WCAP-16489-NP
Revision 0

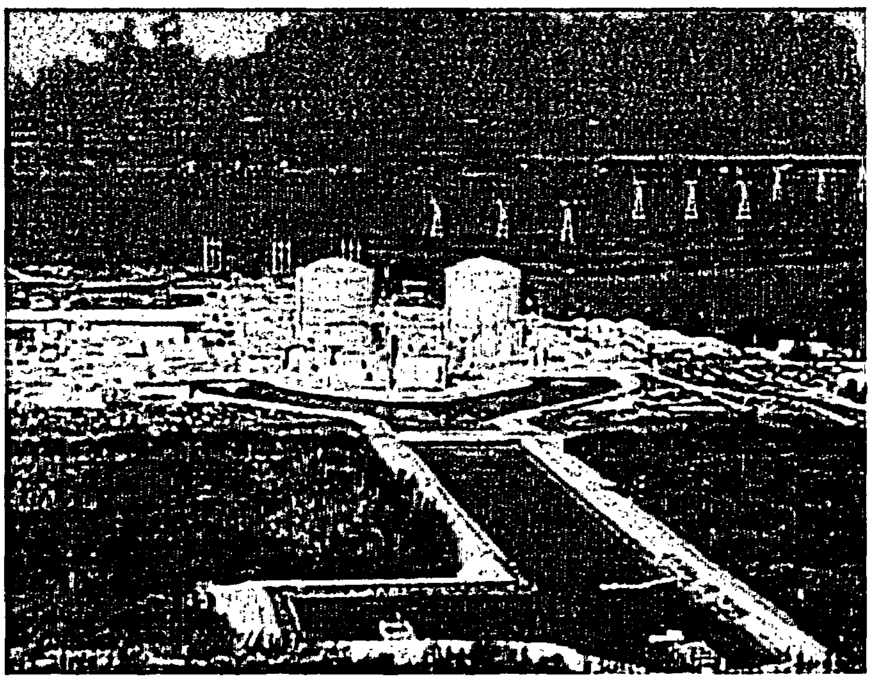
Westinghouse Non-Proprietary Class 3

October 2005

St. Lucie Unit 2

42-Percent Steam Generator Tube Plugging

Licensing Report



Westinghouse

WESTINGHOUSE NON-PROPRIETARY CLASS 3

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St. Lucie Unit 2
42-Percent Steam Generator
Tube Plugging

Licensing Report

K. N. Garner
Systems and Safety Analysis

October 2005

Reviewer: Official record electronically approved in EDMS
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ACRONYMS

ADV	atmospheric dump valves
AFW	auxiliary feedwater
ANS	american nuclear society
AOO	anticipated operational occurrence
AOR	analysis of record
ASGT	asymmetric steam generator transient
ASI	axial shape index
ASME	american society of mechanical engineers
BDAS	boron dilution alarm system
BOC	beginning of cycle
BOL	beginning of life
CE	combustion engineering
CEA	control element assembly
CEDM	control element drive mechanism
CFR	code of federal regulations
CLOF	complete loss of flow
COLR	core operating limits report
CVCS	chemical and volume control system
DEG/PD	double-ended guillotine/pump discharge
DER	double-ended rupture
DNB	departure from nucleate boiling
DNBR	departure from nucleate boiling ratio
DPC	doppler power coefficient
ECCS	emergency core cooling system
EDMS	excore detector monitoring system
EFW	emergency feedwater
EM	evaluation model
EOC	end of cycle
EOL	end of life
EPRI	electric power research institute
EQ	equipment qualification
ESCU	extended statistical combination of uncertainties
FBT	fast bus transfer
FFBT	failure of fast bus transfer
FIV	feedwater isolation valve
FON (fon)	fraction of nominal (i.e., rated thermal power)
FPL	Florida Power and Light
GDC	general design criteria

ACRONYMS (cont.)

HFP	hot full power
HPPT	high pressurizer pressure trip
HPSI	high pressure safety injection
HSGDP	high steam generator differential pressure
HZP	hot zero power
KGU	kilograms of uranium
LBLOCA	large-break loss of coolant accident
LCO	limiting condition of operation
LHR	linear heat rate
LOCA	loss of coolant accident
LOCV	loss of condenser vacuum
LONF	loss of normal feedwater
LOOP	loss of offsite power
LP	low pressure
LPSI	low pressure safety injection
MDC	moderator density coefficient
MFIV	main feedwater isolation valve
MSIV	main steam isolation valve
MSS	main steam system
MSLB	main steamline break
MSSV	main steam safety valve
MTC	moderator temperature coefficient
MWD	megawatt days
NRC	Nuclear Regulatory Commission
NSSS	nuclear steam supply system
OD	outer diameter
PCWG	performance capabilities working group
PD	pump discharge
PHLA	pressurizer high level alarm
PORV	power-operated relief valve
PSV	pressurizer safety valve
PWR	pressurized water reactor
RAOC	relaxed axial offset control
RCP	reactor coolant pump
RCS	reactor coolant system
RPS	reactor protection system

ACRONYMS (cont.)

RTDP	revised thermal design procedure
RTP	rated thermal power
RWT	refueling water tank
S2M	supplement 2 model
SAFDL	specified acceptable fuel design limit
SAL	safety analyses limit
SBLOCA	small break loss of coolant accident
SCS	shutdown cooling system
SDC	shutdown cooling
SG	steam generator
SGTP	steam generator tube plugging
SGTR	steam generator tube rupture
SI	safety injection
SIAS	safety injection actuation signal
SIS	safety injection system
SIT	safety injection tank
SRP	standard review plan
SRSS	square root of the sum of the squares
STDP	standard thermal design procedure
SV	safety valve
T/H	thermal-hydraulic
TM	thermal margin
TM/LP	thermal margin/low pressure
UFSAR	updated final safety analysis report
VHP	variable high power
VHPT	variable high power trip

1 INTRODUCTION AND SUMMARY

1.1 INTRODUCTION

This report summarizes the evaluations and analyses that were performed to confirm the acceptable operation of St. Lucie Unit 2, Reference 1, with up to 42% of the tubes in each steam generator plugged. Sections 2.0 through 5.0 of this report provide the results of the mechanical, nuclear, thermal-hydraulic, and accident analyses, respectively. These analyses are expected to be implemented at St. Lucie Unit 2 for Cycle 16 and include the following conditions:

- Operation up to 89% rated thermal power (2404 MWt nuclear steam supply system power), if the tube plugging in either steam generator exceeds 30% or the minimum reactor coolant system (RCS) flow of 335,000 gpm is not met,
- A maximum of 42% (3532 tubes) removed from service in either steam generator,
- Up to 600 tubes (~7%) plugging asymmetry between the steam generators, and
- A reduction in the required minimum RCS flow from the current value of 335,000 gpm to 300,000 gpm.

FPL transitioned to the Westinghouse reload methodology, WCAP-9272-P-A, Reference 2, for St. Lucie Unit 2 Cycle 15 coincident with NRC approval of up to 30% steam generator tube plugging. The transition established a typical reload interface with FPL as designer, using the same core design methods currently in use for St. Lucie Unit 1 and Turkey Point Units 3 & 4, while maintaining reasonable margins.

Bounding conditions and correlations used in the analysis models have been reviewed to ensure they remain valid for the 42% SGTP analyses. The results of the review and analyses performed confirmed that the analysis models, correlations and bounding conditions used in the 30% SGTP analysis remain valid and appropriate for use in this 42% SGTP analyses. This review of the models and correlations included the ABB-CHF DNB correlation and the steam generator RETRAN model, along with other models and correlations used in the analyses. The review concluded that all operating conditions are within the applicable ranges of the models and correlations. The selection of values for the key safety parameters is discussed in Section 3.4.

1.2 ANALYSIS METHODS

RCS flow has a significant impact on the departure from nucleate boiling ratio (DNBR) calculations. Therefore, reducing the technical specification RCS flow requirement even while reducing plant power may reduce the available analysis margins to reactor protection system (RPS) setpoints and accident analysis acceptance criteria. The projected reduction in minimum RCS flow is sufficiently large to preclude evaluating the change solely with engineering judgment. Reanalysis of some of the licensing basis analyses is performed to show that the acceptance criteria for DNBR, peak primary and secondary side pressure, etc., are still met.

Westinghouse and Combustion Engineering plants operate in similar ways since both use pressurized water reactors. The dissimilarities are addressed within the safety analyses and methodologies, and are supported by the WCAP-9272 Reload Methodology, Reference 2. Table 1-3 lists the methodologies used for the 42% SGTP analyses; these are the same technologies as were approved for use in the 30% SGTP project. The general approach is to use those tools and methods traditionally associated with the WCAP-9272 Reload

Methodology. Key exceptions are noted for steam generator tube rupture, loss-of-coolant accident (LOCA), fuel performance, mechanical design, and DNB correlations.

Code utilization and applicability is as described for the St Lucie Unit 2 30% SGTP application. All code packages used in this project have been previously approved by the NRC for application to St. Lucie Unit 2. The ANC/PHOENIX code package is currently in use for St. Lucie Unit 2 (i.e., ANC/PHOENIX is applicable to modeling CE core designs). Thus, there are no differences in methodology for the nuclear design.

VIPRE-01 (VIPRE), a sophisticated, robust thermal-hydraulic subchannel code that can accurately model various core/fuel configurations with numerous correlations, is used for thermal-hydraulic subchannel analyses. The ABB-NV & ABB-TV correlations have been inserted into the VIPRE code for application to the St. Lucie Unit 2 fuel design.

RETRAN-02 (RETRAN) was selected as the transient analysis code. The currently licensed RETRAN model was previously modified for the St. Lucie Unit 2 control and protection systems and plant equipment operations during the 30% SGTP analysis. These features did not require coding updates and were accommodated through features already available in the approved RETRAN code.

The methods used for the various analyses are documented in NRC-approved topical reports. Any input changes necessary from the 30% SGTP licensing report to provide an appropriate technical basis for the St. Lucie Unit 2 design with 42% tube plugging are defined in the appropriate analysis subsection of this report.

Fuel performance information from FATES-3B is used for the analysis of Cycle 16. Note that, unlike the LOCA relationship to fuel performance, the non-LOCA methods do not rely on the specifics of the fuel performance model. Rather, conservative fuel temperatures, pressures and geometric information are taken from the fuel performance calculations to set up simplified modeling internal to the RETRAN (and related) code calculations. Therefore, the exact nature of the modeling is not paramount, but it is necessary to ensure that the values for the key fuel performance parameters are conservative for application to St. Lucie Unit 2.

The ABB 99EM Code for modeling large break LOCA and the S2M Evaluation Model for Small Break LOCA were used for the St. Lucie Unit 2 42% SGTP program. These are the same models as used in the 30% SGTP analyses. Post-LOCA modeling maintains the methods currently used for the St. Lucie Unit 2 licensing basis as discussed in Section 5.2.5.

1.3 PEAKING FACTORS

The existing full-power radial peaking factor, F_r, design limit is 1.70 (without measurement uncertainties) and the full-power peak linear heat rate is 12.5 kw/ft. For Cycle 16 implementation with 42% SG tube plugging, the radial peaking factor is changed to 1.72 at 89% rated thermal power and the peak linear heat rate limit is reduced to 12.0 kw/ft.

1.4 REVISED THERMAL DESIGN PROCEDURES UNCERTAINTIES

With Cycle 15, St. Lucie Unit 2 transitioned from the extended statistical combination of uncertainties (ESCU) methods to the Westinghouse Revised Thermal Design Procedure (RTDP) for DNB analysis. The

method of uncertainty analysis is discussed in Reference 10 and is the same regardless of whether the application to the safety analysis is RTDP or non-RTDP methodology. The uncertainty analysis statistically combines the individual uncertainties using the square root of the sum of the squares (SRSS) method. The analysis includes uncertainties for:

- The method of measurement,
- The type of field device (that is, RTDs, transmitters, special test measurements), and
- The calibration of the instrumentation.

These uncertainties for temperature, pressure, power, and flow are then used in the development of the reactor core limits and the DNBR limits. The thermal margin/low pressure (TM/LP) reactor trip setpoints are then confirmed from the new core limits for use in the technical specifications.

1.5 PERFORMANCE CABABILITIES WORKING GROUP PARAMETERS

Parameters specified in the Performance Capabilities Working Group (PCWG) parameter sheet, Table 1-1, provide the basis for the 42% SGTP program at St. Lucie Unit 2. Table 1-1 also provides values used in the 30% SGTP analysis. For consistency, all design basis analyses reference this PCWG parameter sheet when evaluating the impact of 42% SGTP on St. Lucie Unit 2. The parameter sheet provides two cases for analysis; one case at 547.1°F T_{cold} consistent with expected plant operating conditions at 42% SGTP, and one case at 546.0°F T_{cold}. These temperatures represent the range of inlet temperatures analyzed to support the 42% SGTP level and the reduction in RCS flow.

Table 1-2 provides loop flow data, based on the parameters specified in Table 1-1, used for the evaluation of various asymmetric plugging configurations for the non-LOCA analyses.

1.6 GENERAL ANALYSIS ASSUMPTIONS

Part of the analysis performed for the 42% SGTP program is to update and confirm the assumptions and inputs used in the analyses. These assumptions and input parameters form the basis upon which the analyses are performed and ultimately establish the St. Lucie Unit 2 licensing basis. Westinghouse documents those assumptions and input parameters to be used in the analysis; FPL reviews the list and provides confirmation and/or revisions, as appropriate. Once concurrence is obtained, the assumptions and input parameters are documented as final values, which are then used in the analysis of record. In general, the only changes are those defined by the program, those required for accurate technical modeling, and those chosen to improve analysis margins.

The major changes identified for the 42% SGTP program are:

- Reduced maximum core thermal output corresponding to 89% power.
- Increase in SGTP up to 42% of the tubes in either steam generator removed from service (3532 tubes/steam generator), with up to 600 tubes (~7%) SGTP asymmetry.
- Reduced minimum technical specification flow of 300,000 gpm.

In addition to these assumptions, results have required reductions in COLR limits such as the peak linear heat rate as discussed in Section 3.6.

1.7 CONCLUSIONS

The evaluations and safety analyses results documented in this report demonstrate the capability of St. Lucie Unit 2 to operate safely under the power, RCS flow, and steam generator tube plugging conditions that are expected throughout Cycle 16. The key conditions include:

- Limiting the maximum thermal output to 89% power (2404 MWt),
- Plugging up to 42% of the tubes in either steam generator (3532 tubes/steam generator), with up to 600 tubes (~7%) SGTP asymmetry, and
- Reducing the minimum reactor coolant system flow rate to 300,000 gpm.

1.8 REFERENCES

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12. CEN-161(B)-P-A, "Improvements to Fuel Evaluation Model," August 1989.
13. CEN-161(B)-P, Supplement 1-P-A, "Improvements to Fuel Evaluation Model," January 1992.
14. CEN-193(B)-P, Supplement 2-P, "Partial Response to NRC Questions on CEN-161(B)-P, 'Improvements to Fuel Evaluation Model,'" March 21, 1982.
15. CEN-345(B)-P, "Responses to NRC Questions on FATES3B," October 17, 1986.
16. Nguyen, T. Q., et al., "Qualification of the PHOENIX-P/ANC Nuclear Design System for Pressurized Water Reactor Cores," WCAP-11596-P-A, June 1988.
17. Miller, R. W., et al., "WCAP-10216-P-A, "Relaxation of Constant Axial Offset Control; FQ Surveillance Technical Specification," February 1994.
18. Letter, A. E. Scherer, Enclosure 1-P to LD-82-001, "CESEC - Digital Simulation of a Combustion Engineering Nuclear Steam Supply System," December 1981.

Table 1-1
Performance Capability Parameters

OWNER UTILITY:	Florida Power and Light Company	**Attachment to PCWG-03-23 and PCWG-05-25**
PLANT NAME:	St. Lucie (STL2)	
UNIT NUMBER:	2	

BASIC COMPONENTS			
Reactor Vessel, ID, in.	172.4	Isolation Valves	No
Core		Number of Loops	2
Number of Assemblies	217	Steam Generator	
Rod Array	16 x 16 CE[1]	Model	Model 67
Rod OD, in.	0.382	Shell Design Pressure, psia	1000
Number of Grids	10/assembly[7]	Reactor Coolant Pump	
Active Fuel Length, in.	136.7	Model/Weir	3543/Yes
Number of Control Rods, FL	91	Pump Motor, hp	6500
Internals Type	PSL2	Frequency, Hz	60

	30% SGTP Program		**42% SGTP Program**	
THERMAL DESIGN PARAMETERS	**Max Tcold**	**Min Tcold**	**Max Tcold**	**Min Tcold**
NSSS Power, %	100	100	89	89
MWt	2720	2720	2424	2424
10^6 BTU/hr	9281	9281	8,271	8,271
Reactor Power, MWt	2700	2700	2404	2404
10^6 BTU/hr	9213	9213	8,203	8,203
Thermal Design Flow, Loop gpm	83,750[4]	83,750[4]	75,000[4]	75,000[4]
Reactor 10^6 lb/hr	126.1	128.4	113.5	113.5
Reactor Coolant Pressure, psia	2250	2250	2250	2250
Core Bypass, %	3.7	3.7	3.7	3.7
Reactor Coolant Temperature, °F				
Core Outlet	605.9	592.9	603.9	602.8
Vessel Outlet	604.0	590.9	601.9	600.8
Core Average	578.6	564.9	576.6	575.5
Vessel Average	576.5	563.0	574.5	573.4
Vessel/Core Inlet	549.0	535.0	547.1	546.0
Steam Generator Outlet	548.6[6]	534.6[6]	546.6[6]	545.5[6]
Steam Generator				
Steam Temperature, °F	513.2	498.6	508.0	506.9
Steam Pressure, psia	766[2]	672[2]	732[2]	724[2]
Steam Flow, 10^6 lb/hr total	11.83	11.79	10.32	10.32
Feed Temperature, °F	435	435	420.8	420.8
Moisture, % max.	0.25	0.25	0.25	0.25
Design FF, hr. sq. ft. °F/BTU	0.00017[3]	0.00017[3]	0.00017[3]	0.00017[3]
Tube Plugging, %	30	30	42.0	42.0
Zero Load Temperature, °F	532	532	532	532

HYDRAULIC DESIGN PARAMETERS		
Pump Design Point, Flow (gpm)/Head (ft.)	87,750/296.75	87,750/296.75
Mechanical Design Flow, gpm	406,000	406,000
Minimum Measured Flow, gpm/total	349,500[5]	314,500[5]

Notes:
1) Fuel Features: Includes Zircaloy/OPTIN cladding.
2) 10 psi (300,000 gpm / 42% plugging) and 12 psi (335,000 gpm / 30% plugging) SG internal pressure drop incorporated.
3) This fouling factor was originally determined by adding conservatism to a best-estimate fouling factor based on plant data. It is less than the warranted fouling factor of 0.0003624 hr. sq. ft. deg-F/Btu
4) TDF = 167,500 gpm/SG loop (30% SGTP) and 150,000 gpm/SG loop (42% SGTP) (each SG contains 1 hot leg and 2 cold legs). This is equivalent to the Tech. Spec. minimum flow in CE terminology.
5) Flow measurement uncertainty is 14,500 gpm.
6) The difference between the SG outlet and Vessel Inlet Temperature is due to RCP net heat input.
7) CE Fuel Grid: 1 Guardian, 8 HID-1L, and 1 Top HID-1L grids per fuel assembly.

Table 1-2 Performance Capability Parameters Asymmetric Flow for Non-LOCA Transient Evaluations Reactor Core and RCS Loop Flow				
Reactor Vessel Tavg	**SGTP Level**	**Loop 1 RCS Flow**	**Loop 2 RCS Flow**	**Reactor Core RCS Flow**
573.4°F	42% (symmetric)	78,420 gpm/loop	78,420 gpm/loop	313,679 gpm
573.4°F	42%/35% (asymmetric)	78,036 gpm/loop	83,437 gpm/loop	322,944 gpm

Table 1-3 Methodology for 42% SGTP Analyses	
Discipline	**42% SGTP Technology**
Reload Methodology	WCAP-9272 (Reference 2)
LBLOCA	99 Evaluation Model (99EM) (Reference 3)
SBLOCA	Supplement 2 Model (S2M) (Reference 4)
Post-LOCA	Consistent with current licensing basis
Transient Analysis*	RETRAN (Reference 5)
Transient Analysis Methods	TM/LP will be modeled explicitly
Thermal-Hydraulics	VIPRE-W (References 6 through 8)
DNB Correlations	ABB-NV (Reference 9)
Thermal Design Procedure	RTDP (Reference 10)
Mechanical Design	Consistent with current licensing basis
Fuel Performance	FATES-3B (References 11 through 15)
Fuel Performance Methods	Consistent with current licensing basis, augmented with high-duty drivers (more explicit corrosion calculation)
Nuclear Design	ALPHA/PHOENIX/ANC (Reference 16)
Nuclear Design Methods	Standard design methods and adjustments for non-standard technologies (LOCA and FP/MD)
Power Distribution Confirmation Methods	RAOC (Reference 17)
* CESEC (Reference 18) has been used for the SGTR event and forms the basis for those transients that were evaluated rather than re-analyzed.	

2 FUEL MECHANICAL DESIGN FEATURES

2.1 INTRODUCTION AND SUMMARY

This section evaluates the effects of operation at 89% power, a minimum reactor coolant system (RCS) flow rate of 300,000 gpm, and up to 42% of the steam generator tubes plugged on the mechanical design of the 16x16 Combustion Engineering (CE) HID-1L fuel design. There is no change in the fuel assembly design for Cycle 16 other than the use of Inconel top grids, thus there will be no impact to the fuel handling equipment or the refueling equipment interfaces

2.2 MECHANICAL PERFORMANCE

Zircaloy-4/OPTIN fuel cladding as currently loaded in St Lucie Unit 2 will be used in the 16x16 CE HID-1L fuel assemblies for Cycle 16. There are no changes to the fuel assembly structural characteristics created by the use of an Inconel top grid, thus the assembly is determined to be acceptable.

The effect of a small decrease in core average temperature due to the combined effects of reduced core power and flow on the core non-heat flux structures has been evaluated. The effects were found to be negligible. Another effect of the reduction in RCS flow is the potential for flow-induced vibration. The reactor internals have been evaluated for the reduced RCS flow rate and found to be acceptable. Flow tests were performed as a part of the 16x16 CE HID-1L assembly development. Acceptable results were found for the 16x16 CE HID-1L assembly for a spectrum of flow rates that encompasses the anticipated (300,000 gpm) flow rate.

Although not currently planned for use in Cycle 16, the potential to use ZIRLO cladding is evaluated in this report.

Consistent with the current fuel design, GUARDIAN grid 16x16 CE HID-1L fuel assemblies that incorporate an Inconel (non-mixing vane) bottom grid will be used for St. Lucie Unit 2. An Inconel top grid to address fretting and wear considerations will be used during Cycle 16. The design and materials for intermediate spacer grids remains unchanged.

The 16x16 CE HID-1L guide thimbles and upper/lower end fittings will remain unchanged. Therefore, the 16x16 CE HID-1L fuel assembly, with expected structural behavior and projected performance at the reduced flow rate of 300,000 gpm, will meet design requirements throughout the fuel's life.

2.3 FUEL ROD PERFORMANCE

Fuel rod design evaluations for the 16x16 CE HID-1L fuel were performed using NRC-approved models and design criteria methods (References 1 through 9) to demonstrate that all fuel rod design criteria are satisfied.

The fuel rod design criteria given below are verified by evaluating the predicted performance of the limiting fuel rod, defined as the rod which gives the minimum margin to the design limit. In general, no single rod is limiting with respect to all the design criteria. Generic evaluations have identified which rods are most likely to be limiting for each criterion, and exhaustive screening of fuel rod power histories to determine the limiting rod is typically not required.

The NRC-approved FATES-3B model for in-reactor behavior is used to calculate the fuel rod performance over its irradiation history. FATES-3B iteratively calculates the interrelated effects of temperature, pressure, cladding elastic and plastic behavior, fission gas release, and fuel densification and swelling as a function of time and linear power.

Fuel Rod Design Criteria

The criteria pertinent to the fuel rod design include:

- Maximum internal hot gas pressure
- Excessive fuel rod DNB propagation
- Fuel rod stress and strain
- Maximum fuel temperature
- Fuel rod fatigue damage
- Cladding creep collapse
- Shoulder gap
- Seismic and LOCA loads

The specific assumptions used in the verification of these criteria for the St. Lucie Unit 2 fuel include:

- St. Lucie Unit 2 42% SGTP at 89% power and associated reduced RCS flow rate of 300,000 gpm.
- Fuel rod duty (steady-state powers, fuel rod axial power shapes, etc.).

Each of these key fuel rod design criteria have been evaluated for application of the 16x16 CE HID-1L fuel assembly with Zircaloy-4/OPTIN and ZIRLO cladding in St. Lucie Unit 2 during Cycle 16. Based on these evaluations, it is concluded that each design criterion can be satisfied by the 16x16 CE HID-1L with Zircaloy-4/OPTIN and ZIRLO cladding design. The design criteria are described in more detail below.

Maximum Internal Gas Pressure

Criterion: The fuel rod internal hot gas pressure shall not exceed the critical maximum pressure determined to cause an outward cladding creep rate that is in excess of the fuel radial growth rate anywhere locally along the entire active fuel length of the fuel rod.

Evaluation: Maximum internal gas pressure depends on fuel rod temperatures, fission gas release, and void volume. The critical pressure limit for no clad lift-off depends on fuel swelling rate and clad tensile creep during normal operation. An evaluation demonstrated that maximum predicted rod internal pressures will not exceed the critical pressure limit at any time in life for anticipated operation of St. Lucie Unit 2..

Fuel Rod DNB Propagation

Criterion: The radiological dose consequences of DNB failures shall remain within the specified limits.

Evaluation: Calculation of DNB propagation depends on rod internal gas pressure, high-temperature creep, and high-temperature rupture stress (burst stress). An evaluation demonstrated that no DNB propagation will occur with the maximum rod internal pressures predicted for St. Lucie Unit 2. If conditions change, an evaluation will be performed to verify the lack of DNB propagation or to demonstrate that with DNB propagation the radiological dose consequences of DNB failures will remain within the specified limits.

Fuel Rod Stress

Criteria: (1) During Conditions I and II, the primary tensile stress in the cladding and the end-cap welds must not exceed 2/3 of the minimum unirradiated yield strength of the material at the applicable temperature. During Condition III, the primary tensile stress limit is the yield strength and during Condition IV seismic and LOCA (mechanical excitation only) conditions, the stress limit is the lesser of 0.7 Su or 2.4 Sm.

(2) During Conditions I, II and III, primary compressive stress in the cladding and the end-cap welds must not exceed the minimum unirradiated yield strength of the material at the applicable temperature. During Condition IV seismic and LOCA (mechanical excitation only) conditions, the stress limit is the lesser of 0.7 Su or 2.4 Sm.

Evaluation: The above fuel rod stress criteria have been evaluated for St. Lucie Unit 2 Cycle 16 fuel design and found to be satisfied. This evaluation considered differential cladding pressures, creep, cladding growth and oxide buildup. All of these parameters involve the material properties and capabilities of the cladding. An evaluation demonstrated that the cladding properties and models will have no appreciable impact on maximum stress.

Fuel Rod Strain

Criteria: (1) At any time during the fuel or integral-burnable-absorber rod lifetime, the net unrecoverable circumferential tensile cladding strain shall not exceed 1% based on beginning-of-life (BOL) cladding dimensions. This criterion is applicable to normal operating conditions, and following a single Condition II or III event or a single anticipated operational occurrence (AOO).

(2) For fuel or integral-burnable-absorber rods having axial average burnups greater than 52 MWD/KGU, the total (elastic + plastic) circumferential cladding strain increment produced as a result of a single Condition II or III event, or a single AOO, shall not exceed 1%.

Evaluation: The above fuel rod strain criteria have been evaluated for St. Lucie Unit 2 Cycle 16 fuel design and found to be satisfied. This evaluation considered differential cladding pressures, creep and cladding growth.

Maximum Fuel Temperature

Criterion: The fuel rod centerline temperature shall not exceed the fuel melt temperature, accounting for degradation due to burnup and addition of burnable absorbers.

Evaluation: An evaluation for St. Lucie Unit 2 demonstrated that maximum predicted fuel temperatures will not exceed the fuel melt temperature limit at any time in life for anticipated operation of St. Lucie Unit 2.

Fuel Rod Fatigue Damage

Criterion: For the number and types of transients which occur during Condition I reactor operation, end-of-life (EOL) cumulative fatigue damage factor in the cladding and in the end-cap welds must be less than 0.8.

Evaluation: The above fuel rod fatigue damage factor criterion has been evaluated for St. Lucie Unit 2 fuel design cladding and found to be satisfied. The evaluation considered rod temperature and pressure, cladding creep, thermal expansion, and pellet swelling.

Cladding Creep Collapse

Criterion: The time required for the radial buckling of the cladding in any fuel or gadolinium absorber rod must exceed the reactor operating time necessary for the appropriate batch to accumulate its design average discharge burnup. This criterion must be satisfied for continuous reactor operation at any reasonable power level and during any Condition I, II, or III situation. It will be considered satisfied if it can be demonstrated that axial gaps longer than 0.125 inch will not occur between fuel pellets and the plenum spring radial support capacity is sufficient to prevent cladding collapse under all design conditions.

Evaluation: The above fuel rod cladding collapse criterion has been evaluated for St. Lucie Unit 2 fuel design cladding and found to be satisfied. This evaluation considered differential cladding pressures, creep, cladding growth, and oxide buildup.

Shoulder Gap

Criterion: The axial length between end fittings must be sufficient to accommodate differential thermal expansion and irradiation-induced differential growth between fuel rods and guide tubes such that it can be shown with 95% confidence that no interference exists.

Evaluation: The above design criterion is commonly referred to as shoulder gap and is evaluated using the irradiation-induced and thermal growth characteristics of the fuel rod cladding. This criterion has been evaluated for St. Lucie Unit 2 fuel design cladding and found to be satisfied.

Seismic and LOCA Loads

Criterion: The fuel rod cladding shall be capable of withstanding the loads resulting from the mechanical excitations occurring during the seismic and/or LOCA without failure resulting from excessive primary stresses.

Evaluation: Minor changes to allowable stress margins may occur with a change in cladding material (OPTIN to ZIRLO) but there will be no impact since significant stress margins exist for cladding under the postulated loading conditions.

2.4 SEISMIC/LOCA IMPACT ON FUEL ASSEMBLIES

The 16x16 CE HID-1L fuel design with Zicaloy-4/OPTIN or ZIRLO cladding and an Inconel Top Grid has been evaluated and it has been concluded that there will be no impact to the seismic/LOCA evaluation. The reduced RCS flow rate, and the resulting window for T_{cold} and T_{hot}, will have no impact on the evaluation.

2.5 CORE COMPONENTS

The core components for St. Lucie Unit 2 are compatible with the 16x16 CE HID-1L fuel design. The 16x16 CE HID-1L guide tubes design remains unchanged. The change to an Inconel Top Grid is insignificant with regard to the spacer grid configuration.

2.6 REFERENCES

1. CENPD-139-P-A, "Fuel Evaluation Model," July 1974.
2. CEN-161(B)-P-A, "Improvements to Fuel Evaluation Model," August 1989.
3. CEN-161(B)-P, Supplement 1-P-A, "Improvements to Fuel Evaluation Model," January 1992.
4. CEN-372-P-A, "Fuel Rod Maximum Allowable Gas Pressure," May 1990.
5. CENPD-382-P-A, "Methodology for Core Designs Containing Erbium Burnable Absorbers," August 1993.
6. CENPD-275-P, Revision 1-P-A, "C-E Methodology for Core Designs Containing Gadolinia-Urania Burnable Absorbers," May 1988.
7. CENPD-275-P, Revision 1-P, Supplement 1-P-A, "C-E Methodology for PWR Cores Designs Containing Gadolinia-Urania Burnable Absorbers," April 1999.
8. CENPD-404-P-A, Revision 0, "Implementation of ZIRLO™ Cladding Material in CE Nuclear Power Fuel Assembly Designs," November 2001.
9. Letter from B. T. Moroney (NRC) to J. A. Stall (FP&L), "St. Lucie Plant, Unit No. 2 – Issuance of Amendment Regarding Change in Reload Methodology and Increase in Steam Generator Tube Plugging Limit (TAC No. MC1566)," January 31, 2005.

3 NUCLEAR DESIGN

3.1 INTRODUCTION AND SUMMARY

The effects of the following changes are evaluated in this section:

- An increase in steam generator tube plugging (SGTP) to 42%, producing a reduced reactor coolant system (RCS) minimum Technical Specification flow rate of 300,000 gpm; and
- A power level restriction to 89% of the rated thermal power.

The specific values of core safety parameters, e.g., power distributions, peaking factors, rod worths, and reactivity parameters, are primarily loading pattern dependent. The variations in the loading pattern dependent safety parameters are expected to be typical of the normal cycle-to-cycle variations for the standard fuel reloads. Standard nuclear design analytical models and methods (References 2, 3 and 4) accurately describe the neutronic behavior of the 16x16 CE HID-1L fuel design with either Zircaloy/OPTIN or ZIRLO cladding.

3.2 DESIGN BASIS

The specific design bases and their relation to the General Design Criteria (GDC) in 10 CFR 50, Appendix A for the current 16x16 CE HID-1L fuel design are the same with either Zircaloy/OPTIN or ZIRLO cladding. The fuel burnup design will remain at 60,000 MWD/MTU.

3.3 METHODOLOGY

Consistent with the WCAP-9272 reload methodology (Reference 1), the purpose of evaluating the reload core analysis for the proposed changes, prior to the cycle-specific reload design, is to ensure that the values for the key safety parameters remain applicable for the expected operating condition. This will allow the majority of any safety analysis re-evaluations/re-analyses to be completed prior to the cycle-specific design analysis.

No changes to the nuclear design philosophy, methods or models are necessary. The reload design philosophy includes the evaluation of the reload core key safety parameters which comprise the nuclear design dependent input to the Updated Final Safety Analysis Report (UFSAR) for each reload cycle. These key safety parameters will be evaluated for each St. Lucie Unit 2 reload cycle. If one or more of the parameters fall outside the bounds assumed in the reference safety analysis, the affected transients will be re-evaluated/ re-analyzed using standard methods and the results documented in the Reload Safety Evaluation (RSE) for that cycle.

3.4 DESIGN EVALUATION – PHYSICS CHARACTERISTICS AND KEY SAFETY PARAMETERS

The process of identification of bounding values for the key reload parameters has been maintained by establishing a set of "baseline neutronics" for use in the safety analyses. These values and the key parameters themselves have been adjusted only slightly from a standard application for a Westinghouse application to accurately model the unique features of the St. Lucie Unit 2 plant, trips, and technical specifications (References 5 and 6). The values established for the baseline neutronics were chosen to be sufficiently conservative to reasonably preclude violations in the reload evaluation process without being overly conservative (resulting in challenges to analysis margins). For the key parameters, limits have been

established based on recent past operation of St. Lucie Unit 2 to identify representative parameter values. From these representative values, limit values for use in the safety analyses have been established with due consideration of the existing analysis assumptions, extensive plant and design experience, and accounting for changes in SGTP and minimum technical specification flow.

The effect of coastdowns to extend the cycle length beyond nominal full power capability has been considered in determination of the key safety parameters.

Table 3-1 provides the key safety parameters ranges compared to the current limits.

3.5 DESIGN EVALUATION – POWER DISTRIBUTIONS AND PEAKING FACTORS

Beyond the power distribution impacts, other changes to the core power distributions and peaking factors are the result of the normal cycle-to-cycle variations in core loading patterns. The normal methods of feed enrichment variation and insertion of fresh burnable absorbers will be employed to control peaking factors. Compliance with the peaking factor technical specifications can be assured using these methods.

3.6 TECHNICAL SPECIFICATION CHANGES RELATIVE TO NUCLEAR DESIGN

The plant technical specifications including the Core Operating Limits Report (COLR) were reviewed. The technical specification changes which impact the nuclear design are:

- Reduced maximum allowed core thermal power limit to 89% of rated thermal power.
- Reduced reactor coolant system (RCS) minimum Technical Specification flow rate.
- Reduced COLR limit for peak linear heat rate (large-break loss-of-coolant accident (LOCA) limitation),
- Reduced COLR limit for the COLR linear heat rate (LHR) LCO when operating on the excore detector monitoring system (EDMS),
- Modified COLR limits for the COLR total integrated radial peaking factor, F_r, LCO, and
- Reduced COLR limits for the COLR DNB Parameter, Fraction of Maximum Allowable Power Level versus Axial Shape Index, LCO.

The reduced peak linear heat rate COLR limit reduces nuclear design flexibility, but was required to satisfy the acceptance criteria of 10 CFR 50.46 for large-break LOCA. A revision of the COLR LHR LCO is required to accommodate the reduced peak LHR limit. The change to the COLR limits in combination with restricting operation to 89% power compensates for the reduced reactor coolant system (RCS) minimum Technical Specification flow while providing additional peaking margin to accommodate higher peaking associated with use of a reload core design optimized for 30% SGTP with 42% SGTP.

3.7 NUCLEAR DESIGN EVALUATION CONCLUSIONS

Except where specifically identified to accommodate margin considerations, the key safety parameters evaluated for St. Lucie Unit 2 (at the reduced RCS flow corresponding to 42% SGTP) are typical of the normal cycle-to-cycle variations experienced as loading patterns change. The usual methods of enrichment and burnable absorber usage will be employed to ensure compliance with the peaking factor technical specifications.

3.8 REFERENCES

1. Davidson, S. L. (Ed.), et al., "Westinghouse Reload Safety Evaluation Methodology," WCAP-9272-P-A, July 1985.

2. Nguyen, T. Q., et al., "Qualification of the PHOENIX-P/ANC Nuclear Design System for Pressurized Water Reactor Cores," WCAP-11596-P-A, June 1988.

3. Liu, Y. S., et al., "ANC: A Westinghouse Advanced Nodal Computer Code," WCAP-10965-P-A, September 1986.

4. Miller, R. W., et al., "WCAP-10216-P-A, Rev. 1A, "Relaxation of Constant Axial Offset Control; FQ Surveillance Technical Specification," February 1994.

5. "Technical Specifications – St. Lucie Plant, Unit 2," Docket No. 50-389, Amendment 138.

6. "Updated Safety Analysis Report - St. Lucie Plant, Unit 2," Docket No. 50-389, Rev. 16.

Table 3-1 Range of Key Safety Parameters		
Safety Parameter	**Current Design Values**	**42% SGTP**
Reactor Core Power (MWt)	2700	2404
Vessel Inlet Coolant Temp at maximum allowed Power (°F)	549	547.1
Coolant System Pressure (psia)	2250	2250
Most Positive MTC (pcm/°F) at > 70% Rated Thermal Power (RTP)	+ 5 @ 70% power, ramping to + 0 @ 100% RTP	+ 5 @ 70% power, ramping to + 0 @ 100% RTP
Most Positive MTC (pcm/°F) at ≤ 70% RTP	+ 5	+ 5
Most Positive MDC ($\Delta K/g/cm^3$)	0.43	0.43
Doppler Temperature Coefficient	-2.90 to -0.91 pcm/°F	-2.90 to -0.91 pcm/°F
Beta-Effective	0.0044 to 0.0070	0.0044 to 0.0070
Normal Operation F_r (without uncertainties)	1.70	1.72
Shutdown Margin (pcm)	3600	3600
Normal Operation Peak Linear Heat Rate (kw/ft)	12.5	12.0

4 THERMAL AND HYDRAULIC DESIGN

4.1 INTRODUCTION AND SUMMARY

This section describes the thermal-hydraulic (T/H) departure from nucleate boiling (DNB) analysis, in support of St. Lucie Unit 2 42% steam generator tube plugging (SGTP) Project. The T/H analysis ensures that the reactor core meets the DNB design criterion.

The specific criterion for pressurized water reactor (PWR) core T/H design, as described in the Updated Final Safety Analysis Report (UFSAR) (Reference 1), is that there should be a 95% probability at a 95% confidence level (95/95) that the hot rod in the core does not experience DNB during normal operation or anticipated operational occurrences (AOOs). Uncertainties in the values of process parameters, core operating parameters, and fuel design parameters are also treated with at least a 95% probability at a 95% confidence level.

The T/H analysis is based on the 16x16 HID-1L fuel design that has been used in St. Lucie Unit 2 core reloads. Table 4-1 illustrates a comparison between the previous T/H design parameters and the new T/H design parameters used in this analysis. A discussion of the T/H methodology and DNB ratio (DNBR) limits is provided in the subsequent sections.

4.2 METHODOLOGY

The T/H analysis of the 42% SGTP is based on the ABB-NV DNB correlation (Reference 2), the Revised Thermal Design Procedure (RTDP) (Reference 3), and the VIPRE-01 (VIPRE) code (References 4, 5 and 6). The W-3 correlation and the Standard Thermal Design Procedure (STDP) are used at the design conditions at which the ABB-NV DNB correlation and RTDP are not applicable. The STDP is the traditional design method with parameter uncertainties applied deterministically in the limiting direction.

4.2.1 ABB-NV DNB Correlation

The ABB-NV DNB correlation is based entirely on rod bundle data and reflects significant improvements in the accuracy of the critical heat flux predictions over previous DNB correlations for Combustion Engineering (CE) fuel designs. The Nuclear Regulatory Commission (NRC) has approved that a 95/95 correlation limit DNBR of 1.13 is appropriate for the CE 16x16 fuel assemblies (Reference 2). Furthermore, it has been shown that the ABB-NV 95/95 correlation limit DNBR of 1.13 remains valid with the VIPRE-01 (VIPRE) code (Reference 6).

4.2.2 Revised Thermal Design Procedure

The RTDP is a statistical DNB analysis method similar to the Extended Statistical Combination of Uncertainty (ESCU) (Reference 7) methodology. With the RTDP methodology, uncertainties in plant operating parameters, nuclear and thermal parameters, fuel fabrication parameters, computer codes, and DNB correlation predictions are combined statistically to obtain the overall DNB uncertainty factor. The same methodology was used for 30% SGTP. This factor is used for defining the design limit DNBR that satisfies the 95/95 DNB design criterion. Since the parameter uncertainties are considered in determining the RTDP

design limit, DNBR calculations in the plant safety analyses are performed using the parameter values without the uncertainties.

The parameter uncertainties considered in RTDP design limit DNBR are the same as those used previously in ESCU. The following uncertainties have been incorporated into the RTDP design limit:

- The nuclear enthalpy rise hot channel factor ($F^N{}_r$)
- The enthalpy rise engineering hot channel factor ($F^E{}_r$)
- Uncertainties in the VIPRE and transient codes
- Uncertainties in inlet flow distribution, cladding outside diameter, and rod pitch
- Uncertainties based on surveillance data associated with reactor coolant system (RCS) coolant flow, coolant temperature, pressure, and reactor core power.

4.2.3 VIPRE Code

VIPRE (Reference 4) is a subchannel code developed by the Battelle Northwest National Laboratories under the sponsorship of Electric Power Research Institute (EPRI). VIPRE was developed based on several versions of the COBRA code. Conservation equations of mass, axial and lateral momentum, and energy are solved for the fluid enthalpy, axial flow rate, lateral flow, and momentum pressure drop. Together with a DNB correlation, VIPRE is used for predicting DNBR margin in the reactor core under steady-state conditions and in non-LOCA transients.

Westinghouse has made additions and enhancements in its version of the VIPRE-01 code, including the installation of the ABB-NV DNB correlation. However, the code modifications do not alter the fundamental VIPRE computational methods and functional capabilities. Westinghouse VIPRE modeling and qualification for PWR non-LOCA T/H safety analysis are described in Reference 5.

4.3 DNBR LIMITS

Table 4-2 provides a listing of parameter uncertainties that are statistically convoluted with the ABB-NV correlation uncertainty in defining an RTDP design limit DNBR. A sensitivity factor for each parameter was determined through VIPRE calculations representing the change in DNBR corresponding to a change in the parameter. The RTDP DNBR limit calculations are illustrated in Table 4-3. In the DNB safety analyses, the design limit DNBR is conservatively increased to provide DNB margin to offset the effect of rod bow and any other DNB penalties that may occur, and to provide flexibility in design and operation of the plant. The increased DNBR is referred to as the safety analysis limit (SAL) DNBR as shown in Table 4-4, along with the plant-specific margin retained between the design limit and the SAL. It should be noted that the DNBR margin summaries are cycle dependent.

4.4 EFFECTS OF FUEL ROD BOW ON DNBR

The concerns about the fuel rod bow phenomenon are the potential effects on bundle power distribution and on the margin of fuel rods to DNB. Thus, the phenomenon of fuel rod bowing must be accounted for in the DNBR safety analysis of Condition I and Condition II events (i.e., normal operations and AOOs). The effects of fuel rod bowing on DNBR margin have been incorporated into the safety and setpoint analysis.

The rod bow penalty for the 42% SGTP remains unchanged from the current value of 1.2% DNBR as discussed in St. Lucie 2 Unit 2 UFSAR (Reference 1). The rod bow penalty is valid with the ABB-NV DNB correlation as discussed in Reference 2.

4.5 REFERENCES

1. "Updated Safety Analysis Report – St. Lucie 2 Nuclear Power Plant," Docket No. 50-389, through Amendment 16, February 2005.
2. CENPD-387-P-A Revision 0, "ABB Critical Heat Flux Correlations for PWR Fuel," May 2000.
3. Friedland, A. J. and Ray, S., "Revised Thermal Design Procedure," WCAP-11397-P-A, April 1989.
4. Stewart, C. W. et al., "VIPRE-01: A Thermal-Hydraulic Code for Reactor Cores," Volume 1-3 (Revision 3, August 1989), Volume 4 (April 1987), NP-2511-CCM-A, Electric Power Research Institute.
5. Sung, Y., et al., "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis," WCAP-14565-P-A (Proprietary), October 1999.
6. Sung, Y. et al., "Addendum 1 to WCAP-14565-P-A, Qualification of ABB Critical Heat Flux Correlations with VIPRE-01 Code," WCAP-14565-P-A, Addendum 1, August 2004.
7. CEN-348(B)-P-A-SUPPL1-P-A, "Extended Statistical Combination of Uncertainties," January 1997.

Table 4-1
Thermal-Hydraulic Design Parameters Comparison

Thermal-Hydraulic Design Parameters	30% SGTP	42% SGTP
Reactor Core Heat Output, MWt	2700	2404
Heat Generated in Fuel, %	97.5	97.5
RCS Pressure, psia	2250	2250
Integrated Radial Peaking Factor[1], F^N_r Part Power Multiplier[2]	1.70 (1 + 0.4*(1 – P))	1.72 (1 + 0.4*(0.89 – P))
Vessel Thermal Design Flow Rate (including bypass), gpm	335,000	300,000
Core Inlet Temperature, °F	549.0	547.1
Design Core Bypass Flow, % of Vessel Flow	3.7	3.7
Core Flow Area, ft^2	54.82	54.82

1. Excluding 6% measurement uncertainty.
2. P = (Thermal Power) / (Rated Thermal Power)

Table 4-2
RTDP Parameter Uncertainties

This proprietary table is provided under separate cover.

Table 4-3a
Calculation of RTDP DNBR Design Limit for Matrix Channel

This proprietary table is provided under separate cover.

Table 4-3b
Calculation of RTDP DNBR Design Limit for Side Thimble Channel

This proprietary table is provided under separate cover.

Table 4-3c
Calculation of RTDP DNBR Design Limit for Corner Thimble Channel

This proprietary table is provided under separate cover.

Table 4-4
DNBR Limits and Margin Summary

This proprietary table is provided under separate cover.

5 ACCIDENT ANALYSIS

5.1 NON-LOCA TRANSIENTS

The transient safety analyses discussed herein support an increase in SGTP from the current licensed plugging level of 30% to 42%, assuming a reduction in operating power to 89% RTP. Changes that are inherent to an increase in SGTP, such as reduced RCS flow, are addressed.

The non-LOCA events are analyzed with NRC approved codes and methods. The initial conditions associated with the 42% SGTP, including the associated steam pressure and reduced RCS flow, are within the range of conditions used in the Non-LOCA analyses performed by Westinghouse for other PWRs. The results of the transients were found to be consistent with expectations and consistent with the observed transient behavior for PWR safety analyses performed by Westinghouse.

The non-LOCA safety analyses presented in Section 5.1 address the increase in steam generator tube plugging from 30% to 42% peak (asymmetric plugging of 600 tubes (~ 7%), and a reduced reactor coolant system (RCS) flow rate of 300,000 gpm.

5.1.0 Non-LOCA Overview

5.1.0.1 Fuel Design Mechanical Features

The effects of fuel design mechanical features on the non-LOCA transient analyses are accounted for in fuel-related input assumptions, such as fuel and cladding dimensions, cladding material, fuel temperatures, and core bypass flow.

5.1.0.2 Peaking Factors, Kinetics Parameters

The power distribution is characterized by an enthalpy hot channel factor (radial peaking, F_r) of 1.72 (Revised Thermal Design Procedure, Reference 5.1.0-1) divided by 1.82 (non-RTDP) and a peak linear rate of 12.0 kw/ft for the 16x16 CE HID-1L fuel design with ZIRLO cladding. F_r is important for transients that are DNB limited (note that Table 5.1.0-2 identifies those events analyzed for DNB concerns as well as the DNB methodology used; RTDP or non-RTDP). Since F_r increases with decreasing power level due to rod insertion, all transients that may be DNB limited are assumed to begin with an F_r consistent with the F_r defined in the COLR for the maximum power level (89% RTP). Peak linear heat rate is important for transients that may be overpower limited. Peak linear heat rate may increase with decreasing power level such that the full power hot-spot heat flux is not exceeded. Consequently, all non-LOCA transients analyzed for the 42% SGTP program that may be overpower limited assume an initial hot full power peak linear heat rate of 12.0 kw/ft.

The analyses of events that are sensitive to minimum shutdown margin assumed to be 3600 pcm (Tavg greater than 200°F), consistent with the current St. Lucie Unit 2 COLR limits.

5.1.0.3 Plant Characteristics and Initial Conditions

Plant Design Conditions

Table 5.1.0-1 lists the Rated Thermal Power level (core) for St. Lucie Unit 2. It also presents the guaranteed Nuclear Steam Supply System (NSSS) thermal power output that includes the thermal power generated by the reactor coolant pumps. The values of the initial conditions used for each transient analyzed are given in Table 5.1.0-2, which support the proposed licensed core power of 2404 MWt associated with the 42% SGTP level. Table 5.1.0-3 presents a comparison of the proposed (42% SGTP) and licensed (30% SGTP) pertinent plant parameters used in the non-LOCA safety analyses.

Initial Conditions

For accidents that are DNB limited, the allowances on power, temperature, and pressure are determined on a statistical basis and included in the design limit DNBR, as described in WCAP-11397 (Reference 5.1.0-1). This procedure is known as the "Revised Thermal Design Procedure" (RTDP).

For accidents that are not DNB limited, or in which the RTDP is not employed, the initial conditions are obtained by applying the maximum steady-state errors. The following steady-state errors are considered:

1. Core power: calorimetric error is a function of analyzed power level (Figure 5.1.0-1)
2. Average RCS temperature: ± 3.0°F temperature measurement error
3. Pressurizer pressure: ± 45 psi steady-state fluctuations and pressure measurement error

Table 5.1.0-2 summarizes initial conditions and computer codes used in the accident analyses and shows which accidents employ RTDP.

Other Major Assumptions

Table 5.1.0-2 lists the non-LOCA initial condition assumptions used. The major assumptions considered in the 42% SGTP analyses are the same as those applied in the current licensing basis (30% SGTP), as follows:

1. The pressurizer safety valves (PSVs) are modeled assuming a ± 3-percent setpoint tolerance.
2. The Main Steam Safety Valves are modeled with different opening pressures for the two banks. The first bank of valves is modeled using a 3% tolerance and a 3% accumulation. A maximum tolerance of 1.0236 or 2.3% is modeled for the second bank of main steam safety valves.
3. The fission product contribution to decay heat assumed in the non-LOCA analyses bounds the American Nuclear Society (ANS)-5.1-1979 residual decay heat model, increased by two standard deviations for conservatism.

5.1.0.4 Thermal Margin/Low Pressure Reactor Trip Setpoints

The current thermal margin/low pressure (TM/LP) reactor trip function ensures that the DNB design basis is satisfied for the St. Lucie Unit 2 plant. It also precludes hot leg boiling to ensure that power can be calculated as a function of T_{cold} and ΔT. The TM/LP reactor trip is a function of the RCS temperature, the pressurizer pressure, the core power as measured by the excore detector or the ΔT and the axial power shape

as defined by the bottom detector signal minus the top detector signal divided by the total power (axial shape index or ASI). The TM/LP reactor trip is valid from the TM/LP floor (low pressurizer pressure trip) to the high pressurizer pressure trip (safety analysis values). The TM/LP is also limited by the locus of conditions defined by:

- the main steam safety valves which will limit an increase in the RCS temperature and
- the variable high power reactor trip function (safety analysis value), which limits the overpower condition.

The TM/LP is based on all of the reactor coolant pumps being in operation and accounts for changes in the axial power shape via the A_1 function, which adjusts the setpoint for variations in the axial power shape.

The current TM/LP reactor trip function, as presented in the St. Lucie Unit 2 Technical Specifications, is presented below.

$$Pvar = 1400 * QR_1 * A_1 + 17.85 * T_{cold} - 9410$$

Where the QR_1 function and the A_1 function are defined in the St. Lucie technical specifications.

The QR_1 function is a linear function which adjusts the TM/LP setpoint to account for the effects of an increase in the F_r at lower power levels. As noted above, the A_1 function adjusts the setpoint for variations in the axial power shapes.

The current TM/LP reactor trip setpoint described above was confirmed to be valid for the St. Lucie Unit 2 42% steam generator tube plugging conditions. The confirmation of the TM/LP reactor trip setpoint was based on the approach presented in the approved WCAP-8745 (Reference 5.1.0-2). The approach presented in WCAP-8745 ensures that the overtemperature ΔT reactor trip setpoint (which is similar in functionality to the TM/LP reactor trip function) protects the core thermal limits, which include the DNB core thermal limits and the hot leg boiling limits. The TM/LP setpoint with an A_1 function of 1.0 (that is, corresponding to an axial power shape with an ASI of 15%) was demonstrated to bound a conservative set of core thermal limits, based on a limiting reference axial power shape for an ASI of 15%. These core limits are applicable to the St. Lucie fuel and are based on a rated thermal power of 2700 MWt, an RCS flowrate of 311,400 gpm and a design F_r of 1.65[(1)], including allowed increases with reduced power level. The core thermal limits present a locus of conditions where the DNB design basis is satisfied and hot leg boiling is precluded and consider variations in the RCS inlet temperature with power and pressure. The relationship of the TM/LP setpoint with an A_1 of "1.0" (minimum value) corresponding to an ASI of 15% to the reference core thermal limits is illustrated in Figure 5.1.0-2. The locus of conditions for the TM/LP is obtained as a function of the inlet temperature and the pressurizer pressure. The area of permissible operation (power, temperature, and pressure) is bounded by the combination of the following.

- Variable high power reactor trip which is conservatively assumed to be 106% of rated thermal power.
- High pressurizer pressure reactor trip which is assumed to be 2415 psia.

(1) This corresponds to F_r of 1.72 at 89% RTP.

- TM/LP floor setpoint, which is assumed to be 1855 psia.
- The main steamline safety valves assuming a pressure corresponding to 110% of design pressure (1100 psia)

It should be noted that the TM/LP "protection lines" in Figure 5.1.0-2 are drawn to include the uncertainties as defined by the approved Extended Statistical Combination of Uncertainties methodology (see CEN-348 (B)-P-A). The uncertainties include processing uncertainties, system parameter uncertainties, ASI uncertainties and critical heat flux correlation uncertainties. These uncertainties, as defined by the extended statistical combination of uncertainties (ESCU) Penalty Factors, have been incorporated into the TM/LP "protection lines." Under nominal conditions, a reactor trip on the TM/LP reactor trip function would occur well within the area bounded by these lines. The figure shows that the safety analysis limit DNBR is bounded by the TM/LP protection lines, the variable high power protection lines, with uncertainties, and the steam generator safety valve lines.

In addition to confirming that the TM/LP reactor trip function protects the core thermal limits, it is necessary to ensure that the current A_1 function is adequately adjusting the TM/LP reactor trip setpoint for skewed axial power shapes. The approach for confirming the A_1 function is similar to the approach performed for the overtemperature ΔT (OTDT) $f(\Delta I)$ function, as discussed in WCAP-8745 and as was done for the 30% SGTP analysis. That is, a DNB analysis is performed on a large number of highly skewed axial power shapes, as generated via the RAOC methodology (Reference 5.1.0-10). A conservative penalty of T_{cold} versus ASI is generated based on this DNB analysis. This curve is used to adjust the core thermal limits for various ASI values. The resulting relationship is compared to the TM/LP A_1 function. The result is that for skewed axial power shapes, the TM/LP A_1 function continues to conservatively protect the locus of conditions corresponding to the safety analysis limit DNBR.

The TM/LP setpoint also includes margin to the core thermal limits, as defined by the gamma bias term, which is intended to account for the delays associated with fluid transport, instrumentation response time, protection system delays and delays associated with the time for the control rods to drop. This gamma bias term is used in the "steady-state" verification of the TM/LP since the dynamic compensation associated with the TM/LP reactor trip function is set to zero. The transient analysis of the Chapter 15 events, such as CEA Withdrawal at Power and RCS Depressurization, ensure that the gamma bias adequately accounts for the above-mentioned delays. This step is necessary as the confirmation of the TM/LP setpoint against the core thermal limits is a "steady-state" confirmation of the setpoint. The Chapter 15 analyses demonstrate that under transient conditions, the TM/LP reactor trip function with uncertainties provides protection such that the DNB design basis is satisfied and hot leg boiling is precluded.

Based on the above discussed evaluation, the current TM/LP reactor trip function has been confirmed to provide the necessary protection to ensure that the DNB design basis is satisfied and to ensure that hot leg boiling is precluded, thereby ensuring that power can be calculated as a function of T_{cold} and ΔT.

5.1.0.5 Reactor Protection System and Engineered Safety Features Evaluation Functions Assumed in Analyses

Limiting trip setpoints assumed in accident analyses and the time delay assumed for each trip function are given in Table 5.1.0-4. The total delay to trip is defined as the time delay from the time that the trip conditions are reached until the time the rods are released. There are various instrumentation delays

associated with each trip function including delays in signal actuation, in opening of the trip breakers, and in the release of the rods by the mechanisms. A reactor trip signal acts to open trip breakers that remove power to the control rod drive mechanisms. The loss of power to the mechanism coils causes the release of the control element assemblies (CEAs), which then fall by gravity into the core.

The difference between the limiting trip point assumed for the analysis and the nominal trip point represents an allowance for instrumentation channel error and setpoint error. Nominal trip setpoints are specified in the plant technical specifications. Additionally, protection system channels are calibrated and instrument response times determined periodically in accordance with the plant technical specifications.

5.1.0.6 CEA Reactivity Characteristics

The negative reactivity insertion following a reactor trip is a function of the position versus time of the CEAs and the variation in rod worth as a function of rod position. The CEA position versus time assumed in accident analyses is shown in Figure 5.1.0-3. Following a 0.74 second breaker opening delay, a CEA insertion time of 2.66 seconds is assumed in the safety analyses unless otherwise noted in the discussion of a specific event. The insertion times are specified in the plant technical specifications.

Figure 5.1.0-4 shows the fraction of total negative reactivity insertion versus normalized rod position for a core that the axial distribution is skewed to the lower region of the core. This curve is used to compute the negative reactivity insertion versus time following a reactor trip which is input to the point kinetics core model used in the transient analyses. The bottom skewed power distribution itself is not an input into the point kinetics core model. There is inherent conservatism in the use of Figure 5.1.0-4 in that it is based on a skewed flux distribution which would exist relatively infrequently.

A total negative reactivity insertion of 5.4 percent Δk following reactor trip is assumed in the transient analyses except where specifically noted otherwise. This assumption is conservative with respect to the calculated trip reactivity worth available. Figure 5.1.0-3 shows the normalized CEA drop time characteristics. The safety analyses assume a drop time of 2.66 seconds. Figures 5.1.0-3 and 5.1.0-4 are used to define a conservative trip reactivity versus time relationship in those transient analyses for which a point kinetics core model is used.

In the CEA Ejection and CEA Withdrawal from a Subcritical or Low Power Condition analyses, which use the TWINKLE code, a one-dimensional axial core model is employed where the negative reactivity insertion resulting from the reactor trip is calculated directly by the reactor kinetics code and is not separable from the other reactivity feedback effects.

5.1.0.7 Reactivity Coefficients

The transient response of the reactor system is dependent on reactivity feedback effects, and in particular the moderator temperature coefficient (MTC) and the Doppler power coefficient. The values used in the analysis of each event are given in Table 5.1.0-2.

In the analysis of the non-LOCA events, either the maximum reactivity feedback values or the minimum reactivity feedback values are assumed for conservatism. Figure 5.1.0-5 shows the upper and lower bound Doppler power coefficients as a function of power, used in the accident analysis. Figure 5.1.0-6 shows the

maximum moderator temperature coefficient as a function of power level. The justification for use of maximum versus minimum reactivity feedback coefficient values is treated on an event-by-event basis. In some cases conservative combinations of parameters are used for a given transient to bound the effects of core life, although these may represent unrealistic combinations.

5.1.0.8 Computer Codes Utilized

Summaries of the principal computer codes used in the transient analyses are given below. The codes used in the analyses of each non-LOCA transient have been listed in Table 5.1.0-2. The same codes were used for the 30% SGTP analyses.

FACTRAN

The FACTRAN program calculates the transient temperature distribution in a cross section of a metal clad UO_2 fuel rod and the transient heat flux at the surface of the cladding using as input the nuclear power and the time-dependent coolant parameters (pressure, flow, temperature, and density). The code uses a fuel model which exhibits the following features simultaneously:

- A sufficiently large number of radial space increments to handle fast transients, such as rod ejection accidents
- Material properties, which are functions of temperature and a sophisticated fuel-to-cladding gap heat transfer calculation
- The necessary calculations to handle post DNB transients: film boiling heat transfer correlations, Zircaloy-water reaction, and partial melting of the fuel

FACTRAN is further discussed in Reference 5.1.0-3.

RETRAN-02

RETRAN-02 ("RETRAN") is used for studies of transient response of a pressurized water reactor (PWR) system to specified perturbations in process parameters. This code simulates a multi-loop system which includes the reactor vessel, hot- and cold-leg piping, reactor coolant pumps, steam generators (tube and shell sides), steamlines, and the pressurizer. The pressurizer heaters, spray, relief valves, and safety valves are also modeled. RETRAN includes a point neutron kinetics model and reactivity effects of the moderator, fuel, boron, and control rods. The secondary side of the steam generator uses a detailed nodalization for the thermal transients. The reactor protection system (RPS) modeled with RETRAN includes reactor trips on variable high power, thermal margin/low pressure (TM/LP), low reactor coolant system (RCS) flow, high pressurizer pressure, low pressurizer pressure (TM/LP floor), low steam generator pressure, and low steam generator water level. Control systems are also simulated including rod control and pressurizer pressure control. Parts of the safety injection system (SIS), including the safety injection tanks, may also be modeled. RETRAN approximates the transient value of DNBR based on input from the core thermal limits.

The initial and transient conditions associated with the 42% SGTP analyses, including the associated steam pressure and reduced RCS flow, were found to be within the range of conditions used in the Non-LOCA analyses performed by Westinghouse for other PWRs. RETRAN is further discussed in References 5.1.0-4 and 5.1.0-5; its application to St. Lucie Unit 2 was approved in Reference 5.1.0-11.

TWINKLE

The TWINKLE program is a multi-dimensional spatial neutron kinetics code that was patterned after steady-state codes presently used for reactor core design. The code uses an implicit finite-difference method to solve the two-group transient neutron diffusion equations in one, two, and three dimensions. The code uses six delayed neutron groups and contains a detailed multi-region fuel-cladding-coolant heat transfer model for calculating point-wise Doppler and moderator feedback effects. The code handles up to 8000 spatial points and performs its own steady-state initialization. Aside from basic cross-section data and thermal-hydraulic parameters, the code accepts as input basic driving functions such as inlet temperature, pressure, flow, boron concentration, control rod motion, and other functions. Various edits are provided; e.g., channel-wise power, axial offset, enthalpy, volumetric surge, point-wise power, and fuel temperatures.

The TWINKLE code is used to predict the kinetic behavior of a reactor for transients that cause a major perturbation in the spatial neutron flux distribution.

TWINKLE is further described in Reference 5.1.0-6.

CESEC

The CESEC digital computer program provides for the simulation of a Combustion Engineering (CE) NSSS. The program can calculate the plant response for non-LOCA initiating events for a wide range of operating conditions.

The primary system components considered in the code include the reactor vessel, the reactor core, the primary coolant loops, the pressurizer, the steam generators, and the reactor coolant pumps. The secondary system components include the secondary side of the steam generators, the main steam system, the feedwater system, and the various steam control valves. In addition, the program models those plant control and protections systems needed to perform the safety analysis.

CESEC is further described in Reference 5.1.0-7.

VIPRE-W

VIPRE-W predicts the 3-D velocity, pressure, and thermal energy fields and fuel rod temperatures for single- and two-phase flow. It solves the finite difference equations for mass, energy, and momentum conservation for an interconnected array of channels, assuming an incompressible, thermally expandable homogeneous flow. The equations are solved with no time step or channel size restrictions for stability. Although the formulation is homogeneous, non-mechanistic models are included for subcooled boiling and vapor/liquid slip in two-phase flow.

Like most other core thermal-hydraulic codes, the VIPRE-W modeling structure is based on a subchannel analysis. The core or section of symmetry is defined as an array of parallel flow channels with lateral connections between adjacent channels. A channel may represent a true subchannel within a rod array, a closed tube, or a larger flow area representing several subchannels or rod bundles. The shape and size of the channels and their interconnections are essentially arbitrary. The user has a great deal of flexibility for modeling reactor cores or any other fluid flow geometry.

The VIPRE code has been updated to include the ABB-NV and ABB-TV critical heat flux correlations, Reference 5.1.0-8.

FATES3B

The FATES code calculates the radial and axial steady state temperature distribution through a single fuel rod using specified values of the rod linear heat rate and coolant flow rate. The effects of fission gas release, fuel swelling, densification and relocation, and clad creep are treated.

5.1.0.9 Classification of Events

The American Nuclear Society (ANS) classification of plant conditions divides plant conditions into four categories in accordance with anticipated frequency of occurrence and potential radiological consequences to the public (Reference 5.1.0-9). The four categories are used to define acceptance criteria and are defined as follows:

- Condition I: Normal operation and operational transients
- Condition II: Faults of moderate frequency
- Condition III: Infrequent faults
- Condition IV: Limiting faults

The basic principle applied in relating design requirements to each of the conditions listed above is that the most probable occurrences should yield the least radiological risk to the public and those extreme situations having the potential for the greatest risk to the public shall be those least likely to occur. Functioning of the reactor trip system and engineered safeguards is assumed to the extent allowed by considerations, such as the single failure criterion, in fulfilling this principle.

5.1.0.9.1 Condition I – Normal Operation and Operational Transients

Condition I occurrences are those that are expected frequently or regularly in the course of normal plant operation, refueling, and maintenance. As such, Condition I occurrences are accommodated with margin between any plant parameter and the value of that parameter that would require either automatic or manual protective action. Inasmuch as Condition I occurrences occur frequently or regularly, they must be considered from the point of view of affecting the consequences of fault conditions (Conditions II, III, and IV). In this regard, analysis of each fault condition described is generally based on a conservative set of initial conditions corresponding to adverse conditions which can occur during Condition I operation.

A typical list of Condition I events is given below:

A. Steady-state and shutdown operations

1. Power operation ($K_{eff} \geq 0.99$, > 5 percent of rated thermal power, $T_{avg} \geq 325°F$)
2. Startup ($K_{eff} \geq 0.99$, ≤ 5 percent of rated thermal power, $T_{avg} \geq 325°F$)
3. Hot standby ($K_{eff} < 0.99$, $T_{avg} \geq 325°F$, shut down cooling (SDC) system isolated)
4. Hot shutdown ($K_{eff} < 0.99$, $325°F > T_{avg} > 200°F$, SDC system in operation)

5. Cold shutdown ($K_{eff} < 0.99$, $T_{avg} \leq 200°F$, SDC system in operation)
6. Refueling ($K_{eff} < 0.95$, $T_{avg} \leq 140°F$, SDC system in operation)

B. Operation with permissible deviations

Various deviations that may occur during continued operation as permitted by the plant technical specifications are considered in conjunction with other operational modes. These include:

1. Operation with components or systems out of service
2. Leakage from fuel with cladding defects
3. Radioactivity in the reactor coolant
   a. Fission products
   b. Corrosion products
   c. Tritium
4. Operation with steam generator leaks up to the maximum allowed by the technical specifications
5. Testing as allowed by the technical specifications

C. Operational transients

1. Plant heatup and cooldown (up to 100°F/hr heatup for the RCS; 200°F/hr cooldown for the pressurizer)
2. Step load changes (up to ± 10 percent)
3. Ramp load changes (up to 5 percent/min)
4. Load rejection up to and including the design load rejection transient

5.1.0.9.2 Condition II - Faults of Moderate Frequency

ANS Condition II occurrences are faults that may occur with moderate frequency during the life of the plant. They are accommodated with, at most, a reactor shutdown with the plant being capable of returning to operation after a corrective action. In addition, no ANS Condition II occurrence shall cause consequential loss of function of fuel cladding and reactor coolant system barriers.

Criteria established for Condition II events include the following:

- Condition II incidents shall be accommodated with, at most, a shutdown of the reactor with the plant capable of returning to operation after corrective action.
- A single Condition II incident shall not cause consequential loss of the function of any barrier to the escape of radioactive products.
- For a Condition II event, any release of radioactive materials in effluents to unrestricted areas shall be in conformance with the Code of Federal Regulations (CFR) Paragraph 20.1 of 10 CFR Part 20, "Standards for Protection Against Radiation."

- By itself, a Condition II incident cannot generate a more serious incident of the Condition III or IV classification without other incidents occurring independently.

The following faults are included in this category:

A. Feedwater system malfunction causing a reduction in feedwater temperature

B. Feedwater system malfunction causing an increase in feedwater flow

C. Excessive increase in secondary steam flow

D. Inadvertent opening of a steam generator relief or safety valve

E. Loss of external load

F. Turbine trip

H. Loss of condenser vacuum and other events resulting in turbine trip

G. Inadvertent closure of main steam isolation valves (boiling water reactor (BWR) event)

I. Steam pressure regulator failure

J. Loss of non-emergency AC power to the station auxiliaries

K. Loss of normal feedwater flow

L. Transients resulting from the malfunction of one steam generator

M. Partial loss of forced reactor coolant flow

N. Uncontrolled CEA bank withdrawal from a subcritical or low-power startup condition

O. Uncontrolled CEA bank withdrawal at power

P. CEA misoperation - dropped assembly, dropped assembly bank, or statically misaligned CEA

Q. Startup of an inactive reactor coolant loop at an incorrect temperature

R. Chemical and volume control system (CVCS) malfunction resulting in a decrease in boron concentration in the reactor coolant

S. Inadvertent operation of emergency core cooling system (ECCS) during power operation

T. CVCS malfunction that increases reactor coolant inventory

U. Inadvertent opening of a pressurizer safety or relief valve

V. Failure of small lines carrying primary coolant outside containment

5.1.0.9.3 Condition III - Infrequent Faults

ANS Condition III occurrences are faults that may occur very infrequently during the life of the plant. They may be accompanied by the failure of only a small fraction of the fuel rods although sufficient fuel damage might occur to preclude resumption of the operation for a considerable outage time. The release of radioactivity will not be sufficient to interrupt or restrict public use of those areas beyond the exclusion radius. An ANS Condition III occurrence will not, by itself, generate an ANS Condition IV fault or result in a consequential loss of function of the RCS or containment barriers.

Criteria established for Condition III events include the following:

- Condition III incidents shall not cause more than a small fraction of the fuel elements in the reactor to be damaged, although sufficient fuel element damage might occur to preclude resumption of operation for a considerable outage time.
- A Condition III incident shall not, by itself, result in a consequential loss of function of the RCS or reactor containment barriers.
- A Condition III incident shall not, by itself, generate a Condition IV fault.

The release of radioactive material due to Condition III incidents may exceed the guidelines of 10 CFR Part 20, "Standards for Protection Against Radiation", but shall not be sufficient to interrupt or restrict public use of those areas beyond the exclusion radius. This is typically interpreted as a small fraction of the 10 CFR Part 100 guidelines.

The following faults are included in this category:

A. Minor steam system piping failures

B. Complete loss of forced reactor coolant flow

C. CEA misoperation - single CEA withdrawal at power

D. Inadvertent loading and operation of a fuel assembly in an improper position

E. Loss of reactor coolant from small ruptured pipes or from cracks in large pipes which actuates the ECCS

F. Waste gas system failure

G. Radioactive liquid waste system leak or failure (atmospheric release)

H. Postulated radioactive releases due to liquid containing tank failure

I. Spent fuel cask drop accidents

5.1.0.9.4 Condition IV - Limiting Faults

ANS Condition IV occurrences are faults that are not expected to take place, but are postulated because their consequences would include the potential for the release of significant amounts of radioactive material. These are the most drastic occurrences that must be designed against and represent limiting design cases.

- Criteria established for Condition IV events include the following:
- Condition IV faults shall not cause a release of radioactive material that results in an undue risk to public health and safety exceeding the guidelines of 10 CFR 100, "Reactor Site Criteria."

A single Condition IV fault shall not cause a consequential loss of required functions of systems needed to cope with the fault, including those of the reactor coolant system (RCS) and the reactor containment system.

The following faults have been classified in this category:

A. Major steam system piping failure

B. Feedwater system pipe break

C. Reactor coolant pump rotor seizure (locked rotor)

D. Reactor coolant pump shaft break

E. Spectrum of CEA ejection accidents

F. Steam generator tube rupture

G. LOCAs resulting from the spectrum of postulated piping breaks within the reactor coolant pressure boundary

H. Design basis fuel handling accident

5.1.0.10 References

5.1.0-1 Friedland, A. J and Ray, S., "Revised Thermal Design Procedure," WCAP-11397-P-A and WCAP-11397-A, April 1989.

5.1.0-2 WCAP-8745, "Design Bases for the Thermal Overpower ΔT and Thermal Overtemperature ΔT Trip functions," Approved September 1986.

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5.1.0-4 McFadden, J. H., et al., "RETRAN-02 - A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems," EPRI NP-1850-CCMA.

5.1.0-5 Huegel, D. S., et al., "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," WCAP-14882-P-A, April 1999.

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5.1.0-7 Letter, A. E. Scherer, Enclosure 1-P to LD-82-001, "CESEC - Digital Simulation of a Combustion Engineering Nuclear Steam Supply System," December 1981.

5.1.0-8 Sung, Y. X., et al., "Addendum 1 to WCAP-14565-P-A Qualification of ABB Critical Heat Flux Correlations with VIPRE-01 Code," WCAP-14565, Addendum 1 (Proprietary), June 2002.

5.1.0-9 ANSI/ANS N18.2-1973, "American National Standard for the Design or Stationary Pressurized Water Reactor Plants."

5.1.0-10 Miller, R. W., et al., "WCAP-10216-P-A, "Relaxation of Constant Axial Offset Control; FQ Surveillance Technical Specification," February 1994.

5.1.0-11 Letter, B. Moroney (NRC) to J. A. Stall (FPL), "St Lucie Plant, Unit No. 2 – Issuance of Amendment Regarding Change in Reload Methodology and Increase in Steam Generator Tube Plugging Limit (TAC No. MC1566), January 31, 2005. [Amendment 138]

Table 5.1.0-1
Nuclear Steam Supply System Power Ratings*

Rated Reactor Core Thermal Power Output, MWt	2700
NSSS Rated Thermal Power, MWt	2714.2
Thermal Power Generated by the Reactor Coolant Pumps, MWt	
Nominal (total, 4 pumps in operation)	14.2
Maximum (total, 4 pumps in operation)	20
* Table 5.1.0-2 provides the specific core power value used in non-LOCA analyses.	

Table 5.1.0-2 (Sheet 1 of 6)
Summary of Initial Conditions and Computer Codes

	Event	Computer Codes Used	Moderator Density Coefficient (Δk/gm/cc)	Moderator Temperature Coefficient (pcm/°F)	Doppler Feedback	DNB Correlation	Revised Thermal Design Procedure	Initial Core (Note 2) Thermal Power (MWt)
Increase in Heat Removal by the Secondary System								
	Decrease in Feedwater Temperature	RETRAN	0.43	N/A	Upper Curve of Figure 5.1.0-5	ABB-NV	Yes	2404
	Increase in Feedwater Flow Rate	RETRAN	0.43	N/A	Upper Curve of Figure 5.1.0-5	ABB-NV	Yes	2404
	Excessive Increase in Main Steam Flow	Bounded by 5.1.6 and 5.1.5	N/A	N/A	N/A	N/A	N/A	N/A
	Inadvertent Opening of an SG Relief or Safety Valve	Bounded by 5.1.6 and 5.1.5	N/A	N/A	N/A	N/A	N/A	N/A
	Pre-Trip Steamline Break with FFBT	RETRAN VIPRE, ANC	0.0 to 0.43	N/A	Upper Curve of Figure 5.1.0-5	ABB-NV	Yes	2404
	Pre-Trip Steamline Break Coincident with LOOP	RETRAN VIPRE	N/A	See Figure 5.1.0-6	Lower Curve of Figure 5.1.0-5	ABB-NV	Yes	2404
	Post-Trip Steamline Break	RETRAN VIPRE, ANC	See Figure 5.1.6-1	N/A	See Figure 5.1.6-2	W-3	No	0 (subcritical)
Decrease in Heat Removal by the Secondary System								
	Loss of Condenser Vacuum – Overpressure Case	RETRAN	N/A	See Figure 5.1.0-6	Upper Curve of Figure 5.1.0-5	N/A	No	2458
	Loss of Condenser Vacuum – DNB Case	RETRAN VIPRE	N/A	See Figure 5.1.0-6	Upper Curve of Figure 5.1.0-5	ABB-NV	Yes	2404
	Loss of Non-Emergency AC to the Station Auxiliaries	Bounded by 5.1.10 and 5.1.14	N/A	N/A	N/A	N/A	N/A	N/A
	Loss of Normal Feedwater Flow	Bounded by 5.1.10 and 5.1.14	N/A	N/A	N/A	N/A	N/A	N/A
	Feedwater System Pipe Rupture – RCS Overpressure Case	RETRAN	N/A	See Figure 5.1.0-6	Upper Curve of Figure 5.1.0-5	N/A	No	2458
	Feedwater System Pipe Rupture – MSS Overpressure Case	RETRAN	N/A	See Figure 5.1.0-6	Upper Curve of Figure 5.1.0-5	N/A	No	2458
	Asymmetric Steam Generator Transient	RETRAN VIPRE, ANC	N/A	See Figure 5.1.0-6	Upper Curve of Figure 5.1.0-5	ABB-NV	Yes	2404

Table 5.1.0-2 (Sheet 2 of 6)
Summary of Initial Conditions and Computer Codes

	Event	Reactor Coolant Pump Heat (MWt)	Reactor Vessel(2) Flow Rate (gpm)	Vessel T-avg(2) (°F)	Pressurizer Pressure (psia)	Pressurizer Water Level (%)	Feedwater Temp.(2) (°F)	SG Tube Plugging Level (%)
Increase in Heat Removal by the Secondary System								
	Decrease in Feedwater Temperature	14.2	311,400	574.5	2225	63.0	420.8	0.0
	Increase in Feedwater Flow Rate	14.2	311,400	574.5	2225	63.0	420.8	0.0
	Excessive Increase in Main Steam Flow	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Inadvertent Opening of an SG relief or Safety Valve	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Pre-Trip Steamline Break with FFBT	14.2	311,400	574.5	2225	63.0	420.8	0.0
	Pre-Trip Steamline Break Coincident with LOOP	14.2	300,000	574.5	2225	63.0	420.8	42
	Post-Trip Steamline Break	0.0	300,000	532.0	2250	33.1	240	0.0
Decrease in Heat Removal by the Secondary System								
	Loss of Condenser Vacuum – Overpressure Case	14.2	300,000	570.4	2180	65.0	420.8	42
	Loss of Condenser Vacuum – DNB Case	14.2	311,400	574.5	2225	65.0	420.8	42
	Loss of Non-Emergency AC to the Station Auxiliaries	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Loss of Normal Feedwater Flow	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Feedwater System Pipe Rupture – RCS Overpressure Case	14.2	300,000	570.4	2180	70.0	420.8	42
	Feedwater System Pipe Rupture – MSS Overpressure	14.2	300,000	577.5	2180	70.0	420.8	0.0
	Asymmetric Steam Generator Transient	14.2	311,400	574.5	2225	70.0 (65.0)(Note 3)	420.8	42

Table 5.1.0-2 (Sheet 3 of 6)
Summary of Initial Conditions and Computer Codes

	Event	Computer Codes Used	Moderator Density Coefficient (Δk/gm/cc)	Moderator Temperature Coefficient (pcm/°F)	Doppler Feedback	DNB Correlation	Revised Thermal Design Procedure	Initial Core(2) Thermal Power (MWt)
Decrease in RCS Flow Rate								
	Partial/Complete Loss of Forced Flow	RETRAN VIPRE	N/A	See Figure 5.1.0-6	Lower Curve of Figure 5.1.0-5	ABB-NV	Yes	2404
	Reactor Coolant Pump Seized Rotor/Shaft Break – DNB Case	RETRAN VIPRE	N/A	See Figure 5.1.0-6	Lower Curve of Figure 5.1.0-5	ABB-NV	Yes	2404
	Reactor Coolant Pump Seized Rotor/Shaft Break – Overpressure/PCT Case	RETRAN	N/A	See Figure 5.1.0-6	Lower Curve of Figure 5.1.0-5	N/A	No	2458
Reactivity and Power Distribution Anomalies								
	Uncontrolled CEA Bank Withdrawal from Subcritical	TWINKLE FACTRAN VIPRE	N/A	5.0	900 pcm	ABB-NV	No	0.0 (subcritical)
	Uncontrolled CEA Bank Withdrawal at Power	RETRAN	0.43	See Figure 5.1.0-6	Upper & Lower Curve of Figure 5.1.0-5	ABB-NV	Yes	2404
	CEA Misoperation (Dropped Rod)	Evaluated	N/A	N/A	N/A	N/A	N/A	N/A
	Startup of an Inactive Loop at an Incorrect Temperature	Precluded by Technical Specifications	N/A	N/A	N/A	N/A	N/A	N/A
	CEA Ejection	TWINKLE FACTRAN	N/A	See Note 1	900 pcm	N/A	No	0.0 & 2754

Table 5.1.0-2 (Sheet 4 of 6)
Summary of Initial Conditions and Computer Codes

	Event	Reactor Coolant Pump Heat (MWt)	Reactor Vessel(2) Flow Rate (gpm)	Vessel T-avg(2) (°F)	Pressurizer Pressure (psia)	Pressurizer Water Level (%)	Feedwater Temp.(2) (°F)	SG Tube Plugging Level (%)
Decrease in RCS Flow Rate								
	Partial/Complete Loss of Forced Flow	14.2	300,000	574.5	2225	63.0	420.8	42
	Reactor Coolant Pump Seized Rotor/Shaft Break – DNB Case	14.2	300,000	574.5	2225	63.0	420.8	42
	Reactor Coolant Pump Seized Rotor/Shaft Break – Overpressure/PCT Case	14.2	300,000	577.5	2395	63.0	420.8	42
Reactivity and Power Distribution Anomalies								
	Uncontrolled CEA Bank Withdrawal from Subcritical	N/A	300,000	532.0	2180	N/A	N/A	N/A
	Uncontrolled CEA Bank Withdrawal at Power	14.2	311,400	574.5	2225	63.0	420.8	42
	CEA Misoperation (Dropped Rod)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Startup of an Inactive Loop at an Incorrect Temperature	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	CEA Ejection	N/A	300,000	532.0 582.7	2205.0	N/A	N/A	N/A

Table 5.1.0-2 (Sheet 5 of 6)
Summary of Initial Conditions and Computer Codes

	Event	Computer Codes Used	Moderator Density Coefficient (Δk/gm/cc)	Moderator Temperature Coefficient (pcm/°F)	Doppler Feedback	DNB Correlation	Revised Thermal Design Procedure	Initial Core(2) Thermal Power (MWt)
Increase in Coolant Inventory								
	Inadvertent ECCS Operation at Power	Precluded by SIS Design	N/A	N/A	N/A	N/A	N/A	N/A
	CVCS Malfunction	RETRAN	0.43	N/A	Lower Curve of Figure 5.1.0-5	N/A	No	2458
Decrease in Coolant Inventory								
	Inadvertent RCS Depressurization	RETRAN	N/A	See Figure 5.1.0-6	Upper Curve of Figure 5.1.0-5	ABB-NV	Yes	2404
	Steam Generator Tube Rupture	CESEC	N/A	N/A	N/A	N/A	No	2458
	LOCAs	Section 5.2	Section 5.2	Section 5.2	Section 5.2	Section 5.2	Section 5.2	Section 5.2
	Primary Line Break Outside Containment	CESEC	N/A	N/A	N/A	N/A	No	2754

Table 5.1.0-2 (Sheet 6 of 6)
Summary of Initial Conditions and Computer Codes

Event	Reactor Coolant Pump Heat (MWt)	Reactor Vessel[2] Flow Rate (gpm)	Vessel T-avg[2] (°F)	Pressurizer Pressure (psia)	Pressurizer Water Level (%)	Feedwater Temp.[2] (°F)	SG Tube Plugging Level (%)
Increase in Coolant Inventory							
Inadvertent ECCS Operation at Power	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CVCS Malfunction	20.0	300,000	577.5	2180	61.0	420.8	42
Decrease in Coolant Inventory							
Inadvertent RCS Depressurization	14.2	311,400	574.5	2225	63.0	420.8	42
Steam Generator Tube Rupture	20.0	300,000	Tcold = 550.1	2395 (2400)[3]	70.0	420.8	42
LOCAs	Section 5.2	Section 5.2	Section 5.2	Section 5.2	Section 5.2	Section 5.2	Section 5.2
Primary Line Break Outside Containment	20.0	>300,000	Tcold < 554	<2410	N/A	N/A	<42

NOTES:
1. The following moderator temperature coefficient (MTC) values were assumed in the analysis of the CEA Ejection event:
   Beginning of life (BOL), hot zero power (HZP) MTC = 5.0 pcm/°F
   BOL, hot full power (HFP) MTC = 0.0 pcm/°F
   End of life (EOL), HZP ITC = -5.0 pcm/°F
   EOL, HFP ITC = -15.0 pcm/°F
2. Parameter values are modified from the 30% SGTP analysis to account for changes in core power, minimum RCS flow rate, T_{cold} range and feedwater temperature corresponding to 89% rated thermal power.
3. Parameter values provided in parenthesis are for 30% SGTP analysis.

Table 5.1.0-3
Nominal Values of Pertinent Plant Parameters Utilized in Accident Analyses

Equivalent Steam Generator Tube Plugging Level (all loops)	0% Hi-T_{avg}	30% Hi-T_{avg}	0% Lo-T_{avg}	30% Lo-T_{avg}	Hi-T_{avg}[3]	
					0%	42%
NSSS Thermal Power (MWt)[1]	2720	2720	2720	2720	2424	2424
Reactor Core Power (MWt)	2700	2700	2700	2700	2404	2404
HFP core inlet temperature (°F)	549.0	549.0	535.0	535.0	547.1	547.1
HFP vessel average temperature (°F)	576.5	576.5	563.0	563.0	574.5	574.5
Zero Load Temperature (°F)	532.0	532.0	532.0	532.0	532.0	532.0
Pressurizer Pressure (psia)	2250	2250	2250	2250	2250	2250
Total Reactor Vessel Inlet Flow (thermal design, gpm)[2]	335,000	335,000	335,000	335,000	300,000	300,000
Total Reactor Coolant Flow (10^6 lb/hr)	126.1	126.1	128.4	128.4	113.3	113.3
Steam Flow from NSSS (10^6 lb/hr)	11.87	11.83	11.82	11.79	10.34	10.32
Steam Pressure at Steam Generator Outlet (psia)	857	766	755	672	870	732
Maximum Steam Moisture Content (%)	0.25	0.25	0.25	0.25	0.25	0.25
Assumed Feedwater Temperature at Steam Generator Inlet (°F)	435	435	435	435	420.8	420.8

Notes:
1. Includes maximum reactor coolant pump heat (20 MWt). Nominal pump heat is 14.2 MWt.
2. Minimum measured flow is 341,400 gpm for 30% SGTP, minimum measured flow is 311,400 gpm for 42% SGTP.
3. A low T_{avg} corresponding to 573.4°F was considered in those analyses where it is conservative.

Table 5.1.0-4 (Sheet 1 of 2)
Safety Analysis RPS and ESFAS Trip Setpoints and Delay Times

RPS Trip Function	Technical Specification Value	Analysis Setpoint
Variable Power Level – High (% Above Initial Power Level)	9.61	10.2
Variable Power Level – Ceiling (% Rated Thermal Power)	107	102.0[(1)]
Variable Power Level – Floor (% Rated Thermal Power)	15	23.0
Pressurizer Pressure – High (psia) Normal Environment Harsh Environment[(2)]	2370	 2415 2460
Pressurizer Pressure – Low (Floor of Thermal Margin/Low Pressure), (psia) Normal Environment Harsh Environment[(2)]	1900	 1855 1810
Steam Generator Pressure – Low (psia) Normal Environment Harsh Environment[(2)]	626	 586 546
Steam Generator Pressure – High Difference, (psid)	120	230
Steam Generator Level – Low (% Narrow Range Tap Span)	20.5	1.0
Reactor Coolant Flow – Low (% of Design Flow ΔP)	N/A	85.7752[(3)] 80.3083 (SLB)[(4)]
Thermal Margin/Low Pressure (psig)	Tech. Spec. Table 2.2-1	Variable, See Figure 5.1.0-2
Engineered Safety Feature Actuation System (ESFAS) Function		
Safety Injection Actuation Signal (SIAS) on Pressurizer Pressure – Low (psia) Normal Environment Harsh Environment[(2)]	1736	 1646 1691
Main Steamline Isolation Signal (MSIS) on Steam Generator Pressure – Low (psia) Normal Environment Harsh Environment[(2)]	600	 560 520
Main Feedwater Isolation on Steam Generator Pressure – Low (psia) Normal Environment Harsh Environment[(2)]	600	 560 520
Auxiliary Feedwater Isolation on Steam Generator Pressure Difference – High (psid)	275	360

Notes:
1. Rod shadowing and downcomer temperature decalibration effects on excore detector signals are applied independently.
2. Harsh environment setpoints apply to inside containment steamline and feedwater line breaks.
3. Setpoint is equivalent to 91.9% of nominal flow for a single loop loss-of-flow event.
4. Setpoint is equivalent to 87.9% of nominal flow for steamline break event with adverse environment.

Table 5.1.0-4 (Sheet 2 of 2) Safety Analysis RPS and ESFAS Trip Setpoints and Delay Times			
RPS Trip Function	**Sensor Response Time Constant (sec)**	**Processing Delay (sec)**	**Total Delay Time (sec)**
Variable High Power		0.4	
Excore Neutron Power detectors	<0.01[5]		0.4
Hot-Leg and Cold-Leg RTDs (Thermal power calculation)	8.0		8.4
Pressurizer Pressure – High	0.75	0.4	1.15
Thermal Margin/Low Pressure		0.4	
Pressurizer Pressure	0.75		1.15
Hot-Leg and Cold-Leg RTDs (Thermal power calculation)	8.0		8.4
Excore Neutron Power detectors (ASI calculation)	N/A		-
Steam Generator Pressure – Low	0.75	0.4	1.15
Steam Generator Pressure – High Difference	0.75	0.4	1.15
Steam Generator Level – Low	0.75	0.4	1.15
Reactor Coolant Flow – Low	0.25	0.4	0.65
ESFAS Function			**Total Delay Time (sec)**
Pressurizer Pressure – Low (SI) → To achieve full SI flowrate			30.0
Steam Generator Pressure – Low → To complete MSIV closure			6.75
Steam Generator Pressure – Low → To complete MFIV closure			5.15
Auxiliary Feedwater Isolation On Steam Generator Pressure Difference – High → To complete auxiliary feedwater isolation to affected SG			120

Notes (cont'd):
5. Typical response time is 50 μ seconds.

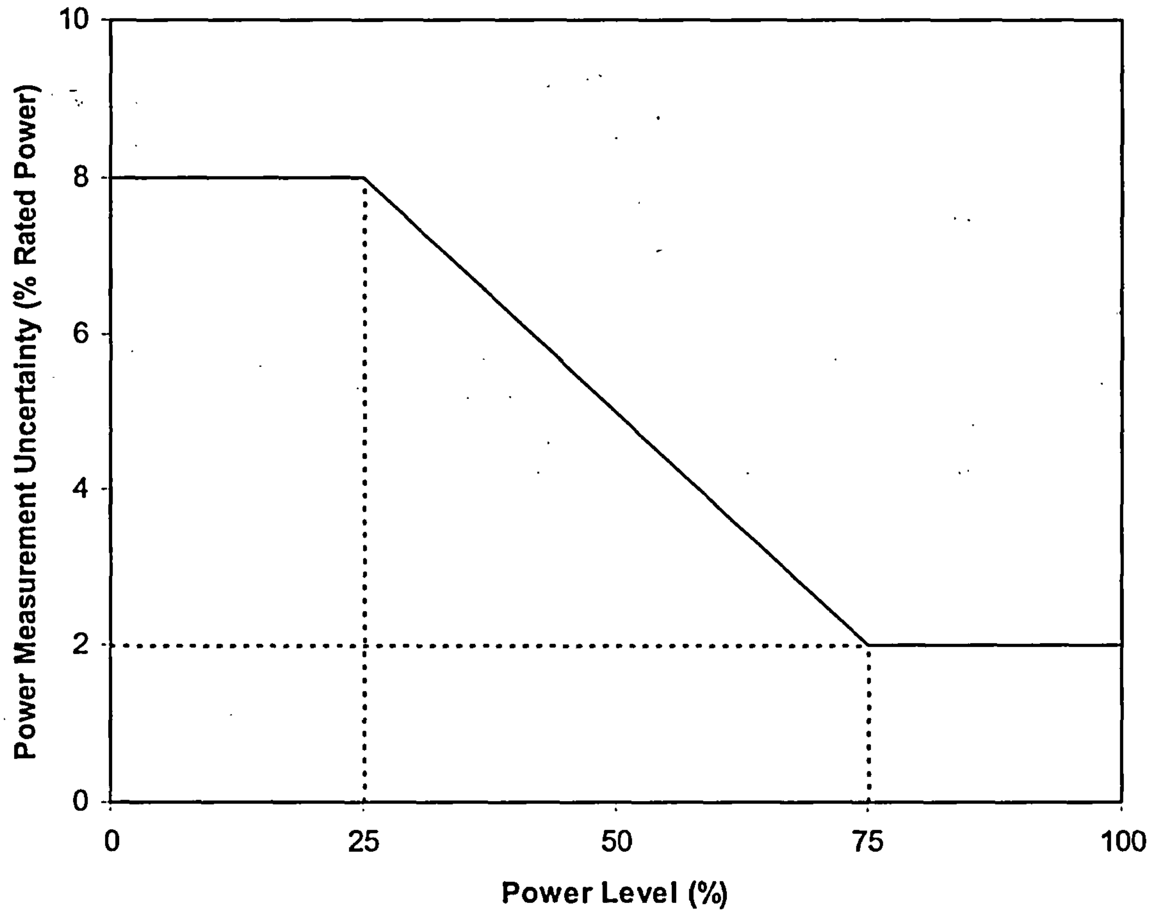

Figure 5.1.0-1
Power Measurement Uncertainty Used in Accident Analysis

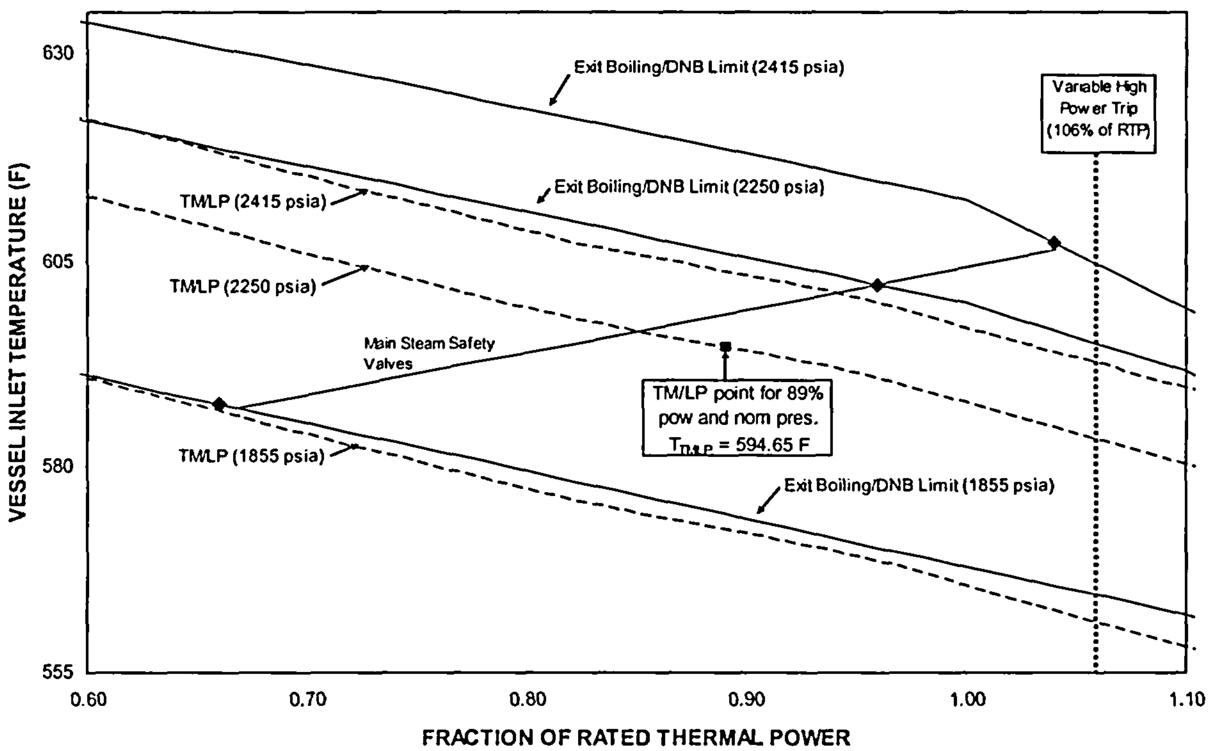

Figure 5.1.0-2
Illustration of the Thermal Margin / Low Pressure Reactor Trip Function and the Core Thermal Limits

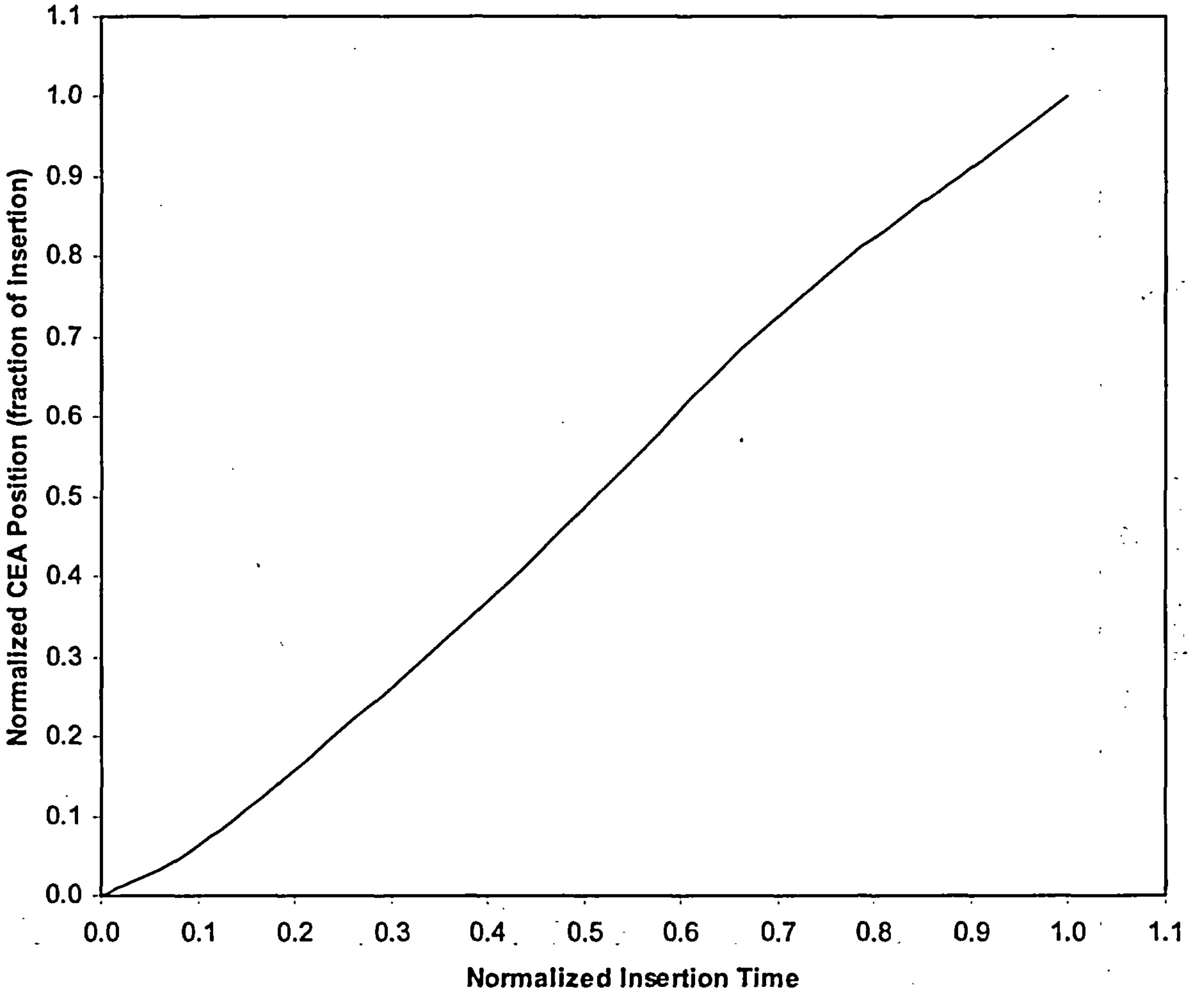

Figure 5.1.0-3
Normalized CEA Position vs. Time following CEA Release from Reactor Trip

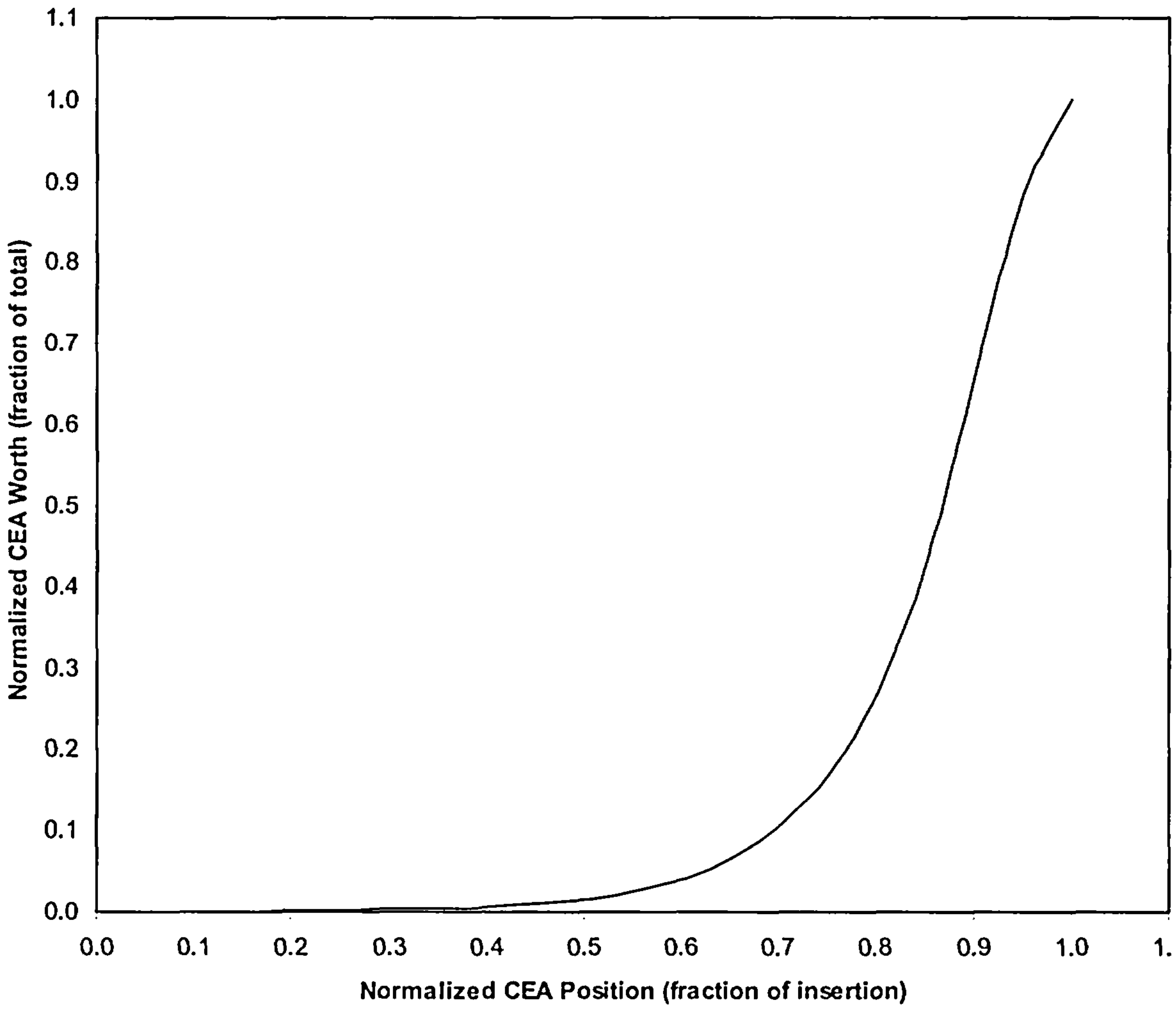

Figure 5.1.0-4
Normalized CEA Worth vs. Position following CEA Release from Reactor Trip

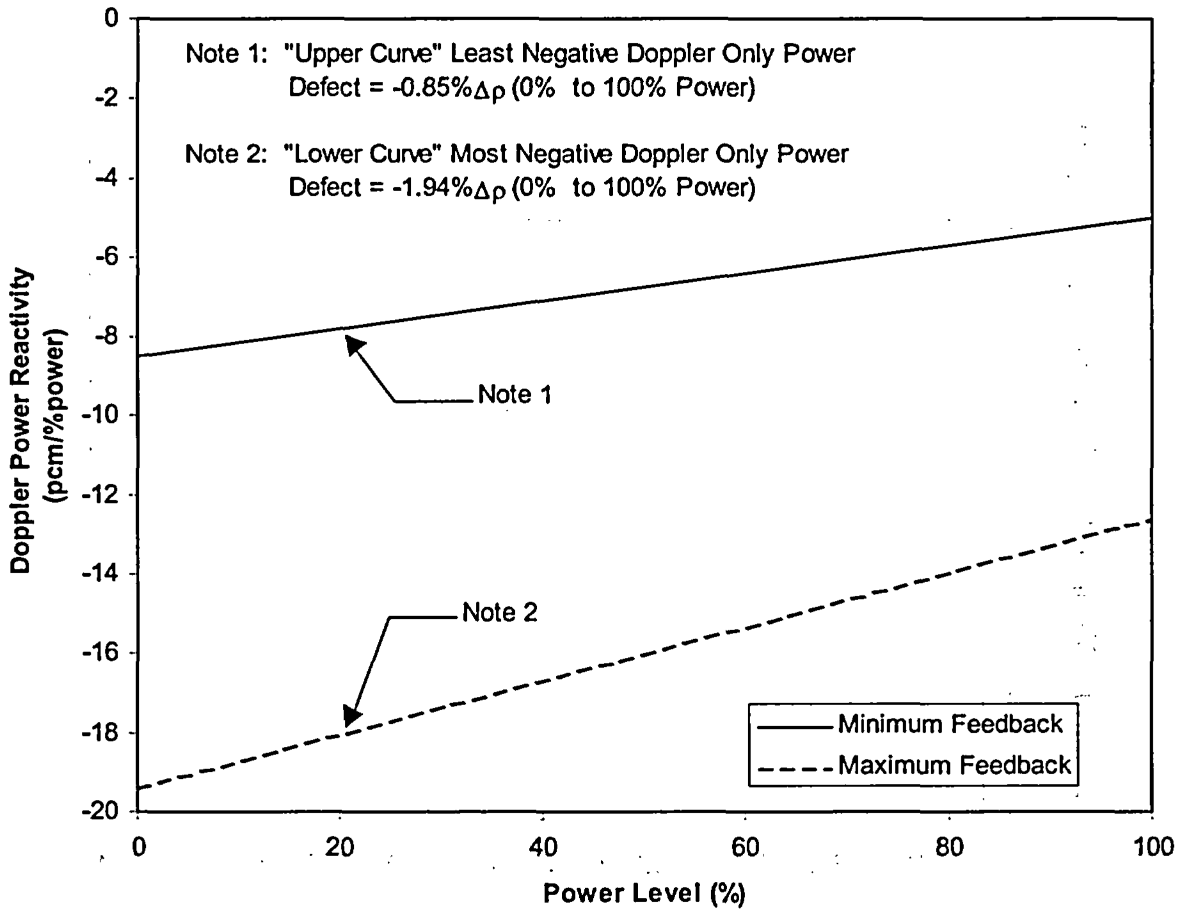

Figure 5.1.0-5
Doppler Power Coefficient Used in Accident Analyses

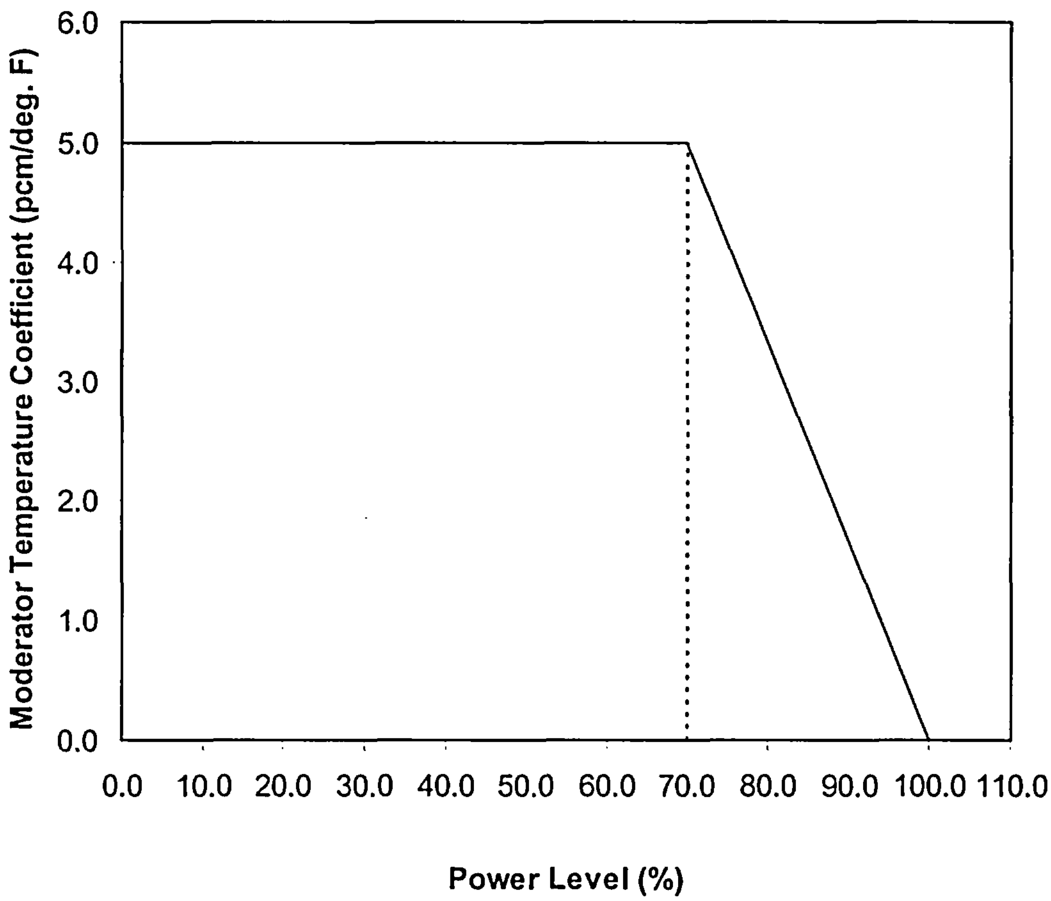

Figure 5.1.0-6

Moderator Temperature Coefficient Used in Accident Analyses

5.1.1 Increase in Feedwater Flow

A change in steam generator feedwater conditions that results in an increase in feedwater flow or a decrease in feedwater temperature could result in excessive heat removal from the plant primary coolant system. Such changes in feedwater flow or feedwater temperature are a result of a failure of a feedwater control valve, feedwater bypass valve, failure in the feedwater control system, or operator error.

Failures that result in an excessive heat removal from the plant primary coolant system cause the primary-side temperature and pressure to decrease significantly. The existence of a negative moderator and fuel temperature reactivity coefficients can cause core reactivity to rise, as the primary-side temperature decreases. In the absence of the reactor protection system (RPS) reactor trip or other protective action, this increase in core power, coupled with the decrease in primary-side pressure, can challenge the core thermal limits. Therefore, the Excessive Heat Removal Due to Feedwater System Malfunctions Event is analyzed to ensure that the departure from nucleate boiling (DNB) is not violated.

5.1.1.1 Accident Description

An example of excessive heat removal from the reactor coolant system (RCS) is the accidental opening of the feedwater regulating valves resulting in an increase of feedwater flow to both steam generators, causing excessive heat removal from the RCS. At power, excess feedwater flow causes a greater load demand on the primary side due to increased subcooling in the steam generator. With the plant at zero-power conditions, the addition of relatively cold feedwater may cause a decrease in primary-side temperature, and, therefore, a reactivity insertion due to the effects of the negative moderator temperature coefficient. The resultant decrease in the average temperature of the core causes an increase in core power due to moderator and control system feedback. This transient is attenuated by the thermal capacity of the primary and secondary sides. If the increase in reactor power is large enough, the primary RPS trip functions (e.g., high neutron flux, variable high-power trip (VHPT)) will prevent any power increase that can lead to a departure from nucleate boiling ratio (DNBR) less than the safety analysis limit value. The RPS trip functions may not actuate if the increase in power is not large enough.

5.1.1.2 Method of Analysis

The feedwater malfunction analysis causing an increase in feedwater flow is performed to demonstrate that the DNB design basis is satisfied. This is accomplished by showing that the calculated minimum DNBR is greater than the DNBR safety analysis limit.

The feedwater system malfunction transient is analyzed using the RETRAN code. The RETRAN computer code is a flexible, transient thermal-hydraulic digital computer code that has been reviewed and approved by the U.S. Nuclear Regulatory Commission (NRC) for pressurized water reactor licensing applications (References 5.1.1-1 and 5.1.1-2). The main features of the program include a point kinetics and one-dimensional kinetics model, one-dimensional homogeneous equilibrium mixture thermal-hydraulic model, control system models, and two-phase natural convection heat transfer correlations. The results from the RETRAN computer code are used to determine if the DNB safety analysis limits for the excessive heat removal due to feedwater malfunction event are met.

Feedwater system failures, including the accidental opening of the feedwater control valves, have the potential of allowing increased feedwater flow to each steam generator that will result in excessive heat removal from the RCS. Therefore, it is assumed that the feedwater control valves fail in the full-open position allowing the maximum feedwater flow to both steam generators. Also addressed is the initiation of a feedwater malfunction event from a hot zero-power (HZP) condition.

The following assumptions are made for the analysis of the feedwater malfunction event involving the accidental opening of the feedwater control valves:

1. The plant is operating at 89% power (and no-load conditions for the HZP case) conditions with the initial reactor power, pressure, and RCS average temperatures assumed to be at the nominal values (no uncertainties applied).
2. Uncertainties in initial conditions are included in the DNBR limit calculated using the Revised Thermal Design Procedure (RTDP) methodology (Reference 5.1.1-3), where applicable (at-power cases).
3. The feedwater temperature of 420.8 °F for the at-power cases is consistent with normal plant conditions at 89% of the rated thermal power. The feedwater enthalpy assumed at no-load conditions corresponds to a feedwater temperature of 240 °F.
4. The excessive feedwater flow event assumes accidental opening of the feedwater control valves with the reactor at 89% power and zero power while modeling a post-reactor-trip condition with minimum shutdown margin. The feedwater flow malfunction results in a step increase to 120% of the rated thermal power feedwater flow to both steam generators.
5. Maximum (end-of-life) reactivity feedback conditions with a minimum Doppler-only power defect is conservatively assumed.
6. The heat capacity of the RCS metal and steam generator shell are ignored, thereby maximizing the temperature reduction of the RCS coolant.
7. The feedwater flow resulting from a fully open control valve is terminated by the steam generator high-high water level signal or operator action.

The automatic rod control system is not modeled as it is disabled at the plant. The RPS functions to trip the reactor on the appropriate signal. No single active failure will prevent the RPS from functioning properly.

Protection against undesirable conditions is provided by steam generator water level alarms with automatic or manual control actions to reduce feedwater flow, and in extreme cases by reactor trips due to high power (VHPT), low pressurizer pressure, thermal margin/low pressure (TM/LP), or low steam generator pressure.

5.1.1.3 Results

The results of the analyses demonstrate that the at-power case meets the applicable DNBR acceptance criterion.

The limiting case is the excessive feedwater flow from 89% power initial condition. This case gives the largest reactivity feedback and results in the greatest power increase. The power increases until reactor trip is actuated when the variable high power trip setpoint is reached. The peak core heat flux and minimum DNB

condition is reached shortly after the control element assemblies (CEAs) begin to fall. The consequences of the event are mitigated prior to reaching a high steam generator water level condition in either steam generator. However, feedwater will be terminated after reaching the high-high steam generator water level setpoint. The limiting feedwater flow increase conditions were analyzed and it was confirmed that the calculated minimum DNBR is above the safety analysis DNBR limit. Therefore, the applicable DNBR acceptance criterion is met.

The excessive feedwater flow from a zero power condition models a HZP post-trip condition (i.e., HZP stuck rod coefficients, minimum shutdown margin) with maximum reactivity feedback conditions (end of life). The effects of an increased feedwater flow and combined reactivity feedback effect at post-trip conditions is not sufficient enough to offset the impact of the minimum shutdown worth of the CEAs. As a result, there is no return to power, and therefore, no challenge to the minimum DNBR criterion.

Table 5.1.1-1 shows the time sequence of events for the at-power feedwater malfunction transient case resulting in an increase in feedwater flow. Figures 5.1.1-1 through 5.1.1-7 show transient responses for various system parameters during a feedwater system malfunction causing a feedwater flow increase initiated from at-power conditions. As shown in Table 5.1.1-2, the increased feedwater flow at zero power conditions does not result in an appreciable return to power condition.

5.1.1.4 Conclusions

The results of the analysis show that the RPS trip functions provide adequate protection against the feedwater malfunction transient. No fuel or cladding damage is predicted for this accident. All acceptance criteria are satisfied.

5.1.1.5 References

5.1.1-1 WCAP-14882-P-A, Rev. 0, "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," April, 1999.

5.1.1-2 EPRI NP-1850-CCM, Rev. 6, "RETRAN-02-A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems," December 1995.

5.1.1-3 WCAP-11397-P-A, "Revised Thermal Design Procedure," April 1989.

Table 5.1.1-1 Feedwater System Malfunction Event at Power, Increased FW Flow Sequence of Events and Transient Results	
Event	**Time (seconds)**
Main feedwater control valves fail full open (Initiation of transient)	100.0
Variable High Power Trip setpoint is reached	124.14
Trip signal occurs	124.54
CEAs begin to drop into core	125.28
Minimum DNBR occurs	126.00
Turbine trip	126.54
Results	
Peak Nuclear Power, fraction	1.05891
Peak Core Heat Flux, fraction	1.04761
Minimum DNBR	2.24

Table 5.1.1-2 Feedwater System Malfunction Event at Zero Power, Increased FW Flow Sequence of Events and Transient Results	
Event	**Time (seconds)**
Main feedwater control valves fail full open	0.0
Hi-hi steam generator water level trip setpoint is reached	15.96
Feedwater isolation valves fully closed	85.05
Results	
Return-to-Power Peak, fraction	<0.003
Peak Core Heat Flux, fraction	<0.011

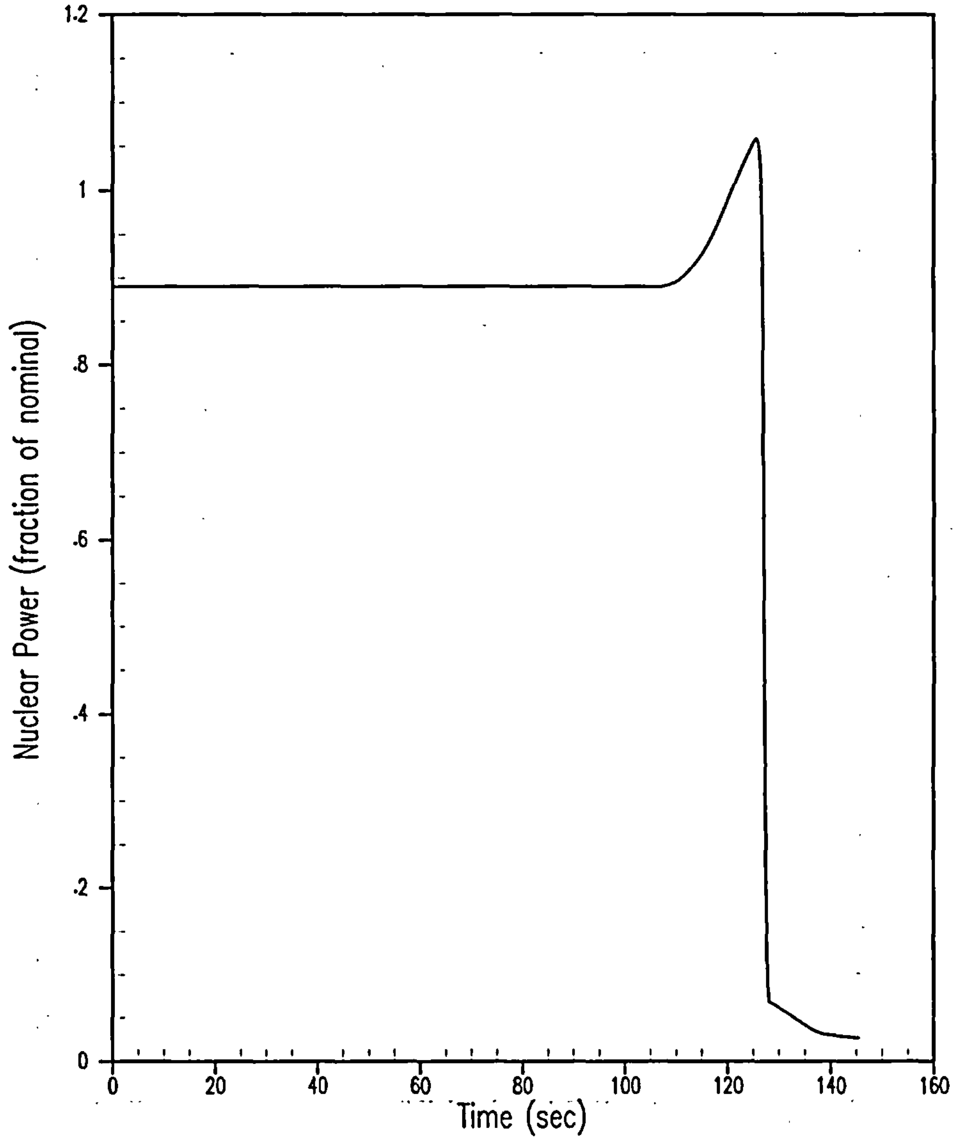

Figure 5.1.1-1
Feedwater Malfunction, Increased Feedwater Flow at Power
Nuclear Power

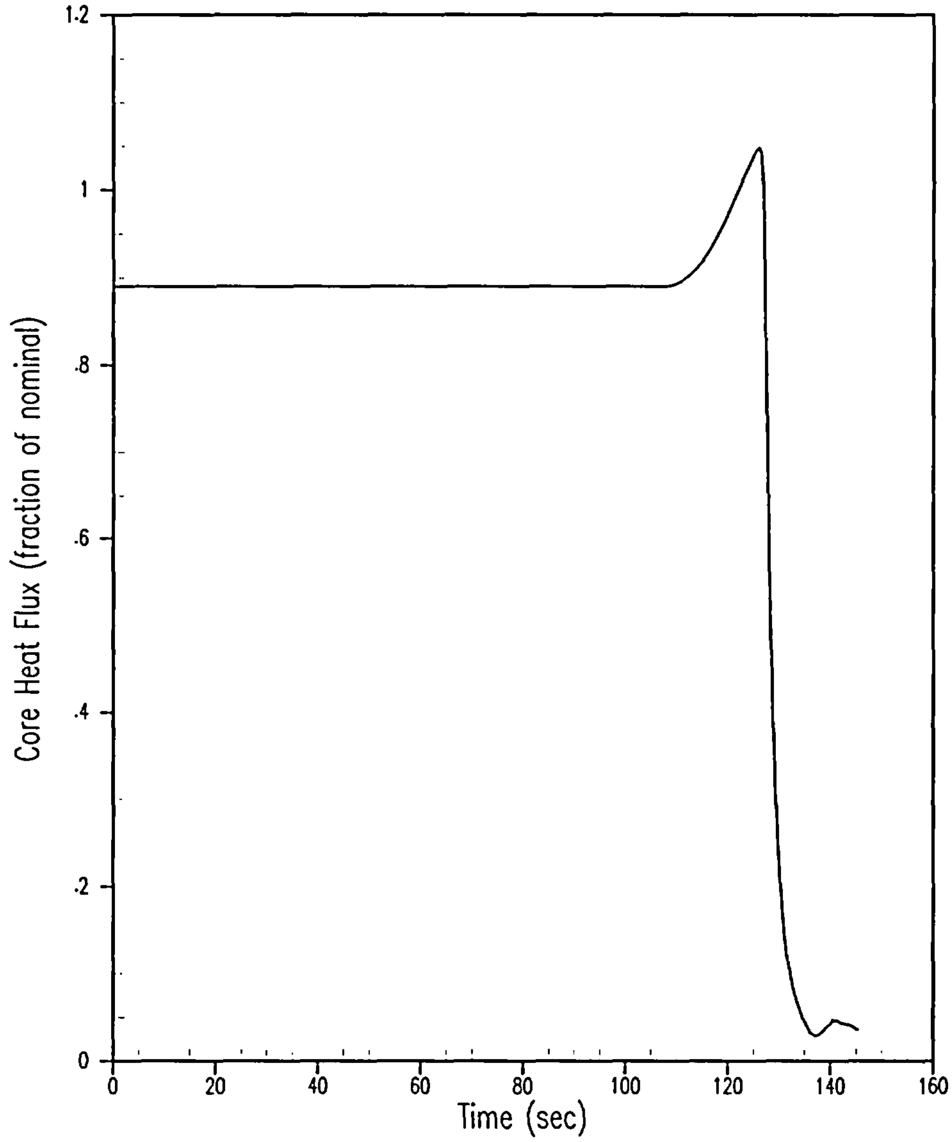

Figure 5.1.1-2
Feedwater Malfunction, Increased Feedwater Flow at Power
Core Heat Flux

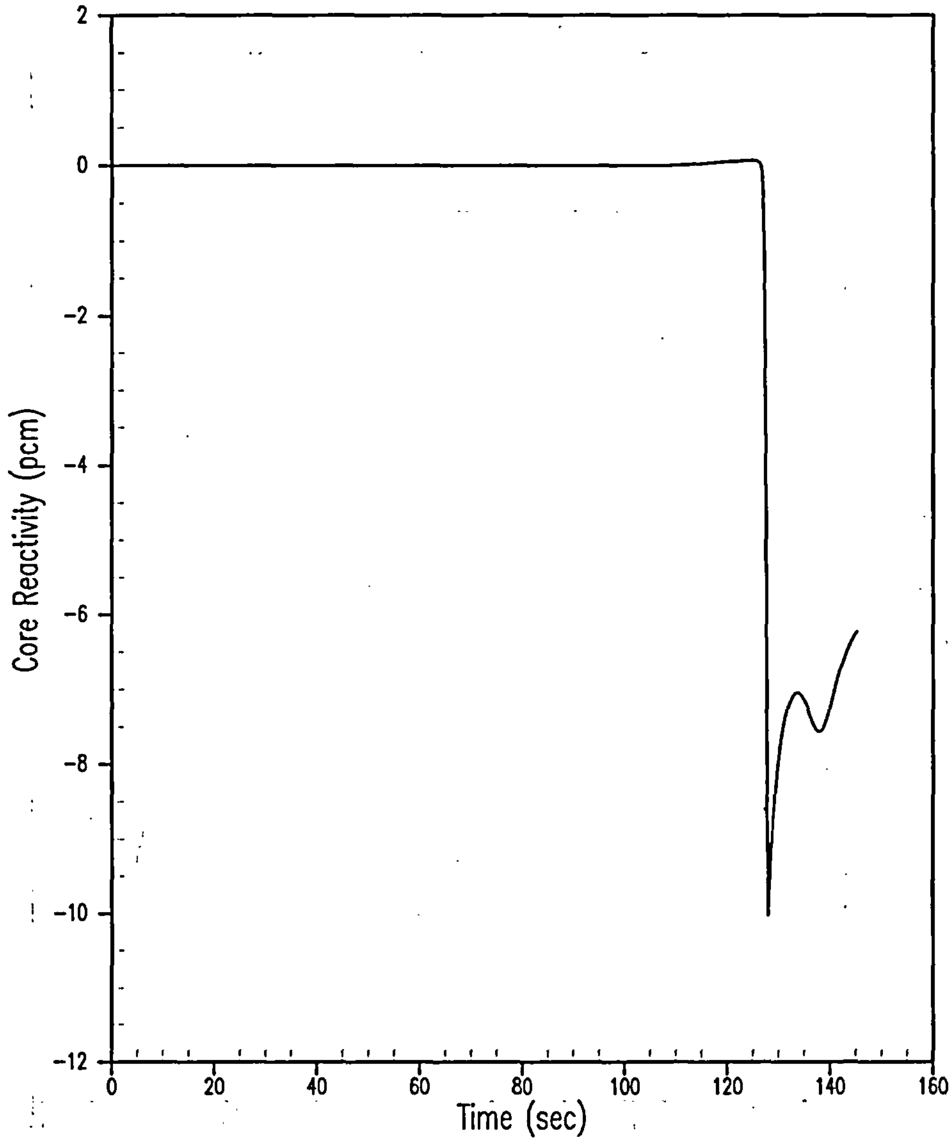

Figure 5.1.1-3
Feedwater Malfunction, Increased Feedwater Flow at Power
Core Reactivity

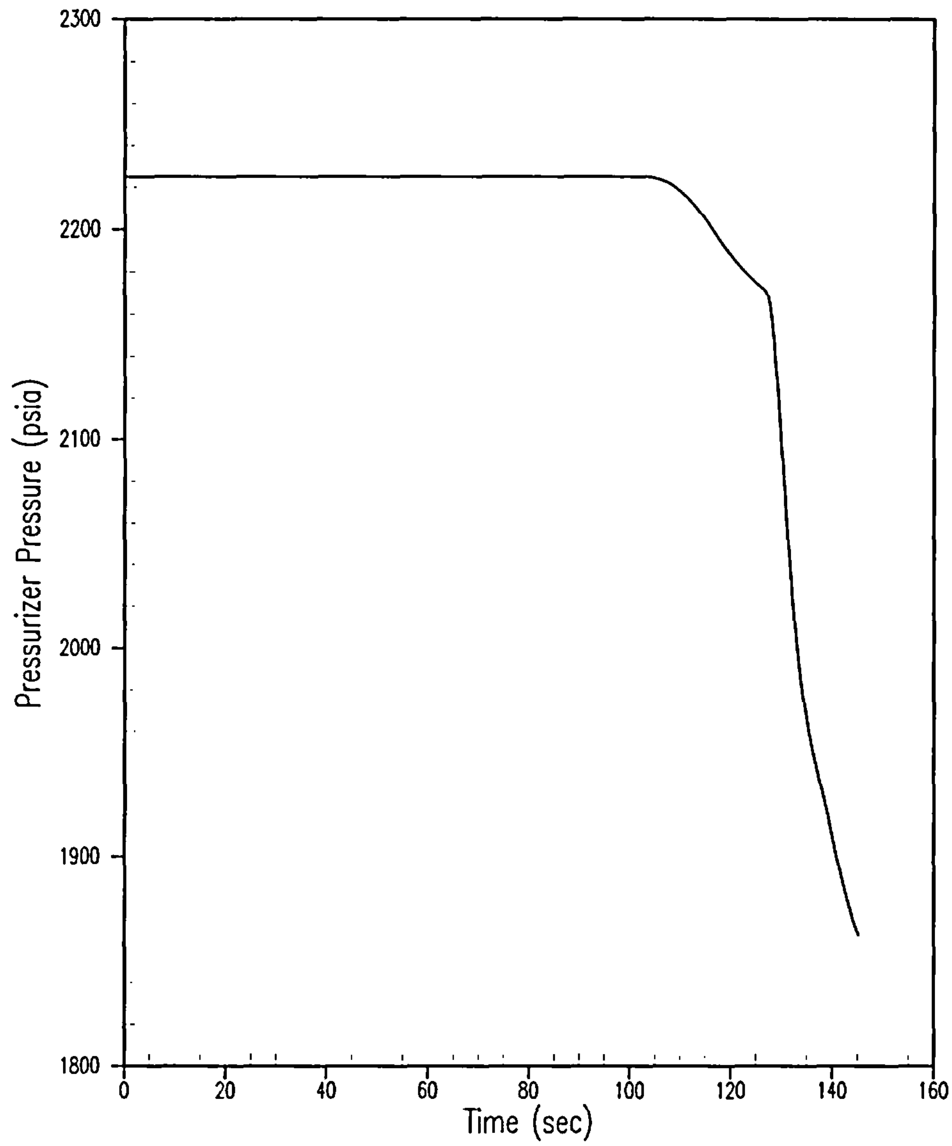

Figure 5.1.1-4
Feedwater Malfunction, Increased Feedwater Flow at Power
Pressurizer Pressure

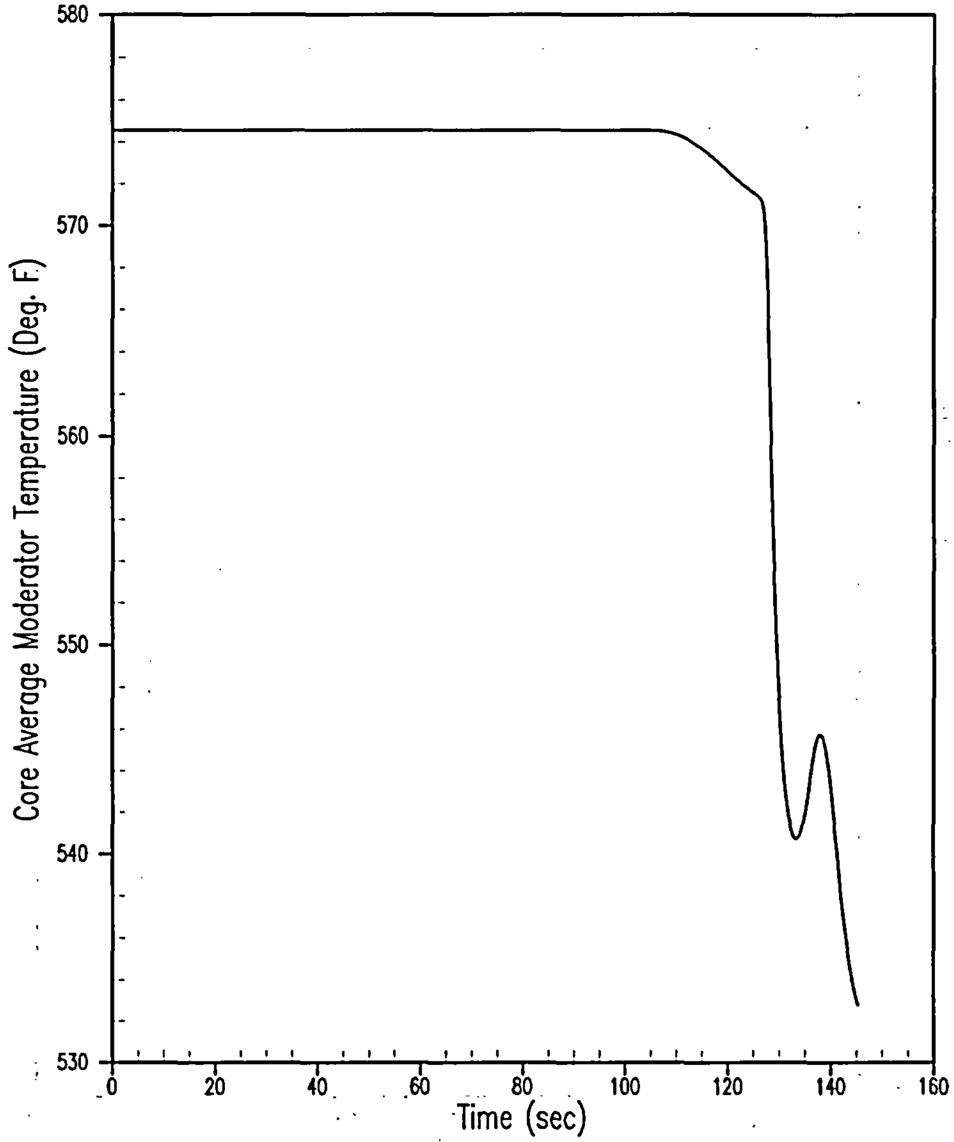

Figure 5.1.1-5
Feedwater Malfunction, Increased Feedwater Flow at Power
Core Average Moderator Temperature

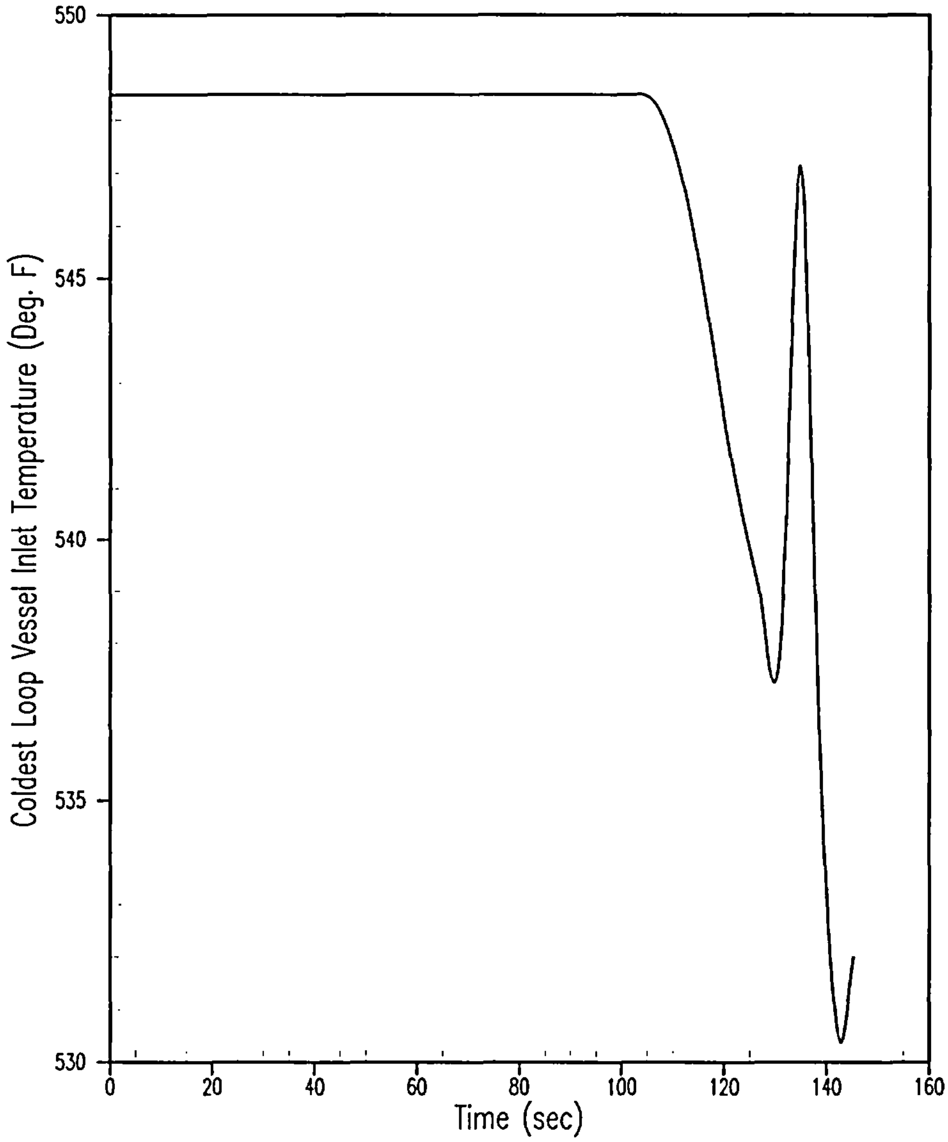

Figure 5.1.1-6
Feedwater Malfunction, Increased Feedwater Flow at Power
Vessel Inlet Temperature

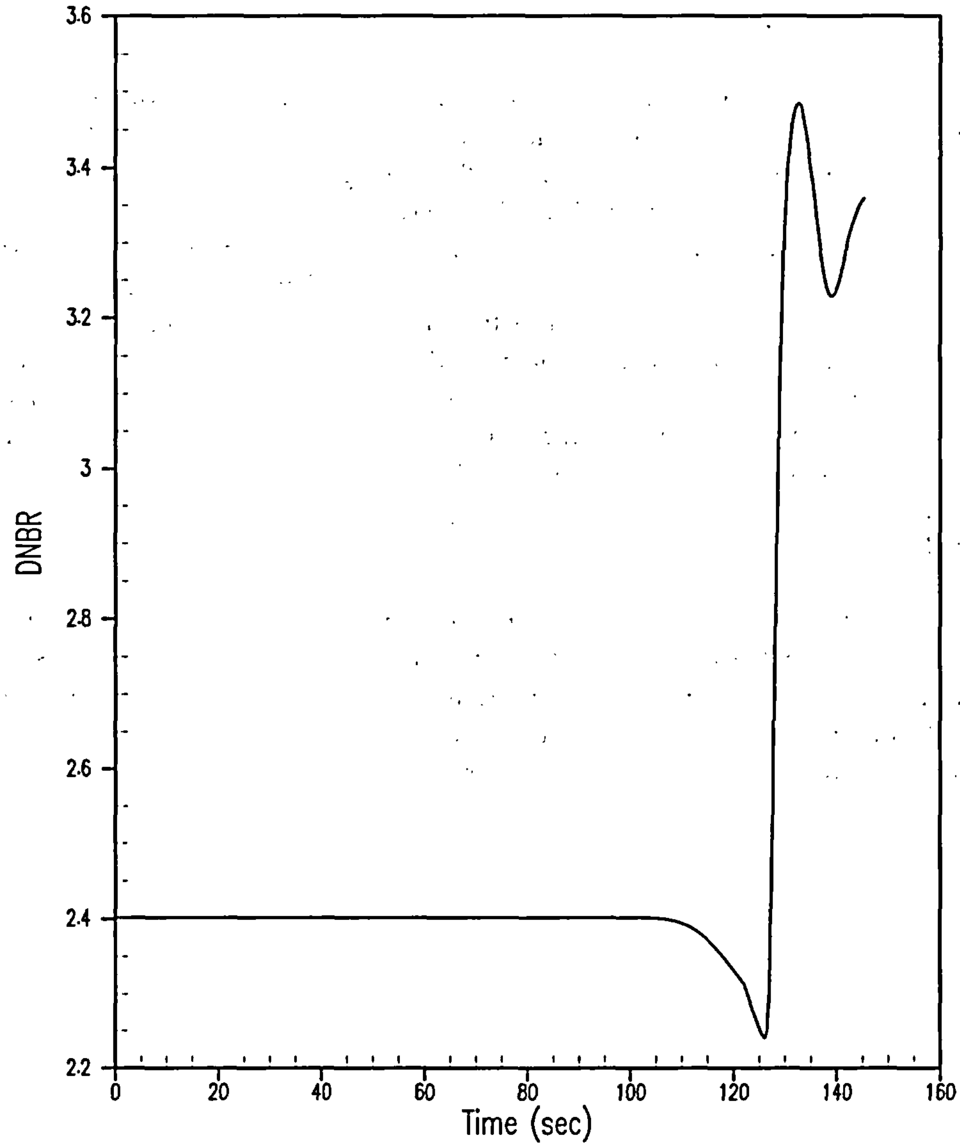

Figure 5.1.1-7
Feedwater Malfunction, Increased Feedwater Flow at Power
DNBR

5.1.2 Inadvertent Opening of Steam Generator Safety Valve/Atmospheric Dump Valve

5.1.2.1 Accident Description

The inadvertent opening of a main steam relief or safety valve results in a transient similar to a steamline break event. Upon the inadvertent opening of a main steam relief or safety valve, steam flow would increase causing a mismatch between the reactor core power and the steam generator load demand. The increased steam flow draws more heat from the primary side. This reduces the temperature of the water in the RCS. In the presence of a negative moderator temperature coefficient, the RCS temperature reduction can result in a nuclear power increase if analyzed from an at power condition. If analyzed from subcritical conditions, the assumption of a stuck CEA in conjunction with a negative moderator temperature coefficient could result in a reactivity transient that overcomes the shutdown margin and results in a subsequent return to power. In both cases, the reduced coolant temperature results in a reduction in the RCS pressure due to the increase in coolant density. Given an increase in core power and the reduction in the RCS pressure, the possible consequence of this accident is DNB with subsequent fuel damage.

5.1.2.2 Conclusions

Based on the fact that both the pre-trip with fast bus transfer and post-trip steamline break analyses (Sections 5.1.5 and 5.1.6) meet the acceptance criteria associated with an American Nuclear Society (ANS) Condition II event, the inadvertent opening of a main steam relief or safety valve event is bounded. Therefore, an explicit analysis of the inadvertent opening of a main steam relief or safety valve event is not required to support an increase in SGTP to 42% and associated decrease in coolant flow for St. Lucie Unit 2.

