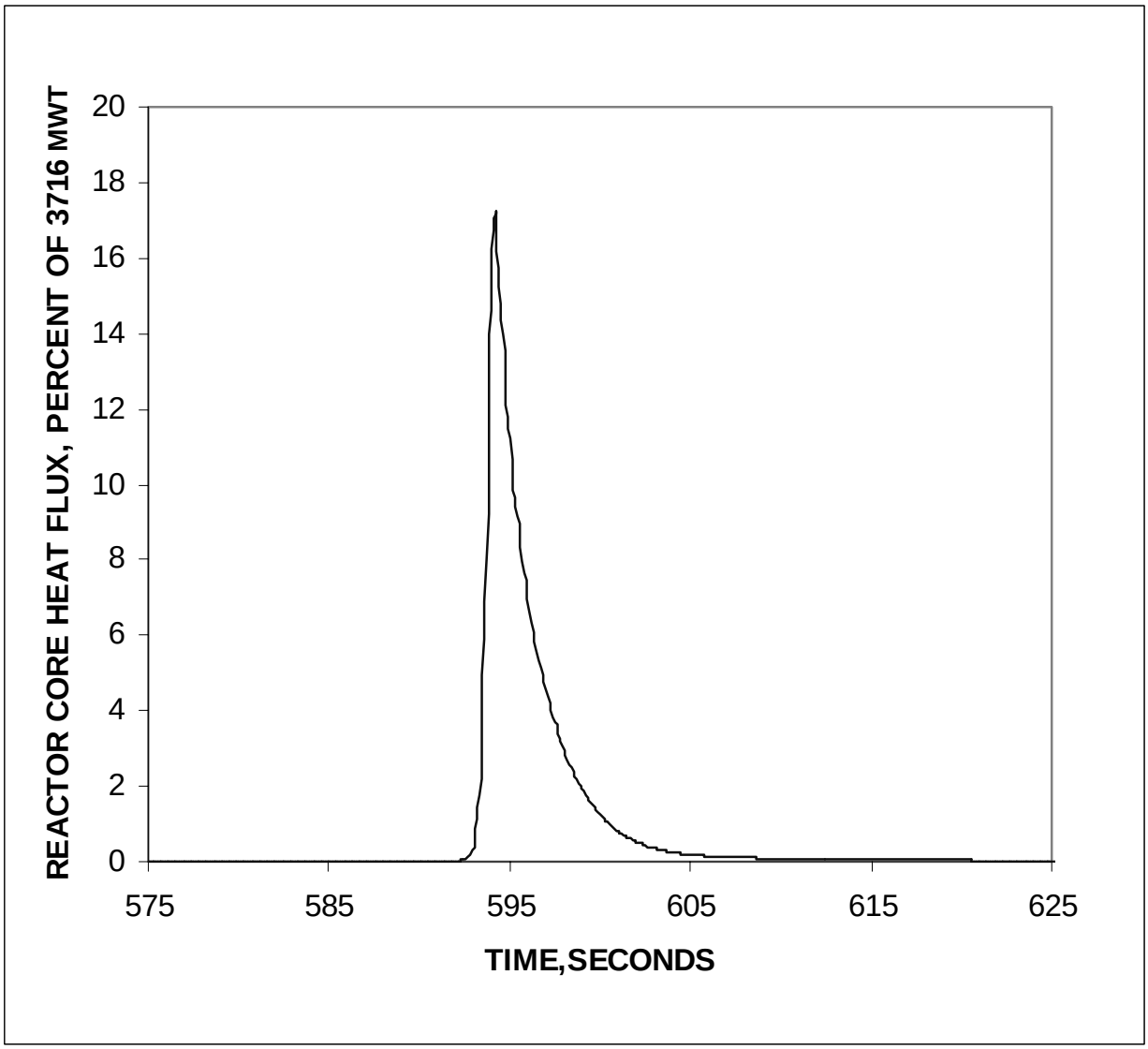

Figure 2.13.4.1.1-2
CEAW from Subcritical
Core Heat Flux vs. Time

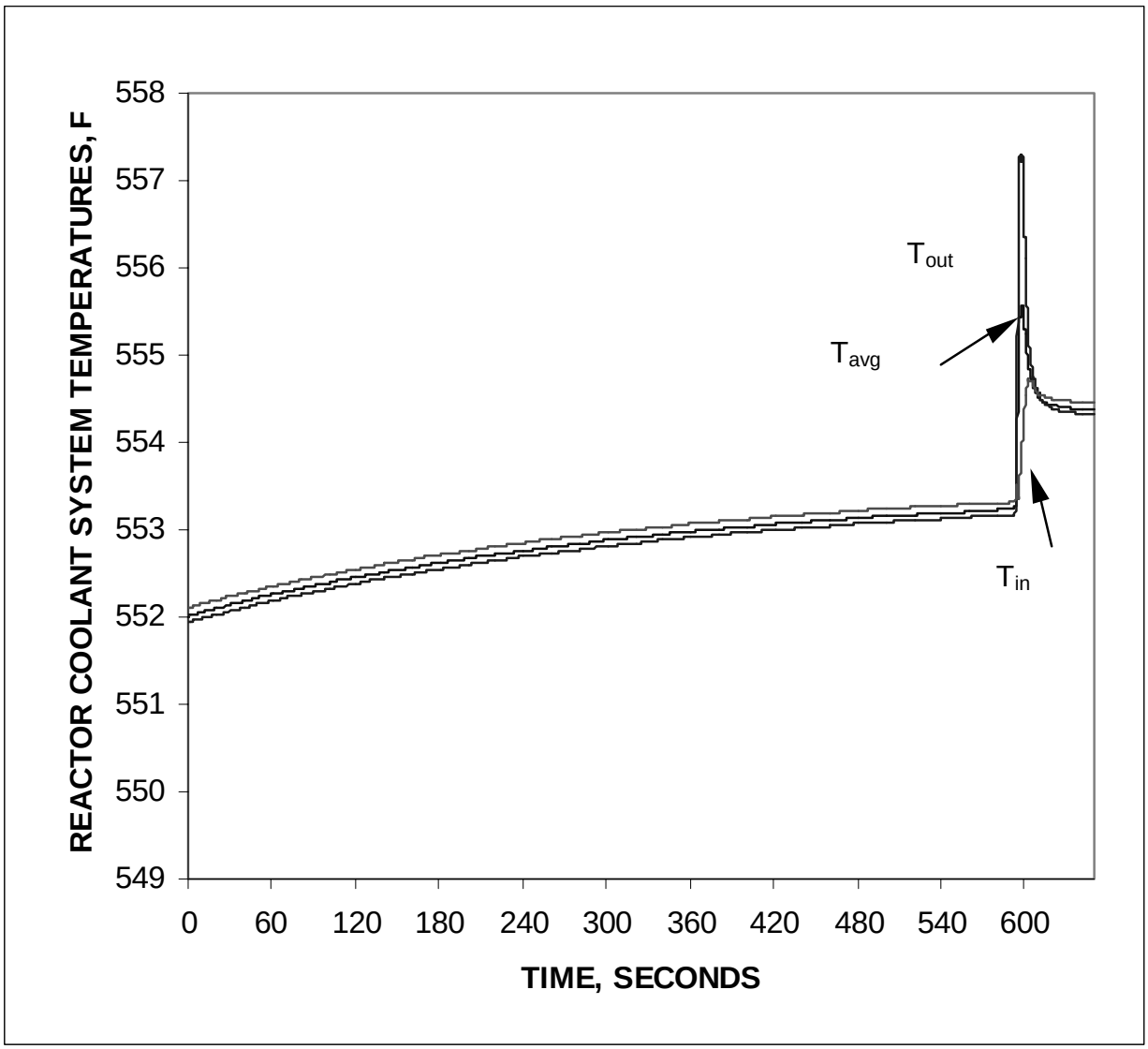

Figure 2.13.4.1.1-3
CEAW from Subcritical
RCS Temperatures vs. Time

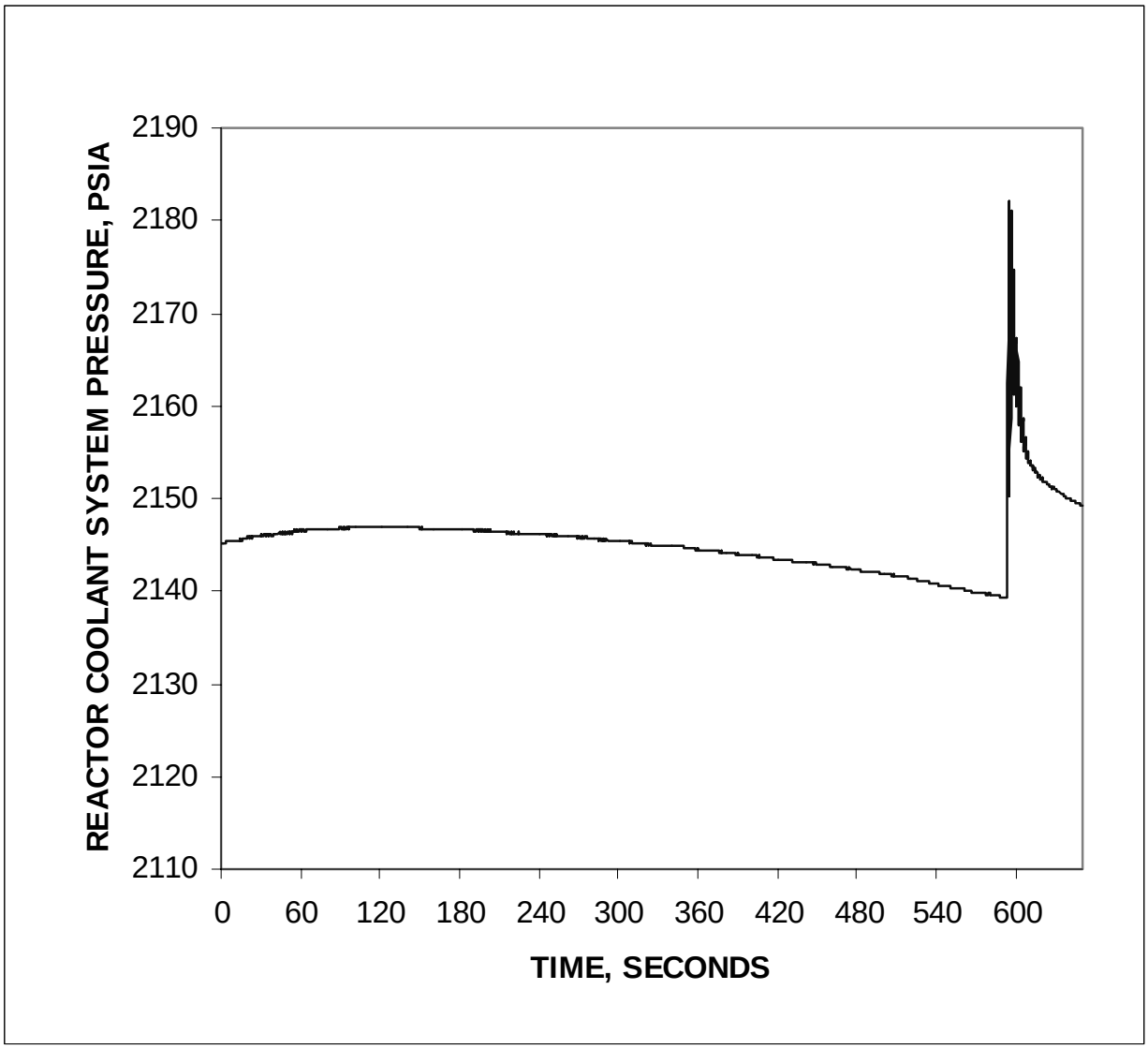

Figure 2.13.4.1.1-4
CEAW from Subcritical
RCS Pressure vs. Time

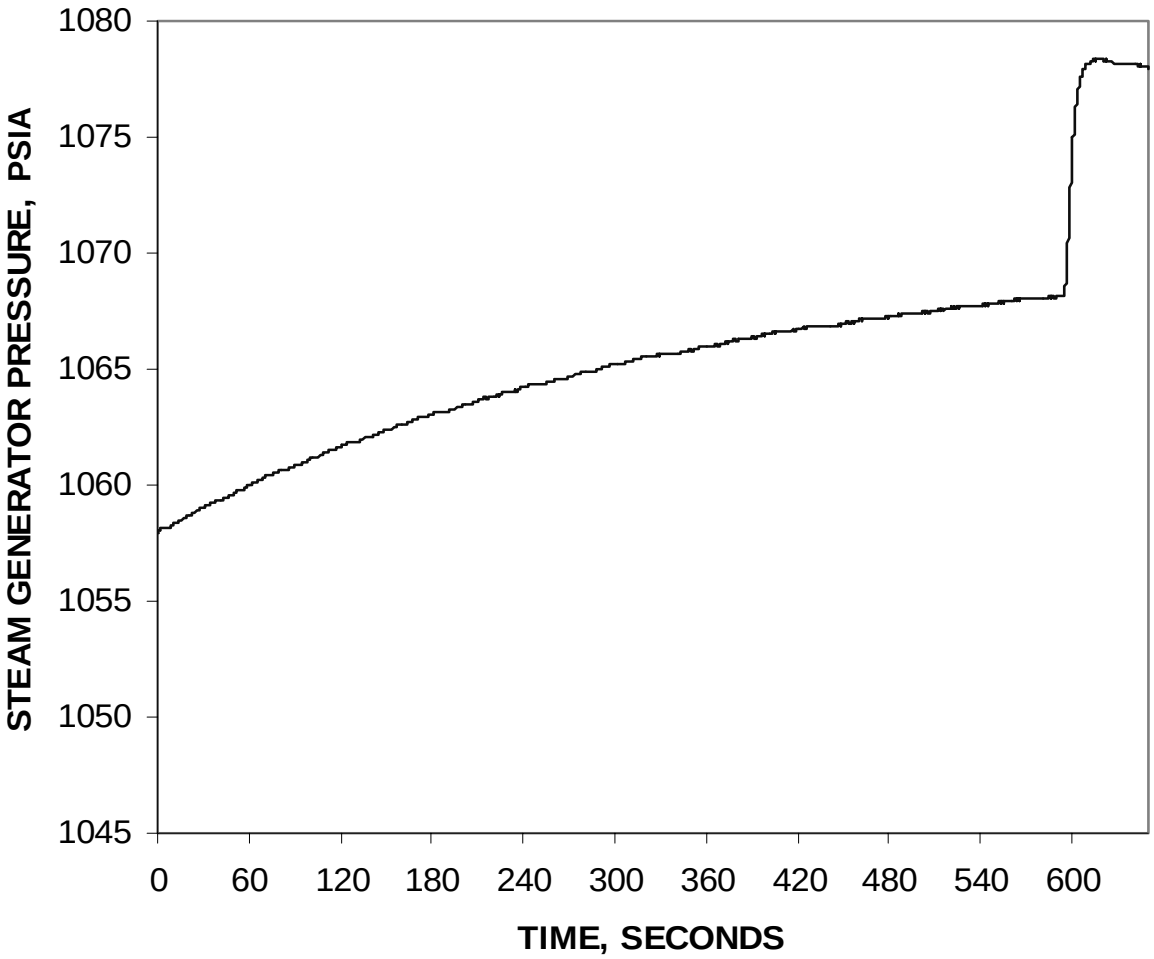

Figure 2.13.4.1.1-5
CEAW from Subcritical
SG Pressure vs. Time

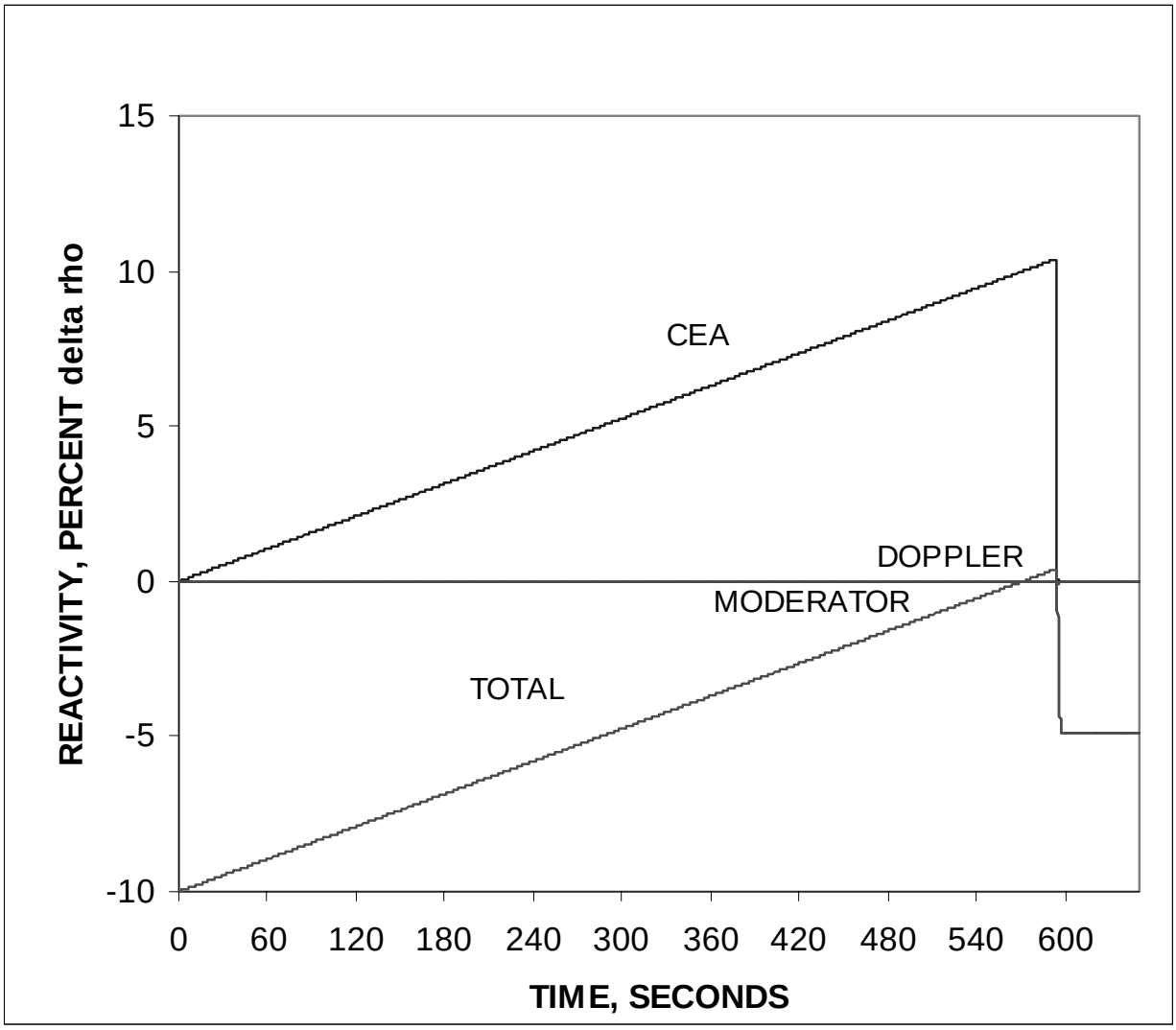

Figure 2.13.4.1.1-6
CEAW from Subcritical
Reactivity vs. Time

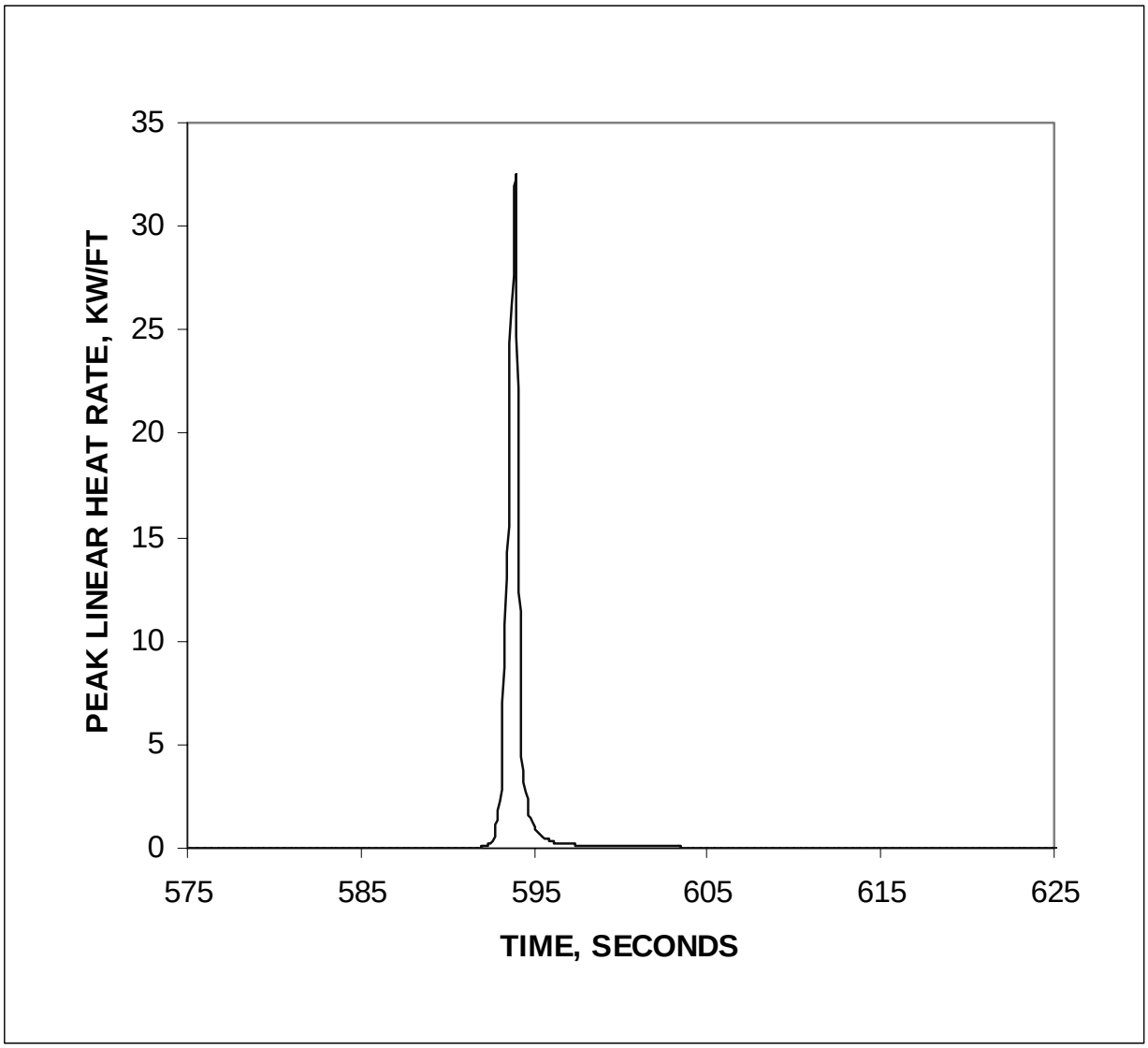

Figure 2.13.4.1.1-7
CEAW from Subcritical
Peak LHR vs. Time

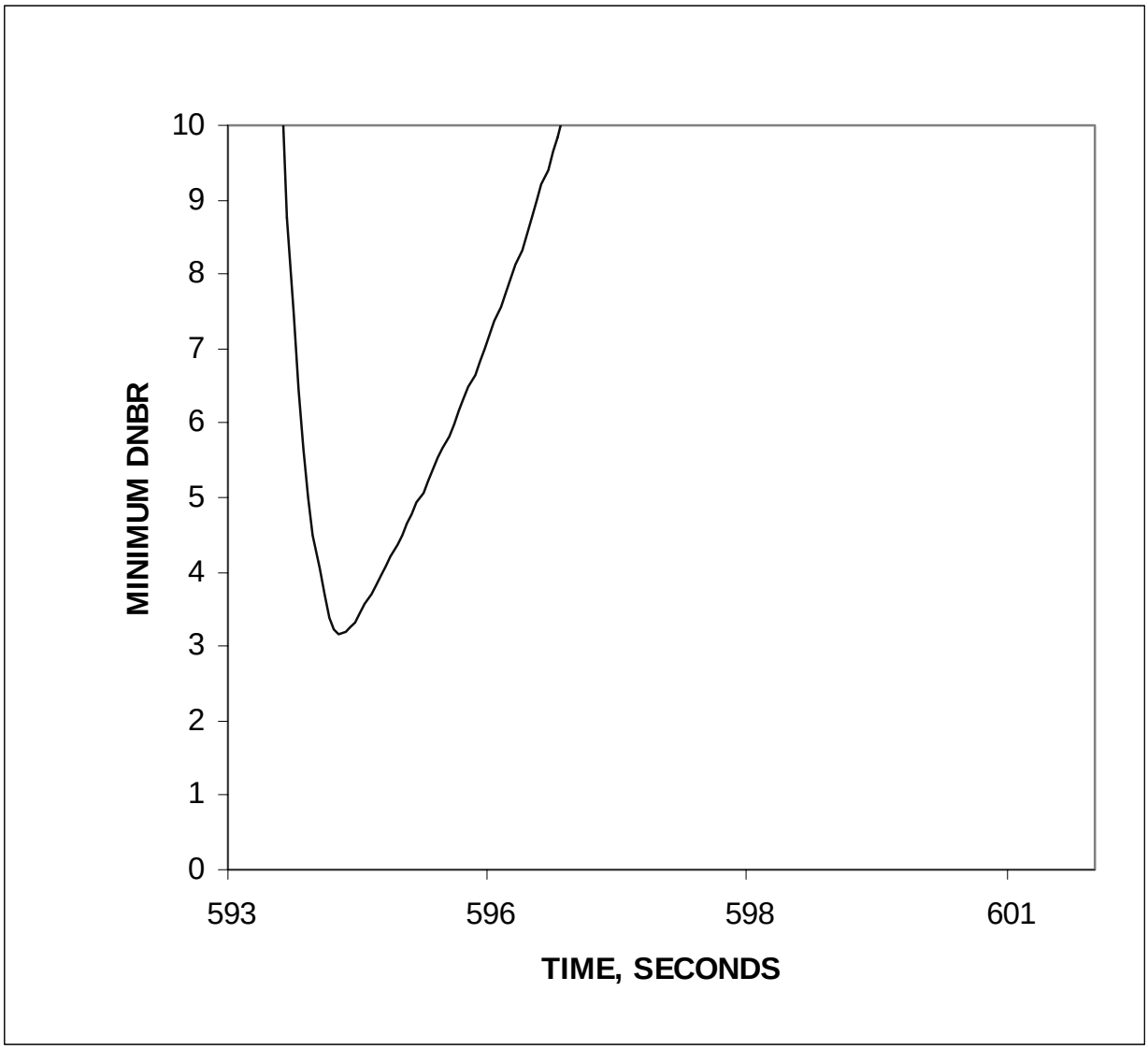

Figure 2.13.4.1.1-8
CEAW from Subcritical
DNBR vs. Time

2.13.4.1.2 Uncontrolled CEAW from Low Power

The objective of the uncontrolled CEA bank withdrawal from critical condition event analysis is to document the impact of the increase in rated power from 3441 MWt to 3716 MWt, and the impact of using CENTS instead of CESEC.

The impact of the above changes results in no violation of the SAFDLs.

2.13.4.1.2.1 General Description of the Event

The withdrawal of CEAs from low power adds positive reactivity to the reactor core, causing both the core power level and the core heat flux to increase. Since the transient is initiated at low power levels, the normal reactor feedback mechanisms (moderator feedback and Doppler feedback) do not occur until power generation in the core is large enough to cause changes in the fuel and moderator temperatures. The RPS is designed to prevent such a transient from resulting in a minimum DNBR less than 1.26 by initiating a CPCS variable over power trip (VOPT). The CPCS VOPT is modeled using the floor of the VOPT plus uncertainties. The HPPT is credited as a secondary trip for the protection of the reactor coolant pressure boundary. No failure that can cause a CEAW can prevent the insertion of CEA banks upon receipt of an RPS trip signal.

The uncontrolled CEA bank withdrawal may be the result of a single failure in the CEDM or the CEDMCS. An uncontrolled CEAW may also be the result of operator error.

Analyses have shown that the most adverse results for the CEAW events occur with the maximum reactivity addition rates. The analysis of the CEAW from critical conditions therefore utilizes the maximum reactivity addition rate with the CEAW speed of 30 inches/minute.

The uncontrolled CEA bank withdrawal events from critical conditions are considered from hot-zero power (HZP).

2.13.4.1.2.2 Purpose of Analysis and Acceptance Criteria

The purpose of the analysis was to determine that the fuel SAFDLs were not violated

The following criteria apply to the CEAW bank withdrawal from HZP event:

- DNBR > 1.26
- Fuel temperature < fuel melt temperature limit
- Radiological dose ≤ small fraction of 10CFR100 limits
- RCS pressures ≤ 110% of design.

For uncontrolled CEA bank withdrawals initiated at power for critical conditions, SAFDL protection (DNBR and LHR) is provided by the CPCS.

Peak RCS pressure is bounded by the loss of condenser vacuum (LOCV) event (Section 2.13.2.1.3). Secondary releases are bounded by the feedwater line break (FWLB) event (Section 2.13.2.3.1). Therefore, these cases are not presented.

The CEA bank withdrawal from low-power event is described in Chapter 15.4.1.2 of the SAR (Reference 2.13-1).

2.13.4.1.2.3 Impact of Changes

The EPU uncontrolled CEA bank withdrawal resulted in a smaller power increase prior to mitigation of the event. The decrease in peak power was caused by the earlier RPS response resulting in halting of CEA motion followed by trip.

This event is now analyzed with the CENTS code versus the CESEC code (Reference 2.13-2). The CENTS code is used in this analysis in exactly the same manner as CESEC was in the current analysis. In this case the substitution of one code for the other introduces no significant changes.

2.13.4.1.2.4 Analysis Overview

The methodology used in this analysis is the same as that used in the analysis of record. This analysis has utilized the CENTS computer code (Reference 2.13-2) for the transient analysis simulation. The minimum DNBR was determined using the CETOP code (Reference 2.13-3).

Input parameters from Table 2.13.4.1.2-1 and the bounding physics data from Section 2.13.0.2 have been incorporated in this analysis with the following clarifications:

- The least negative Doppler was assumed.
- A minimum delayed neutron fraction and neutron lifetime consistent with those defined in Section 2.13.0.2 were assumed.
- A CEA coil decay time of 0.6 seconds was assumed, after which the CEAs dropped back into the core. A CEA worth of 5.0% $\Delta\rho$, and an ASI of +0.6 were conservatively assumed.
- A least negative MTC of 0.5×10^{-4} $\Delta\rho/°F$ was assumed.
- A conservative CPCS VOPT setpoint of 35% of rated power and a response time of 0.429 seconds were assumed. This timing is a conservative assumption with respect to the CPC delay times discussed in Section 2.13.0.3 and nuclear instrumentation response times.
- An initial core power of 10^{-6} % of rated thermal power was assumed.
- A reactivity insertion rate of 1.6×10^{-4} $\Delta\rho$/sec was assumed.

2.13.4.1.2.5 Radiological Consequences

No SAFDL violation occurs during the HZP CEAW event. Source terms are, therefore, limited to the initial primary and secondary limits on coolant activity in the Technical Specifications. Doses for this event are bounded by the IOSGADV with LOOP event in Section 2.13.1.2.4.5. Both events have the same criteria (small fraction of 10CFR100 guidelines), and the IOSGADV with LOOP event radiological dose assumptions are conservative for the HZP CEAW event.

2.13.4.1.2.6 Analysis Results

A CEA bank withdrawal at HZP results in a core power increase. As core power increases, both RCS temperatures and pressures also increase. The action of the CPCS VOPT terminates the transient.

The NSSS and RPS responses to the HZP CEA bank withdrawal event are shown in Table 2.13.4.1.2-2 and in Figures 2.13.4.1.2-1 through 2.13.4.1.2-8.

For the limiting HZP CEA bank withdrawal event, a deposited energy analyses shows that the peak core power results in fuel temperatures below the fuel melt limit. The peak heat flux results in a minimum DNBR no less than 1.26. This was not a limiting peak RCS pressure event. There was no violation of the SAFDLs for HZP.

Table 2.13.4.1.2-1
Assumptions for the Uncontrolled CEA Withdrawal at HZP

Parameter	3716 MWt Power Uprate Assumption	Current Power Level Assumption
Initial Core Power Fraction	10^{-6}	10^{-6}
Core Inlet Temperature, °F	552	549
RCS Flowrate, 10^6 lbm/hr	148	148
Pressurizer Pressure, psia	2090	2000
SG Pressure, psia	1058	---
One pin radial peaking factor, with uncertainty	3.17	2.38
MTC, 10^{-4} $\Delta\rho$/°F	+0.5	+0.5
Doppler coefficient multiplier	0.85	0.85
CEA Reactivity Addition Rate, 10^{-4} $\Delta\rho$/sec	1.6	1.6
CEA Worth on trip, %$\Delta\rho$	-5.0	-5.0

Table 2.13.4.1.2-2
Sequence of Events for the Uncontrolled CEA Withdrawal at HZP

3716 MWt EPU Time (sec)	Current Power Level Time (sec)	Event	3716 MWt EPU Setpoint/Value	Current Power Level Setpoint/Value
0.0	0.0	Initiation of CEA bank withdrawal	---	---
24.2	24.3	High VOPT signal generated, % of rated thermal power	35	41
24.7	24.8	Trip breakers open	---	---
25.0	25.4	Maximum core power occurs, % of RTP	66.7	85
25.3	25.4	Shutdown CEAs begin to drop into core	---	---
25.8	25.5	Maximum core average heat flux occurs, % of full power heat flux	32.6	38
25.8	25.5	Minimum DNBR occurs	≥ 1.26	≥ 1.26
34.7	---	MSSVs open	1085	---

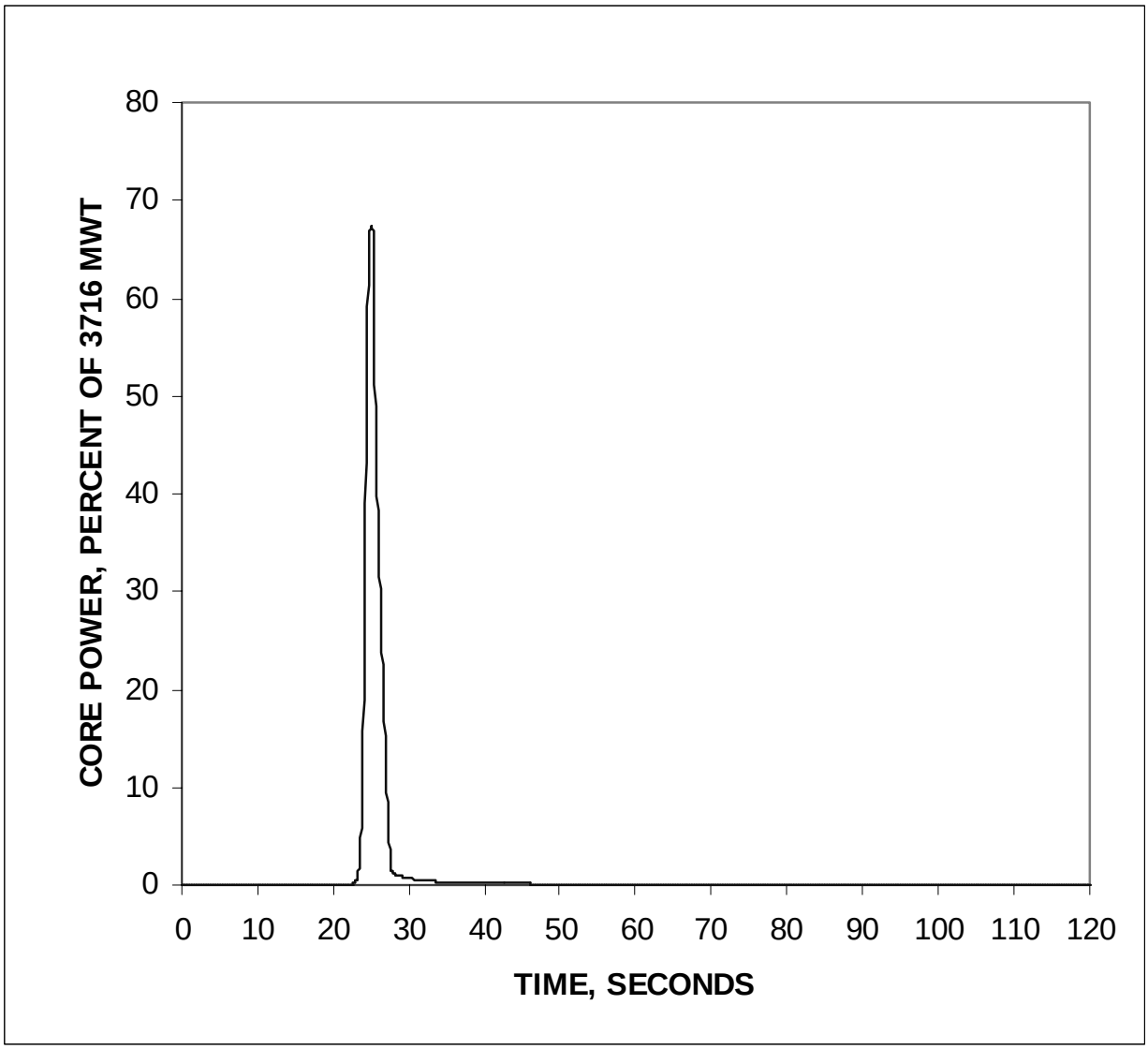

Figure 2.13.4.1.2-1
CEAW at Low-Power
Core Power vs. Time

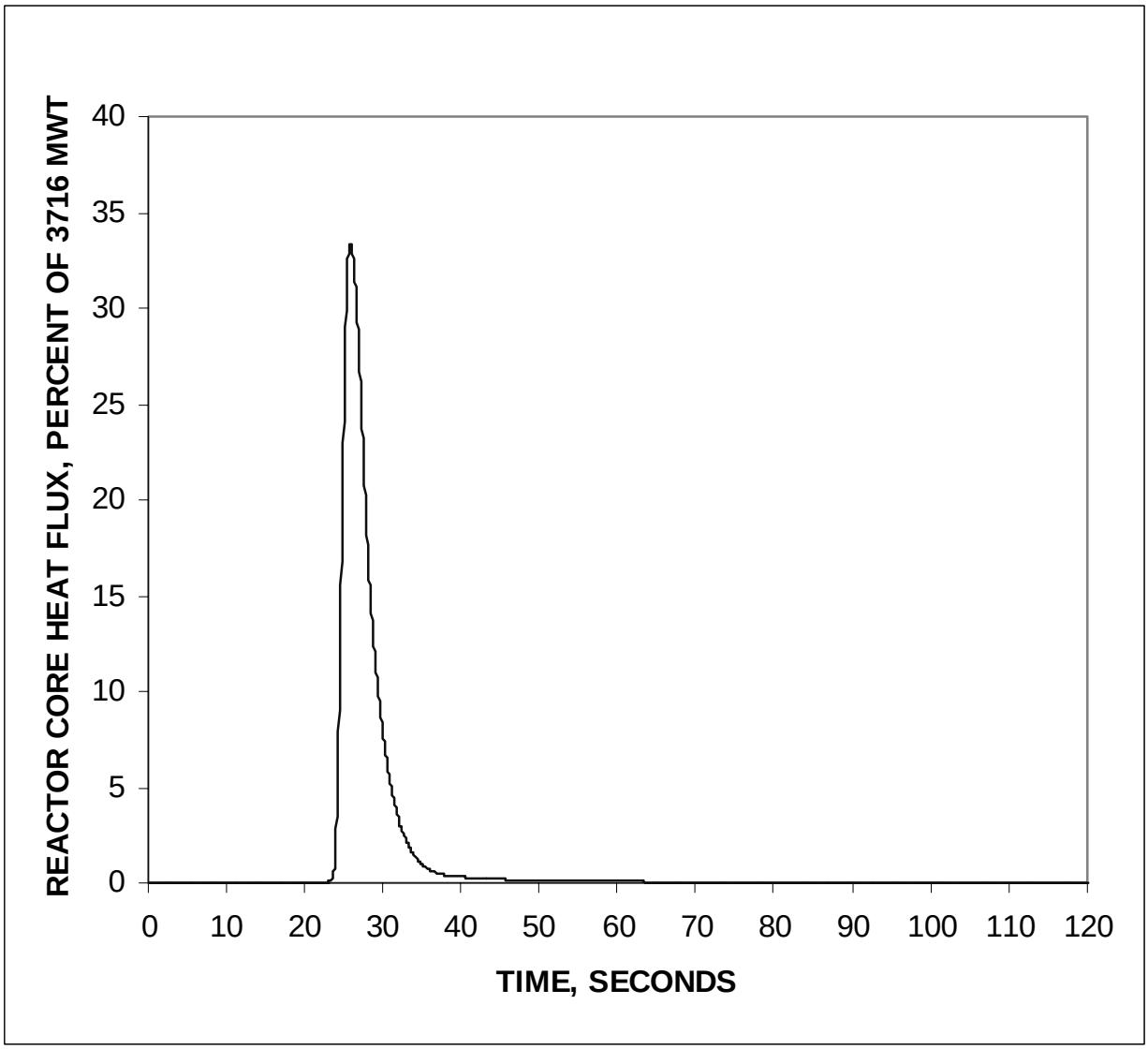

Figure 2.13.4.1.2-2
CEAW at Low-Power
Core Heat Flux vs. Time

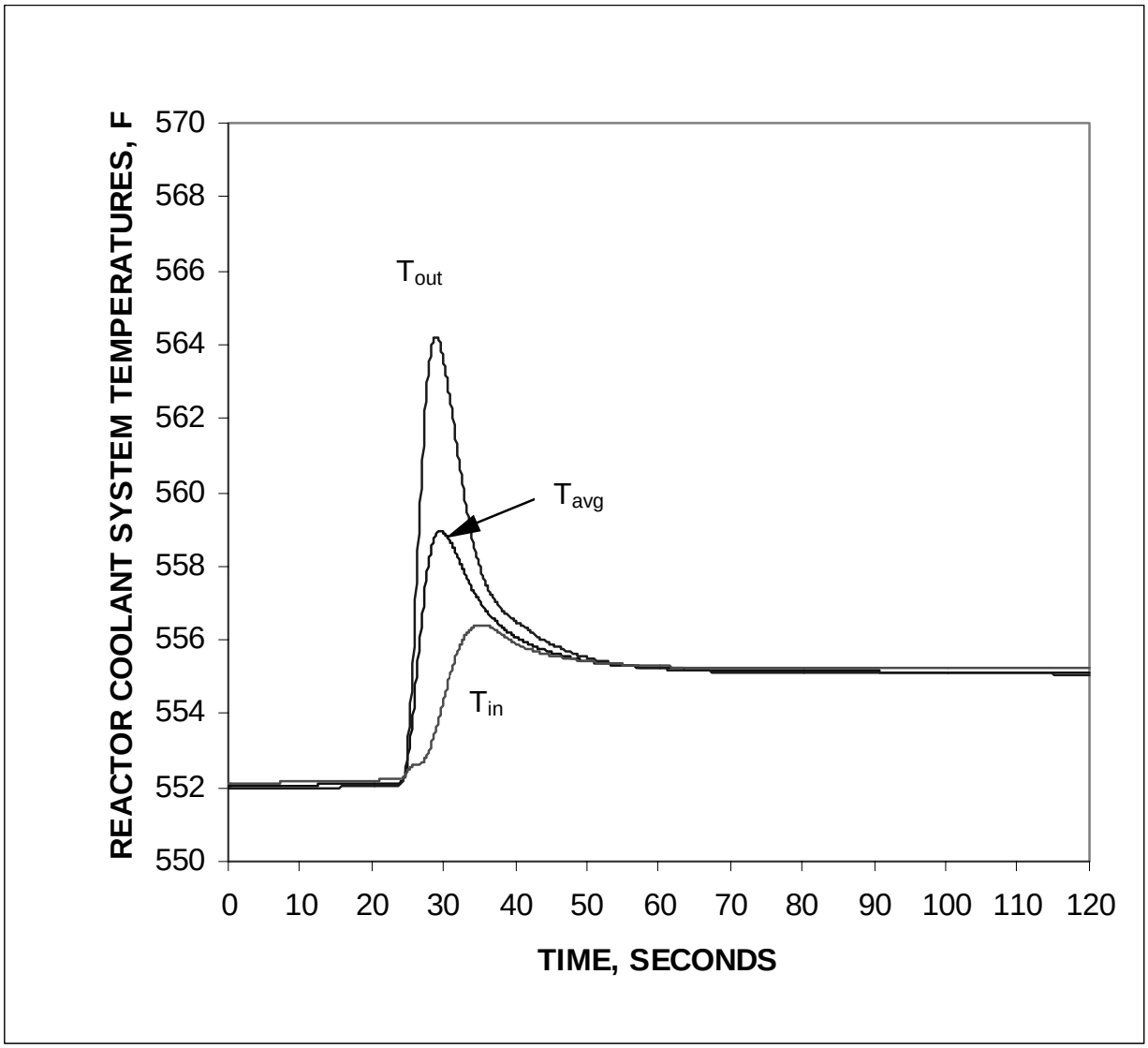

Figure 2.13.4.1.2-3
CEAW at Low-Power
RCS Temperatures vs. Time

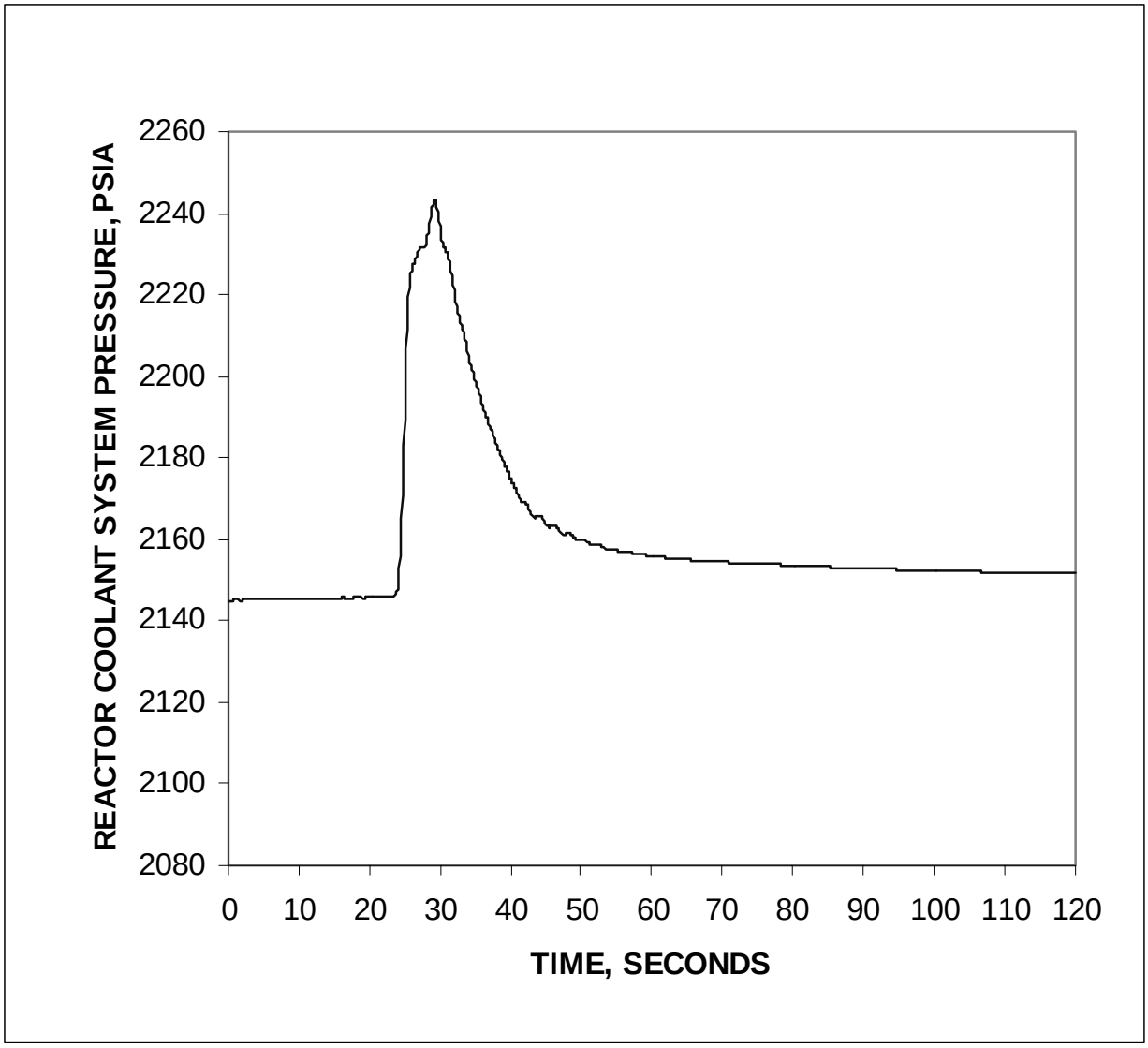

Figure 2.13.4.1.2-4
CEAW at Low-Power
RCS Pressure vs. Time

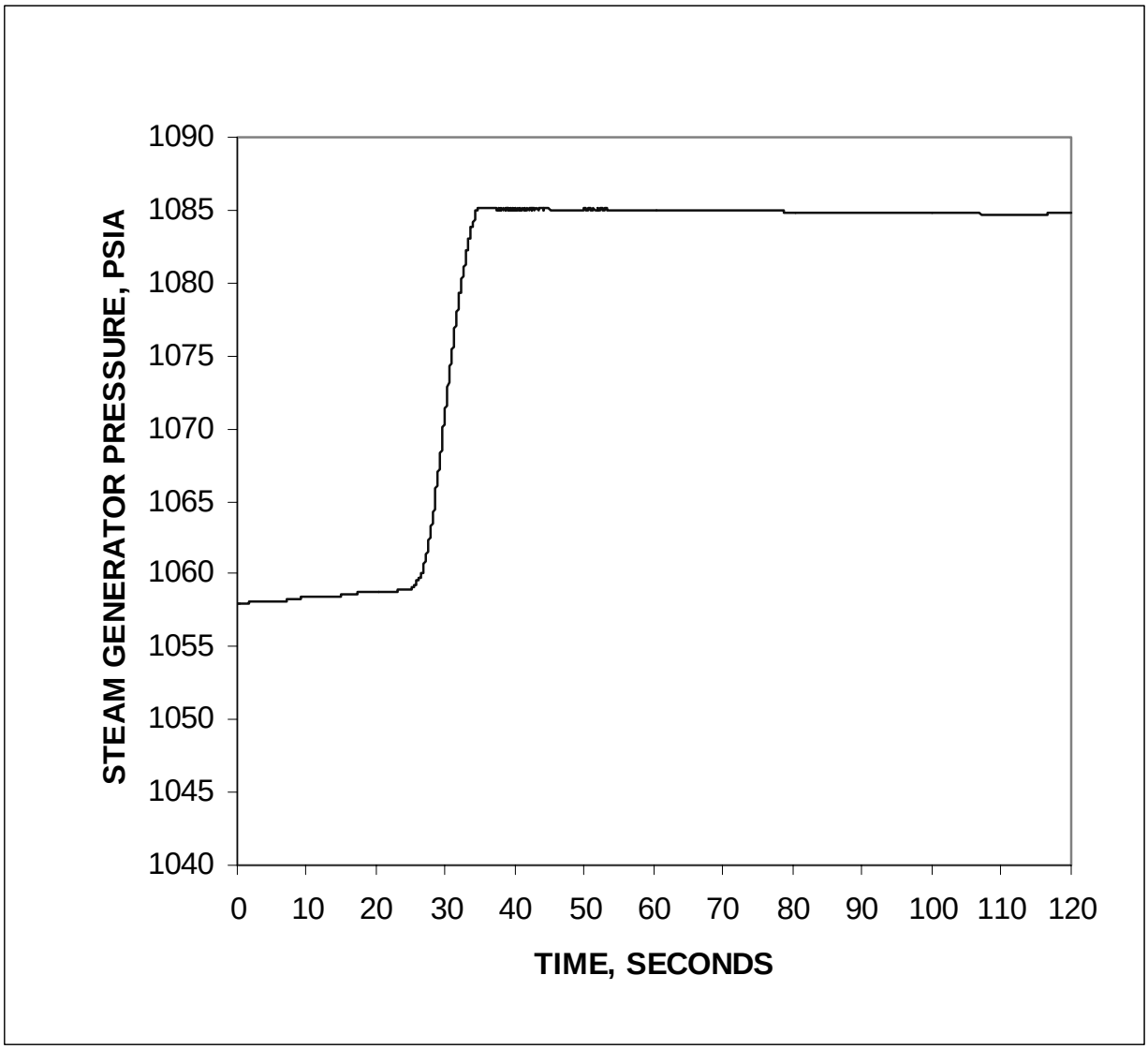

Figure 2.13.4.1.2-5
CEAW at Low-Power
SG Pressure vs. Time

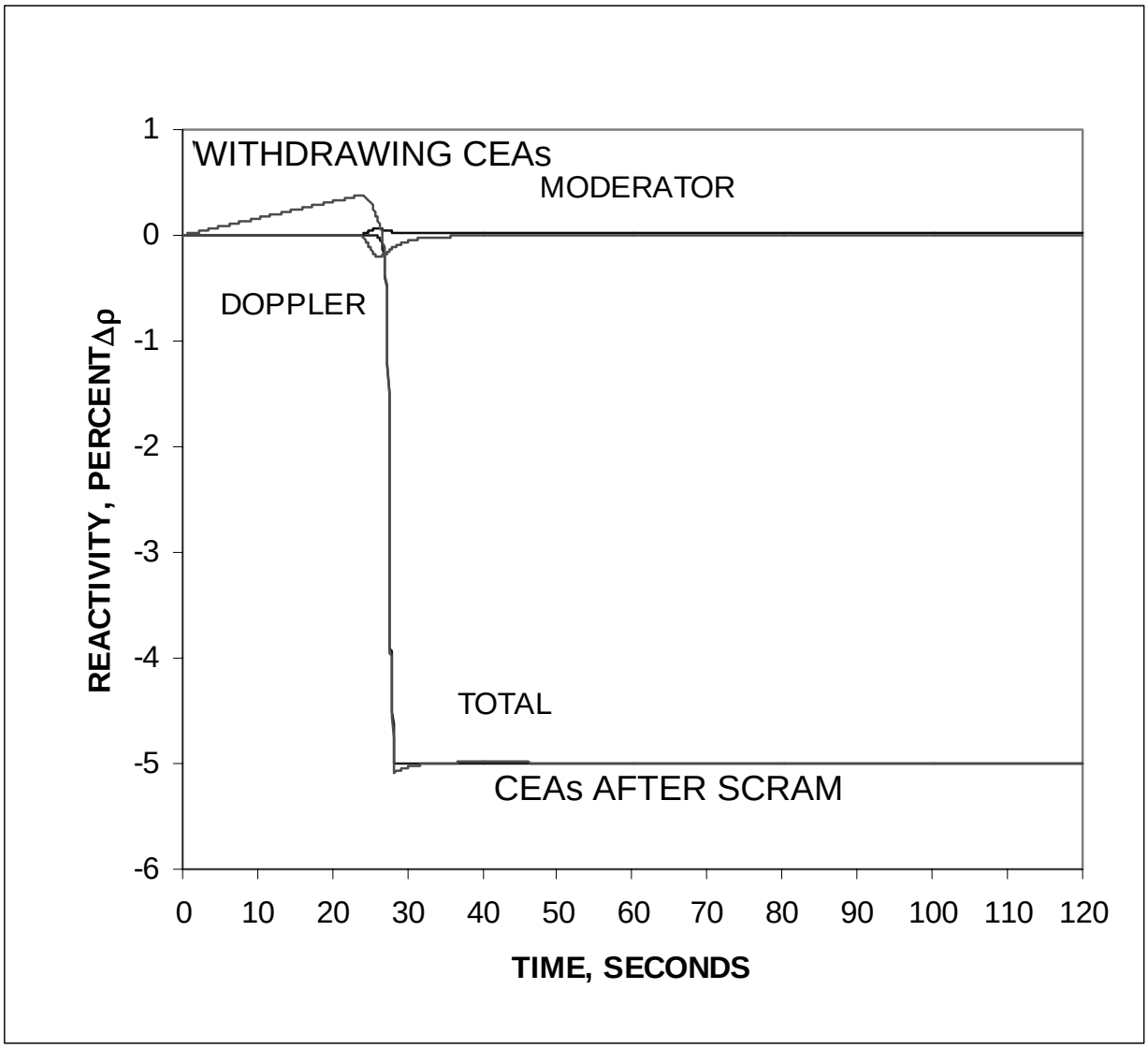

Figure 2.13.4.1.2-6
CEAW at Low-Power
Reactivity vs. Time

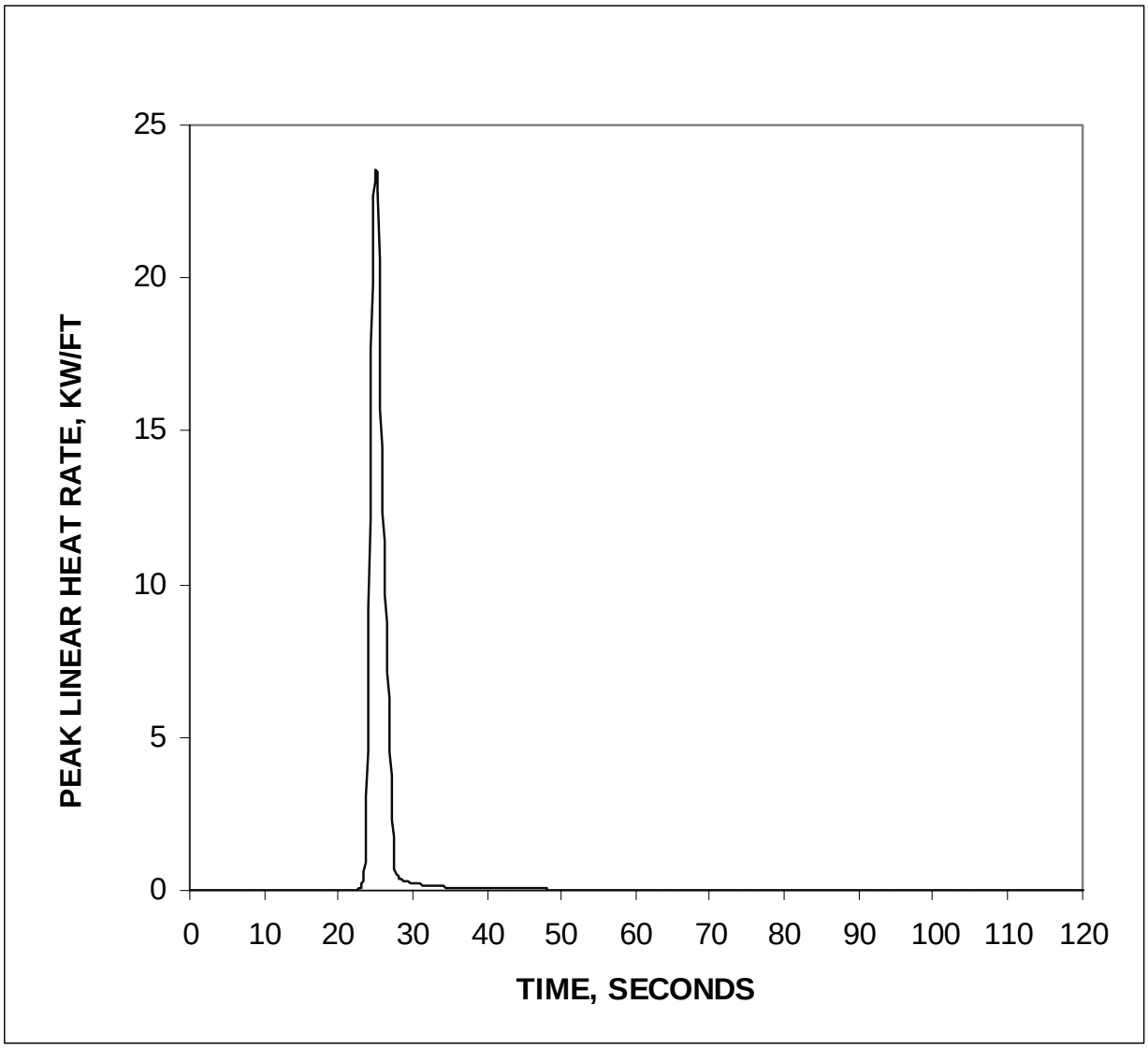

Figure 2.13.4.1.2-7
CEAW at Low-Power
Peak LHR vs. Time

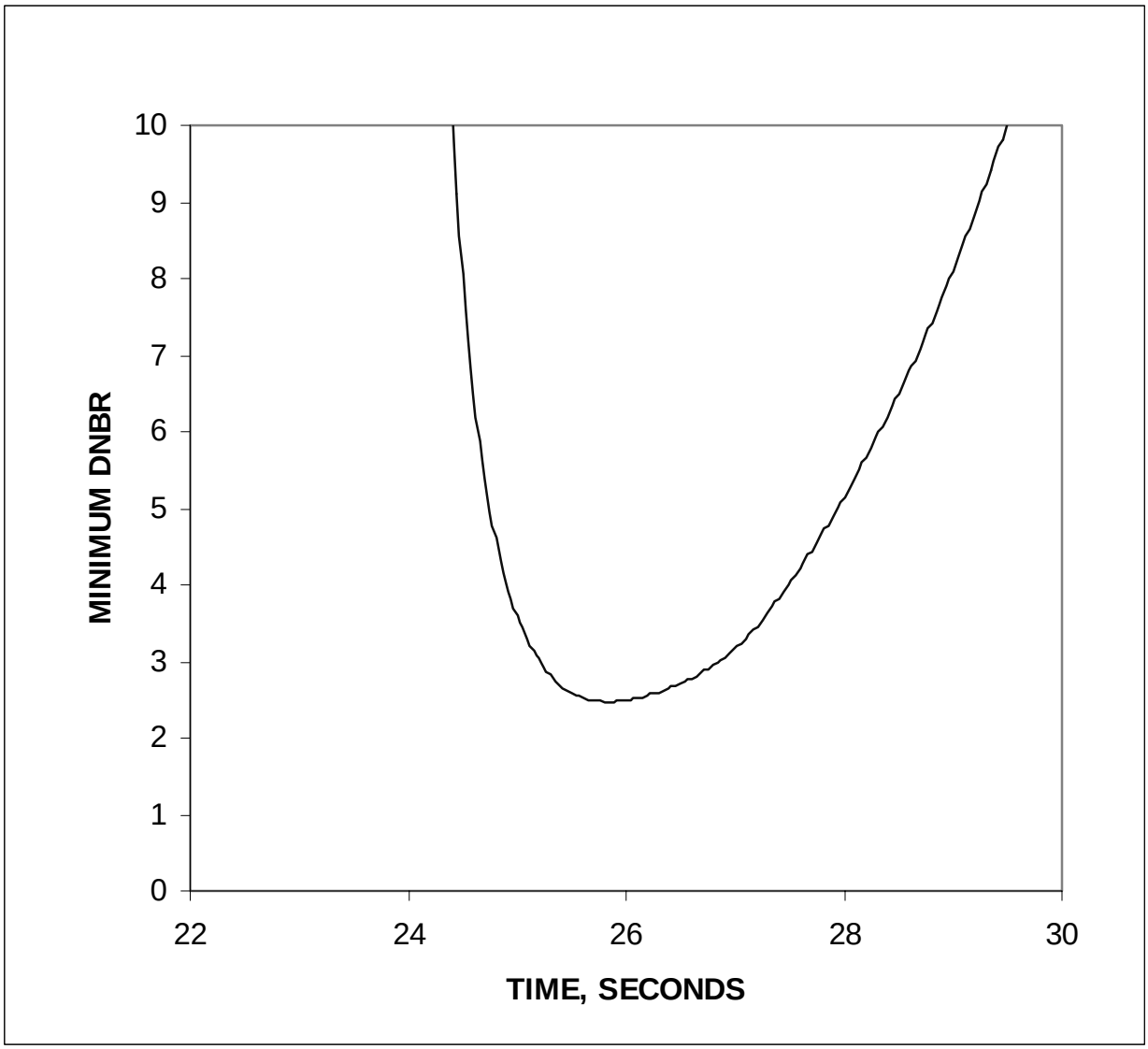

Figure 2.13.4.1.2-8
CEAW at Low-Power
DNBR vs. Time

2.13.4.1.3 Uncontrolled CEAW at Power

The objective of Uncontrolled CEAW at power event analysis was to document the impact the following changes:

- An increase in rated thermal power to 3716 MWt
- A change from the CESEC to the CENTS code as the primary NSSS simulation tool
- A reduction in steam generator pressure
- A reduction in CEA worth at trip

The impact of the power uprate results in no violation of the SAFDLs for this SAR event.

2.13.4.1.3.1 General Description of the Event

The sequential withdrawal of CEAs from a hot-full power (HFP) condition adds reactivity to the reactor core, causing the core power level to increase. A continuous withdrawal of CEAs could result from a malfunction in the Reactor Regulating System, the CEDMCS, or by operator error. No failure that can cause a CEAW can prevent the insertion of CEA banks upon receipt of a RPS trip signal.

Analyses have shown that the most adverse results for the CEAW events occur with the maximum reactivity addition rates. This analysis therefore utilizes the maximum reactivity addition rate with the CEAW speed of 30 in/minute.

The sequential CEA withdrawal event is terminated by a CPCS VOPT trip, CPCS high local power density (LPD) trip, a CPCS low DNBR trip or a HPPT. The CPCS has dynamic compensation lead-lag filters that project increases in core heat flux and core power. These dynamic compensation filters in conjunction with static power correction factors ensure that the CEAW transients are terminated prior to the SAFDLs being violated.

2.13.4.1.3.2 Purpose of Analysis and Acceptance Criteria

The following criteria apply to the CEAW bank withdrawal at power event:

- DNBR > 1.26
- Fuel temperature < fuel melt temperature limit, demonstrated by peak LHR ≤ 21.0 kW/ft
- Radiological dose ≤ small fraction of 10CFR100 limits
- RCS pressures ≤ 110% of design.

The CEA bank withdrawal at power event is described in Chapter 15.4.1.3 of the FSAR (Reference 2.13-1).

2.13.4.1.3.3 Impact of Changes

The increase in rated power has the potential to increase linear heat generation rate (LHGR) and decrease DNBR.

This event is now analyzed with the CENTS code versus the CESEC code (Reference 2.13-2). The CENTS code is used in this analysis exactly the same manner as CESEC has been in the current analysis. In this case the substitution of one code for the other introduces no significant changes.

2.13.4.1.3.4 Analysis Overview

This analysis has utilized the CENTS computer code for the transient analysis simulation.

The input parameters from Table 2.13.4.1.3-1 and the bounding physics data from Section 2.13.0.2 have been incorporated in this analysis with the following clarifications:

- The BOC Doppler curve was assumed.
- A delayed neutron fraction and neutron lifetime consistent with those defined in Section 2.13.0.2 of this report were assumed.
- The CEA insertion curve based on the limiting +0.3 ASI shape was assumed. This curve accounts for a 0.6-second CEA holding coil delay. A CEA worth of –6.0% $\Delta\rho$ was conservatively assumed.
- An initial core power of 3735 MWt was assumed based on a rated power of 3716 MWt and a 0.5% measurement uncertainty.
- A most positive/least negative MTC of 0.0 * 10-4 $\Delta\rho$/°F at hot-full power (HFP) was used.
- Maximum reactivity insertion rate (RIR) of 0.55 x 10-4 $\Delta\rho$/sec was assumed.
- The CPCS VOPT ceiling was not credited. The CPCS VOPT follow trip of 10% was assumed resulting in a power trip at 110.5% of full power.
- The analysis of the high-power CEAW event covers a spectrum of CEA bank worths from the maximum worth, presented herein, to lesser worths which result in slower trip response times\different primary trips. The entire spectrum of CEA bank worths are used to ensure adequate initial thermal margin and acceptable trip response. Initial thermal-hydraulic conditions for the analysis presented herein are selected to be the most adverse for tuning of the CPCS.

2.13.4.1.3.5 Radiological Consequences

No SAFDL violation occurs during the CEAW event. Source terms are therefore limited to the initial primary and secondary limits on coolant activity in the Technical Specifications. Doses for this event are bounded by the IOSGADV with LOOP event in Section 2.13.1.2.4.5. Both events have the same criteria (small fraction of 10CFR100 guidelines), and the IOSGADV with LOOP event radiological dose assumptions are conservative for the CEAW event.

2.13.4.1.3.6 Analysis Results

For the limiting HFP CEA bank withdrawal event, the peak core power results in a peak linear heat rate (LHR) of less than 21 kW/ft. The peak heat flux results in a minimum DNBR greater than 1.26. This is not a limiting peak RCS pressure event. Thus, there is no violation of the SAFDLs for HFP.

The NSSS and PPS responses for the HFP CEA bank withdrawal event are shown in Table 2.13.4.1.3-2 and in Figures 2.13.4.1.3-1 through 2.13.4.1.3-13.

Table 2.13.4.1.3-1
Assumptions for 3716-MWt
CEA Withdrawal at Power

Parameter	Power Uprate Assumption	Current Power Level Assumption
Initial Core Power, MWt	3735	2591.6
Core Inlet Temperature, °F	533	560
RCS Flowrate, 10^6 lbm/hr	177.6	127
Pressurizer Pressure, psia	2090	2000
SG Pressure, psia	733	944.6
MTC, $*10^{-4}$ $\Delta\rho$/°F	0.0	+0.5
Doppler Coefficient Multiplier	0.85	0.85
CEA Worth on Trip, 10^{-2} $\Delta\rho$	6.0	8.55
One Pin Radial Peaking Factor	1.81	1.71

Table 2.13.4.1.3-2
Sequence of Events for 3716-MWt
CEA Withdrawal at Power

EPU Time (sec)	Current Power Level Time (sec)	Event	EPU Setpoint/Value	Current Power Level Setpoint/Value
0.0	0.0	Withdrawal of CEA bank is initiated	---	---
11.6	N/A	CPCS VOPT generates a reactor trip signal	110% power	N/A
12.1	42.9	Reactor trip breakers open	---	---
12.3	43.7	Maximum core power, % of full power	110.5% power	109.0
12.4	45.20	Minimum DNBR	1.44	1.19
12.7	43.2	CEAs begin to drop into core	---	---
14.8	46.55	Maximum RCS pressure, psia	2,287	2,534
21.9	45.20	SG safety valves open, psia	1,038	1,085

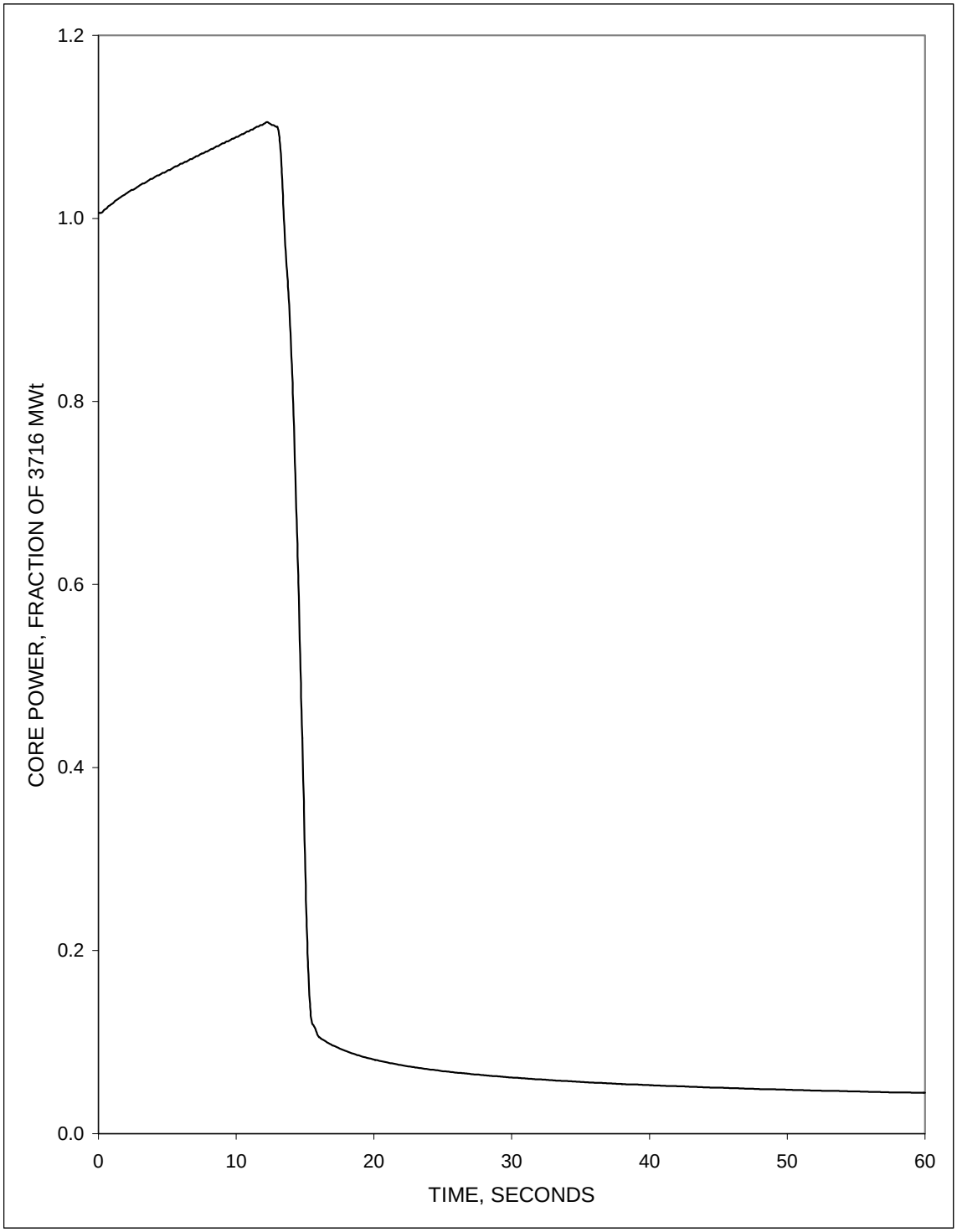

Figure 2.13.4.1.3-1
CEAW at Power
Core Power vs. Time

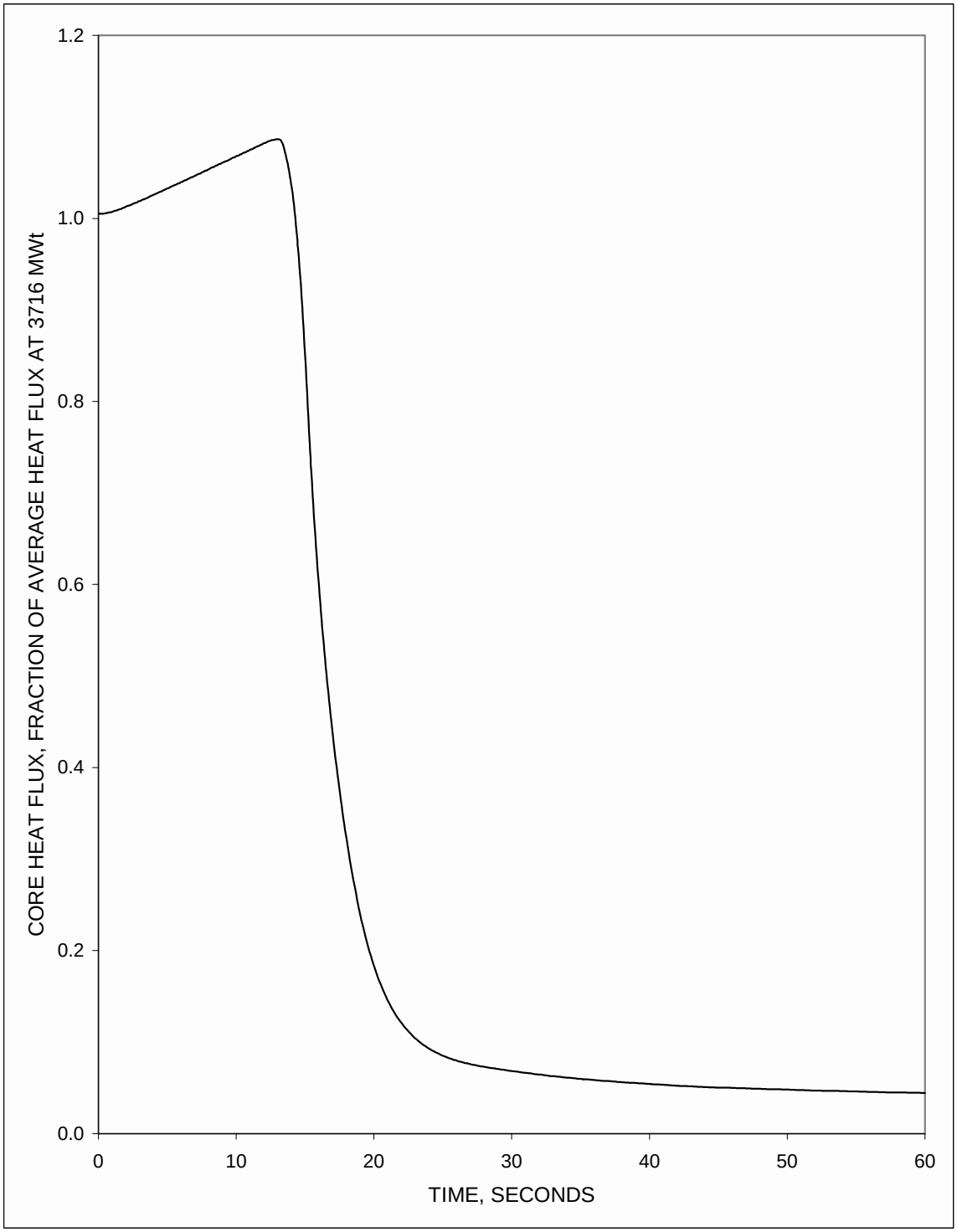

Figure 2.13.4.1.3-2
CEAW at Power
Core Heat Flux vs. Time

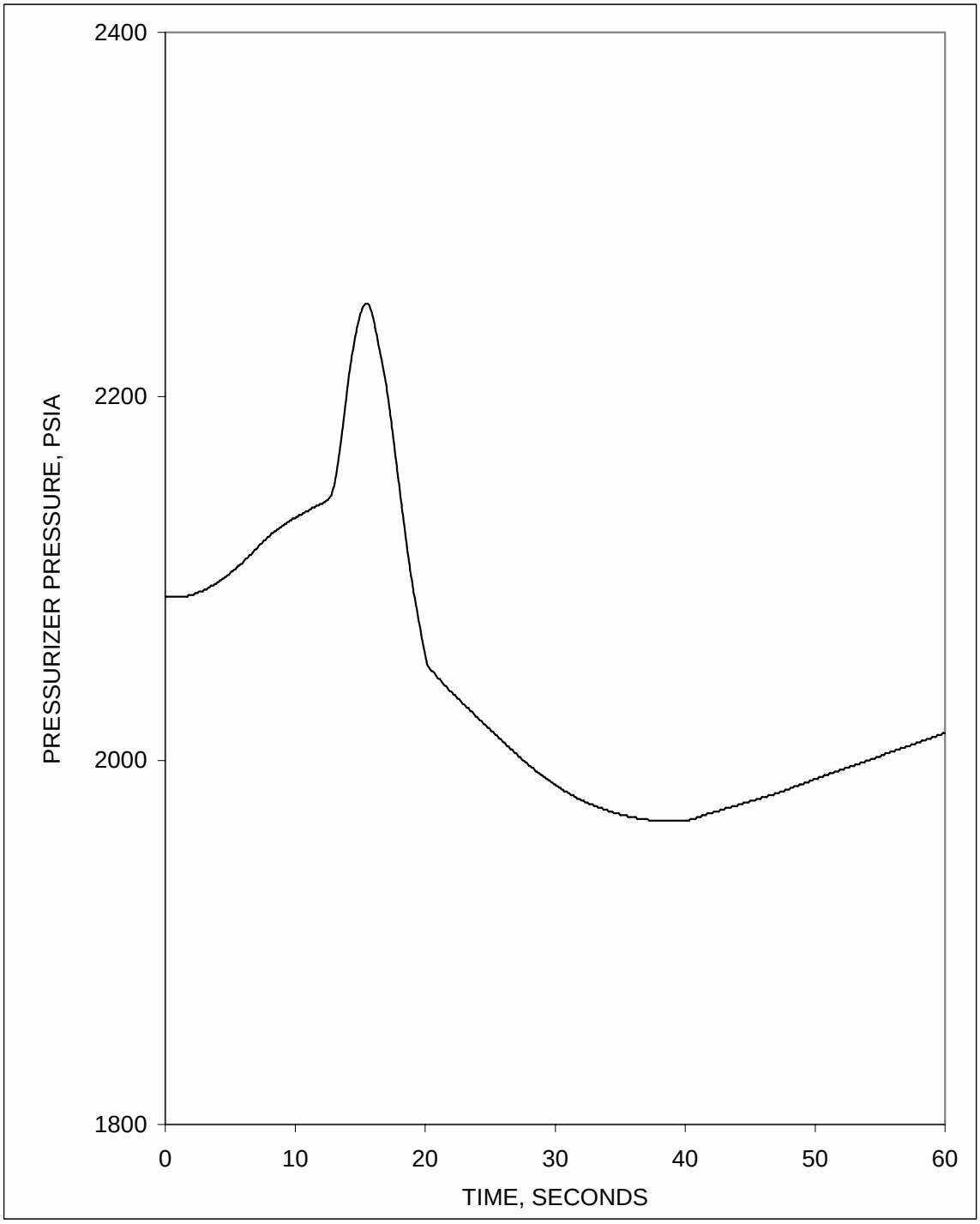

Figure 2.13.4.1.3-3
CEAW at Power
RCS Pressure vs. Time

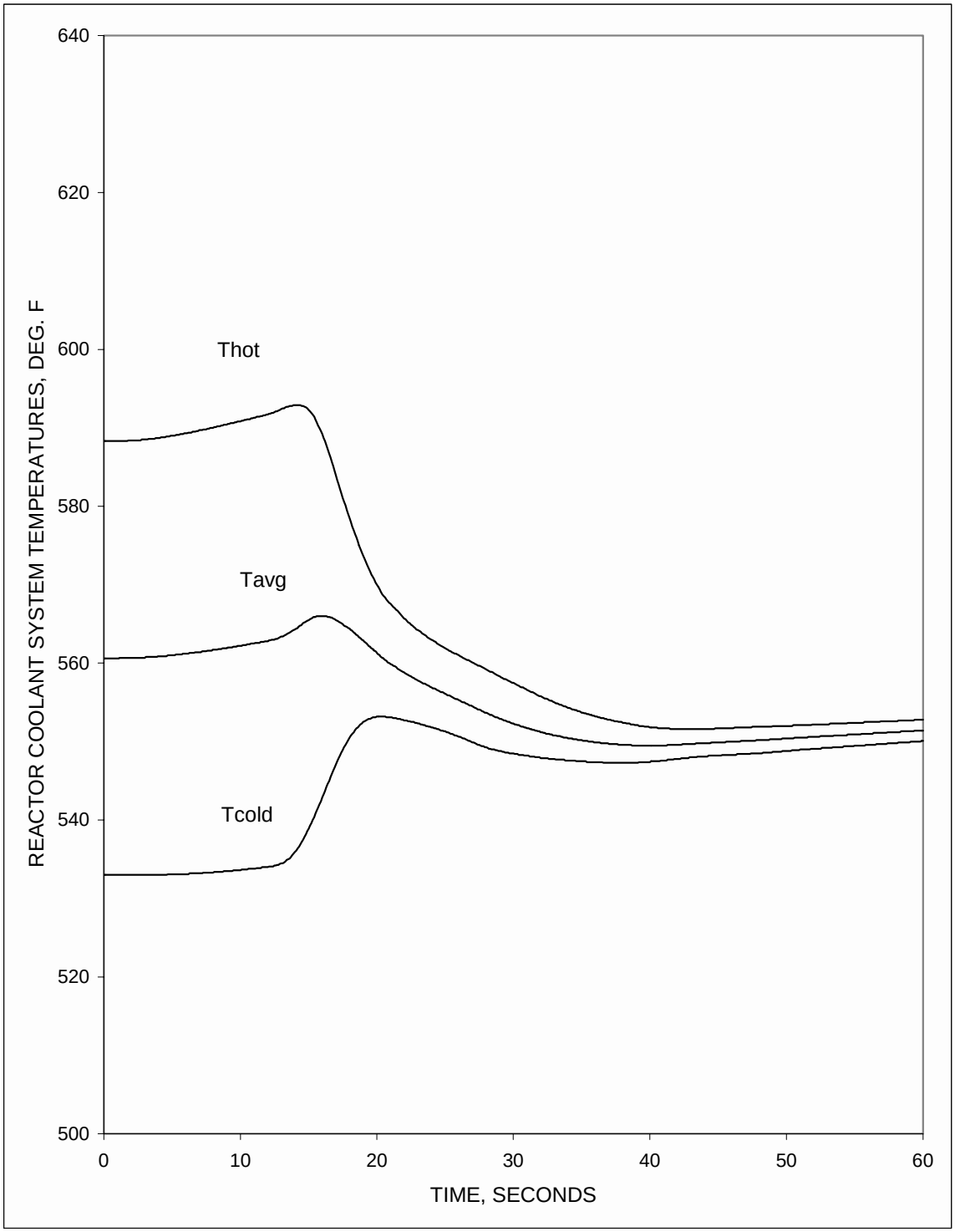

Figure 2.13.4.1.3-4
CEAW at Power
RCS Temperatures vs. Time

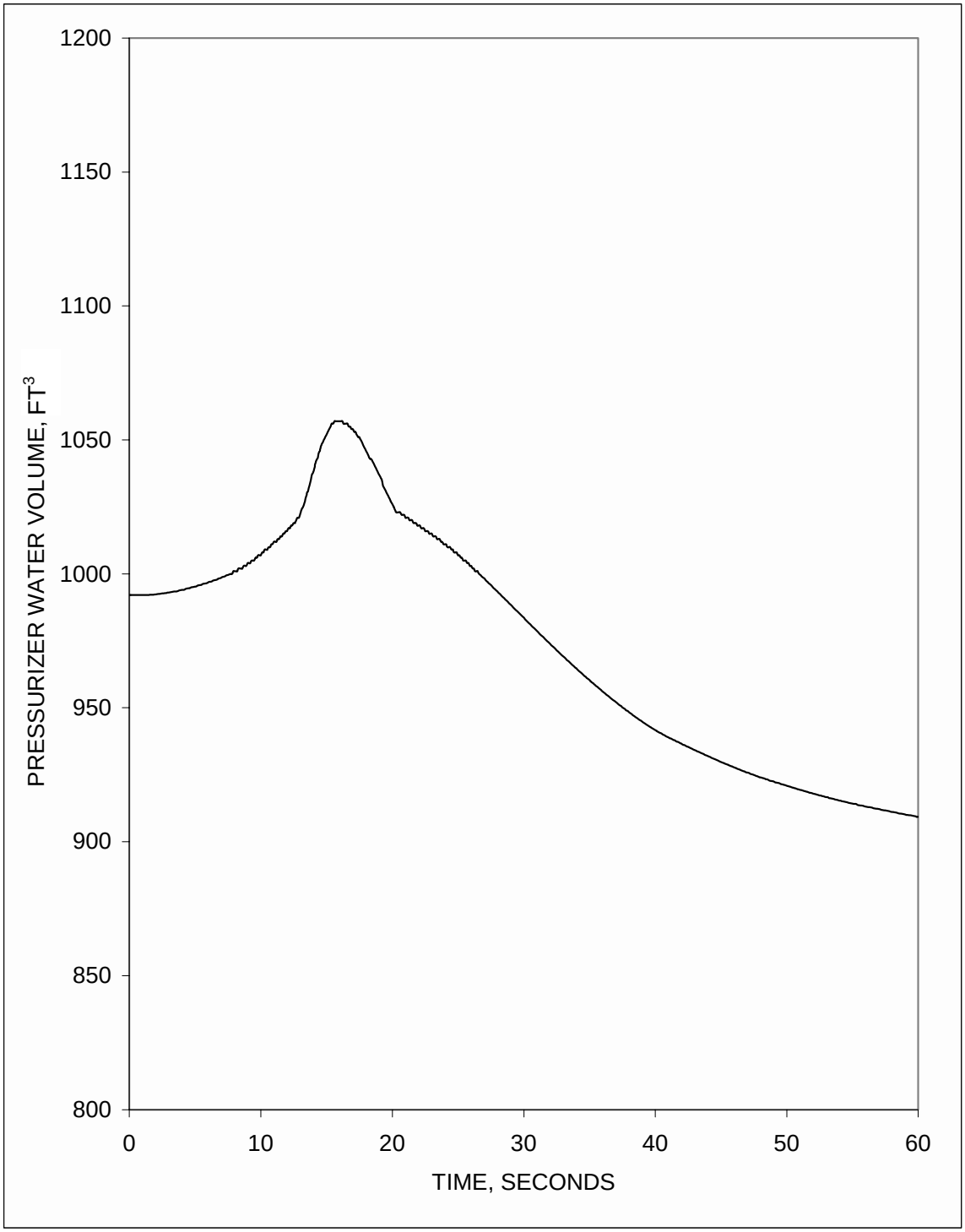

Figure 2.13.4.1.3-5
CEAW at Power
Pressurizer Water Volume vs. Time

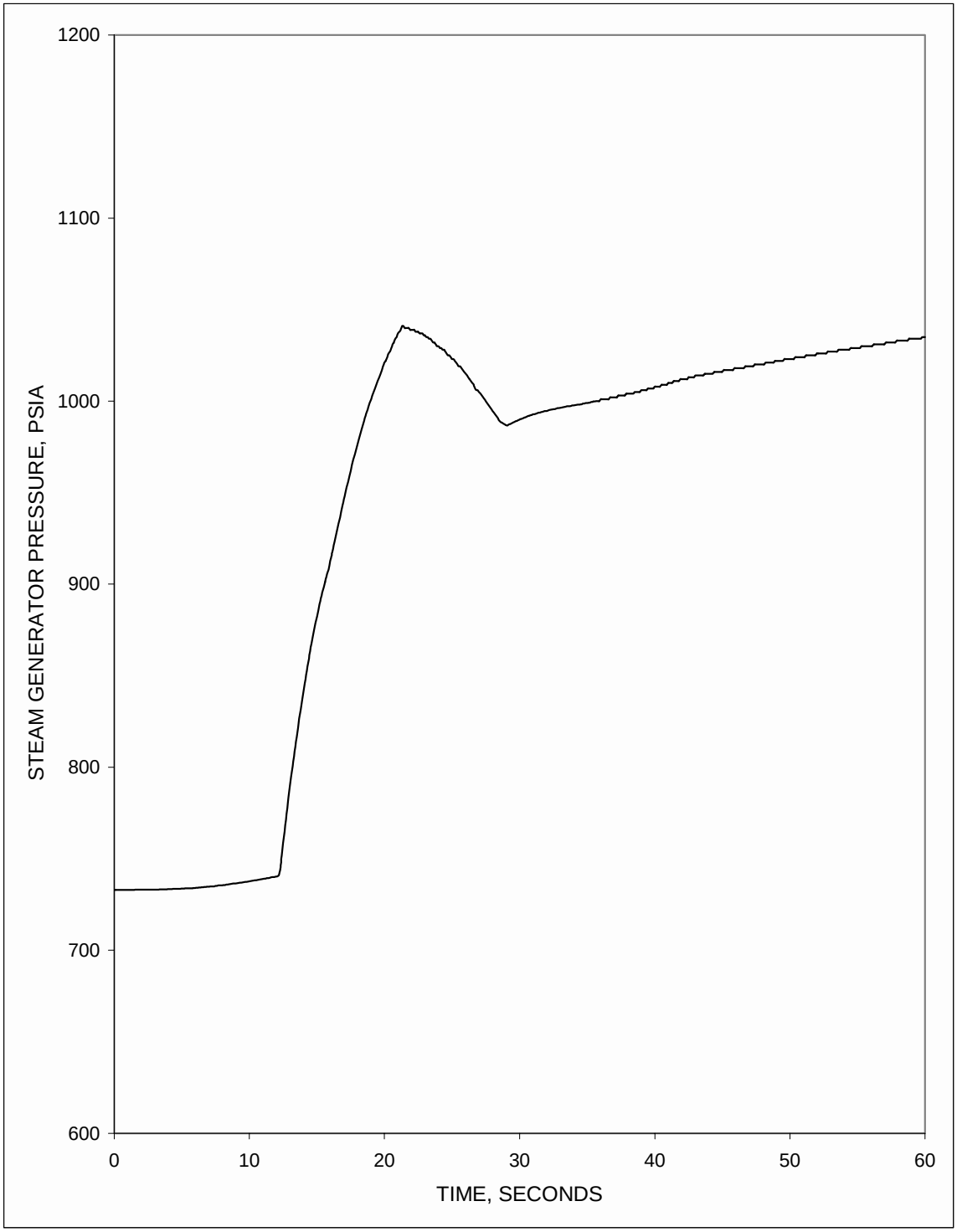

Figure 2.13.4.1.3-6
CEAW at Power
SG Pressure vs. Time

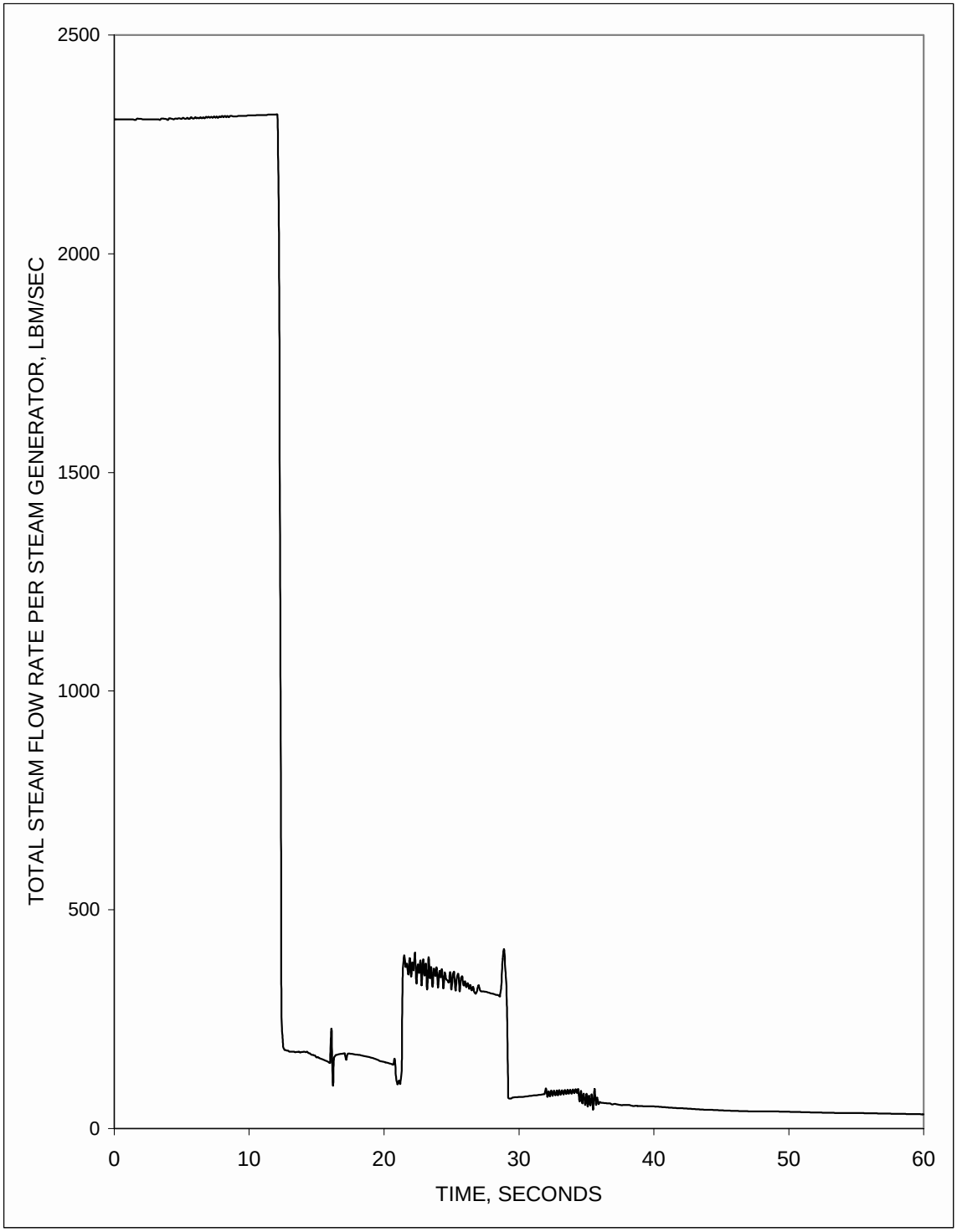

Figure 2.13.4.1.3-7
CEAW at Power
Steam Flow vs. Time

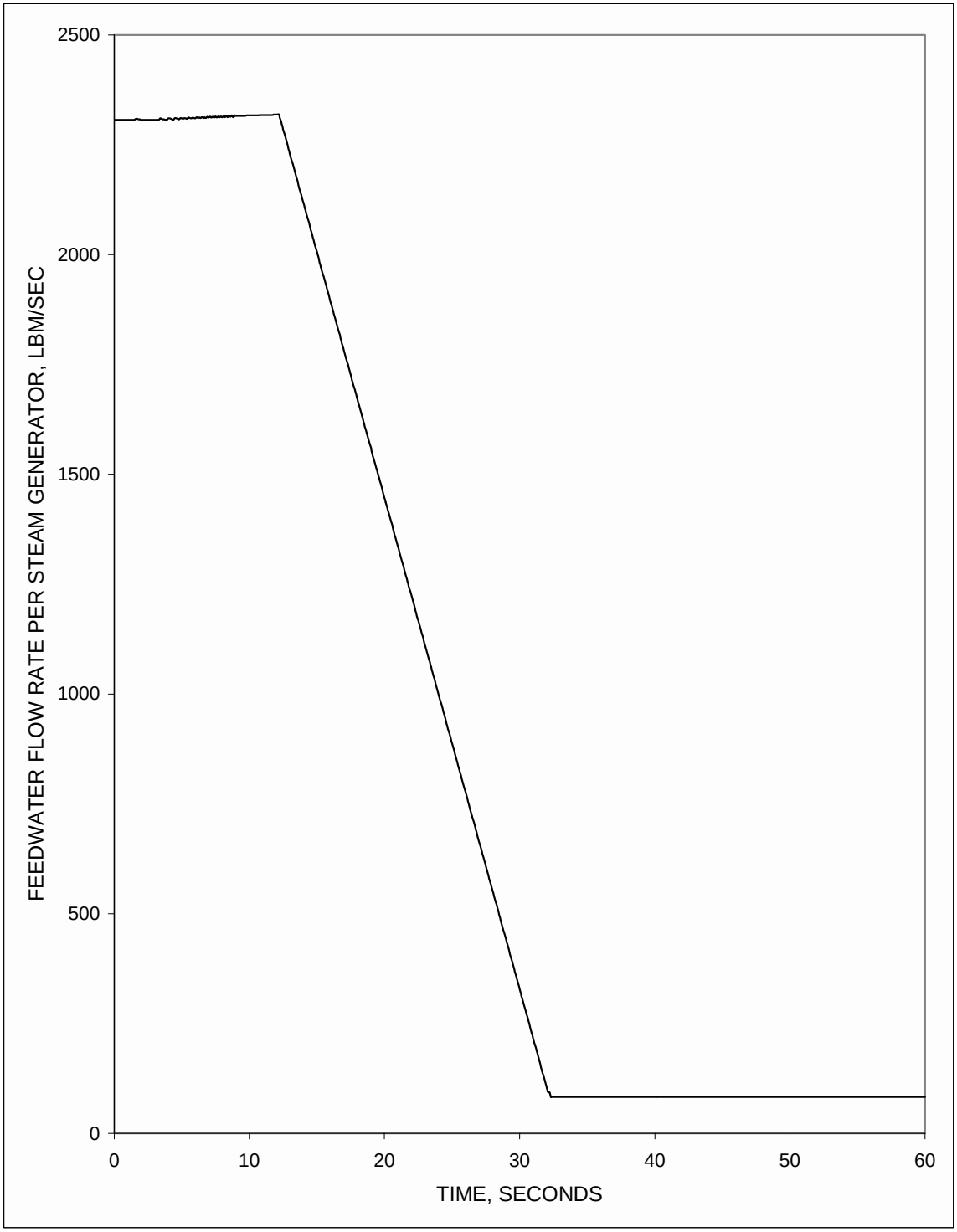

Figure 2.13.4.1.3-8
CEAW at Power
Feedwater Flow vs. Time

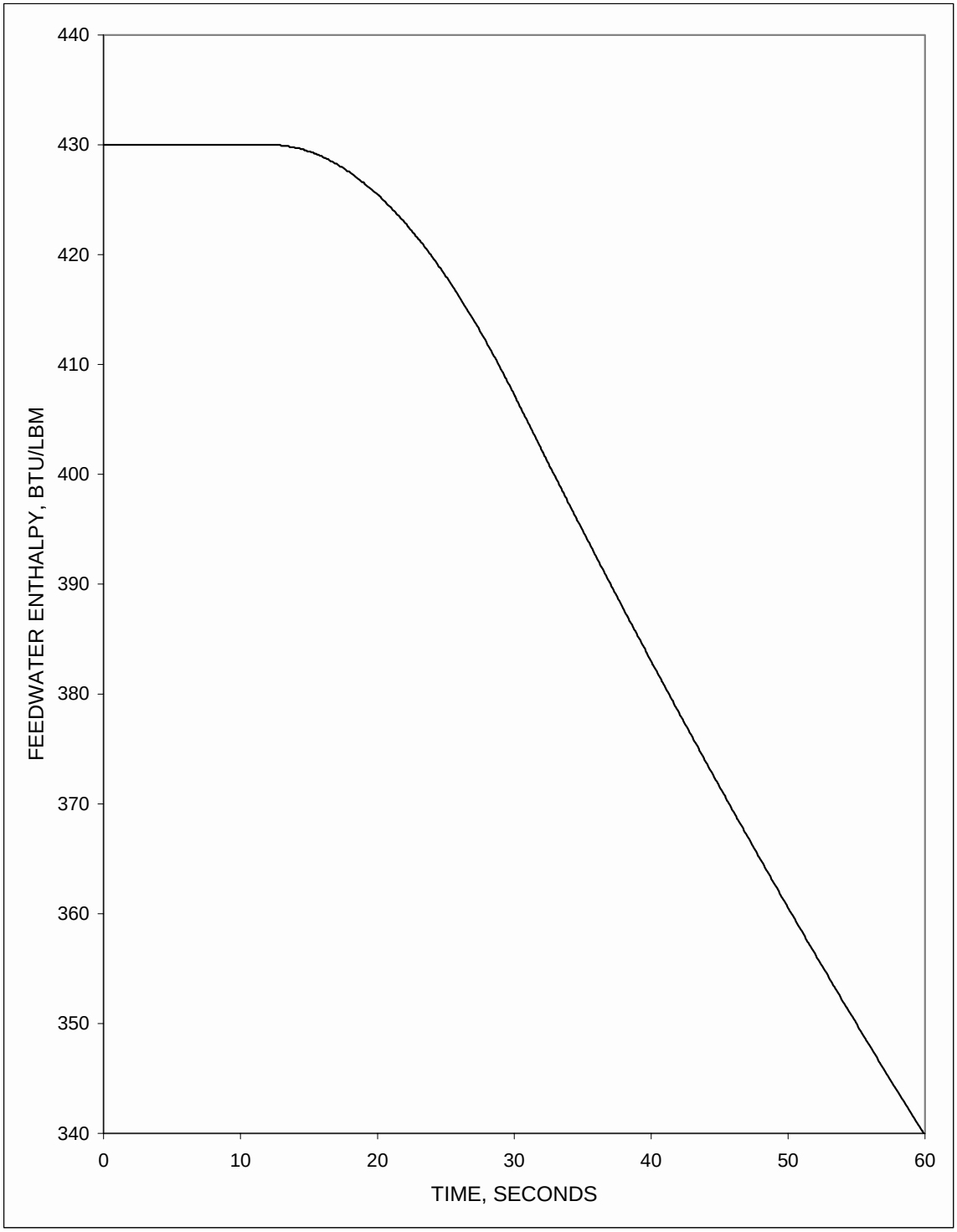

Figure 2.13.4.1.3-9
CEAW at Power
Feedwater Enthalpy vs. Time

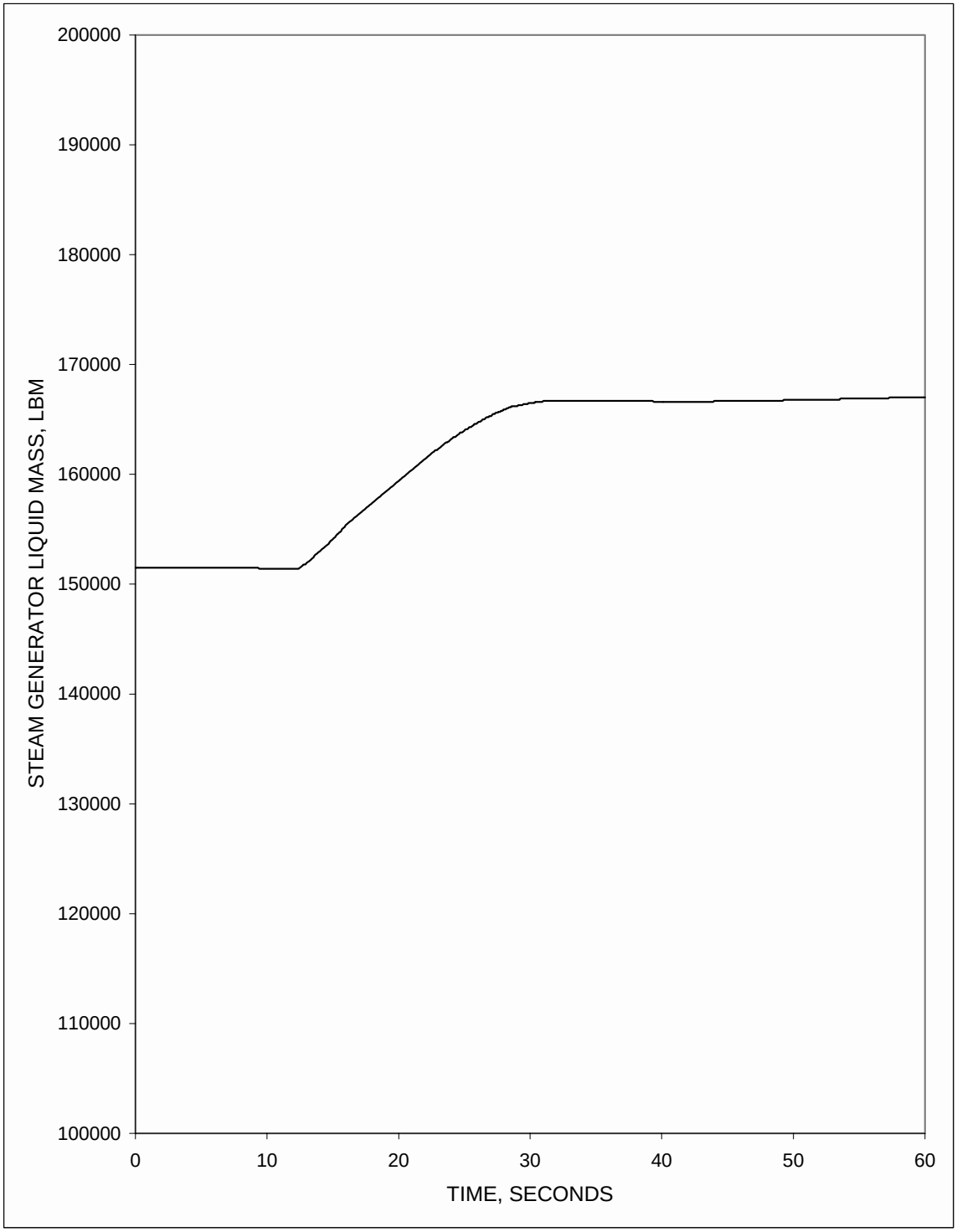

Figure 2.13.4.1.3-10
CEAW at Power
SG Liquid Mass vs. Time

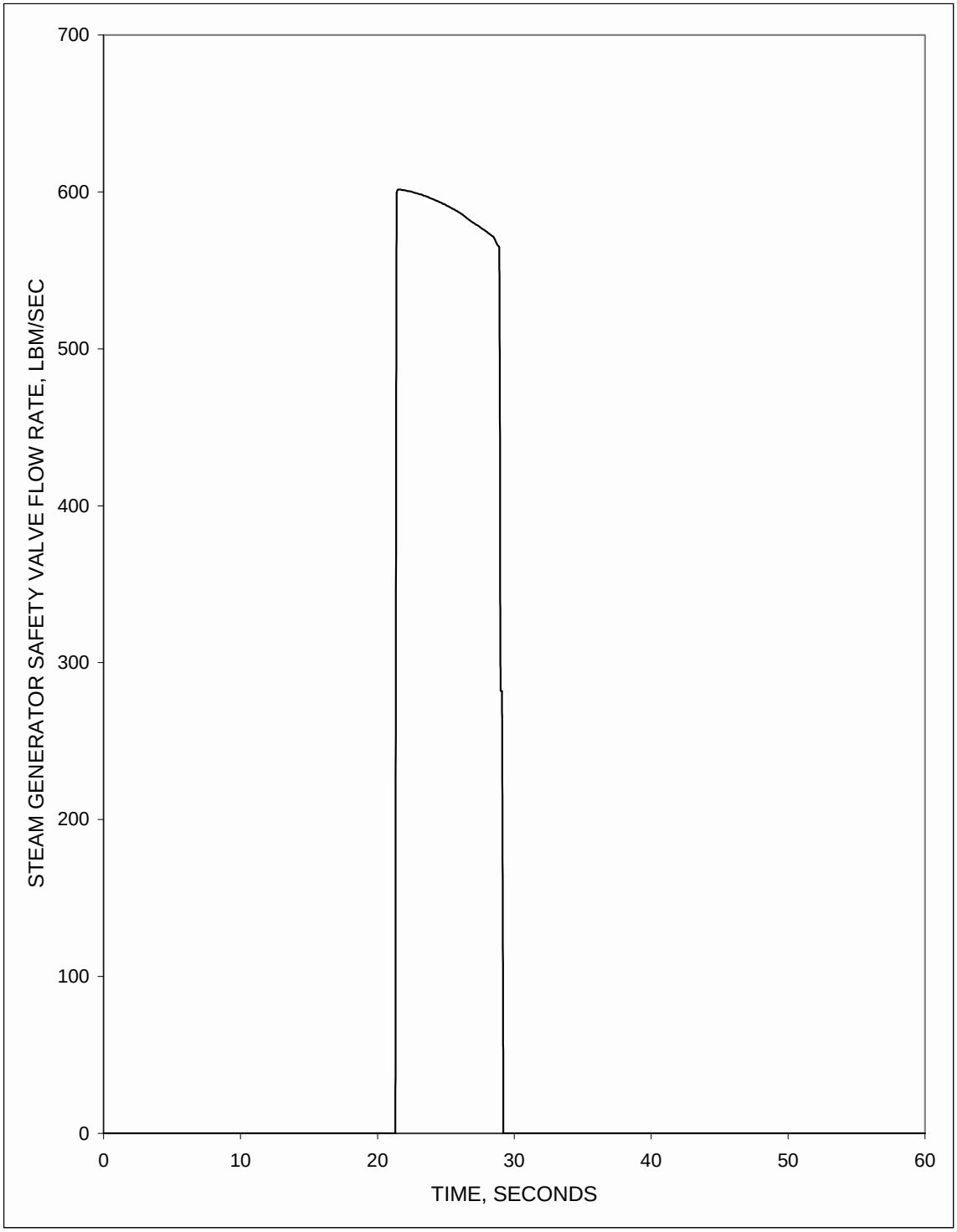

Figure 2.13.4.1.3-11
CEAW at Power
Secondary Safety Valve Flow vs. Time

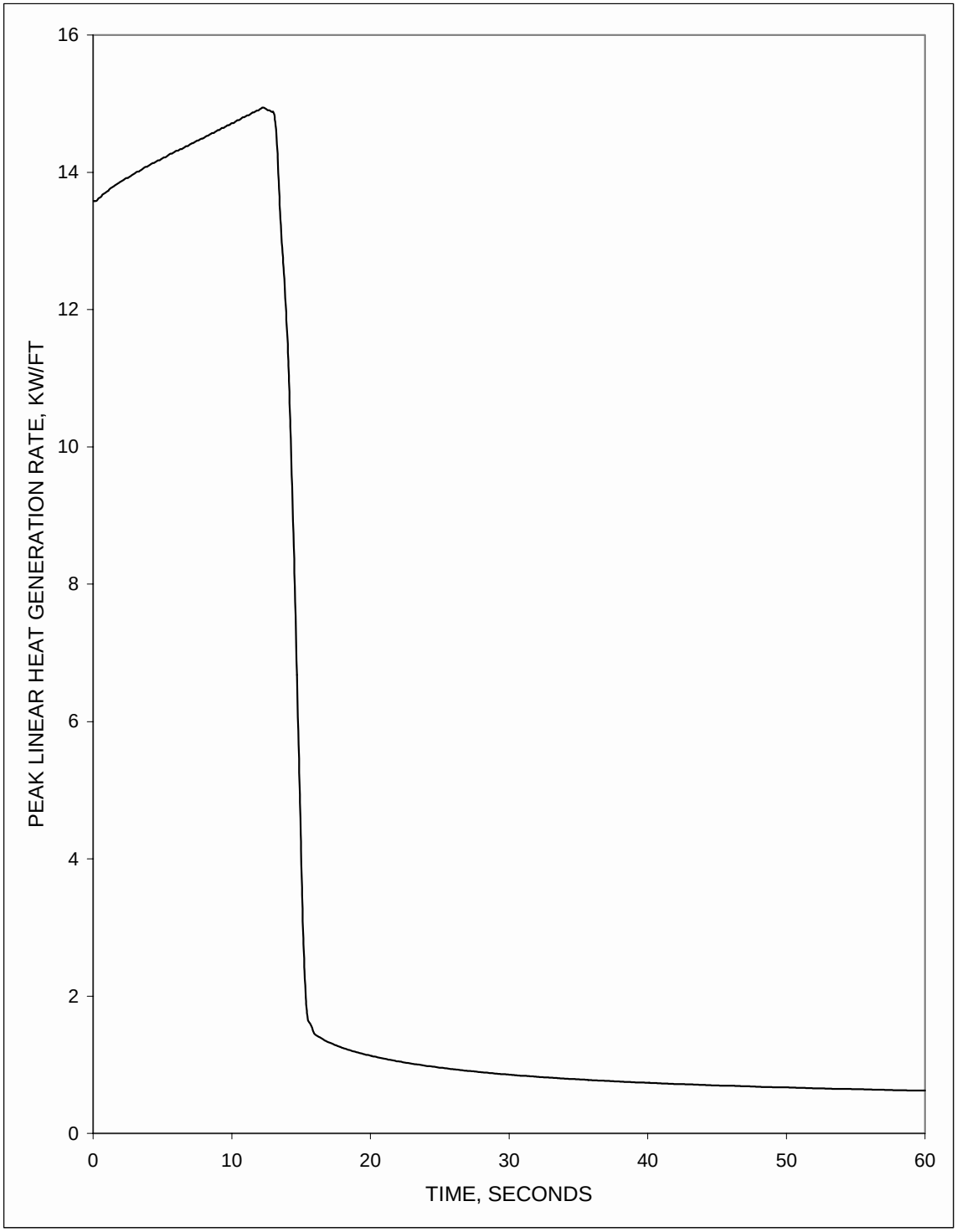

Figure 2.13.4.1.3-12
CEAW at Power
Peak Linear Heat Generation Rate vs. Time

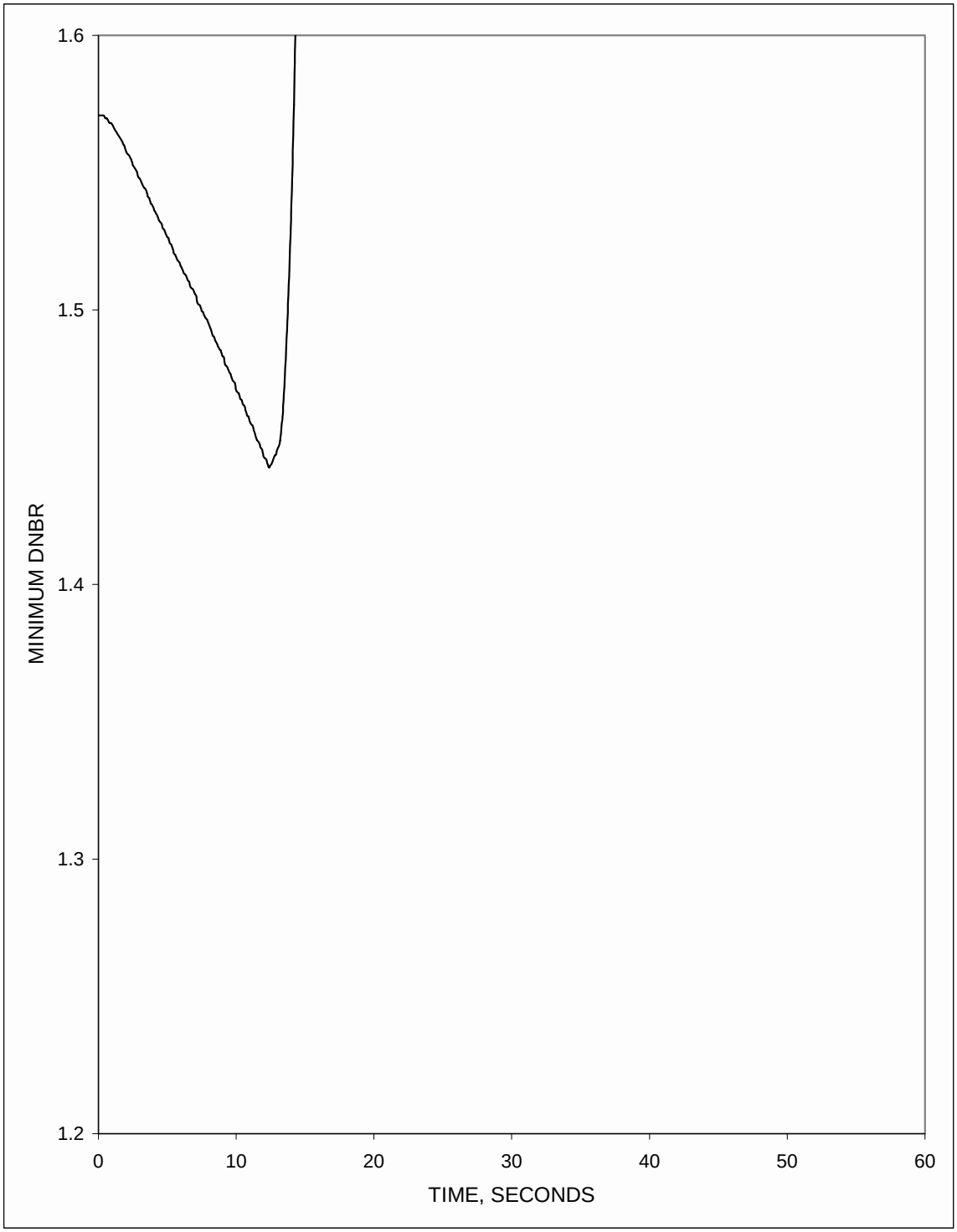

Figure 2.13.4.1.3-13
CEAW at Power
Minimum DNBR vs. Time

2.13.4.1.4 CEA Misoperation

The objective of the CEA misoperation analyses is to demonstrate that the events do not violate the DNBR and LHR SAFDLs for Waterford 3 with power uprate at 3716 MWt.