5.1.3 Decrease in Feedwater Temperature

A change in steam generator feedwater conditions that results in an increase in feedwater flow or a decrease in feedwater temperature could result in excessive heat removal from the plant primary coolant system. Such changes in feedwater flow or feedwater temperature are a result of a failure of a feedwater control valve, feedwater bypass valve, failure in the feedwater control system, loss of feedwater heaters, or operator error.

The occurrence of these failures that result in an excessive heat removal from the plant primary coolant system cause the primary-side temperature and pressure to decrease significantly. The existence of negative moderator and fuel temperature reactivity coefficients can cause core reactivity to rise, as the primary-side temperature decreases. In the absence of the RPS reactor trip or other protective action, this increase in core power, coupled with the decrease in primary-side pressure, can challenge the core thermal limits. Therefore, the Excessive Heat Removal Due to Feedwater System Malfunctions Event is analyzed to ensure that the DNB is not violated.

5.1.3.1 Accident Description

Another example of excessive heat removal from the RCS is the transient associated with loss of high-pressure feedwater heaters. In the event of a loss of high-pressure feedwater heaters, there could be an immediate reduction in feedwater temperature to the steam generators. At power, the increased subcooling will create a greater load demand on the RCS due to the increased heat transfer in the steam generator.

With the plant at no-load conditions, the addition of cold feedwater may cause a decrease in RCS temperature and, therefore, a reactivity insertion due to the effects of the negative moderator temperature coefficient. However, the rate of energy change is reduced as load and feedwater flow decrease, so that the transient is less severe than higher initial power cases.

The net effect on the RCS due to a reduction in feedwater temperature is similar to the effect of increasing secondary steam flow. If the increase in reactor power is large enough, the primary RPS trip functions (e.g., variable high power trip VHPT) will prevent any power increase that can lead to a DNBR less than the safety analysis limit value.

5.1.3.2 Method of Analysis

The feedwater malfunction analysis resulting in a feedwater temperature reduction is performed to demonstrate that the DNB design basis is satisfied. This is accomplished by showing that the calculated minimum DNBR is greater than the safety analysis limit DNBR using the same methods described in the feedwater flow increase analysis (Section 5.1.1) with the following assumptions.

The following assumptions made for the analysis of the feedwater malfunction event involving the loss of the high pressure feedwater heaters are the same as those for increased feedwater flow, except:

1. At 89% power conditions, the reduced feedwater enthalpy is 292.81 Btu/lbm which corresponds to a reduced feedwater temperature of 320.8 °F.
2. The excessive feedwater temperature reduction assumes the at-power feedwater flow is maintained to both steam generators.

3. The feedwater temperature reduction event resulting from the loss of the high-pressure feedwater heaters is terminated by the steam generator high water level signal that closes all main feedwater control and feedwater control bypass valves. High-high steam generator level protection will trip the turbine, stop the main feedwater pumps, and close the main feedwater pump discharge valves.

Protection against undesirable conditions is similar to that described for increased feedwater event.

5.1.3.3 Results

The loss of high-pressure feedwater heaters causes a reduction in feedwater temperature, which increases the thermal load on the primary system. The power increases until reactor trip is actuated when the variable high-power trip setpoint is reached. The peak core heat flux and minimum DNB condition is reached shortly after the CEAs begin to drop into the core. The consequences of the event are mitigated prior to reaching a high steam generator water level condition in either steam generator. The limiting at-power feedwater temperature reduced conditions were analyzed and it was confirmed that the calculated minimum DNBR is above the DNBR safety analysis limit. Therefore, the applicable DNBR acceptance criterion is met.

Table 5.1.3-1 shows the time sequence of events for the at-power feedwater malfunction transient case resulting in a reduction in feedwater temperature. Figures 5.1.3-1 through 5.1.3-7 show transient responses for various system parameters during a feedwater system malfunction causing a feedwater temperature reduction.

5.1.3.4 Conclusions

The results of the analysis show that the RPS trip functions provide adequate protection against the feedwater malfunction transient. No fuel or cladding damage is predicted for this accident. All acceptance criteria are satisfied.

Table 5.1.3-1
Feedwater System Malfunction Event at Power, Reduced FW Temperature
Sequence of Events and Transient Results

Event	Time (seconds)
Loss of feedwater heater occurs	0.0
Variable High Power Trip setpoint is reached	68.41
Trip signal occurs	68.81
CEAs begin to drop into core	69.55
Minimum DNBR occurs	69.75
Turbine trip	70.81
Results	
Peak Nuclear Power, fraction	1.00520
Peak Core Heat Flux, fraction	1.00462
Minimum DNBR	2.32

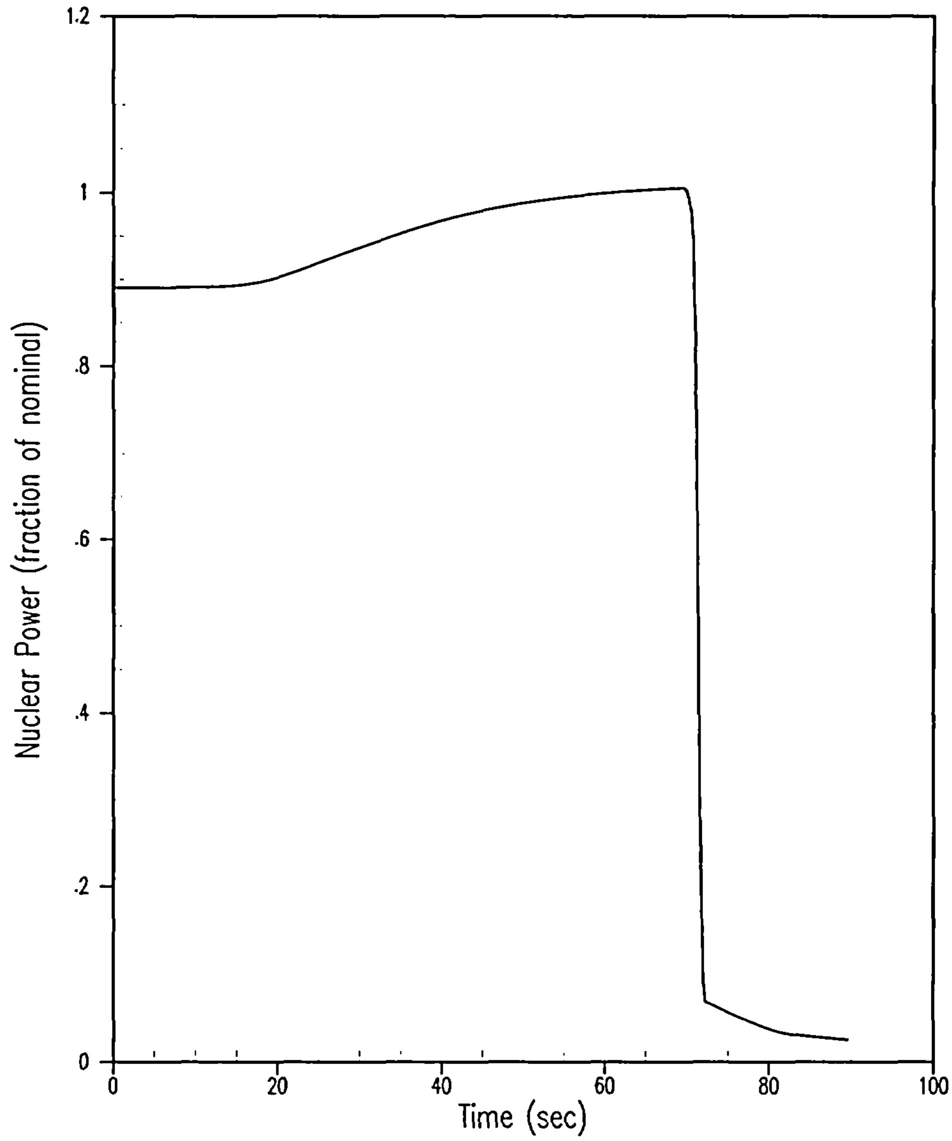

Figure 5.1.3-1
Feedwater Malfunction, Reduced Feedwater Temperature at Power
Nuclear Power

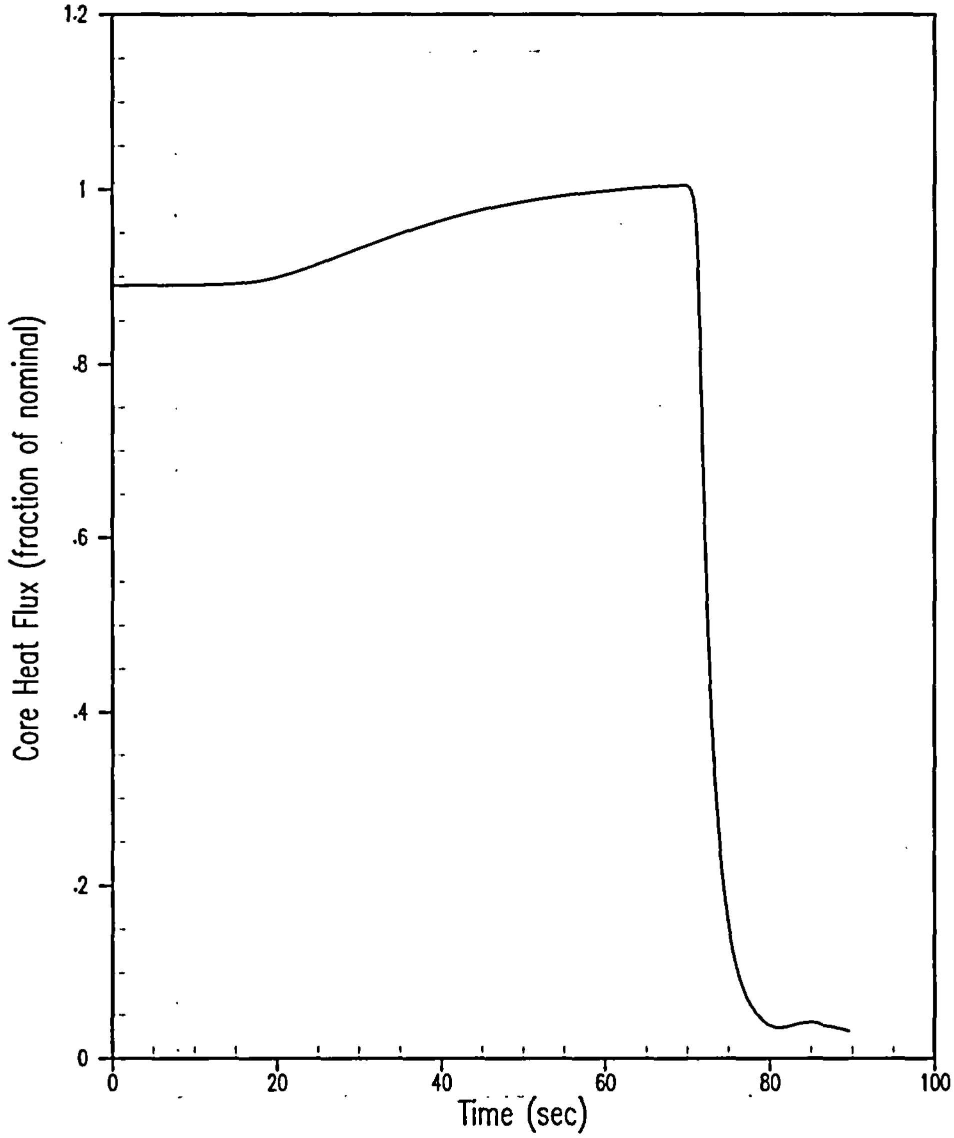

Figure 5.1.3-2
Feedwater Malfunction, Reduced Feedwater Temperature at Power
Core Heat Flux

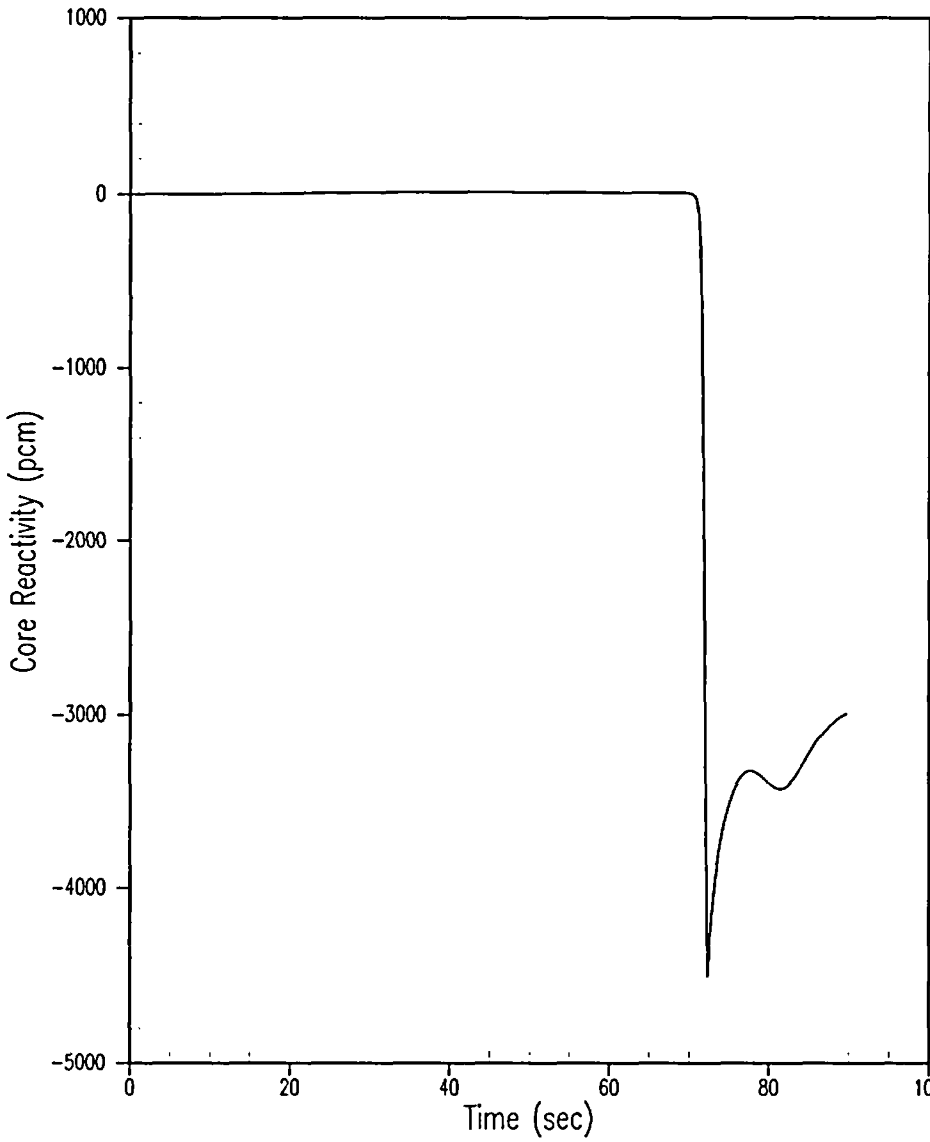

Figure 5.1.3-3
Feedwater Malfunction, Reduced Feedwater Temperature at Power
Core Reactivity

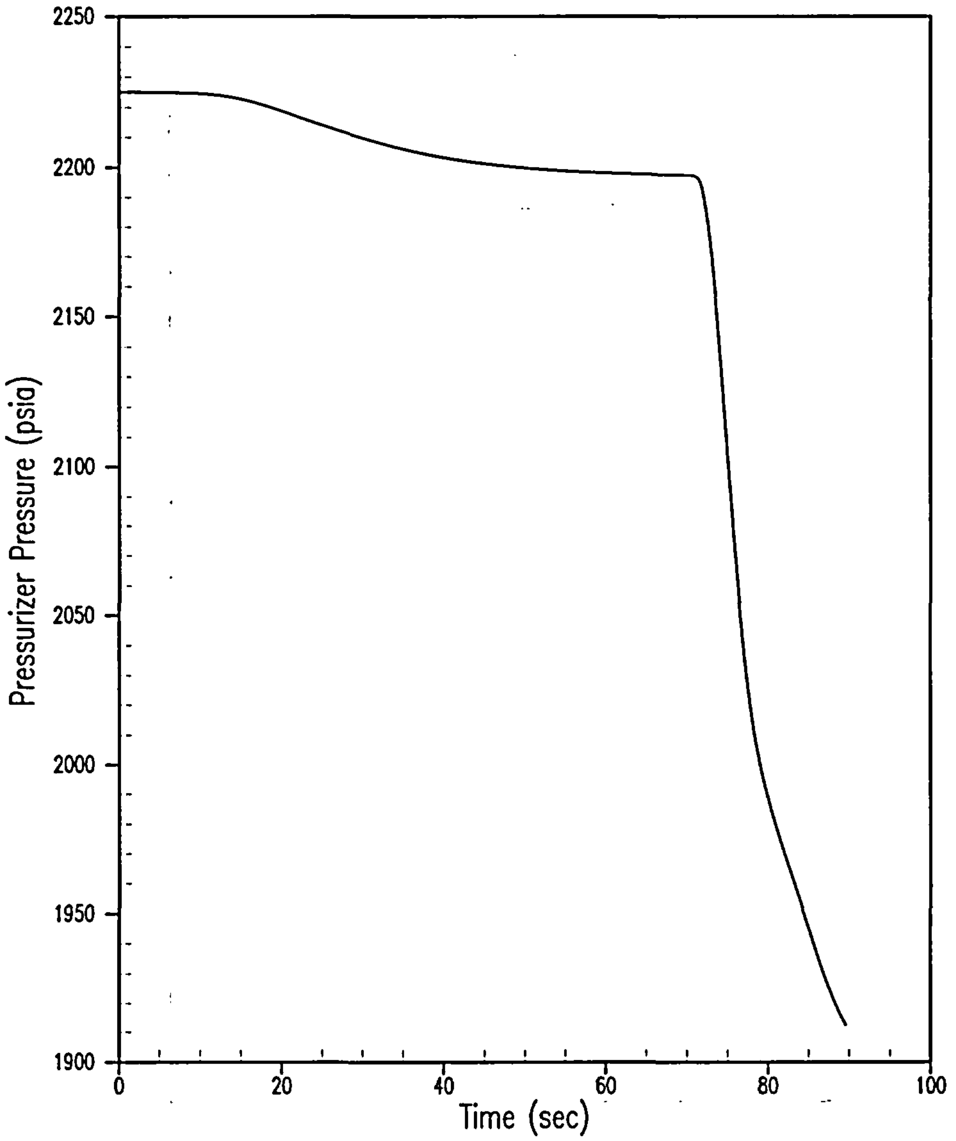

Figure 5.1.3-4
Feedwater Malfunction, Reduced Feedwater Temperature at Power
Pressurizer Pressure

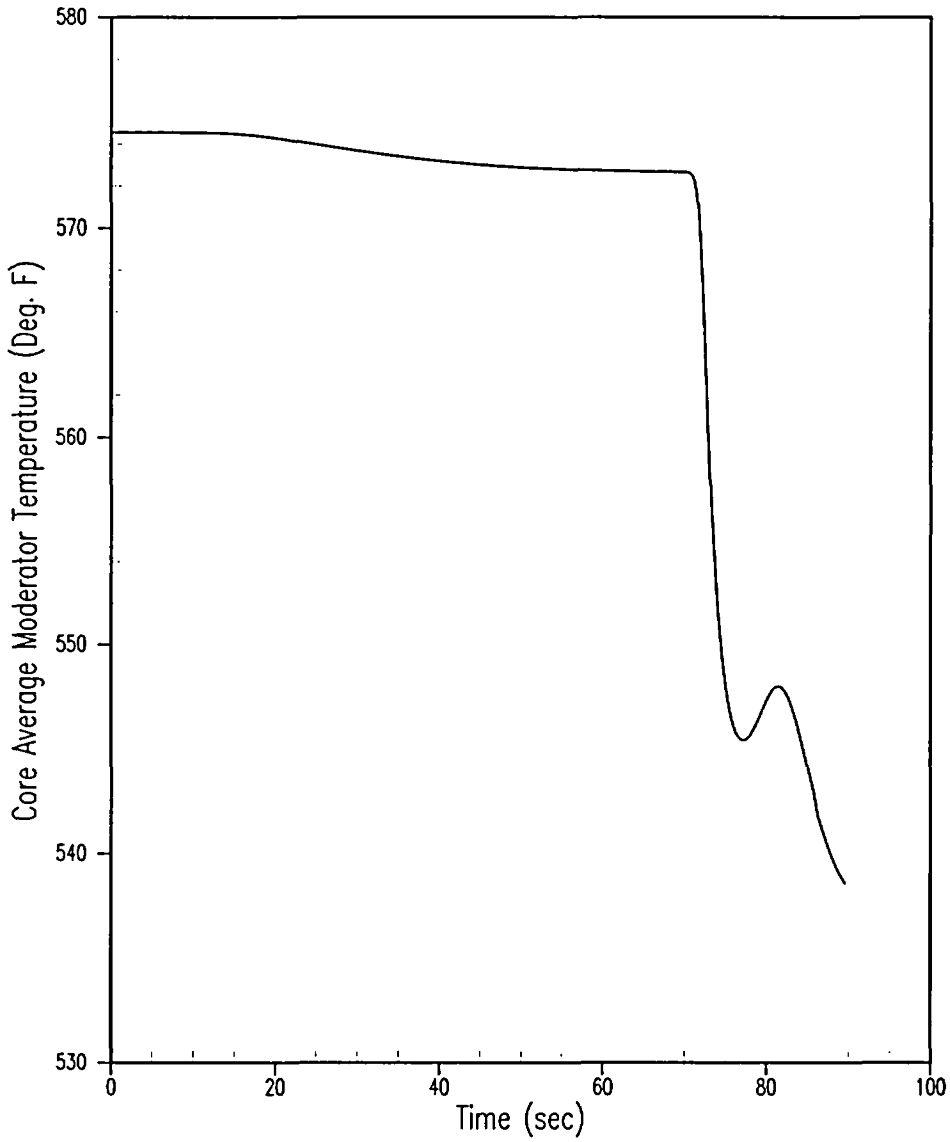

Figure 5.1.3-5
Feedwater Malfunction, Reduced Feedwater Temperature at Power
Core Average Moderator Temperature

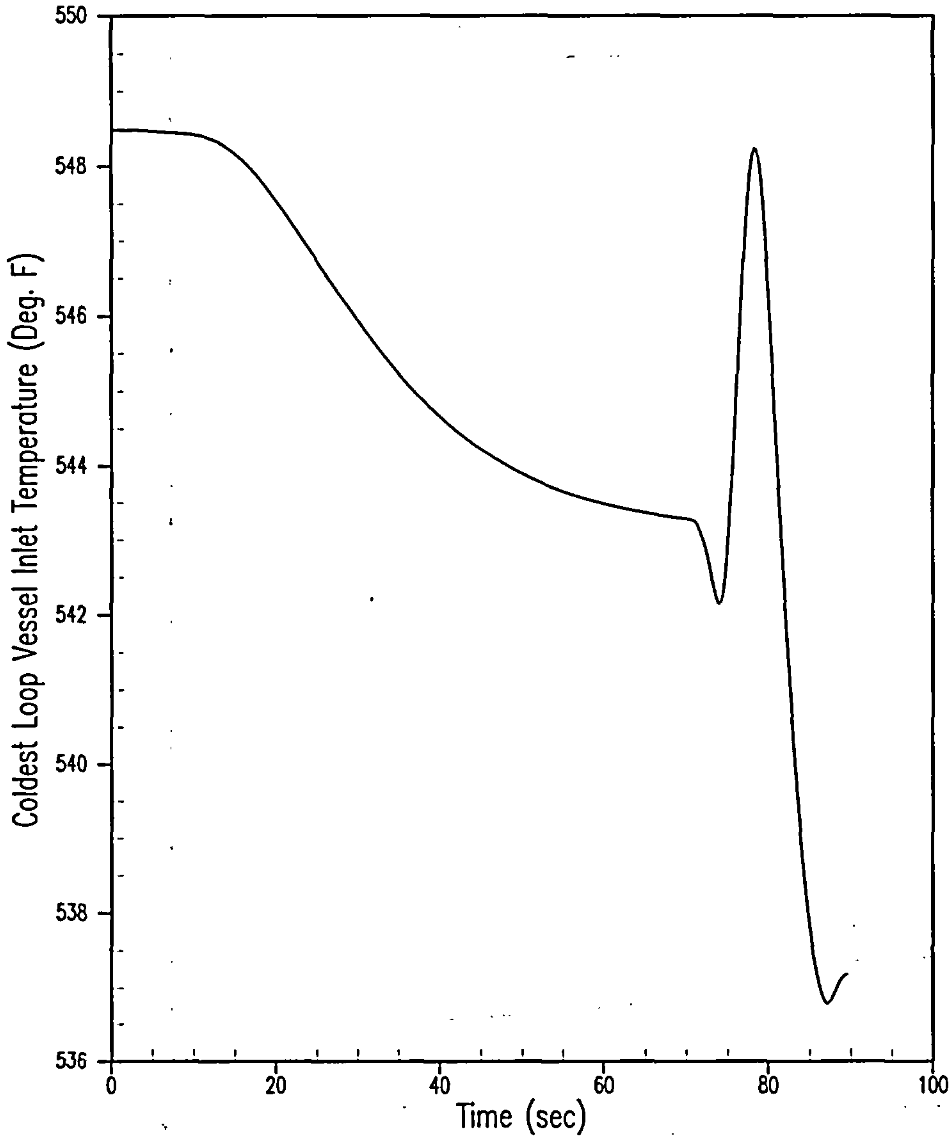

Figure 5.1.3-6
Feedwater Malfunction, Reduced Feedwater Temperature at Power
Vessel Inlet Temperature

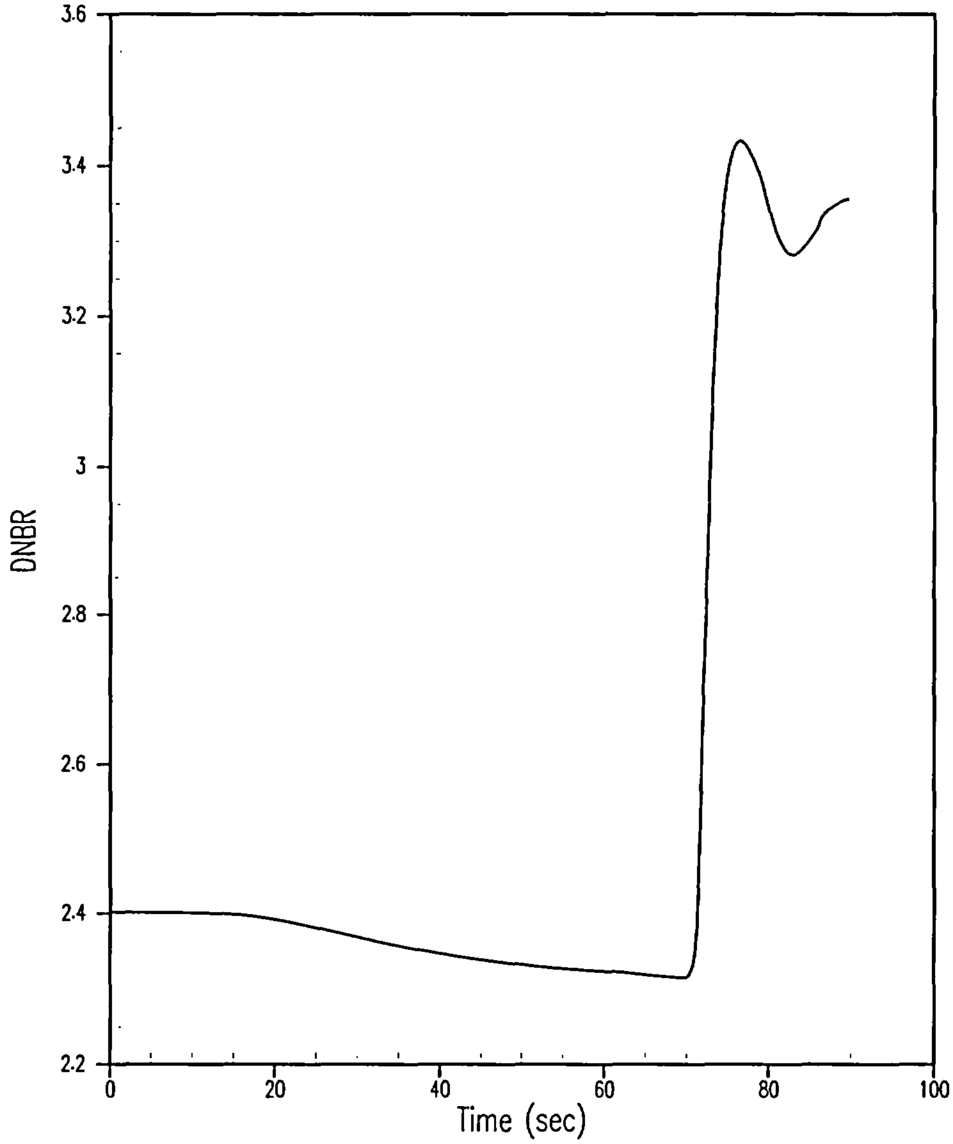

Figure 5.1.3-7
Feedwater Malfunction, Reduced Feedwater Temperature at Power
DNBR

5.1.4 Increase in Main Steam Flow

5.1.4.1 Accident Description

An excessive increase in main steam flow event (excessive load increase) is defined as a rapid increase in the steam flow that causes a power mismatch between the reactor core power and the steam generator load demand. For this accident, the steam flow is typically assumed to increase by not more than 30% percent of the initial value. This accident could result from one of the following:

- An administrative violation such as excess loading by the operator
- Equipment malfunction in the steam dump control
- Turbine throttle valve control malfunction

The increased steam flow draws more heat from the primary side. This reduces the temperature of the water in the RCS. In the presence of a negative moderator temperature coefficient, the RCS temperature reduction can result in a nuclear power increase. The reduced coolant temperature also results in a reduction in the pressurizer water volume, due to the increased density of the cooler RCS water, and a reduction in the pressurizer pressure. Given an increase in core power and the reduction in the RCS pressure, the possible consequence of this accident (assuming no protective functions) is DNB with subsequent fuel damage.

5.1.4.2 Conclusions

Based on the fact that the pre-trip steamline break with fast bus transfer analysis of Section 5.1.5 meets the acceptance criteria associated with an ANS Condition II event, the excessive increase in main steam flow event is bounded. Therefore, an explicit analysis of the excessive increase in main steam flow event is not required to support the increase in SGTP to 42% and associated reduction in coolant flow for St. Lucie Unit 2.

5.1.5 Pre-Trip Steam System Piping Failure

5.1.5.1 Accident Description

A rupture in the main steam system piping (SLB) from an at-power condition creates an increased steam load, which extracts an increased amount of heat from the reactor coolant system (RCS) via the steam generators. This results in a reduction in RCS temperature and pressure. In the presence of a strong negative moderator temperature coefficient, typical of end-of-cycle life conditions, the colder core inlet coolant temperature causes the core power to increase from its initial level due to the positive reactivity insertion. The power approaches a level equal to the total steam flow. Depending on the break size, a reactor trip may occur due to overpower conditions or as a result of low steam generator pressure.

The steam system piping failure accident evaluation described in Section 5.1.6 addresses a hot zero power initial condition with the control rods inserted in the core, except for the most reactive rod in the fully withdrawn position, out of the core. That condition could occur while the reactor is at hot shutdown at the minimum required shutdown margin or after the plant has been tripped manually or by the reactor protection system following a steam line break from an at-power condition. For an at-power break, Section 5.1.6 addresses the limiting condition with respect to core protection for the time period following reactor trip. The purpose of this section is to describe the analysis of a steam system piping failure occurring from an at-power initial condition and to demonstrate that core protection is maintained prior to and immediately following reactor trip. Two analyses are presented: one that assumes the failure of the fast bus transfer (FFBT) of a 6.9 kV bus which results in losing power to two of the four reactor coolant pumps, and one that assumes the SLB occurs coincident with a loss of offsite power (LOOP).

Depending on the size of the break, this event is classified as either an ANS Condition III (infrequent fault) or Condition IV (limiting fault), as defined in Section 5.1.0.9. The acceptance criteria for this event are defined in Sections 5.1.0.9.3 or 5.1.0.9.4 depending on the size of the break.

5.1.5.2 Method of Analysis

The analysis of the steam line rupture is performed in the following stages:

1. The RETRAN code (References 5.1.5-1 and 5.1.5-4) is used to calculate the nuclear power, core heat flux, and RCS temperature and pressure transients resulting from the cooldown following the steam line break.
2. The RETRAN code is also used in the analysis of the steamline rupture with FFBT to calculate the primary flow coastdown initiated at the turbine trip, which results in two of the four reactor coolant pumps coasting down.
3. The RETRAN code is also used to calculate the primary flow coastdown following reactor trip as a result of the loss of offsite power, which results in all four of the reactor coolant pumps coasting down.
4. The core radial and axial peaking factors are determined using the thermal-hydraulic conditions from the transient analysis as input to the nuclear core models. The VIPRE code (Reference 5.1.5-5) is then used to calculate the DNBR for the limiting time during the transient.

This accident is analyzed with the Revised Thermal Design Procedure (Reference 5.1.5-2). Plant characteristics and initial conditions are provided in Table 5.1.0-2.

The following assumptions are made in the transient analysis for the SLB with FFBT case:

1. Initial Conditions: The initial core power, reactor coolant temperature, and RCS pressure are assumed to be at their 89%-of-rated-power values. The 89% power condition is more limiting than lower-power in terms of DNBR. The RCS Minimum Measured Flow is used. Uncertainties in initial conditions are included in the DNBR limit as described in Reference 5.1.5-2.

2. Break size: A spectrum of break sizes is analyzed. Small breaks do not result in a reactor trip. Intermediate size breaks result in a reactor trip on variable high power trip (VHPT). Larger break sizes result in a reactor trip on Low Steam Generator Pressure.

3. Break flow: In computing the steam flow during a steam line break, the Moody curve (Reference 5.1.5-3) for fL/D = 0 is used.

4. Reactivity Coefficients: The analysis is performed over a range of moderator density coefficients (MDCs) which bounds end-of-cycle reactivity feedback coefficients with the minimum Doppler power feedback to maximize the power increase following the break.

5. Protection System: This analysis only considers the initial phase of the transient initiated from an at-power condition. Protection in this phase of the transient is provided by a reactor trip. Other protection system features are actuated to mitigate the effects of the steam line break for a post-trip condition.

6. Control Systems: The results of the analysis would not be more severe as a result of control system actuation, therefore their effects have been ignored in the analysis. Control systems are not credited in mitigating the effects of the transient.

7. Fast Bus Transfer Failure: The FFBT at the time of turbine trip (0.0 seconds following reactor trip breaker opening) is modeled, which results in two of the four reactor coolant pumps coasting down. The remaining two reactor coolant pumps are assumed to coast down 3 seconds following the time of reactor trip breaker opening due to the loss of offsite power. The flow transient associated with the FFBT is superimposed on the limiting break case for the DNB evaluation only by applying the RCS flow coastdown transient on the VIPRE DNB calculations. This conservatively overpredicts the core coolant density feedback for the nuclear power transient during the flow coastdown.

8. Rod Drop Time: No credit is taken of any drop time reduction due to the core flow reduction experienced during the to two-pump coastdown.

9. Scram Reactivity: A minimum scram reactivity based upon the most bottom-peaked axial power distribution is used in RETRAN.

The following assumptions are incorporated in the VIPRE model used to evaluate the statepoints generated by RETRAN:

1. In VIPRE, the DNBR is calculated based on a top-peak axial power shape.

2. In VIPRE, the peak power assembly with the peak rod at the radial peaking factor (F_r) design limit and a low peak-to-average power ratio is modeled at the core location corresponding to the minimum flow assembly.

The following assumptions are made in the transient analysis for the case of SLB coincident with LOOP:

1. Initial Conditions: The initial core power, reactor coolant temperature, and RCS pressure are assumed to be at their 89%-of-rated-power values. The RCS Thermal Design Flow is used. Uncertainties in initial conditions are included in the DNBR limit as described in Reference 5.1.5-2.
2. Break size: A maximum break size of 6.3 ft^2 is analyzed which maximizes the depressurization of the RCS.
3. Break flow: In computing the steam flow during a steam line break, the Moody curve (Reference 5.1.5-3) for fL/D = 0 is used.
4. Reactivity Coefficients: A conservatively large absolute value of the Doppler-only power coefficient is used, along with the most-positive MTC limit for 89% power operation (1.827 pcm/°F). These assumptions maximize the core power during the initial part of the transient when the minimum DNBR is reached and is used in this analysis since the cooler primary system water from the steam generator, due to the steam piping rupture, does not have sufficient time to result in a core water density increase prior to the reactor trip.
5. Trip Reactivity: A conservatively low trip reactivity value (5.4% $\Delta\rho$) is used to minimize the effect of rod insertion following reactor trip and maximize the heat flux statepoint used in the DNBR evaluation for this event. The value is based on the assumption that the highest worth RCCA is stuck in its fully withdrawn position.
6. Protection System: This analysis only considers the initial phase of the transient initiated from an at-power condition. Reactor trip is provided by a low RCS flow setpoint that includes harsh environmental error effects and is assumed to be 87.9% of nominal RCS flow.
7. Control Systems: The results of the analysis would not be more severe as a result of control system actuation. Therefore, their effects have been ignored in the analysis. Control systems are not credited in mitigating the effects of the transient.
8. Loss of Offsite Power: This analysis assumes that a loss of offsite power occurs concurrent with the steamline break event causing the four RCPs to coastdown. The statepoints from this case, which include, power, pressure, temperature, and core flow are used to determine the resulting DNBR, as calculated by the VIPRE code.

5.1.5.3 Results

<u>SLB with FFBT</u>

A spectrum of moderator density coefficients (MDCs) was considered, ranging from 0.0 Δk/gm/cc to 0.43 Δk/gm/cc. At each MDC, a spectrum of break sizes were analyzed to determine the most severe break size. For break sizes of approximately 0.5 ft^2 to 3.3 ft^2, the power increase results in a reactor trip on VHPT (either excore power or ΔT-power). For break sizes of approximately 3.4 ft^2 and larger, a reactor trip is generated within a few seconds of the break on the Low Steam Generator Pressure signal.

The limiting case for demonstrating DNB protection is the 3.2 ft^2 break for an MDC of 0.43 Δk/gm/cc. This case is analyzed with a FFBT, which models the RCS flow coastdown of two pumps initiated at the time of turbine trip, which occurs coincident with reactor trip breaker opening. The calculated time sequence of events for this case is shown in Table 5.1.5-1a. Figure 5.1.5-1a shows the heat flux behavior over a range of

break sizes for each MDC examined. Figures 5.1.5-2a through 5.1.5-10a show the transient response for the limiting case.

SLB Coincident with LOOP

The results of the analysis show that the number of rods entering DNB is within the acceptance criterion of 2.5%. The calculated time sequence of events for this case is shown in Table 5.1.5-1b. Figures 5.1.5-1b through 5.1.5-6b show the transient response for this case.

5.1.5.4 Conclusions

For the SLB with FFBT, a detailed analysis to assess both the minimum DNBR and the peak linear heat rate was performed using radial and axial core peaking factors based on the statepoints generated from the limiting case. Because the radial and axial peaking factors are dependent on the cycle-specific loading pattern, the minimum DNBR and peak linear heat rate are verified to meet their respective limits on a cycle-specific basis through the WCAP-9272 reload process. The analysis determined that the DNB design basis limit is met for the limiting case. Although the steamline break accident is classified as an ANS Condition III or IV event, the analysis demonstrates that the acceptance criteria for an ANS Condition II event are satisfied for all ruptures occurring from an at-power condition. This analysis bounds the ANS Condition II events of sections 5.1.2 (Inadvertent Opening of Steam Generator Safety Valve/Atmospheric Steam Dump Valve) and 5.1.4 (Increase in Main Steam Flow).

For the SLB coincident with LOOP, a detailed analysis to assess both the minimum DNBR was performed using radial and axial core peaking factors based on the limiting statepoints. The analysis determined that less than 2.5% of the rods experience DNB. Because the radial and axial peaking factors are dependent on the cycle-specific loading pattern, the minimum DNBR and peak linear heat rate are verified on a cycle-specific basis through the WCAP-9272 reload process.

5.1.5.5 References

5.1.5-1 WCAP-14882-P-A, Rev. 0, "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," April, 1999.

5.1.5-2 WCAP-11397-P-A, "Revised Thermal Design Procedure," April 1989.

5.1.5-3 Moody, F. S., "Transactions of the ASME Journal of Heat Transfer," Figure 3, page 134, February 1965.

5.1.5-4 EPRI NP-1850-CCM, Rev. 6, "RETRAN-02-A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems," December 1995.

5.1.5-5 Sung, Y., et al., "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis," WCAP-14565-P-A, October 1999.

Table 5.1.5-1a Pre-Trip Steam Line Break Analysis with FFBT Sequence of Events		
Event	**Time (sec)**	**Value**
MSLB Transient Initiated	20.01	---
Variable Overpower – ΔT Power Setpoint Reached	29.56	102%
Reactor Trip Signal Generated	29.96	0.40 sec. delay from setpoint
Turbine Trip on Reactor Trip	29.96	0.0 sec. delay from reactor trip
Coastdown of 2 pumps initiated	29.97	
Peak Linear Heat Rate Reached	30.35	<22.00 kW/ft
CEA Release	30.70	0.74 sec. delay from reactor trip
Peak Heat Flux Reached	31.76	110.7%
Minimum DNBR Reached	32.01	>1.37 (SAL DNBR)*

* The SAL DNBR of 1.37 meets the 95/95 DNB design criterion with additional margin.

Table 5.1.5-1b Pre-Trip Steam Line Break with a Coincident Loss of Offsite Power Sequence of Events		
Event	**Time (sec)**	**Value**
MSLB Transient Initiated & Loss of Offsite Power (All RCPs begin to coastdown)	10.01	
Low Flow Reactor Trip Setpoint Reached	11.28	87.9% of Thermal Design Flow
Reactor Trip	11.68	0.40 sec. delay from setpoint
CEA Release	12.42	0.74 sec. delay from reactor trip
Minimum DNBR Reached	14.26	Safety Analysis Limit (SAL) DNBR of 1.37. Any fuel rods with DNBR < SAL DNBR are assumed to fail.

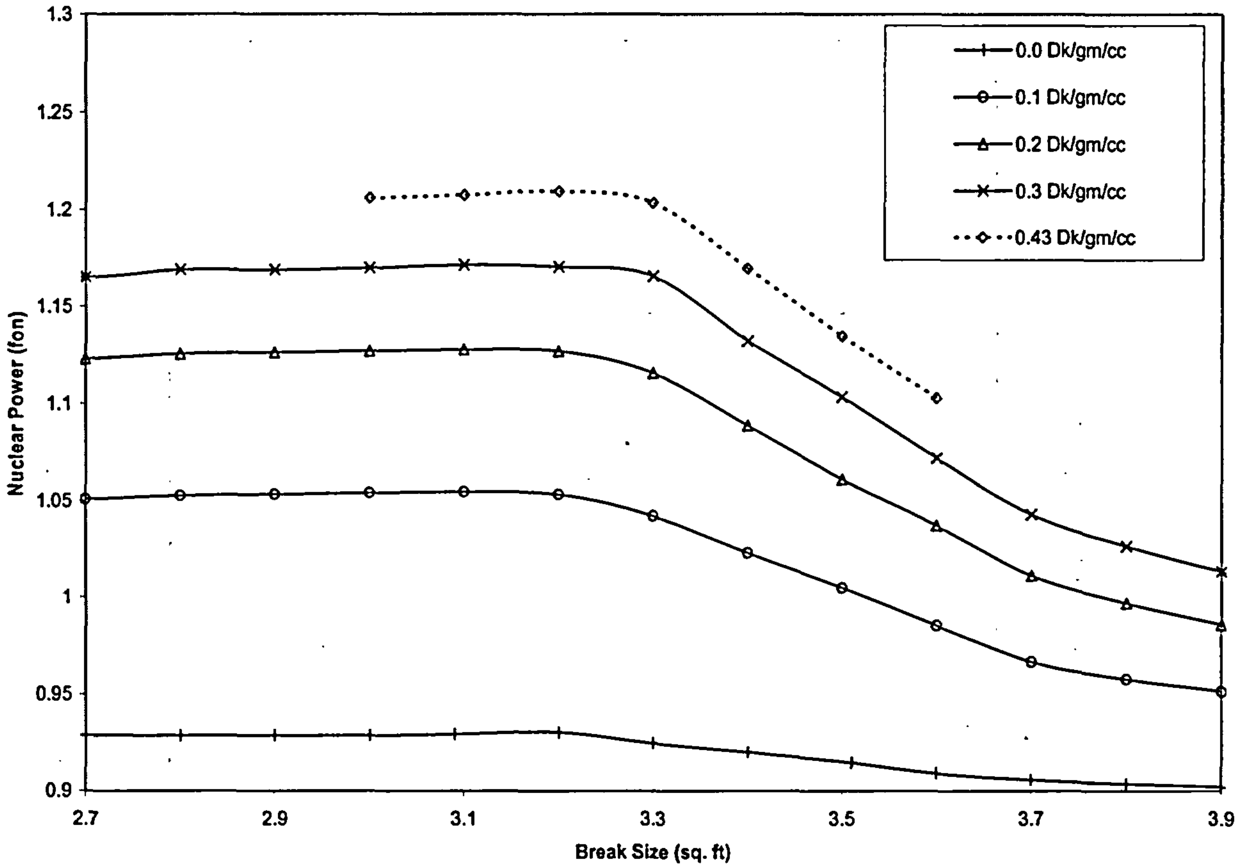

Figure 5.1.5-1a
Pre-Trip Main Steamline Break - FFBT
Peak Nuclear Power vs. Break Size for a Spectrum of MDCs

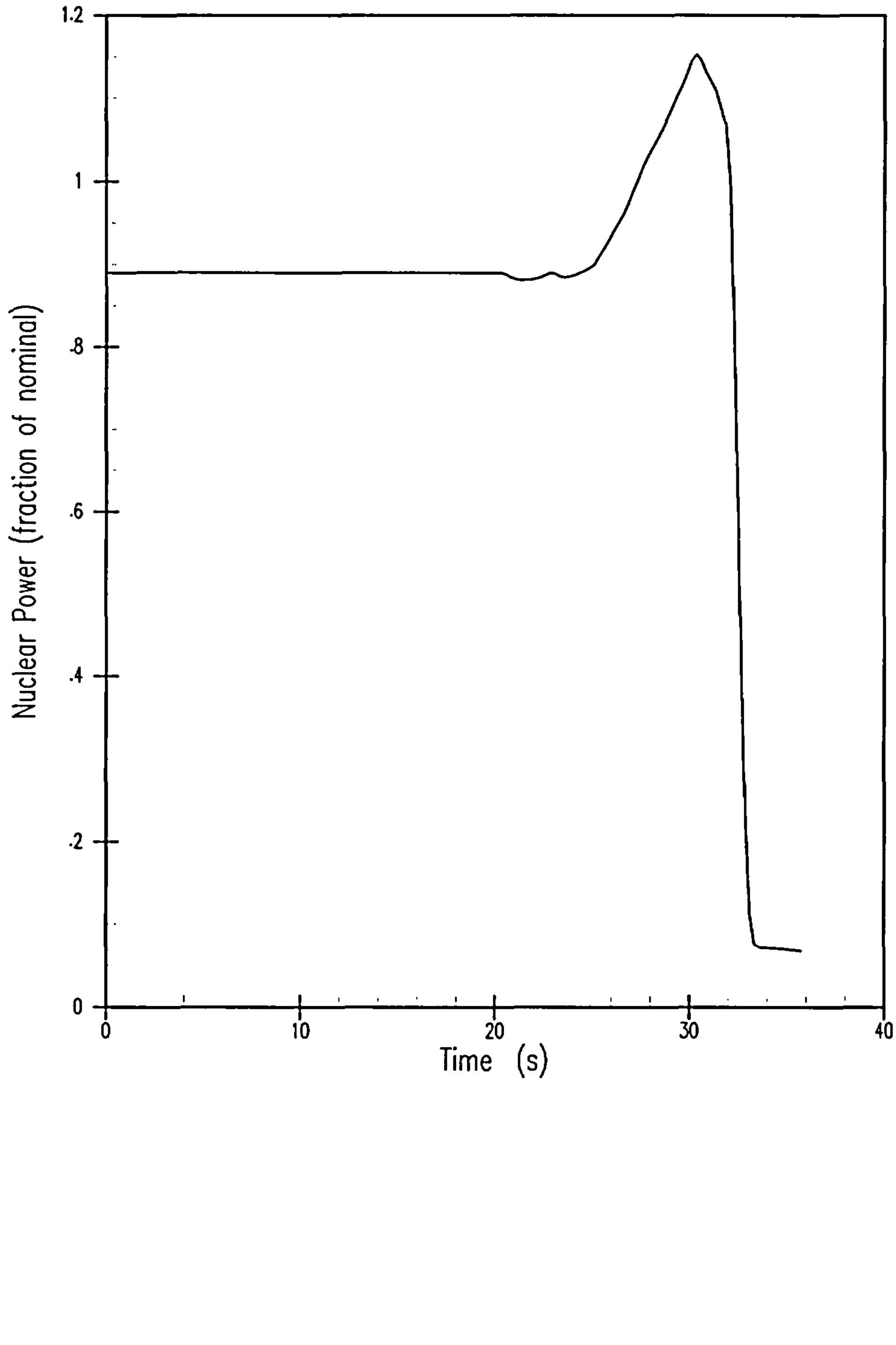

Figure 5.1.5-2a
Pre-Trip Main Steamline Break - FFBT
Nuclear Power

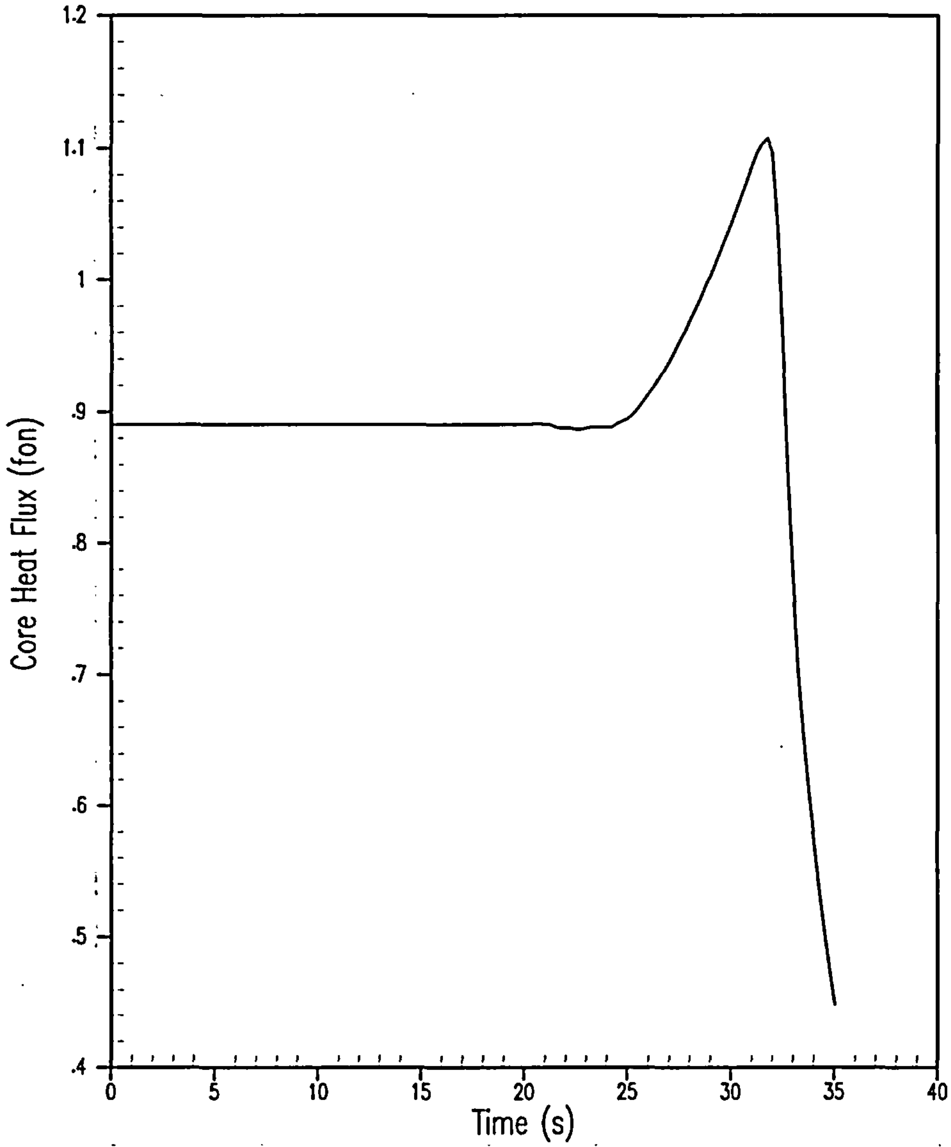

Figure 5.1.5-3a
Pre-Trip Main Steamline Break – FFBT
Core Heat Flux

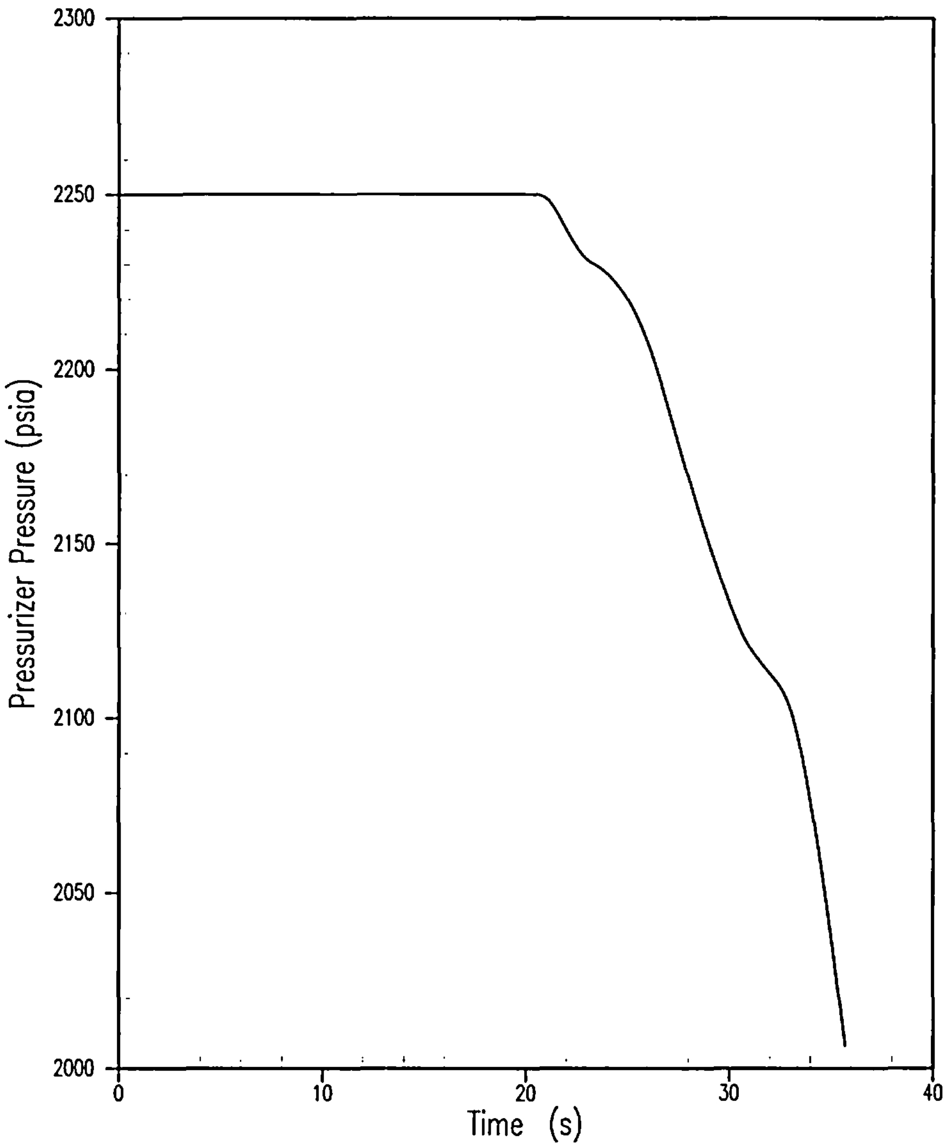

Figure 5.1.5-4a
Pre-Trip Main Steamline Break – FFBT
Pressurizer Pressure

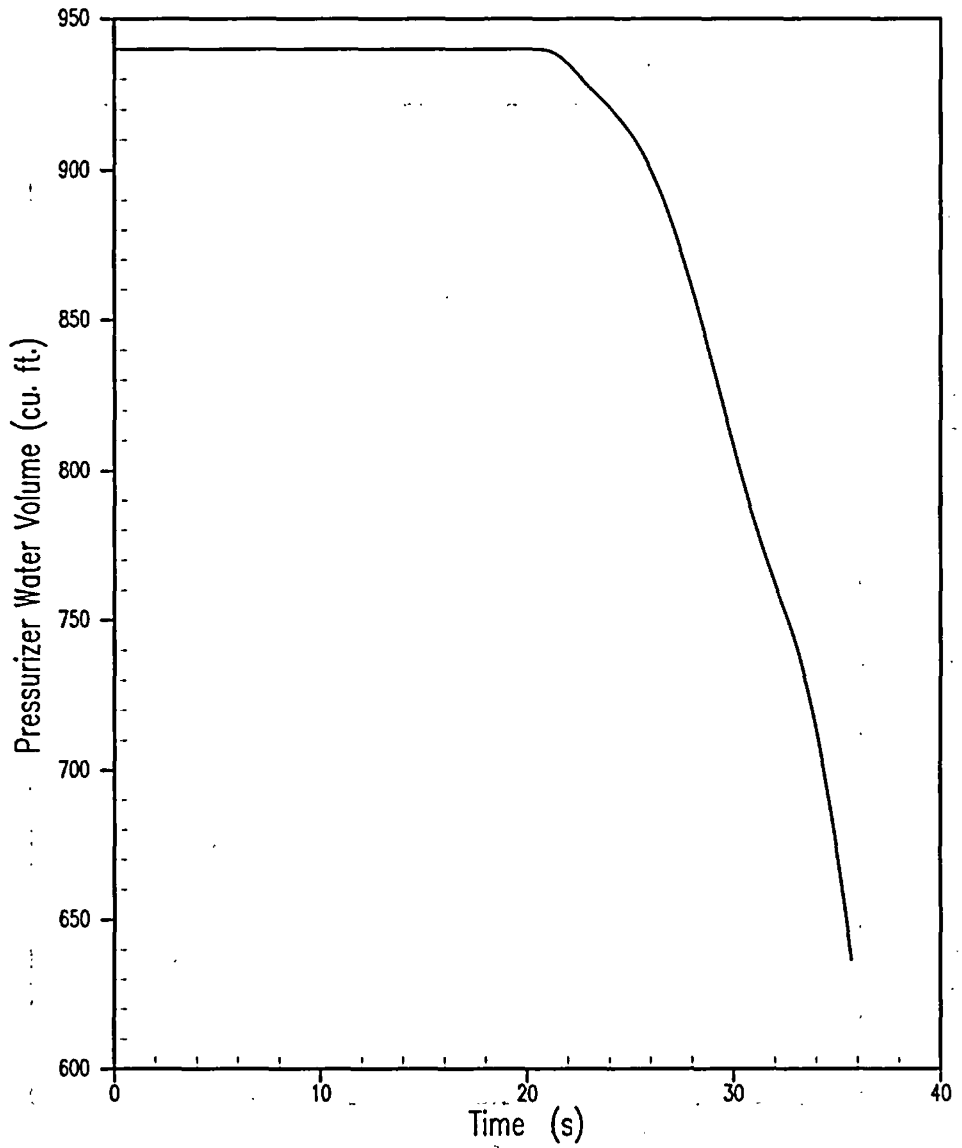

Figure 5.1.5-5a
Pre-Trip Main Steamline Break – FFBT
Pressurizer Water Volume

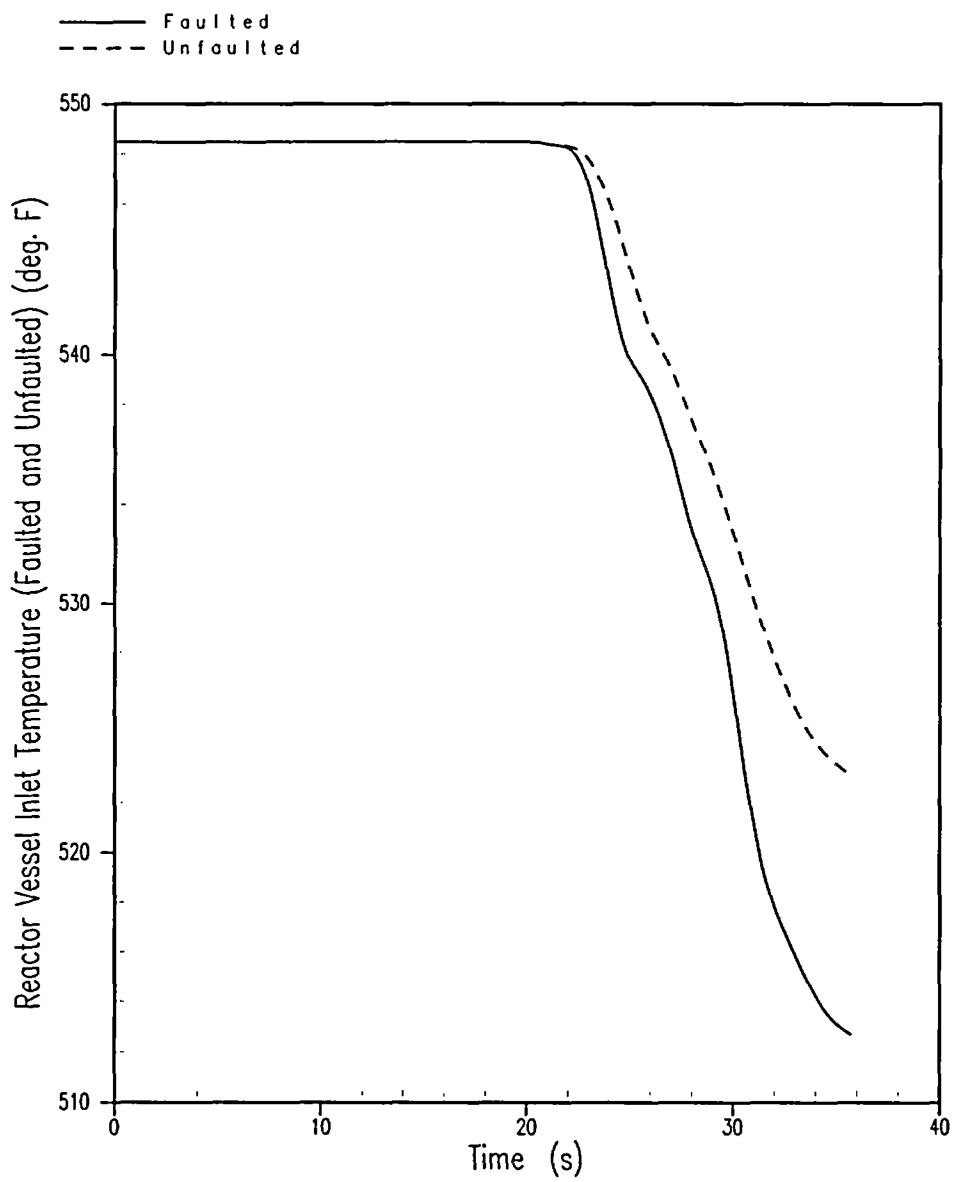

Figure 5.1.5-6a
Pre-Trip Main Steamline Break – FFBT
Reactor Vessel Inlet Temperature

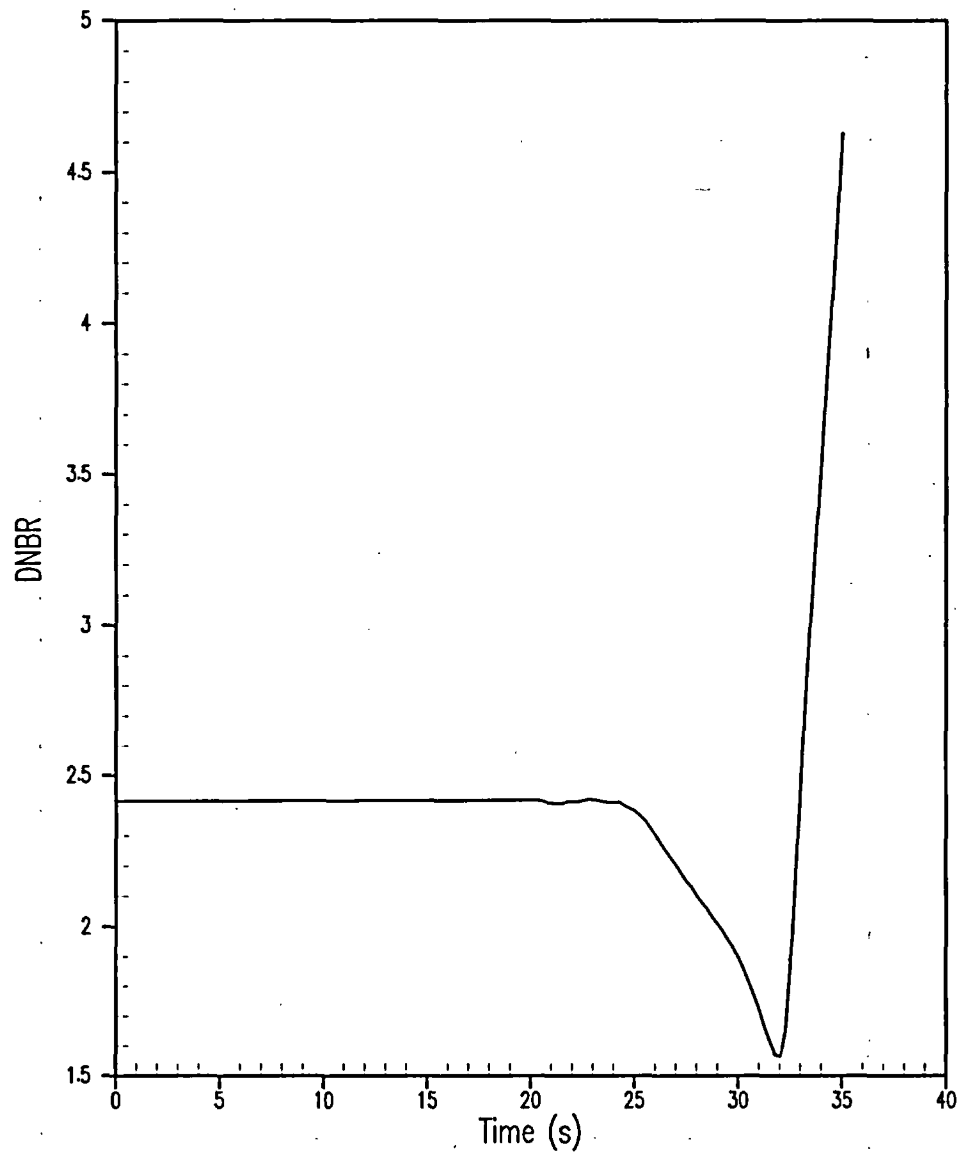

Figure 5.1.5-7a
Pre-Trip Main Steamline Break – FFBT
DNBR

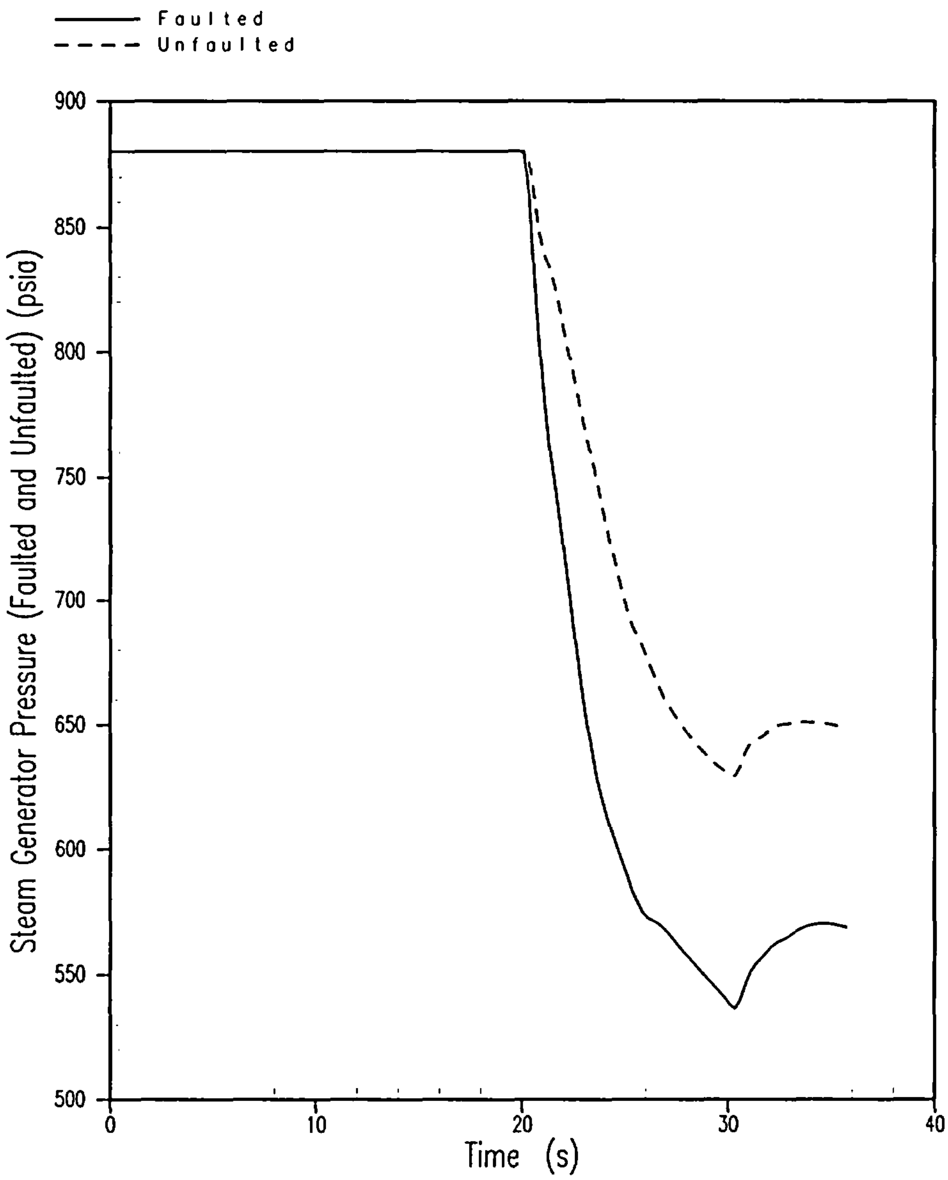

Figure 5.1.5-8a
Pre-Trip Main Steamline Break – FFBT
Steam Generator Steam Pressure

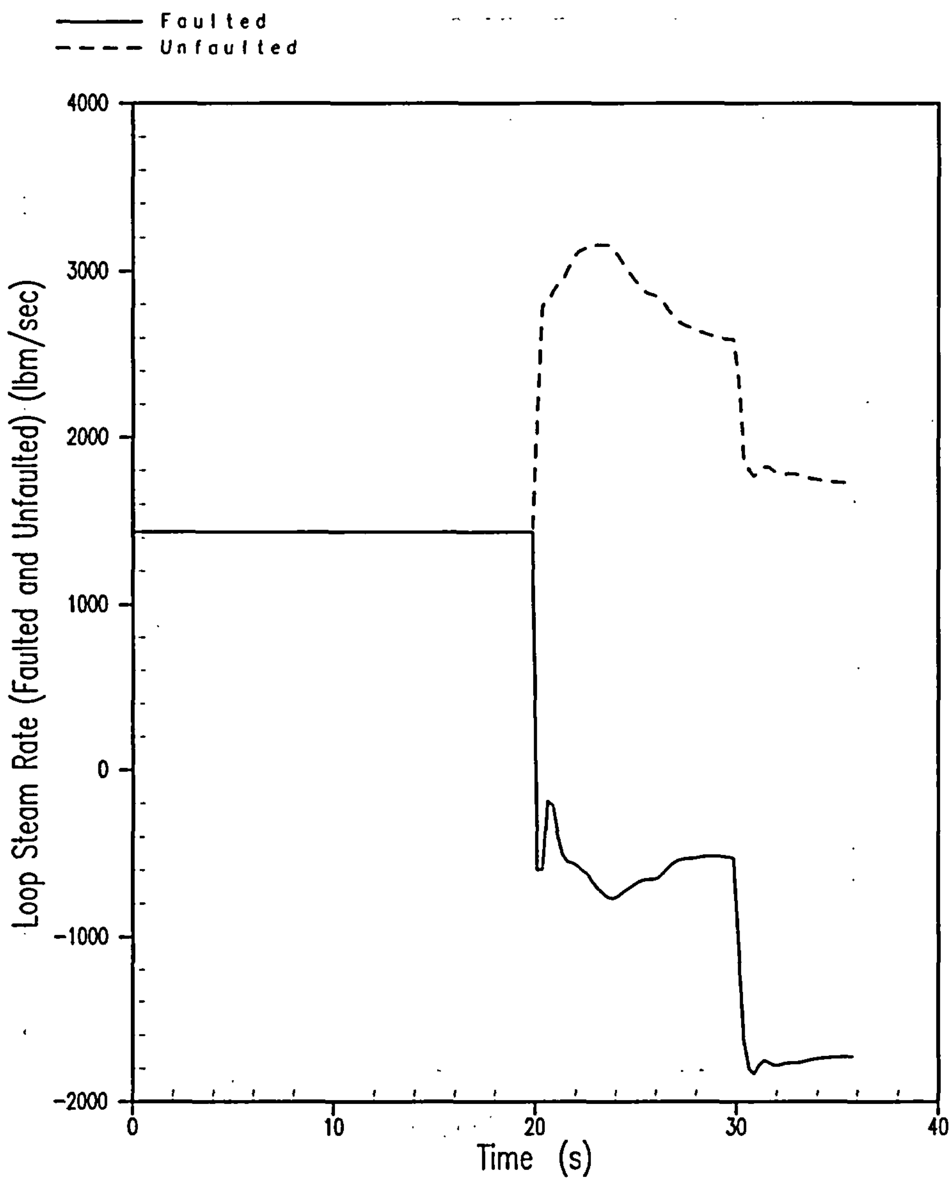

Figure 5.1.5-9a
Pre-Trip Main Steamline Break – FFBT
Loop Steam Rate

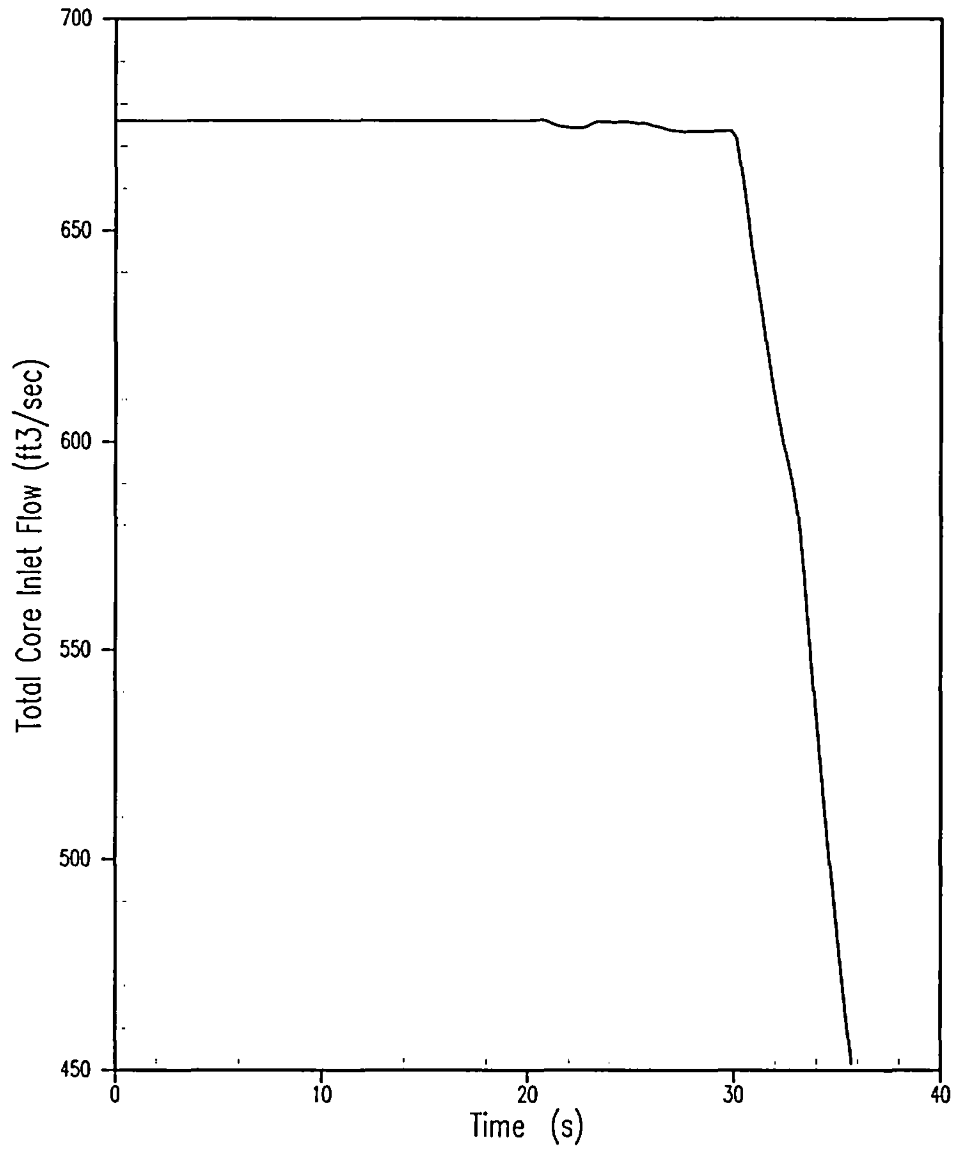

Figure 5.1.5-10a
Pre-Trip Main Steamline Break – FFBT
Core Inlet Flow

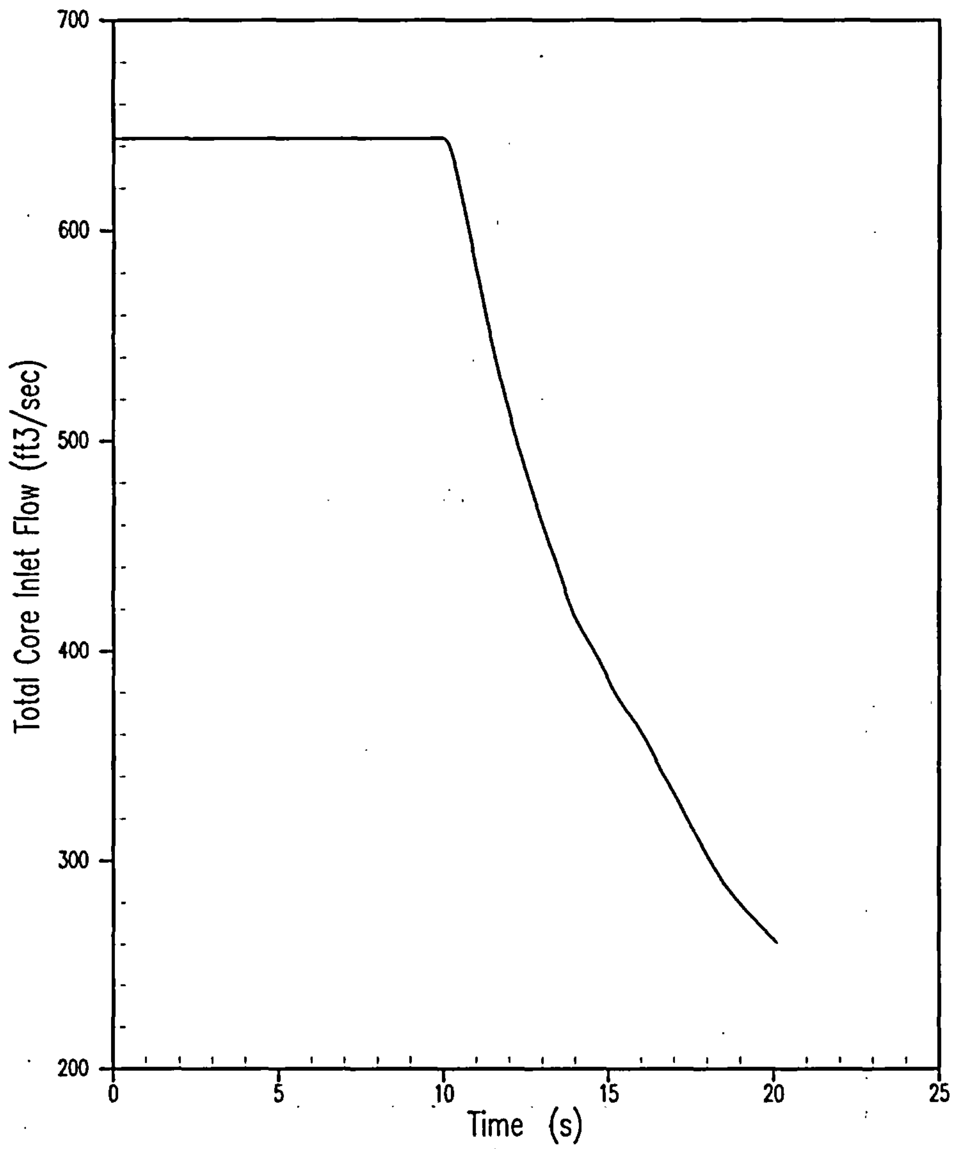

Figure 5.1.5-1b
Pre-Trip Main Steamline Break with LOOP
Total Core Inlet Flow

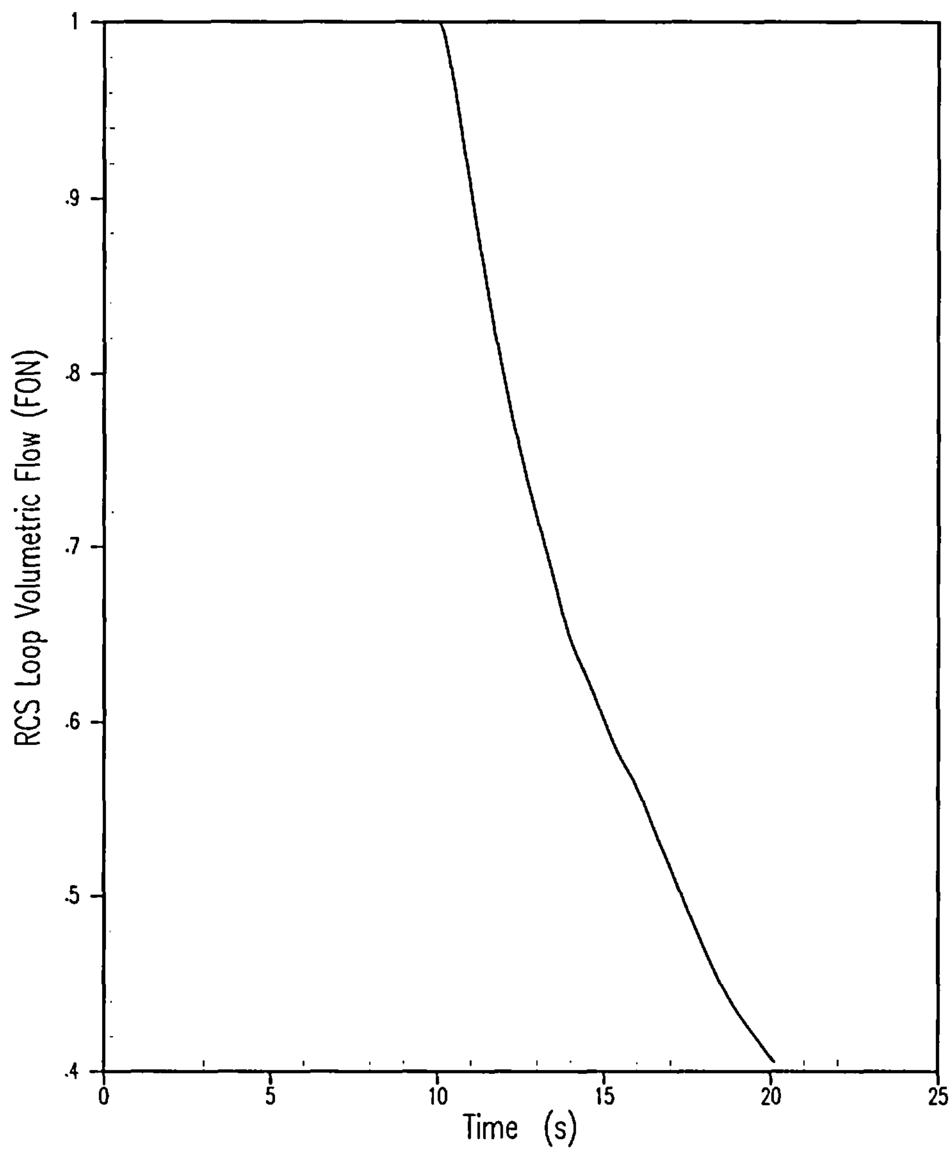

Figure 5.1.5-2b
Pre-Trip Main Steamline Break with LOOP
RCS Loop Volumetric Flow

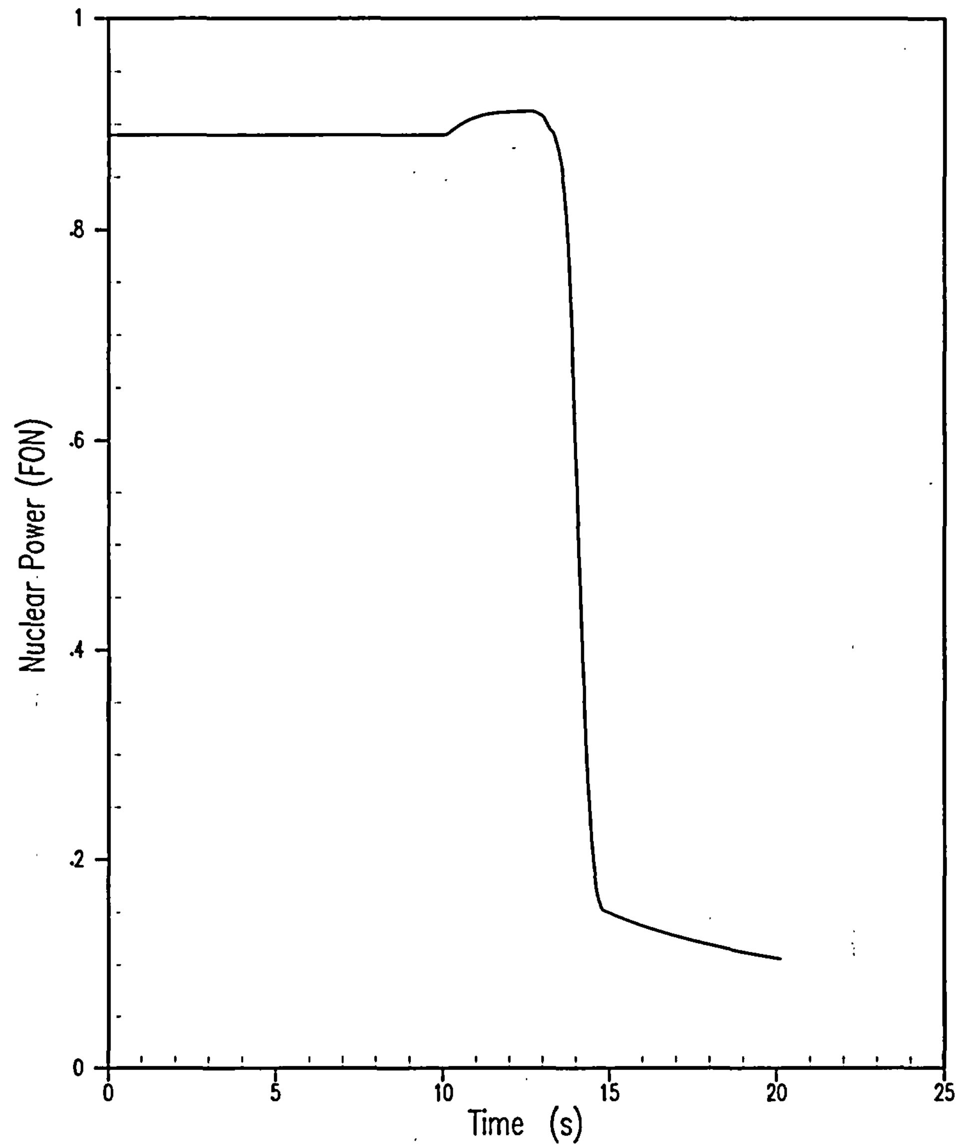

Figure 5.1.5-3b
Pre-Trip Main Steamline Break with LOOP
Nuclear Power

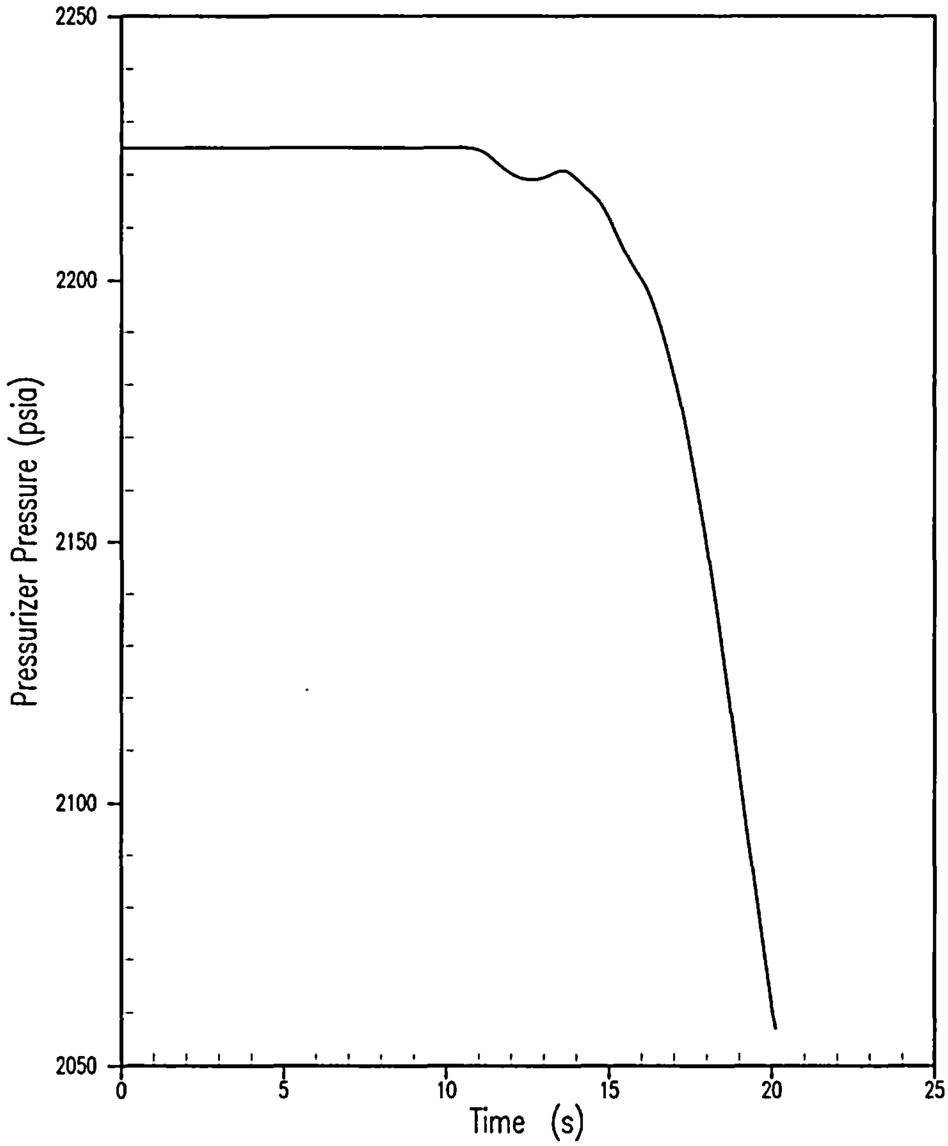

Figure 5.1.5-4b
Pre-Trip Main Steamline Break with LOOP
Pressurizer Pressure

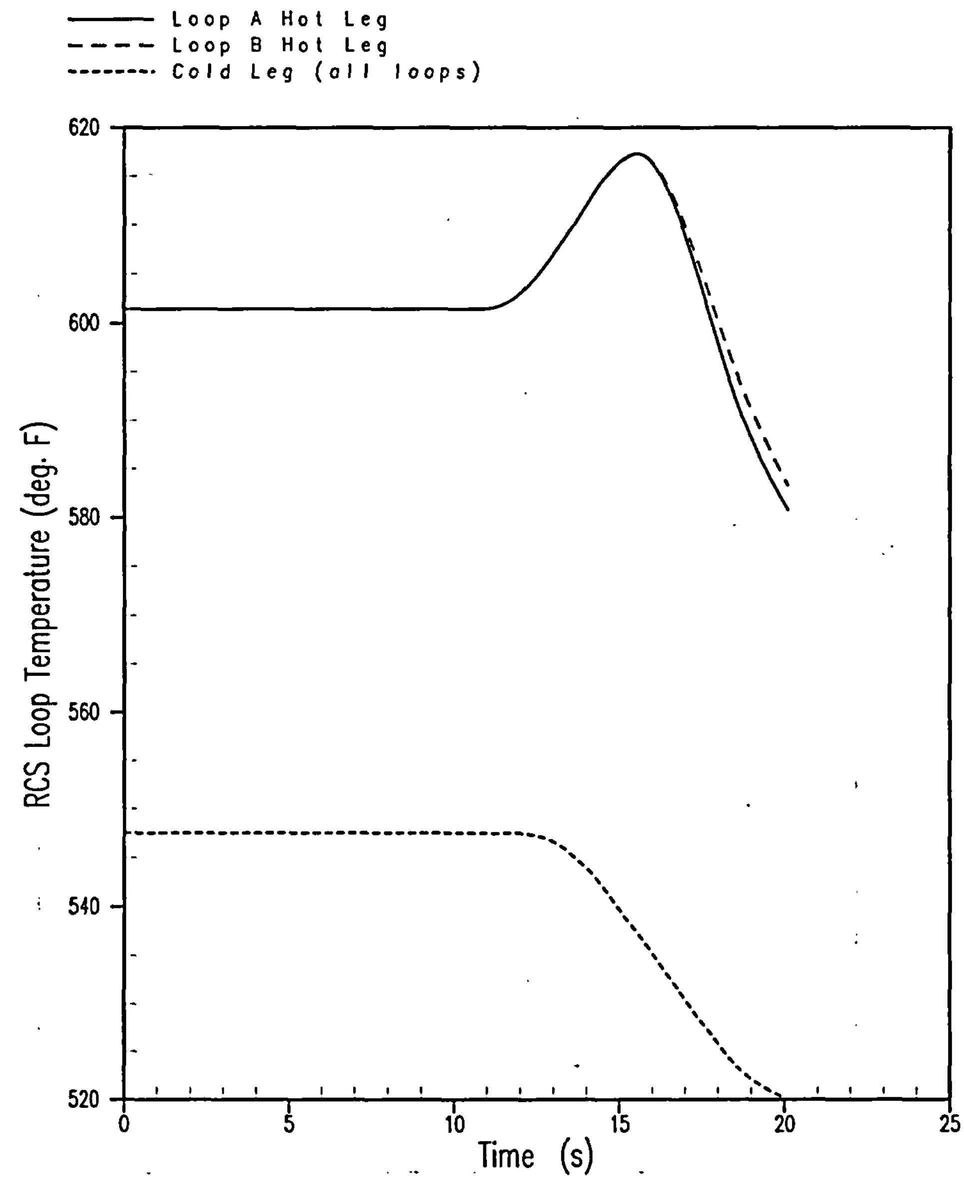

Figure 5.1.5-5b
Pre-Trip Main Steamline Break with LOOP
RCS Loop Temperature

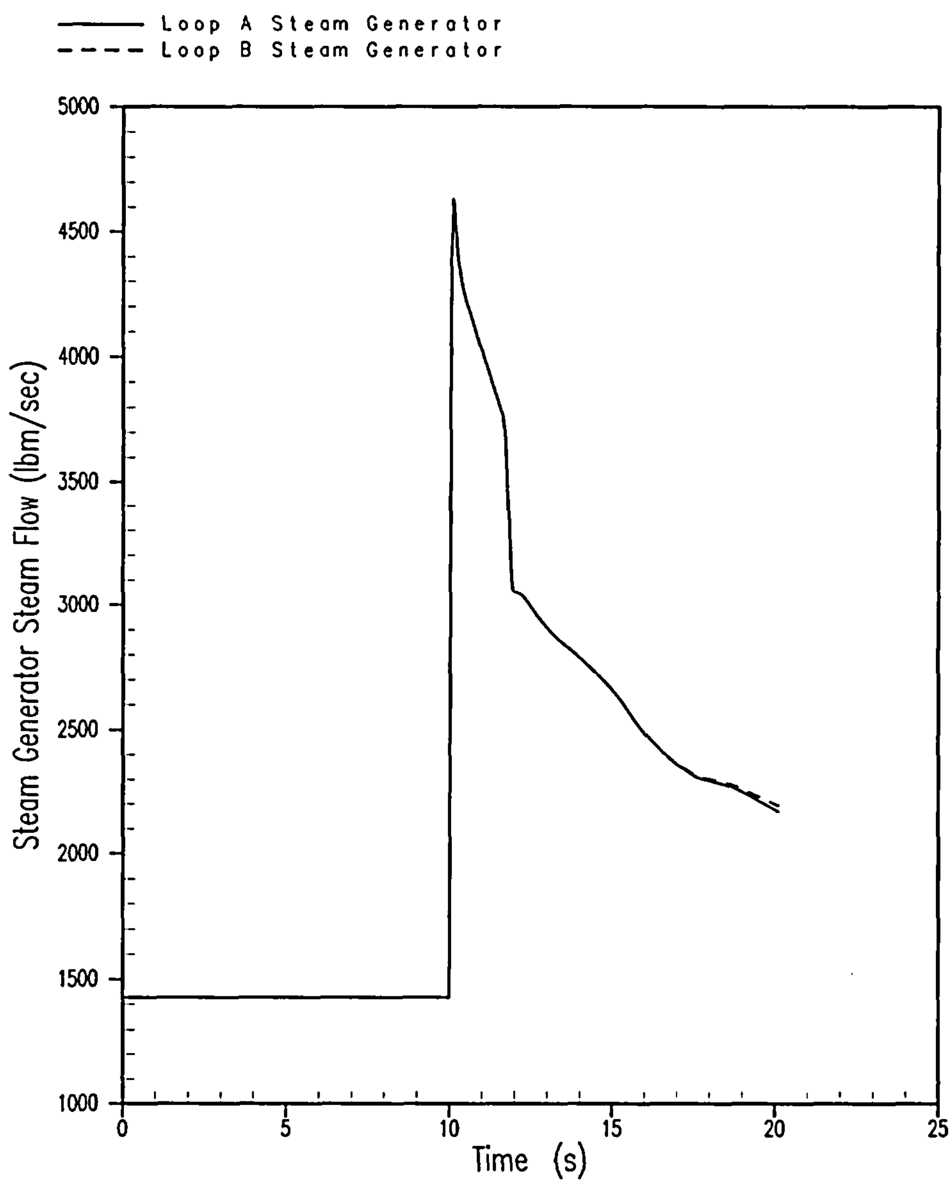

Figure 5.1.5-6b
Pre-Trip Main Steamline Break with LOOP
Steam Generator Steam Flow

5.1.6 Post-Trip Steam System Piping Failures

5.1.6.1 Accident Description

A steamline break transient results in an uncontrolled increase in steam flow release from the steam generators, with the flow decreasing as the steam pressure drops. This steam flow release increases the heat removal from the RCS, which decreases the RCS temperature and pressure. With the existence of a negative moderator temperature coefficient (MTC), the RCS cooldown results in a positive reactivity insertion, and consequently a reduction of the core shutdown margin for the post-trip condition. If the most reactive CEA is assumed to be stuck in its fully withdrawn position after reactor trip, the possibility is increased that the core may become critical and subsequently return to power. A return to power following a steamline break from the post-trip condition is a concern with the high-power peaking factors that may exist when the most reactive CEA is stuck in its fully withdrawn position. Following a steamline break, the core is ultimately shut down by the boric acid injected into the RCS by either the emergency core cooling system (safety injection) or the actuation of the Safety Injection Tanks (SITs). Additionally, the event may be terminated due to reaching a dry-out condition in the affected steam generator.

The 42% steam generator tube plugging (SGTP) post-trip steamline break statepoints were based on the 30% SGTP post-trip steamline break statepoints generated for Reference 5.1.6-1, Section 5.1.6. The 30% SGTP post-trip steamline break statepoints were modified to make them applicable to the 42% SGTP program by applying a multiplier to the reactor coolant system (RCS) thermal design flow (TDF) to correct the flow from 335,000 gpm to 300,000 gpm. This change in RCS flow accounts for the increase in steam generator tube plugging. The reduction in flow resulting from the increase in SGTP results in less heat transfer and consequently a less adverse return to power. Therefore the statepoints used in the 30% SGTP analysis are conservative with respect to the response that would be predicted by the RETRAN code. Additionally, the 42% flow value is addressed in the ANC calculation of the transient power shapes. Assumptions 1 though 11 in Section 5.1.6.2 are consistent with the 30% SGTP analysis. Assumption 12 reflects the lower flow assumption associated with the 42% SGTP program that was used for the ANC and VIPRE analyses.

The steamline break analysis discussed herein was performed to demonstrate that core coolable geometry is maintained. Assuming the most reactive CEA is stuck in its fully withdrawn position, and applying the most limiting single failure of one safety injection train, steamline break core response cases were examined. Although DNB and fuel cladding damage are not necessarily unacceptable consequences of a steamline break transient, the analysis described herein demonstrates that there is no consequential damage to the primary system, and that the core remains in place and intact, by showing that the DNB design-basis is satisfied following a steamline break.

The systems and components that provide the necessary protection against a steamline break are listed as follows:

1. Safety injection system actuation by any of the following:
   - Pressurizer pressure - low
   - Containment pressure - high

2. Closure of the main steam isolation valves (MSIVs) after receipt of any of the following:
   - Steam generator pressure - low
   - Containment pressure - high
3. Closure of the main feedwater isolation valves.

Each main steamline is connected to a steam generator through an exit nozzle with an effective flow area of 6.305 ft^2 and contains a venturi-type flow restrictor located upstream of the MSIV and inside containment. These flow restrictors limit the steam release rate during a steamline break transient. The nozzle flow restrictors limit the effective maximum steamline break size to 2.27 ft^2 per steam generator.

5.1.6.2 Method of Analysis

The analysis of the steamline break transient demonstrates that the DNB design basis is satisfied and that the peak linear heat rate does not exceed the limit value. This is accomplished by showing that the calculated minimum DNBR is greater than the safety analysis limit DNBR of 1.45 (W-3 low pressure DNB correlation limit) and that the peak linear heat rate remains below 22 kW/ft. The overall analysis process is described as follows.

Using the RETRAN code (References 5.1.6-2 and 5.1.6-3), transient values of key plant parameters identified as statepoints (core average heat flux, core pressure, core inlet temperature, RCS flow rate, and core boron concentration) were calculated first. Next, the advanced nodal code (ANC) core design code was used to:

- Evaluate the nuclear response to the RCS cooldown so as to verify the RETRAN transient prediction of the average core power/reactivity

- Determine the peaking factors associated with the return to power in the region of the stuck CEA

Finally, using the RETRAN-calculated statepoints and the ANC-calculated peaking factors, the detailed thermal and hydraulic computer code VIPRE was used to calculate the minimum DNBR based on the W-3 DNB correlation. The peak linear heat rate is calculated based on the results of the ANC analysis.

The following assumptions were made in the analysis of the main steamline break:

1. A hypothetical double-ended rupture (DER) of a main steamline was postulated at HZP/hot shutdown conditions. The maximum break size seen by the faulted steam generator is limited to the flow area of the steam generator outlet nozzle (6.305 ft2). The maximum break size seen by the unfaulted steam generator is limited to the flow area of the inline flow restrictor (2.27 ft2). The initial conditions correspond to a subcritical reactor, an initial vessel average temperature at the no-load value of 532°F, and no core decay heat. These conditions are conservative, compared to hot full power, for a steamline break transient because the resultant RCS cooldown does not have to remove any latent heat. Also, the steam generator water inventory is greatest at no-load conditions, which increases the capability for cooling the RCS. Thus, the analysis of the hot zero power case bounds the case of a post-trip analysis from hot full power.

2. One DER case was analyzed. A case assuming a loss of offsite power is bounded by the case assuming that offsite power is maintained throughout the event (see Reference 5.1.6-4). Steamline break

transients associated with the inadvertent opening of a steam dump or relief valve were not analyzed because the resultant RCS cooldown. Therefore, the minimum DNBR would be less limiting compared to the DER cases.

3. Perfect moisture separation within the steam generators was conservatively assumed.

4. An end-of-life shutdown margin of 3.6 %Δk corresponding to no-load, equilibrium xenon conditions, with the most reactive CEA stuck in its fully withdrawn position was assumed. The stuck CEA was assumed to be in the core location exposed to the greatest cooldown; that is, related to the faulted loop. The reactivity feedback model included a positive MDC corresponding to an end-of-life rodded core with the most reactive CEA in its fully withdrawn position. The variation of the MDC due to changes in coolant density and boron concentration was accounted for in the model. Figure 5.1.6-1 presents the k_{eff} versus temperature relationship at 900 psia corresponding to the MDC plus the Doppler temperature feedback effect. The Doppler power feedback corresponding to the stuck CEA conditions is provided in Figure 5.1.6-2.

   The reactivity and power predicted by RETRAN were compared to those predicted by the ANC core design code. The ANC core analysis considered the following:

   - Doppler reactivity feedback from the high fuel temperature near the stuck CEA
   - Moderator feedback from the water conditions near the stuck CEA
   - Power redistribution effects
   - Non-uniform core inlet temperature effects

   The ANC core analysis confirmed that the RETRAN-predicted reactivity is acceptable.

5. The Moody critical flow curve was applied to conservatively maximize the break flow rate assuming no frictional losses.

6. The closure of the MSIV of the intact/unfaulted loop was conservatively modeled to be complete at 6.75 seconds after receipt of a low steam generator pressure (520 psia) signal from the same loop.

7. The safety injection pumps were assumed to provide flow to the RCS at 20 seconds after receipt of a safety injection signal on low pressurizer pressure (1646 psia). This delay accounts for signal processing and pump startup delays.

8. The minimum capability for the injection of boric acid solution, corresponding to the most restrictive single active failure in the SIS, was assumed. The assumed safety injection flow (see Figure 5.1.6-3) corresponds to the operation of one high-head safety injection pump. Boric acid solution from the refueling water tank (RWT), with a minimum concentration of 1720 ppm and a minimum temperature of 51°F, was the assumed source of the safety injection flow. The safety injection lines downstream of the RWT were assumed to initially contain unborated water to conservatively maximize the time it takes to deliver the highly concentrated RWT boric acid solution to the reactor coolant loops.

9. Main feedwater flow equal to the nominal (100% power) value was assumed to initiate coincident with the postulated break. Feedwater flow to the unfaulted loop was maintained until a feedwater isolation signal was generated. Feedwater isolation to the faulted loop was delayed an additional 90 seconds beyond the receipt of a feedwater isolation signal. The feedwater isolation to the faulted steam generator was assumed to be complete at 92.9 seconds after the steam generator pressure in the faulted loop reaches the low setpoint.

10. A minimum SGTP level of 0% was assumed to maximize the heat transfer capabilities of the steam generators and therefore maximize the cooldown of the RCS.

11. Due to the design of the auxiliary feedwater system which automatically isolates the auxiliary feedwater from the broken loop, no auxiliary feedwater was assumed to be delivered during the event.

12. A thermal design flow of 300,000 gallons per minute was assumed.

5.1.6.3 Results

The results of the statepoint evaluation demonstrate that the post-trip steamline break event meets the applicable DNBR and peak linear heat rate acceptance criteria. The time sequence of events is presented in Table 5.1.6-1.

Figures 5.1.6-4 through 5.1.6-11 show the steam pressure, steam flow, pressurizer pressure, pressurizer water volume, reactor vessel inlet temperature, core heat flux, core boron concentration, and core reactivity following a double-ended rupture of a main steamline at initial no-load conditions with offsite power available (full reactor coolant flow). The break size was limited to 6.305 ft^2 on the faulted steam generator and to 2.27 ft^2 on the unfaulted steam generator by the inline flow restrictors. Both steam generators were assumed to discharge through the break until steamline isolation had occurred.

5.1.6.4 Conclusions

The main steamline break transient was conservatively analyzed with respect to the reactor core response. Key analysis assumptions were made to conservatively maximize the cooldown of the RCS, so as to maximize the positive reactivity insertion, and thus maximize the peak return to power. Other key assumptions include: end-of-life shutdown margin with the most-reactive CEA stuck in its fully withdrawn position, maximum delays in actuating engineered safeguard features such as safety injection, main steam isolation and feedwater isolation, and minimum safety injection flow with a minimum boron concentration.

A DNBR statepoint analysis was performed for the post-trip steamline break event with offsite power. The case with offsite power available, that is, the case with full reactor coolant flow, was found to be the limiting case. The minimum DNBR was determined to be greater than the DNBR safety analysis limit, and thus the DNBR design basis is met. Additionally, the peak linear heat rate was demonstrated not to exceed the limit value.

5.1.6.5 References

5.1.6-1 St. Lucie Unit 2 30-Percent Steam Generator Tube Plugging and WCAP-9272 Reload Methodology Transition Project Licensing Report, October 2003.

5.1.6-2 WCAP-14882-P-A, Rev. 0, "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," April, 1999.

5.1.6-3 EPRI NP-1850-CCM, Rev. 6, "RETRAN-02-A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems," December 1995.

5.1.6-4 Letter, B. Moroney (NRC) to J. A. Stall (FPL), "St Lucie Plant, Unit No. 2 – Issuance of Amendment Regarding Change in Reload Methodology and Increase in Steam Generator Tube Plugging Limit (TAC No. MC1566), January 31, 2005. [Amendment 138]

Table 5.1.6-1 Post-Trip Steamline Break Analysis Assumptions and Sequence of Events		
Event	**Time (sec)**	**Value**
MSLB (6.305 ft^2 DER) Transient Initiated	0.01	---
Manual Reactor Trip Initiated	0.01	---
MSIV/MFIV Closure Signal on Low Steam Generator Pressure	3.36	520 psia
Feedwater Isolation (MFIV Closure) on Loop 2	8.51	5.15 sec. delay
Steamline Isolation (MSIV Closure) on Loops 1 and 2	10.11	6.75 sec. delay
SI Actuation Signal on Low Pressurizer Pressure	13.71	1646 psia
Core Criticality Attained	48.05	---
Feedwater Isolation (MFIV Closure) on Loop 1	92.92	90.0 sec. delay
Peak Heat Flux Reached	305.50	18.2%
Minimum DNBR Reached	305.50	1.491
Peak Linear Heat Rate Reached	305.50	20.8 kW/ft

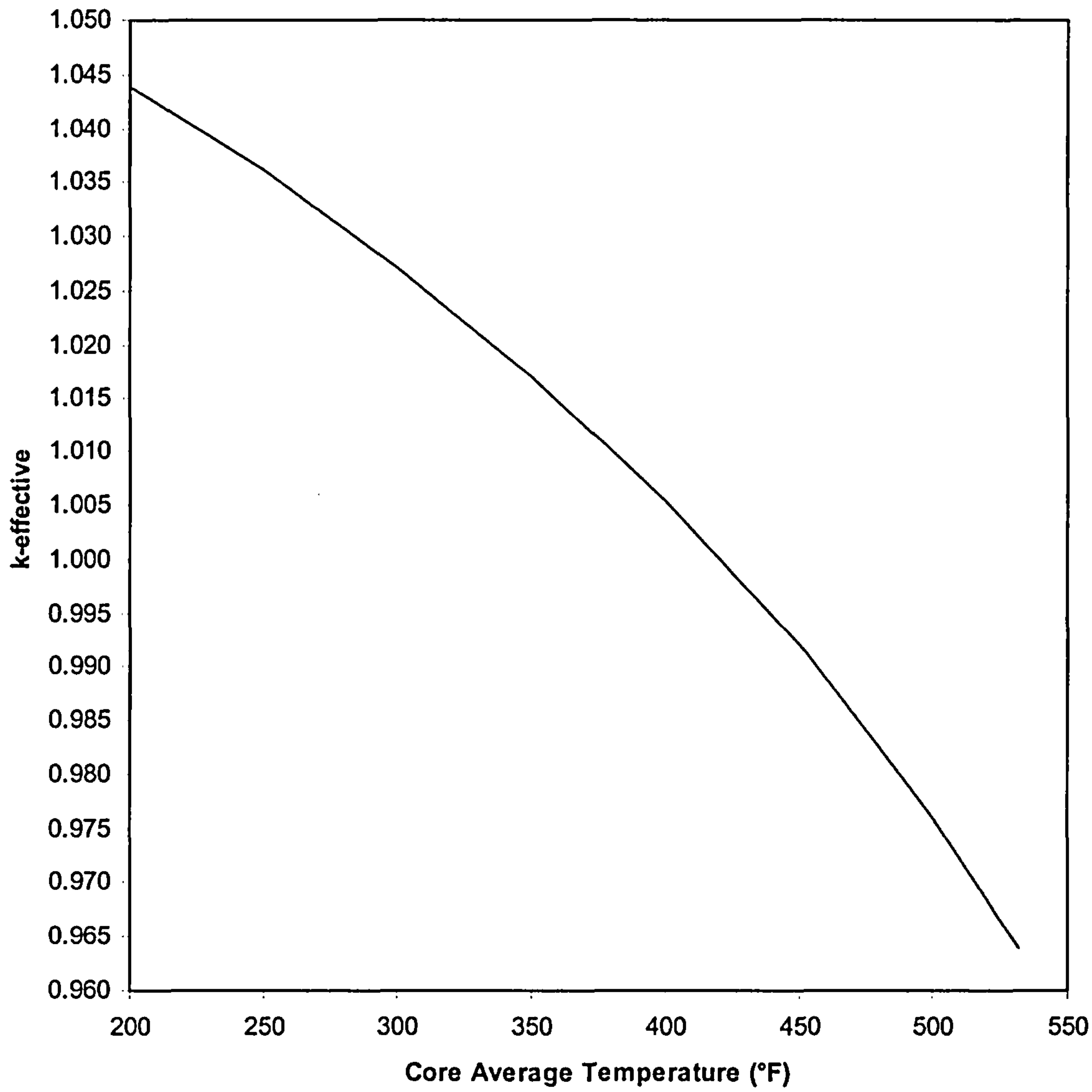

Figure 5.1.6-1
Variation of K_{eff} with Core Temperature (3.6 %Δk SDM, 900 psia)

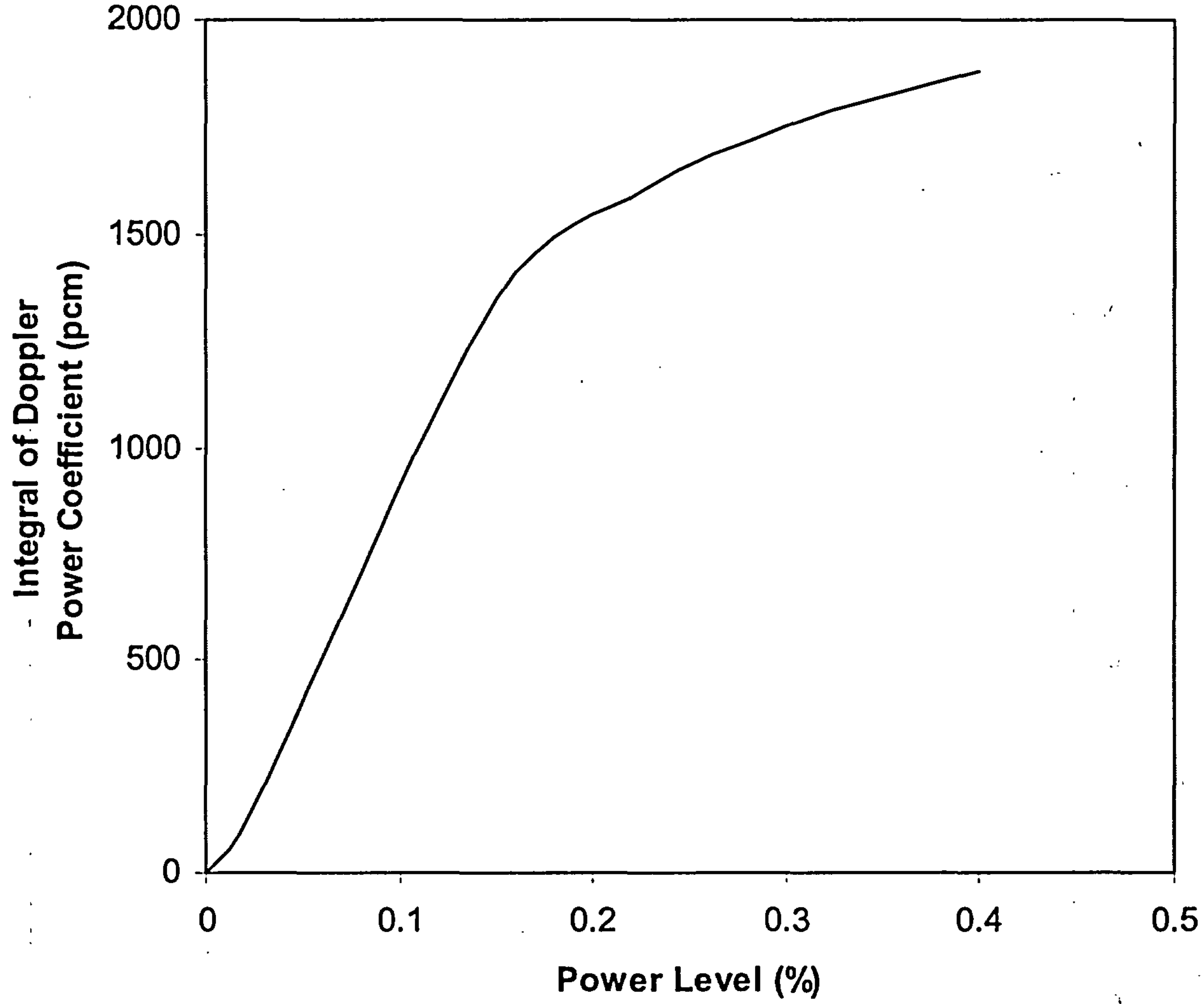

Figure 5.1.6-2
Stuck CEA Doppler Power Feedback

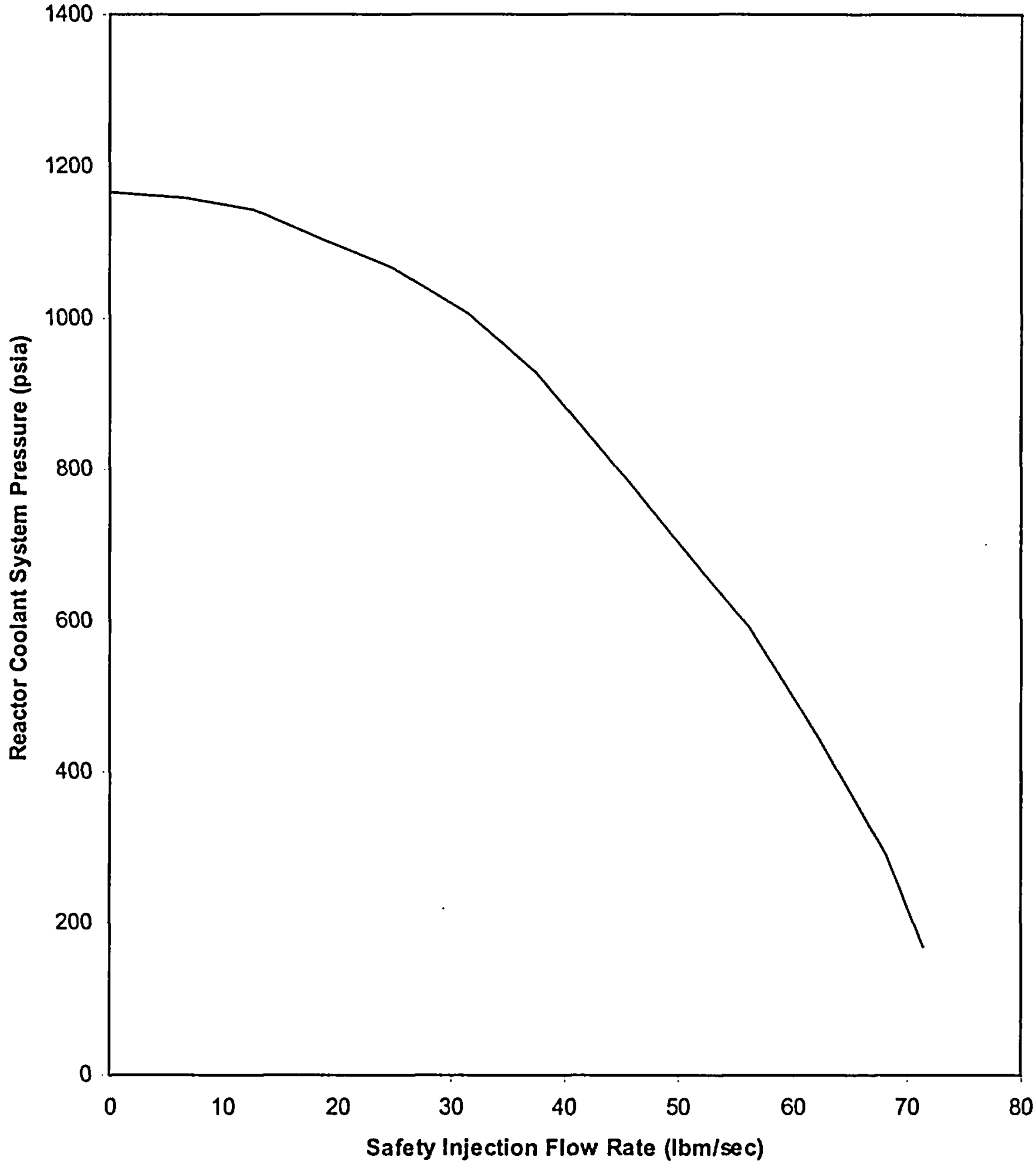

Figure 5.1.6-3
Safety Injection Curve

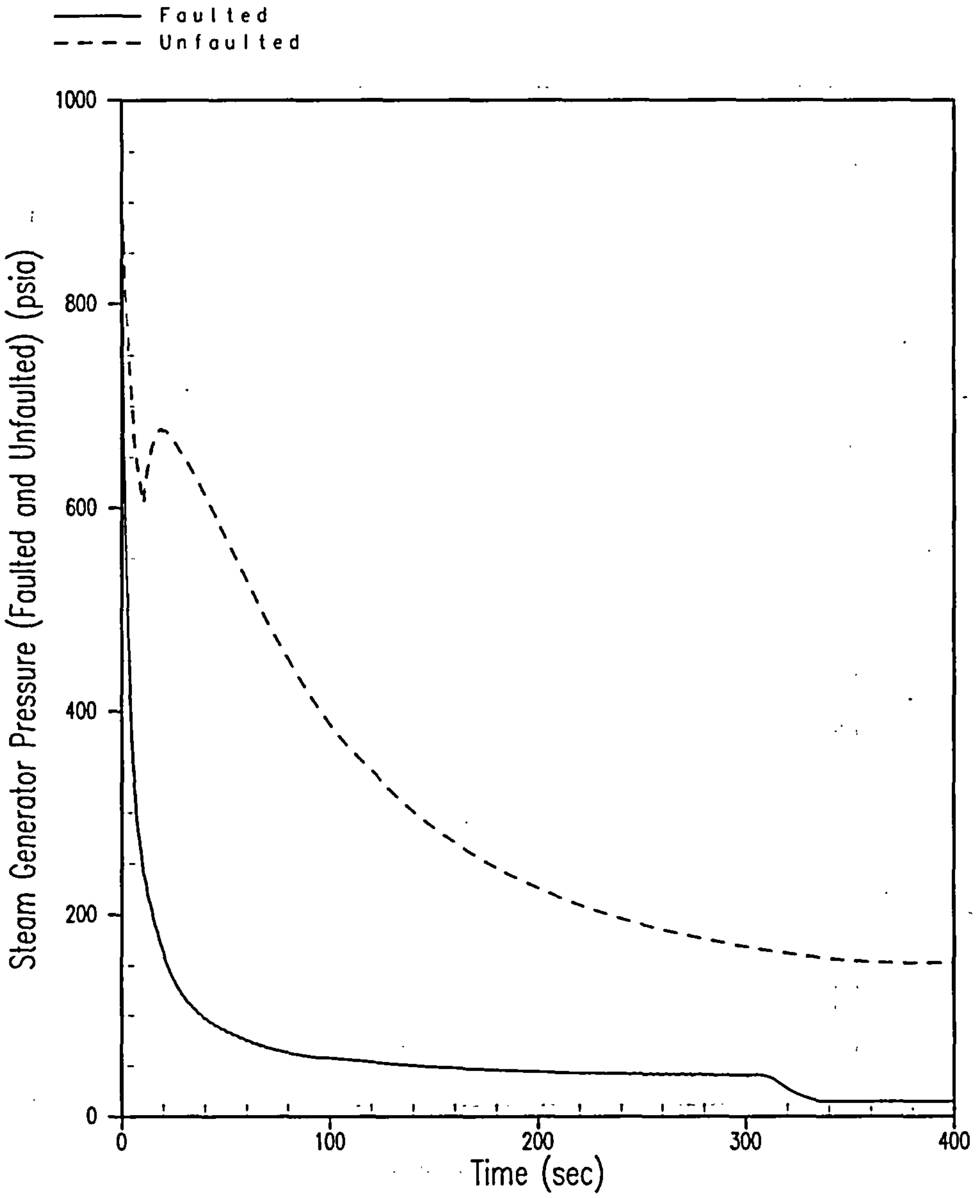

Figure 5.1.6-4
Post-Trip Main Steamline Break
Steam Generator Steam Pressure

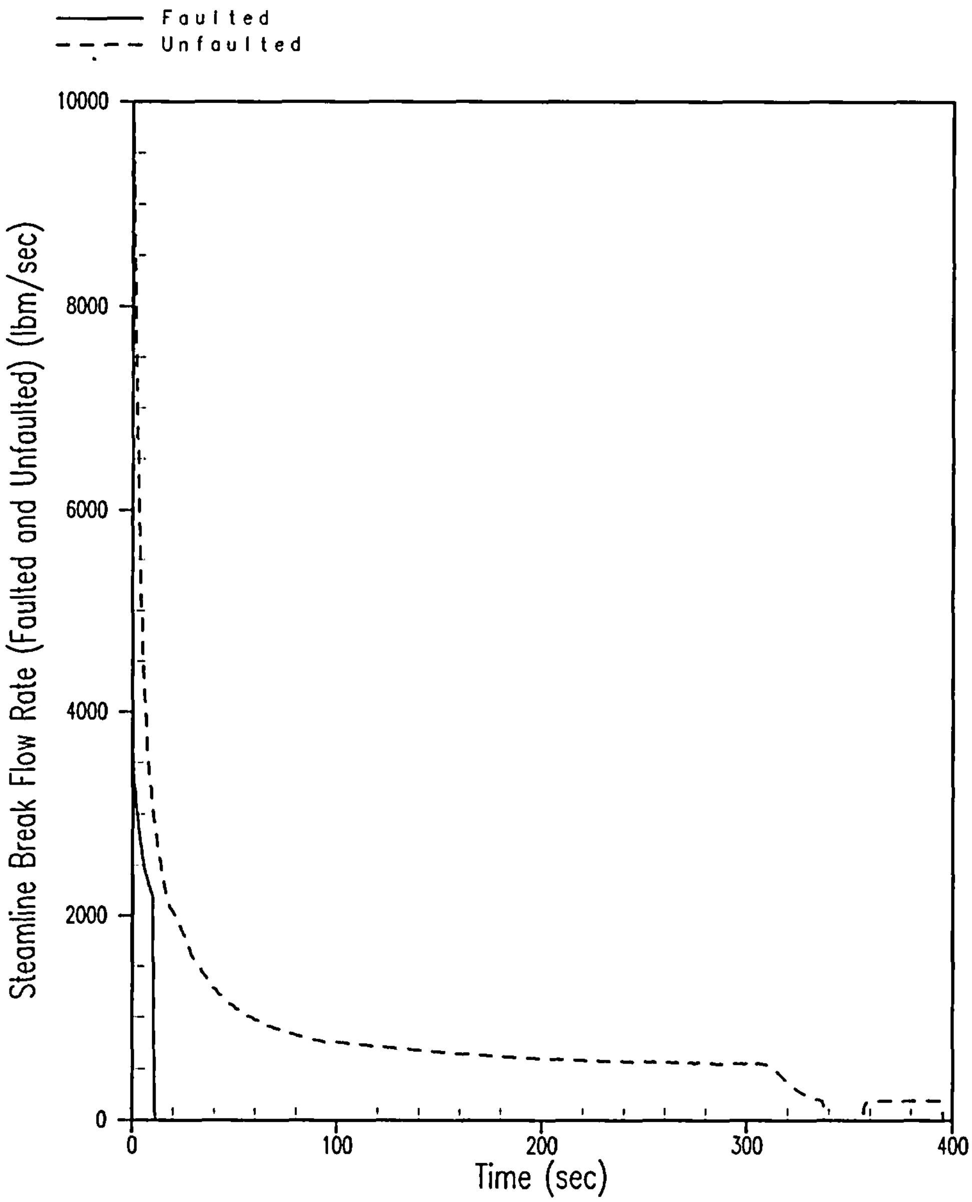

Figure 5.1.6-5
Post-Trip Main Steamline Break
Break Mass Flow Rate

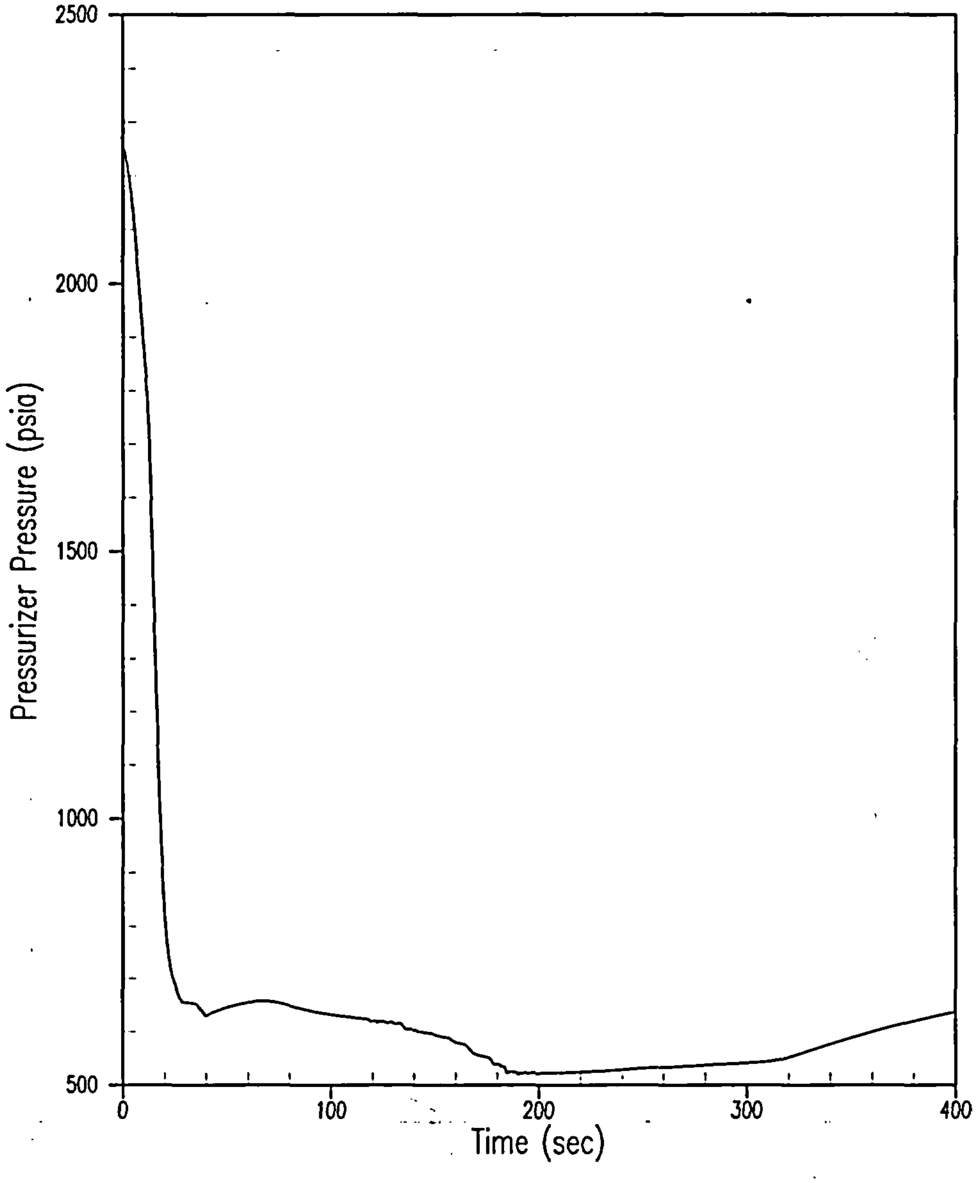

Figure 5.1.6-6
Post-Trip Main Steamline Break
Pressurizer Pressure

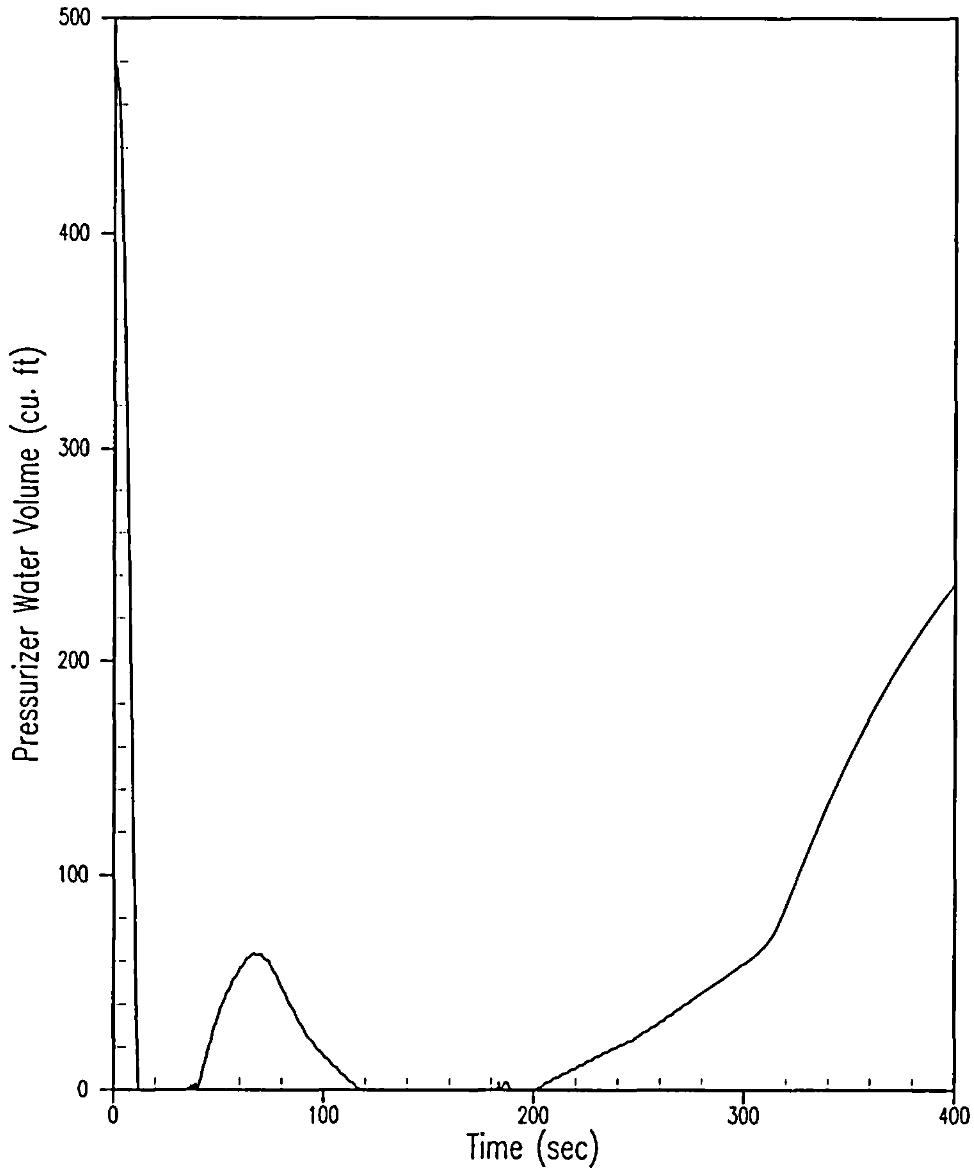

Figure 5.1.6-7
Post-Trip Main Steamline Break
Pressurizer Water Volume

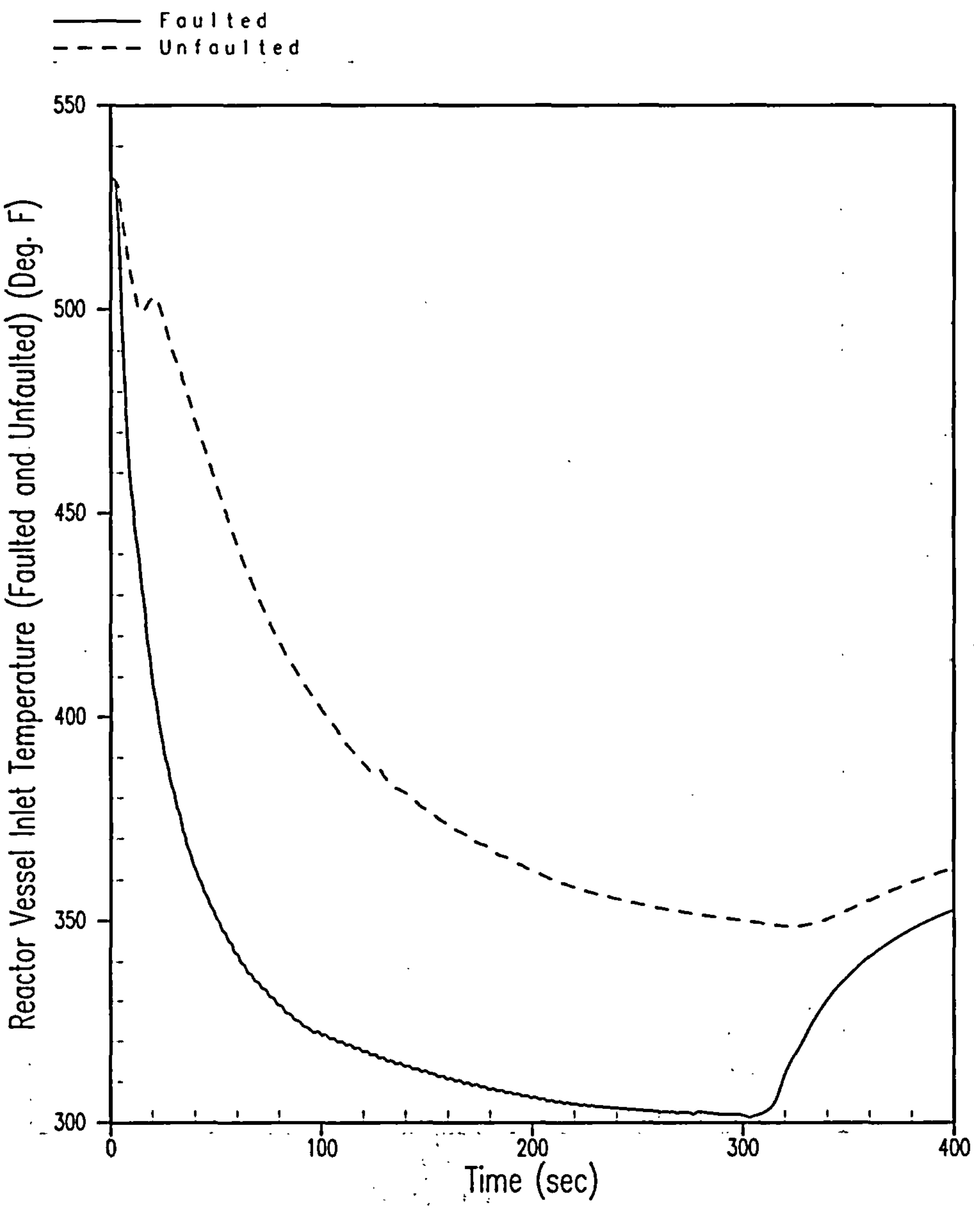

Figure 5.1.6-8
Post-Trip Main Steamline Break
Reactor Vessel Inlet Temperature

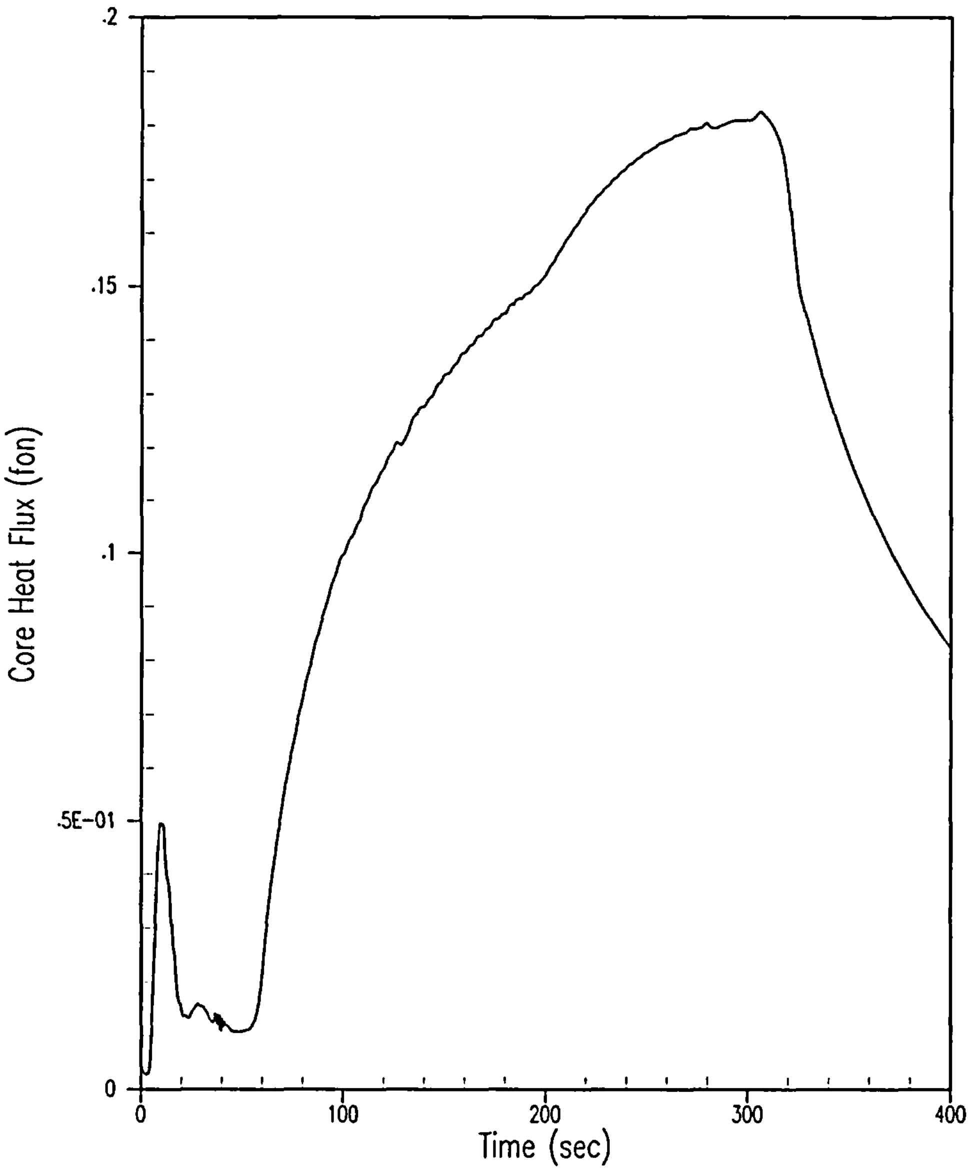

Figure 5.1.6-9
Post-Trip Main Steamline Break
Core Heat Flux

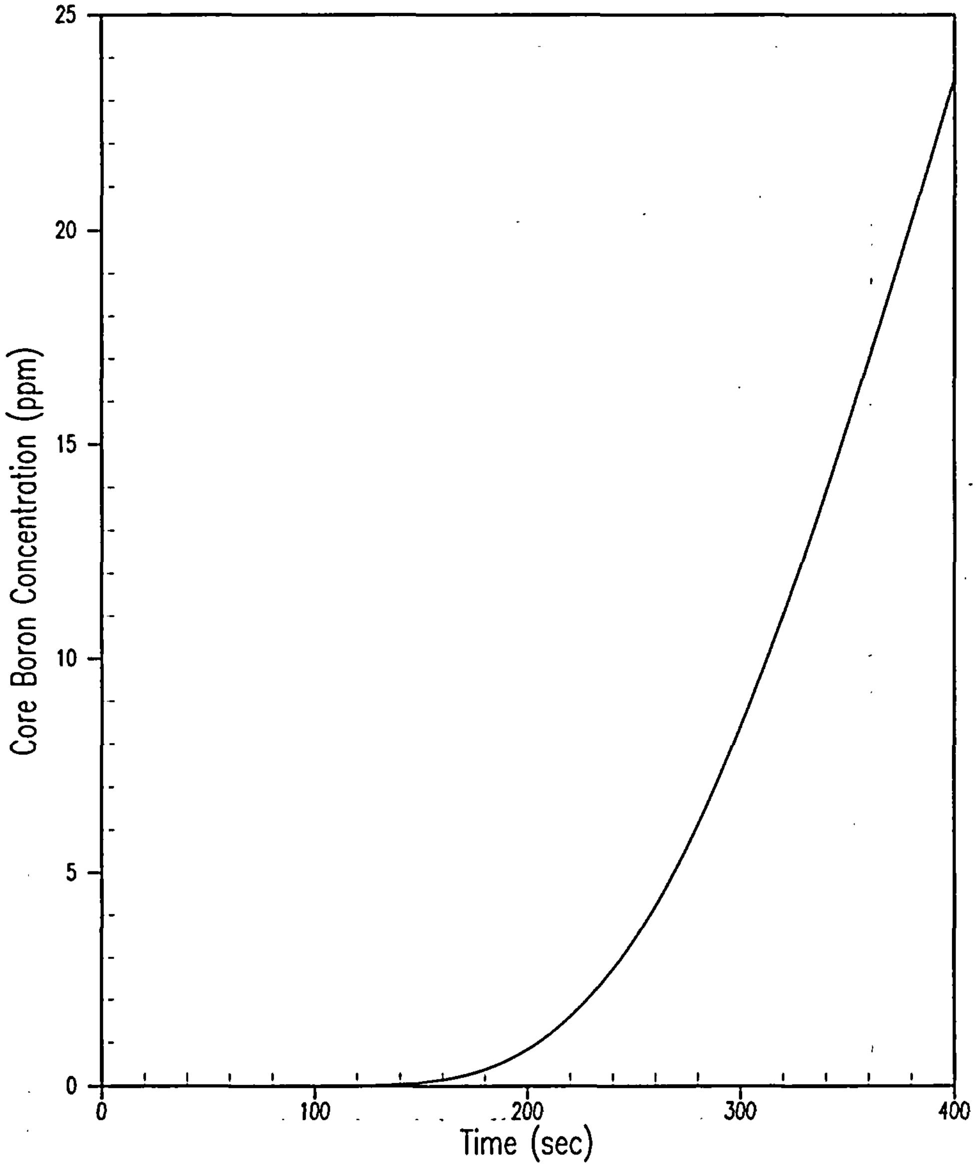

Figure 5.1.6-10
Post-Trip Main Steamline Break
Core Averaged Boron Concentration

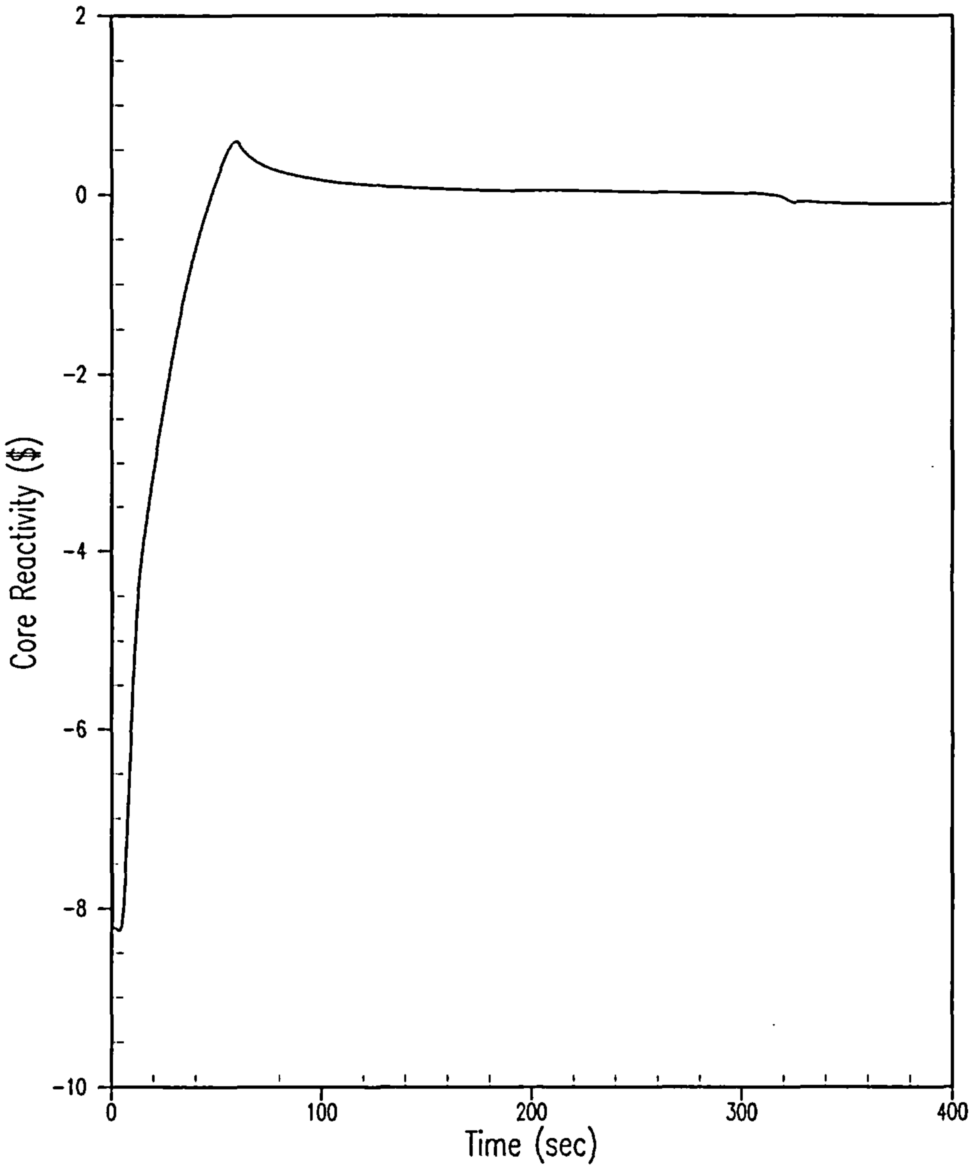

Figure 5.1.6-11
Post-Trip Main Steamline Break
Reactivity

5.1.7 Steam System Piping Failures Outside Containment

The steam system piping failures outside containment are bounded by the steam system piping failures inside containment discussed in Section 5.1.5 and 5.1.6.

5.1.8 Turbine Trip

A Turbine Trip is caused by an electrical or mechanical malfunction of the turbine, which produces a reduction of steam flow from the steam generators to the turbine due to the closure of the turbine stop valves. The core and system performance following a Turbine Trip would be no more adverse than those following a Loss of Condenser Vacuum, which is described in Section 5.1.10. The radiological consequences due to steam releases from the secondary system would be less severe than the consequences of the Feedwater Line Break (see Section 5.1.12). Therefore, a detailed analysis of the Turbine Trip event was not necessary.

5.1.9 Loss of Normal Feedwater Flow and Loss of Offsite Power

The Loss of Normal Feedwater Flow (LONF) event is defined as a complete loss of main feedwater flow while the reactor is operating at the maximum power level. A loss of main feedwater flow may occur due to the following causes:

- Breaks in the main feedwater system piping upstream of the main feedwater check valves
- Failure or trip of the main feedwater pumps, including loss of power (for motor-driven feedwater pumps) or loss of motive steam (for turbine-driven feedwater pump).
- Spurious closure of main feedwater isolation valves or the main feedwater regulating valves.

The immediate consequence of a loss of main feedwater flow is a reduction in the steam generator water level, which if left unmitigated, will ultimately result in a reactor trip and auxiliary feedwater (AFW) actuation on a low steam generator water level signal. Following reactor trip, the rate of heat generation in the RCS (decay heat plus reactor coolant pump heat input) may exceed the heat removal capability of the secondary system. In this case, there will be an increase in the steam generator pressure and an increase in RCS pressure, RCS temperature, and pressurizer water level. This trend continues until the RCS heat generation rate falls below the secondary-side heat removal capability.

At that time, the primary pressure and temperature begin to decrease, thereby terminating the transient in terms of potential challenges to the applicable safety criteria. It is assumed that if such a transient were to occur at the plant, emergency operating procedures would be followed to bring the plant to a stable condition.

A loss-of-offsite-power (LOOP) event is identical to the LONF event except that a loss of power to the RCPs occurs simultaneously with the loss of feedwater flow. Therefore, the post-trip heat removal relies upon natural circulation in the RCS loops.

The consequences of these events are bounded by other analyzed events as follows:

- With respect to core consequences, the LONF and The LOOP events are not as limiting as the complete loss of flow event, which is analyzed to demonstrate that the DNB design basis is satisfied.

- The LONF event results in a slight increase in the RCS temperature prior to the reactor trip, there is no appreciable increase in the core power, and RCS flow is maintained. The DNBR effect of the reduction in RCS flow for the complete loss of flow event is more significant than the effect of the increase in the RCS temperatures observed for the LONF event, prior to the reactor trip.

- In the case of the LOOP event, the RCPs would coast down immediately in addition to the loss of feedwater flow. This transient would essentially be identical to the complete loss of flow event with the only exception that the reduction in feedwater flow will eventually reduce the cooling of the primary system which would result in an increased RCS pressure, thereby increasing the DNBR in comparison to the complete loss of flow analysis. The increase in SG primary side exit temperature would not have sufficient time to transport to the core inlet to adversely affect the DNBR calculation. Therefore, the LOOP event has similar RCS conditions to the complete loss of flow event with the exception of a higher RCS pressure caused by loss of feedwater flow. As such, the minimum DNBR conditions are bounded by the complete loss of flow event.

- In addition, since there is no appreciable power increase in either the LONF or LOOP event and since the fuel centerline melting is primarily driven by the core power, the fuel centerline melt limits will not be challenged. Therefore, the DNB and fuel centerline melting criteria continue to be satisfied for the LONF and LOOP events.

- With respect to overpressurization, the Loss of Condenser Vacuum event (LOCV) will be more limiting than either the LONF or LOOP events. The LOCV presents a much more significant reduction in the heat removal capability of the steam generators than the LONF or LOOP events because the LOCV event combines the loss of normal feedwater with a turbine trip. This causes the LOCV to have a faster pressurization of the RCS compared to the LONF and LOOP events. The net result for the LOCV event is a total loss of secondary heat sink, which results in the greatest challenge to primary and secondary overpressurization. Therefore, the LOCV remains the most limiting event with respect to primary and secondary overpressurization.

- With respect to long-term cooling, the ability of the auxiliary feedwater system to remove decay heat following reactor trip is demonstrated by the analyses presented in Chapter 10 of the Updated Final Safety Analysis Report (UFSAR).

It is the conclusion of this evaluation that for both the LONF and LOOP events, all criteria are bounded by other events. Therefore, no new analyses are required to support the increase in SGTP to 42% and associated reduction in coolant flow for St. Lucie Unit 2.

5.1.10 Loss of Condenser Vacuum

5.1.10.1 Accident Description

The Loss of Condenser Vacuum event is defined as a complete loss of steam load or a turbine trip without a direct reactor trip. This anticipated transient is analyzed as a turbine trip with a simultaneous loss of feedwater to both steam generators due to low suction pressure on the feedwater pumps. The atmospheric dump valves and the steam dump and bypass system valves are assumed to be unavailable, which minimizes the amount of cooling and maximizes the RCS and secondary peak pressures during the event.

In the event of a large loss of load in which the steam dump valves fail to open, the main steam safety valves (MSSVs) may lift and the reactor may be tripped by either of the following signals: high pressurizer pressure, or thermal margin / low pressure (TM/LP). No credit is taken for the Loss of Load trip as it is a control grade trip only. The steam generator shell-side pressure and reactor coolant temperatures will increase rapidly. However, the pressurizer safety valves (PSVs) and MSSVs are sized to protect the RCS and steam generators against overpressure for all load losses without assuming the operation of the steam dump system. The RCS and main steam system (MSS) steam relieving capacities were designed to ensure safety of the unit without requiring pressurizer pressure control, steam bypass control systems, or a reactor trip on turbine trip.

5.1.10.2 Method of Analysis

The loss of condenser vacuum is analyzed: (1) to confirm that the PSVs and MSSVs are adequately sized to prevent overpressurization of the primary RCS and MSS, respectively; and (2) to ensure that the increase in RCS temperature does not result in a DNB in the core. This is accomplished by ensuring that the DNB design basis is satisfied, ensuring that the peak primary RCS pressure remains below 110 % of the design limit (2750 psia), and that the final case confirms that the peak MSS pressure remains below 110% of the steam generator shell design pressure (1100 psia).

In this analysis, the behavior of the unit is evaluated for a complete loss of steam load with no credit taken for a direct reactor trip on turbine trip. This assumption will delay reactor trip until conditions in the RCS cause a trip on some other signal. Thus, the analysis assumes a worst-case transient and demonstrates the adequacy of the pressure relieving devices and plant-specific RPS setpoints assumed in the analysis for this event.

The loss of condenser vacuum event is analyzed using the RETRAN computer code. The code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generators, and MSSVs. The code computes pertinent plant variables including temperatures, pressures, and power levels.

Three cases are analyzed. One is performed to address DNB concerns, one ensures that the peak primary RCS pressure remains below 110 % of the design limit (2750 psia), and the final case confirms that the peak MSS pressure remains below 110% of the steam generator shell design pressure (1100 psia). The major assumptions for these cases are summarized as follows, which are the same as used in the 30% SGTP analysis. Input parameters from Table 5.1.0-2 have been incorporated into the analysis.

- For the case analyzed to demonstrate that the DNB design basis is satisfied, minimum reactivity feedback conditions with automatic pressurizer pressure control are modeled. For this case, initial

condition uncertainties on the core power, reactor coolant temperature, and reactor coolant pressure are included in determining the DNBR limit value. Minimum reactivity feedback is modeled by assuming an MTC value consistent with the initial power level assumed and a least negative Doppler power coefficient (DPC). Automatic pressurizer pressure control with the full effects of the pressurizer spray in reducing or limiting the primary coolant pressure is assumed. Safety valves are also available and are modeled assuming a setpoint tolerance of -3%.

- For the case analyzed to demonstrate the adequacy of the primary pressure-relieving devices minimum reactivity feedback conditions without automatic pressurizer pressure control are modeled. For this case, initial core power and reactor coolant temperature are assumed at the minimum values consistent with the initial power level assumed, including allowances for calibration and instrument errors. Initial pressurizer pressure is assumed at the minimum value for this case, since it delays reactor trip on high pressurizer pressure and results in more severe primary-side temperature and pressure transients. Minimum reactivity feedback is modeled by assuming an MTC value consistent with the initial power level assumed and a least negative Doppler power coefficient (DPC). No credit is taken for the effect of the pressurizer spray or power-operated relief valve (PORVs) in reducing or limiting the primary coolant pressure. Pressurizer safety valves are assumed operable, but are modeled assuming a + 3% setpoint tolerance.
- For the case analyzed to demonstrate the adequacy of the MSSVs, minimum reactivity feedback conditions and automatic pressurizer pressure control are assumed. Minimum reactivity feedback is modeled by assuming an MTC value consistent with the initial power level assumed and a least negative Doppler power coefficient (DPC). Credit is taken for the effect of the pressurizer spray in reducing or limiting the primary coolant pressure, thus conservatively delaying the actuation of the reactor trip signal. Delaying the reactor trip ensures that the energy input to the secondary system, and subsequently the MSS pressure, is maximized. The PORVs are modeled with one valve aligned to the pressurizer and one valve locked out. The PORVs are actuated upon the receipt of the high pressurizer pressure trip signal and serve to protect the PSVs against spurious actuation by limiting the primary pressure increase post-trip.

Main feedwater flow to the steam generators is assumed to be lost at the time of turbine trip. No credit is taken for AFW flow since a stabilized plant condition will be reached before AFW initiation is normally assumed to occur. However, the AFW pumps would be expected to start on a trip of the main feedwater pumps. The AFW flow would remove core decay heat following plant stabilization.

The analysis is performed for operation with a maximum uniform steam generator tube plugging level for St. Lucie Unit 2 of no greater than 42%.

5.1.10.3 Results

The transient responses for a total loss of condenser vacuum from at-power operation are shown in Figures 5.1.10-1 through 5.1.10-5 for the RCS overpressure case and Figures 5.1.10-6 through 5.1.10-10 for the DNB case.

The total loss of condenser vacuum event was analyzed assuming the plant to be initially operating at 89% rated power at BOC with no credit taken for the pressurizer spray or PORVs to maximize the primary RCS pressure response. Figures 5.1.10-1 through 5.1.10-5 show the transient responses for this case. The neutron flux remains relatively constant prior to reactor trip, while pressurizer pressure, pressurizer water volume,

and RCS average temperature increase due to the sudden reduction in primary to secondary heat transfer. The reactor is tripped on the high pressurizer pressure trip signal. In this case, the PSVs are actuated and maintain the primary RCS pressure below 110% of the design value. Table 5.1.10-1 summarizes the sequence of events and limiting conditions for this case.

Figures 5.1.10-6 through 5.1.10-10 show the transient responses for the event. The transient DNBR response is calculated by assuming minimum feedback reactivity coefficients and full use of the pressurizer spray. Following event initiation, the pressurizer pressure and average RCS temperature increase due to the rapidly reduced steam flow and heat removal capacity of the secondary side. The peak pressurizer pressure and water volume and RCS average temperature are reached shortly after the reactor is tripped on the high pressurizer pressure trip signal. The DNBR initially increases slightly, then decreases due to the opening of the PORVs until the reactor trip is tripped, and finally, following reactor trip, increases rapidly. The minimum DNBR remains well above the safety analysis limit value. Table 5.1.10-2 summarizes the sequence of events and limiting conditions for this case.

Table 5.1.10-3 summarizes the transient response for the total loss of steam load with minimum feedback reactivity coefficients assuming full credit for the pressurizer spray to maximize the MSS pressure response. Following event initiation, the pressurizer pressure and average RCS temperature increase due to the rapidly reduced steam flow and heat removal capacity of the secondary side. The peak pressurizer pressure and water volume and RCS average temperature are reached shortly after the reactor is tripped on the high pressurizer pressure trip signal. The MSS pressure increases, resulting in the actuation of the MSSVs, and then decreases rapidly following reactor trip. The MSSVs actuate to limit the MSS pressure below 110% of the steam generator shell design pressure. The transient response for the MSS pressure case is similar to that shown for the peak RCS pressure case (Figures 5.1.10-1 through 5.1.10-5).

5.1.10.4 Conclusions:

The results of the analyses show that the plant design is such that a loss of condenser vacuum without a direct or immediate reactor trip presents no hazard to the integrity of the primary RCS or MSS. Pressure-relieving devices that have been incorporated into the plant design are adequate to limit the maximum pressures to within the safety analysis limits, i.e., 2750 psia for the primary RCS and 1100 psia for the MSS. The integrity of the core is maintained by operation of the RPS, i.e., the minimum DNBR is maintained above the safety analysis limit value. Therefore, the WCAP-9272 methodology demonstrates that no core safety limit will be violated as a result of implementing up to 42% steam generator tube plugging at the reduced thermal power.

Table 5.1.10-1 Loss of Condenser Vacuum Without Pressurizer Pressure Control (for Primary RCS Overpressure) Sequence of Events and Transient Results	
Event	**Time (seconds)**
Turbine Trip	10.0
Main Feedwater Terminates (both loops)	10.0
Reactor trip on High Pressurizer Pressure	19.8
Rod Motion Begins	20.5
Pressurizer Safety Valve Opens	20.8
Time of Peak RCS Pressure	21.9
First Main Steam Safety Valve Opens	22.9
Results	
Peak RCS Pressure	2664 psia
RCS Pressure Maximum Limit	2750 psia

Table 5.1.10-2 Loss of Condenser Vacuum With Pressurizer Pressure Control (for Minimum DNB) Sequence of Events and Transient Results	
Event	**Time (seconds)**
Turbine Trip	10.0
Main Feedwater Terminates (both loops)	10.0
Pressurizer Power Operated Relief Valve Opens	18.1
First Main Steam Safety Valve Opens	21.3
Reactor Trip on High Pressurizer Pressure	22.7
Rod Motion Begins	23.5
Time of Minimum DNBR	24.9
Results	
Minimum DNBR Value	2.244
DNBR Minimum Limit (side thimble)	1.34

Table 5.1.10-3 Loss of Condenser Vacuum With Pressurizer Pressure Control (for Main Steam System Overpressure) Sequence of Events and Transient Results	
Event	**Time (seconds)**
Turbine Trip	10.0
Main Feedwater Terminates (both loops)	10.0
First Main Steam Safety Valve Opens	16.7
Pressurizer Power Operated Relief Valve Opens	18.7
Reactor Trip on High Pressurizer Pressure	21.0
Rod Motion Begins	21.7
Time of Peak MSS Pressure	26.4
Results	
Peak MSS Pressure	1077 psia
MSS Pressure Maximum Limit	1100 psia

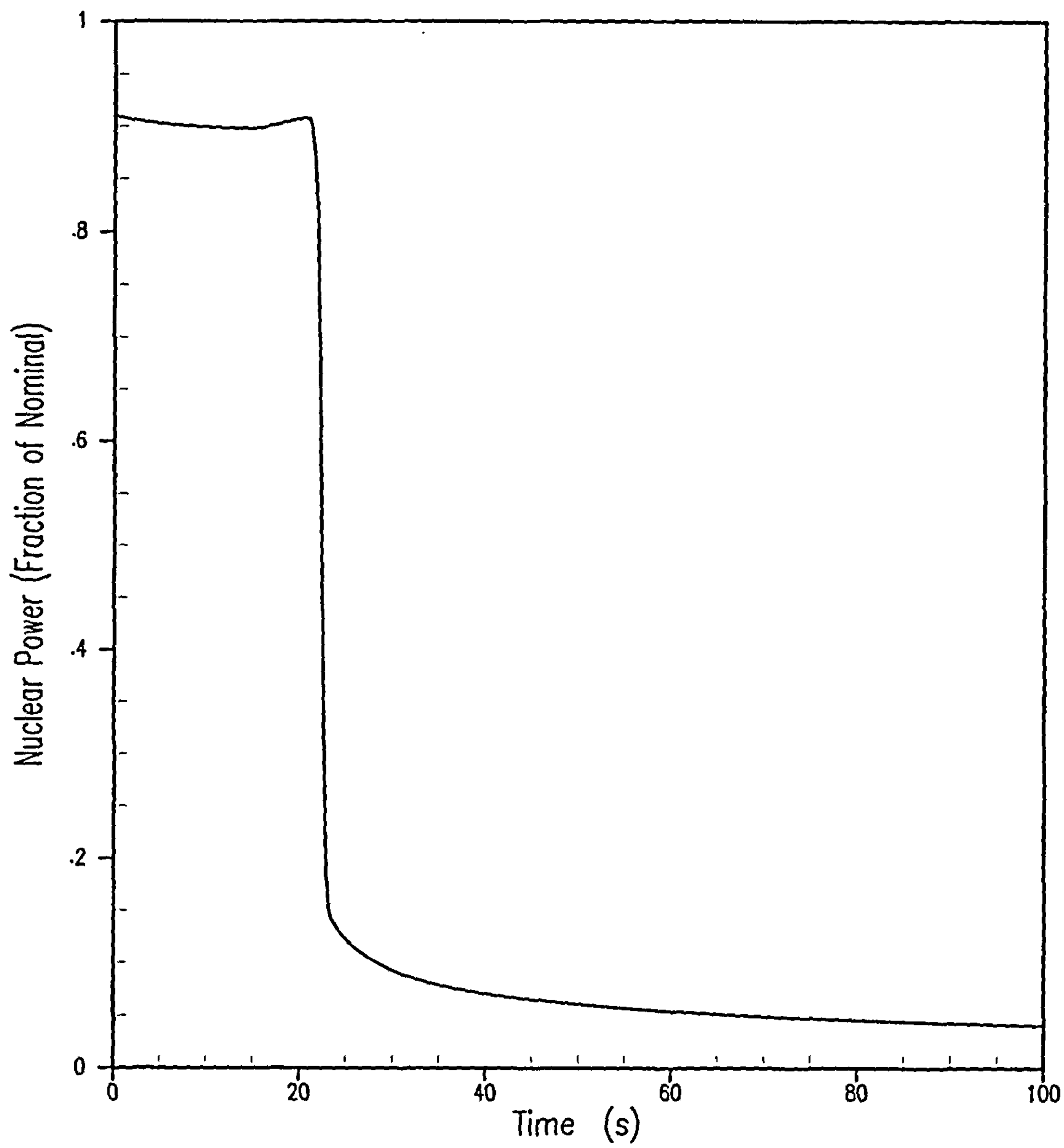

Figure 5.1.10-1
Loss of Condenser Vacuum (RCS Overpressure Case)
Nuclear Power

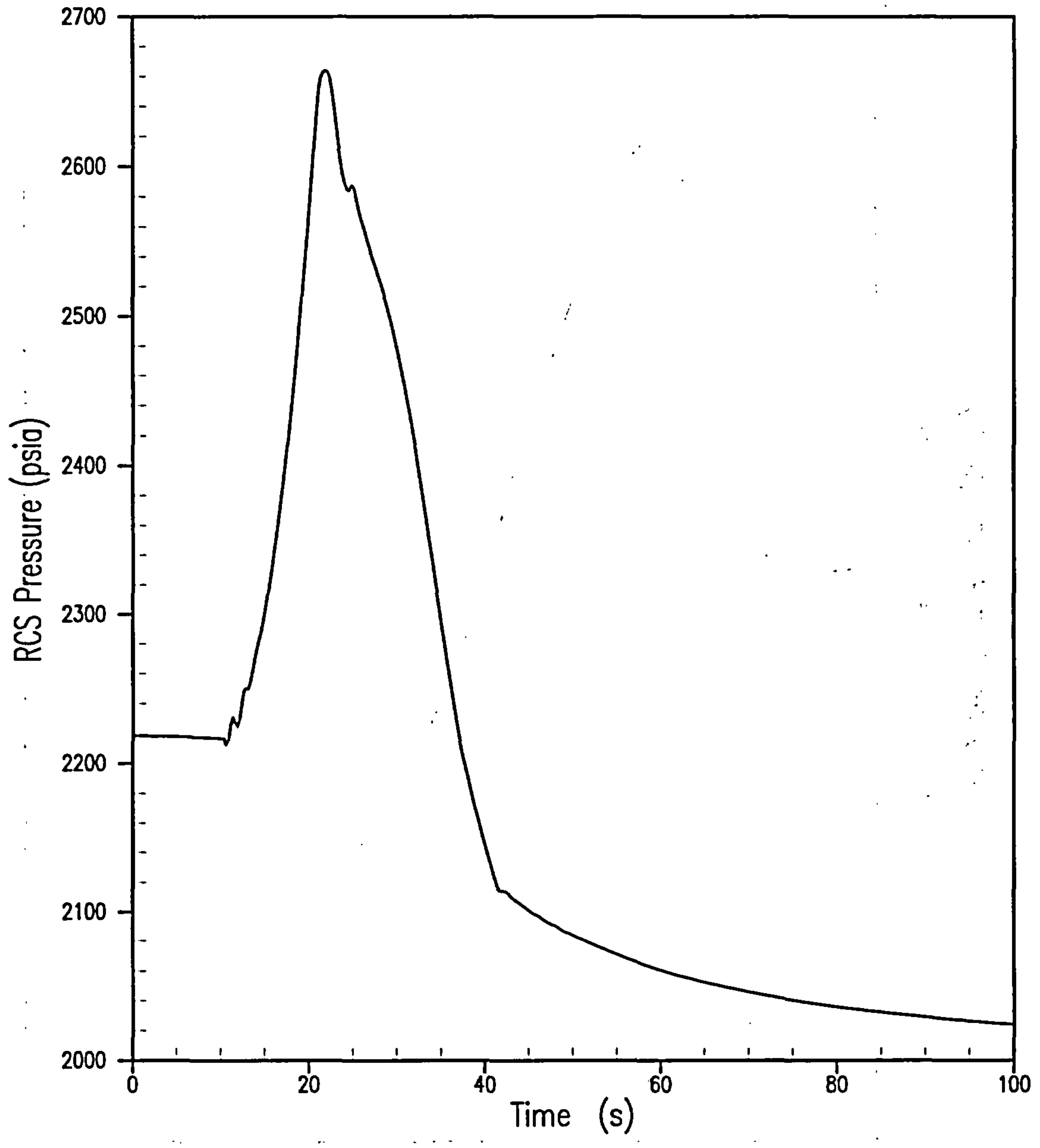

Figure 5.1.10-2
Loss of Condenser Vacuum (RCS Overpressure Case)
RCS Pressure (Vessel Lower Plenum Pressure)

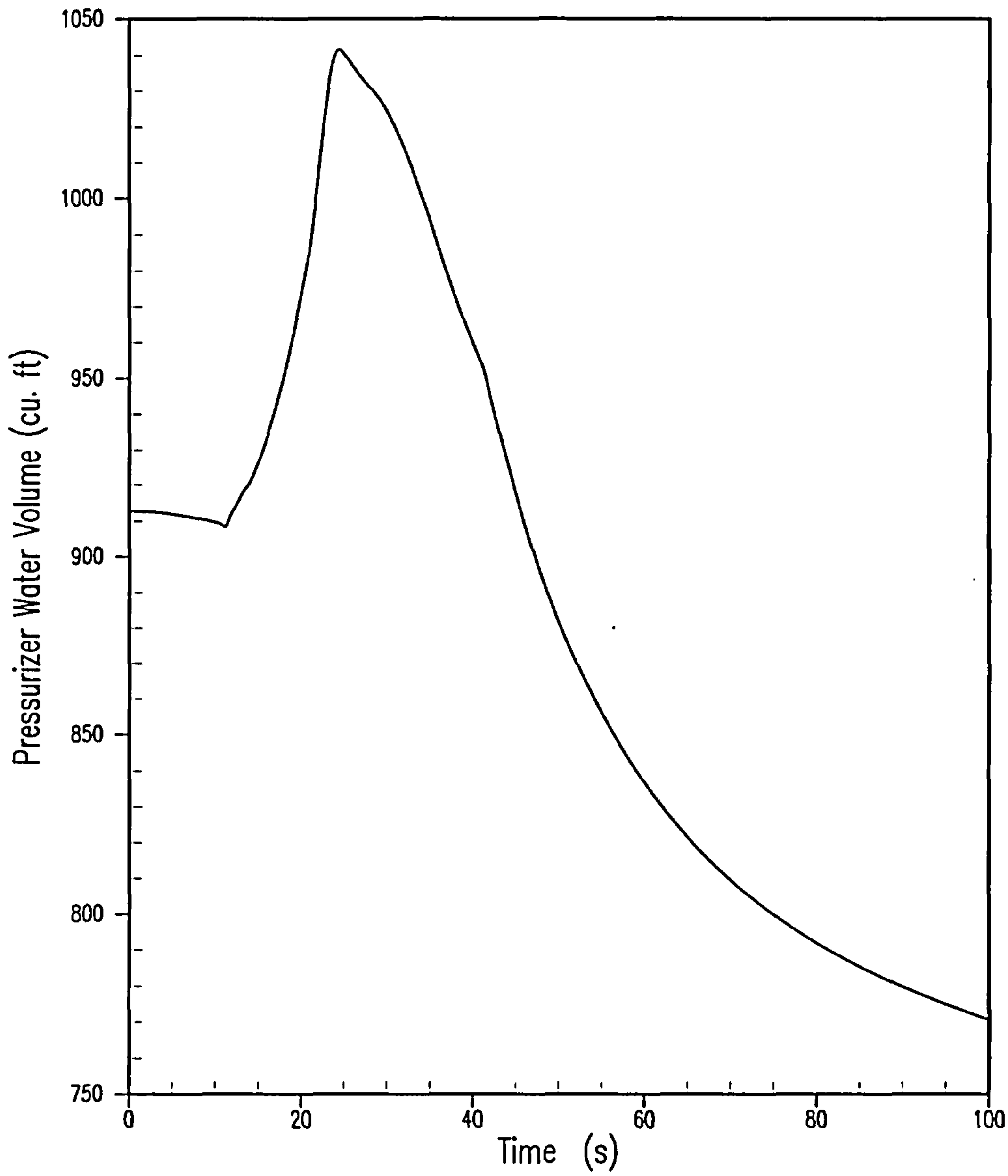

Figure 5.1.10-3
Loss of Condenser Vacuum (RCS Overpressure Case)
Pressurizer Water Volume

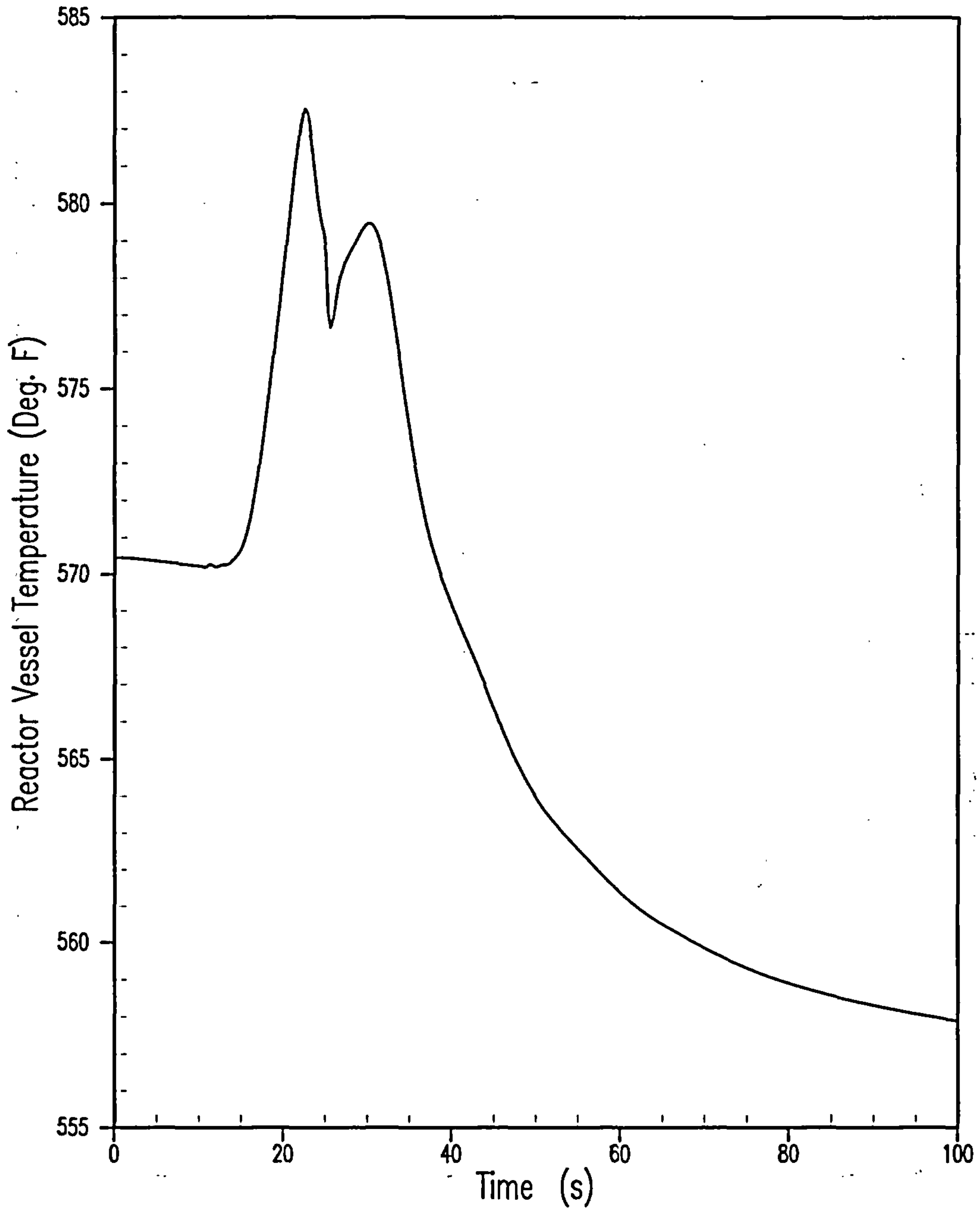

Figure 5.1.10-4
Loss of Condenser Vacuum (RCS Overpressure Case)
Vessel Average Temperature

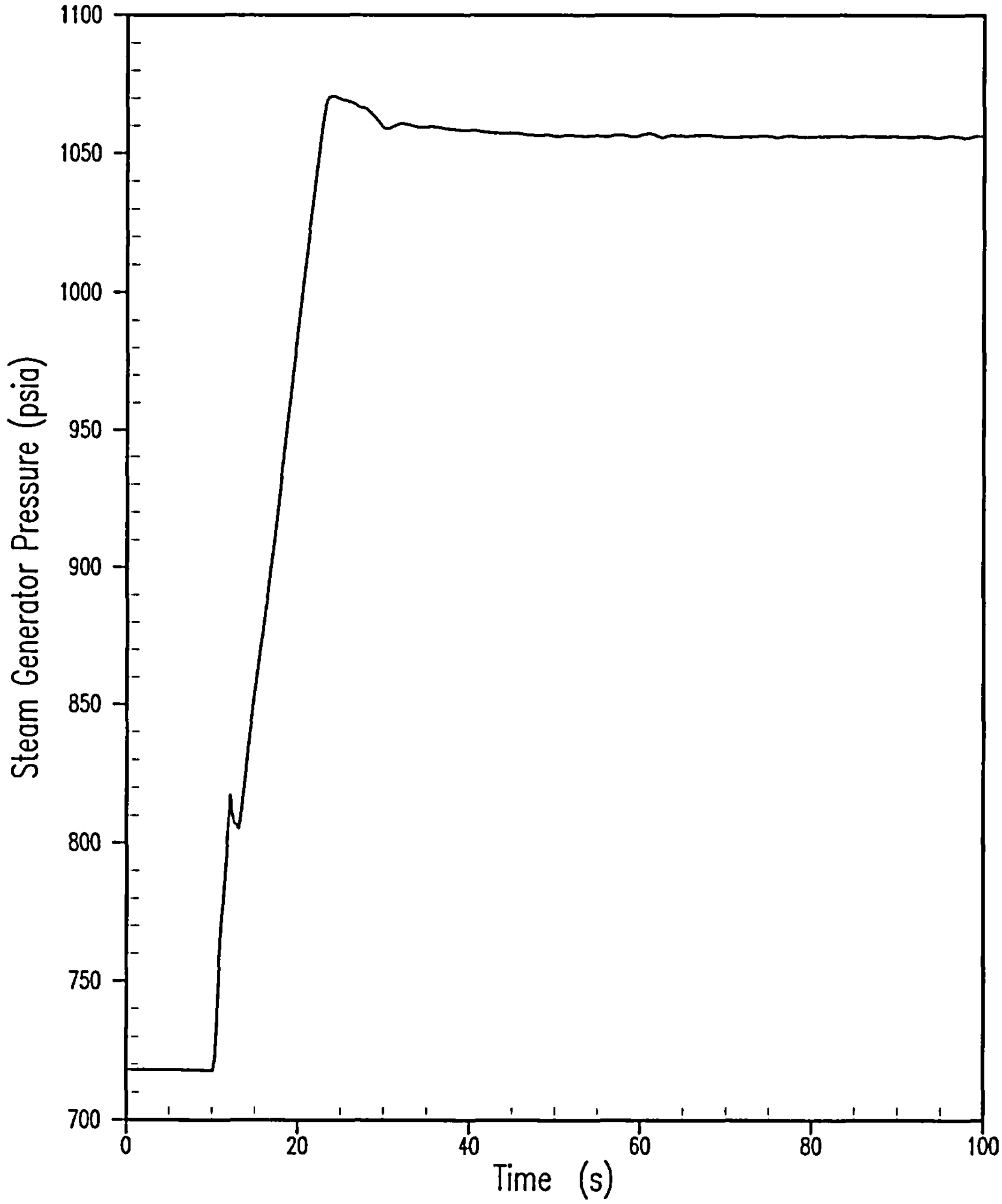

Figure 5.1.10-5
Loss of Condenser Vacuum (RCS Overpressure Case)
Steam Generator Pressure

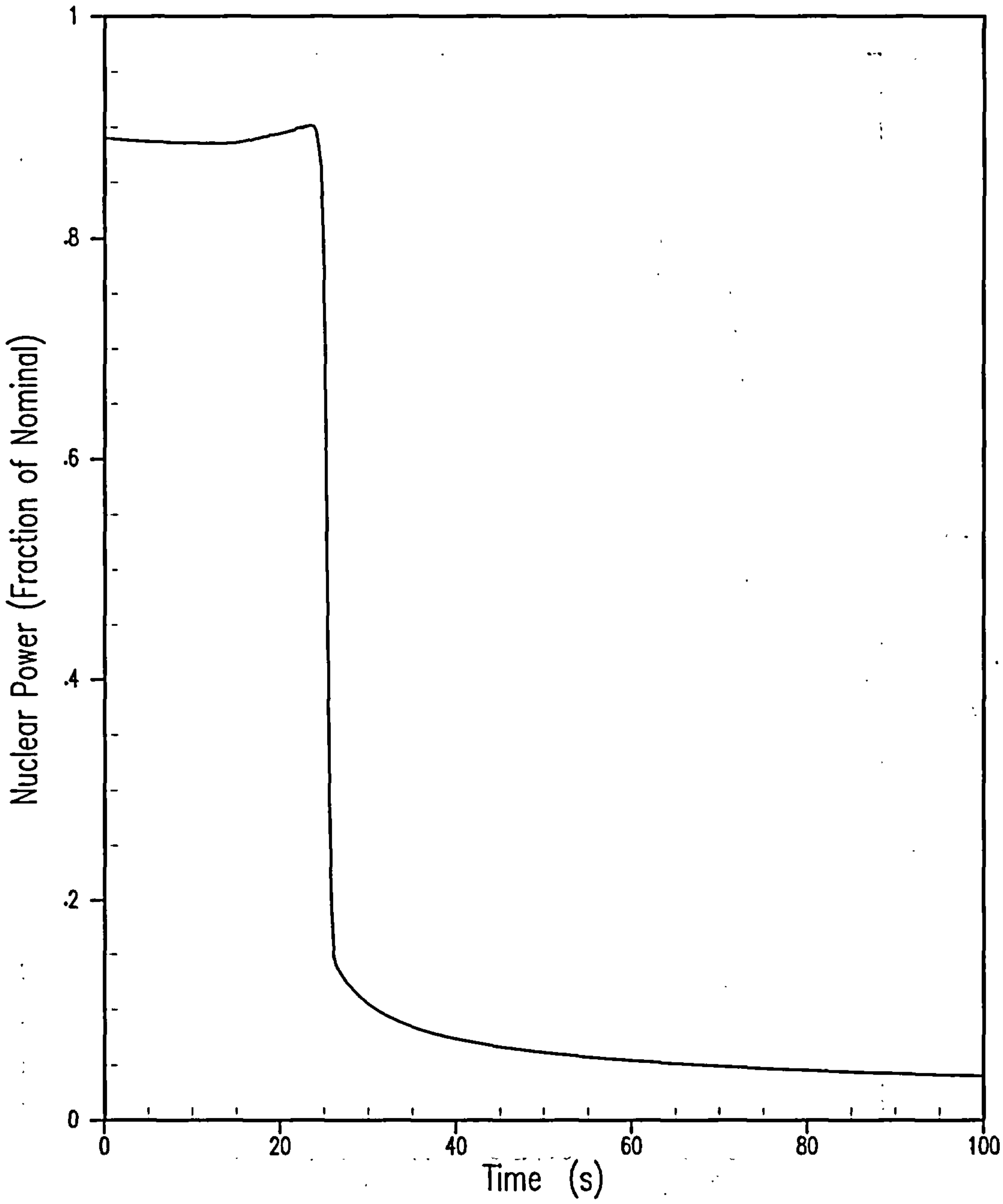

Figure 5.1.10-6
Loss of Condenser Vacuum (DNB Case)
Nuclear Power

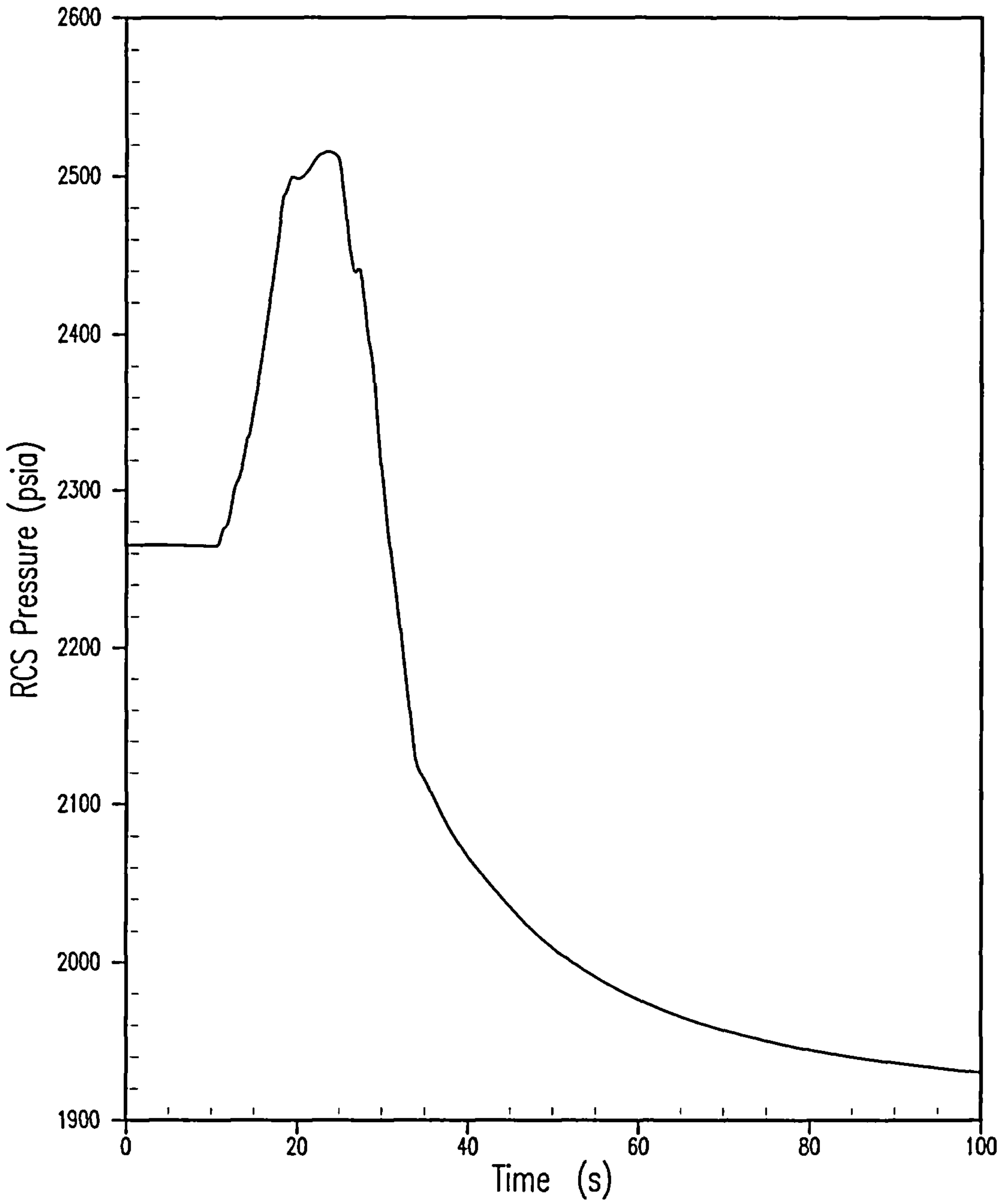

Figure 5.1.10-7
Loss of Condenser Vacuum (DNB Case)
RCS Pressure (Vessel Lower Plenum Pressure)

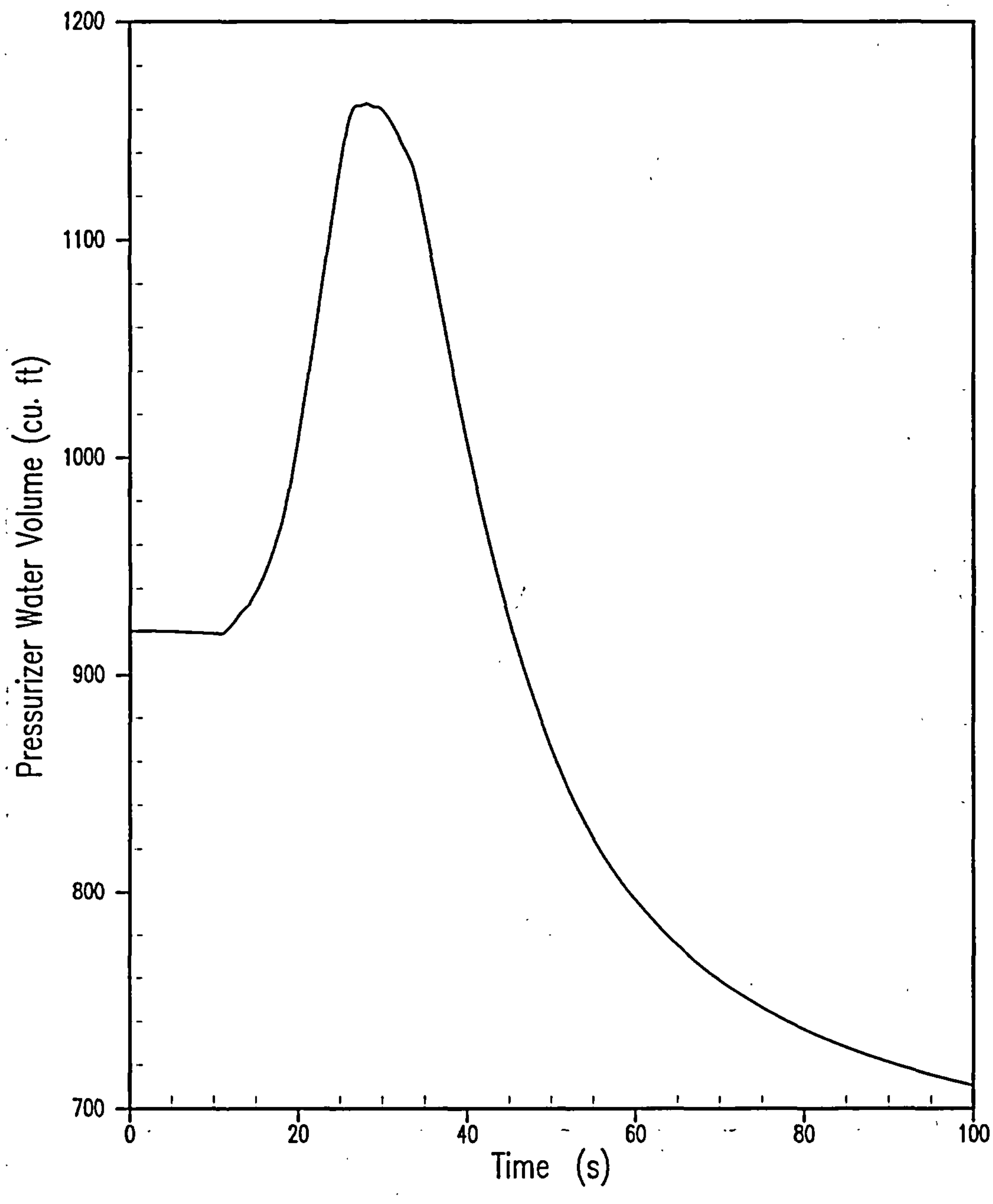

Figure 5.1.10-8
Loss of Condenser Vacuum (DNB Case)
Pressurizer Water Volume

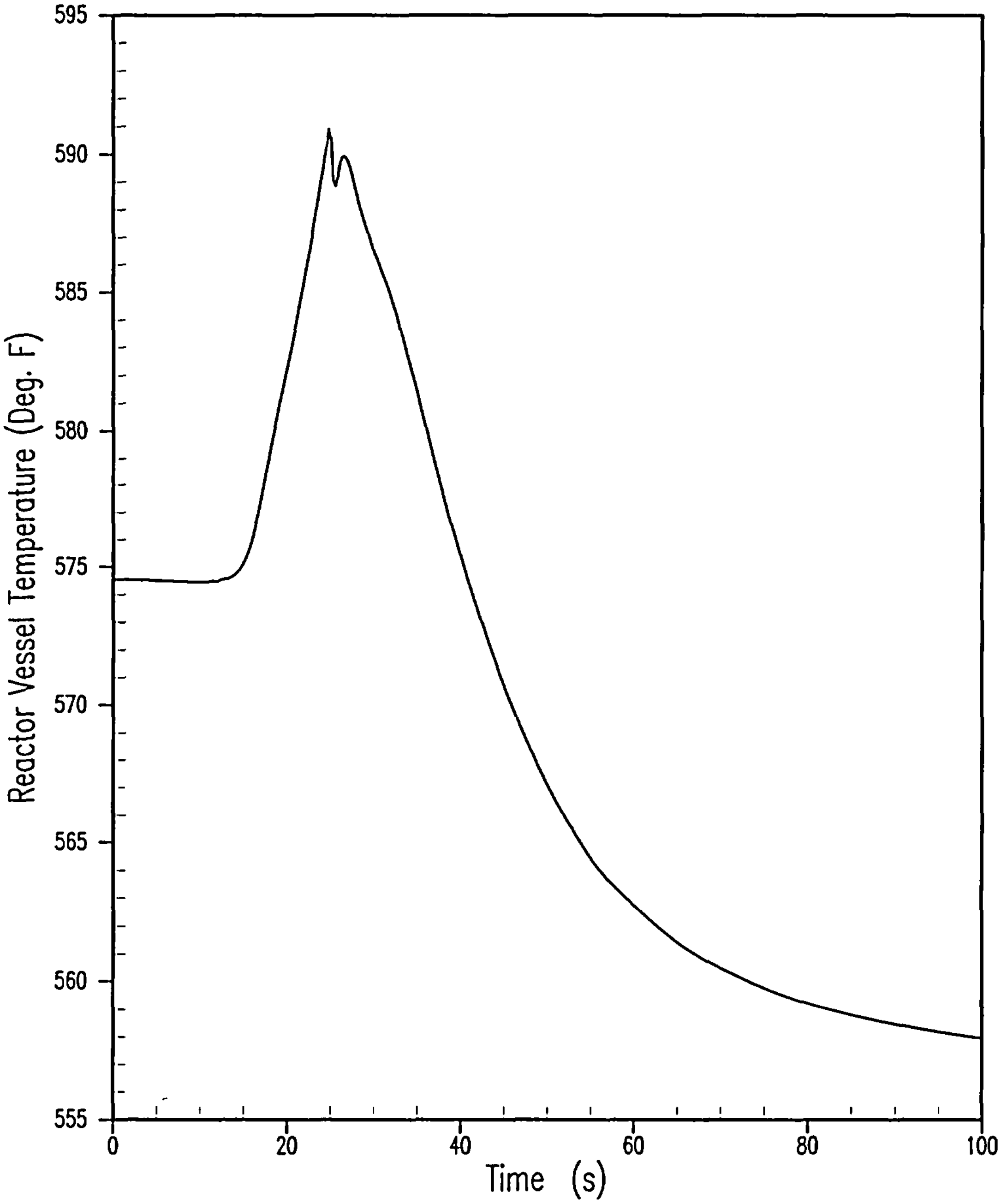

Figure 5.1.10-9
Loss of Condenser Vacuum (DNB Case)
Vessel Average Temperature

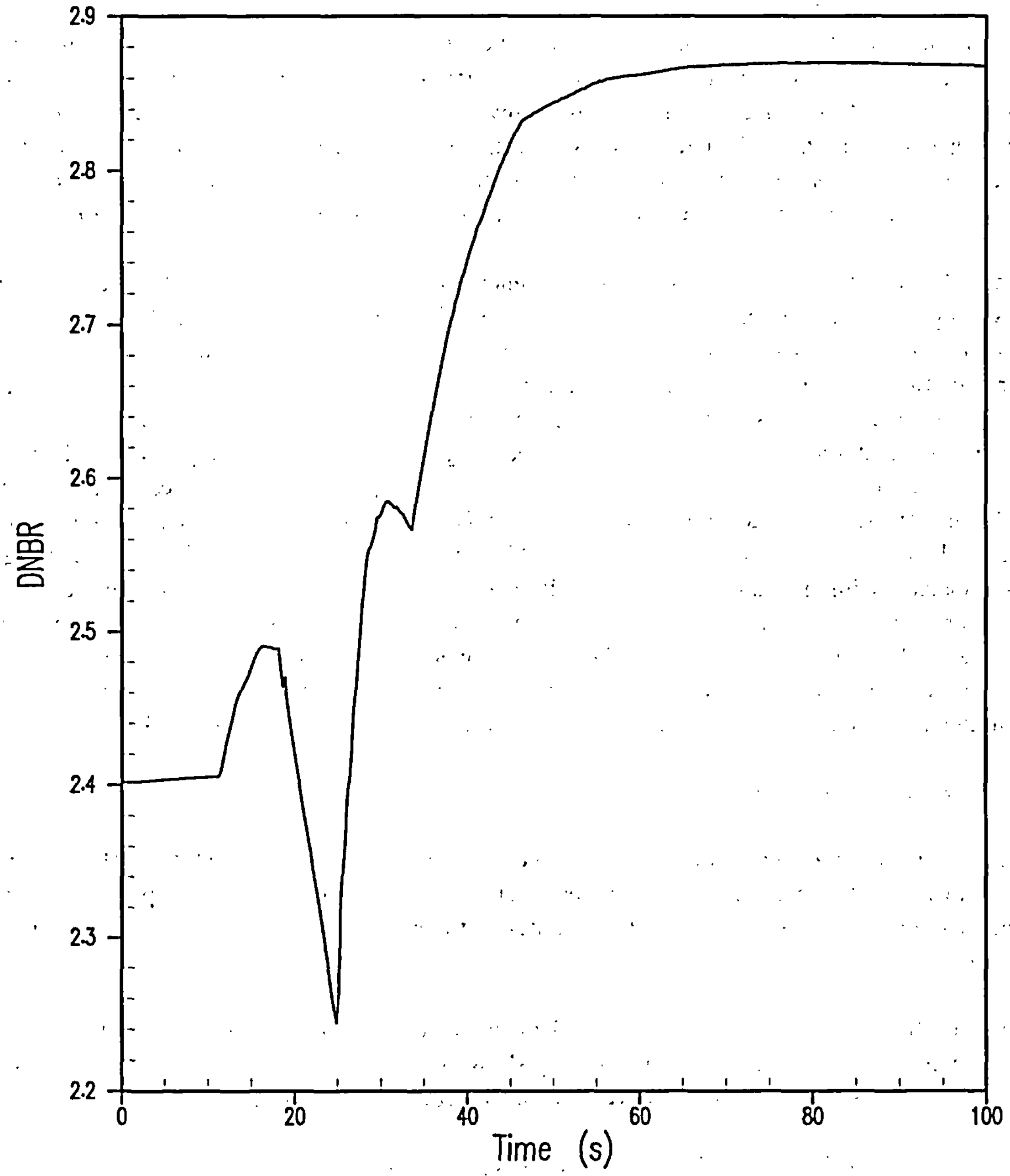

Figure 5.1.10-10
Loss of Condenser Vacuum (DNB Case)
DNBR

5.1.11 Asymmetric Steam Generator Transient

5.1.11.1 Accident Description

The Asymmetric Steam Generator Transient (ASGT) event is defined as a complete loss of steam load to one steam generator. This transient is modeled as an inadvertent closure of the main steamline isolation valve to one steam generator. A concurrent termination of feedwater flow to the affected steam generator is assumed in the analysis to conservatively bound any potential response of the feedwater system. Feedwater isolation to the affected steam generator will result in an increase the vessel inlet temperature asymmetry during the transient, which is conservative with respect to demonstrating that the DNB design basis is satisfied.

In the event of a large loss of load to a single steam generator, the MSSVs may lift and the reactor may be tripped by a high steam generator differential pressure (HSGDP) reactor trip. This trip function is specifically designed to provide protection against an ASGT. Upon the loss of load to a single steam generator, the affected steam generator pressure increases to the opening setpoint (including tolerances) of the MSSVs. Once relief flow is established through the MSSVs, the pressure begins to decrease in the affected steam generator and settles to a value corresponding to the MSSV setpoint pressure. The unaffected steam generator continues to supply steam to the turbine and attempts to replace the steam load previously supplied by the affected steam generator because the turbine demand is assumed to be maintained at its initial steam load. The increase in steam flow from the unaffected steam generator results in an overcooling of the cold legs associated with the unaffected loop. Additionally, the steam pressure in the unaffected steam generator decreases due to the increased steam flow in that loop. The increase in the core inlet temperature from the affected loops in combination with the decrease in core inlet temperature from the unaffected loops results in a large core temperature asymmetry. The asymmetric core temperature distributions result in an increase in the radial and axial peaking in the core, resulting in a challenge to the DNB design basis.

5.1.11.2 Method of Analysis

The ASGT event is analyzed by employing the detailed digital computer code RETRAN. The code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level.

The analysis of the ASGT has been performed to demonstrate that the DNB design basis and the peak rod power criteria are satisfied. This is accomplished by showing that the calculated minimum DNBR is greater than the safety analysis limit DNBR. The overall analysis process is described as follows.

The analysis of the ASGT event, as determined by the RETRAN code, calculates transient values of key plant parameters identified as statepoints (core average heat flux, core pressure, core inlet temperature, and RCS flow rate). The core radial and axial peaking factors are determined using the thermal-hydraulic conditions from the transient analysis as input to the nuclear core models. The detailed thermal and hydraulic computer code VIPRE was then used to calculate the DNBR response for the transient based on the core radial and axial peaking factors, and based on the limiting statepoints for the event.

The following assumptions were made in the analysis of the ASGT:

1. The initial reactor power and RCS temperature are assumed to be at values consistent with 89% of rated power, the initial RCS flow rate is assumed at a value consistent with the minimum measured flow rate and the initial RCS pressure is assumed at a value consistent with minimum value allowed by the plant technical specifications. Uncertainties in initial conditions are statistically included in the calculation of the DNBR limit as described in the Revised Thermal Design Procedures.
2. Two cases were analyzed; one assuming 0% of the steam generator U-tubes to be plugged and one assuming 42% of the steam generator U-tubes to be plugged. These cases will cover any asymmetry within these limits.
3. The initiating event is an inadvertent closure of a single MSIV with an assumed simultaneous termination of feedwater flow to the same steam generator.
4. The ASGT event results in a loss of steam flow and associated main feedwater flow to the affected steam generator. This causes a heatup in the associated primary RCS loop. The turbine demand is assumed to be maintained at its initial steam load by the unaffected loop. This causes a cooldown to occur in the primary loop associated with the unaffected steam generator. The reactivity feedback is weighted to the unaffected loop since end-of-life reactivity feedback is assumed, which results in an increase in the core power due to the colder RCS temperature conditions.
5. The model assumes reactivity feedback coefficients that maximize the increase in nuclear power prior to reactor trip. These reactivity coefficients were weighted to the RCS loop associated with the unaffected steam generator to maximize the power increase. The affects associated with the asymmetric vessel inlet distribution caused by the transient were used to calculate conservative radial and axial peaking factors.
6. The cases are analyzed with the automatic pressurizer pressure control system assumed to be operable. Thus, full credit is taken for the effect of the pressurizer spray in limiting any primary coolant pressure increase above the initial pressure.

5.1.11.3 Results

The results of the statepoint evaluation demonstrate that the ASGT event meets the applicable DNB and the peak rod power (kW/ft) acceptance criteria. Table 5.1.11-1 summarizes the sequence of events and limiting conditions for the 0% steam generator tube plugging case and Table 5.1.11-2 correspondingly summarizes the results of the 42% steam generator tube plugging case.

The transient response for the ASGT event are shown in Figures 5.1.11-1 through 5.1.11-12 assuming 0% SGTP, maximum reactivity feedback conditions with automatic pressurizer pressure control (pressurizer spray). Figures 5.1.11-13 through 5.1.11-24 are based on 42% SGTP, maximum reactivity feedback conditions, and automatic pressurizer pressure control (pressurizer spray).

The overall transient response for the ASGT evaluated herein provides a similar system response as reported in the analysis of record.

5.1.11.4 Conclusions

The ASGT event was conservatively analyzed with respect to the reactor core response. Key analysis assumptions were made to conservatively maximize the asymmetry in vessel inlet temperatures, so as to maximize the core power and peaking factors.

Two cases were performed to assess both the minimum DNBR and peak rod power (kw/ft) for 0% SGTP and for 42% SGTP. The case with 42% of the steam generator tubes plugged was found to be the most limiting case. Both the DNB design basis and the peak rod power limit are met for both cases analyzed.

Table 5.1.11-1 Asymmetric Steam Generator Transient 0% Steam Generator Tube Plugging Sequence of Events and Transient Results	
Event	**Time (seconds)**
Main Steam Isolation (Loop Two)	10.1
Manual Feedwater Termination (Loop Two)	10.1
Reactor Trip on HSGDP	15.8
Rod Motion Begins	16.6
Time of Minimum DNBR	17.4
Results	
Minimum DNBR Value	2.023
DNBR Limit (matrix)	1.37

Table 5.1.11-2 Asymmetric Steam Generator Transient 42% Steam Generator Tube Plugging Sequence of Events and Transient Results	
Event	**Time (seconds)**
Main Steam Isolation (Loop Two)	10.1
Manual Feedwater Termination (Loop Two)	10.1
Reactor Trip on HSGDP	15.7
Rod Motion Begins	16.4
Time of Minimum DNBR	17.25
Results	
Minimum DNBR Value	2.014
DNBR Limit (matrix)	1.37

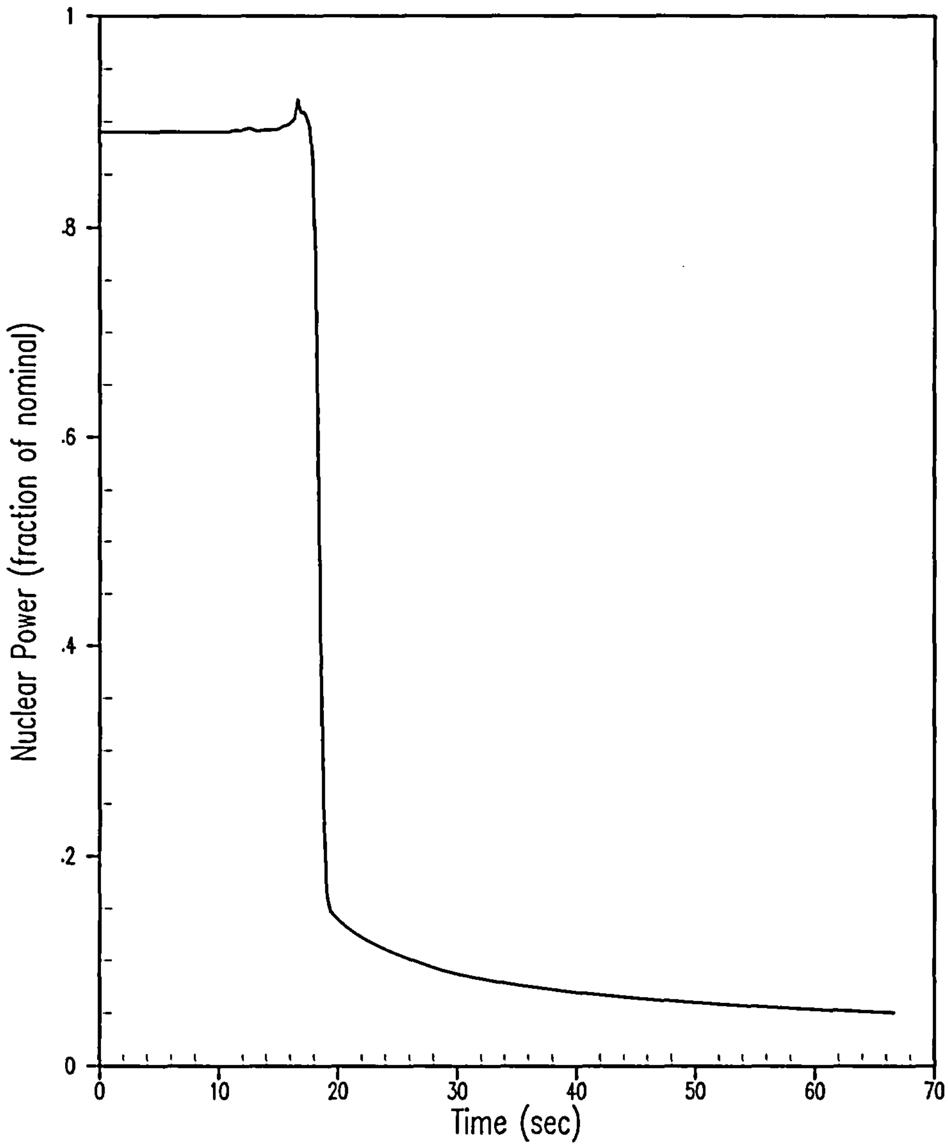

Figure 5.1.11-1
Asymmetric Steam Generator Transient - 0% Tube Plugging
Nuclear Power

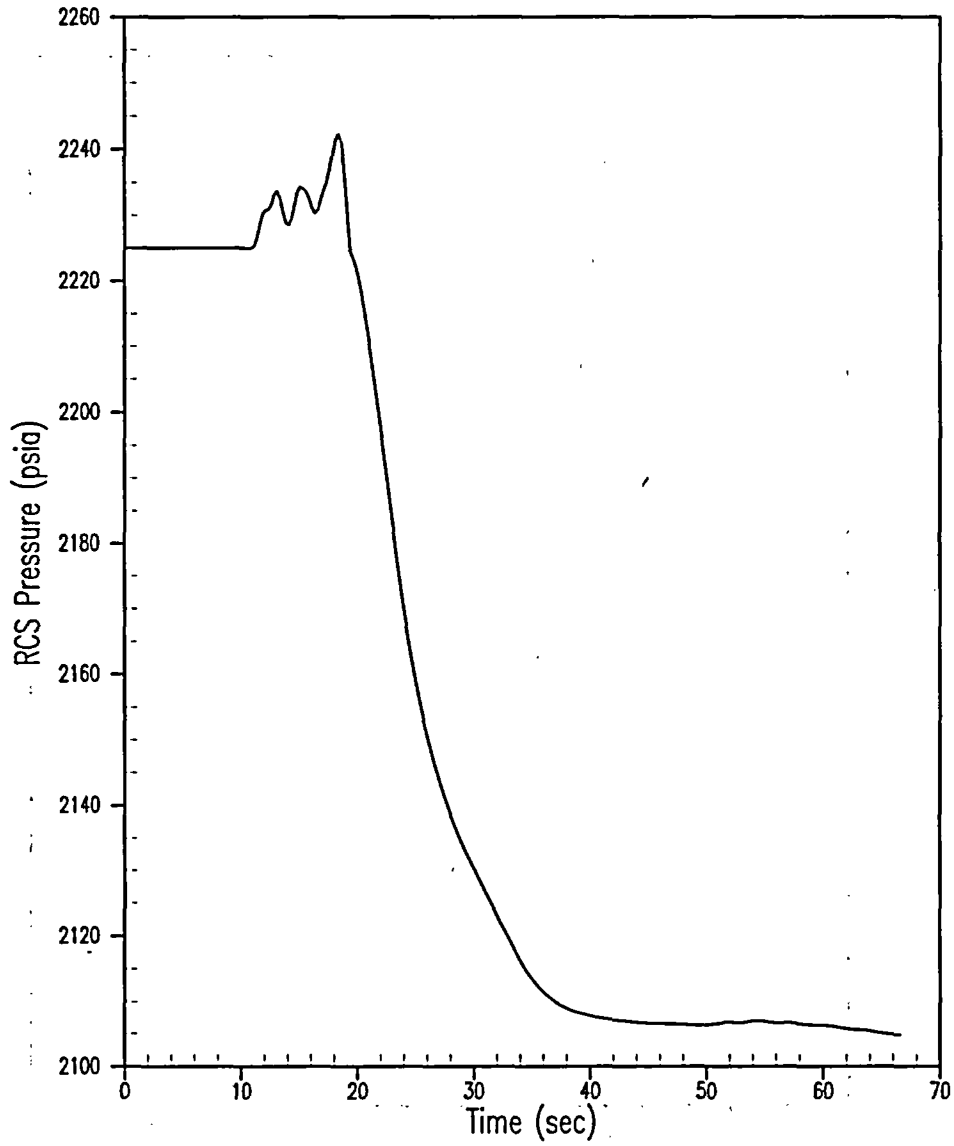

Figure 5.1.11-2
Asymmetric Steam Generator Transient - 0% Tube Plugging
RCS (Pressurizer) Pressure

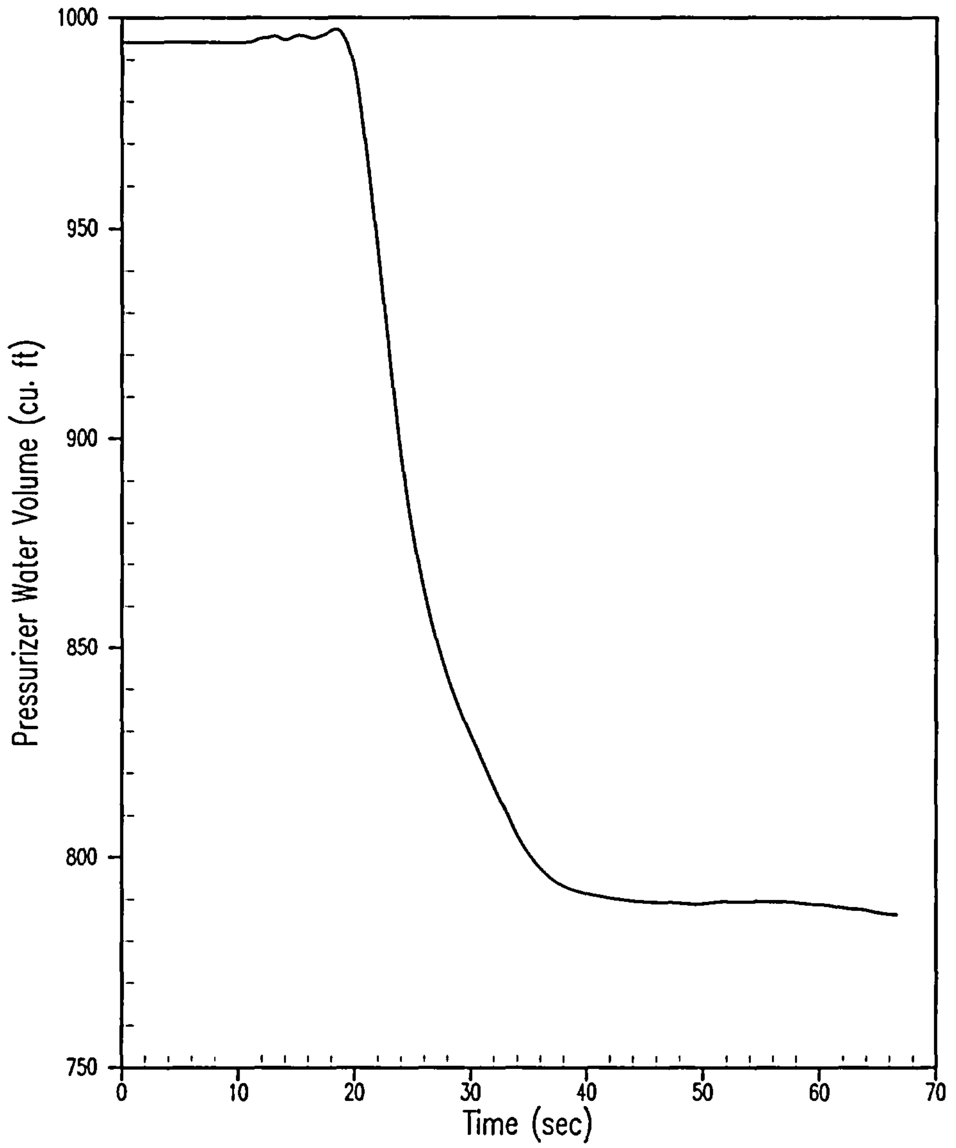

Figure 5.1.11-3
Asymmetric Steam Generator Transient - 0% Tube Plugging
Pressurizer Water Volume

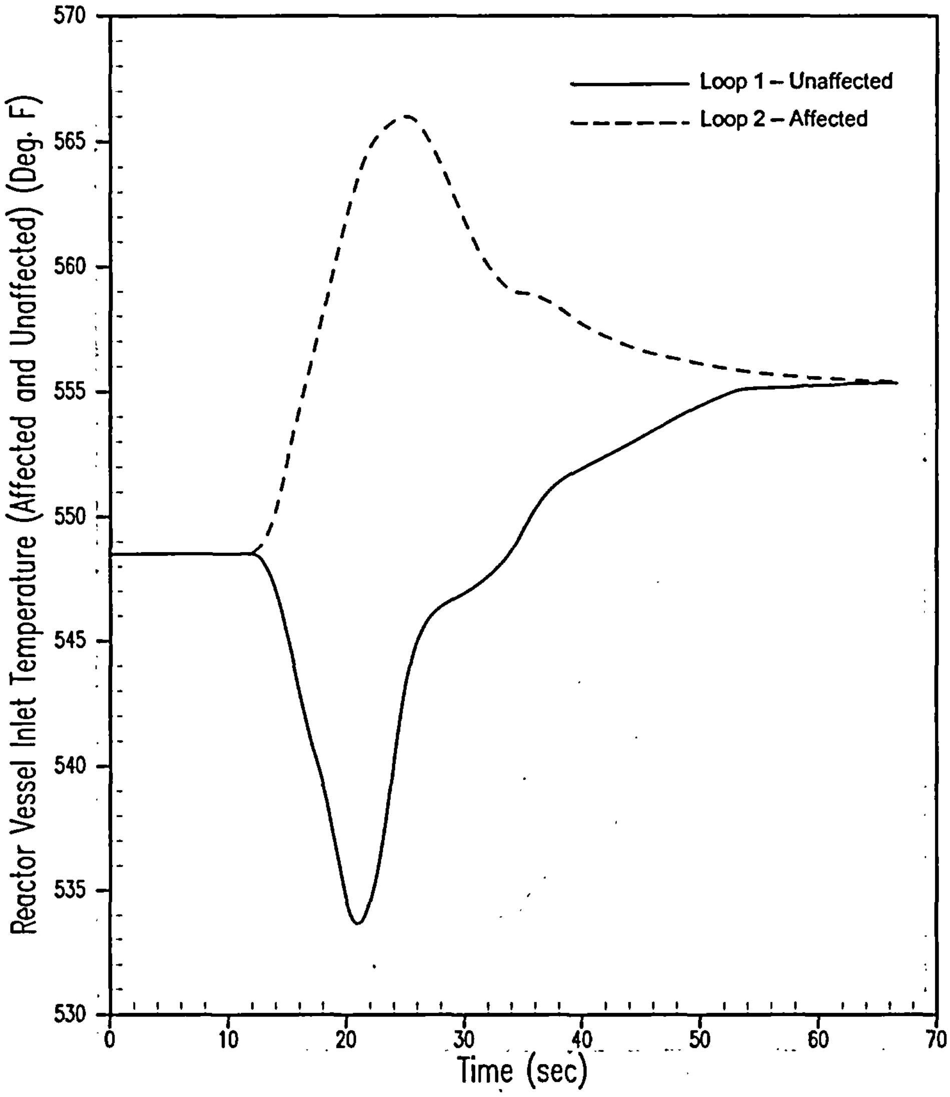

Figure 5.1.11-4
Asymmetric Steam Generator Transient - 0% Tube Plugging
Vessel Inlet Temperature

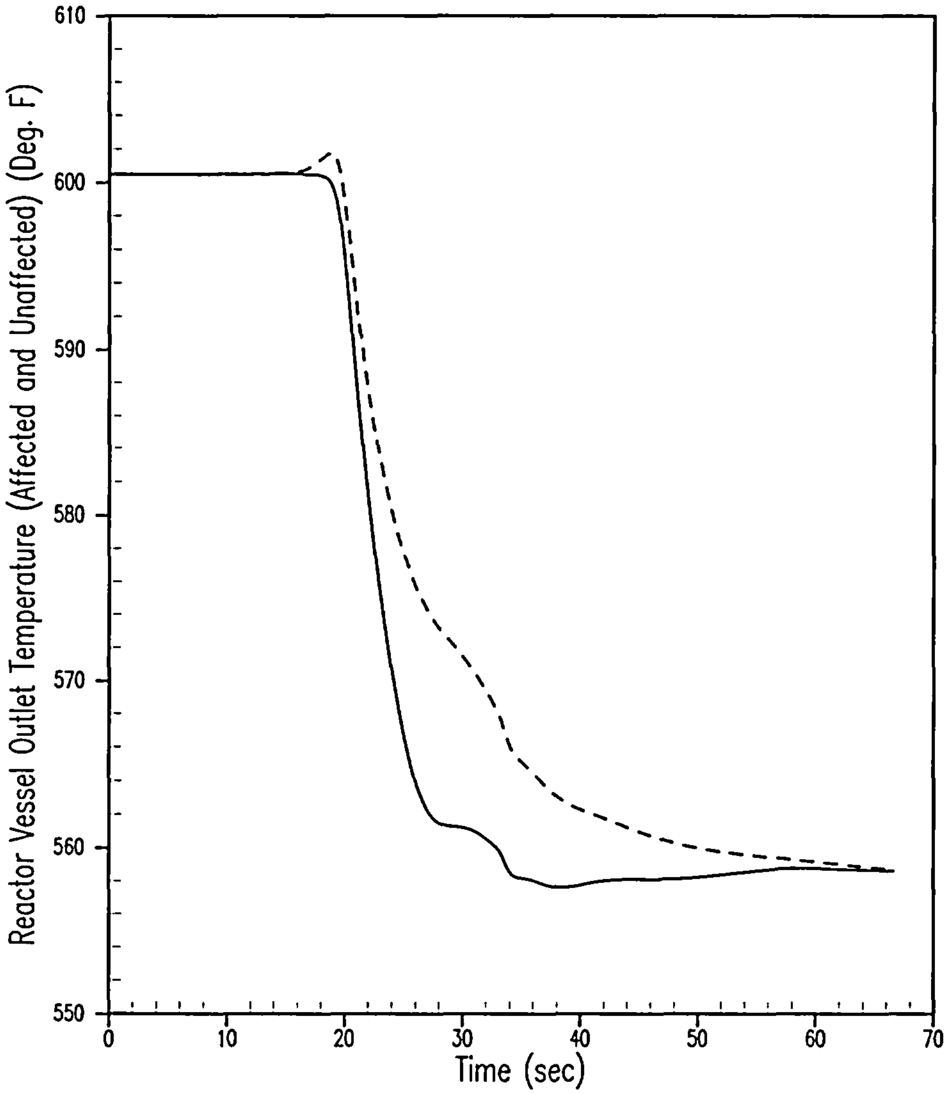

Figure 5.1.11-5
Asymmetric Steam Generator Transient - 0% Tube Plugging
Vessel Outlet Temperature

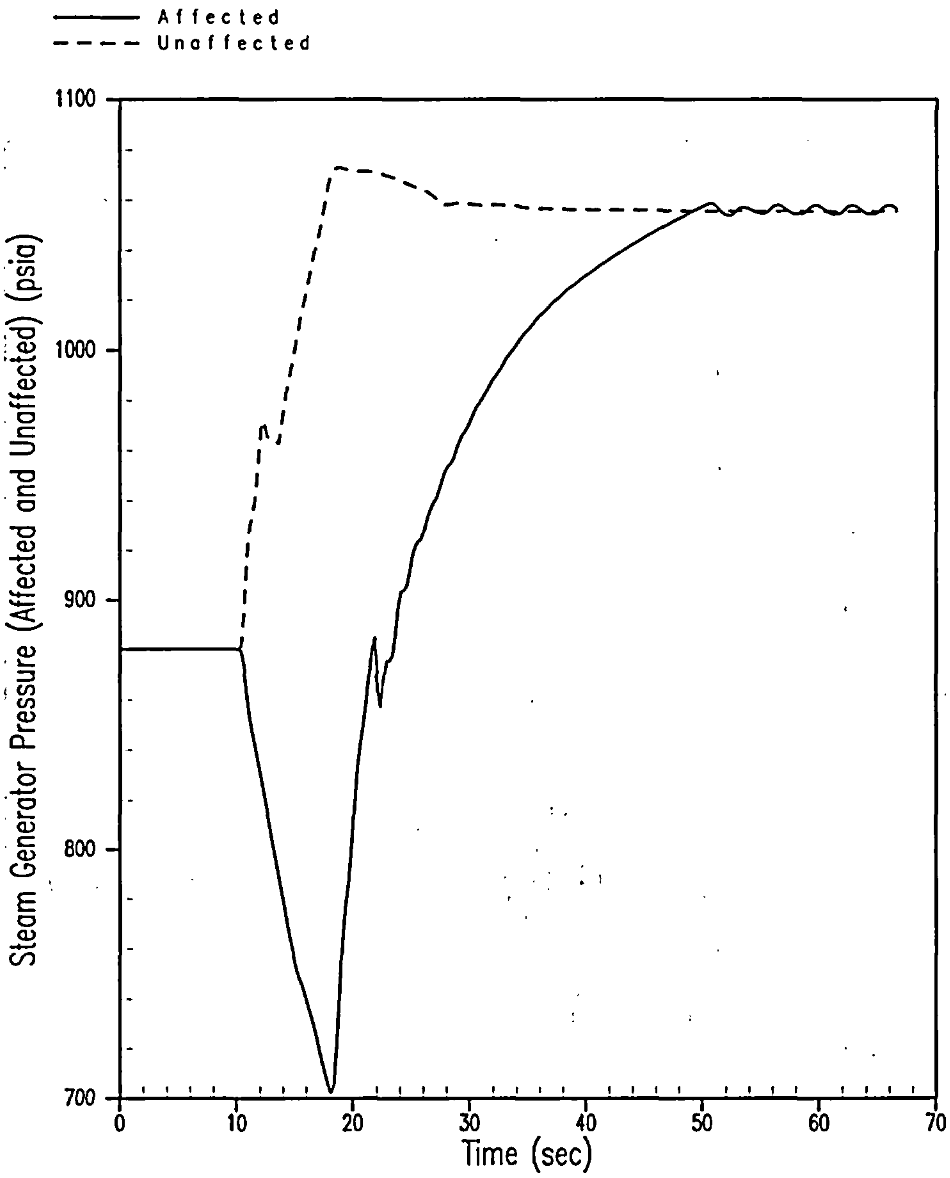

Figure 5.1.11-6
Asymmetric Steam Generator Transient - 0% Tube Plugging
Steam Generator Pressure

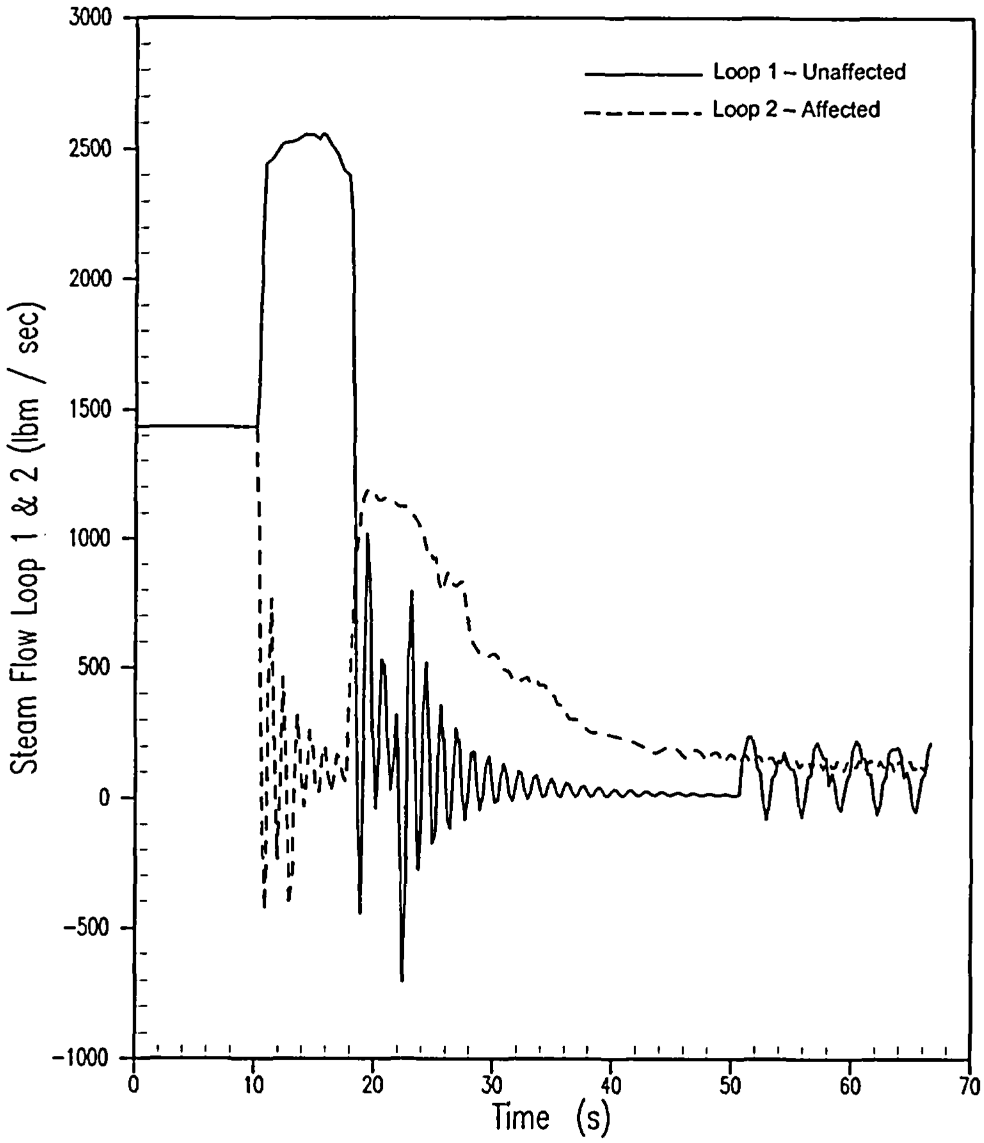

Figure 5.1.11-7
Asymmetric Steam Generator Transient - 0% Tube Plugging
Steam Flow

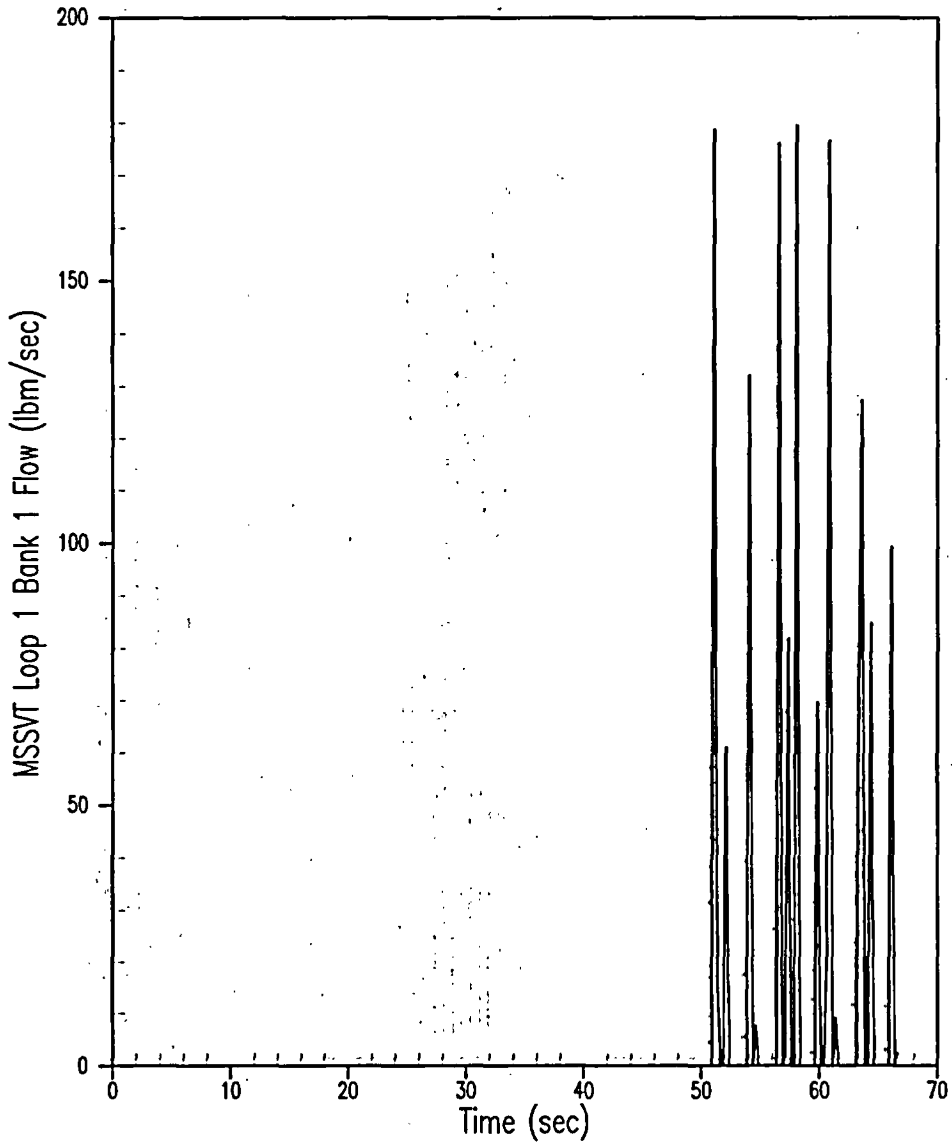

Figure 5.1.11-8
Asymmetric Steam Generator Transient - 0% Tube Plugging
Main Steam Safety Valve Flow (Loop 1 – Bank 1 Unaffected Steam Generator)

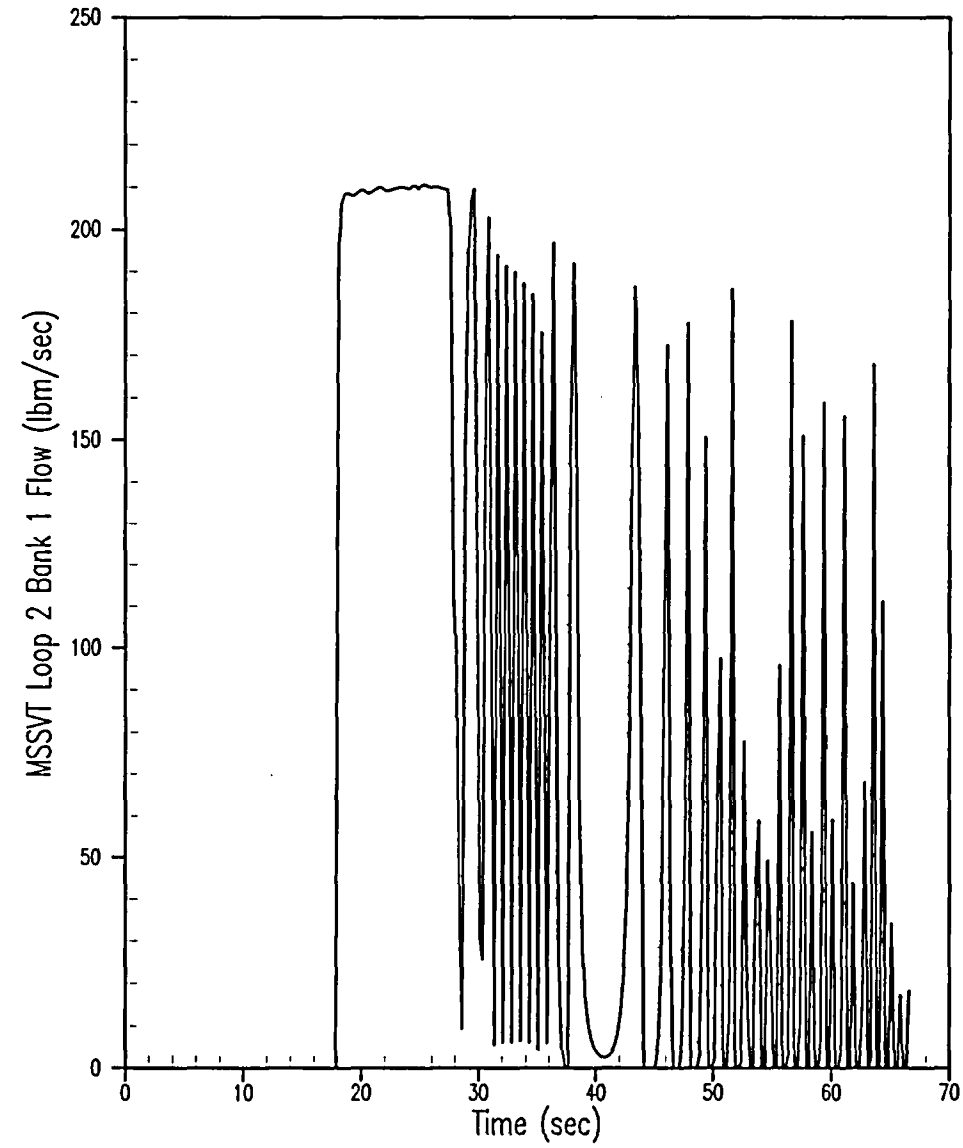

Figure 5.1.11-9
Asymmetric Steam Generator Transient - 0% Tube Plugging
Main Steam Safety Valve Flow (Loop 2 – Bank 1 Affected Steam Generator)

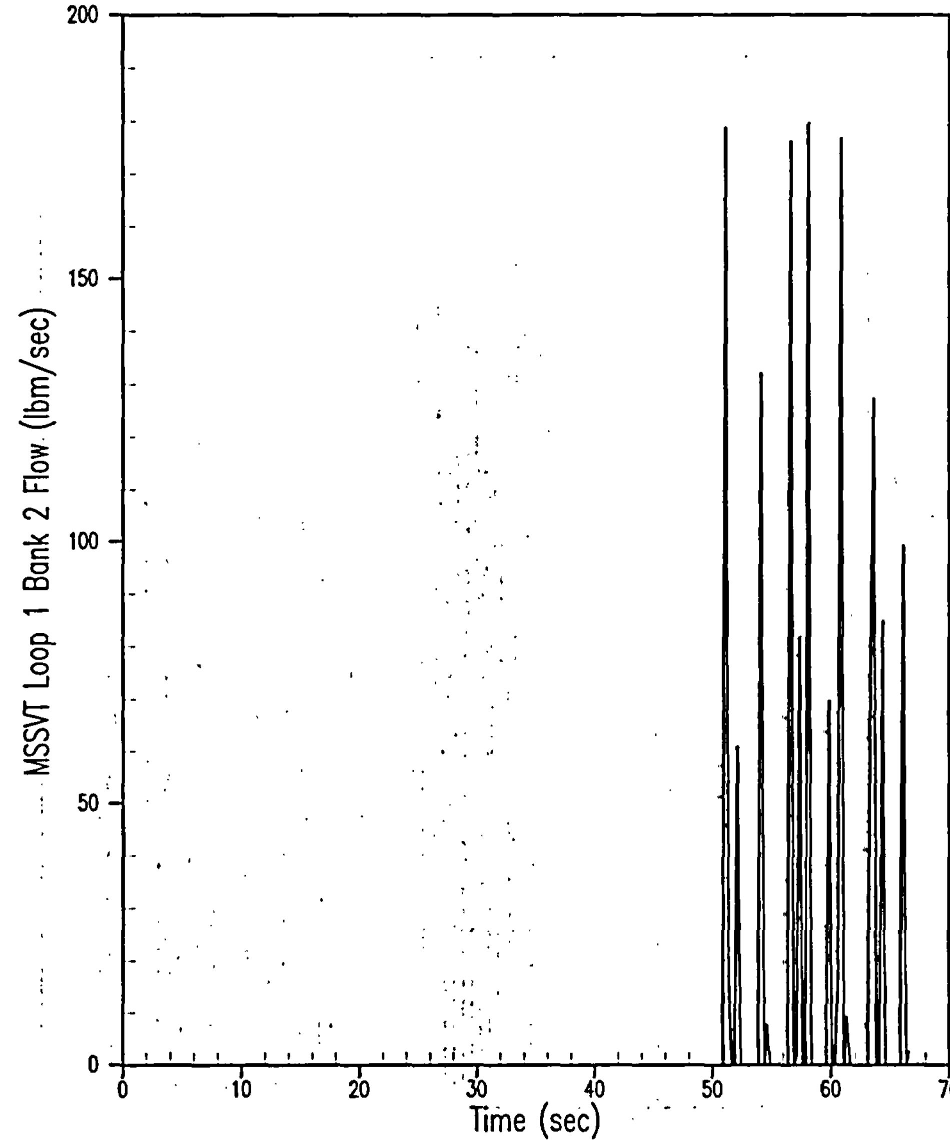

Figure 5.1.11-10
Asymmetric Steam Generator Transient - 0% Tube Plugging
Main Steam Safety Valve Flow (Loop 1 – Bank 2 Unaffected Steam Generator)

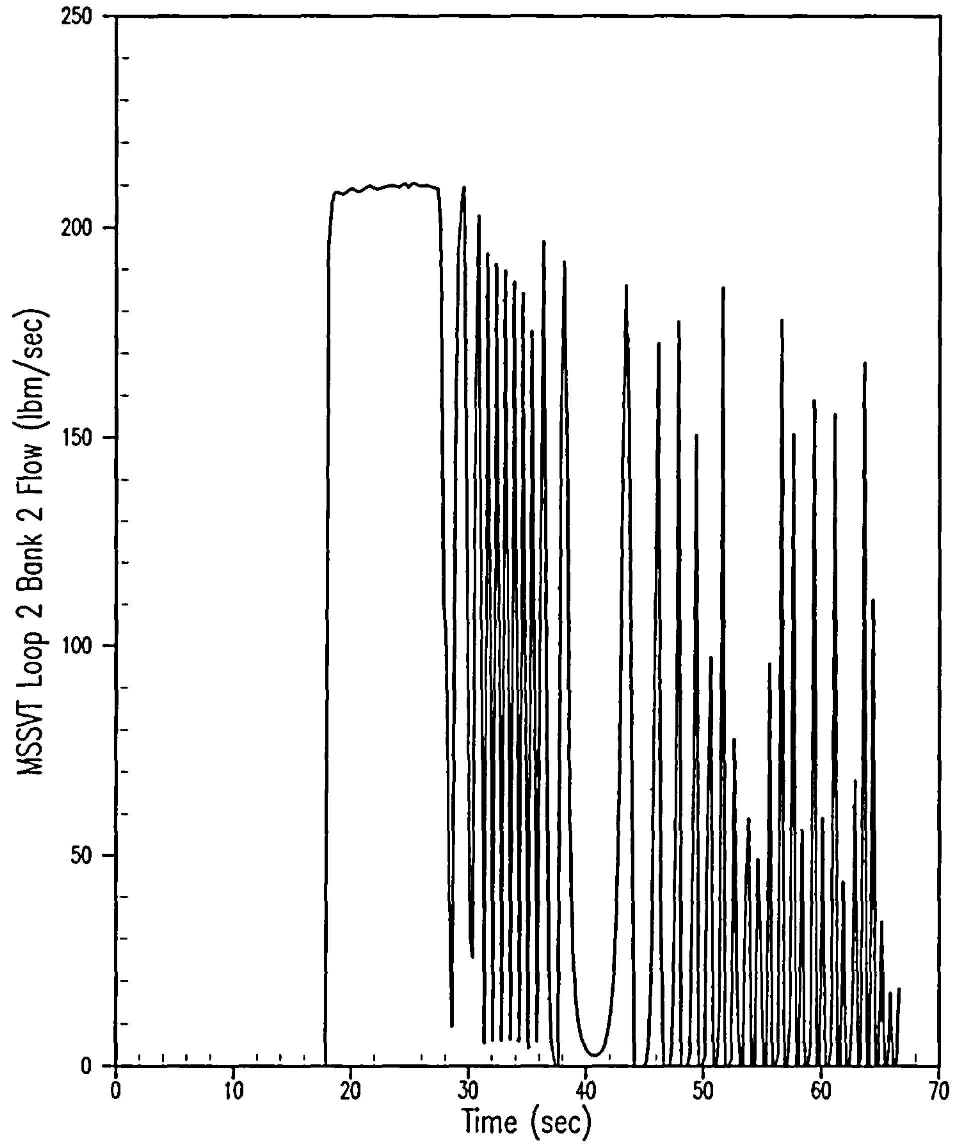

Figure 5.1.11-11
Asymmetric Steam Generator Transient - 0% Tube Plugging
Main Steam Safety Valve Flow (Loop 2 – Bank 2 Affected Steam Generator)

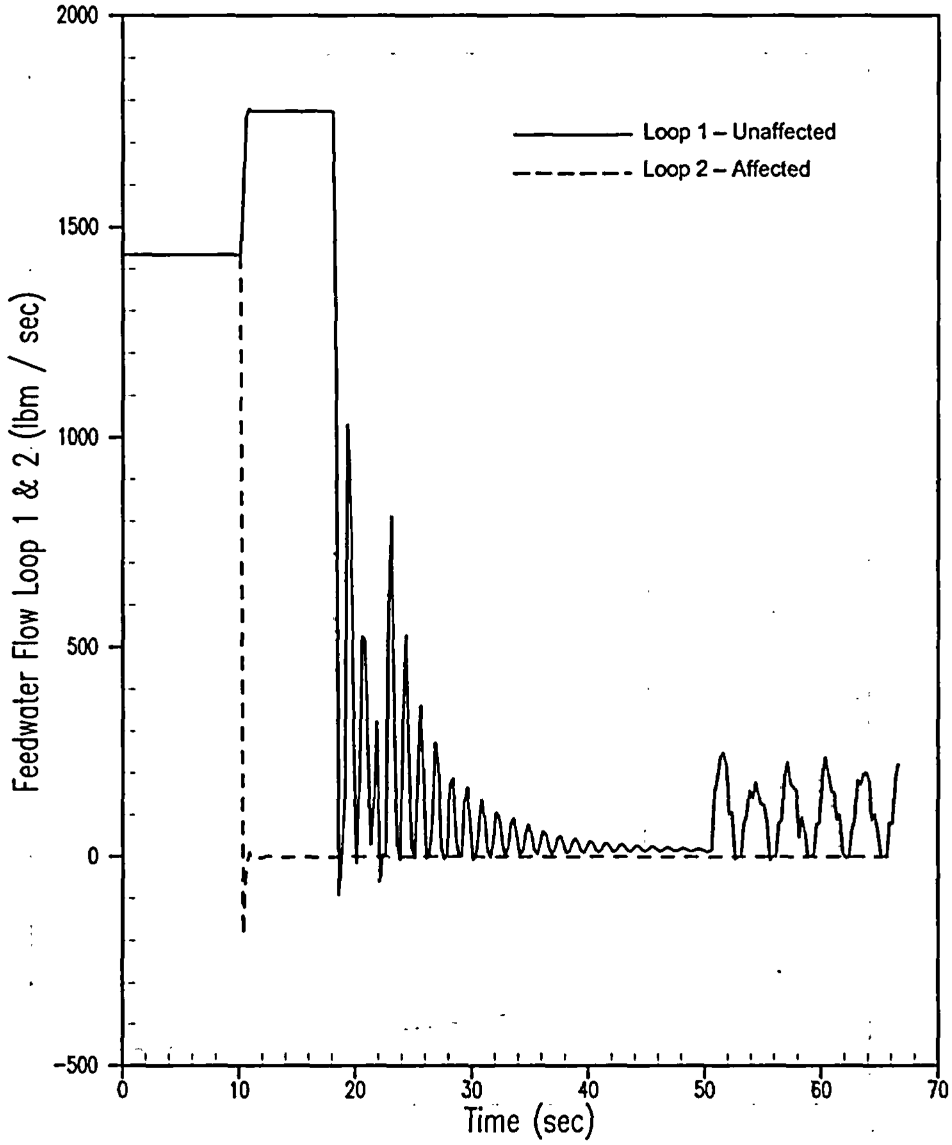

Figure 5.1.11-12
Asymmetric Steam Generator Transient - 0% Tube Plugging
Feedwater Flow

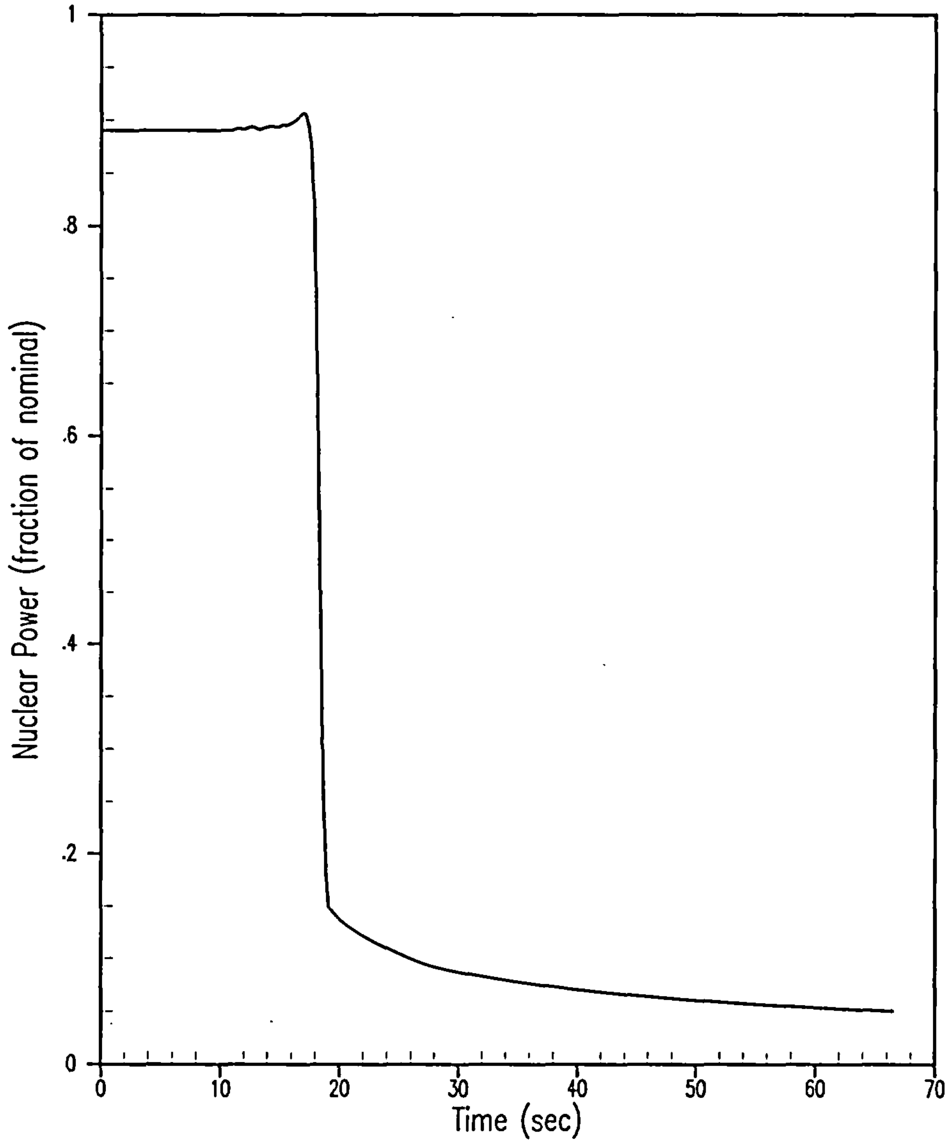

Figure 5.1.11-13
Asymmetric Steam Generator Transient - 42% Tube Plugging
Nuclear Power

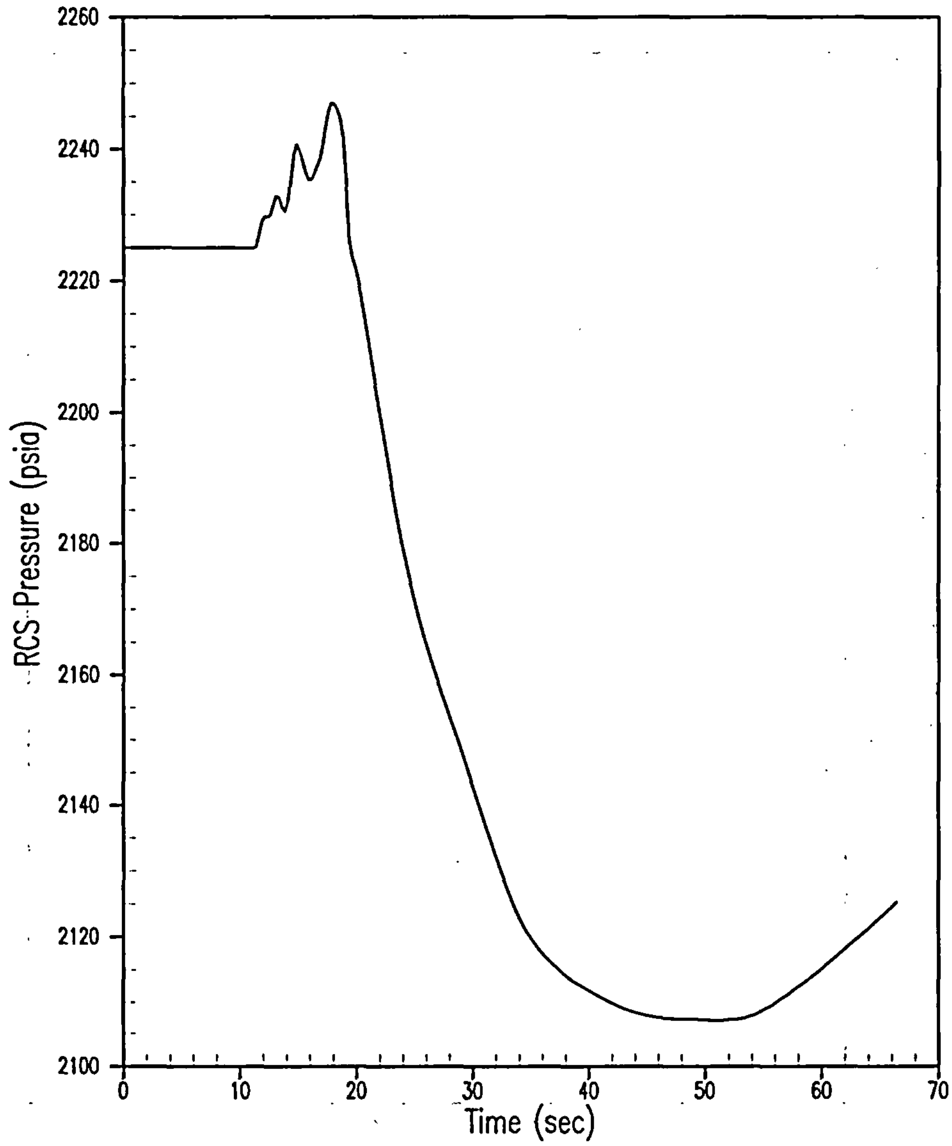

Figure 5.1.11-14
Asymmetric Steam Generator Transient - 42% Tube Plugging
RCS (Pressurizer) Pressure

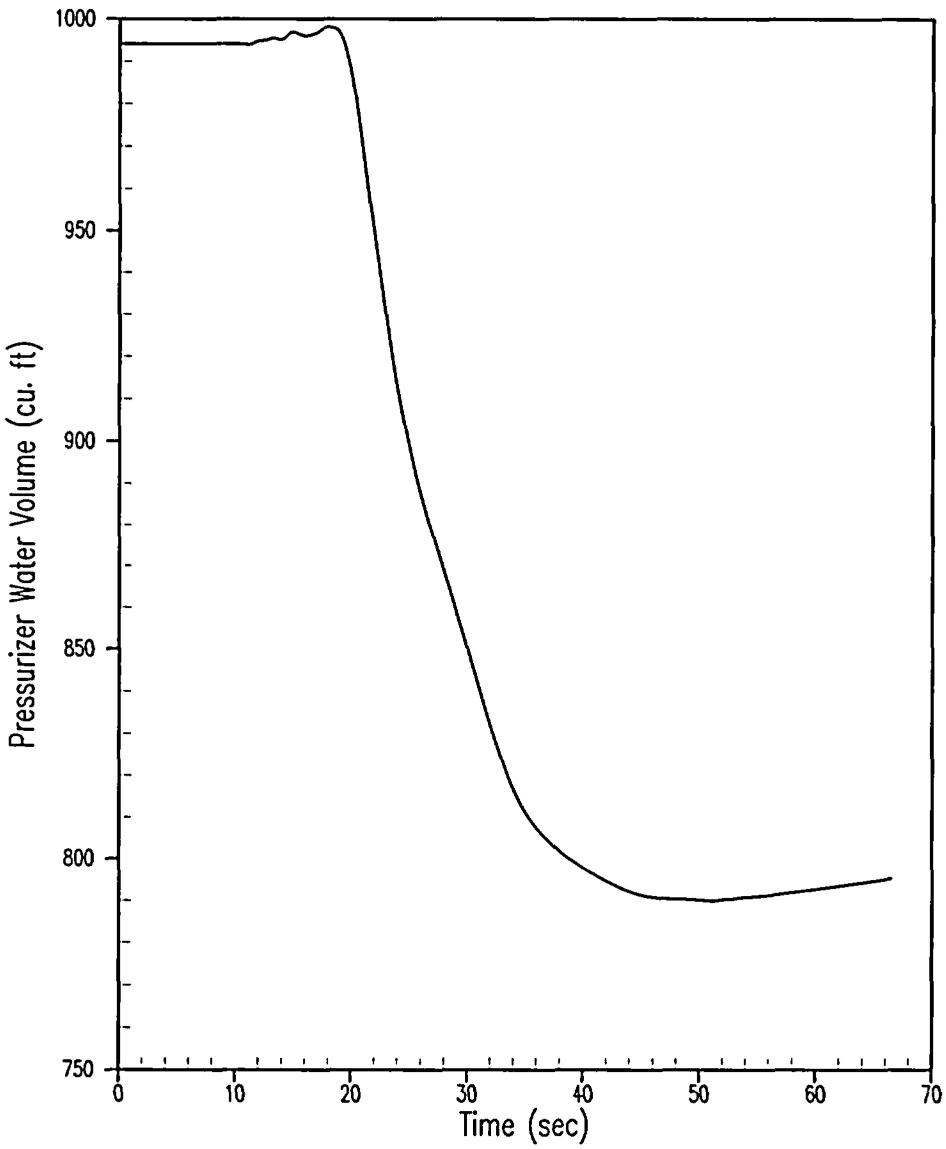

Figure 5.1.11-15
Asymmetric Steam Generator Transient - 42% Tube Plugging
Pressurizer Water Volume

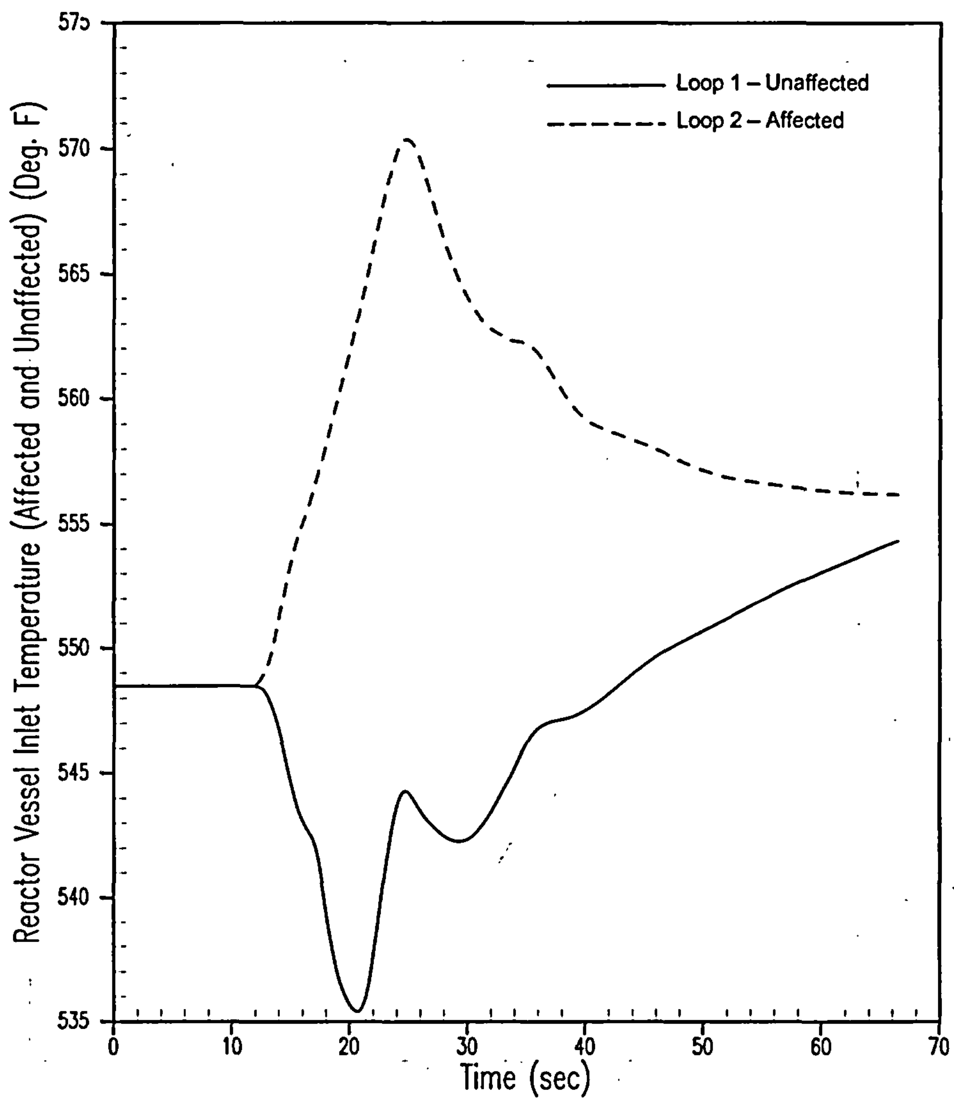

Figure 5.1.11-16
Asymmetric Steam Generator Transient - 42% Tube Plugging
Vessel Inlet Temperature

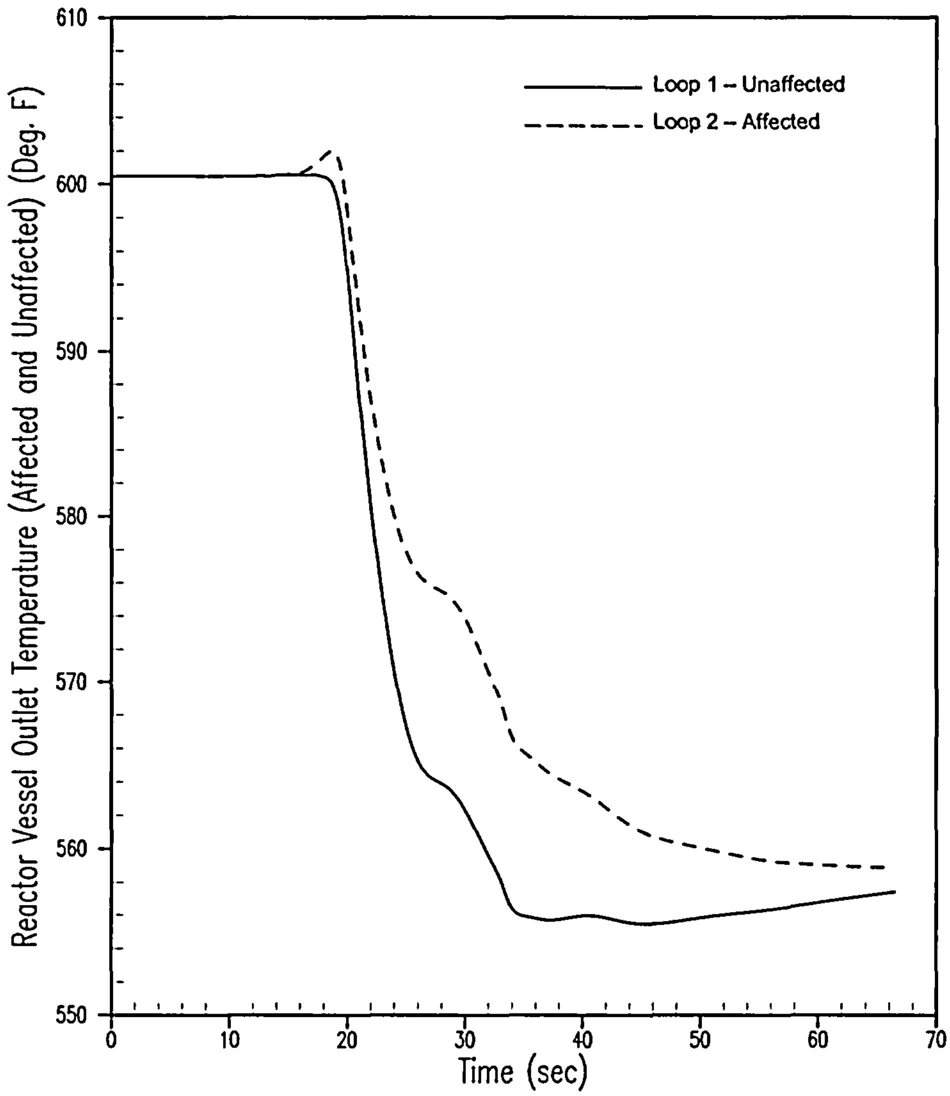

Figure 5.1.11-17
Asymmetric Steam Generator Transient - 42% Tube Plugging
Vessel Outlet Temperature

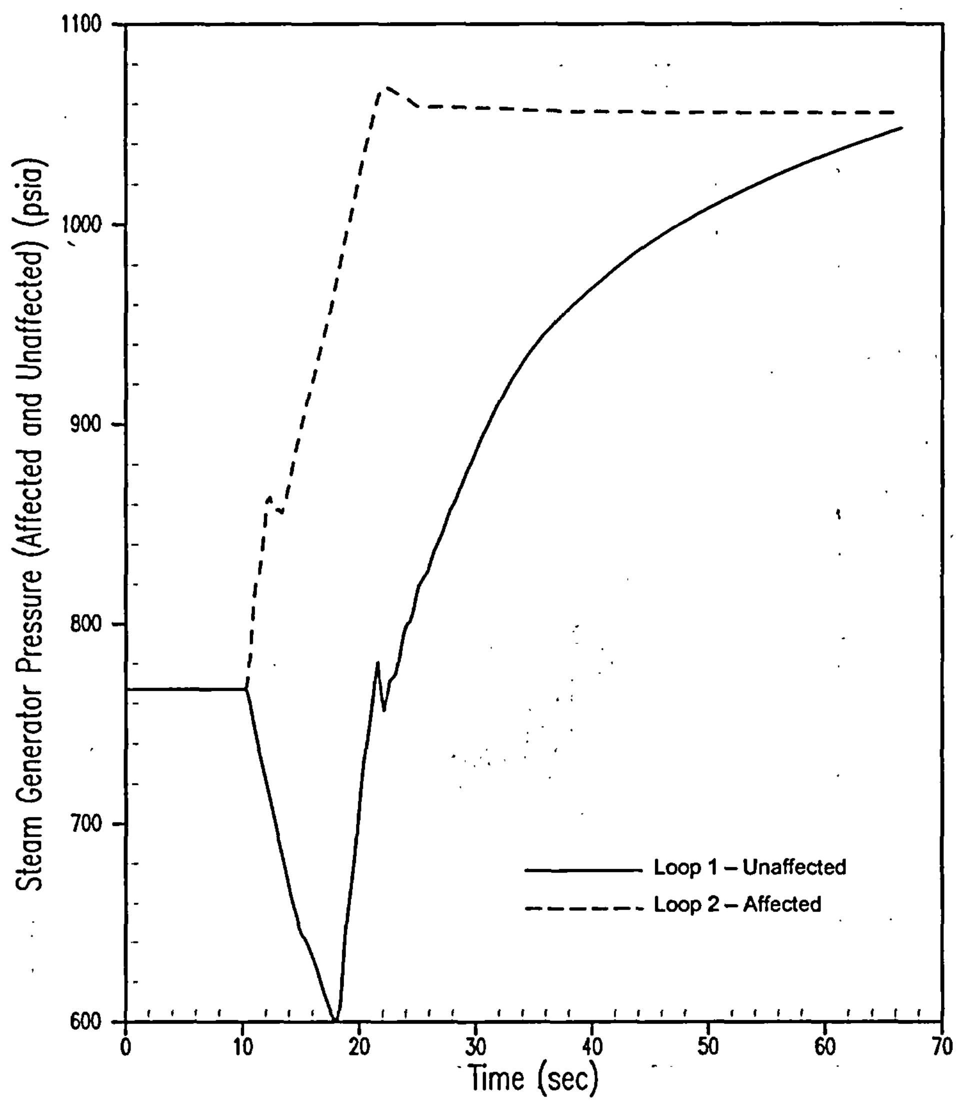

Figure 5.1.11-18
Asymmetric Steam Generator Transient - 42% Tube Plugging
Steam Generator Pressure

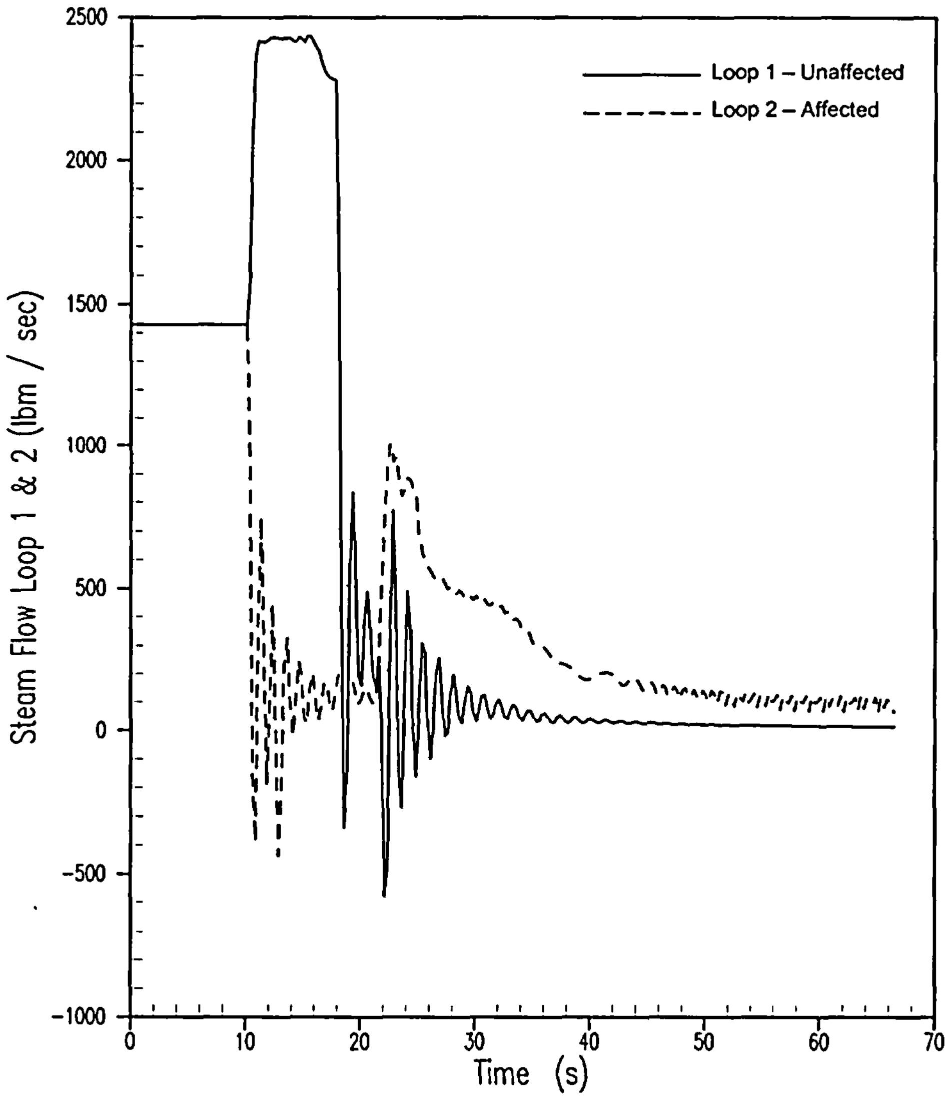

Figure 5.1.11-19
Asymmetric Steam Generator Transient - 42% Tube Plugging
Steam Flow

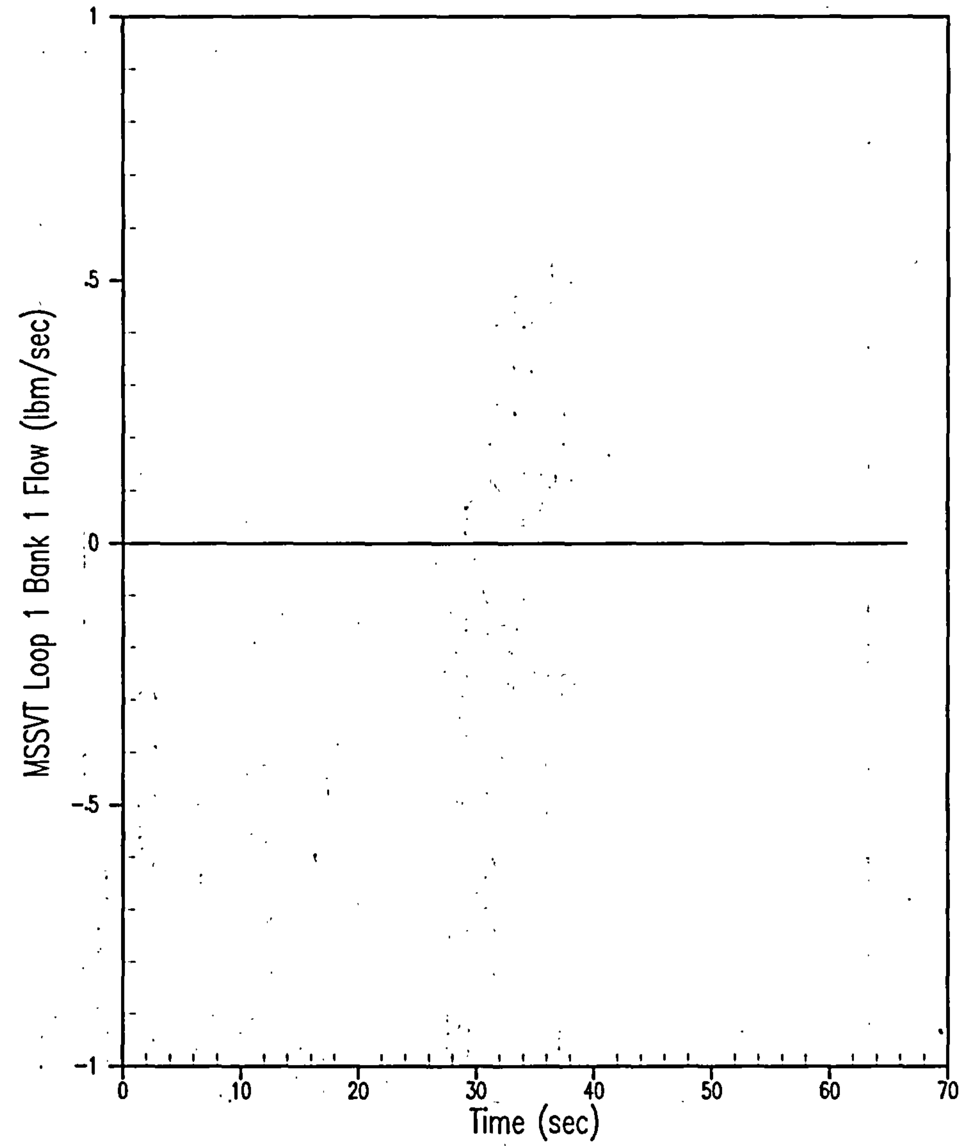

Figure 5.1.11-20
Asymmetric Steam Generator Transient - 42% Tube Plugging
Main Steam Safety Valve Flow (Loop 1 – Bank 1 Unaffected Steam Generator)

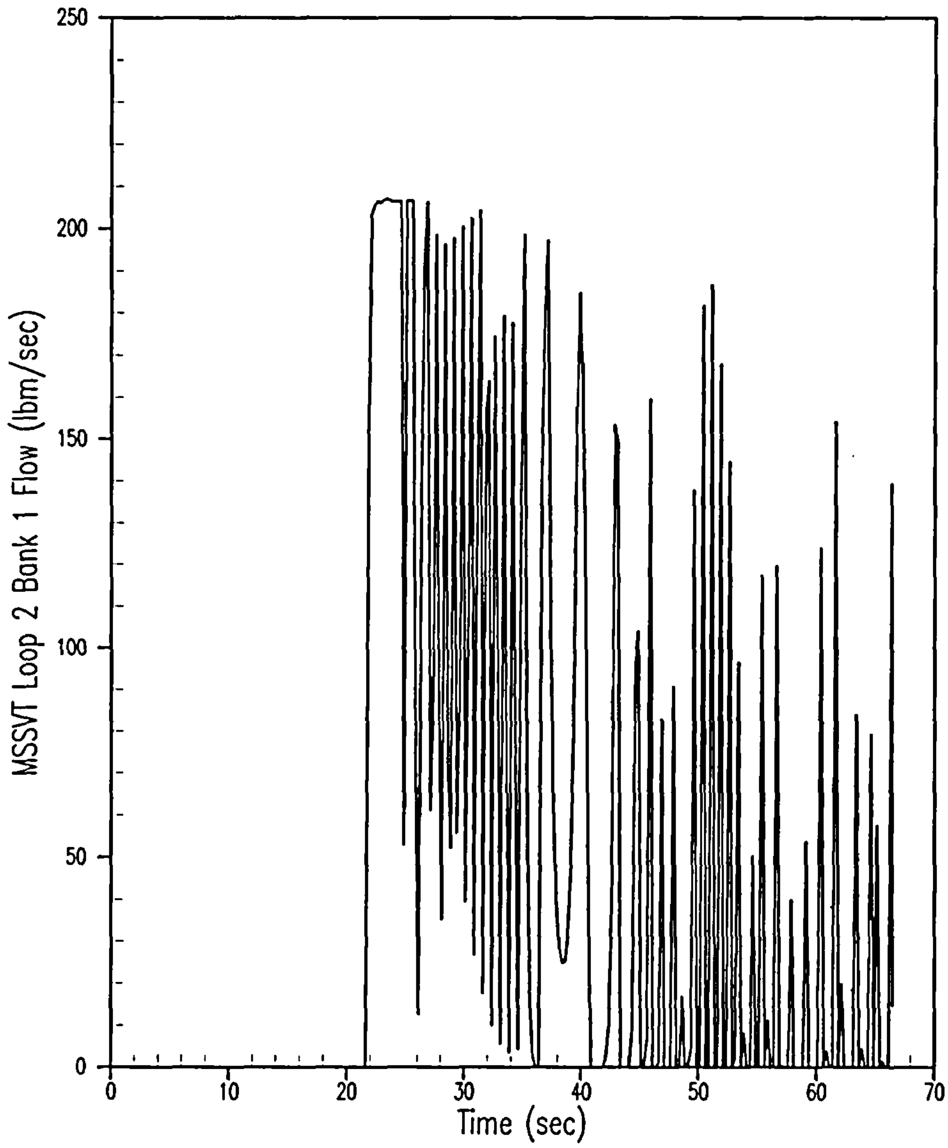

Figure 5.1.11-21
Asymmetric Steam Generator Transient - 42% Tube Plugging
Main Steam Safety Valve Flow (Loop 2 – Bank 1 Affected Steam Generator)

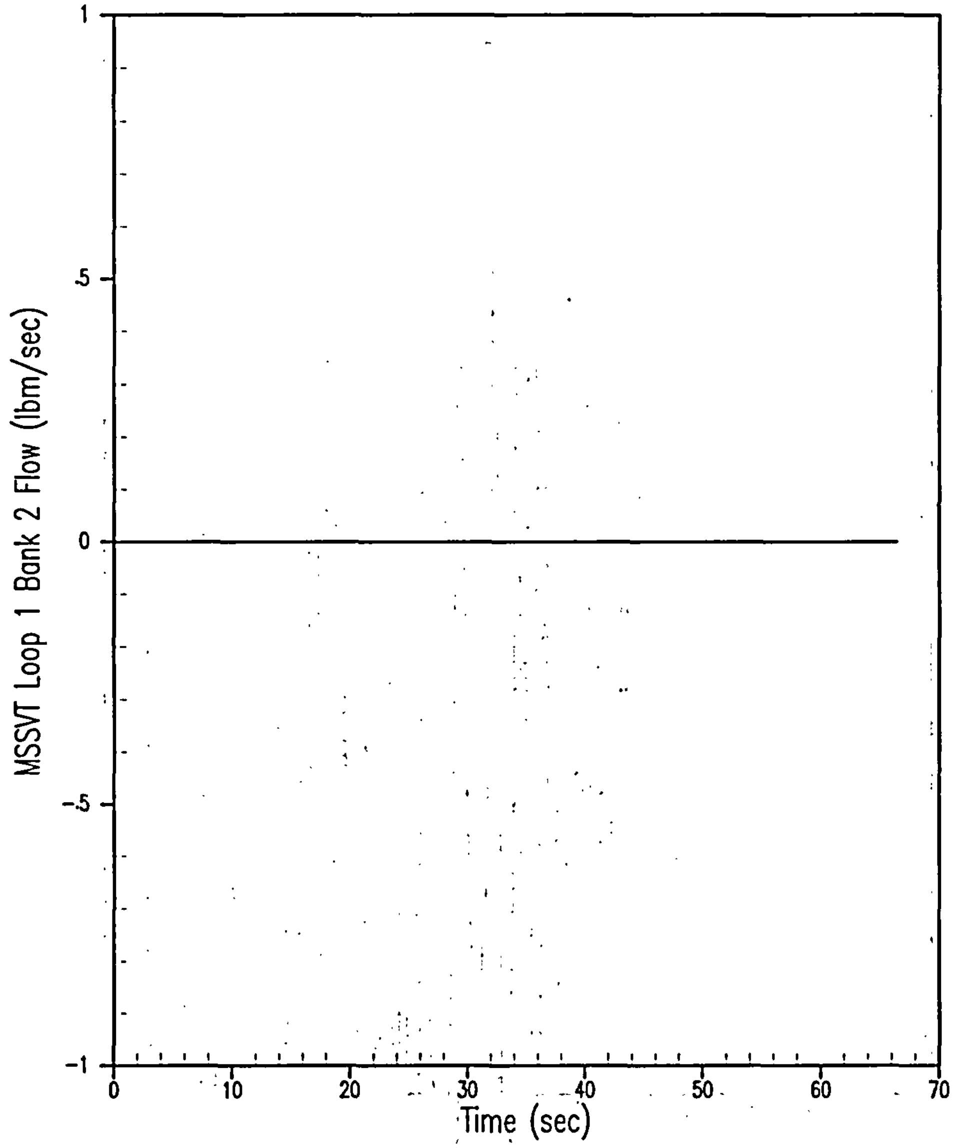

Figure 5.1.11-22
Asymmetric Steam Generator Transient - 42% Tube Plugging
Main Steam Safety Valve Flow (Loop 1 – Bank 2 Unaffected Steam Generator)

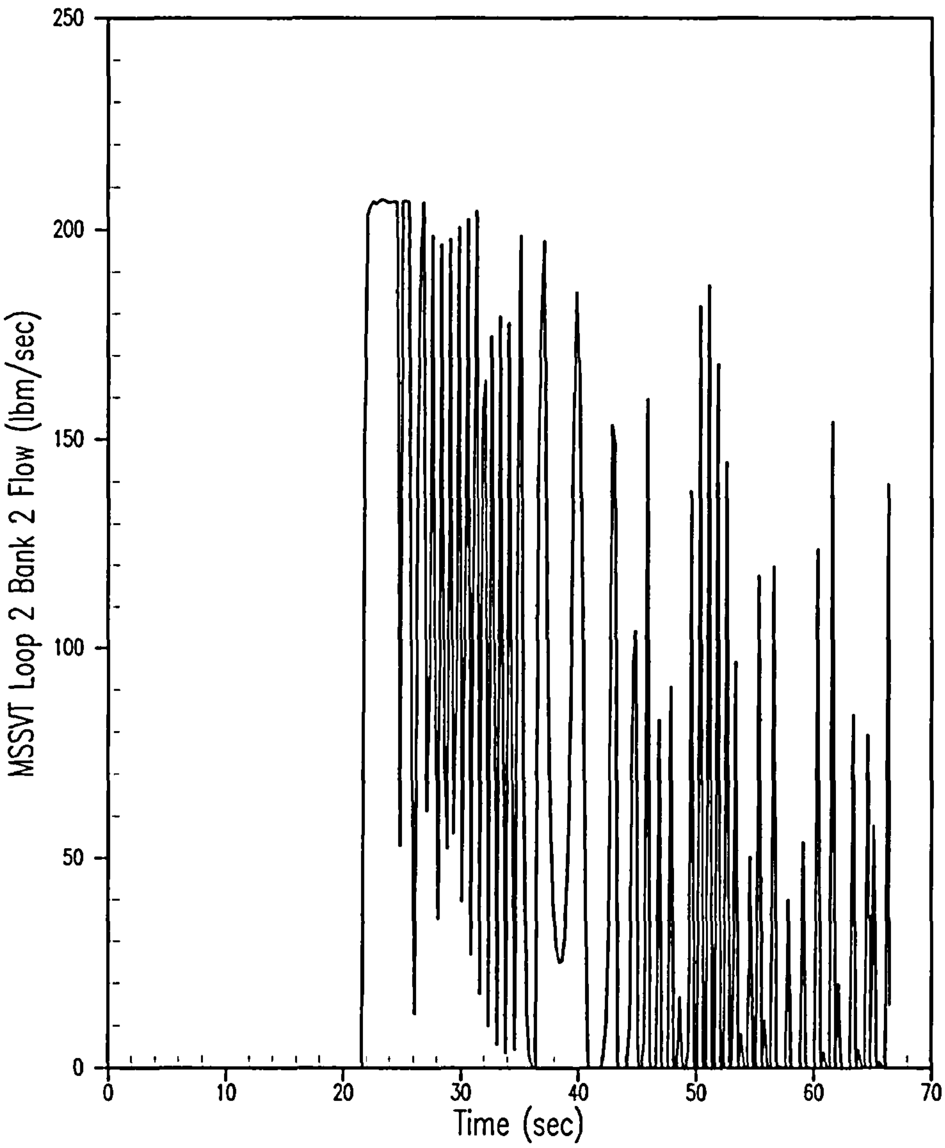

Figure 5.1.11-23
Asymmetric Steam Generator Transient - 42% Tube Plugging
Main Steam Safety Valve Flow (Loop 2 – Bank 2 Affected Steam Generator)

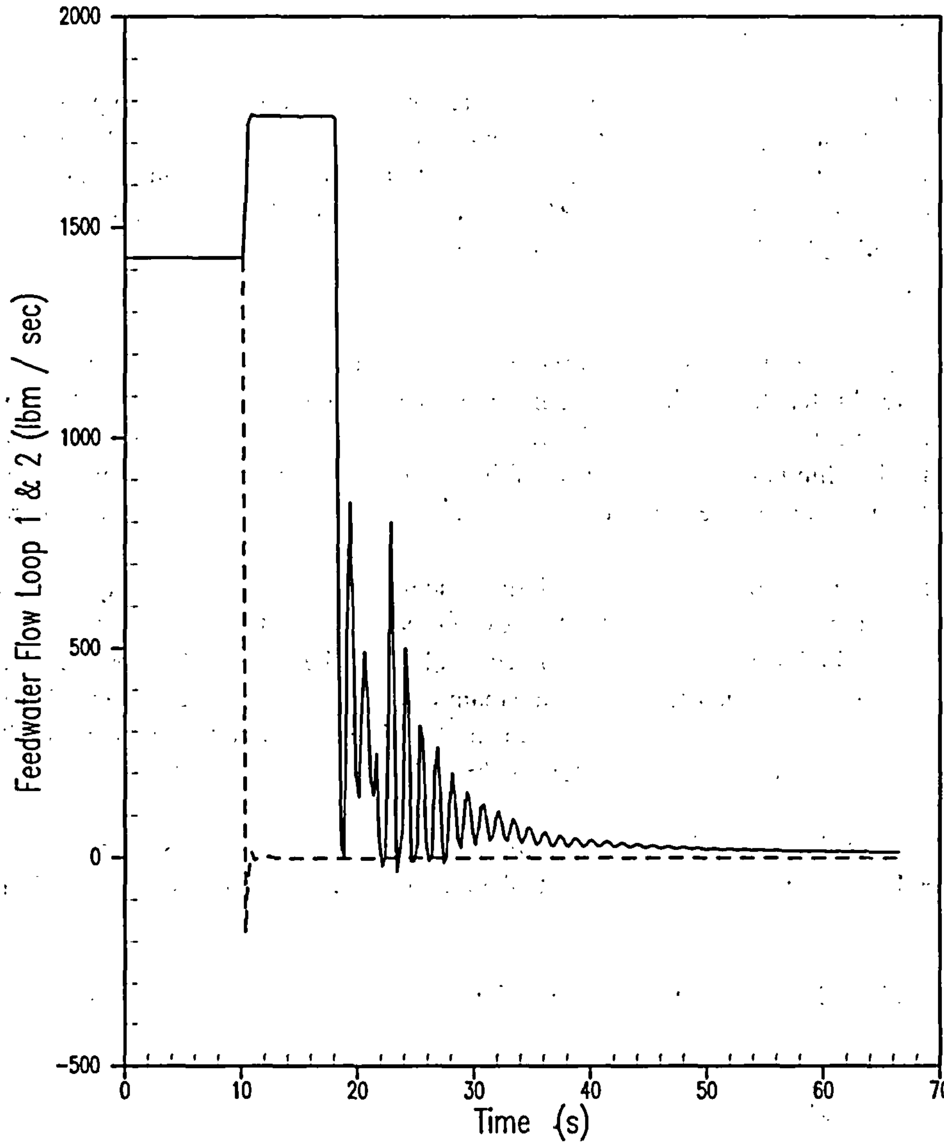

Figure 5.1.11-24
Asymmetric Steam Generator Transient - 42% Tube Plugging
Feedwater Flow

5.1.12 Feedwater Line Break

5.1.12.1 Accident Description

A major feedwater line rupture is defined as a break in a feedwater line large enough to prevent the addition of sufficient feedwater to maintain shell-side fluid inventory in the steam generators. Depending upon the size and location of the rupture and the plant operating conditions, the event can cause either a cooldown or a heatup of the reactor coolant system. Since the RCS cooldown resulting from a secondary system pipe break is covered by the steamline break event, only the RCS heatup aspects are emphasized for the case of feedwater line break.