The limiting CEA misoperation event is the CEA drop. For actual power uprate cores, the reload process will determine the values of radial distortion factors associated with dropped CEAs and CEA subgroups. The thermal margin equivalents of this distortion will be preserved by COLSS and the other thermal-margin-related Core Operating Limit Report (COLR) items.

2.13.4.1.4.1 General Description of the Event

A single full-length control element assembly (CEA) drop results from an interruption in the electrical power to the control element drive mechanism (CEDM) holding coil of a single full length CEA. This interruption can be caused by a holding coil failure or loss of power to the holding coil. The limiting case is the CEA drop, which does not cause a trip to occur, but results in an approach to the DNBR SAFDL.

A dropped CEA subgroup, which is any one set of four symmetrical CEAs moved by the same CEDMCS, can be caused by an electrical failure in the CEA coil power programmers. The effect of any misreported CEA on core power distribution is assessed by the CEA calculators which provide augmented power distribution penalty factors to the core protection calculators (CPCs). The CPCs then can initiate a low DNBR or high-power density trip if specified acceptable fuel design limits are approached.

The single CEA drop is the most adverse CEA misoperation event in terms of approach to the SAFDLs since dropped CEA subgroup is symmetric and produces less power distribution distortion.

The transient is initiated by the release and subsequent drop of a full-length CEA. A rapid decrease in power follows, accompanied by a decrease in reactor coolant temperatures and pressure. In the presence of a negative moderator temperature coefficient (MTC), positive reactivity is added. After the CEA drop, the mismatch between the secondary side (initial turbine demand) and primary side (post-drop power less than initial demand) results in feedbacks that act to restore the primary power to the initial power level. The resultant increase in the hot pin radial peaking factor coupled with a return to 100% of full power (following the temporary power depression) can result in a DNBR that violates the DNBR SAFDL at some time during the transient.

2.13.4.1.4.2 Purpose of Analysis and Acceptance Criteria

The purpose of this analysis is to demonstrate that the full-length CEA drop event does not violate the DNBR and LHR SAFDLs for Waterford 3 with power uprate at 3716 MWt

The following criteria apply to the full-length CEA drop event:

- DNBR > 1.26
- Fuel temperature < fuel melt temperature limit, demonstrated by peak LHR ≤ 21.0 kW/ft
- Radiological dose ≤ small fraction of 10CFR100 limits
- RCS pressures ≤ 110% of design.

2.13.4.1.4.3 Impact of Changes

The increase in core power lowers the DNBR.

The changes to core inlet temperature or reactor flowrate noted in Table 2.13-2 are not significant for the results of this analysis because the inlet temperature and core flow have stabilized to near initial values by the time when minimum DNBR is reached. The specific verification of the core uprate radial power distortion factors will be done as part of the normal reload core design process.

The change in the dropped rod reactivity worth is not significant for the results of this calculation since this analysis shows that core power returns to full power before 1 minute into the event.

The event is now analyzed with the CENTS code versus the CESEC code. The CENTS code is used in the same fashion as was CESEC; thus there is negligible impact on this analysis.

2.13.4.1.4.4 Analysis Overview

The system response during the CEA Drop scenario is calculated with the CENTS code. At time equal to zero a single CEA is dropped into the system over the time span of 1 second. The rod drop reactivity is selected to bound the maximum reactivity of a single CEA. The transient is run at 100% power. In the presence of negative moderator temperature coefficient (MTC) the core returns to full power with a small reduction in core inlet temperature. The analysis assumes nominal values for RCS flow, core inlet temperature, and pressurizer pressure as results are insensitive to these parameters.

The thermal margin necessary to account for the static radial distortion and 15 minutes of Xenon redistribution is preserved in plant LCOs. During this time the operators act to realign the CEAs. Should recovery of the dropped CEA not be possible within this time period, the operators are provided with time dependent power reduction requirements to provide the additional thermal margin necessary to compensate for continued Xenon redistribution.

2.13.4.1.4.5 Radiological Consequences

No SAFDL violation occurs during the CEA drop event. Source terms are therefore limited to the initial primary and secondary limits on coolant activity in the Technical Specifications. Doses for this event are bounded by the IOSGADV with LOOP event in Section 2.13.1.2.4.5. Both events have the same criteria (small fraction of 10CFR100 guidelines), and the IOSGADV with LOOP event radiological dose assumptions are conservative for the CEA drop event.

2.13.4.1.4.6 Analysis Results

The full length CEA drop event does not violate the DNBR ($\geq$ 1.26) and LHR ($\leq$ 21 kW/ft) SAFDLs for Waterford 3 with power uprate at 3716 MWt. The specific verification of the core uprate radial power distortion factors to meet the SAFDLs requirements will be done as part of the normal reload process.

The CEA drop event is not a pressure increasing event and thus it does not challenge the limits on maximum RCS and steam generator pressure.

The core power at the time of minimum DNBR is 100.6% at 900 sec.

The core and system response is given in Figures 2.13.4.1.4-1 through 2.13.4.1.4-8. The calculated DNBR vs. time transient is given in Figure 2.13.4.1.4-9.

The assumptions and sequence of events for the CEA drop event are given in Tables 2.13.4.1.4-1 and 2.13.4.1.4-2.

Table 2.13.4.1.4-1
Comparison of Assumptions for the CEA Drop Event

Parameter	3716 MWt Power Uprate Assumption	Current Power Level Assumption Reference 3, Table 15.4-9
Initial core power, MWt	3735	3441
Core inlet temperature, °F	543	553
Pressurizer pressure, psia	2250	2250
Pressurizer level, %	67.5	---
RCS flowrate x 10^6 lb/hr	158.4	396000
Dropped CEA reactivity worth, %$\Delta\rho$	-0.15	-0.05
Time for CEA to be fully inserted, sec.	1	1
MTC, $10^{-4}\Delta\rho$/°F	-4.2	-3.3
Doppler coefficient multiplier	1.15	1.15
Prompt CEA radial distortion upon drop	1.147	1.09
15 minute Xenon radial distortion	1.097	1.043
PPCS	Auto	---
PLCS	Auto	---

Table 2.13.4.1.4-2
Comparison of the Sequence of Events for the CEA Drop Event

EPU Time (sec)	Current Power Level Time (sec)	Event	3716 MWt EPU Setpoint/Value	Current Power Level Setpoint/Value
0	0	CEA drop initiated	---	---
1.0	1.0	CEA reaches full insertion	---	---
1.2	1.1	Core power level reaches minimum value and begins to increase due to reactivity feedbacks (% of 3410 MWt [current], % of 3716 MWt [uprate])	88.6	92.5
41	27.9	Core power returns to 100% power value (% of 3410 MWt [current], % of 3716 MWt [uprate])	100	100
305	250	Core inlet temperature reaches new steady state value (°F)	539.5	552
900	900	Minimum DNBR is reached	>1.26	>1.26
900	---	Maximum PLHGR (kW/ft)	< 21	---
900	---	Maximum Fr	2.1655	---
900	---	Core power (%)	100.62	---
900	900	Operators act to reduce core power if dropped CEA has not been realigned	---	---

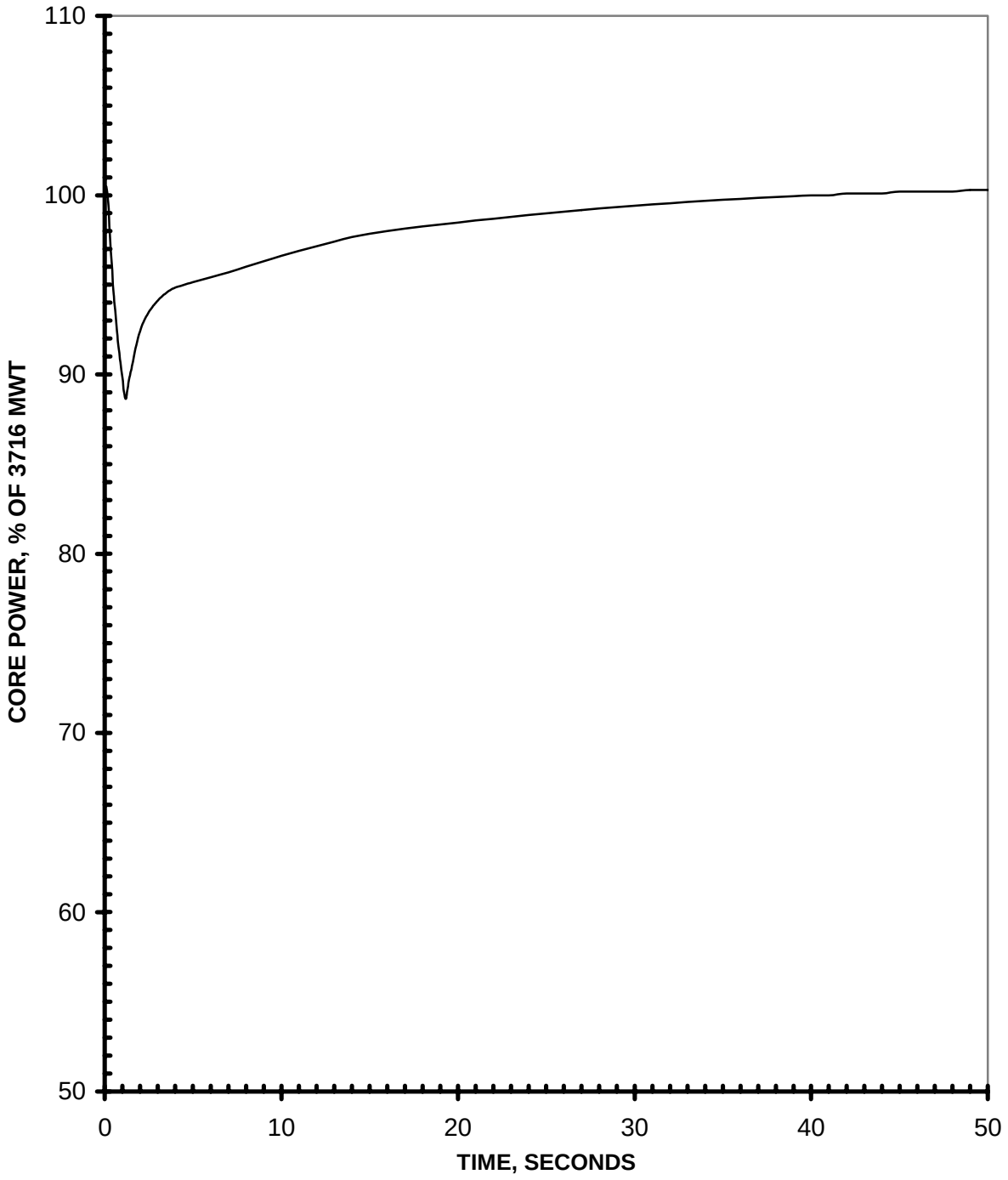

Figure 2.13.4.1.4-1
CEA Misoperation - Single CEA Drop
Core Power vs. Time

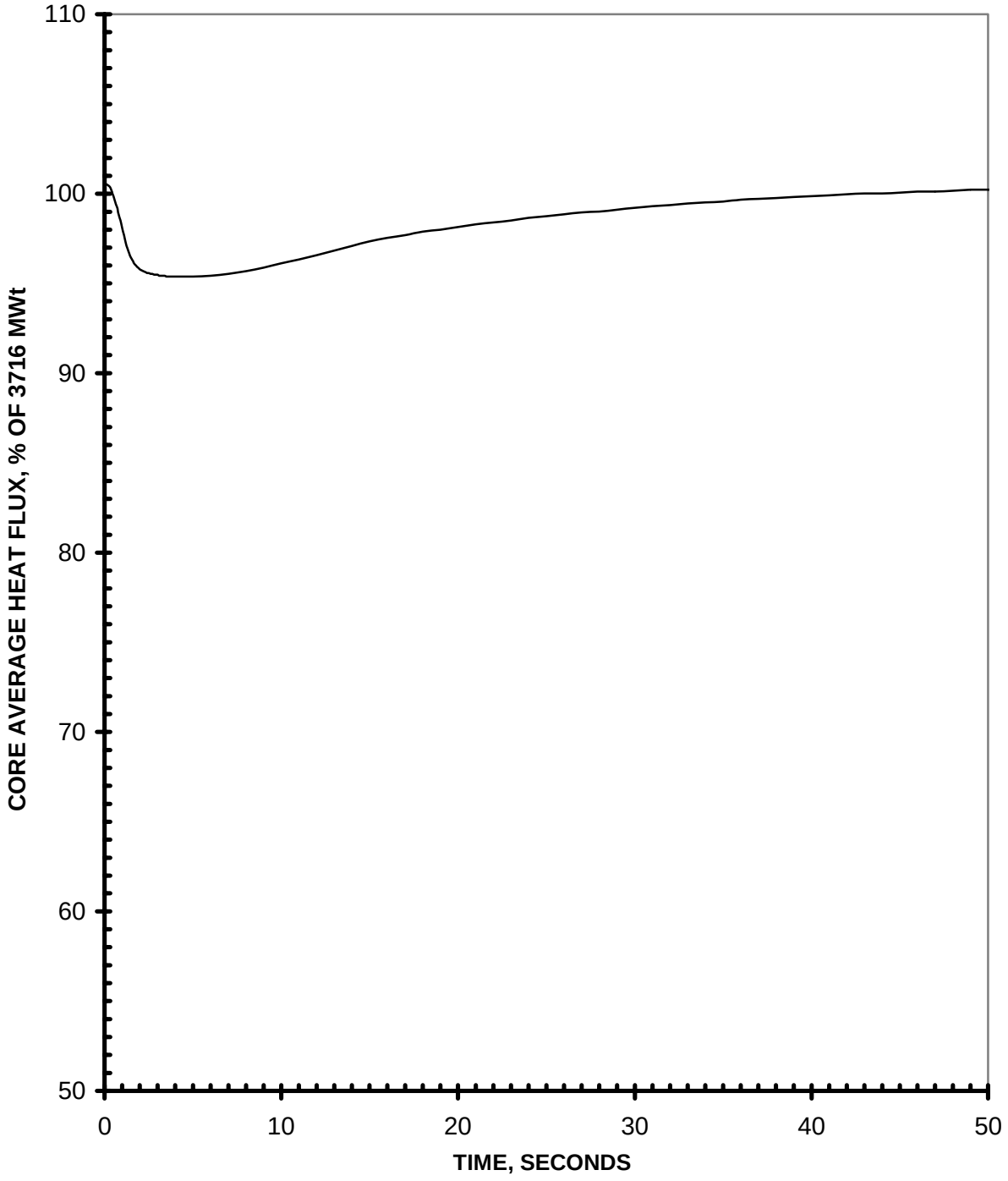

Figure 2.13.4.1.4-2
CEA Misoperation - Single CEA Drop
Core Heat Flux vs. Time

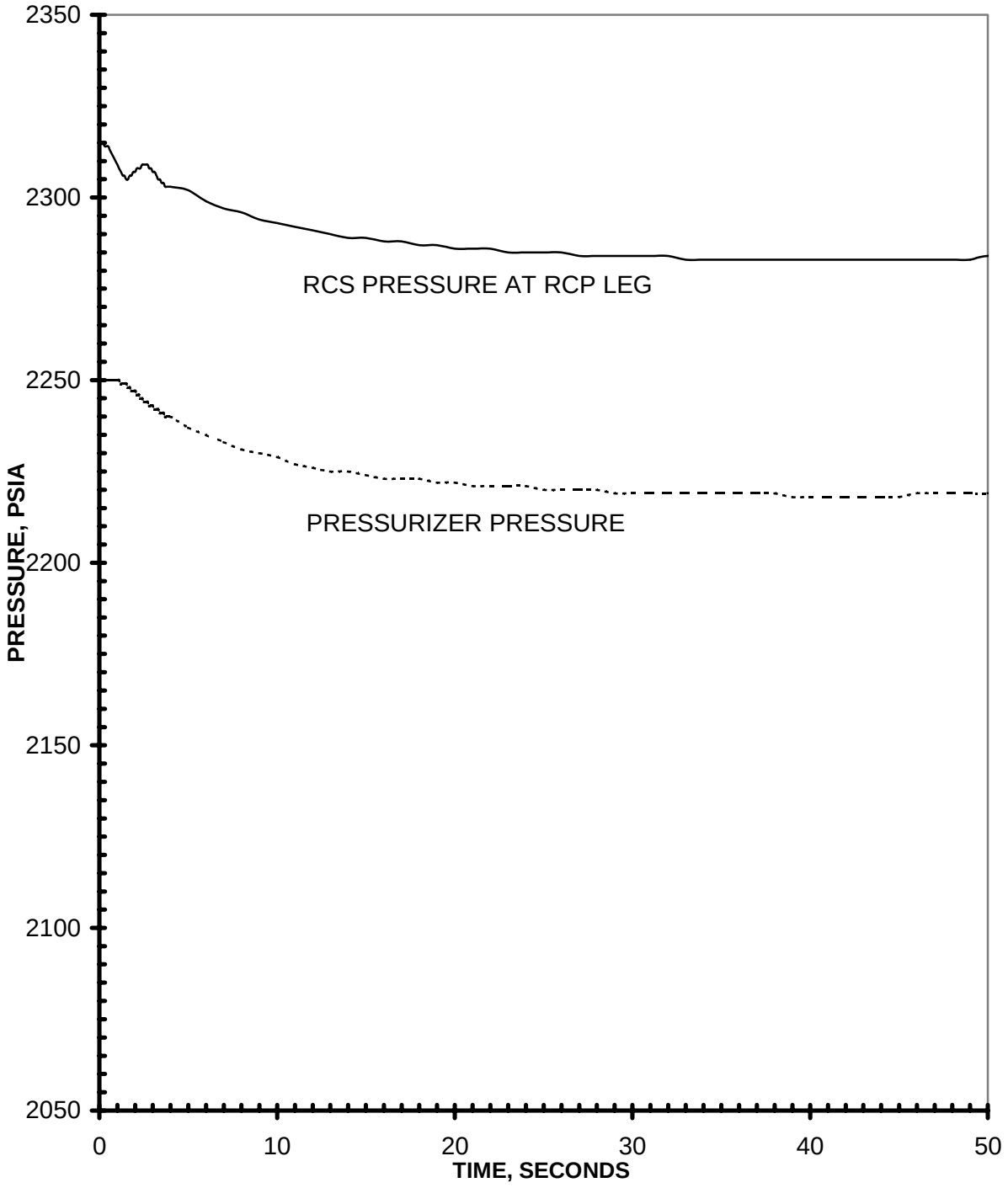

Figure 2.13.4.1.4-3
CEA Misoperation - Single CEA Drop
RCS Pressure vs. Time

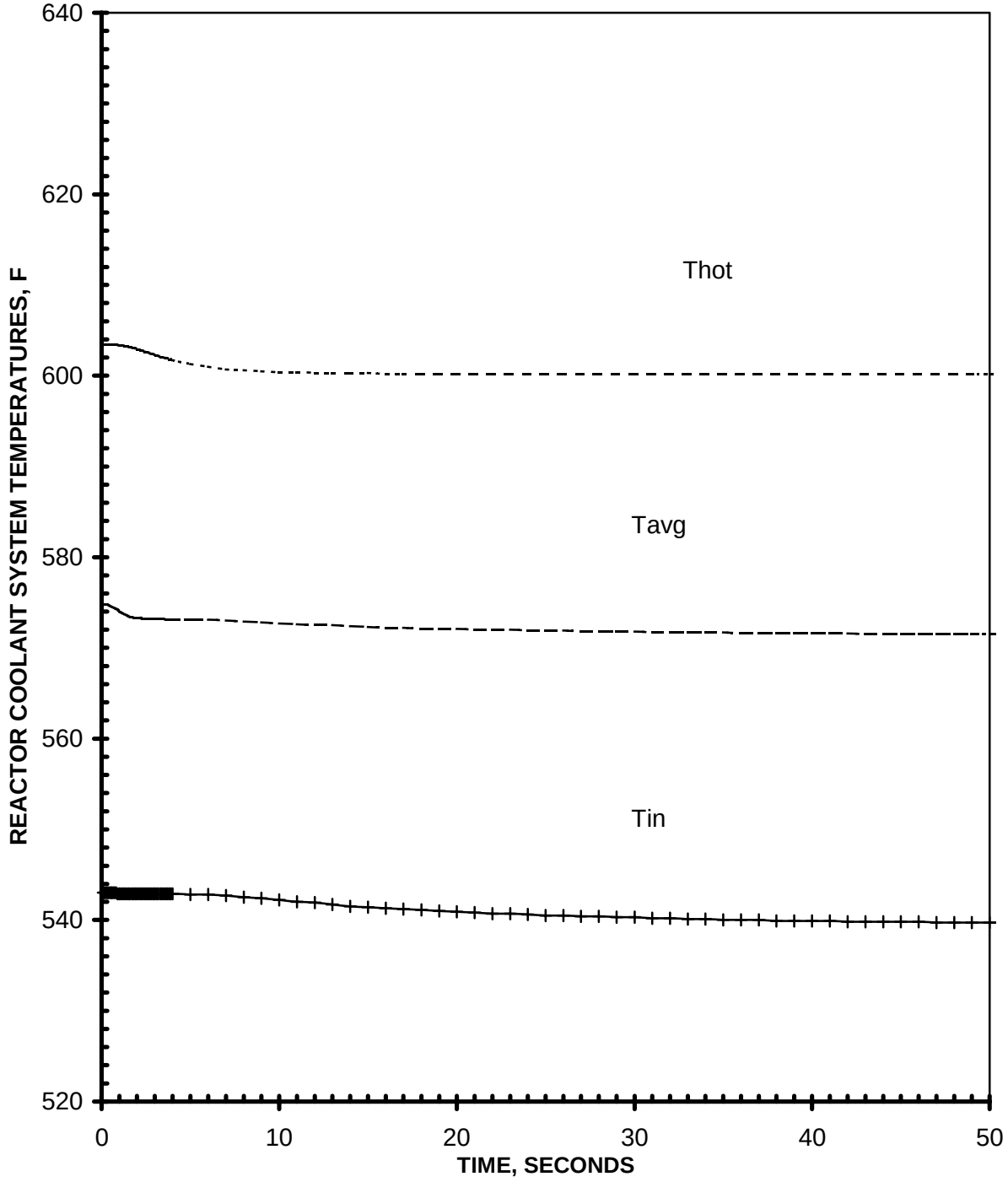

Figure 2.13.4.1.4-4
CEA Misoperation - Single CEA Drop
RCS Temperatures vs. Time

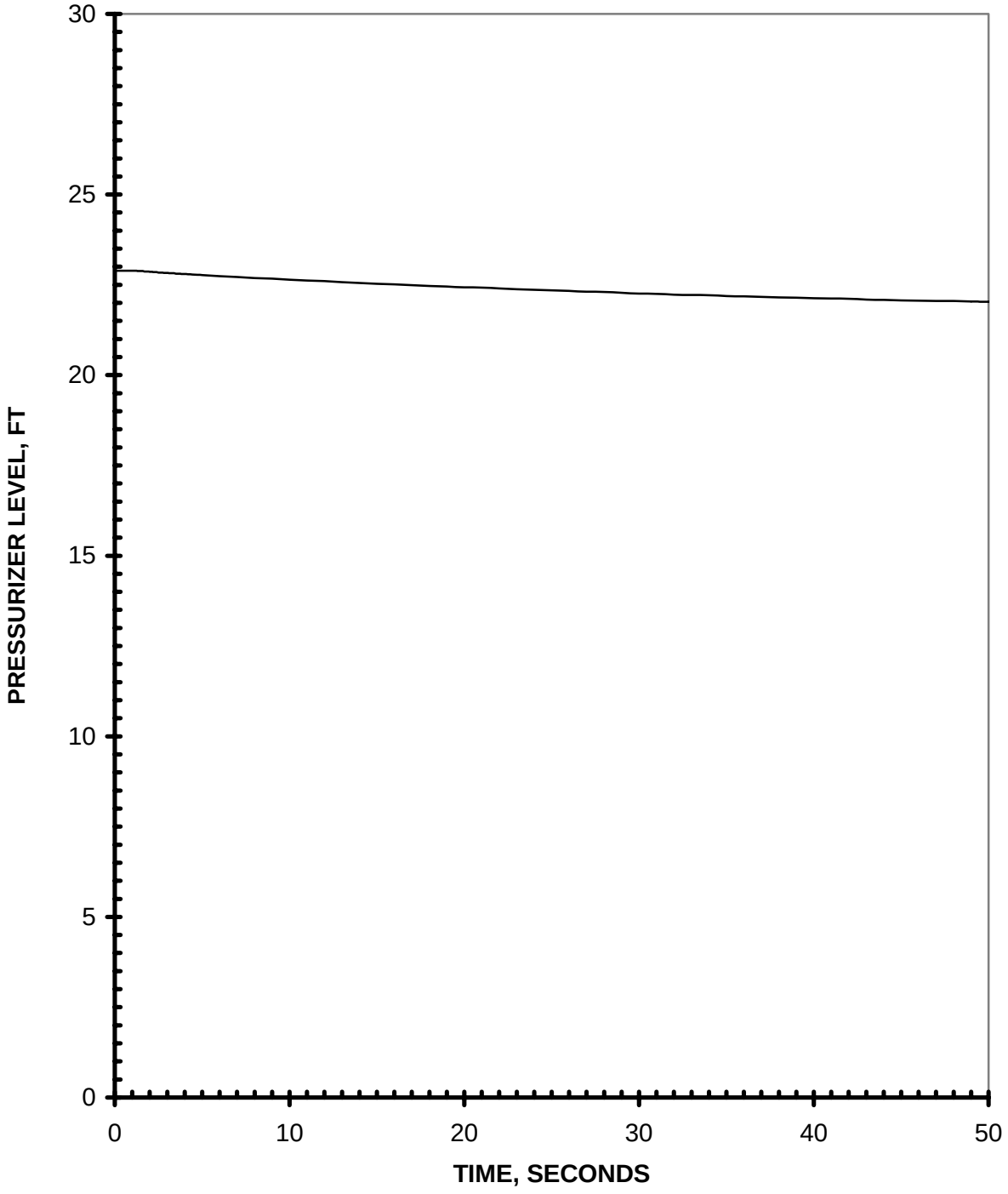

Figure 2.13.4.1.4-5
CEA Misoperation - Single CEA Drop
Pressurizer Level vs. Time

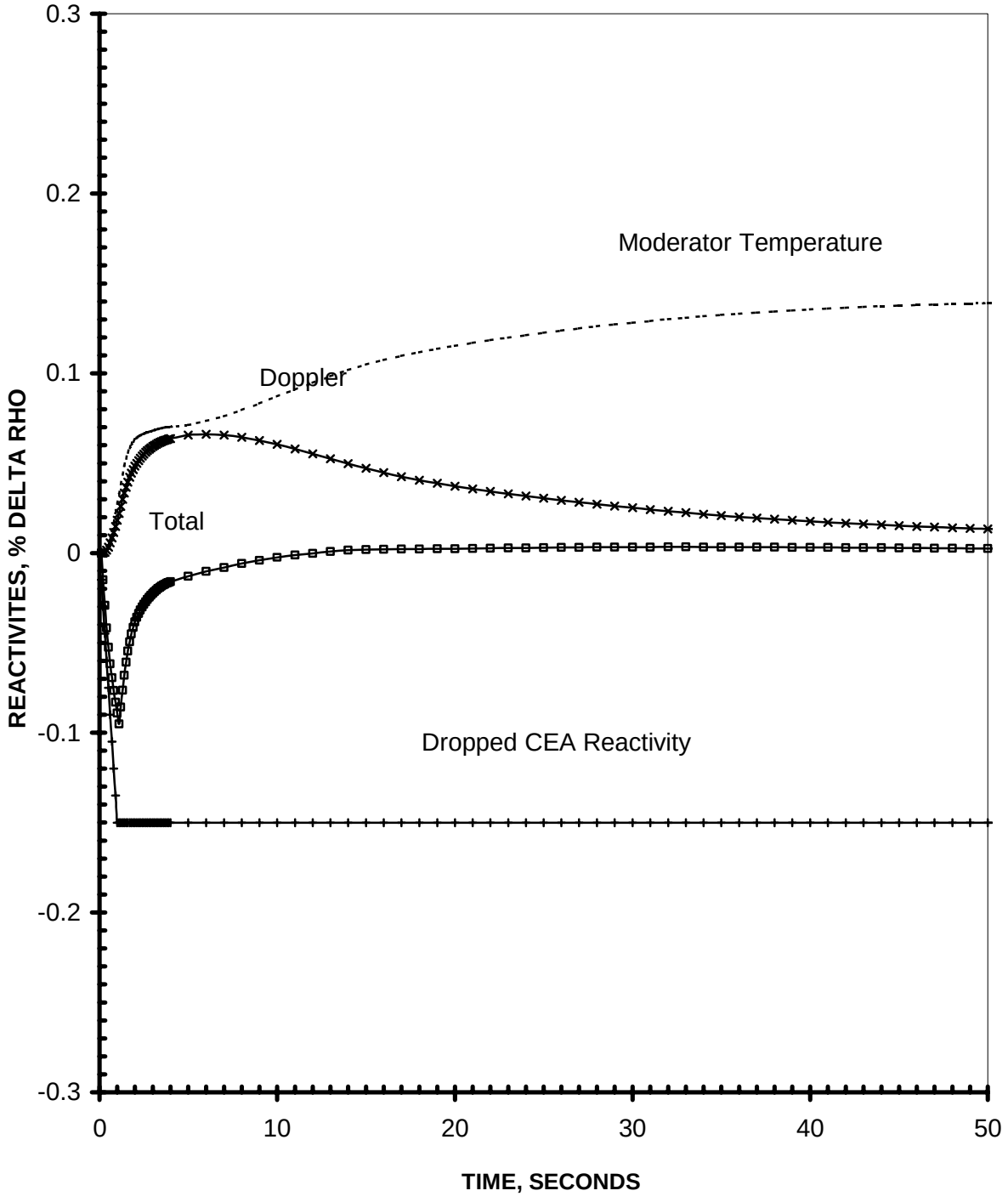

Figure 2.13.4.1.4-6
CEA Misoperation - Single CEA Drop
Reactivities vs. Time

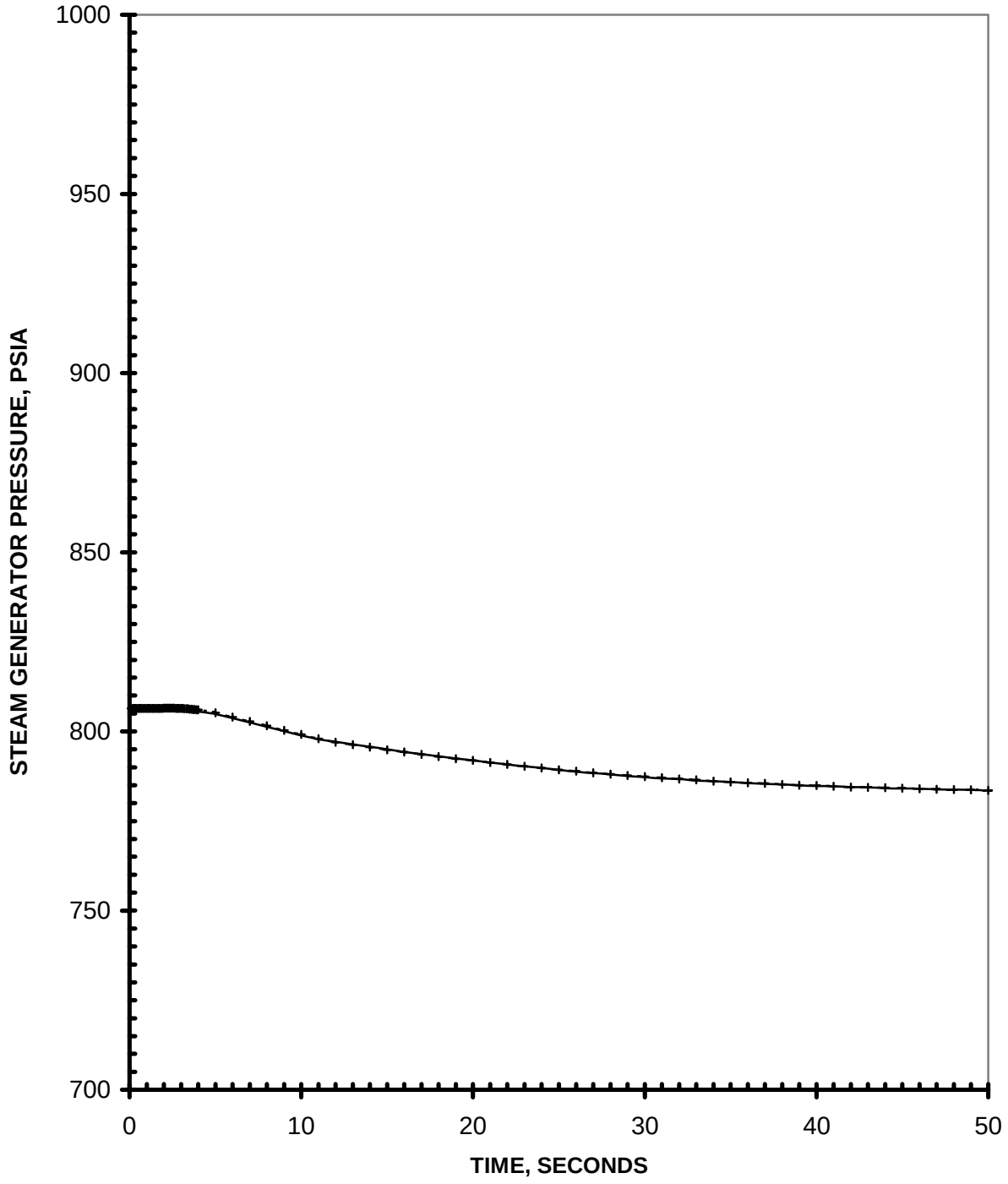

Figure 2.13.4.1.4-7
CEA Misoperation - Single CEA Drop
SG Pressure vs. Time

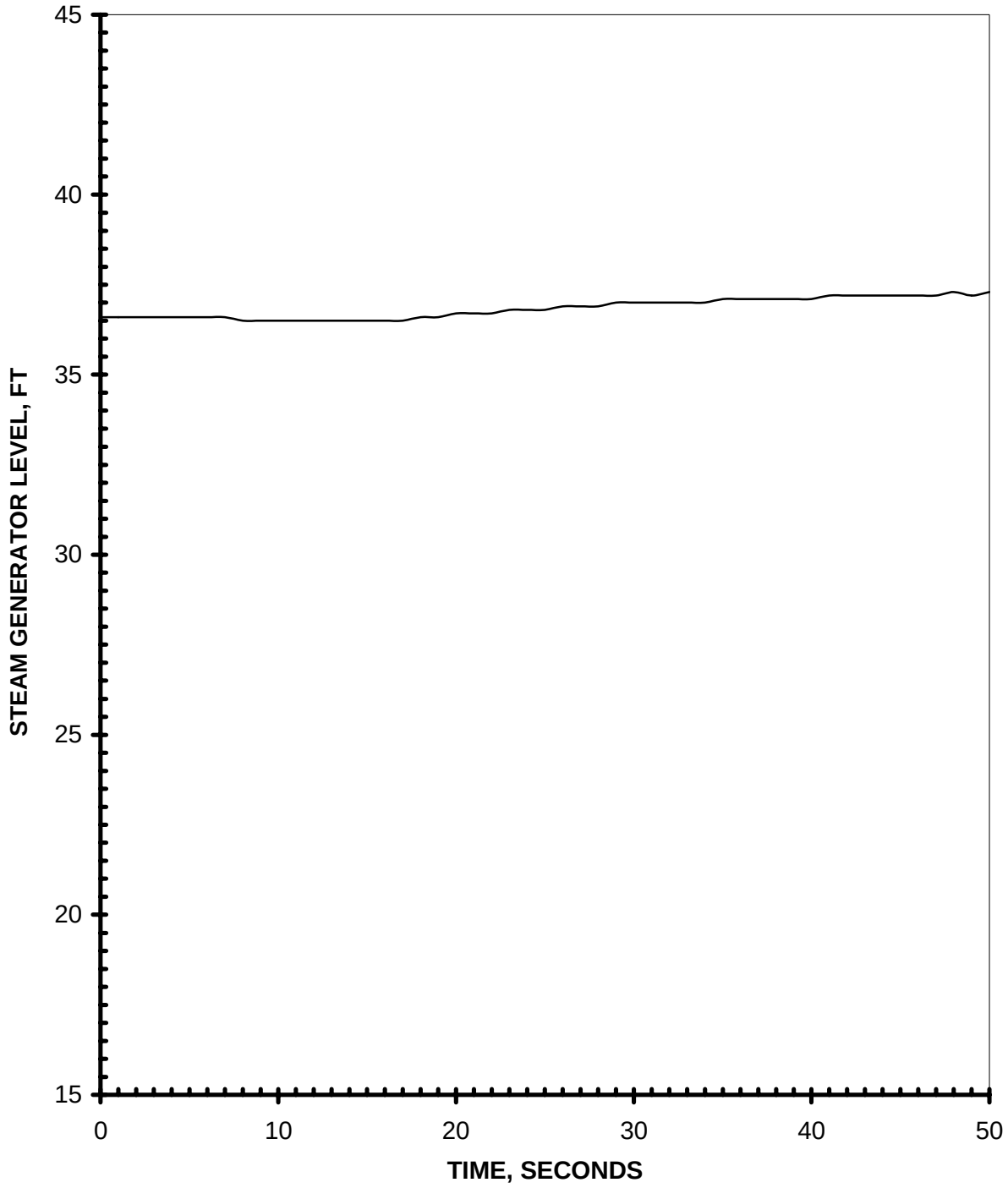

Figure 2.13.4.1.4-8
CEA Misoperation - Single CEA Drop
SG Level vs. Time

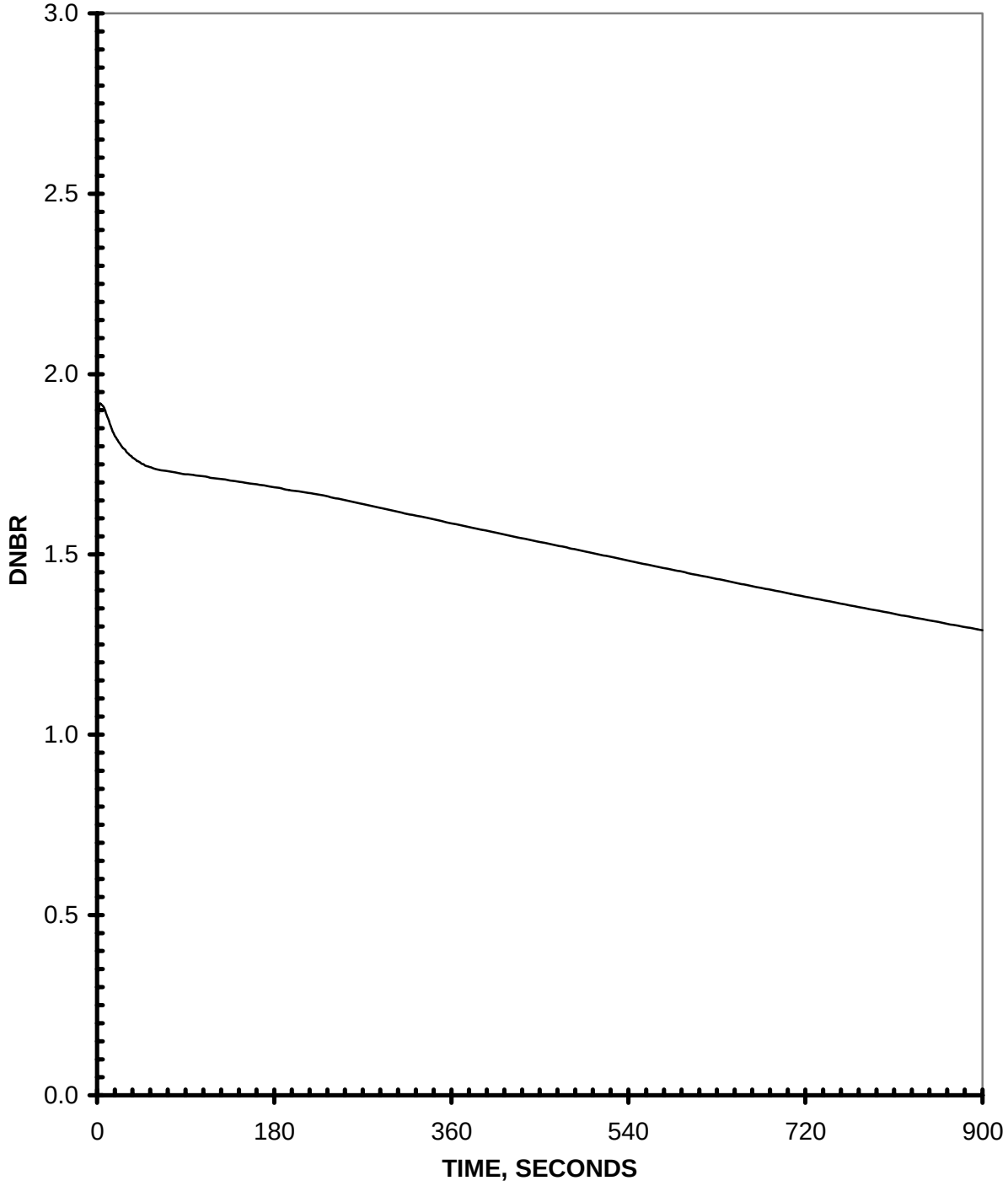

Figure 2.13.4.1.4-9
CEA Misoperation - Single CEA Drop
Minimum DNBR vs. Time

2.13.4.1.5 Inadvertent Boron Dilution

This event is unaffected by the power uprate and bounded by the current FSAR event.

2.13.4.1.6 Startup of an Inactive Reactor Coolant Pump

This event is unaffected by the power uprate and bounded by the current FSAR event.

2.13.4.1.7 CEAW Modes 3, 4 and 5 ARI

This event is unaffected by the power uprate and bounded by the current FSAR event.

2.13.4.2 Infrequent Incidents

None

2.13.4.3 Limiting Faults

2.13.4.3.1 Inadvertent Loading of a Fuel Assembly into an Improper Position

The fuel misloading events are described in Chapter 15.4.3.1 of the FSAR (Reference 2.13-1).

The objective of the analysis of the inadvertent loading of a fuel assembly into an improper position event is to document the impact of the following changes:

- The increase in rated power to 3716 MWt.
- Change to support recent changes to the TRM related to ICI operability.

2.13.4.3.1.1 General Description of the Event

The core reloading process is governed by strict procedures that minimize the possibility of fuel misloadings. These procedures require that a tag board in the main control room be constantly updated by a designated member of the reactor operations staff whenever a fuel assembly is being moved. At the completion of core loading, the exposed surfaces of the top end fittings are inspected to verify that all assemblies are correctly loaded.

In the unlikely event that two assemblies of different initial reactivities would be interchanged, most misloadings would be detected using either the incore or excore neutron detectors (See Figure 2.13.4.3.1-1) during the power ascension physics testing. Misloadings that result in significant azimuthal tilt would be detected by the differences in signals between the four excore detectors during routine monitoring of their signals during the initial power ascension. In addition analysis has shown that if all the incore detectors in the vicinity of the misload are operational, then most of the misloads that may result in a significant increase in power peaking will be detected during fuel symmetry verification test (See Table 2.13.4.3.1-1)

performed at 30% power or less during the initial startup of each cycle. However if some of the incore detectors in the vicinity of the misloaded assembly are inoperable, then some of the misloads that could result in substantial increase in core power peaking may not be detected during the initial power ascension physics testing. Of this small class, the worst case that can be envisioned is the interchange of a fresh shimmed assembly with a once burned assembly near the center of the core. Although this type of misload may result in high local power peaking it may not be detectable if most of the incore detectors in the vicinity of the misload are inoperable since it produces essentially no core wide global power tilt during the power ascension physics testing.

For Waterford 3, operation with an undetectable misload may result in a potential non-conservatism of the COLSS (Reference 2.13-18) and CPC online margin assessment due to the potential non-conservatism of the CECOR (Reference 2.13-17) measurement of local power peaking for the misloaded core. If the CECOR measured values for the radial peaking factors are conservative then safety limits will not be exceeded even during operation with an undetectable misload, since these peaking factors are used by COLSS and CPC to calculate margin to the SAFDLs.

If all the ICIs in the vicinity of the misload are operable then most of the impact of the misload on power peaking will be accounted for. However if some of the ICIs in the vicinity of the misload are inoperable, then the CECOR measurement radial peaking factor may be significantly non-conservative for a core with an undetectable misload. However even in this case the SAFDL will not be exceeded provided that the overpower margin associated with the error in measured peaking factor does not exceed the minimum (required) overpower margin (ROPM) reserved by COLSS. Thus this analysis determines the ROPM that must be reserved by COLSS to assure that the DNB SAFDL is not violated due to a fuel assembly misloading.

2.13.4.3.1.2 Purpose of Analysis and Acceptance Criteria

The NRC acceptance criteria for this analysis are defined by SRP 15.4.7 (Reference 2.13-14). The specific requirements on what the analysis should consider and how the requirements were met in the subject analysis are as follows:

- *A sufficient number of fuel-load errors must be studied by the applicant and presented to show that the worst situation undetectable by incore instrumentation has been identified*. In the present analysis, this criteria has been satisfied by explicitly calculating the power distribution inferred by the incore detector system (CECOR) associated with several postulated misloads and then analytically determining whether any of the various power distribution related startup test will be able to detect the specific misload.
- *Changes in the power distribution and increased local power density* must be considered. This criterion has been satisfied by calculating the power distributions (using ROCS) associated with various misloads, including the power distributions associated with the worst undetectable misload during power operation throughout the cycle.
- *If fuel design limits have been exceeded then the offsite consequences should be a small fraction of the 10CFR100 Guidelines*. This criterion has been satisfied by calculating the minimum DNBR and ROPM associated with the worst undetectable misload and demonstrating that the fuel SAFDLs are not exceeded. The calculated ROPM for this event is compared to the ROPM reserved by COLSS. In addition the MDNBR for the worst

undetectable misload calculated at nominal conditions demonstrates that a significant margin to SAFDL exists.

2.13.4.3.1.3 Impact of Changes

The power uprate will result in an increase in the reactivity difference between fresh and burned fuel. This reactivity difference will result in greater power peaking when fresh and burned assemblies are interchanged. In addition the power uprate will result in more adverse thermal-hydraulic conditions that will reduce the minimum departure from nucleate boiling ratio (MDNBR) and overpower margin.

This analysis has also been extended to be consistent with recent changes to the TRM related to ICI operability requirements. These changes were implemented in order to assure that severe misloads are detected and corrected prior to power operation even when several ICIs are inoperable.

2.13.4.3.1.4 Analysis Overview

The methodology used herein for the assembly misloading analysis is summarized follows:

- Several candidate worst case misloads are selected for analysis. The selection of the representative worst undetectable misload was based on the reactivities and fissile content of the assemblies as well as reactivities of other assemblies in the vicinity of the misloaded assembly.
- A determination is made as to whether the misload is detectable during the startup tests. This is done by using the ROCS code (Reference 2.13-16) to calculate the signal at each of the ICI locations for the fuel symmetry verification test for each postulated assembly misloading. These signals were then used by CECOR to infer the “measured” power distribution. These CECOR cases consider several different configurations of failed instruments in the vicinity of the high-power misloaded assembly consistent with the revised requirements for ICI operability set forth in the Technical Requirement Manual (TRM).
- If the misload is judged detectable by the Fuel Symmetry Verification Test then it is eliminated from further consideration.
- Of the misloads judged undetectable several of the worst candidates are selected for analysis under full power operating conditions. The worst candidates are defined as those having the highest CECOR decalibration factor (DF).
- For each of the assembly misloadings selected for full power analysis the power distribution was calculated by both ROCS and CECOR at several different burnup points. The CECOR cases consider several different configurations of failed instruments consistent with the ICI operability criteria. The ROCS and CECOR core power distributions are then used to establish the maximum CECOR Decalibration Factor during full power operation.
- The power distributions calculated by ROCS and CECOR for the burnup point corresponding to the maximum CECOR DF is used to calculate the minimum DNBR and ROPM using the CETOP code for the worst case misload.

- The largest value of ROPM calculated for the worst undetectable misload is compared to the ROPM installed into COLSS to assure that the DNB SAFDL will not violated under any allowed operating condition.

2.13.4.3.1.5 Radiological Release

There are no radiological releases anticipated for this event since the DNB SAFDL is not violated.