A feedwater line break reduces the capability of the secondary system to remove heat generated by the core from the RCS. The feedwater flow to the steam generators is reduced or terminated, resulting in a decrease in the shell-side fluid inventory. Moreover, fluid from the faulted steam generator can be expelled through the broken pipe, thereby eliminating the capability of the steam generator to remove heat from the RCS. A broken feedwater line may also prevent the addition of main feedwater to the intact steam generator.

The feedwater line break is one of the events that defines the required minimum capacity of the auxiliary feedwater system for removing core residual heat following reactor trip. If sufficient heat removal capability is not provided, core residual heat following reactor trip could raise the RCS coolant temperature to the extent that the resulting fuel damage would compromise the maintenance of a coolable geometry of the core, and result in potential radioactive releases. For St. Lucie Unit 2, the analysis used to justify the auxiliary feedwater requirements for a postulated feedwater line break is presented in UFSAR Chapter 10.4.9A.

A feedwater line break during 89% of rated thermal power operation may also cause a short-term pressure increase in both the RCS and main steam system challenging the integrity of the RCS and MSS pressure boundaries.

A feedwater line break is classified as an ANS Condition III or IV event, an infrequent or limiting fault, depending on break size.

5.1.12.2 Method of Analysis

The feedwater line break analysis assumes a break in a feedwater line at the steam generator inlet nozzle. Such a break results in an uncontrolled discharge of fluid from the steam generator. A break upstream of the feedwater line check valve would affect the RCS only as a loss of normal feedwater.

This accident is analyzed: (1) to confirm that the pressurizer safety valves (PSVs) and MSSVs are adequately sized to prevent overpressurization of the primary RCS and MSS, respectively; and (2) to ensure that the DNB design basis is satisfied. Chapter 10.4.9A of the UFSAR demonstrates the adequacy of the auxiliary feedwater system in removing long-term decay heat.

The feedwater line break transient is analyzed by employing the detailed digital computer code RETRAN (References 5.1.12-1 and 5.1.12-2). The code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and MSSVs. The code computes pertinent plant variables including temperatures, pressures, and power level.

The event is analyzed to conservatively meet Condition II acceptance criteria. The following scenarios are considered; one ensures that the peak primary RCS pressure remains below 110% of the design limit for all breaks (without FBT and without LOOP), one ensures that the peak primary RCS pressure remains below 110% of the design limit (2750 psia) for breaks of less than 0.2 ft^2 with the failure of the fast bus transfer, one ensures that the peak primary RCS pressure remains below 120% of the design limit (3000 psia) for large breaks (greater than 0.2 ft^2) with failure of the fast bus transfer, and one confirms that the peak MSS pressure remains below 110% of the steam generator shell design pressure (1100 psia). Note that a case to address DNB concerns is not analyzed for the 42% tube plugging program, as the results for the complete loss of flow event in Section 5.1.14 are bounding with respect to DNB concerns. The major assumptions for these cases are summarized as follows.

In order to give conservative results in calculating the maximum RCS and MSS pressures during the transient, the following assumptions are made:

1. The initial reactor power level is assumed to be at 89% of rated thermal power plus uncertainty, the initial RCS flow rate is assumed at a value consistent with the thermal design flow rate, and the initial RCS pressure is assumed at a value consistent with minimum value allowed by the plant technical specifications minus the pressure measurement uncertainty.
2. For maximum RCS pressure, the RCS temperature is assumed to be at Low-T_{avg} conditions minus uncertainty. For maximum MSS pressure, the RCS temperature is assumed to be at High-T_{avg} conditions plus uncertainty.
3. For maximum RCS pressure, the initial steam generator tube plugging level is assumed to be at the maximum plugging level. For maximum MSS pressure, the initial steam generator tube plugging level is assumed to be at the minimum plugging level.
4. The initial steam generator water level is assumed to be at the minimum water level, consistent with the low-level alarm setpoint minus the steam generator level measurement uncertainty.
5. The High Pressurizer Pressure and Low Steam Pressure reactor trip setpoints for adverse conditions are assumed. The Low Steam Generator Level reactor trip is not credited.
6. The feedline break is assumed to occur at the physical inlet nozzle location on the steam generator.
7. An fL/D of 0 (zero) is assumed for the break and the blowdown quality is calculated by the RETRAN code.
8. A break size spectrum is analyzed to determine the limiting size with respect to RCS and MSS overpressurization.
9. Minimum reactivity feedback is assumed to maximize the energy input to the primary coolant.
10. No credit is taken for the effect of the pressurizer spray in reducing or limiting primary coolant pressure. Pressurizer Safety Valves are available, but are modeled assuming a +3% setpoint tolerance. Finally, the PORV is not considered since it would actuate after reactor trip on High Pressurizer Pressure and limit the pressure increase.

The initial conditions are summarized in Table 5.1.0-2.

The Feedline Break methodology also considers the possibility of a Loss of Offsite Power (LOOP) event. For this analysis, the LOOP is assumed to occur 3 seconds after reactor trip, resulting in the remaining 2

Reactor Coolant Pumps (RCPs) coasting down. However, assuming a loss of offsite power does not adversely impact the RCS or MSS overpressurization results. For the RCS pressure cases, peak pressure occurs immediately after reactor trip on High Pressurizer Pressure. By the time the RCPs begin coastdown, the limiting point in the transient has already occurred. For MSS pressure cases, losing RCPs retards heat transfer to the intact SG, leading to a lower peak secondary side pressure. For DNBR, the results of the Complete Loss of Flow analysis are bounding, since the conditions of this event prior to reactor trip are more limiting.

5.1.12.3 Results

The Feedwater Line Break event was analyzed assuming the plant to be initially operating at 89% of rated thermal power at BOC (minimum feedback reactivity coefficients) to determine the primary RCS pressure response. A break spectrum for the case with the failure of the fast bus transfer was analyzed to assure that the maximum RCS pressure case would be captured. For the case with the failure of the fast bus transfer, Figures 5.1.12-1 through 5.1.12-7 show the transient results for the limiting break case, 0.31 ft^2. For smaller breaks with FBT, the limiting case (0.2 ft^2) results in peak RCS pressures below 110% of the design pressure. Since the limiting case (0.31 ft^2) also meets the 110% of design pressure value, no separate figures are provided for this case. In the large feedwater line break with fast bus transfer, the PSVs actuate and maintain the primary RCS pressure below 120% of the design value. As this case is not limiting, no separate figures are provided. Table 5.1.12-1 summarizes the results of the break spectrum analysis and Table 5.1.12-3 provides the sequence of events and limiting conditions for the 0.31 ft^2 case. For the case in which the fast bus transfer does not fail and offsite power is available, the maximum primary pressure will remain below 110% of the design value.

Table 5.1.12-2 summarizes the break spectrum results for the Feedwater Line Break event at BOC (minimum feedback reactivity coefficients) assuming 0% SGTP to determine the secondary MSS pressure response. Further, the low steam generator level reactor trip function was not credited. The break spectrum was analyzed from 0.005 ft^2 to 0.375 ft^2 to assure that the maximum MSS pressure case would be captured. The limiting break size was found to be 0.1 ft^2. The MSS pressure increases, resulting in opening the MSSVs, then decreases rapidly following reactor trip. The MSSVs actuate to limit the MSS pressure below 110% of the steam generator shell design pressure. Table 5.1.12-4 provides the sequence of events and limiting conditions for the 0.1 ft^2 case, and Figures 5.1.12-8 through 5.1.12-14 show the transient results. (Note: Due to the small break size, the MSS pressure and break flow response for the 0.1 ft^2 case is much different from those presented for the limiting RCS Overpressurization cases.)

As discussed above, the Feedwater Line Break DNB case is not analyzed for the 42% SGTP program.

5.1.12.4 Conclusions

The results of the analyses show that the plant design is such that a feedwater line break presents no hazard to the integrity of the primary RCS or MSS by meeting all applicable Condition II acceptance criteria. Pressure relieving devices that have been incorporated into the plant design are adequate to limit the maximum pressures to within the safety analysis limits, i.e., 2750 psia or 3000 psia, as appropriate, for the primary RCS and 1100 psia for the MSS. The integrity of the core is maintained by operation of the reactor protection system, (i.e., the minimum DNBR is maintained above the safety analysis limit value), based on the results of the complete loss of flow event in Section 5.1.14, which bounds the feedline break event. Thus, no core safety limit will be violated as a result of implementing up to 42% steam generator tube plugging.

5.1.12.5 References

5.1.12-1 WCAP-14882-P-A, Rev. 0, "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses."

5.1.12-2 EPRI NP-1850-CCM, "Validation and Verification of the MTR-PC Thermohydraulic Package."

Table 5.1.12-1
Feedwater Line Break, RCS Overpressurization Case Results
(Failure of the FBT)

Break Size (ft^2)	Max RCS Pressure (psia)
0.375	2707.6
0.35	2709.2
0.34	2709.9
0.33	2710.1
0.325	2710.4
0.31	**2710.6**
0.30	2710.2
0.29	2706.7
0.28	2705.6
0.27	2704.2
0.25	2700.6
120% of Design Pressure Limit; (110% - 0.2 ft^2 break)	3000; (2750 for 0.2 ft^2 break)

Table 5.1.12-2 Feedwater Line Break MSS Overpressurization Case Results	
Break Size (ft^2)	**Max MSS Pressure (psia)**
0.375	934.6
0.300	990.8
0.250	1035.7
0.200	1063.3
0.150	1073.3
0.100	1078.6
0.050	1077.8
0.010	1077.4
0.005	1077.4
110% of Design Pressure Limit	1100

Table 5.1.12-3 Sequence of Events and Transient Feedwater Line Break RCS Overpressure Results for the Limiting Break Size = 0.31 ft^2 (Failure of the FBT)	
Event	**Time (seconds)**
Initiation of Event	0.01
Manual Feedwater Isolation (both loops)	0.01
High Pressurizer Pressure signal	34.3
Reactor Trip (Breakers open)	34.7
Failure of Fast Bus Transfer (2 RCPs coastdown)	34.8
Rod Motion Begins (0.74 seconds following Breaker opening)	35.5
Time of Peak RCS Pressure	37.4
Results	
Peak RCS Pressure	2710.6 psia
RCS Pressure Limit	2750 psia

Table 5.1.12-4
Sequence of Events and Transient Feedwater Line Break MSS Overpressure Results for the Limiting Break Size = 0.1 ft^2

Event	Time (seconds)
Initiation of Event	0.01
Manual Feedwater Isolation (both loops)	0.01
High Pressurizer Pressure signal	38.5
Reactor Trip (Breakers open)	38.9
Rod Motion Begins (0.74 seconds following Breaker opening)	39.6
Time of Peak MSS Pressure	43.7
Results	
Peak MSS Pressure	1078.6 psia
MSS Pressure Limit	1100 psia

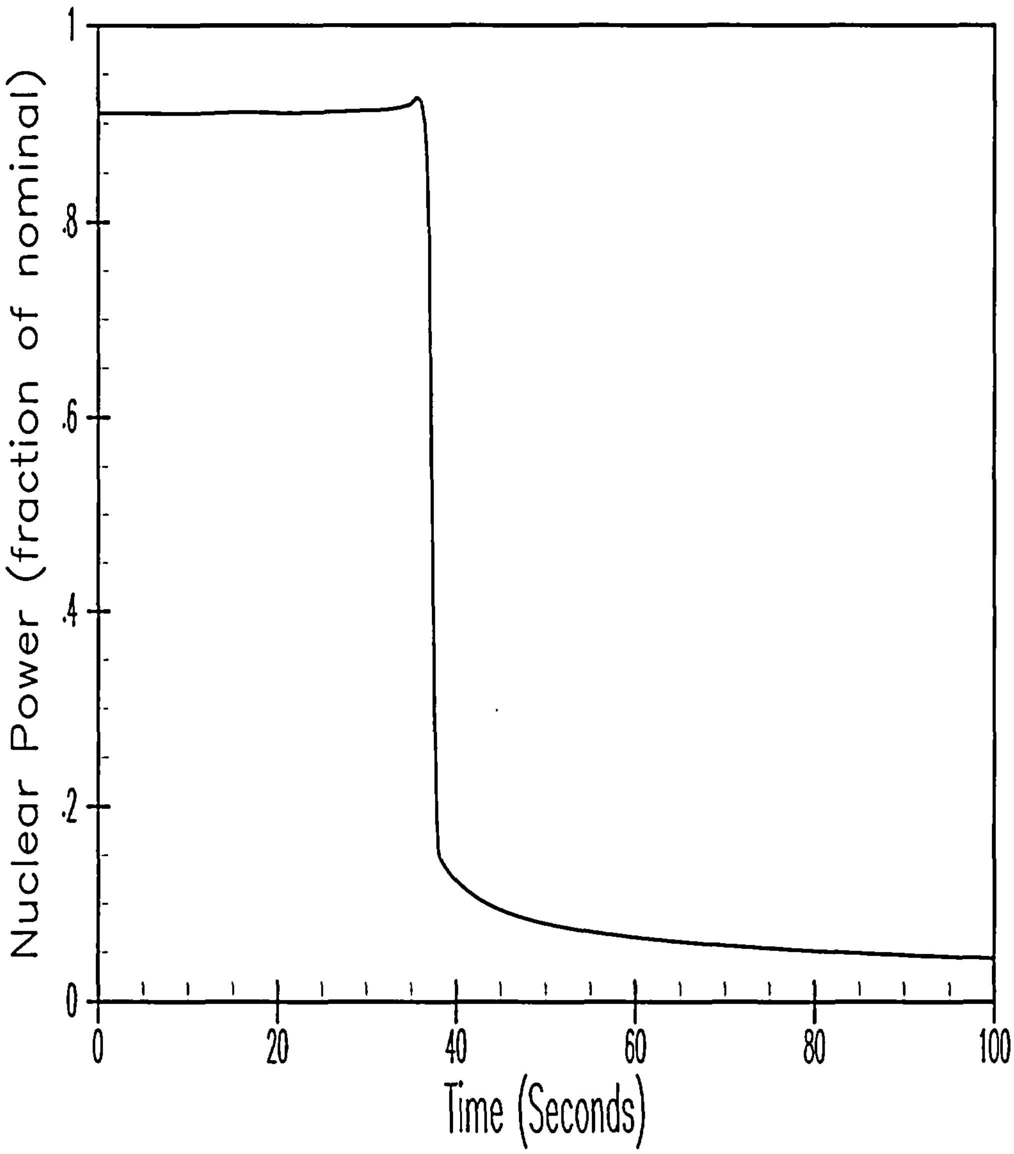

Figure 5.1.12-1
Feedwater Line Break RCS Overpressure Case with FFBT
Limiting Break Size = 0.31 ft^2
Nuclear Power

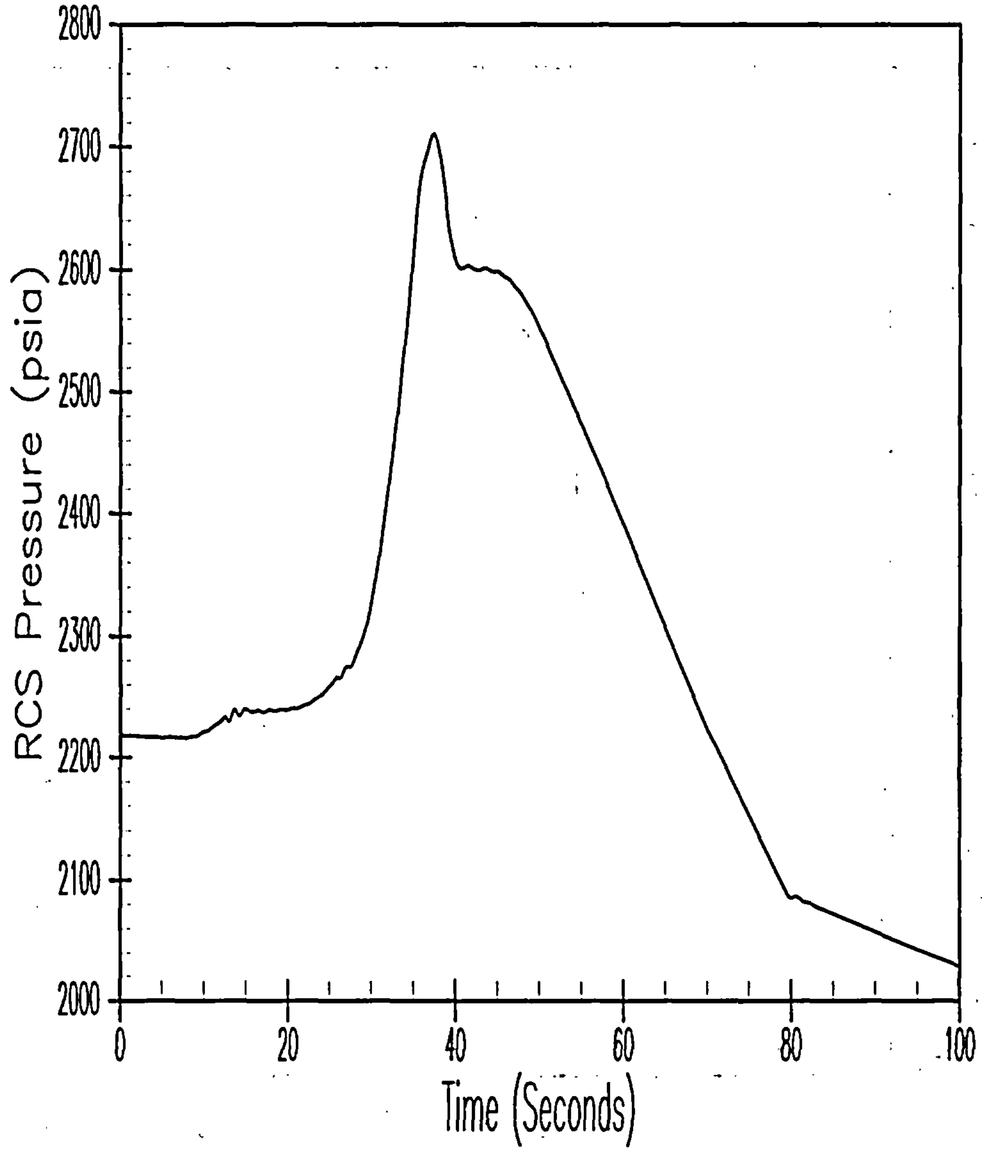

Figure 5.1.12-2
Feedwater Line Break RCS Overpressure Case with FFBT
Limiting Break Size = 0.31 ft^2
RCS Pressure

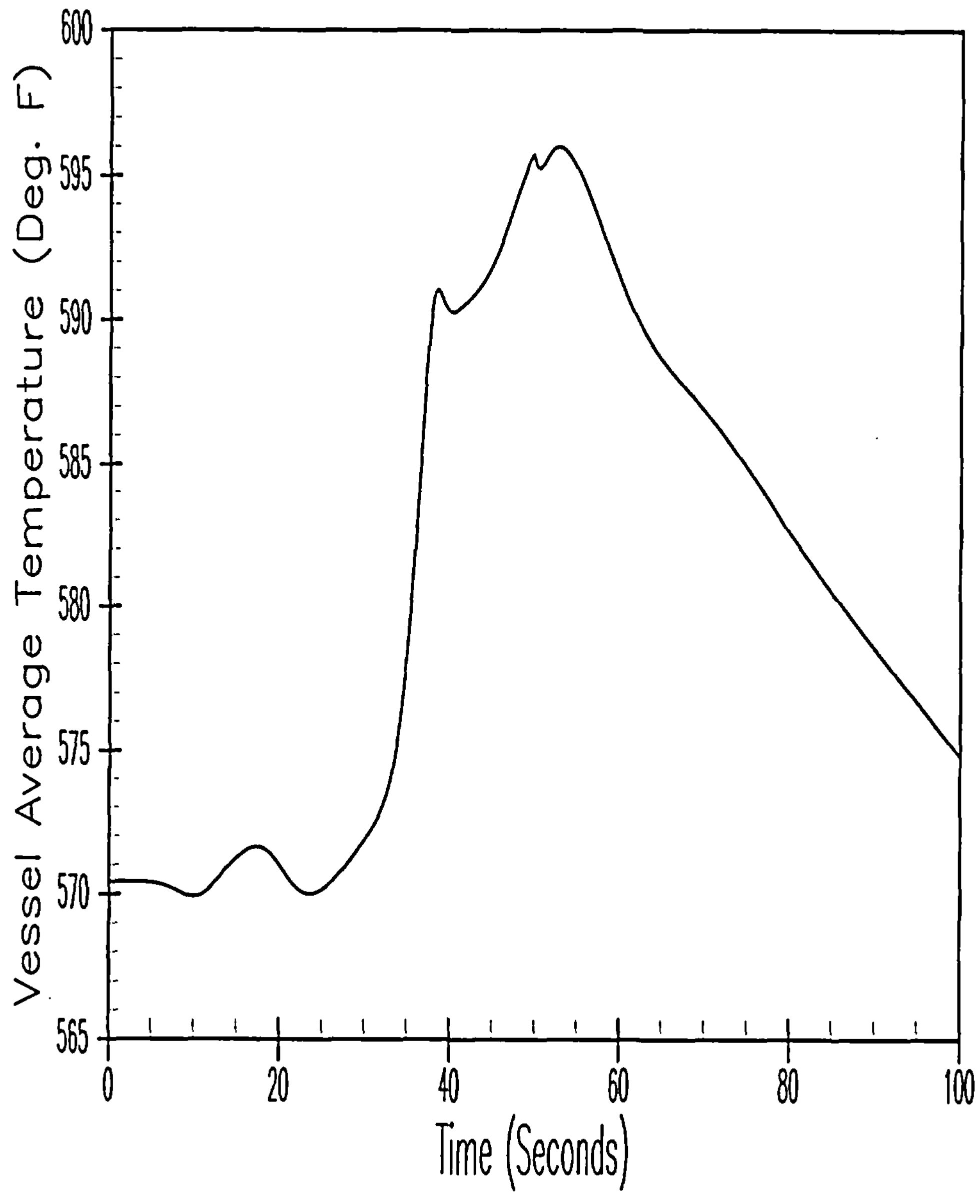

Figure 5.1.12-3
Feedwater Line Break RCS Overpressure Case with FFBT
Limiting Break Size = 0.31 ft^2
Vessel Average Temperature

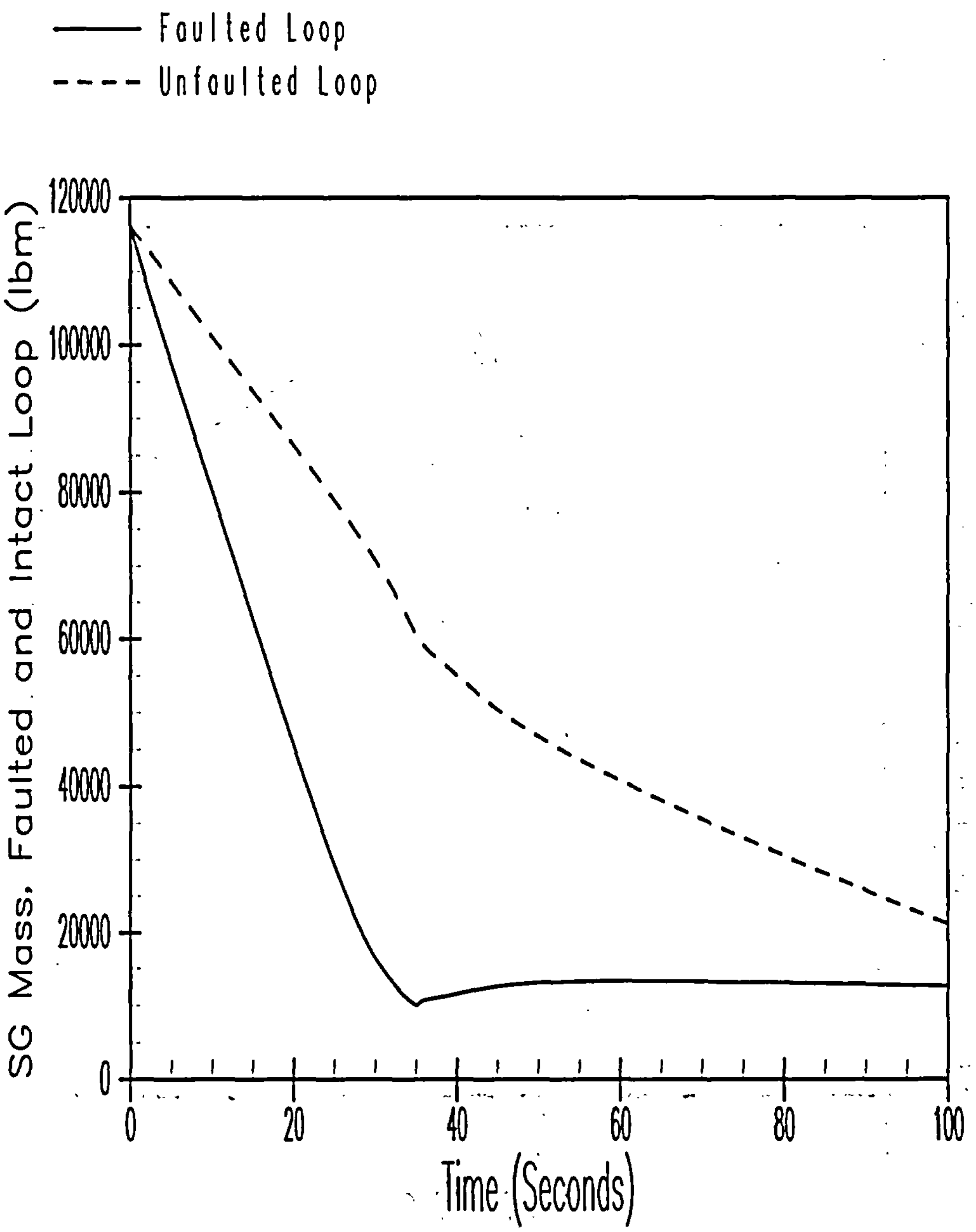

Figure 5.1.12-4
Feedwater Line Break RCS Overpressure Case with FFBT
Limiting Break Size = 0.31 ft^2
Steam Generator Mass

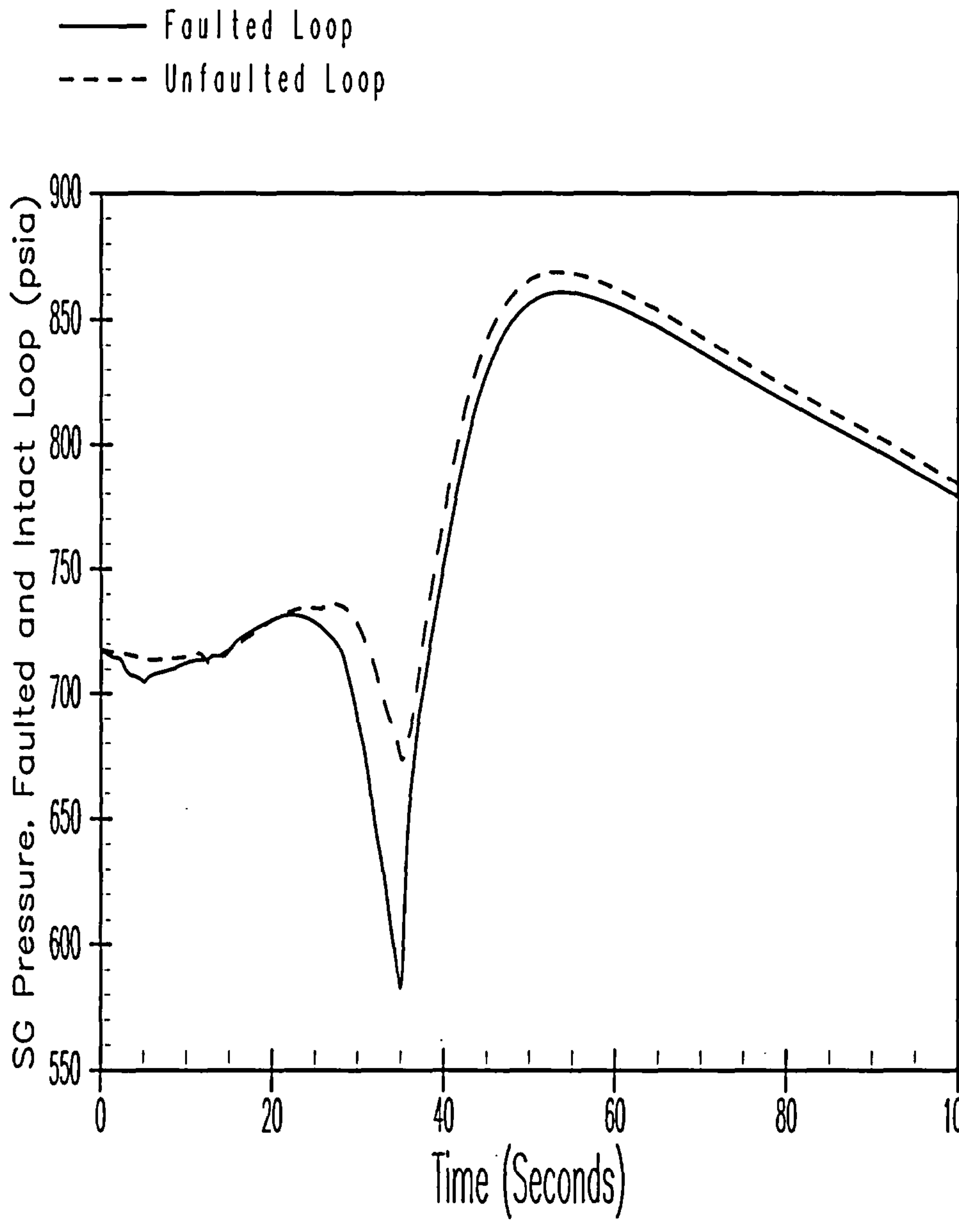

Figure 5.1.12-5
Feedwater Line Break RCS Overpressure Case with FFBT
Limiting Break Size = 0.31 ft^2
Steam Generator Pressure

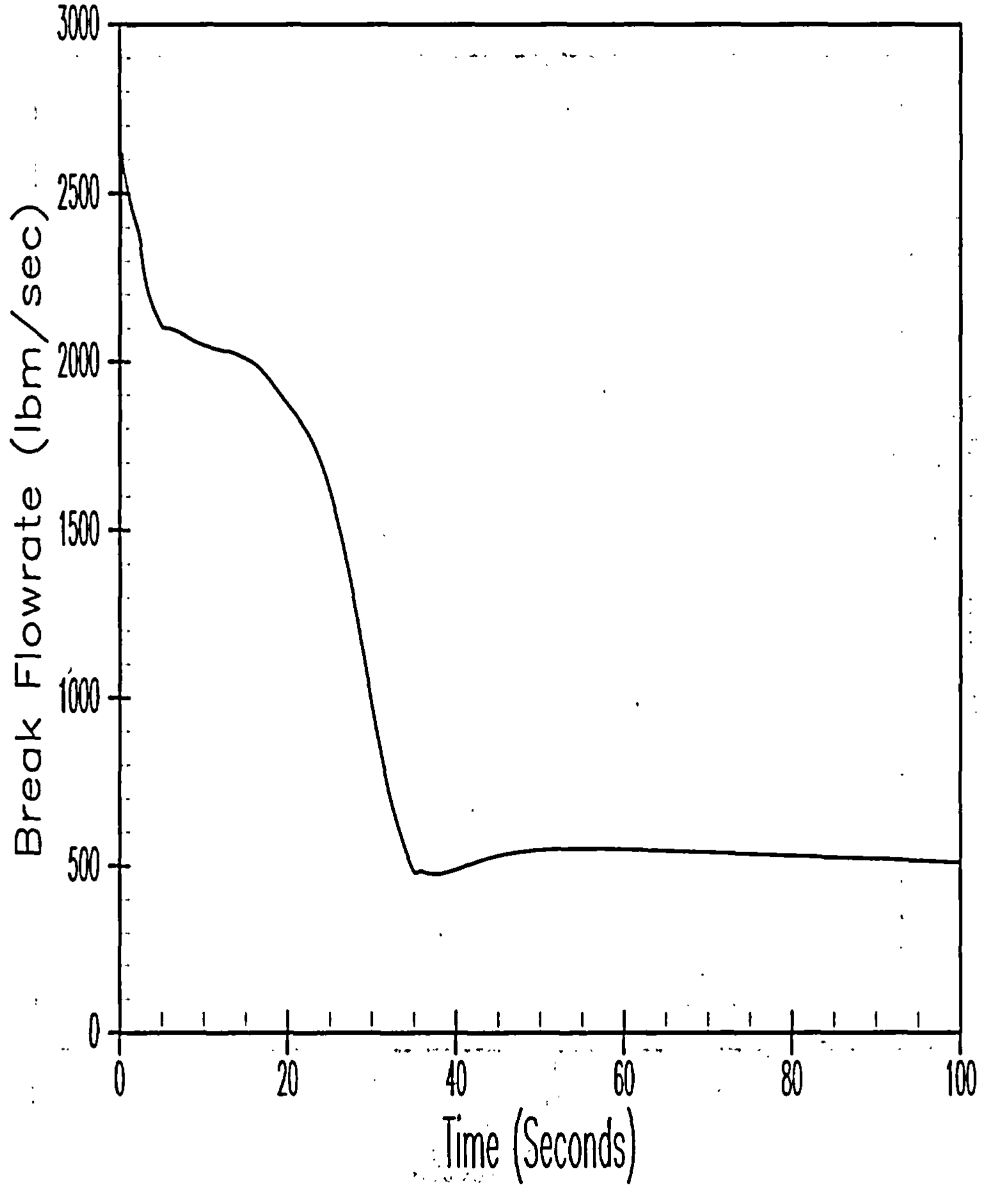

Figure 5.1.12-6
Feedwater Line Break RCS Overpressure Case with FFBT
Limiting Break Size = 0.31 ft²
Break Flowrate

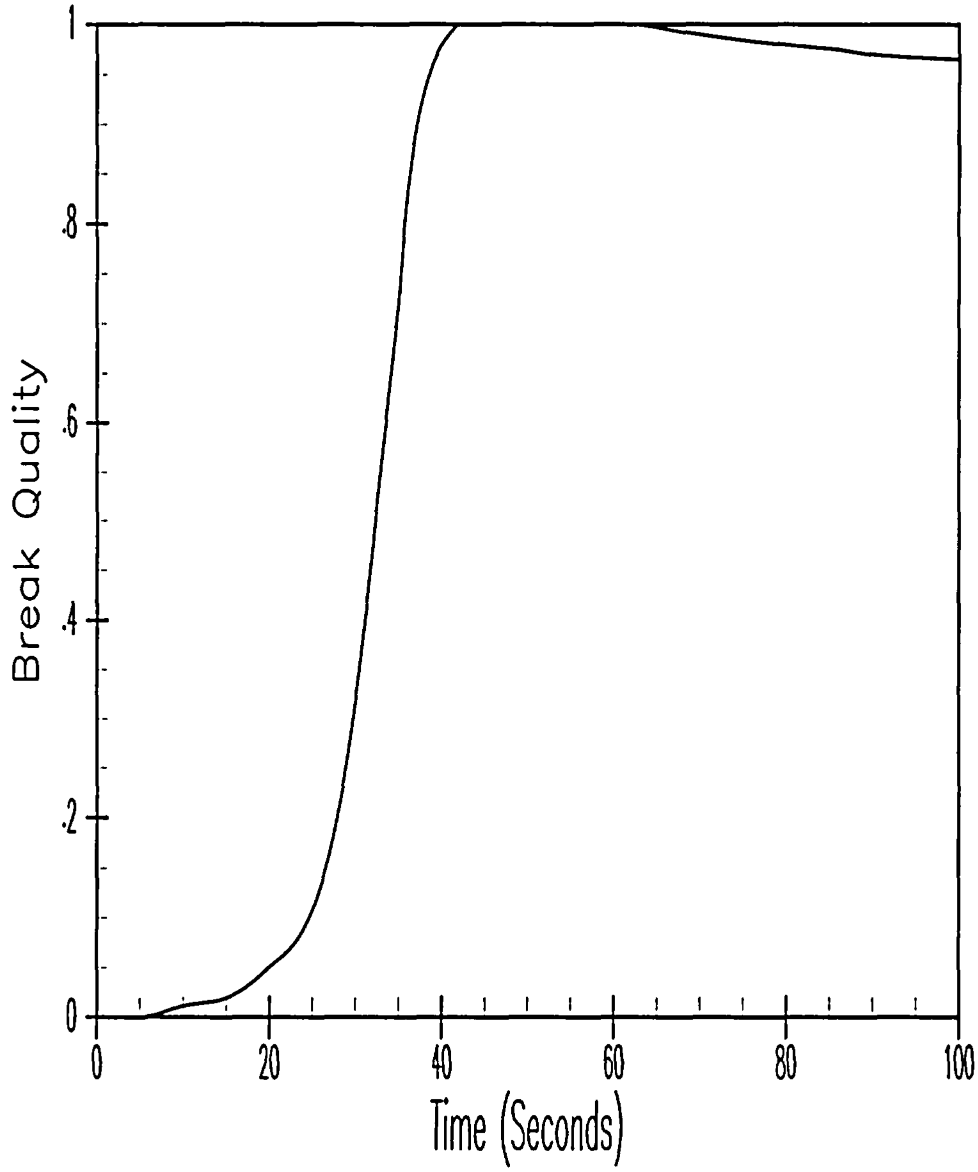

Figure 5.1.12-7
Feedwater Line Break RCS Overpressure Case with FFBT
Limiting Break Size = 0.31 ft^2
Break Quality

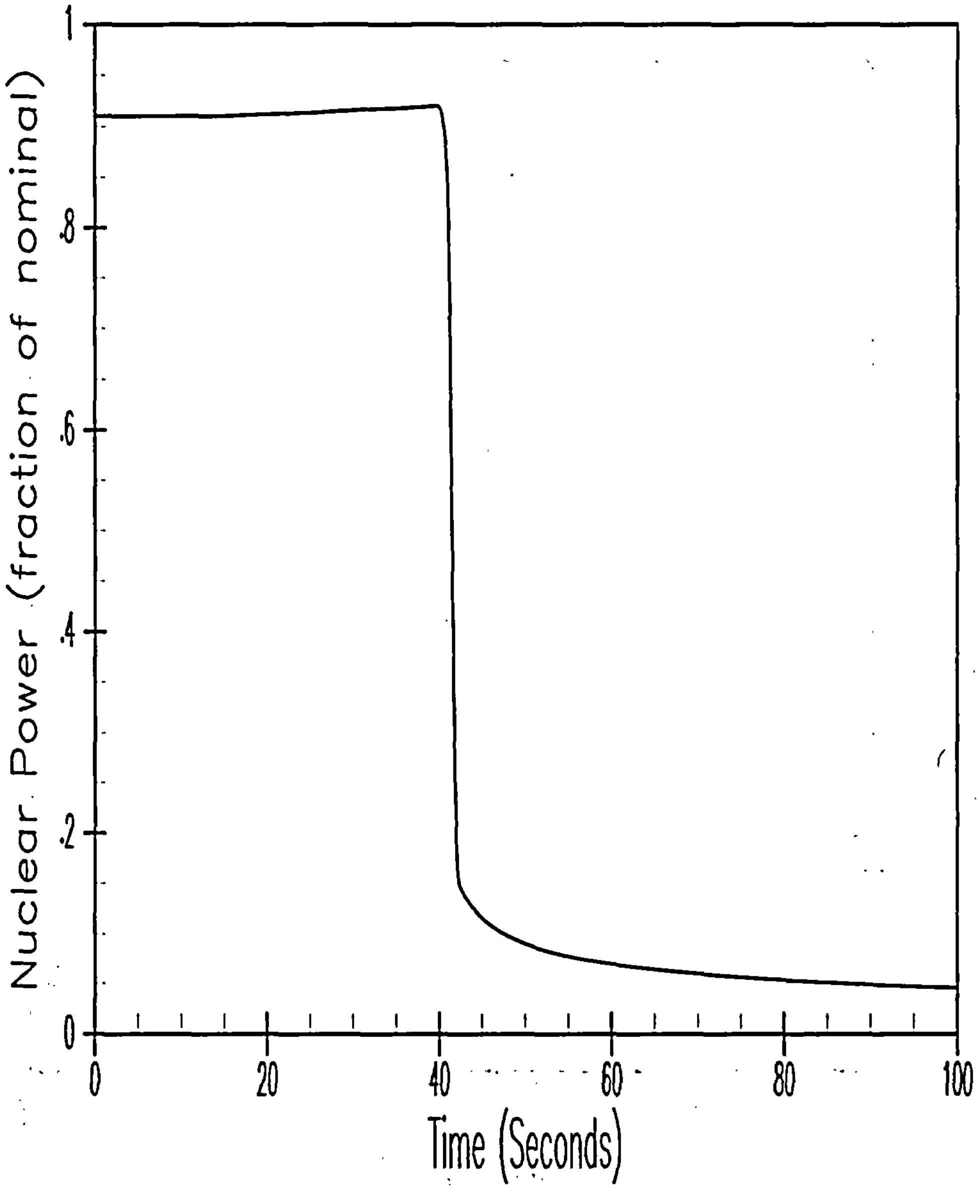

Figure 5.1.12-8
Feedwater Line Break MSS Overpressure Case
Limiting Break Size = 0.1 ft^2
Nuclear Power

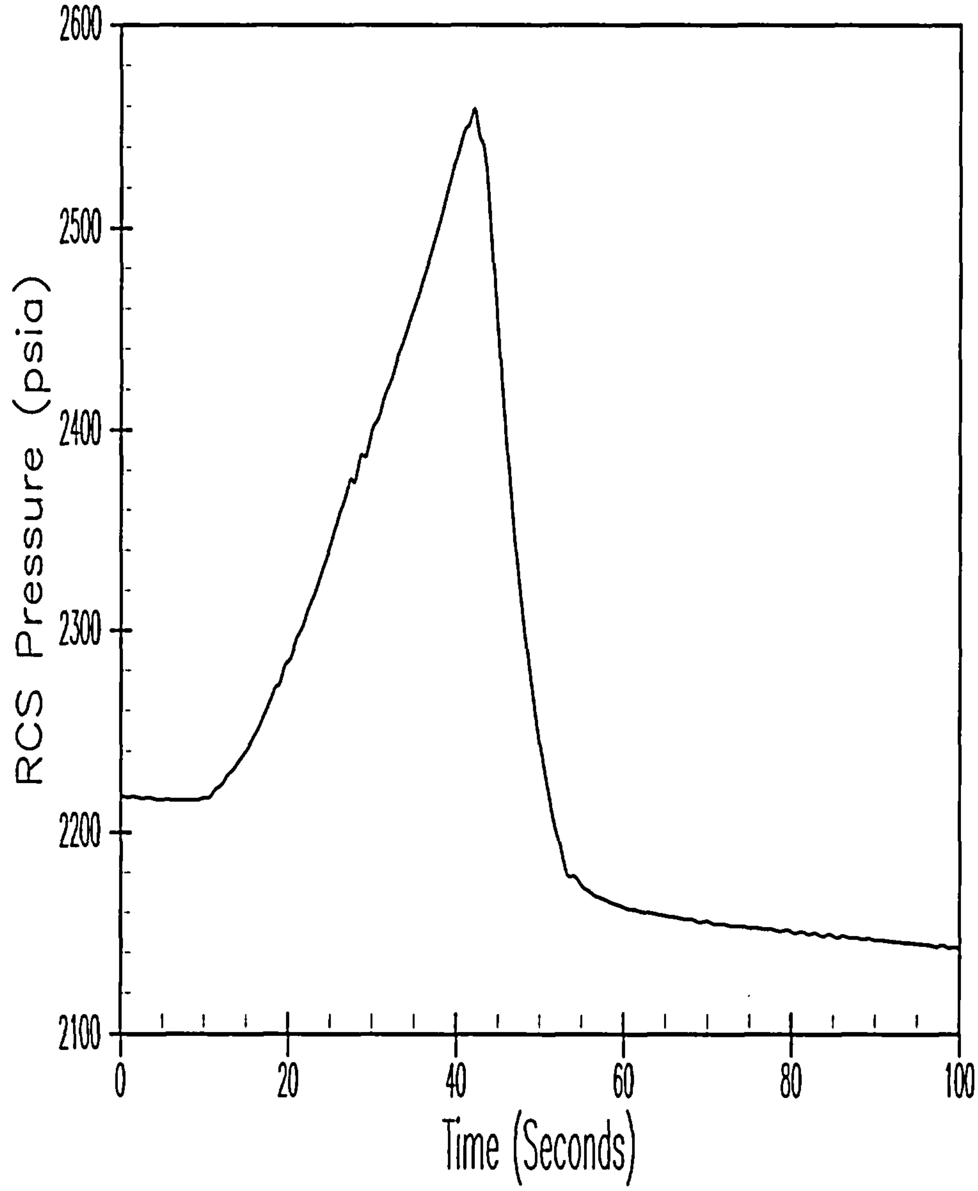

Figure 5.1.12-9
Feedwater Line Break MSS Overpressure Case
Limiting Break Size = 0.1 ft^2
RCS Pressure

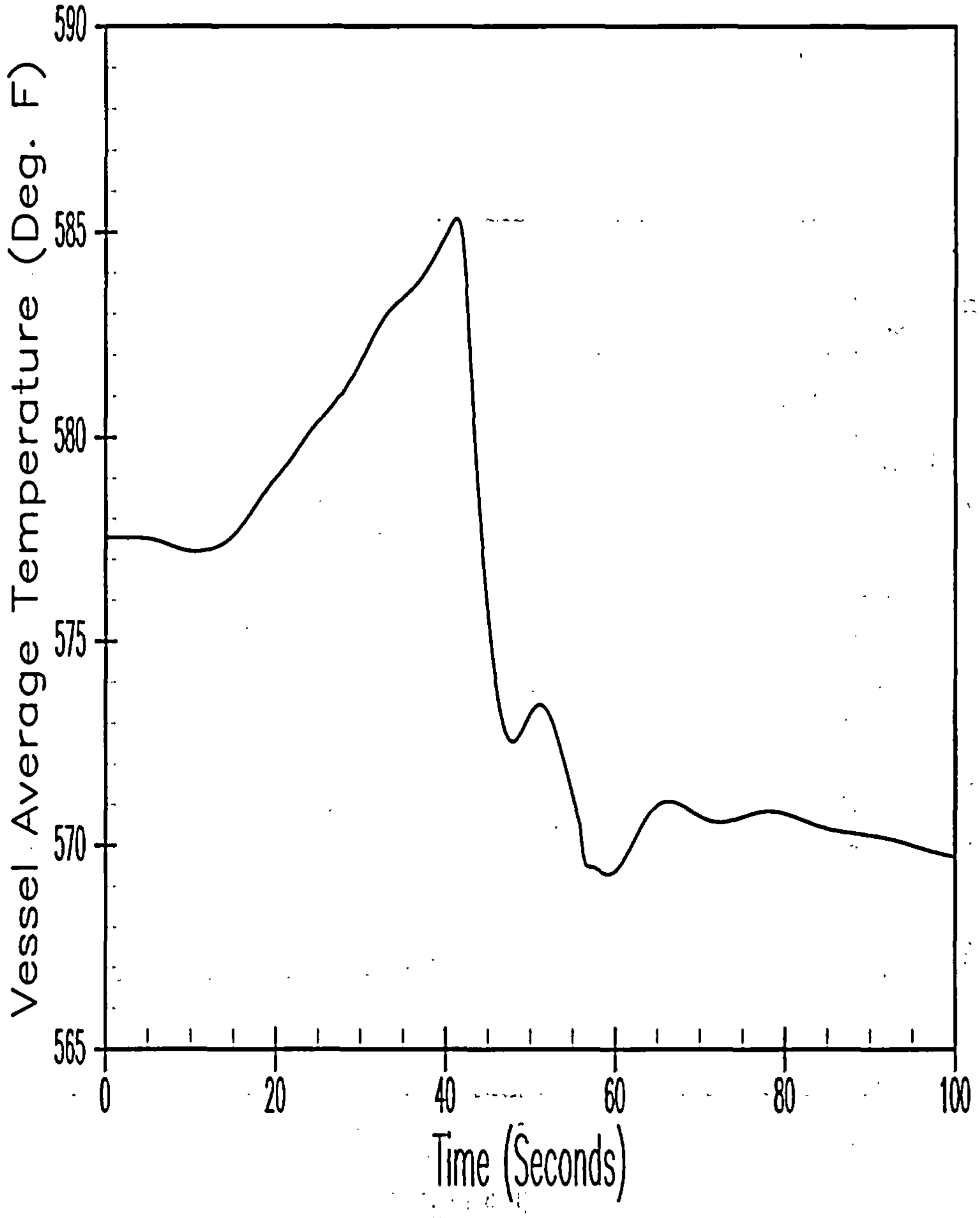

Figure 5.1.12-10
Feedwater Line Break MSS Overpressure Case
Limiting Break Size = 0.1 ft^2
Vessel Average Temperature

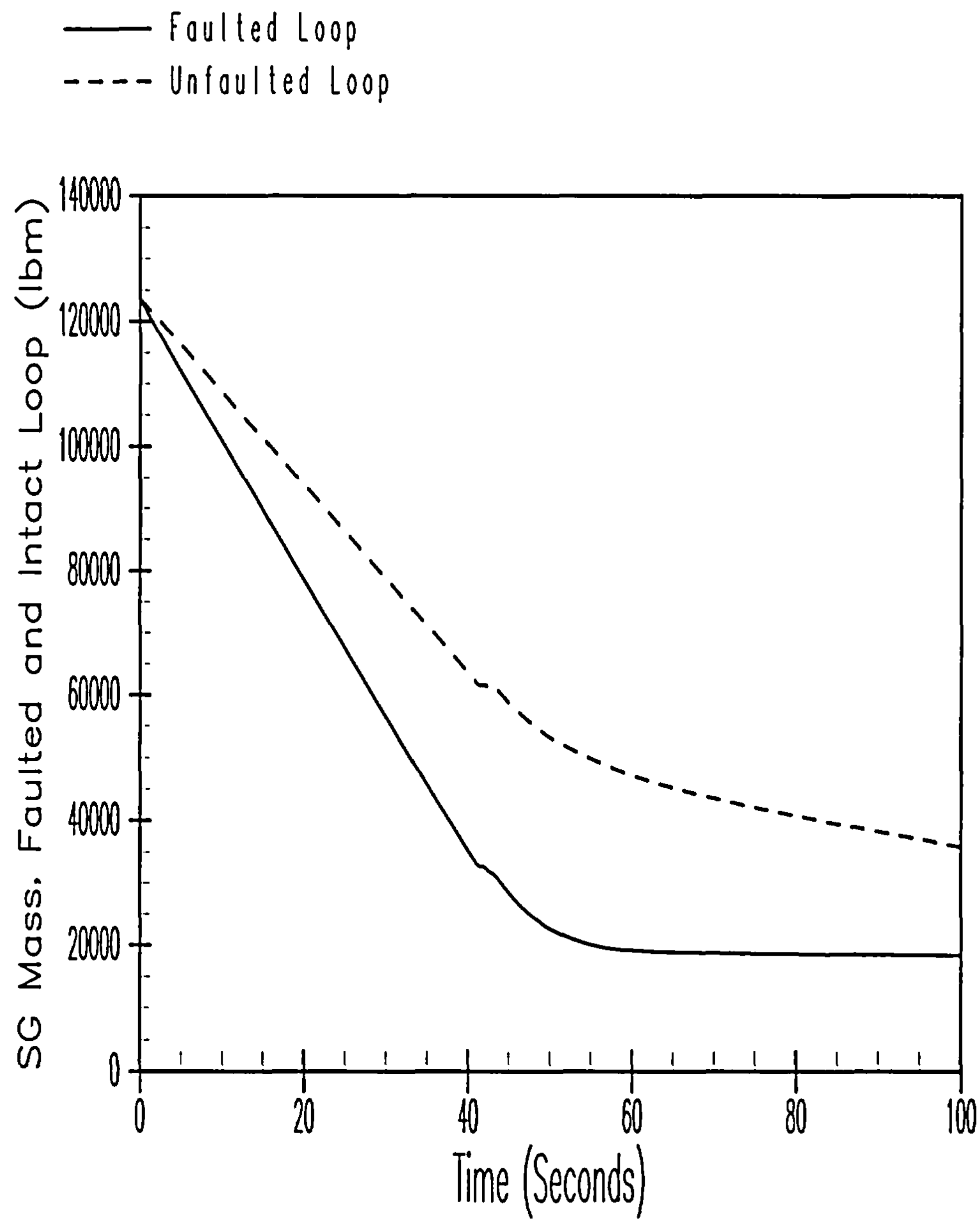

Figure 5.1.12-11
Feedwater Line Break MSS Overpressure Case
Limiting Break Size = 0.1 ft^2
Steam Generator Mass

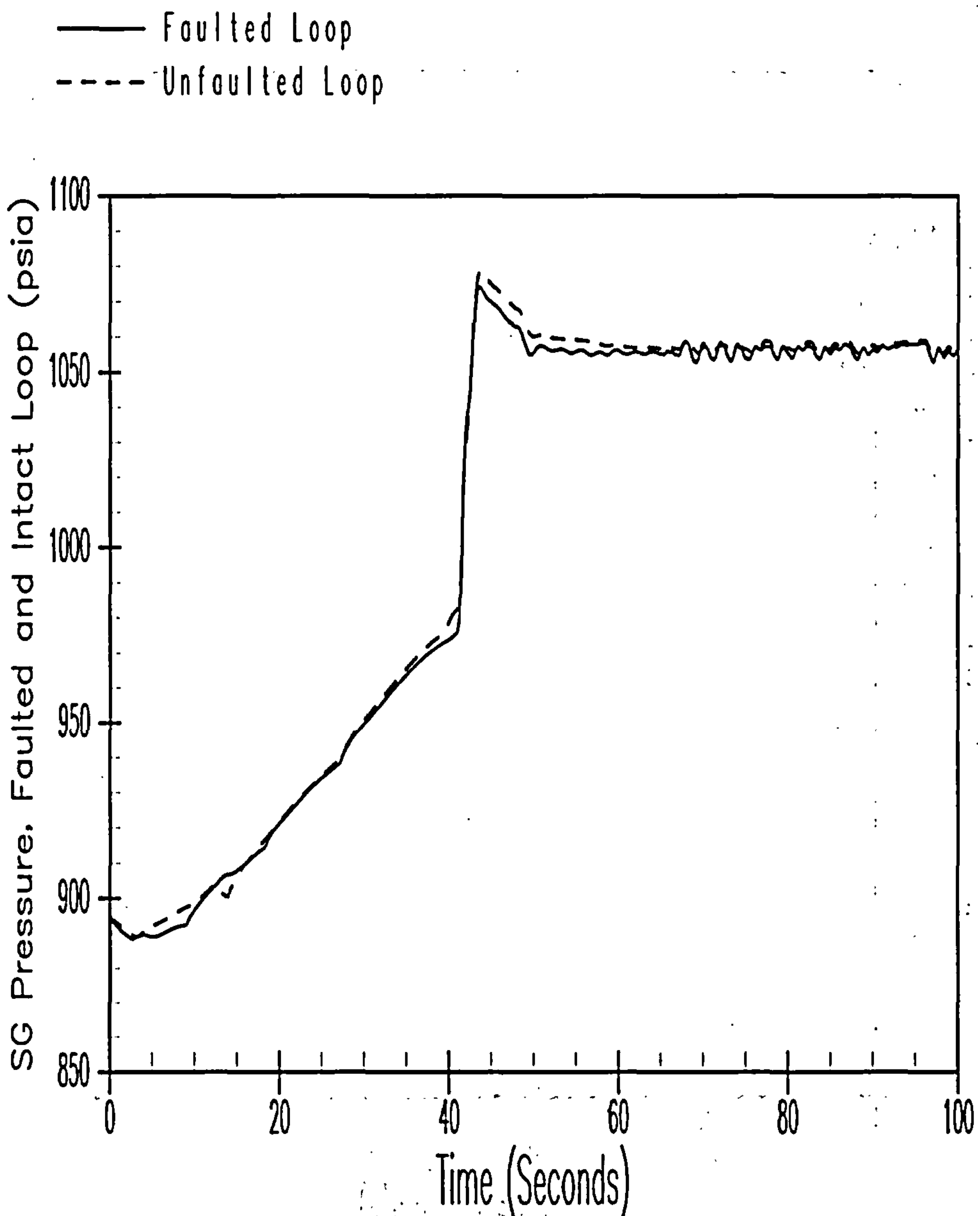

Figure 5.1.12-12
Feedwater Line Break MSS Overpressure Case
Limiting Break Size = 0.1 ft^2
Steam Generator Pressure

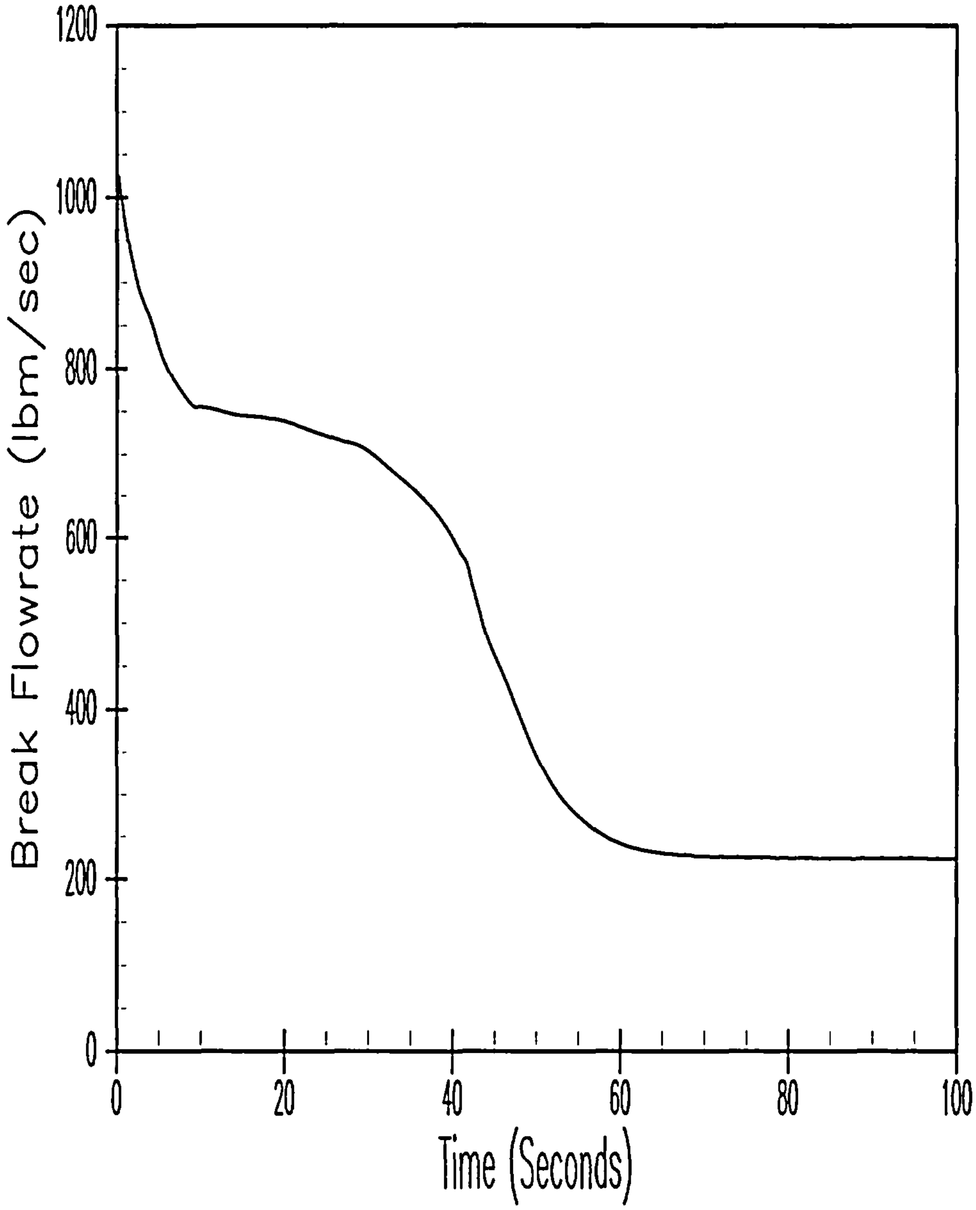

Figure 5.1.12-13
Feedwater Line Break MSS Overpressure Case
Limiting Break Size = 0.1 ft^2
Break Flowrate

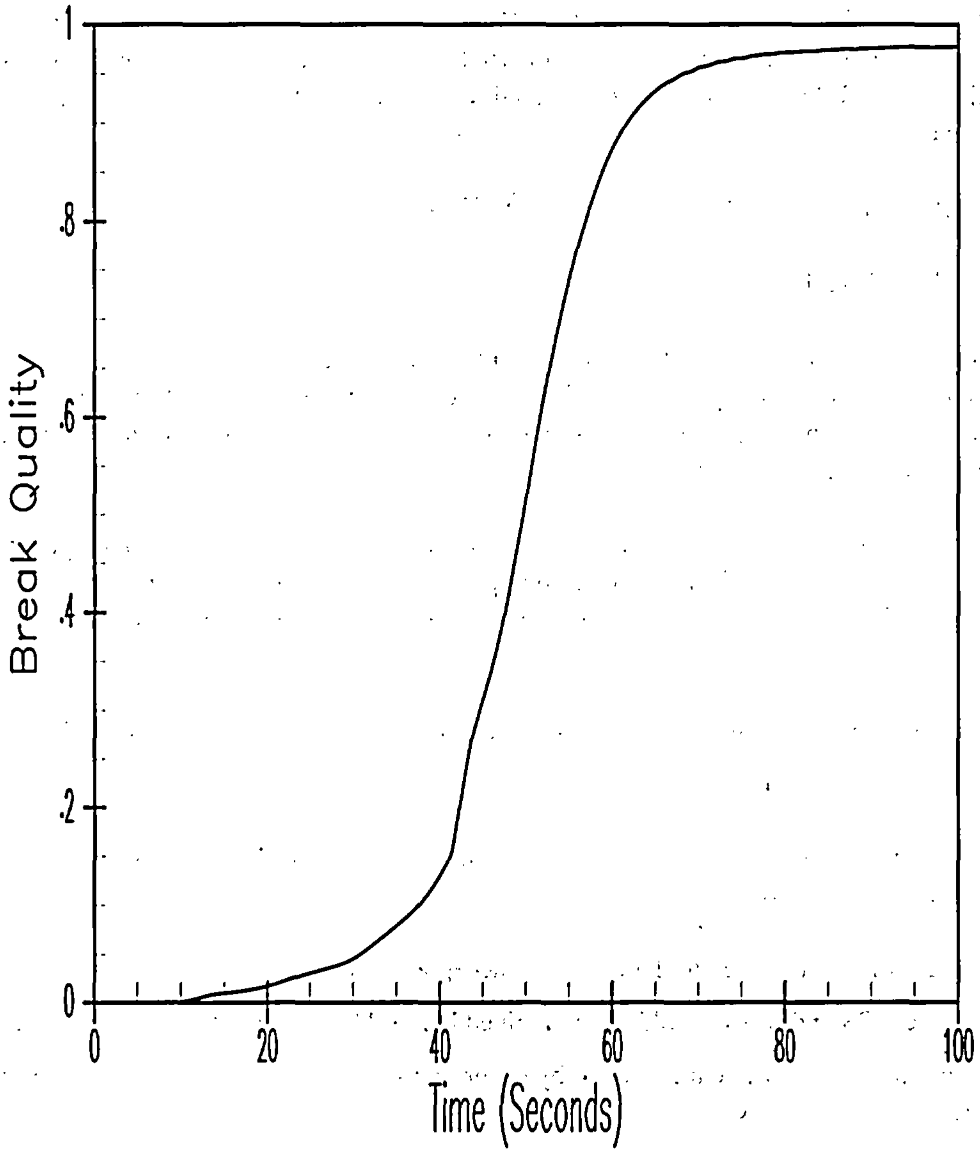

Figure 5.1.12-14
Feedwater Line Break MSS Overpressure Case
Limiting Break Size = 0.1 ft^2
Break Quality

5.1.13 Decrease in Reactor Coolant Flow Rate

Partial loss of forced reactor flow is caused by loss of electrical power to one or more of the reactor coolant pumps (RCPs). This is caused by the opening of an RCP power supply circuit breaker or the loss of a 6.9 kV bus. The core and system performance following a partial loss of forced reactor coolant flow would be no more adverse than those following a total loss of forced reactor coolant flow discussed in the Section 5.1.14. Therefore, an explicit analysis of the Partial Loss of Flow event is not presented herein.

5.1.14 Total Loss of Forced Reactor Coolant Flow

5.1.14.1 Accident Description

A complete loss of forced reactor coolant flow may result from a simultaneous loss of electrical supplies to all RCPs. If the reactor is at power at the time of the accident, the immediate effect of loss-of-coolant flow is a rapid increase in the coolant temperature. This increase could result in DNB with subsequent fuel damage if the reactor were not tripped promptly.

Normal power for the RCPs is supplied through buses from a transformer connected to the generator and the offsite power system. Two diametrically opposed pumps are on a separate bus. When a generator trip occurs, the buses continue to be supplied from external power lines and the pumps continue to supply coolant flow to the core.

The following signal provides the necessary protection against a complete loss-of-flow accident:

- Low reactor coolant loop flow reactor trip

The reactor trip on low primary coolant flow is provided to protect against loss-of-flow conditions that affect one or both reactor coolant loops.

This event is conservatively analyzed to the following acceptance criteria:

- Pressure in the RCS and MSS should be maintained below 110 percent of the design values.
- Fuel cladding integrity shall be maintained by ensuring that the minimum DNBR remains above the limit value.
- An incident of moderate frequency should not generate a more serious plant condition without other faults occurring independently.

5.1.14.2 Method of Analysis

The complete loss-of-flow transient is analyzed as a loss of four RCPs with both loops in operation. The event is analyzed to show that the integrity of the core is maintained as the DNBR remains above the safety analysis limit value. The loss-of-flow event does result in an increase in RCS and MSS pressures, but these pressure increases are generally not severe enough to challenge the integrity of the RCS and MSS. Since the maximum RCS and MSS pressures do not exceed 110 percent of their respective design pressures for the loss-of-condenser vacuum event, it is concluded that the maximum RCS and MSS pressures will also remain below 110 percent of their respective design pressures for the loss-of-flow events.

The limiting case analyzed is a complete loss-of-flow transient due to a loss of power to four pumps.

The transient is analyzed with two computer codes. First, the RETRAN computer code is used to calculate the loop and core flow during the transient, the time of reactor trip based on the calculated flows, the nuclear power transient, and the primary-system pressure and temperature transients. The VIPRE computer code is then used to calculate the heat flux and DNBR transients based on the nuclear power and RCS temperature (enthalpy), pressure, and flow from RETRAN. The DNBR transients presented represent the minimum of the typical or thimble cell for the fuel.

This event is analyzed with the Revised Thermal Design Procedure (RTDP) (Reference 5.1.14-1). Initial reactor (Nuclear Steam Supply System) power is 89% of rated thermal power, and the associated pressurizer pressure and RCS temperature are assumed to be at the initial values as shown in Table 5.1.0-2. Thermal Design flow is also assumed. A conservatively large absolute value of the Doppler-only power coefficient is used, along with the most-positive MTC limit for 89% power operation (1.827 pcm/°F). These assumptions maximize the core power during the initial part of the transient when the minimum DNBR is reached.

A limiting DNB axial power shape is assumed in VIPRE for the calculation of DNBR. This shape provides the most limiting minimum DNBR for the loss-of-flow events.

A conservatively low trip reactivity value (5.4-percent $\Delta\rho$) is used to minimize the effect of rod insertion following reactor trip and maximize the heat flux statepoint used in the DNBR evaluation for this event. This value is based on the assumption that the highest worth RCCA is stuck in its fully withdrawn position. A conservative trip reactivity worth versus rod position was modeled in addition to a conservative rod drop time (2.341 seconds from release to full insertion), similar to the current analysis of record.

The flow coastdown analysis is based on a momentum balance around each reactor coolant loop and across the reactor core. This momentum balance is combined with the continuity equation, a pump momentum balance, and the pump characteristics. Also, it is based on conservative estimates of system pressure losses.

A maximum, uniform, steam generator tube plugging level of 42% was assumed in the RETRAN analysis. Reactor coolant system loop flow asymmetry due to a loop-to-loop steam generator tube plugging imbalance does not need to be considered for transients in which all RCPs experience a coastdown.

5.1.14.3 Results

Figures 5.1.14-1 through 5.1.14-8 illustrate the transient response for the complete loss-of-flow case. All RCPs decelerate at a constant rate until a reactor trip on low flow is initiated. The minimum DNBR occurred at (3.55) seconds of the transient and meets the DNB design basis.

The minimum DNBR is: 1.564 (typical cell) / 1.504 (thimble cell), which occurred at 3.55 seconds (Safety Analysis DNBR limit: 1.37 (matrix cell) / 1.35 (corner thimble cell)).

The calculated sequence of events for the complete loss-of-flow case is shown on Table 5.1.14-1. Following reactor trip, the RCPs will continue to coast down, and natural circulation flow will eventually be established. With the reactor tripped, a stable plant condition will eventually be attained. Normal plant shutdown may then proceed.

5.1.14.4 Conclusions

The analysis performed has demonstrated that, for the complete loss-of-flow event, the DNBR does not decrease below the Safety Analysis Limit value at any time during the transient. Therefore, no fuel or cladding damage is predicted and all applicable acceptance criteria are met.

5.1.14.5 References

5.1.14-1 Friedland, A. J. and Ray, S., "Revised Thermal Design Procedure," WCAP-11397-P-A, WCAP-11397-A, April 1989.

Table 5.1.14-1 Sequence of Events – Complete Loss of Reactor Coolant Flow	
Event	**Time (seconds)**
All Operating RCPs Lose Power and Coastdown Begins	0.0
Low Flow Reactor Trip Setpoint is Reached	0.97
Reactor Trip Signal occurs	1.37
Rods Begin to Drop	2.11
Minimum DNBR Occurs	3.55

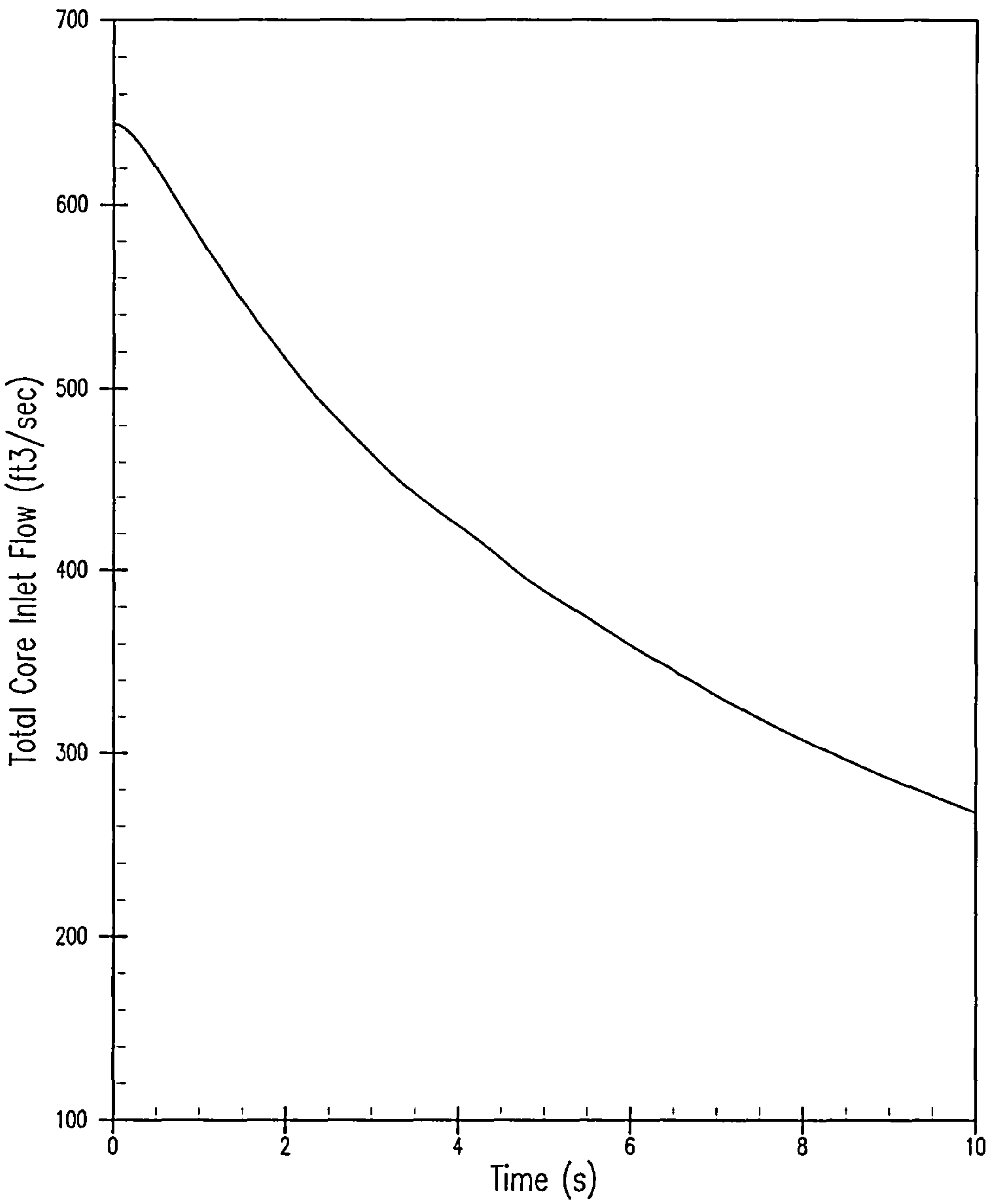

Figure 5.1.14-1
Complete Loss of Flow (CLOF – 4 Pumps Coasting Down)
Total Core Inlet Flow

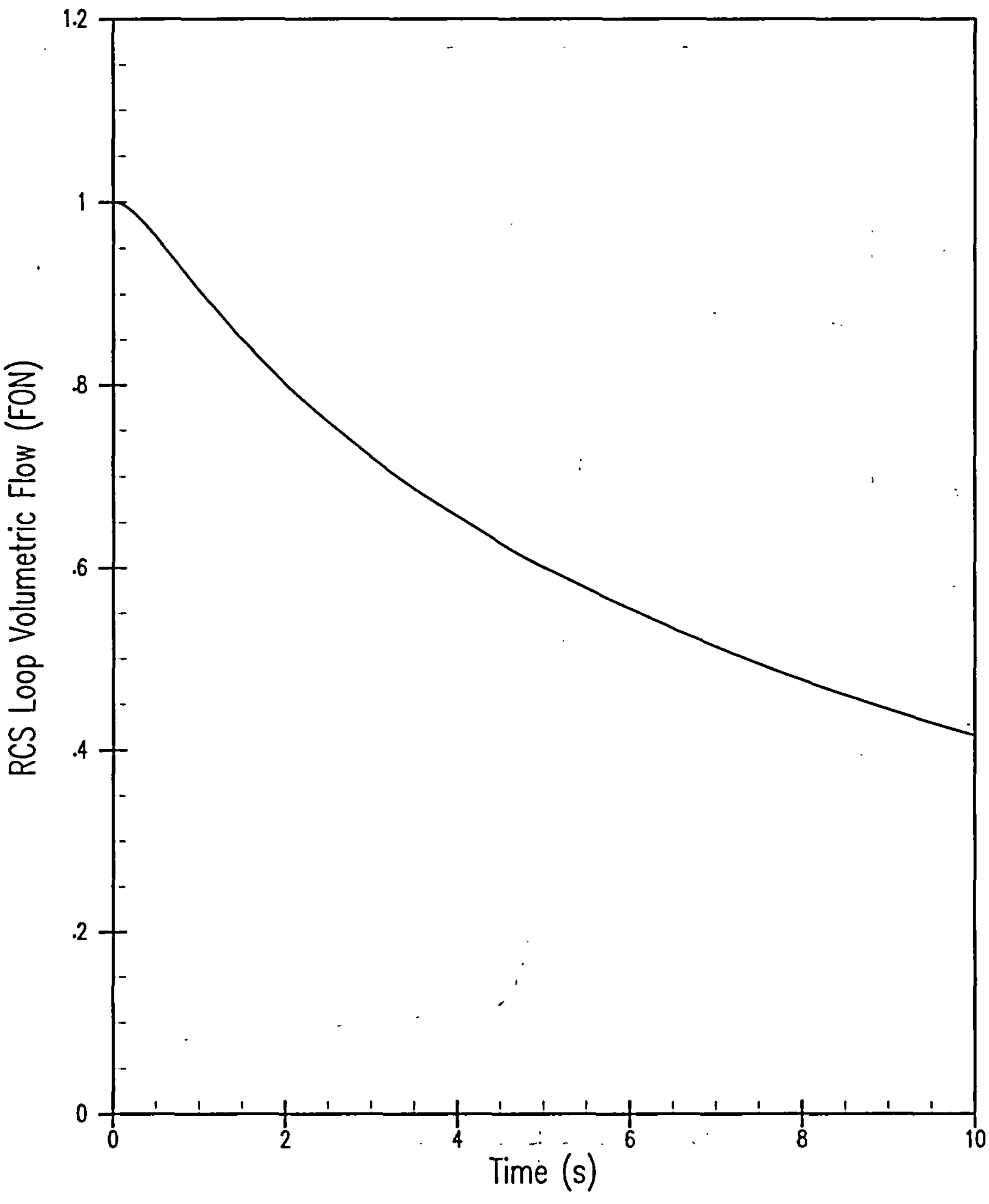

Figure 5.1.14-2
Complete Loss of Flow (CLOF – 4 Pumps Coasting Down)
RCS Loop Flow

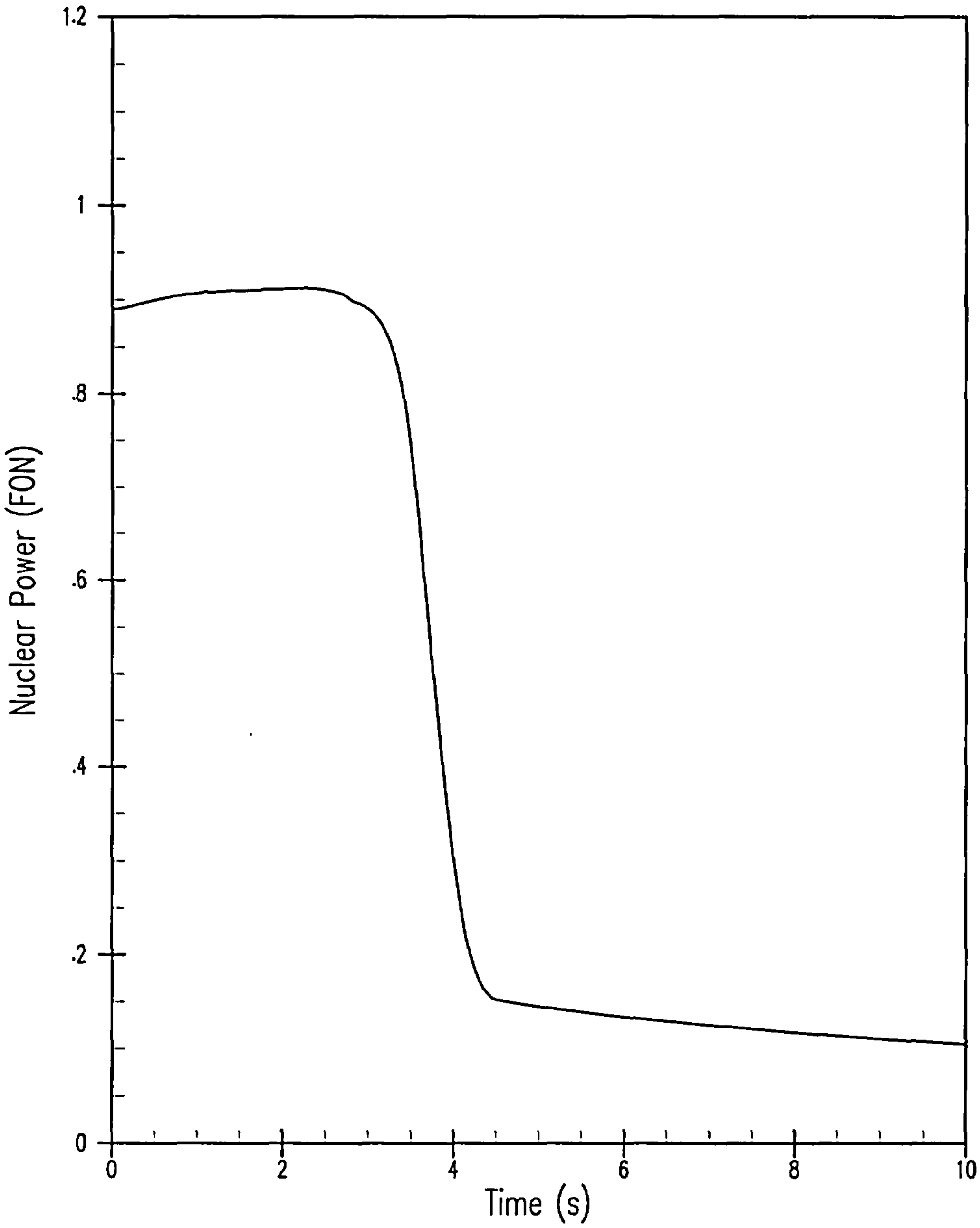

Figure 5.1.14-3
Complete Loss of Flow (CLOF – 4 Pumps Coasting Down)
Nuclear Power

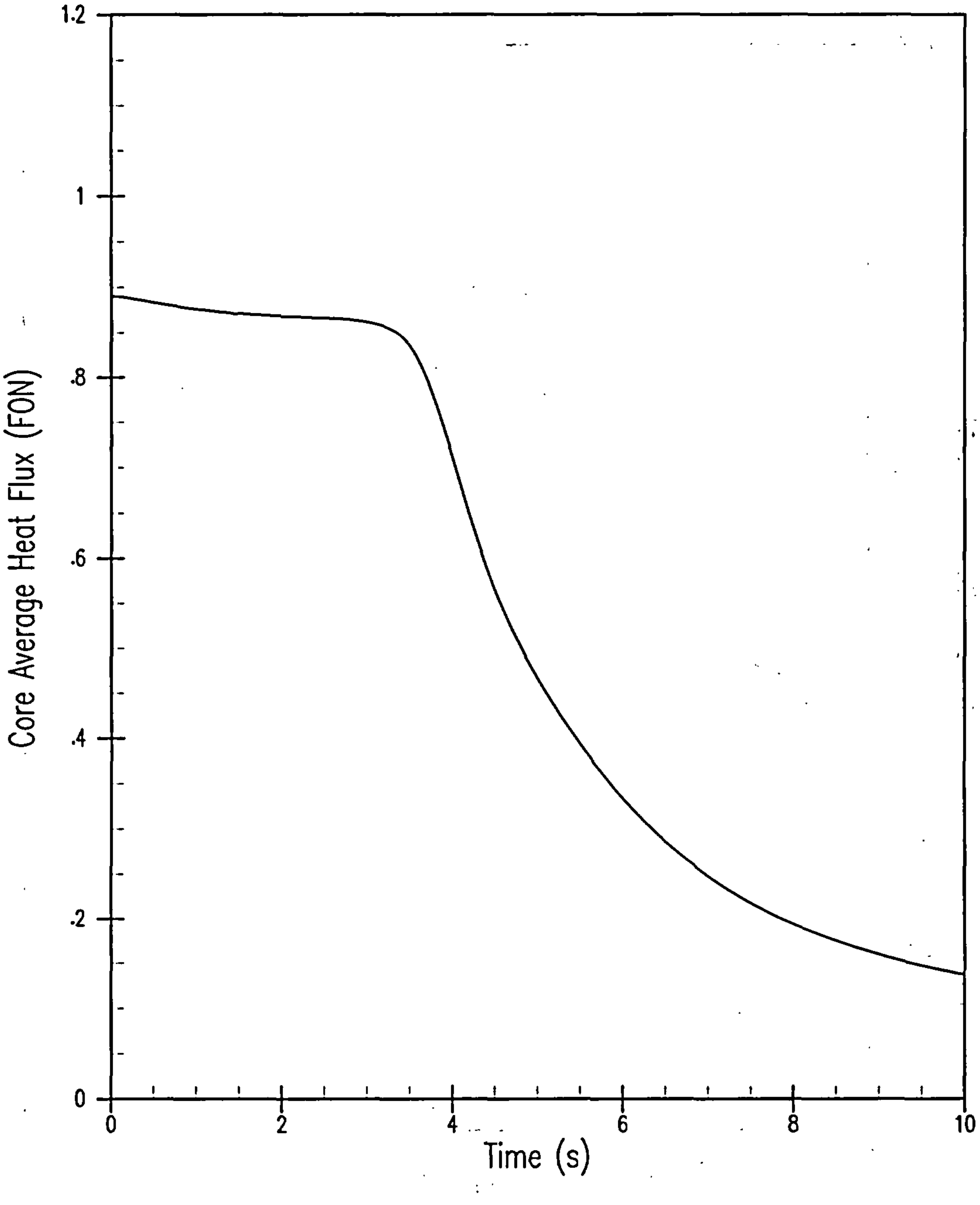

Figure 5.1.14-4
Complete Loss of Flow (CLOF – 4 Pumps Coasting Down)
Core Average Heat Flux

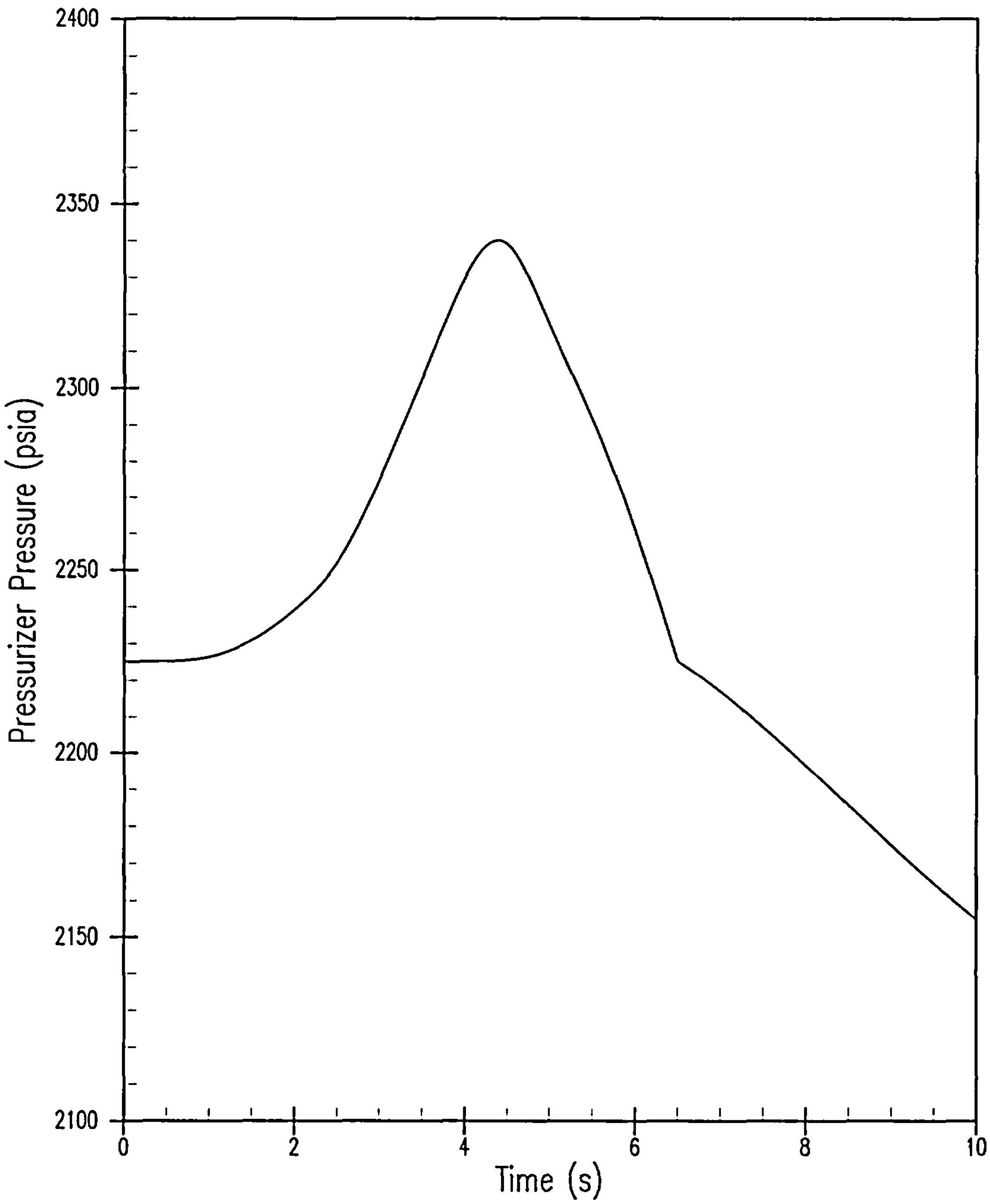

Figure 5.1.14-5
Complete Loss of Flow (CLOF – 4 Pumps Coasting Down)
Pressurizer Pressure

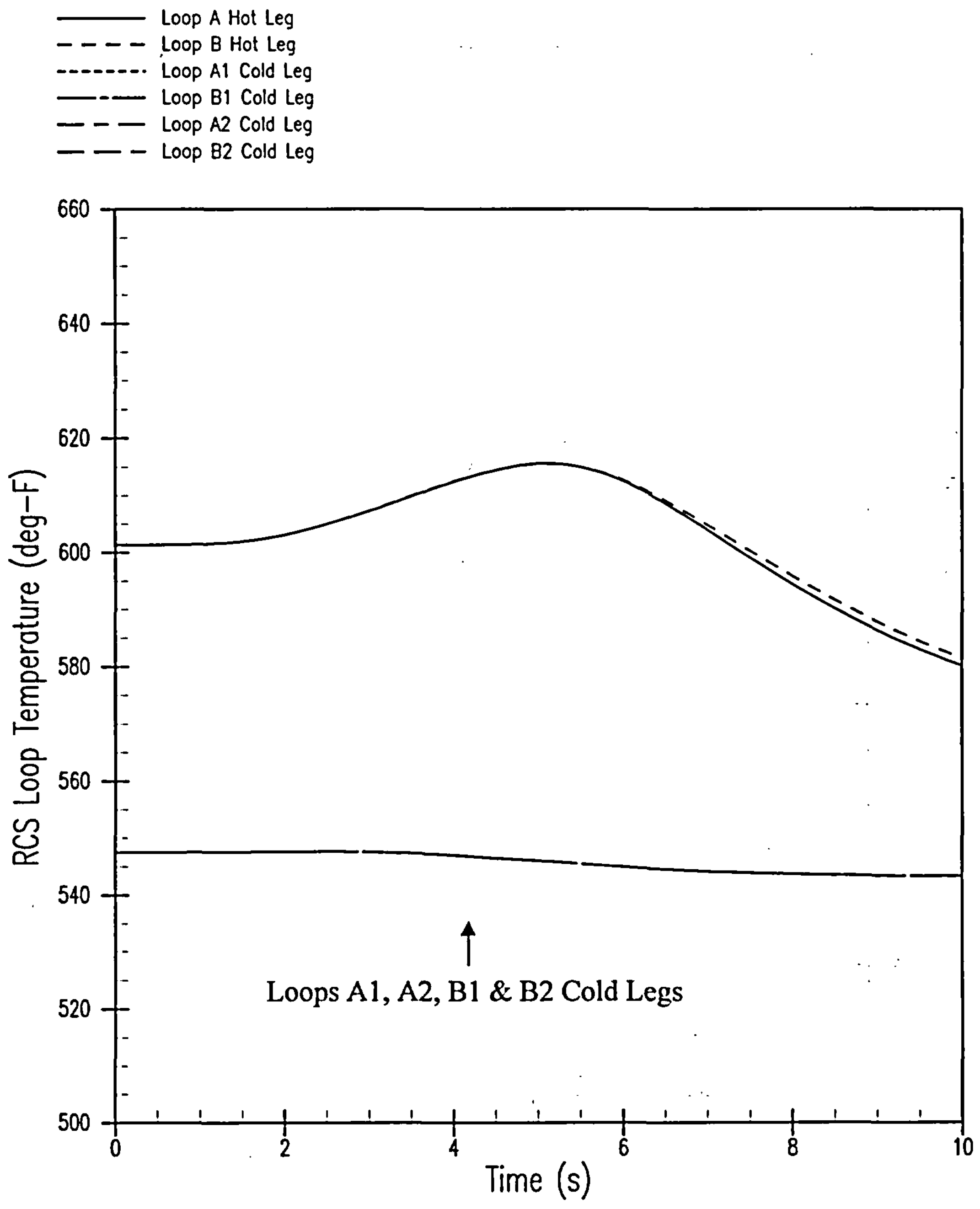

Figure 5.1.14-6
Complete Loss of Flow (CLOF – 4 Pumps Coasting Down)
RCS Faulted Loop Temperature

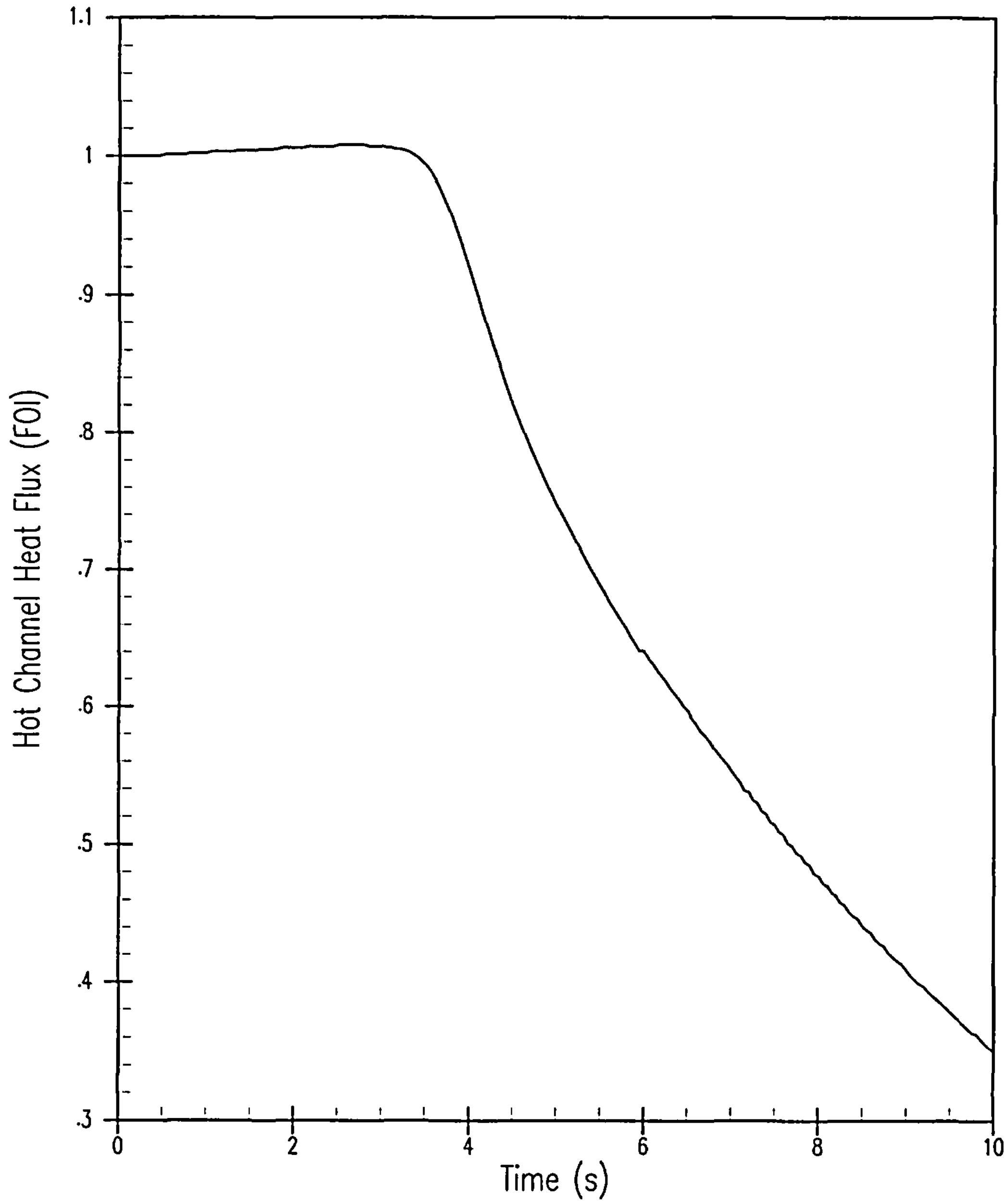

Figure 5.1.14-7
Complete Loss of Flow (CLOF – 4 Pumps Coasting Down)
Hot Channel Heat Flux

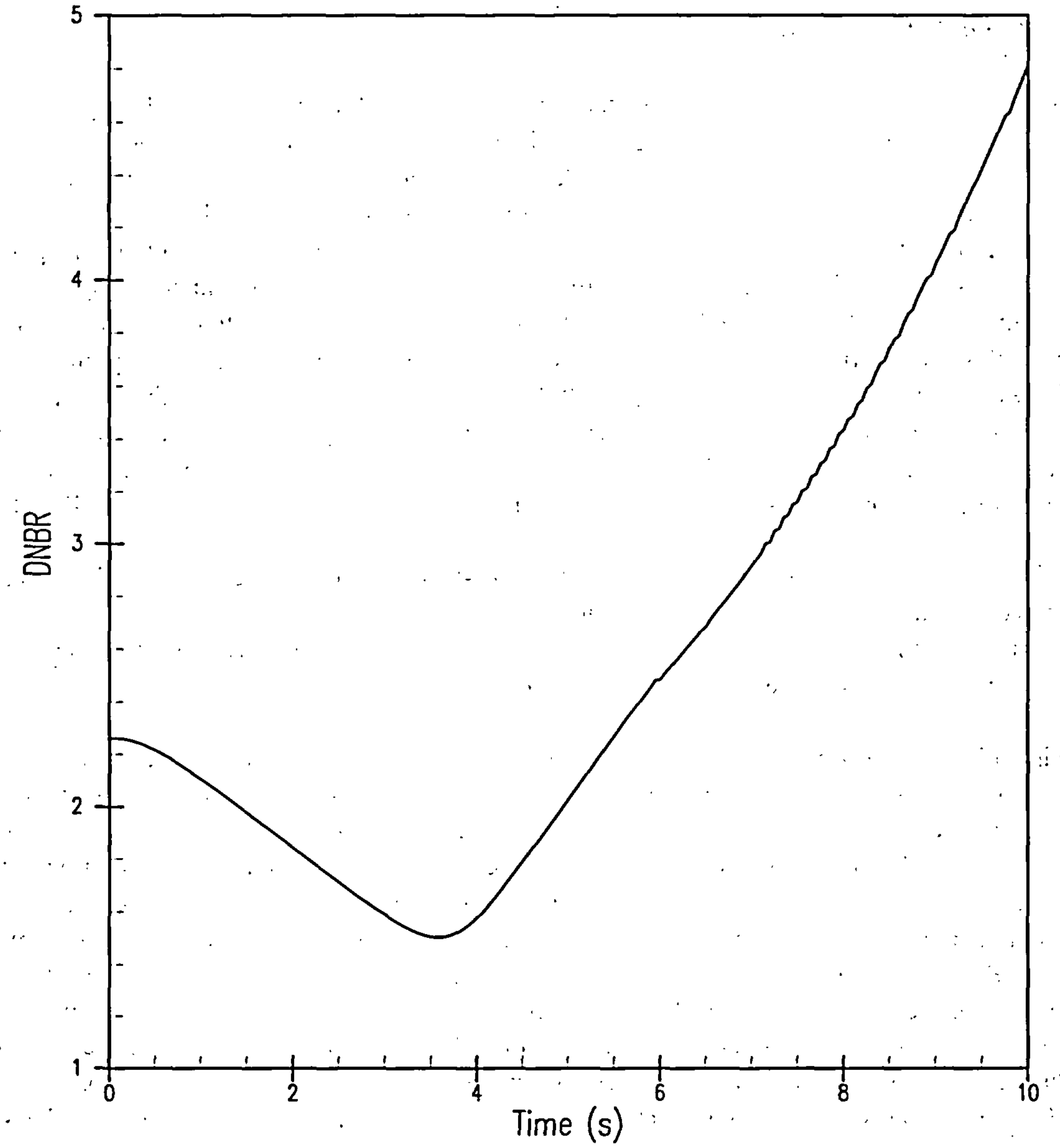

Figure 5.1.14-8
Complete Loss of Flow (CLOF – 4 Pumps Coasting Down)
DNBR

5.1.15 Total Single RCP Shaft Seizure/Sheared Shaft

5.1.15.1 Accident Description

The postulated locked-rotor accident is an instantaneous seizure of an RCP rotor. Flow through the affected reactor coolant loop is rapidly reduced, leading to an initiation of a reactor trip on a low-flow signal. The consequences of a postulated pump shaft break accident are similar to the locked-rotor event. With a broken shaft, the impeller is free to spin, as opposed to it being fixed in position during the locked-rotor event. Therefore, the initial rate of reduction in core flow is greater during a locked-rotor event than in a pump shaft break event because the fixed shaft causes greater resistance than a free-spinning impeller early in the transient, when flow through the affected loop is in the positive direction. As the transient continues, the flow direction through the affected loop is reversed. If the impeller is able to spin free freely, the flow to the core will be less than that available with a fixed-shaft during periods of reverse flow in the affected loop. Because peak pressure, cladding temperature, and DNB occur very early in the transient, the reduction in core flow during the period of forward flow in the affected loop dominates the severity of the results. Consequently, the bounding results for the locked-rotor transients also are applicable to the RCP shaft break.

After the locked rotor, reactor trip is initiated on an RCS low-flow signal. Failure of the fast bus transfer and turbine trip occurs coincident with reactor trip breaker opening. Failure of the fast bus transfer results in the coast-down of two of the three unaffected RCPs. At three seconds after turbine trip, the remaining unaffected RCP is assumed to lose power (due to a loss of offsite power) and coast down freely.

Following initiation of the reactor trip, heat stored in the fuel rods continues to be transferred to the coolant causing the coolant to expand. At the same time, heat transfer to the shell side of the steam generators is reduced. This is because, first, the reduced flow results in a decreased tube-side film coefficient; and then because the reactor coolant in the tubes cools down while the shell-side temperature increases (turbine steam flow is reduced to zero upon plant trip). The rapid expansion of the coolant in the reactor core, combined with reduced heat transfer in the steam generators, causes an insurge into the pressurizer and a pressure increase throughout the RCS. The insurge into the pressurizer compresses the steam volume, actuates the automatic spray system, opens the PORV, and opens the pressurizer safety valves, in that sequence. The PORV (one PORV is isolated during normal operation) is designed for reliable operation and would be expected to function properly during the accident. However, for conservatism in the peak-pressure evaluation, their pressure-reducing effect and the pressure-reducing effect of the pressurizer sprays are not included in the analysis.

The locked-rotor event is analyzed to the following criteria:

- Pressure in the RCS should be maintained below the designated limit.
- Coolable core geometry is ensured by showing that the peak cladding temperature and maximum oxidation level for the hot spot are below 2700°F and 16.0 percent by weight, respectively.
- Activity release is such that the calculated doses meet 10 CFR Part 100 guidelines.

For St. Lucie Unit 2, the locked-rotor RCS pressure limit is equal to 110 percent of the design value, or 2750 psia. For the secondary side, the locked-rotor pressure limit is also assumed to be equal to 110 percent of design pressure, or 1100 psia. Since the loss of condenser vacuum analysis bounds the locked rotor with respect to MSS overpressurization, a specific MSS overpressurization analysis is not performed.

A hot-spot evaluation is performed to calculate the peak cladding temperature and maximum oxidation level. Finally, a calculation of the "rods-in-DNB" is performed for input to the radiological dose analysis.

5.1.15.2 Method of Analysis

The locked-rotor transient is analyzed with two computer codes. First, the RETRAN computer code is used to calculate the loop and core flow during the transient, the time of reactor trip based on the calculated flows, the nuclear power transient, and the primary-system pressure and temperature transients. The VIPRE computer code is then used to calculate the thermal behavior of the fuel located at the core hot spot including the rods-in-DNB using the nuclear power and RCS temperature (enthalpy), pressure, and flow from RETRAN. It is assumed that all rods which exceed DNB limit have failed.

For the case analyzed to determine the maximum RCS pressure and peak cladding temperature, the plant is assumed to be in operation under the most adverse steady-state operating conditions; that is, a steady-state thermal power of 89% of rated thermal power plus uncertainty, steady-state pressure plus uncertainty, and steady-state coolant average temperature plus uncertainty. The case analyzed to determine the rods-in-DNB utilizes the RTDP methodology. Initial reactor power is 89% of rated thermal power, and the associated pressurizer pressure and RCS temperature are assumed to be at the initial values as shown in Table 5.1.0-2. Thermal Design flow is also assumed.

A maximum, uniform, steam generator tube plugging level of 42 percent was assumed in the RETRAN analysis. The effect of a flow asymmetry resulting from asymmetric tube plugging is addressed in the DNB analysis of the locked rotor statepoints.

A conservatively large absolute value of the Doppler-only power coefficient is used, along with the most-positive MTC limit for 89% power operation (1.827 pcm/°F). These assumptions maximize the core power during the initial part of the transient when the peak RCS pressures and hot-spot results are reached.

A conservatively low trip reactivity value (5.4-percent $\Delta\rho$) is used to minimize the effect of rod insertion following reactor trip and maximize the heat flux statepoint used in the DNBR evaluation for this event. This value is based on the assumption that the highest worth RCCA is stuck in its fully withdrawn position. A conservative trip reactivity worth versus rod position was modeled in addition to a conservative rod drop time (2.66 seconds from release to full insertion). No reduction in rod drop time is credited due to the reduced core flow rate experienced during the two-pump coastdown.

For the peak RCS pressure evaluation, the initial pressure is conservatively set as shown in Table 5.1.0-2 to allow for errors in the pressurizer pressure measurement and control channels. This is done to obtain the highest possible rise in the coolant pressure during the transient. The peak RCS pressure occurs in the lower plenum of the vessel. The pressure transient in the lower plenum is shown in Figure 5.1.15-6.

For this accident, an evaluation of the consequences with respect to the fuel rod thermal transient is performed. The evaluation incorporates the assumption of rods going into DNB as a conservative initial condition to determine the cladding temperature and zirconium water reaction resulting from the locked rotor. Results obtained from the analysis of this hot-spot condition represent the upper limit with respect to cladding temperature and zirconium water reaction. In the evaluation, the rod power at the hot spot is assumed to be 2.9 times the average rod power (that is, $F_Q = 2.90$) at the initial core power level. In VIPRE

models, the peak power assembly with the peak rod at the F_r design limit and a low peak-to-average power ratio is then modeled at the core location with the minimum assembly flow.

Film Boiling Coefficient

The film boiling coefficient is calculated in the VIPRE code using the Bishop-Sandberg-Tong film boiling correlation. The fluid properties are evaluated at film temperature. The program calculates the film coefficient at every time step based upon the actual heat transfer conditions at the time. The nuclear power, system pressure, bulk density, and RCS flow rate as a function of time are based on the RETRAN results.

Fuel Cladding Gap Coefficient

The magnitude and time dependence of the heat transfer coefficient between fuel and cladding (gap coefficient) has a pronounced influence on the thermal results. The larger the value of the gap coefficient, the more heat is transferred between the pellet and cladding. Based on investigations on the effect of the gap coefficient upon the maximum cladding temperature during the transient, the gap coefficient was assumed to increase from a steady-state value consistent with initial fuel temperature to 10,000 BTU/hr-ft^2-°F at the initiation of the transient. Therefore, the large amount of energy stored in the fuel because of the small initial value is released to the cladding at the initiation of the transient.

Zirconium-Steam Reaction

The zirconium-steam reaction can become significant above 1800°F (cladding temperature). The Baker-Just parabolic rate equation is used to define the rate of zirconium-steam reaction. The effect of the zirconium-steam reaction is included in the calculation of the hot-spot cladding temperature transient.

5.1.15.3 Results

Figures 5.1.15-1 through 5.1.15-9 illustrate the transient response for the locked-rotor event. The peak RCS pressure is 2637 psia and is less than the acceptance criterion of 2750 psia. Also, the peak cladding temperature is 1668.3°F, which is considerably less than the limit of 2700°F. The zirconium-steam reaction at the hotspot is 0.20 percent by weight, which meets the criterion of less than 16-percent zirconium-steam water reaction. For the radiological dose evaluation, the total percentage of fuel rods calculated to experience DNB is less than 1 percent (rods-in-DNB case). The sequence of events for the peak RCS pressure/peak cladding temperature case is given in Table 5.1.15-1. This transient trips on a low primary reactor coolant flow trip setpoint, which is assumed to be 91.9 percent.

5.1.15.4 Conclusions

The analysis performed has demonstrated that for the locked-rotor event, the RCS pressure remains below 110 percent of the design pressure and the hot-spot cladding temperature and oxidation levels remain below the limit values. Therefore, all applicable acceptance criteria are met. In addition, the total percentage of rods calculated to experience DNB is less than 1 percent.

Table 5.1.15-1 Sequence of Events – Reactor Coolant Pump Locked Rotor		
Event	**Time (seconds)**	
	Rods-in-DNB Case	**Peak Clad Temp Case**
Rotor on One Pump Locks	0.0	0.0
Low Flow Reactor Trip Setpoint Reached	0.3	0.3
Reactor Trip Signal occurs	0.7	0.7
Failure of Fast Bus Transfer (Two RCPs Coastdown)	0.7	0.7
Rod Motion Begins (0.74 seconds after Breakers open)	1.4	1.4
Minimum DNBR	2.9	N/A
Maximum Cladding Temperature Occurs	N/A	3.5
Maximum RCS Pressure Occurs	N/A	3.8
Remaining Active Pump Begins to Coastdown	3.7	3.7

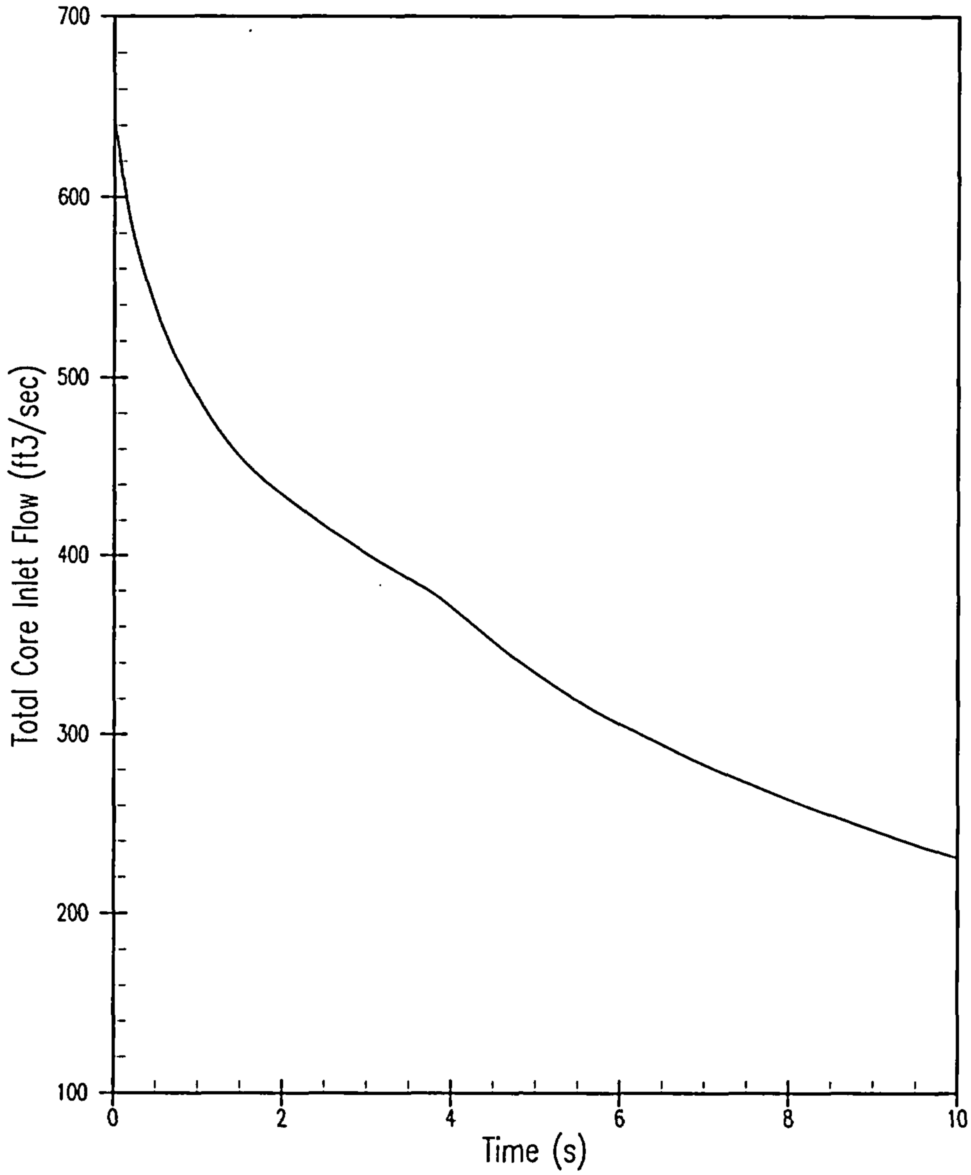

Figure 5.1.15-1
Locked Rotor/Shaft Break
Total Core Inlet Flow

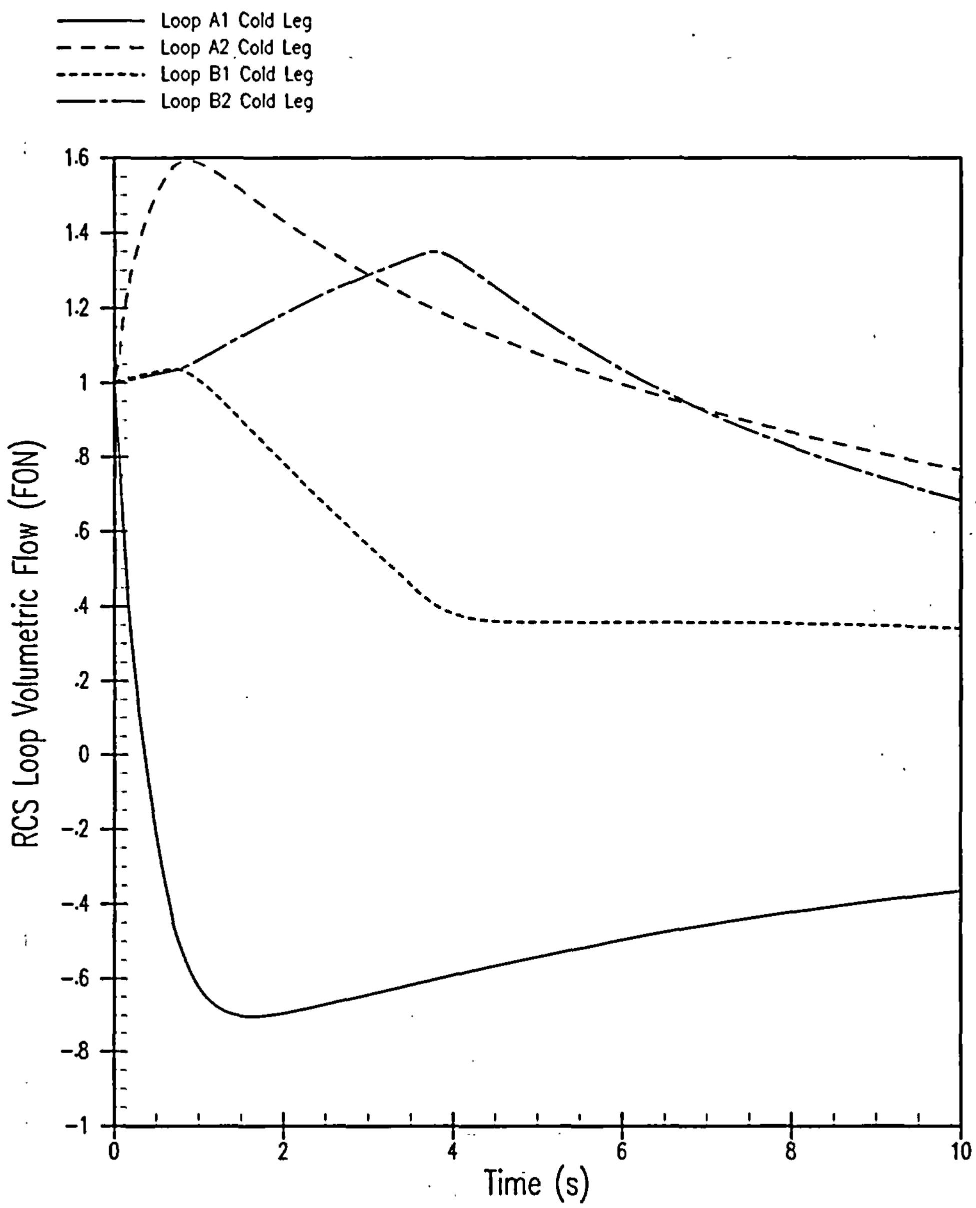

Figure 5.1.15-2
Locked Rotor/Shaft Break
RCS Loop Flow

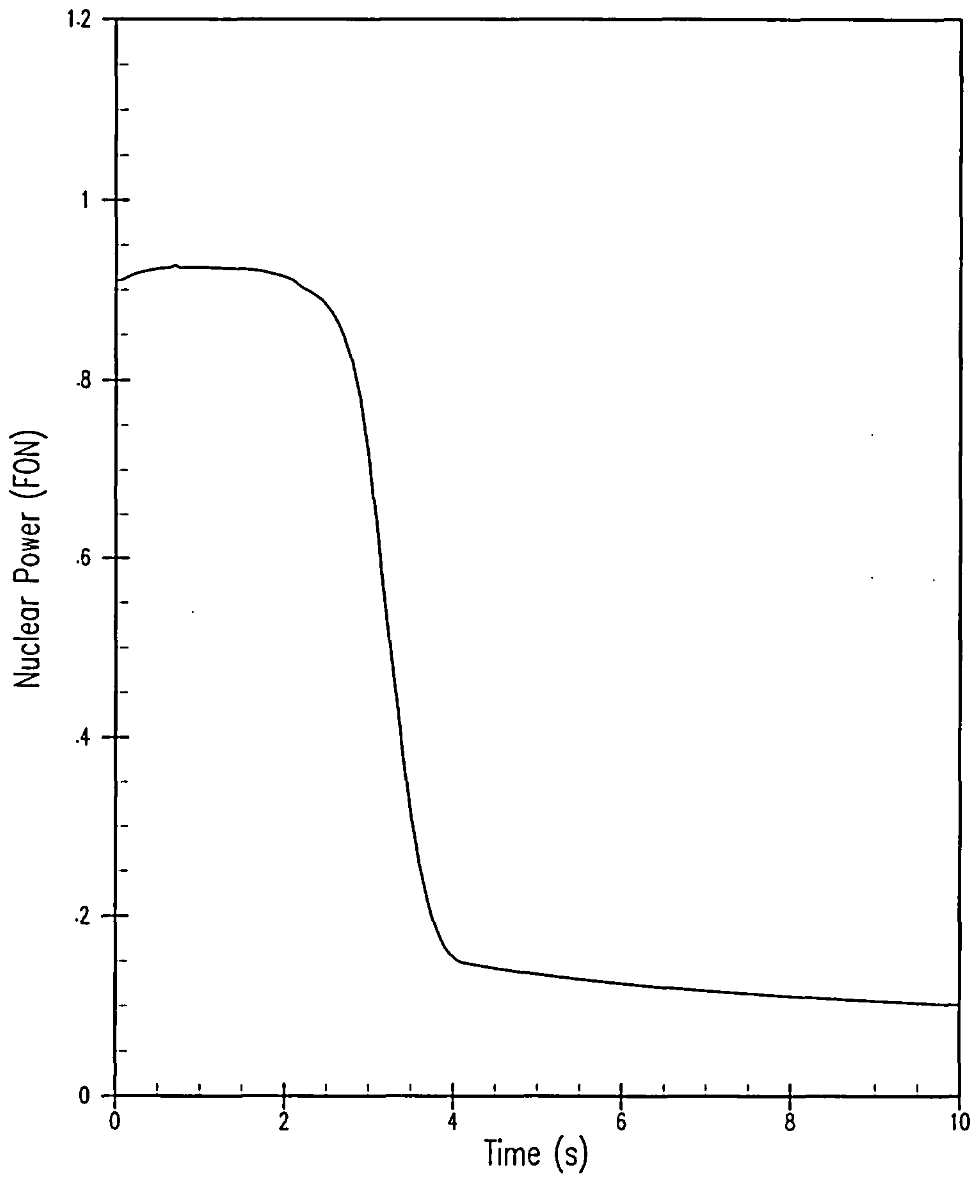

Figure 5.1.15-3
Locked Rotor/Shaft Break
Nuclear Power

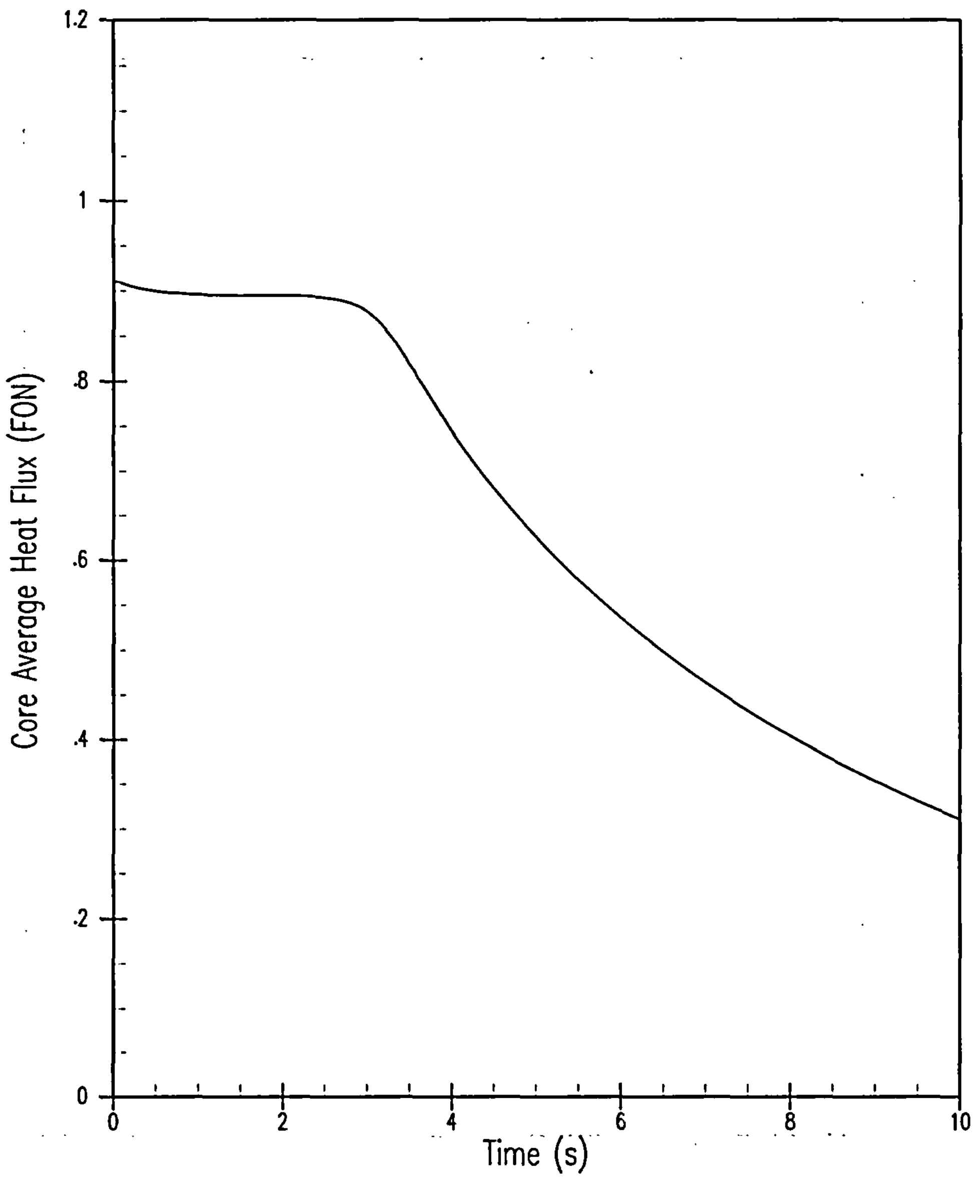

Figure 5.1.15-4
Locked Rotor/Shaft Break
Core Average Heat Flux

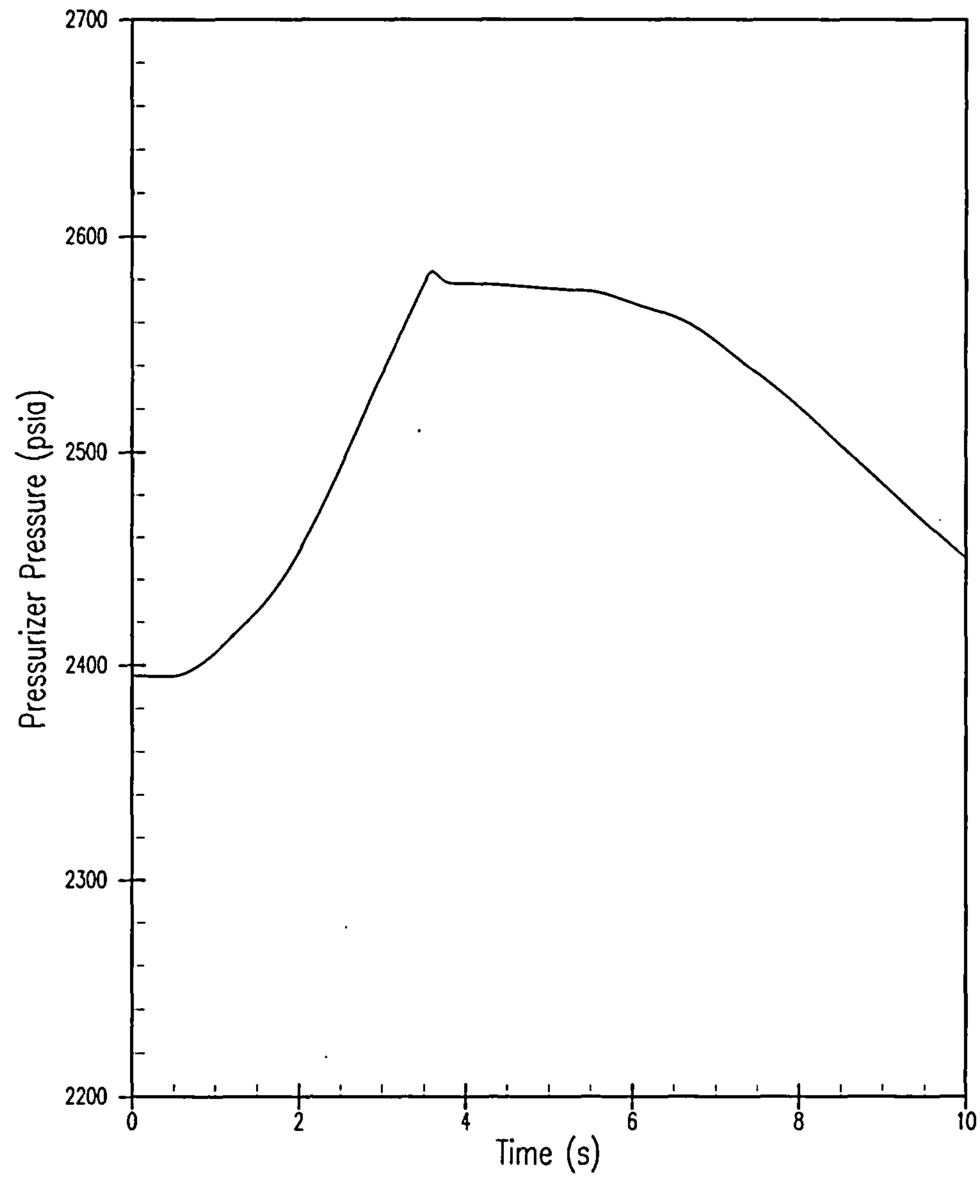

Figure 5.1.15-5
Locked Rotor/Shaft Break
Pressurizer Pressure

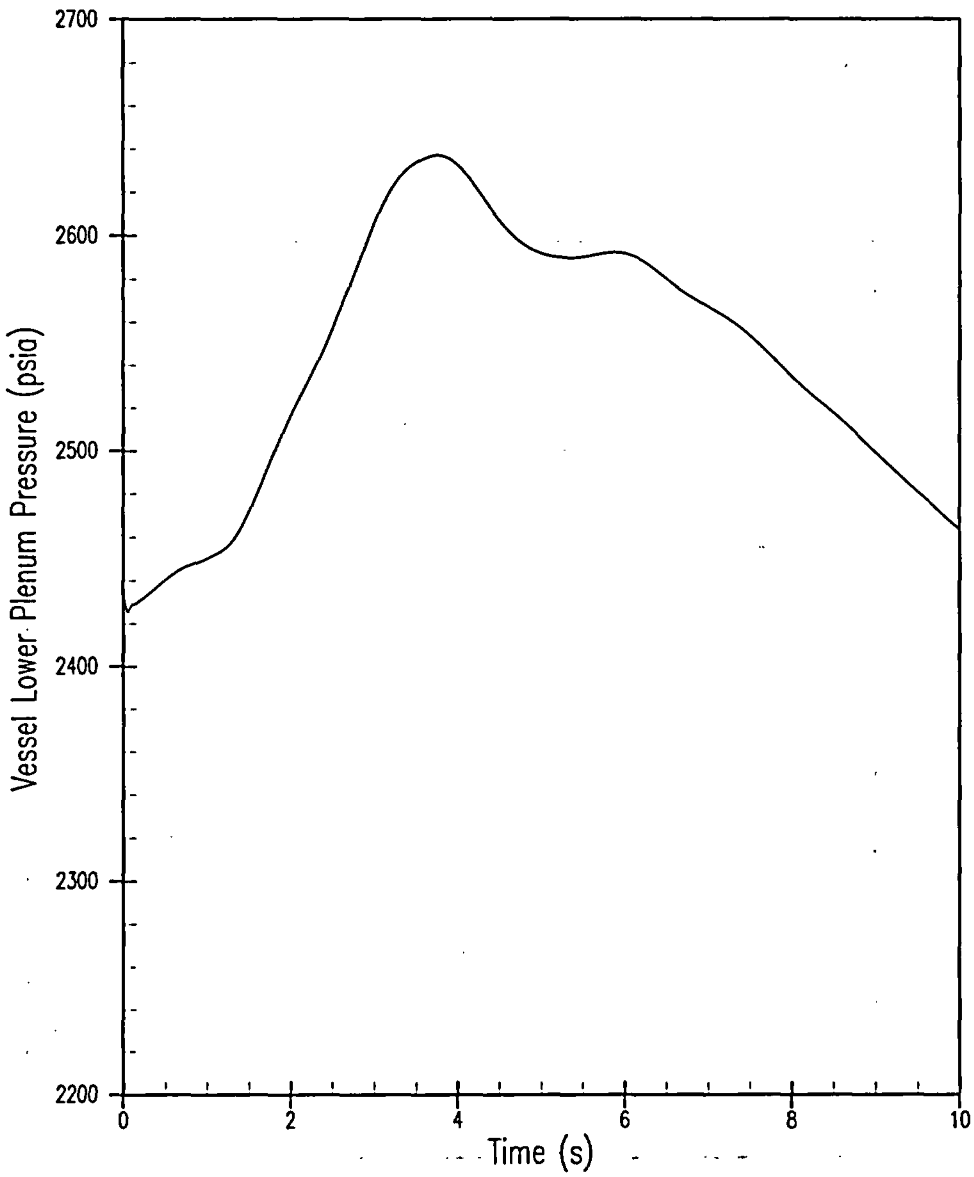

Figure 5.1.15-6
Locked Rotor/Shaft Break
Vessel Lower Plenum Pressure

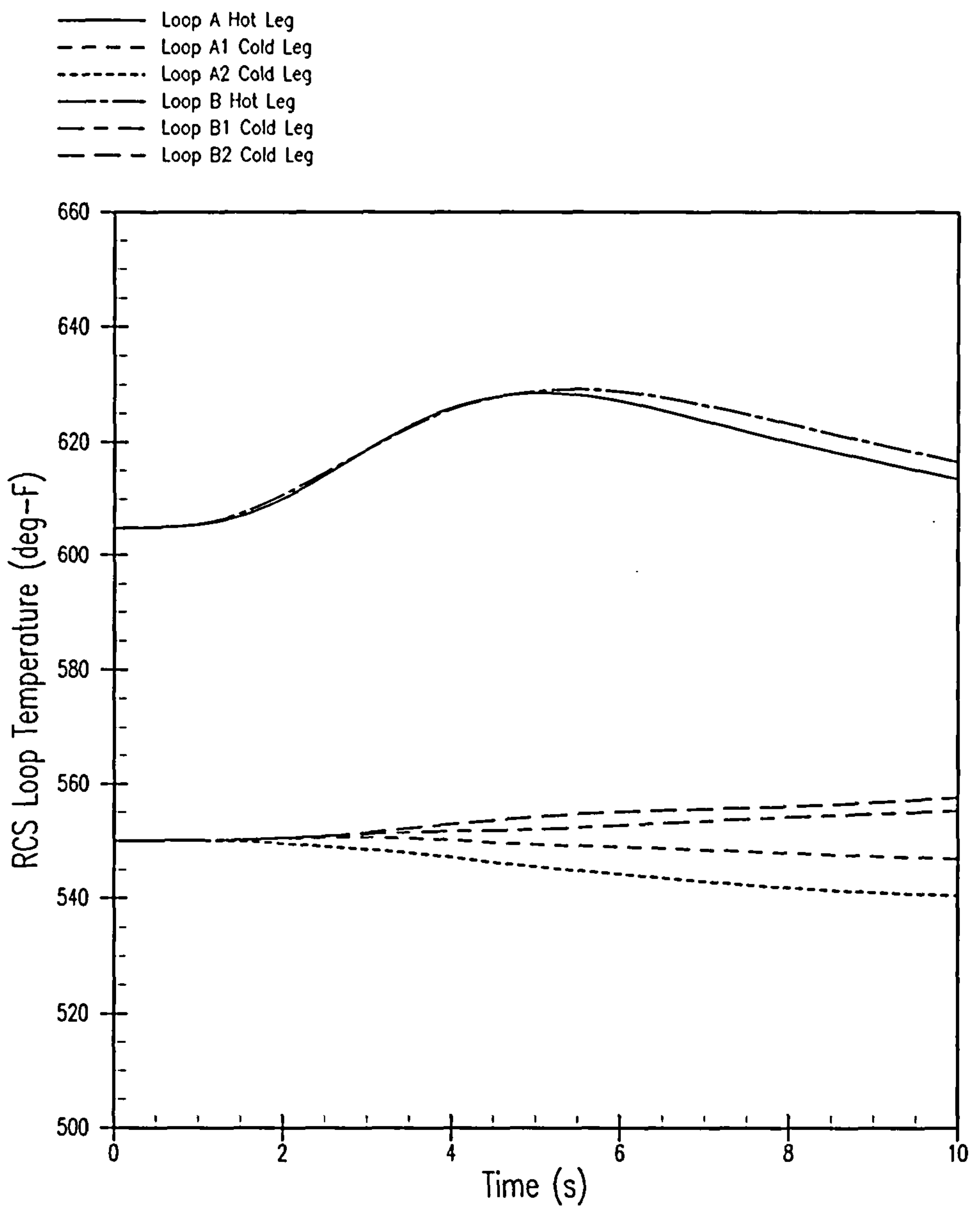

Figure 5.1.15-7
Locked Rotor/Shaft Break
RCS Loop Temperature

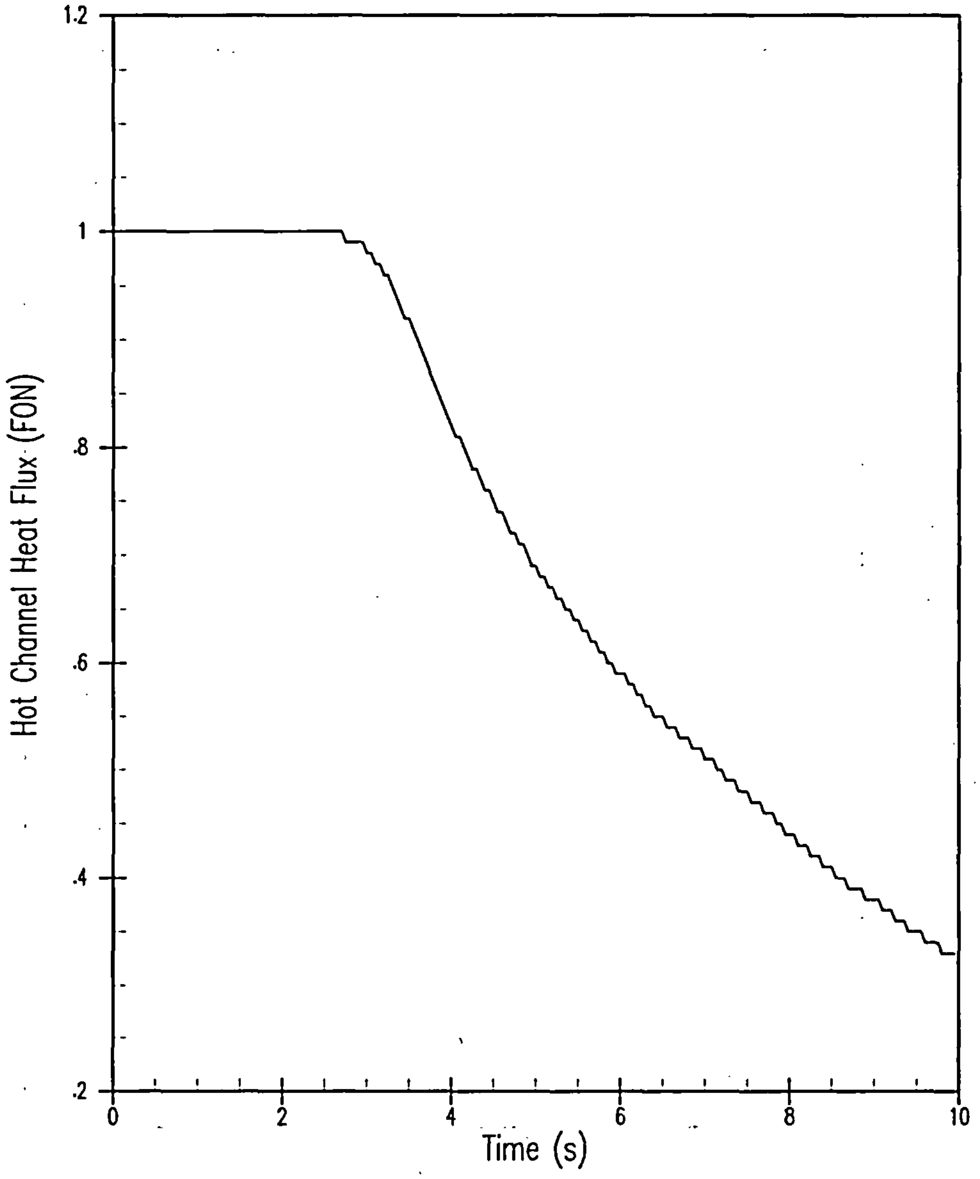

Figure 5.1.15-8
Locked Rotor/Shaft Break
Hot Channel Heat Flux

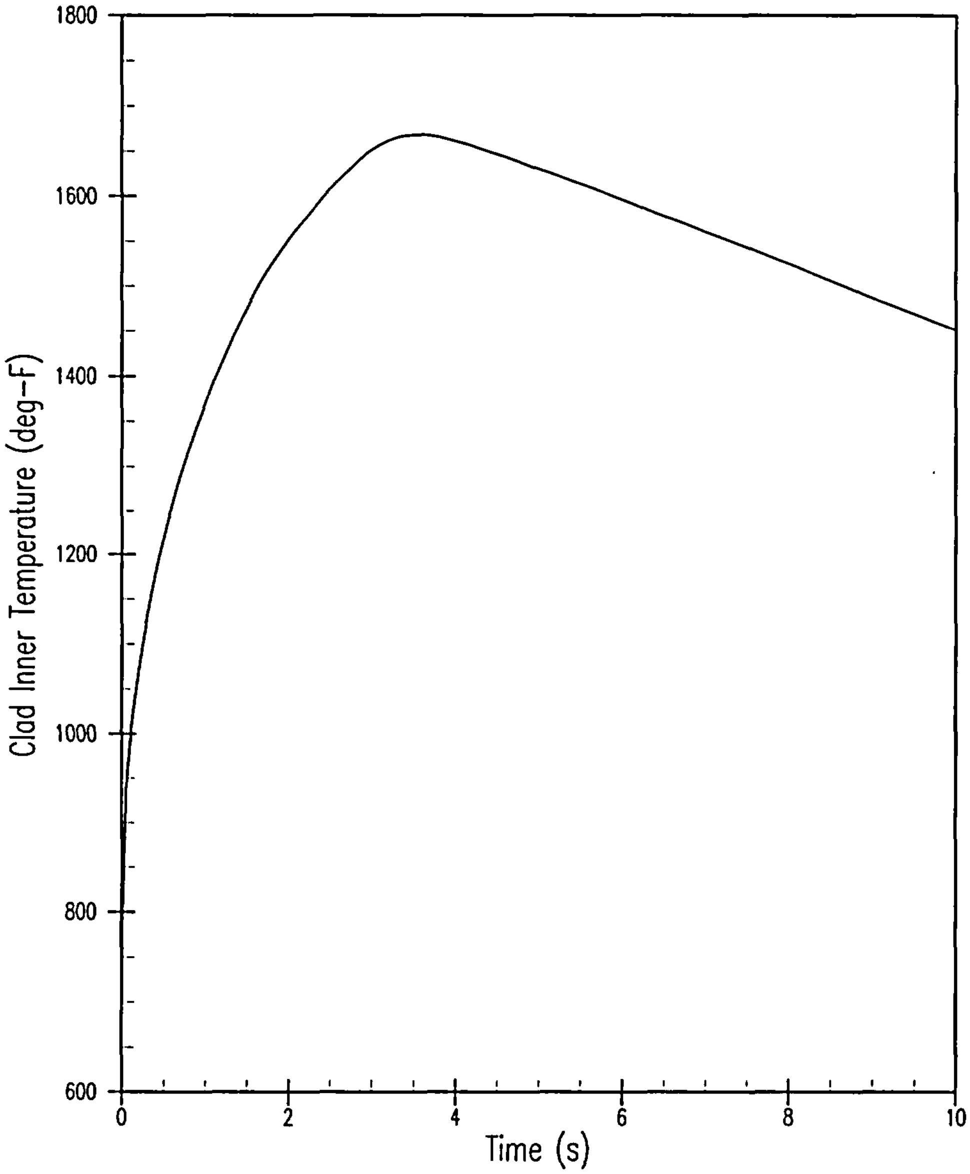

Figure 5.1.15-9
Locked Rotor/Shaft Break
Hot-Spot Cladding Inner Temperature

5.1.16 Uncontrolled Control Element Assembly Bank Withdrawal at Power

5.1.16.1 Accident Description

The Uncontrolled CEA Withdrawal At-Power event is defined as the inadvertent addition of reactivity to the core caused by the withdrawal of CEA banks when the core is above the no-load condition. The reactivity insertion resulting from the bank (or banks) withdrawal will cause an increase in core nuclear power and a subsequent increase in core heat flux and RCS temperature. A CEA bank withdrawal can occur with the reactor subcritical, at HZP, or at power. The uncontrolled CEA bank withdrawal at power event is analyzed for Mode 1 (power operation). The uncontrolled CEA bank withdrawal from a subcritical or low-power condition is considered as an independent event in Section 5.1.17.

The CEA Withdrawal At-Power event is simulated by modeling a constant reactivity insertion rate starting at time zero and continuing until an automatic reactor trip occurs or, for very low reactivity insertion rates, sufficient time has passed to credit a manual reactor trip. The analysis assumes a spectrum of possible reactivity insertion rates up to a maximum positive reactivity insertion rate greater than that occurring for the simultaneous withdrawal, at maximum speed, of two sequential CEA banks having the maximum differential rod worth.

The transient RCS response to the CEA Bank Withdrawal event is terminated by manual or automatic action to preclude the power mismatch and resultant temperature rise from resulting in DNB and/or fuel centerline melt. Additionally, the increase in RCS temperature caused by this event will increase the RCS pressure, and if left unchecked, could challenge the integrity of the RCS pressure boundary or the MSS pressure boundary.

To avert the core damage that might otherwise result from this event, the RPS is designed to automatically terminate any such event before the DNBR falls below the limit value, the fuel rod kW/ft limit is reached, or the peak primary and secondary pressures exceed their respective limits. Depending on the initial power level and the reactivity insertion rate, the reactor may be tripped and the CEA withdrawal terminated by any of the following trip signals:

- Variable High Power (VHP)
- High Pressurizer Pressure
- Thermal Margin/Low Pressure
- High Local Power Density

5.1.16.2 Method of Analysis

The Uncontrolled CEA Bank Withdrawal At-Power event is analyzed to show that: (1) the integrity of the core is maintained by the RPS because the DNBR and peak kW/ft remain within the safety analysis limit values and (2) the peak RCS and MSS pressures remain below 110 percent of the corresponding design limits. Of these criteria, the most limiting are the need to ensure that the DNBR and peak kW/ft limits are met.

The CEA Bank Withdrawal At-Power transient is analyzed with the RETRAN computer program (Reference 5.1.16-1). The program simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generators, and steam generator relief and safety valves. The program computes pertinent plant variables including temperatures, pressures, and power level.

Selected initial conditions used in the safety analysis are summarized in Table 5.1.0-2. To obtain conservative values for minimum DNBR and ensure that the peak kW/ft limits are met, the following analysis assumptions are made:

1. Cases analyzed to assess the acceptability with respect to DNBR limits are analyzed with the RTDP DNB methodology (Reference 5.1.16-2). Therefore, the initial reactor power, RCS pressure, RCS flow and RCS temperatures are assumed to be at their nominal values. Uncertainties in these initial conditions are included in the limit DNBR.

2. Reactivity coefficients - Two feedback conditions are analyzed:

   - Minimum reactivity feedback - The MTC of reactivity ramps linearly from a zero MTC of reactivity (0 pcm/°F) at 100-percent rated thermal power to a positive MTC of reactivity (+5 pcm/°F) at 70-percent power. As such, a positive MTC of reactivity of 1.83 pcm/°F is assumed for 89-percent power. For power levels less than or equal to 70-percent power, a positive MTC of reactivity (+5 pcm/°F) is conservatively assumed, corresponding to the beginning of core life. A conservatively small (in absolute magnitude) Doppler power coefficient is used in the analysis (see Figure 5.1.0-5).

   - Maximum reactivity feedback - A conservatively large positive moderator density coefficient and a large (in absolute magnitude) negative Doppler power coefficient are assumed (Figure 5.1.0-5).

3. The variable high power reactor trip on high neutron flux or high indicated power from temperature measurement (ΔT-power) is actuated at a conservative safety analysis ceiling value of 102-percent of rated thermal power. The decalibration of the excore detectors is conservatively modeled as the CEAs are withdrawn to account for the effect of the reduced indicated excore detector power which delays the reactor trip on the neutron flux signal.

4. The Δ-power feature of the variable high power trip is simulated in the analysis using two different approaches:

   - For the cases initiated from less than 89-percent power (20, 50, and 65-percent of rated thermal power) a conservative safety analysis setpoint of 30-percent of rated thermal power on high neutron flux or high indicated ΔT-power is modeled. This 30-percent Δ-power trip setpoint includes setpoint uncertainties, power measurement uncertainties and accounts for excore decalibration due to CEA withdrawal.

   - For the cases initiated from 89-percent power, a Δ-power trip setpoint of 11.0-percent of rated thermal power based on the highest of the excore or ΔT-power signals is modeled. Decalibration of the excore detectors as the CEAs withdraw is explicitly modeled since this effect tends to reduce the indicated excore detector power and thereby delay the reactor trip.

5. In all cases, the thermal margin/low pressure trip is modeled without taking credit for any reduction in the calculated trip setpoint pressure associated with any skewed axial shape index (ASI). Two different approaches are employed with regard to the indicated core power signal that is used by the thermal margin/low pressure function. The initial power level dictates the approach selected for any particular case.

   - For the cases initiated from less than 89-percent power (20, 50, and 65-percent of rated thermal power), excore decalibration due to CEA withdrawal was not modeled. No such modeling was required because all of these cases produced an earlier reactor trip on signals other than the thermal margin/low pressure trip function.

   - For cases initiated from 89-percent power, the highest of the excore or ΔT-power signals is used by the thermal margin/low pressure trip logic. The decalibration of the excore detectors is

conservatively modeled as the CEAs are withdrawn to account for the effect of the reduced indicated excore detector power which delays the reactor trip on the neutron flux signal input to the TM/LP.

6. The high pressurizer pressure reactor trip setpoint assumed in the safety analysis is 2415 psia.
7. All of the reactor trip functions modeled in the CEA withdrawal at-power analysis include appropriate instrumentation and setpoint errors. The delays for trip actuation are assumed to be the maximum values (see Table 5.1.0-4).
8. The CEA trip insertion characteristics are based on the assumption that the highest worth assembly is stuck in its fully withdrawn position (see Figure 5.1.0-4).
9. A range of reactivity insertion rates is examined. The maximum positive reactivity insertion rate is greater than that which would be obtained from the simultaneous withdrawal of the two control rod banks having the maximum combined differential rod worth at a conservative speed. The maximum bounding reactivity insertion rate that is required for consideration is 53 pcm/sec.
10. The analysis includes consideration of up to 42-percent steam generator tube plugging in both steam generators.
11. Power levels of 20, 50, 65, and 89-percent of rated thermal power are considered.

5.1.16.3 Results

Selected results are reported in Table 5.1.16-1 for the CEA bank withdrawal at power transients analyzed to support 42-percent steam generator tube plugging. The limiting results are summarized in Table 5.1.16-2.

For all of the cases analyzed, including reactivity insertion rates of up to 53 pcm/second, the RCS pressure never exceeds 110% of design limit, or 2750 psia. The reactivity insertion rate of 53 pcm/sec bounds that calculated for the simultaneous withdrawal, at maximum speed, of two sequential CEA banks having the maximum differential rod worth.

Figures 5.1.16-1 through 5.1.16-4 show the response of nuclear power, pressurizer pressure, RCS vessel T_{avg}, and DNBR to a rapid (53 pcm/sec) CEA withdrawal incident starting from 89-percent of rated thermal power with minimum reactivity feedback conditions. Reactor trip on the variable high power function occurs shortly after the start of the accident. Since this case results in a rapid increase in the nuclear power with the core heat flux lagging behind because of the thermal time constants of the plant, small changes in the reactor core T_{avg} and pressurizer pressure result. Therefore, a large margin to the safety analysis limit DNBR is maintained.

The response of nuclear power, pressurizer pressure, RCS vessel T_{avg}, and DNBR for a slow (2 pcm/sec) CEA withdrawal from 89-percent of rated thermal power with minimum reactivity feedback conditions is shown in Figures 5.1.16-5 through 5.1.16-8. Reactor trip on the variable high power function occurs after a longer period of time compared to the rapid CEA withdrawal mentioned above and thus, the rise in temperature is consequently larger. Again, the minimum DNBR is greater than the safety analysis limit value.

Figures 5.1.16-9 through 5.1.16-12 shows the minimum predicted DNBR as a function of the reactivity insertion rate for the four initial power levels analyzed (100, 65, 50 and 20-percent of rated thermal power) for both minimum and maximum reactivity feedback conditions. It can be seen that the combination of reactor trip functions modeled provides protection over the entire range of reactivity insertion rates because the minimum DNBR is never less than the safety analysis limit value.

In the referenced figures, the shape of the curves of minimum DNBR versus reactivity insertion rate is a function of both the reactor core and coolant system transient response and the reactor trips assumed to provide protection for this event.

Referring to Figure 5.1.16-9 for example, it is noted that:

1. For the reported minimum reactivity feedback cases initiated from 89-percent of rated thermal power, the reactor trip was on the variable high power trip. For these cases, even with excore decalibration effects modeled, the variable high power reactor trip on the excore detector indicated power signal produces the reactor trip. This demonstrates that even for cases with low reactivity insertion rates, in the presence of a minimum reactivity feedback condition, the neutron flux level in the core rises relatively rapidly compared to coolant temperature changes that lag behind due to the thermal capacity of the fuel and coolant system fluid. For the 89-percent power minimum feedback cases, the minimum predicted DNBR values remain well above the safety analysis limit value of 1.34 over the entire range of reactivity insertion rates considered.

2. When modeling maximum reactivity feedback for cases initiated from 89-percent power, protection is provided by the high pressurizer pressure reactor trip function. For the cases with maximum reactivity feedback and relatively low reactivity insertion rates, the core power increase is limited. For the cases with maximum reactivity feedback and higher reactivity insertion rates, the resulting rate of increase in the neutron flux is more rapid. However, since the indicated power signal is largely impacted by the very conservative modeling of excore decalibration effects employed in the 89-percent power cases, a reactor trip on the variable high power trip is precluded. The minimum predicted DNBR values are all well above the safety analysis limit value of 1.34 for the maximum feedback cases over the entire range of reactivity insertion rates.

5.1.16.4 Conclusions

The results for the Uncontrolled CEA Bank Withdrawal At-Power transient demonstrate that the combination of the variable high power and high pressurizer pressure reactor trip functions provide adequate protection over the entire range of possible reactivity insertion rates, expected initial power levels and for different times in life. That is, the minimum calculated DNBR is always greater than the safety analysis limit value. In addition, it was demonstrated that the peak kW/ft is less than the limit value for fuel melting and that the peak pressures in the RCS and MSS do not exceed 110-percent of their respective design pressures.

Thus, all pertinent safety analysis criteria are met for the Uncontrolled CEA Bank Withdrawal At-Power event in support of the 42-percent steam generator tube plugging program.

5.1.16.5 References

5.1.16-1 McFadden, J. H., et al. "RETRAN-02- A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems," EPRI NP-1850-CCMA.

5.1.16-2 Friedland, A. J. and Ray, S., "Revised Thermal Design Procedure," WCAP-11397-P-A and WCAP-11397-A, April 1989.

Table 5.1.16-1 Sequence of Events for Uncontrolled CEA Withdrawal at Power (89% Initial Power & Minimum Reactivity Feedback)	
Event	**Time (Seconds)**
Case A:	
Initiation of Uncontrolled CEA Withdrawal at 89% Power with Minimum Reactivity Feedback (53 pcm/sec)	0
Variable High Power Trip Setpoint Reached	2.33
Reactor Trip Signal Occurs	2.73
Rods Begin to Fall into Core	3.47
Minimum DNBR Occurs	4.5
Case B:	
Initiation of Uncontrolled CEA Withdrawal at 89% Power with Minimum Reactivity Feedback (2 pcm/sec)	0
Variable High Power Trip Setpoint Reached	41.33
Reactor Trip Signal Occurs	41.73
Rods Begin to Fall into Core	42.47
Minimum DNBR occurs	43.0

Table 5.1.16-2 Limiting Results for CEA Bank Withdrawal at Power Transient			
Criterion	**Limiting Value**	**Analysis Limit**	**Case**
DNBR	1.71	1.34 (side thimble)	89% power, maximum reactivity feedback, 11 pcm/second reactivity insertion rate
Core Heat Flux (FON)	1.13	1.15	89% power, maximum reactivity feedback 53 pcm/second reactivity insertion rate
MSS Pressure (psia)	1076.7	1100.0	89% power, maximum reactivity feedback, 10 pcm/second reactivity insertion rate

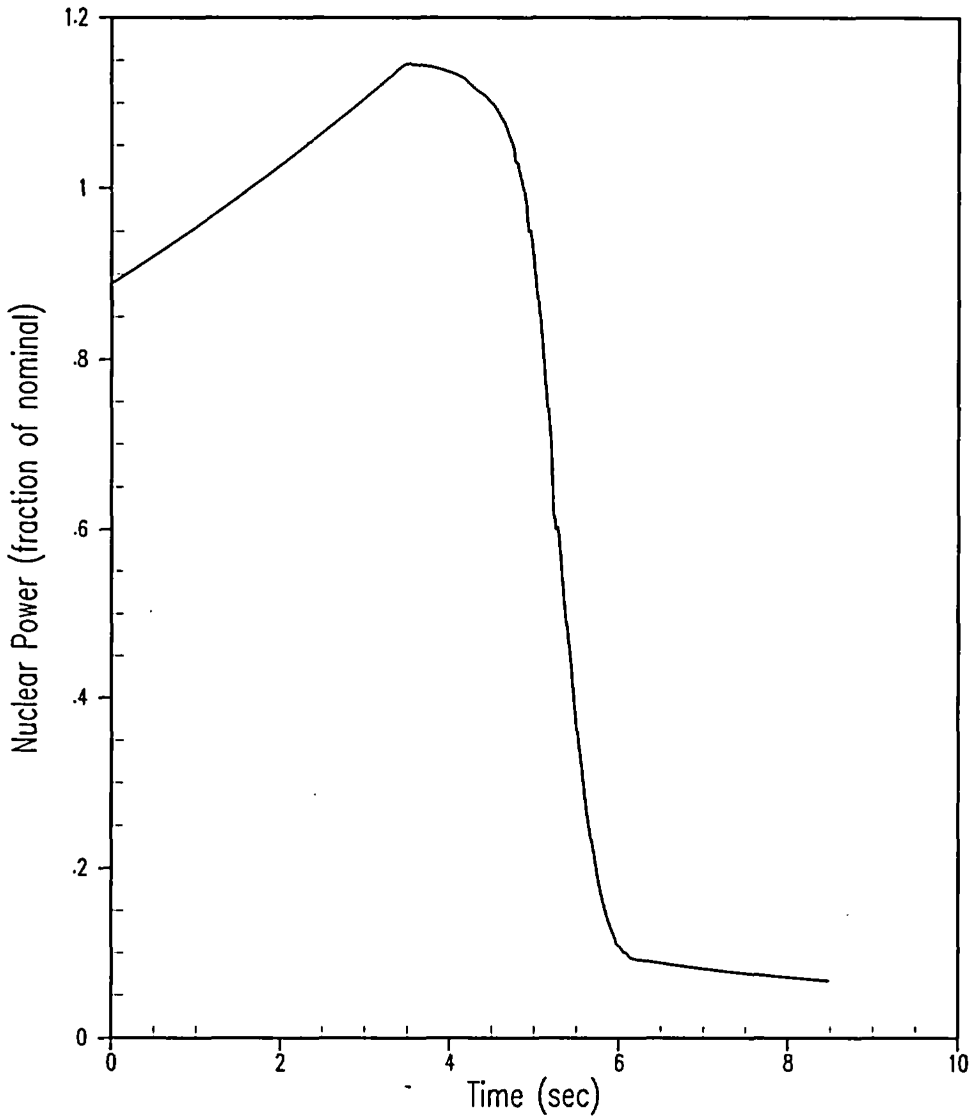

Figure 5.1.16-1
Uncontrolled CEA Bank Withdrawal at Power - 89% Power, 53 pcm/sec Reactivity Insertion Rate & Minimum Feedback, Variable High Power Trip & Maximum Nominal RCS Vessel T_{avg}
Nuclear Power

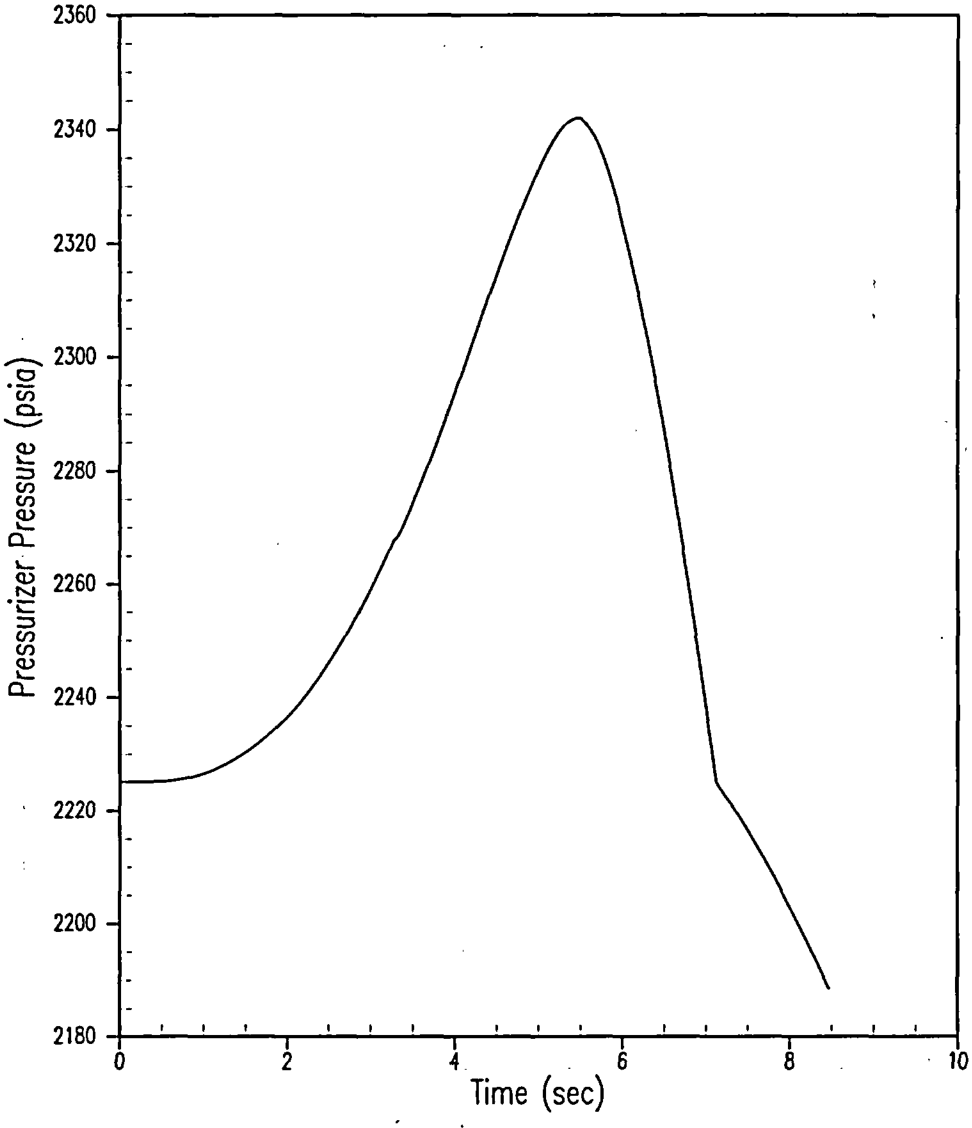

Figure 5.1.16-2
Uncontrolled CEA Bank Withdrawal at Power - 89% Power, 53 pcm/sec Reactivity Insertion Rate & Minimum Feedback, Variable High Power Trip & Maximum Nominal RCS Vessel T_{avg}
Pressurizer Pressure

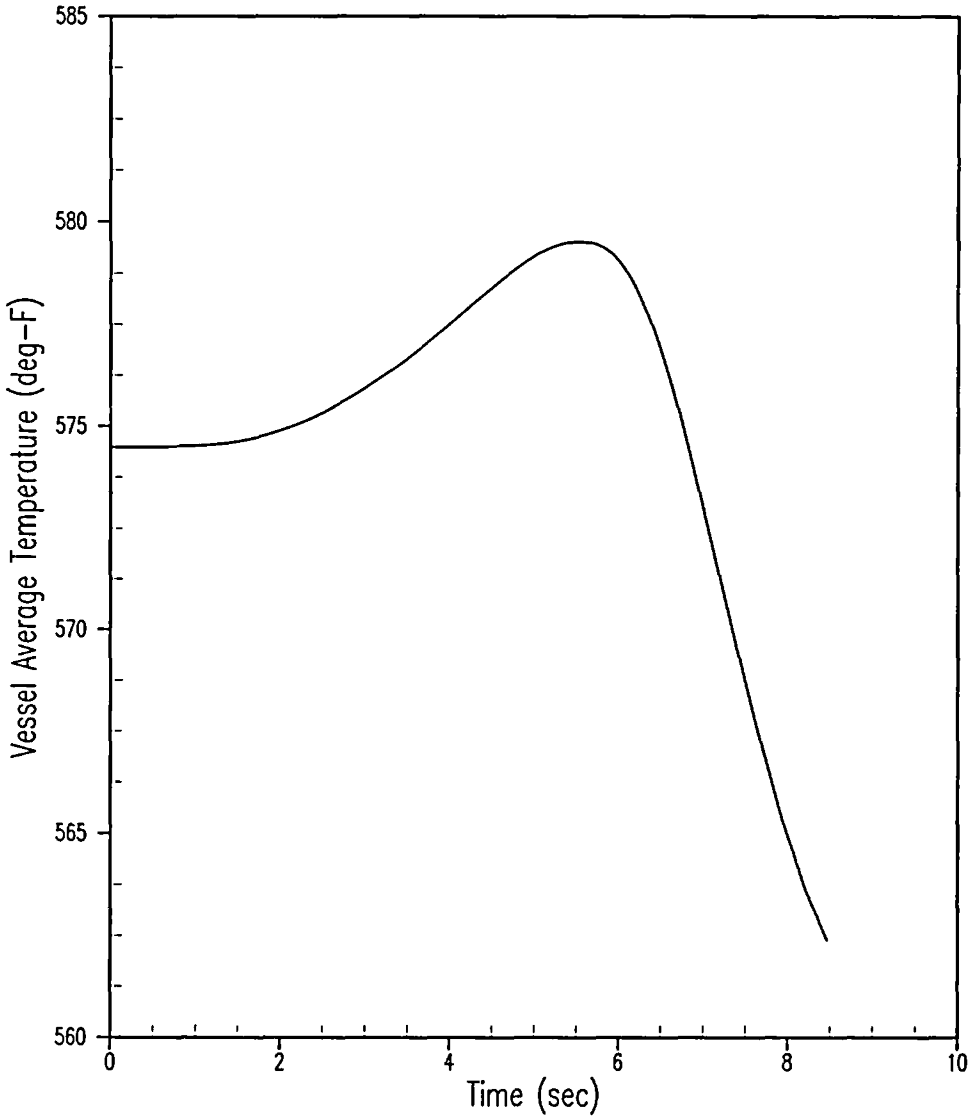

Figure 5.1.16-3
Uncontrolled CEA Bank Withdrawal at Power - 89% Power, 53 pcm/sec Reactivity Insertion Rate & Minimum Feedback, Variable High Power Trip & Maximum Nominal RCS Vessel T_{avg}
Vessel Average Temperature

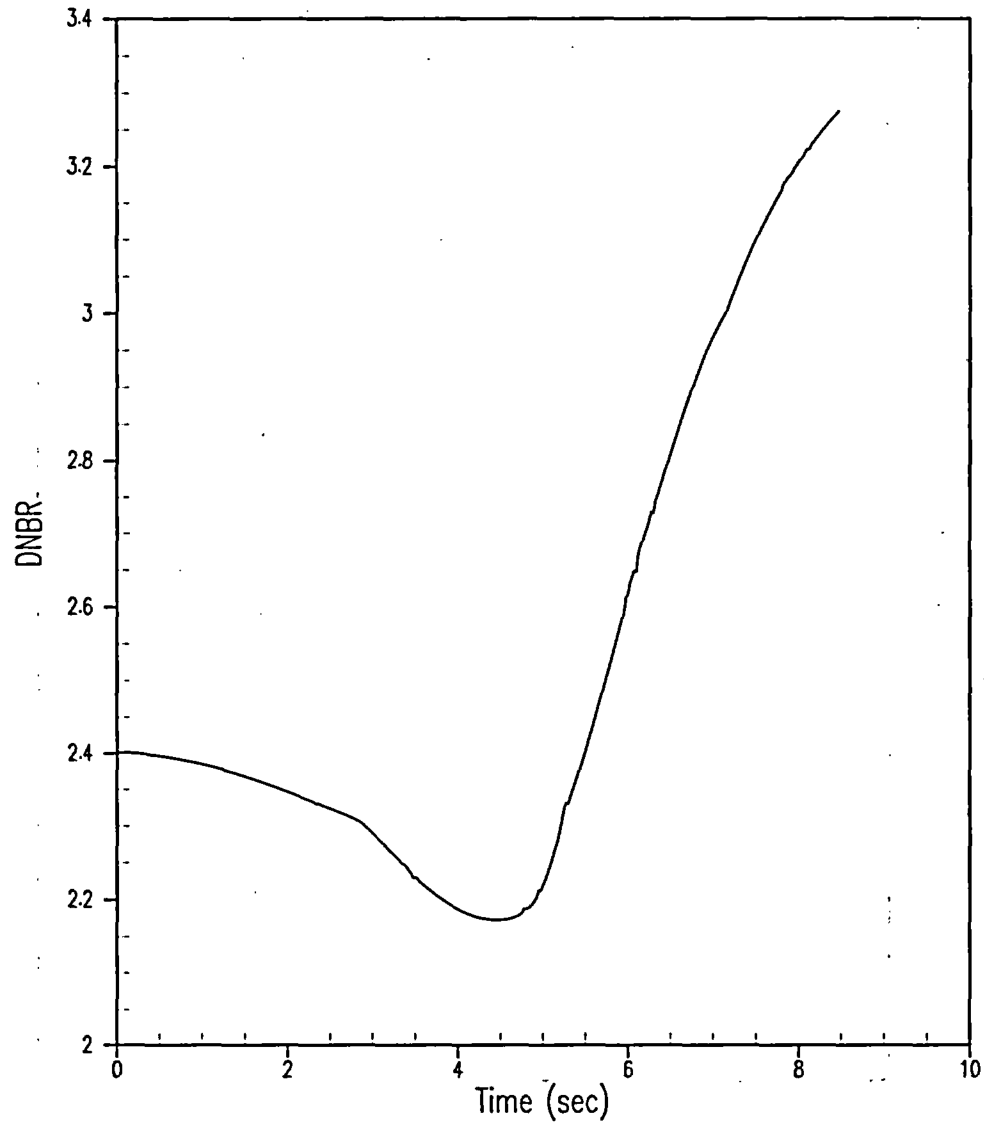

Figure 5.1.16-4
Uncontrolled CEA Bank Withdrawal at Power - 89% Power, 53 pcm/sec Reactivity Insertion Rate & Minimum Feedback, Variable High Power Trip & Maximum Nominal RCS Vessel T_{avg} DNBR

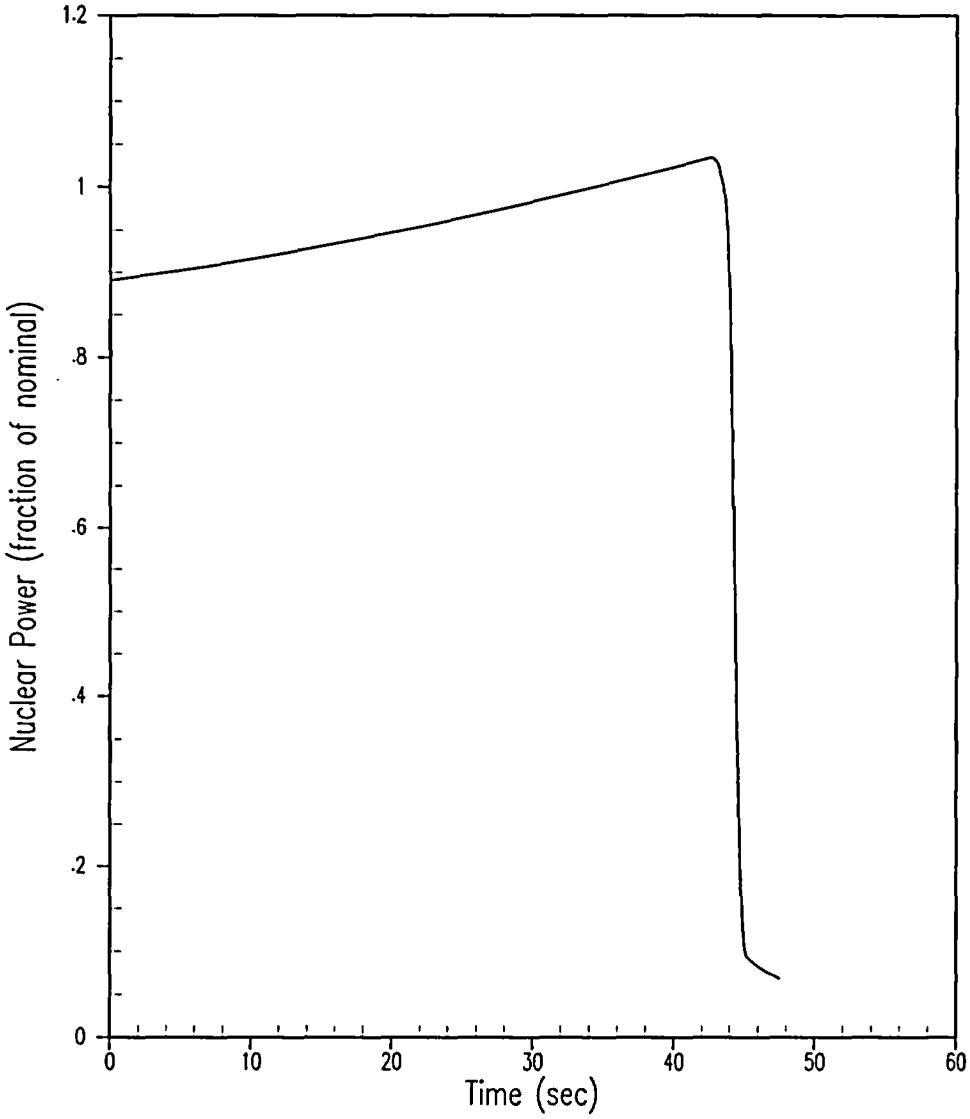

Figure 5.1.16-5
Uncontrolled CEA Bank Withdrawal at Power - 89% Power, 2 pcm/sec Reactivity Insertion Rate & Minimum Feedback, Variable High Power Trip & Maximum Nominal RCS Vessel T_{avg} Nuclear Power

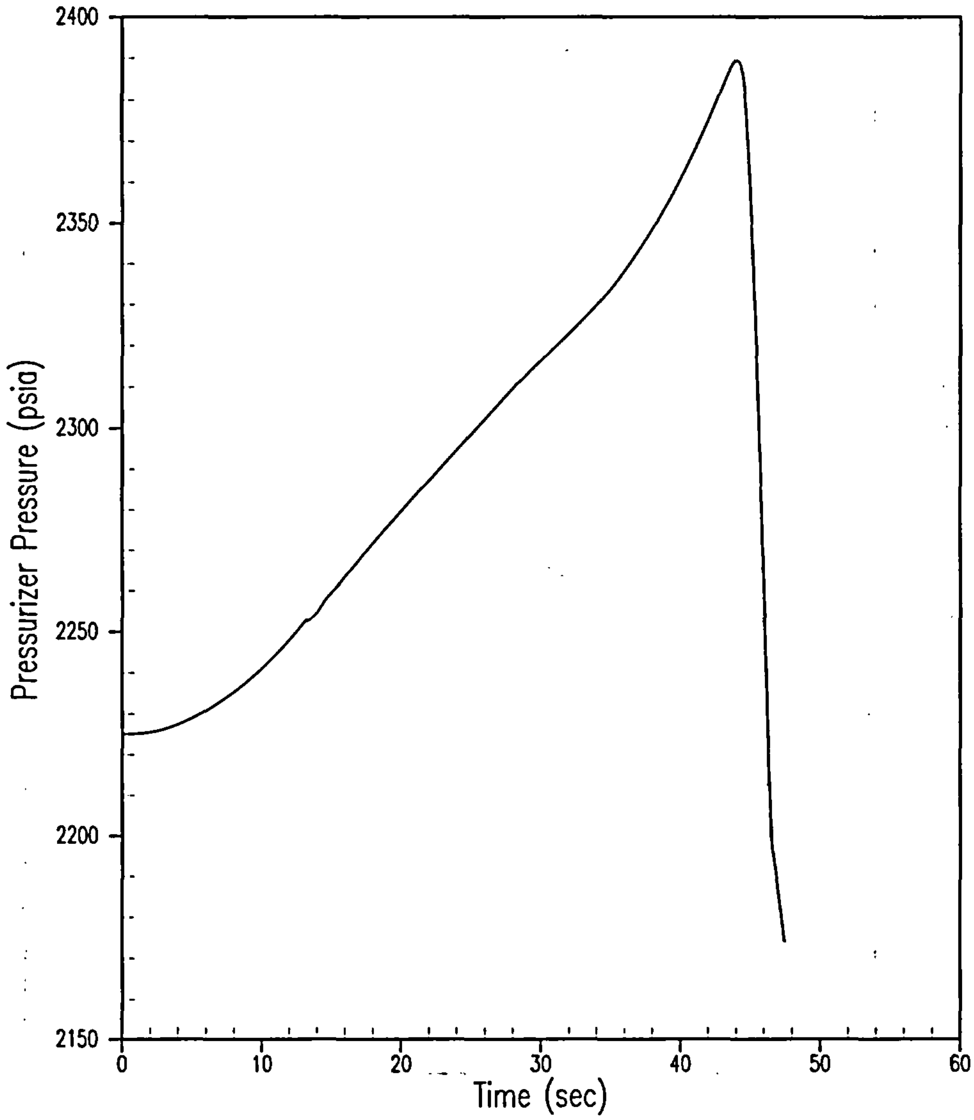

Figure 5.1.16-6
Uncontrolled CEA Bank Withdrawal at Power - 89% Power, 2 pcm/sec Reactivity Insertion Rate & Minimum Feedback, Variable High Power Trip & Maximum Nominal RCS Vessel T_{avg}
Pressurizer Pressure

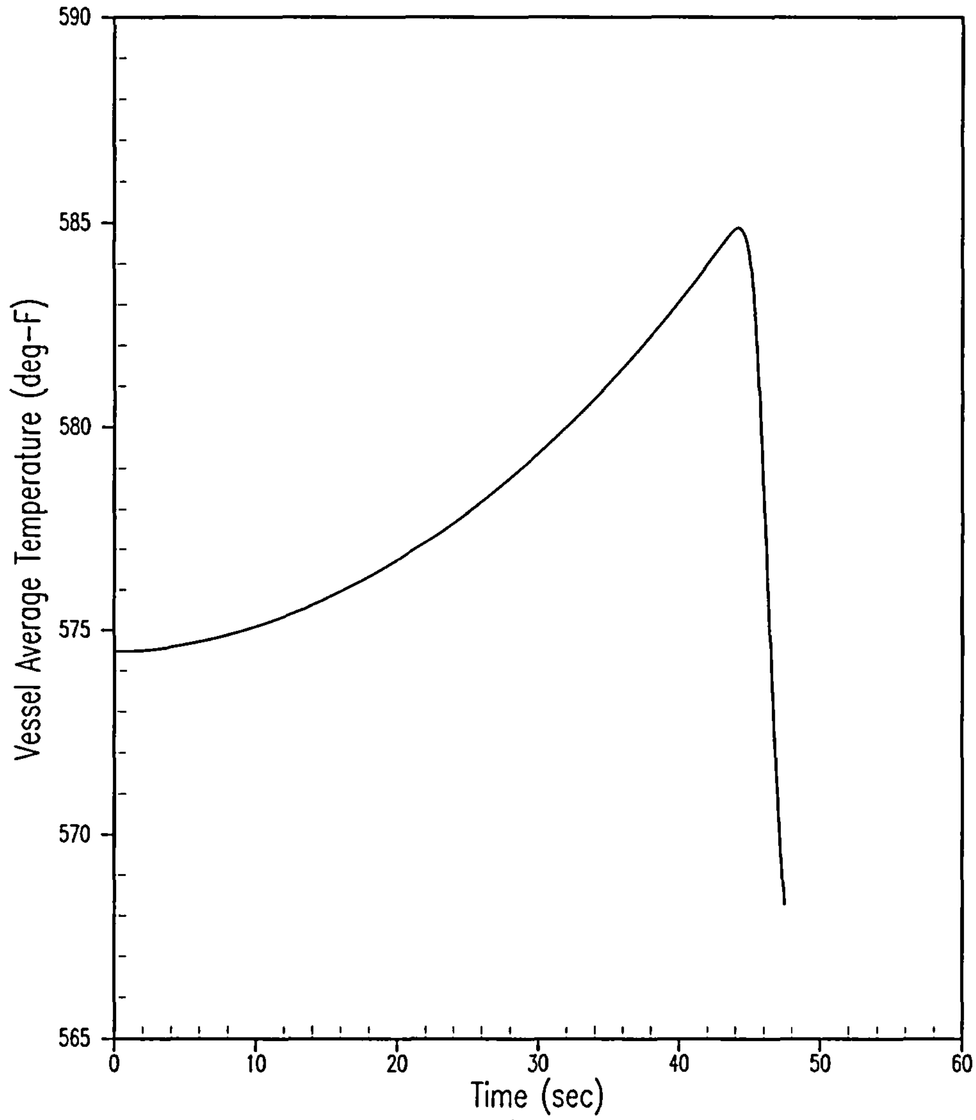

Figure 5.1.16-7
Uncontrolled CEA Bank Withdrawal at Power - 89% Power, 2 pcm/sec Reactivity Insertion Rate & Minimum Feedback, Variable High Power Trip & Maximum Nominal RCS Vessel T_{avg}
Vessel Average Temperature

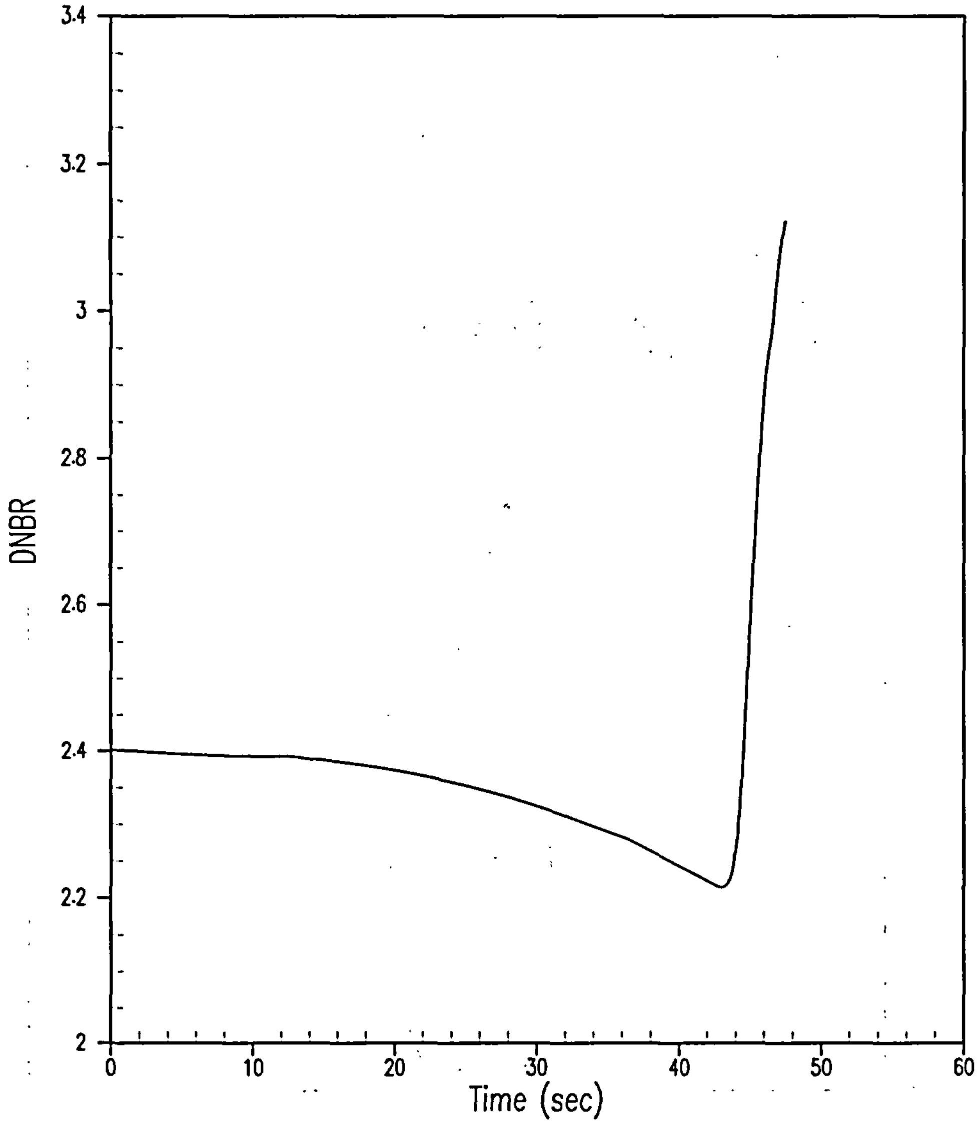

Figure 5.1.16-8
Uncontrolled CEA Bank Withdrawal at Power - 89% Power, 2 pcm/sec Reactivity Insertion Rate & Minimum Feedback, Variable High Power Trip & Maximum Nominal RCS Vessel T_{avg}
DNBR

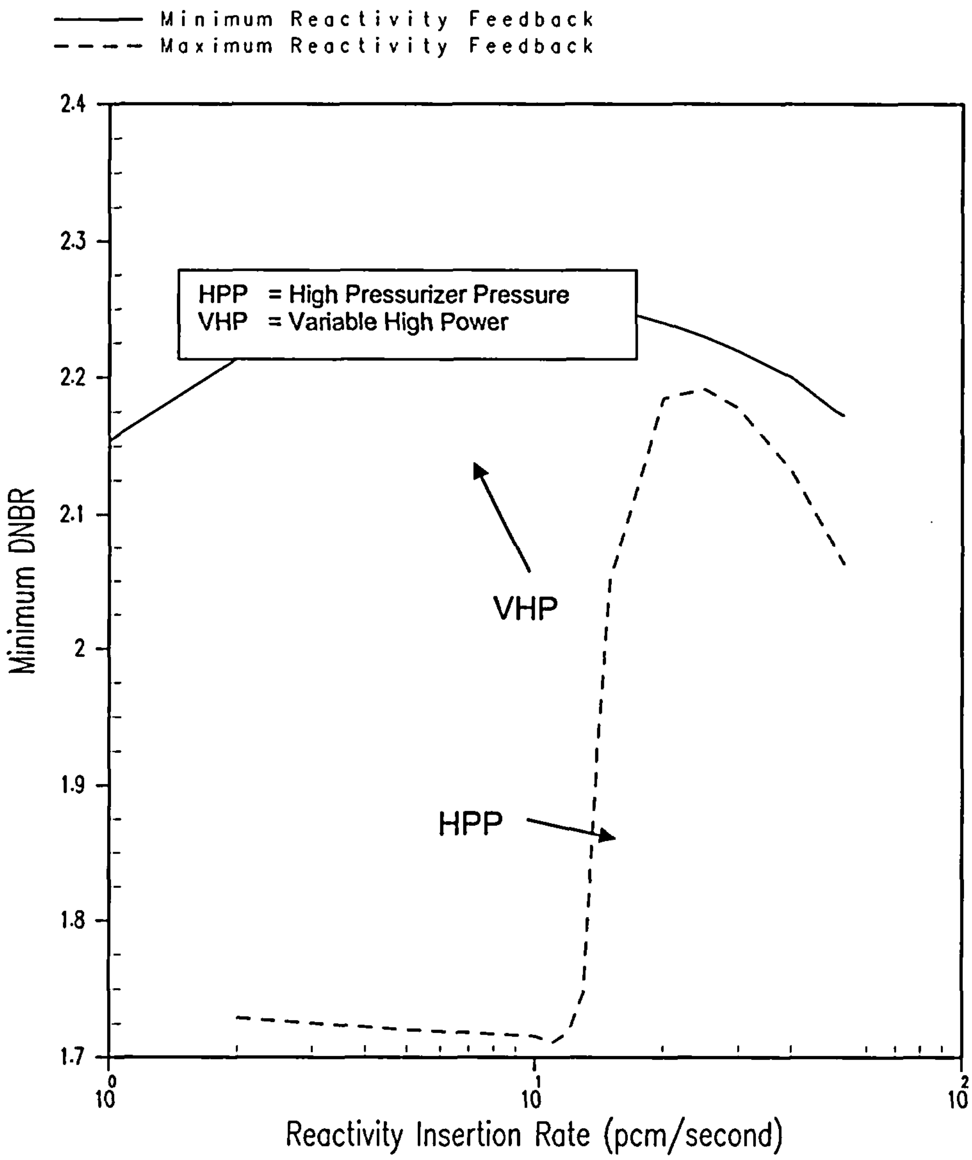

Figure 5.1.16-9
Uncontrolled CEA Bank Withdrawal at Power - Initial Power Level of 89%
Minimum DNBR

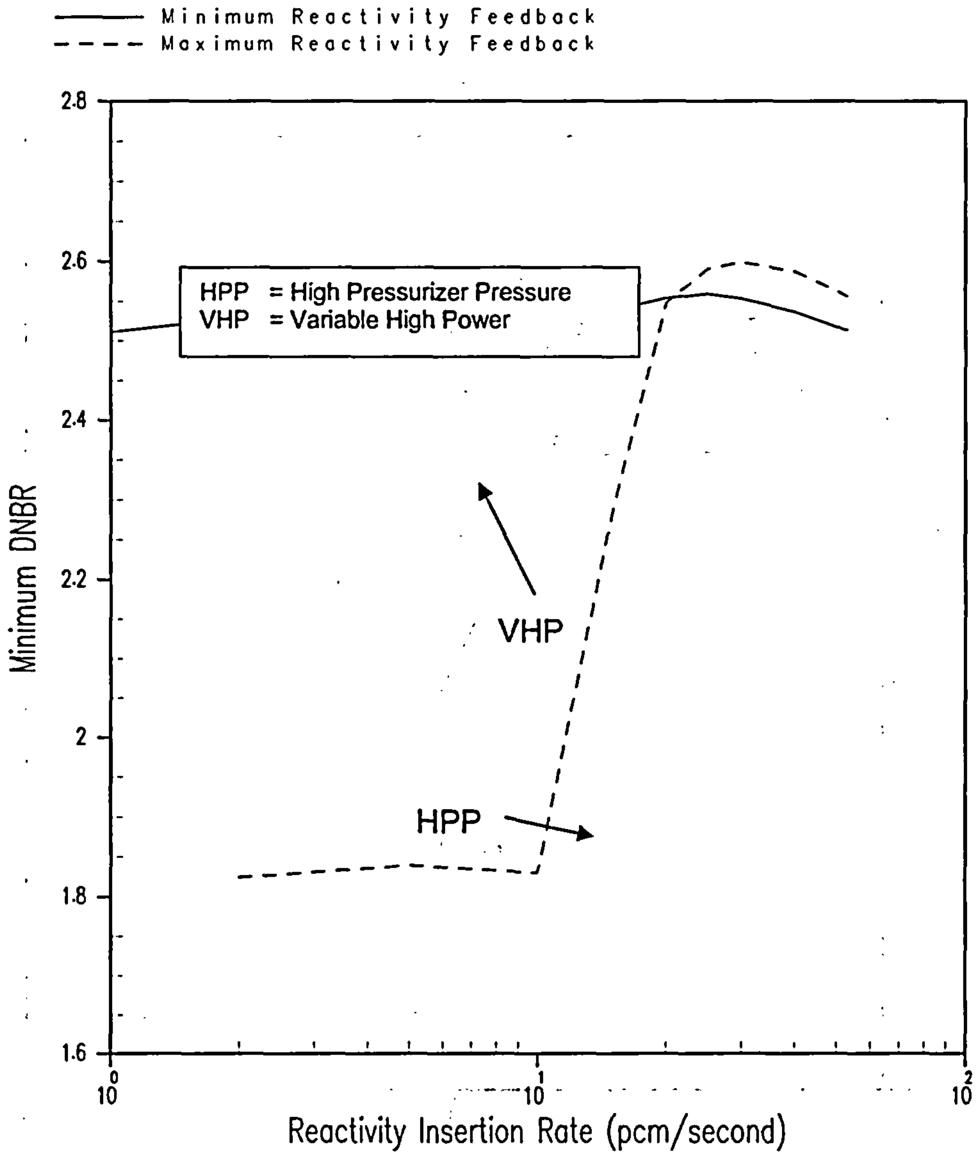

Figure 5.1.16-10
Uncontrolled CEA Bank Withdrawal at Power - Initial Power Level of 65%
Minimum DNBR

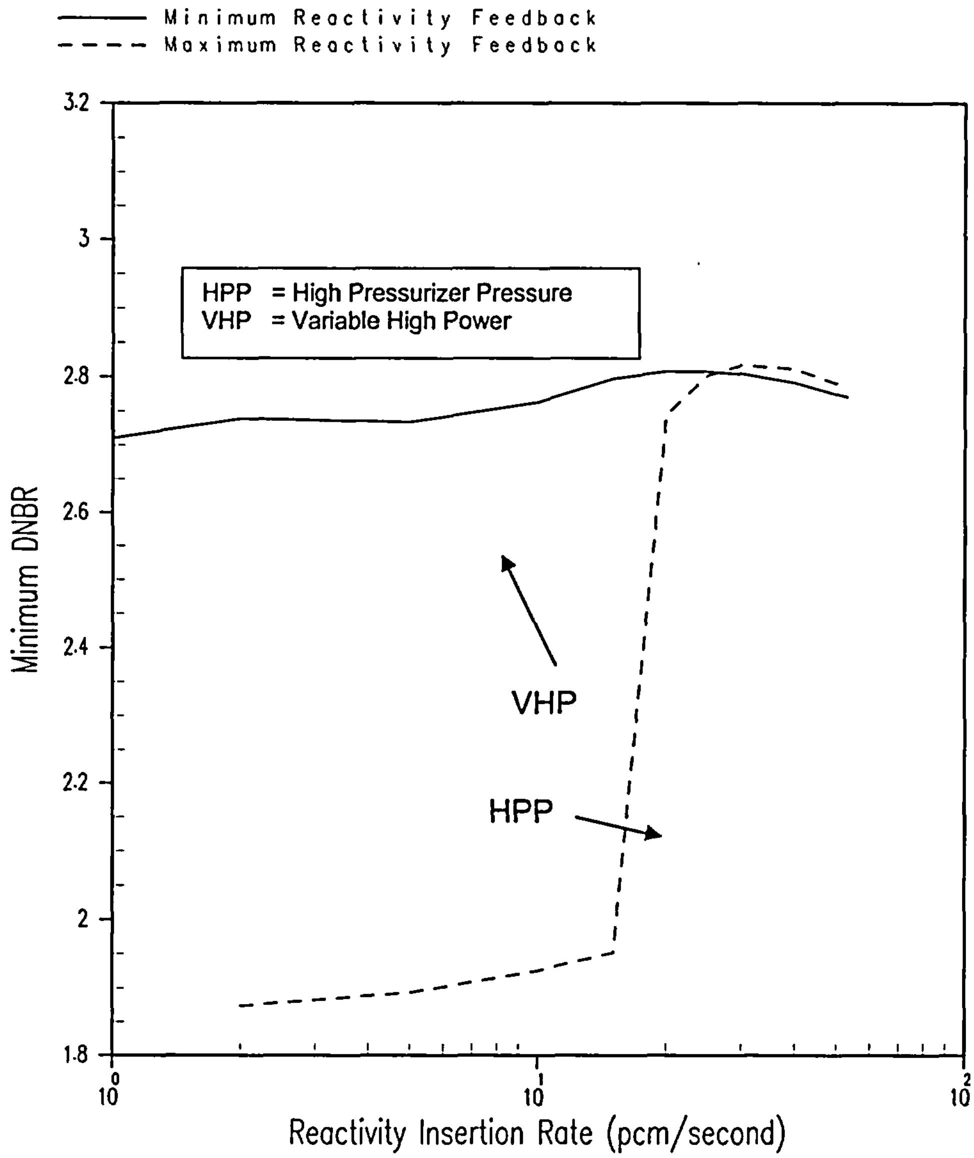

Figure 5.1.16-11
Uncontrolled CEA Bank Withdrawal at Power - Initial Power Level of 50%
Minimum DNBR

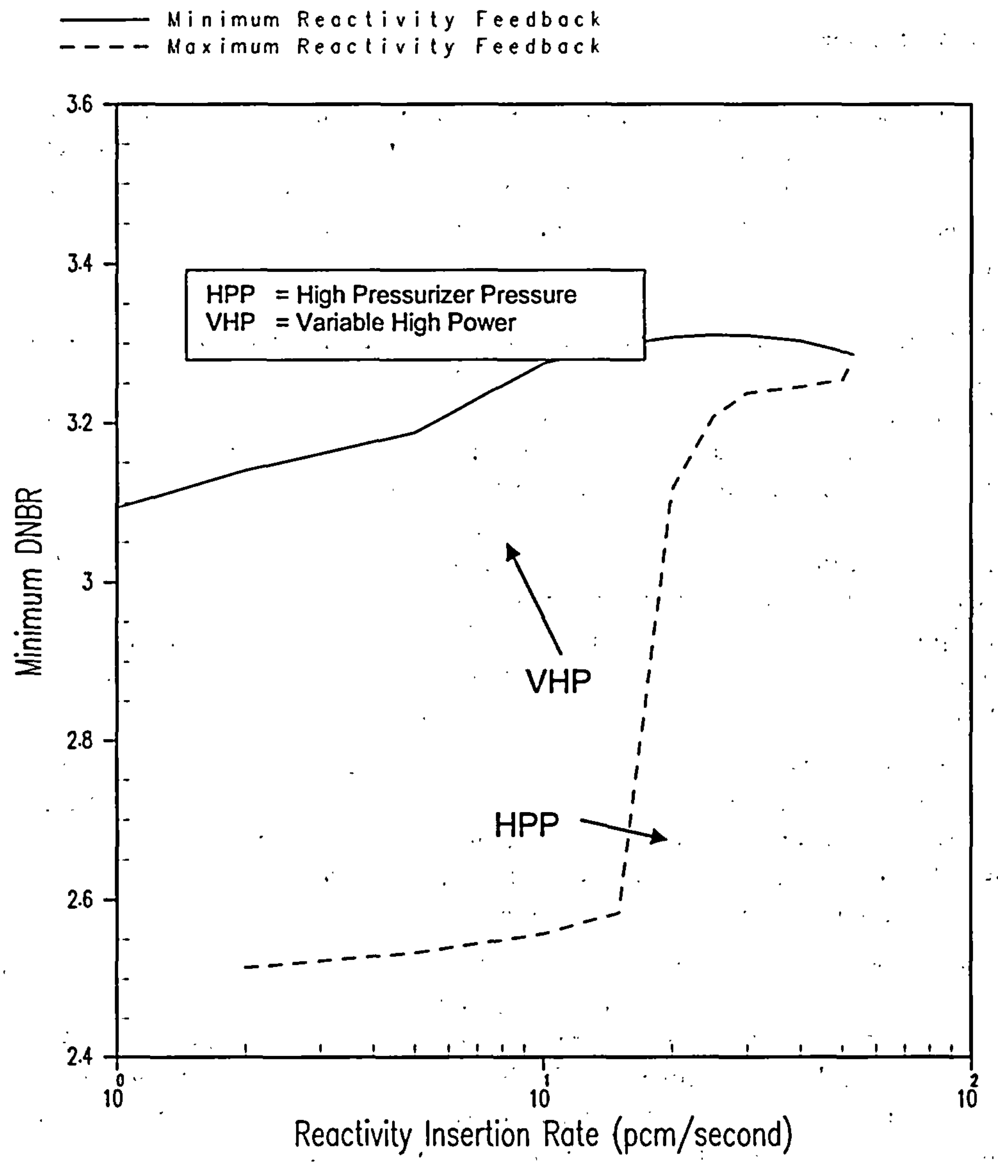

Figure 5.1.16-12
Uncontrolled CEA Bank Withdrawal at Power - Initial Power Level of 20%
Minimum DNBR

5.1.17 Uncontrolled Control Element Assembly Withdrawal from a Subcritical Condition

5.1.17.1 Accident Description

The CEA withdrawal accident is defined as an uncontrolled addition of reactivity to the reactor core caused by withdrawal of CEA banks resulting in a power excursion. While the occurrence of a transient of this type is unlikely, such a transient could be caused by a malfunction of the reactor control or the control element drive system. This could occur with the reactor either subcritical, at HZP, or at power. The "at power" case is discussed in Section 5.1.16.

Withdrawal of a CEA bank adds reactivity at a prescribed and controlled rate to bring the reactor from a subcritical condition to a low-power level during startup. Although the initial startup procedure typically uses the method of boron dilution, the normal startup is with CEA bank withdrawal. A CEA bank movement can cause much faster changes in reactivity than can be made by changing boron concentration (see Section 5.1.19, Chemical and Volume Control System Malfunction).

The neutron flux response to a continuous reactivity insertion is characterized by a very fast flux increase terminated by the reactivity feedback effect of the negative Doppler coefficient. This self-limitation of the power burst is of primary importance since it limits the power to a tolerable level during the delay time for protective action. Should a continuous control element assembly withdrawal event occur, the following automatic features of the reactor protection system are available to terminate the transient:

- The Variable Power Level – High trip is provided to trip the reactor when the reactor power reaches a high preset value. This setpoint is set to a fixed increment ($\leq$ 9.61% technical specification value) above the existing reactor power level, with a minimum setpoint of 15% of rated thermal power and a maximum of $\leq$ 107% of rated thermal power. This trip is actuated when two-out-of-four power range channels indicate a power level above the setpoint.
- The Rate-of-Change of Power – High trip is provided to trip the reactor when the rate-of-change of neutron flux power reaches a high preset value ($\leq$ 2.49 decades per minute technical specification value). It is actuated when two-out-of-four wide-range logarithmic neutron flux monitoring channels indicate a rate above the preset setpoint. This trip function may be bypassed below 10^{-4}% and above 15% of rated thermal power. Bypass is automatically removed when wide-range logarithmic neutron flux power is $\geq 10^{-4}$% and power range neutron flux power is $\leq$ 15% of rated thermal power.

5.1.17.2 Method of Analysis

The analysis of the uncontrolled CEA bank withdrawal from subcritical accident is performed in three stages. First, the spatial neutron kinetics computer code TWINKLE (Reference 5.1.17-1) is used to calculate the core average nuclear power transient including the various core feedback effects; that is, Doppler and moderator reactivity. FACTRAN (Reference 5.1.17-2) uses the average nuclear power calculated by TWINKLE and performs a fuel rod transient heat transfer calculation to determine the average heat flux and temperature transients. Finally, the peak core-average heat flux calculated by FACTRAN is used in VIPRE for transient DNBR calculations.

In order to give conservative results for a startup accident, the following assumptions are made:

1. Since the magnitude of the power peak reached during the initial part of the transient for any given rate of reactivity insertion is strongly dependent on the Doppler power defect, a conservatively low (absolute magnitude) value is used (900 pcm).

2. The contribution of the moderator reactivity coefficient is negligible during the initial part of the transient because the heat transfer time constant between the fuel and the moderator is much longer than the neutron flux response time constant. However, after the initial neutron flux peak, the MTC can affect the succeeding rate of power increase. The effect of moderator temperature changes on the rate of nuclear power increase is calculated in TWINKLE based on temperature-dependent moderator cross-sections. The MTC value used in this event analysis is + 5 pcm/°F at HZP.

3. The analysis assumes the reactor to be at HZP nominal temperature of 532°F. This assumption is more conservative than that of a lower initial system temperature (that is, shutdown conditions). The higher initial system temperature yields a larger fuel-to-water heat transfer coefficient, a larger specific heat of the water and fuel, and a less negative (smaller absolute magnitude) Doppler power coefficient (DPC). The less negative DPC reduces the Doppler feedback effect, thereby increasing the neutron flux peak. The high neutron flux peak combined with a high fuel-specific heat and larger heat transfer coefficient yields a larger peak heat flux. The analysis assumes the initial effective multiplication factor (k_{eff}) to be 1.0 since this results in the maximum neutron flux peak.

4. Reactor trip is initiated by the Variable High Power trip at a conservative trip setpoint of 35%. This increase from the nominal setpoint of 15 percent accounts for uncertainties. Figure 5.1.17-1 shows that the rise in nuclear flux is so rapid that the effect of error in the trip setpoint on the actual time at which the rods are released is negligible. In addition, the total reactor trip reactivity is based on the assumption that the highest worth CEA is stuck in its fully withdrawn position. Further, the delays for trip signal actuation and CEA release are accounted for in the analysis.

5. A very conservative maximum positive reactivity insertion rate of 40 pcm/sec was assumed, which is greater than that for the simultaneous withdrawal of the two sequential CEA banks having the greatest combined worth at the maximum speed (30 in/min). This is confirmed for each reload cycle.

6. The DNB analysis assumes the most-limiting axial and radial power shapes possible during the fuel cycle associated with having the two highest combined worth banks in their high worth position.

7. The analysis assumes the initial power level to be below the power level expected for any shutdown condition (10^{-9} fraction of nominal power). The combination of highest reactivity insertion rate and low initial power produces the highest peak heat flux.

8. The accident analysis employs the Standard Thermal Design Procedure (STDP) methodology. Use of the STDP stipulates that the RCS flow rate will be based on the thermal design flow (TDF) and that the RCS pressure is the nominal pressure minus the uncertainty. Since the event is analyzed from HZP, the steady-state STDP uncertainties on core power and RCS average temperature are not used in defining the initial conditions.

9. The fuel rod heat transfer calculations performed to determine the maximum fuel temperature during this event assume a total peaking factor or hot channel factor, FQ, that is a function of the axial and radial power distributions. The conservatively high value used in this analysis is presented in Table 5.1.17-1.

10. Both UO_2-only fuel and fuel with up to 8 weight-percent (w/o) Gadolinia content were considered in the transient analysis.

5.1.17.3 Results

Figures 5.1.17-1 through 5.1.17-5 show the transient behavior for a reactivity insertion rate of 40 pcm/sec, with the accident terminated by the reactor trip at 35 percent of rated thermal power. The rate is greater than that calculated for the two highest worth sequential control banks, with both assumed to be in their highest incremental worth region.

Figure 5.1.17-1 shows the neutron flux transient. The neutron flux overshoots the full-power value for a very short period of time. Therefore, the energy release and fuel temperature increase are relatively small. The heat flux response of interest for the DNB considerations is shown in Figure 5.1.17-2. The beneficial effect of the inherent thermal lag in the fuel is evidenced by a peak heat flux of much less than the full power value. Figures 5.1.17-3 through 5.1.17-5 show the transient response of the hot-spot fuel centerline, fuel average, and cladding temperatures, respectively. DNBR calculations indicate that the minimum DNBR remains above the safety analysis limit value at all times.

Table 5.1.17-1 presents the assumptions and results of the analysis. Table 5.1.17-2 presents the calculated sequence of events. After reactor trip, the plant returns to a stable condition. The plant may subsequently be cooled down further by following normal shutdown procedures.

5.1.17.4 Conclusions

In the event of a CEA withdrawal accident from the subcritical condition, the core and the RCS are not adversely affected since the combination of thermal power and coolant temperature result in a DNBR greater than the limit value. Therefore, no fuel or cladding damage is predicted as a result of this transient. In addition, the RCS pressure will not approach the limit since the total amount of excess energy deposited in the reactor coolant is relatively small and there is no prolonged power mismatch between the primary and secondary side that could cause a significant RCS pressure increase. In addition, any insurge during this event would not be nearly as severe as for the Loss of Condenser Vacuum event. Therefore, all acceptance criteria for this event are met.

5.1.17.5 References

5.1.17-1 Barry, R. F. and Risher, D. H., Jr., "TWINKLE – A Multi-Dimensional Neutron Kinetics Computer Code," WCAP-7979-P-A and WCAP-8028-A, January 1975.

5.1.17-2 Hargrove, H. G., "FACTRAN – A FORTRAN IV Code for Thermal Transients in a UO2 Fuel Rod," WCAP-7908-A, December 1989.

Table 5.1.17-1 Assumptions and Results – Uncontrolled CEA Withdrawal from a Subcritical Condition		
Initial Power Level, %	0	
Reactivity Insertion Rate, pcm/sec	40	
Delayed Neutron Fraction	0.0070	
Doppler Power Defect, pcm	900	
Trip Reactivity, % Δk	2.0	
Hot Channel Factor	7.82	
Number of RCPs Operating	4	
Results		
	Calculated Value	**Limit**
Peak Fuel Centerline Temperature, °F	2747	4717
Peak Fuel Average Temperature, °F	2242	4717
Minimum DNBR (small thimble cell)	1.478	1.29
Minimum DNBR (large thimble cell)	1.477	1.29
Minimum DNBR (typical cell)	1.652	1.29

Table 5.1.17-2 Sequence of Events – Uncontrolled CEA Withdrawal from a Subcritical Condition	
Event	**Time (seconds)**
Initiation of Uncontrolled CEA Bank Withdrawal	0
Variable High Power Trip Setpoint (Lower Limit Setting) is Reached	17.5
Peak Nuclear Power Occurs	17.8
Rod Motion Begins	18.6
Peak Heat Flux Occurs	19.1
Minimum DNBR Occurs	19.1
Peak Cladding Temperature Occurs	19.3
Peak Fuel Average Temperature Occurs	19.8
Peak Fuel Centerline Temperature Occurs	20.7

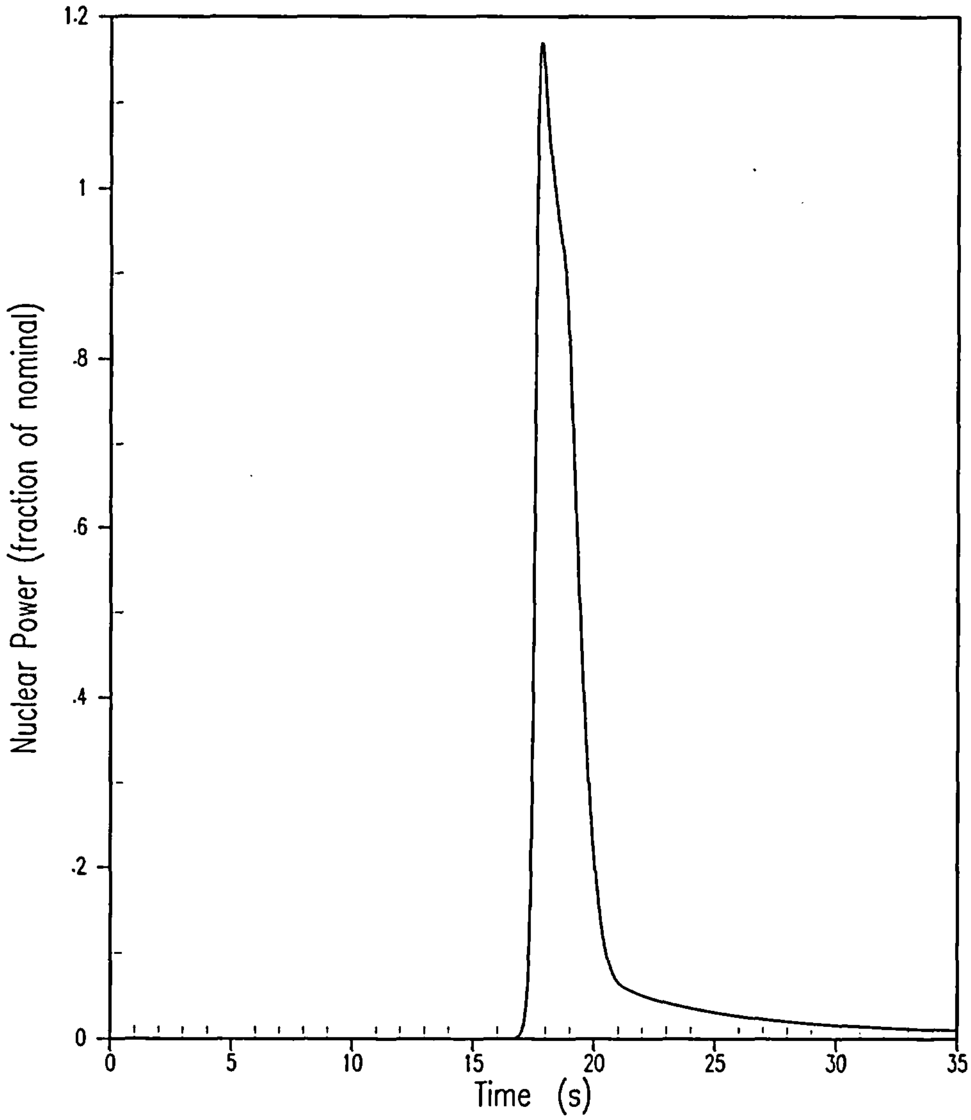

Figure 5.1.17-1
Uncontrolled CEA Withdrawal from a Subcritical Condition
Reactor Power

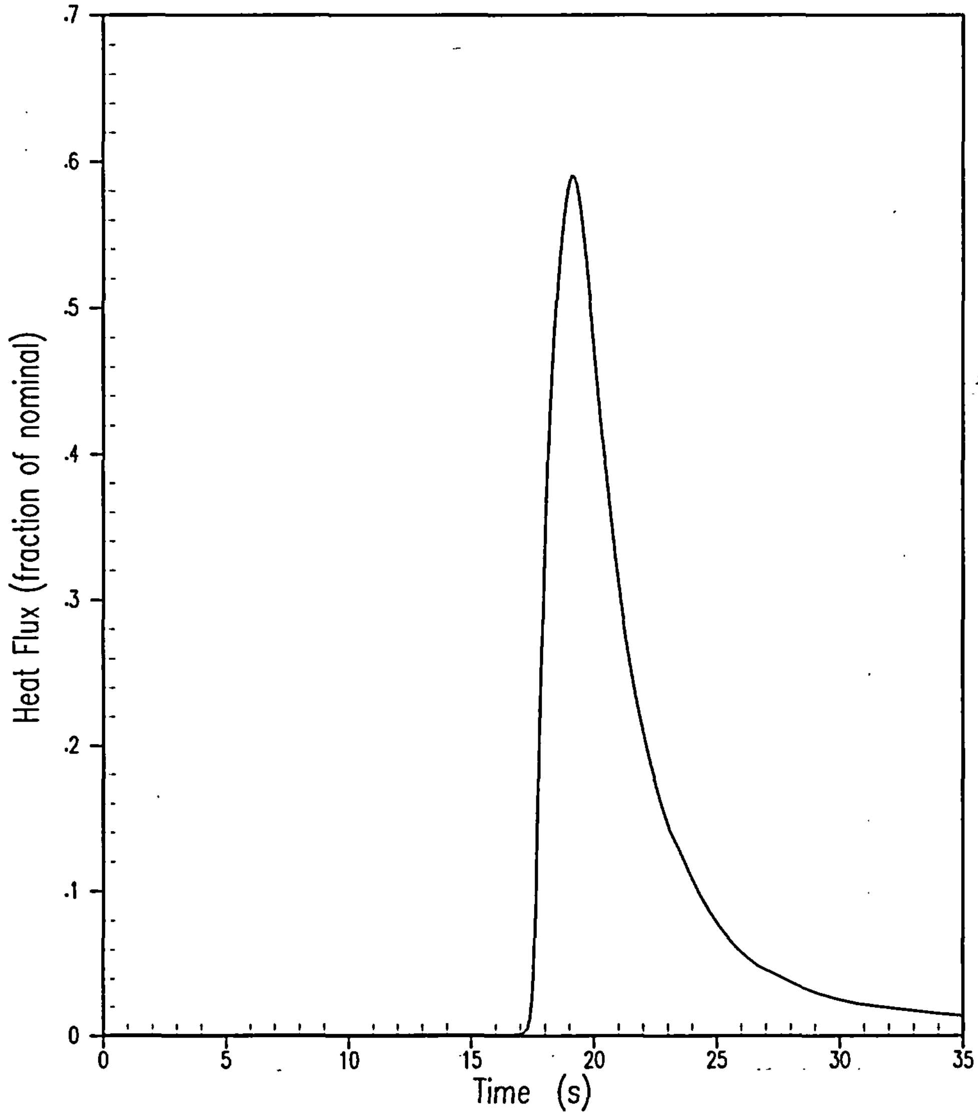

Figure 5.1.17-2
Uncontrolled CEA Withdrawal from a Subcritical Condition
Heat Flux

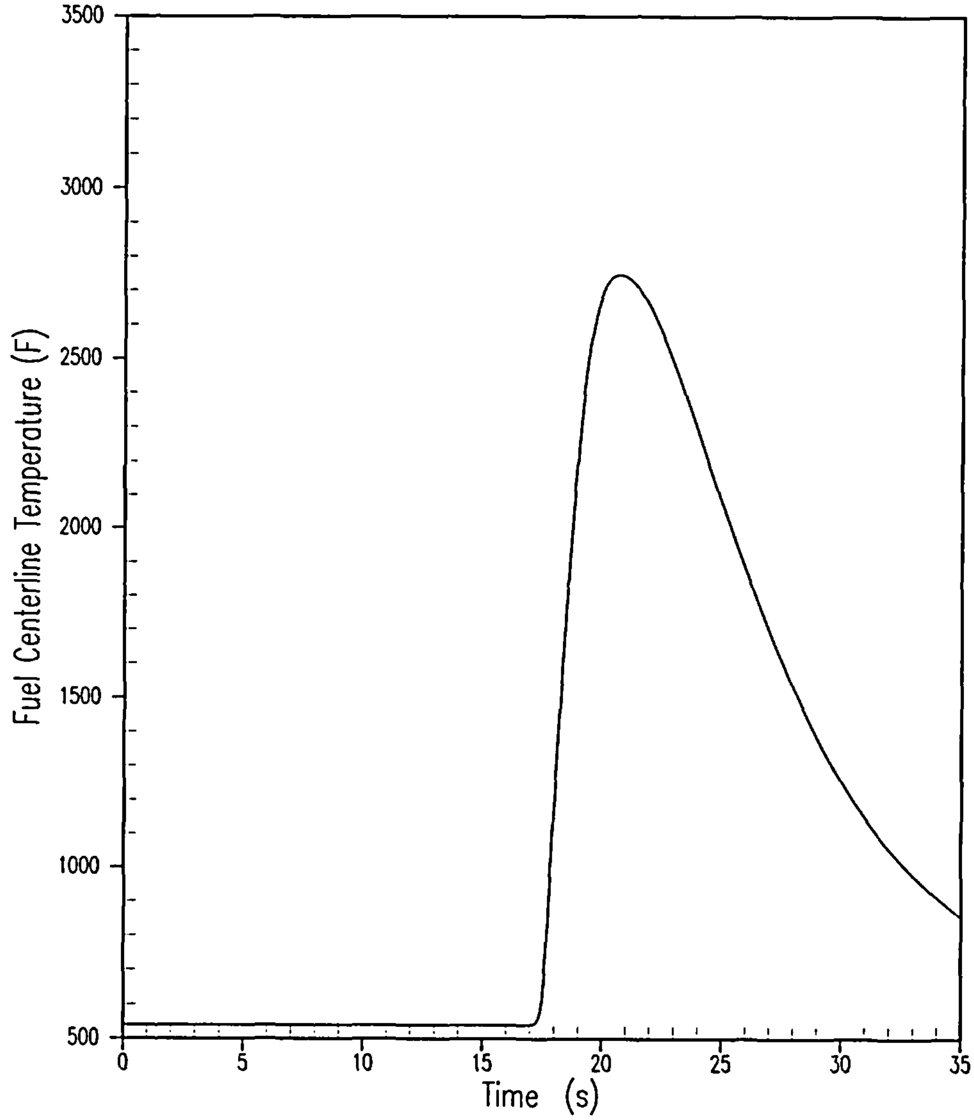

Figure 5.1.17-3
Uncontrolled CEA Withdrawal from a Subcritical Condition
Hot Spot Fuel Centerline Temperature

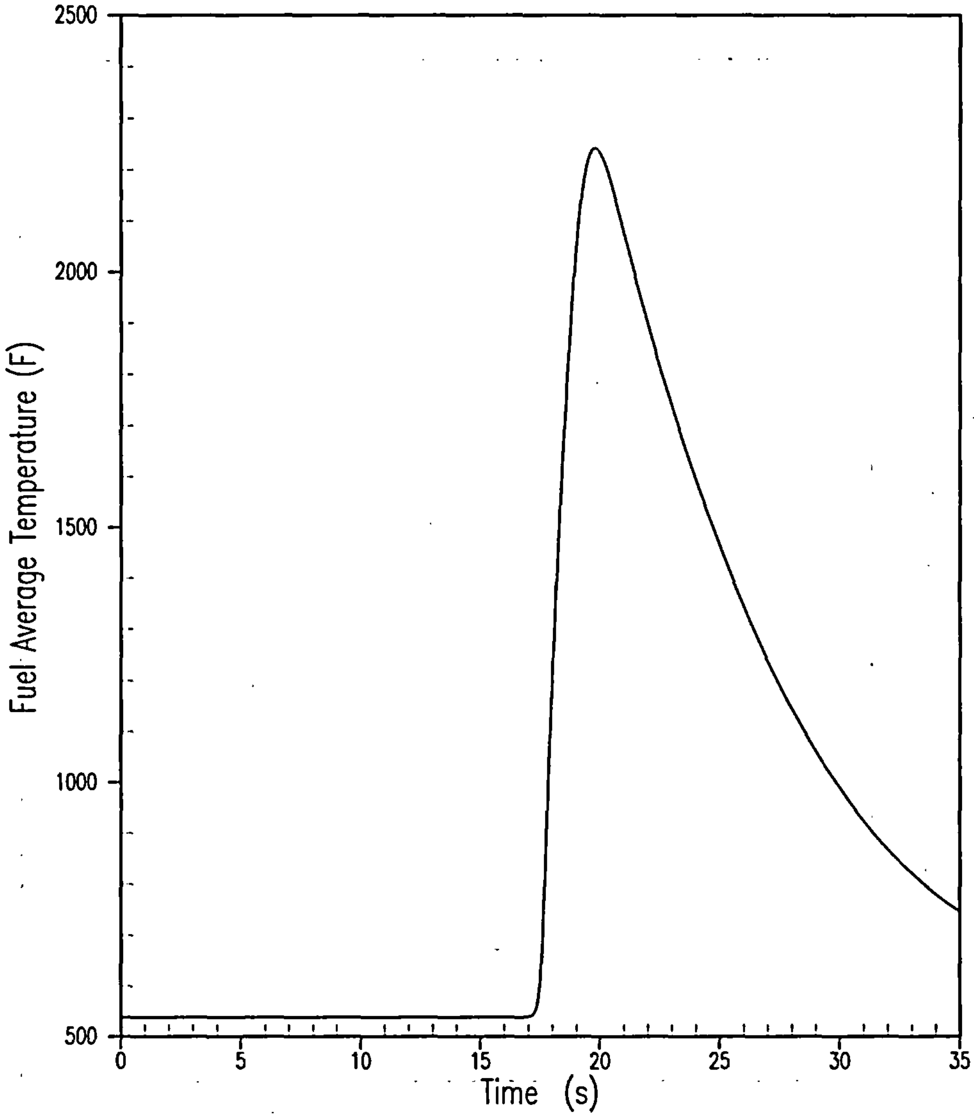

Figure 5.1.17-4
Uncontrolled CEA Withdrawal from a Subcritical Condition
Hot Spot Fuel Average Temperature

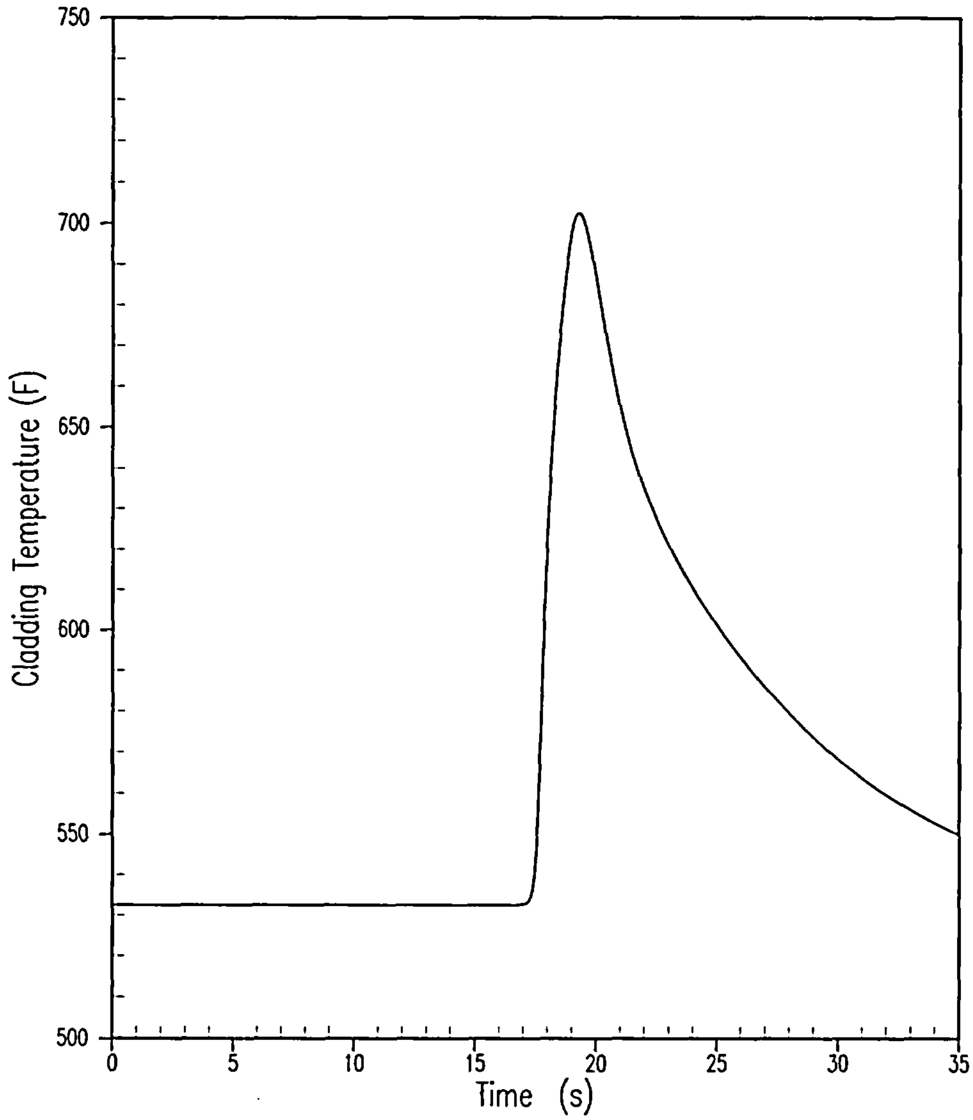

Figure 5.1.17-5
Uncontrolled CEA Withdrawal from a Subcritical Condition
Hot Spot Cladding Temperature

5.1.18 Control Element Assembly Drop Event

5.1.18.1 Identification of Causes and Accident Description

A CEA Drop Event is a Condition II event that is assumed to be initiated by a single electrical or mechanical failure which causes any number and combination of rods from a CEA subgroup to drop to the bottom of the core. The resulting negative reactivity insertion causes nuclear power to rapidly decrease. An increase in the hot channel factor may occur due to the skewed power distribution representative of a CEA drop configuration. Since this is a Condition II event, it must be shown that the DNB design basis is met for the combination of power, hot channel factor, and other system conditions which exist following a CEA Drop Event.

The CEA Drop Event accident includes:

- Full-length CEA drop
- Full-length CEA subgroup drop

The St. Lucie Unit 2 CEA drop detection system is assumed inoperable with no credit taken for the turbine runback feature. With a decrease in reactor power caused by a CEA drop and the turbine load unchanged, a power mismatch results between the primary and secondary system, which leads to a cooldown of the RCS. In addition, the automatic withdrawal capability of the control element drive mechanism is disabled. Following a CEA drop, the plant will establish a new equilibrium condition at the original power level but as a reduced RCS temperature and pressure.

5.1.18.2 Method of Analysis

Full-length CEA Subgroup and Full-length CEA Drop

The transient following a CEA Drop Event is determined by a detailed digital simulation of the plant using the RETRAN computer code as described in Reference 5.1.18-1. The RETRAN computer code is a digital computer code, developed to simulate transient behavior in light water reactor systems. This program includes point kinetics and one-dimensional kinetics model, one-dimensional homogenous equilibrium mixture thermal-hydraulic model, control system models, two-phase natural convection heat transfer correlation, a non-equilibrium pressurizer model, etc. The code computes pertinent plant variables including temperatures, pressures, and power levels. Since RETRAN employs a point kinetics model, a CEA drop is modeled as a negative reactivity insertion corresponding to the reactivity worth of the dropped CEA regardless of the configuration of the CEA(s) that drop. The system transient is calculated by assuming a constant turbine load demand at the initial value (no turbine runback) and no bank withdrawal. A spectrum of dropped CEA worths from 100 pcm to 1000 pcm was analyzed.

Transient conditions are calculated that are then analyzed with nuclear models to obtain a hot channel factor consistent with the primary system conditions and reactor power. By incorporating the primary conditions from the transient and the hot channel factor from the nuclear analysis, the DNB design basis is shown to be met.

5.1.18.3 Results

Full-length CEA Subgroup and Full-length CEA Drop

A full-length CEA Subgroup or a full-length CEA Drop results in a negative reactivity insertion. The core is not adversely affected during this period since power is decreasing rapidly. Following a CEA Drop Event, power may be reestablished by reactivity feedback. In cases where reactivity feedback does not offset the worth of the dropped CEA, a cooldown condition exists until a reactor trip is reached on a TM/LP (floor) or a low steam generator pressure signal. Figures 5.1.18-1 through 5.1.18-4 show a typical transient response to a dropped CEA of 500 pcm worth at an MTC of 0 pcm/°F from full power initial conditions.

In cases where reactivity is large enough to offset the worth of the dropped CEA, reactor power is reestablished at the original power level at a reduced RCS temperature and pressure condition. Figures 5.1.18-5 through 5.1.18-8 show a typical transient response to a dropped CEA of 500 pcm worth at a moderator temperature coefficient of -25 pcm/°F from full power initial conditions. Each case is initiated from full power conditions since the transient response is more severe than if the transient were initiated at a lower initial power level.

In addressing potential impacts caused by increased steam generator tube plugging (to 42% SGTP levels), including the impact of a reduced minimum thermal design flow (TDF) of 300,000 gpm at a reduced (89%) hot-full-power condition, it has been concluded that the minimum DNBR is less severe than that currently analyzed for St. Lucie Unit 2 (at 30% SGTP level conditions) and will continue to meet the DNB design basis limit at the 42% SGTP program conditions.

Following plant stabilization, the operator may manually retrieve the CEA by following approved operating procedures.

5.1.18.4 Conclusions

Following a limiting CEA Drop condition event, the plant will either trip or return to a stabilized condition at the initial power level. Results of the analysis show that a CEA Drop Event does not adversely affect the core, since the DNBR remains above the safety analysis limit value for a bounding range of dropped CEA worths.

5.1.18.5 References

5.1.18-1 WCAP-14882-P-A, Revision 0, "RETRAN-02 Modeling and Qualification for Westinghouse Pressurizer Water Reactor Non-LOCA Safety Analysis," April 1999.

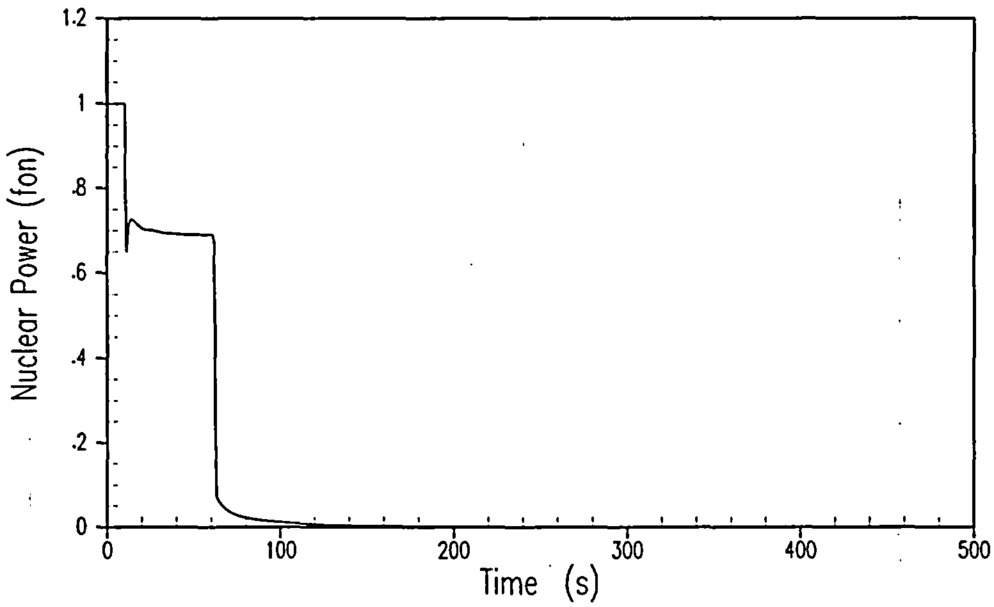

Figure 5.1.18-1
Representative Transient Response to a Dropped CEA Worth of 500 pcm at a Moderator Temperature Coefficient of 0 pcm/°F
Nuclear Power

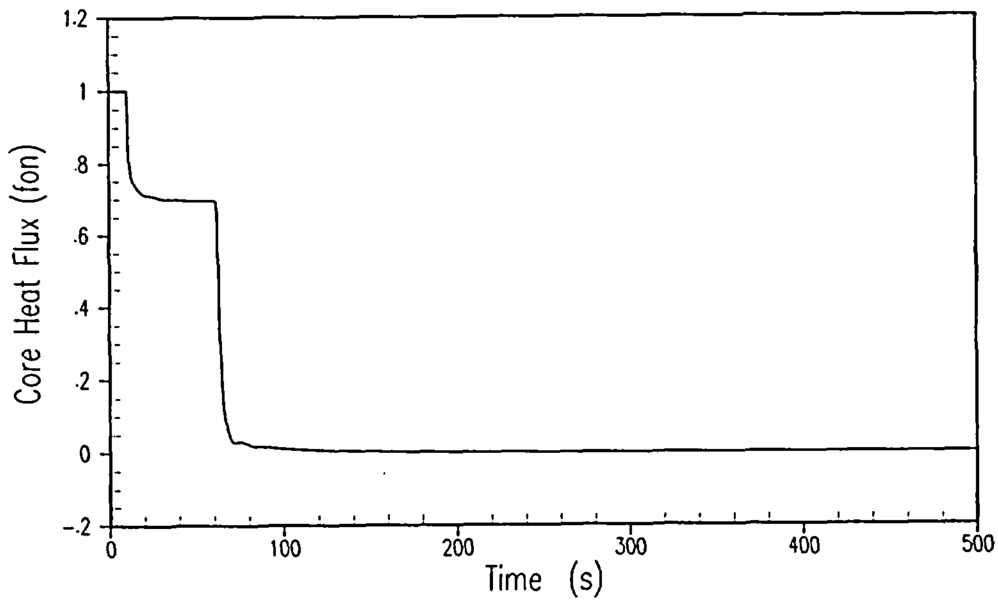

Figure 5.1.18-2
Representative Transient Response to Dropped CEA Worth of 500 pcm at a Moderator Temperature Coefficient of 0 pcm/°F
Core Heat Flux

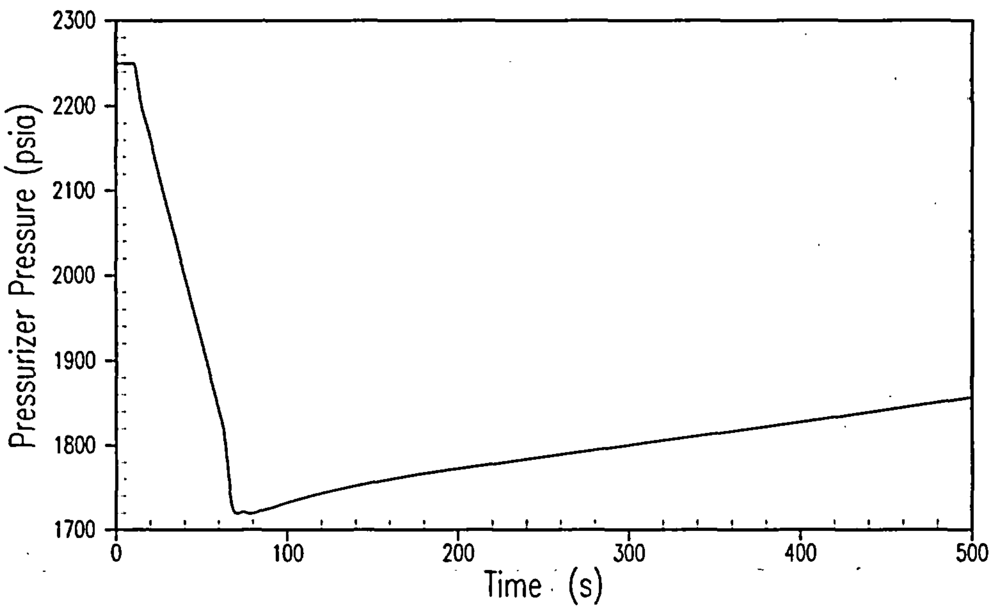

Figure 5.1.18-3
Representative Transient Response to Dropped CEA Worth of 500 pcm
at a Moderator Temperature Coefficient of 0 pcm/°F
Pressurizer Pressure

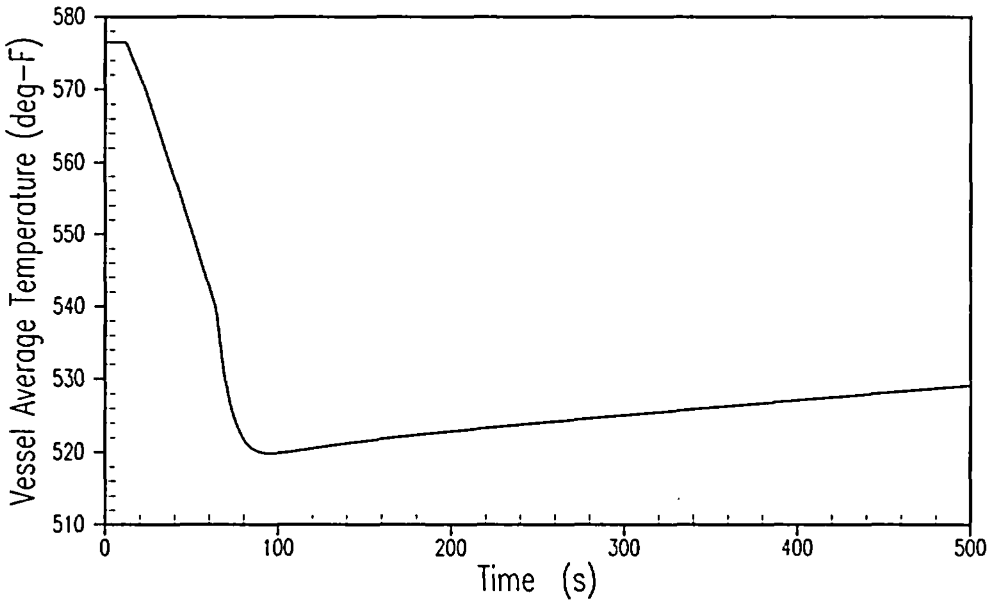

Figure 5.1.18-4
Representative Transient Response to Dropped CEA Worth of 500 pcm at a Moderator Temperature Coefficient of 0 pcm/°F Vessel Average Temperature

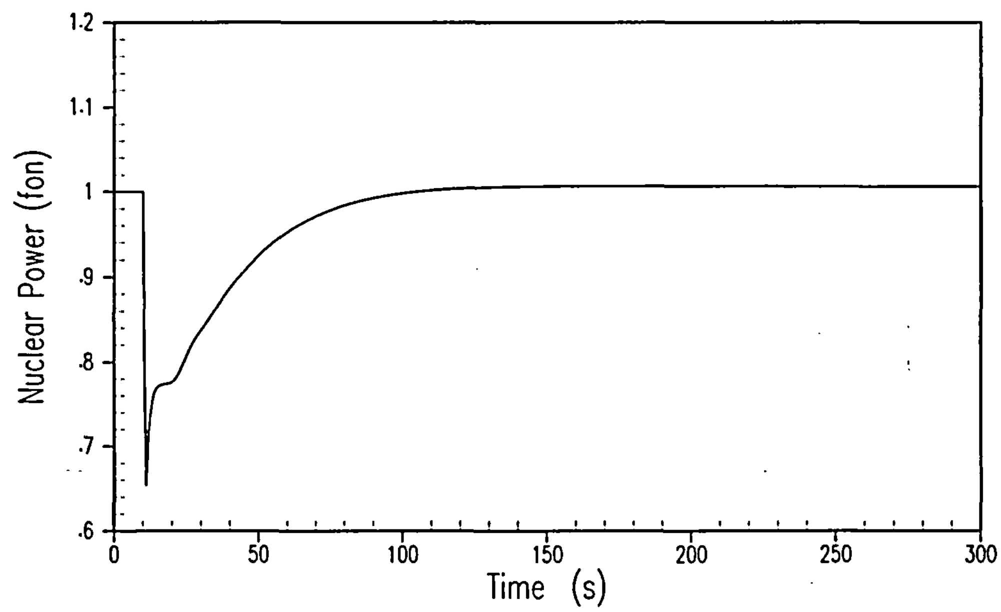

Figure 5.1.18-5
Representative Transient Response to a Dropped CEA Worth of 500 pcm at a Moderator Temperature Coefficient of -25 pcm/°F
Nuclear Power

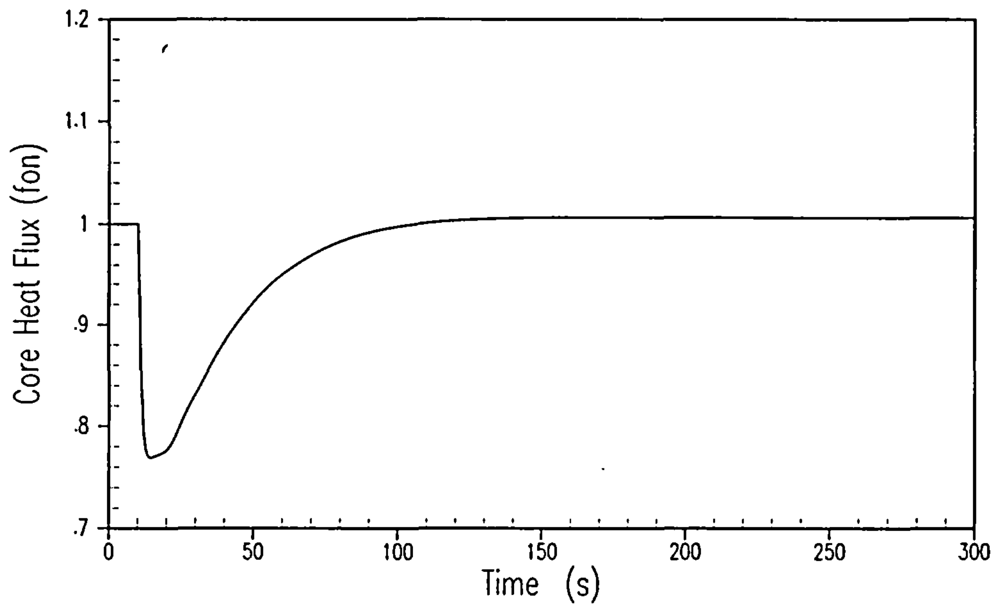

Figure 5.1.18-6
Representative Transient Response to Dropped CEA Worth of 500 pcm at a Moderator Temperature Coefficient of -25 pcm/°F
Core Heat Flux

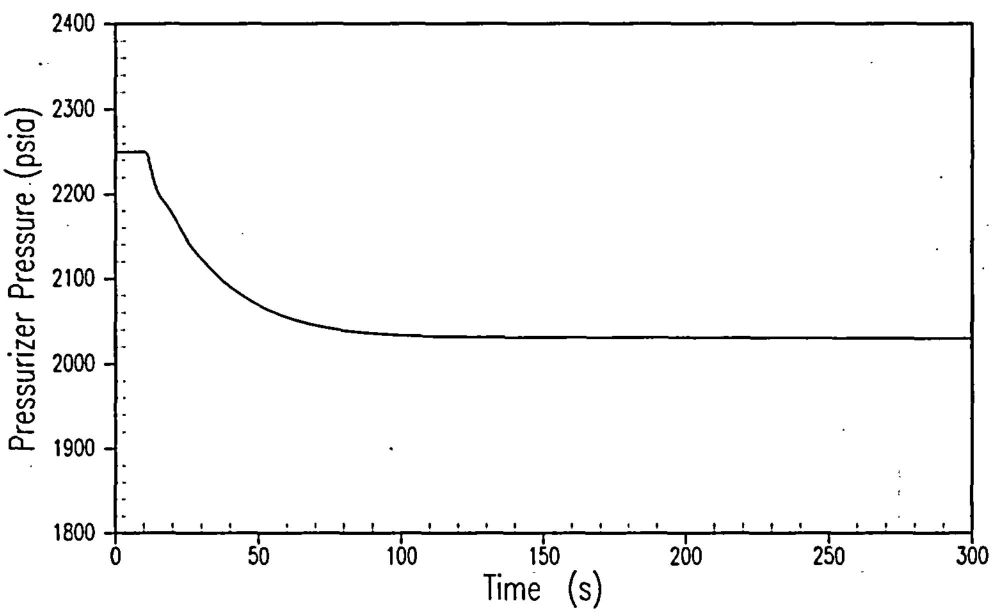

Figure 5.1.18-7
Representative Transient Response to Dropped CEA Worth of 500 pcm at a Moderator Temperature Coefficient of -25 pcm/°F
Pressurizer Pressure

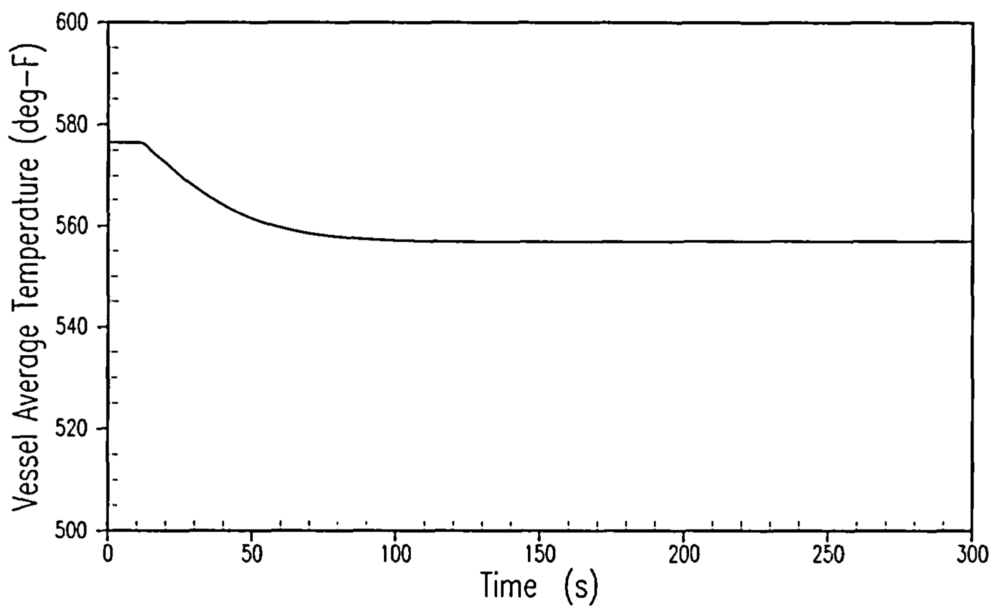

Figure 5.1.18-8
Representative Transient Response to Dropped CEA Worth of 500 pcm at a Moderator Temperature Coefficient of -25 pcm/°F
Vessel Average Temperature

5.1.19 Chemical and Volume Control System Malfunction - Uncontrolled Boron Dilution

5.1.19.1 Accident Description

An Uncontrolled Boron Dilution event is defined as any event caused by a malfunction or an inadvertent operation of the CVCS that results in a dilution of the active portion of the RCS. The active portion of the RCS is defined as that volume of water that circulates through the core. For example, when in shutdown cooling (SDC), no credit is allowed for the volume of water in the stagnant portions of the RCS. A dilution of the RCS can be the result of adding water, which has a boron concentration that is less than the system boron concentration.

The CVCS regulates both the chemistry and the quality of coolant in the RCS. Changing the boron concentration in the RCS is a part of normal plant operation, compensating for long-term reactivity effects such as fuel burnup, xenon buildup and decay, and plant startup. During refueling operations, borated water is supplied from the refueling water tank (RWT).

Boron concentration in the RCS can be decreased by controlled addition of demineralized water. During normal operation, concentrated boric acid solution and demineralized water is introduced into the volume control tank in concentrations corresponding to the required concentration for proper plant operation. A purification ion exchanger with a de-borating resin is normally used for boron removal when the boron concentration in the RCS is low and the feed and bleed method becomes inefficient.

The following provide a direct indication of a boron dilution in process:

- BDAS – Boron Dilution Alarm System, which provides an alarm (UFSAR 7.7.1.1.11),
- and sampling.

The CVCS malfunction analysis (boron dilution) is performed to ensure that the analysis results meet the acceptance criteria for all modes, and remain consistent with the BDAS setpoint and sampling frequency for Modes 3, 4, 5, and 6.

To cover all phases of plant operation, boron dilution during refueling, cold shutdown, hot shutdown, hot standby, startup, and power modes of operation is considered in this analysis. Assumptions used in the analysis result in conservative determinations of the time available for operator or system response after detection of a dilution transient in progress. Dilution flow rates listed for each mode are based on the dilution source fluid conditions for reactor makeup water at 40°F and 14.7 psia. The analysis results are based on calculations which account for density compensation between the dilution source conditions and the mode-specific RCS conditions listed.

5.1.19.2 Method of Analysis

Boron dilutions during all six modes of operation (refueling, cold shutdown, hot shutdown, hot standby, startup, and power operation) are considered in this analysis.

Dilution during Refueling (Mode 6)

The plant is normally maintained in Mode 6 at the beginning of cycle when fuel is being loaded and arranged in the core and at the end of cycle for the removal of spent fuel. Mode 6 is also used for the performance of plant maintenance. In Mode 6, when the head bolts are being tensioned or detensioned for the replacement or removal of the vessel head, the water level in the vessel is maintained below the top of the flange. The primary coolant forced flow is provided by the shutdown cooling system (SCS). Cases with 1, 2, and 3 charging pumps operating are analyzed for this mode.

The following conditions are assumed for the limiting Mode 6 analysis with the RCS drained to the hot leg centerline:

- Dilution flow is the maximum capacity of one, two, or three charging pumps; 49, 98, or 147 gpm, respectively.
- A minimum RCS water volume of 3412 ft^3 is assumed, which is more conservative (that is, smaller) than the volume necessary to fill the reactor vessel up to the mid-plane of the nozzles plus the volume of one SCS train.
- The minimum boron concentration during refueling ($k_{eff} < 0.95$) and minimum change in boron concentration from initial to critical conditions are plant-specific values that are determined and verified every cycle as part of the reload process.

Dilution during Cold Shutdown (Mode 5)

In this mode, the plant is being taken from a long-term mode of operation, refueling (Mode 6), to a short-term mode of operation, hot shutdown (Mode 4). Typically, the plant is maintained in the cold shutdown mode when reduced RCS inventory is necessary or ambient temperatures are required. The water level can be dropped to the mid-plane of the hot leg for maintenance work that requires the steam generators to be drained. The limiting scenario for Mode 5 is typically the case where the vessel is drained and the reactor is shut down by boron to the technical specifications requirement. Cases with 1, 2, and 3 charging pumps operating are analyzed for the case with the water level at (or above) the hot leg centerline, and with 1 charging pump for the case with the water level at the bottom of the hot leg. The boron dilution event is analyzed assuming the following conditions:

- Dilution flow is the maximum capacity of one, two, or three charging pumps; 49, 98, or 147 gpm, respectively.
- Minimum RCS water volumes of 3412 ft^3 corresponding to the active RCS volume (not including the pressurizer volume) for the case with the water level at the hot leg centerline, and 2656 ft^3 corresponding to the active RCS volume for the case with the water level at the bottom of the hot leg are assumed.
- The maximum critical boron concentration and minimum change in boron concentration from initial to critical conditions are plant-specific values that are determined and verified every cycle as part of the reload verification process.

Dilution during Hot Shutdown (Mode 4)

In Mode 4, the plant is being taken from a short-term mode of operation, cold shutdown (Mode 5), to a long-term mode of operation, hot standby (Mode 3). Typically, the plant is maintained in the hot shutdown mode to achieve plant heatup before entering Mode 3. In Mode 4, the primary coolant forced flow can be provided by either the SCS or an RCP, depending on the system pressure. Cases with 1, 2, and 3 charging pumps operating are analyzed for this mode. The boron dilution event in Mode 4 is analyzed assuming the following conditions:

- Dilution flow is the maximum capacity of one, two, or three charging pumps; 49, 98, or 147 gpm, respectively.
- A minimum RCS water volume of 3712 ft^3 corresponding to the active RCS volume (not including the pressurizer volume) is assumed for the case with the plant on shutdown cooling system with no RCPs running. A minimum RCS water volume of 7095 ft^3 (not including the pressurizer volume and including the effects of 42% SGTP) is assumed for the case with the plant operating with at least one RCP running.
- The maximum critical boron concentration and minimum change in boron concentration from initial to critical conditions are plant-specific values that are determined and verified every cycle as part of the reload verification process.

Dilution during Hot Standby (Mode 3)

In Mode 3, the plant is being taken from one short-term mode of operation, hot shutdown (Mode 4), to another, startup (Mode 2). The plant is maintained in Mode 3 at the beginning of cycle for startup testing of certain systems and to achieve plant heatup before entering Mode 2 and going critical. During cycle operation, the plant will enter Mode 3 following a reactor trip or as the result of a technical specification action statement.. In Mode 3, all reactor coolant pumps may not be in operation. If the control rods are withdrawn to the HZP insertion limits, the inadvertent dilution scenario is similar to the Mode 2 analysis. Cases with 1, 2, and 3 charging pumps operating are analyzed for this mode. Conditions assumed for the analysis are:

- Dilution flow is the maximum capacity of one, two, or three charging pumps; 49, 98, or 147 gpm, respectively.
- A minimum RCS water volume of 7095 ft^3 corresponding to the active RCS volume (not including the pressurizer volume and including the effects of 42% steam generator tube plugging) with at least one RCP running is assumed.
- The maximum critical boron concentration and minimum change in boron concentration from initial to critical conditions are plant-specific values that are determined and verified every cycle as part of the reload verification process.

Dilution during Startup (Mode 2)

In this mode, the plant is being taken from one long-term mode of operation, hot standby (Mode 3), to another, power (Mode 1). All normal actions required to change power level require operator initiation. For a normal approach to criticality, the operator manually initiates a limited dilution and manually withdraws the control rods. Conditions assumed for the analysis are:

- Dilution flow is the maximum capacity of all three charging pumps, 147 gpm.
- A minimum RCS water volume of 7095 ft^3 corresponding to the active RCS volume (not including the pressurizer and including the effects of 42% steam generator tube plugging) is assumed.
- The maximum critical boron concentration and minimum change in boron concentration from initial to critical conditions during startup are plant-specific values that are confirmed to be valid every cycle as part of the reload verification process.

This mode of operation is a transitory operational mode in which the operator intentionally dilutes and withdraws control rods to take the plant critical. During this mode, the plant is in manual rod control with the operator required to maintain a high awareness of the plant status. For a normal approach to criticality, the operator must manually initiate a limited dilution and withdraw the control rods. This process takes several hours. The technical specifications require that the reactor does not go critical with the control rods below the insertion limits. For inadvertent boron dilution with slow reactivity additions, this event is bounded by the CEA withdrawal event. For fast reactivity additions, this event is protected by the high rate of change of power reactor trip. Once dilution has been identified, the operator terminates the flow of non-borated water.

Dilution at Power (Mode 1)

The plant is operated at power with the rod control system in the manual mode. The analysis is performed assuming three charging pumps are in operation. Conditions assumed for this mode are:

- Dilution flow is the maximum capacity of all three charging pumps, 147 gpm.
- A minimum RCS water volume of 7095 ft^3 at 582.7°F is assumed. This is a very conservative estimate of the active RCS volume (not including the pressurizer and including the effects of 42% steam generator tube plugging).
- The maximum critical boron concentration (corresponding to the rods inserted to the insertion limits) and the minimum change in boron concentration from this initial condition to an HZP critical condition with all rods inserted are plant-specific values that are confirmed to be valid every cycle as part of the reload verification process. Full rod insertion, minus the most reactive stuck rod, is assumed to occur due to reactor trip.

If the dilution is not secured, the reactor will be shut down by either the TM/LP reactor trip, the high pressurizer pressure (HPP) reactor trip or the variable high power trip (VHPT).

Once dilution has been identified, the operator terminates the flow of non-borated water.

5.1.19.3 Operator Action Time Requirements

Analyses to determine the extent of fuel cladding damage and the overpressurization of the RCS are not done for this event. Instead, a calculation is performed to determine the time to alert the operator, either by BDAS or RCS sampling, so that the time available for operator action prior to the loss of the plant shutdown margin meets the respective acceptance criteria for each mode. Fifteen minutes for all modes other than Mode 6, and thirty minutes for the refueling condition (Mode 6) of plant operation are the criteria outlined in the Standard Review Plan (SRP), Section 15.4.6. If these operator action times are met, it can be concluded that the fuel cladding damage and RCS overpressurization criteria are also satisfied.

5.1.19.4 Results

The results provided below are based on using representative St. Lucie Unit 2 boron concentration values, which will be verified on a cycle-specific basis.

Dilution during Refueling (Mode 6)

For dilution during refueling, the maximum time available for alarm annunciation, such that the 30-minute operator action criterion remains satisfied, is 80, 53, or 37 minutes with 1, 2, or 3 charging pumps, respectively.

Dilution during Cold Shutdown (Mode 5 – filled to hot leg centerline)

For dilution during cold shutdown (filled to hot leg centerline), the maximum time available for alarm annunciation, such that the 15-minute operator action criterion remains satisfied, is 32 minutes with 1, 2, or 3 charging pumps.

Dilution during Cold Shutdown (Mode 5 – drained to bottom of hot leg)

For dilution during cold shutdown (drained to bottom of hot leg), the maximum time available for alarm annunciation, such that the 15-minute operator action criterion remains satisfied, is 32 minutes with 1 charging pump.

Dilution during Hot Shutdown (Mode 4 – at least one RCP operating)

For dilution during hot shutdown (at least one RCP operating), the maximum time available for alarm annunciation, such that the 15-minute operator action criterion remains satisfied, is 203, 94, or 57 minutes with 1, 2, or 3 charging pumps, respectively.

Dilution during Hot Shutdown (Mode 4 – with Shutdown Cooling System)

For dilution during hot shutdown (with SCS), the maximum time available for alarm annunciation, such that the 15-minute operator action criterion remains satisfied, is 99, 41, or 33 minutes with 1, 2, or 3 charging pumps, respectively.

Dilution during Hot Standby (Mode 3)

For dilution during hot standby, the maximum time available for alarm annunciation, such that the 15-minute operator action criterion remains satisfied, is 156, 70, or 41 minutes with 1, 2, or 3 charging pumps, respectively.

For Dilution during Startup (Mode 2)

For dilution during startup, the maximum time available for alarm annunciation, such that the 15-minute operator action criterion remains satisfied is 77.45 minutes.

For Dilution during Full-Power Operation (Mode 1)

With the reactor in manual control, if no operator action is taken, the power and temperature rise causes the reactor to reach the HPP reactor trip setpoint. The boron dilution accident in this case is essentially identical to a CEA withdrawal accident at power. Prior to the HPP trip, an HPP alarm would be actuated. There is sufficient time available (more than 84 minutes) after a reactor trip for the operator to determine the cause of dilution, isolate the reactor makeup water source, and initiate reboration before the reactor can return to criticality.

5.1.19.5 Monitoring Frequency

Should the automatic boron dilution alarm be inoperable, UFSAR Section 13.7.2.4 contains requirements for the maximum frequency of RCS chemistry sampling. These sampling frequencies ensure that the specified criteria are met to ensure sufficient time is available to the operators, from the detection of dilution until criticality is achieved to mitigate the consequences of this event. The backup boron dilution detection monitoring frequencies provided in UFSAR Table 13.7.2-3 are verified every cycle and changed as necessary.

5.1.19.6 Conclusions

The time sequence of events is provided in Table 5.1.19-1. The boron dilution analyses at refueling, cold shutdown, hot shutdown, hot standby, startup, and full-power conditions show the acceptability of the increase to 42% steam generator tube plugging.

Table 5.1.19-1 Sequence of Events - Uncontrolled Boron Dilution			
Mode		**Event**	**Time (minutes)**
Refueling (Mode 6)		Dilution begins	0
		Maximum available time from initiation of boron dilution to alarm annunciation	80 (1 charging pump) 53 (2 charging pumps) 37 (3 charging pumps)
		Time from alarm annunciation to criticality	> 30
Cold Shutdown (Mode 5)	Filled to hot leg centerline	Dilution begins	0
		Maximum available time from initiation of boron dilution to alarm annunciation	32 (1, 2, or 3 charging pumps)
		Time from alarm annunciation to criticality	> 15
	Drained to bottom of hot leg	Dilution begins	0
		Maximum available time from initiation of boron dilution to alarm annunciation	32 (1 charging pump)
		Time from alarm annunciation to criticality	> 15
Hot Shutdown (Mode 4)	At least one RCP operating	Dilution begins	0
		Maximum available time from initiation of boron dilution to alarm annunciation	203 (1 charging pump) 94 (2 charging pumps) 57 (3 charging pumps)
		Time from alarm annunciation to criticality	> 15
	Shutdown Cooling System (SCS)	Dilution begins	0
		Maximum available time from initiation of boron dilution to alarm annunciation	99 (1 charging pump) 41 (2 charging pumps) 33 (3 charging pumps)
		Time from alarm annunciation to criticality	> 15
Hot Standby (Mode 3)		Dilution begins	0
		Maximum available time from initiation of boron dilution to alarm annunciation	156 (1 charging pump) 70 (2 charging pumps) 41 (3 charging pumps)
		Time from alarm annunciation to criticality	> 15
Startup (Mode 2)		Dilution begins	0
		Maximum available time from initiation of boron dilution to alarm annunciation	77.45
		Time from alarm annunciation to criticality	> 15
At Power (Mode 1)		Dilution begins	0
		HPP reactor trip signal reached	122.49
		Rod motion begins	123.63
		Shutdown margin is lost (if dilution continues after trip)	> 15

5.1.20 Control Element Assembly Ejection

5.1.20.1 Accident Description

This accident is the result of the extremely unlikely mechanical failure of a control element drive mechanism (CEDM) pressure housing such that the reactor coolant system (RCS) pressure would eject the CEA and drive shaft. The consequences of this mechanical failure, in addition to being a minor LOCA, may also be a rapid reactivity insertion together with an adverse core power distribution, possibly leading to localized fuel rod damage.

Rapid ejection of a CEA from the core would require a complete circumferential break of the CEDM housing or the CEDM nozzle on the reactor vessel head. The CEDM housing and CEDM nozzle are an extension of the reactor coolant system boundary and designed and manufactured to Section III of the ASME Boiler and Pressure Vessel Code. Hence, the occurrence of such a failure is considered highly unlikely.

If a CEA ejection accident were to occur, a fuel rod thermal transient that could cause a Departure from Nucleate Boiling (DNB) may occur together with limited fuel damage. The amount of fuel damage that can result from such an accident will be governed mainly by the worth of the ejected CEA and the power distribution attained with the remaining control element pattern. The transient is limited by the Doppler reactivity effects of the increase in fuel temperature and is terminated by reactor trip actuated by the high power level trip. The transient is terminated before conditions are reached that can result in damage to the reactor coolant pressure boundary, or significant disturbances in the core, its support structures or other reactor pressure vessel internals that would impair the capability to cool the core.

The neutron flux response to a continuous reactivity insertion is characterized by a very fast flux increase terminated by the reactivity feedback effect of the negative Doppler Power Coefficient (DPC). This self limitation of the power burst is of primary importance since it limits the power to a tolerable level during the delay time for protective action. Should a CEA ejection accident occur, the following automatic features of the reactor protection system are available to terminate the transient:

- The Variable Power Level - High trip is provided to trip the reactor when the reactor power reaches a high preset value. This setpoint is set to a fixed increment (≤ 9.61% Technical Specification value) above the existing reactor power level, with a minimum setpoint of 15% of Rated Thermal Power and a maximum of ≤ 107% of Rated Thermal Power. This trip is actuated when two-out-of-four power range channels indicate a power level above the setpoint.
- The Rate-of-Change of Power - High trip is provided to trip the reactor when the rate-of-change of neutron flux power reaches a high preset value (≤ 2.49 decades per minute Technical Specification value). It is actuated when two-out-of-four Wide Range Logarithmic Neutron Flux Monitoring channels indicate a rate above the preset setpoint. This trip function may be bypassed below 10^{-4}% and above 15% of Rated Thermal Power. Bypass is automatically removed when Wide Range Logarithmic Neutron Flux power is ≥ 10^{-4}% and Power Range Neutron Flux power is ≤ 15% of Rated Thermal Power.

The ultimate acceptance criteria for this event is that any consequential damage to either the core or the RCS must not prevent long-term core cooling, and that any offsite dose consequences must be within the guidelines of 10 CFR 100. To demonstrate compliance with these requirements, it is sufficient to show that the RCS pressure boundary remains intact, and that no fuel dispersal in the coolant, gross lattice distortions,

or severe shock waves will occur in the core. Therefore, the following acceptance criteria are applied to the CEA ejection accident:

- Maximum average fuel pellet enthalpy at the hot spot must remain below 200 cal/g (360 Btu/lbm).
- Peak RCS pressure must remain below that which would cause the stresses in the RCS to exceed the faulted condition stress limits.
- Maximum fuel melting must be limited to the innermost 10 percent of the fuel pellet at the hot spot, independent of the above pellet enthalpy limit.

5.1.20.2 Method of Analysis

The calculation of the CEA ejection transient is performed in two stages: a core neutron kinetic analysis and a hot-spot fuel heat transfer analysis. The spatial neutron kinetics code TWINKLE (Reference 5.1.20-1) is used in a 1-D axial kinetics model to calculate the core nuclear power including the various total core feedback effects; that is, Doppler reactivity and moderator reactivity. The average core nuclear power is multiplied by the post-ejection hot-channel factor, and the fuel enthalpy and temperature transients at the hot spot are calculated with the detailed fuel and cladding transient heat transfer computer code, FACTRAN (Reference 5.1.20-2). The power distribution calculated without feedback is pessimistically assumed to persist throughout the transient. Additional details of the methodology are provided in WCAP-7588 (Reference 5.1.20-3).

In calculating the nuclear power and hot-spot fuel rod transients following CEA ejection, the following conservative assumptions are made:

1. The Revised Thermal Design Procedure (RTDP) is not used for the CEA ejection analysis. Instead, the Standard Thermal Design Procedure (STDP) (maximum uncertainties in initial conditions) is employed. The analysis assumes uncertainties of 2.0 percent in nominal core power, 3.0°F in nominal vessel T_{avg}, and 45 psi in nominal pressurizer pressure.
2. A minimum value for the delayed neutron fraction for BOC and EOC conditions is assumed, which increases the rate at which the nuclear power increases following CEA ejection.
3. A minimum value of the Doppler power defect is assumed, which conservatively results in the maximum amount of energy deposited in the fuel following CEA ejection. A minimum value of the moderator feedback is also assumed. A positive MTC is assumed for the BOC, zero-power case.
4. Maximum values of ejected CEA worth and post-ejection total hot-channel factors are assumed for all cases considered. These parameters are calculated using standard nuclear design codes for the maximum allowed bank insertion at a given power level as determined by the rod insertion limits. No credit is taken for the flux flattening effects of reactivity feedback.
5. The total time for CEA ejection is assumed to be 0.05 seconds.
6. For the HZP cases, the reactor is assumed to be tripped by the nuclear power signal of the Variable High Power (VHP) trip at the lower limit (floor) setpoint. For the HFP cases, the reactor trip is assumed to occur on the variable power level function of the VHP trip at a conservative setpoint. Appropriate error allowances are added to the Technical Specification setpoints to determine the analysis trip point. A trip time delay of 0.4 seconds for reactor trip breaker opening is used, with the control rods assumed to start moving 0.74 seconds after breaker opening.

7. The analysis conservatively assumes the trip rods are inserted starting from the fully withdrawn position, using a conservative rod position versus time curve. Also, the total trip reactivity is based on the conservative assumption that the highest worth adjacent CEA is stuck in its fully withdrawn position in addition to the ejected rod.
8. Both UO_2-only fuel and 8 weight percent (w/o) gadolinium-doped fuel were modeled in the analysis.

5.1.20.3 Results

Figures 5.1.20-1 through 5.1.20-8 present the nuclear power and hot-spot fuel rod thermal transients for the CEA ejection cases analyzed. The transient results of the analysis are summarized in Table 5.1.20-1. A time sequence of events is provided in Table 5.1.20-2. For all cases, the maximum fuel pellet enthalpy remained below 200 cal/g. The peak hot-spot fuel centerline temperature remained below the fuel melting temperature (4900°F at BOC and 4800°F at EOC for UO2-only; 4816°F at BOC and 4717°F at EOC for 8 w/o gadolinia-doped fuel) for all cases except the BOL HFP case. The peak hot-spot fuel centerline temperature exceeded the fuel melting temperature for the BOL HFP case (8 w/o gadolinia-doped fuel), however, the fuel melting was well within the 10% fuel melt criterion. The UO2-only fuel was found to be more limiting for the HZP cases. The 8 w/o gadolinia-doped fuel (without taking credit for the power suppression due to the gadolinium) was more limiting for the HFP cases.

5.1.20.4 Conclusions

The analysis performed has demonstrated that, for the CEA ejection event, the fuel thermal criteria are not exceeded. Based on the generic assessment in WCAP-7588, Revision 1-A (Reference 5.1.20-3) and the peak pressure results documented in the current FSAR (Reference 5.1.20-4), the peak reactor coolant pressure will be less than that which would cause stresses to exceed the Faulted Condition stress limits. In addition, based on the generic assessment in Reference 5.1.20-3 and the rods-in-DNB results documented in Reference 5.1.20-4, the number of rods-in-DNB is expected to not exceed 9.5%. Therefore, all acceptance criteria for this event have been met.

5.1.20.5 References

5.1.20-1 Risher, D. H., Jr. and Barry, R. F., "TWINKLE – A Multi-Dimensional Neutron Kinetics Computer Code," WCAP-7979-P-A and WCAP-8028-A, January 1975.

5.1.20-2 Hargrove, H. G., "FACTRAN – A FORTRAN IV Code for Thermal Transients in a UO2 Fuel Rod," WCAP-7908-A, December 1989.

5.1.20-3 D. H. Risher, "An Evaluation of the Rod Ejection Accident in Westinghouse Pressurized Water Reactors Using Spatial Kinetics Methods," WCAP-7588, Revision 1-A, January 1975.

5.1.20-4 "St. Lucie Unit 2 Updated Final Safety Analysis Report," Amendment 16, dated February 2005.

Table 5.1.20-1
Assumptions and Results – CEA Ejection

Beginning of Cycle	Full Power	Zero Power
Initial Power Level, %	102	0
Ejected RCCA Worth, % Δk	0.25	0.60
Delayed Neutron Fraction	0.0050	0.0050
Doppler Power Defect, % Δk	0.900	0.900
Feedback Reactivity Weighting	1.262	2.633
Trip Reactivity, % Δk	3.0	2.0
F_Q Before Ejection	2.809	N/A
F_Q After Ejection	5.25	15.0
Number of RCPs Operating	4	4
Maximum Fuel Pellet Enthalpy, cal/g	154.3	71.6
Maximum Fuel Melted, %	0.03	None
End of Cycle	**Full Power**	**Zero Power**
Initial Power Level, %	102	0
Ejected RCCA Worth, % Δk	0.25	0.60
Delayed Neutron Fraction	0.0044	0.0044
Doppler Power Defect, % Δk	0.900	0.900
Feedback Reactivity Weighting	1.262	3.802
Trip Reactivity, % Δk	3.0	2.0
F_Q Before Ejection	2.809	N/A
F_Q After Ejection	5.25	26.25
Number of RCPs Operating	4	4
Maximum Fuel Pellet Enthalpy, cal/g	144.9	81.0
Maximum Fuel Melted, %	None	None

Table 5.1.20-2 Sequence of Events – CEA Ejection	
Beginning of Cycle - Hot Zero Power	**Time (seconds)**
CEA Ejection Occurs	0.00
Variable High Power Trip Setpoint (Lower Limit Setting) is Reached	0.49
Peak Nuclear Power Occurs	0.56
Rods Begin to Fall Into the Core	1.63
Peak Cladding Average Temperature Occurs	2.4
Peak Fuel Average Temperature Occurs	2.6
Beginning of Cycle - Hot Full Power	**Time (seconds)**
CEA Ejection Occurs	0.00
Variable High Power Trip Setpoint is Reached	0.03
Peak Nuclear Power Occurs	0.09
Rods Begin to Fall Into the Core	1.17
Peak Fuel Average Temperature Occurs	2.3
Peak Cladding Average Temperature Occurs	2.4
End of Cycle - Hot Zero Power	**Time (seconds)**
CEA Ejection Occurs	0.00
Variable High Power Trip Setpoint (Lower Limit Setting) is Reached	0.31
Peak Nuclear Power Occurs	0.36
Rods Begin to Fall Into the Core	1.45
Peak Cladding Average Temperature Occurs	1.9
Peak Fuel Average Temperature Occurs	2.0
End of Cycle - Hot Full Power	**Time (seconds)**
CEA Ejection Occurs	0.00
Variable High Power Trip Setpoint is Reached	0.02
Peak Nuclear Power Occurs	0.09
Rods Begin to Fall Into the Core	1.16
Peak Fuel Average Temperature Occurs	2.3
Peak Cladding Average Temperature Occurs	2.4

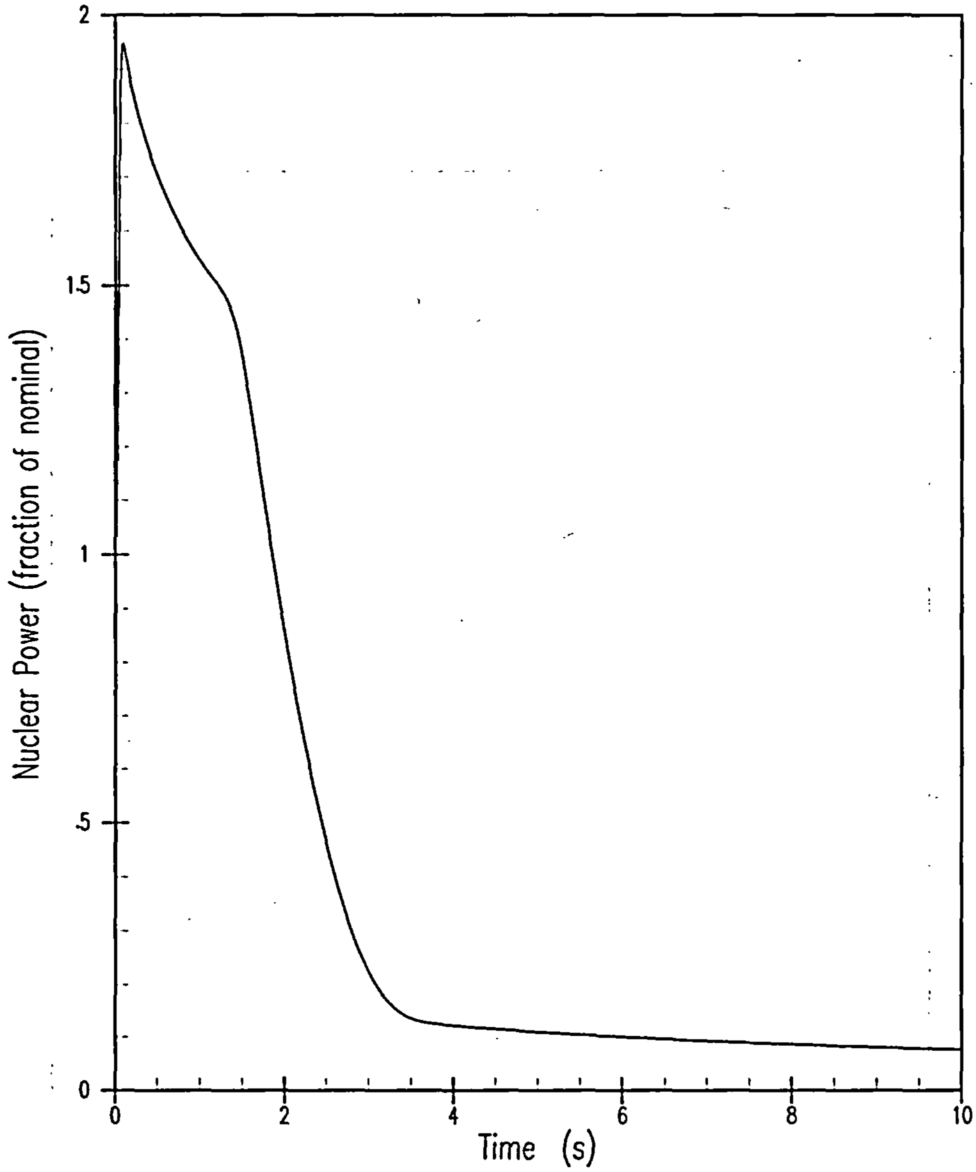

Figure 5.1.20-1
CEA Ejection Accident from Full Power Beginning of Cycle
Reactor Power

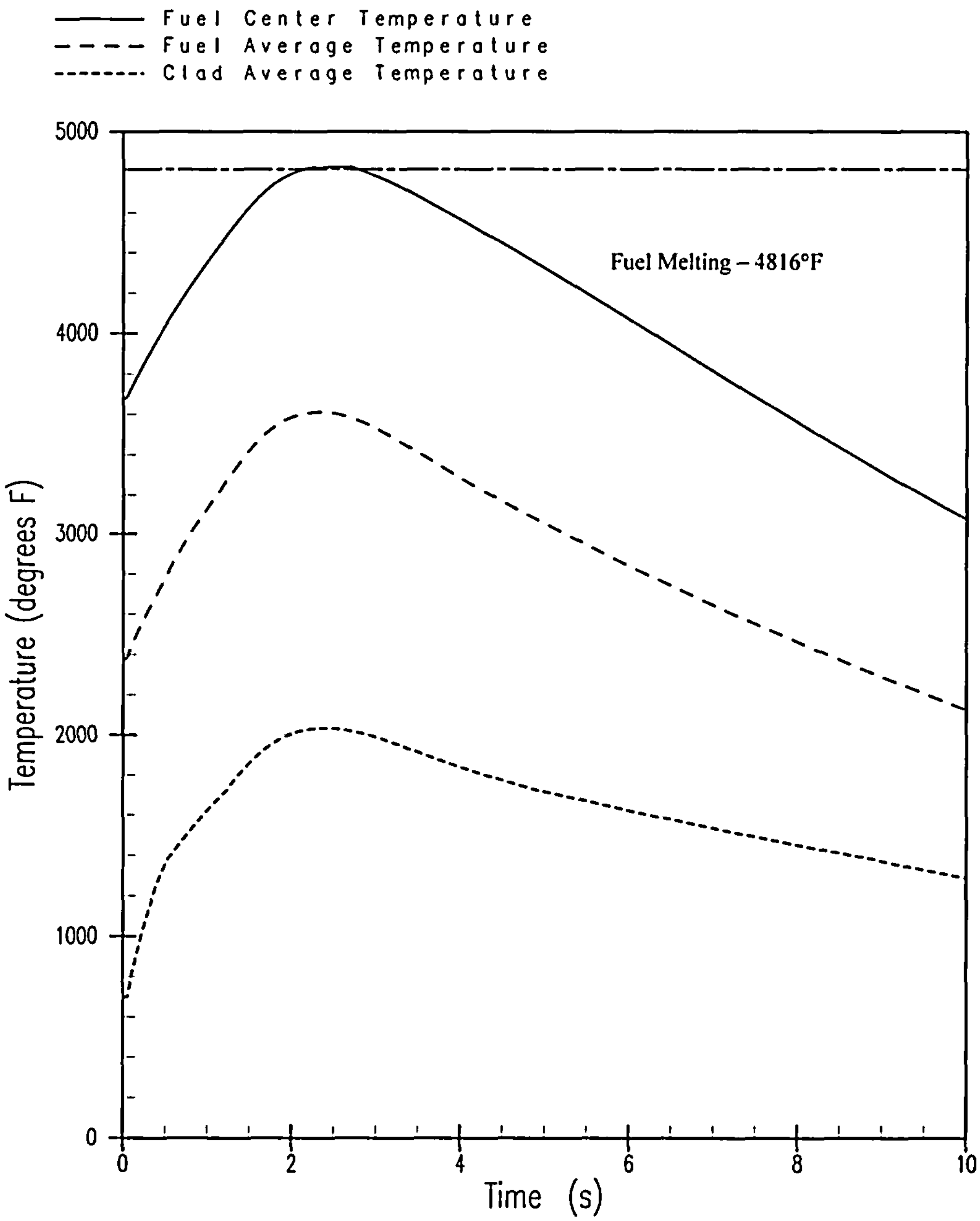

Figure 5.1.20-2
CEA Ejection Accident from Full Power Beginning of Cycle
Fuel and Cladding Temperatures

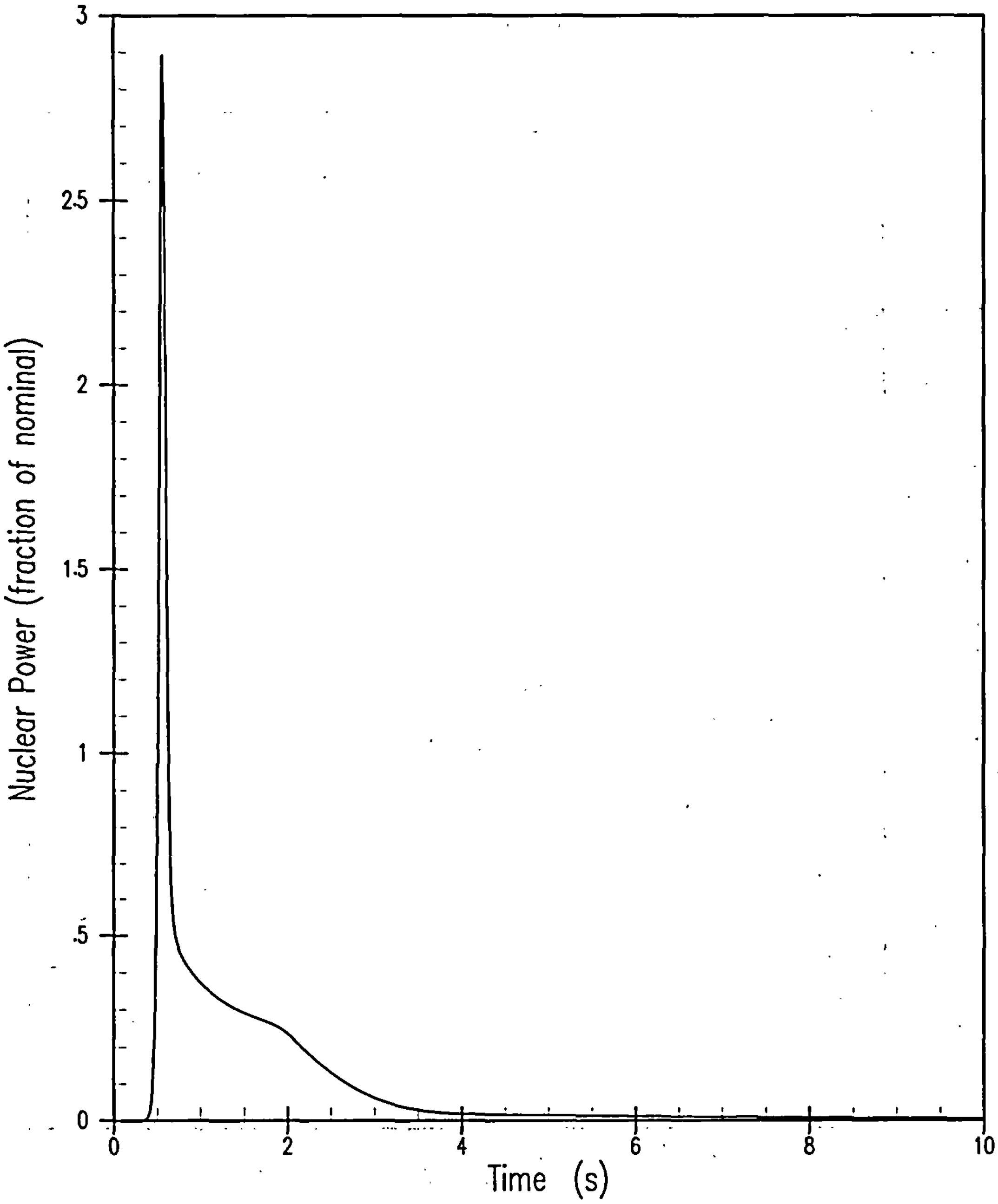

Figure 5.1.20-3
CEA Ejection Accident from Zero Power Beginning of Cycle
Reactor Power

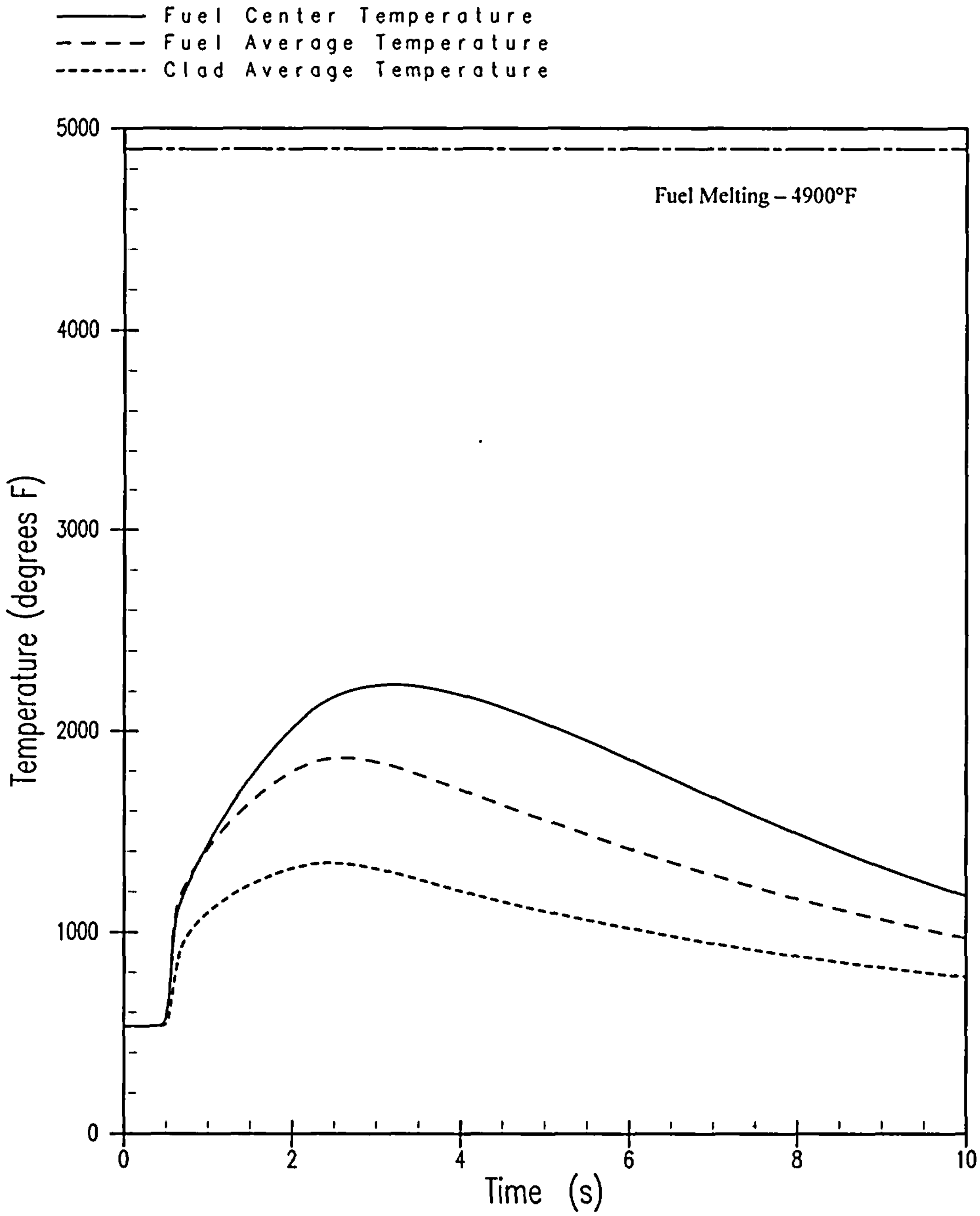

Figure 5.1.20-4
CEA Ejection Accident from Zero Power Beginning of Cycle
Fuel and Cladding Temperatures

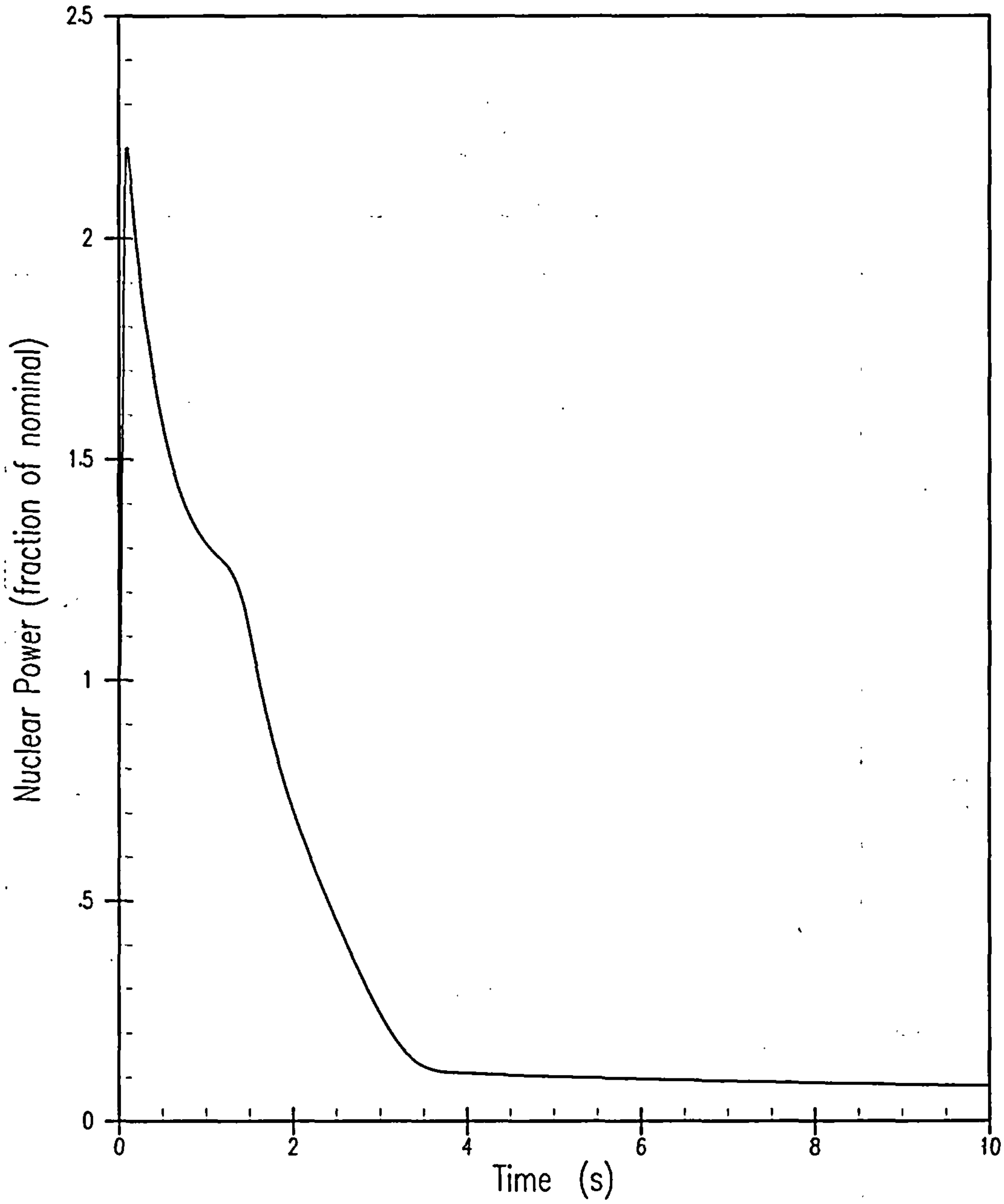

Figure 5.1.20-5
CEA Ejection Accident from Full Power End of Cycle
Reactor Power

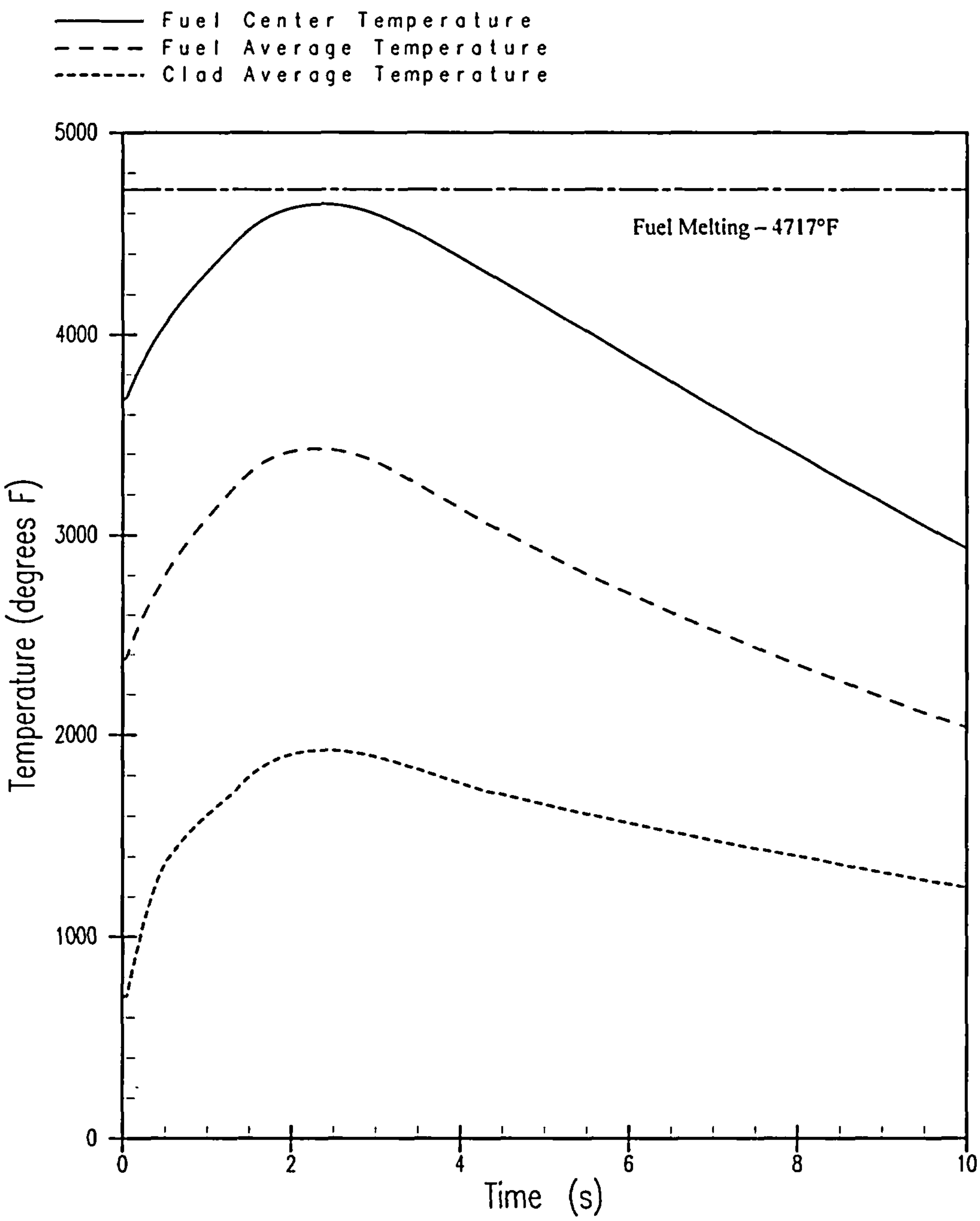

Figure 5.1.20-6
CEA Ejection Accident from Full Power End of Cycle
Fuel and Cladding Temperatures

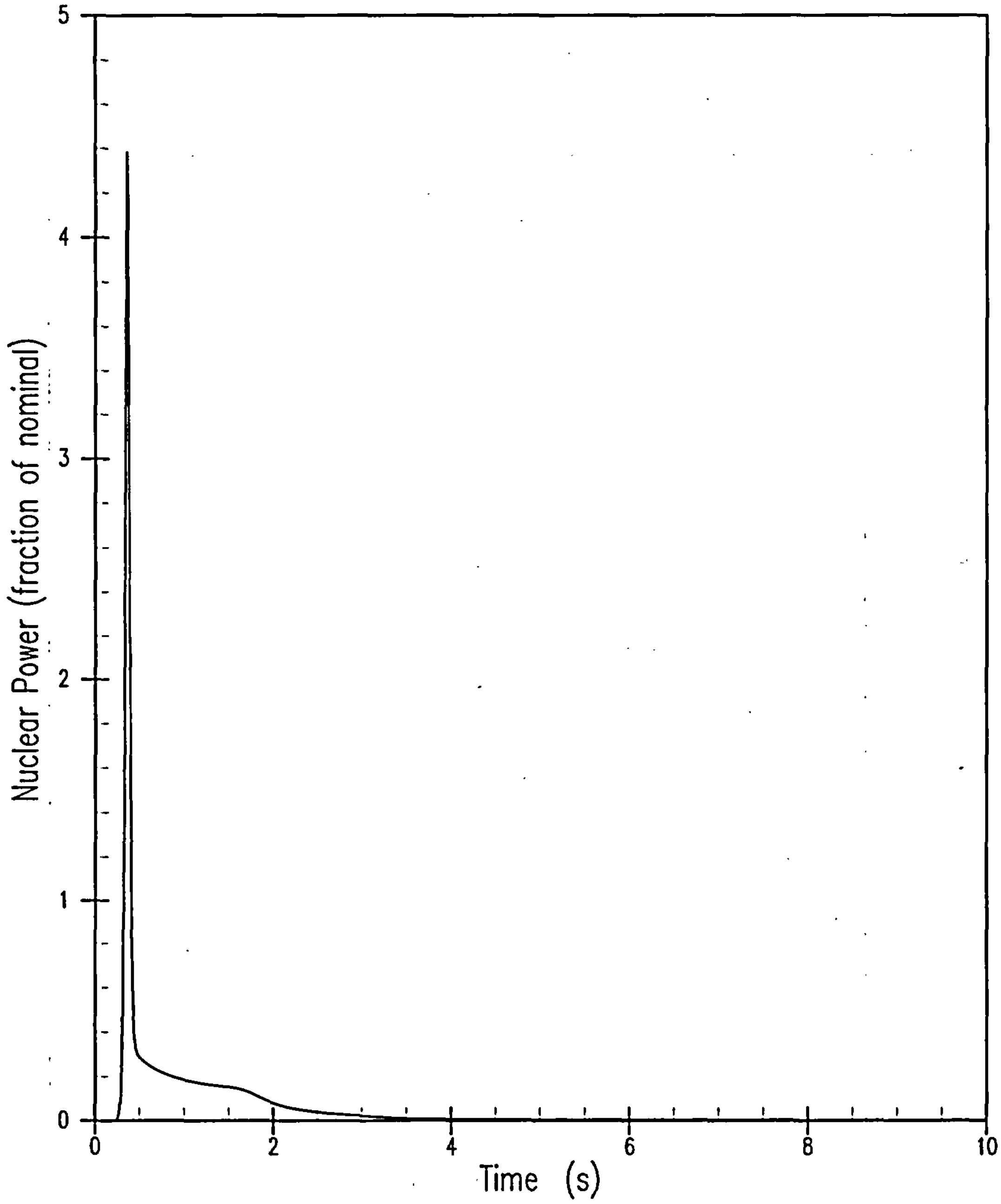

Figure 5.1.20-7
CEA Ejection Accident from Zero Power End of Cycle
Reactor Power

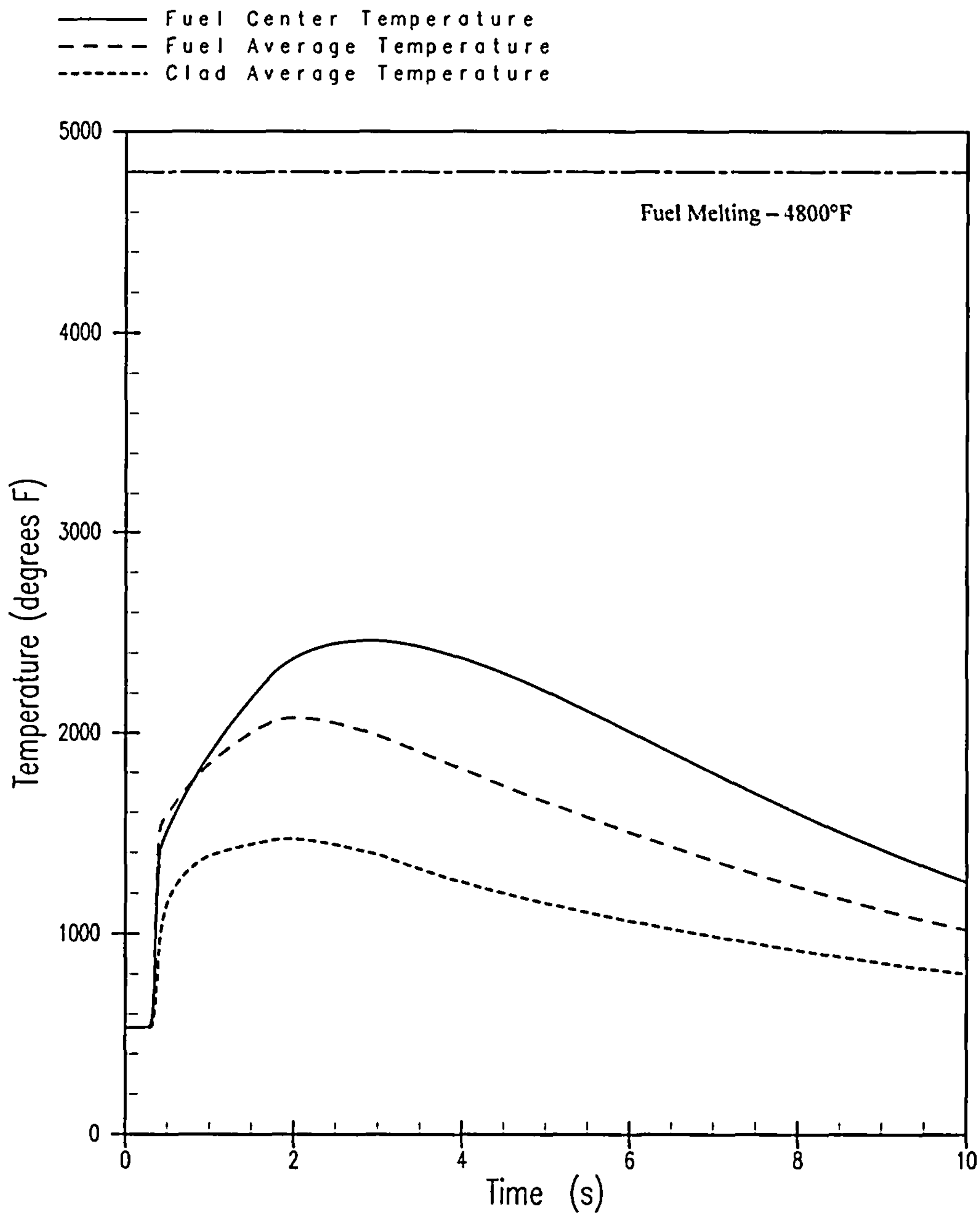

Figure 5.1.20-8
CEA Ejection Accident from Zero Power End of Cycle
Fuel and Cladding Temperatures

5.1.21 Chemical and Volume Control System Malfunction – Increased RCS Inventory

5.1.21.1 Accident Description

A CVCS Malfunction event that produces an unplanned increase in RCS inventory may be caused by operator error or a failure in the pressurizer level transmitter, which causes an erroneous low-low level signal. The generated signal will be transmitted to the controller, which responds by actuating a second charging pump and closing the letdown flow control valve to its minimum flow position. The CVCS Malfunction is assumed to occur without increasing or diluting the primary coolant initial boron concentration. With the mismatch between letdown and charging flow, the pressurizer mixture level and pressure increase. The pressurizer sprays mitigate the pressure increase. The operators are alerted to the event either by a high pressurizer pressure trip (HPPT) or by the pressurizer high level alarm (PHLA). Twenty minutes after either HPPT or the PHLA, it is assumed that the operators mitigate the event by reducing charging flow or restoring letdown flow. The case of a CVCS malfunction that produces a boron dilution is presented in Section 5.1.19.