2.13.4.3.1.6 Analysis Results

Table 2.13.4.3.1-2 shows that if all the incore detectors in the vicinity of the misloaded assembly are operational then the misload will be detected during power ascension physics testing since it would exceed the physics startup test acceptance criteria of 10% for the maximum power difference between a detector and the average of its symmetric detector group.

If 3 out of the 4 incore instruments in the vicinity of the misload are inoperable, then the misload may not fail the power ascension acceptance test criteria and operation under a misloaded condition at power may occur. Figure 2.13.4.3.1-2 shows the mid-cycle power distribution for the worst undetectable misload of this type. Table 2.13.4.3.1-3 shows the cycle maximum power peaking factors associated with this misload. If all of the incore detectors in the vicinity of the misload are operable then the error in measured power peaking due to the misload will be 6%. Since the measured power peaking is used by COLSS to determine the available overpower margin (OPM) and since the minimum COLSS available OPM will be confirmed as part of the core reload process to exceed the requirements for the fuel misload analysis, COLSS preserves enough thermal margin so that there is no violation of the DNB SAFDL. Thus, no fuel damage is expected. If 3 out of the 4 ICIs in the vicinity of the misload are inoperable, then the error in measured power peaking due to the misload will be 15%. This corresponds to an overestimate in the available COLSS OPM of 18%; the COLSS OPM is typically 20% and is confirmed to exceed the required value as part of the core reload process. Furthermore, since it is very improbable that 3 out of 4 of the incore detectors in the vicinity of the misload would be inoperable, it is highly likely that the misload will be detected during power ascension or early in the cycle before a significant decrease in operating margin occurs.

Based on these results:

- If all the ICIs in the vicinity of the misload are operational, then the ROPM associated with the representative worst case undetectable misload is expected to be <10%.
- With the current TRM requirement of 1 operable ICI in every 4-by-4 array of fuel assemblies, the worst undetectable misload will not result in fuel failure under any allowed operating condition even with up to 25% failed ICIs.
- The MDNBR at nominal core conditions for the representative worst case undetectable misload including allowance for physics calculational uncertainties is 2.086. In addition, the peak linear heat generation rate (PLHGR) for this worst undetectable misload is also well below the LHR SAFDL for fuel centerline melt. These results indicate that there is sufficient OPM for the representative worst case undetectable misload to accommodate a reasonable

combination of off-nominal core operating conditions and/or expected operational occurrences without resulting in doses that exceed a small fraction of 10CFR100.

On this basis it is concluded that the acceptance criteria for consequence of operation with the worst case undetectable misload is satisfied for the Waterford 3 3716-MWt power uprate cores even assuming that up to 25% of the ICIs are inoperable.

Table 2.13.4.3.1-1
Startup Test Criteria Used for Detecting Fuel Misloads

Criteria
The power in each operable symmetric detector shall be within ±10.0% of the average power in its symmetric detector group.
The vector tilt shall be less than 3% (for >20% power).
The measured value radial peak including tilt (FrT) shall be within ±10% of the predicted value (ROCS).

Table 2.13.4.3.1-2
Maximum Difference in Measured Symmetric Instrument Power for Representative Worst Case Undetectable Misload during Power Ascension Testing

Case	Maximum Difference %
Nominal (no misload)	≈ 0
Measured by CECOR for Representative Worst Case Undetectable Misload, Assuming all ICIs in Vicinity of Misload Are Operable	13.1
Measured by CECOR assuming 3-out–of-4 of the ICIs in Vicinity of Misload Are Inoperable	8.2

Table 2.13.4.3.1-3
Maximum Power Peaking Factors Occurring for Representative Worst Case Undetectable Misload

Case	Cycle Max Radial Peaking Factor
Nominal (no misload)	1.57
Representative Worst Case Undetectable Misload	1.86
Measured by CECOR for Representative Worst Case Undetectable Misload, Assuming all ICIs in Vicinity of Misload Are Operable	1.75
Measured by CECOR Assuming 3-out-of–4 of the ICIs in Vicinity of Misload Are Inoperable	1.59

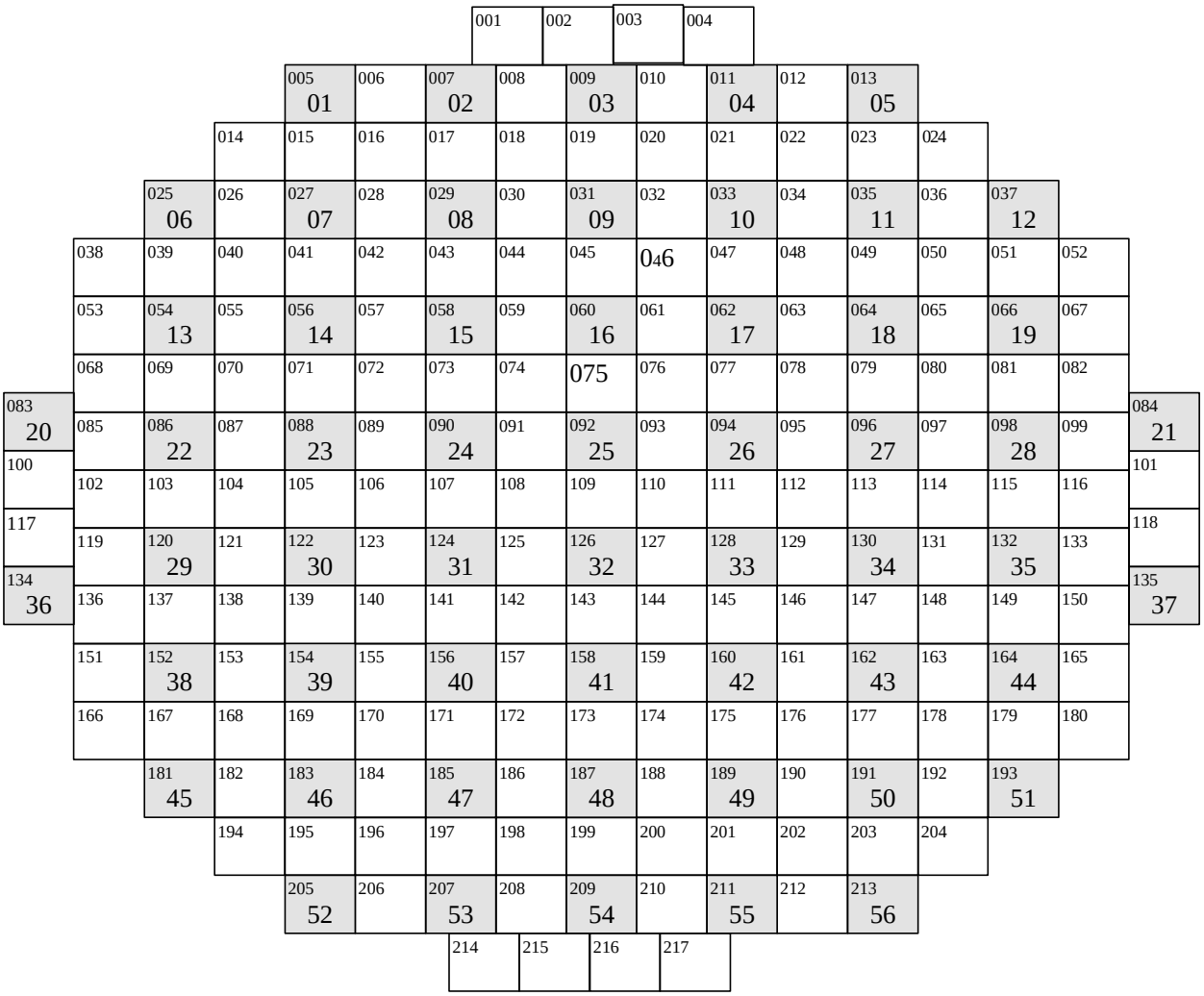

Figure 2.13.4.3.1-1
Locations of Incore Neutron Detectors

Assembly Type
Max Rod Power
Assembly Power

						X3 0.48 0.22	X8 0.61 0.32	X8 0.61 0.32	X3 0.48 0.22					
			X2 0.43 0.18	X6 0.64 0.35	Y8 0.96 0.61	Z2 1.42 1.10	Z3 1.40 1.16	Z2 1.42 1.10	Y8 0.95 0.61	X6 0.64 0.34	X2 0.44 0.18			
		X2 0.63 0.29	Y6 0.91 0.61	Z2 1.33 1.07	Z3 1.44 1.28	Z6 1.48 1.38	Y6 1.14 1.10	Z6 1.48 1.38	Z3 1.43 1.27	X2 1.65 1.63	Y6 1.75 1.76	Z2 1.84 1.89		
	X2 0.63 0.29	Z2 1.37 0.99	Z3 1.43 1.24	Y8 1.10 1.00	Y3 1.19 1.07	Y7 1.20 1.11	Z6 1.54 1.45	Y7 1.18 1.10	Y3 1.16 1.05	Y8 1.07 0.98	Z3 1.41 1.23	Z2 1.36 0.98	X2 0.62 0.28	
X2 0.44 0.18	Y6 0.91 0.60	Z3 1.43 1.24	Y2 1.39 1.21	Z7 1.57 1.44	Y3 1.31 1.18	Z7 1.61 1.49	Y3 1.35 1.25	Z7 1.56 1.45	Y3 1.24 1.12	Z7 1.49 1.38	Y2 1.35 1.19	Z3 1.41 1.23	Y6 0.90 0.60	X2 0.43 0.18
X6 0.63 0.34	Z2 1.31 1.06	Y8 1.09 0.99	Z7 1.56 1.42	Y8 1.33 1.22	Z8 1.81 1.64	Y7 1.35 1.26	Z8 1.63 1.53	Y7 1.22 1.18	Z8 1.57 1.47	Y8 1.18 1.13	Z7 1.49 1.38	Y8 1.07 0.98	Z2 1.32 1.06	X6 0.64 0.34
Y8 0.92 0.59	Z3 1.37 1.24	Y3 1.14 1.03	Y3 1.28 1.15	Z8 1.80 1.62	Z6 1.86 1.78	Z8 1.81 1.64	Y2 1.35 1.25	Z8 1.57 1.48	Y2 1.38 1.27	Z8 1.56 1.46	Y3 1.24 1.12	Y3 1.16 1.05	Z3 1.42 1.27	Y8 0.96 0.61
X3 0.46 0.21	Z2 1.35 1.05	Z6 1.37 1.29	Y7 1.08 1.02	Z7 1.56 1.41	Y7 1.34 1.23	Z8 1.81 1.63	Y2 1.51 1.24	Y2 1.17 1.09	Y2 1.33 1.15	Z8 1.56 1.46	Y7 1.20 1.16	Z7 1.54 1.44	Y7 1.17 1.10	Z6 1.47 1.37	Z2 1.42 1.10	X3 0.48 0.22
X8 0.58 0.31	Z3 1.32 1.10	Y6 1.03 0.99	Y2 1.14 1.05	Y3 1.29 1.14	Z8 1.59 1.48	Y2 1.30 1.24	Y2 1.20 1.09	S4 0.88 0.84	Y2 1.13 1.06	Y2 1.27 1.19	Z8 1.55 1.47	Y3 1.31 1.22	Z6 1.52 1.43	Y6 1.14 1.09	Z3 1.40 1.16	X8 0.61 0.32
X8 0.58 0.31	Z2 1.34 1.05	Z6 1.36 1.28	Y7 1.06 1.00	Z7 1.49 1.36	Y7 1.19 1.15	Z8 1.56 1.47	Y2 1.33 1.15	Y2 1.13 1.06	Y2 1.32 1.14	Z8 1.55 1.46	Y7 1.20 1.16	Z7 1.54 1.43	Y7 1.17 1.10	Z6 1.47 1.37	Z2 1.42 1.10	X8 0.61 0.32
X3 0.46 0.21	Y8 0.92 0.59	Z3 1.36 1.22	Y3 1.11 1.01	Y3 1.21 1.10	Z8 1.55 1.45	Y2 1.37 1.26	Z8 1.56 1.46	Y2 1.27 1.19	Z8 1.56 1.46	Y2 1.37 1.26	Z8 1.56 1.46	Y3 1.24 1.12	Y3 1.16 1.05	Z3 1.43 1.27	Y8 0.96 0.61	X3 0.48 0.22
X6 0.62 0.34	Z2 1.29 1.04	Y8 1.06 0.97	Z7 1.48 1.37	Y8 1.18 1.13	Z8 1.56 1.46	Y7 1.20 1.16	Z8 1.55 1.47	Y7 1.20 1.16	Z8 1.56 1.46	Y8 1.18 1.13	Z7 1.49 1.38	Y8 1.07 0.99	Z2 1.32 1.07	X6 0.64 0.34
X2 0.43 0.18	Y6 0.89 0.59	Z3 1.40 1.22	Y2 1.34 1.19	Z7 1.48 1.38	Y3 1.24 1.12	Z7 1.54 1.44	Y3 1.31 1.22	Z7 1.54 1.44	Y3 1.24 1.12	Z7 1.49 1.38	Y2 1.35 1.19	Z3 1.41 1.23	Y6 0.90 0.60	X2 0.44 0.18
	X2 0.62 0.28	Z2 1.36 0.98	Z3 1.41 1.23	Y8 1.07 0.99	Y3 1.16 1.05	Y7 1.18 1.10	Z6 1.52 1.44	Y7 1.18 1.10	Y3 1.16 1.05	Y8 1.07 0.99	Z3 1.41 1.23	Z2 1.36 0.98	X2 0.63 0.29	
		X2 0.63 0.29	Y6 0.91 0.60	Z2 1.32 1.07	Z3 1.43 1.27	Z6 1.47 1.38	Y6 1.14 1.09	Z6 1.47 1.38	Z3 1.43 1.27	Z2 1.32 1.07	Y6 0.90 0.60	X2 0.62 0.28		
			X2 0.44 0.18	X6 0.64 0.34	Y8 0.96 0.61	Z2 1.42 1.10	Z3 1.40 1.17	Z2 1.42 1.10	Y8 0.96 0.61	X6 0.64 0.34	X2 0.43 0.18			
						X3 0.48 0.22	X8 0.61 0.32	X8 0.61 0.32	X3 0.48 0.22					

Denotes position of Misloaded Assemblies

Figure 2.13.4.3.1-2
Power Distribution for Representative Worst Case Undetectable Misload

2.13.4.3.2 Control Element Assembly Ejection

The objective of the control element assembly (CEA) ejection event analysis is to document the impact of the following changes:

- The increase in rated power to 3716 MWt
- Changes in ejected CEA worth reflecting the uprate core designs
- Switch from CESEC to CENTS to evaluate the peak pressure response of the NSSS

2.13.4.3.2.1 General Description of the Event

An ejected CEA is assumed to occur due to a complete circumferential break of either the control element drive mechanism (CEDM) housing or the CEDM nozzle on the reactor vessel. The ejection of the CEA results in positive reactivity insertion into the core, which causes local powers and fuel temperatures to increase. The increasing fuel temperature in conjunction with the Doppler fuel temperature coefficient causes negative reactivity to be inserted into the core. The negative reactivity mitigates the power rise due to the ejected CEA.

After ejection of a CEA, core power rises rapidly. The event proceeds until Doppler feedback terminates the power rise and the Core Protection Calculator System (CPCS) variable overpower trip (VOPT) setpoint is reached. The event is terminated when negative reactivity is added due to the insertion of the CEAs.

2.13.4.3.2.2 Purpose of Analysis and Acceptance Criteria

Two analyses were performed: the DNBR analysis and the Fuel Enthalpy Analysis. The purpose of the DNBR analysis was to quantify the number of fuel pins violating the DNBR SAFDL of 1.26 at initial power levels of 20%, 50%, 80%, and 100% rated thermal power (RTP). The purpose of the fuel enthalpy analysis was to find the isenthalpic lines of 250 and 280 cal/gm on the power specific pin censuses for 0%, 20%, 50%, 80%, and 100% RTP. Note that the HZP cases presented in the FSAR have unrealistically high CEA worths. Cases from HZP do not present a challenge in actual Waterford 3 core designs as the PDIL allows the same insertion for 20% power and HZP and due to the lower power, additional initial thermal margin exists at HZP.

The analysis has the following acceptance criteria:

- The radially averaged fuel enthalpy must be less than or equal to 280 cal/gm. The incipient fuel melting enthalpy limit is 250 cal/gm.
- The peak RCS pressure must be less than or equal to 2750 psia.
- Radiological consequences must be within 10CFR100 limits.

The CEA ejection events are described in Chapter 15.4.3.2 of the FSAR (Reference 2.13-1).

2.13.4.3.2.3 Impact of Changes

The CENTS code was used in the same manner as the CESEC code to model the peak NSSS pressure response to the CEA ejection. In both cases, no credit was taken for the pressure relieving effect of modeling the breach in the RCS pressure boundary.

The increase in rated thermal power has the potential to be adverse in terms of the peak RCS pressure. Impact on the fuel performance cases is small as both uprate and current core designs begin the events from minimum thermal margin conditions.

The assumed ejected CEA worths have increased slightly for the uprate cores. The values used in the analysis bound those expected for actual uprate cycles.

2.13.4.3.2.4 Analysis Overview

This analysis has utilized the STRIKIN II (Reference 2.13-9) computer code for the DNBR data and fuel enthalpy calculations. Fuel failures were calculated from the DNBR data using the convolution method. (See Section 2.13.0.5) The CENTS (Reference 2.13-2) code was used to calculate the peak RCS pressure. (Reference 2.13-2)

Input parameters from Tables 2.13.4.3.2-1 (STRIKIN) and 2.13.4.3.2-3 (CENTS), and the bounding physics data from Section 2.13.0.2 of this report have been incorporated in this analysis with the following clarifications:

- The least negative (BOC) Doppler was assumed.
- An EOC delayed neutron fraction consistent with that defined in Section 2.13.0.2 was assumed.
- For all power levels, the CEA insertion curve assumed accounts for a 0.6-second holding coil delay. A conservative CEA worth for each power level was assumed.
- The least negative/most positive (BOC) MTC was assumed.
- The variable overpower trip (VOPT) of the CPCS was employed in the analysis. A CPCS trip delay time of 0.629 seconds was conservatively assumed. This timing is a conservative assumption with respect to the CPC delay times discussed in Section 2.13.0.3 and nuclear instrumentation response times.
- The VOPT assumed an excore uncertainty of 40% from Table 2.13.4.3.2-1. This is a conservative allowance covering the asymmetry in core power production/excore response and assumes failures in the excore detector channels seeing the greatest power increase.
- An initial core power of 3735 MWt was assumed based on a rated power of 3716 MWt and a 0.5% uncertainty.
- Of the four excore channels, the one closest to the ejected CEA location is assumed inoperable and a failure of the next best detector channel is assumed.

Previous analyses ran BOC cases and EOC cases from both HZP and HFP. The HFP power cases yield more conservative results. The most limiting overall conditions (BOC vs. EOC) were used.

2.13.4.3.2.5 Radiological Release

With the release path resulting from the CEA ejection, the 10CFR100 limits would not be exceeded until greater than 15% of the fuel pins fail due to DNB.

The radiological consequences for the CEA ejection were calculated assuming that the radioisotopes in the gas gap of the pins which experience DNB were mixed with the RCS volume. The two available release paths for this activity to reach the environment are 1) containment leakage and 2) release via SG tube leakage and the MSSS during cooldown of the plant.

Cycle-specific fuel failure evaluations for power uprate cores will be performed to ensure that this fuel failure limit will not be exceeded. For the CEA ejection, the fuel failure limit was determined to be 15.0% of the fuel pins.

The radiological consequences resulting from these fuel failure results are:

	2-Hour EAB	**8-Hour LPZ**
Thyroid	< 300 rem	< 300 rem
Whole Body	< 25 rem	< 25 rem

2.13.4.3.2.6 Analysis Results

The CEA ejection results in a limited number of pins experiencing DNBR and no fuel pins experiencing melting. The limit on fuel failure is determined by the dose calculation presented above and will be enforced by setpoints and core designs for actual uprate cycles.

A spectrum of power levels is examined and the worst case fuel failures may occur for less than rated power conditions in any specific uprate core. The fuel failure limitations will however be enforced throughout the spectrum.

Peak RCS pressure psia remains below 110% of design pressure without crediting the breach of the RCS pressure boundary as a path for pressure relief.

Table 2.13.4.3.2-1
Assumptions for the CEA Ejection (Full Power)

Parameter	3716-MWt Power Uprate Assumption	Current Power Level Assumption	Current Power Level Assumption
		BOC	EOC
Initial Core Power, MWt	3735	3478	3478
Delayed neutron fraction, β	0.004120	0.007234	0.005295
Pzr level %	67.5	---	---
MTC, 10^{-4} $\Delta\rho$/°F	-0.2	+0.5	-1.3
Ejected CEA worth, 10^{-2} $\Delta\rho$	0.20	0.1639	0.1463
Doppler coefficient multiplier	0.85	0.85	0.85
Initial 3-D fuel pin peaking factor	2.01	3.50	3.55
Ejected 3-D fuel pin peaking factor	5.58	4.73	4.87
CEA worth on reactor trip, %$\Delta\rho$	-5.00	-6.4	-6.4
Postulated CEA ejection time, sec	0.05	0.05	0.05
Core inlet coolant temperature, °F	533	534	530
RCS flowrate, 10^6 lbm/hr	165.2*	143.0	143.0
Pressurizer pressure, psia	2310	2250	2250

* Calculated from mass flux POL.

Table 2.13.4.3.2-2
CEA Ejection Sequence of Events (Full Power)

3716 MWt EPU Time (sec)	Current Power Level Time (sec)	Event	3716-MWt EPU Setpoint/Value	Current Power Level Setpoint/Value
0.00	0.0	Mechanical failure of CEDM causes CEA to eject	---	---
0.05	0.05	CEA fully ejected	---	---
0.07	0.05	CPC VOPT, % of full power	159	130
0.07	0.10	Maximum core power occurs, % of full power	190.2	139.2
0.699	0.45	Trip breakers open	---	---
1.299	0.75	CEAs begin to drop into core	---	---
2.37	2.80	Maximum clad surface temperature in hot node, °F	1170	1160
3.2	2.81	Maximum fuel centerline temperature in hot node, °F	4939	5144
4.8	4.25	CEA fully inserted, core power reduced to below 10% power	---	---
1800	1800	Operator teakes control of plant	---	---
28,800	---	SDC initiated	---	---

Table 2.13.4.3.2-3
Assumptions for the CEA Ejection Peak RCS Pressure Case

Parameter	3716-MWt Power Uprate Assumption
Initial core power level, MWt	3735
Delayed neutron fraction	0.004120
MTC, 10^{-4} $\Delta\rho$/°F	-0.2
Ejected CEA worth, 10^{-2} $\Delta\rho$	0.20
Doppler coefficient multiplier	0.85
CEA worth on trip, 10^{-2} $\Delta\rho$	-5.00
Postulated CEA ejection time, sec	0.05
Core inlet temperature, °F	533
RCS flowrate, 10^{6} lbm/hr	177.6
Pressurizer pressure, psia	2310
Pressurizer level, %	67.5
SG pressure, psia	753
SG level, %	68

Table 2.13.4.3.2-4
CEA Ejection Peak RCS Pressure Sequence of Events

3716 MWt EPU Time (sec)	Event	3716-MWt EPU Setpoint/Value
0.00	Mechanical failure of CEDM causes CEA to eject	---
0.00	CEA fully ejected	---
0.07	CPC VOPT, % of full power	159
0.08	Maximum core power occurs, % of full power	187.0
0.699	Trip breakers open	---
1.299	CEAs begin to drop into core	---
2.9	Maximum RCS pressure, psia	2519*
4.8	CEA fully inserted, core power reduced to below 10% power	---

* 2597 psia for BOC cycle 1 HFP CEA ejection.

Table 2.13.4.3.2-5
Full-Power CEA Ejection Results

Parameter	3716-MWt Power Uprate Assumption	Current Power Level Assumption	Current Power Level Assumption
		BOC	EOC
Total average enthalpy of hottest fuel pellet, cal/gm	156.14	154.2	146.4
Total centerline enthalpy of hottest fuel pellet, cal/gm	249.9	271.0	263.0
Fraction of rods that experience clad damage due to DNB	0.150	0.0912	0.0350
Fraction of fuel having incipient centerline melting (centerline enthalpy ≥ 250 cal/gm)	0.0	0.0179	0.0043
Fraction of fuel having radially averaged enthalpy ≥ 280 cal/gm	0.0	0.0	0.0

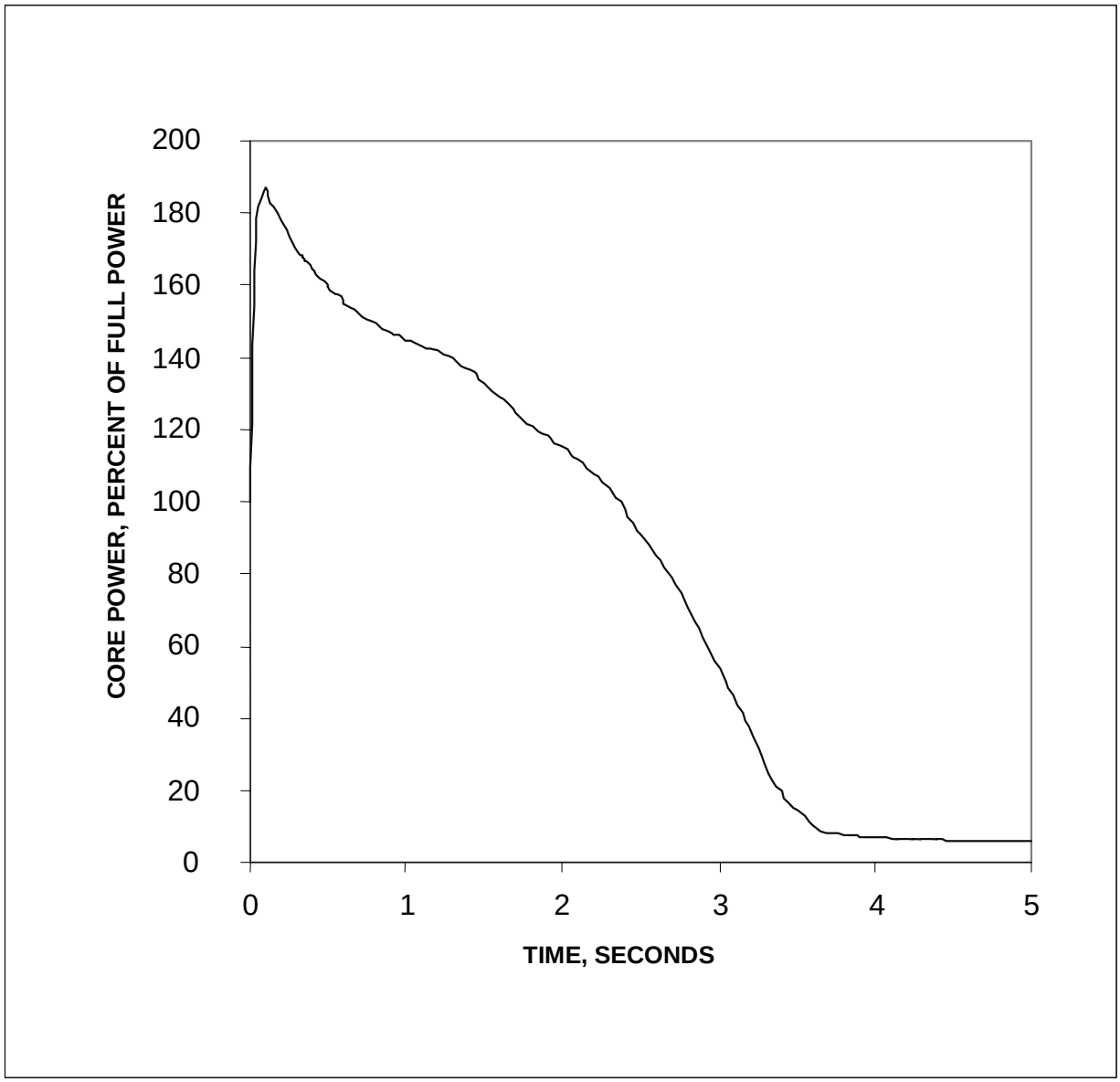

Figure 2.13.4.3.2-1
CEA Ejection Core Power vs. Time

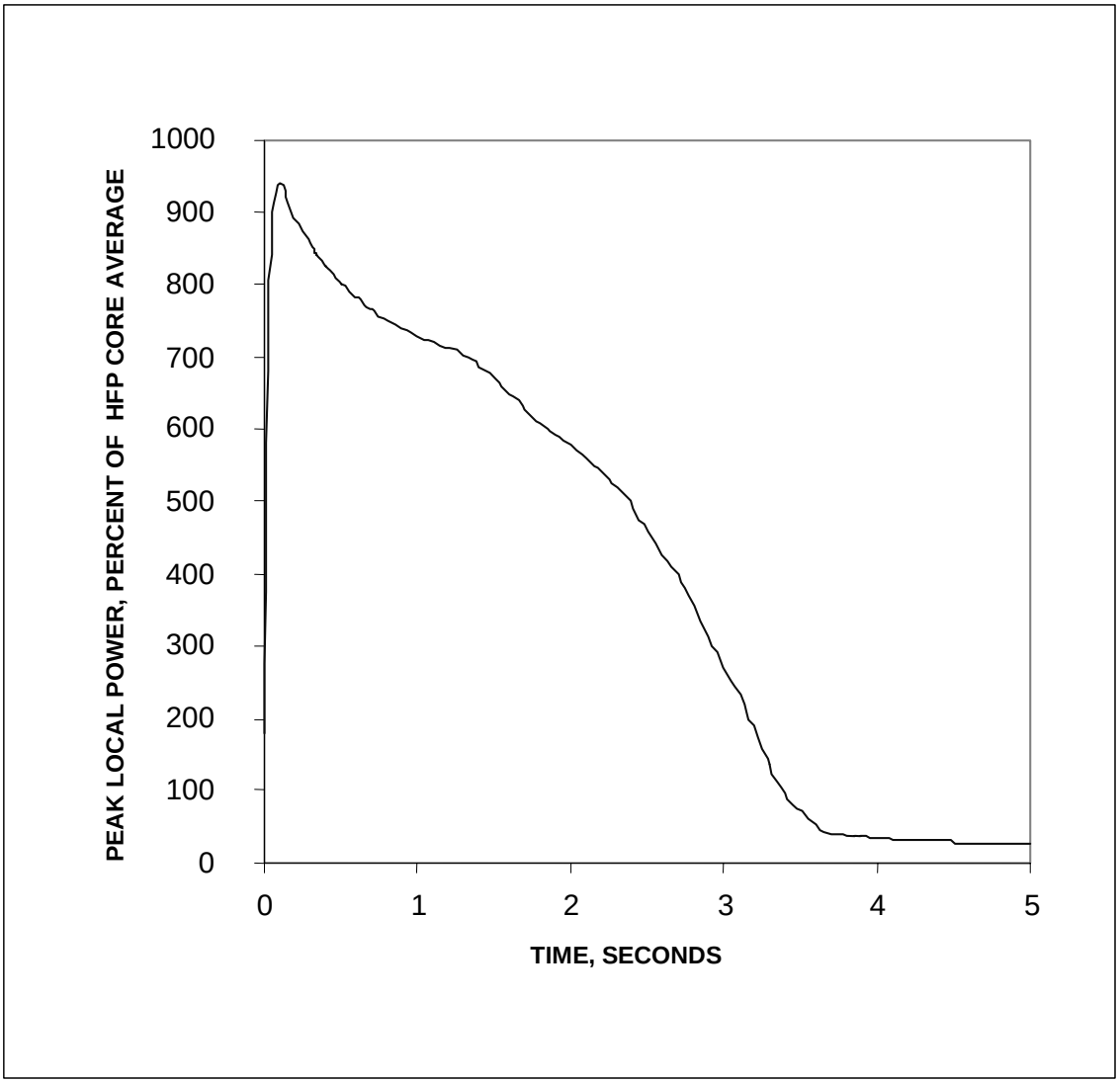

Figure 2.13.4.3.2-2
CEA Ejection Peak Local Power vs. Time

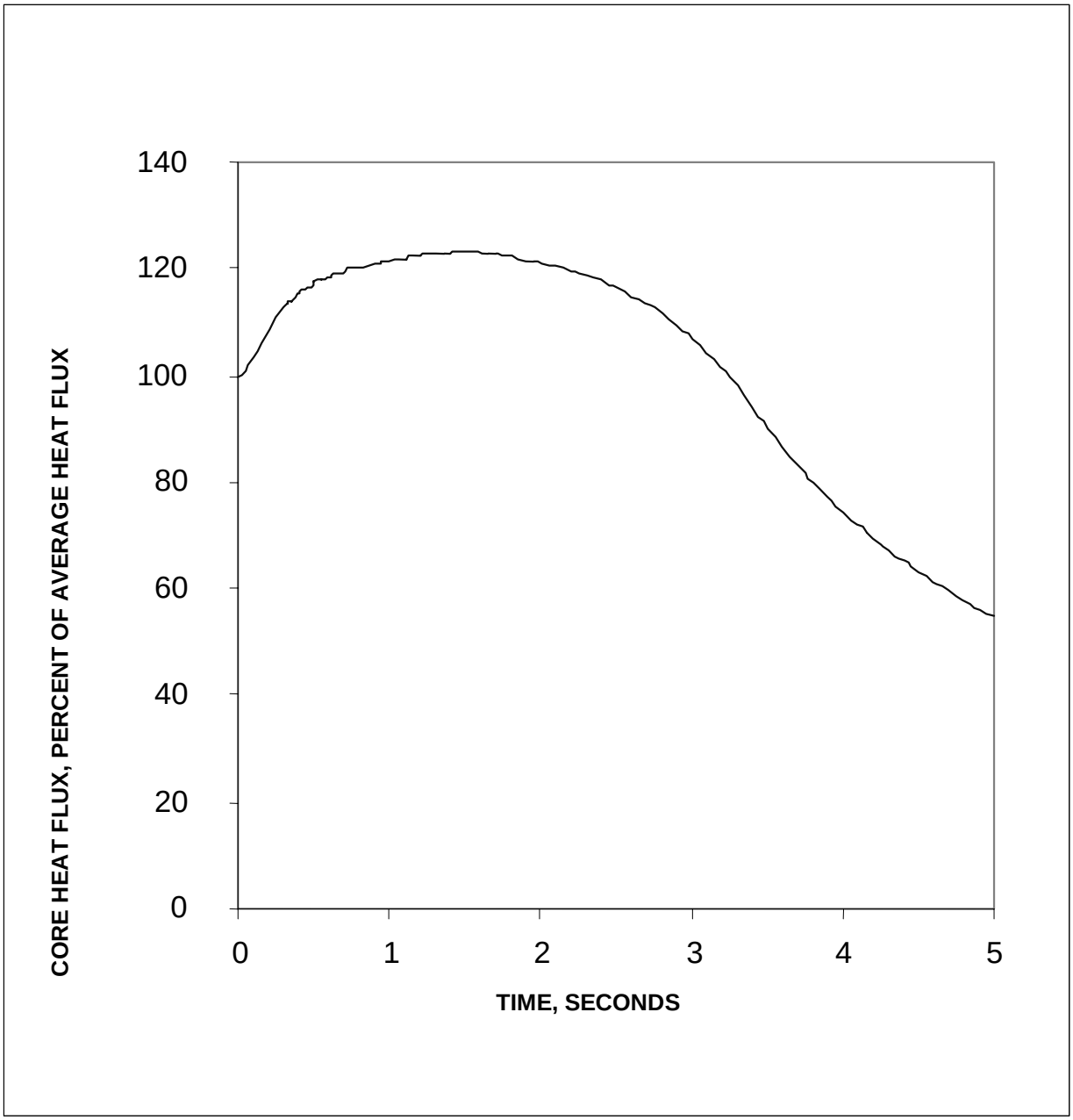

Figure 2.13.4.3.2-3
CEA Ejection Core Heat Flux vs. Time

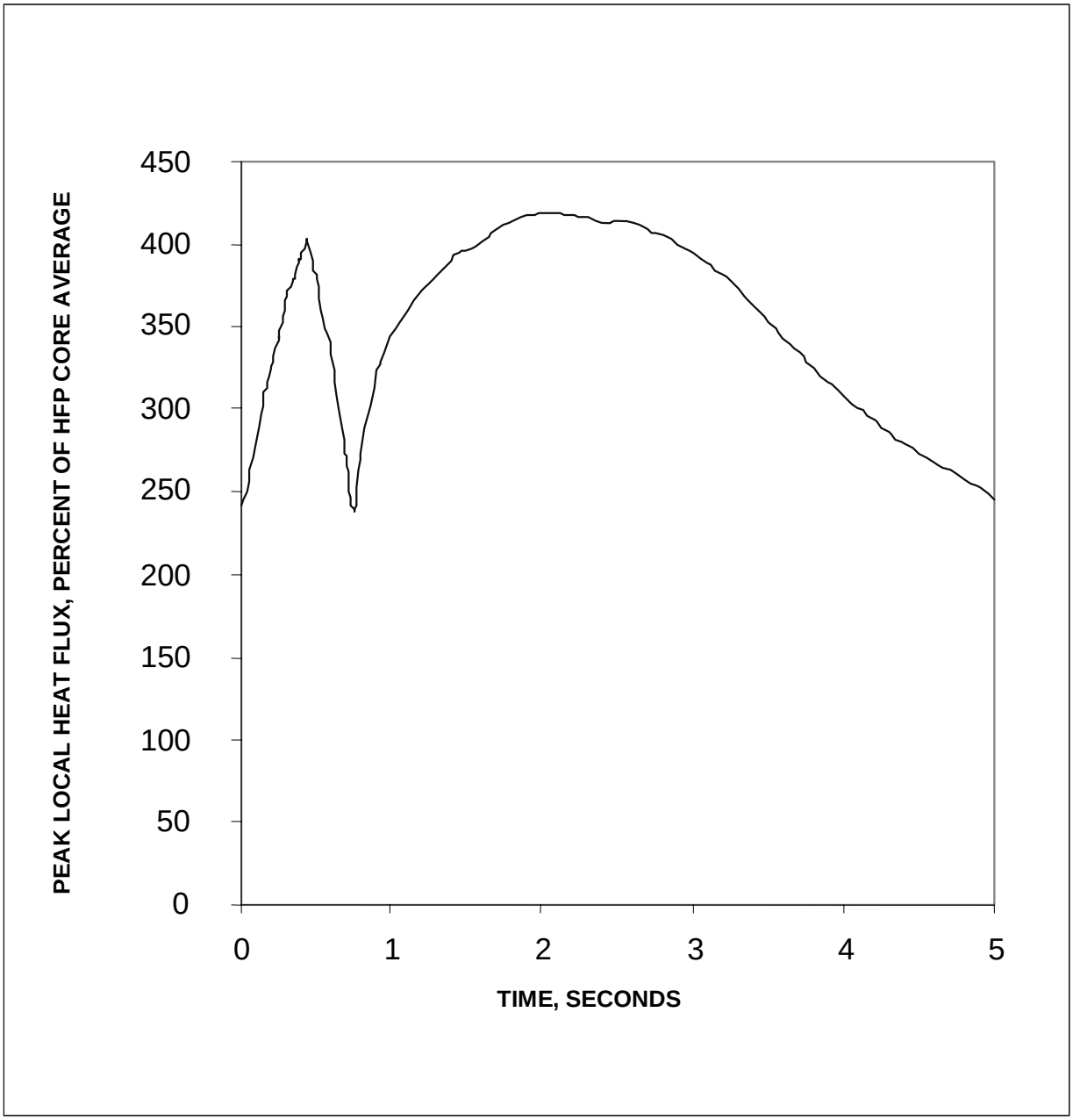

Figure 2.13.4.3.2-4
CEA Ejection Peak Core Heat Flux vs. Time

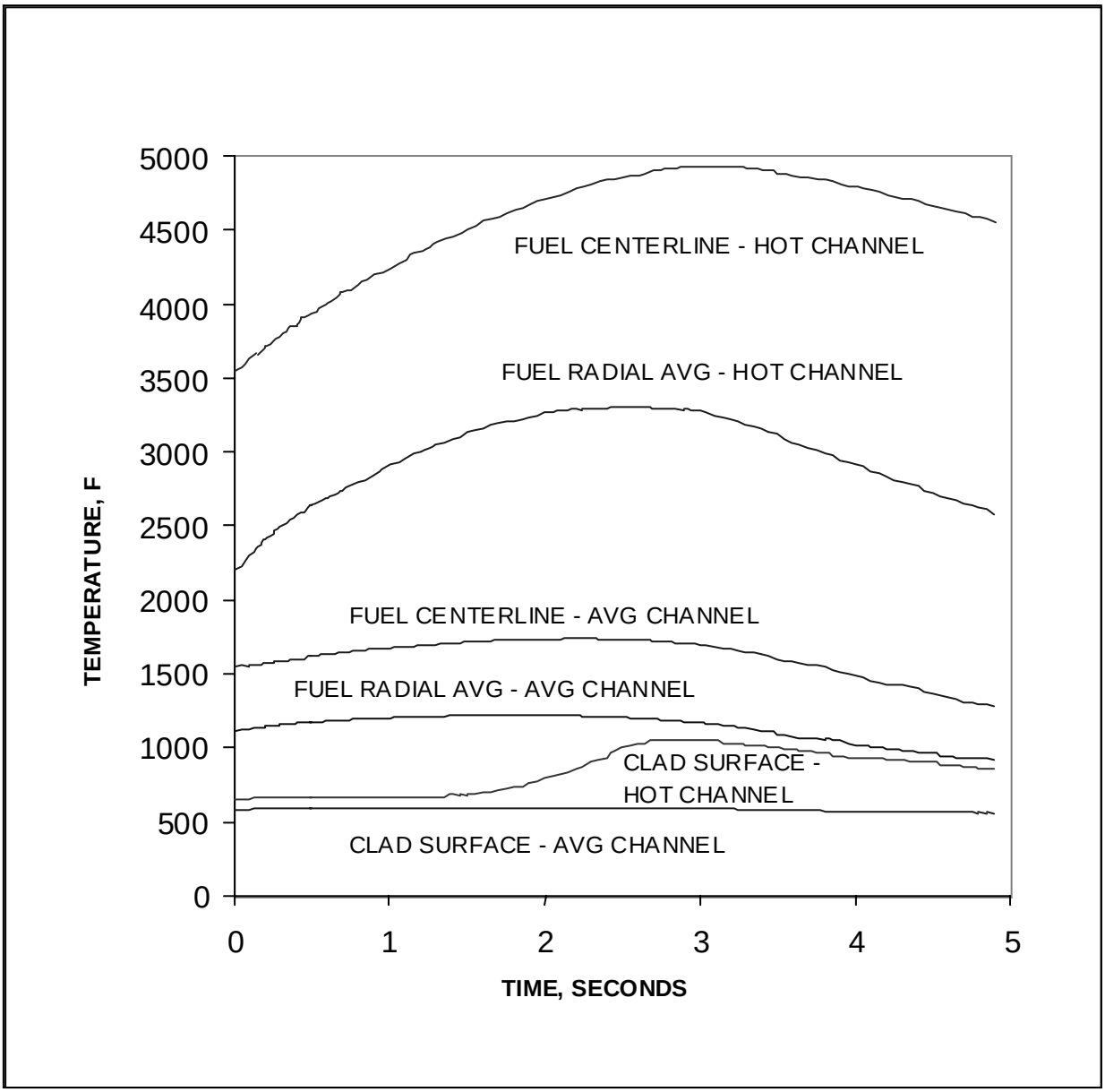

Figure 2.13.4.3.2-5
CEA Ejection Hot & Average Channel Fuel & Clad Temperatures vs. Time

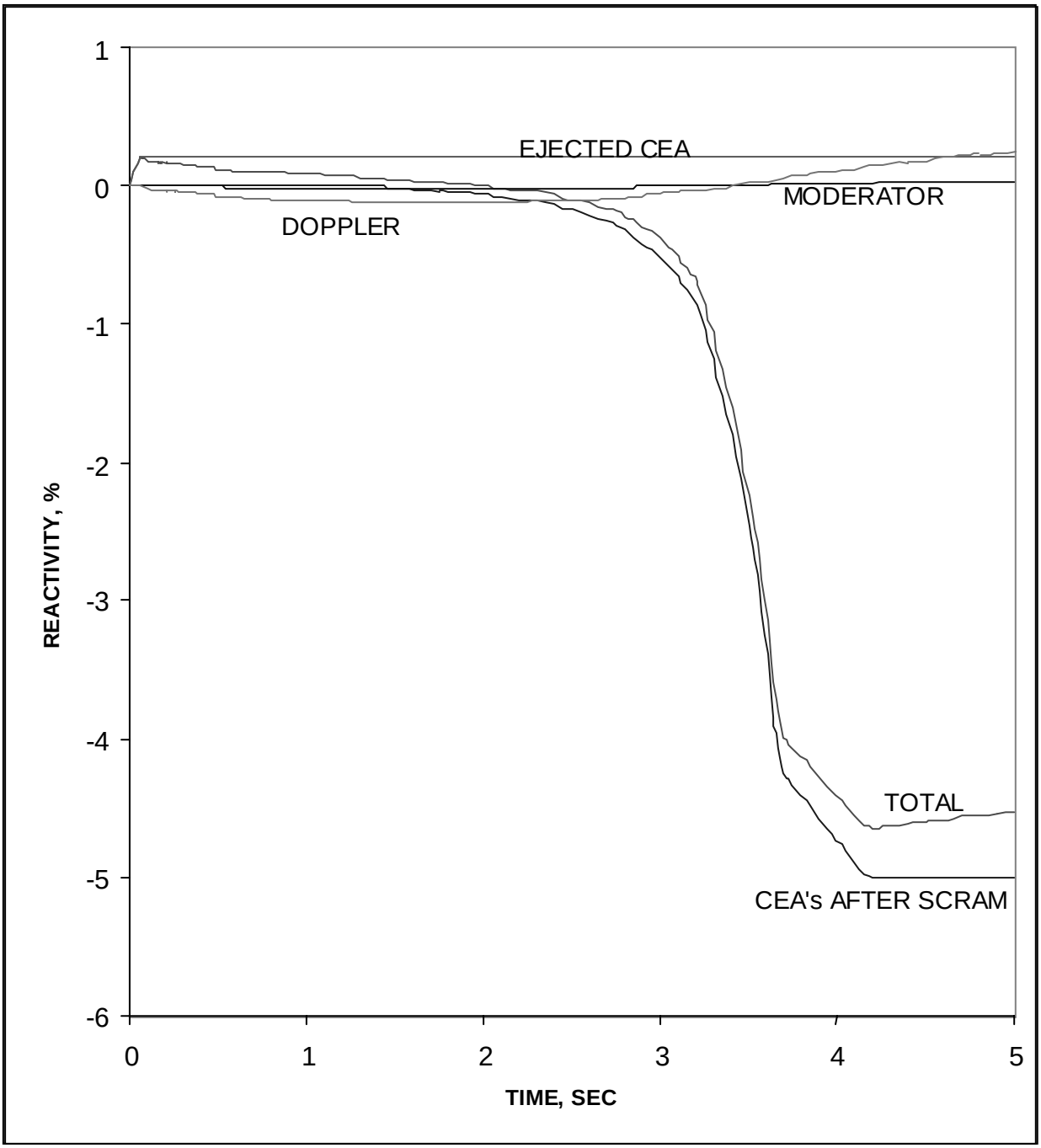

Figure 2.13.4.3.2-6
CEA Ejection Reactivity Components vs. Time

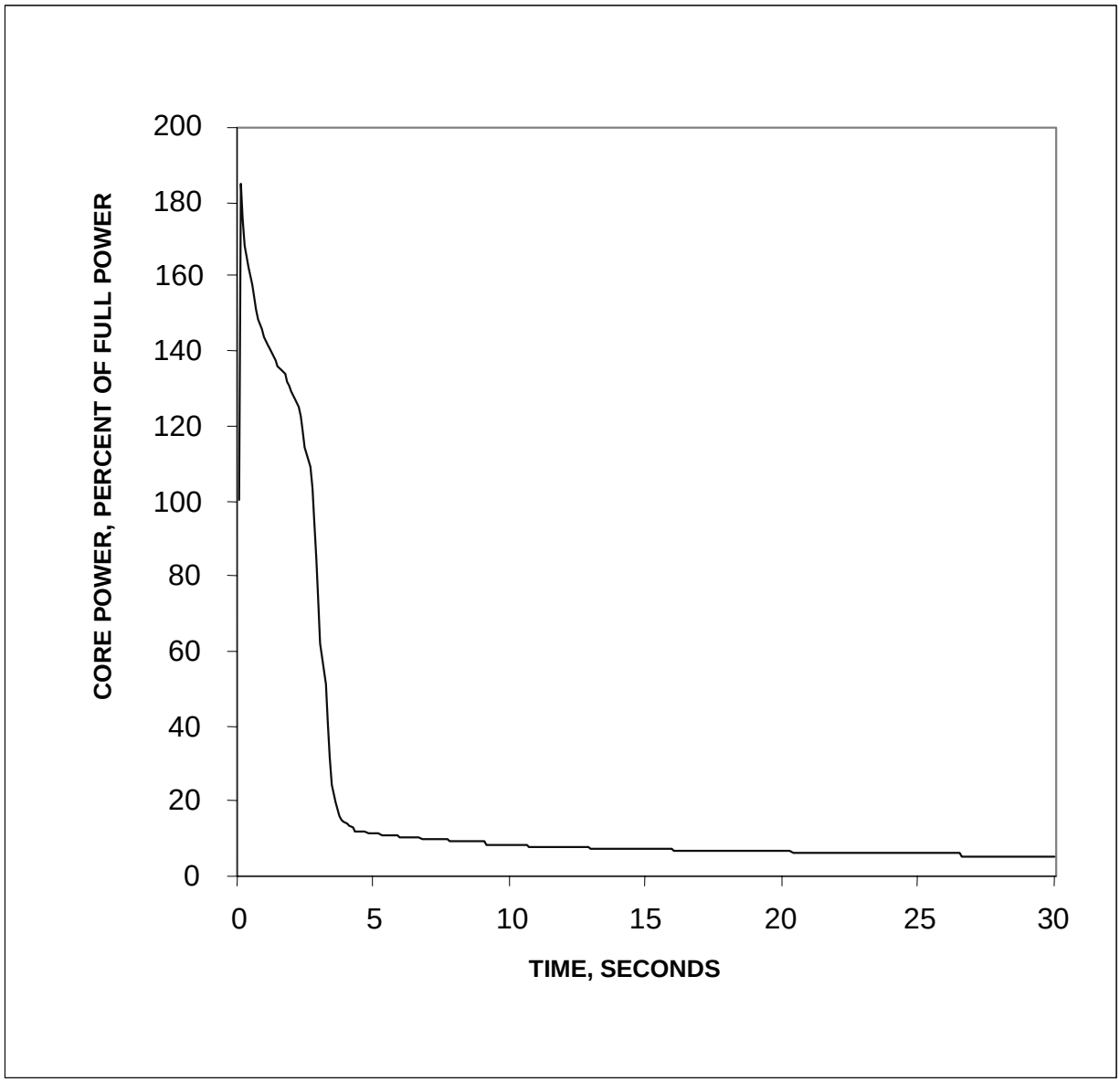

Figure 2.13.4.3.2-7
CEA Ejection Core Power vs. Time for Peak RCS Pressure

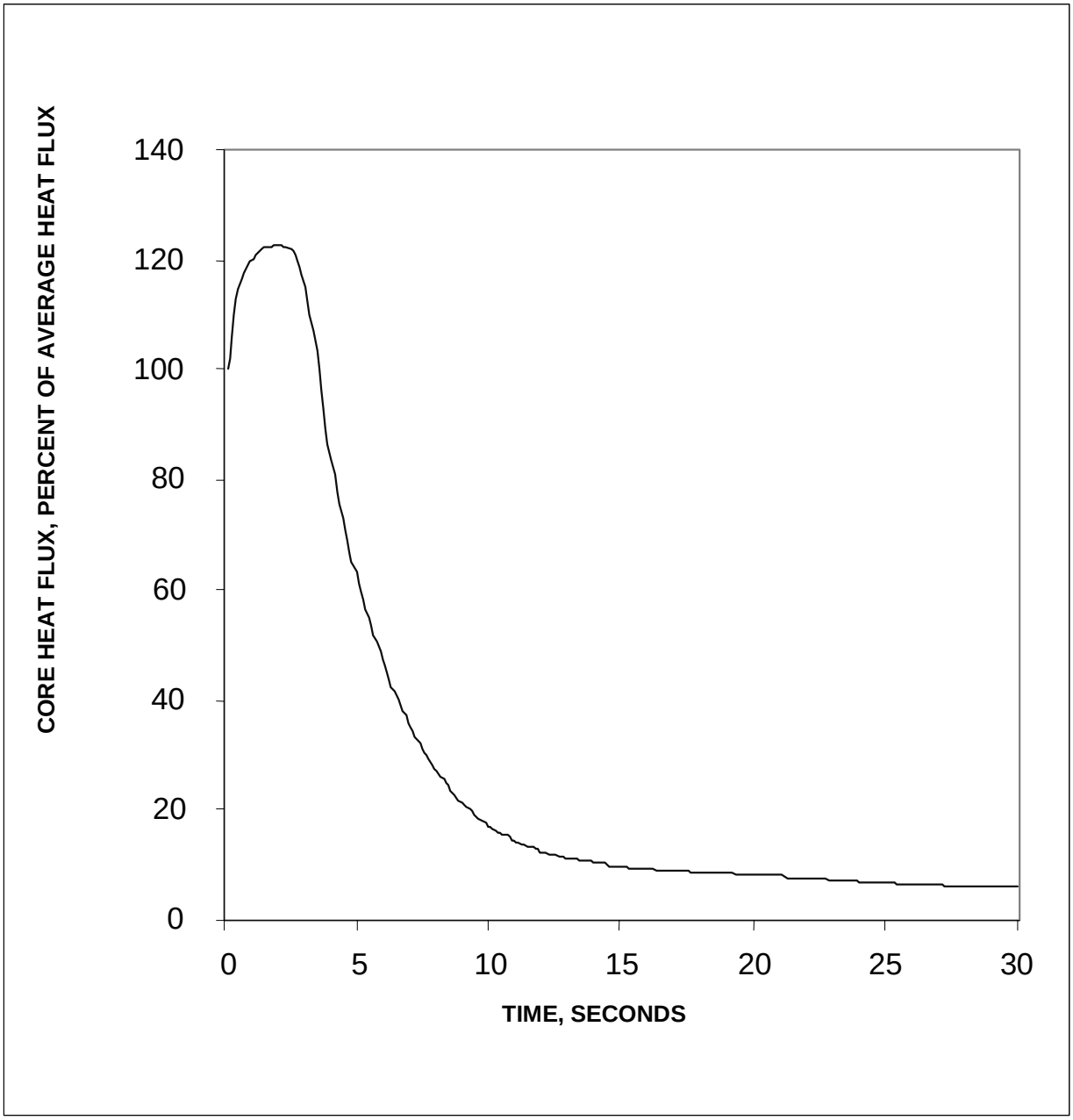

Figure 2.13.4.3.2-8
CEA Ejection Core Heat Flux vs. Time for Peak RCS Pressure

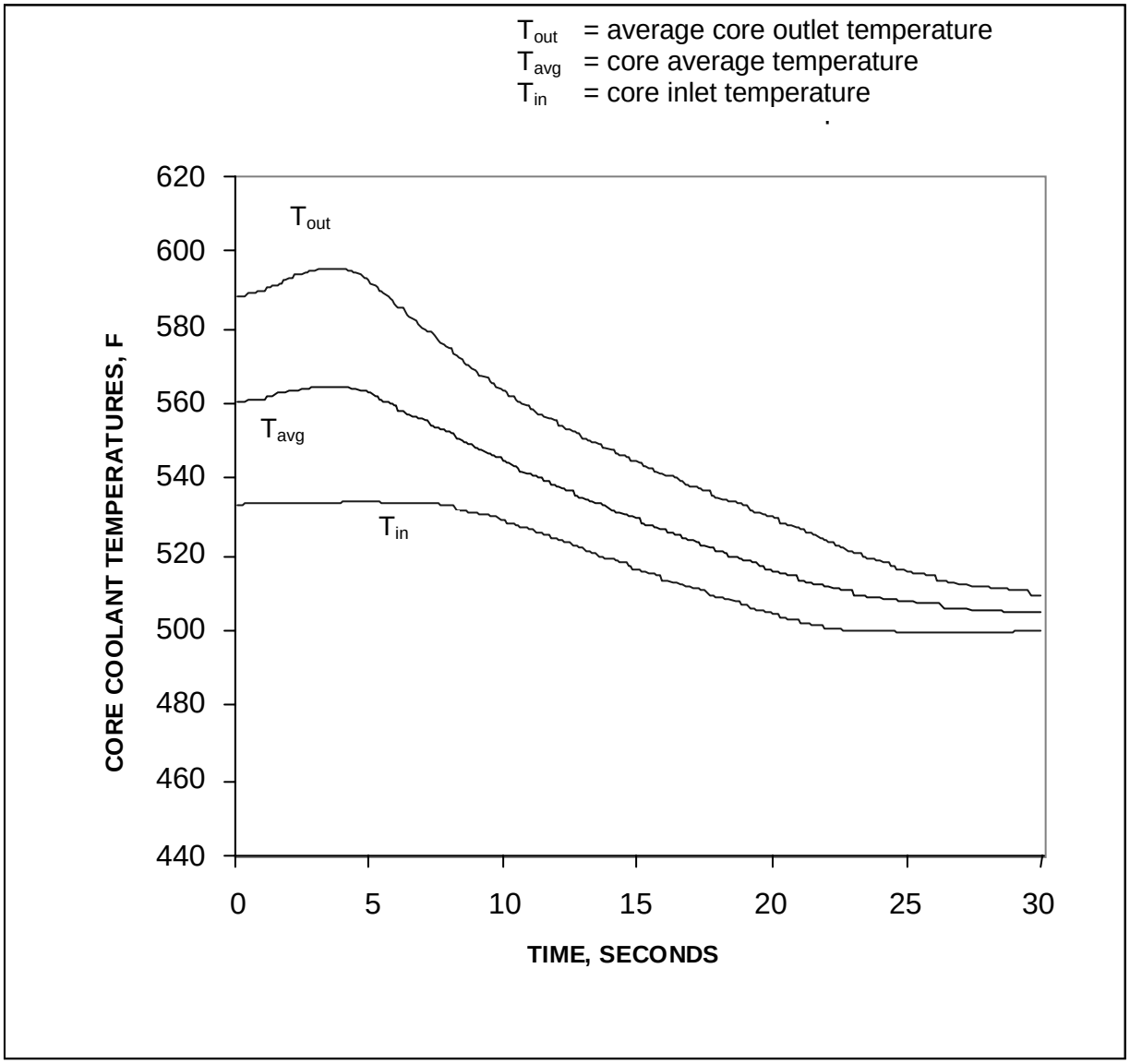

Figure 2.13.4.3.2-9
CEA Ejection Core Coolant Temperatures vs. Time for Peak RCS Pressure