5.1.21.2 Method of Analysis

The CVCS malfunction at-power transient is analyzed by employing the detailed digital computer code RETRAN (References 5.1.21-1 and 5.1.21-2). The code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level.

The analysis of the CVCS Malfunction event has been performed to demonstrate that operators have a sufficient amount of time to preclude pressurizer filling following a high pressurizer level alarm. To maximize the peak pressurizer mixture volume following the high pressurizer level alarm, the following assumptions are made:

1. An initial core power of 2458 MWt, based on 89% rated power of 2700 MWt and 2% uncertainty, is assumed.
2. 42% of the steam generator U-tubes are assumed to be plugged.
3. Initial values of pressurizer pressure, vessel average temperature (T_{avg}) and pressurizer level are provided in Table 5.1.0-2.
4. Maximum charging flow is 49 gpm per pump for a total of 98 gpm for two charging pumps. This is reduced by 4 gpm for the reactor coolant pump bleedoff flow and results in a total charging flow assumption of 94 gpm.
5. The initiating event is an erroneous low-low level signal that actuates a second charging pump and closes the letdown flow control valve to the minimum position.
6. The assumed single failure is the complete closure of the letdown flow control valve that occurs concurrently with the start of the second charging pump.
7. The charging flow boron concentration is assumed to be equal to the initial RCS boron concentration.
8. The pressurizer high level alarm setpoint is assumed to be 70% of tap span.
9. The pressurizer safety valves are assumed to have a -2% tolerance that corresponds to an opening setpoint of 2450.3 psia.

10. Operator action is assumed to occur at 20 minutes after the PHLA actuates.
11. Maximum reactivity feedback conditions are assumed.
12. Pressurizer sprays and heaters are assumed in the automatic mode.

The CVCS Malfunction is a Condition II event and is analyzed to show that the Condition II limits (specifically, generation of a more serious plant condition, pressurizer fill) are not exceeded. The applicable Condition II acceptance criteria are discussed as follows.

With respect to peak RCS and main steam system pressures, the CVCS Malfunction at-power event is bounded by the Loss of Condenser Vacuum event described in Section 5.1.10, which is analyzed with assumptions that are made to conservatively calculate the RCS and main steam system pressure transients.

With respect to the fuel damage acceptance criterion, the CVCS Malfunction at-power event is bounded by the CEA Bank Withdrawal at-power event described in Section 5.1.16. During the CVCS Malfunction there are very small increases in core power and RCS temperatures, and a very small change in RCS mass flow. The RCS pressure increase is limited by the pressurizer sprays and offsets any negative effects due to the minimal changes in other DNB-related parameters.

With respect to the acceptance criterion of not generating a more serious plant condition, this is satisfied by demonstrating that the PSVs do not discharge water. Due to the mismatch between charging and letdown flows, the pressurizer water volume increases during the CVCS Malfunction at-power event. Operator action is required to preclude water discharge through the PSVs.

With respect to the fission product barrier failure criterion, this is met by demonstrating that the DNB design basis is satisfied. Thus, there is no loss of function of any fission product barrier for the CVCS Malfunction at-power event.

5.1.21.3 Results

The RETRAN code analysis assumptions are listed in Table 5.1.0-2 and in the section above. Table 5.1.21-1 lists the Sequence of Events. Figures 5.1.21-1 to 5.1.21-5 present the key transient parameters response during the event.

The transient is assumed to start at 10 seconds, and the pressurizer high level alarm alerts the operators at 338.6 seconds. At 1538.6 seconds (20 minutes later), the pressurizer mixture volume is 1509.1 ft^3, which corresponds to 9.9 ft^3 of margin to filling the pressurizer water solid.

The maximum pressurizer pressure is 2224 psia at 564.5 seconds. This is well below the pressurizer safety valves opening setpoint of 2450.3 psia.

5.1.21.4 Conclusions

The results demonstrate that the pressurizer volume does not become water solid prior to 20 minutes after the PHLA is actuated. The CVCS Malfunction at-power event is assumed to be mitigated by operator action prior to the pressurizer filling and no water is discharged through the PSVs. Thus, it is concluded that this transient does not generate a more serious plant condition.

5.1.21.5 References

5.1.21-1 WCAP-14882-P-A, Rev. 0, "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized
Water Reactor Non-LOCA Safety Analyses," April, 1999.

5.1.21-2 McFadden, J. H., et al, "RETRAN-02-A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Systems," EPRI NP-1850-CCMA.

Table 5.1.21-1 Sequence of Events - CVCS Malfunction Event		
Time, sec	**Event**	**Setpoint or Value**
10.0	Erroneous low-low level pressurizer level control system signal, Second charging pump starts, Letdown flow is isolated	---
338.6	Pressurizer high level alarm occurs	70% of tap span
564.5	Maximum pressurizer pressure	2224 psia
1538.6	Operator action occurs to mitigate the event.	---

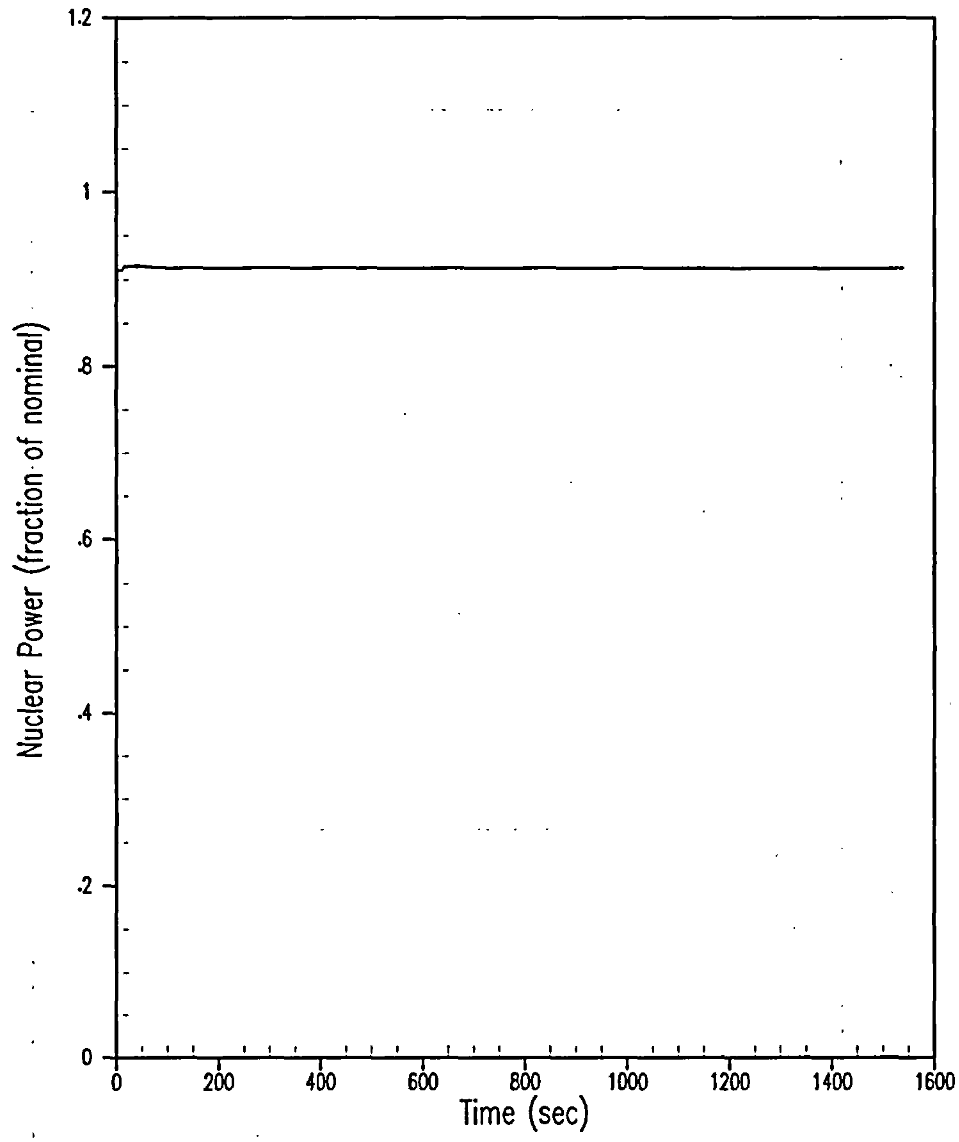

Figure 5.1.21-1
CVCS Malfunction at Power
Nuclear Power

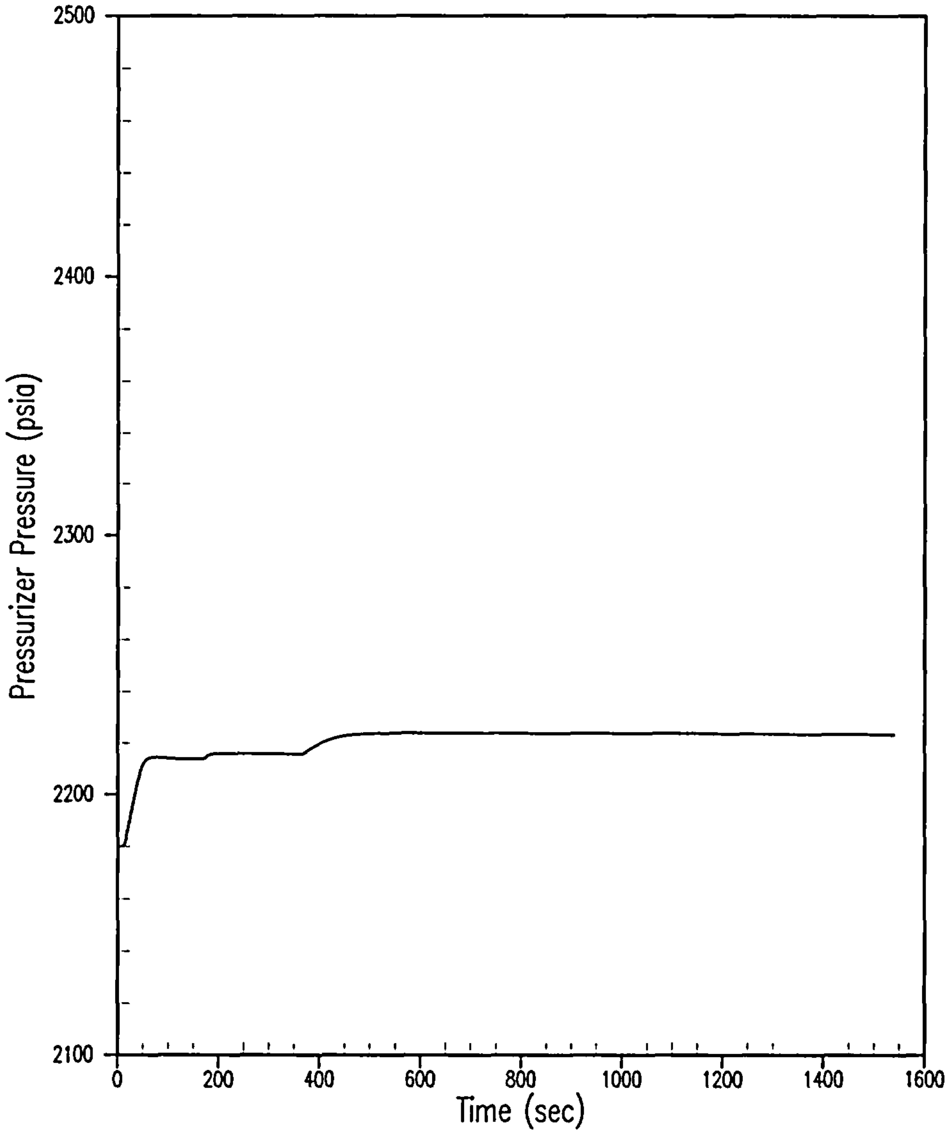

Figure 5.1.21-2
CVCS Malfunction at Power
Pressurizer Pressure

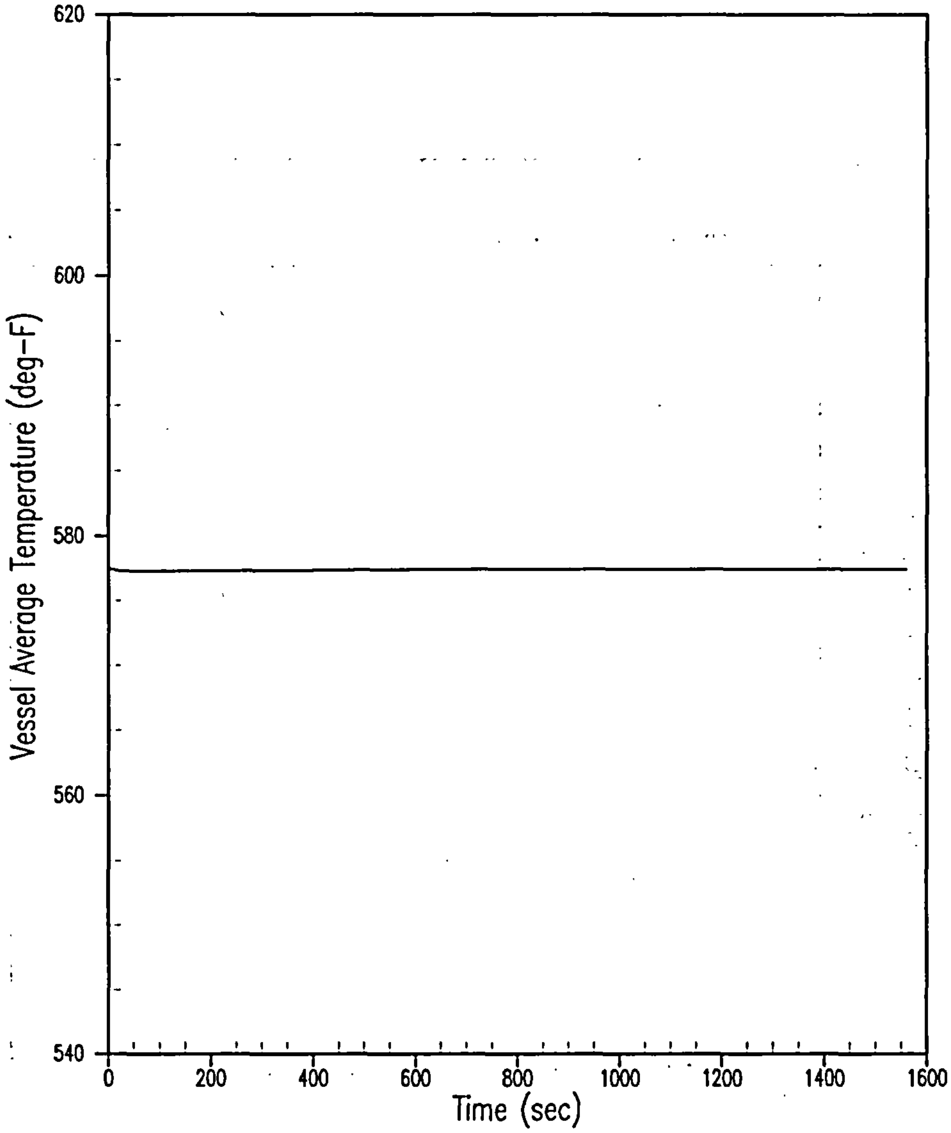

Figure 5.1.21-3
CVCS Malfunction at Power
Vessel Average Temperature

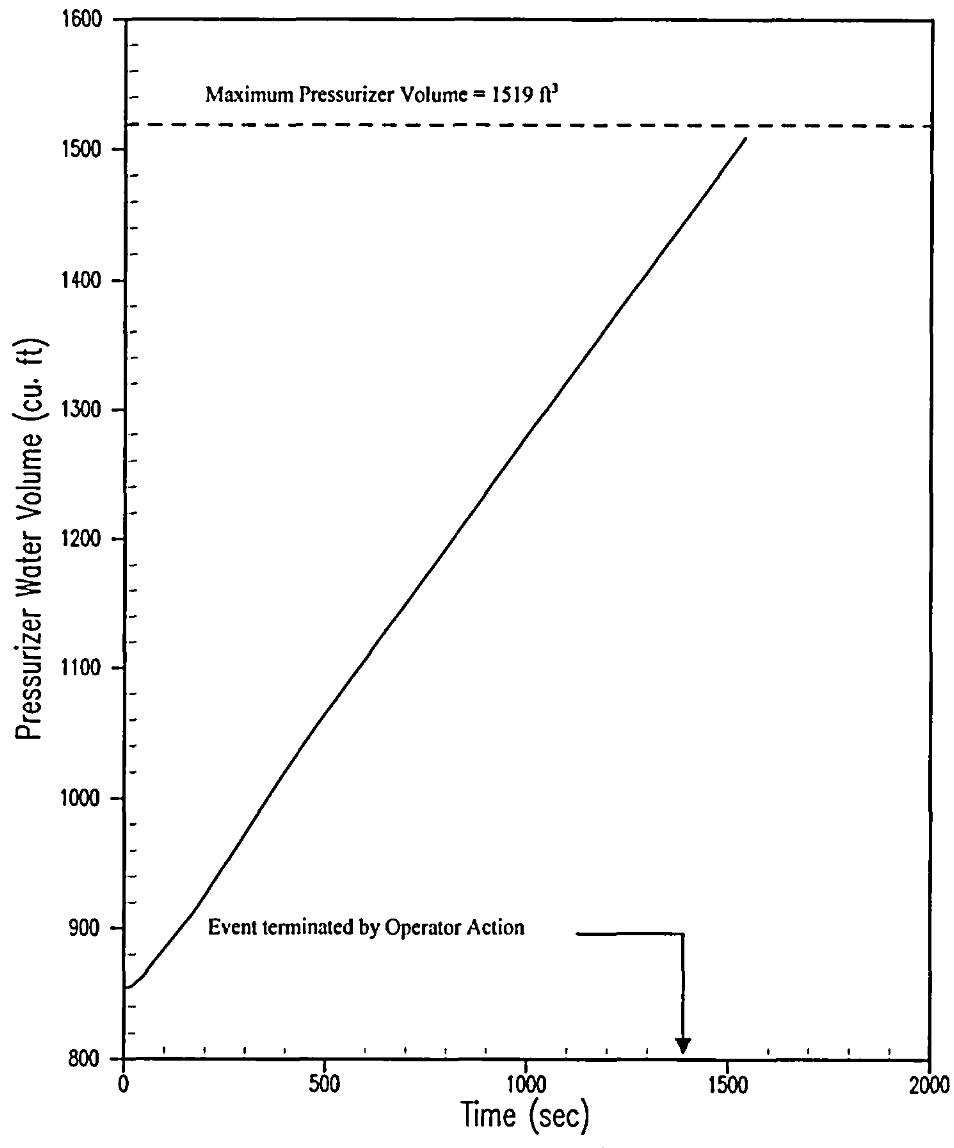

Figure 5.1.21-4
CVCS Malfunction at Power
Pressurizer Water Volume

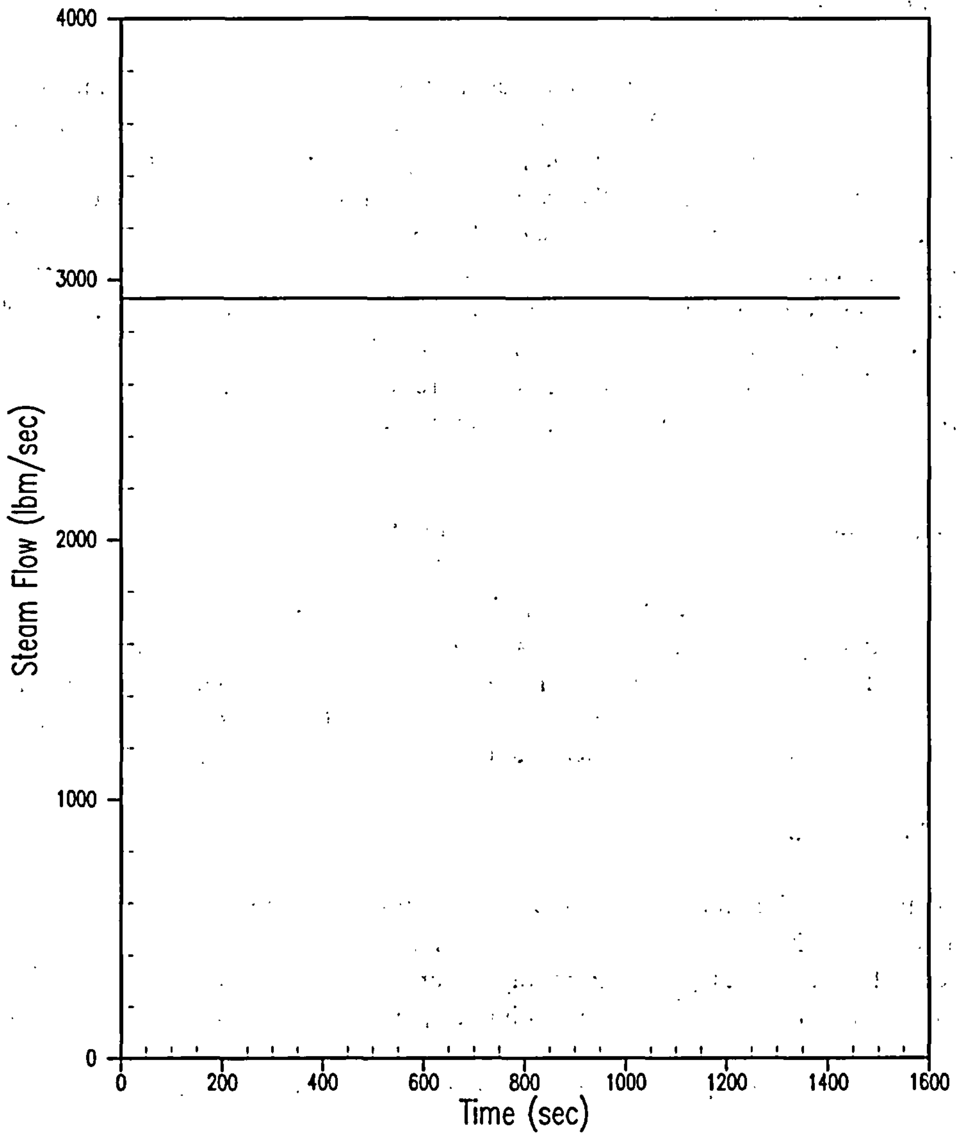

Figure 5.1.21-5
CVCS Malfunction at Power
Steam Flow

5.1.22 Pressurizer Pressure Decrease – Inadvertent Opening of the Pressurizer Relief Valves

5.1.22.1 Accident Description

An accidental depressurization of the RCS could occur as a result of one of the following: an inadvertent opening of both of the pressurizer PORVs, an inadvertent opening of a single PSV, or a malfunction of the pressurizer spray system. Since a PSV is sized to relieve approximately half the steam flow rate of a PORV, and the pressurizer spray system, even if fully open, cannot depressurize the RCS at the rate of two open PORVs, the most severe core conditions are associated with an inadvertent opening of both of the PORVs. It is assumed that a mechanical failure, spurious actuation signal, or unanticipated operator action will cause the opening of both PORVs. Initially, the event results in a rapidly decreasing RCS pressure which could reach the hot-leg saturation pressure if a reactor trip did not occur. The pressure continues to decrease throughout the transient. The effect of the pressure decrease is to decrease power via the moderator density feedback. Pressurizer level increases initially due to expansion caused by depressurization and then decreases following reactor trip.

The reactor core is protected against fuel damage by the TM/LP trip function.

An inadvertent opening of both of the pressurizer relief valves is classified as an ANS Condition II event, a fault of moderate frequency. It should be noted that a stuck open PSV is considered a more serious Condition III event. However, in the case of St. Lucie Unit 2, the relief capacity of a PORV far exceeds that of a PSV. Thus, the assumption of the opening of both PORVs and demonstration that the more restrictive Condition II acceptance criteria are met removes the PSV scenario from concern.

5.1.22.2 Method of Analysis

The accidental depressurization transient is analyzed by employing the detailed digital computer code RETRAN (References 5.1.22-1 and 5.1.22-2). The code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level.

This accident is analyzed with the revised thermal design procedure described in Reference 5.1.22-3.

Plant characteristics and initial conditions are discussed in Section 5.1.0. In order to give conservative results in calculating the DNBR during the transient, the following assumptions are made:

1. The initial reactor power and RCS temperature are assumed to be at their nominal values consistent with 89% power, the initial RCS flow rate is assumed at a value consistent with the minimum measured flow rate, and the initial RCS pressure is assumed at a value consistent with minimum value allowed by the plant technical specifications. Uncertainties in initial conditions are statistically included in the calculation of the DNBR limit as described in Reference 5.1.22-3.

2. A least negative moderator temperature coefficient of reactivity corresponding to 0.917 pcm/°F is assumed, consistent with operation at 89% rated thermal power. The spatial effect of void due to local or subcooled boiling is not considered in the analysis with respect to reactivity feedback or core power shape.

3. A least negative Doppler power coefficient is assumed such that the resultant amount of negative feedback is conservatively low in order to maximize any power increase due to moderator reactivity feedback.

The automatic rod control system is not modeled as it is disabled at the plant. The RPS functions to trip the reactor on the appropriate signal. No single active failure will prevent the RPS from functioning properly.

5.1.22.3 Results

The system response to an inadvertent opening of both PORVs is shown in Figures 5.1.22-1 through 5.1.22-4. Figure 5.1.22-1 illustrates the nuclear power transient following the depressurization. Nuclear power remains relatively constant while pressurizer pressure decreases from the initial value until reactor trip occurs on the floor of the TM/LP trip. The pressure transient and average coolant temperature transient following the accident are given in Figures 5.1.22-2 and 5.1.22-3, respectively. The DNBR decreases initially, but increases rapidly following the trip, as shown in Figure 5.1.22-4. The DNBR remains above the limit value throughout the transient.

The calculated sequence of events for the inadvertent opening of both PORVs is shown in Table 5.1.22-1.

5.1.22.4 Conclusion

The results of the analysis show that the TM/LP RPS signal provides adequate protection against the accidental depressurization of the RCS. No fuel or clad damage is predicted for this accident. All acceptance criteria are satisfied.

5.1.22.5 References

5.1.22-1 WCAP-14882-P-A, Rev. 0, "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," April, 1999.

5.1.22-2 McFadden, J. H., et al, "RETRAN-02-A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems," EPRI NP-1850-CCMA.

5.1.22-3 WCAP-11397-P-A, "Revised Thermal Design Procedure," April 1989.

Table 5.1.22-1 Pressurizer Pressure Decrease – Inadvertent Opening of the Pressurizer Relief Valves Sequence of Events and Transient Results	
Event	**Value**
Inadvertent Opening of Both PORVs	10.1 seconds
Reactor Trip on TM/LP	26.1 seconds
Rod Motion Begins	26.9 seconds
Time of Minimum DNBR	28.0 seconds
Minimum DNBR	1.63

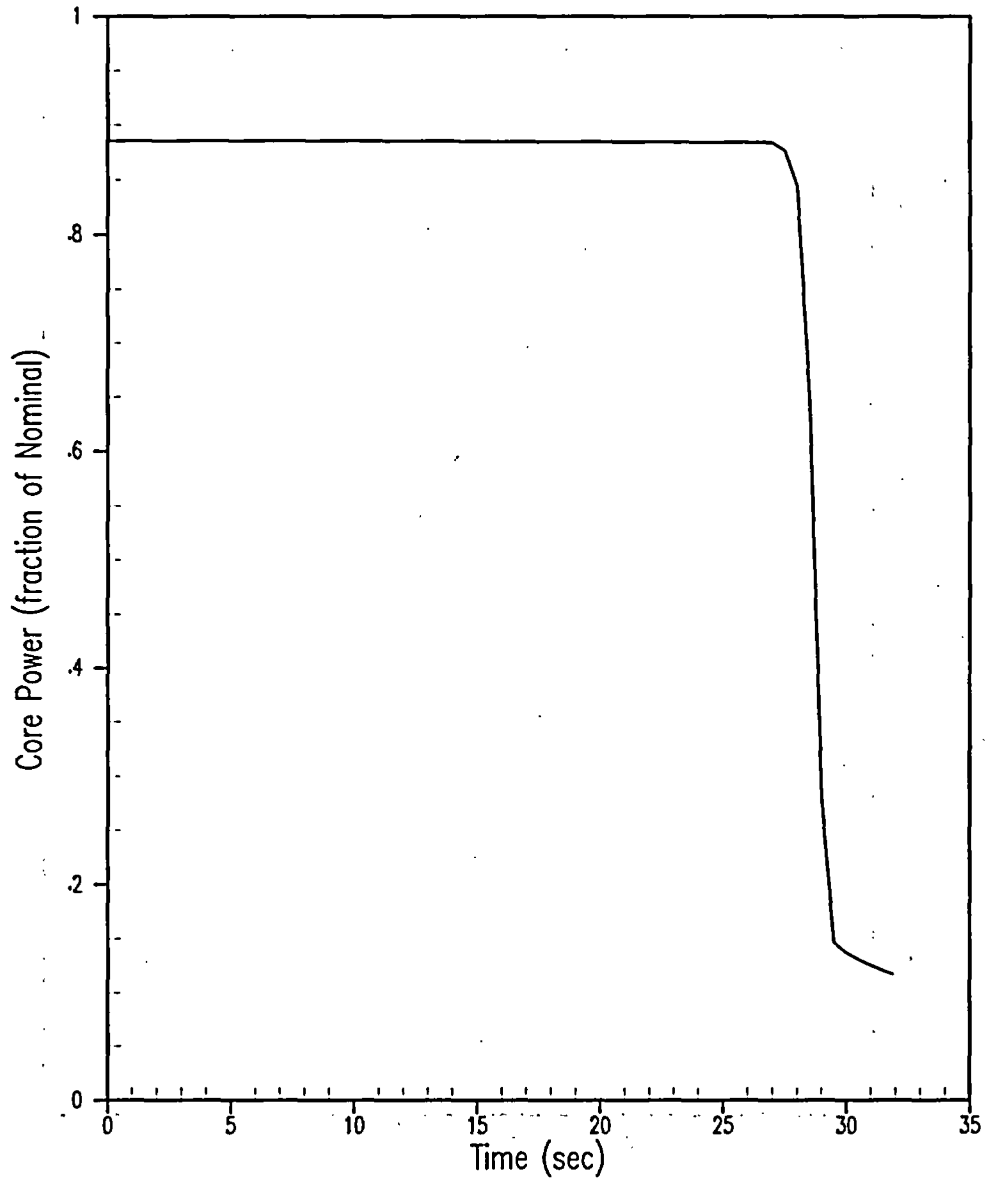

Figure 5.1.22-1
Accidental Depressurization of the Reactor Coolant System Event
Nuclear Power

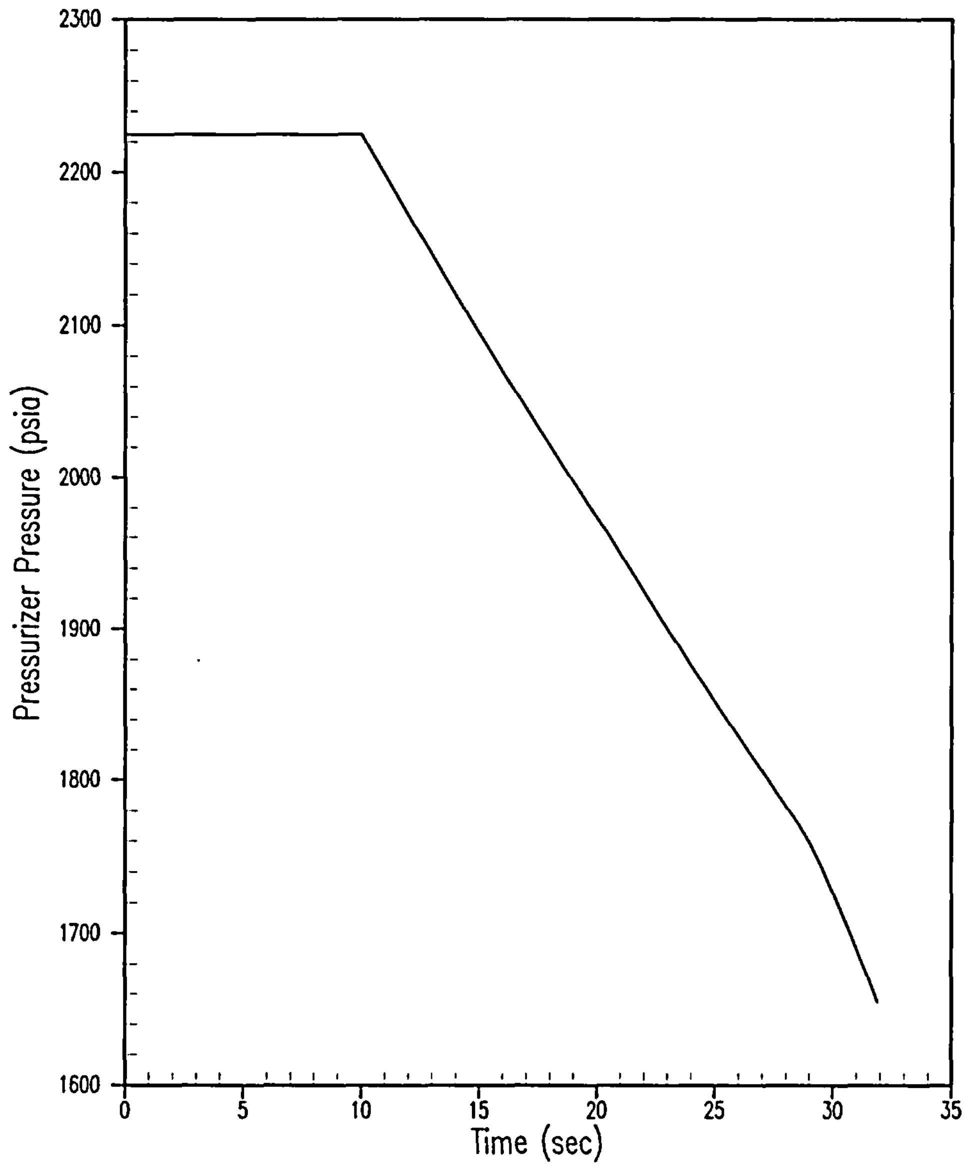

Figure 5.1.22-2
Accidental Depressurization of the Reactor Coolant System Event
Pressurizer Pressure

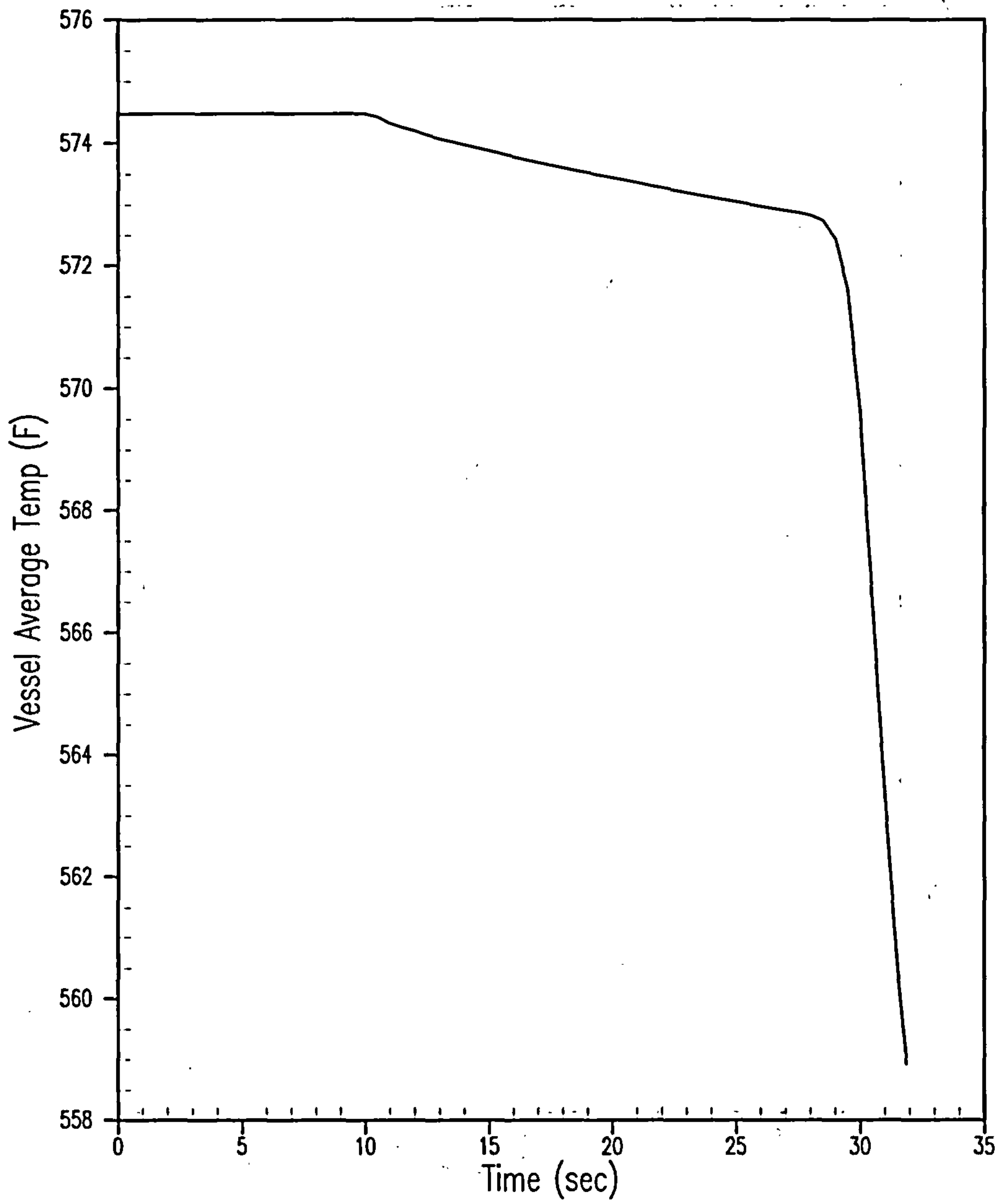

Figure 5.1.22-3
Accidental Depressurization of the Reactor Coolant System Event
Vessel Average Temperature

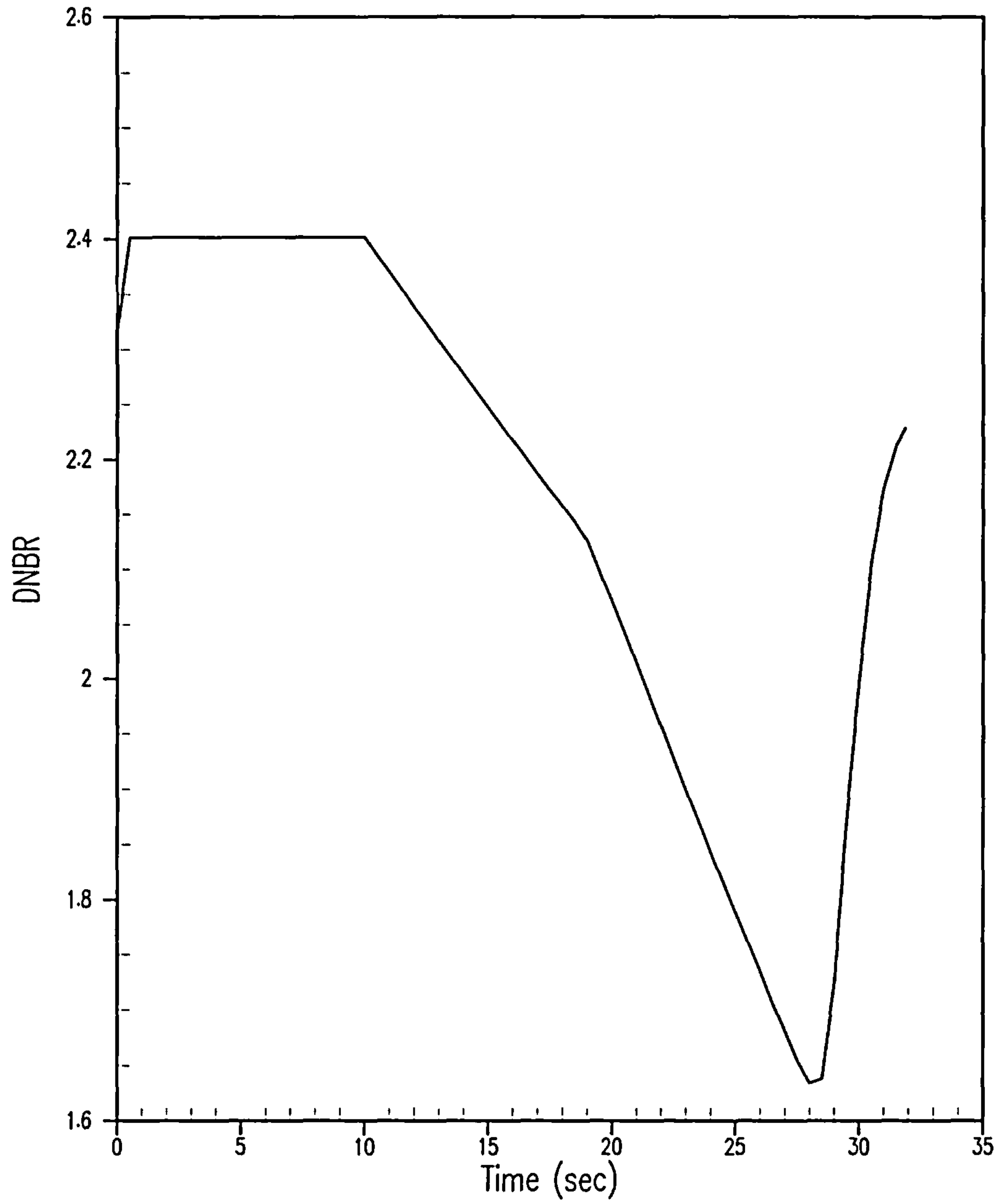

Figure 5.1.22-4
Accidental Depressurization of the Reactor Coolant System Event
DNBR

5.1.23 Primary Line Break Outside Containment

5.1.23.1 Introduction

A Primary Line Break Outside Containment Event may result from a break in a letdown line, instrument line, or sample line. The double-ended break of the letdown line outside containment upstream of the outside containment isolation valve was selected for this analysis since it is the largest line and results in the largest release of reactor coolant to the environment.

The Primary Line Break Outside Containment provided in Reference 5.1.23-1, Section 15.6.3.1.7, was evaluated to account for a decrease in the minimum RCS flow from 335,000 gpm to 300,000 gpm, and an increase in steam generator tube plugging to 42%. Because this event analysis is not within the scope of the WCAP-9272 reload methodology, this evaluation remains based on the methods of the current analysis of record (AOR) as presented in Reference 5.1.23-1, Section 15.6.3.1.7 which included use of the CESEC transient analysis code. Also, the scope of this evaluation is limited to assessing the impact on the mass releases that become the source terms for dose calculations previously determined for this event as presented in Reference 5.1.23-1, Section 15.6.3.1.7.

5.1.23.2 Input Assumptions

Other than reduced RCS flow and increased tube plugging, there are no adverse plant changes relative to the key parameters identified in the AOR, as presented in Reference 5.1.23-1, Table 15.6.3.1-7.

5.1.23.3 Acceptance Criteria

The Primary Line Break event does not directly challenge peak linear heat rate, peak RCS pressure, or peak secondary pressure criteria; and is bounded by the inadvertent opening of a pressurizer relief valve event with respect to RCS depressurization rate, and approach to the DNB criterion. Primary Line Break has been evaluated with respect to offsite radiological doses.

5.1.23.4 Description of Analyses and Results

An evaluation of the Primary Line Break Outside Containment event was performed to determine the impact of the two plant changes presented above. This was done by reviewing the key input and assumptions of the AOR and determining the impact of any adverse changes. The leak rate from the letdown line break is determined by the upstream (i.e., cold leg) temperature and pressure, and neither will be adversely affected by an RCS flow change or tube plugging. Temperature is constant prior to reactor trip and the range of initial cold leg temperatures is not being changed by the increase in SGTP. The pressure decreases prior to reactor trip on low pressurizer pressure, with the pressure determined by the pressurizer conditions and the decrease in reactor coolant volume caused by the break. The pressurizer conditions, including the range of initial pressure and liquid level, charging flow, and heater capacity are not adversely changed by the increase in SGTP.

With no change to the pre-trip sequence of events, the time of trip will not be affected since the low pressurizer pressure trip setpoint is not being changed by an increase in SGTP.

Following reactor trip the leak rate is conservatively held constant at 45 lbm/sec for 10 minutes, and therefore, is independent of small variations in cold leg temperature and pressure. Any impact of initial RCS flow and tube plugging on post-trip cold leg temperature and pressure would be small, since cold leg temperature drops and equilibrates to a value determined by the MSSV opening setpoint (which is not changed by an increase in SGTP). The post-trip pressure decrease is caused by the coolant contraction as the RCS average temperature also drops to a value determined by the MSSV opening setpoint. The amount of contraction / depressurization will be slightly greater as initial average temperature increases due to reduced RCS flow, and will diminish slightly if the reactor coolant mass is decreased due to tube plugging. Both effects are small, and offsetting.

The evaluation determined that the decrease in the minimum RCS flow from 335,000 gpm to 300,000 gpm, and an increase to 42% steam generator tube plugging have a negligible impact on this event.

5.1.23.5 Conclusions

With regard to coolant leakage, this evaluation showed that the previously reported results (Reference 5.1.23-1, Section 15.6.3.1.7) remain valid.

5.1.23.6 References

5.1.23-1 St. Lucie Unit 2 Updated Final Safety Analysis Report, Amendment 16, dated February 2005.

5.1.24 Steam Generator Tube Rupture with a Loss of Offsite Power

5.1.24.1 Introduction

The Steam Generator Tube Rupture (SGTR) with a Loss of Offsite Power event provided in the St. Lucie Unit 2 UFSAR (Reference 5.1.24-1), Section 15.6.2.1.7 was evaluated to account for increased steam generator tube plugging to 42%.

5.1.24.2 Input Assumptions

The SGTR Event was analyzed assuming the initial conditions in Table 5.1.24-1. In addition, the following assumptions were made:

1. While the reactor is operating at power (89% RTP) prior to trip, the steam mixture containing reactor coolant fission products passes through the turbine and the condenser.
2. Following the reactor and turbine trip, fission product activity release occurs via the MSSVs until operator action at 1800 seconds.
3. Within thirty minutes (1800 seconds) after the tube rupture occurs, the operator identifies the problem and isolates the affected steam generator. At this time, plant cooldown is initiated using the unaffected steam generator atmospheric dump valves (ADVs).

This analysis assumes that following the SGTR, the RCS pressure drops until reaching the TM/LP low pressurizer pressure trip setpoint, thus preventing violation of the DNBR specified acceptable fuel design limit (SAFDL). Crediting the earliest trip maximizes the offsite doses. Offsite power is assumed to be lost at time of trip. The RCS continues to depressurize and the pressurizer empties.

Subsequent to reactor trip, stored and fission product decay heat is dissipated by the reactor coolant and main steam systems. In the absence of forced reactor coolant flow (due to a loss of offsite power), convective heat transfer is supported by natural circulation. The increasing steam generator pressure results in steam release to atmosphere via the MSSVs. At 1800 seconds, the operators are assumed to isolate the affected steam generator and initiate plant cooldown through the unaffected steam generator atmospheric dump valves. With the availability of stand-by power, emergency feedwater (EFW) is automatically initiated on a low steam generator water level signal. To maximize the offsite dose results this analysis conservatively assumes that the emergency feedwater will be unavailable until 1800 seconds and the normal feedwater flow ramps down immediately following loss of offsite power.

All other input remained the same as that in Reference 5.1.24-1, Section 15.6.2.1.7. Table 5.1.24-1 documents the changes in input parameters due to increased steam generator tube plugging to 42%.

5.1.24.3 Acceptance Criteria

The SGTR event was analyzed to assure that the following dose criteria are not exceeded:

- With an assumed pre-accident iodine spike in the reactor coolant and with the highest worth control rod assumed to stick in the fully withdrawn position on scram, the calculated doses do not exceed the values of 10 CFR 100, and

- With an equilibrium iodine concentration corresponding to full power operation and an assumed accident generated iodine spike, the calculated doses do not exceed 10% of 10 CFR 100.

Steam generator or RCS pressure limits are not challenged by SGTR, and the TM/LP trip assures the DNBR SAFDL is met for SGTR.

5.1.24.4 Description of Analysis/Evaluation and Results

The thermal hydraulic response of the NSSS to the SGTR was simulated using the CESEC-III, Mod 5 computer code.

Table 5.1.24-2 provides the radiological exposure for the SGTR event. The inputs/assumptions used are given in Tables 5.1.24-4 through 5.1.24-8.

Table 5.1.24-3 contains the sequence of events for the SGTR Event with a Loss of Offsite Power.

Figures 5.1.24-1 through 5.1.24-13 show the NSSS response for the system parameters important in dose calculation.

5.1.24.5 Conclusions

The radiological releases calculated for the SGTR Event with a concurrent loss of offsite power are provided in Table 5.1.24-2.

Primary and secondary system pressures are well below upset pressure limits thus assuring the integrity of these systems.

5.1.24.6 References

5.1.24-1 St. Lucie Unit 2 Updated Final Safety Analysis Report, Amendment 16, Docket No. 50-389.

5.1.24-2 Letter, W. Jefferson, Jr. (FPL) to NRC Document Control Desk, "Proposed License Amendments Alternate Source Term and Conforming Amendments," L-2003-220, September 18, 2003.

5.1.24-3 Letter, W. Jefferson, Jr. (FPL) to NRC Document Control Desk, "Proposed License Amendment, WCAP-9272 Reload Methodology and Implementing 30% Steam Generator Tube Plugging Limit," L-2003-276, December 2, 2003.

Table 5.1.24-1 Key Parameters Assumed for the Steam Generator Tube Rupture Event With a Loss Of Offsite Power		
Parameter	**Units**	**Value**
Total RCS Power (Core Thermal Power + Pump Heat)	MWt	2472.1
Initial Core Coolant Inlet Temperature	°F	550.1
Initial RCS Vessel Flow Rate	gpm	300,000
Number of SG Plugged Tubes	---	42%
Initial Steam Generator Pressure	psia	732
Steam Generator U-Tube Break Size	in2	0.336
CEA Worth at Trip	%Δρ	-5.4
Initial Pressurizer Pressure	psia	2395

Table 5.1.24-2 Radiological Exposures as a Result of a Steam Generator Tube Rupture Event With A Loss of Offsite Power			
Case	**Worst 2-hour EAB Dose (rem TEDE)**	**30-Day LPZ Dose (rem TEDE)**	**30-Day Control Room Dose (rem TEDE)**
SGTR pre-accident iodine spike	0.30	0.29	3.81
Acceptance Criteria (pre-accident iodine spike)	25	25	5
SGTR concurrent iodine spike	0.08	0.07	0.94
Acceptance Criteria (concurrent iodine spike)	2.5	2.5	5

Table 5.1.24-3 Sequence of Events for the Steam Generator Tube Rupture Event With Loss of Offsite Power		
Time (sec)	**Event**	**Setpoint / Value**
0.0	Tube Rupture Occurs	---
351.6	Reactor Trip Signal on Floor of TM/LP, psia	2142
353.24	CEAs Begin to Drop	----
361.1	MSSVs open,* psia	970
364.9	Maximum SG Pressure, psia	971
520.4	Pressurizer Empties	----
528.2	SIAS Generated on Low Pressurizer Pressure, psia	1578
558.2	HPSI Pumps Reach Full Speed	----
1800	1. Operator Borates to Cold Shutdown Concentration	
	2. Operator Isolates Affected SG by Closing MSIV	
	3. Operator Activates ADVs (Intact SG) to Commence Cooldown of RCS	
	Steam Releases via Turbine to Condenser Prior to Trip (50.1% Affected SG/49.9% Intact SG), lbm	1,030,805
	MSSVs Close, Affected/Intact SG Steam Releases, lbm (from Reactor Trip to 1800 seconds)	79,756 / 78,940
	Affected SG Leakage Before Trip, lbm	19,084
	Affected SG Leakage from Reactor Trip up to 1800 seconds, lbm	54,948
	RCS to Affected SG Total Tube Leakage up to 1800 seconds, lbm	74,032
7200	RCS to Intact SG Total 2 hour T/S Leakage, lbm	723.2
	Total Intact SG Steam Releases via ADV (from 1800 seconds to 2 hrs), lbm	572,026
28800	RCS to Intact SG Total 8 hour T/S Leakage (based on 0.5 gpm), lbm	2,929
	Total Intact SG Steam Releases via ADV (from 1800 seconds to 8 hrs), lbm	1,479,854
* MSSVs Cycle Until Operator Activates ADVs @ 1800 Sec		

Table 5.1.24-4 (Page 1 of 2) Steam Generator Tube Rupture Dose Consequences Inputs and Assumptions		
Input/Assumption	**30% SGTP**	**42% SGTP**
Core Power Level	2754 MW_{th} (2700 + 2%)	Since there is no fuel failure for the SGTR and all RCS activities are adjusted based on Technical Specification limits, the power value would only impact the initial RCS equilibrium activity which is adjusted to the Technical Specification limits and therefore, does not produce a significant impact on the SGTR results.
Initial RCS Equilibrium Activity (1.0 µCi/gm DE I-131 and 100/E-bar gross activity)	Table 1.7.2-1 from Ref 5.1.24-2	Same concentrations per unit mass
Initial Secondary Side Equilibrium Iodine Activity (0.1 µCi/gm DE I-131)	Table 1.7.3-1 from Ref 5.1.24-2	Same concentrations per unit mass
Maximum pre-accident spike iodine concentration	60µCi/gm DE I-131	Same
Maximum equilibrium iodine concentration	1.0µCi/gm DE I-131	Same
Duration of accident-initiated spike	8 hours	Same
Steam Generator Tube Leakage Rate	Faulted SG – 0.15 gpm Intact SG – 0.15 gpm	Same
Time to establish shutdown cooling and terminate steam release	8 hours	Same
Time for RCS to reach 212°F and terminate SG tube leakage	12 hours	Same
RCS Mass	Pre-accident spike – 475,385 lb_m Concurrent spike – 452,000 lb_m	Same. The initial RCS isotopic concentrations (i.e., per unit mass) are established based on the Technical Specification RCS activity concentration limit. The maximum RCS liquid mass is conservatively used to maximize the RCS isotopic inventory for the pre-accident spike. The RCS mass that was the basis for the RCS isotopic concentrations and the letdown system design is utilized for the concurrent iodine spike case to assure consistency between the RCS isotopic concentration basis and appearance rates.

Table 5.1.24-4 (Page 2 of 2)
Steam Generator Tube Rupture
Dose Consequences Inputs and Assumptions

Input/Assumption	30% SGTP	42% SGTP
SG Secondary Side Mass	Minimum – 105,000 lb_m (one SG)	Same
Integrated Mass Release	See Table 5.1.24-5	See Table 5.1.24-5
Secondary Coolant Iodine Activity prior to accident	0.1 μCi/gm DE I-131	Same
Steam Generator Secondary Side Partition Coefficients	Faulted SG (flashed tube flow) – none Faulted SG (non-flashed tube flow) – 100 Intact SG – 100	Same Same Same
Break Flow Flash Fraction	Pre-trip (up to 379.2 sec) - 17.19% Post-trip - 6.6%	Pre-trip (up to 351.6 sec) - 17.75%* Post-trip - 6.55%*
Atmospheric Dispersion Factors Offsite Onsite	 Table 1.8.2-1 of Ref 5.1.24-2 Tables 1.8.1-2 and 1.8.1-3 of Ref 5.1.24-2	 Same Same
Control Room Ventilation System Time of automatic control room isolation Time of manual control room unisolation	Table 1.6.3-1 of Ref 5.1.24-2 360 seconds 1.5 hours	CR ventilation - Same CR isolation - 381.6 seconds (conservatively assumed 30 seconds after LOOP versus control room rad monitors) CR unisolation - Same
Breathing Rates Offsite Control Room	 RG 1.183, Section 4.1.3 RG 1.183, Section 4.2.6	 Same Same
Control Room Occupancy Factor	RG 1.183 Section 4.2.6	Same

Table 5.1.24-5
SGTR Integrated Mass Releases [(1)]

Time (hours)	Break Flow in Ruptured SG (lb_m)		Steam Release from Ruptured SG (lb_m)		Steam Release from Unaffected SG (lb_m)	
	30% SGTP	42% SGTP	30% SGTP	42% SGTP	30% SGTP	42% SGTP
0 – 0.5	77,007[(4)]	77,734[(2)]	0 - 0.1053 hrs (379.2 sec): 661,842[(4)] (via Condenser) 0.1053 – 0.5 hrs: 85,089[(5)] (via MSSVs)	0 - 0.0977 hrs (351.6 sec): 542,255[(2)] (via Condenser) 0.0977 – 0.5 hrs: 86,137[(3)] (via MSSVs)	0 - 0.1053 hrs (379.2 sec): 656,568[(4)] (via Condenser) 0.1053 – 0.5 hrs: 83,989[(5)] (via MSSVs)	0 - 0.0977 hrs (351.6 sec): 540,091[(2)] (via Condenser) 0.0977 – 0.5 hrs: 85,255[(3)] (via MSSVs)
0.5 – 2.0	0	Same	0	0	600,628[(4)] (via ADVs)	600,628[(2)] (via ADVs)
2 – 8	N/A	Same	N/A	N/A	953,219[(4)]	953,219[(2)]

[(1)] Flowrate assumed to be constant within time period.
[(2)] 42% SGTP value from Table 5.1.24-3 conservatively increased by 5%.
[(3)] 42% SGTP value from Table 5.1.24-3 conservatively increased by 8%.
[(4)] 30% SGTP value from Table 5.1.24-3 in Ref 5.1.24-3 conservatively increased by 5%.
[(5)] 30% SGTP value from Table 5.1.24-3 in Ref 5.1.24-3 conservatively increased by 8%.

Table 5.1.24-6 60 μCi/gm D.E. I-131 Activities	
Isotope	Activity (μCi/gm)
Iodine-131	48.8
Iodine-132	10.15
Iodine-133	60.67
Iodine-134	6.067
Iodine-135	30.33
Note: Isotopic concentrations per unit mass are unchanged from 30% SGTP to the 42% SGTP case since the concentrations are initially based on the Technical Specification limits, which are also per unit mass.	

Table 5.1.24-7 Iodine Equilibrium Appearance Assumptions		
Input Assumption	Value from Ref 5.1.24-2 as used in Ref 5.1.24-3	Value Used in Limiting Case for 42% SGTP
Maximum Letdown Flow	128 gpm	Same
Assumed Letdown Flow *	150 gpm at 120°F, 2250 psia	Same
Maximum Identified RCS Leakage	10 gpm	Same
Maximum Unidentified RCS Leakage	1 gpm	Same
RCS Mass	452,000 lb_m	Same. In order to be consistent with the RCS activity based on the Technical Specification RCS concentration limits, the same RCS mass is used for the appearance rate determination.
* maximum letdown flow plus uncertainty		

Table 5.1.24-8 Concurrent Iodine Spike (335 x) Activity Appearance Rate		
Isotope	**Activity Appearance Rate (Ci/min)**	**Total 8 hour production (Ci)**
Iodine-131	1.6535E+02	7.937E+04
Iodine-132	9.2074E+01	4.420E+04
Iodine-133	2.3993E+02	1.152E+05
Iodine-134	1.1164E+02	5.359E+04
Iodine-135	1.6138E+02	7.746E+04
Note: Based on the carried number of decimal places, there was an insignificant change in isotopic concentrations per unit mass from Ref 5.1.24-3 (30% SGTP) to the 42% SGTP case values above.		

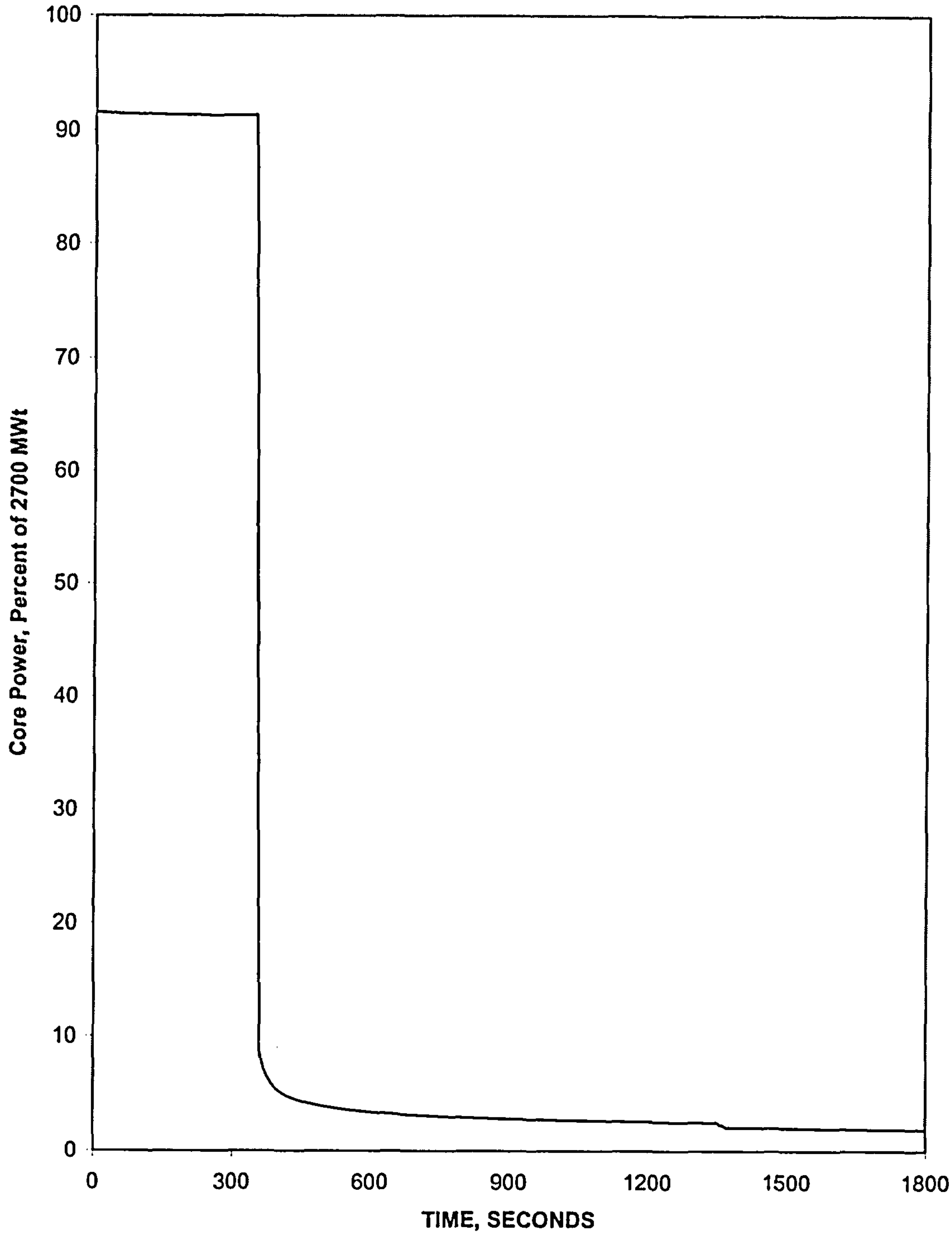

Figure 5.1.24-1
Steam Generator Tube Rupture with Loss of Offsite Power
Core Power

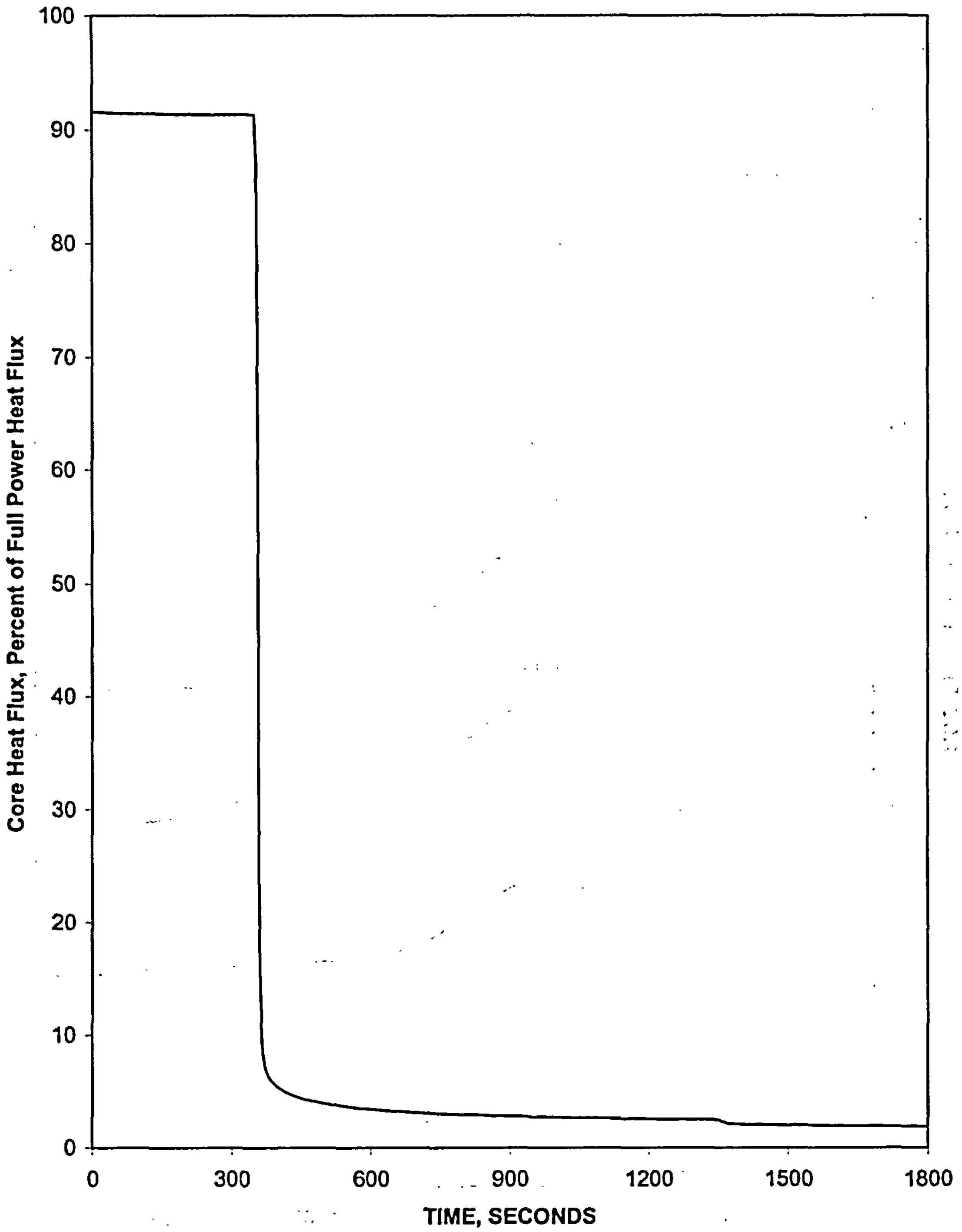

Figure 5.1.24-2
Steam Generator Tube Rupture with Loss of Offsite Power
Core Heat Flux

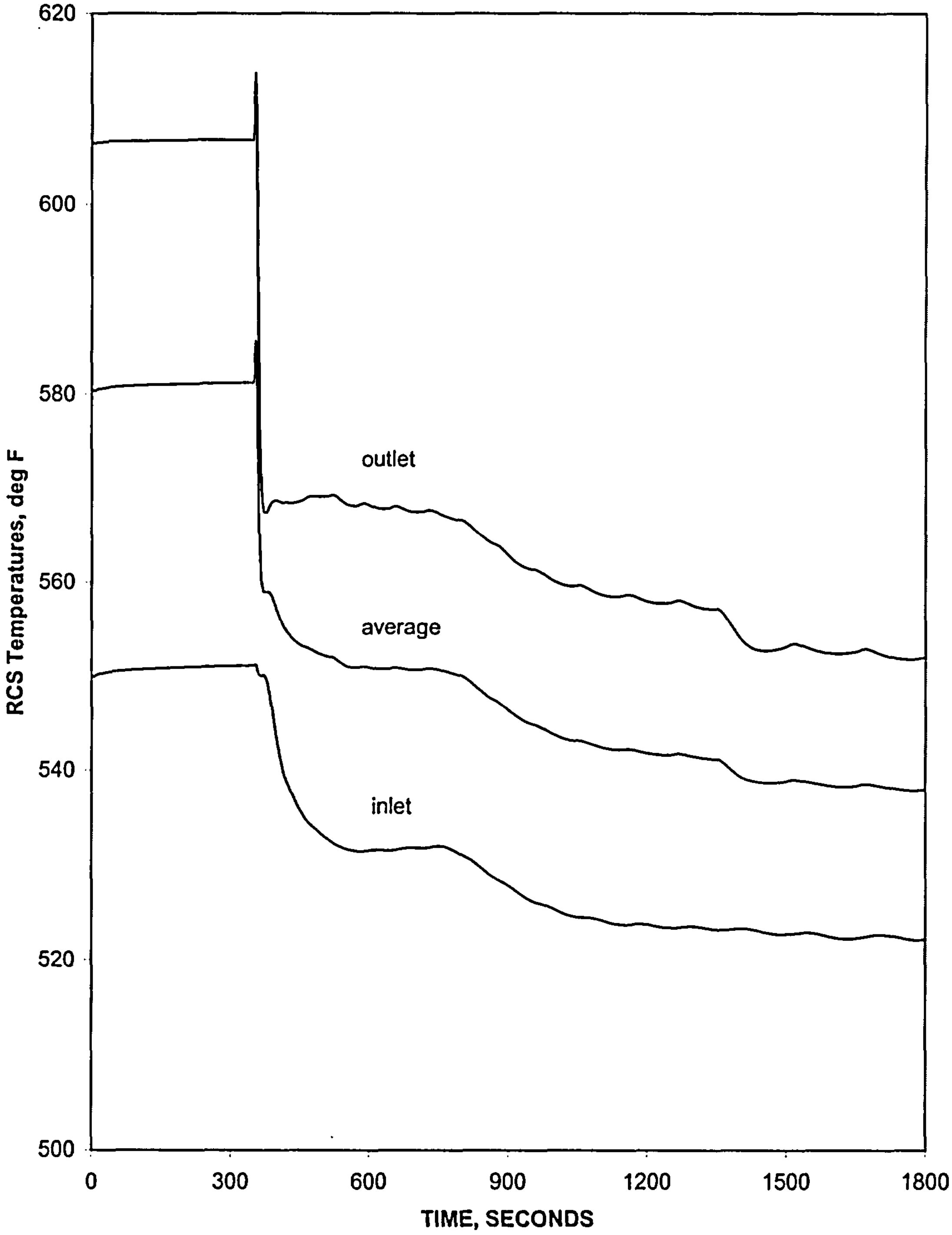

Figure 5.1.24-3
Steam Generator Tube Rupture with Loss of Offsite Power
Reactor Coolant System Temperatures

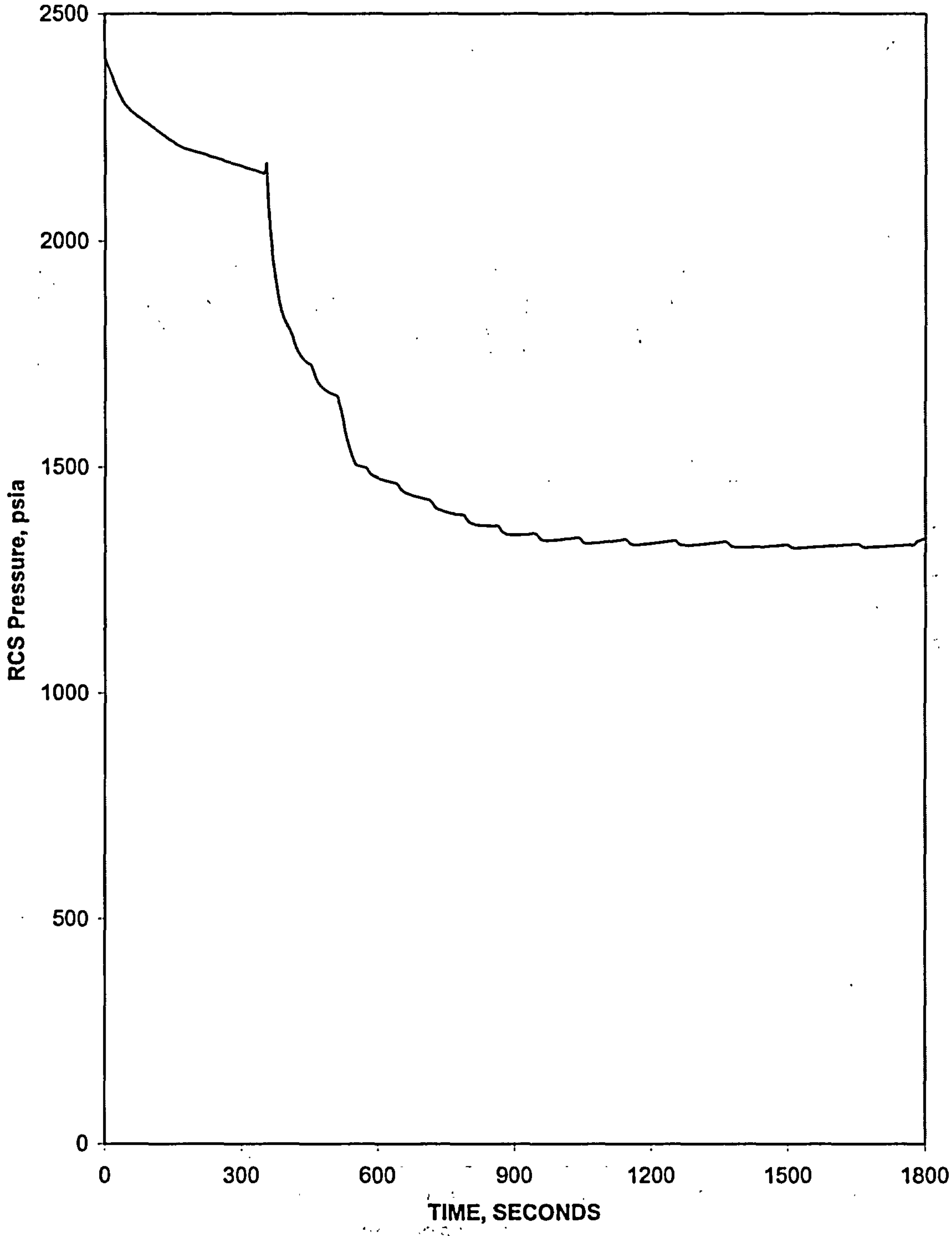

Figure 5.1.24-4
Steam Generator Tube Rupture with Loss of Offsite Power
Reactor Coolant System Pressure

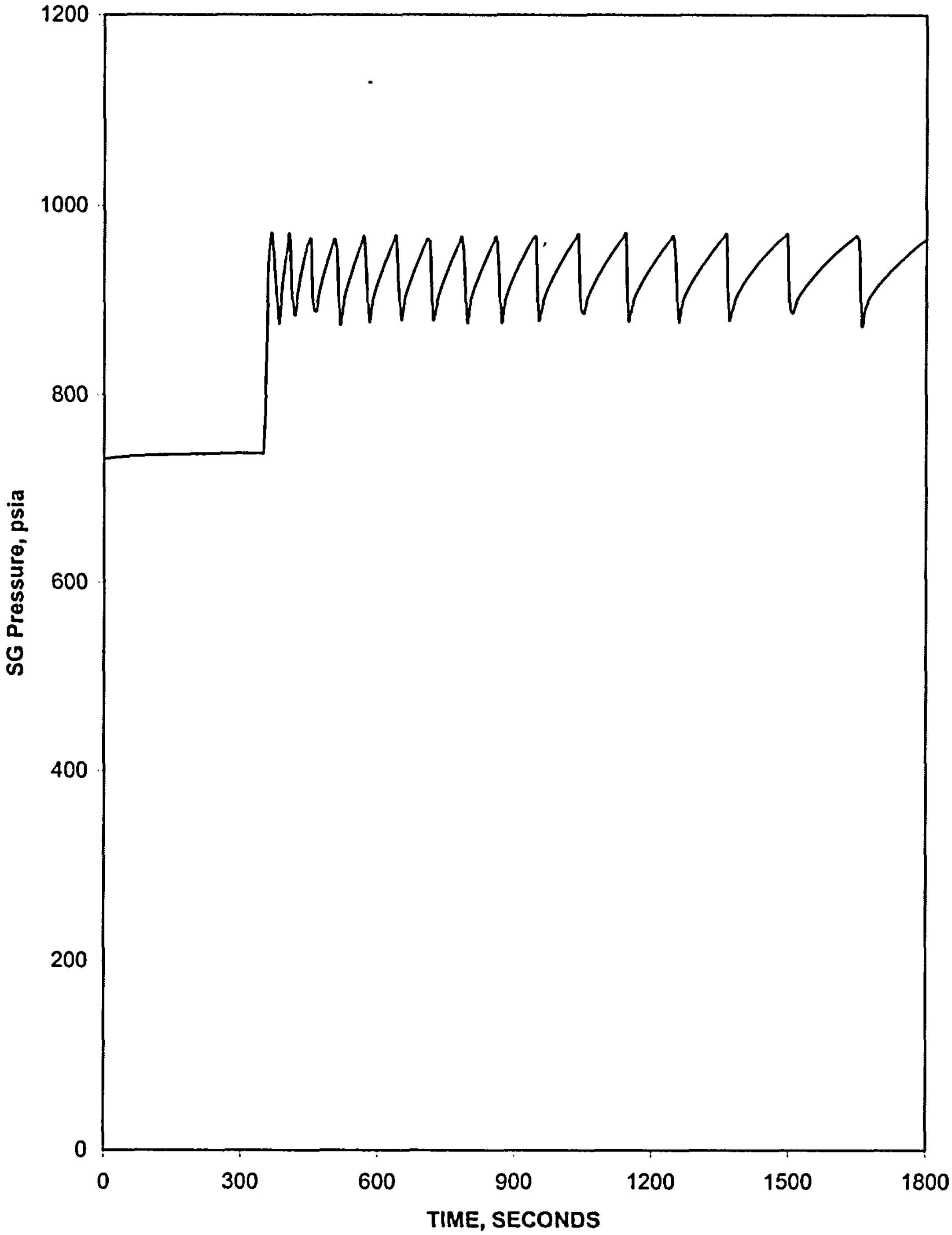

Figure 5.1.24-5
Steam Generator Tube Rupture with Loss of Offsite Power
Steam Generator Pressure

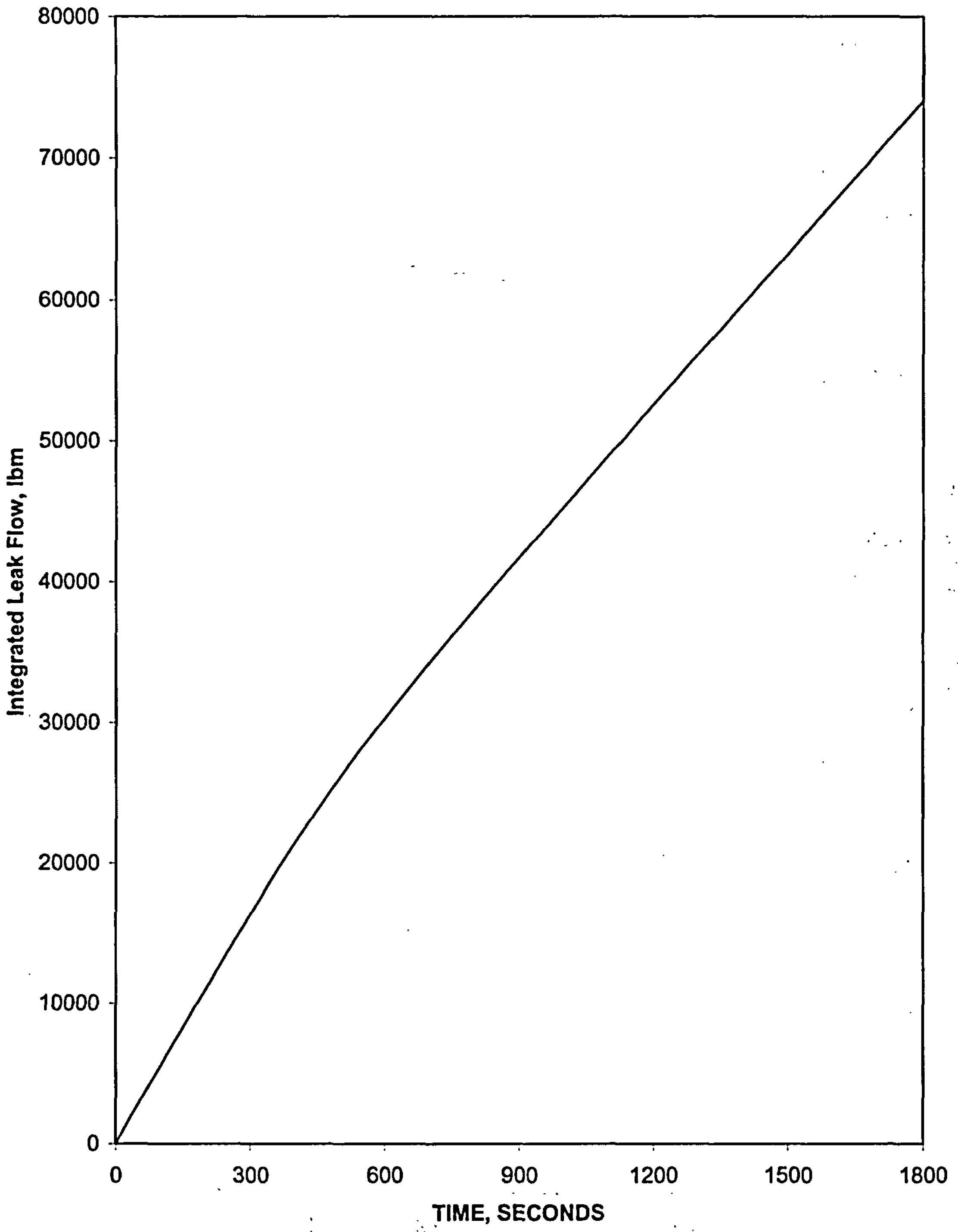

Figure 5.1.24-6
Steam Generator Tube Rupture with Loss of Offsite Power
Integrated Leak Flow

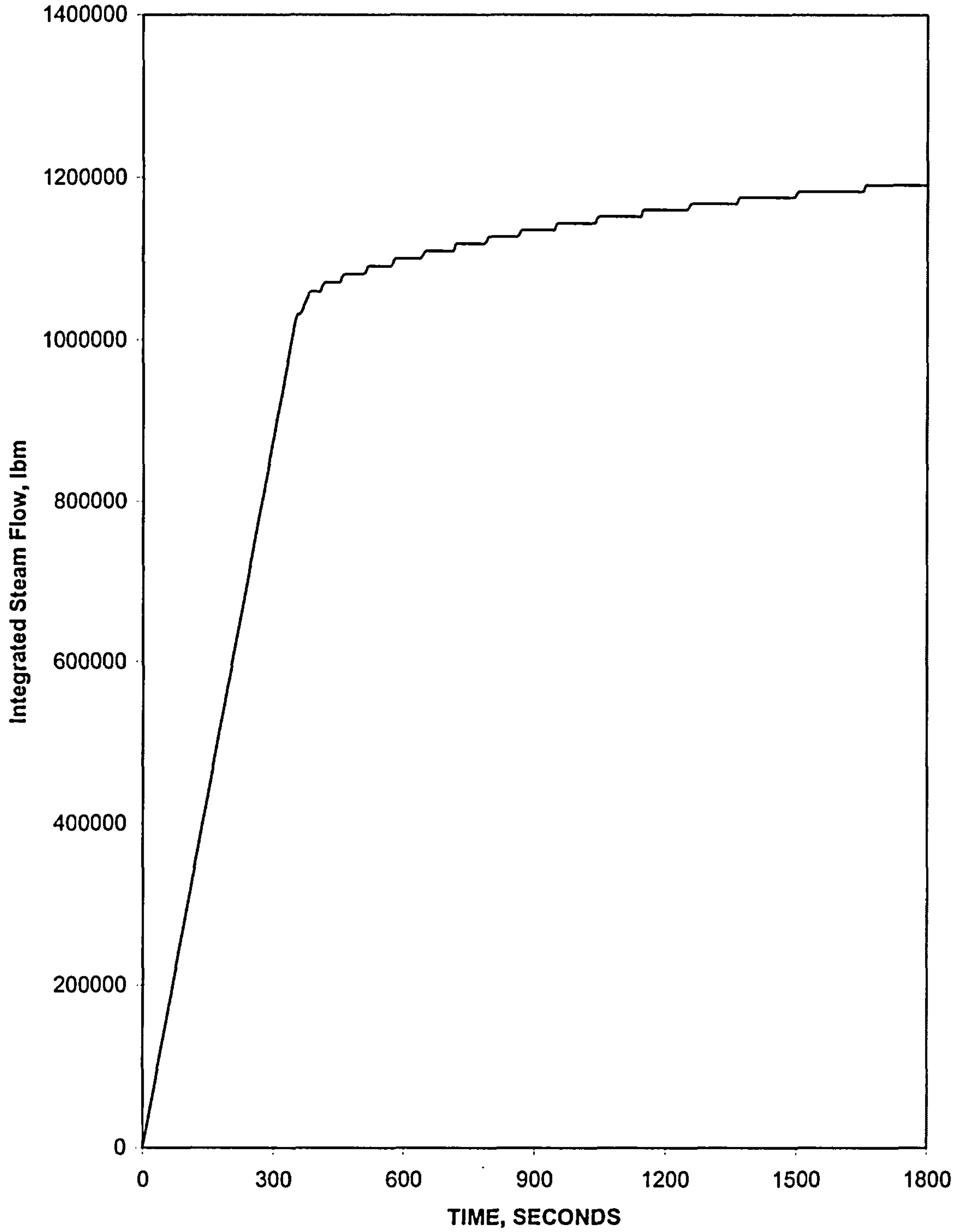

Figure 5.1.24-7
Steam Generator Tube Rupture with Loss of Offsite Power
Integrated Steam Flow

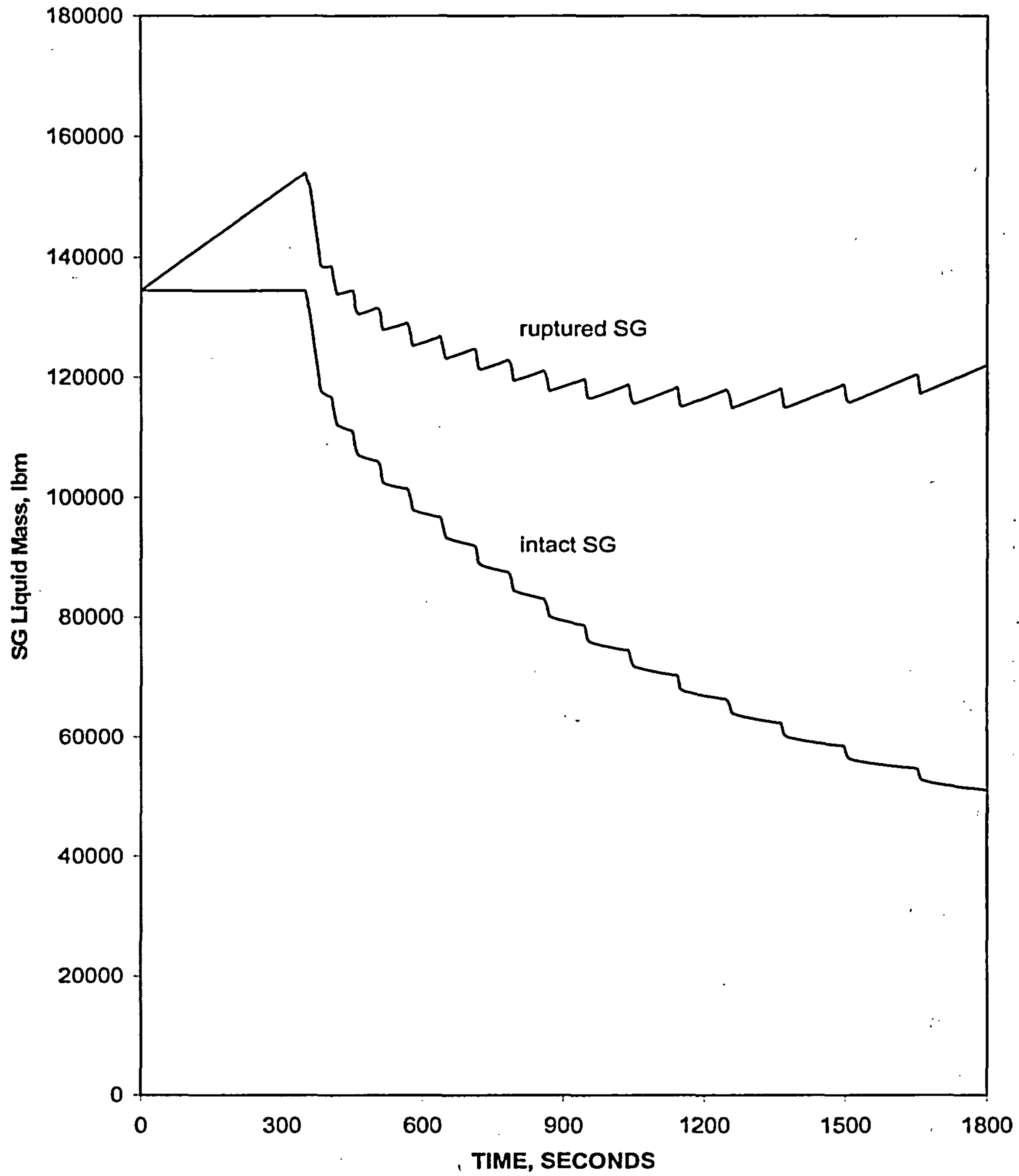

Figure 5.1.24-8
Steam Generator Tube Rupture with Loss of Offsite Power
Water Mass

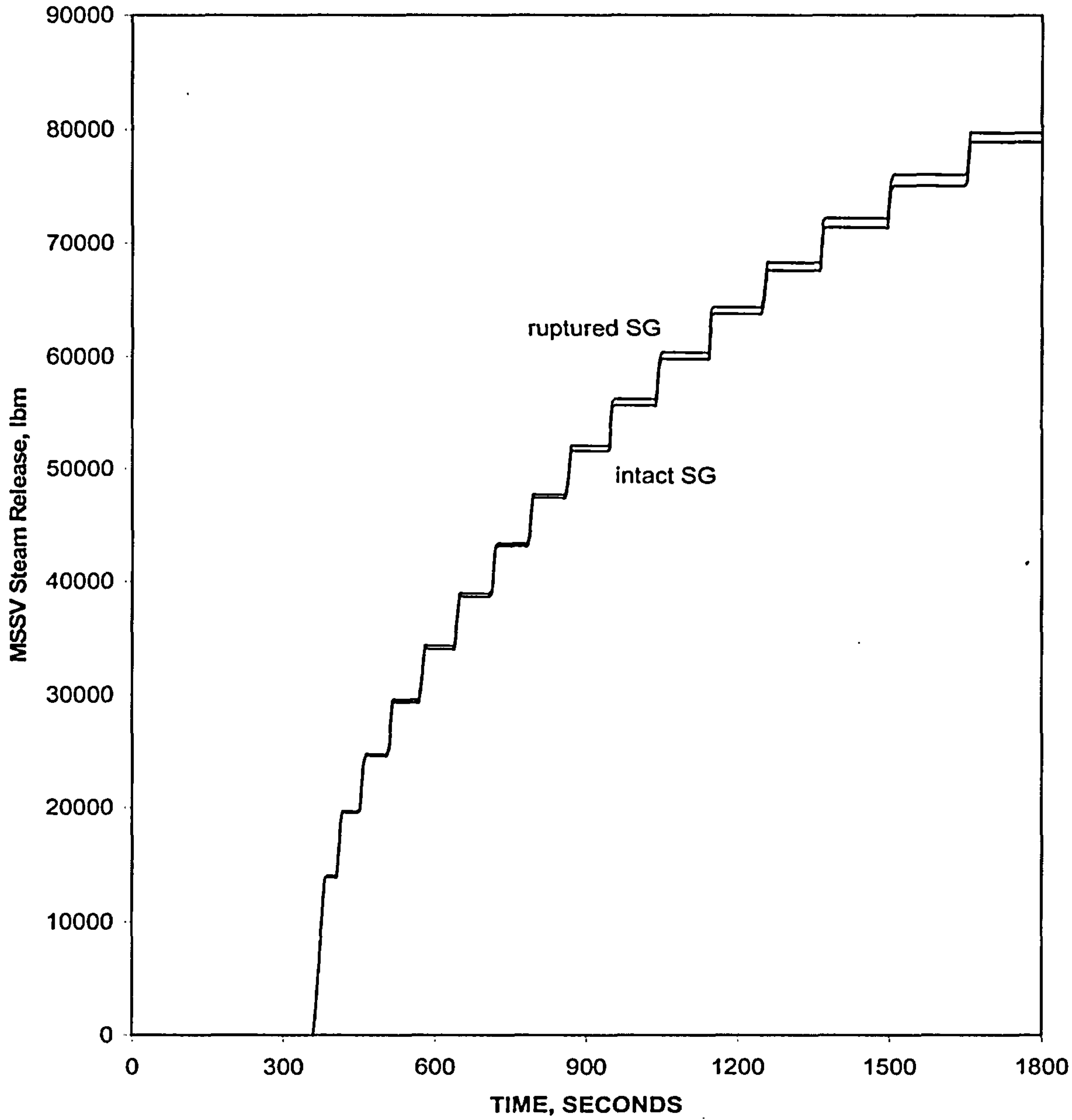

Figure 5.1.24-9
Steam Generator Tube Rupture with Loss of Offsite Power
Steam Releases

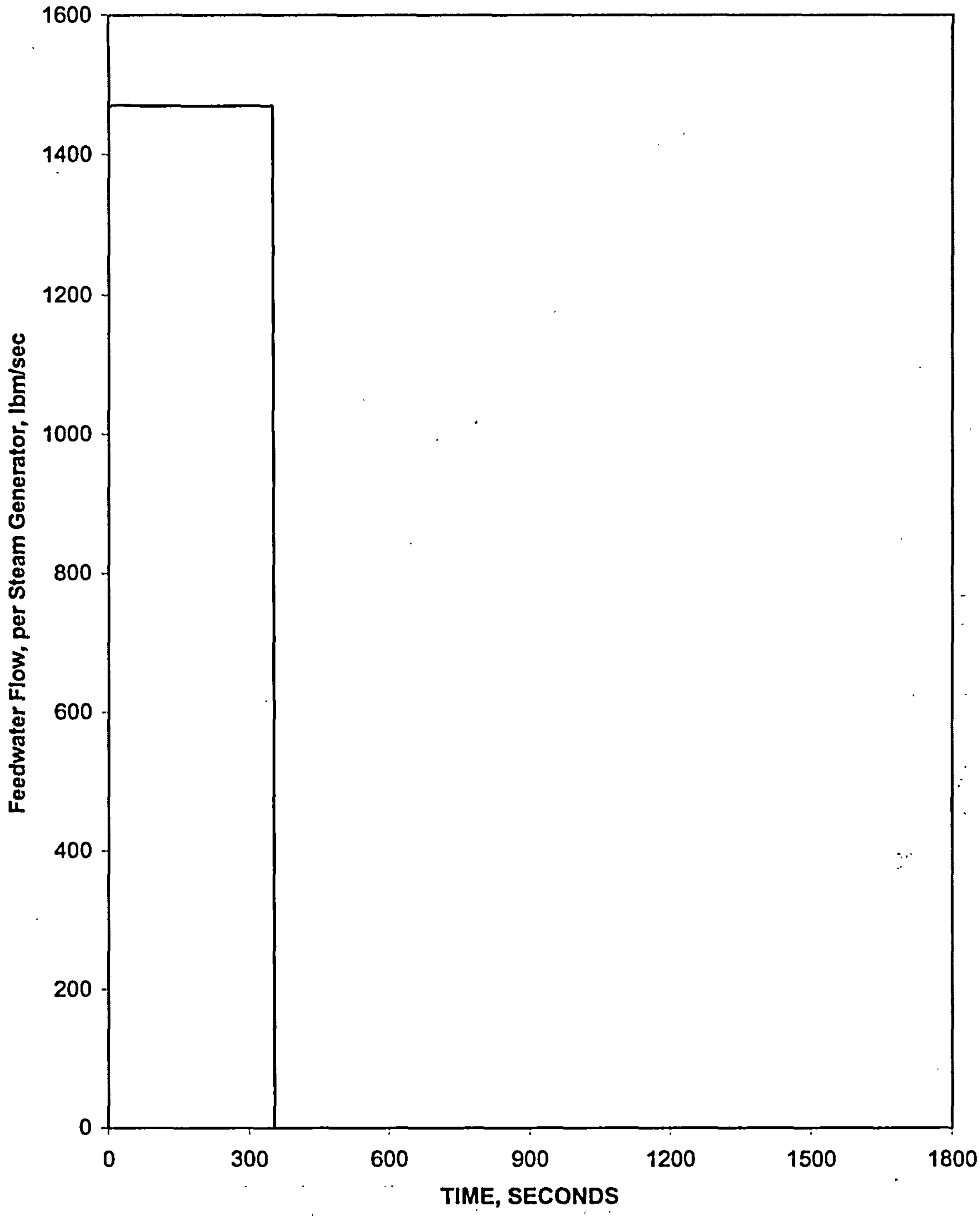

Figure 5.1.24-10
Steam Generator Tube Rupture with Loss of Offsite Power
Feedwater Flow

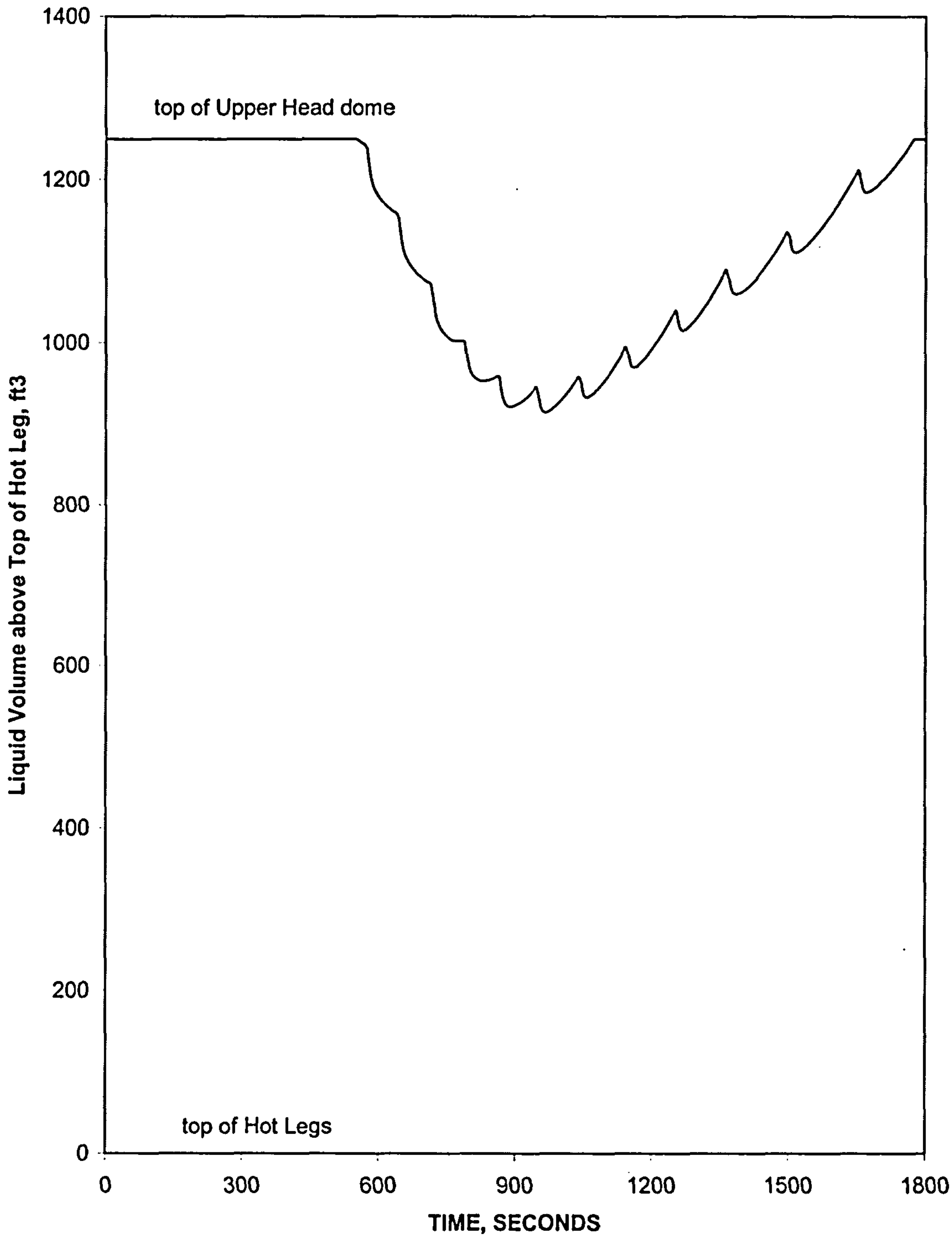

Figure 5.1.24-11
Steam Generator Tube Rupture with Loss of Offsite Power
Liquid Volume Above Top of Hot Leg

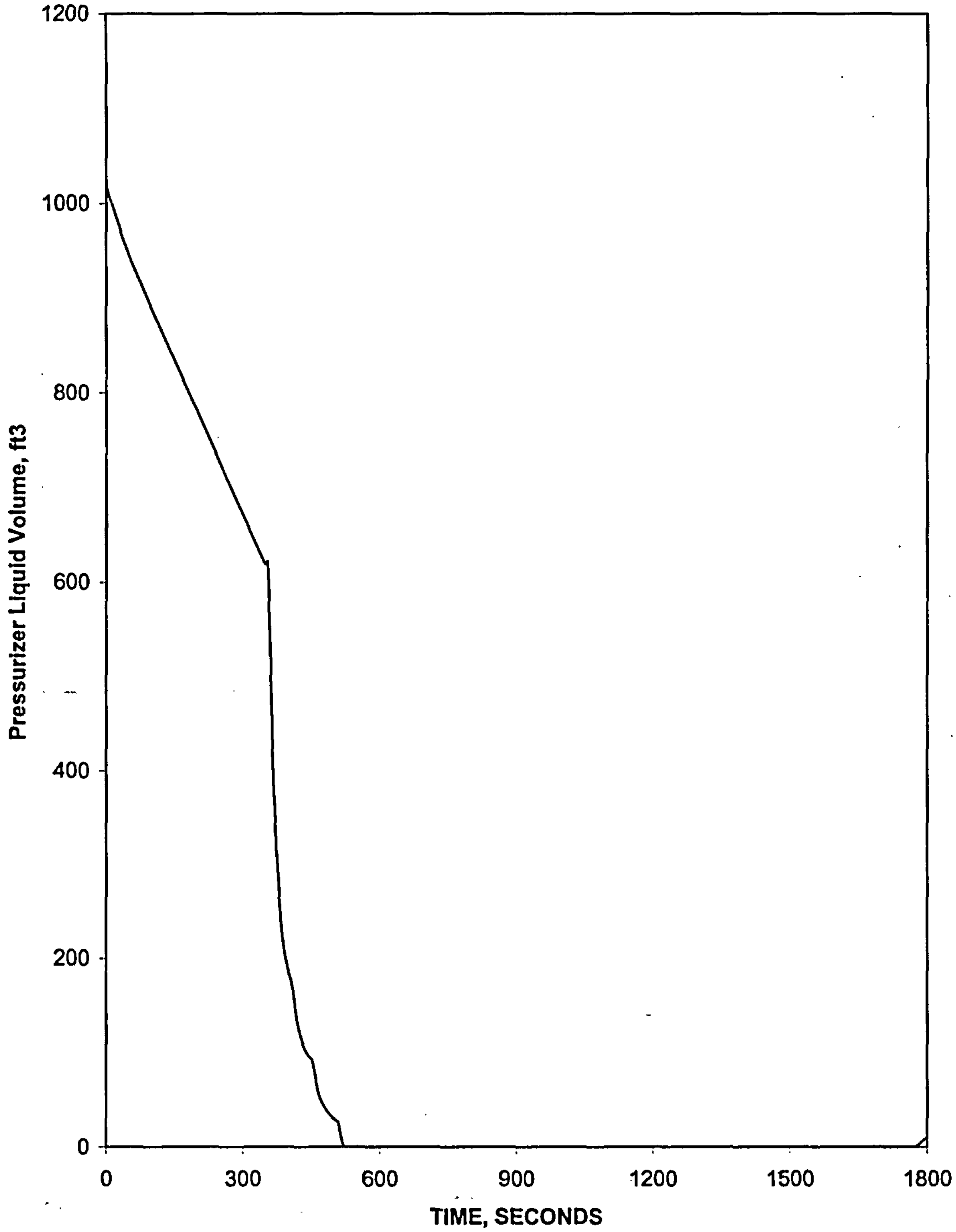

Figure 5.1.24-12
Steam Generator Tube Rupture with Loss of Offsite Power
PZR Water Volume

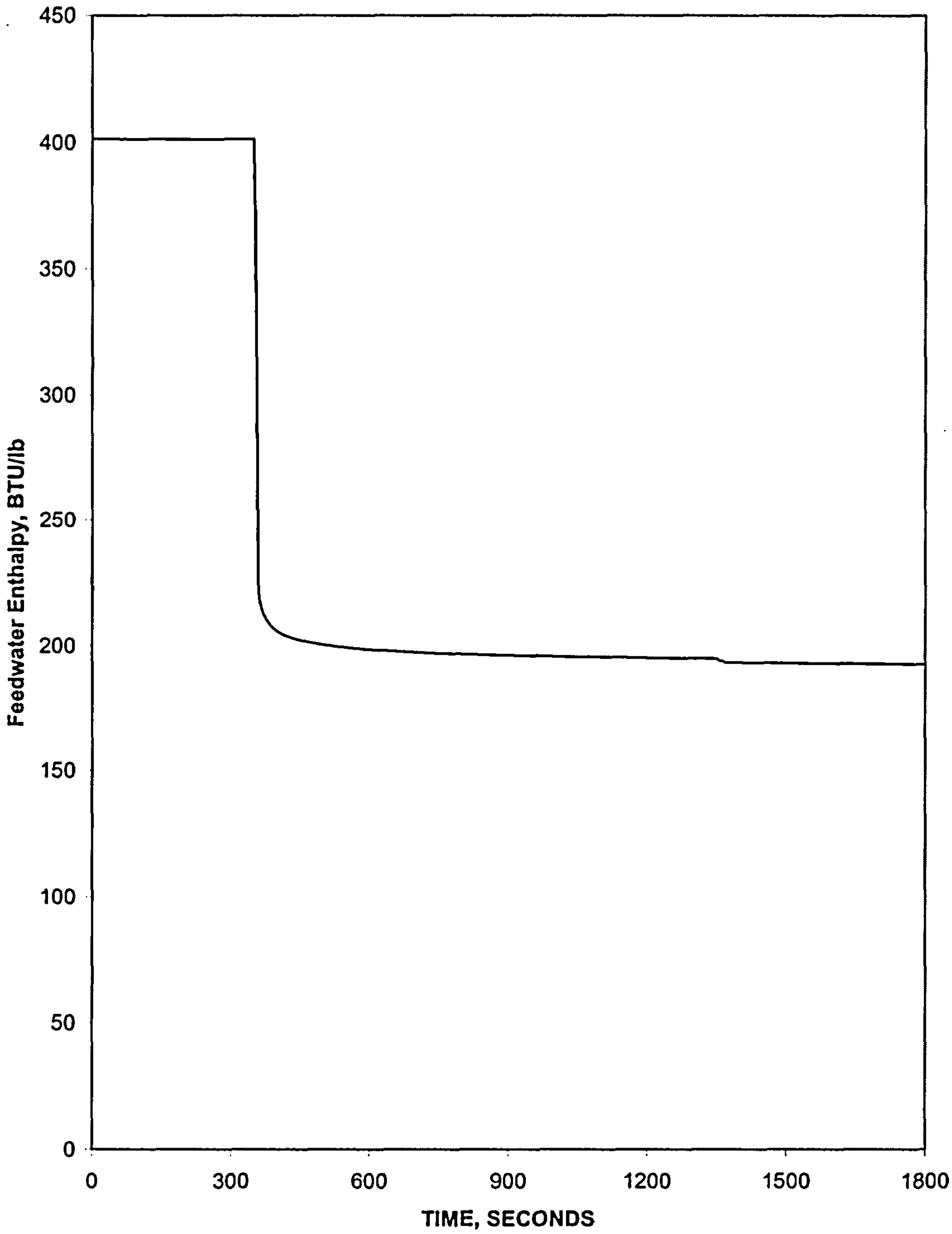

Figure 5.1.24-13
Steam Generator Tube Rupture with Loss of Offsite Power
Feedwater Enthalpy

5.2 ECCS PERFORMANCE

5.2.1 Introduction

This section provides the emergency core cooling system (ECCS) performance analysis for St. Lucie Unit 2 with 42% steam generator tube plugging (SGTP), a reduced technical specification minimum reactor coolant system (RCS) flow rate of 300,000 gpm and a core power limit of 89%. The objective of the analysis is to demonstrate conformance to the ECCS acceptance criteria in 10 CFR 50.46(b) for St. Lucie Unit 2 with 42% SGTP and the associated reduction in RCS flow rate. The ECCS performance analysis consists of three individual analyses, namely, the large-break loss-of-coolant accident (LBLOCA), small-break loss-of-coolant accident (SBLOCA) and post-LOCA long-term cooling analyses.

Section 5.2.2 identifies the acceptance criteria for the ECCS performance analysis. Sections 5.2.3 through 5.2.5 summarize the LBLOCA, SBLOCA, and post-LOCA long-term cooling analyses. The summaries include a description of the methodology, the plant design data, and the results of the analyses. The conclusions of the ECCS performance analysis are presented in Section 5.2.6.

5.2.2 Acceptance Criteria

Five acceptance criteria for ECCS performance analyses are specified in 10 CFR 50.46(b), Reference 5.2-1; they are as follows.

Criterion 1: Peak Cladding Temperature: 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.

Additionally, 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 10 CFR 50.46(a)(1)(i) or must conform to the required and acceptable features of Appendix K ECCS Evaluation Models (Reference 5.2-2). The evaluation models used to perform the St. Lucie Unit 2 ECCS performance analysis for 42% SGTP are Appendix K evaluation models.

5.2.3 Large-Break LOCA

5.2.3.1 Methodology

The LBLOCA ECCS performance analysis used the 1999 evaluation model (EM) version of the Westinghouse LBLOCA evaluation model for Combustion Engineering designed pressurized water reactors (PWRs) (References 5.2-3, 5.2-4). The current St. Lucie Unit 2 LBLOCA analysis (Reference 5.2-5) was based on the same EM for full power operation with up to 30% SGTP.

Several computer codes are used in the 1999 EM. The computer codes are described in the references cited below with additional descriptive information provided in the 1999 EM topical report (Reference 5.2-3). The CEFLASH-4A computer code (Reference 5.2-6) is used to perform the blowdown hydraulic analysis of the RCS and the COMPERC-II computer code (Reference 5.2-7) is used to perform the RCS refill/reflood hydraulic analysis and to calculate the minimum containment pressure. It is also used in conjunction with the methodology described in Reference 5.2-8 to calculate the FLECHT-based reflood heat transfer coefficients used in the hot rod heatup analysis. The HCROSS (Reference 5.2-9) and PARCH (Reference 5.2-10) computer codes are used to calculate steam cooling heat transfer coefficients. The hot rod heatup analysis, which calculates the peak cladding temperature and maximum cladding oxidation, is performed with the STRIKIN-II computer code (Reference 5.2-11). Core-wide cladding oxidation is calculated using the COMZIRC computer code (Appendix C of Supplement 1 of Reference 5.2-7). The 1999 EM uses the models for ZIRLO™ cladding that are described in Section 6 of Reference 5.2-12. The initial steady state fuel rod conditions used in the LBLOCA analysis are determined using the FATES3B computer code (Reference 5.2-13).

The Safety Evaluation Reports for the evaluation model and computer code topical reports that comprise the 1999 EM are documented in References 5.2-14 through 5.2-22.

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 UO_2 fuel rods with both Zircaloy-4 and ZIRLO™ cladding. Gadolinia integral fuel burnable absorber fuel rods with 4 to 8 wt% gadolinia, operate at less than 90% power relative to the power of the peak UO_2 fuel rod and were therefore not analyzed for the limiting LBLOCA ECCS performance analyses with 42% SGTP.

The analysis included a study to determine the most limiting single failure of ECCS equipment. The study analyzed no failure, failure of an emergency diesel generator, and failure of a low pressure safety injection (LPSI) pump. 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 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 30 seconds. The most limiting single failure (i.e., the failure that resulted in the highest calculated peak cladding temperature) was no failure of ECCS equipment. 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 emergency diesel generator or an LPSI pump is not the most damaging failure because, in both cases, there is sufficient safety injection pump flow to keep the reactor vessel downcomer filled to the cold leg

nozzles. This maintains the same driving force for reflooding the core as for no failure, but results in less spillage into the containment. A study was also performed to investigate the impact of variations in safety injection tank (SIT) operating parameters and refueling water tank temperature on peak cladding temperature. The combination of minimum temperature and pressure and maximum water volume and injection line flow resistance for the SITs and minimum refueling water tank temperature was determined to result in the highest peak cladding temperature.

A spectrum of guillotine breaks in the reactor coolant pump discharge leg was analyzed. As described in Section 3.4 of Reference 5.2-3, the discharge leg is the most limiting break location and a guillotine break is more limiting than a slot break. In particular, the 1.0, 0.8, 0.6, 0.4, and 0.3 Double-Ended Guillotine breaks in the reactor coolant Pump Discharge leg (DEG/PD) were analyzed. The 0.4 DEG/PD break was determined to be the limiting large break LOCA (i.e., the break that results in the highest calculated peak cladding temperature).

5.2.3.2 Input Assumptions

Important core, RCS, ECCS, and containment design data used in the large break LOCA analysis are listed in Table 5.2.3.2-1. The fuel rod conditions listed in Table 5.2.3.2-1 are for the hot rod burnup that produced the highest calculated peak cladding temperature. 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. Table 5.2.3.2-1 also contains the important core and plant design data for the previous analysis at 100% operating power with 30% SGTP.

5.2.3.3 Results

Table 5.2.3.3-1 lists the peak cladding temperature and oxidation percentages for the spectrum of large break LOCAs. Times of interest are listed in Table 5.2.3.3-2. Tables 5.2.3.3-1 and 5.2.3.3-2 also contain the results and times of interest for the previous analysis at 100% rated thermal power with 30% SGTP. The variables listed in Table 5.2.3.3-3 are plotted as a function of time for each break size in Figures 5.2.3.3-1 through 5.2.3.3-27 and Figures 5.2.3.3-39 through 5.2.3.3-47. The additional variables listed in Table 5.2.3.3-4 are plotted for the 0.4 DEG/PD break, the limiting large break LOCA, in Figures 5.2.3.3-28 through 5.2.3.3-38. The results demonstrate conformance to the ECCS acceptance criteria as summarized below.

Parameter	Criterion	Result
Peak Cladding Temperature	≤2200°F	2112°F
Maximum Cladding Oxidation	≤17%	16.54%
Maximum Core-Wide Oxidation	≤1%	<1%
Coolable Geometry	Yes	Yes

The results are applicable to St. Lucie Unit 2 with up to 42% tube plugging in each steam generator, a tube plugging differential between the two steam generators of up to 800 tubes, 89% core power, and a minimum RCS flow rate of 300,000 gpm.

5.2.4 Small-Break LOCA

5.2.4.1 Methodology

The SBLOCA ECCS performance analysis used the Supplement 2 version (referred to as the S2M or Supplement 2 Model) of the Westinghouse SBLOCA evaluation model for Combustion Engineering designed PWRs (References 5.2-23, 5.2-24). The current St. Lucie Unit 2 SBLOCA analysis (Reference 5.2-5) was based on the same EM for full power operation with up to 30% SGTP.

In the S2M evaluation model, the CEFLASH-4AS computer program (Reference 5.2-25) is used to perform the hydraulic analysis of the RCS until the time the SITs begin to inject. After injection from the SITs begins, the COMPERC-II computer program (Reference 5.2-7) is used to perform the hydraulic analysis. The hot rod cladding temperature and maximum cladding oxidation are calculated by the STRIKIN-II computer program (Reference 5.2-11) during the initial period of forced convection heat transfer and by the PARCH computer program (Reference 5.2-10) 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 S2M uses the models for ZIRLO™ cladding that are described in Section 6 of Reference 5.2-12. The initial steady state fuel rod conditions used in the SBLOCA analysis are determined using the FATES3B computer program (Reference 5.2-13).

The Safety Evaluation Reports for the evaluation model and computer code topical reports that comprise the S2M are documented in References 5.2-26 and 5.2-27 as well as several of the Safety Evaluation Reports identified in Section 5.2.3.1.

The COMPERC-II computer code was not run for this analysis because flow from the SITs was not credited in the analysis even if the RCS was calculated to depressurize below the minimum SIT gas pressure. Table 5.2.3.3-2 identifies when SIT injection would have begun if it were credited.

The break spectrum analysis was performed for the fuel rod conditions at the burnup that results in the maximum initial stored energy in the fuel. In addition, the rod internal pressure was adjusted to cause cladding rupture to occur at the time that resulted in the highest peak cladding temperature and highest cladding oxidation. The calculations included the analysis of both UO_2 fuel rods and gadolinia burnable absorber fuel rods and Zircaloy-4 and ZIRLO™ cladding.

The analysis was performed using the failure of an emergency diesel generator as the most limiting single failure of the ECCS. This failure causes the loss of both a high pressure safety injection (HPSI) pump and a 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 St. Lucie Unit 2 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. However, 50% of the flow from one LPSI pump is available to cool the core given a failure of an emergency diesel generator and a break in the reactor coolant pump discharge leg.

A spectrum of three break sizes in the reactor coolant pump discharge leg was analyzed. The reactor coolant pump discharge leg is the limiting break location because it maximizes the amount of spillage from the ECCS. In particular, the 0.04, 0.045, and 0.05 ft^2/PD breaks were analyzed. The 0.045 ft^2/PD break was

determined to be the limiting SBLOCA (i.e., the break that results in the highest calculated peak cladding temperature). The 0.04, 0.045, and 0.05 ft^2/PD breaks are at the upper end of the range of break sizes for which the hot rod cladding heatup transient is terminated solely by injection from a HPSI pump. It is within this range of break sizes that the limiting SBLOCA resides. Smaller breaks are too small to experience as much core uncovery as these breaks. For larger breaks, injection from the SITs and a HPSI pump recovers the core and terminates the heatup of the cladding before the cladding temperature approaches the peak cladding temperature of the limiting SBLOCA.

5.2.4.2 Input Assumptions

Important core, RCS, and ECCS design data used in the SBLOCA analysis are listed in Tables 5.2.4.2-1 and 5.2.4.2-2.

5.2.4.3 Results

Table 5.2.4.3-1 lists the peak cladding temperature and oxidation percentages for the spectrum of SBLOCAs. Times of interest are listed in Table 5.2.4.3-2. The variables listed in Table 5.2.4.3-3 are plotted as a function of time for each break size in Figures 5.2.4.3-1 through 5.2.4.3-24. The results for the 0.045 ft^2/PD break, the limiting SBLOCA, demonstrate conformance to the ECCS acceptance criteria as summarized below.

Parameter	Criterion	Result
Peak Cladding Temperature	≤ 2200°F	1477°F
Maximum Cladding Oxidation	≤ 17%	1.8 %
Maximum Core-Wide Oxidation	≤ 1%	< 0.18%
Coolable Geometry	Yes	Yes

The results are applicable to St. Lucie Unit 2 with up to 42% tube plugging in each steam generator, a tube plugging differential between the two steam generators of up to 800 tubes, a core power of 2452 MWt (including uncertainty) and a minimum RCS flow rate of 300,000 gpm.

5.2.5 Post-LOCA Long-Term Cooling

5.2.5.1 Methodology

The post-LOCA long-term cooling analysis used the Westinghouse post-LOCA long-term cooling evaluation model for Combustion Engineering designed PWRs, CENPD-254-P-A (Reference 5.2-28) with the exception noted below. The St. Lucie Unit 2 long-term cooling analysis for 30% SGTP (Reference 5.2-5) used the CENPD-254-P-A evaluation model without the exception noted below. The Safety Evaluation Report documenting NRC approval of CENPD-254-P-A is contained in Reference 5.2-28. In a letter dated August 1, 2005, (Reference 5.2-29) NRC suspended approval of CENPD-254-P-A because of concerns enumerated in a Technical Evaluation enclosed in the letter. FPL, Westinghouse, and NRC staff discussed an approach for the 42% SGTP long-term cooling analysis in light of the August 1, 2005 letter during a 42% SGTP project status meeting held on September 1, 2005 at NRC headquarters in Rockville, Maryland. The analysis described herein uses the approach discussed in that meeting.

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 was 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 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 boric acid precipitation analysis was performed with the BORON computer code (Reference 5.2-28, Appendix C). The decay heat removal analysis was performed with the CELDA, NATFLOW, and CEPAC computer codes (Reference 5.2-28, Appendices A, B, and D).

The boric acid precipitation analysis used a boric acid concentration of 27.6 wt% as the solubility limit of boric acid without crediting the effects of trisodium phosphate present in the containment sump. This is the solubility limit of boric acid in a boric acid-water solution at 212°F (i.e., the boiling point of pure water at 14.7 psia). Atmospheric pressure is a conservative minimum value for the core pressure following a LBLOCA.

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. The St. Lucie Unit 2 boric acid precipitation analysis for 42% SGTP used a mixing volume that consisted of the following:

- 50% of the volume of the lower plenum;
- The liquid volume in the core and outlet plenum up to the elevation of the bottom of the hot legs.

The liquid volume in the core was calculated using the CEFLASH-4AS phase separation model (Reference 5.2-24). The liquid volume in the outlet plenum was calculated by applying the core-to-outlet plenum area ratio to the core exit void fraction, which was calculated using the CEFLASH-4AS phase separation model. A calculation of the heads of liquid in the downcomer and the mixing volume and the pressure drop from the core to the break confirmed that the bottom of the hot legs is a conservative value for the elevation of the top of the mixing volume over the time period of interest. The 30% SGTP boric acid precipitation analysis used a different definition of the mixing volume, the most significant difference being that it did not account for voids in the core and outlet plenum.

The exception to the CENPD-254-P-A evaluation model that was implemented in the analysis is associated with the treatment of the inventory of the Boric Acid Makeup Tanks (BAMTs) in the boric acid precipitation

analysis. In accordance with Item 3 on page C-2 of Reference 5.2-28, the CENPD-254-P-A evaluation model assumes that the inventory of the BAMTs is directly deposited in the mixing volume before any consideration is given to other sources of boric acid. In other words, it is assumed that there is no loss of the BAMT inventory out the broken cold leg due to either (1) injection of BAMT inventory into the broken cold leg or (2) spillage of BAMT inventory injected into the intact cold legs that subsequently flows through the downcomer to the broken cold leg. In this analysis, the BAMT inventory, which is injected via the charging pumps, is assumed to mix in the intact cold legs with the safety injection pump flow from the Refueling Water Tank (RWT). The resultant mixture then supplies the flow to the mixing volume with the excess spilling to the containment sump. This modification was implemented by changing the BORON inputs for the boric acid concentrations of the BAMTs and RWT to the mixed mean concentration of these two sources.

As described in response to an NRC request for additional information (page 5 of Amendment 1 of Reference 5.2-28), the decay heat model used in the CENPD-254-P-A evaluation model uses a multiplier of 1.2 up to 1000 seconds and 1.1 after 1000 seconds. As discussed in the September 1, 2005 42% SGTP project status meeting, the 42% SGTP post-LOCA long-term cooling analysis was also performed using a multiplier of 1.2 after 1000 seconds. In conformance with the CENPD-254-P-A evaluation model, the 42% SGTP analysis uses a multiplier of 1.1 after 1000 seconds. However, a supplementary analysis was performed with the 1.2 multiplier. In addition to the detailed results for the analysis using a decay heat multiplier of 1.1 after 1000 seconds, the results of the supplementary analysis are described herein.

The methodology described above for the boric acid precipitation analysis is more conservative than that used in the Waterford 3 extended power uprate boric acid precipitation analysis (Reference 5.2-30), which was approved by the NRC in Reference 5.2-31. Table 5.2.5.1-1 compares important features of the two methodologies.

5.2.5.2 Input Assumptions

Important plant design data used in the 42% SGTP post-LOCA long-term cooling analysis are listed in Table 5.2.5.2-1. The data used in the 30% SGTP analysis are also provided for comparison.

5.2.5.3 Results

The post-LOCA boric acid precipitation analysis determined that a minimum flow rate of 275 gpm from a HPSI pump to both the hot and cold legs of the RCS, initiated between two and six hours post-LOCA, maintains the boric acid concentration in the core below the solubility limit of 27.6 wt% 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 two hours post-LOCA.

Figures 5.2.5.3-1a and 5.2.5.3-1b compare the core boil-off rate with the minimum simultaneous hot and cold leg injection flow rate of 275 gpm with a decay heat multiplier of 1.1 and 1.2 after 1000 seconds respectively. Both Figures show that the initiation of 275 gpm of hot and cold leg injection at six hours post-LOCA provides a substantial and time-increasing flushing flow through the core. Figures 5.2.5.3-2a and 5.2.5.3-2b present the core boric acid concentration as a function of time for the limiting break with a decay heat multiplier of 1.1 and 1.2 after 1000 seconds, respectively. Figure 5.2.5.3-2a shows that with a decay heat multiplier of 1.1 after 1000 seconds and without simultaneous hot and cold leg injection, the boric acid concentration in the core exceeds the solubility limit at approximately 9.7 hours post-LOCA. When 275 gpm

of simultaneous hot and cold leg injection is initiated at six hours post-LOCA, the maximum boric acid concentration in the core is 20.0 wt%, a margin of 7.6 wt% to the solubility limit of 27.6 wt%. Figure 5.2.5.3-2a also shows that a flushing flow rate of 25 gpm started by six hours post-LOCA is sufficient to prevent the core boric acid concentration from reaching the solubility limit. Figure 5.2.5.3-2b shows that with a decay heat multiplier of 1.2 after 1000 seconds and without simultaneous hot and cold leg injection, the boric acid concentration in the core exceeds the solubility limit at approximately 8.5 hours post-LOCA. When 275 gpm of simultaneous hot and cold leg injection is initiated at six hours post-LOCA, the maximum boric acid concentration in the core is 21.8 wt%, a margin of 5.8 wt% to the solubility limit of 27.6 wt%. Figure 5.2.5.3-2b also shows that a flushing flow rate of 25 gpm started by six hours post-LOCA is sufficient to prevent the core boric acid concentration from reaching the solubility limit. Table 5.2.5.3-1 compares the results of the analysis with a decay heat multiplier of 1.1 after 1000 seconds to those of the supplementary analysis performed with a decay heat multiplier of 1.2 after 1000 seconds and to the results of the 30% SGTP boric acid precipitation analysis.

Figure 5.2.5.3-3 presents the sequence of events and time schedule for the operator actions that comprise the St. Lucie Unit 2 long-term cooling plan. As described below, this figure is supported by the analysis with a decay heat multiplier of 1.1 after 1000 seconds and the supplementary analysis performed with a decay heat multiplier of 1.2 after 1000 seconds. 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 16 hours and a decision pressure of 180 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 0.005 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. The supplementary analysis performed for a decay heat multiplier of 1.2 after 1000 seconds produced similar results. In particular, it supports the same decision time, decision pressure, and overlap of break ranges. Table 5.2.5.3-2 compares important results of the 42% SGTP decay heat removal analysis to those of the 30% SGTP analysis.

Figure 5.2.5.3-4 is a plot of break area versus RCS refill time. Figure 5.2.5.3-5 is a plot of RCS pressure at the decision time of 16 hours post-LOCA versus break area. Figure 5.2.5.3-6 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). The three figures discussed above are for the case with a decay heat multiplier of 1.1 after 1000 seconds.

In summary, the results of the post-LOCA long-term cooling analysis, including the results of the supplementary analysis performed with a decay heat multiplier of 1.2 after 1000 seconds, demonstrate conformance to Criterion 5 of the ECCS acceptance criteria. The results are applicable to St. Lucie Unit 2 with up to 42% tube plugging in each steam generator, a tube plugging differential between the two steam generators of up to 800 tubes, a minimum RCS flow rate of 300,000 gpm, and a maximum core power of 2452 MWt (including a 2% power measurement uncertainty).

5.2.6 Conclusions

An ECCS performance analysis was performed for St. Lucie Unit 2 with 42% SGTP, a core power of 89% and a reduced technical specification minimum RCS flow rate of 300,000 gpm. 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 peak cladding temperature, was determined to be the 0.4 DEG/PD break.

The results of the analysis demonstrate conformance to the ECCS acceptance criteria at a rated core power of 2452.08 MWt (2404 MWt including a 2% power measurement uncertainty based on 89% power) and a peak linear heat generator rate (PLHGR) of 12.0 kw/ft as follows:

Criterion 1: Peak Cladding Temperature: The calculated maximum fuel element cladding temperature shall not exceed 2200°F.

Result: The ECCS performance analysis calculated a peak cladding temperature of 2112°F for the 0.4 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 16.54% of the total cladding thickness before oxidation for the 0.4 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 (i.e., a maximum core-wide cladding oxidation) of less than 1% of the hypothetical amount for the 0.4 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 large-break and small-break LOCA ECCS performance analyses demonstrated that the St. Lucie Unit 2 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 tank 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.

5.2.7 References

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Table 5.2.3.2-1 LBLOCA ECCS Performance Analysis Core and Plant Design Data			
Quantity	**Value for 30% SGTP**	**Value for 42% SGTP**	**Units**
Reactor power level (102% of operating power)	2754	2452.08	MWt
PLHGR of the hot rod	12.5	12.0	kW/ft
PLHGR of the average rod in assembly with hot rod	11.2	10.79	kW/ft
Gap conductance at the PLHGR(1)	1660	1414	BTU/hr-ft^2-°F
Fuel centerline temperature at the PLHGR(1)	3255.4	3006.5	°F
Fuel average temperature at the PLHGR(1)	2061.55	1960.96	°F
Hot rod gas pressure(1)	1002.8	970.31	psia
Moderator temperature coefficient at initial density	$0.3x10^{-4}$	$0.3x10^{-4}$	Δρ/°F
RCS flow rate	$128.9x10^6$	$115.4x10^6$	lbm/hr
Core flow rate	$124.1x10^6$	$111.1x10^6$	lbm/hr
RCS pressure	2250	2250	psia
Cold leg temperature	532	532	°F
Hot leg temperature	588	588	°F
Number of plugged tubes per steam generator	2520	3535	—
Low pressurizer pressure SIAS setpoint	1646	1646	psia
Safety injection tank pressure (min/max)	499.7 / 679.7	499.7 / 679.7	psia
Safety injection tank water volume (min/max)	1388 / 1588	1388 / 1588	ft^3
LPSI+HPSI pump flow rate (min, 1 train/max, 2 trains)	2843 / 7480	2844 / 7480	gpm
Containment pressure	13.782	13.782	psia
Containment temperature	90.0	90.0	°F
Containment humidity	100.0	100.0	%
Containment net free volume	$2.6313x10^6$	$2.6313x10^6$	ft^3
Containment spray pump flow rate	3450	3450	gpm/pump
Refueling water tank temperature	51.0	51.0	°F

(1) These quantities correspond to the rod average burnup of the hot rod (500 MWD/MTU) that yields the highest peak cladding temperature.

Table 5.2.3.3-1 LBLOCA ECCS Performance Analysis Results						
	Peak Cladding Temperature (°F)		Maximum Cladding Oxidation (%)		Maximum Core-Wide Cladding Oxidation (%)	
Break Size	30% SGTP	42% SGTP	30% SGTP	42% SGTP	30% SGTP	42% SGTP
1.0 DEG/PD	2091	2000	14.26	11.68	<1.0	<1.0
0.8 DEG/PD	2097	2046	14.48	13.32	<1.0	<1.0
0.6 DEG/PD	2130	2058	16.10	14.16	<1.0	<1.0
0.4 DEG/PD	2092	2112	14.85	16.54	<1.0	<1.0
0.3 DEG/PD	--	2050	--	14.60	--	<1.0

Table 5.2.3.3-2 LBLOCA ECCS Performance Analysis Times of Interest (seconds after break)										
	SITs On		Time of Annulus Downflow		Start of Reflood		SITs Empty		Hot Rod Rupture	
Break Size	30% SGTP	42% SGTP	30% SGTP	42% SGTP	30% SGTP	42% SGTP	30% SGTP	42% SGTP	30% SGTP	42% SGTP
1.0 DEG/PD	10.7	10.5	21.8	21.8	38.0	38.0	111.0	110.9	53.6	64.5
0.8 DEG/PD	11.9	11.7	23.2	22.9	39.1	38.8	112.4	112.2	52.0	58.1
0.6 DEG/PD	14.2	13.8	25.5	25.3	41.0	40.8	114.7	114.5	47.2	55.2
0.4 DEG/PD	18.8	18.0	30.9	29.8	45.4	44.5	119.9	118.7	50.8	47.4
0.3 DEG/PD	--	22.4	--	35.6	--	49.3	--	124.5	--	57.6

Table 5.2.3.3-3 LBLOCA ECCS Performance Analysis Variables Plotted as a Function of Time for Each Break
Variable
Core Power
Pressure in Center Hot Assembly Node
Break Flow Rate
Hot Assembly Flow Rate (Below Hot Spot)
Hot Assembly Flow Rate (Above Hot Spot)
Hot Assembly Quality
Containment Pressure
Mass Added to Core During Reflood
Peak Cladding Temperature[(1)]
(1) The cladding temperature at the elevation of cladding rupture is also shown for the limiting break.

Table 5.2.3.3-4 LBLOCA ECCS Performance Analysis Variables Plotted as a Function of Time for the Limiting Break
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 Rod Internal Gas Pressure
Core Bulk Channel Flow Rate

Table 5.2.4.2-1 SBLOCA ECCS Performance Analysis Core and Plant Design Data			
Quantity	**30% SGTP Value**	**42% SGTP Value**	**Units**
Reactor power level (102% of operating power)	2754	2452	MWt
Peak linear heat generation rate	13.0	13.0	kW/ft
Axial shape index	-0.15	-0.15	asiu
Moderator temperature coefficient at initial density	0.3×10^{-4}	0.3×10^{-4}	$\Delta\rho$/°F
RCS flow rate	335,000	300,000	gpm
RCS pressure	2250	2250	psia
Cold leg temperature	552.0	552.0	°F
Hot leg temperature	607.9	607.2	°F
Number of plugged tubes per steam generator	2520	3533	—
MSSV first bank opening pressure	1029	1029	psia
Low pressurizer pressure reactor trip setpoint	1810	1810	psia
Low pressurizer pressure SIAS setpoint	1646	1646	psia
HPSI pump flow rate	Table 5.2.4.2-2	Table 5.2.4.2-2	gpm
Safety injection tank pressure	500	500	psia

Table 5.2.4.2-2 High Pressure Safety Injection Pump Minimum Delivered Flow to RCS (Assuming Failure of an Emergency Diesel Generator) Unchanged from 30% to 42% SGTP	
RCS Pressure (psia)	**Flow Rate (gpm)**
1198	0
1177	100
1104	200
1035	250
943	300
829	350
699	400
551	450
393	500
217	550
0	604

(1) The flow is assumed to be split equally to each of the four discharge legs.
(2) The flow to the broken discharge leg is assumed to spill out the break.

Table 5.2.4.3-1a 30% SGTP SBLOCA ECCS Performance Analysis Results			
Break Size	Peak Cladding Temperature (°F)	Maximum Cladding Oxidation (%)	Maximum Core-Wide Cladding Oxidation (%)
0.04 ft^2/PD	1672	3.26	<0.28
0.05 ft^2/PD	1943	9.80	< 0.64
0.06 ft^2/PD	1818	5.61	<0.42

Table 5.2.4.3-1b 42% SGTP SBLOCA ECCS Performance Analysis Results			
Break Size	Peak Cladding Temperature (°F)	Maximum Cladding Oxidation (%)	Maximum Core-Wide Cladding Oxidation (%)
0.04 ft^2/PD	1443	1.50	<0.16
0.045 ft^2/PD	1477	1.80	< 0.18
0.05 ft^2/PD	1318	0.60	<0.10

Table 5.2.4.3-2a 30% SGTP SBLOCA ECCS Performance Analysis Times of Interest (seconds after break)				
Break Size	HPSI Flow Delivered to RCS	LPSI Flow Delivered to RCS	SIT Flow Delivered to RCS	Peak Cladding Temperature Occurs
0.04 ft^2/PD	168	(1)	2282(2)	2113
0.05 ft^2/PD	135	(1)	1587(2)	1700
0.06 ft^2/PD	114	(1)	1341(2)	1739

(1) Calculation completed before LPSI flow delivery to RCS begins.
(2) SIT injection calculated to begin but not credited in analysis.

Table 5.2.4.3-2b 42% SGTP SBLOCA ECCS Performance Analysis Times of Interest(seconds after break)				
Break Size	HPSI Flow Delivered to RCS	LPSI Flow Delivered to RCS	SIT Flow Delivered to RCS	Peak Cladding Temperature Occurs
0.04 ft^2/PD	168	(1)	2101(2)	1902
0.045 ft^2/PD	150	(1)	1769(2)	1796
0.05 ft^2/PD	138	(1)	1674(2)	1878

(1) Calculation completed before LPSI flow delivery to RCS begins.
(2) SIT injection calculated to begin but not credited in analysis.

Table 5.2.4.3-3 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

Table 5.2.5.1-1
Post-LOCA Long-Term Cooling Analysis
Comparison of Important Features of the Boric Acid Precipitation Analysis Methodology

Feature	St. Lucie Unit 2 42% SGTP Analysis	Waterford 3 Extended Power Uprate Analysis
Mixing volume accounts for voiding in core and outlet plenum	Yes	Yes
Mixing volume credits 50% of lower plenum liquid volume	Yes	Yes
Elevation of top of mixing volume	Bottom of hot legs	Top of hot legs
Boric acid solubility limit credits effect of tri-sodium phosphate present in containment sump	No (Solubility limit 27.6%)	Yes (Solubility limit 36%)
Injection from BAMT mixes with injection from RWT in reactor coolant pump discharge legs	Yes	Yes
Decay heat multiplier after 1000 seconds	1.1 (Supplementary analysis uses 1.2)	1.1

Table 5.2.5.2-1
Post-LOCA Long-Term Cooling Analysis
Core and Plant Design Data

Quantity	Value		Units
	30% SGTP	42% SGTP	
Reactor power level (including 2% uncertainty)	2754	2452	MWt
Number of plugged tubes per steam generator	2520	3533	—
SG/RCS cooldown rate	75	75	°F/hr
Shutdown cooling entry temperature	300	300	°F
RCS pressure measurement uncertainty	±90	±90	psi
Number of atmospheric dump valves/SG	1	1	—
Atmospheric dump valve flow rate, at 55 psia	51,300	51,300	lbm/hr/valve
Condensate storage tank volume	262,400	262,400	gal
Reactor coolant system			
liquid mass	456,000	456,000	lbm
boron concentration	2440	2440	ppm
Boric acid makeup tanks			
number	2	2	—
liquid volume per tank	9,975	9,975	gal
boric acid concentration	3.57	3.57	wt%
Refueling water tank			
liquid mass	4,325,565	4,325,565	lbm
boron concentration	2200	2200	ppm
Safety injection tanks			
number	4	4	—
liquid volume per tank	1588	1588	ft^3
boron concentration	2200	2200	ppm
Charging pumps			
number	3	3	—
flow rate per pump	49	49	gpm
Flow rates for emptying the RWT			
HPSI pump flow rate	548	548	gpm
LPSI pump flow rate	2426	2426	gpm
CS pump flow rate	2700	2700	gpm

Table 5.2.5.3-1 Post-LOCA Long-Term Cooling Analysis Comparison of Important Results of the 42% SGTP and 30% SGTP Boric Acid Precipitation Analyses			
Quantity	**42% SGTP Analysis**		**30% SGTP Analysis**
Decay heat multiplier after 1000 Seconds	1.2	1.1	1.1
Boric acid solubility limit, wt%	27.6	27.6	27.6
Time the core boric acid concentration reaches the solubility limit without simultaneous hot and cold side injection, hours post-LOCA	8.5	9.7	7.8
Time the potential for entrainment of hot side injection in the hot legs ends, hours post-LOCA	<2	<2	<2
Time window for initiating simultaneous hot and cold side injection, hours post-LOCA	2 - 6	2 - 6	2 - 6
Minimum simultaneous hot and cold side injection flow rate, gpm	275	275	275
Maximum core boric acid concentration when the minimum simultaneous hot and cold side injection flow rate is initiated at the end of the time window, wt%	21.8	20.0	24.2
Margin to the solubility limit when the minimum simultaneous hot and cold side injection flow rate is initiated at the end of the time window, wt%	5.8	7.6	3.4
Core boil-off flow rate at the beginning of the window for initiating simultaneous hot and cold side injection, hours post-LOCA	268	246	~275

Table 5.2.5.3-2 Post-LOCA Long-Term Cooling Analysis Comparison of Important Results of the 42% SGTP and 30% SGTP Boric Acid Precipitation Analyses		
Quantity	**42% SGTP Analysis**	**30% SGTP Analysis**
Decision time, hours	16	16
Decision pressure, psia	180	130
Largest break to refill by decision time, ft^2	0.036	0.038
Smallest break for which decay heat will be removed in the long term by simultaneous hot and cold leg injection, ft^2	0.005	0.007

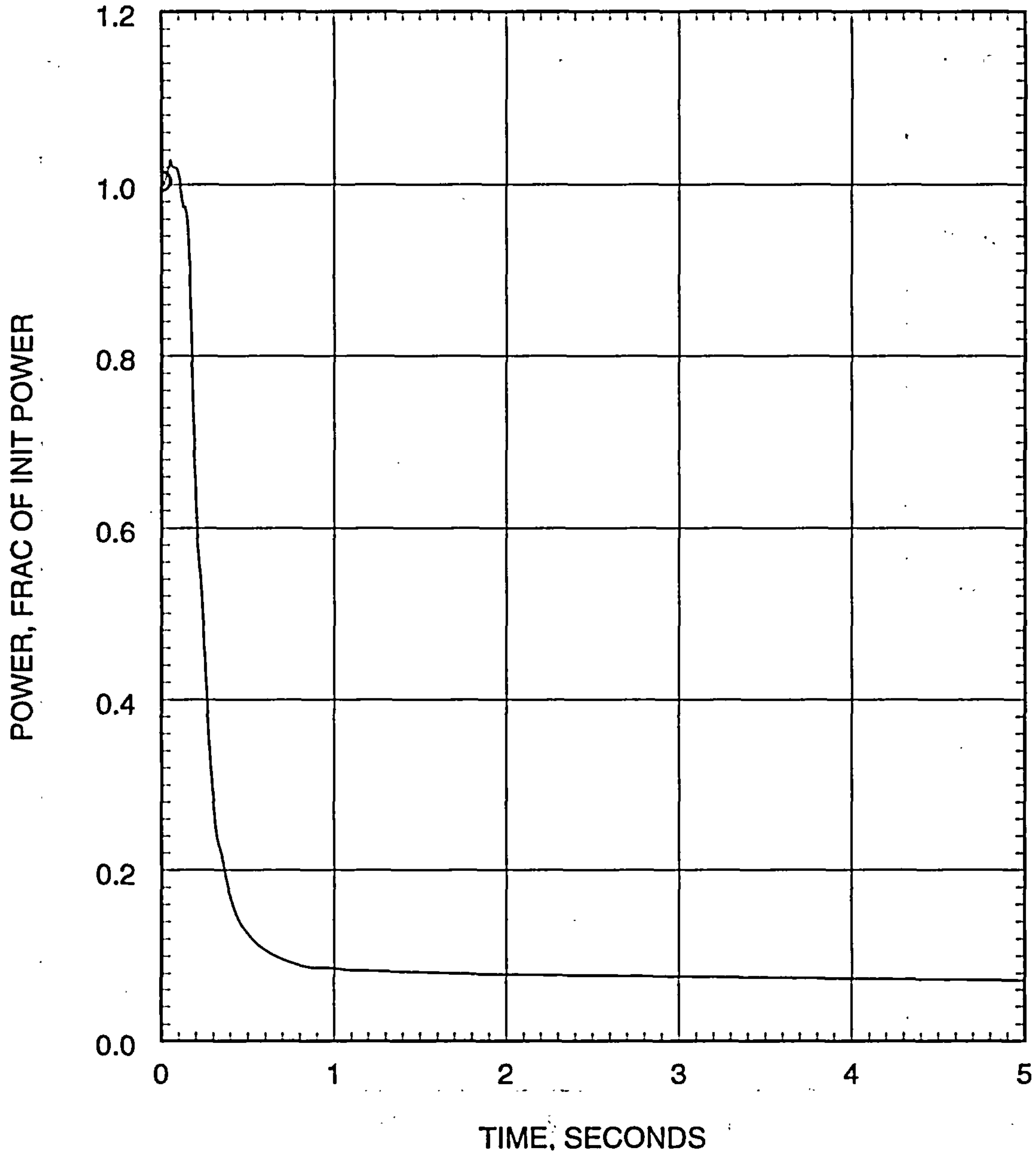

Figure 5.2.3.3-1
1.0 DEG/PD Large Break LOCA
Normalized Power vs. Time

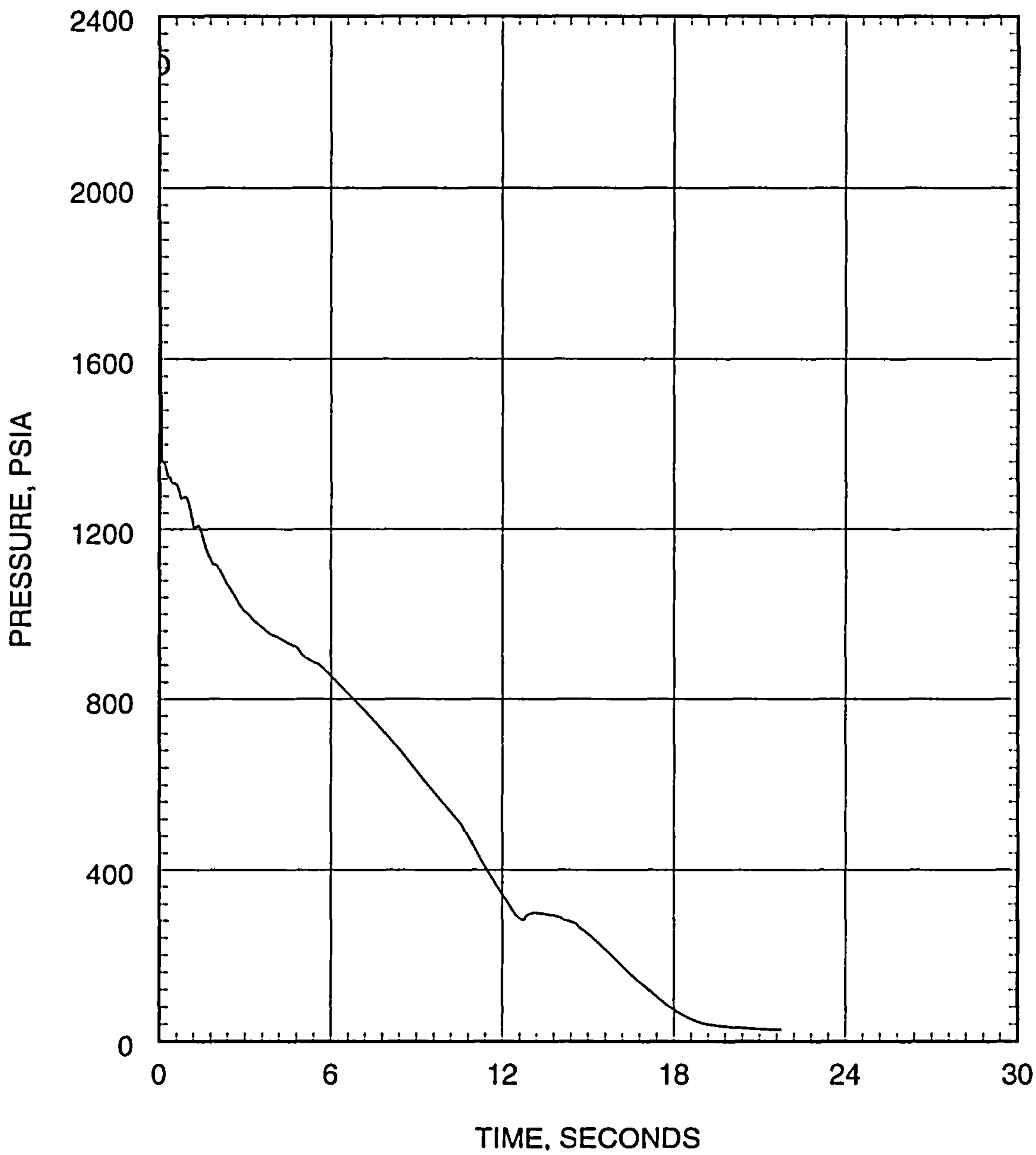

Figure 5.2.3.3-2
1.0 DEG/PD Large Break LOCA
Pressure in Center Hot Assembly Node vs. Time

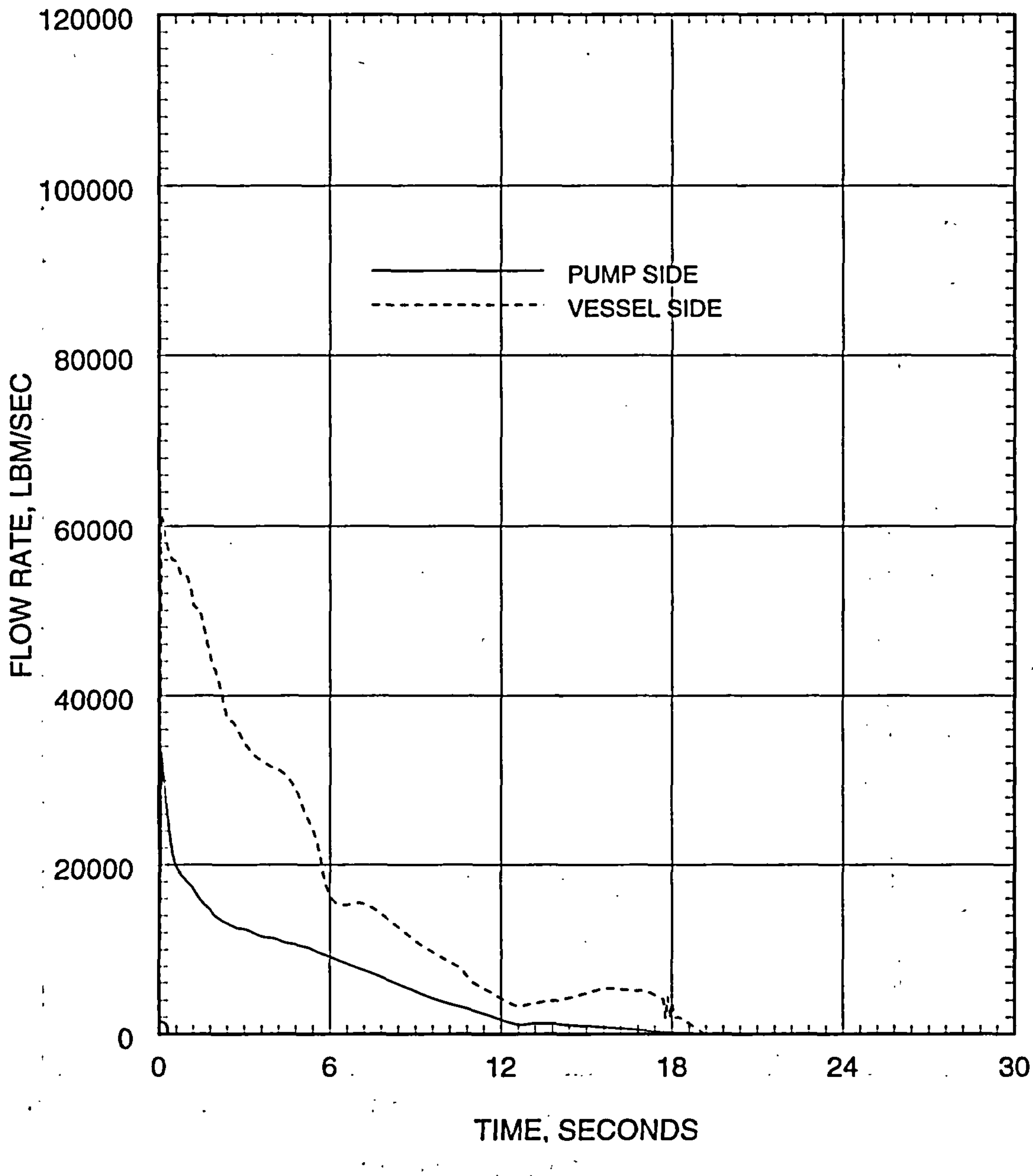

Figure 5.2.3.3-3
1.0 DEG/PD Large Break LOCA
Break Leak Flow Rate vs. Time

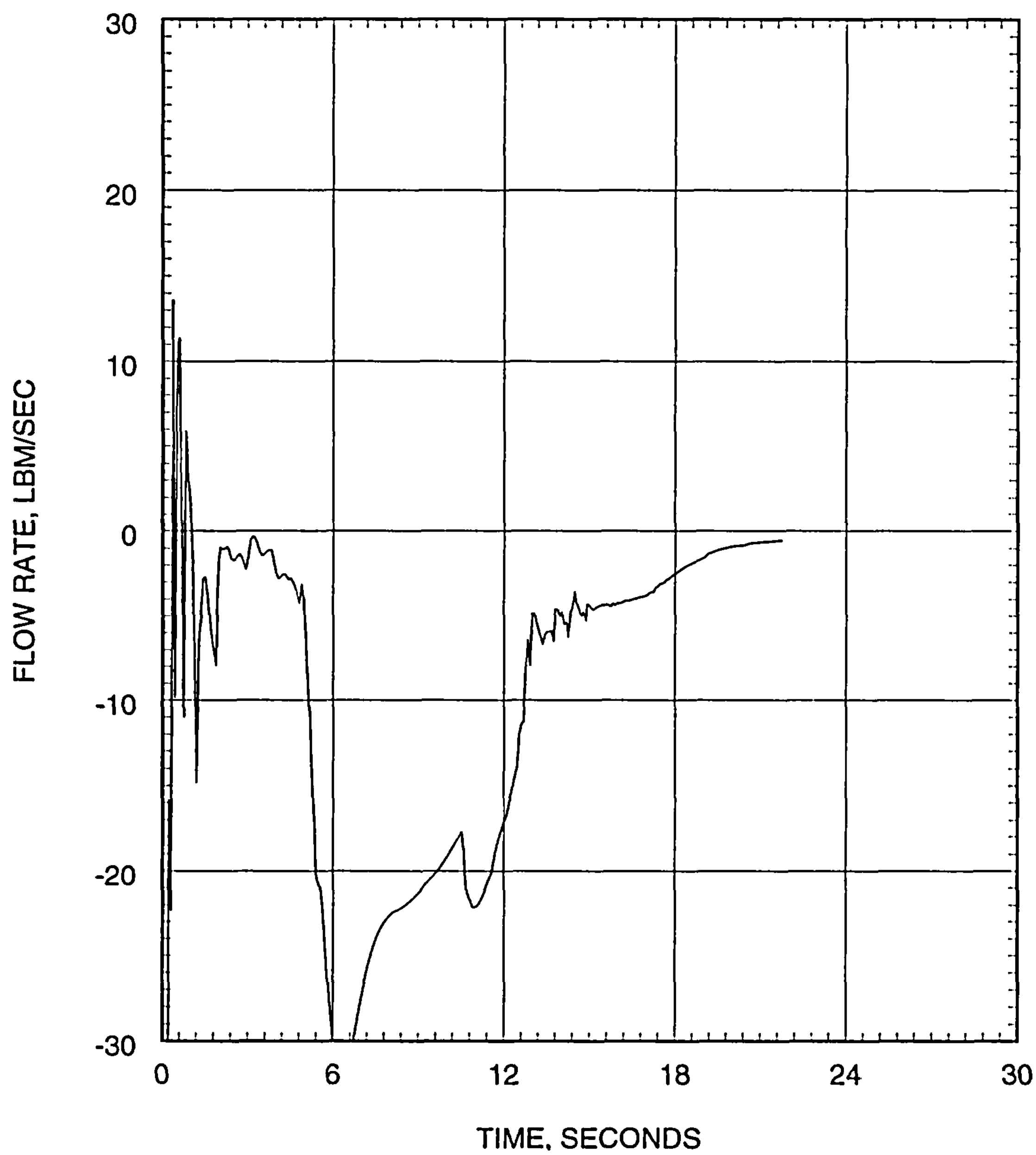

Figure 5.2.3.3-4
1.0 DEG/PD Large Break LOCA
Hot Assembly Flow Rate below Hot Spot vs. Time

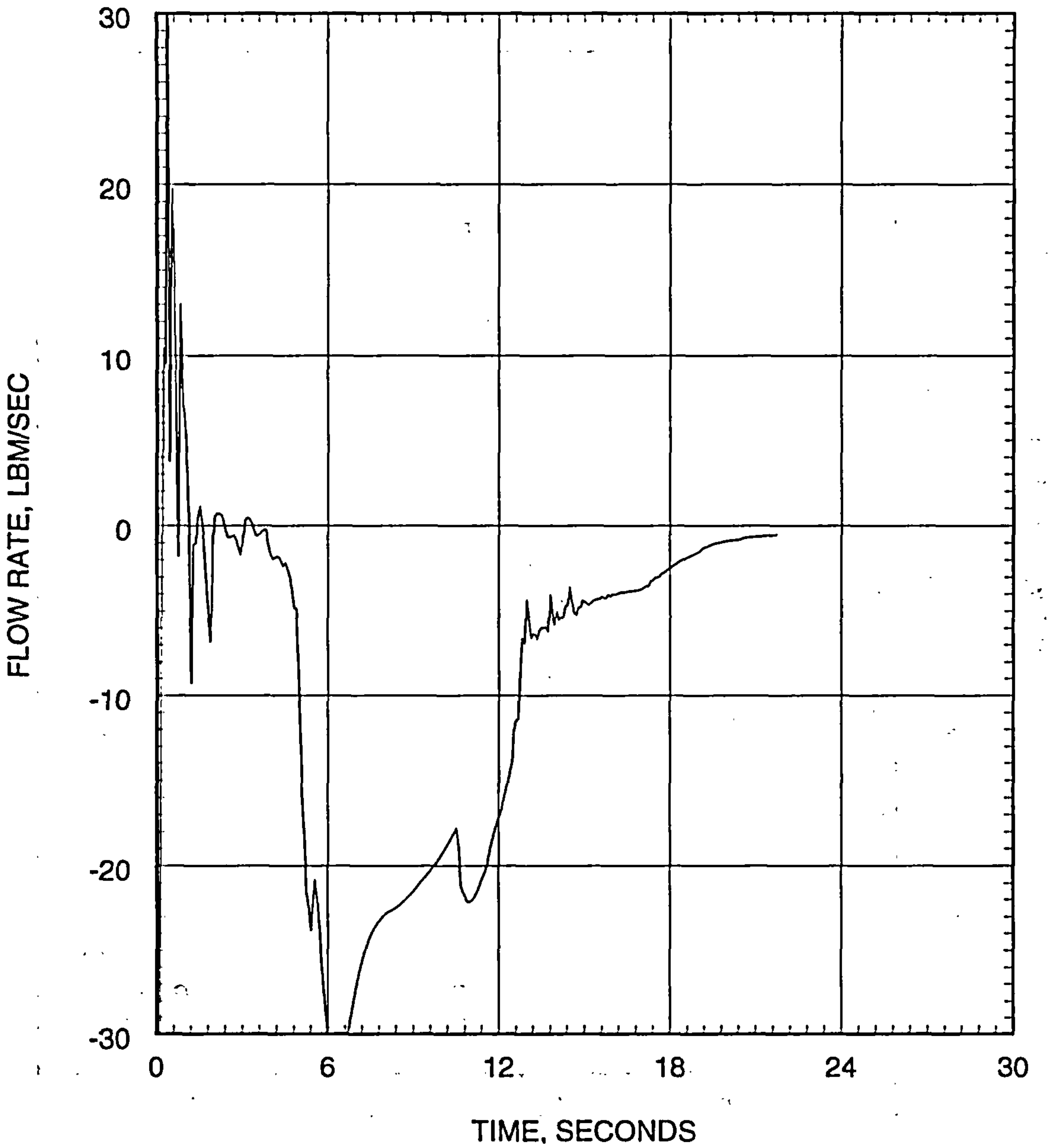

Figure 5.2.3.3-5
1.0 DEG/PD Large Break LOCA
Hot Assembly Flow Rate above Hot Spot vs. Time

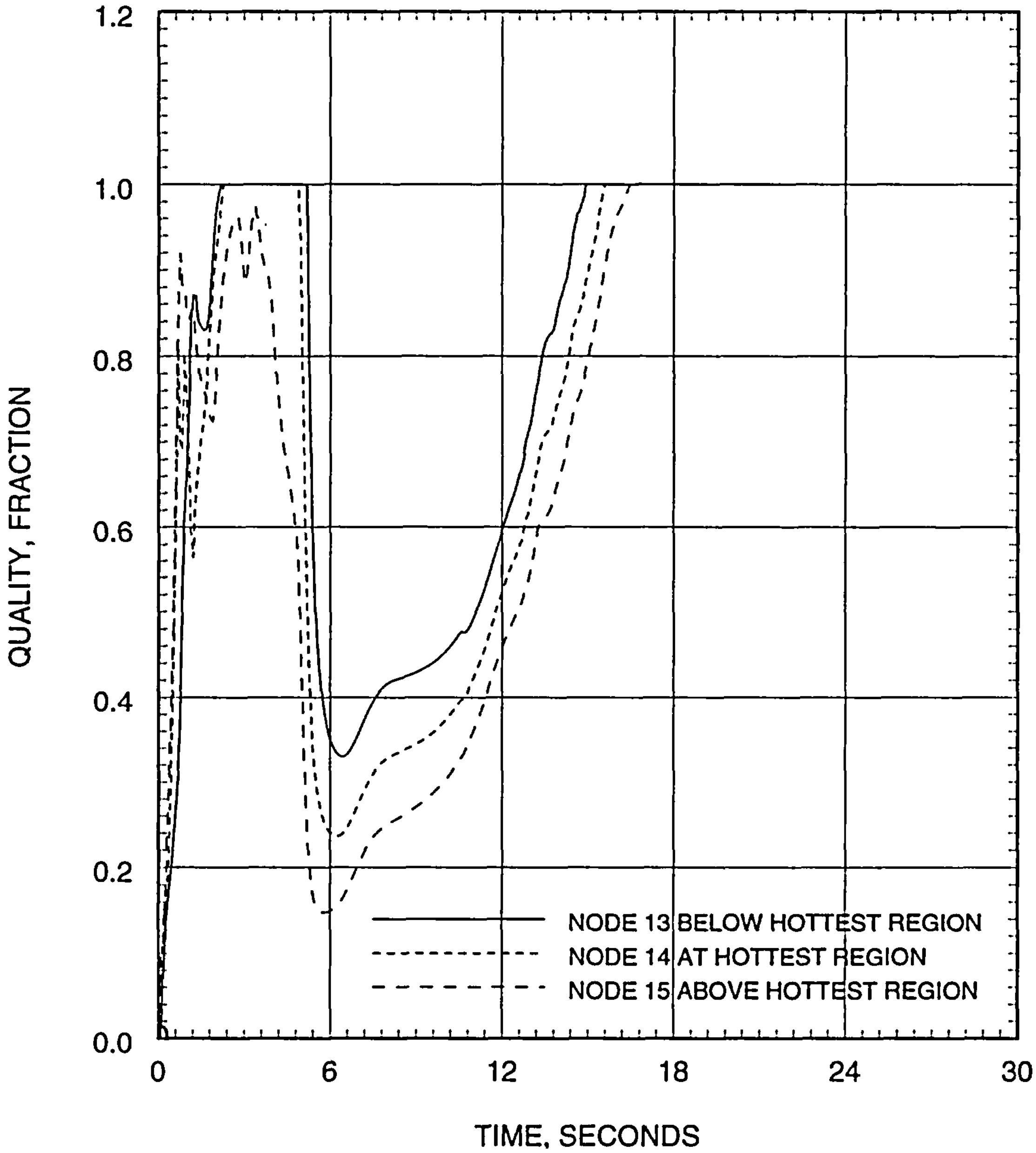

Figure 5.2.3.3-6
1.0 DEG/PD Large Break LOCA
Hot Assembly Quality vs. Time

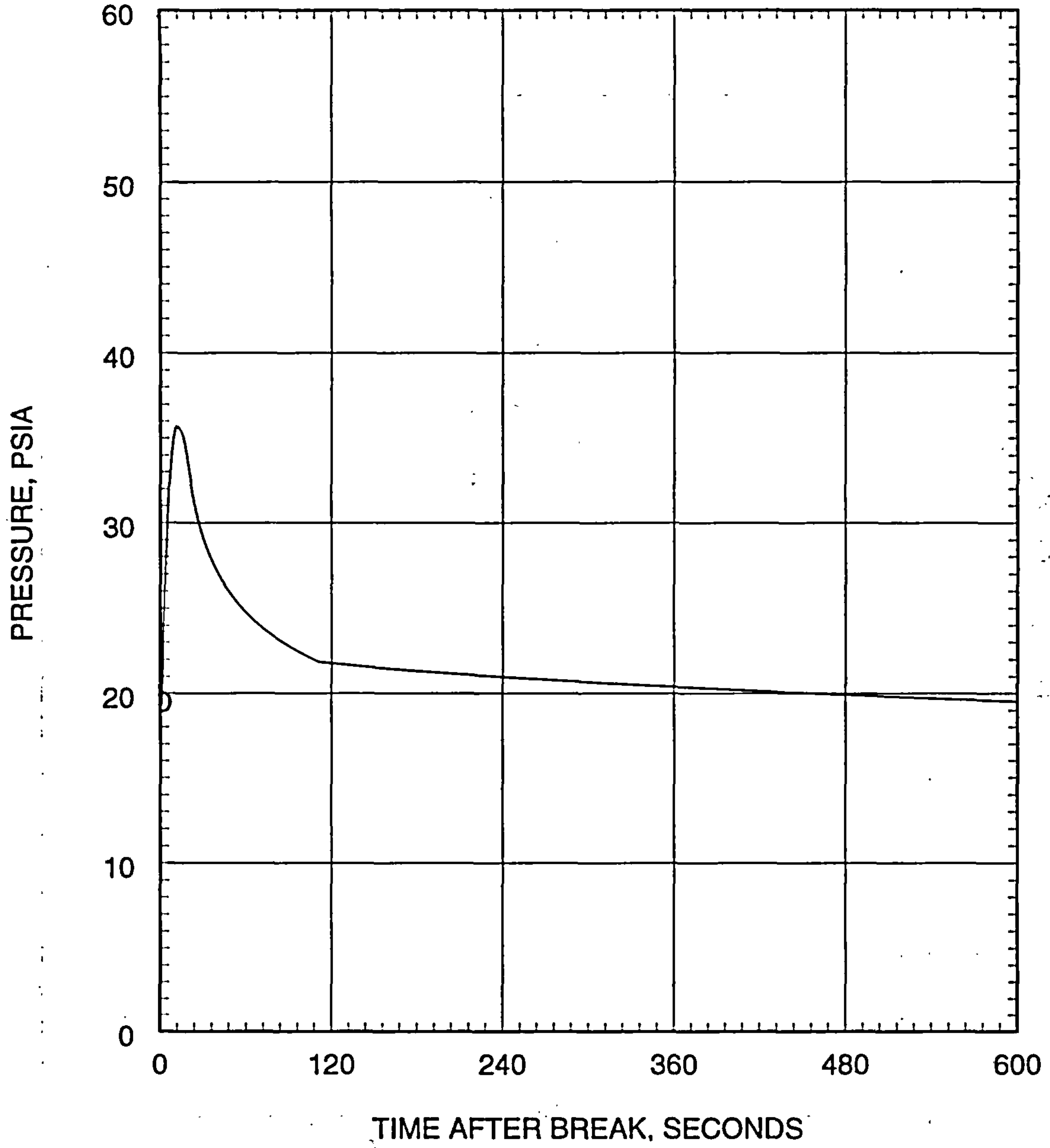

Figure 5.2.3.3-7
1.0 DEG/PD Large Break LOCA
Containment Pressure vs. Time

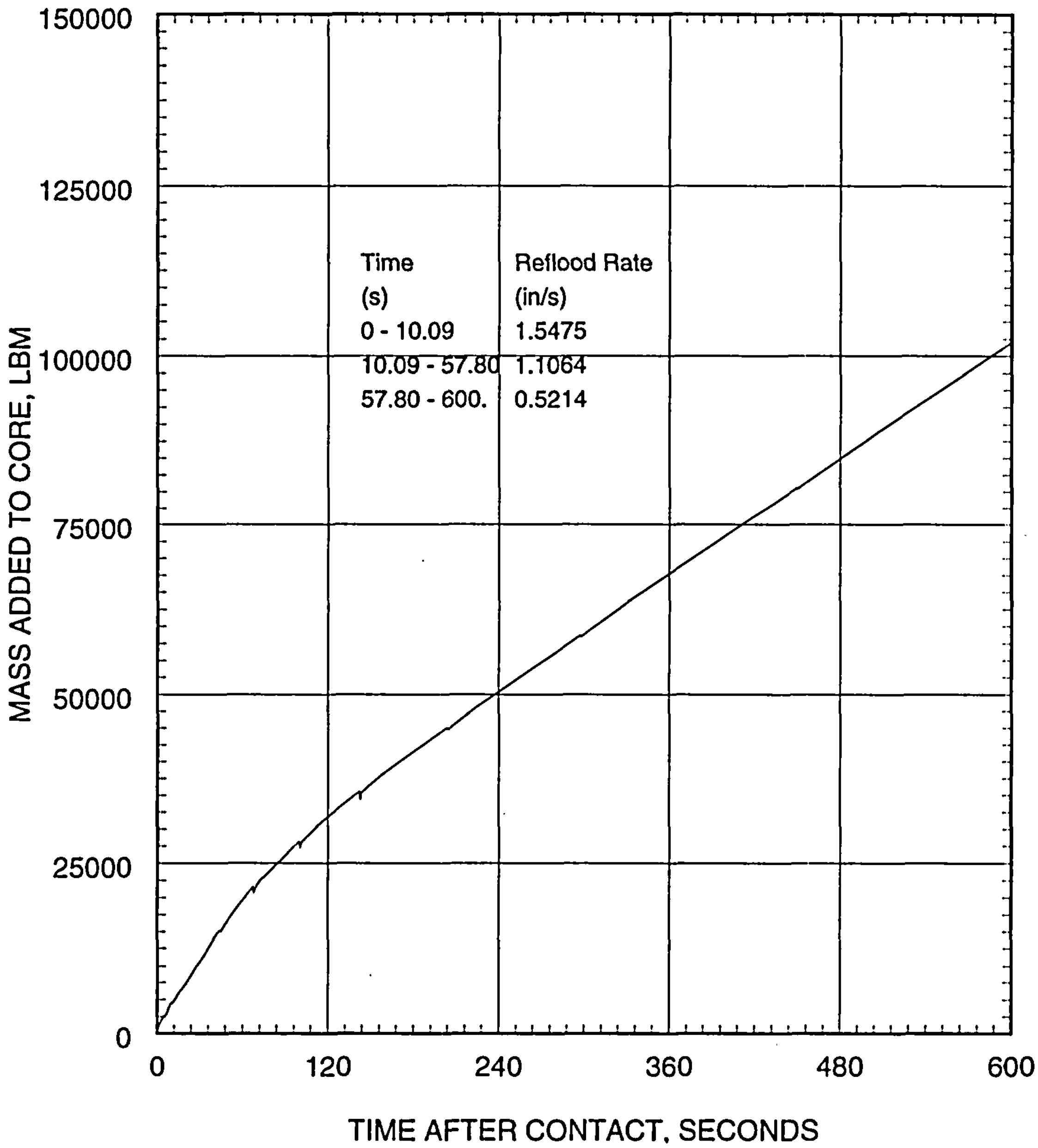

Figure 5.2.3.3-8
1.0 DEG/PD Large Break LOCA
Mass Added to Core vs. Time during Reflood

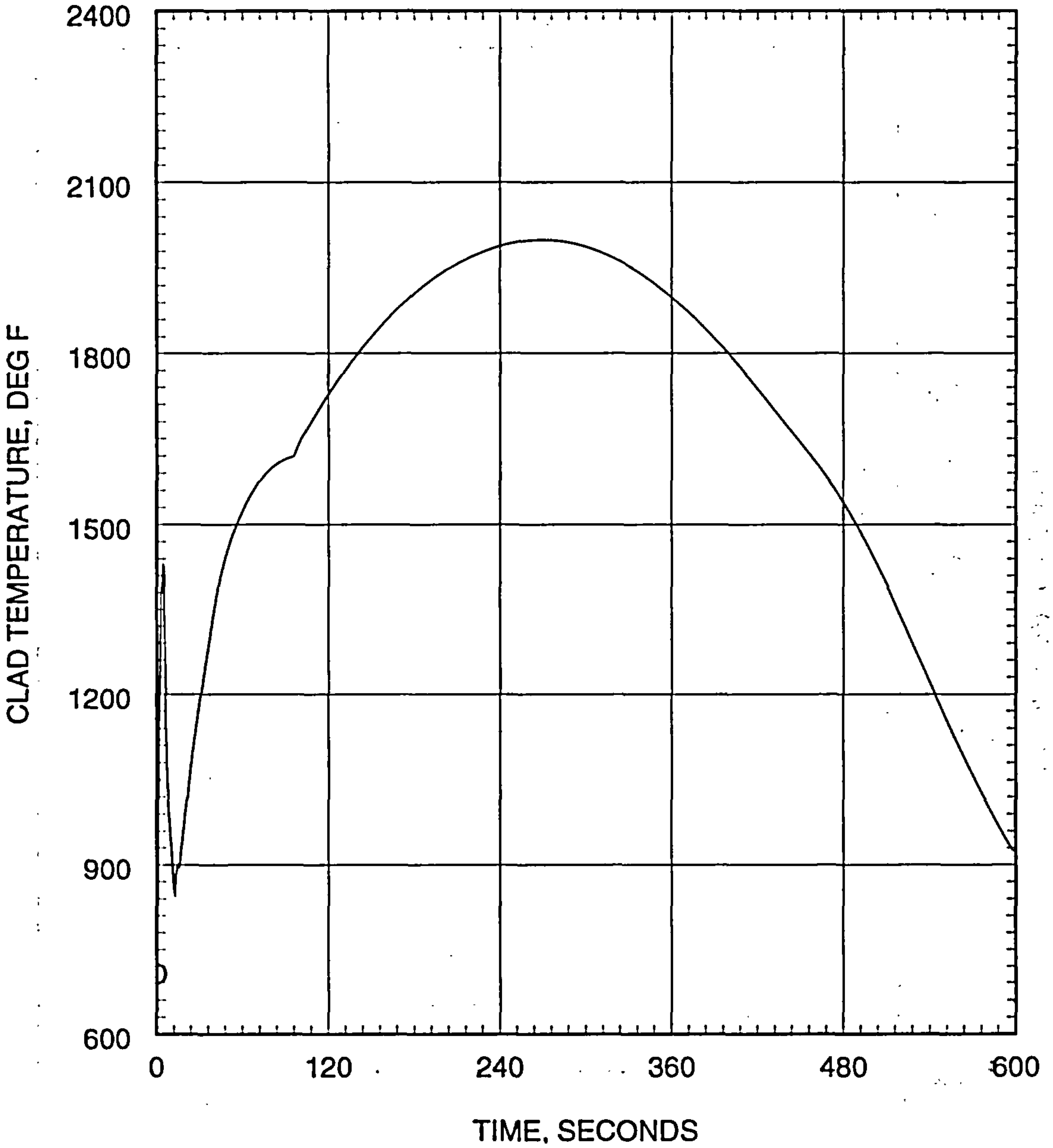

Figure 5.2.3.3-9
1.0 DEG/PD Large Break LOCA
Peak Cladding Temperature vs. Time

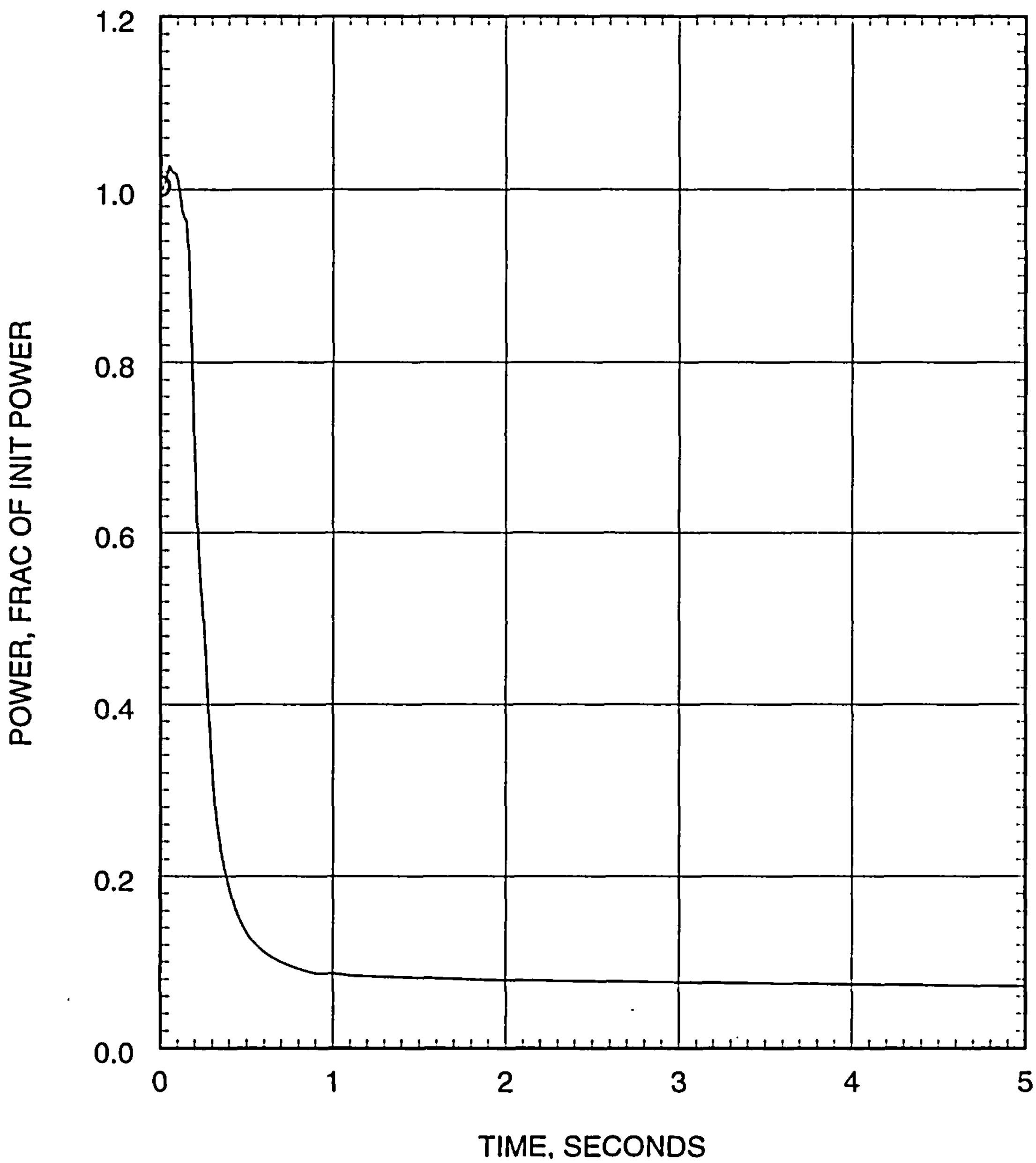

Figure 5.2.3.3-10
0.8 DEG/PD Large Break LOCA
Normalized Core Power vs. Time

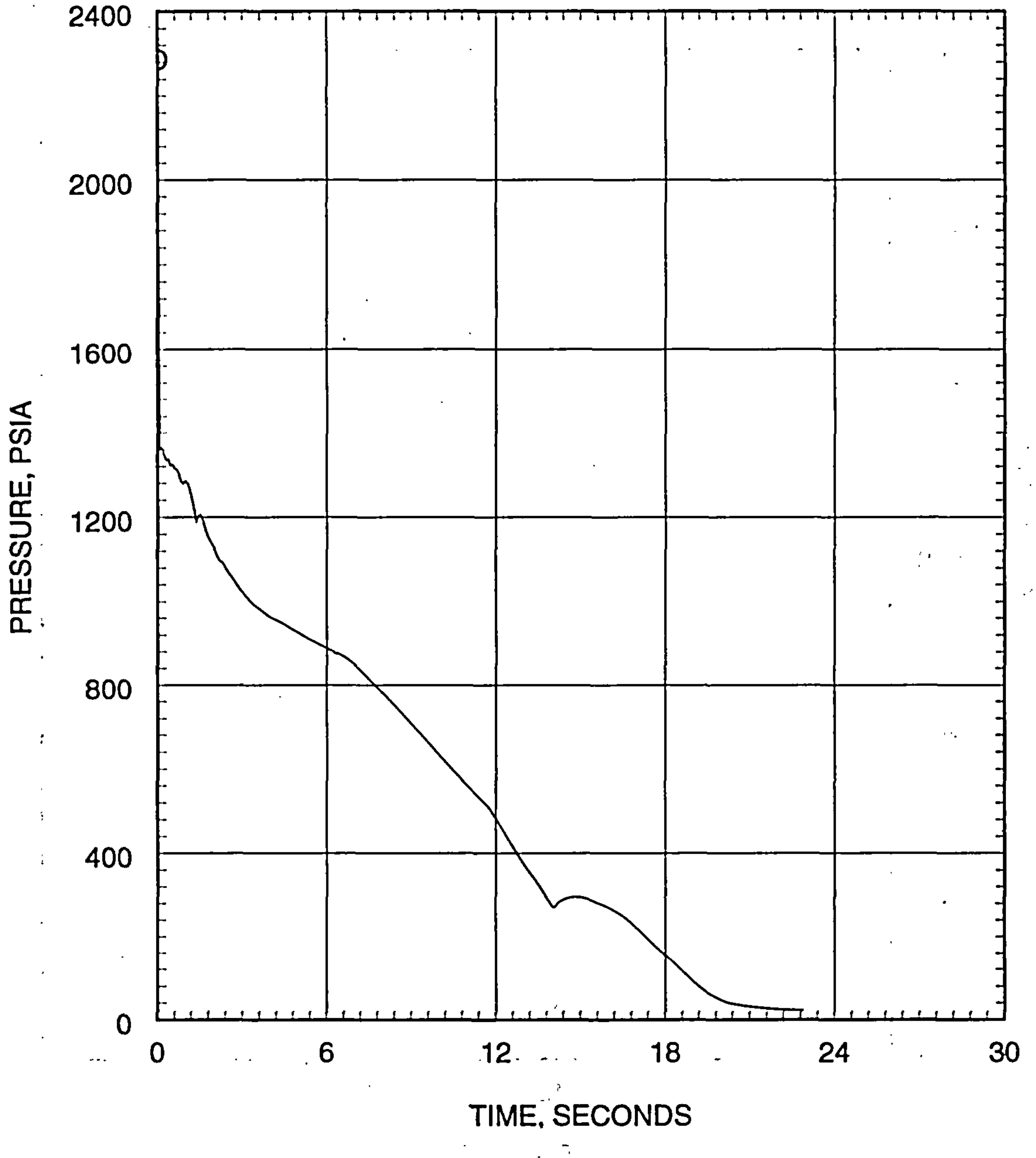

Figure 5.2.3.3-11
0.8 DEG/PD Large Break LOCA
Pressure in Center Hot Assembly Node vs. Time

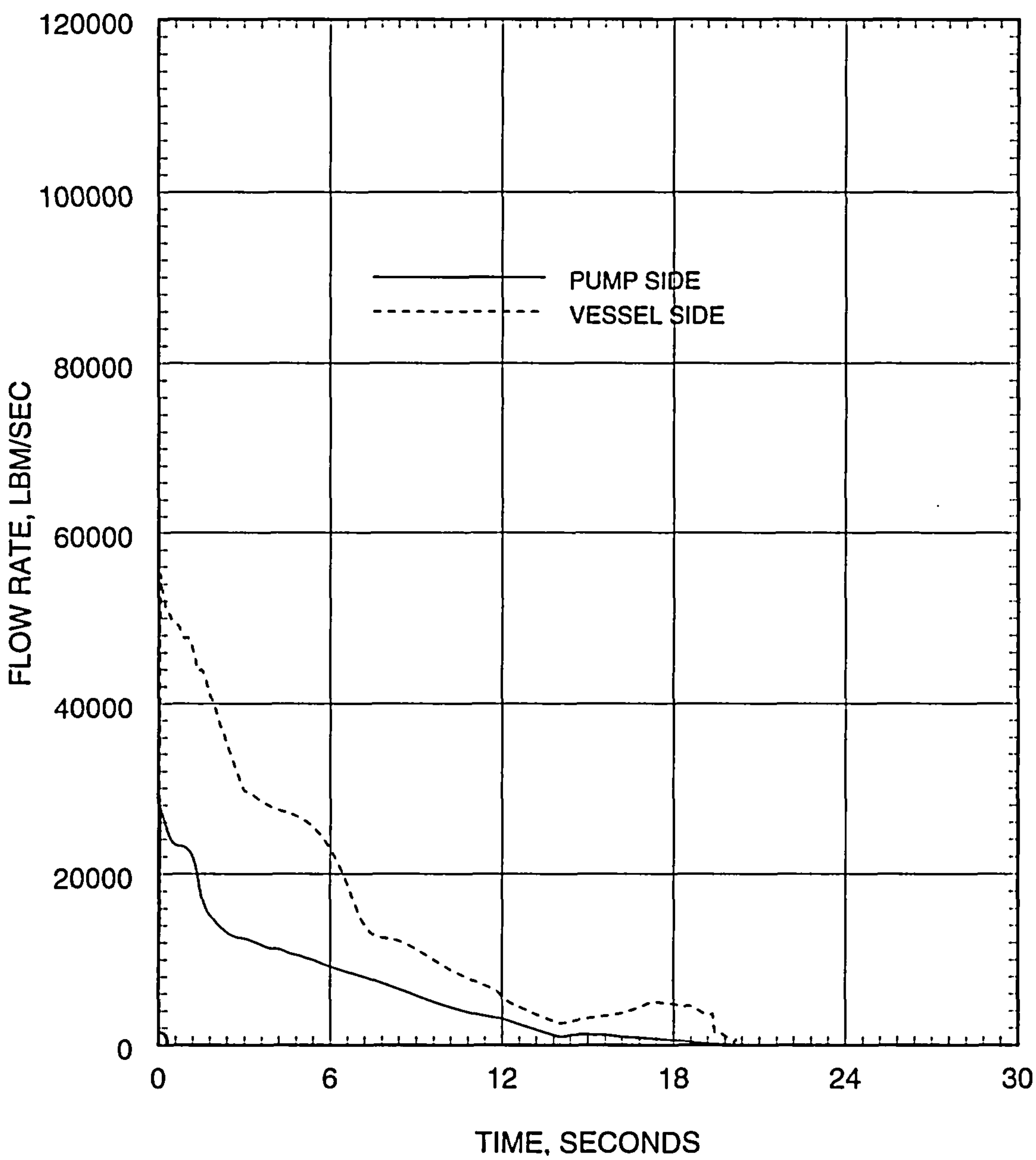

Figure 5.2.3.3-12
0.8 DEG/PD Large Break LOCA
Break Leak Flow Rate vs. Time

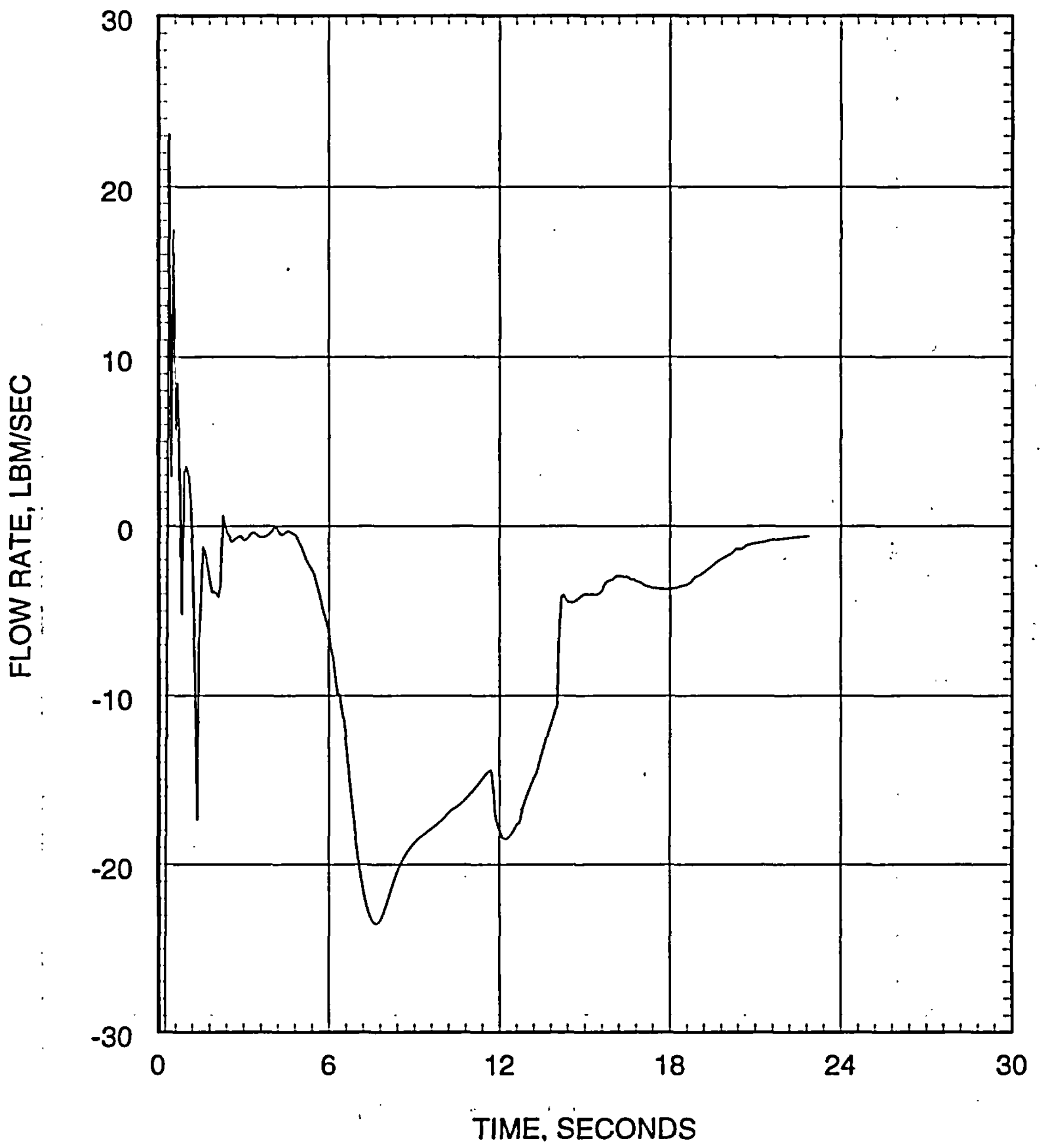

Figure 5.2.3.3-13
0.8 DEG/PD Large Break LOCA
Hot Assembly Flow Rate below Hot Spot vs. Time

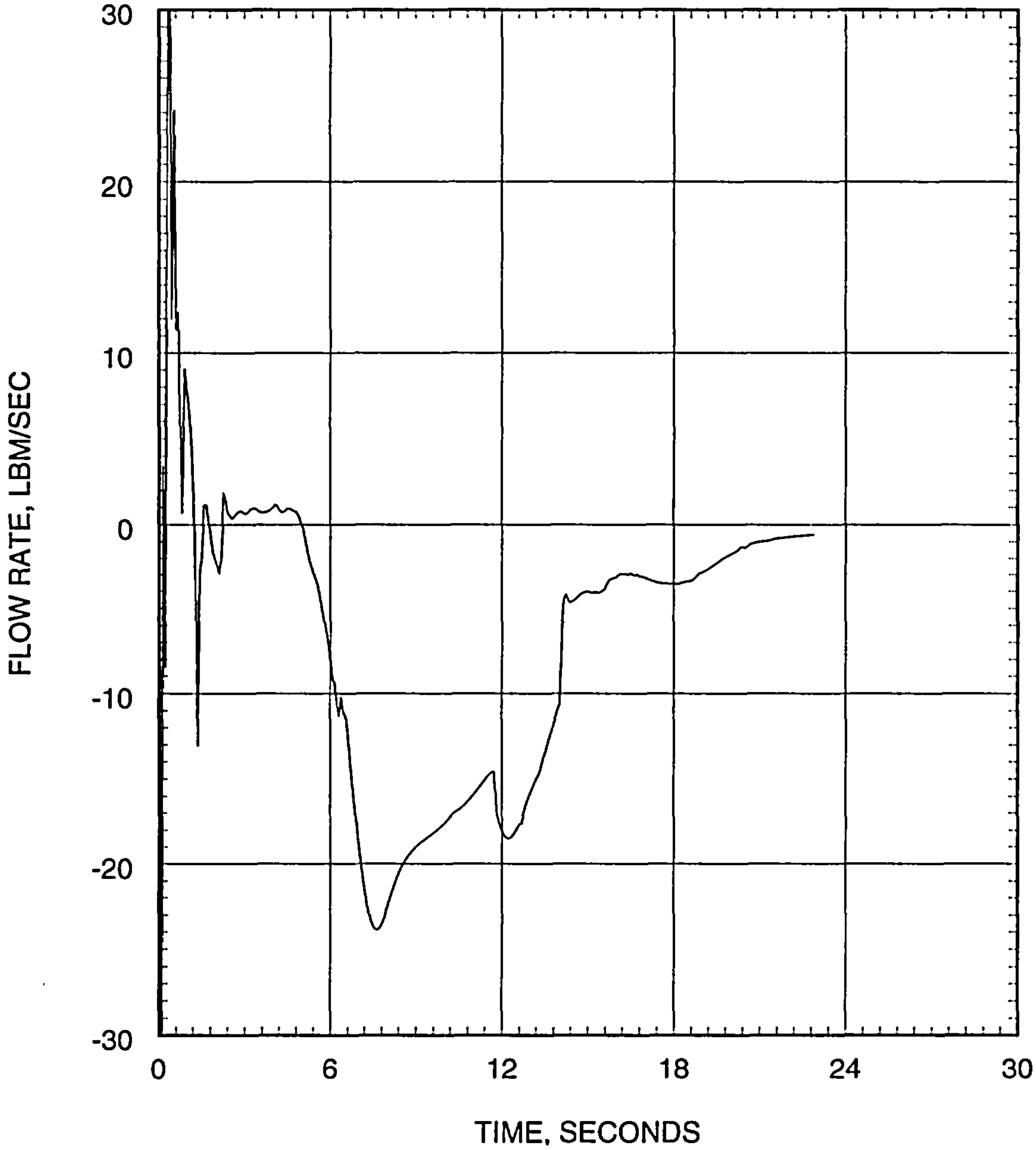

Figure 5.2.3.3-14
0.8 DEG/PD Large Break LOCA
Hot Assembly Flow Rate above Hot Spot vs. Time

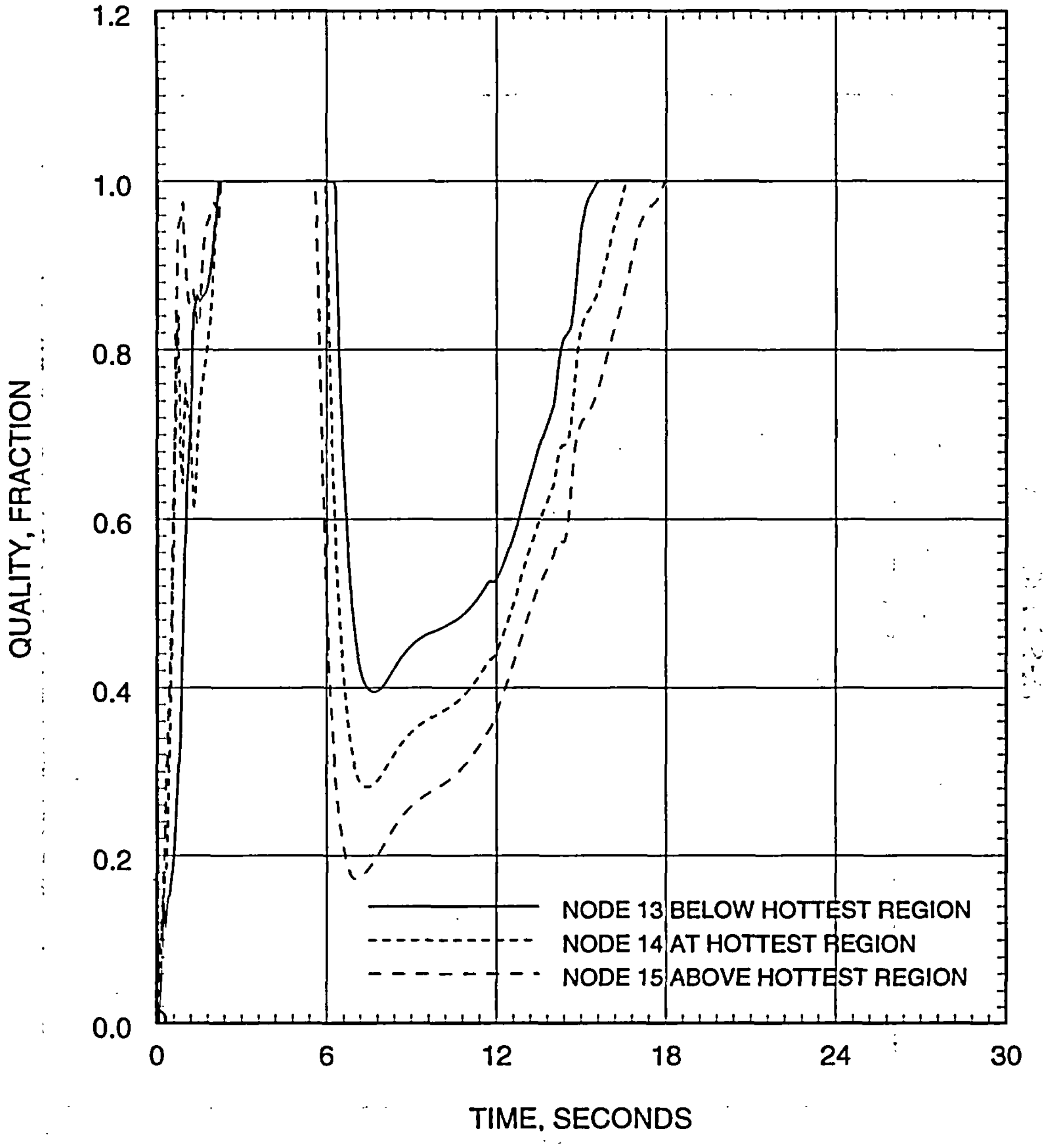

Figure 5.2.3.3-15
0.8 DEG/PD Large Break LOCA
Hot Assembly Quality vs. Time

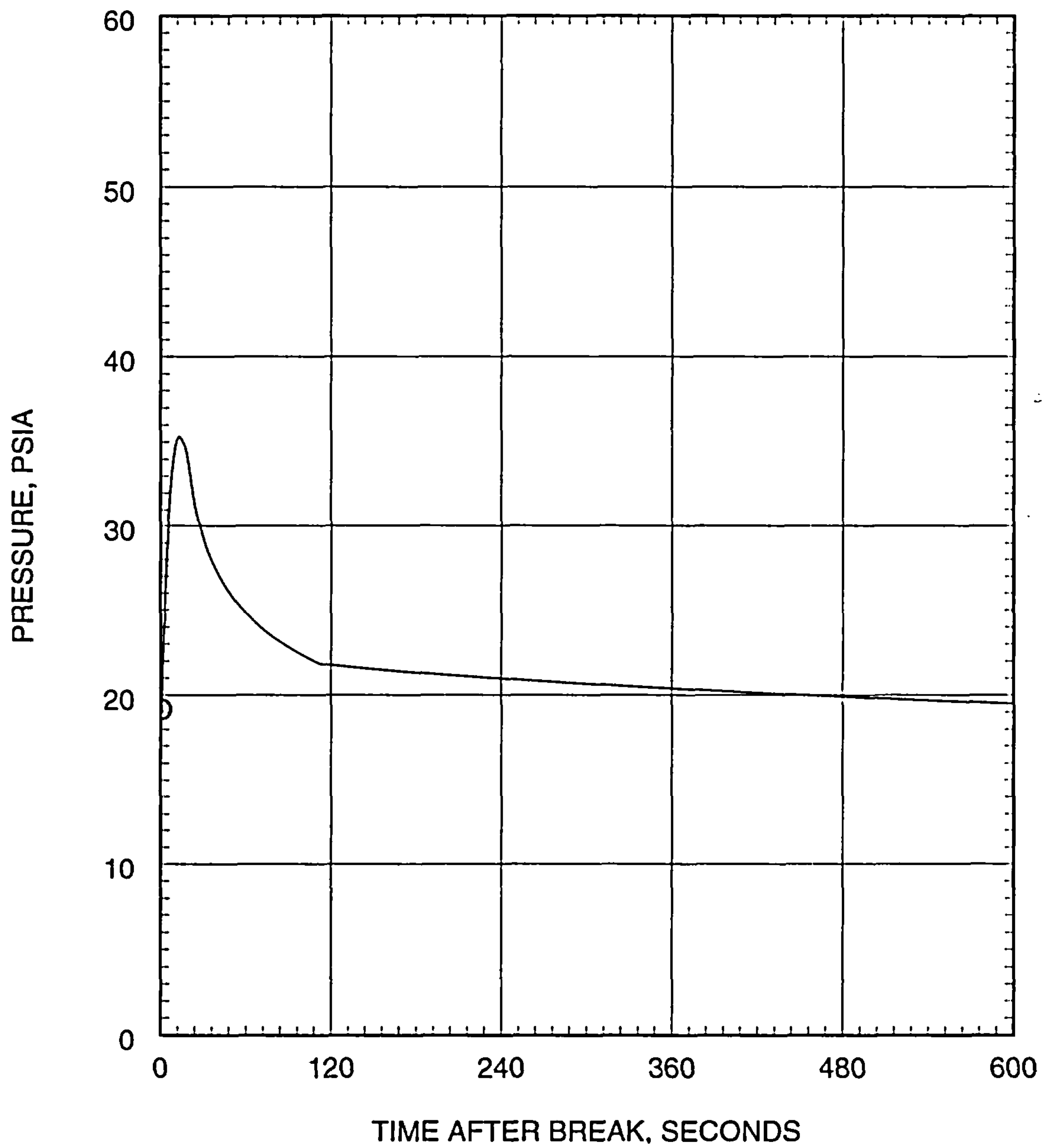

Figure 5.2.3.3-16
0.8 DEG/PD Large Break LOCA
Containment Pressure vs. Time

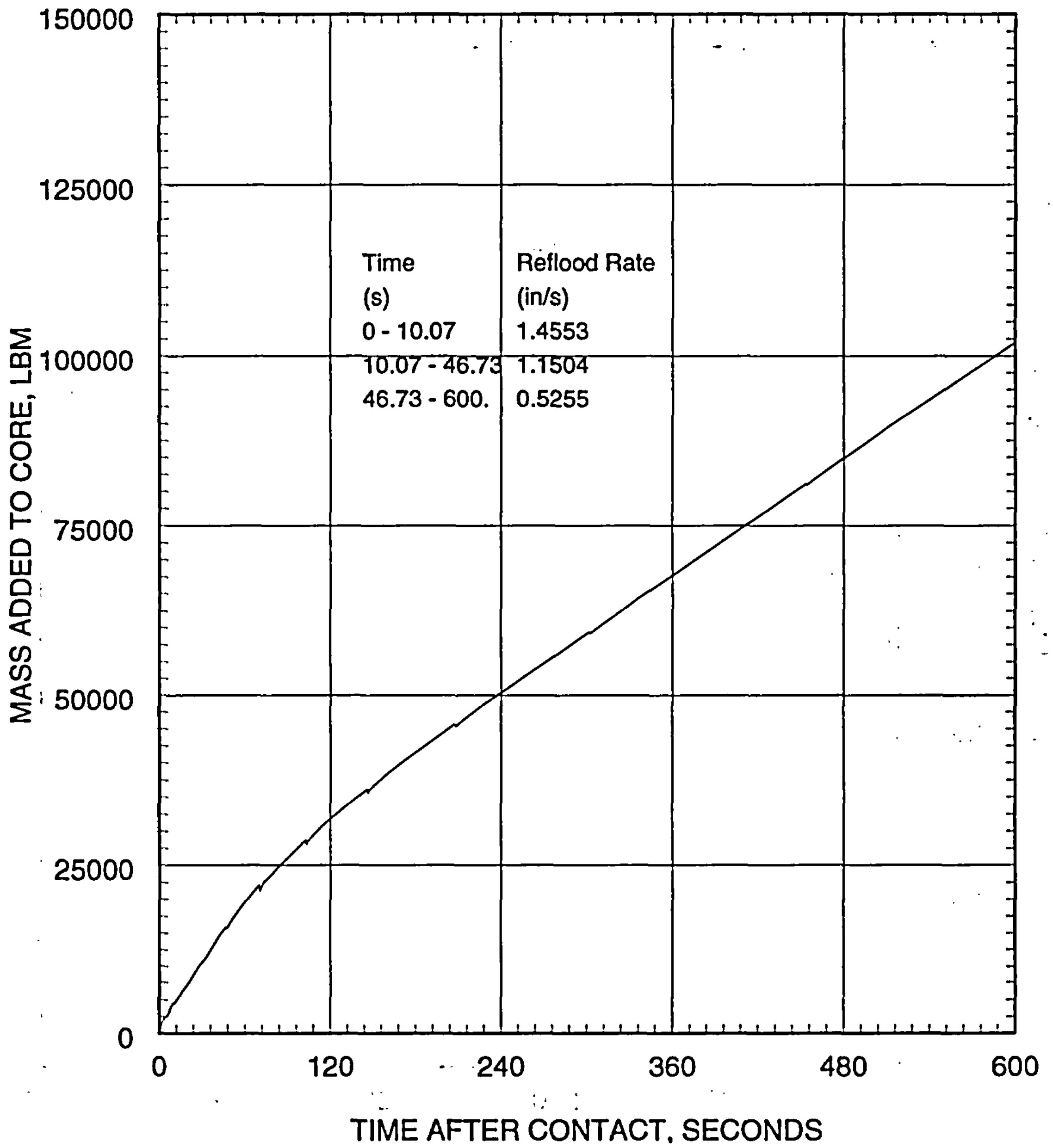

Figure 5.2.3.3-17
0.8 DEG/PD Large Break LOCA
Mass Added to Core vs. Time during Reflood

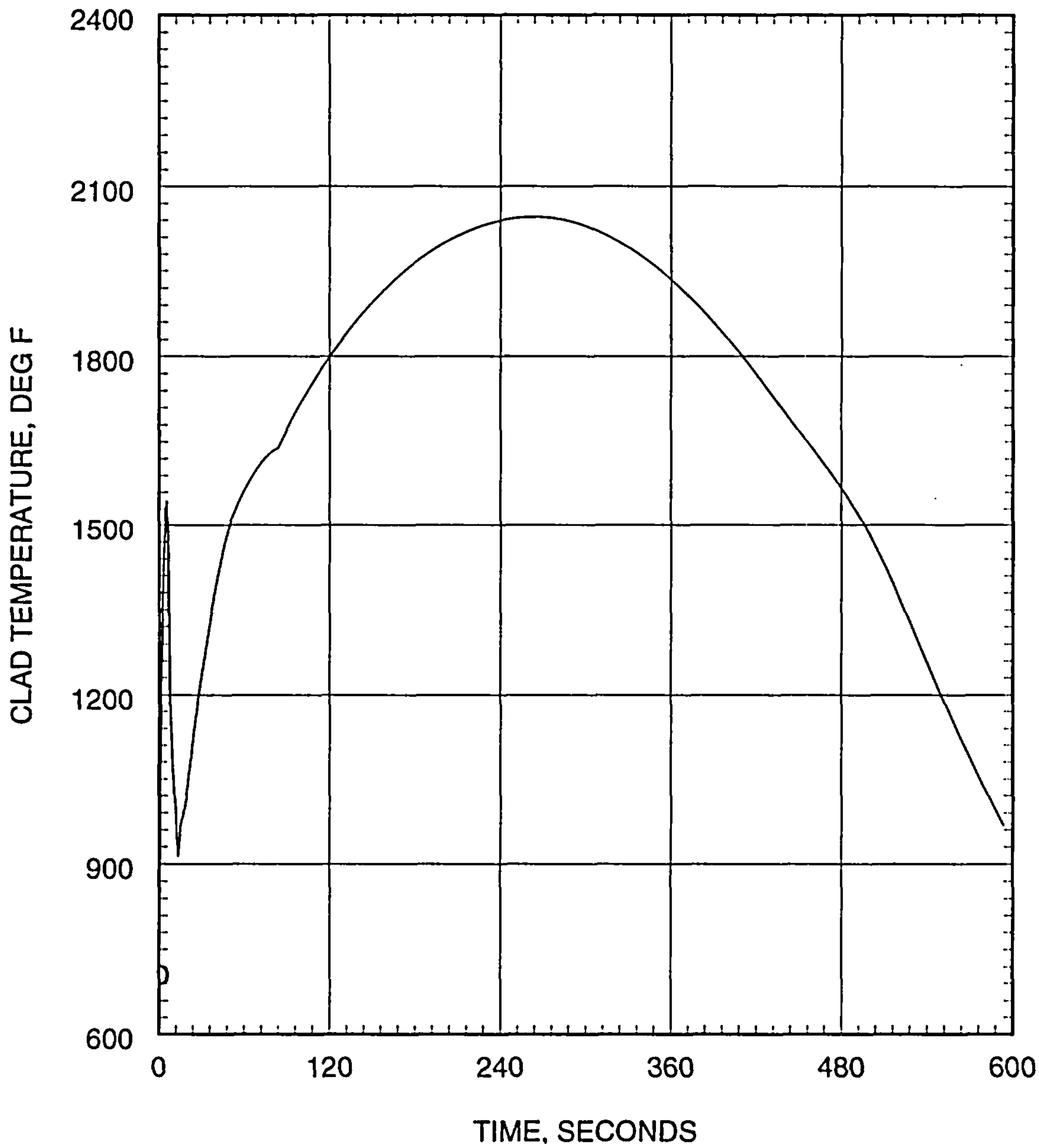

Figure 5.2.3.3-18
0.8 DEG/PD Large Break LOCA
Peak Cladding Temperature vs. Time

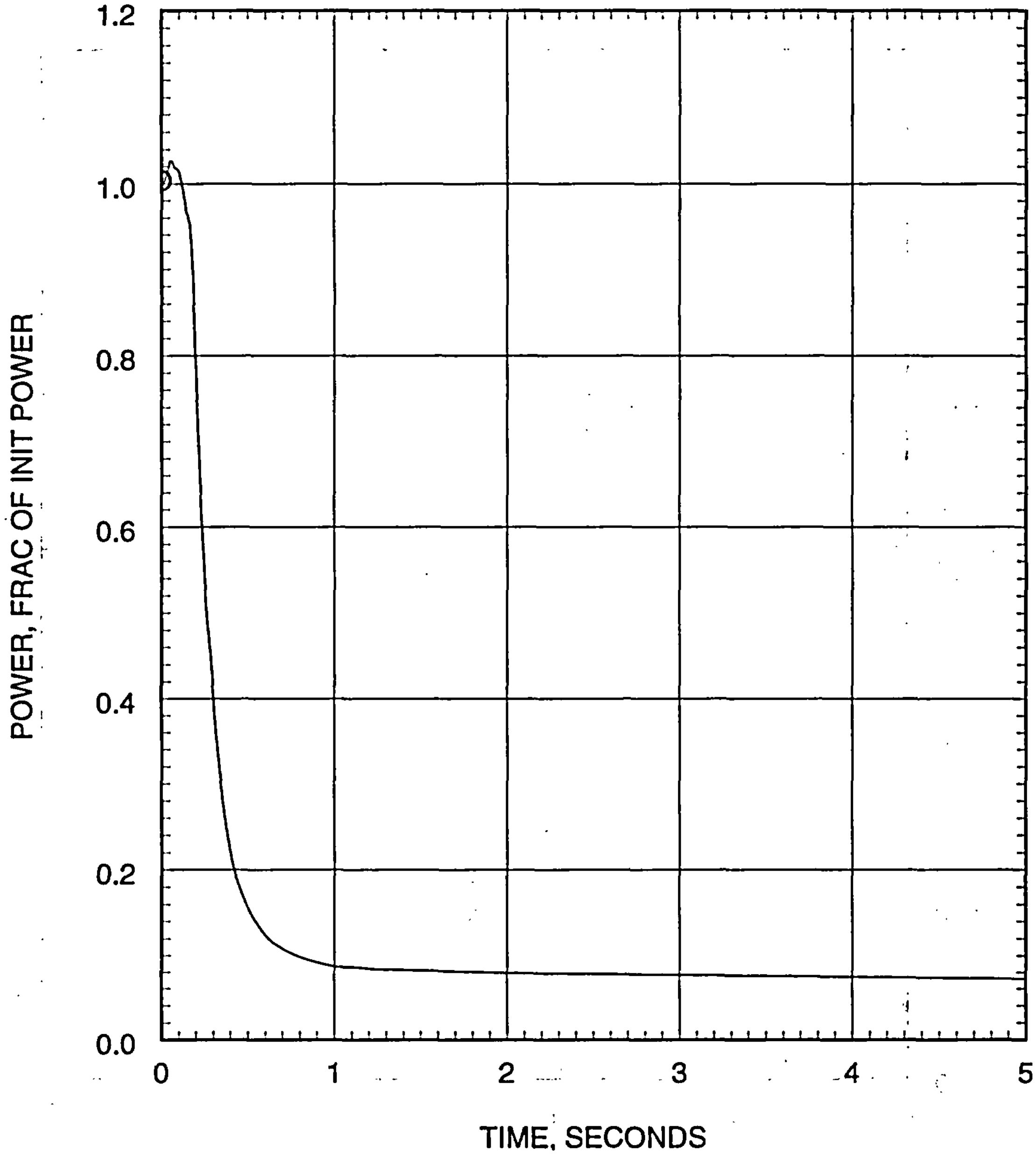

Figure 5.2.3.3-19
0.6 DEG/PD Large Break LOCA
Normalized Core Power vs. Time

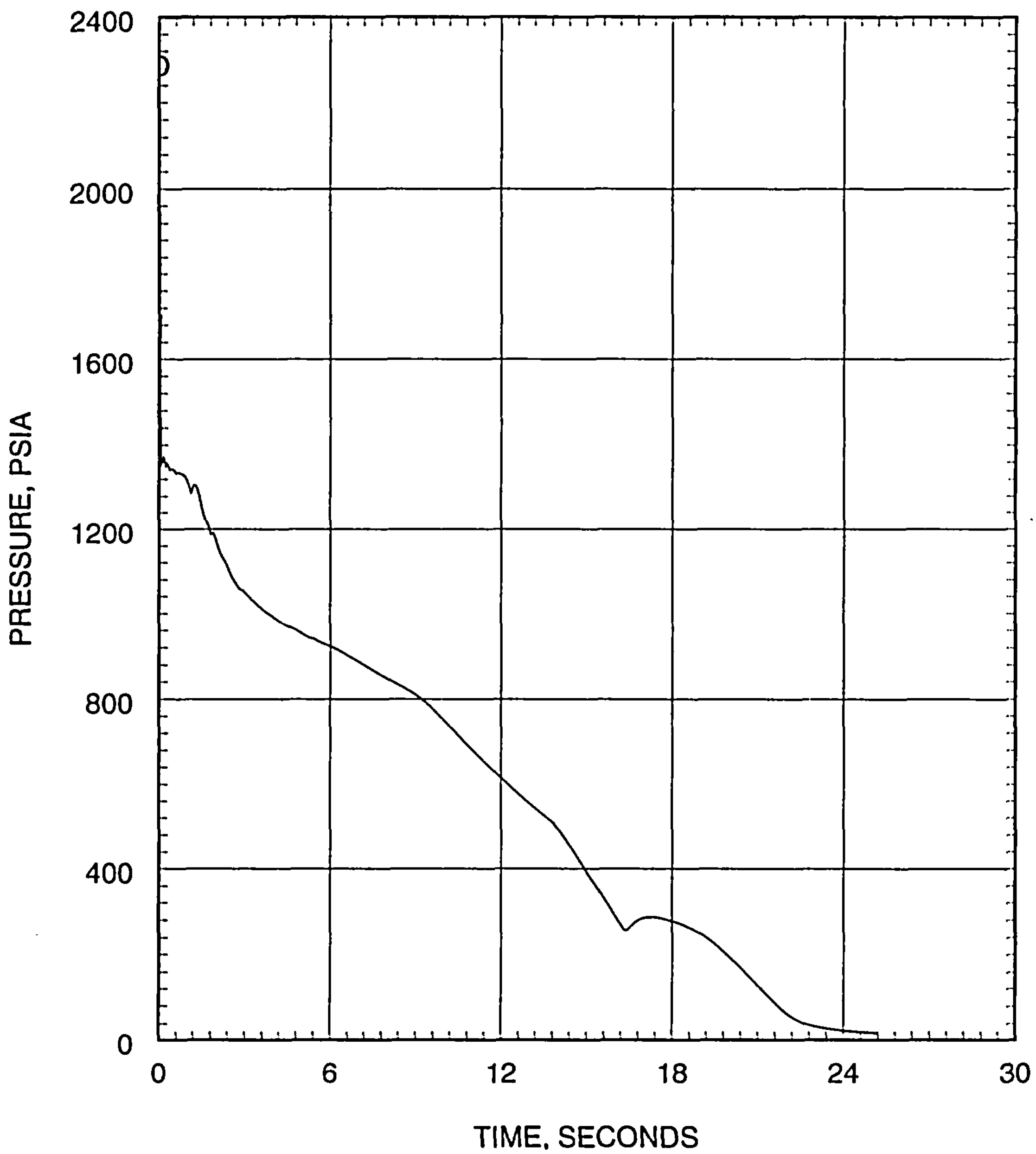

Figure 5.2.3.3-20
0.6 DEG/PD Large Break LOCA
Pressure in Center Hot Assembly Node vs. Time

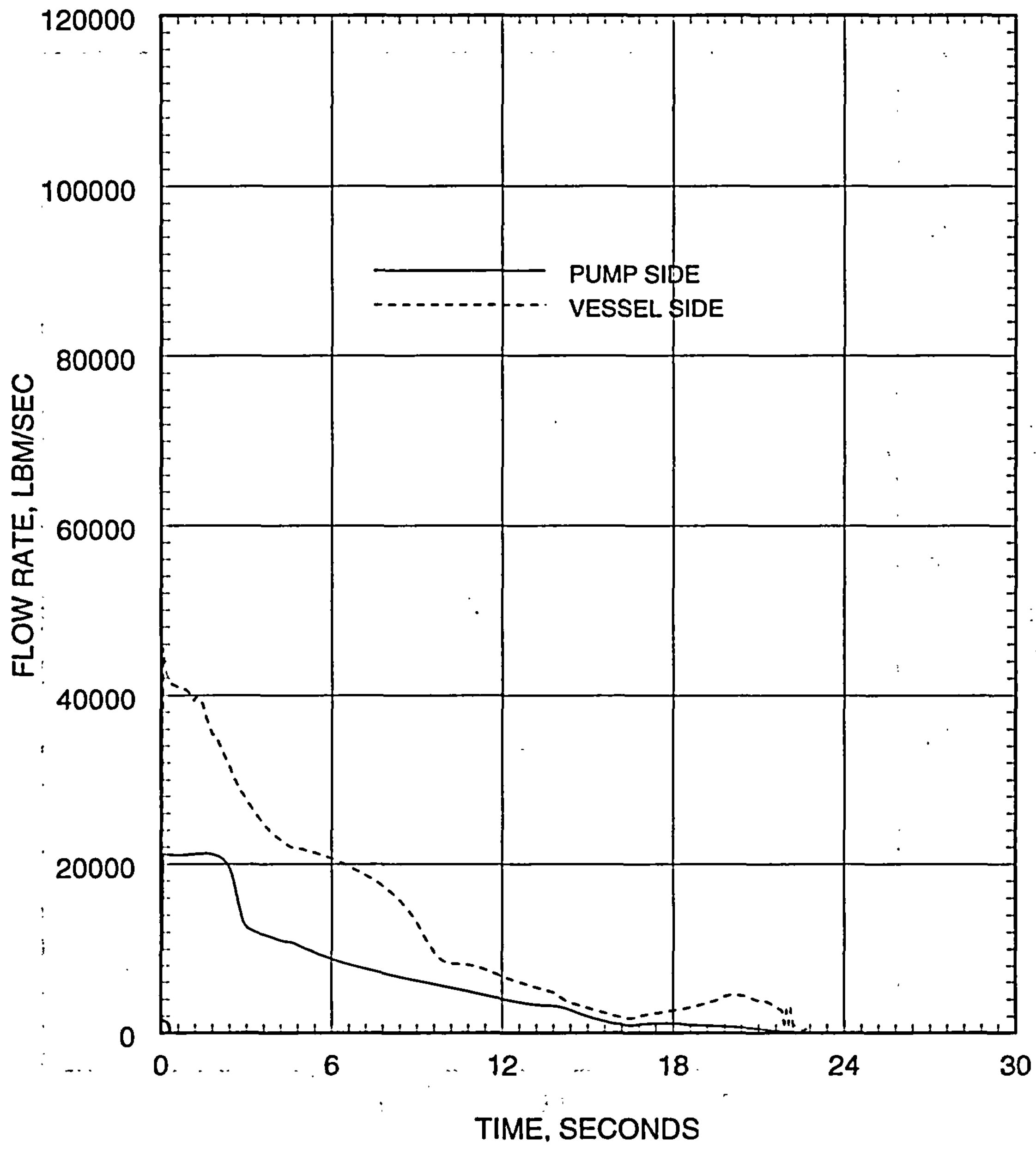

Figure 5.2.3.3-21
0.6 DEG/PD Large Break LOCA
Break Leak Flow Rate vs. Time

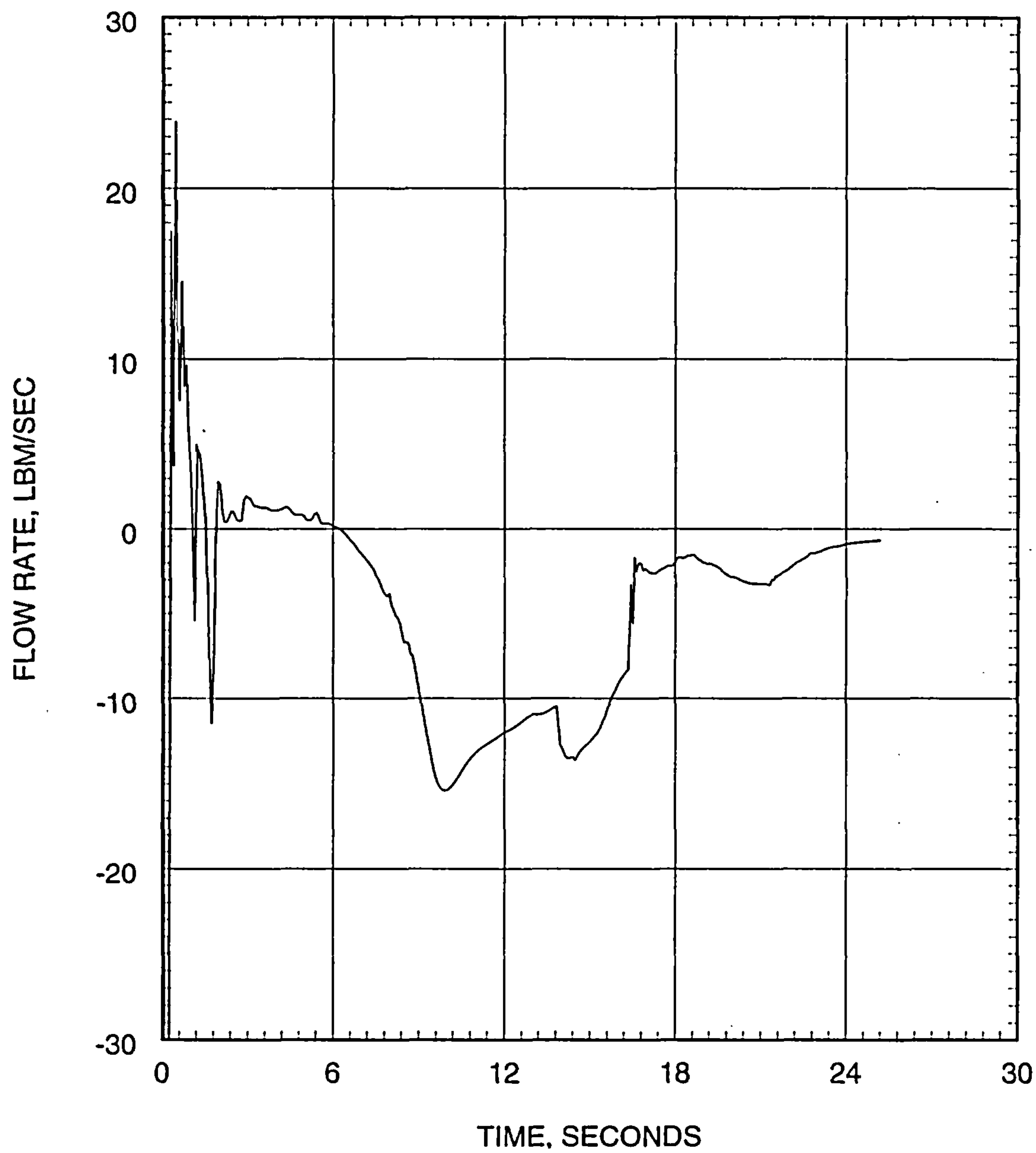

Figure 5.2.3.3-22
0.6 DEG/PD Large Break LOCA
Hot Assembly Flow Rate below Hot Spot vs. Time

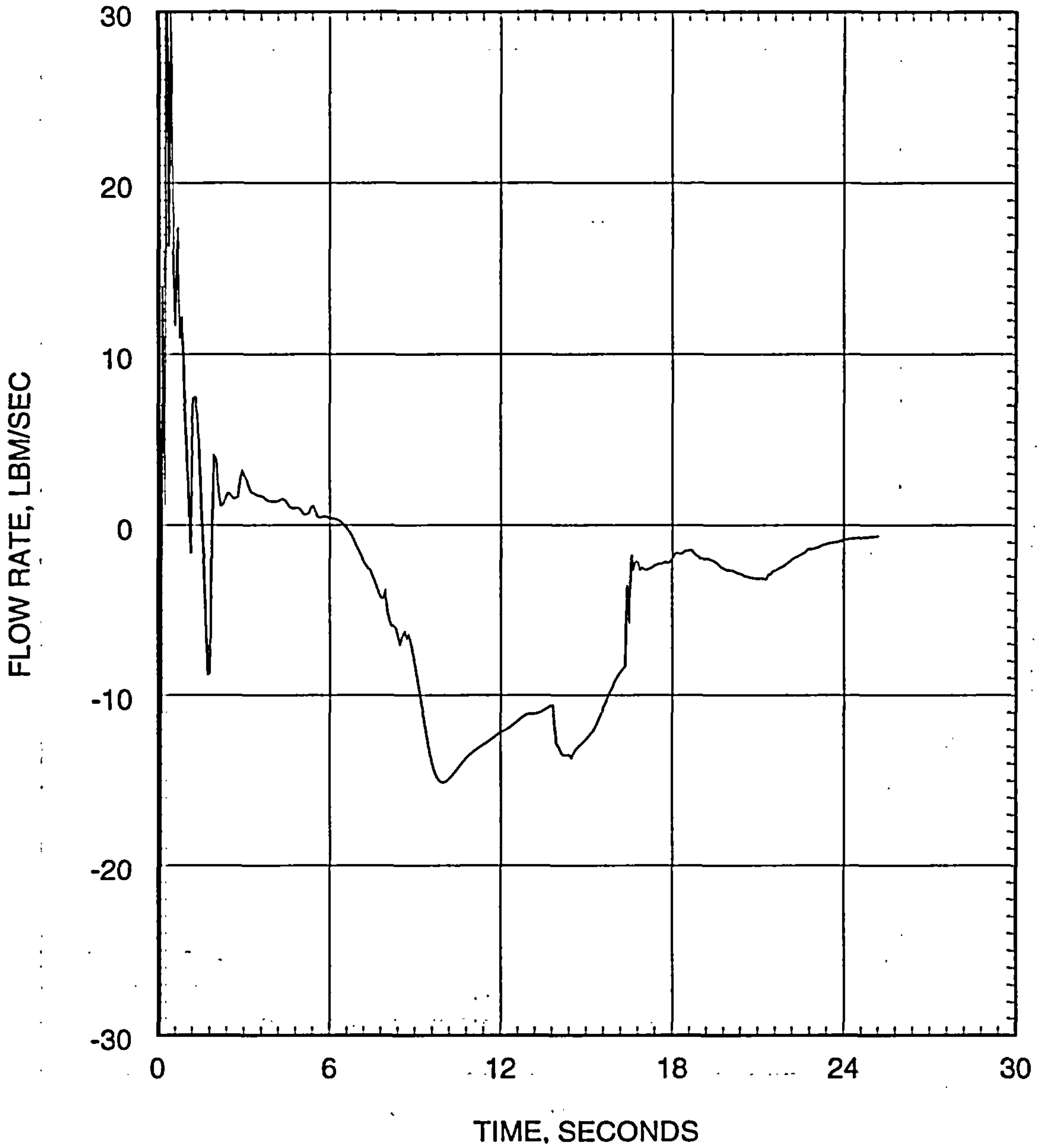

Figure 5.2.3.3-23
0.6 DEG/PD Large Break LOCA
Hot Assembly Flow Rate above Hot Spot vs. Time

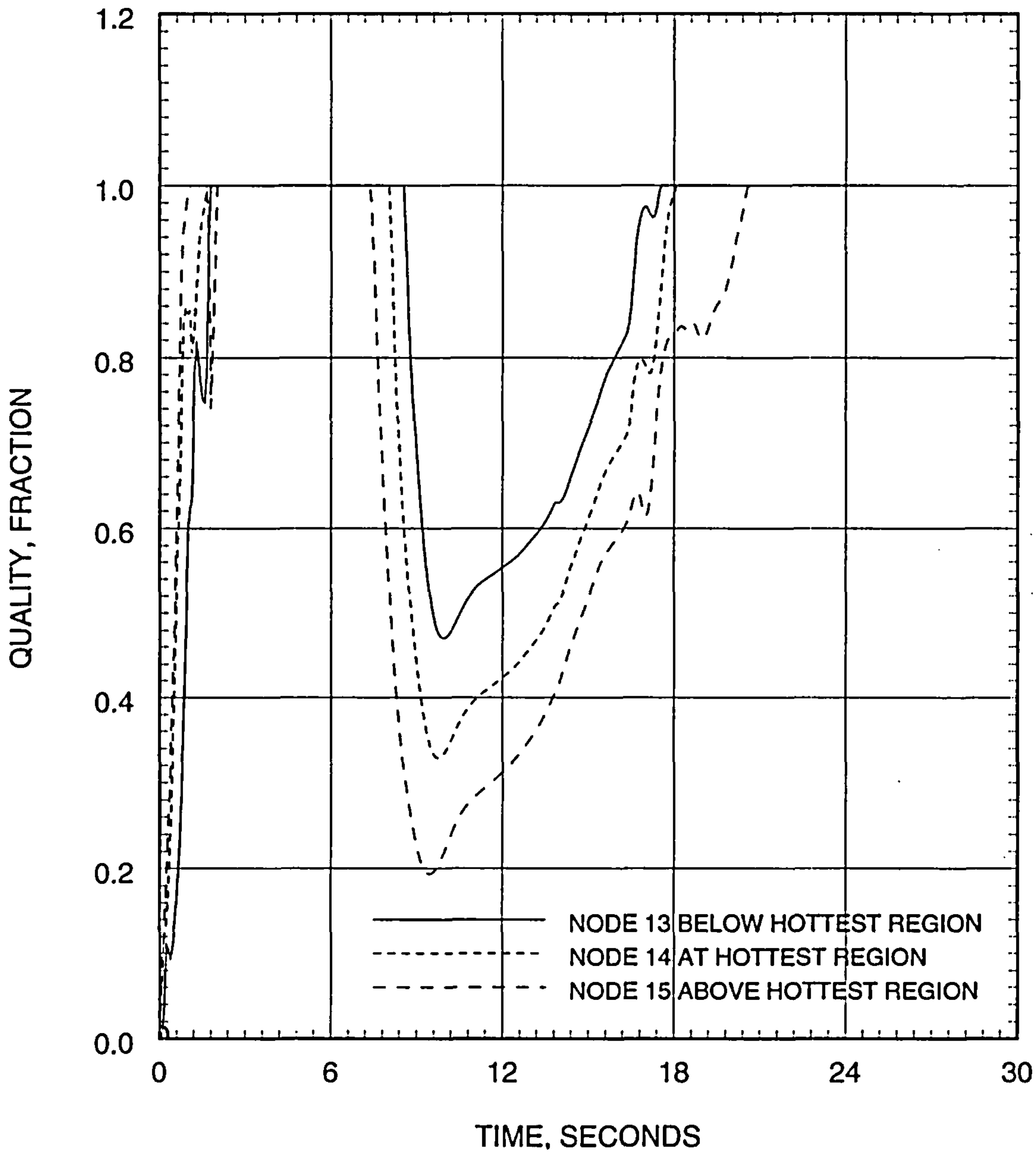

Figure 5.2.3.3-24
0.6 DEG/PD Large Break LOCA
Hot Assembly Quality vs. Time

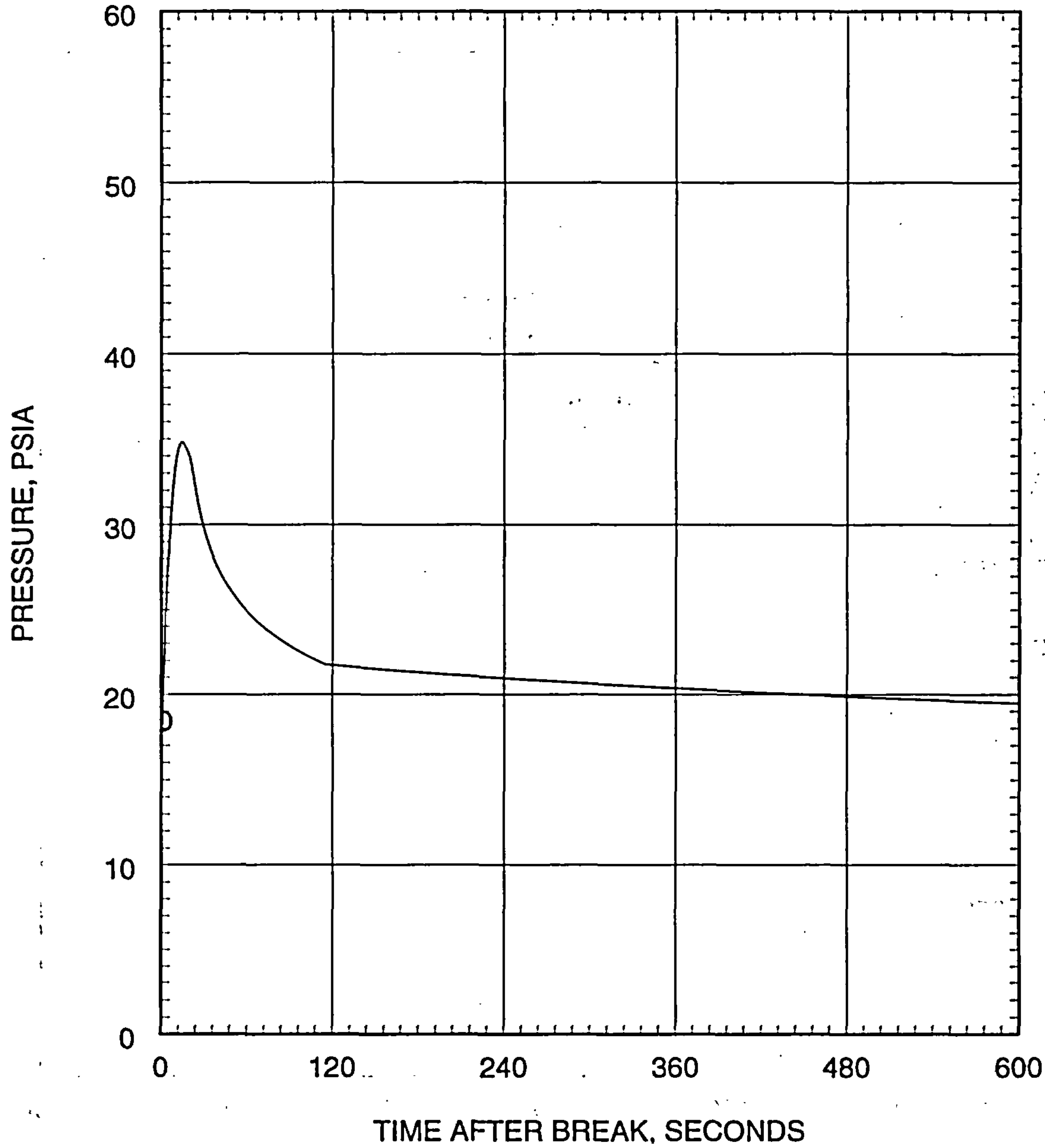

Figure 5.2.3.3-25
0.6 DEG/PD Large Break LOCA
Containment Pressure vs. Time

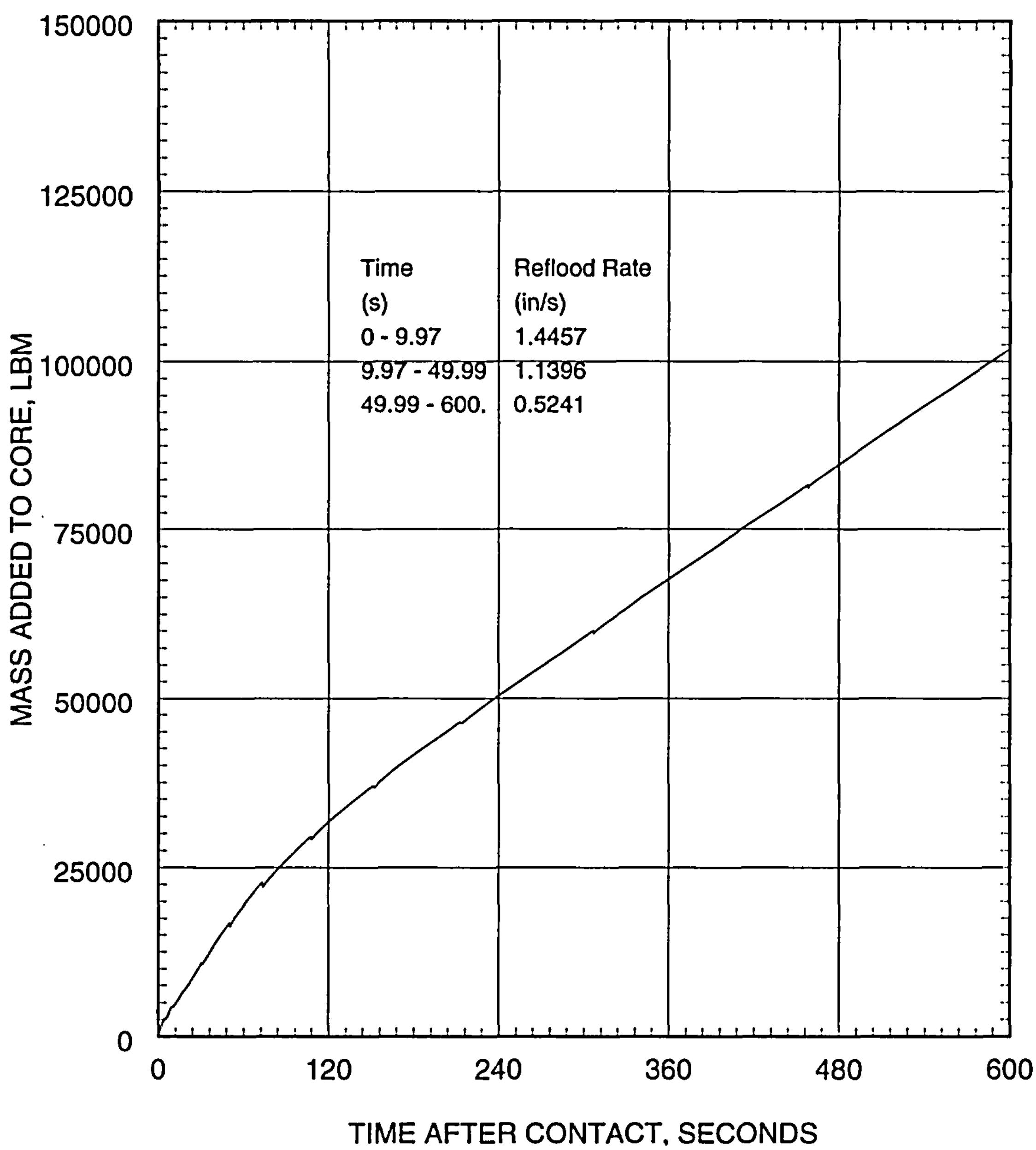

Figure 5.2.3.3-26
0.6 DEG/PD Large Break LOCA
Mass Added to Core vs. Time during Reflood

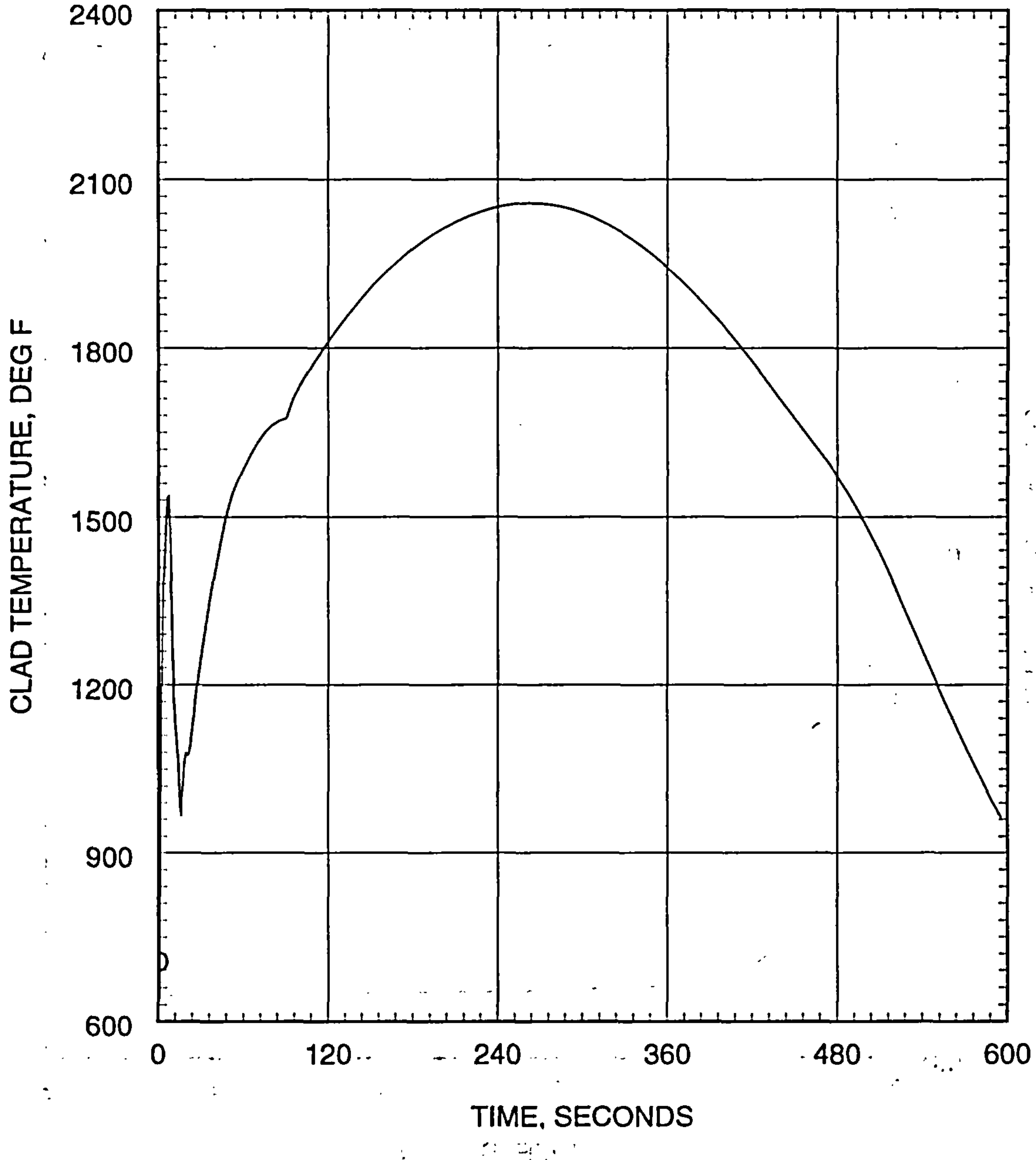

Figure 5.2.3.3-27
0.6 DEG/PD Large Break LOCA
Peak Cladding Temperature vs. Time

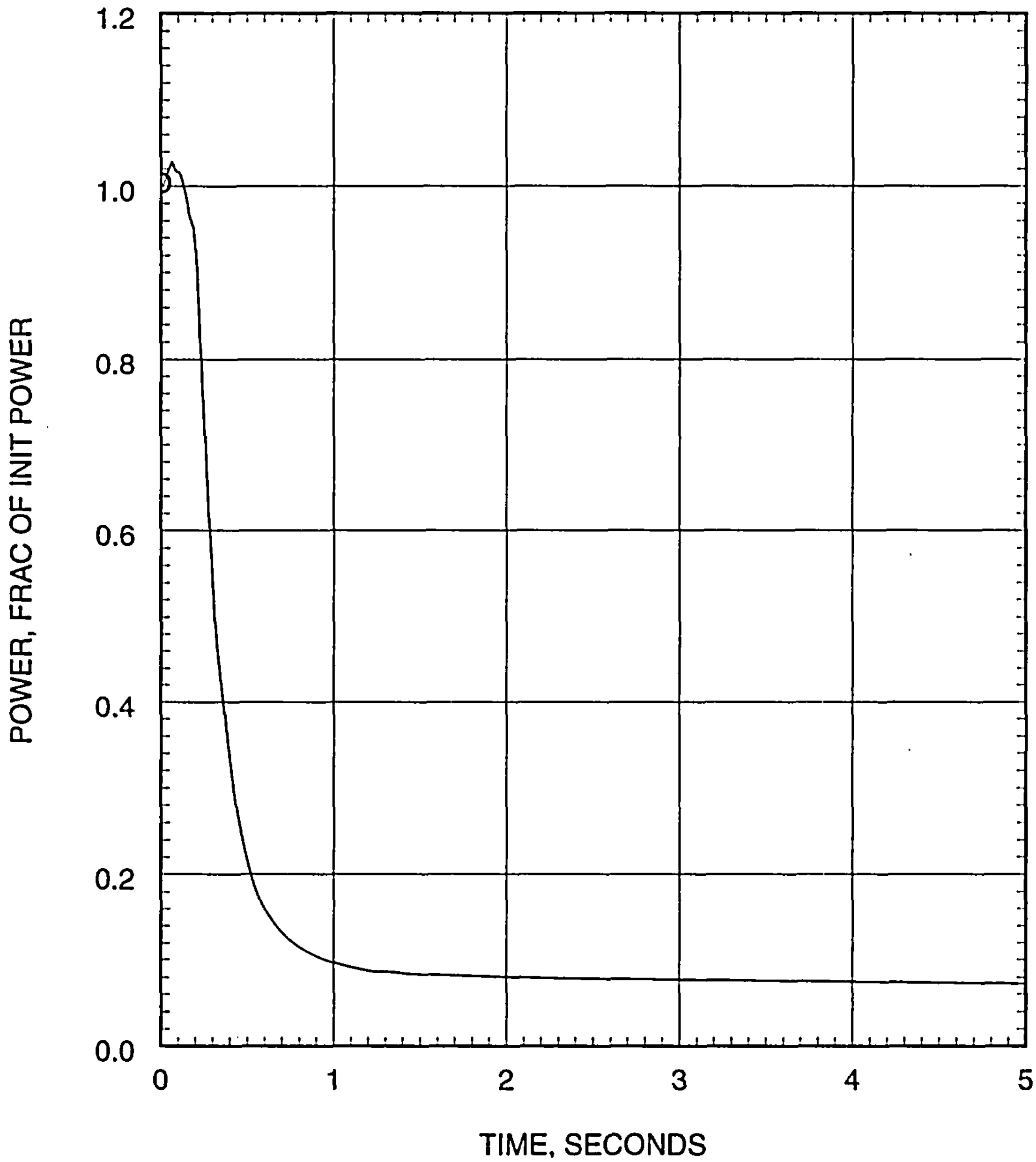

Figure 5.2.3.3-28
0.4 DEG/PD Large Break LOCA
Normalized Core Power vs. Time

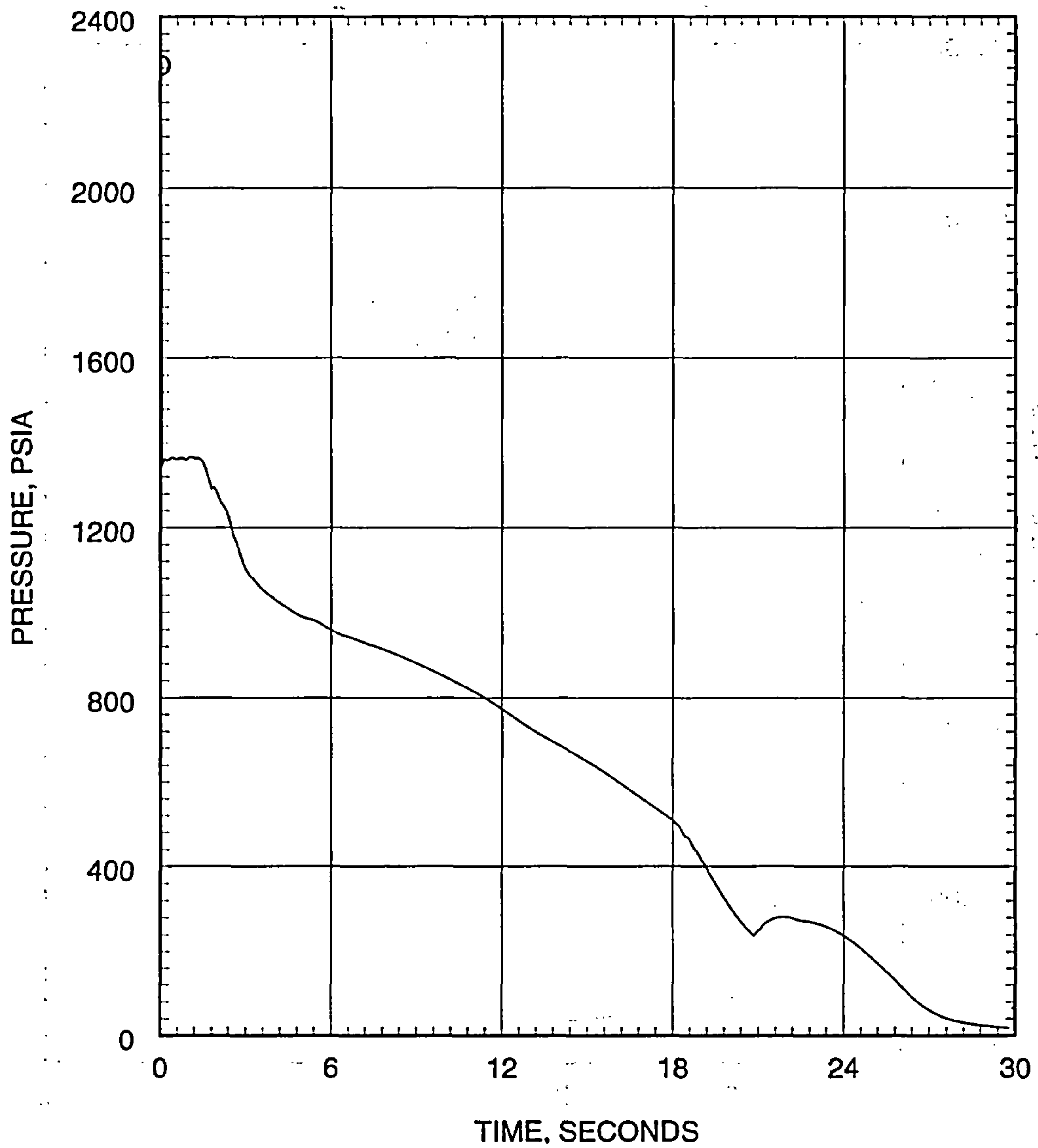

Figure 5.2.3.3-29
0.4 DEG/PD Large Break LOCA
Pressure in Center Hot Assembly Node vs. Time

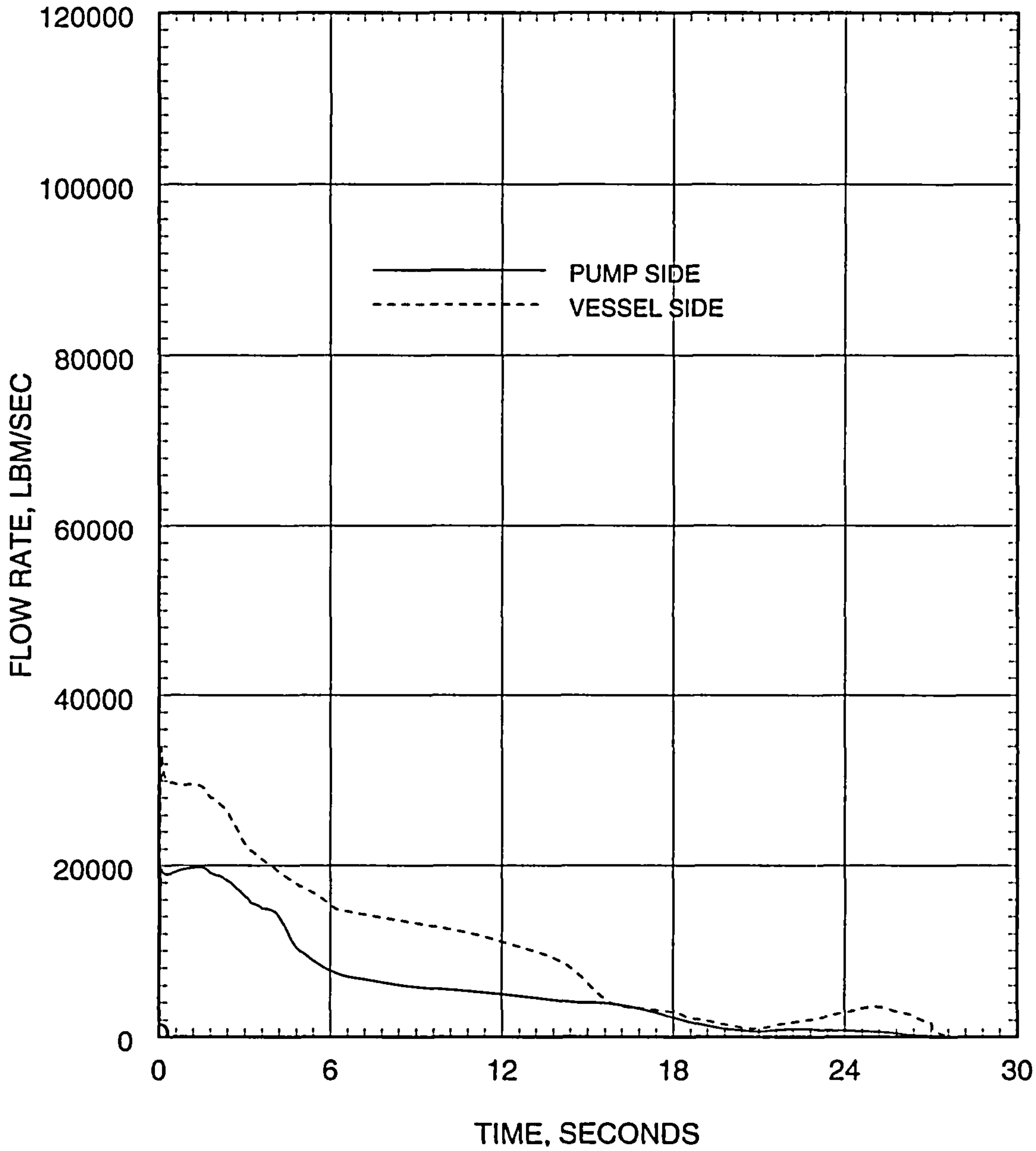

Figure 5.2.3.3-30
0.4 DEG/PD Large Break LOCA
Leak Flow Rate vs. Time

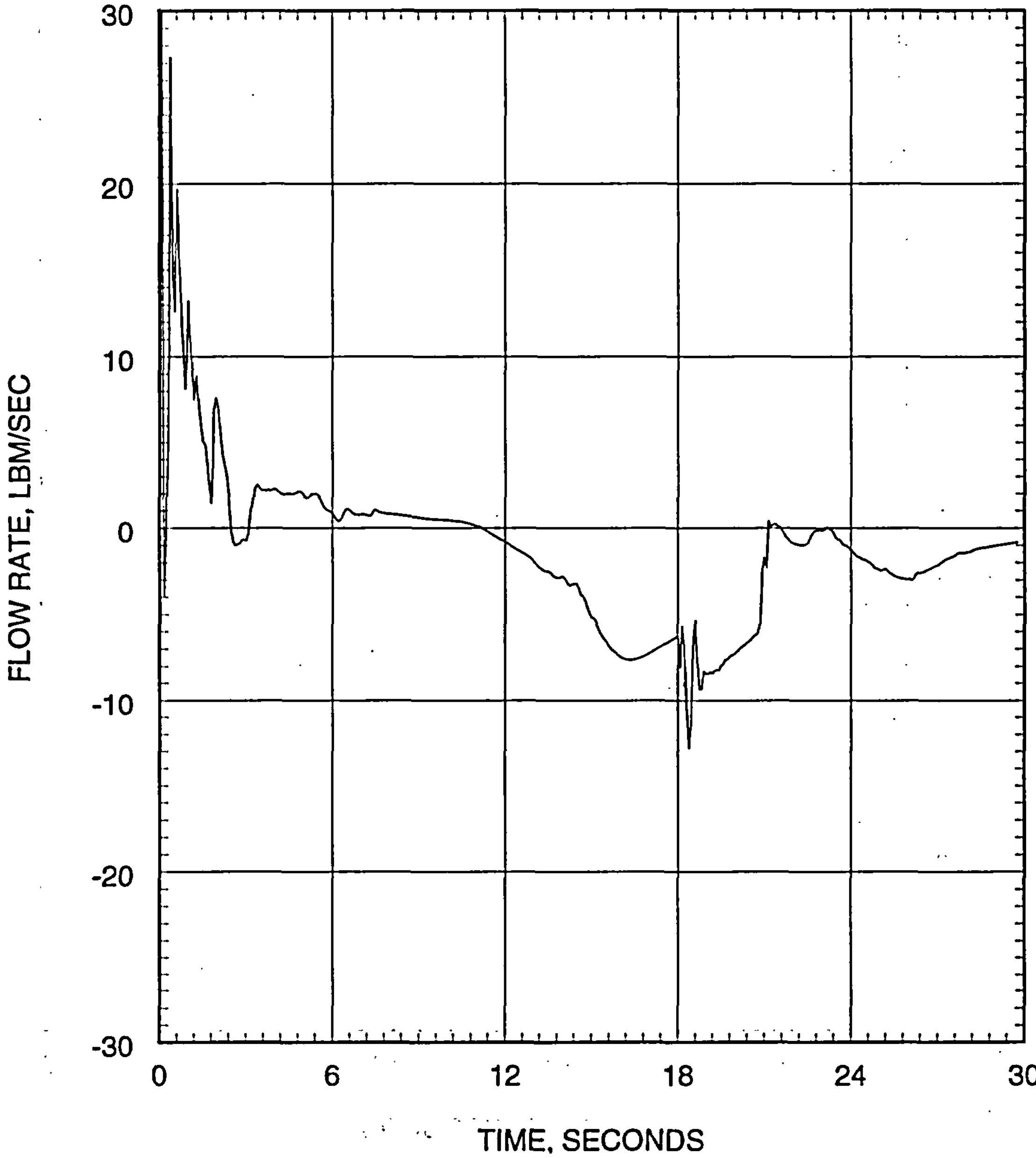

Figure 5.2.3.3-31
0.4 DEG/PD Large Break LOCA
Hot Assembly Flow Rate vs. Time below Hot Spot

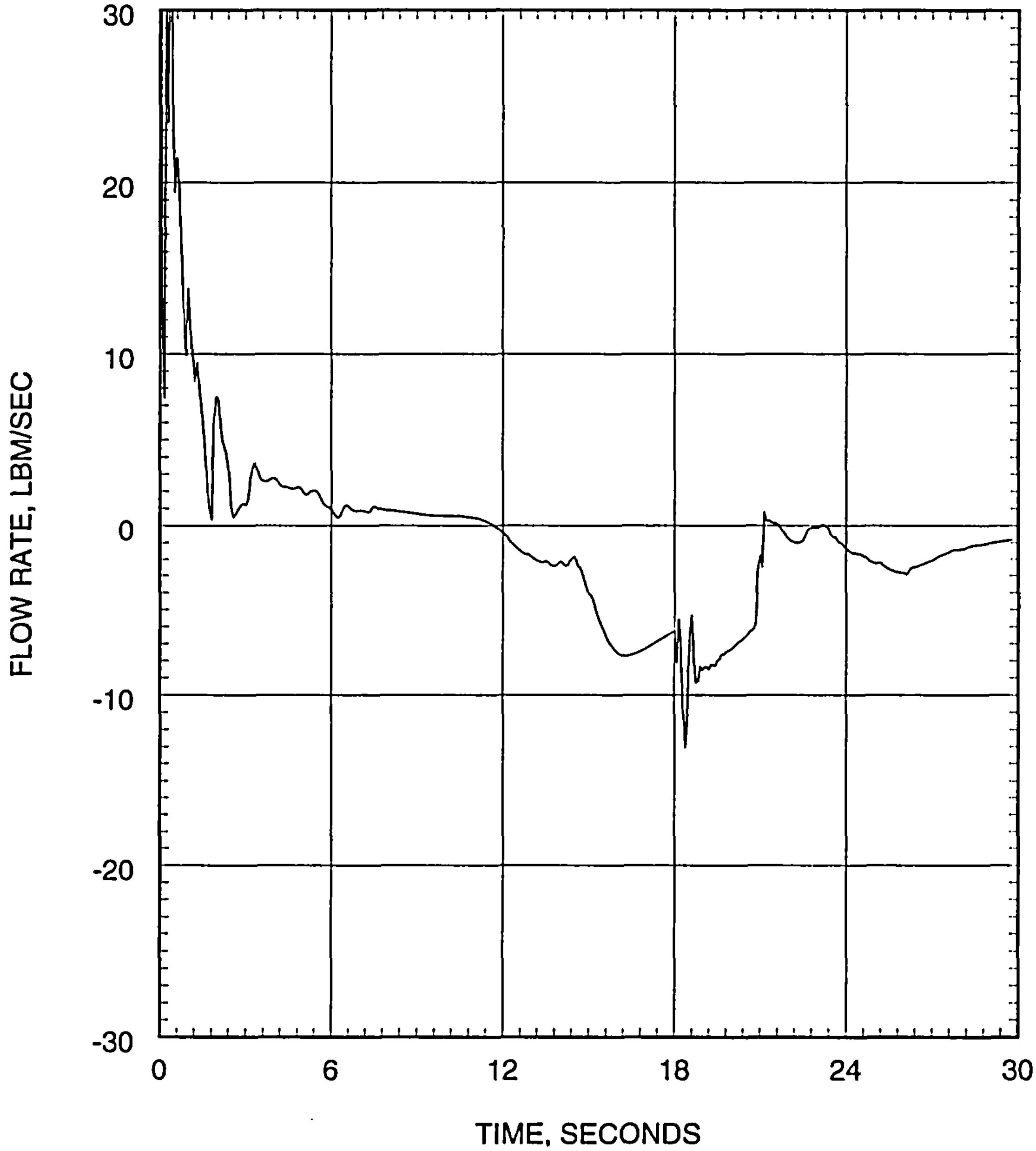

Figure 5.2.3.3-32
0.4 DEG/PD Large Break LOCA
Hot Assembly Flow Rate vs. Time above Hot Spot

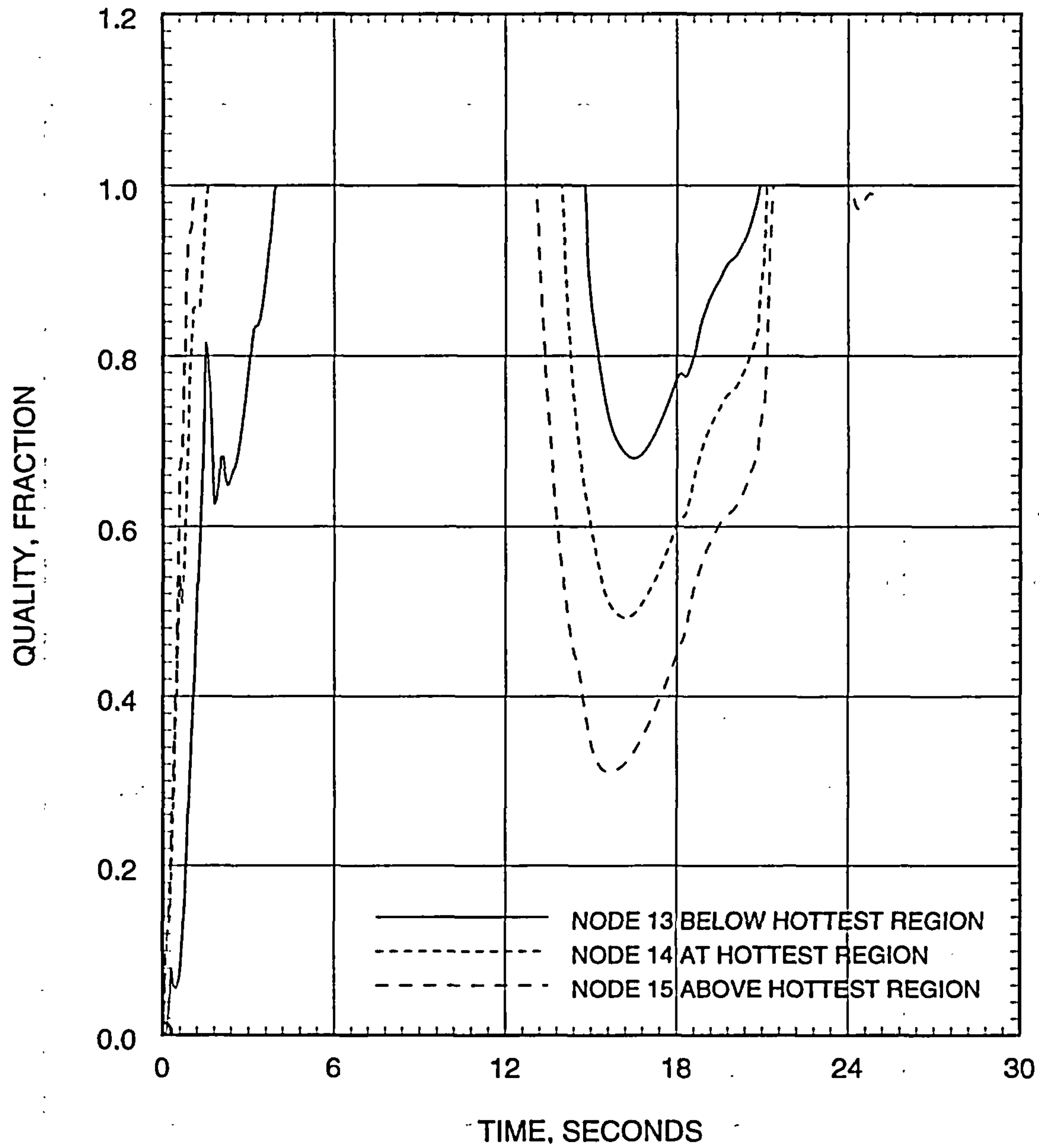

Figure 5.2.3.3-33
0.4 DEG/PD Large Break LOCA
Hot Assembly Quality vs. Time

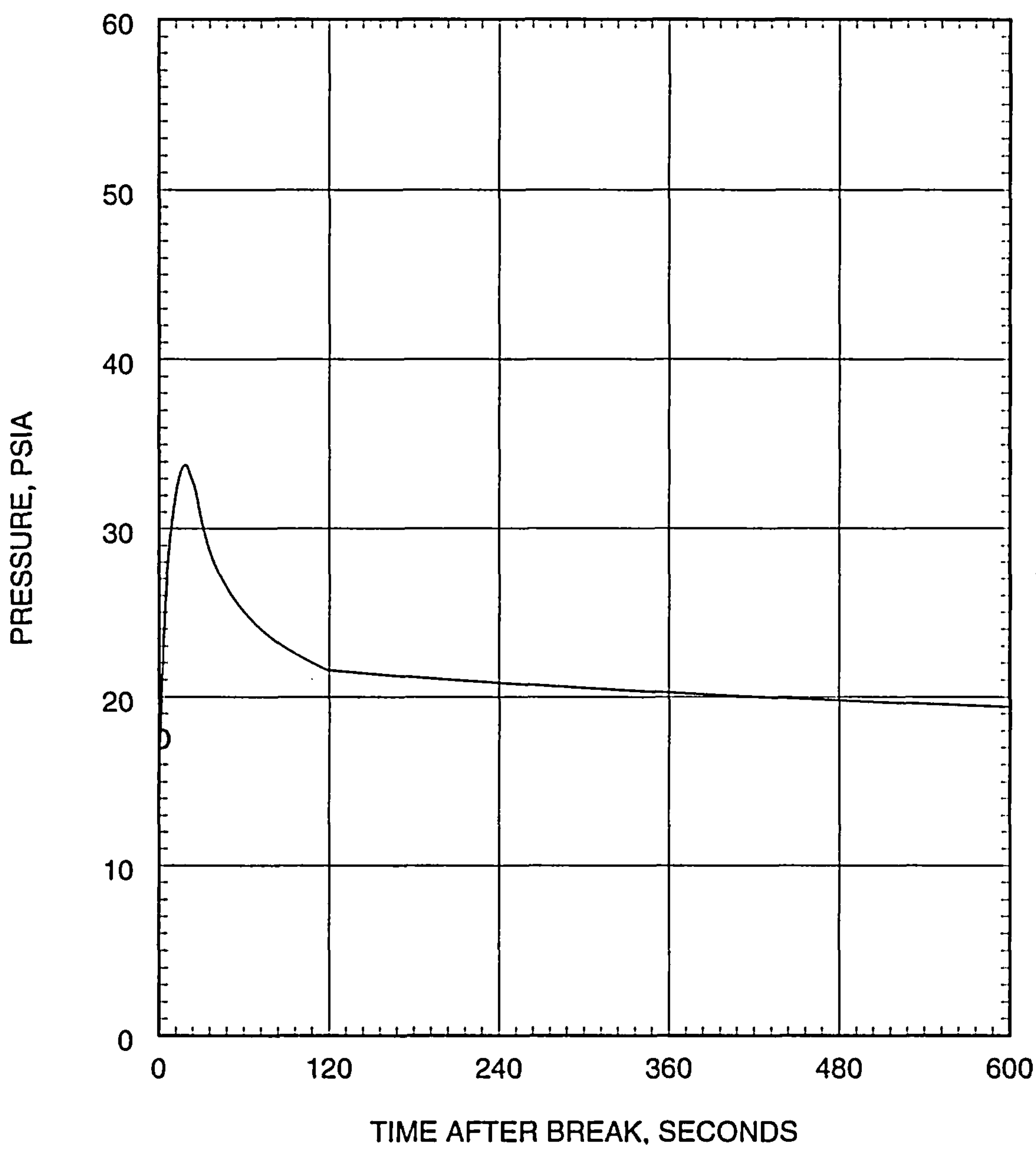

Figure 5.2.3.3-34
0.4 DEG/PD Large Break LOCA
Containment Pressure vs. Time

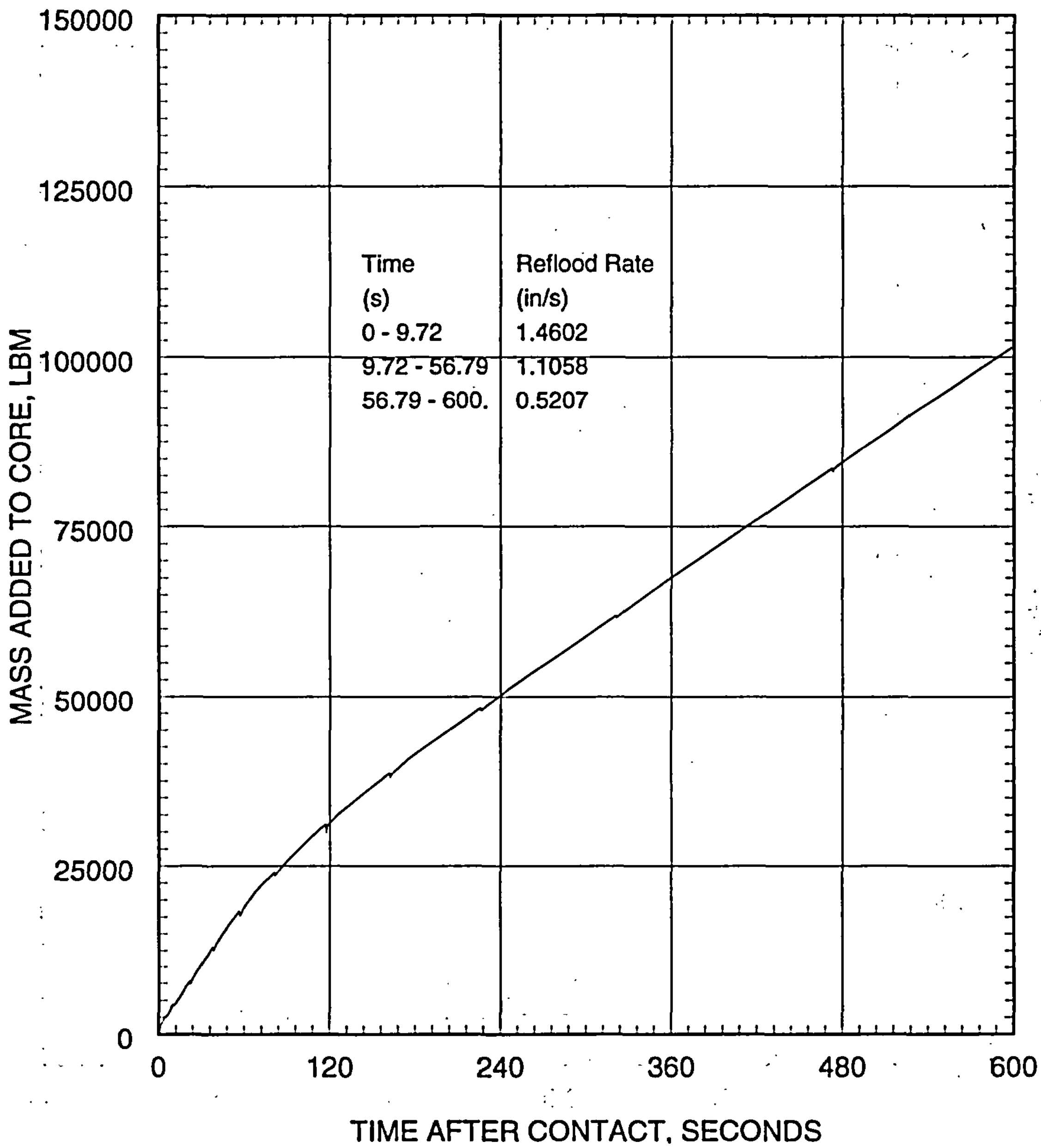

Figure 5.2.3.3-35
0.4 DEG/PD Large Break LOCA
Mass Added to Core vs. Time during Reflood