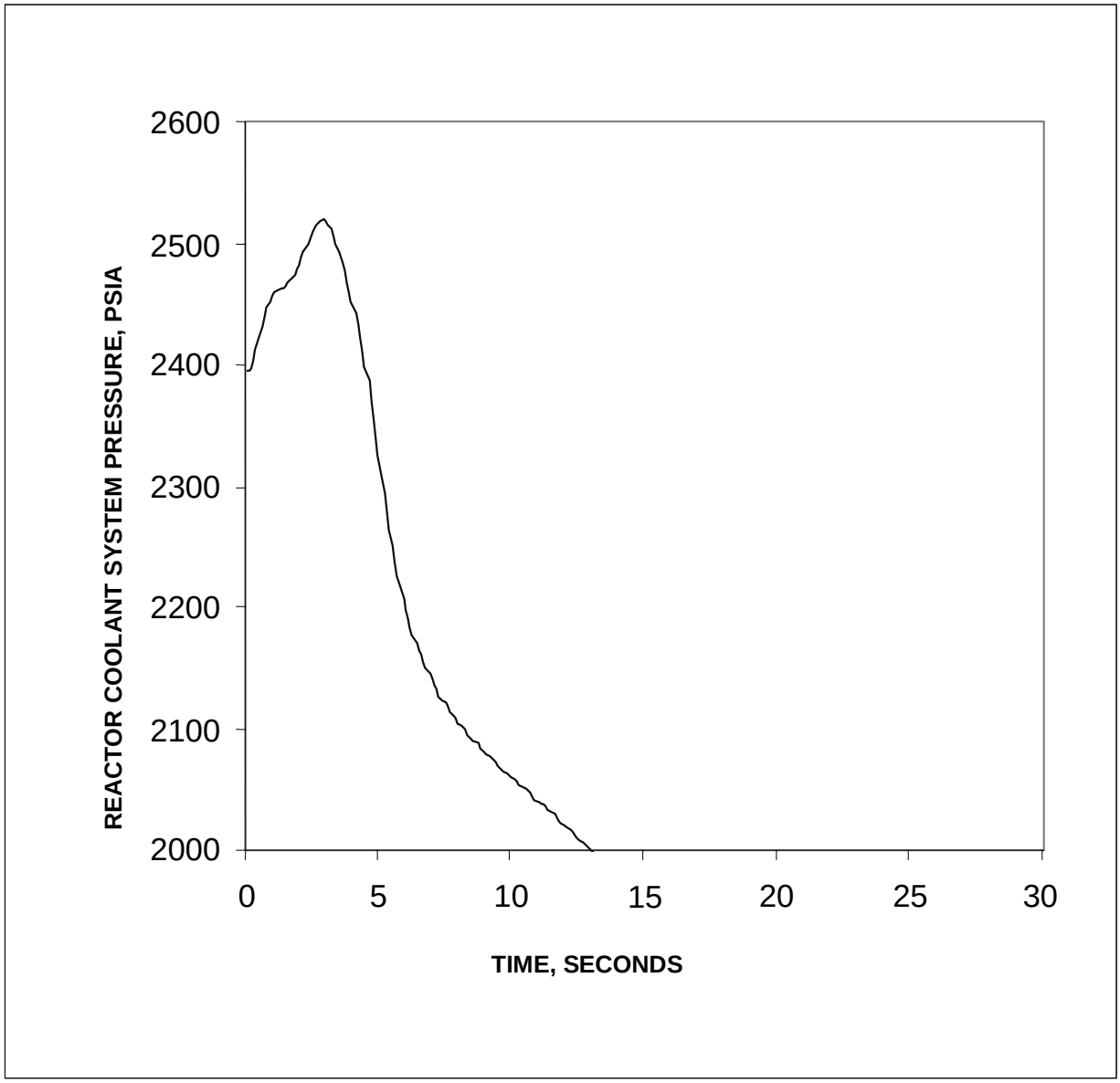

Figure 2.13.4.3.2-10
CEA Ejection Peak RCS Pressure vs. Time for Peak RCS Pressure

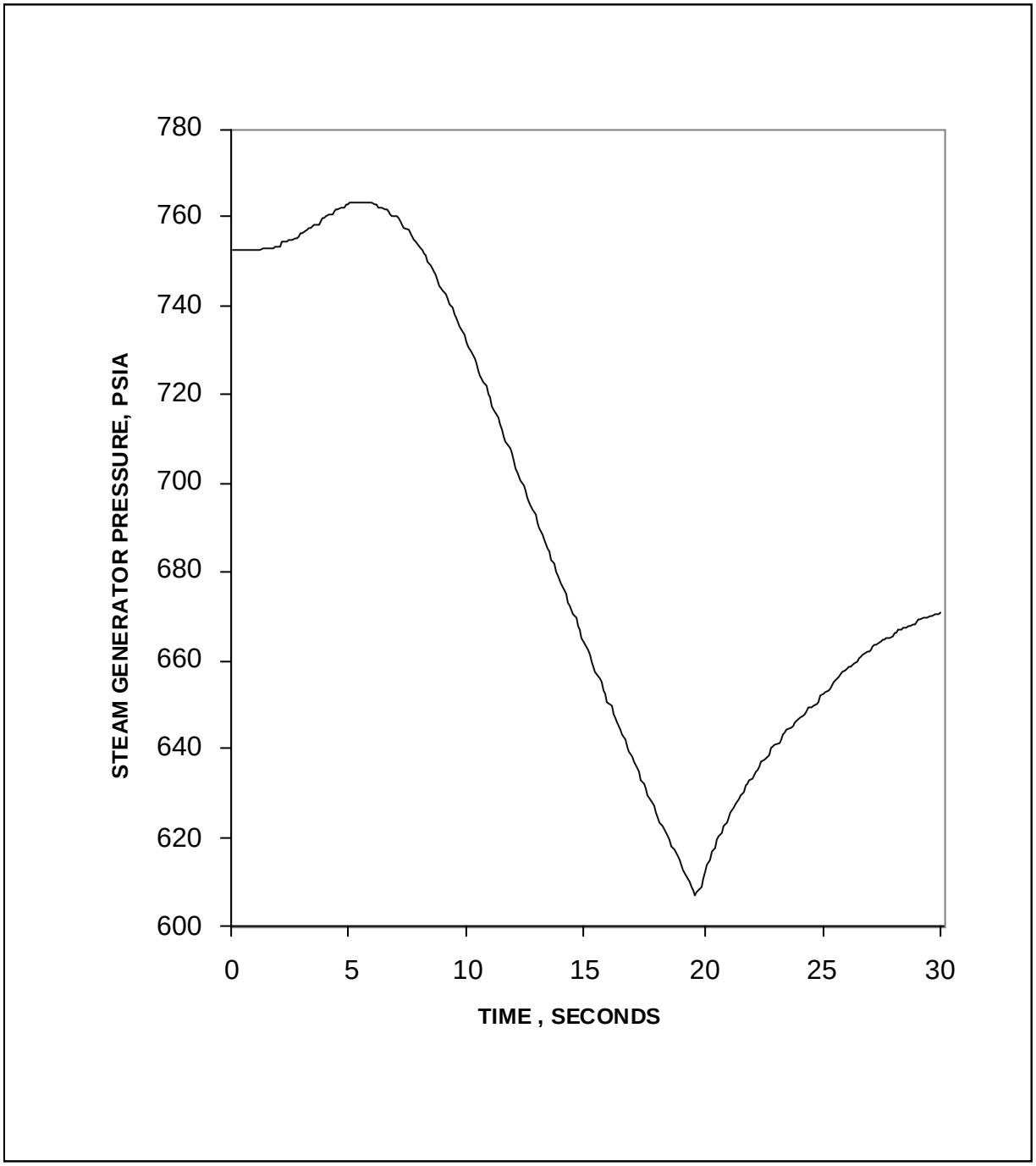

Figure 2.13.4.3.2-11
CEA Ejection SG Pressure vs. Time for Peak RCS Pressure

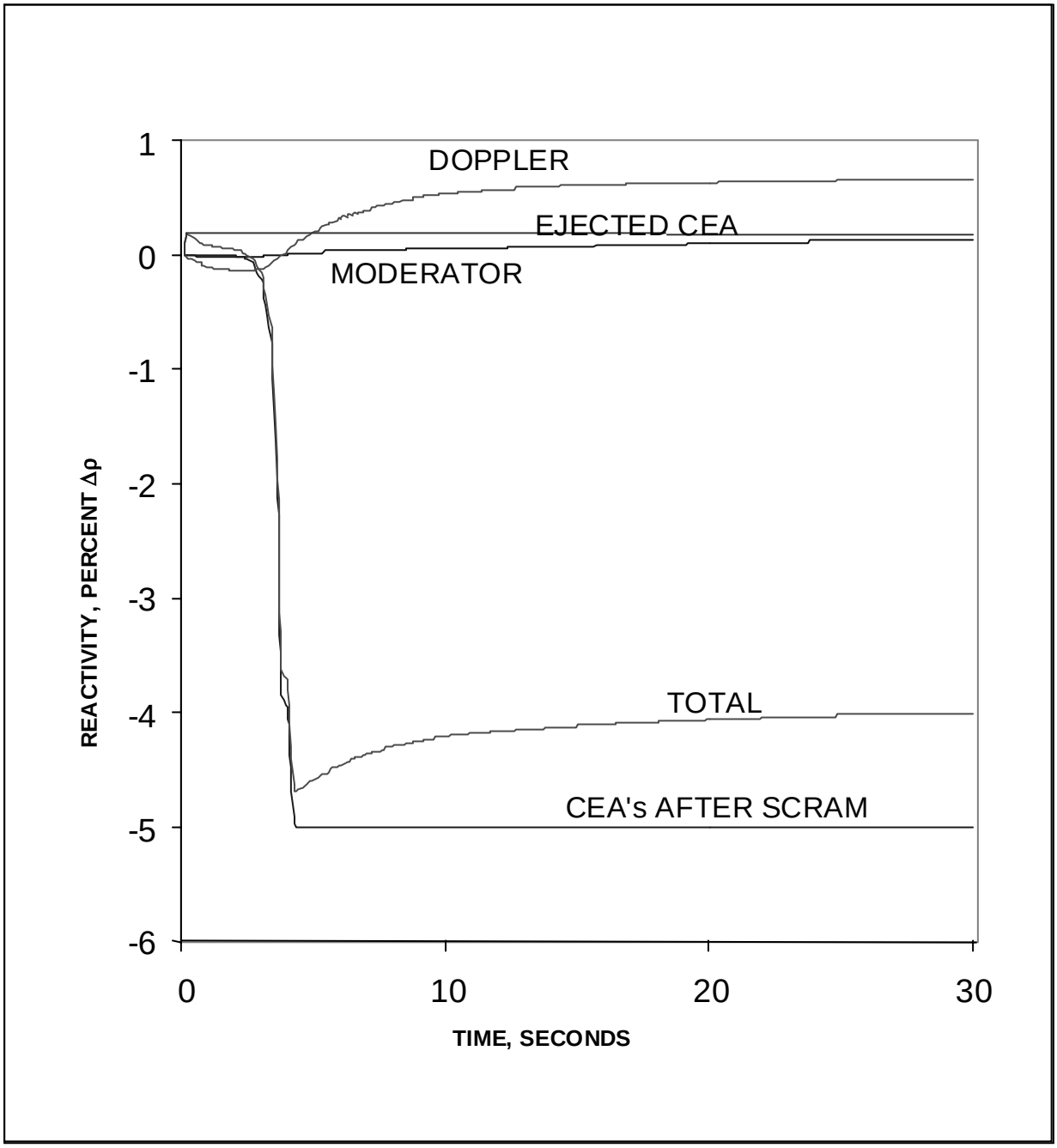

Figure 2.13.4.3.2-12
CEA Ejection Reactivity Components vs. Time for Peak RCS Pressure

2.13.5 Increase in Reactor Coolant Inventory

2.13.5.1 Moderate Frequency Incidents

2.13.5.1.1 Chemical & Volume Control System (CVCS) Malfunction

This event is bounded by current FSAR results.

2.13.5.1.2 Inadvertent Emergency Core Cooling System (ECCS)

This event is bounded by current FSAR results.

2.13.5.2 Infrequent Events

2.13.5.2.1 CVCS Malfunction with Single Active Failure (SAF)

This event is bounded by current FSAR results.

2.13.5.3 Limiting Faults

None.

2.13.6 Decrease in Reactor Coolant System (RCS) Inventory

2.13.6.1 Moderate Frequency Incidents

None

2.13.6.2 Infrequent Incidents

None

2.13.6.3 Limiting Faults

2.13.6.3.1 Small Primary Line Break Outside Containment

The objective of the letdown line break outside of containment (OC) event analysis is to document the impact of the following changes:

- An increase in rated power from 3441 MWt to 3716 MWt,
- A change to the CENTS code, and
- An application of a more negative MTC.

The impact of the above changes results in an increase in the exclusion area boundary (EAB) and low population zone (LPZ) radiological doses.

2.13.6.3.1.1 General Description of the Event

The letdown line break outside containment (OC) provides a release path for the reactor coolant OC. The letdown line (2-inch Schedule 160 Pipe) is the largest penetration of containment of primary piping. Primary mass releases from the letdown line pipe break would bound those of the smaller primary sample line and instrument line breaks. The limiting break size is not a double-ended guillotine break, but a smaller area that delays the reactor trip until approximately 1800 seconds at the time of operator action.

The integrity of the lines containing primary coolant external to the containment is significant radiologically since a rupture of this barrier results in the release of reactor coolant outside of containment. Following such a break, the RCS pressure decreases due to the loss of reactor coolant. Pressurizer level is also decreased if the break is sufficiently large that the Pressurizer Level Control System (PLCS) can not maintain level.

A rupture of the letdown line outside containment upstream of the letdown line control valve releases primary fluid to the auxiliary building. The operator is alerted by temperature and pressure alarms in the CVCS and by radiation alarms in the auxiliary building. However, no credit is taken for mitigation of the event prior to operator action at 1800 seconds in the analysis.

The available primary RPS trips that may provide protection against this transient include :

- Low pressurizer pressure trip
- CPCS hot leg saturation trip
- CPCS out-of-range trip on pressurizer pressure
- CPCS low DNBR trip

The CPCS low DNBR trip will provide a reactor trip and prevent the DNB and linear heat rate SAFDLs from being exceeded. To conservatively maximize the amount of primary mass released outside of containment, this trip is not explicitly credited in the letdown line break event analysis as a RPS trip to mitigate an event.

Either operator action at 1800 seconds or a safety injection actuation signal (SIAS) on low pressurizer pressure terminates the break flow by isolating the letdown line inside containment. Reactor coolant inventory is replenished by the safety injection pumps and by the charging pumps. Operation of the HPSI pumps as well as the charging pumps ensures that the core will not uncover and prevents any significant increase in clad temperature.

2.13.6.3.1.2 Purpose of Analysis and Acceptance Criteria

The purpose of this analysis is to determine that the letdown line break outside of containment event EAB and LPZ radiological dose results are less than a small fraction of 10CFR100 limits.

The following criteria apply to the letdown line break outside of containment event:

- DNBR ≥ DNB SAFDL
- Peak RCS pressure ≤ 2750 psia
- Peak secondary pressure ≤ 1210 psia
- Radiological doses are a small fraction of 10CFR100 limits

The letdown line break event is described in Chapter 15.6.3.1 of the FSAR (Reference 2.13-1).

2.13.6.3.1.3 Impact of Changes

The increase in rated power results in an increase in core outlet temperature.

The application of the negative MTC versus a positive MTC results in slight increase in primary coolant release for a given break size. This has a very small effect as the event is performed parametric in break size.

This event is now analyzed with the CENTS code (Reference 2.13-2) versus the CESEC code.

2.13.6.3.1.4 Analysis Overview

The methodology used in this analysis is similar to the methodology used in the current analysis of record, except that the CENTS code is used instead of the CESEC and COAST codes. The CETOP (Reference 2.13-3) code is used to calculate the minimum DNBR.

Parametric analyses were performed to determine whether minimum or maximum values of important input parameters where limiting. A decrease in core inlet temperature results in a lower core outlet temperature and steam generator (SG) pressure values. For a given break area, a lower core inlet temperature results in a slightly larger primary mass release. This has a very small effect as the event is performed parametric in break size.

An increase in RCS flow rates results in lower core outlet temperature and steam generator pressure values. For a given break area, a higher initial RCS flow rate results in a slight increase in primary mass release for a given break size. This has a very small effect as the event is performed parametric in break size.

Input parameters from Table 2.13.6.3.1-1 and the bounding physics data from Section 2.13.0.2 of this report have been incorporated in this analysis:

- The most negative MTC of $-4.2 * 10^{-4}$ $\Delta\rho/°F$ was assumed.
- A parametric analysis on break size was performed to generate a reactor trip at the time of operator action that is conservatively assumed to occur at 1800 seconds.
- A CPCS hot leg saturation trip and out-of-range (low pressurizer pressure) trip were conservatively assumed.
- An initial core power of 3735 MWt was assumed, based on a rated power of 3716 MWt and a 0.5% uncertainty.
- An initial RCS flow of $178.9 * 10^6$ lbm/hr was assumed.
- An initial minimum core inlet temperature of 533°F was assumed.
- An initial pressurizer pressure of 2312 psia was assumed.
- It was determined from parametric studies that the limiting break size for mass releases is the largest size that allows the event to go to the assumed 30 minute operator action time without having generated a reactor trip. A double-ended break is not limiting due to the earlier trip and break isolation time.

2.13.6.3.1.5 Radiological Consequences

During the letdown line break, a total of 78,000 lbm of primary coolant are discharged outside of containment prior to isolation of the leak path at 30 minutes. This coolant is assumed to be at the long-term limit for primary system activity.

Following reactor trip, both SGs are steamed through the ADVs to achieve cooldown of the plant to shutdown cooling entry conditions. During the first 2 hours of the cooldown, 962,000 lbm of steam are discharged from the ADVs to remove decay heat and commence the cooldown of the RCS. Even though shutdown cooling entry conditions are achieved in the

4-to-5 hour time frame, the radiological consequences calculation assume that the plant is being maintained via the ADVs for the duration of the 8-hour dose calculation. A total of 2,303,000 lbm of steam are released to the atmosphere through the ADVs.

The radiological consequences resulting from the letdown line break are:

	2-Hour EAB (PIS)	8-Hour LPZ (PIS)
Thyroid	< 30 rem	< 30 rem
Whole Body	< 2.5 rem	< 2.5 rem

2.13.6.3.1.6 Analysis Results

The NSSS and Reactor Protection System (RPS) responses for the letdown line break event are shown in Table 2.13.6.3.1-2 and in Figures 2.13.6.3.1-1 through 2.1.3.6.3.1-8. The limiting letdown line break area that resulted in a simultaneous reactor trip with operator action at 1800 seconds was 0.0032 ft^2. Figure 2.13.6.3.1-9 provides the integrated mass released through the break. During the first 30 minutes following the initiation of the transient, less than 78,000 lbm of reactor coolant is released from the ruptured letdown line. At this time operator action occurs to isolate the letdown line and trip the reactor. Prior to operator action there are no secondary steam releases through the main steam safety valves or ADVs.

The radiological releases for a letdown line break event are less than the NUREG-0800 guidelines of a small fraction of 10CFR100 limits.

Table 2.13.6.3.1-1
Assumptions for Letdown Line Break Outside Containment

Parameter, Units	3716-MWt Power Uprate Assumptions	Current Power Level Assumption
Initial core power, MWt	3735	3478
Core inlet temperature, °F	533.	557.6
RCS flowrate, 10^6 lbm/hr	178.9	148
Pressurizer pressure, psia	2312	2250
Pressurizer level, %	67.5	---
SG pressure, psia	742	998
MTC, 10^{-4} $\Delta\rho$/°F	-4.2	+0.5

Table 2.13.6.3.1-2
Sequence of Events for a
Letdown Line Break Outside Containment

3716-MWt EPU Time (sec)	Current Power Level Time (sec)	Event	3716-MWt EPU Setpoint/Value	Current Power Level Setpoint/Value
0.0	0.0	Letdown line rupture occurs	---	---
1800	1778.8	CPCS out-of-range trip on low pressurizer pressure occurs, psia (CPCS hot leg saturation trip) (1)	1736	---
> 1800	1779.4	CEAs begin to drop into the core	---	---
> 1800	1788.8	Safety injection actuation signal, psia	1560	1560
> 1800	1798.8	Isolation of ruptured letdown line	---	---
> 1800	> 1800	SIS flow initiated	---	---
> 1800	> 1800	Operator initiates plant cooldown	---	---
28,800	28,000	Shutdown cooling initiated, °F	350	350

(1) For the current power level, the CPCS hot leg saturation trip mitigated the event. For power uprate, the CPCS out-of-range trip on low pressurizer pressure mitigated the event.

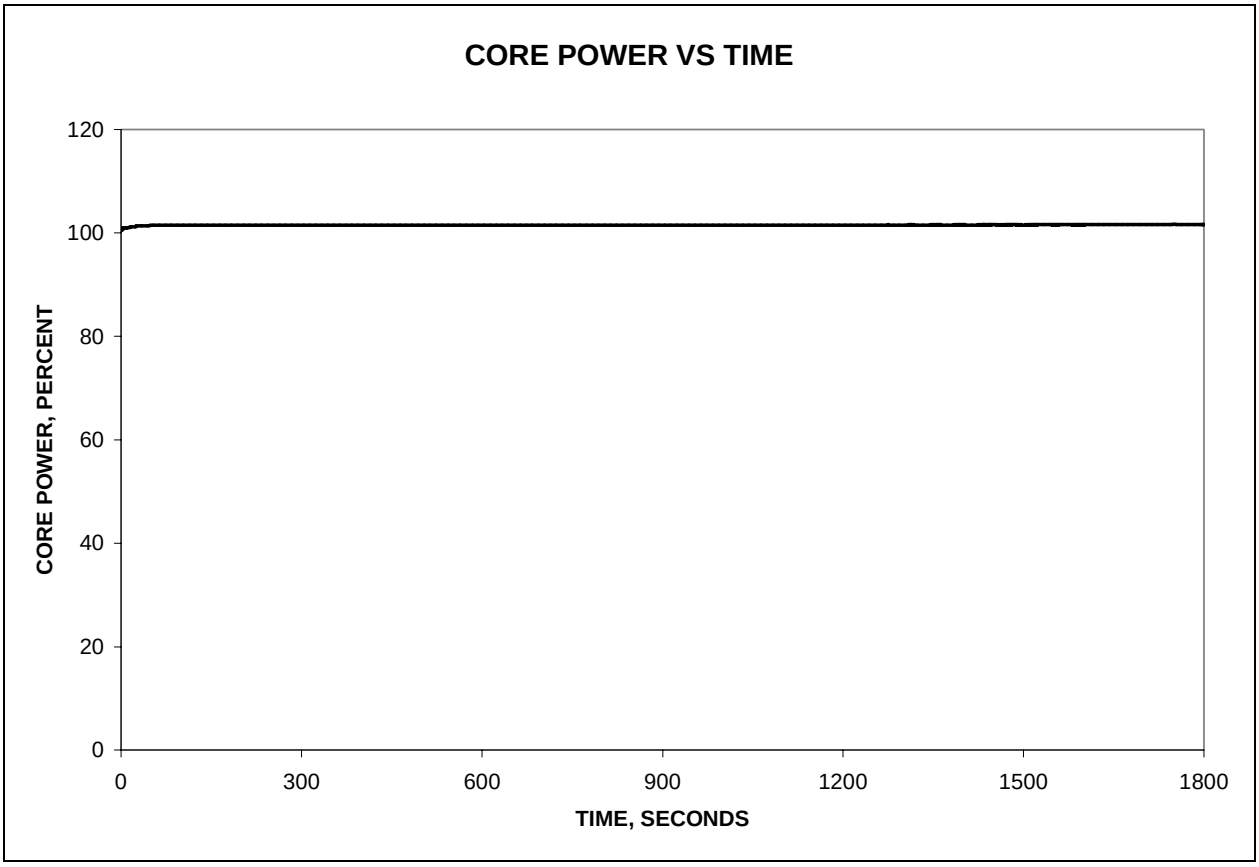

Figure 2.13.6.3.1-1
Letdown Line Break Outside Containment
Core Power vs. Time

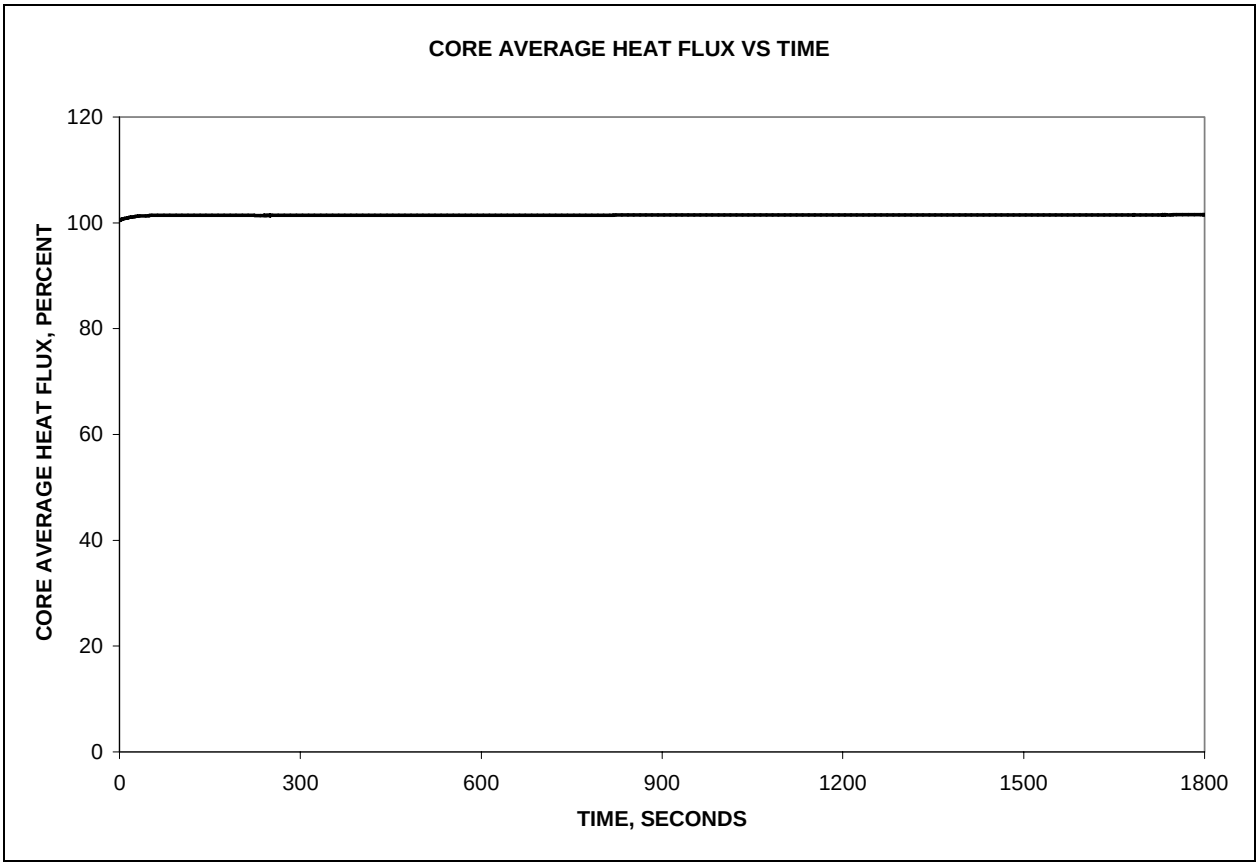

Figure 2.13.6.3.1-2
Letdown Line Break Outside Containment
Core Heat Flux vs. Time

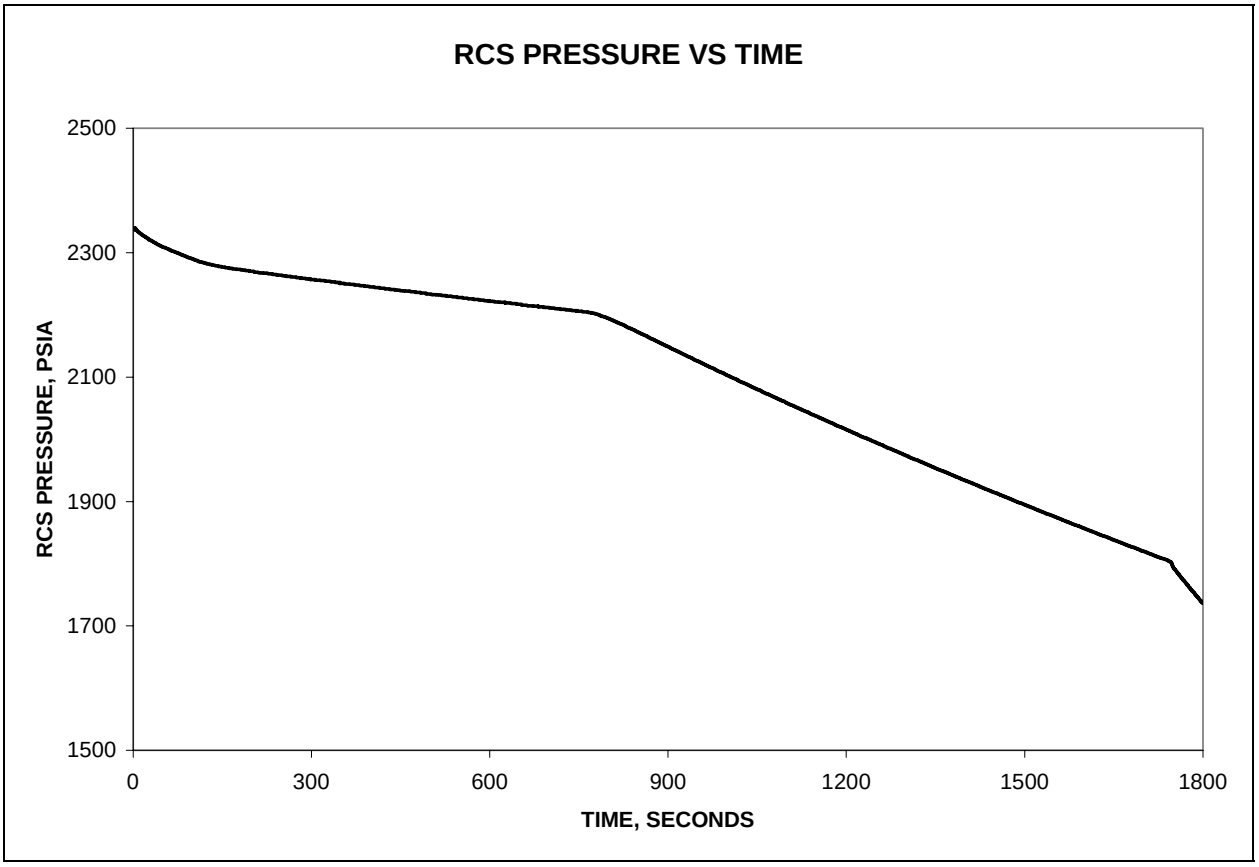

Figure 2.13.6.3.1-3
Letdown Line Break Outside Containment
RCS Pressure vs. Time

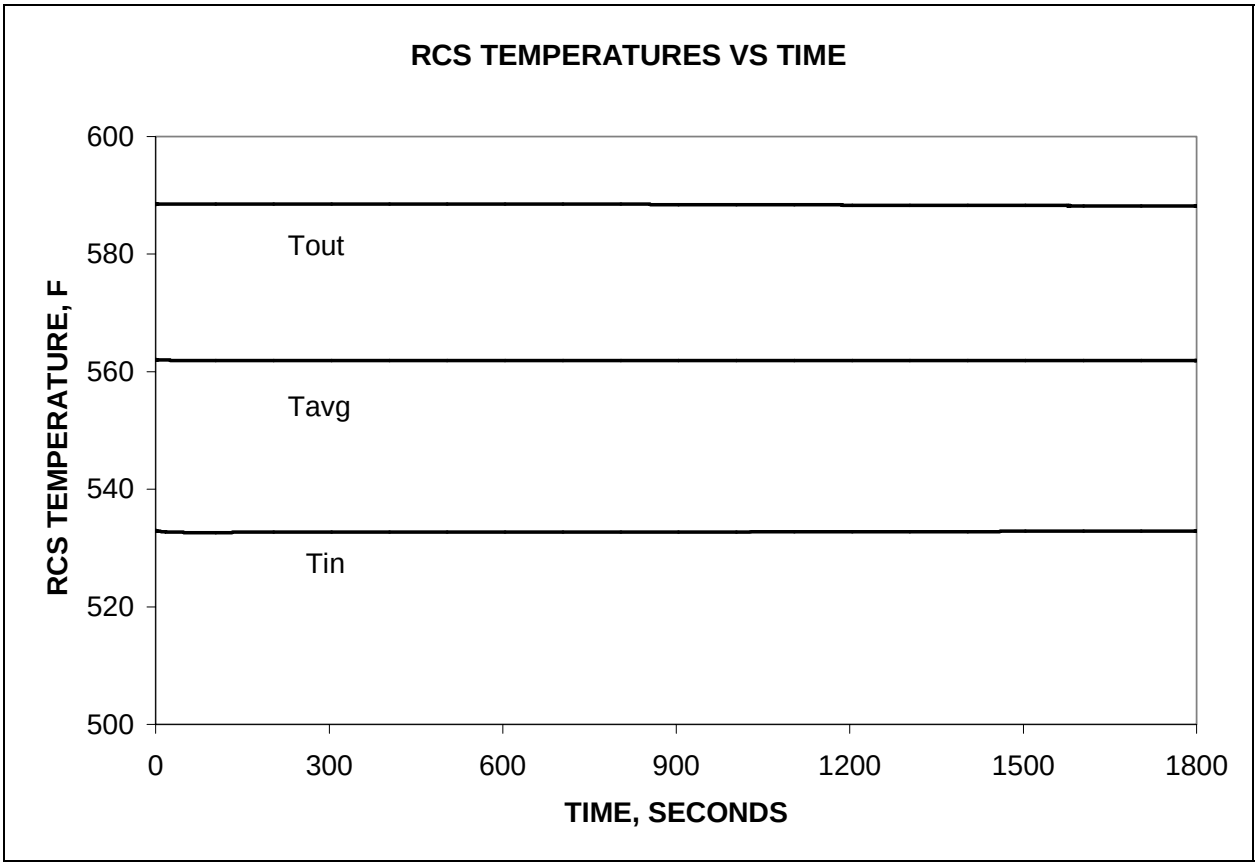

Figure 2.13.6.3.1-4
Letdown Line Break Outside Containment
RCS Temperatures vs. Time

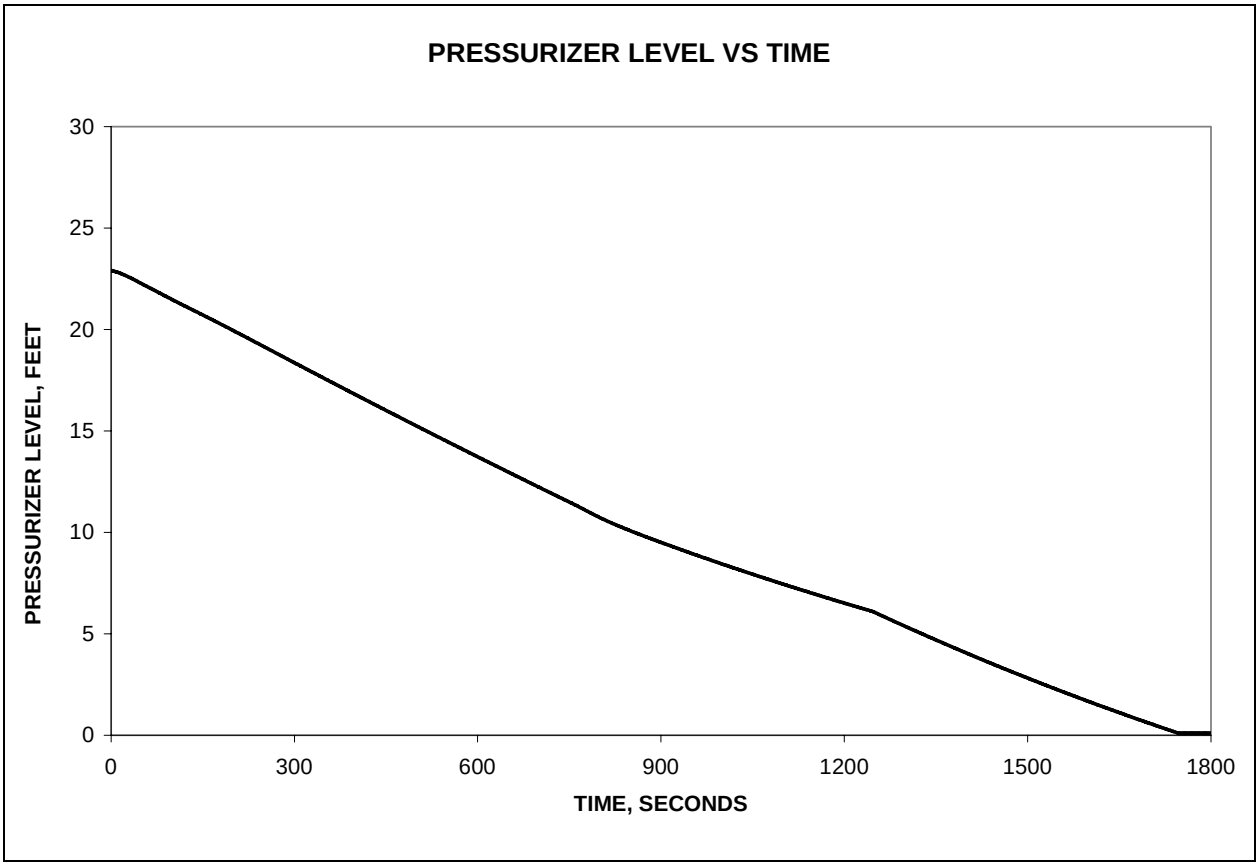

Figure 2.13.6.3.1-5
Letdown Line Break Outside Containment
Pressurizer Level vs. Time

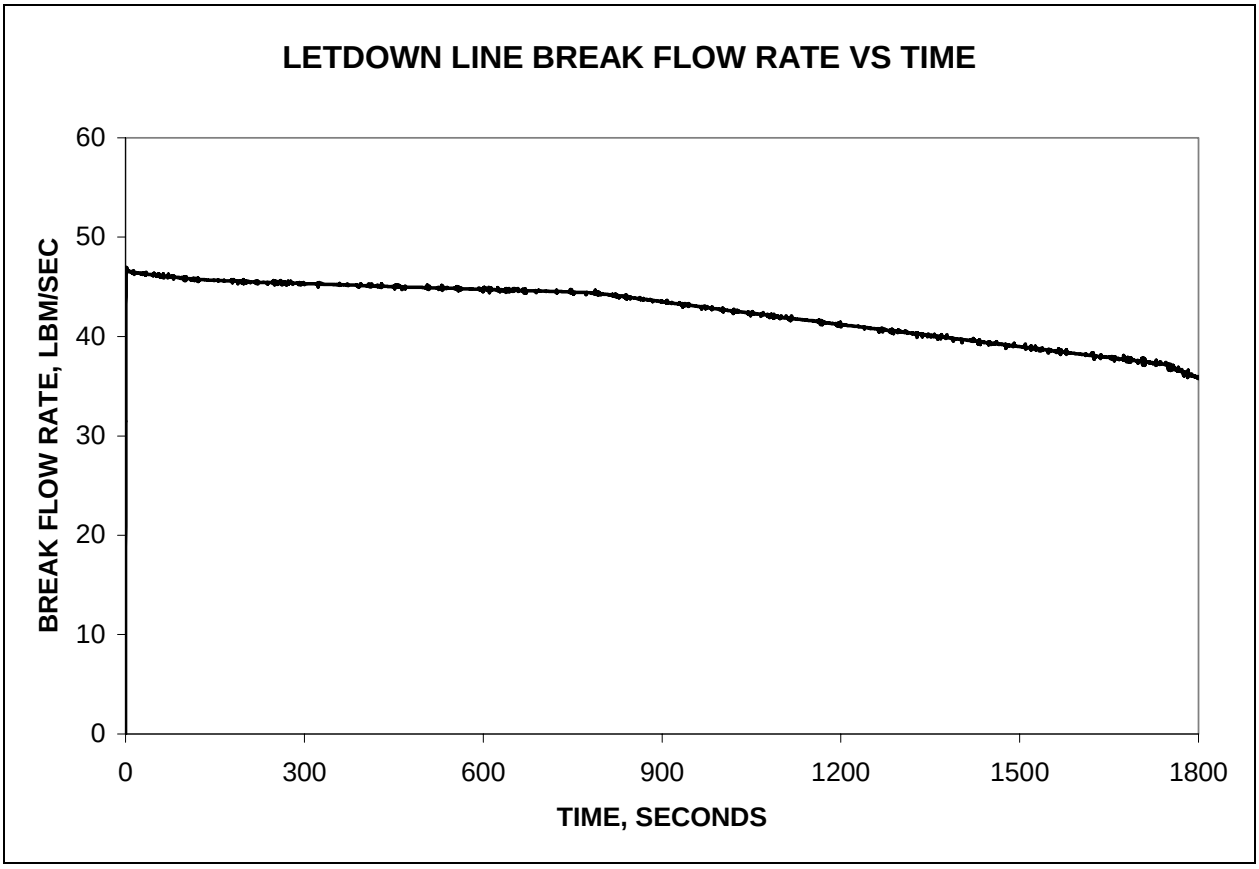

Figure 2.13.6.3.1-6
Letdown Line Break Outside Containment
Letdown Line Break Flow Rate vs. Time

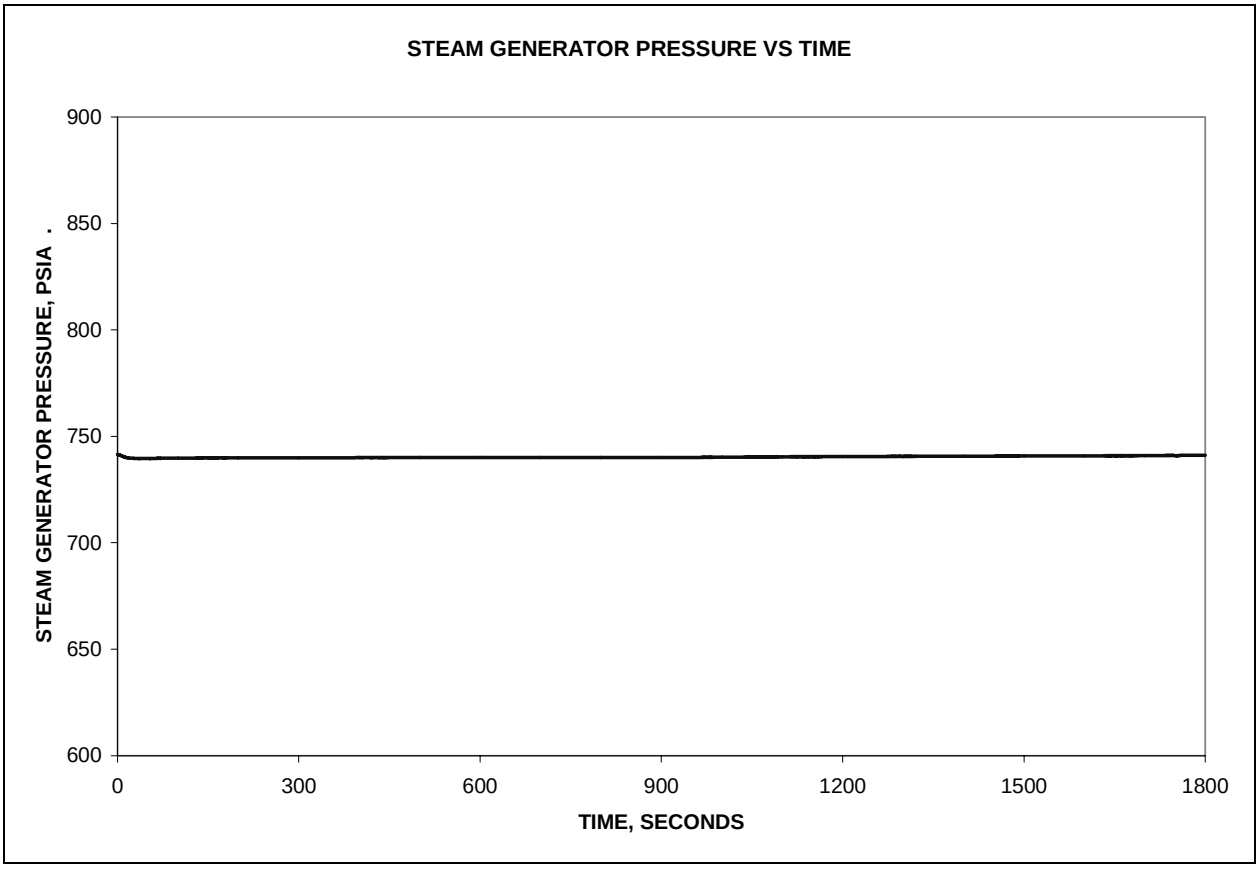

Figure 2.13.6.3.1-7
Letdown Line Break Outside Containment
SG Pressure vs. Time

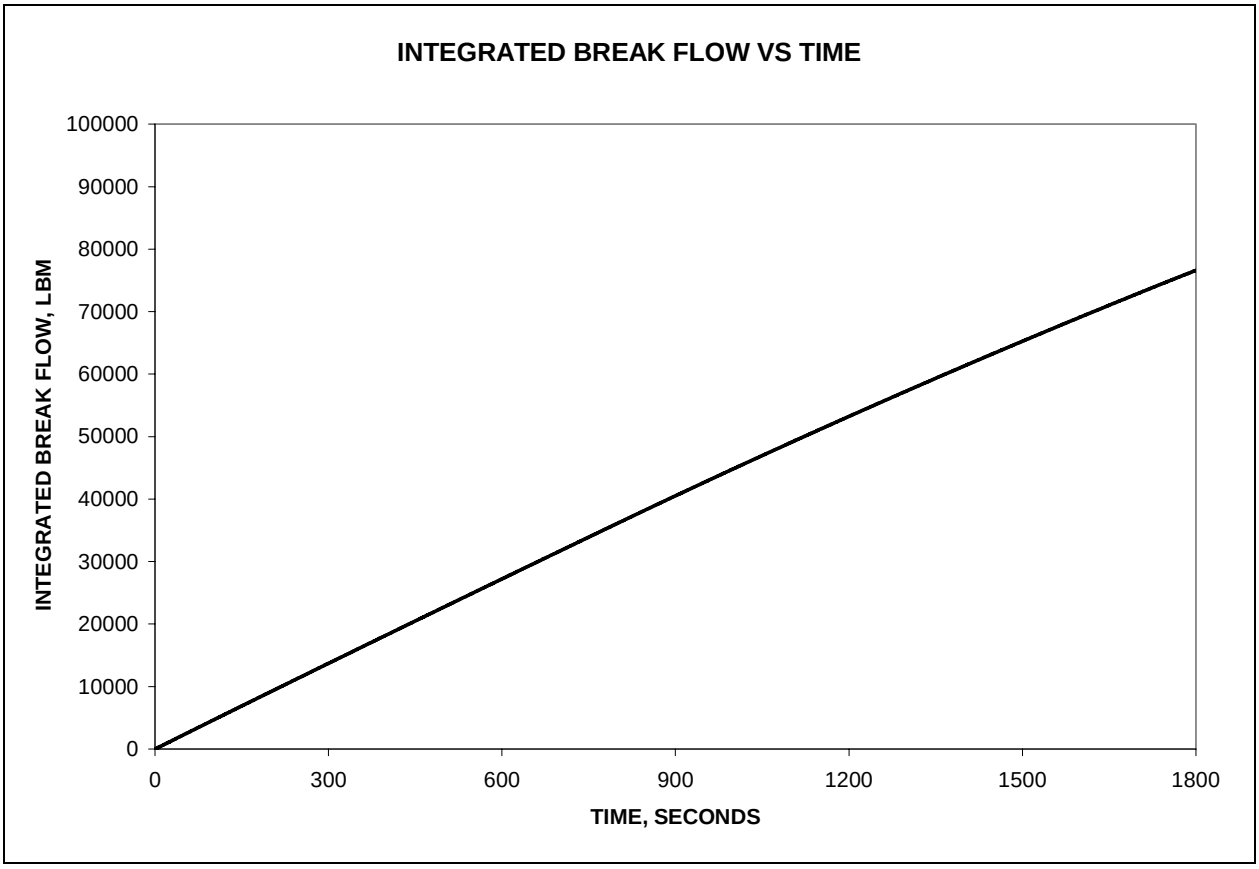

Figure 2.13.6.3.1-8
Letdown Line Break Outside Containment
Integrated Break Flow vs. Time

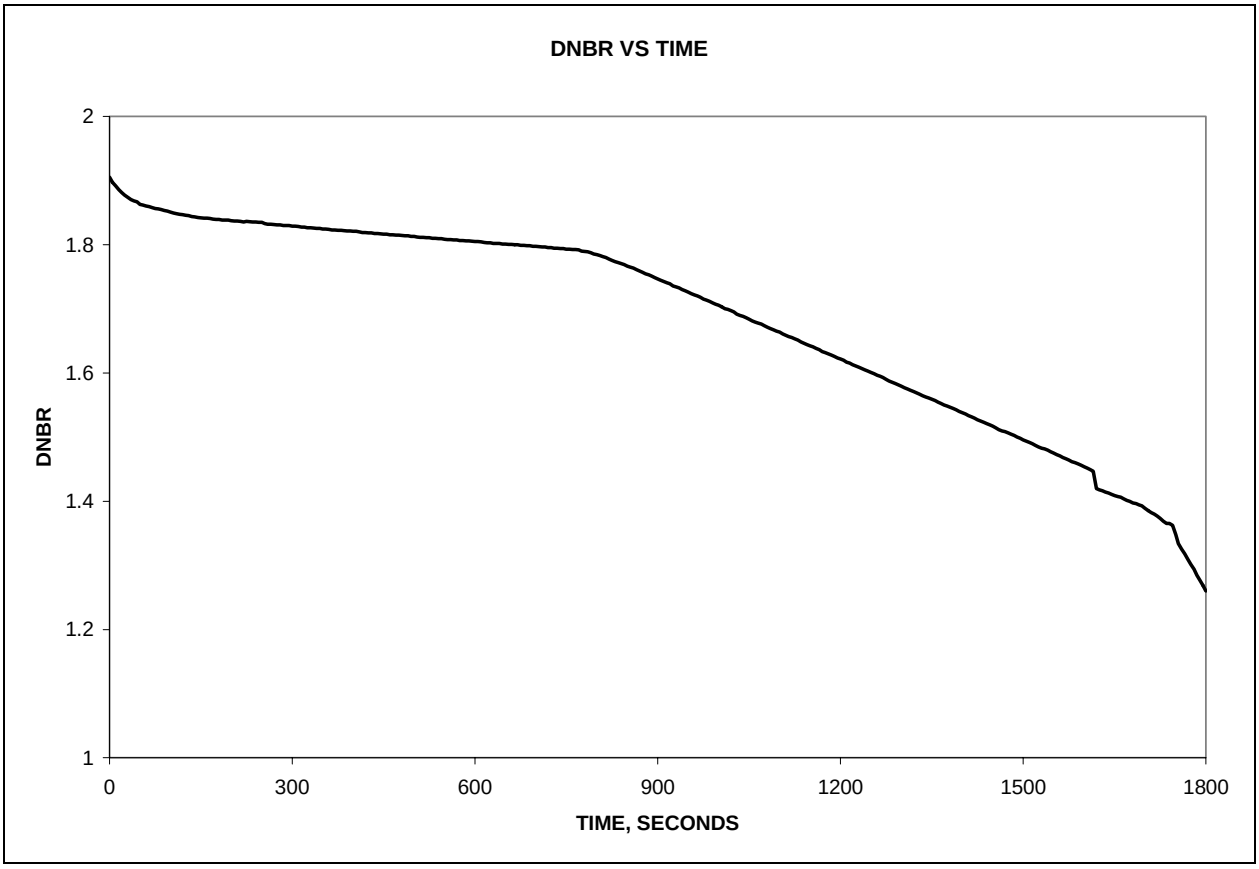

Figure 2.13.6.3.1-9
Letdown Line Break Outside Containment
Minimum DNBR vs. Time

2.13.6.3.2 Steam Generator Tube Rupture

The objective of the steam generator tube rupture (SGTR) with loss-of-offsite power (LOOP) analysis is to document the impact of the following changes:

- Change from CESEC to CENTS as the primary simulation tool
- A decrease in secondary system pressures due to the uprate
- Associated lowering of the MSIS setpoint

The impact of the EPU resulted in no violation of maximum RCS and SG pressure limits for the SAR events.

2.13.6.3.2.1 General Description of the Event

The SGTR accident is a penetration of the barrier between the Reactor Coolant System (RCS) and the Main Steam Supply System (MSSS), which results from the failure of a steam generator (SG) U-tube. Integrity of the barrier between the RCS and MSSS is significant from a radiological release standpoint. The primary coolant activity from the leaking SG tube mixes with the shell side water in the affected SG. After the reactor trip and turbine trip, the radioactive fluid will be released through the ADVs as a result of the LOOP.

A SGTR event results in a depressurization of the RCS. Prior to reactor trip, the radioactivity is transported through the turbine to the condenser where noncondensable radioactive materials would be released via the condenser air ejectors. Because of the reactor trip, the turbine/generator trips and normal offsite power is assumed to be lost. It is assumed that electrical power would then be unavailable for the station auxiliaries such as reactor coolant pumps (RCPs) main feedwater pumps (MFPs), and main circulating water pumps. Under such circumstances, the plant would experience a loss of load, normal feedwater flow, forced RCS flow, condenser vacuum, and SG blowdown. A LOOP after the reactor and turbine/generator trip results in the greatest releases of radioactivity to the atmosphere, therefore, it is assumed for a limiting analysis. The plant is brought to SDC entry conditions through the use of SG ADVs, pressurizer heaters, auxiliary spray, the Safety Injection System (SIS), charging and the Emergency Feedwater System (EFS).

Diagnosis of the SGTR accident is facilitated by radiation monitors that initiate alarms and inform the operator of abnormal activity levels and that corrective operator action is required. These radiation monitors are located in the condenser air ejector discharge, SG blowdown lines, and main steam lines. Additional diagnostic information is provided by the RCS pressure and pressurizer level response and by the level response in the affected SG.

2.13.6.3.2.2 Purpose of Analysis and Acceptance Criteria

The purpose of the analysis was to determine whether the peak primary and secondary system pressures remain below their respective acceptance criteria, DNBR remained above the DNB SAFDL, and to provide input for the offsite dose analysis.

The following criteria apply to the SGTR event:

- DNBR ≥ DNB SAFDL
- Peak RCS pressure ≤ 2750 psia
- Peak secondary pressure ≤ 1210 psia
- Radiological doses are within 10CFR100 limits

The SGTR w/LOOP event is described in Chapter 15.6.3.2 of the FSAR (Reference 2.13-1).

2.13.6.3.2.3 Impact of Changes

In the reanalysis of the SGTR, the CENTS code is used in the same fashion as the CESEC code.

The decreased secondary system pressures associated with the EPU conditions tend to increase the primary-to-secondary system leakage predicted in the early phases of the event.

The increase in rated thermal power (RTP), and resulting decay heat load tend to increase the amount of steaming necessary to perform plant cooldown.

2.13.6.3.2.4 Analysis Overview

This analysis utilized the CENTS computer code (Reference 2.13-2) for the transient analysis simulation. The minimum DNBR evaluation was determined using the CETOP code (Reference 2.13-3). As stated in the FSAR, the LOOP case is bounding for offsite doses. This is due to the fact that the release path for the LOOP is direct to the atmosphere rather than through the condenser when offsite power is available. This analysis assumes that the LOOP occurs 3.0 seconds after reactor trip which is a conservative assumption as discussed in Reference 2.13-13. This assumption is consistent with the SGTR with LOOP assumptions made on other plants and included in CESSAR FSAR Chapter 15.

The input parameters from Table 2.13.6.3.2-1 and the bounding physics data from Section 2.13.0.2 of this report were incorporated with the following clarifications:

- The BOC Doppler curve was assumed.
- A BOC delayed neutron fraction and neutron lifetime consistent with those defined in Section 2.13.0.2 were assumed.
- An initial core power of 3735 MWt, based on a rated power of 3716 MWt and a 0.5% uncertainty, was assumed.
- A most positive (least negative) MTC of $-0.2 * 10^{-4}$ $\Delta\rho/°F$ at HFP was used.
- The maximum HFP core inlet temperature of 552 °F was assumed.
- A minimum RCS flow of 1.48×10^{8} lbm/hr was assumed.

2.13.6.3.2.5 Radiological Consequences

During the SGTR, a total of 65,200 lbm of primary coolant passes through the rupture into the affected SG. Prior to reactor trip, both SGs are steaming normally to the condenser. The high partition factor associated with the condenser makes releases from this source insignificant. Following reactor trip, both SGs are steamed through the ADVs. The affected SG is then isolated until it is necessary to bring the affected SGs ADV back into service for reaching equilibrium for shutdown cooling entry and SG inventory control. A total of 133,400 lbm of steam is released to the atmosphere through the affected SGs ADV.

The majority of the cooldown of the plant is performed by steaming the unaffected SG. A total of 998,000 lbm of steam are released through the unaffected generator's ADV during the cooldown of the plant. Radioactivity release through this intact SG is assumed due to tube leakage from primary-to-secondary.

The radiological consequences for the SGTR with LOOP were calculated for both a pre-existing iodine spike and an event generated iodine spike.

The radiological consequences resulting from the SGTR with LOOP are:

	2-Hour EAB (PIS)	8-Hour LPZ (PIS)
Thyroid	< 300 rem	< 300 rem
Whole Body	< 25 rem	< 25 rem

	2-Hour EAB (GIS)	8-Hour LPZ (GIS)
Thyroid	< 30 rem	< 30 rem
Whole Body	< 2.5 rem	< 2.5 rem

Note:
GIS – generated iodine spike
PIS – pre-existing iodine spike

2.13.6.3.2.6 Analysis Results

The peak RCS and SG pressures remained below their respective criterion of 2750 psia and 1210 psia. The NSSS and RPS responses for the SGTR event are shown in Table 2.13.6.3.2-2 and in Figures 2.13.6.3.2-1 through 2.13.6.3.2-13.

Table 2.13.6.3.2-1
Assumptions for 3716 MWt
SGTR with LOOP

Parameter	3716-MWt Power Uprate Assumption	Current Power Level Assumption
Initial Core Power, MWt	3735	3478
Core Inlet Temperature, °F	552	560
RCS Flowrate, 10^6 lbm/hr	148	141
Pressurizer Pressure, psia	2090	2000
Pressurizer Level, %	33	---
SG Pressure, psia	872	949
SG Level, % NR	26.5	88.5
MTC 10^{-4} $\Delta\rho$/°F	-0.2	N/A
Doppler Coefficient Multiplier	.85	N/A
CEA Worth for Trip, % $\Delta\rho$	-6.0	N/A
SBCS	Inoperative	Inoperative
Feedwater Regulation System	Inoperative	Inoperative
EFS	Automatic	Automatic
SG ADVs	Automatic	Automatic
ADV Setpoint, psia	980	1050
SIAS Setpoint, psia	1560	1560

Table 2.13.6.3.2-2
Sequence of Events for 3716 MWt
SGTR with LOOP

EPU Time (Sec.)	Current Power Level Time (Sec.)	Event	3716-MWt EPU Setpoint/Value	Current Power Level Setpoint/Value
0.0	0.0	Tube rupture occurs	---	---
45	40	Second charging pump turned on, on pressurizer level error, ft	-0.75	-0.75
70	70	Third charging pump turned on, on pressurizer level error, ft	-1.17	-1.17
442.7	109.3	CPC hot leg saturation trip condition reached, °F	13	13
445.4		Trip breakers open	---	---
446		CEAs begin to drop	---	---
449	109.7	LOOP	---	---
450	112.1	SG ADVs open, psia	980	1050
450	113.5	SG MSSVs open, psia	1085	1085
455	142	SG MSSVs close, psia	1041.6	1041.6
485	170.1	SIAS actuated on pressurizer pressure, psia	1560	1560
515	645	Safety injection flow begins to enter RCS	---	---
595	138.1	Pressurizer empties	---	---

Table 2.13.6.3.2-2 (cont.)
Sequence of Events for 3716 MWt
Steam Generator Tube Rupture with Loss of Offsite Power

EPU Time (Sec.)	Current Power Level Time (Sec.)	Event	3716 MWt EPU Setpoint/Value	Current Power Level Setpoint/Value
875 Operator control with 2-minute interval between actions begins.	530	Operator initiates EFW flow to unaffected SG	225	225
	650	Operator takes manual control of the SG ADVs. Initiates plant cooldown by steaming through the unaffected SG ADV.	---	---
	4190	Operator initiates auxiliary spray in order to depressurize the RCS below 1000 psia and regain level control in the pressurizer.	---	---
	3350	Operator manual controls EFW flow to the intact SG to maintain 68% to 71% WR.	71	77
	4310	Operator manually controls safety injection, auxiliary spray flow and the pressurizer backup heater output to try to maintain subcooling (28°F) and pressurizer level (33%-60%)	---	---
1980	4070	Operator isolates the affected SG	---	---
23630	8270	Operator opens ADV to the affected SG as needed to maintain level below 94% WR.	---	---
28800.	28800	Shutdown cooling entry conditions reached, RCS pressure, psia/Temperature, °F	392/350	392/350

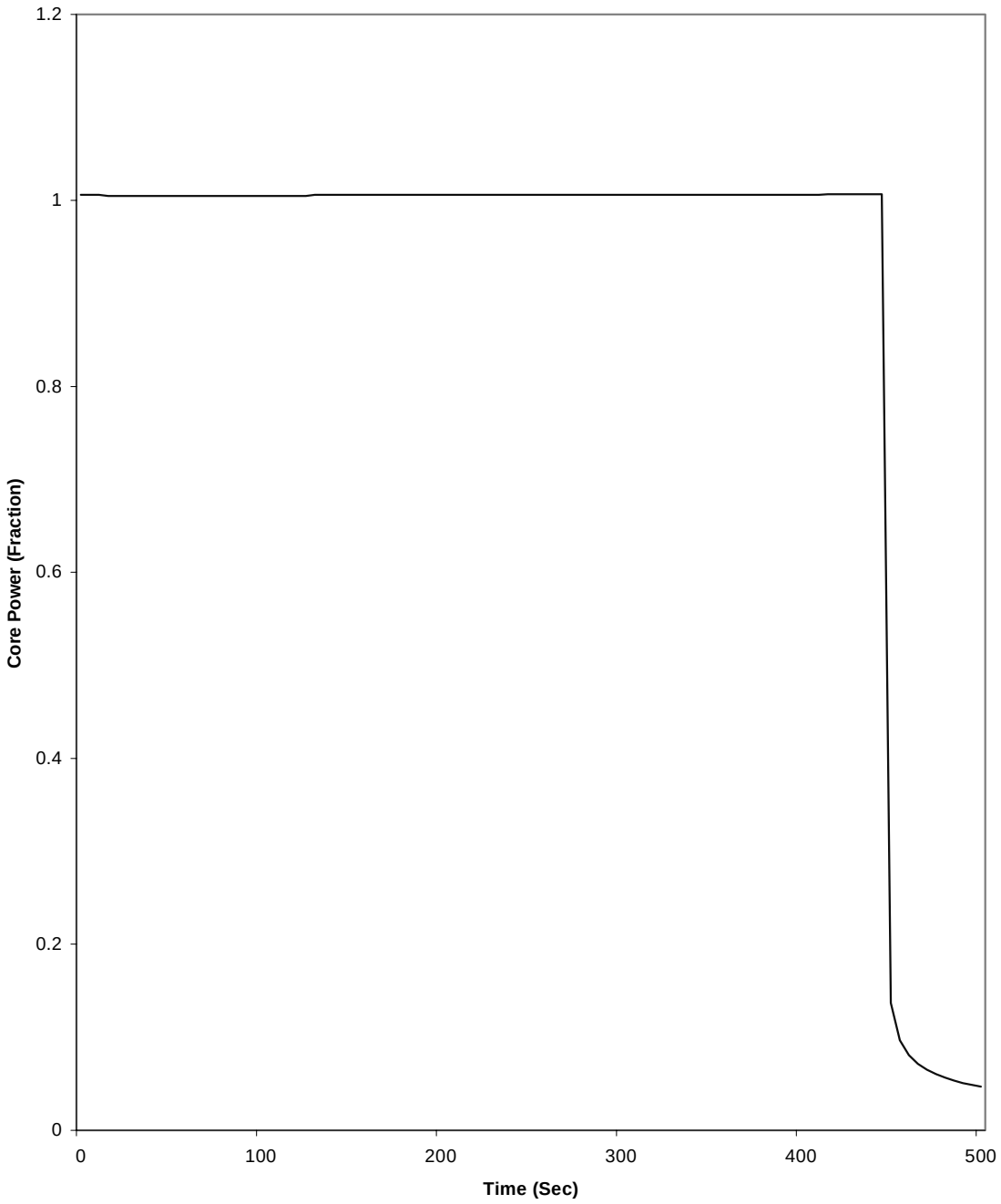

Figure 2.13.6.3.2-1
SGTR with LOOP
Core Power vs. Time

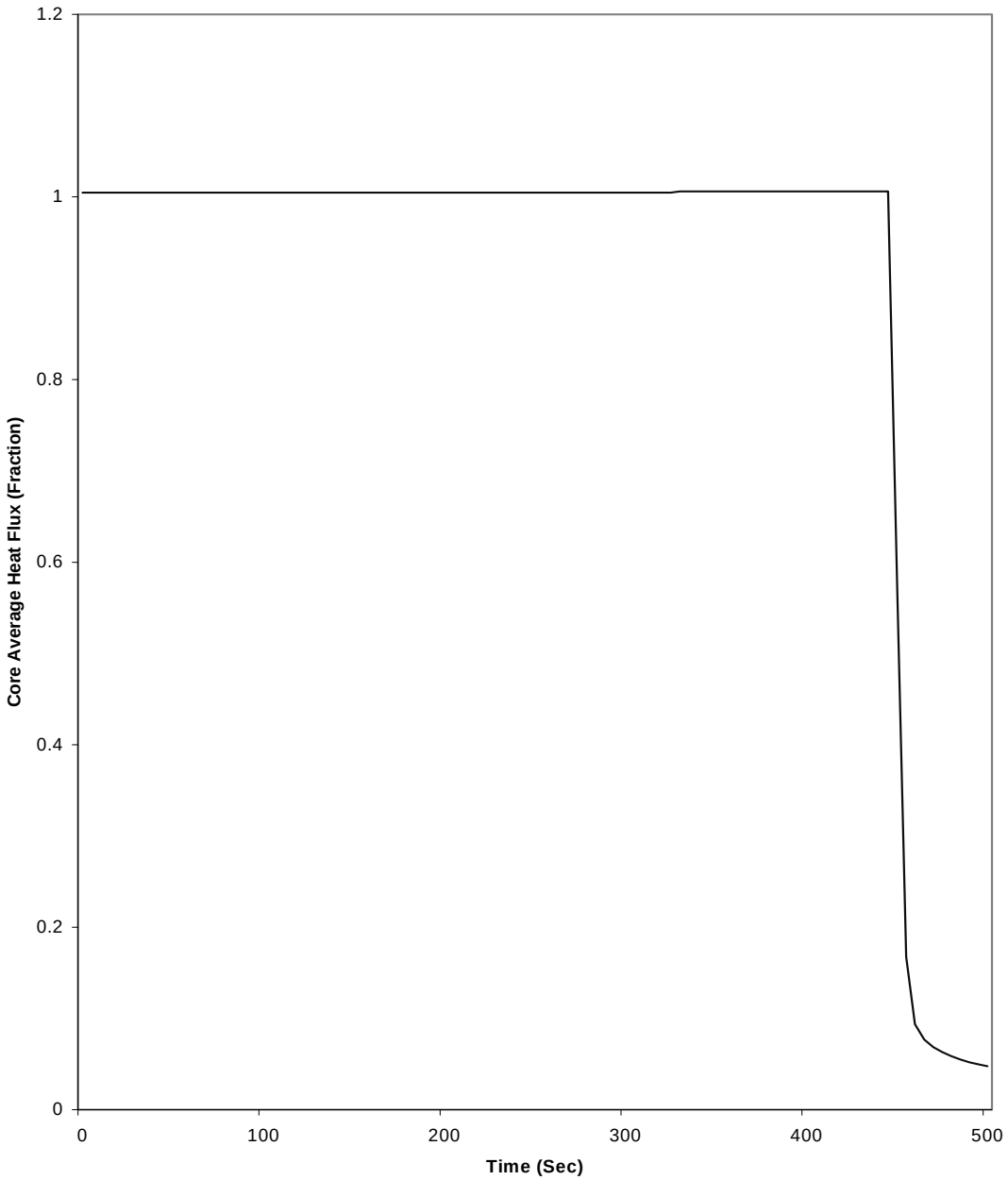

Figure 2.13.6.3.2-2
SGTR with LOOP
Core Heat Flux vs. Time

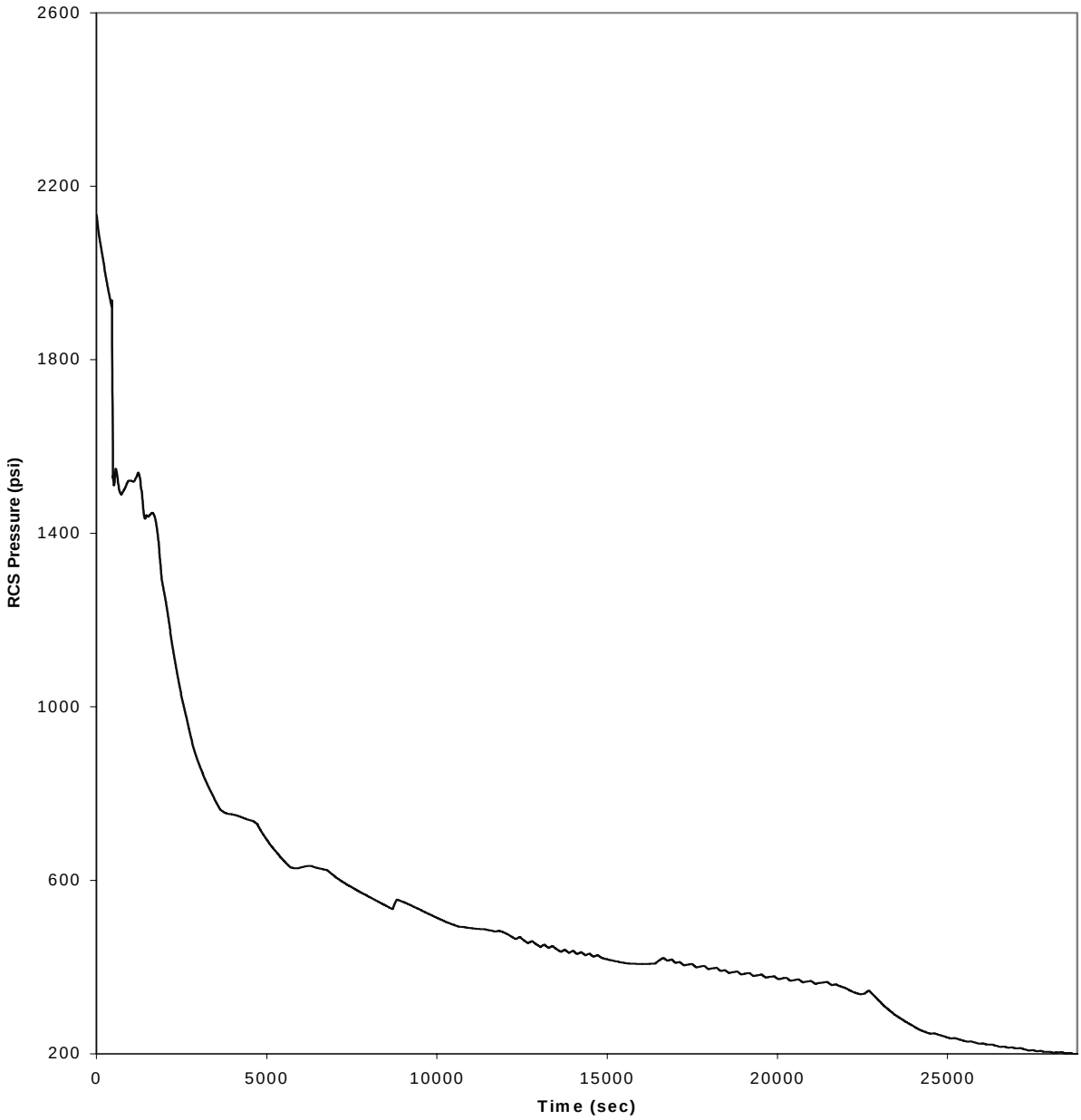

Figure 2.13.6.3.2-3
SGTR with LOOP
RCS Pressure vs. Time

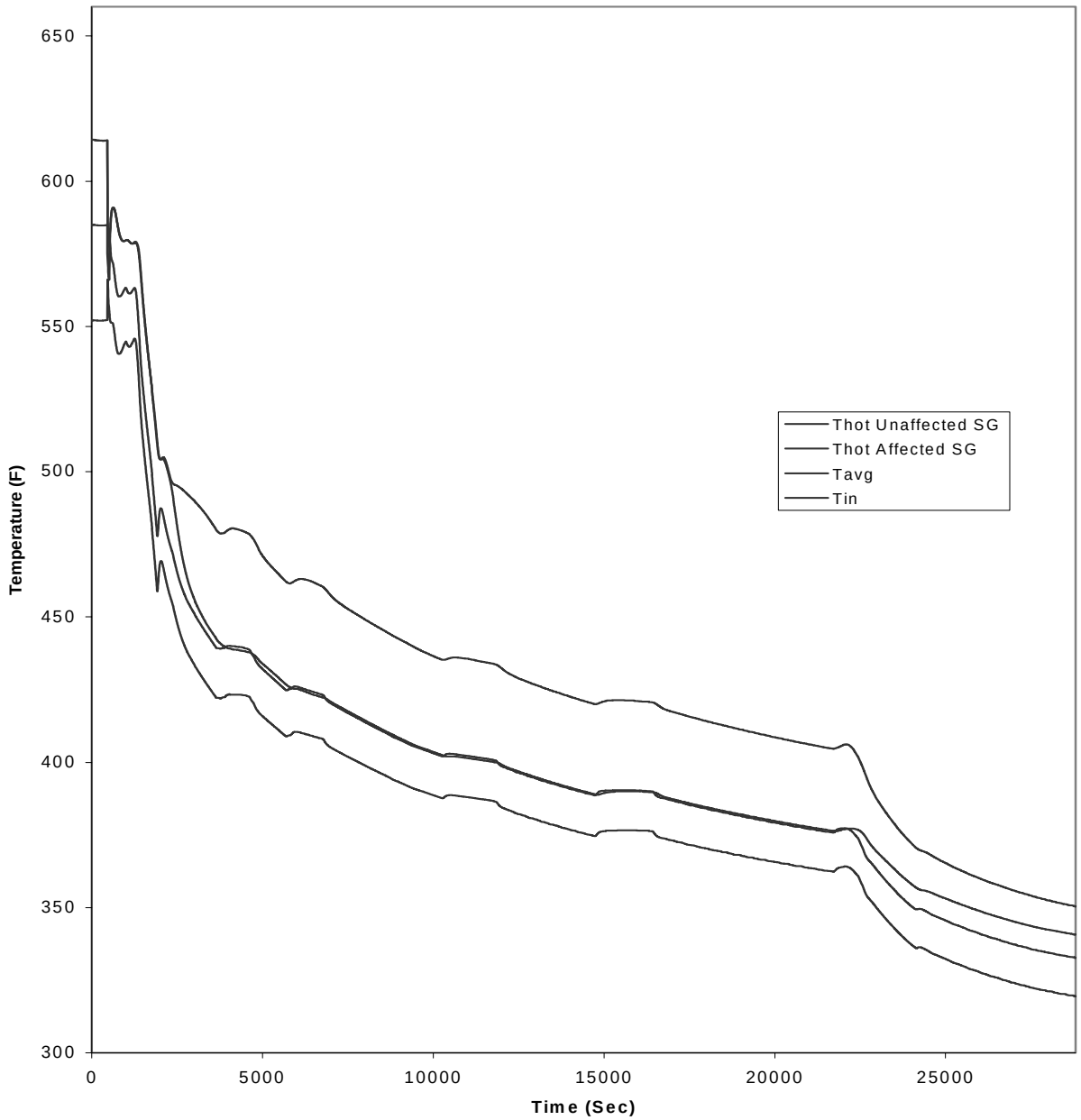

Figure 2.13.6.3.2-4
SGTR with LOOP
RCS Temperatures vs. Time

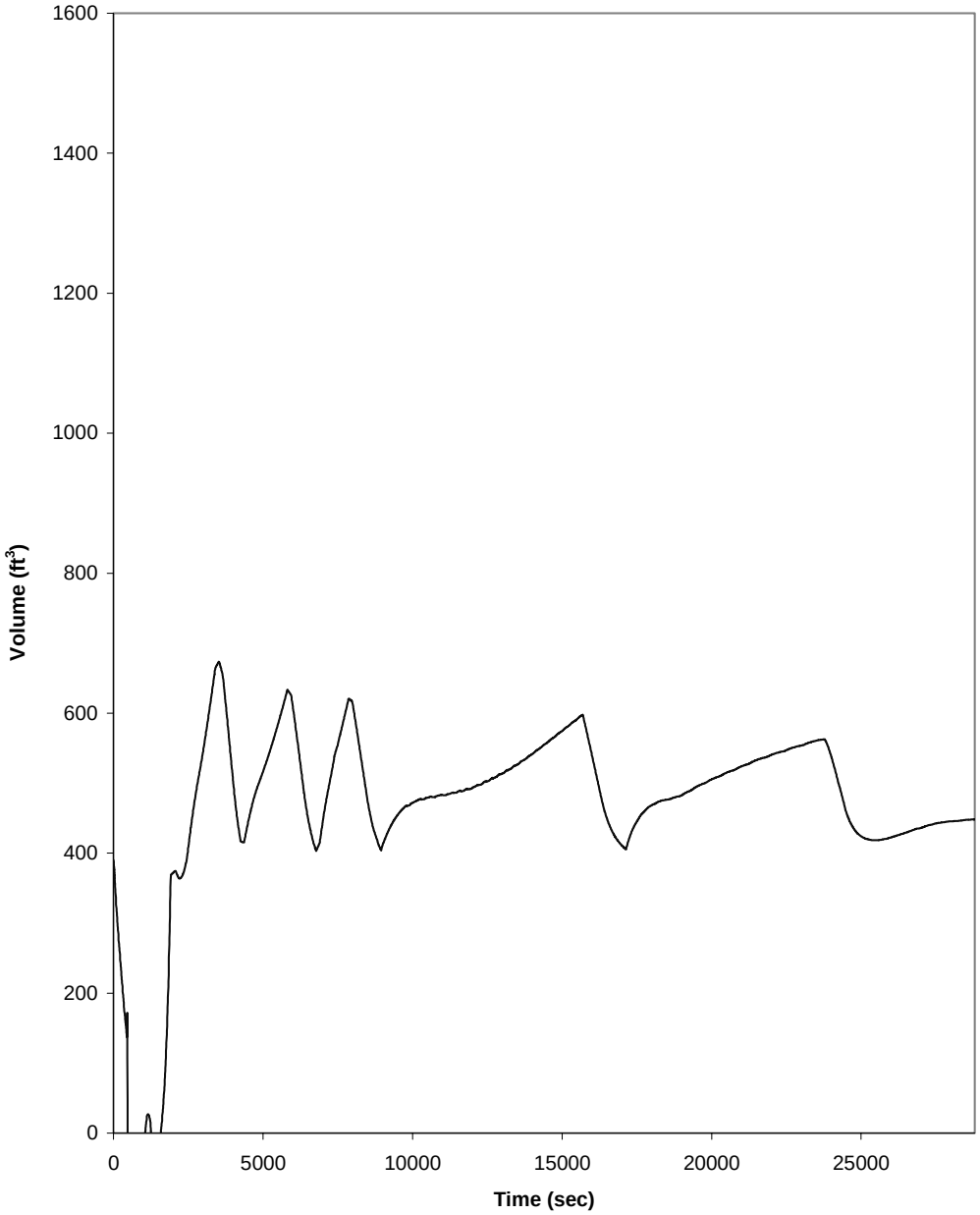

Figure 2.13.6.3.2-5
SGTR with LOOP
Pressurizer Water Volume vs. Time

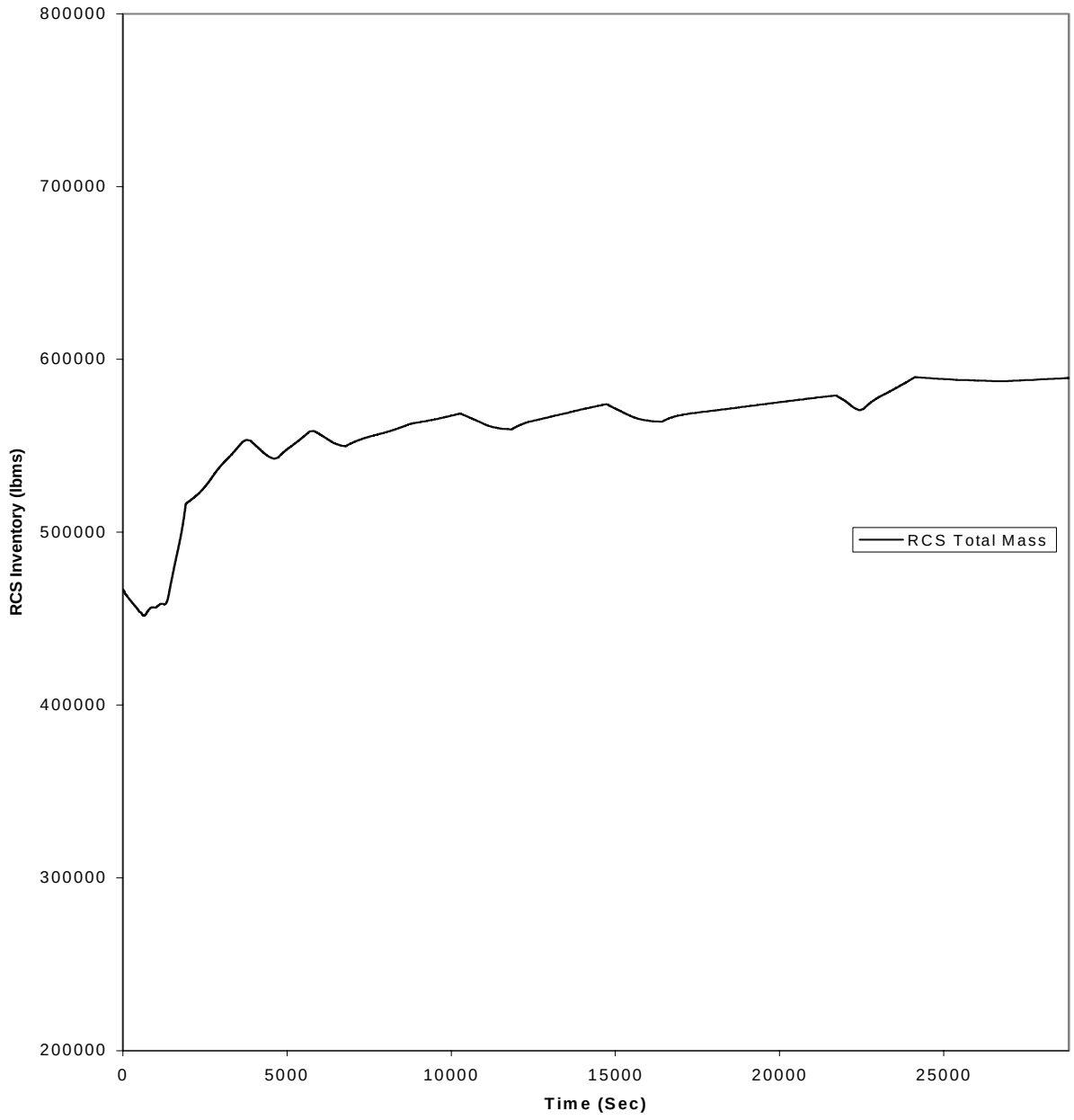

Figure 2.13.6.3.2-6
SGTR with LOOP
RCS Inventory vs. Time

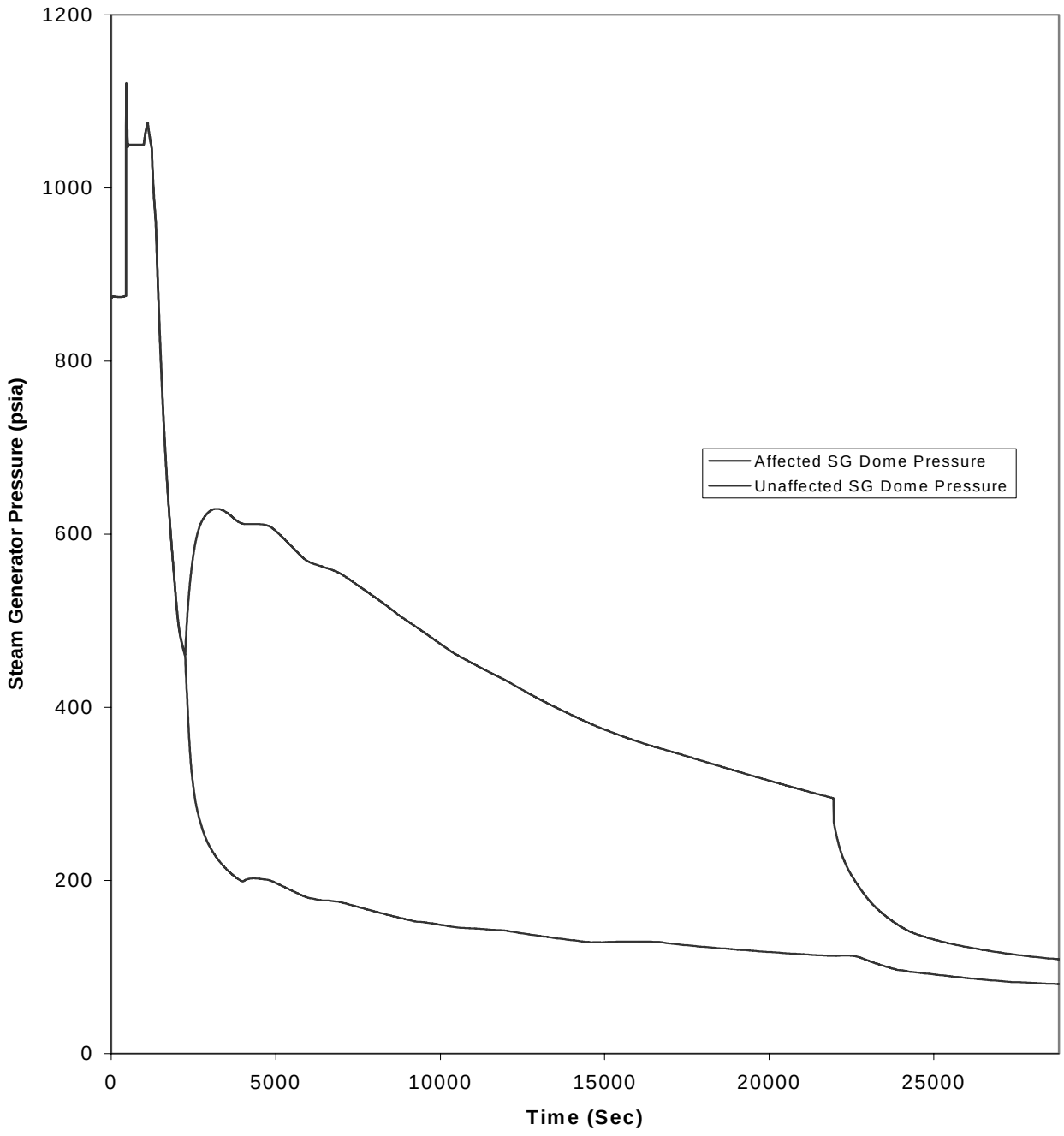

Figure 2.13.6.3.2-7
SGTR with LOOP
SG Pressure vs. Time

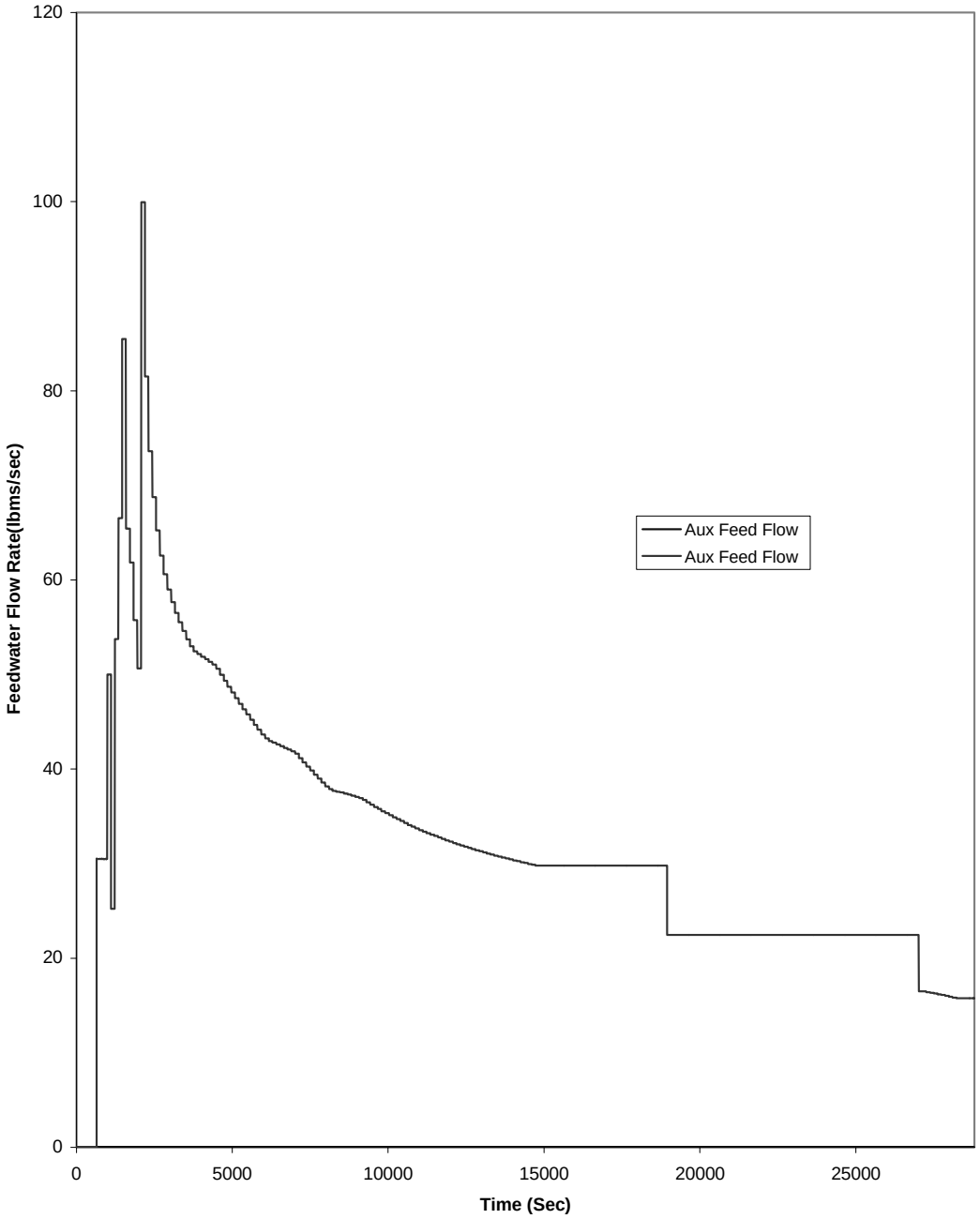

Figure 2.13.6.3.2-8
SGTR with LOOP
Feedwater Flowrate per SG vs. Time

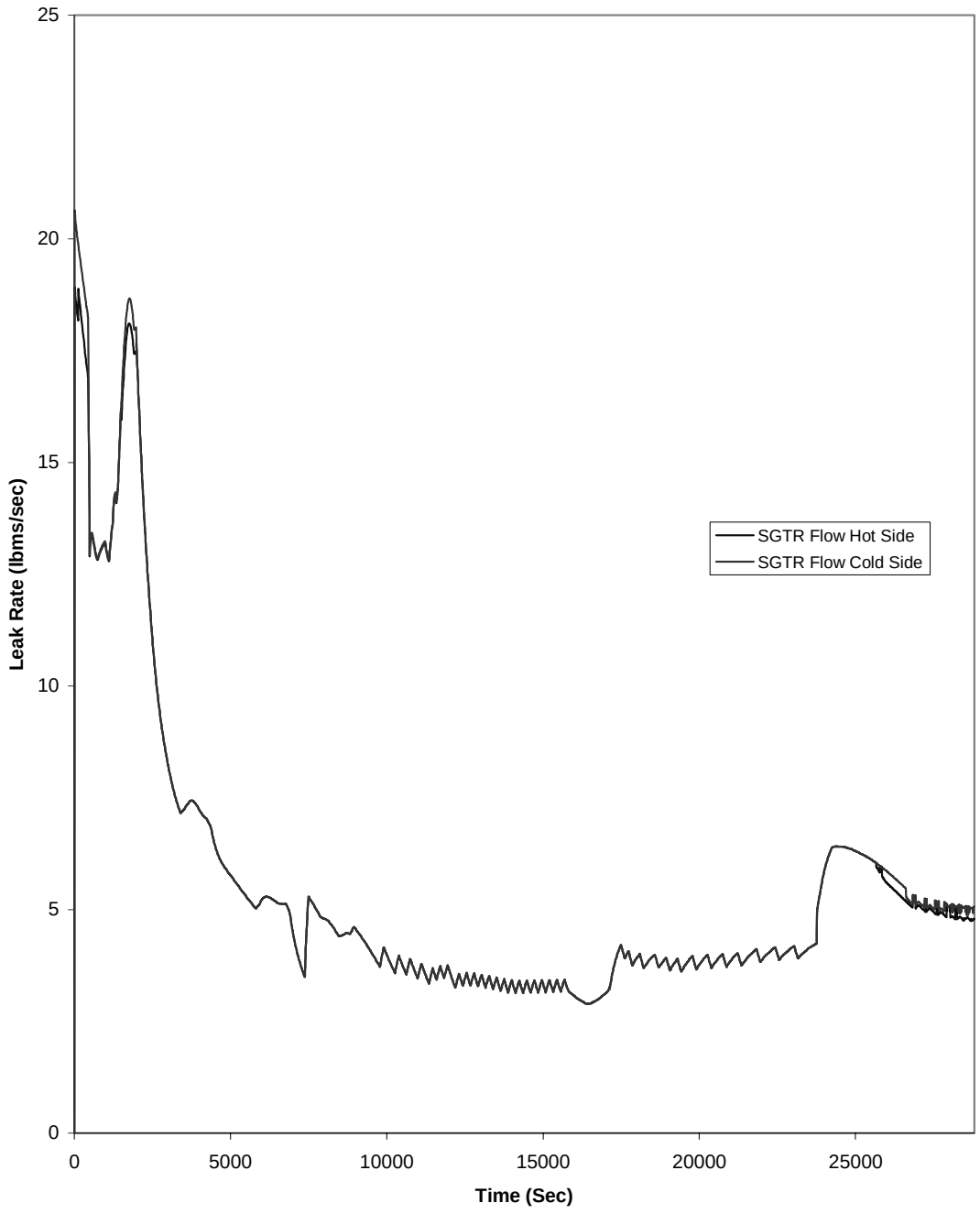

Figure 2.13.6.3.2-9
SGTR with LOOP
Primary-to-Secondary Leak Rate vs. Time

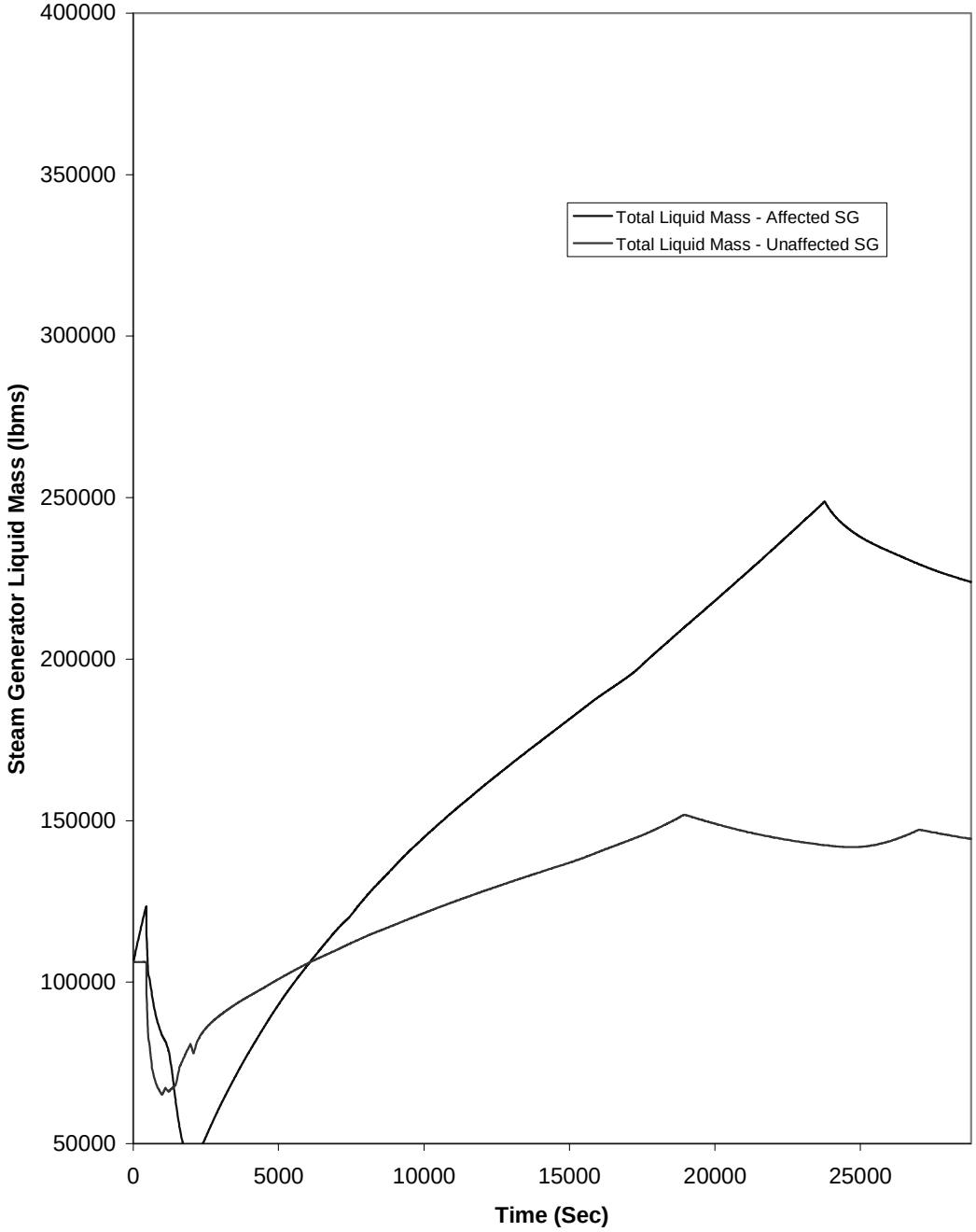

Figure 2.13.6.3.2-10
SGTR with LOOP
SG Liquid Mass vs. Time

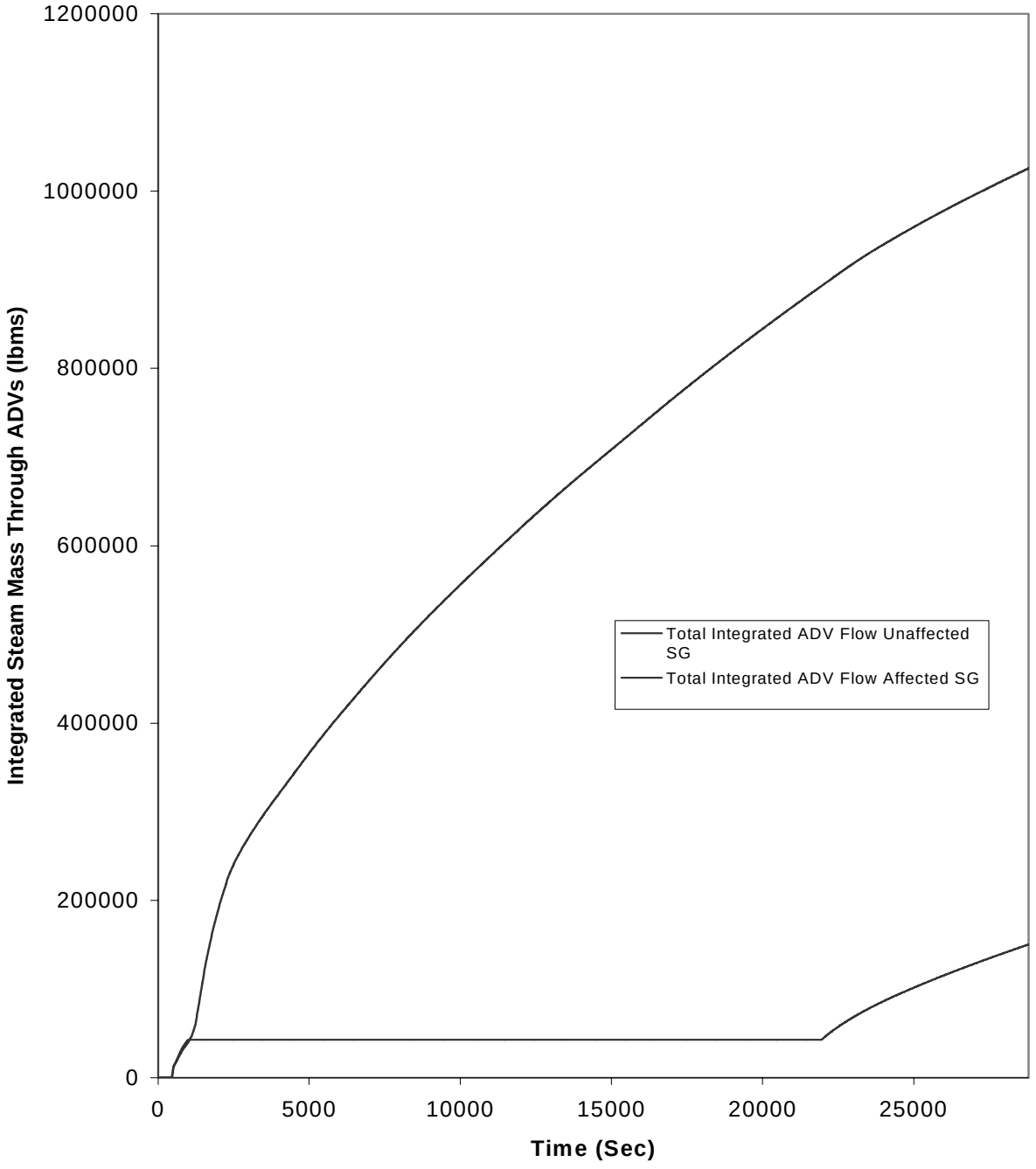

Figure 2.13.6.3.2-11
SGTR with LOOP
Integrated Steam Mass Through ADVs vs. Time

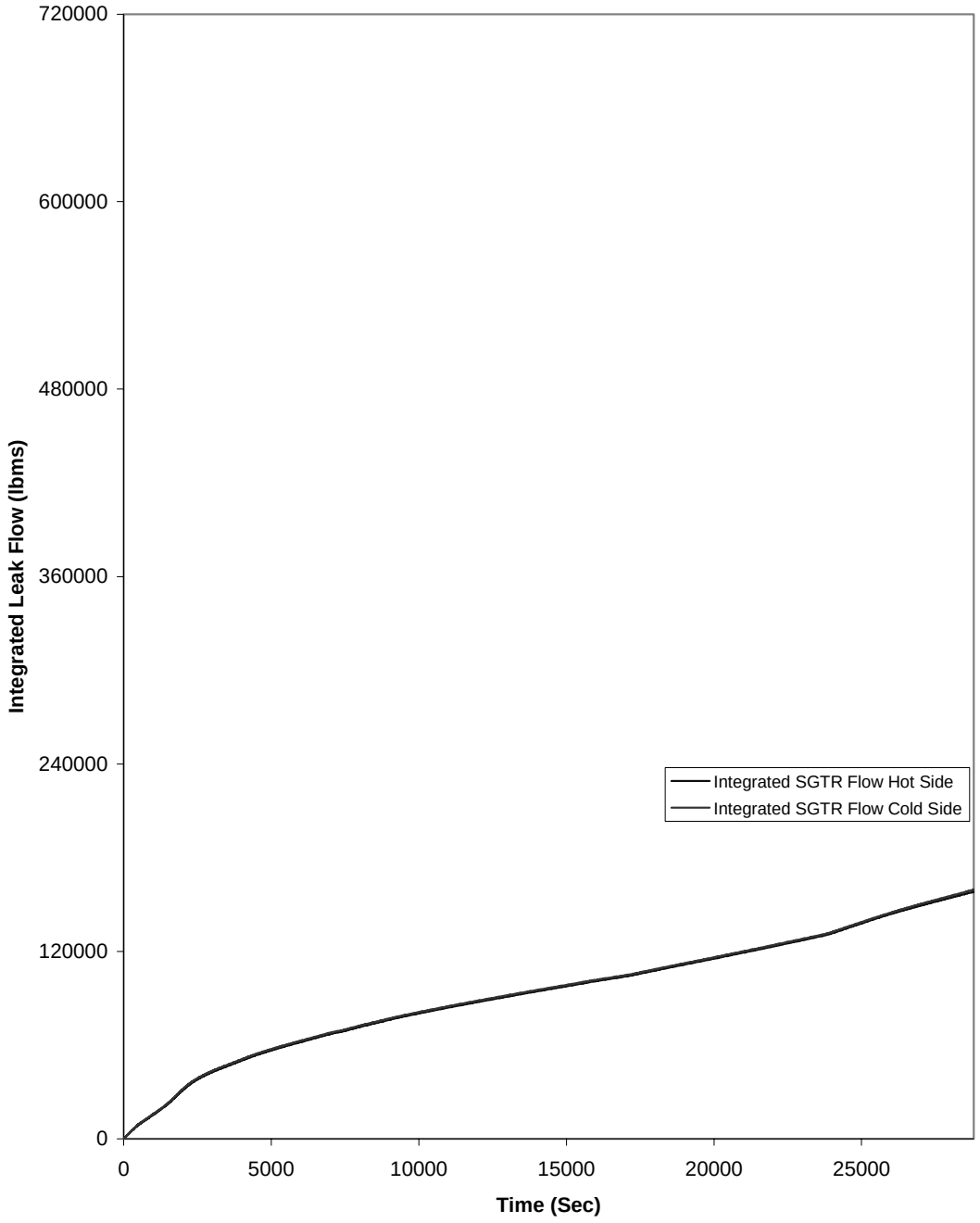

Figure 2.13.6.3.2-12
SGTR with LOOP
Integrated Primary-to-Secondary Leak Flow vs. Time

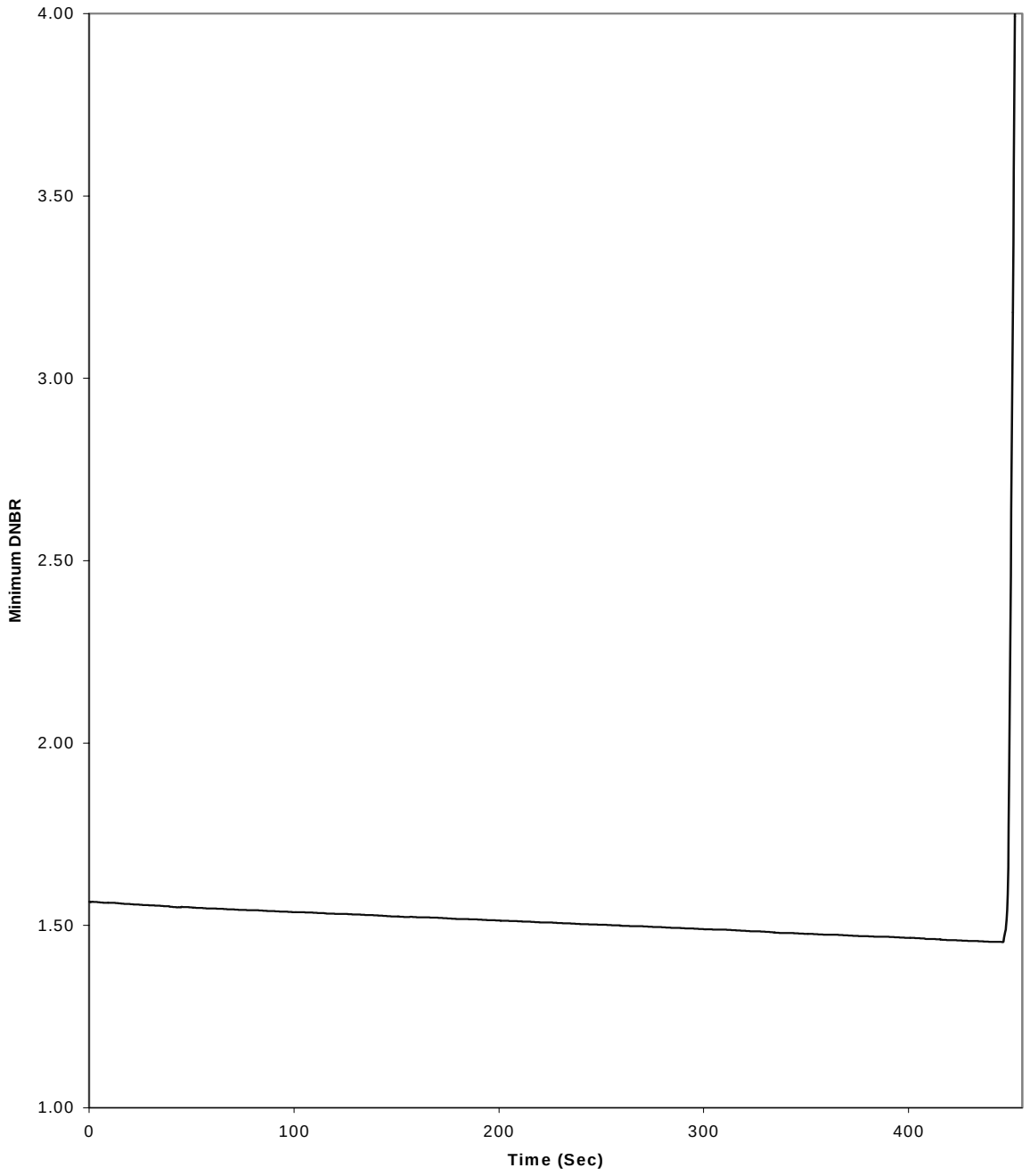

Figure 2.13.6.3.2-13
SGTR with LOOP
Minimum DNBR vs. Time

2.13.6.3.3 Loss of Coolant Accident (LOCA) Radiological Consequences

The radiological consequences for a design basis LOCA at EPU conditions included changes in certain input data, specifically:

- An increase in rated power to 3716 MWt
- New offsite and control room atmospheric dispersion factors (χ/Q) values
- An increase in the amount of assumed un-filtered control room in-leakage to 50 cfm

The acceptance criteria for the exclusion area boundary, low population zone and control room radiological doses were met utilizing the revised input data.

2.13.6.3.3.1 General Description of the Event

The design basis LOCA is postulated as a break in the reactor coolant pressure boundary piping. An immediate release of a portion of the core's radioactive inventory to the containment is assumed. In accordance with Regulatory Guide (RG) 1.4 the following fractions of the core's radioactive inventory are assumed to be airborne within the containment and are immediately available for leakage from the primary reactor containment:

- 100 percent of the noble gases
- 25 percent of the iodines

In accordance with RG 1.4, the iodine isotopes are assumed to be 91% elemental iodine, 5% particulate iodine, and 4% organic iodine.

2.13.6.3.3.2 Purpose of Analysis and Acceptance Criteria

The purpose of the analysis is to determine the impact of the above changes on the exclusion area boundary (EAB), low population zone (LPZ) and control room radiological doses.

The acceptance criterion for the LOCA dose analysis is to keep the EAB and LPZ radiological doses within 10CFR100 limits and the control room radiological doses within GDC 19 and SRP 6.4 acceptable limits.

2.13.6.3.3.3 Impact of Changes

The increase in rated thermal power will result in an increase in the activity release to the containment and in turn higher resultant offsite and control room doses. The pre-EPU Waterford 3 LOCA dose calculation assumes a power level of 3560 MWt which is 105% of 3390 MWt (original RTP). The EPU LOCA dose calculations will assume a power level equal to 100.5% of 3716 MWt (0.5% bounds the current Waterford 3 power measurement uncertainty and is consistent with RG 1.4 guidance) or 3735 MWt. Since the TID-14844 source term is in terms of Ci/MWt the activity release in the containment will increase by a factor of about 1.05 (3735/3560).

The new 2-hour EAB χ/Q value of 4.31E-04 (sec/m^3) is lower than the old χ/Q value of 6.30E-04 (sec/m^3) and therefore has a favorable impact on EAB dose results. The new LPZ χ/Q values are lower than the old χ/Q values for the 0.0-to-8 hours and 8-to-24 hours, but higher for the 24-to-96 hours and 96 hours to 30 days. Therefore, the overall offsite dose impact of the new χ/Q values is varied. Since the new control room χ/Q values are calculated for various release points versus one set of χ/Q values for current control room dose calculation, the overall control room dose impact of the new χ/Q values is also varied.

The increase in unfiltered in-leakage has an adverse impact on the control room doses.

2.13.6.3.3.4 Analysis Overview

Waterford 3 LOCA dose methodology is described in FSAR Section 15.B, with analysis inputs provided in FSAR Section 15.6.3.3. The power uprate evaluation included the dose from reactor building leakage, and an assumed one gpm engineered safety feature (ESF) leakage. The ESF leakage is in an area that is serviced by Controlled Ventilation Area System (CVAS) (filtered release through the plant stack). The activity released to the CVAS areas from containment leakage and 1 gpm post-recirculation ESF leakage is assumed to be immediately processed by CVAS and released to the environment. The TID-14844 source term was used in this analysis. The containment was assumed to leak at 0.5% volume per day (consistent with Waterford 3 Technical Specifications) in the first 24 hours and is reduced to 0.25% volume per day leakage after 24 hours.

Three leakage paths including, (1) leakage to reactor auxiliary building serviced by CVAS, (2) leakage to the secondary containment (containment annulus) that is serviced by Shield Building Ventilation System (filtered release through the plant stack), and (3) direct leakage to the environment (bypass leakage) are considered in the LOCA dose calculation. Additionally, 1 gpm of sump water is assumed to leak in the areas serviced by CVAS from ESF systems for the duration of the accident (30 days). The ESF leakage starts after actuation of the recirculation mode of safety injection operation. The impact of this leakage is included in the overall LOCA dose results. An instantaneous uniform distribution of the core release is assumed in the sprayed and unsprayed regions that consist of 85% and 15% of the containment volume respectively. The offsite and control room doses are calculated based on:

- ICRP-30 dose conversion factors,
- Offsite breathing rate per RG 1.4,
- A constant control room operator breathing rate equal to the highest breathing rate per RG 1.4,
- A control room occupancy factor consistent with SRP 6.4 recommendation and
- New offsite and control room dispersion factors calculated based on current meteorological data.

New X/Q values, as described in Section 2.13.0.5, are used in this analysis.

2.13.6.3.3.5 Analysis Results

The resultant offsite and control room doses are provided below:

	Thyroid Dose (Rem)			Whole Body Dose (Rem)			Skin Dose (Rem)
	EAB	LPZ	Control Room	EAB	LPZ	Control Room	Control Room
LOCA Doses	23.0	21.0	9.0	7.0	3.0	1.50	29.5
Acceptance Criteria	300	300	30	25	25	5	30

The above results demonstrate that the resultant LOCA off site doses are within the limits of 10CFR100 and the resultant control room doses are within the limits of GDC 19 and SRP 6.4.

2.13.6.4 Inadvertent Opening of a Pressurizer Safety Valve

This event is bounded by Small Break LOCA. Refer to Section 2.12.6 for the discussion of this event.

2.13.7 Radioactive Release from a Subsystem or Component

2.13.7.1 Moderate Frequency Incidents

None

2.13.7.2 Infrequent Incidents

None

2.13.7.3 Limiting Faults

None

2.13.7.3.1 Radioactive Waste Gas System Leak or Failure

Deleted from NUREG-0800, Standard Review Plan. Not required to be addressed per Section 2.7 of draft Review Standard RS-001, “Review Standard for Extended Power Uprates.”

2.13.7.3.2 Liquid Waste System Leak or Failure

Deleted from NUREG-0800, Standard Review Plan. Not required to be addressed per Section 2.7 of draft Review Standard RS-001, “Review Standard for Extended Power Uprates.”

2.13.7.3.3 Postulated Radioactive Releases Due to Liquid Containing Tank Failures

Not required to be addressed per Section 2.7 of draft Review Standard RS-001, “Review Standard for Extended Power Uprates.”

2.13.7.3.4 Radiological Consequences of Fuel Handling Accidents

Waterford 3 previously re-analyzed the fuel-handling accident (FHA) in support of License Amendments 169 and 176. These amendments have been approved by the NRC in safety evaluations dated October 2, 2000, and November 21, 2001, respectively. The calculation used the power uprate activity source term generated during the Waterford 3 spent fuel pool re-rack project. The spent fuel pool re-rack project assumed a power level of 3844.3 MWt and was approved in License Amendment 144 via a safety evaluation dated July 10, 1998.

2.13.7.3.4.1 General Description of the Event

The analysis assumes that a fuel assembly is dropped during fuel handling. The worst case fuel assembly horizontal impact results from a vertical drop, followed by rotation of the fuel

assembly to the horizontal position. During this rotation, it is postulated that the assembly strikes a protruding structure failing no more than 4 rows of fuel rods.

The analysis used the power uprate source term calculated as part of spent fuel pool re-rack. Key assumptions employed in the generation of the source term and dose analysis included:

- Power level of 3844.3 MWt = 3716 MWt power plus 3.45% power uncertainty
- Time after shutdown: 72 hours (3 days, consistent with Waterford 3 Technical Specification)
- Power peaking factor: 1.8
- No credit is taken for filtration
- All the activity released to the containment or the Fuel-Handling Building as a result of the spent fuel handling accident is assumed to be immediately released to the environment.
- Current offsite and control room dispersion factors.

2.13.7.3.4.2 Analysis Results

The offsite and control room doses for an FHA in the fuel building, without crediting any filtration, or a FHA inside the Containment Building assuming the equipment hatch and personnel airlock are open, are given below:

Dose Category	EAB (2 hr.) Rem (Acceptable limit)	CR–Rem (Acceptable limit)
Whole Body	0.176 (6)	0.015 (5)
Skin	-------	0.623 (30)
Thyroid	53.69 (75)	0.932 (30)

The resultant control room doses are within the acceptable limits of GDC 19 and SRP 6.4 and the resultant offsite doses were well within (less than 25%) of the 10CFR100 limits.

This analysis was performed using the current offsite and control room dispersion factors. As can be seen from the results, the control room doses and offsite whole body dose are significantly lower than the acceptance criteria. The limiting dose is the EAB thyroid dose. The old and new dispersion factors (χ/Q) for the EAB are:

	χ/Q (sec/m^3)
Current	6.30E-04
New	4.31E-04

Since the old χ/Q value used in the FHA is much larger than the new χ/Q value, the analysis results bounds the calculation with the new χ/Q.

The above control room dose results are based on 13 cfm un-filtered in-leakage with an χ/Q value of 1.66E-03 sec/m^3. The worst χ/Q for the fuel handling accident is releases from the

plant stack to the east control room intake (2.77E-03 sec/m^3). To account for a higher un-filtered in-leakage, e.g., 100 cfm, the control room dose results are conservatively increased by a factor of 13 ((2.77e-03/1.66E-03)*(100cfm/13cfm) = 12.84, assuming an unfiltered in-leakage of 100 cfm):

Dose Category	CR–Rem (Acceptable limit)
Whole Body	0.20 (5)
Skin	8.10 (30)
Thyroid	12.12 (30)

The above result demonstrate the control room dose results due to an FHA will be within the acceptable limits if performed using the new χ/Q values and an un-filtered in-leakage of 100 cfm.

2.13.7.3.5 Spent Fuel Cask Drop Accidents

Waterford FSAR Section 15.7.3.5.1 “Cask Drop into Spent Fuel Pool and/or Cask Pit Storage Area,” refers to FSAR Section 9.1.4 for a description of the cask handling crane, and states that the crane cannot travel “Over the spent fuel pool, the cask pit storage area, or any unprotected safety related equipment. Thus, an accident resulting from dropping a cask or other major load into the spent fuel pool or cask storage area is not credible."

FSAR Section 15.7.3.5.2, “Cask Drop to Flat Surface” refers to the Section 9.1.4 discussion of the cask handling crane and states that a "potential cask drop is limited to less than an equivalent 30 ft. drop onto a flat, essentially unyielding surface." The conclusion is stated that "Since the cask is designed to withstand such loadings, radiological consequences of these accidents are not evaluated."

The cited restrictions on cask handling crane movement and maximum potential cask drop height will not be altered. The cask handling crane will not be modified. For these reasons, the licensing basis for not analyzing radiological consequences of spent fuel cask drop accidents remains valid, and such analyses are not required for power uprate.

2.13.8 Anticipated Transients Without Scram (ATWS)

ATWS is addressed in Waterford 3 FSAR Sections 7.8 and 15.8. As described therein, Waterford 3 includes ATWS mitigation systems as required by 10 CFR 50.62, the ATWS rule. The EPU does not change the design of ATWS mitigation systems as described in FSAR Section 7.8. The EPU lowers steam generator and main steam operating pressures. Lower main steam operating pressures result in lowering the diverse emergency feedwater actuation signal permissive setpoint for actuating the emergency feedwater system. Lowering the permissive setpoint results in a diverse emergency feedwater actuation signal configuration consistent with the configuration described in FSAR Section 7.8. Additionally, actuation setpoints remain such that mitigation systems will not be actuated before initiation of the Plant Protection System.

2.13.9 Miscellaneous

2.13.9.1 Moderate Frequency Incidents

2.13.9.1.1 Asymmetric Steam Generator

The objective of the asymmetric steam generator transient (ASGT) analysis is to demonstrate that the ASGT event does not violate the DNBR and LHR SAFDLs for Waterford 3 with power uprate at 3716 MWt. The analysis was performed for the power uprate to evaluate the impact of:

- Change in most negative moderator temperature coefficient (MTC) from -4.0×10^{-4} $\Delta\rho/°F$ to -4.2×10^{-4} $\Delta\rho/°F$
- Use of CENTS rather than CESEC
- Increase in rated thermal power
- A decrease in the CPC differential cold leg temperature trip setpoint from 18°F to 11°F.

2.13.9.1.1.1 General Description of the Event

The event is initiated by the inadvertent closure of a single main steam isolation valve (MSIV), which results in a loss of load to the affected SG. Upon the loss of load to the single SG, its pressure and temperature increase to the opening pressure of the secondary safety valves. The core inlet temperature of the loop with the affected SG increases resulting in a temperature tilt across the core. The steam flow from the unaffected SG increases to “pick up” the lost load causing a decrease in its temperature and pressure. This causes the unaffected SG loop core inlet temperature to decrease, thereby enhancing the temperature tilt at the core inlet. In the presence of a negative MTC, the radial peak increases in the cold side of the core, resulting in a condition that potentially could cause an approach to DNBR and core thermal margin (CTM) limits. The CPC high differential cold leg temperature trip serves as the primary means of mitigating this transient.

2.13.9.1.1.2 Purpose of Analysis and Acceptance Criteria

The purpose of this analysis is to demonstrate that the ASGT event does not violate the DNBR and LHR SAFDLs for Waterford 3 with power uprate at 3716 MWt.

The following criteria apply to the ASGT event:

- DNBR > 1.26
- Fuel temperature < fuel melt temperature limit, demonstrated by peak LHR ≤ 21.0 kW/ft
- Radiological dose ≤ small fraction of 10CFR100 limits
- RCS pressures ≤ 110% of design.

2.13.9.1.1.3 Impact of Changes

The impact of the changes is as follows:

a) The radial power distortion occurring during the ASGT is driven by the MTC and the temperature tilt existing across the core inlet. The increase in negative MTC potentially increases the asymmetry in core power for a given core inlet delta temperature.

b) The higher power level will change the rate at which the inlet temperature asymmetry develops following the closure of an MSIV. This will affect trip time and the further increases in power tilt between the trip condition and the time of DNBR turnaround in the trip sequence.

c) The event is now analyzed with the CENTS code versus the CESEC code. The CENTS model is used in the same manner as the CESEC model had been used.

d) The CPC differential cold leg temperature trip setpoint is reduced to compensate for the impact of items a and b, above.

2.13.9.1.1.4 Analysis Overview

The NSSS response is calculated with the CENTS code. At time equals zero, the MSIV to one of the SGs is closed. The time of the CPC high differential cold leg temperature trip is calculated with the CPCFORTRAN code using an interface file generated by CENTS with the core flow, RCS inlet temperature, cold leg temperatures, and RCS pressure. The transient thermal margin and DNBR are calculated with the CETOP code using an interface file generated by CENTS. The important physical effect driving DNBR degradation is the core power tilt developed by the asymmetry in the core inlet temperature and the MTC. The most negative MTC is used to model this radial power tilt. In combination with this, the NSSS response from the least negative MTC is used to minimize any core wide decreases in power from the asymmetry. The transient is also analyzed for symmetric and asymmetric steam generator tube plugging (SGTP).

2.13.9.1.1.5 Radiological Consequences

No SAFDL violation occurs during the ASGT event. Source terms are therefore limited to the initial primary and secondary limits on coolant activity in the Technical Specifications. Doses for this event are bounded by the IOSGADV with LOOP event in Section 2.13.1.2.4.5 of this report. Both events have the same criteria (small fraction of 10CFR100 guidelines), and the IOSGADV with LOOP event radiological dose assumptions are conservative for the ASGT event.

2.13.9.1.1.6 Analysis Results

The ASGT event does not violate the DNBR ($\geq$ 1.26) and LHR ($\leq$ 21 kW/ft) SAFDLs for Waterford 3 with power uprate at 3716 MWt.

The ASGT event with power uprate at 3716 MWt does not violate the limits on maximum RCS and SG pressure.

The assumptions and sequence of events for the ASGT event are given in Tables 2.13.9.1.1-1 and 2.13.9.1.1-2. Figures 2.13.9.1.1-1 to 2.13.9.1.1-5 show the NSSS response for core power, core heat flux, RCS temperatures, RCS pressures, and steam generator pressures. Figure 2.13.9.1.1-6 shows the DNBR curve for the ASGT event.

Table 2.13.9.1.1-1
Comparison of Assumptions for the ASGT Event

Parameter	Power Uprate Assumption	Current Power Level Assumption
Initial core power , MWt	3735	3478
Core inlet temperature, °F	552	553
Pressurizer pressure, psia	2250	2250
Pressurizer level, %	67.5	---
RCS flowrate, x 10^6 lbm/hr	148.0	---
SG Pressure, psia	864	---
SG Level, %NR	67.8	---
MTC, $10^{-4}\Delta\rho$/°F	-4.2*	-3.3
Doppler coefficient multiplier	1.30	0.85
CEA worth for trip, x 10^{-2} $\Delta\rho$	-5.0	---
Radial distortion factor for a 20°F core inlet temperature asymmetry	1.22	1.26

* This value is the MTC used for quantifying the primary DNBR degradation mechanism. It is used in combination with a -0.1685×10^{-4} $\Delta\rho$/°F MTC in the transient simulation.

Table 2.13.9.1.1-2
Comparison of the Sequence of Events for the ASGT Event

EPU Time (sec)	Current Power Level Time (sec)	Event	EPU Setpoint/Value	3716 MWt Current Power Level Setpoint/Value
0.0	0.0	Initiate closure of a single MSIV	---	---
0.1	0.10	MSIV on affected SG is fully closed	---	---
0.1	0.10	Steam flow from unaffected SG increases to maintain turbine power	---	---
4.93	6.00	CPC Delta-T setpoint reached (differential cold leg temperature)	11°F	18°F
5.33	6.40	Trip breakers open	---	---
5.50	6.10	Safety valves open on affected SG	1117 psia	1096 psia
5.93	6.70	CEAs begin to drop	---	---
7.50	7.30	Minimum DNBR	> 1.26	> 1.26
11.30	10.90	Maximum SG pressure	1167 psia	1135 psia

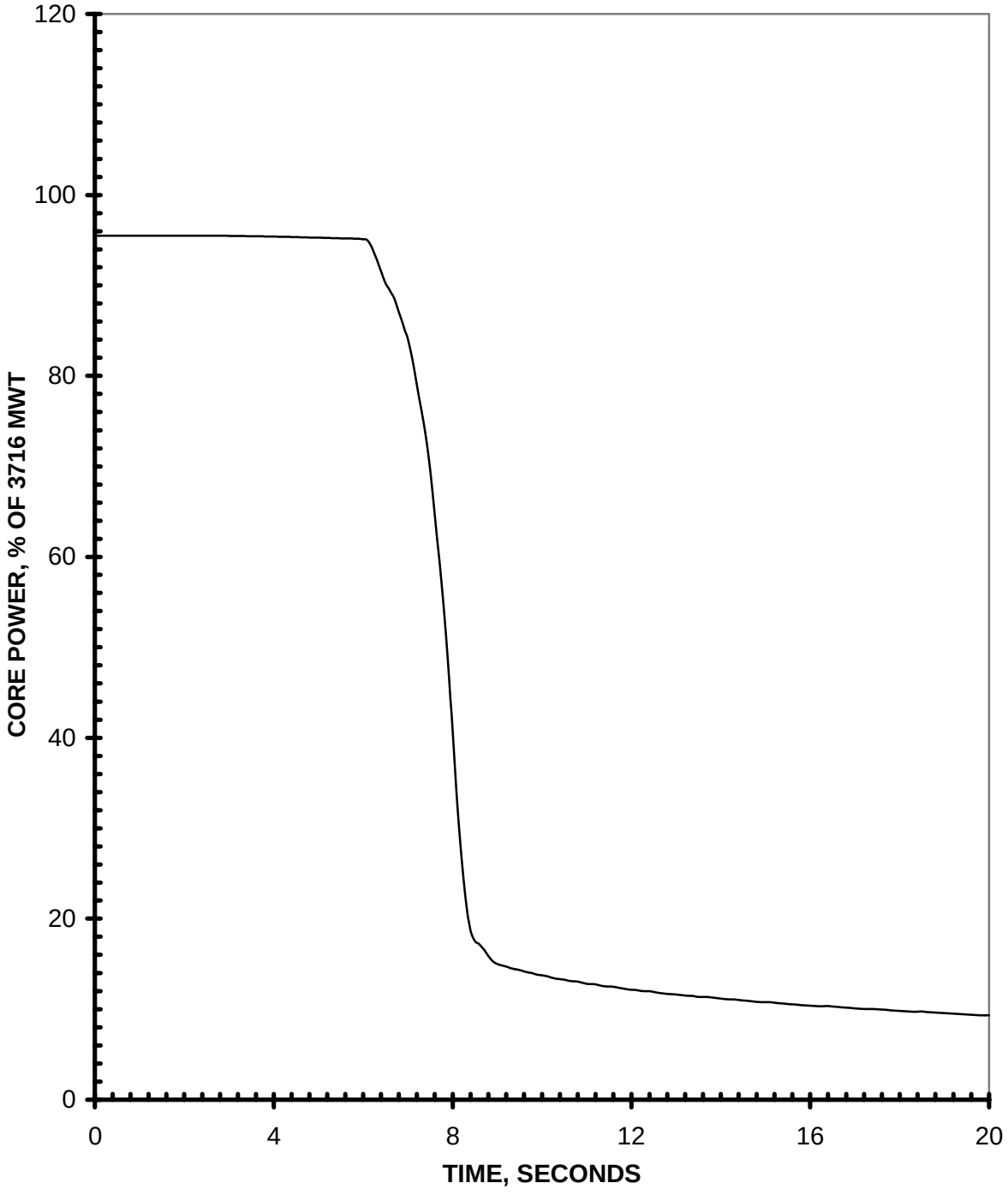

Figure 2.13.9.1.1-1
Asymmetric SG Core Power vs. Time

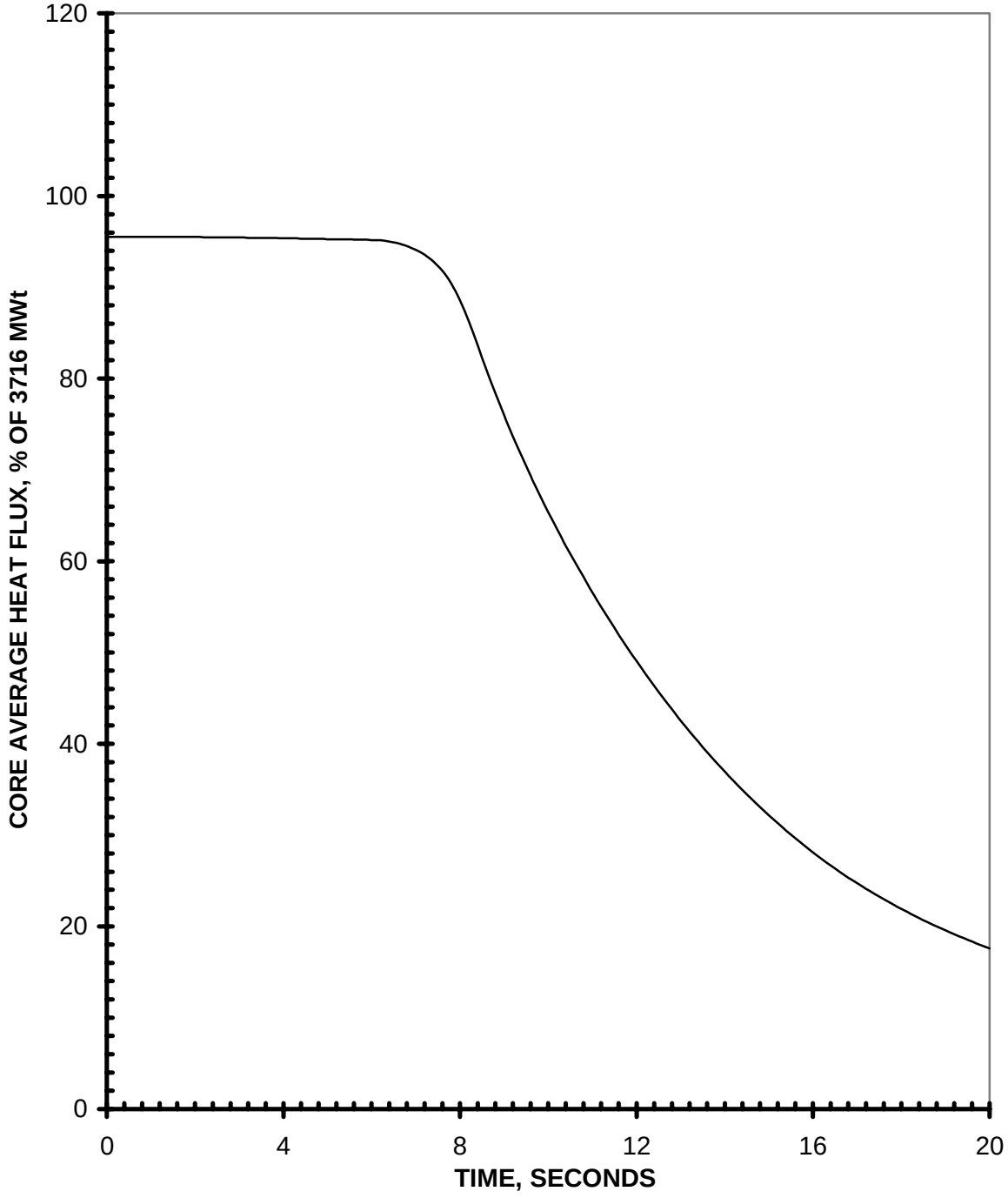

Figure 2.13.9.1.1-2
Asymmetric SG Core Heat Flux vs. Time

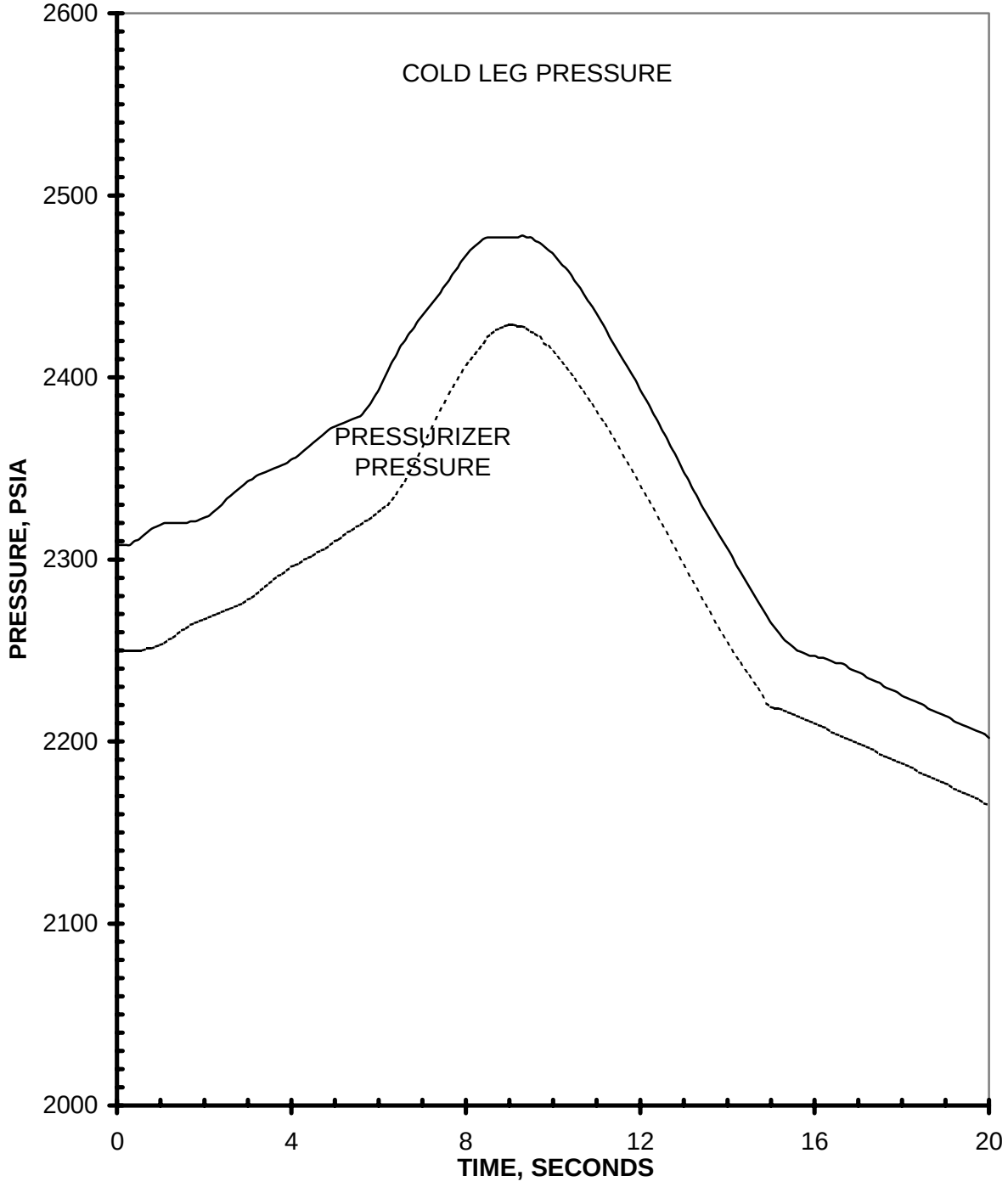

Figure 2.13.9.1.1-3
Asymmetric SG RCS Pressure vs. Time

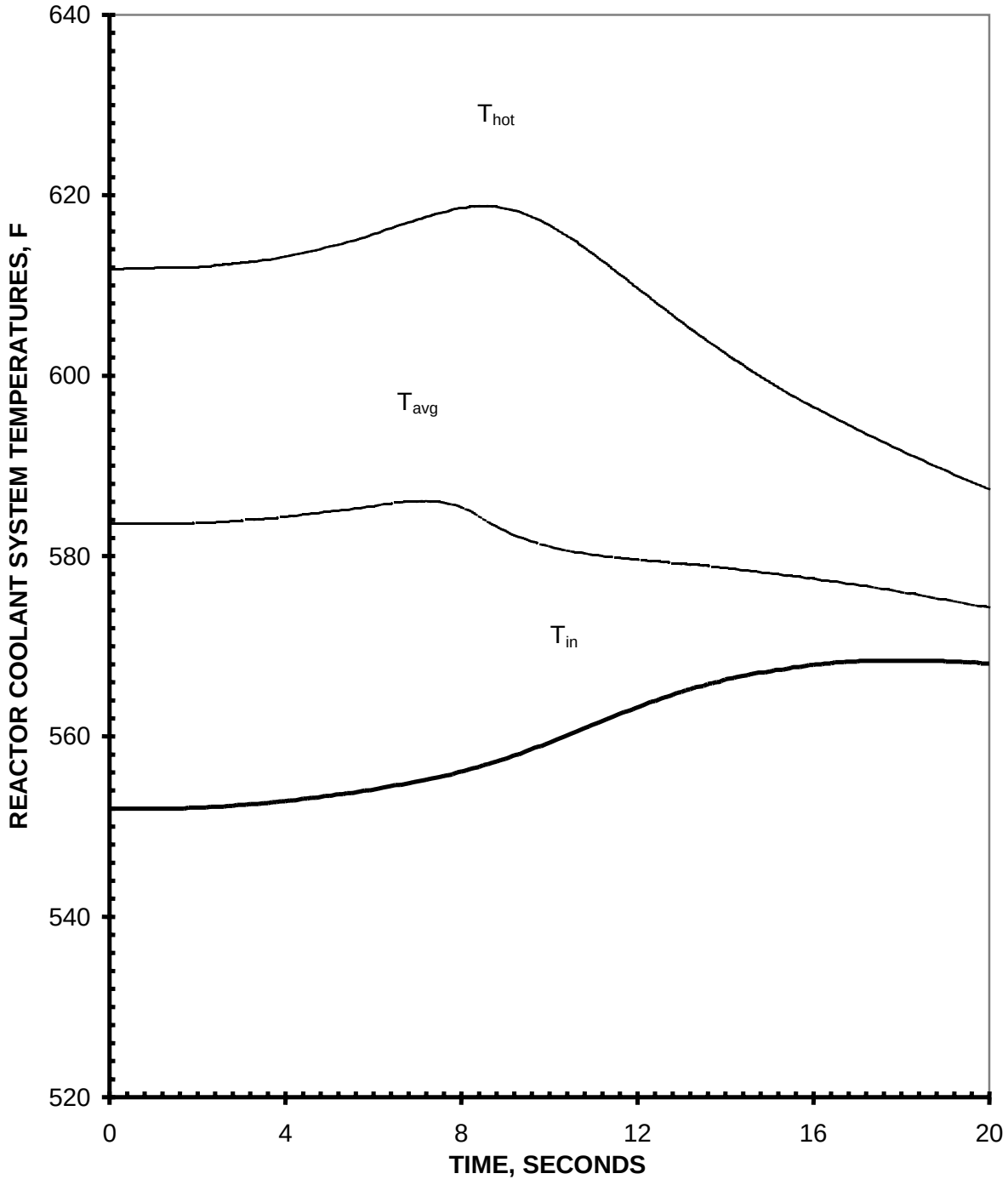

Figure 2.13.9.1.1-4
Asymmetric SG RCS Temperatures vs. Time

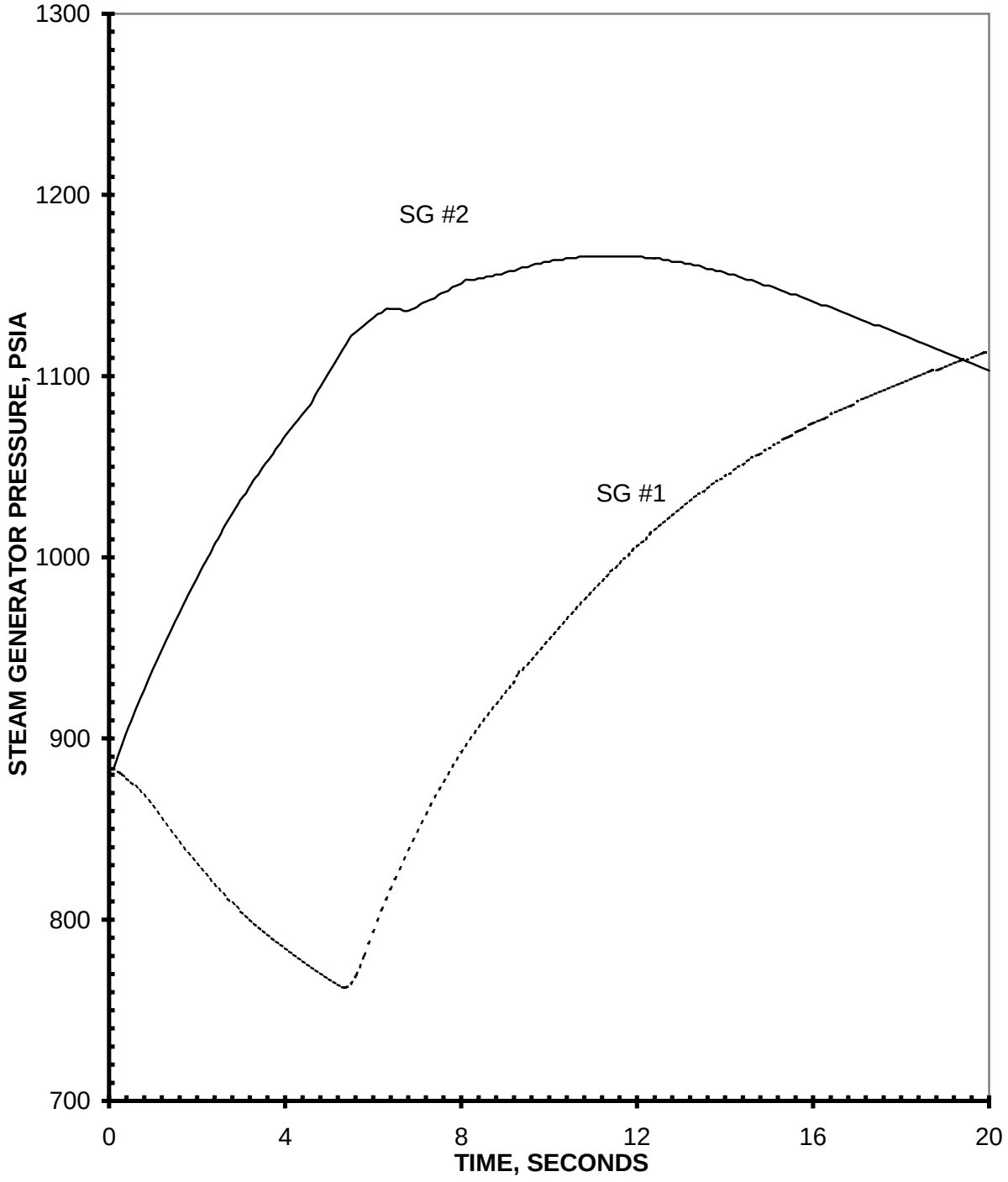

Figure 2.13.9.1.1-5
Asymmetric SG Pressure vs. Time

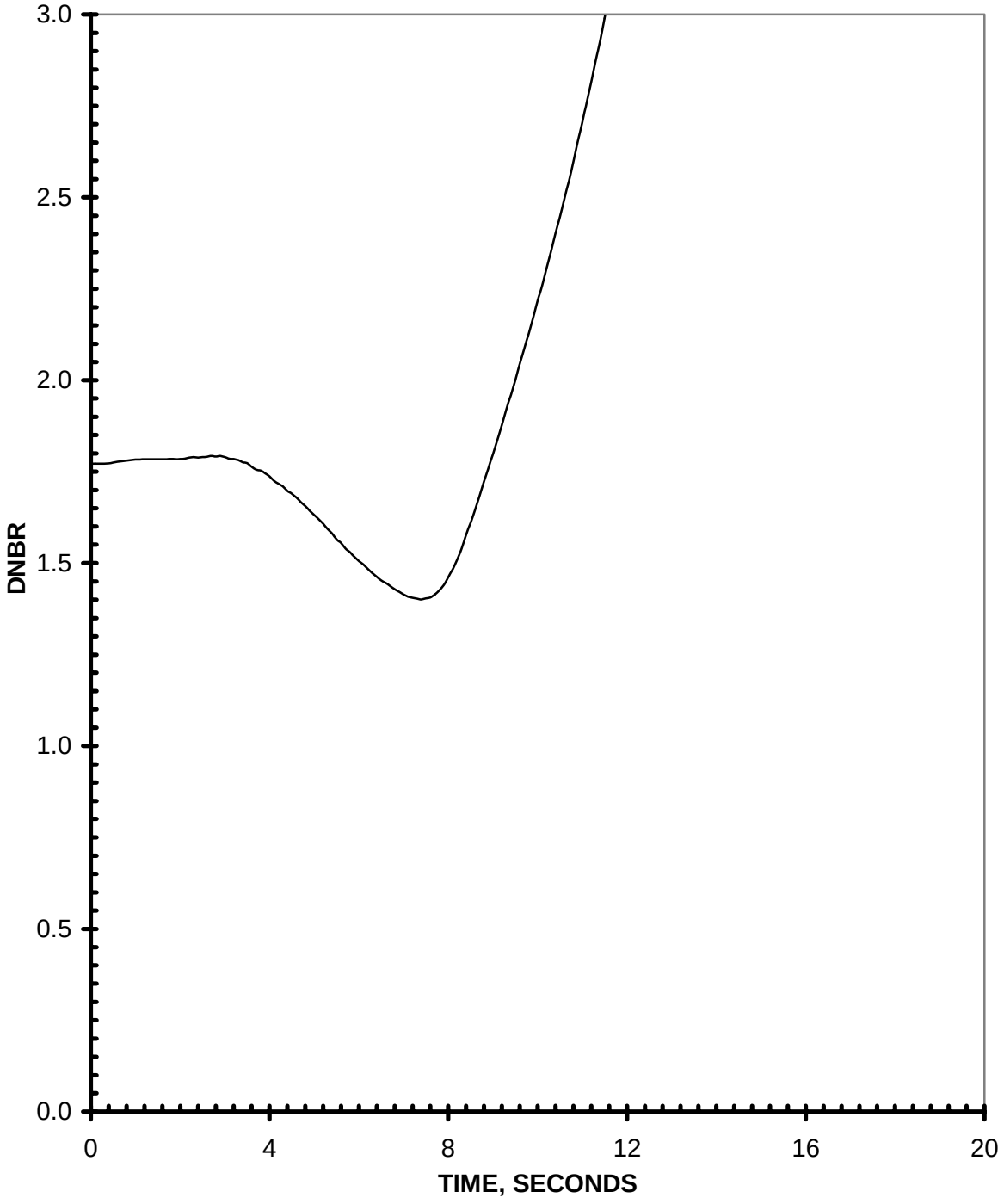

Figure 2.13.9.1.1-6
Asymmetric SG Minimum DNBR vs. Time

2.13.10 References

2.13-1 *Waterford Steam Electric Station Unit 3 Final Safety Analysis Report (FSAR)*, Revision 12, Docket No. 50-382.

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2.13-3 CEN-191(B)-P, *CETOP-D Code Structure and Modeling Methods for Calvert Cliffs 1 and 2*, December 1981.

2.13-4 CENPD-188-A, *HERMITE, A Multi-Dimensional Space-Time Kinetics Code for PWR Transients*, March 1976.

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2.13-6 CENPD-98, *COAST Code Description*, April 1973.

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2.13-8 CE-NPSD-335-P, *Function Design Requirements for a Core Protection Calculator*, Rev. 02-P, April 1988.

2.13-9 CENPD-135P, *STRIKIN II, A Cylindrical Geometry Fuel Rod Heat Transfer Program*, August 1974.

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2.13-11 CENPD-190-A, *C-E Method for Control Element Assembly Ejection Analysis*, July 1976.

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2.13-13 LD-82-040, *Turbine Trip Delay Time*, A. E. Scherer to D. G. Eisenhut (Docket STN-50-470F), March 31, 1982.

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2.13-18 CEN-312-P, *Overview Description of the Core Operating Limit Supervisory System (COLSS)*, Rev. 0-1-P, November 1986.

2.13-19 ARCON96, NUREG/CR-6331, Revision 1, *Atmospheric Relative Concentrations in Building Wakes*, May 1977.

2.13-20 NUREG/CR-2858, PNL-4413, *PAVAN: An Atmospheric Dispersion Program for Evaluating Design Basis Accidental Releases of Radioactive Materials from Nuclear Power Stations*, November 1982.

3.0 FACILITY OPERATING LICENSE, TECHNICAL SPECIFICATION, AND TECHNICAL REQUIREMENTS MANUAL CHANGES

3.1 FACILITY OPERATING LICENSE CHANGES

Facility operating license changes are addressed in Attachment 1 of the license amendment request submittal letter, W3F1-2003-0074.

3.2 TECHNICAL SPECIFICATION CHANGES

Technical Specification changes are addressed in Attachment 1 of the license amendment request submittal letter, W3F1-2003-0074.

3.3 TECHNICAL REQUIREMENTS MANUAL CHANGES

Technical Requirements Manual (TRM) changes are addressed in Attachment 4 of the license amendment request submittal letter, W3F1-2003-0074.

4.0 REGULATORY COMMITMENTS

Regulatory commitments are addressed in Attachment 8 of the license amendment request submittal letter, W3F1-2003-0074.

5.0 ENVIRONMENTAL CONSIDERATIONS

The purpose and need for the extended power uprate (EPU) for Waterford Steam Electric Station, Unit 3 (Waterford 3) is to provide an option that allows for power generation capability beyond the current nuclear power plant operating license to meet future system generating needs, as such needs may be determined by state, utility, and where authorized, federal (other than NRC) decision makers.

A scoping study performed for Waterford 3 recommended a power uprate to 3716 MWt (9.6% of the original rated thermal power of 3390 MWt). The proposed action to increase the licensed core thermal power level to 3716 MWt is based on the operational goal of increasing electrical generating capacity. With the uprate, Waterford 3 will continue to be a significant part of the Entergy strategy of maintaining a flexible and robust fleet of electric generation stations.

There are two significant aspects of maintaining a flexible and robust generation fleet. The first is to retain low cost power options and the second is to maintain a fleet with sufficient diversity to allow utilities to respond to changes in the underlying cost of power. The increase in capacity of Waterford 3 provides the Entergy System with lower cost power than can be obtained in the current and anticipated energy market. In addition, the increased capacity reduces exposure to potential cost increases in fossil fuel based alternatives. Summer peak temperatures in the south challenge the ability of Entergy and other power producers to meet peak load demands and nuclear power has shown to be a reliable source during these peak periods.

In addition, there is an ongoing need for existing Entergy System generating capacity, including that provided by Waterford 3. Reliability purchases have increased substantially over the last few years and load growth is expected to further increase the system's resource requirements. High availability and low energy cost positions nuclear generation at the foundation of Entergy's resource portfolio. Even though potential load loss, cogeneration options, and retail competition may cause variability in the System's future resource requirements, the power uprate for Waterford 3 is expected to provide an economically sound choice with minimal impact to the environment.

Therefore, a power uprate of Waterford 3 is an important step in improving the economic performance of the system both before and after utility deregulation. The improved performance is accomplished by cost reductions in production and total bus bar cost per kilowatt-hour, which is afforded by the Waterford 3 power uprate.

5.1 ENVIRONMENTAL IMPACTS OF THE PROPOSED ACTION

The effects of a Waterford 3 power uprate have been comprehensively evaluated. The evaluation determined that sufficient safety and design margins can be maintained such that the increase in the rated core thermal power can be accomplished without adverse impact on the health and safety of the public or the environment.

The environmental impacts of Waterford 3 have been described in the Final Environmental Impact Statement (FES), dated September 1981 (Reference 5-1), (NUREG-0779), and this Power Uprate Licensing Amendment Request (PULR).

The original operating license for Waterford 3 allowed a rated thermal power level of 3390 MWt. Based on Entergy's analyses of the nonradiological and radiological impacts, the environmental impacts of the power uprate are essentially unchanged from the environmental impacts previously evaluated in the FES. The power uprate does not involve extensive changes to plant systems that directly or indirectly interface with the environment. Additionally, no changes are necessary to the Louisiana Pollutant Discharge Elimination System (LPDES) Permit issued by the Louisiana Department of Environment Quality (LDEQ).

5.2 NONRADIOLOGICAL IMPACTS

The following contains the nonradiological environmental impacts of the power uprate on land use, water use, waste discharges, terrestrial and aquatic biota, transmission facilities, and social and economic conditions at Waterford 3.

5.2.1 Land Use Impacts

Existing Land Use

The Waterford 3 property encompasses 3560 acres. Wetlands are the largest land use category on the property followed by agriculture. There are two state highways and one railroad line that crosses the property. Other land use on the property includes levees, forest land on the batture, barren lands on the batture and a canal. There is no residential or recreational land on the property (see Waterford 3 FES, Section 4.3.1 [Reference 5-1]).

Cultural Resources

The Waterford 3 property contains two areas with cultural resource remains from the Waterford Plantation that have been determined to be eligible for the National Register of Historic Places. These areas lie outside the limits of the plant security fence and are at a distance from the plant where they are not affected by plant operations. Both of these areas consist solely of artifactual material (glass, metal, bone, ceramic, wood, etc.) lying beneath the present ground surface. No standing ruins or readily identifiable surface remains are present.

During issuance of the operating license, Waterford 3 entered into an agreement with State Historic Preservation Office (SHPO). As part of this agreement, a Cultural Resources Protection Plan was developed and implemented by the Waterford 3 site. This plan requires the site to notify SHPO and the NRC in the event that any of the activities listed below are to occur within the boundary of these areas:

a) Excavation (including trenching, drilling or any other form of soil removal or displacement, whether by hand or machine)
b) Landscaping, sodding, or planting of shrubbery or trees except that routine maintenance of existing landscaping and/or continuation of agricultural activities
c) Placement of any fill, spoil, or ground cover
d) Any construction

If a mitigation plan is necessary, Waterford 3 is required by the Cultural Resources Protection Plan to submit a mitigation plan prepared by an archaeologist to the NRC, who in turn will consult with the SHPO. For those activities in close proximity to, but not within the boundary of a protected area, Waterford 3 is not required to notify the SHPO under this Plan. Since the EPU will not be modifying any land use and no activities will be occurring near or within these designated cultural resource areas, there will be no impact from the EPU and no need to implement the Cultural Resources Protection Plan.

Noise

In Section 5.5.1 of the Waterford 3 FES (Reference 5-1), it was concluded that estimated noise levels produced during the operation of the plant would not interfere with normal conversation and impose no known mental or physiological stress upon humans and vertebrate biota. The power uprate will not change the character, sources, or energy of noise generated at Waterford 3. Modified structures, systems and components necessary to implement the power uprate will be installed within existing plant buildings and no noticeable increase in ambient noise levels within the plant is expected.

Conclusion

The proposed EPU would not modify land use at the site or have impacts on lands with historic or archeological significance as discussed above. There are no plans to construct any new facilities or disturb the land around existing facilities, including buildings, access roads, parking facilities, laydown areas, onsite transmission and distribution equipment, or power line rights-of-way in conjunction with the proposed EPU. In addition, the EPU would not significantly affect the storage of materials, including chemicals, fuels, and other materials stored aboveground or underground and would not alter the aesthetics of the site. Therefore, the land use impact conclusions in Section 5.2 of the Waterford 3 FES (Reference 5-1) remain valid under the proposed EPU conditions.

5.2.2 Water Use Impacts

Nonradiological environmental impacts from ground water and surface water usage at Waterford 3 have been evaluated and are discussed below. Radiological impacts on ground and surface water use impacts are provided in Sections 5.2.2.1 and 5.2.2.2, below.

5.2.2.1 Groundwater Use

Waterford 3 does not utilize groundwater for plant operations. Therefore, there are no impacts to onsite groundwater use.

5.2.2.2 Surface Water Use

Waterford 3 withdraws water from the Mississippi River at a design summer rate of 1,003,404 gpm, which includes 1,003,200 gpm of circulating water. Of the 1,003,200 gpm, 975,100 gpm passes through the main condenser where its temperature is raised approximately 16.4°F. The Turbine Closed Cooling Water System (TBCCWS) heat exchangers

and the steam generator blowdown heat exchangers use the remaining 28,100 gpm, which undergo a temperature increase of approximately 7.6°F. The resultant design temperature rise of the combined flow is approximately 16.1°F above the intake water temperature.

When the station is operating, all 4 circulating water pumps are utilized when the intake water temperature exceeds 70°F. The system design flow rate for 4 pump operation is 1,003,200 gpm, with a temperature rise at this rate of 16.1°F. Three pump operations occur when the station is operating and the intake water temperature is below 70°F. The flow rate during this condition is approximately 84% of the design four-pump flow rate.

The Mississippi River is classified as a large river based on the discussions within the Generic Environmental Impact Statement (GEIS) (Reference 5-2). Nuclear power plants that use once-through condenser cooling systems are located on large lakes, reservoirs, estuaries, oceans, and rivers, and except possibly during extended periods of drought, are unlikely to experience problems with the water supply. Because net water consumption by facilities using once-through cooling is negligible compared with the size of the body of water, such plants should have only a limited potential for impacts on water availability for downstream use. Should water-use conflicts arise during operation of existing power plants, local officials who are responsible for allocating water resources would have to weigh the use of water for power generation. Based on review of literature and operational monitoring reports, consultations with utilities and regulatory agencies, and comments on the draft GEIS, water use conflicts are found to be of small significance for all plants and cumulative impacts are not of concern. Net water consumption by facilities using once-through cooling is negligible compared with the size of the body of water. Because of abundant water supply, consumptive water use will have impacts of only small significance on riparian plant and animal communities at sites that use once-through cooling systems (see the GEIS, Section 4.2.1.3 [Reference 5-2]).

Conclusions reached in the GEIS are further supported by Section 5.3.1.1 of the Waterford 3 FES (Reference 5-1), as discussed below.

> The Mississippi River is the principal water source of all municipal, industrial, and agricultural use for towns and water districts downstream of Baton Rouge, Louisiana. All of the water required for plant operation, except potable water, will be withdrawn from the Mississippi River at an average rate of about 63.3 m3/second (2236 cfs). Consumptive use will be negligible, amounting to only 0.01 percent of the water withdrawn. Because of this, operation of Waterford 3 will not affect availability of water to downstream water users. Potable water is obtained from the St. Charles Parish Waterworks. The anticipated potable water demand by Waterford 3 is about 37.9 m3/day (10,000 gal/day) (see Waterford 3 FES, Section 5.3.1.1).

Since there will be no increase in surface water withdrawal for the EPU, surface water use impacts described in the GEIS and the Waterford 3 FES (References 5-1 and 5-2) remain valid.

5.2.3 Discharge Impacts

Environmental impacts such as thermal discharges, chemical discharges to surface water, sanitary waste discharges, cold shock to aquatic biota, hazardous waste effluents, and air

emissions were evaluated in the FES. The power uprate causes no significant change to the FES evaluations.

5.2.3.1 Thermal Discharge

Heat Shock

The heat dissipation system for Waterford 3 consists of the Circulating Water System (CWS) and the Component Cooling Water System (CCWS). The CWS withdraws water from the Mississippi River for use in the condenser to condense the turbine exhaust steam to water for reuse in the power production cycle. Following its use in the condenser, the circulating cooling water is returned to the Mississippi River. The water from the circulating water system is also used in the heat exchangers of the TBCCWS and the Steam Generator Blowdown System (SGBS). The CCWS is a closed-loop system, incorporating a dry cooling tower, which is used in the component cooling water heat exchangers to indirectly cool the reactor coolant and the Reactor Auxiliary System components (see Waterford 3 ER, Section 3.4.1 [Reference 5-3]).

The CWS withdraws water via an intake canal leading from the river to an intake structure containing the traveling water screens and the circulating water pumps. Water is transported from the pumps through the condenser and to the discharge structure and then returned to the river through a discharge canal. Water is withdrawn from the Mississippi River at a design flow rate of 1,003,404 gpm, which includes 1,003,200 gpm of circulating water. Of the 1,003,200 gpm, 975,100 gpm passes through the main condenser where its temperature is raised about 16.4°F. The TBCCWS heat exchangers and the SGBS heat exchangers use the remaining 28,100 gpm, which undergo a temperature increase of about 7.6°F. The resultant temperature rise of the combined flow of 1,003,200 gpm is approximately 16.1°F. Therefore, during full load and design flow conditions, the circulating cooling water discharged to the river is approximately 16.1°F above the intake temperature (see Waterford 3 ER, Section 3.4.2 [Reference 5-3]).

However, based on current plant operating conditions, only 888,000 gpm of water passes through the main condenser. Since the amount of water passing through the main condenser is less than the design flow rate, temperature rise after power uprate will be approximately 18.9°F. After combining with the TBCCWS heat exchangers and the SGBS, the circulating water discharged to the river will be approximately 18.6°F above the intake temperature, that is 2.2°F above the design rate of 16.1°F. Based on previous years of compliance monitoring as it relates to the circulating water discharge temperature, the highest temperature recorded was 107.9°F in September 1999. If the 2.2°F increase from power uprate was added to this highest temperature recorded measurement, it would total 110.1°F, which is still below the daily maximum temperature discharge limitations of 118°F outlined in Waterford 3 LPDES Permit LA0007374.

Temperature and heat discharge limitations from the CWS discharge are regulated by the LDEQ via Waterford 3 LPDES Permit LA0007374 (Reference 5-4). As already stated, the daily maximum temperature discharge limitations outlined in the Permit is 118°F. Daily maximum heat discharge limitation outlined in the Permit is 9.5×10^3 MBTU/hour. These limitations have not been exceeded since the Permit was issued in July 1999. The impacts from heat shock are

insignificant when operating within the temperature and heat limits outlined in the LPDES Permit.

Thermal Plume

Thermal discharge impacts were evaluated extensively in Section 5.3.2 of the Waterford 3 FES (Reference 5-1) and found to have insignificant impacts. These evaluations were further supported by a Demonstration under Section 316(a) of the Clean Water Act (Reference 5-5) that was submitted by Waterford 3 in April 1979 and approved at that time by the Environmental Protection Agency (EPA). In addition, during the renewal of Waterford 3 LPDES Permit LA0007374 that was issued in July 1999, the thermal plume was again evaluated by Waterford 3 and the LDEQ to verify that the proposed temperature and heat increases could attain the temperature criteria outlined in LDEQ's water quality standards (maximum of 2.8°C (5°F) rise above ambient for streams and rivers). Based on this evaluation that is described in LPDES Fact Sheet and Rationale (Reference 5-6), Waterford 3 and LDEQ determined that these increases would be within the criteria outlined in the water quality standards. Therefore, temperature and heat increases were granted in the final Permit. As already discussed above, Waterford 3 will have to operate within the temperature limits outlined in the LPDES Permit at any power level. Therefore, conclusions reached in Section 5.3.2 of the Waterford 3 FES (Reference 5-1) and the LDEQ Fact Sheet and Rationale (Reference 5-6) remain valid.

5.2.3.2 Chemical and Sanitary Discharges

Surface water and wastewater discharges, including water treatment chemical usage, at Waterford 3 are regulated by the LDEQ via LPDES Permit LA0007374 (Reference 5-4). This Permit, which is periodically reviewed and reissued by the LDEQ, authorizes discharges from fourteen outfalls, only one of which has the potential to be affected by the power uprate. The one affected outfall is the once-through cooling water (Outfall 001) that is addressed below.

Water treatment chemicals that are currently regulated and approved by the LDEQ for use in the once-through cooling water (Outfall 001) will not change as a result of the power uprate. Chemicals typically utilized in the once-through cooling water are associated with zebra mussel treatments, which is an activity that only occurs on a periodic basis. Although Outfall 001 receives effluent wastewater discharges from nine other internal outfalls, water treatment chemical usage in not expected to change. Therefore, the concentration of pollutants in the once-through effluent stream will remain the same and have insignificant impact, which is consistent with the conclusion reached in Section 2.1.2.4 of the GEIS (Reference 5-2) for once-through cooling systems.

Sanitary wastes at the Waterford 3 facility are discharged at two different locations. Sanitary wastes from the training center are collected and discharged from an onsite sewage treatment plant that is regulated through LPDES Permit LA0007374 (Reference 5-4). Sanitary wastes from all other site facilities are collected in one of seven sewage lift stations located around the plant site and then ultimately transferred to the St. Charles Parish Killona sewage treatment facility. Since there will be no increase in the Waterford 3 staffing levels as a result of the power uprate, there will be no increase in sanitary waste. Therefore, the power uprate requires no changes to the sanitary waste systems or to the parameters regulated by the LPDES permit. Impacts from sanitary waste discharges will be small, which is consistent with the conclusion reached in Section 2.1.2.4 of the GEIS (Reference 5-2) for once-through cooling systems.

5.2.3.3 Cold Shock

Cold shock occurs when organisms that have been acclimated to warm water (e.g., in a discharge canal in winter) are exposed to sudden temperature decreases when artificial heating ceases. Cold-shock mortalities are relatively rare and usually involve small numbers of fish. Population-level effects have not been demonstrated. Where necessary, the discharge structure or the plant operating procedures have been modified to reduce cold-shock effects (see the GEIS, Section 4.2.2.1.5 [Reference 5-2]).

Impacts of cold shock are considered to be of small significance if populations of aquatic organisms in the vicinity of the plant are not reduced. Based on review of literature and operational monitoring reports, consultations with utilities and regulatory agencies, and comments on the draft GEIS, cold-shock-related mortalities of aquatic organisms have been a problem at few existing nuclear power plants. Operational and structural mitigation measures have been effective at the plants that experienced cold shock mortalities. Because mitigation has been effective in those few cases where cold shock has been a problem, effects are considered to be of small significance for all plants (see the GEIS, Section 4.2.2.1.5 [Reference 5-2]).

Cold shock was evaluated in Section 5.6.2.2 of the Waterford 3 FES (Reference 5-1) and supports the conclusion in Section 4.2.2.1.5 of the GEIS (Reference 5-2). This section of the FES concluded that although cold shock is possible 20 percent of the year, it is not a serious threat at the Waterford 3 site. Shock would be limited to an area of about two acres mostly downstream from the Waterford 3 discharge point with gizzard shad and threadfin shad (both small forage fish) most likely affected (see Waterford 3 FES, Section 5.6.2.2 [Reference 5-1]). Therefore, Waterford 3 concludes that the impact from cold shock as a result of the power uprate will be small.

5.2.4 Hazardous Waste Generation and Air Emissions

Waterford 3, which operates under a hazardous waste generator's identification number assigned by the LDEQ Hazardous Waste Division, generates hazardous waste from routine plant operations. Hazardous waste is managed at the site through procedures and employee control measures in a manner that minimizes generation to the extent practicable. Since Waterford 3 has been successful in minimizing hazardous waste generation, the site is currently classified as a small quantity generator by the LDEQ. This classification allows the site to operate under less regulatory burdens and does not require the submittal of an annual hazardous waste report.

Waterford 3 holds an Air Permit that was issued and is monitored by the LDEQ Air Division. This Permit identifies emission sources at Waterford 3 and the associated conditions imposed by the LDEQ. Emission sources at the Waterford 3 site include diesel generators, diesel pumps, portable boiler, wet cooling towers and bulk storage tanks. Waterford 3 is currently in the process of modifying the Permit to establish two portable emission points to cover diesel fuel oil and gasoline engines brought onsite during maintenance and refueling outages.

Therefore, the EPU will have no impact on the quality or quantity of effluents from these sources, and operation under EPU conditions will not reduce the margin to the limits established by the applicable permits.

5.2.5 Terrestrial Biota Impacts

The power uprate will not change the previously evaluated land use at Waterford 3 and will not disturb the habitat of any terrestrial plant or animal species. There are no significant increases in previously evaluated environmental impacts from the once-through cooling operation at power uprate conditions.

Endangered terrestrial species listed in St. Charles Parrish include the Bald Eagle, Brown Pelican, Gulf Sturgeon, Pallid Sturgeon, and West Indian Manatee. However, none of these species are known to inhabit or regularly use the parts of the site that will be affected by operational activities. Therefore, the conclusion in Section 5.5.3 of the Waterford 3 FES (Reference 5-1) remains valid.

As stated in Section 3.1 of this report, the power uprate will not disturb land and land use will remain unchanged. Therefore, the power uprate will not adversely impact the habitat of any terrestrial plant or animal species. There are no deleterious effects on the diversity of biological systems or the sustainability of species due to the power uprate and it does not involve additional changes to the stability or integrity of ecosystems. Therefore, it is concluded that the description of the impact on terrestrial ecology, including endangered and threatened plant and animal species will remain valid for the power uprate.

5.2.6 Aquatic Biota Impacts

Waterford 3 has a skimmer wall at the river face of the intake structure to prevent the entrance of large debris. Water entering the intake passes through a coarse screen (trash rack) and enters into eight bays, each equipped with a traveling water screen system. Fish and other organisms removed from the cooling water by the traveling screens are washed to a trough and then sluiced to the river at a point downstream of the intake. The power uprate will not require additional water withdrawal capacity or a change in current pumping operations. Therefore, average water velocity through the traveling screens will remain consistent with that described in the Demonstration Under Section 316(b) of the Clean Water Act conducted by Waterford 3 in 1979 (Reference 5-7).

Losses associated with the impingement and entrainment of organisms via the traveling water screen system was initially assessed by Waterford 3 in 1979 via a Demonstration Under Section 316(b) of the Clean Water Act (Reference 5-7). This demonstration was submitted to the EPA and was approved at that time as reflecting best technology available for minimizing adverse environmental impact. This approval was reflected in previous National Pollutant Discharge Elimination System Permits issued by the EPA to Waterford 3. Therefore, the effect of the power uprate on the impingement and entrainment of organisms is unchanged and therefore remains insignificant. Therefore, the power uprate does not affect Waterford 3's compliance with Sections 316(a) or 316(b) of the Federal Water Pollution Control Act.

5.2.7 Transmission Facility Impacts

Two 230-kV transmission lines were built between the plant and the switchyard on the site, a distance of about 0.6 miles along a corridor 76 yards wide, covering an area of about 17 acres. The line is almost entirely within the exclusion area and passes over areas designated for

utilities or agriculture (see Waterford 3 FES, Section 5.5.2 [Reference 5-1]). There were no new offsite transmission lines built specifically for Waterford 3 or the Waterford 3 EPU (see Waterford 3 FES, Summary and Conclusions [Reference 5-1]).

The main generator output will increase to approximately 1333 MVa. Existing 230 kV output oil circuit breakers, bus work, and mechanical disconnect switches are being replaced and additional pad-mounted capacitors are being installed in the switching station by Entergy's Transmission Department to cope with the increased output. The existing transmission line design is adequate for this power uprate and does not require modification. The plant's main transformers were evaluated for the power uprate. This evaluation determined that transformer modifications or replacement are required to support the power uprate. Therefore, there are no impacts from the EPU.

5.2.8 Social, Economic and Physical Impacts

Waterford 3 employs approximately 750 people and is one of the significant contributors to the local tax base. The power uprate will not significantly affect the size of the Waterford 3 workforce and will have no material effect on the labor force required for future outages. Because the plant modifications needed to implement the power uprate will be negligible compared to the overall value of the plant, any increase in sales taxes and local and national business revenues will be negligible relative to the large amount of taxes paid by Waterford 3. It is expected that improving the economic performance of Waterford 3 through cost reductions and lower total bus bar costs per kilowatt hour will enhance the value of Waterford 3 as a generating asset and lower the probability of early plant retirement.

Early plant retirement would have a negative long-term impact upon the local economy and the community as a whole by reducing public services, employment, income, business revenues and property values. Therefore, the conclusions reached in Section 6.6 of the Waterford 3 FES (Reference 5-1) regarding social and economic impacts and benefits remain valid under power uprate conditions.

The potential for direct physical impacts of the power uprate, such as vibration and dust from construction activities, has been considered. The power uprate will be accomplished primarily by changes in station operation and a few physical modifications to the facility. These limited modifications will be accomplished without physical changes to transmission corridors, access roads, other offsite facilities, or additional project-related transportation of goods or materials. Therefore, no significant additional construction disturbances causing noise, odors, vehicle exhaust, dust, vibration, or shock from blasting are anticipated, and the conclusions in FES Section 5.2 (Reference 5-1) remain valid.

5.2.9 Summary

In summary, the power uprate will not result in a significant change in nonradiological impacts on land use, water use, waste discharges, terrestrial and aquatic biota, transmission facilities, or social and economic factors, and will have no nonradiological environmental impacts other than those evaluated in the FES. Table 5.2-1 provides a tabular summary of the nonradiological results.

Table 5.2-1
Summary of Nonradiological Environmental Impacts

Land Use Impacts	No change in land use or aesthetics; will not impact lands with historic or archeological significance. No significant impact due to noise.
Water Use Impacts	
Surface Water	There is no increase in the water withdrawal rate from the river. Withdrawal rate remains within previous levels.
Groundwater Use	No groundwater use.
Discharge Impacts	
Thermal Discharge (Heat Shock)	No significant increase in temperature or heat. Current LPDES Permit has adequate limits to accommodate any expected temperature and heat increases.
Thermal Discharge (Thermal Plume)	No increase in thermal plume size since expected temperature and heat increases will remain within LPDES Permit limits.
Chemical and Sanitary Discharge	No expected change to chemical use and subsequent discharge, or sanitary waste systems; no change in pollutants to once-through cooling water effluent. No changes to sanitary waste discharges.
Cold Shock	GEIS generically concluded impacts from cold shock were SMALL. Waterford 3 FES also determined that cold shock was not a serious threat at the site.
Hazardous Waste and Air Emissions	No changes to hazardous waste streams or air emission sources.
Terrestrial Biota Impacts	No change in terrestrial biota impacts; no known threatened or endangered species within the site boundary.
Aquatic Biota Impacts	No change in aquatic biota impacts; no known threatened or endangered species in the area of surface water intake or discharge.
Transmission Line Facility Impacts	No change to transmission line design or operation other than replacing the oil circuit breakers with gas circuit breakers; no significant change in exposure to electromagnetic fields (EMFs).
Social and Economic Impacts	No significant change in the local economy. Few modifications to physical station facility.

5.3 RADIOLOGICAL IMPACTS

Waterford 3 evaluated radiological environmental impacts on waste streams, in-plant and offsite doses, accident analyses, and fuel cycle and transportation factors. The following is a general description of the waste treatment streams at Waterford 3 and an evaluation of the environmental impacts.

5.3.1 Surface Water

There is no discussion in the Waterford 3 FES (Reference 5-1) regarding radiological impacts on surface water. Power uprate will not cause any radiological effects to surface water in the station environs.

5.3.2 Groundwater

It was concluded in Section 2.4.13.3 ("Accident Effects") of the Waterford 3 FSAR (Reference 5-8), that there is no danger of contaminating the local or regional groundwater regime through the introduction of radioactive materials from accidental spillage. In addition, radiological impacts to groundwater were evaluated in Section 5.9.2.5(5) of the Waterford 3 FES (Reference 5-1). It was concluded by the NRC that the Waterford 3 site is not unique in its liquid pathway contribution to risk when compared with other land-based sites. These conclusions remain valid for the EPU.

5.3.3 Radioactive Waste Stream Impacts

Waterford 3 uses Waste Treatment Systems designed to collect, process, and dispose of radioactive gaseous, liquid, and solid waste in accordance with the requirements of 10CFR20 and Appendix I to 10CFR50 (Reference 5-9). These radioactive waste treatment systems are discussed in the Waterford 3 FES. The power uprate will not affect the environmental monitoring of these waste streams or the radiological monitoring requirements contained in licensing basis documents. The power uprate does not result in any changes in operation or design of equipment in the gaseous, liquid, or solid waste systems. The power uprate will not introduce new or different radiological release pathways and will not increase the probability of an operator error or equipment malfunction that will result in an uncontrolled radioactive release. Changes in the gaseous, liquid, and solid waste streams for radiological environmental impact of the power uprate, are set forth below.

5.3.4 Gaseous Radioactive Waste Impacts

See Section 2.5.7 of this document for a discussion on gaseous radioactive waste.

5.3.5 Liquid Radioactive Waste Impacts

See Section 2.5.7 of this document for a discussion on liquid radioactive waste.

5.3.6 Solid Radioactive Waste Impacts

See Section 2.5.7 of this document for a discussion on solid radioactive waste.

5.3.7 Dose Impacts

In-plant and offsite radiation was evaluated as part of the environmental impacts of the power uprate.

5.3.7.1 In-Plant Radiation

See Section 2.8.1 of this document for a discussion on in-plant radiation.

5.3.7.2 Offsite Doses

See Section 2.8.1 of this document for a discussion on offsite dose.

5.3.7.3 Accident Analysis Impacts

The radiological consequences from postulated accidents under power uprate conditions are addressed in Section 2.13, “Non-LOCA Accident Analysis,” of this report. Section 2.13 of this report addresses moderate frequency incidents, infrequent incidents, and limiting faults. Section 2.13.6.3.3 addresses the radiological consequences for the loss-of-coolant accident (LOCA). The results contained in Section 2.13 show that the radiological consequences of design basis accidents under power uprate conditions are within the acceptance criteria of 10CFR100 (Reference 5-10) and do not involve any significant impact to the human environment.

5.3.8 Fuel Cycle and Transportation Impacts

The environmental impacts of the fuel cycle and of transportation of fuel and wastes are described in Tables S-3 and S-4 of 10CFR51.51 (Reference 5-11) and 10CFR51.52 (Reference 5-12), respectively. An NRC assessment (53FR30355, dated August 11, 1998) evaluated the applicability of Tables S-3 and S-4 to higher burnup cycles. The assessment concluded that there is no significant change in environmental impacts for fuel cycles with uranium enrichments up to 5.0 weight-percent U-235 and burnups less than 60 gigawatt-day per metric ton of uranium (GWd/MTU) from the parameters evaluated in Tables S-3 and S-4. In Operating License amendment 144 dated July 10, 1998 (Reference 5-13), Waterford 3 was granted the ability to increase the fuel enrichment from 4.9% to 5.0%. Since the fuel enrichment for the power uprate will not exceed 5.0 weight-percent U-235 and the rod average discharge exposure will not exceed 60 GWd/MTU, the environmental impacts of the proposed power uprate will remain bounded by these conclusions and will not be significant.

5.3.9 Summary

The power uprate will not significantly increase the probability or consequences of an accident, will not introduce any new radiological release pathways, will not result in a significant increase in occupational or public radiation exposures, and will not result in significant additional fuel cycle environmental impacts. Accordingly, it is concluded that no significant radiological environmental impacts are associated with the proposed action. Table 5.3-1 summarizes the radiological environmental impacts of the power uprate.

5.4 REFERENCES

5-1 *Waterford 3 Final Environmental Impact Statement*, September 1981.

5-2 *Generic Environmental Impact Statement* (GEIS).

5-3 Waterford 3 ER.

5-4 Waterford 3 Louisiana Pollutant Discharge Elimination System (LPDES) Permit, LA0007374.

5-5 *Demonstration under Section 316(a) of the Clean Water Act*, April 1979.

5-6 LPDES Fact Sheet and Rationale.

5-7 *Demonstration under Section 316(b) of the Clean Water Act*, 1979.

5-8 *Waterford 3 Final Safety Analysis Report* (FSAR).

5-9 10CFR20, NRC.

5-10 10CFR100, NRC.

5-11 10CFR51.51, NRC.

5-12 10CFR51.52, NRC.

5-13 *Operating License Amendment 144*, July 10, 1998.

Table 5.3-1
Summary of Radiological Environmental Impacts

Surface Water	No change in radiological impact to surface water
Groundwater:	No change in radiological impact to ground water
Radiological Waste Stream Impacts:	No changes in design or operation of waste streams
Gaseous Waste:	An increase in the release of iodine, krypton and xenon gaseous waste is expected, but the offsite dose rates are not expected to increase more than 15%.
Liquid Waste:	No change in Waterford 3 liquid release policy.
Solid Waste:	
Wet Waste:	No appreciable change in radioactive secondary resins expected due to PU
Dry Waste:	No significant changes in dry waste foreseen.
Irradiated Components:	No significant changes in irradiated components foreseen.
Dose Impacts:	
In-Plant Radiation	Even though a slight increase in RCS activity levels is possible, in-plant exposures are controlled to mitigate worker exposures.
Offsite Doses	Slight increase in gaseous activity levels possible, but doses will remain ALARA and within Part 20 limits
Accident Analysis Impacts:	No increase in the probability of an accident. Some increase in consequences of an accident but still within NRC acceptance limits.
Fuel Cycle and Transportation:	Increase in bundle average enrichment; impacts will remain within the conclusions of Table S-3 and Table S-4 of 10CFR51.

Attachment 6

W3F1-2003-0074

Waterford 3 Extended Power Uprate Report
Appendix 1 – Safety Evaluation Report Compliance

(Proprietary)

Attachment 7

W3F1-2003-0074

Waterford 3 Extended Power Uprate Report
Appendix 1 –Safety Evaluation Report Compliance

(Non-proprietary)

November 5, 2003

Waterford 3
Extended Power Uprate
Appendix 1 – Safety Evaluation Report Compliance (Non-Proprietary Version)

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Safety Evaluation Report (SER) Compliance

A tabulation of codes and methodologies used in sections 2.12 and 2.13 of the power uprate licensing report is provided in this appendix. The following tables are included:

Table 1 presents the methodologies and Codes supporting the large-break loss-of-coolant accident (LBLOCA) analysis (Section 2.12.3 of the Power Uprate Report [PUR]), and identifies the relevant SER Limitations and/or Constraint Tables of Section 1 of this appendix.

Table 2 presents the methodologies and Codes supporting the small-break loss-of-coolant accident (SBLOCA) analysis (Section 2.12.4 of the PUR), and identifies the relevant SER Limitations and/or Constraint Tables of Section 1 of this appendix.

Table 3 presents the Codes supporting (non-LOCA) Accident Analyses (Section 2.13 of the PUR), and identifies the relevant SER Limitations and/or Constraint Tables of Section 1.

Table 11 of Section 1 of this appendix is the SER Limitations and/or Constraint Table supporting the Long Term Cooling-Emergency Core Cooling System (ECCS) Performance (Section 2.12.5 of the PUR). The relevant methodology is Reference 2.12-27 of Section 2.12.8 of the PUR.

Tables 19, 20, 21 and 22 of Section 1 of this appendix present SER Limitations and/or Constraints supporting the FATES3B code which was cited in Sections 2.12.3.1 and 2.12.4.1 of the PUR.

Table A1

Topical Reports and Safety Evaluation Reports Supporting the LBLOCA Analysis (Section 2.12.3 of the PUR)

Subject	Topical Report Reference No. in PUR (Section 2.12.8)	Safety Evaluation Report Reference No. in PUR (Section 2.12.8)	SER Compliance Table No. (Section 1)
LBLOCA Evaluation Model (CENPD-132)	2.12-4	2.12-13	Table 1
Supplement 1	2.12-4	2.12-13	Table 1
Supplement 2	2.12-4	2.12-14	Table 2
Supplement 3	2.12-4	2.12-15	Table 3
Supplement 4	2.12-5	2.12-28	Table 4
CEFLASH-4A (CENPD-133)	2.12-6	2.12-13	Table 1
Supplement 2	2.12-6	2.12-13	Table 1
Supplement 4	2.12-6	2.12-28	Table 4
Supplement 5	2.12-6	2.12-15	Table 3
COMPERC-II (CENPD-134)	2.12-7	2.12-13	Table 1
Supplement 1	2.12-7	2.12-15	Table 1
Supplement 2	2.12-7	2.12-15	Table 3
STRIKIN-II (CENPD-135)	2.12-11	2.12-13	Table 1
Supplement 2	2.12-11	2.12-13	Table 1
Supplement 4	2.12-11	2.12-16	Table 7
Supplement 5	2.12-11	2.12-17	Table 8
PARCH (CENPD-138)	2.12-10	2.12-13	Table 1
Supplement 1	2.12-10	2.12-13	Table 1
Supplement 2	2.12-10	2.12-18	Table 9
HCROSS Appendix A to Enclosure 1 to LD-81-095	2.12-9	2.12-15	Table 3
COMZIRC Appendix C to Supplement 1 to CENPD-134	2.12-7	2.12-13	Table 1
Application of FLECHT Correlation to 16x16 Fuel Assemblies (CENPD-213)	2.12-8	2.12-19	Table 10
Application of NUREG-0630 Cladding Rupture and Swelling Models (Enclosure 1 to LD-81-095)	2.12-9	2.12-15	Table 3

Table A2

Topical Reports and Safety Evaluation Reports Supporting the SBLOCA Analysis (Section 2.12.4 of the PUR)

Subject	Topical Report Reference No. in PUR (Section 2.12.8)	Safety Evaluation Report Reference No. in PUR (Section 2.12.8)	SER Compliance Table No. (Section 1)
SBLOCA Evaluation Model (CENPD-137) Supplement 1 Supplement 2	2.12-23 2.12-23 2.12-23	2.12-13 2.12-24 2.12-25	Table 1 Table 5 Table 6
CEFLASH-4AS Supplement 1 to CENPD-133 Supplement 3 to CENPD-133	2.12-26 2.12-26	2.12-13 2.12-24	Table 1 Table 5
COMPERC-II (CENPD-134)	2.12-7	2.12-13	Table 1
STRIKIN-II (CENPD-135) Supplement 2 Supplement 4 Supplement 5	2.12-11 2.12-11 2.12-11 2.12-11	2.12-13 2.12-13 2.12-16 2.12-17	Table 1 Table 1 Table 7 Table 8
PARCH (CENPD-138) Supplement 1 Supplement 2	2.12-10 2.12-10 2.12-10	2.12-13 2.12-13 2.12-18	Table 1 Table 1 Table 9

Table A3

Waterford 3 Power Uprate Analysis Codes and Applicable SERs for PUR Section 2.13

Submittal Section	Event	Code(s)	Applicable Table No. (Section 1)
2.13.1.1.3	Increased Main Steam Flow	CENTS CETOP	Tables 12, 13
2.13.1.1.4	Inadvertent Opening of a Steam Generator Atmos. Dump Valve (IOSGADV)	CENTS CETOP	Tables 12, 13
2.13.1.2.3	Increased Main Steam Flow with Loss of AC (LOAC)	HERMITE CENTS CETOP	Tables 12, 13, 14
2.13.1.2.4	IOSGADV with LOAC	HERMITE CENTS CETOP	Tables 12, 13, 14
2.13.1.3.1	Steam System Piping Failures Post Trip Analysis	CENTS	Table 12
2.13.1.3.3	Steam System Piping Failures Pre-Trip Power Excursion	CENTS CETOP	Tables 12, 13
2.13.2.1.3	Loss of Condenser Vacuum	CENTS CETOP	Tables 12, 13
2.13.2.2.1	Loss of External Load with SF	CENTS CETOP	Tables 12, 13
2.13.2.2.5	Loss of Normal Feedwater Flow	CENTS CETOP	Tables 12, 13
2.13.2.3.2	Loss of Normal Feedwater Flow with SF	CENTS CETOP	Tables 12, 13
2.13.3.2.1	Total Loss of Forced Reactor Coolant Flow	HERMITE CENTS CETOP	Tables 12, 13, 14
2.13.3.3.1	Single Reactor Coolant Pump Shaft Seizure/Sheared Shaft	HERMITE CENTS CETOP TORC	Tables 12, 13, 14, 15, 16
2.13.4.1.1	Uncontrolled Control Element Ass'y (CEA) Withdrawal From Subcritical	CENTS CETOP	Tables 12, 13
2.13.4.1.2	Uncontrolled CEA Withdrawal From Low Power	CENTS CETOP	Tables 12, 13
2.13.4.1.3	Uncontrolled CEA Withdrawal at Power	CENTS CETOP	Tables 12, 13
2.13.4.1.4	CEA Misoperation - CEA Drops CEA Misoperation - Single CEA Withdrawals CEA Misoperation – Inadvertent Reactor Power Cutback	CENTS CETOP	Tables 12, 13
2.13.4.3.1	Inadvertent Loading of a Fuel Assembly into an Improper Position	ROCS	Table 17
2.13.4.3.2	Control Element Assembly Ejection	STRIKIN II CENTS	Tables 12, 18

Table A3

Waterford 3 Power Uprate Analysis Codes and Applicable SERs for PUR Section 2.13

Submittal Section	Event	Code(s)	Applicable Table No. (Section 1)
2.13.6.3.1	Small Primary Line Break Outside Containment	CENTS CETOP	Tables 12, 13
2.13.6.3.2	Steam Generator Tube Rupture	CENTS CETOP	Tables 12, 13
2.13.9.1.1	Asymmetric Steam Generator	CENTS CETOP	Tables 12, 13

Section 1

Tabulation of the Nuclear Regulatory Commission (NRC) Safety Evaluation Report Limitations and/or Constraints and Conformance Associated with Waterford 3 PUR Safety Analyses (PUR Sections 2.12 and 2.13)

TABLE 1

Implementation Limitations and/or Constraints Identified in NRC SER

O.D. Parr (NRC) to F.M. Stern, Combustion Engineering (CE), June 13, 1975

a,c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

TABLE 1

Implementation Limitations and/or Constraints Identified in NRC SER

O.D. Parr (NRC) to F.M. Stern, Combustion Engineering (CE), June 13, 1975

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TABLE 1

Implementation Limitations and/or Constraints Identified in NRC SER

O.D. Parr (NRC) to F.M. Stern, Combustion Engineering (CE), June 13, 1975

a,c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

TABLE 2

Implementation Limitations and/or Constraints Identified in NRC SER

O.D. Parr (NRC) to A.E. Scherer (CE), December 9, 1975

a,c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

TABLE 3

Implementation Limitations and/or Constraints Identified in NRC SER

D.M. Crutchfield (NRC) to A.E. Scherer (CE), July 31, 1986

Safety Evaluation of Combustion Engineering ECCS Large Break Evaluation Model and Acceptance for Referencing of Related Licensing Topical Reports

a,c

No.	NRC SER Constraint	Applicability LBLOCA	Conformance [Yes/No]	Comments

TABLE 3

Implementation Limitations and/or Constraints Identified in NRC SER

D.M. Crutchfield (NRC) to A.E. Scherer (CE), July 31, 1986

Safety Evaluation of Combustion Engineering ECCS Large Break Evaluation Model and Acceptance for Referencing of Related Licensing Topical Reports

a,c

No.	NRC SER Constraint	Applicability LBLOCA	Conformance [Yes/No]	Comments

TABLE 3

Implementation Limitations and/or Constraints Identified in NRC SER

D.M. Crutchfield (NRC) to A.E. Scherer (CE), July 31, 1986

Safety Evaluation of Combustion Engineering ECCS Large Break Evaluation Model and Acceptance for Referencing of Related Licensing Topical Reports

a,c

No.	NRC SER Constraint	Applicability LBLOCA	Conformance [Yes/No]	Comments

TABLE 4

Implementation Limitations and/or Constraints Identified in NRC SER

S.A. Richards (NRC) to P.W. Richardson (Westinghouse)

"Safety Evaluation of Topical Report CENPD-132, Supplement 4, Revision 1, Calculative Methods for the CE Nuclear Power Large Break LOCA Evaluation Model (TAC No. MA5660)," December 15, 2000

a,c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

TABLE 4

Implementation Limitations and/or Constraints Identified in NRC SER

S.A. Richards (NRC) to P.W. Richardson (Westinghouse)

"Safety Evaluation of Topical Report CENPD-132, Supplement 4, Revision 1, Calculative Methods for the CE Nuclear Power Large Break LOCA Evaluation Model (TAC No. MA5660)," December 15, 2000

a,c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

TABLE 4

Implementation Limitations and/or Constraints Identified in NRC SER

S.A. Richards (NRC) to P.W. Richardson (Westinghouse)

"Safety Evaluation of Topical Report CENPD-132, Supplement 4, Revision 1, Calculative Methods for the CE Nuclear Power Large Break LOCA Evaluation Model (TAC No. MA5660)," December 15, 2000

a,c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

TABLE 5

Implementation Limitations and/or Constraints Identified in NRC SER

K. Kniel (NRC) to A.E. Scherer (CE), September 27, 1977

"Evaluation of Topical Reports CENPD-133, Supplement 3-P and CENPD-137, Supplement 1P," September 27, 1977

a,c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

TABLE 6

Implementation Limitations and/or Constraints Identified in NRC SER

T.H. Essig (NRC) to I.C. Rickard (ABB CE)

"Acceptance for Referencing of the Topical Report CENPD-137(P), Supplement 2, Calculative Methods for the CE Small Break LOCA Evaluation Model (TAC No. M95687)," December 16, 1997.

a,c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

TABLE 7

Implementation Limitations and/or Constraints Identified in NRC SER

K. Kniel (NRC) to A.E. Scherer (CE)

"Combustion Engineering Emergency Core Cooling System Evaluation Model," November 12, 1976

a,c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

TABLE 8

Implementation Limitations and/or Constraints Identified in NRC SER

R.L. Baer (NRC) to A.E. Scherer (CE)

"Evaluation of Topical Report CENPD-135 Supplement 5," September 6, 1978

a,c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

TABLE 9

Implementation Limitations and/or Constraints Identified in NRC SER

K. Kniel (NRC) to A.E. Scherer (CE)

"Evaluation of Topical Report CENPD-138, Supplement 2-P," April 10, 1978

a,c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

TABLE 10

Implementation Limitations and/or Constraints Identified in NRC SER

K. Kniel (NRC) to A.E. Scherer (CE), August 2, 1976

a,c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

TABLE 11

Implementation Limitations and/or Constraints Identified in NRC SER

R.L. Baer (NRC) to A.E. Scherer (CE)

"Staff Evaluation of Topical Report CENPD-254-P," July 30, 1979

a,c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

TABLE 12

Implementation Limitations and/or Constraints Identified in NRC SER

NRC letter, M.J. Virgilio (NRC) to S.A. Toelle (CE)

"Acceptance for Referencing of Licensing Topical Report CE-NPD 282-P, Technical Manual for the CENTS Code, (TAC No. M82718)," March 17, 1994

a,c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

TABLE 12

Implementation Limitations and/or Constraints Identified in NRC SER

NRC letter, M.J. Virgilio (NRC) to S.A. Toelle (CE)

"Acceptance for Referencing of Licensing Topical Report CE-NPD 282-P, Technical Manual for the CENTS Code, (TAC No. M82718)," March 17, 1994

a,c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

TABLE 13

Implementation Limitations and/or Constraints Identified in NRC SER

NRC Letter, J.A. Miller (NRC) to J. W. Williams (FP&L), "The Commission has issued the enclosed Amendment No. 8 to Facility Operating License No. NFP-16 for the St. Lucie Plant Unit No. 2…," November 1984.

a.c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

TABLE 14

Implementation Limitations and/or Constraints Identified in NRC SER

NRC letter, O.D. Parr (NRC) to A.E. Scherer, June 10, 1976.

a,c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

TABLE 15

NRC Imposed Safety Evaluation Report Limitations and/or Constraints

Letter, Karl Kniel (NRC) to A.E. Scherer (CE)

"Evaluation of Topical Report CENPD-161-P, entitled TORC Code – A Computer Code for Determining the Thermal Margin of a Reactor Core, Amendment 1-P to CENPD-161-P, and the nonproprietary versions thereof," September 14, 1976.

a.c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

TABLE 15

NRC Imposed Safety Evaluation Report Limitations and/or Constraints

Letter, Karl Kniel (NRC) to A.E. Scherer (CE)

"Evaluation of Topical Report CENPD-161-P, entitled TORC Code – A Computer Code for Determining the Thermal Margin of a Reactor Core, Amendment 1-P to CENPD-161-P, and the nonproprietary versions thereof," September 14, 1976.

a,c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

TABLE 15

NRC Imposed Safety Evaluation Report Limitations and/or Constraints

Letter, Karl Kniel (NRC) to A.E. Scherer (CE)

"Evaluation of Topical Report CENPD-161-P, entitled TORC Code – A Computer Code for Determining the Thermal Margin of a Reactor Core, Amendment 1-P to CENPD-161-P, and the nonproprietary versions thereof," September 14, 1976.

a,c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

TABLE 15

NRC Imposed Safety Evaluation Report Limitations and/or Constraints

Letter, Karl Kniel (NRC) to A.E. Scherer (CE)

"Evaluation of Topical Report CENPD-161-P, entitled TORC Code – A Computer Code for Determining the Thermal Margin of a Reactor Core, Amendment 1-P to CENPD-161-P, and the nonproprietary versions thereof," September 14, 1976.

a,c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

TABLE 16

Implementation Limitations and/or Constraints Identified in NRC SER

Letter, R.L. Tedesco (NRC) to A.E. Scherer (CE)

"Acceptance for Referencing of Topical Report CENPD-206(P), TORC Code Verification and Simplified Modeling Methods," December 11, 1980.

a,c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

TABLE 16

Implementation Limitations and/or Constraints Identified in NRC SER

Letter, R.L. Tedesco (NRC) to A.E. Scherer (CE)

"Acceptance for Referencing of Topical Report CENPD-206(P), TORC Code Verification and Simplified Modeling Methods," December 11, 1980.

a.c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

TABLE 16

Implementation Limitations and/or Constraints Identified in NRC SER

Letter, R.L. Tedesco (NRC) to A.E. Scherer (CE)

"Acceptance for Referencing of Topical Report CENPD-206(P), TORC Code Verification and Simplified Modeling Methods," December 11, 1980.

a.c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

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Implementation Limitations and/or Constraints Identified in NRC SER

Letter, R.L. Tedesco (NRC) to A.E. Scherer (CE)

"Acceptance for Referencing of Topical Report CENPD-206(P), TORC Code Verification and Simplified Modeling Methods," December 11, 1980.

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No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

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Implementation Limitations and/or Constraints Identified in NRC SER

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No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

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Letter, R.L. Tedesco (NRC) to A.E. Scherer (CE)

"Acceptance for Referencing of Topical Report CENPD-206(P), TORC Code Verification and Simplified Modeling Methods," December 11, 1980.

a.c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

TABLE 17

Implementation Limitations and/or Constraints Identified in NRC SER

NRC letter, C.O. Thomas (NRC) to A.E. Scherer (CE), "Acceptance for Referencing of Licensing Topical Report CENPD-266-P, CENPD-266-NP, The ROCS and DIT Computer Codes for Nuclear Design," April 4, 1983

a,c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

TABLE 17

Implementation Limitations and/or Constraints Identified in NRC SER

NRC letter, C.O. Thomas (NRC) to A.E. Scherer (CE), "Acceptance for Referencing of Licensing Topical Report CENPD-266-P, CENPD-266-NP, The ROCS and DIT Computer Codes for Nuclear Design," April 4, 1983

a,c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

TABLE 18

Implementation Limitations and/or Constraints Identified in NRC SER

NRC letter, O.D. Parr (NRC) to A.E. Scherer (CE), June 10, 1976

a,c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

TABLE 19

Implementation Limitations and/or Constraints Identified in NRC SER

NRC letter, A.C. Thadani (NRC) to A.E. Scherer (CE), "Generic Approval of CE Fuel Performance Code FATES 3B (CEN-161(B)-P, Supplement 1-P) (TAC No. M81769)," November 6, 1991

a,c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

TABLE 20

Implementation Limitations and/or Constraints Identified in NRC SER

A. Clark (NRC) to A.E. Lundvall (BGE)

"Safety Evaluation of CEN-161 (FATES-3)," March 31, 1983.

A.C. Thadoni (NRC) to A.E. Scherer (CE)

"Acceptance for Generic Referencing of the Topical Report CEN-161, Improvements to Fuel Evaluation Model (FATES 3)," May 22, 1989.

a,c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

TABLE 20

Implementation Limitations and/or Constraints Identified in NRC SER

A. Clark (NRC) to A.E. Lundvall (BGE)

"Safety Evaluation of CEN-161 (FATES-3)," March 31, 1983.

A.C. Thadoni (NRC) to A.E. Scherer (CE)

"Acceptance for Generic Referencing of the Topical Report CEN-161, Improvements to Fuel Evaluation Model (FATES 3)," May 22, 1989.

a.c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

TABLE 20

Implementation Limitations and/or Constraints Identified in NRC SER

A. Clark (NRC) to A.E. Lundvall (BGE)

"Safety Evaluation of CEN-161 (FATES-3)," March 31, 1983.

A.C. Thadoni (NRC) to A.E. Scherer (CE)

"Acceptance for Generic Referencing of the Topical Report CEN-161, Improvements to Fuel Evaluation Model (FATES 3)," May 22, 1989.

a.c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

TABLE 21

Implementation Limitations and/or Constraints Identified in NRC SER

NRC letter, O.D. Parr (NRC) to F.M. Stern (CE), December 4, 1974

a,c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

TABLE 21

Implementation Limitations and/or Constraints Identified in NRC SER

NRC letter, O.D. Parr (NRC) to F.M. Stern (CE), December 4, 1974

a,c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

TABLE 21

Implementation Limitations and/or Constraints Identified in NRC SER

NRC letter, O.D. Parr (NRC) to F.M. Stern (CE), December 4, 1974

a,c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

TABLE 21

Implementation Limitations and/or Constraints Identified in NRC SER

NRC letter, O.D. Parr (NRC) to F.M. Stern (CE), December 4, 1974

a,c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

TABLE 21

Implementation Limitations and/or Constraints Identified in NRC SER

NRC letter, O.D. Parr (NRC) to F.M. Stern (CE), December 4, 1974

a,c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

TABLE 22

Implementation Limitations and/or Constraints Identified in NRC SER

NRC letter, S.A. McNeil (NRC) to J.A. Tiernan (BG&E)
Safety Evaluation of Topical Report CEN-161(B)-P, Supplement 1-P, "Improvements to Fuel Evaluation Model," February 4, 1987

a,c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

TABLE 22

Implementation Limitations and/or Constraints Identified in NRC SER

NRC letter, S.A. McNeil (NRC) to J.A. Tiernan (BG&E)
Safety Evaluation of Topical Report CEN-161(B)-P, Supplement 1-P, “Improvements to Fuel Evaluation Model,” February 4, 1987

a,c

No.	NRC SER Constraint	Applicability	Conformance [Yes/No]	Comments

Attachment 8

W3F1-2003-0074

List of Regulatory Commitments

List of Regulatory Commitments

The following table identifies those actions committed to by Entergy in this document. Any other statements in this submittal are provided for information purposes and are not considered to be regulatory commitments.

PUR Section	Commitment	Type (Check One)		Scheduled Completion Date (If Required)
		One-Time Action	Continuing Compliance	
Cover Letter	Control room dose for non-LOCA events under EPU conditions will be addressed based on the results of the Generic Letter 2003-01 required evaluation. Additionally, LOCA and FHA control room doses provided in this submittal will be reevaluated, as necessary, based on the results of the Generic Letter 2003-01 required evaluation.	X		End of RF13
2.2.2.2	With respect to Class 2 and 3 Code compliance, Systems that fail to meet the current design requirements in their current configuration as a result of changes in input parameters will be redesigned and physically modified, as required to meet the current design requirements.	X		End of RF13
2.2.2.2	To ensure that changes resulting from EPU do not cause excessive vibration that could be detrimental to system performance, vibration monitoring will be performed following EPU to identify sources of vibrations and appropriate corrective actions will be taken to eliminate or minimize these vibrations.	X		Cycle 14
2.3.1	Further analysis will be performed to ensure the electrical EQ equipment located inside containment will remain qualified.	X		End of RF13
2.3.2.2	Plant modifications will be made as necessary to upgrade the main transformers to support EPU.	X		End of RF13
2.3.2.2	An alkalizer skid will be added as part of the main generator rewind project to address main generator stator cooling water chemistry concerns.	X		End of RF13

PUR Section	Commitment	Type (Check One)		Scheduled Completion Date (If Required)
		One-Time Action	Continuing Compliance	
2.3.2.2	Due to the EPU, the existing breakers' continuous load and short circuit interrupting ratings will be exceeded, as well as the associated mechanical disconnect switches on either side of each breaker. New breakers and disconnects are required to meet 1333 MVA and will be installed over RF12 and RF13.	X		End of RF13
2.4.1	The EPU also affects the ADV controllers. The existing ADV analog controllers are being replaced with more accurate digital controllers.	X		End of RF13
2.4.1.1	However, because the EPU lowers steam generator and main steam operating pressures, the diverse emergency feedwater actuation signal (DEFAS) permissive setpoint will be lowered;	X		End of RF13
2.4.1.2	The EPU configuration has been analyzed to a lower steam generator pressure. These PPS changes will be implemented for EPU.	X		End of RF13
2.4.1.2	CPC constants will be updated to be consistent with the new definition of 100% power and other requirements of the EPU and cycle specific analysis.	X		End of RF13
2.4.2.1	The EPU requires adjustments to NSSS control systems setpoints and parameters to provide proper control system performance for the EPU operating conditions.	X		Power Ascension during Cycle 14
2.4.2.1	The COLSS constants that are based on the reactor thermal power and instrumentation uncertainties will be modified as necessary as part of the reload fuel design process. These constants will be calculated and implemented as part of the reload fuel design process.	X		End of RF13
2.5.1.2	The EPU will employ the same measures that have been taken for existing valves to prevent missile generation.	X		End of RF13

PUR Section	Commitment	Type (Check One)		Scheduled Completion Date (If Required)
		One-Time Action	Continuing Compliance	
2.5.2.4	Based on this rule change to 10 CFR 50.44, Entergy will be submitting a separate license amendment request to eliminate the Waterford 3 technical specification requirements for combustible gas control in containment. This license amendment request will be submitted by the end of 2003.	X		12/31/03
2.5.3.1	In response to Generic Letter 2003-01, *Control Room Habitability*, Entergy has committed to complete the requested evaluation prior to the end of September 2004. This evaluation will include a validation of the inleakage assumptions made in the dose consequence analyses. The results of this evaluation will determine further appropriate actions, if any, that must be taken to resolve this issue. (Reference commitment A26565)	X		9/30/04
2.5.5.3	These higher heat loads will increase the temperature of the CCWS return flow in some of the CCWS piping sections. The impact of these higher temperatures on the CCW piping, supports and components will be evaluated. Also, the impact of these higher temperatures on the shutdown cooling heat exchanger room cooler will be evaluated.	X		End of RF13
2.5.6.1	In order to accept the higher MSSS flows for EPU, the HP turbine steam path will be replaced.	X		End of RF13
2.5.6.1	The feedwater control system setpoints will be modified slightly to increase pump speed at a lower demand.	X		End of RF13
2.5.6.1	The MSR safety valves are undersized for the EPU conditions and will be replaced as required.	X		End of RF13
2.5.6.2	Measures will be implemented as necessary to prevent potential condenser tube vibration under power uprate conditions.	X		End of RF13

PUR Section	Commitment	Type (Check One)		Scheduled Completion Date (If Required)
		One-Time Action	Continuing Compliance	
2.5.8.1	Entergy will perform additional testing to reconfirm the acceptability of the fuel oil consumption rates utilized in the fuel oil usage calculation prior to implementing the EPU.	X		End of RF13
2.9.1	Setpoints that are mentioned in emergency operating procedures or off normal procedures will be changed to new uprate values.	X		End of RF13
2.9.1	The time window to establish simultaneous hot and cold leg injection in the LOCA emergency operating procedure will be changed from 2 and 4 hours to 2 and 3 hours.	X		End of RF13
2.9.1	As discussed in Section 2.5.2.4, Entergy is submitting a separate license amendment request to eliminate the Technical Specification requirements for combustible gas control in containment. Resulting EOP changes, regarding operation of the combustible gas control system, will be made during the implementation phase following approval and issuance of the associated amendment.	X		60 days following issuance of combustible gas control amendment
2.9.4	Color banding will change for the following indicated parameters: a) Pressurizer pressure narrow range b) Pressurizer pressure wide range c) RCS cold leg temperature d) RCS hot leg temperature e) SIT levels	X		End of RF13
2.9.5.1	Prior to EPU implementation, the simulator will be upgraded to provide operator training at EPU conditions.	X		Beginning of last operator training cycle prior to RF13

PUR Section	Commitment	Type (Check One)		Scheduled Completion Date (If Required)
		One-Time Action	Continuing Compliance	
2.9.5.1	The training staff will provide training as determined by the Operations Training Review Group. Operators will receive training using the systematic approach to training process. This training will cover procedure changes, new or revised technical specifications / safety analysis, and equipment modifications for the EPU. The topics will include items such as high pressure turbine upgrade, new atmospheric dump valve controllers, and instrument range / alarm changes. Classroom training / testing and simulator training/testing with the new equipment/instrument changes installed will ensure the operators understand the changes to plant systems. Startup training will be conducted prior to the conclusion of the outage for the operations crews with emphasis on core reload, positive moderator temperature coefficient, reactor engineering interface, and teamwork skills.	X		End of RF13
2.9.5.3	The EPU simulator modification, design, analysis, and test data will be evaluated based on, but is not limited to, the following: a) Engineering report modification packages b) Design and analysis data including heat balance, balance-of-plant (BOP) flow changes, and plant systems set point changes c) Updated plant and physics data book d) Engineering reports on system response and new accident analyses e) Best-estimate data	X		Beginning of last operator training cycle prior to RF13
2.9.5.4	The simulator will be compared to actual plant data.	X		During Cycle 14
2.10	A Cycle 14 power ascension test program will be performed as described in Section 2.10.	X		Startup after RF13

Attachment 9

W3F1-2003-0074

Westinghouse Electric Company Application for Withholding Proprietary Information from Public Disclosure

Westinghouse

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Our ref: CAW-03-1733

November 10, 2003

APPLICATION FOR WITHHOLDING PROPRIETARY
INFORMATION FROM PUBLIC DISCLOSURE

Subject: Appendix 1of Report, "Waterford 3 Extended Power Uprate," Transmitted to NRC in Attachment 6 to Entergy Letter W3F1-2003-0074

The proprietary information in the above referenced document for which withholding is being requested is further identified in Affidavit CAW-03-1733 signed by the owner of the proprietary information, Westinghouse Electric Company LLC. The affidavit, which accompanies this letter, sets forth the basis on which the information may be withheld from public disclosure by the Commission and addresses with specificity the considerations listed in paragraph (b)(4) of 10 CFR Section 2.790 of the Commission's regulations.

Accordingly, this letter authorizes use of the accompanying affidavit by Entergy Operations, Inc.

Correspondence with respect to the proprietary aspects of this application for withholding or the Westinghouse affidavit should reference this letter, CAW-03-1733 and should be addressed to the undersigned.

Very truly yours,

G. D. Hess for

I. C. Rickard
Licensing Project Manager
Regulatory Compliance and Plant Licensing

Enclosures

CAW-03-1733

AFFIDAVIT

STATE OF CONNECTICUT:

ss

COUNTY OF HARTFORD:

Before me, the undersigned authority, personally appeared Norton L. Shapiro, who, being by me duly sworn according to law, deposes and says that he is authorized to execute this Affidavit on behalf of Westinghouse Electric Company LLC ("Westinghouse"), and that the averments of fact set forth in this Affidavit are true and correct to the best of his knowledge, information, and belief:

Norton L. Shapiro
Consulting Engineer
Westinghouse Electric Company, LLC

Sworn to and subscribed
before me this 10th day
of November, 2003

Notary Public
My Commission Expires:
May 31, 2008

(1) I am a Consulting Engineer in Nuclear Services, Westinghouse Electric Company LLC ("Westinghouse"), and as such, I have been specifically delegated the function of reviewing the proprietary information sought to be withheld from public disclosure in connection with nuclear power plant licensing and rule making proceedings, and am authorized to apply for its withholding on behalf of the Westinghouse Electric Company LLC.

(2) I am making this Affidavit in conformance with the provisions of 10 CFR Section 2.790 of the Commission's regulations and in conjunction with the Westinghouse application for withholding accompanying this Affidavit.

(3) I have personal knowledge of the criteria and procedures utilized by the Westinghouse Electric Company LLC in designating information as a trade secret, privileged or as confidential commercial or financial information.

(4) Pursuant to the provisions of paragraph (b)(4) of Section 2.790 of the Commission's regulations, the following is furnished for consideration by the Commission in determining whether the information sought to be withheld from public disclosure should be withheld.

(i) The information sought to be withheld from public disclosure is owned and has been held in confidence by Westinghouse.

(ii) The information is of a type customarily held in confidence by Westinghouse and not customarily disclosed to the public. Westinghouse has a rational basis for determining the types of information customarily held in confidence by it and, in that connection, utilizes a system to determine when and whether to hold certain types of information in confidence. The application of that system and the substance of that system constitute Westinghouse policy and provide the rational basis required.

Under that system, information is held in confidence if it falls in one or more of several types, the release of which might result in the loss of an existing or potential competitive advantage, as follows:

(a) The information reveals the distinguishing aspects of a process (or component, structure, tool, method, etc.) where prevention of its use by any of

Westinghouse's competitors without license from Westinghouse constitutes a competitive economic advantage over other companies.

(b) It consists of supporting data, including test data, relative to a process (or component, structure, tool, method, etc.), the application of which data secures a competitive economic advantage, e.g., by optimization or improved marketability.

(c) Its use by a competitor would reduce his expenditure of resources or improve his competitive position in the design, manufacture, shipment, installation, assurance of quality, or licensing a similar product.

(d) It reveals cost or price information, production capacities, budget levels, or commercial strategies of Westinghouse, its customers or suppliers.

(e) It reveals aspects of past, present, or future Westinghouse or customer funded development plans and programs of potential commercial value to Westinghouse.

(f) It contains patentable ideas, for which patent protection may be desirable.

There are sound policy reasons behind the Westinghouse system which include the following:

(a) The use of such information by Westinghouse gives Westinghouse a competitive advantage over its competitors. It is, therefore, withheld from disclosure to protect the Westinghouse competitive position.

(b) It is information that is marketable in many ways. The extent to which such information is available to competitors diminishes the Westinghouse ability to sell products and services involving the use of the information.

(c) Use by our competitor would put Westinghouse at a competitive disadvantage by reducing his expenditure of resources at our expense.

(d) Each component of proprietary information pertinent to a particular competitive advantage is potentially as valuable as the total competitive advantage. If competitors acquire components of proprietary information, any one component may be the key to the entire puzzle, thereby depriving Westinghouse of a competitive advantage.

(e) Unrestricted disclosure would jeopardize the position of prominence of Westinghouse in the world market, and thereby give a market advantage to the competition of those countries.

(f) The Westinghouse capacity to invest corporate assets in research and development depends upon the success in obtaining and maintaining a competitive advantage.

(iii) The information is being transmitted to the Commission in confidence and, under the provisions of 10 CFR Section 2.790, it is to be received in confidence by the Commission.

(iv) The information sought to be protected is not available in public sources or available information has not been previously employed in the same original manner or method to the best of our knowledge and belief.

(v) The proprietary information sought to be withheld in this submittal is that which is appropriately marked in Appendix 1 of the report entitled, "Waterford 3 Extended Power Uprate," being transmitted to the NRC in Attachment 6 to Entergy Letter W3F1-2003-0074, and Application for Withholding Proprietary Information from Public Disclosure, to the Document Control Desk. The proprietary information as provided by Westinghouse for inclusion in the Waterford 3 Extended Power Uprate report is expected to be applicable for other licensee submittals in response to certain NRC requirements for demonstration of compliance with safety evaluation report limitations and constraints.

Further, this information has substantial commercial value as follows:

a) Westinghouse can sell defense of its compliance with safety evaluation report constraints and limitations in support of licensing interactions with the NRC.

b) The information requested to be withheld reveals distinguishing aspects of methodology developed by Westinghouse.

Public disclosure of this proprietary information is likely to cause substantial harm to the competitive position of Westinghouse because it would enhance the ability of competitors to provide similar licensing defense services for commercial power reactors without commensurate expenses. Also, public disclosure of the information would enable others to use the information to meet NRC requirements for licensing documentation without purchasing the right to use the information.

The development of the technology described in part by the information is the result of applying the results of many years of experience in an intensive Westinghouse effort and the expenditure of a considerable sum of money.

In order for competitors of Westinghouse to duplicate this information, similar technical programs would have to be performed and a significant manpower effort, having the requisite talent and experience, would have to be expended

Further the deponent sayeth not.

PROPRIETARY INFORMATION NOTICE

Transmitted herewith are proprietary and/or non-proprietary versions of documents furnished to the NRC in connection with requests for generic and/or plant-specific review and approval.

In order to conform to the requirements of 10 CFR 2.790 of the Commission's regulations concerning the protection of proprietary information so submitted to the NRC, the information which is proprietary in the proprietary versions is contained within brackets, and where the proprietary information has been deleted in the non-proprietary versions, only the brackets remain (the information that was contained within the brackets in the proprietary versions having been deleted). The justification for claiming the information so designated as proprietary is indicated in both versions by means of lower case letters (a) through (f) located as a superscript immediately following the brackets enclosing each item of information being identified as proprietary or in the margin opposite such information. These lower case letters refer to the types of information Westinghouse customarily holds in confidence identified in Sections (4)(ii)(a) through (4)(ii)(f) of the affidavit accompanying this transmittal pursuant to 10 CFR 2.790(b)(1).

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