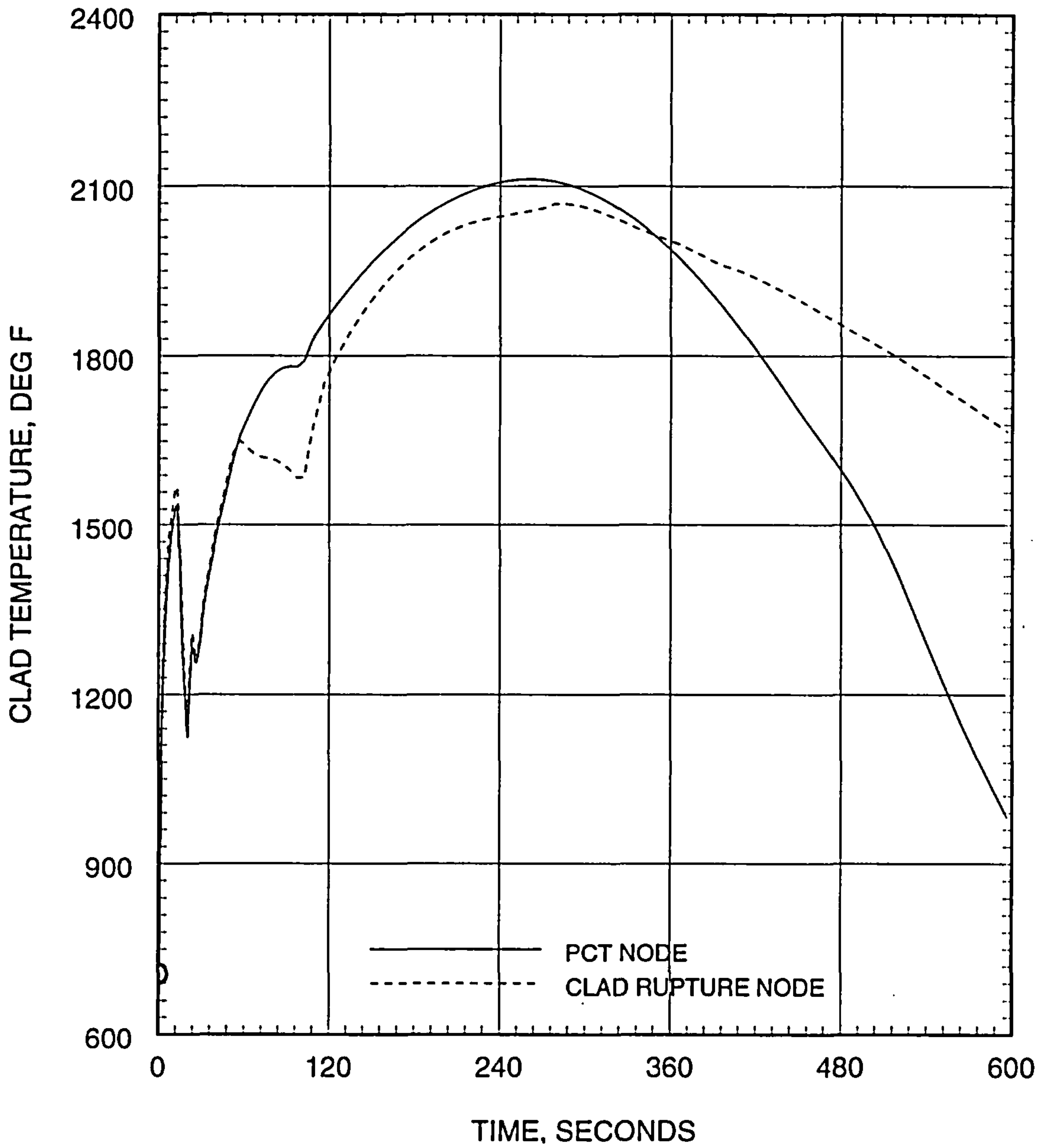

Figure 5.2.3.3-36
0.4 DEG/PD Large Break LOCA
Peak Cladding Temperature vs. Time

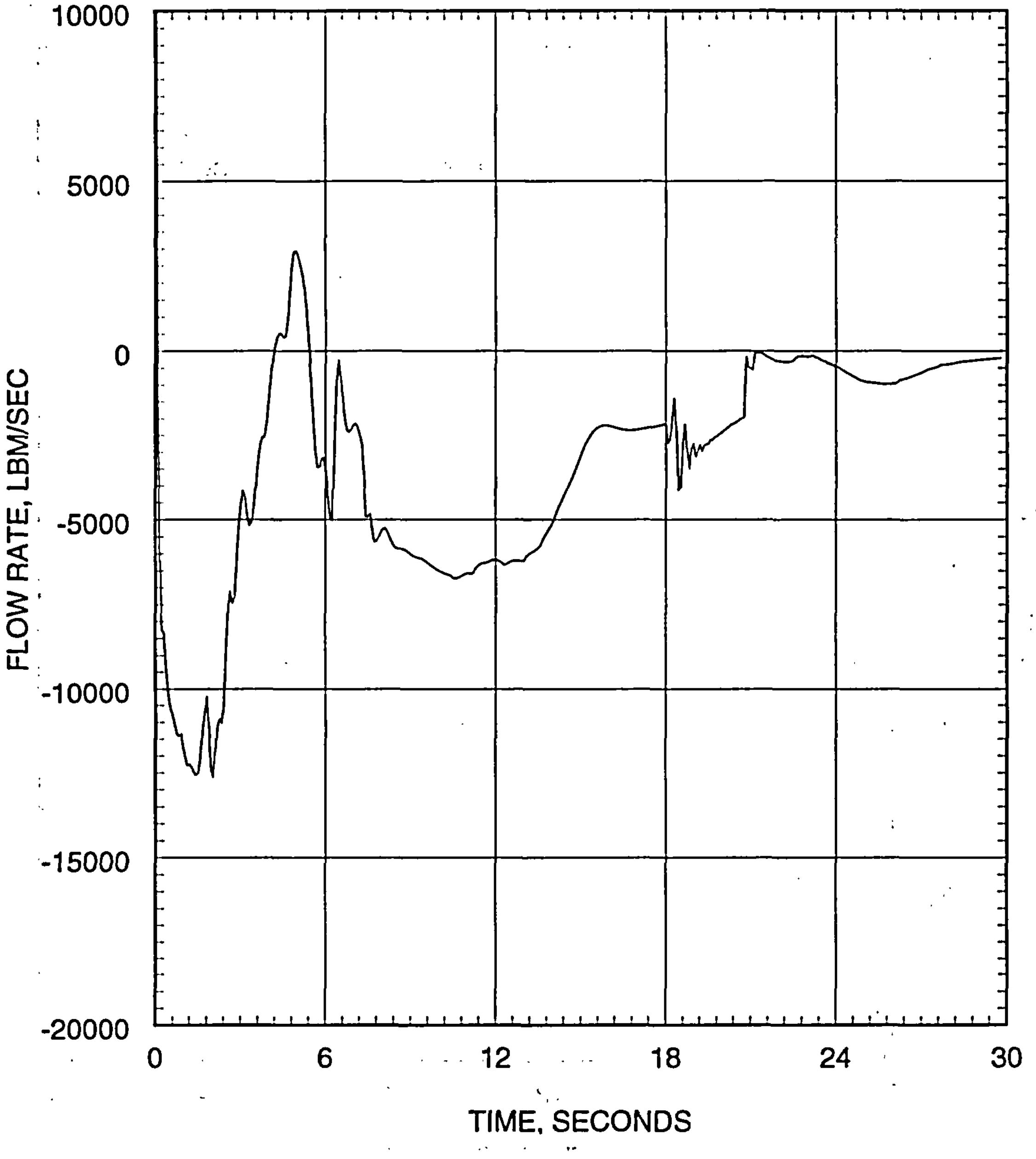

Figure 5.2.3.3-37
0.4 DEG/PD Large Break LOCA
Mid Annulus Flow Rate vs. Time

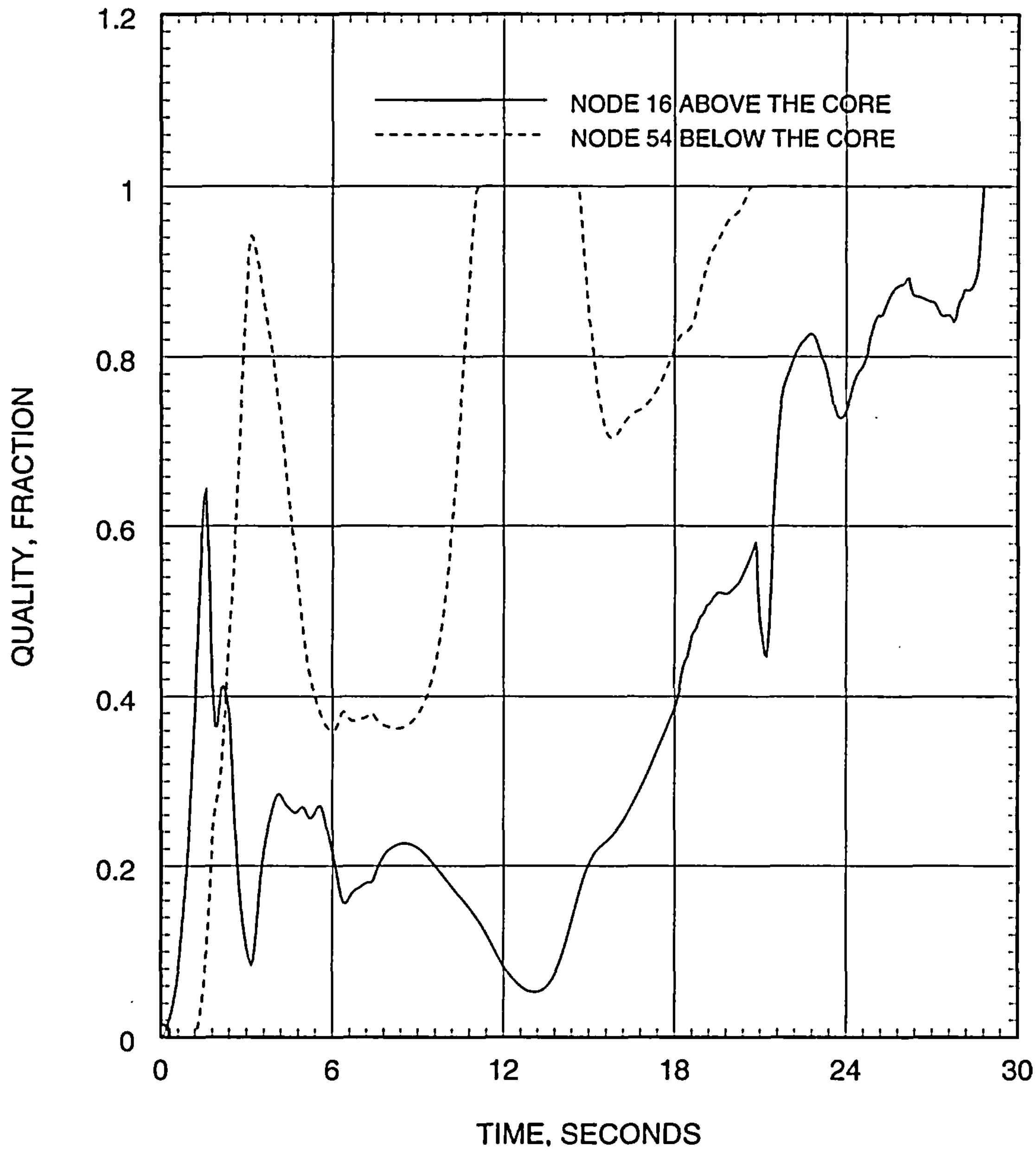

Figure 5.2.3.3-38
0.4 DEG/PD Large Break LOCA
Quality Above and Below the Core vs. Time

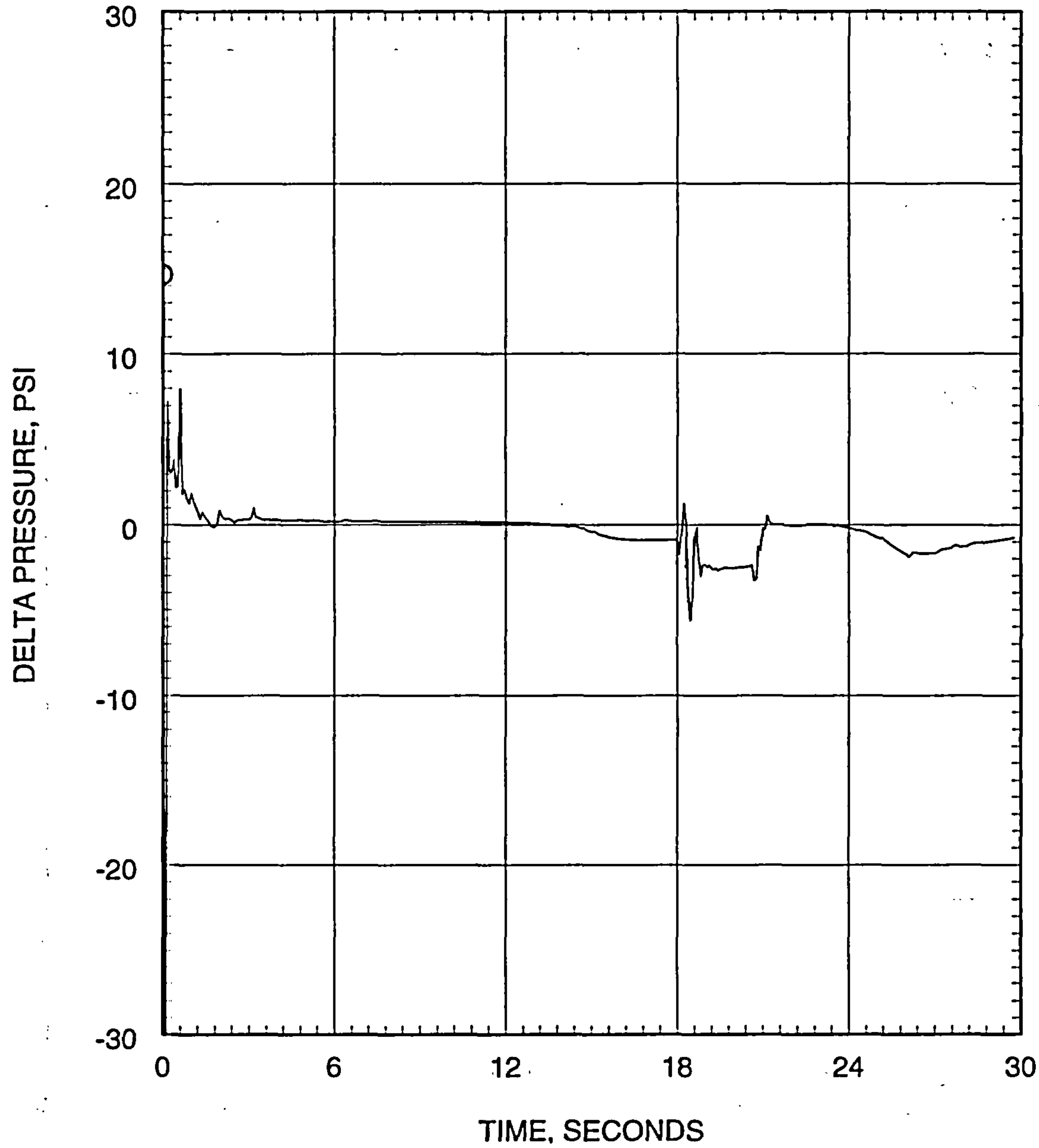

Figure 5.2.3.3-39
0.4 DEG/PD Large Break LOCA
Core Pressure Drop vs. Time

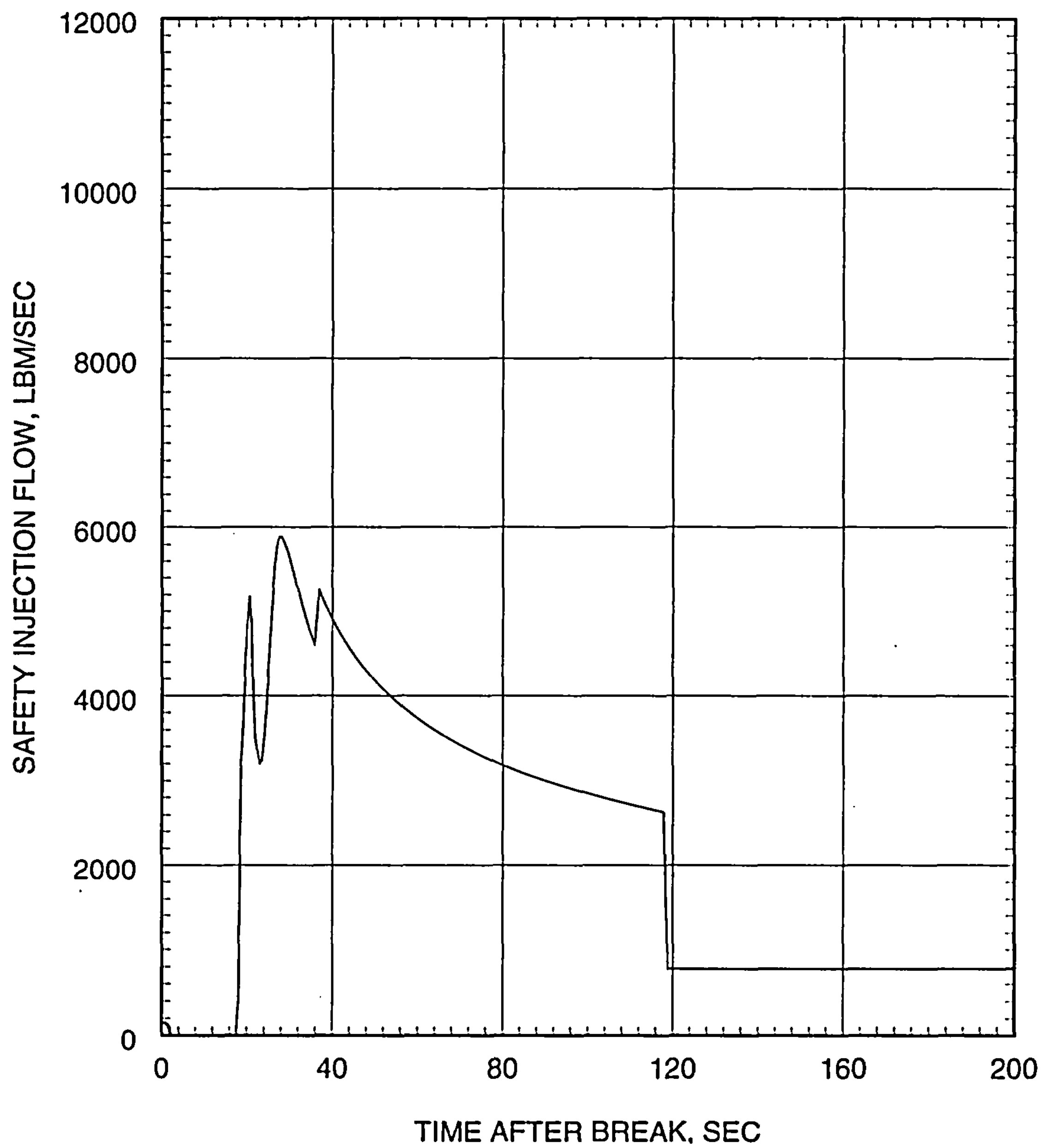

Figure 5.2.3.3-40
0.4 DEG/PD Large Break LOCA
Safety Injection Flow Rate into Intact Discharge Legs vs. Time

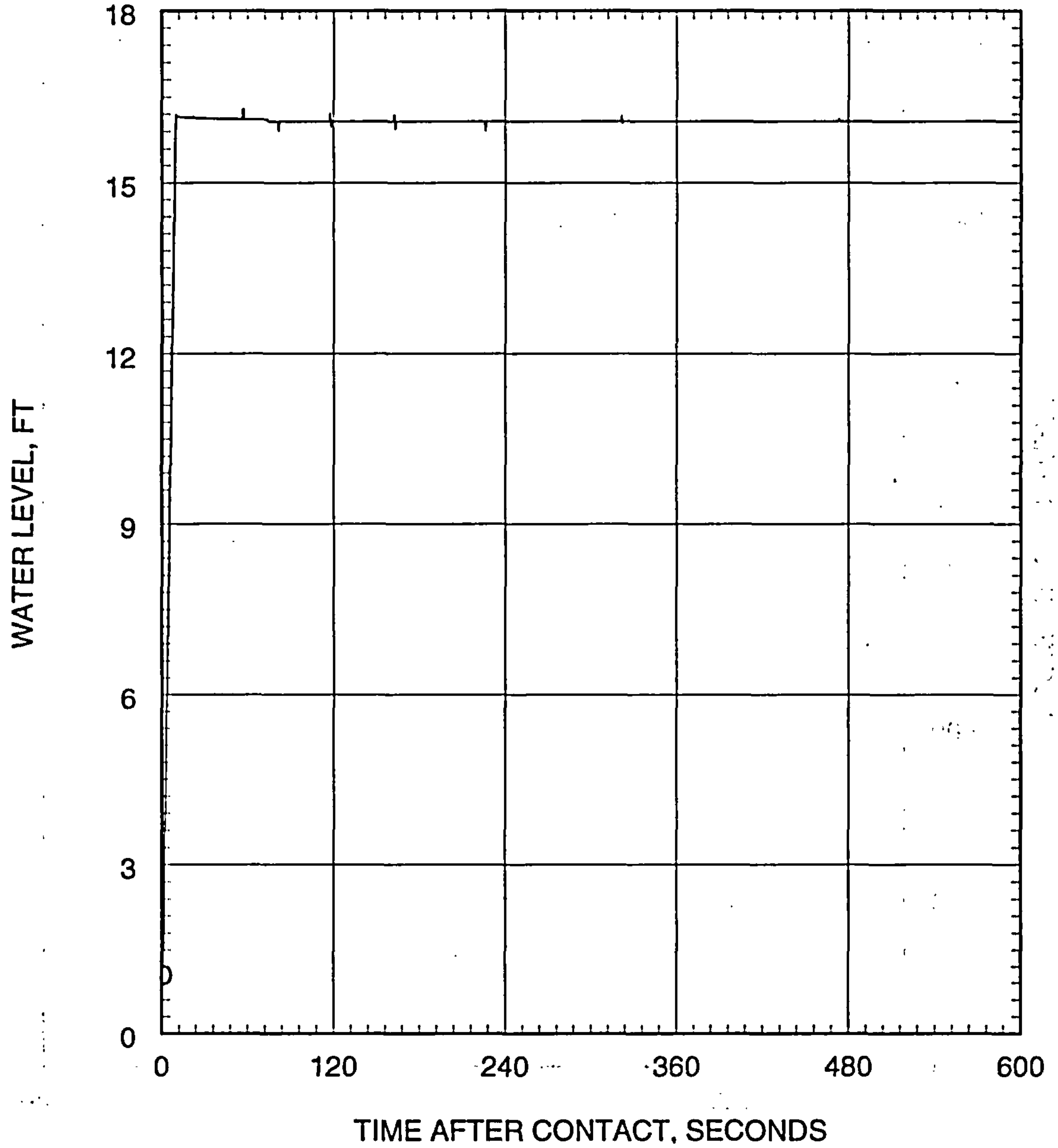

Figure 5.2.3.3-41
0.4 DEG/PD Large Break LOCA
Water Level in Downcomer vs. Time during Reflood

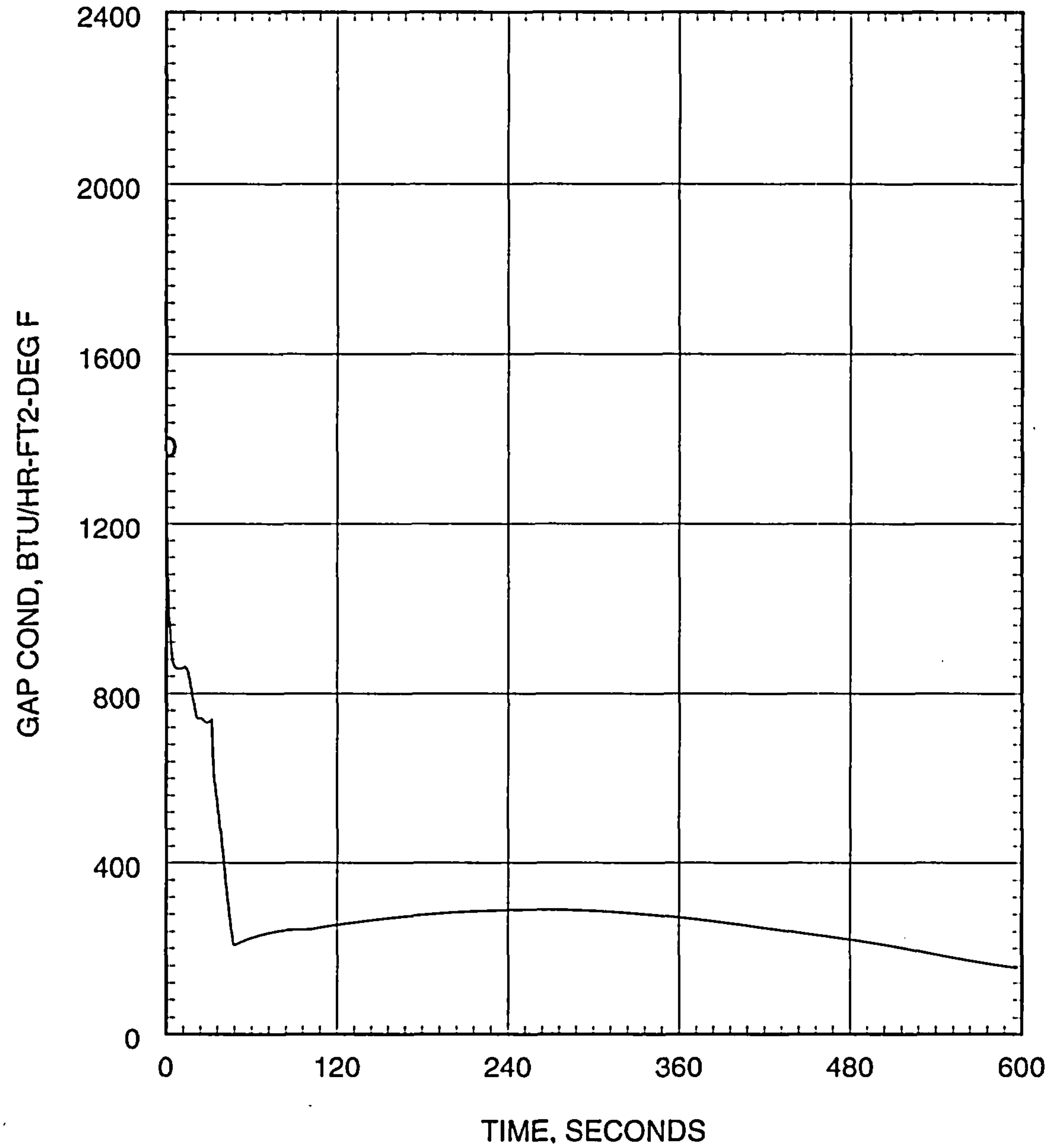

Figure 5.2.3.3-42
0.4 DEG/PD Large Break LOCA
Hot Spot Gap Conductance vs. Time

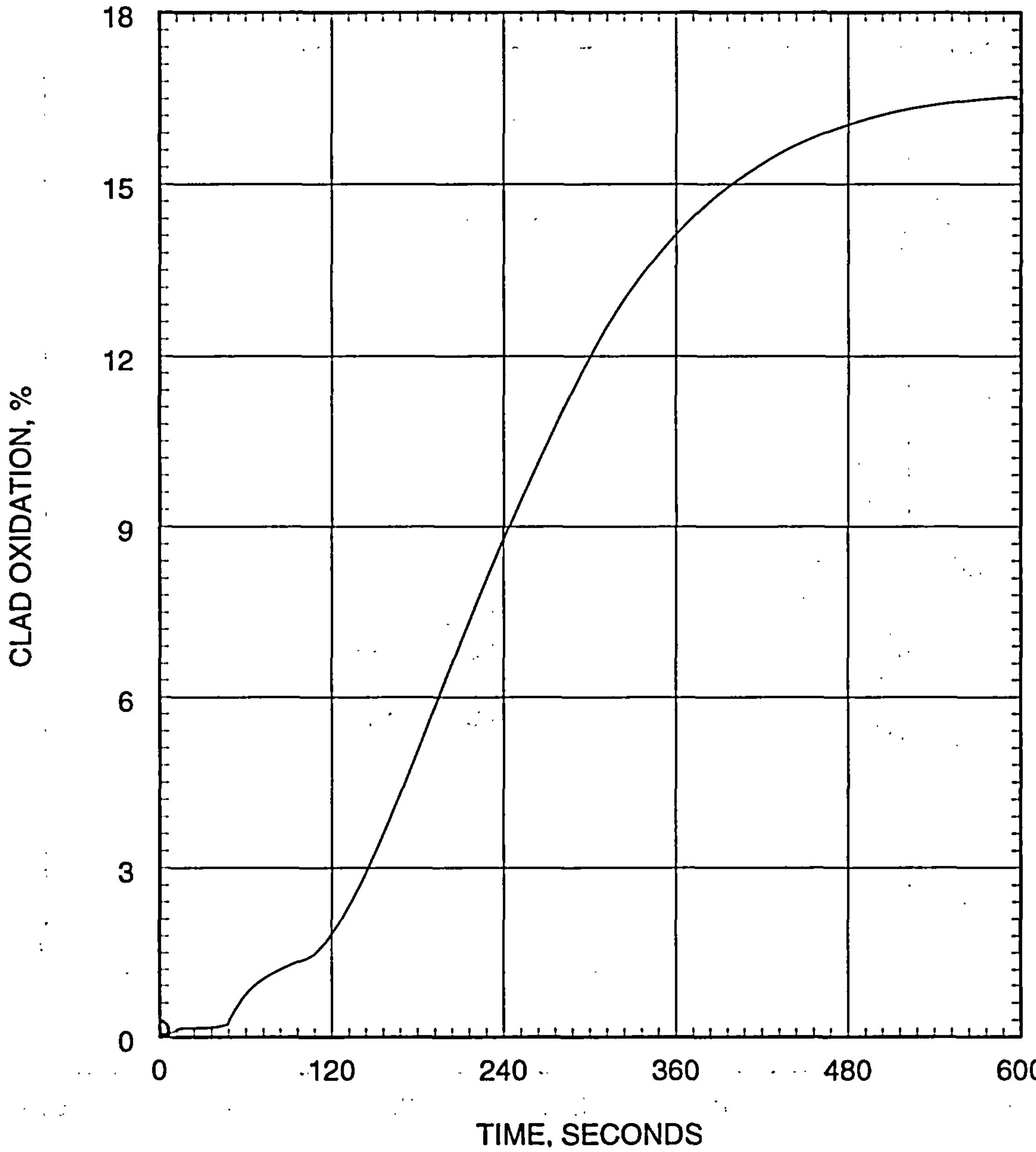

Figure 5.2.3.3-43
0.4 DEG/PD Large Break LOCA
Maximum Local Cladding Oxidation vs. Time

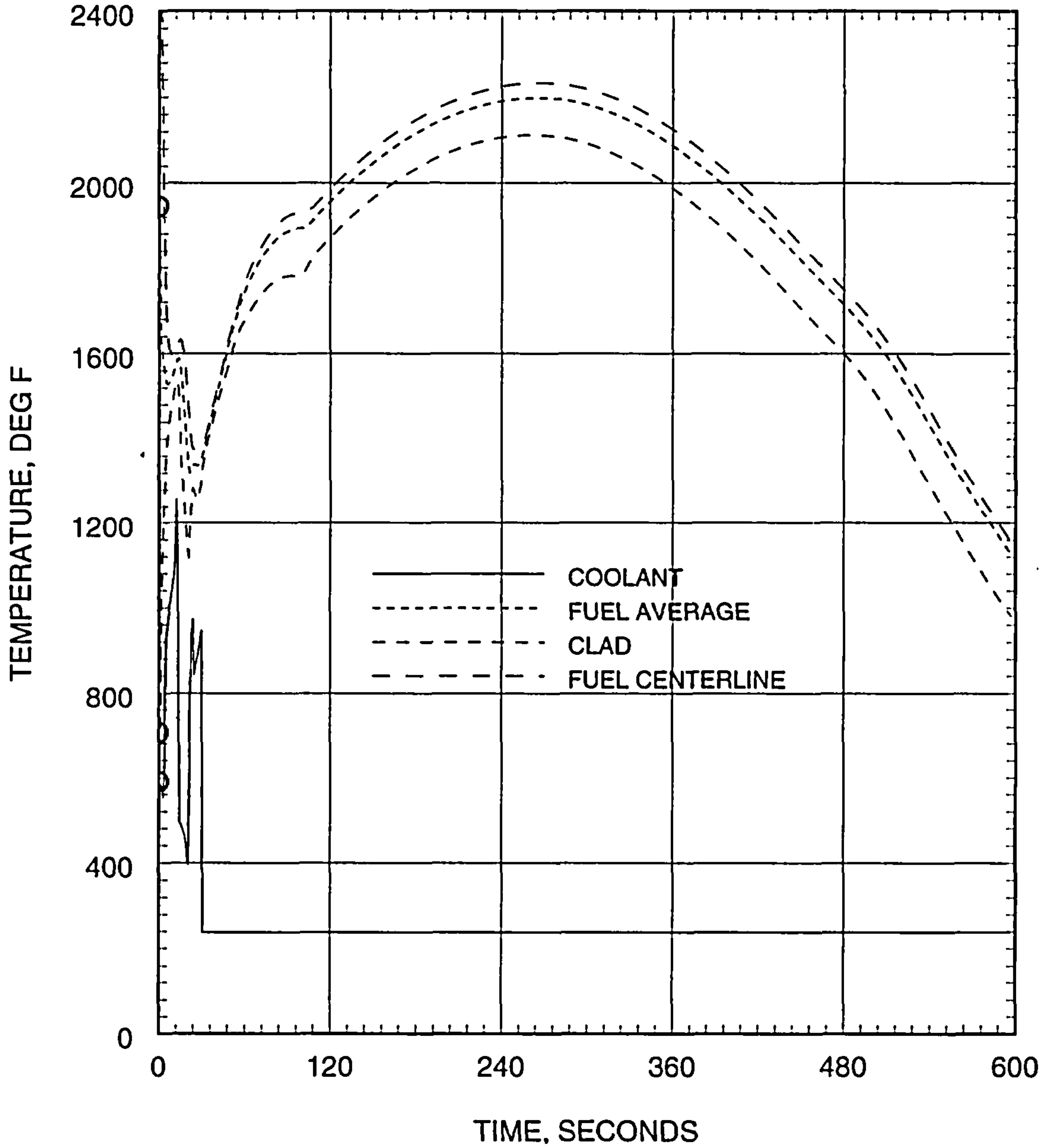

Figure 5.2.3.3-44
0.4 DEG/PD Large Break LOCA
Hot Spot Fuel & Coolant Temperatures vs. Time

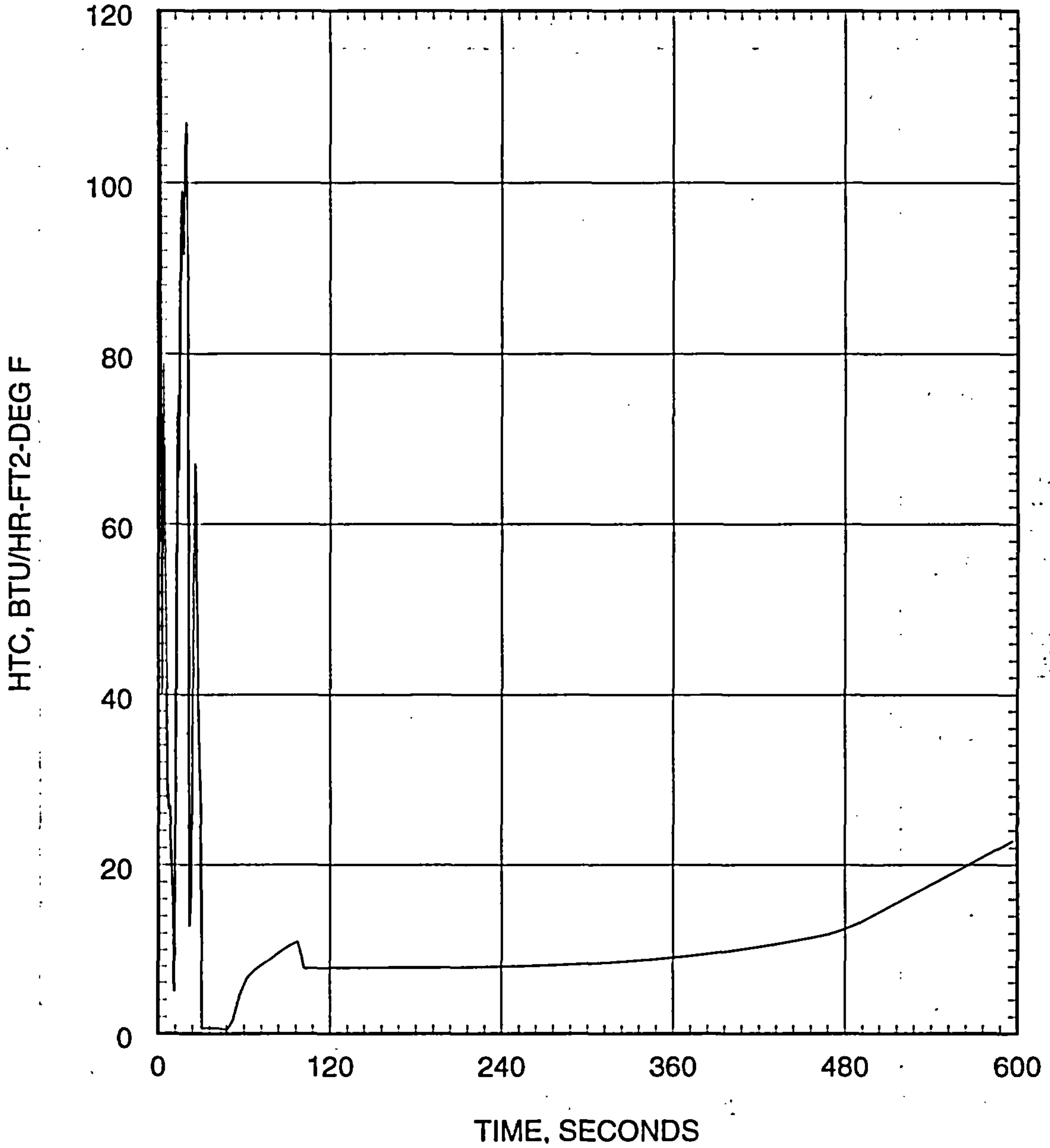

Figure 5.2.3.3-45
0.4 DEG/PD Large Break LOCA
Hot Spot Heat Transfer Coefficient vs. Time

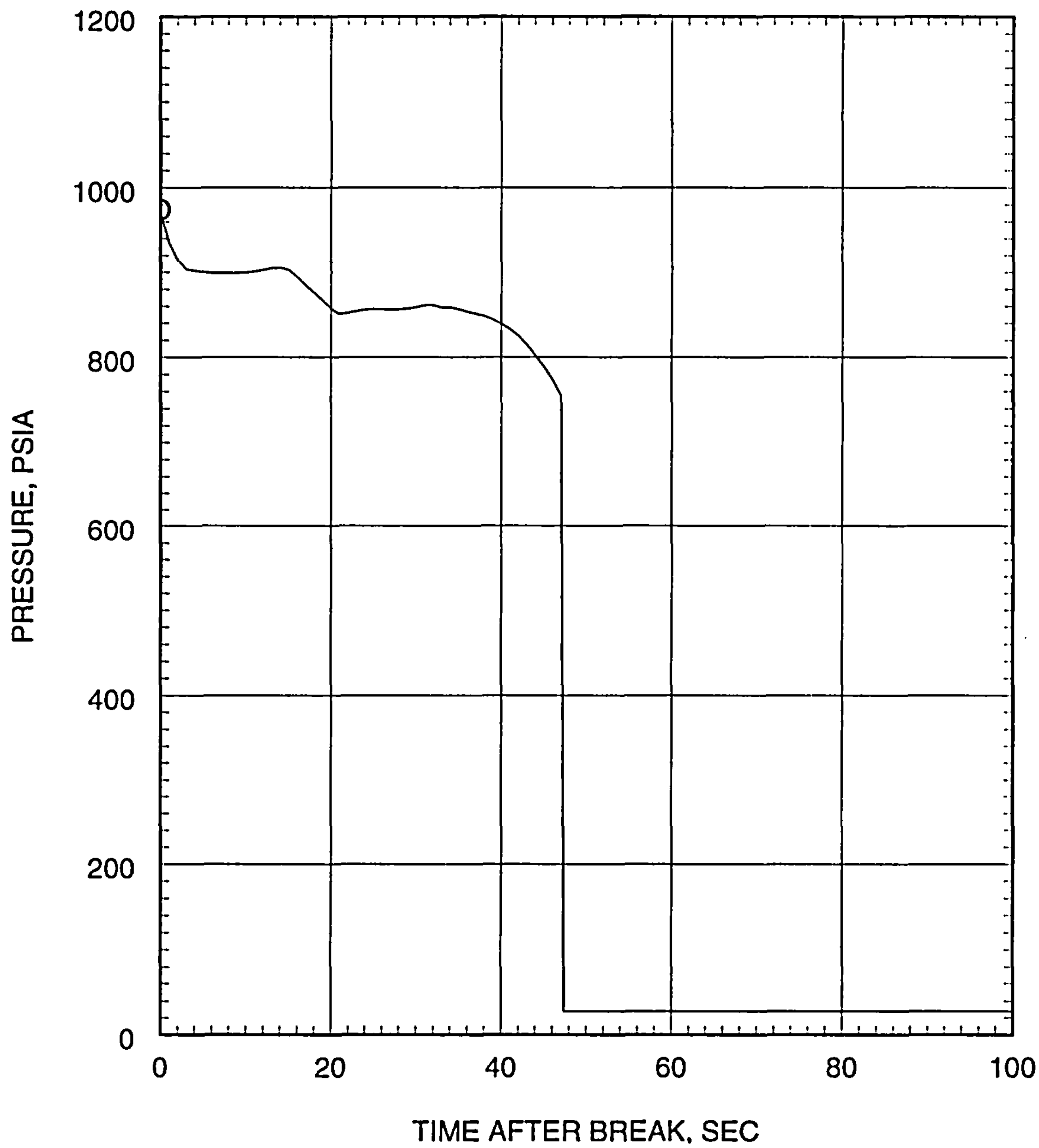

Figure 5.2.3.3-46
0.4 DEG/PD Large Break LOCA
Hot Rod Internal Gas Pressure vs. Time

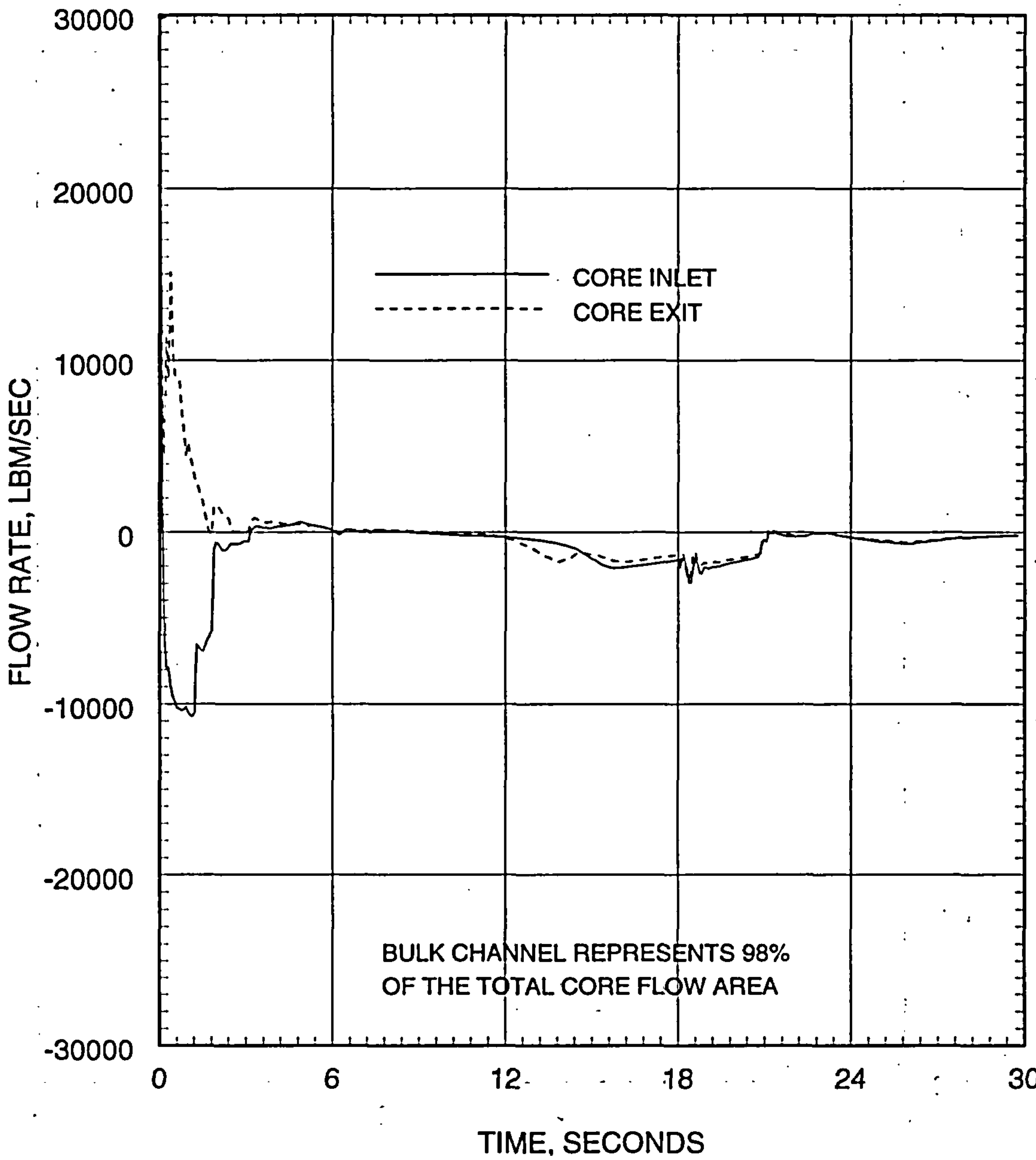

Figure 5.2.3.3-47
0.4 DEG/PD Large Break LOCA
Bulk Channel Flow Rate vs. Time

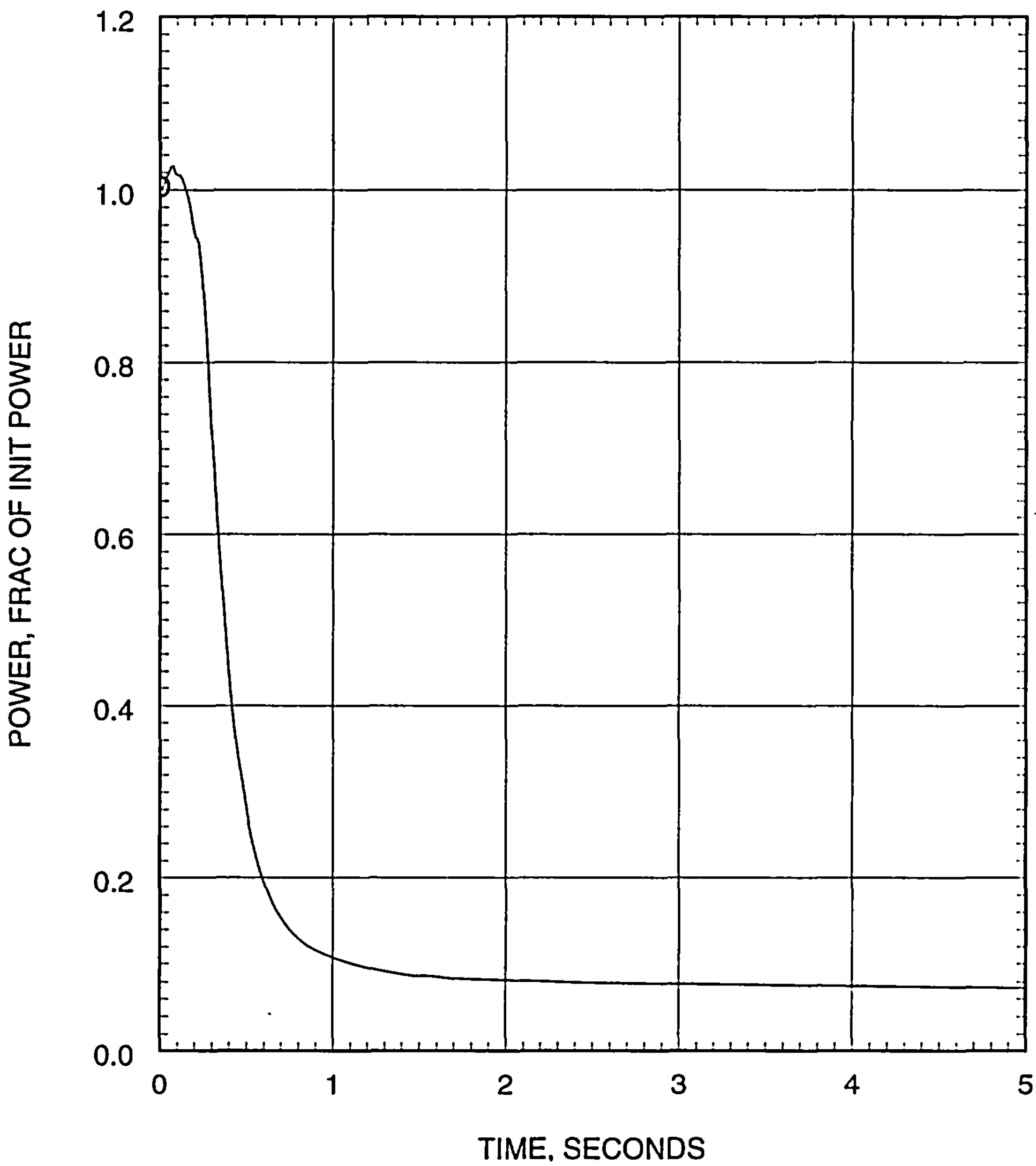

Figure 5.2.3.3-48
0.3 DEG/PD Large Break LOCA
Normalized Core Power vs. Time

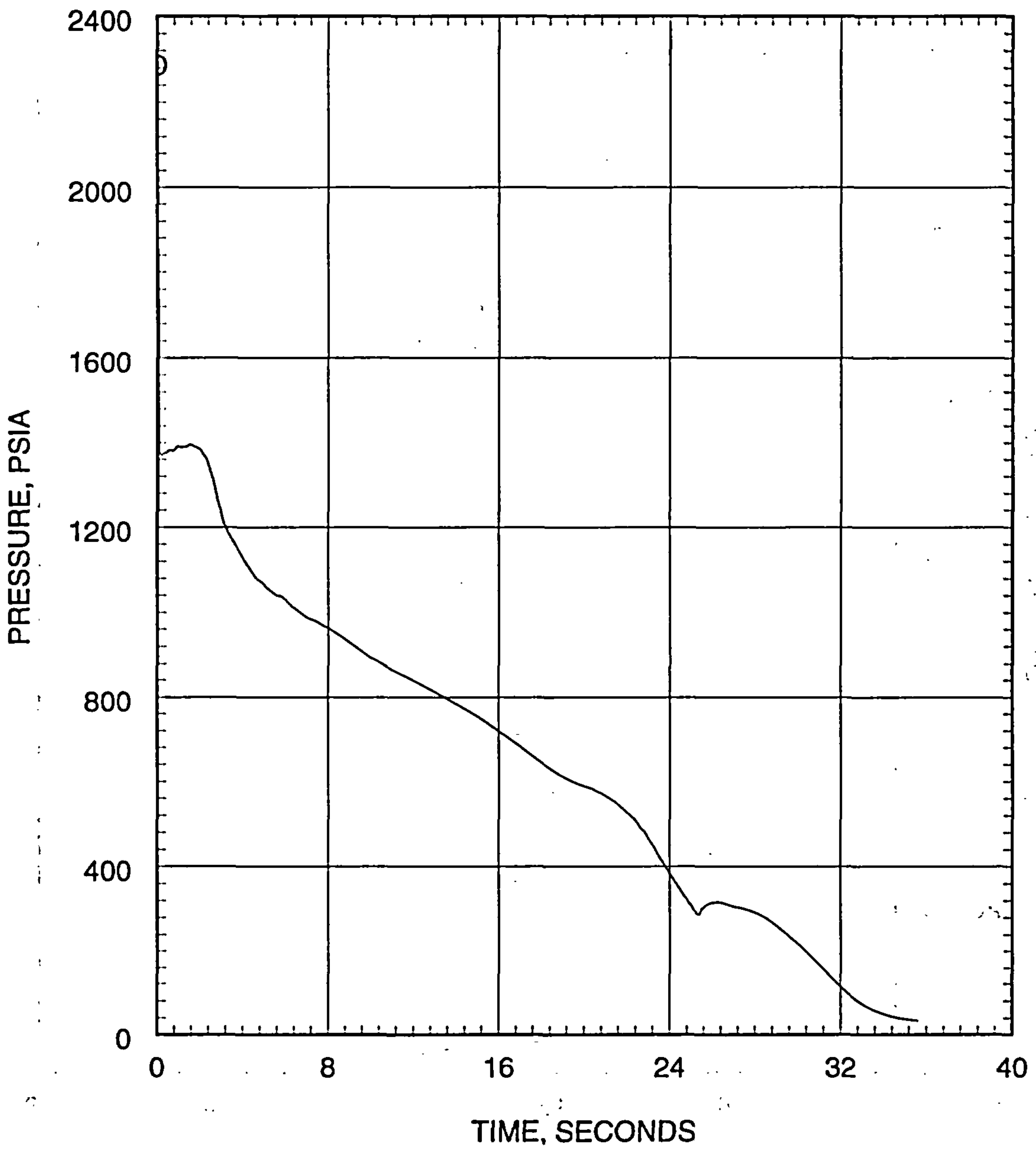

Figure 5.2.3.3-49
0.3 DEG/PD Large Break LOCA
Pressure in Center Hot Assembly Node vs. Time

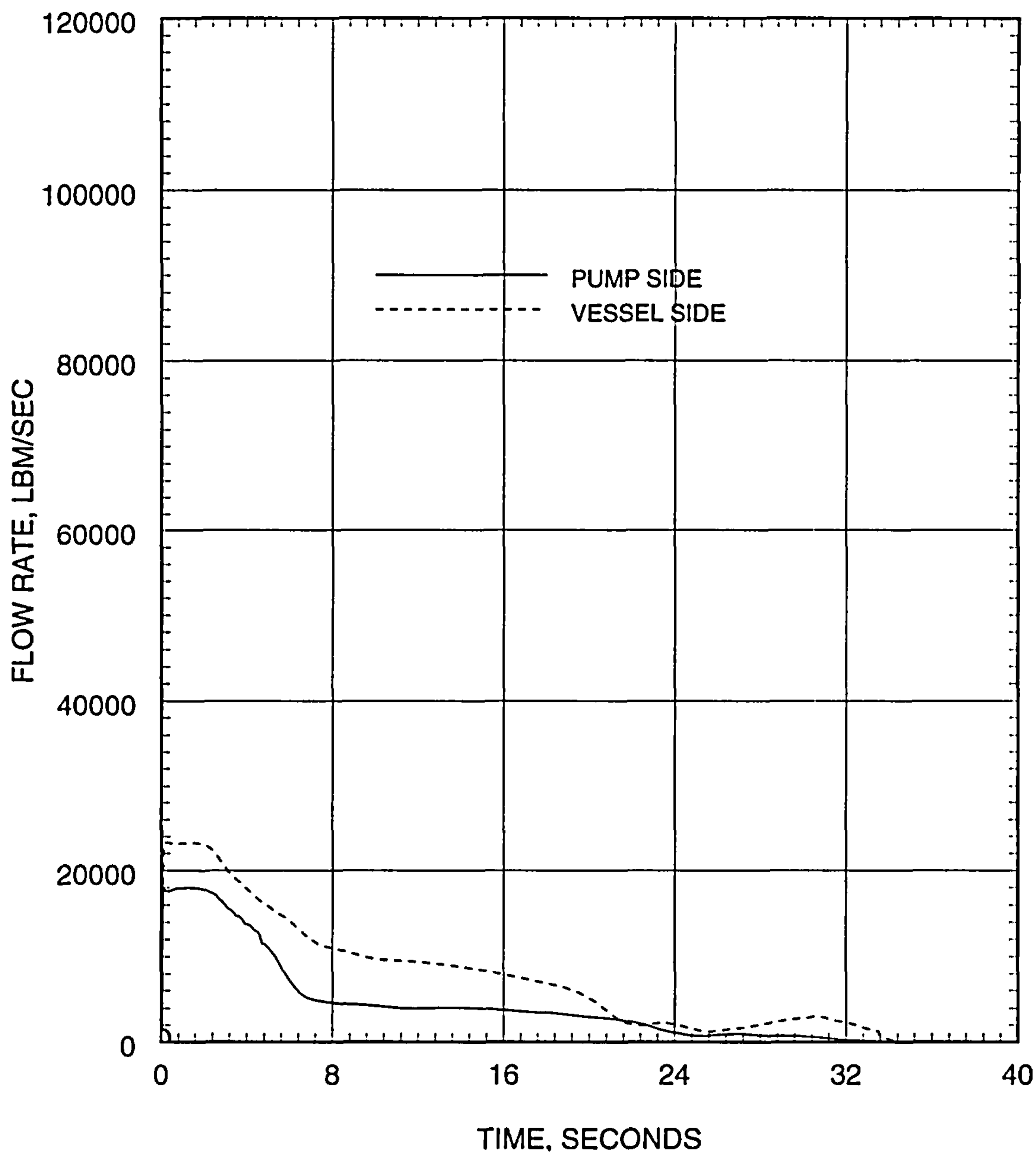

Figure 5.2.3.3-50
0.3 DEG/PD Large Break LOCA
Leak Flow Rate vs. Time

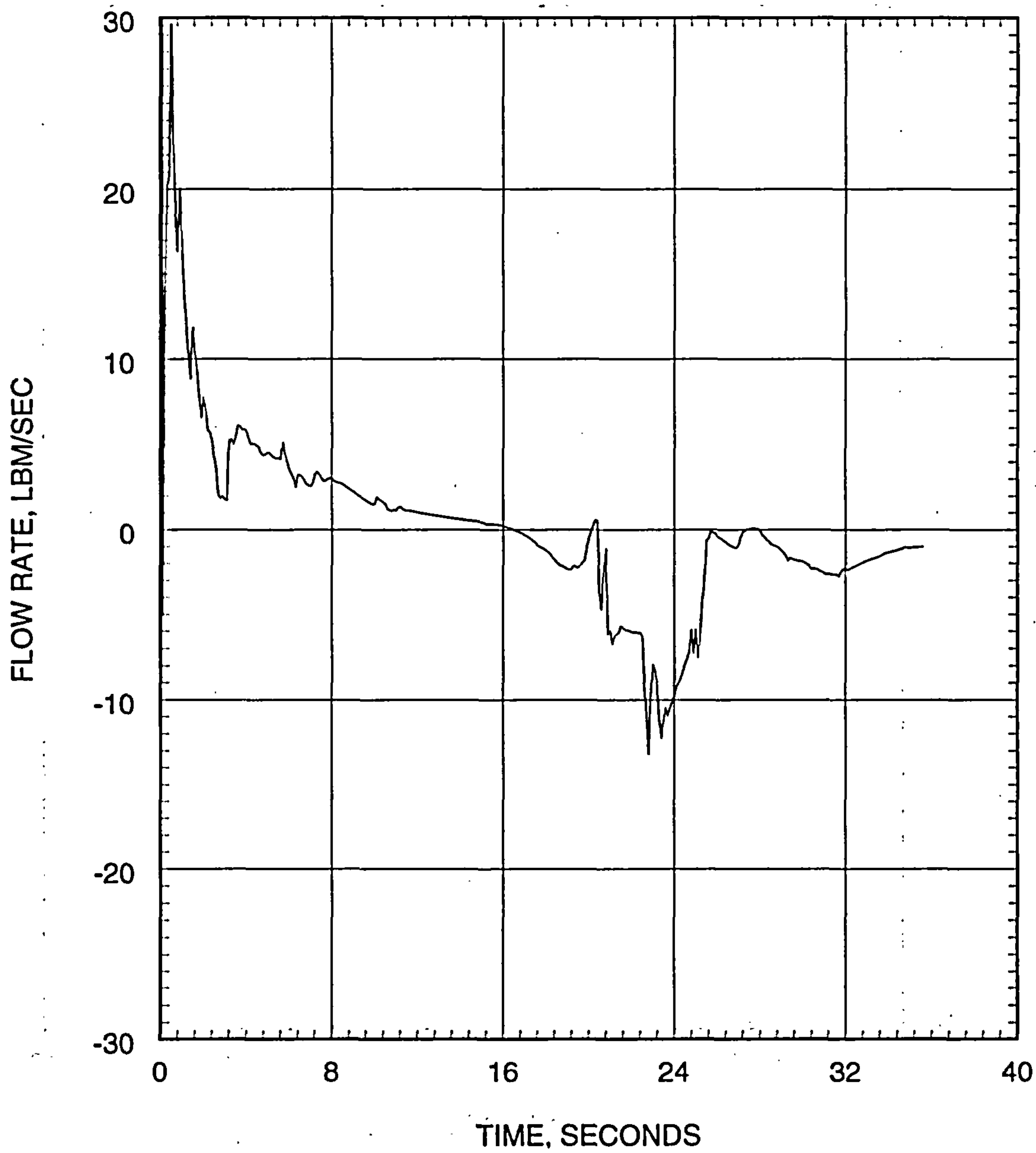

Figure 5.2.3.3-51
0.3 DEG/PD Large Break LOCA
Hot Assembly Flow Rate vs. Time below Hot Spot

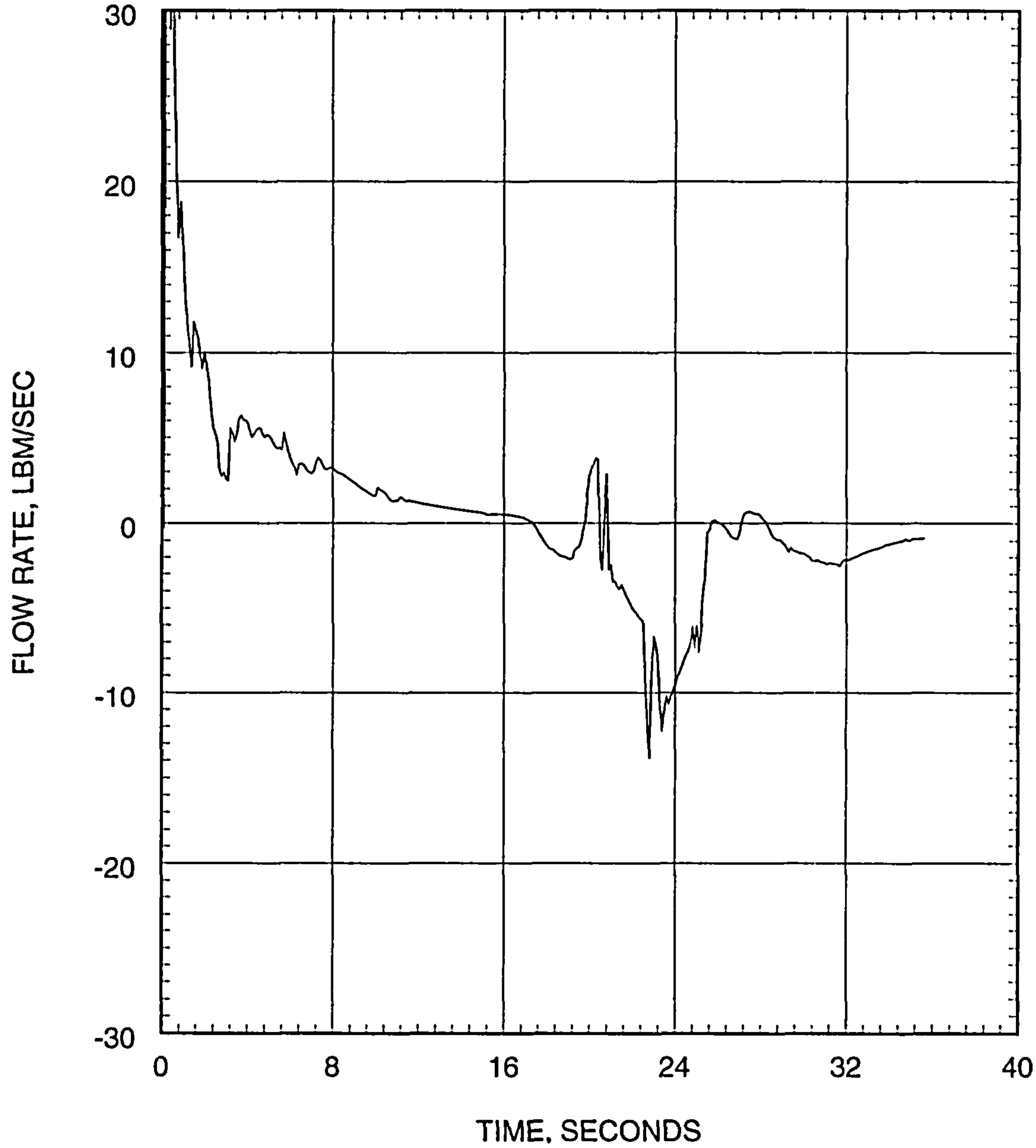

Figure 5.2.3.3-52
0.3 DEG/PD Large Break LOCA
Hot Assembly Flow Rate vs. Time above Hot Spot

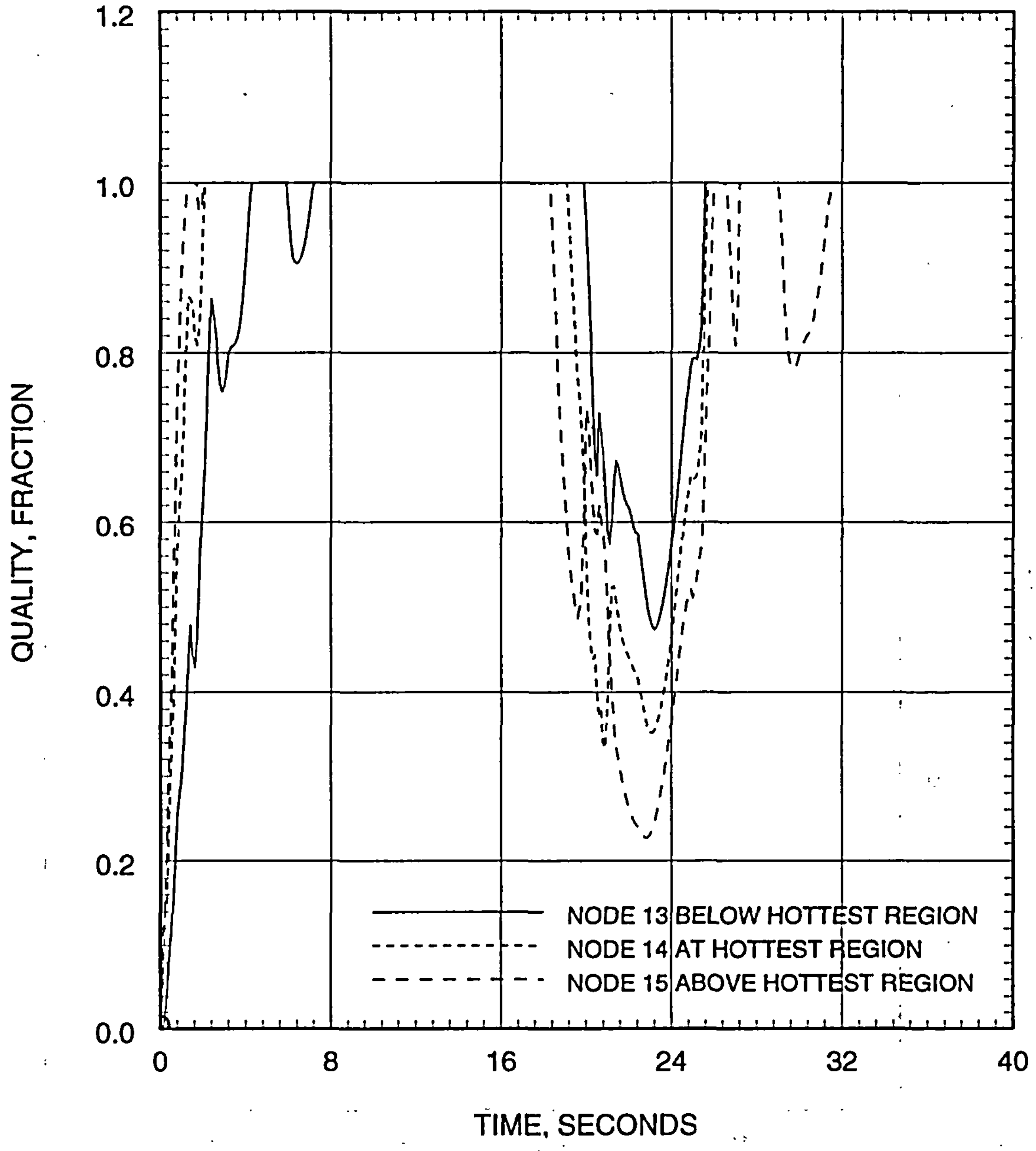

Figure 5.2.3.3-53
0.3 DEG/PD Large Break LOCA
Hot Assembly Quality vs. Time

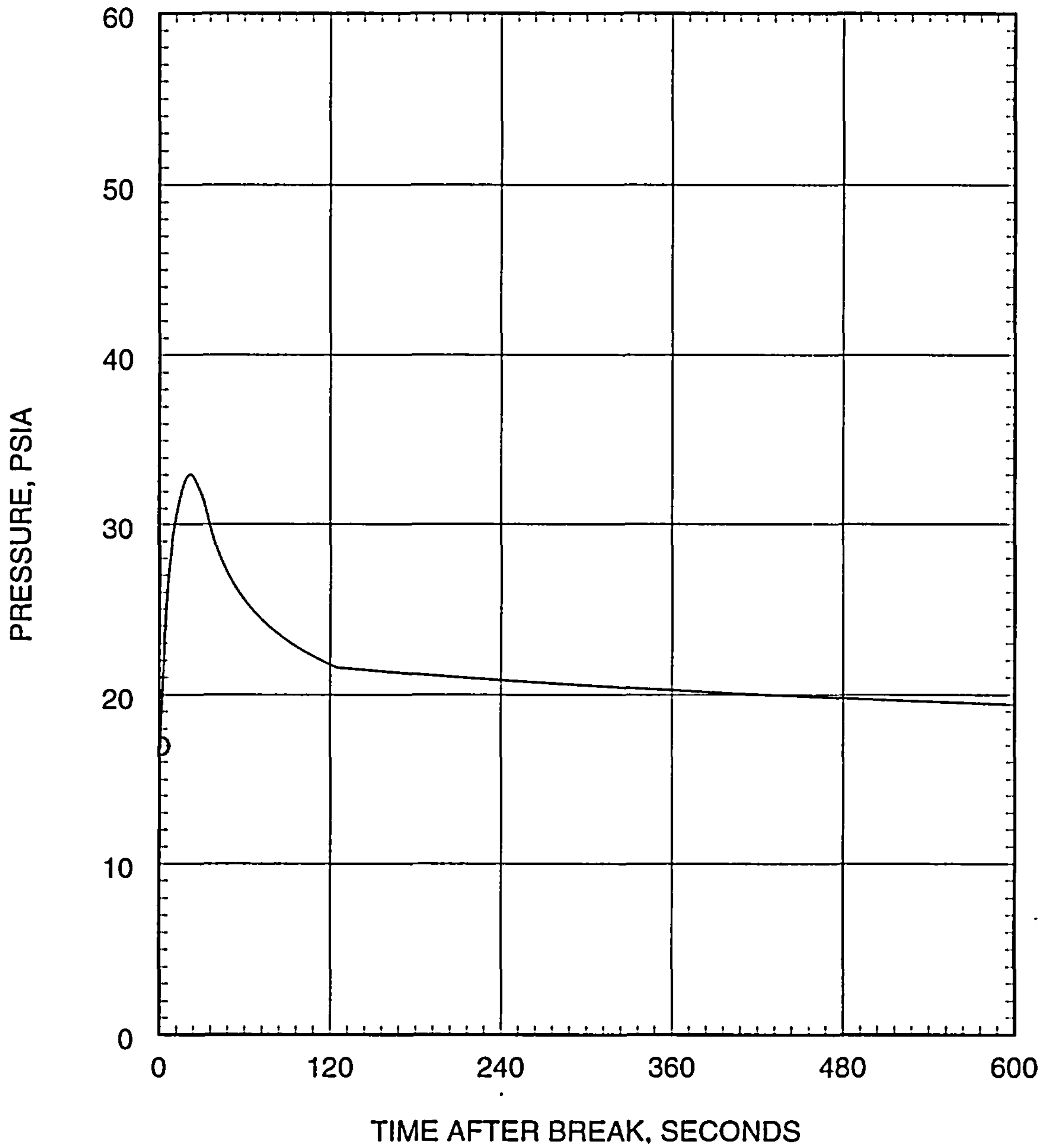

Figure 5.2.3.3-54
0.3 DEG/PD Large Break LOCA
Containment Pressure vs. Time

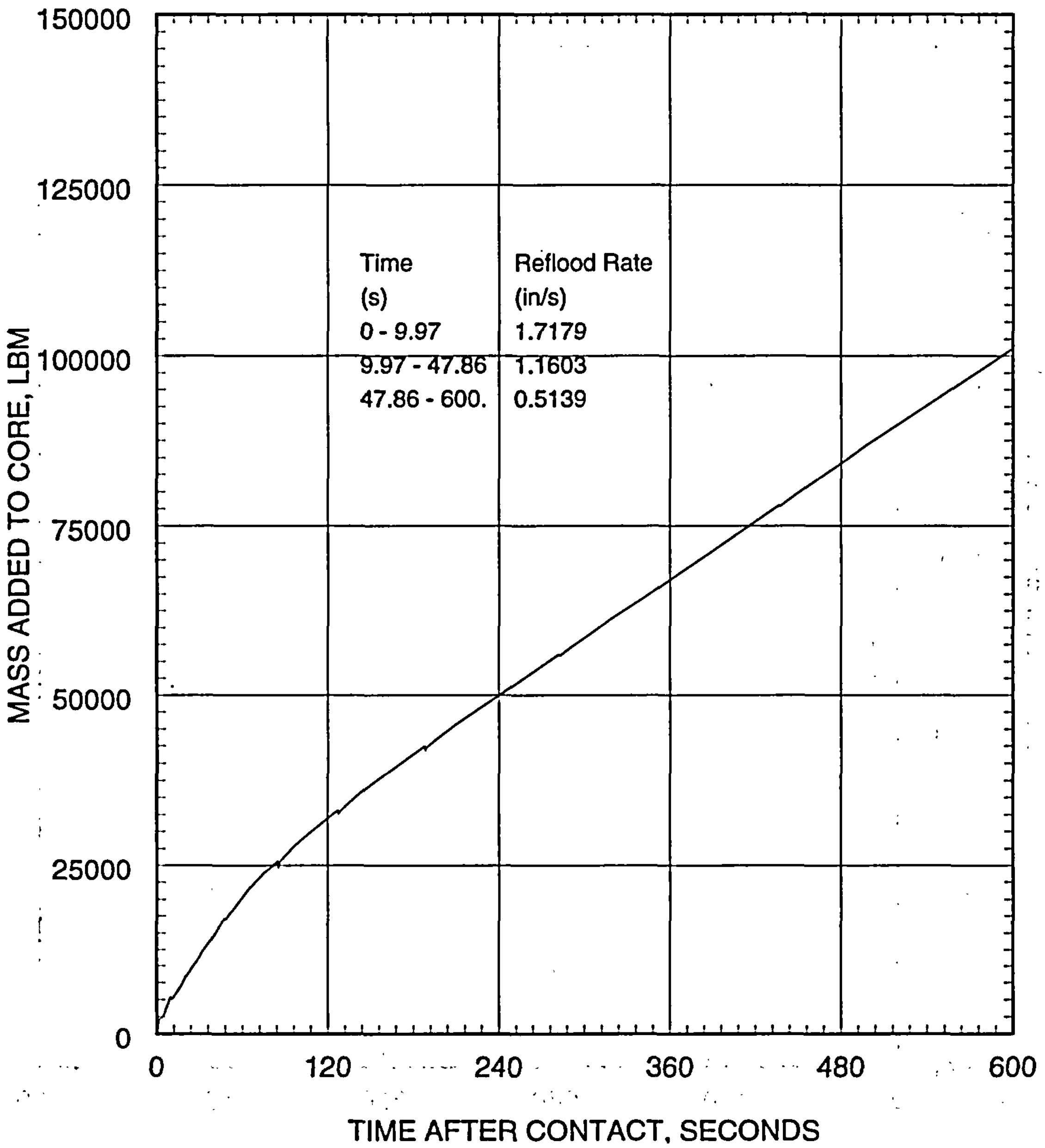

Figure 5.2.3.3-55
0.3 DEG/PD Large Break LOCA
Mass Added to Core vs. Time during Reflood

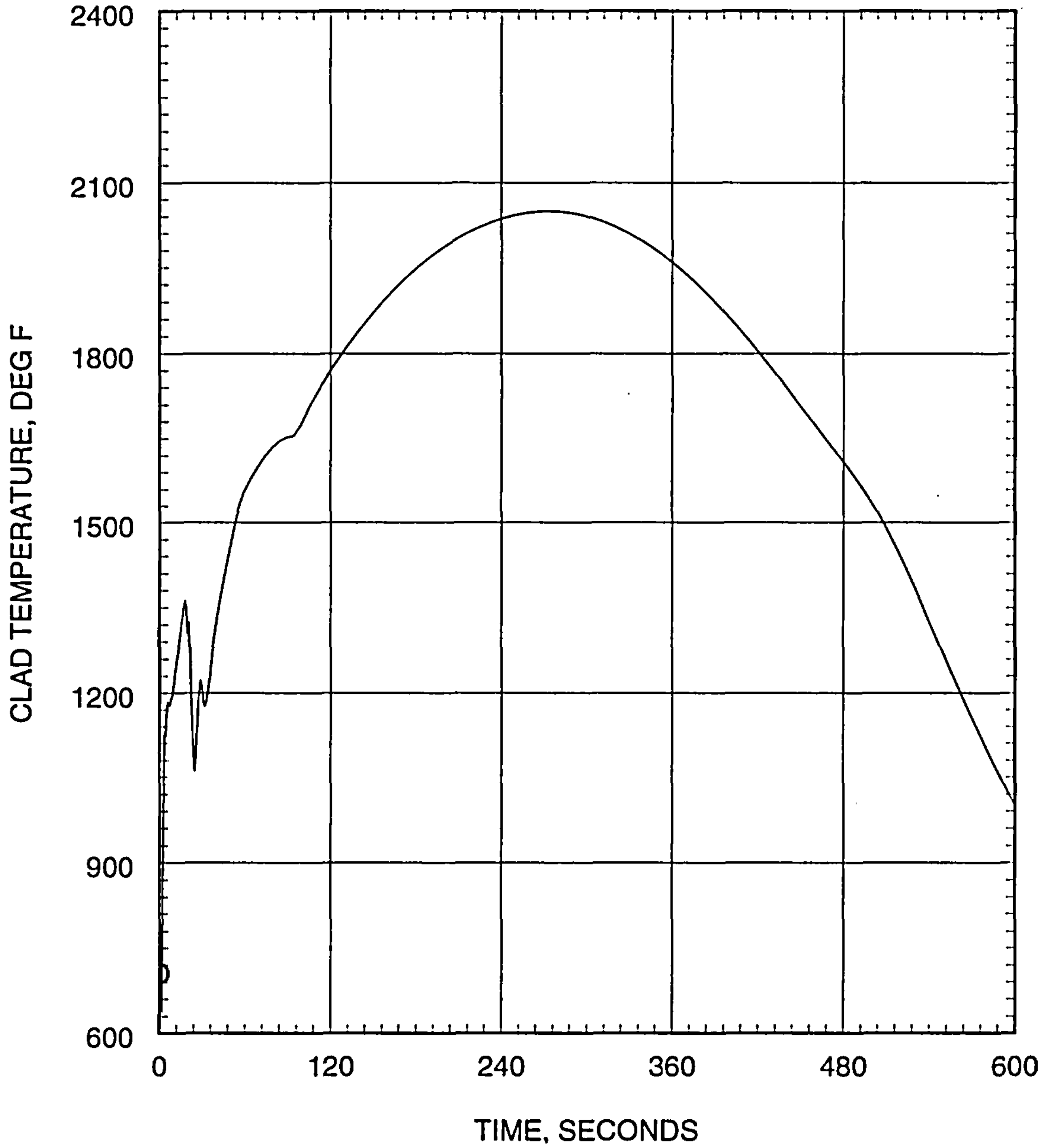

Figure 5.2.3.3-56
0.3 DEG/PD Large Break LOCA
Peak Cladding Temperature vs. Time

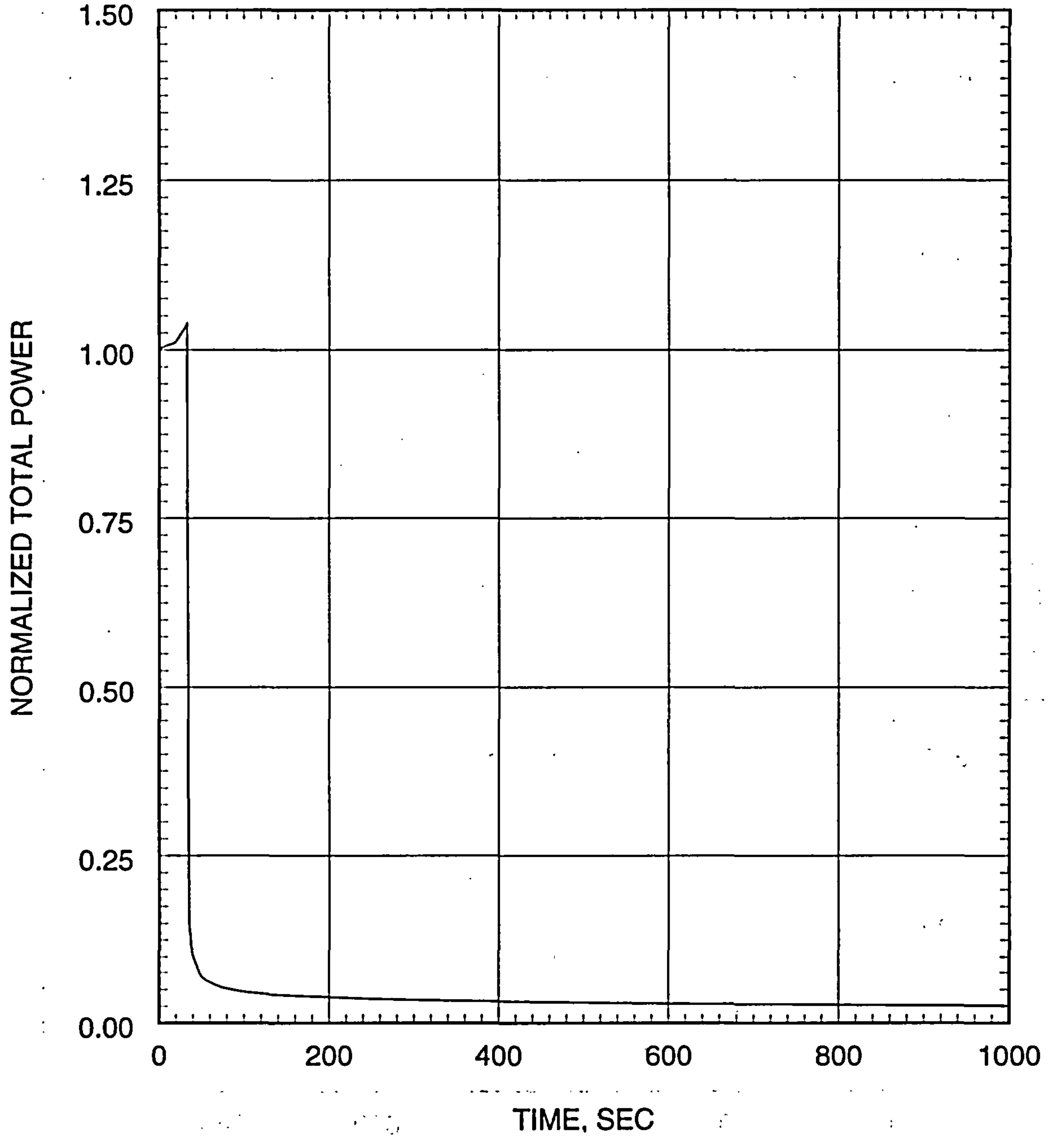

Figure 5.2.4.3-1
Small Break LOCA ECCS Performance Analysis
0.04 ft^2/PD Break
Core Power

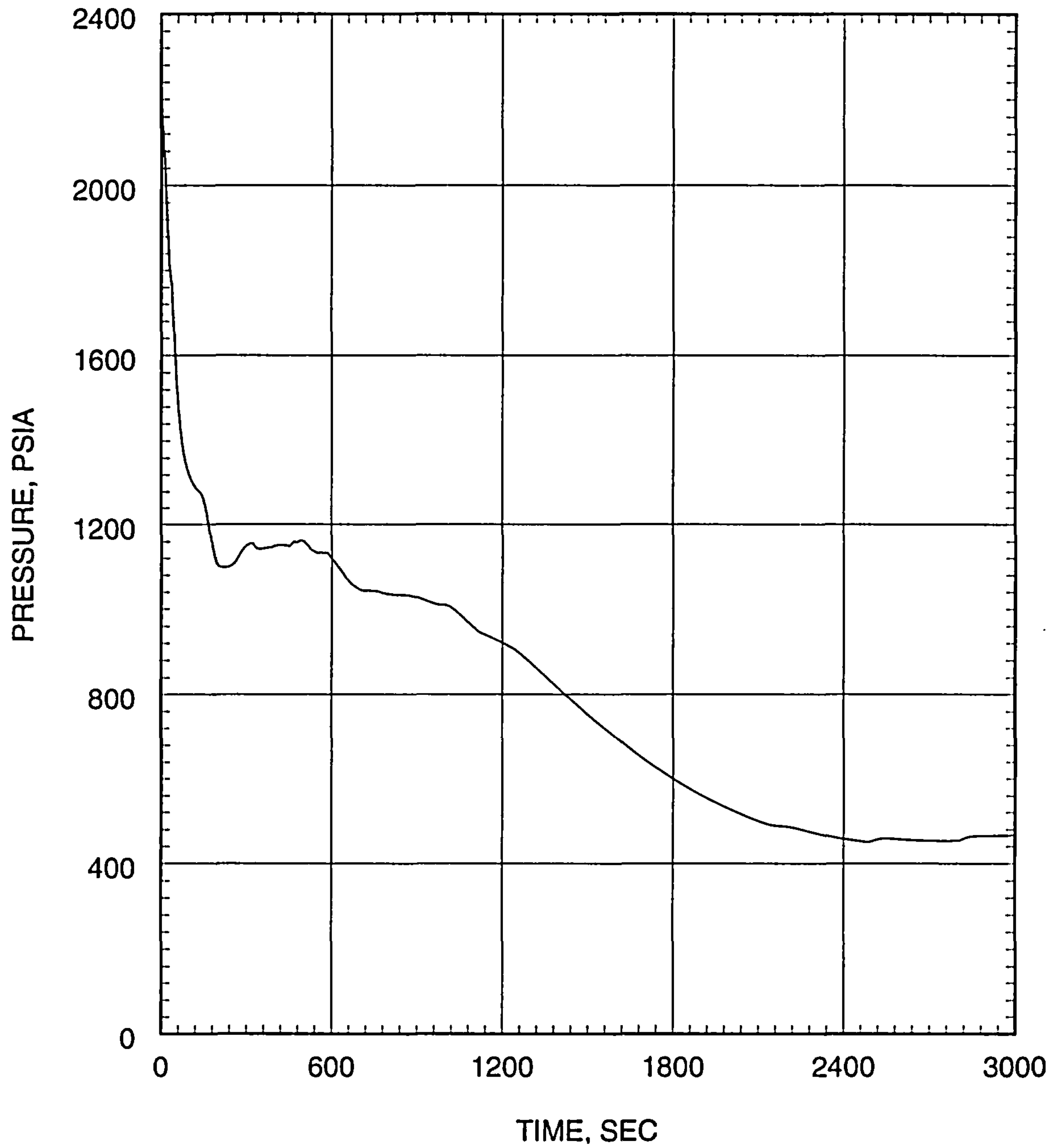

Figure 5.2.4.3-2
Small Break LOCA ECCS Performance Analysis
0.04 ft²/PD Break
Inner Vessel Pressure

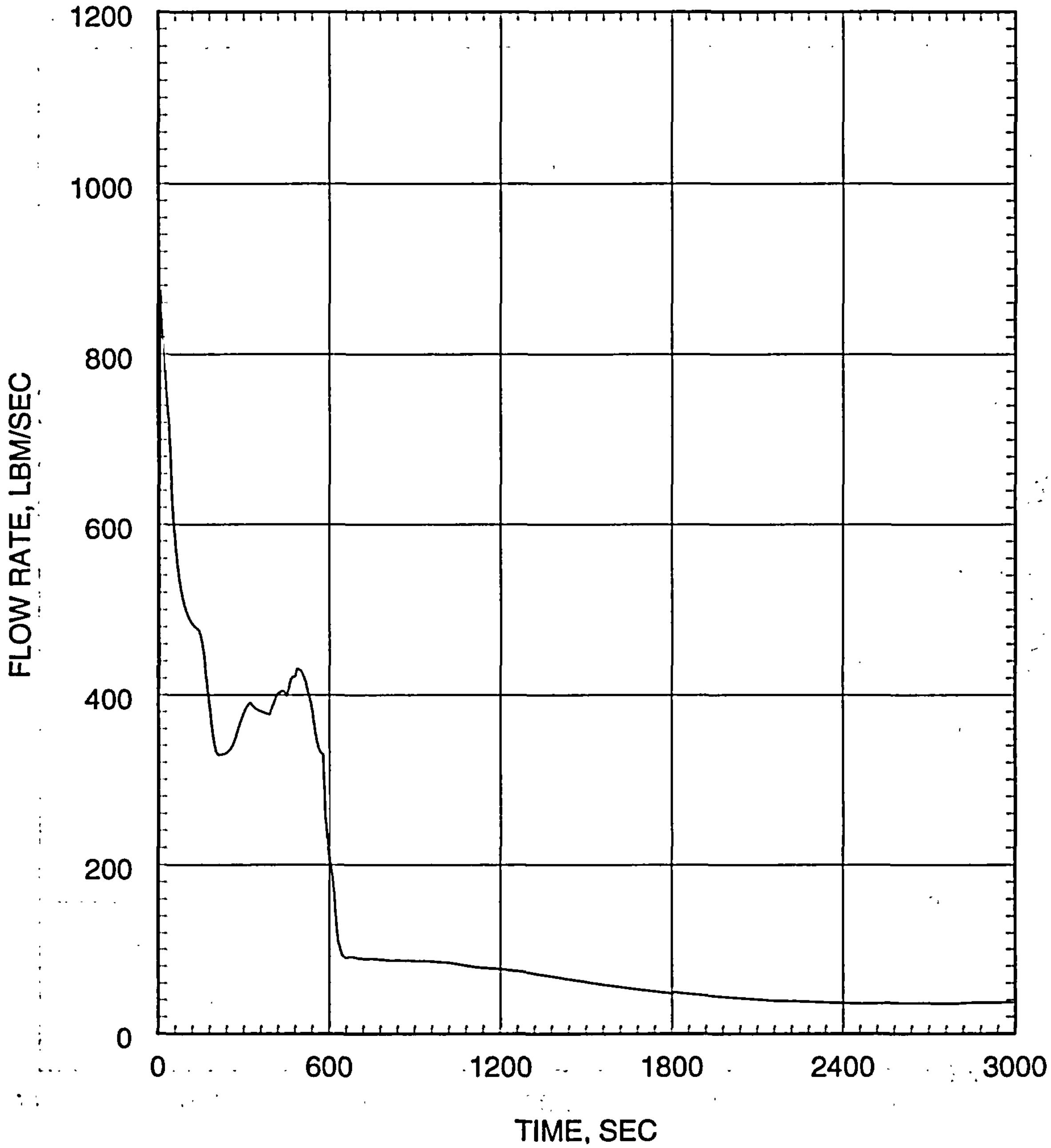

Figure 5.2.4.3-3
Small Break LOCA ECCS Performance Analysis
0.04 ft^2/PD Break
Break Flow Rate

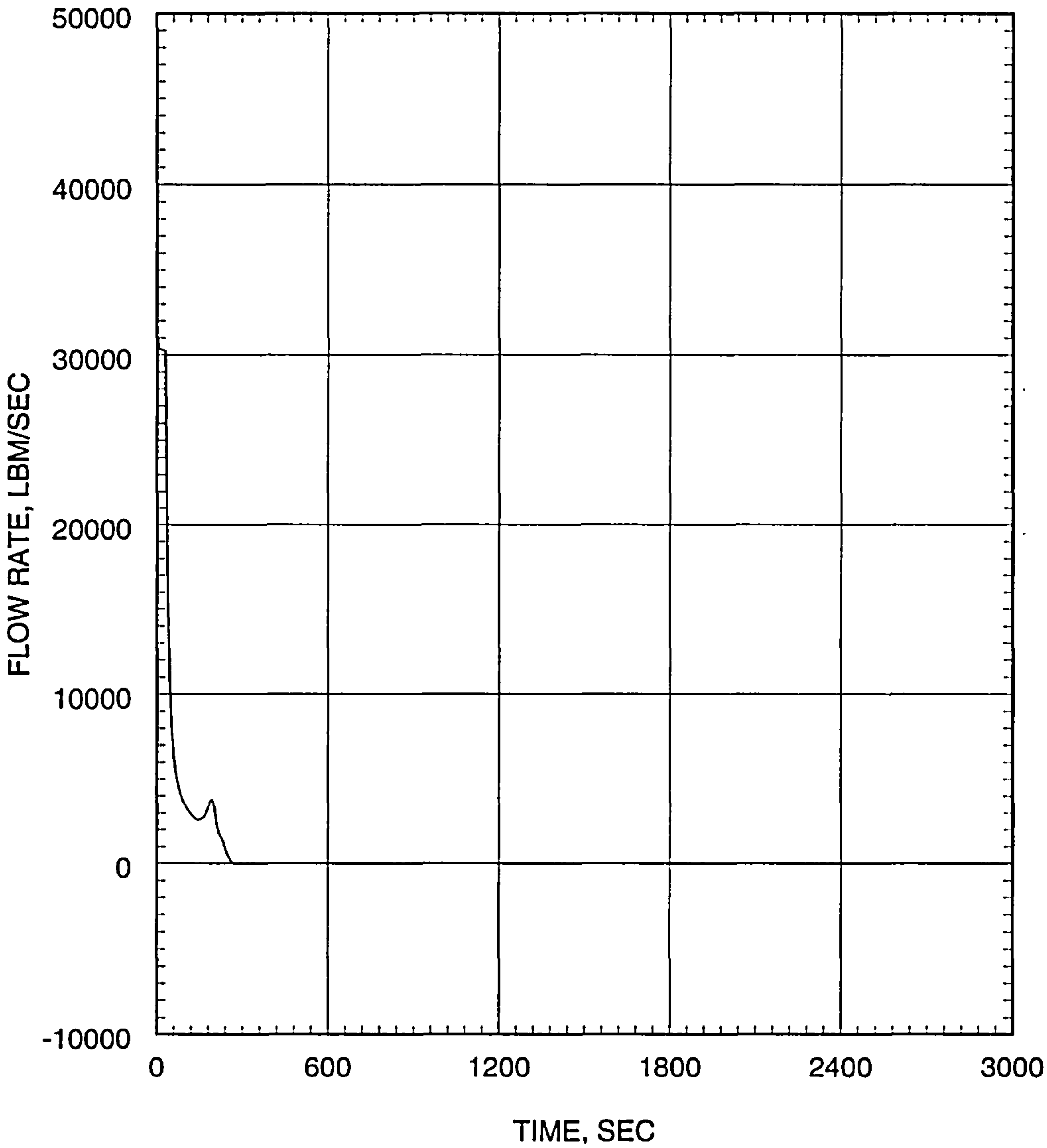

Figure 5.2.4.3-4
Small Break LOCA ECCS Performance Analysis
0.04 ft^2/PD Break
Inner Vessel Inlet Flow Rate

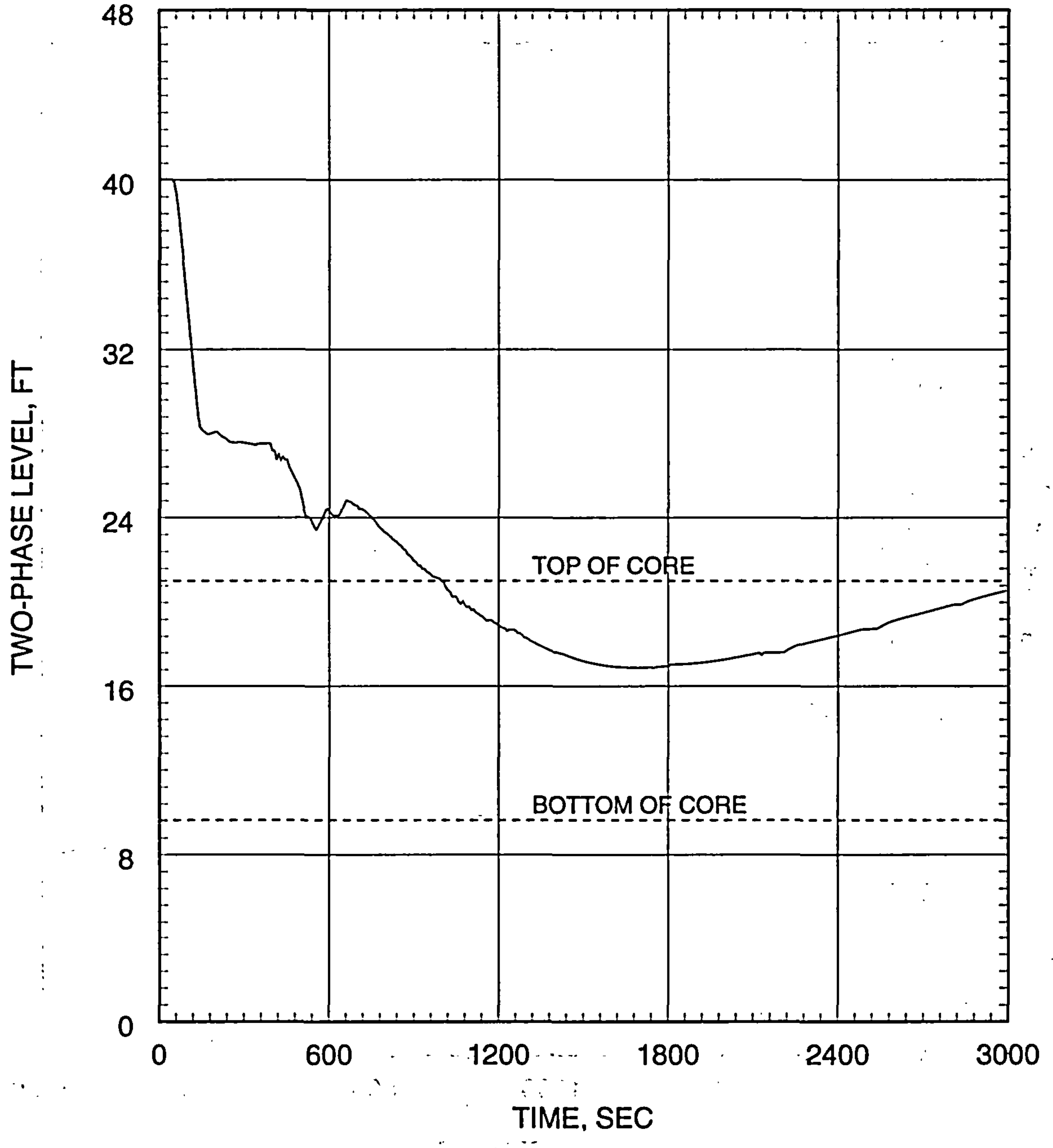

Figure 5.2.4.3-5
Small Break LOCA ECCS Performance Analysis
0.04 ft^2/PD Break
Inner Vessel Two-Phase Mixture Level

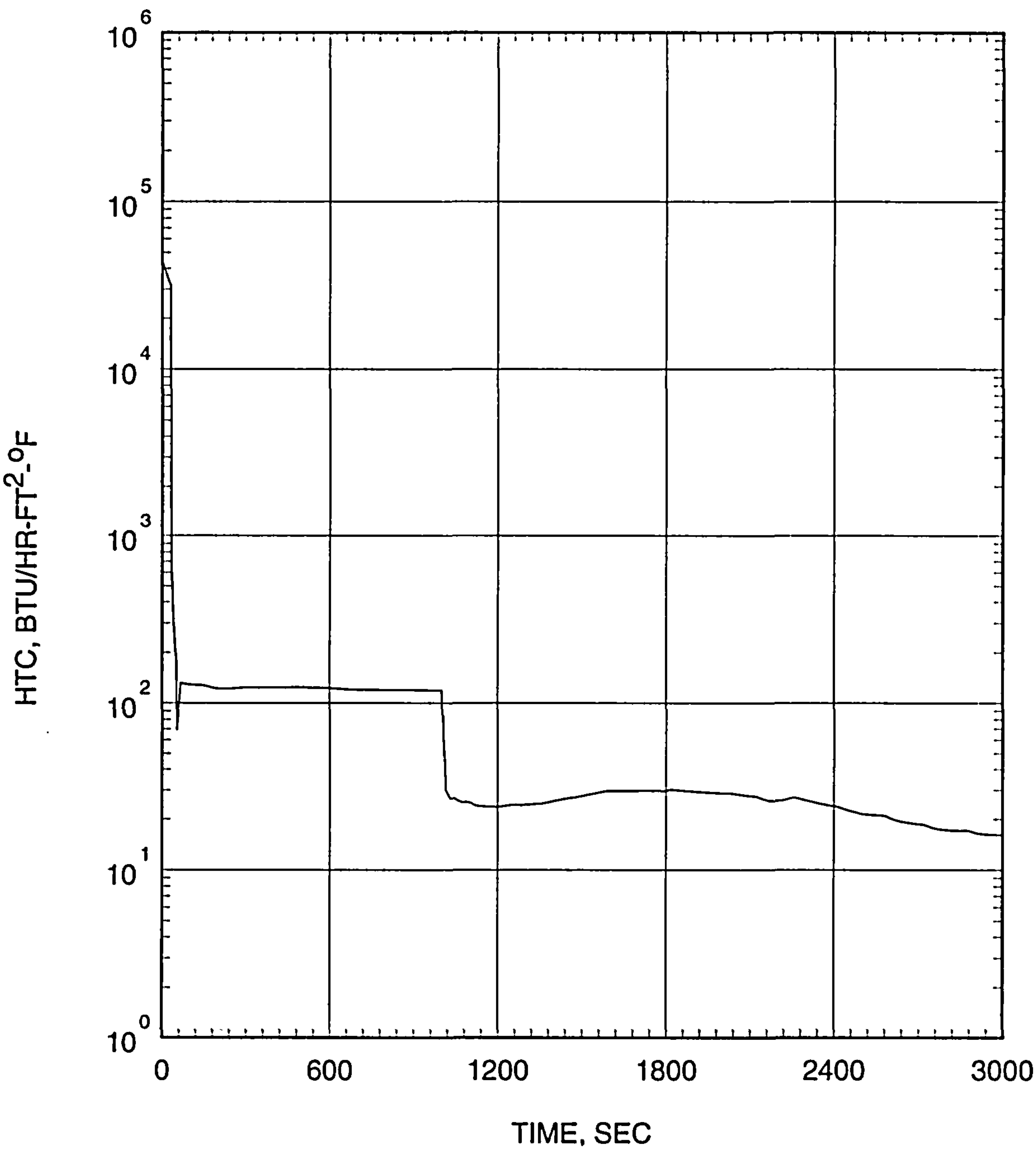

Figure 5.2.4.3-6
Small Break LOCA ECCS Performance Analysis
0.04 ft^2/PD Break
Heat Transfer Coefficient at Hot Spot

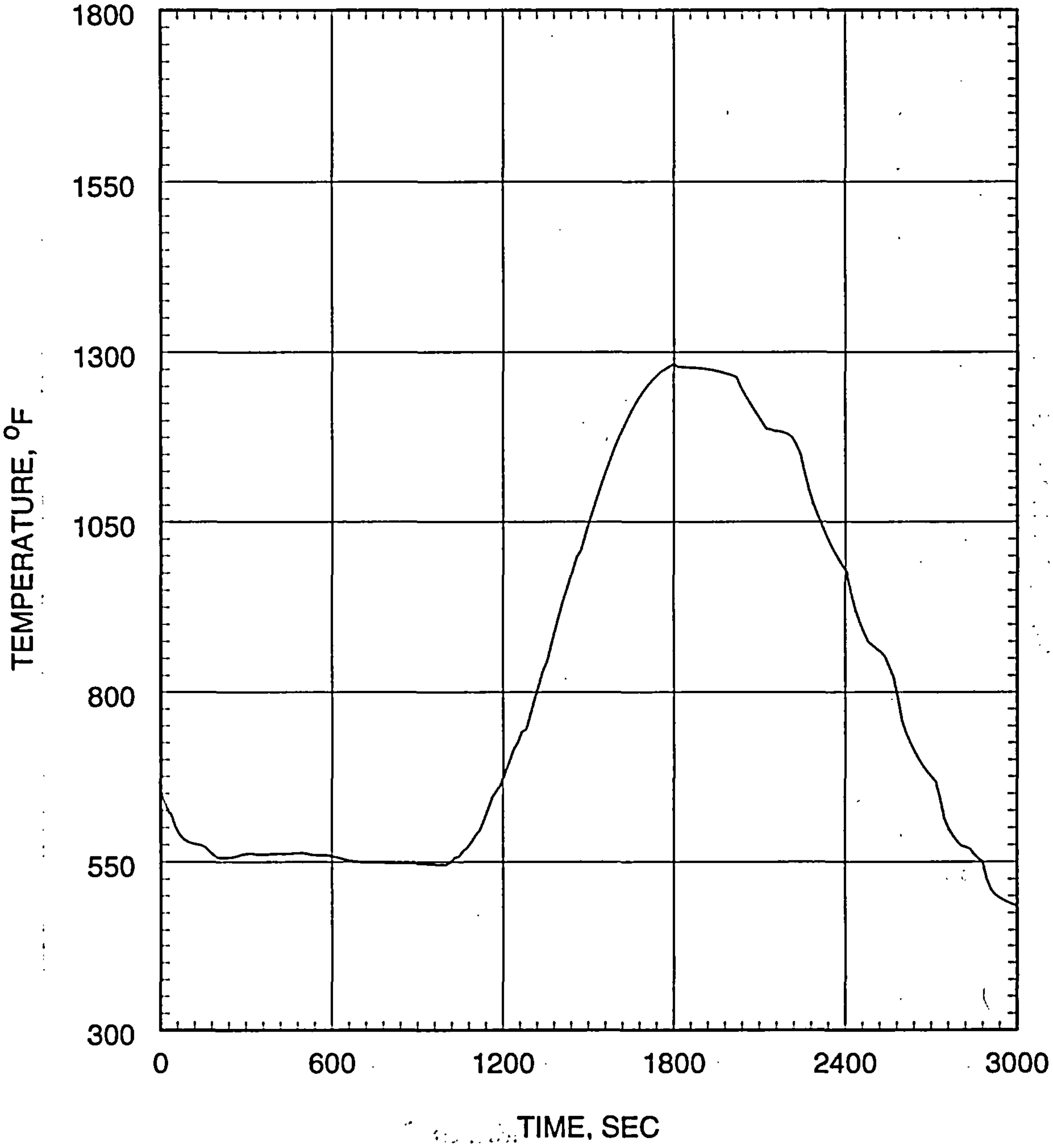

Figure 5.2.4.3-7
Small Break LOCA ECCS Performance Analysis
0.04 ft^2/PD Break
Coolant Temperature at Hot Spot

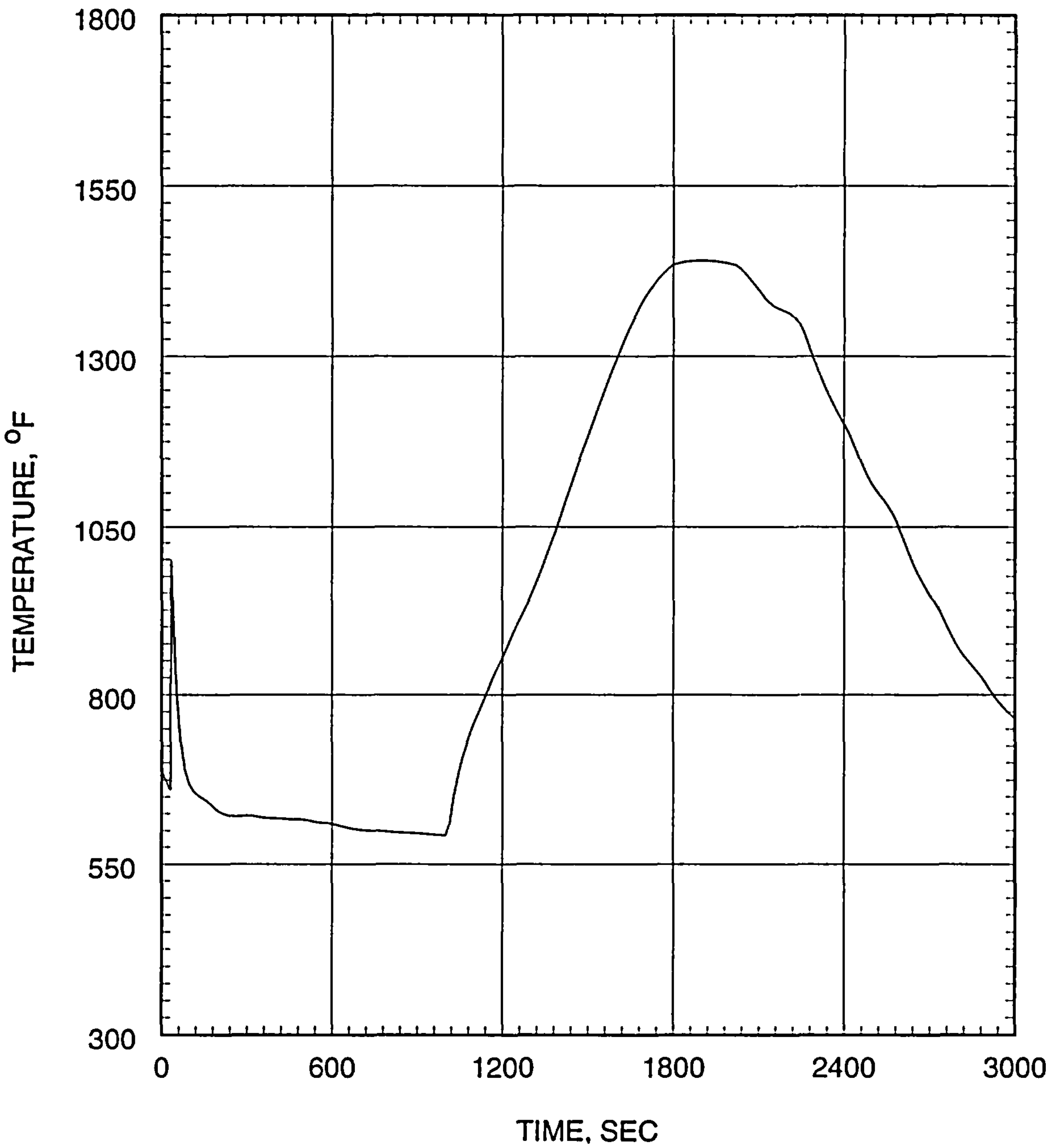

Figure 5.2.4.3-8
Small Break LOCA ECCS Performance Analysis
0.04 ft^2/PD Break
Cladding Temperature at Hot Spot

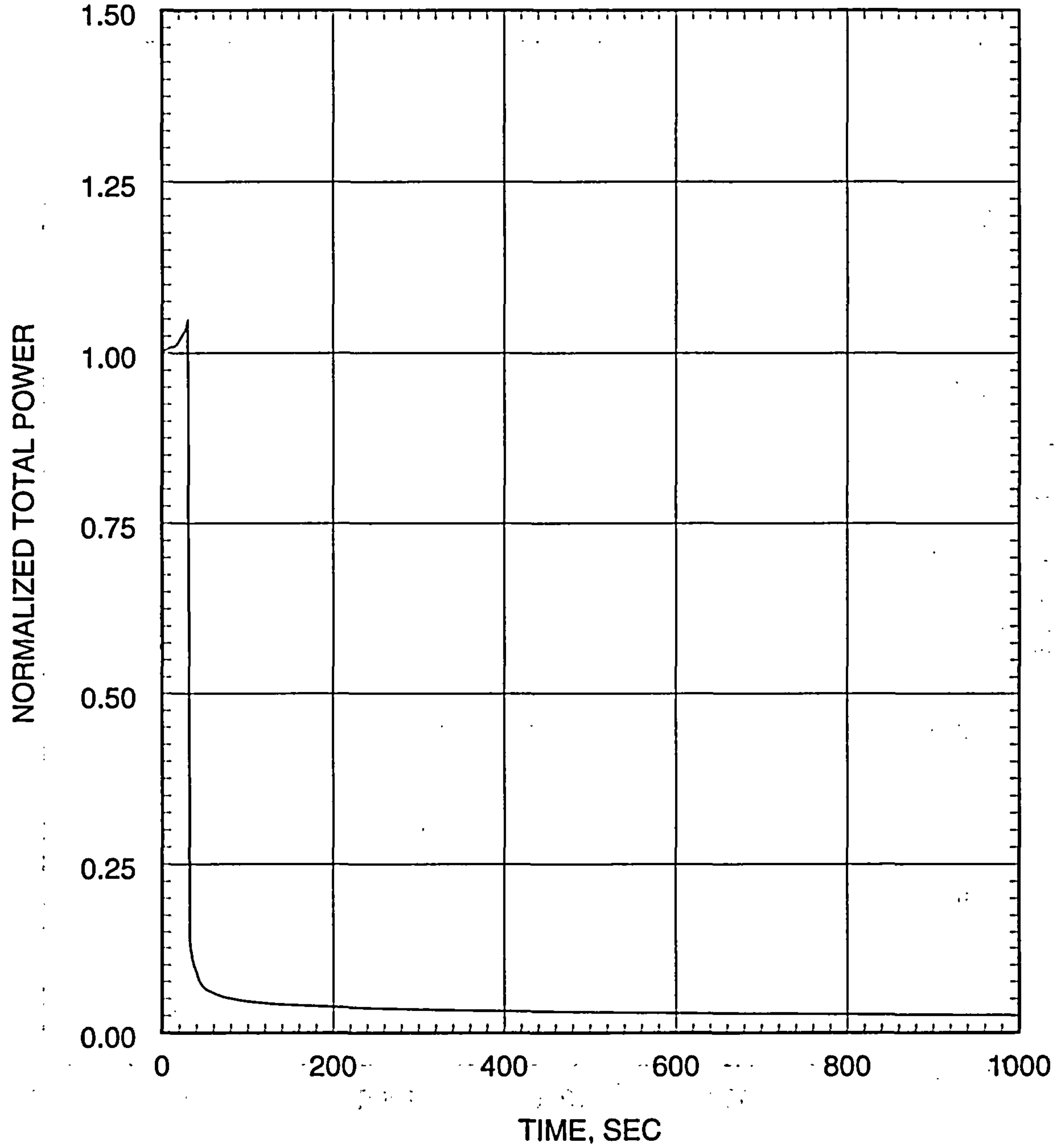

Figure 5.2.4.3-9
Small Break LOCA ECCS Performance Analysis
0.045 ft^2/PD Break
Core Power

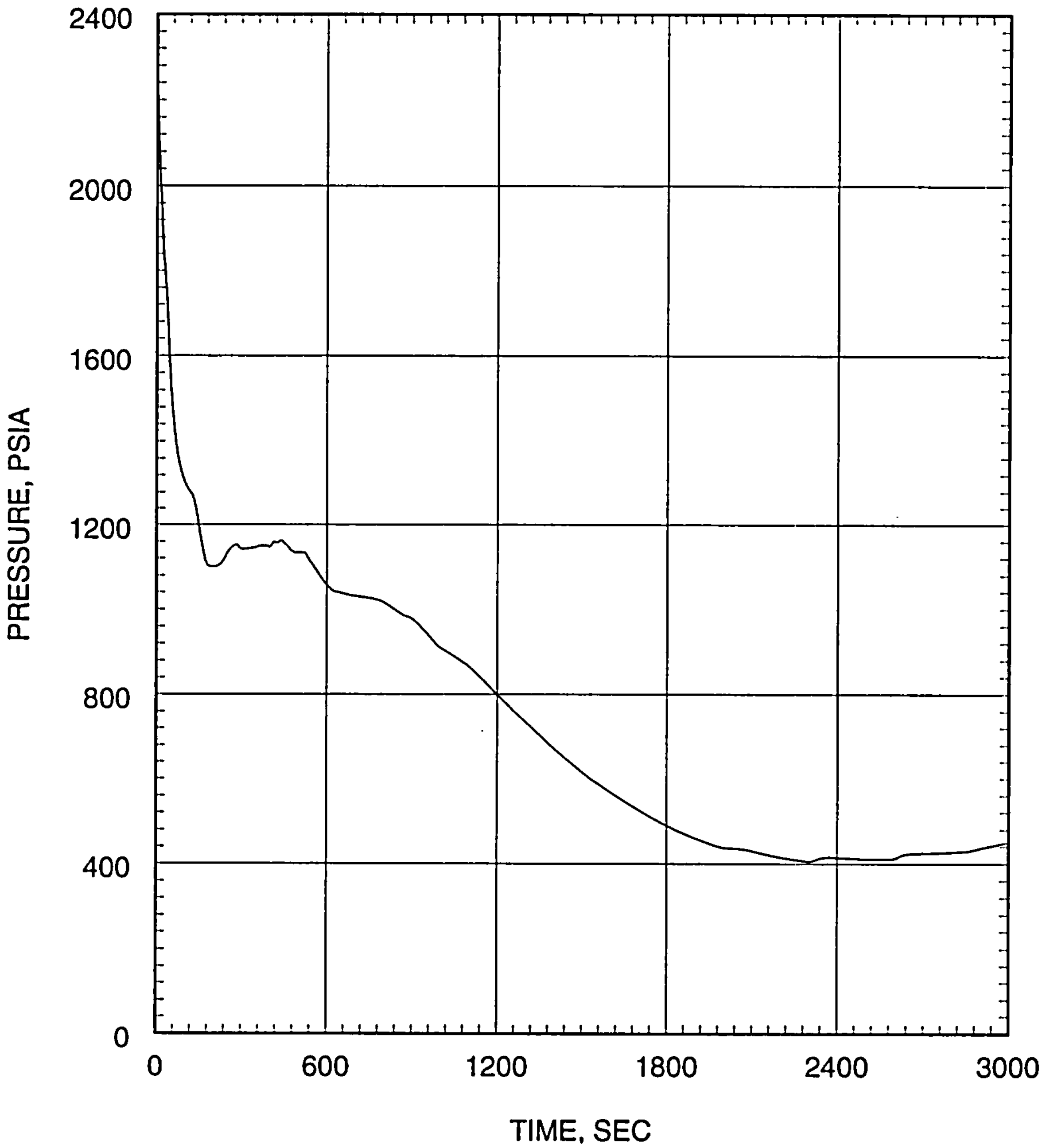

Figure 5.2.4.3-10
Small Break LOCA ECCS Performance Analysis
0.045 ft^2/PD Break
Inner Vessel Pressure

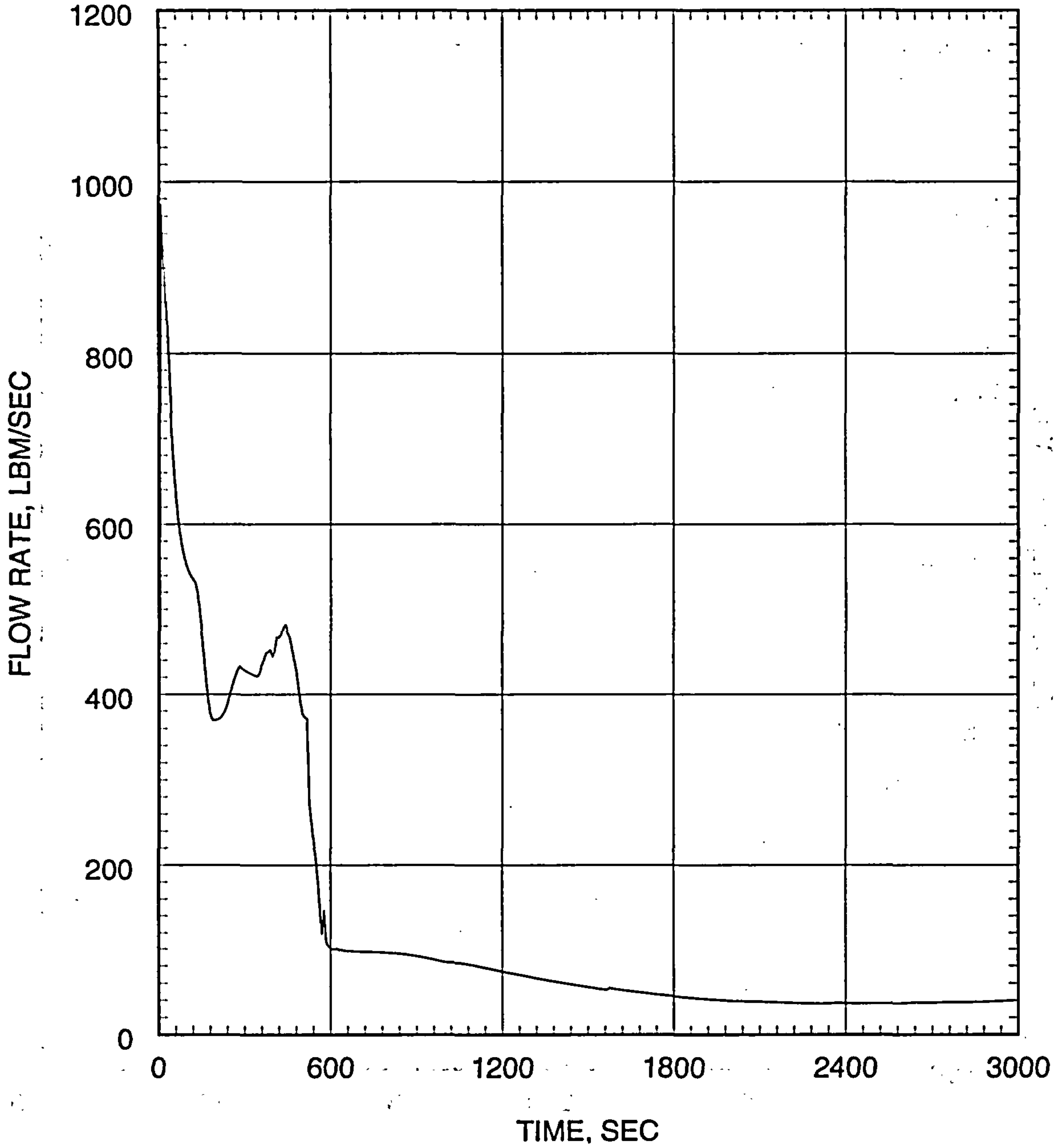

Figure 5.2.4.3-11
Small Break LOCA ECCS Performance Analysis
0.045 ft^2/PD Break
Break Flow Rate

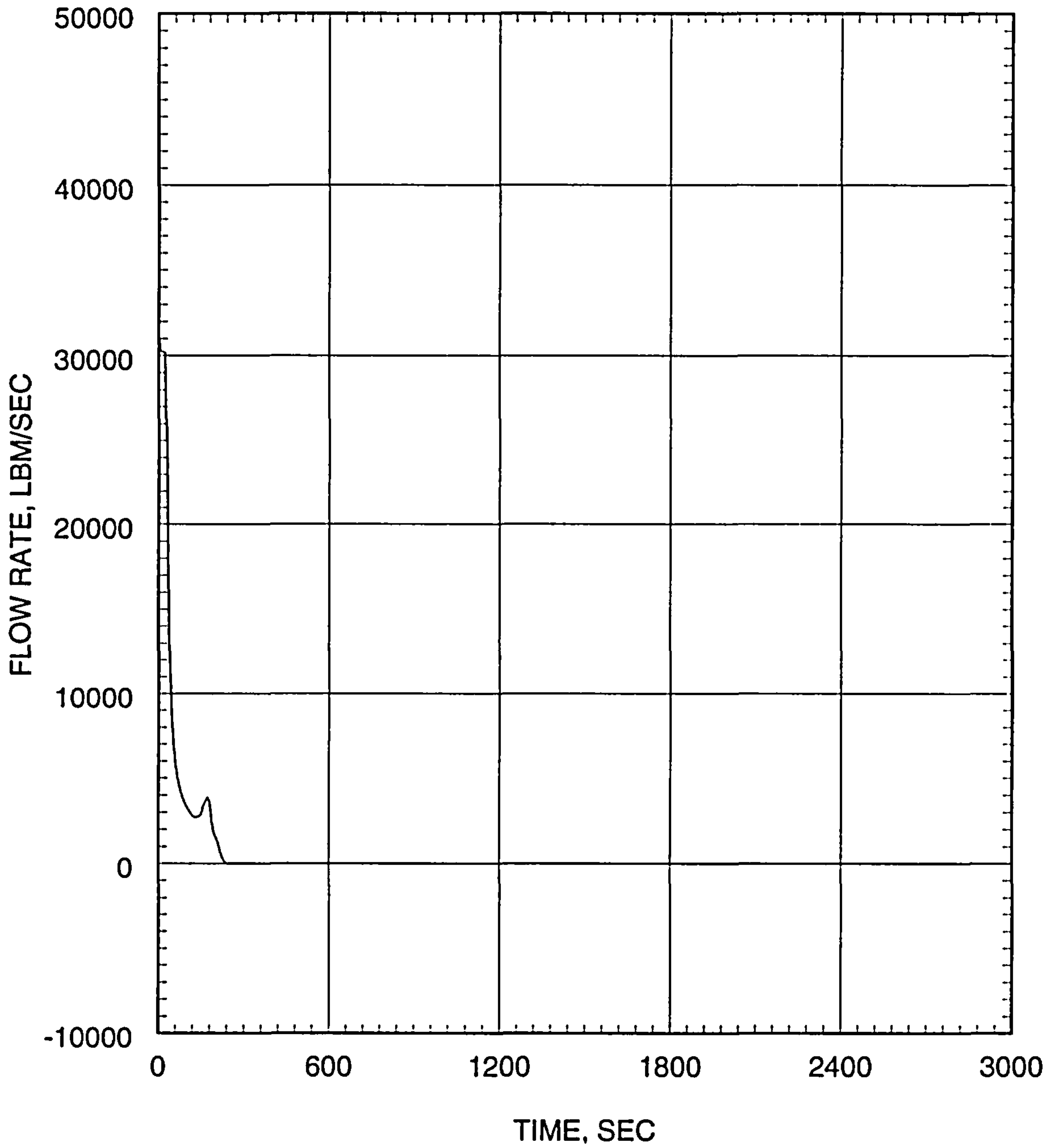

Figure 5.2.4.3-12
Small Break LOCA ECCS Performance Analysis
0.045 ft^2/PD Break
Inner Vessel Inlet Flow Rate

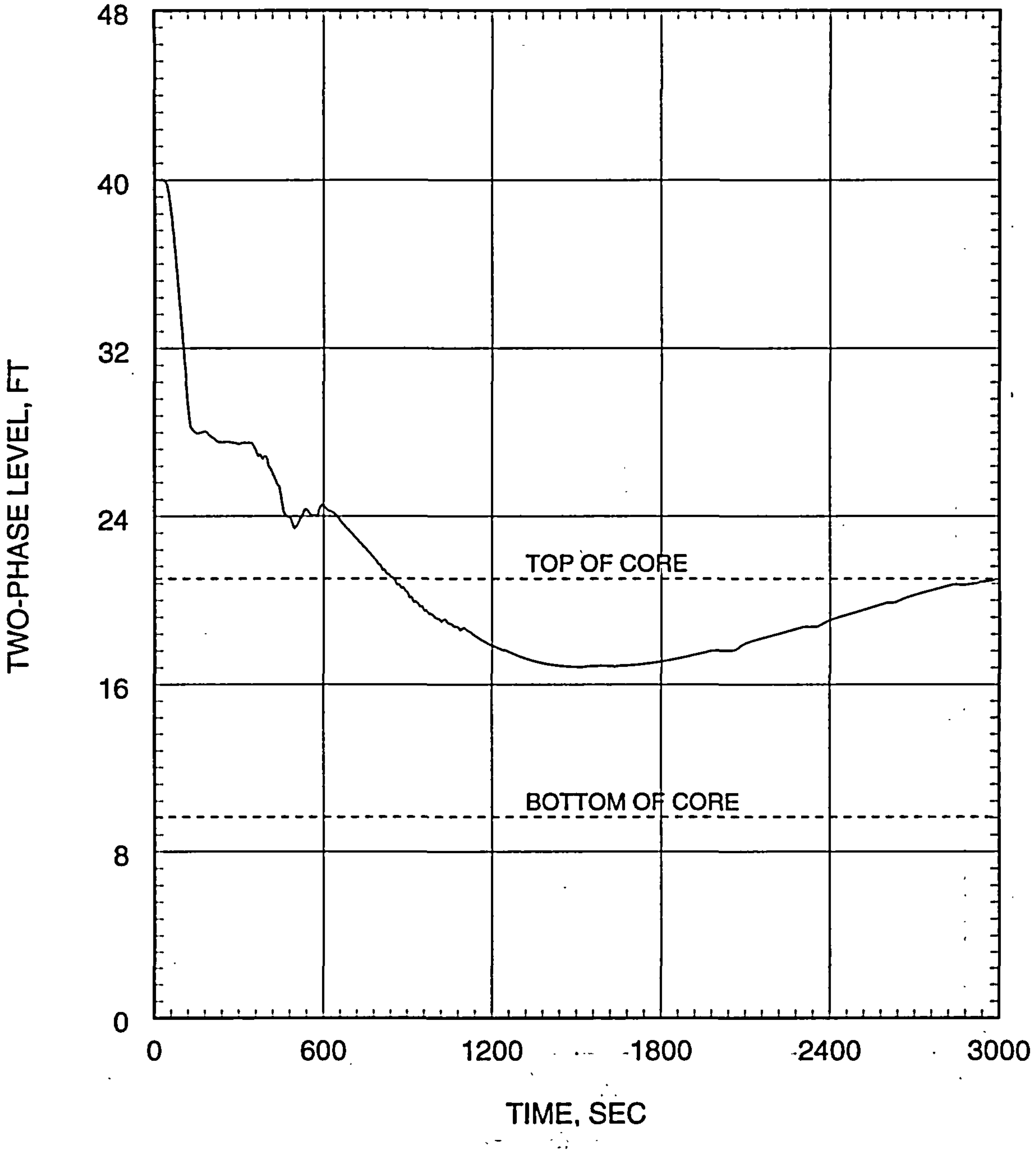

Figure 5.2.4.3-13
Small Break LOCA ECCS Performance Analysis
0.045 ft^2/PD Break
Inner Vessel Two-Phase Mixture Level

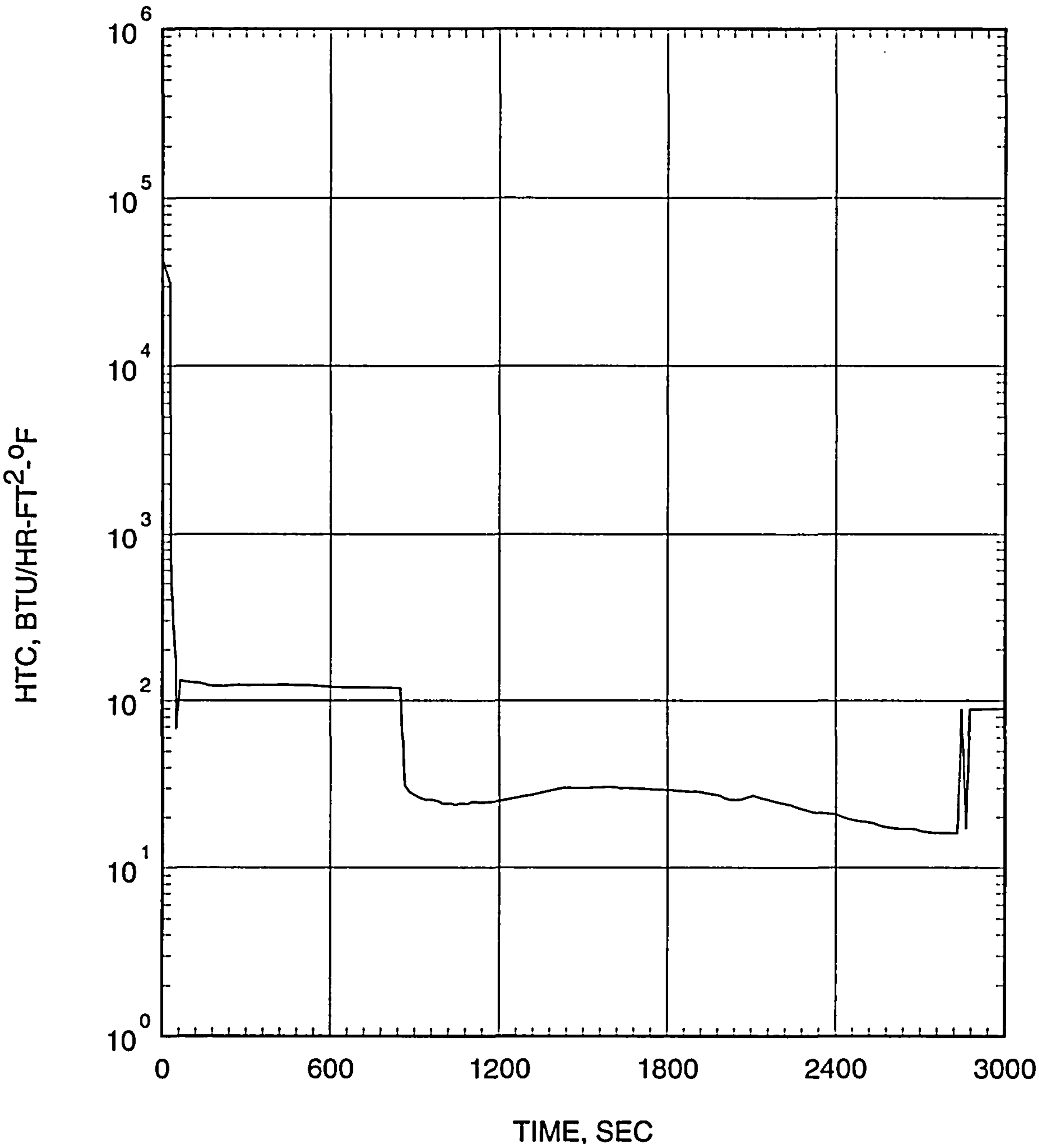

Figure 5.2.4.3-14
Small Break LOCA ECCS Performance Analysis
0.045 ft²/PD Break
Heat Transfer Coefficient at Hot Spot

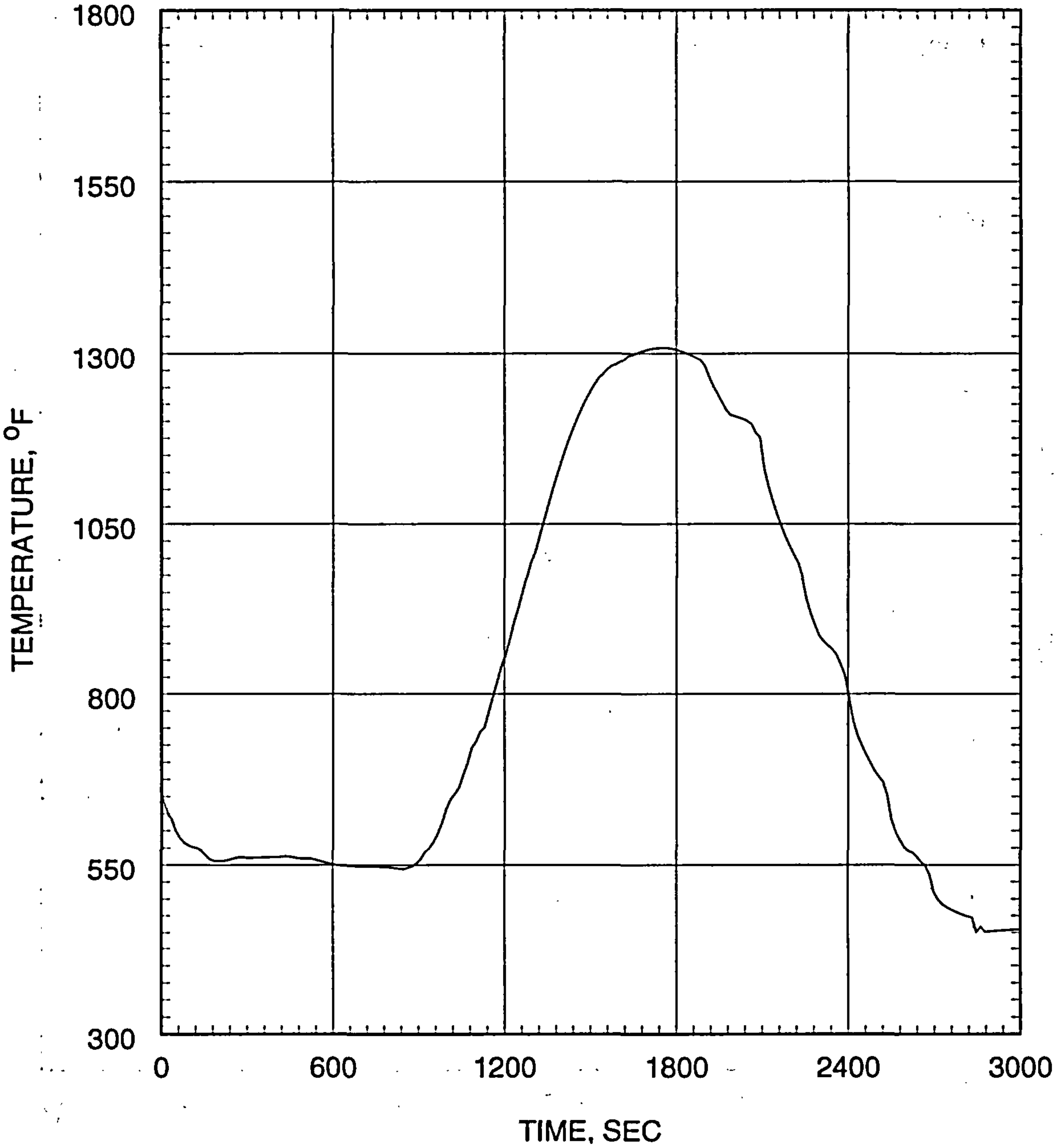

Figure 5.2.4.3-15
Small Break LOCA ECCS Performance Analysis
0.045 ft^2/PD Break
Coolant Temperature at Hot Spot

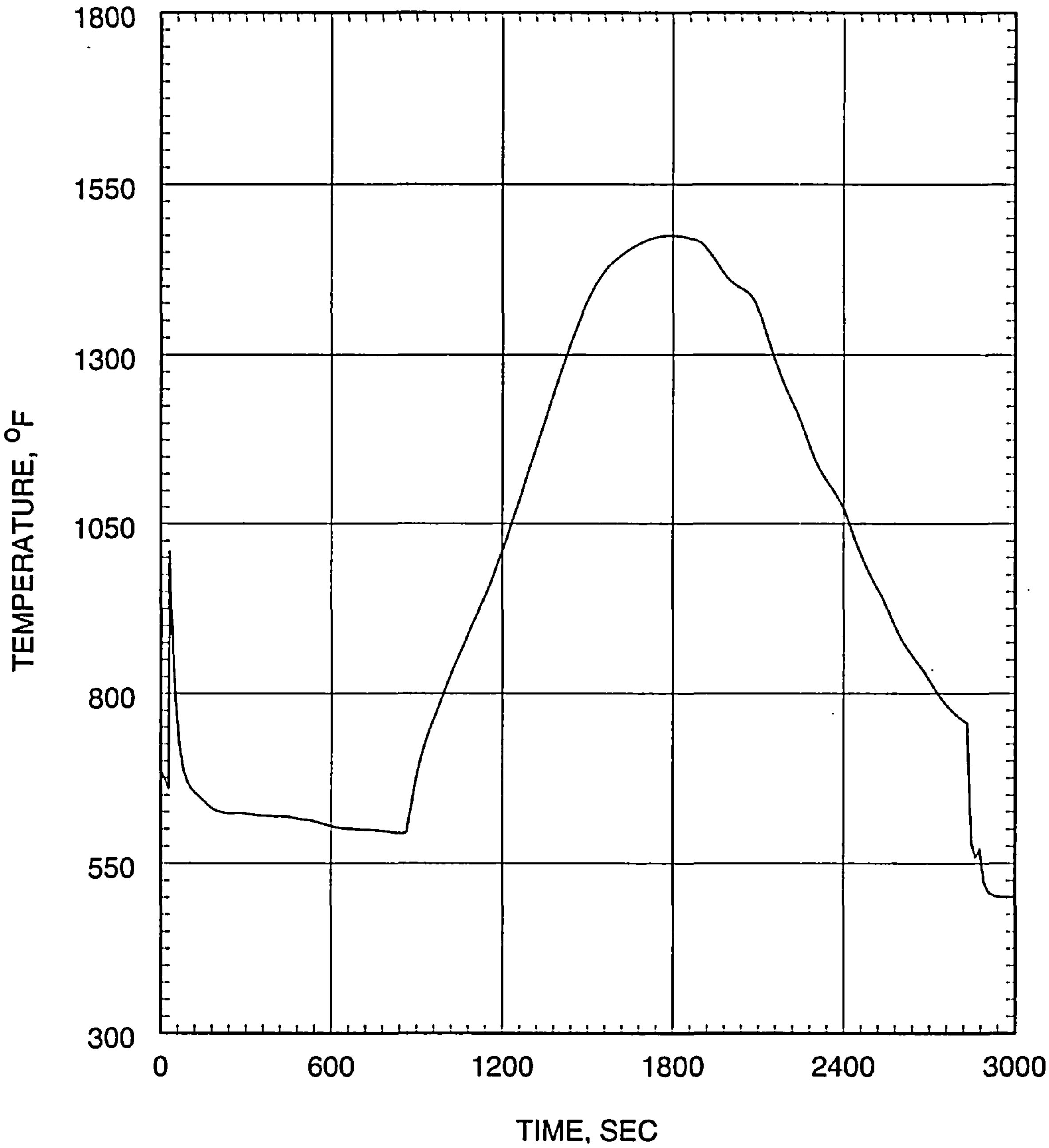

Figure 5.2.4.3-16
Small Break LOCA ECCS Performance Analysis
0.045 ft^2/PD Break
Cladding Temperature at Hot Spot

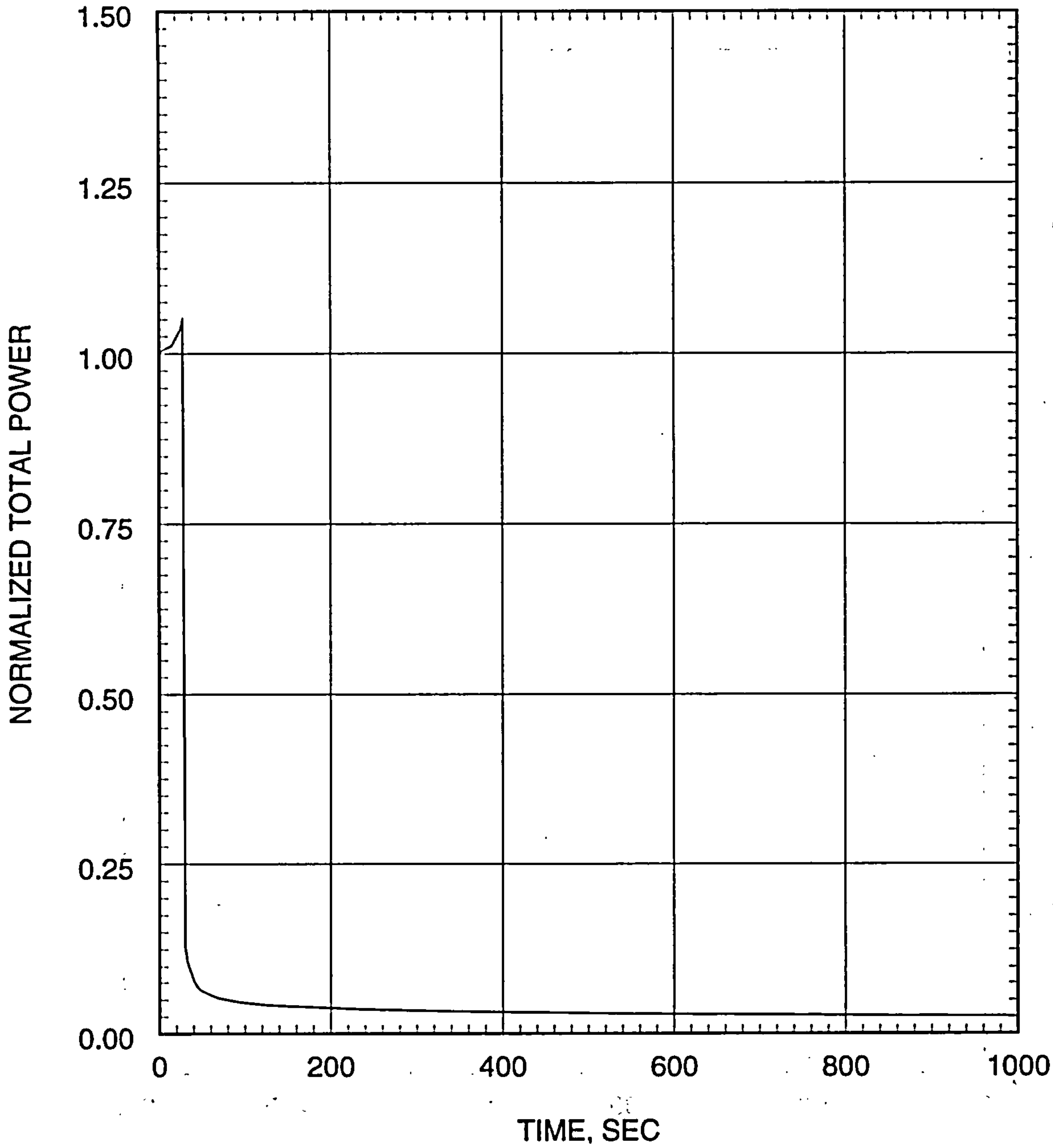

Figure 5.2.4.3-17
Small Break LOCA ECCS Performance Analysis
0.05 ft^2/PD Break
Core Power

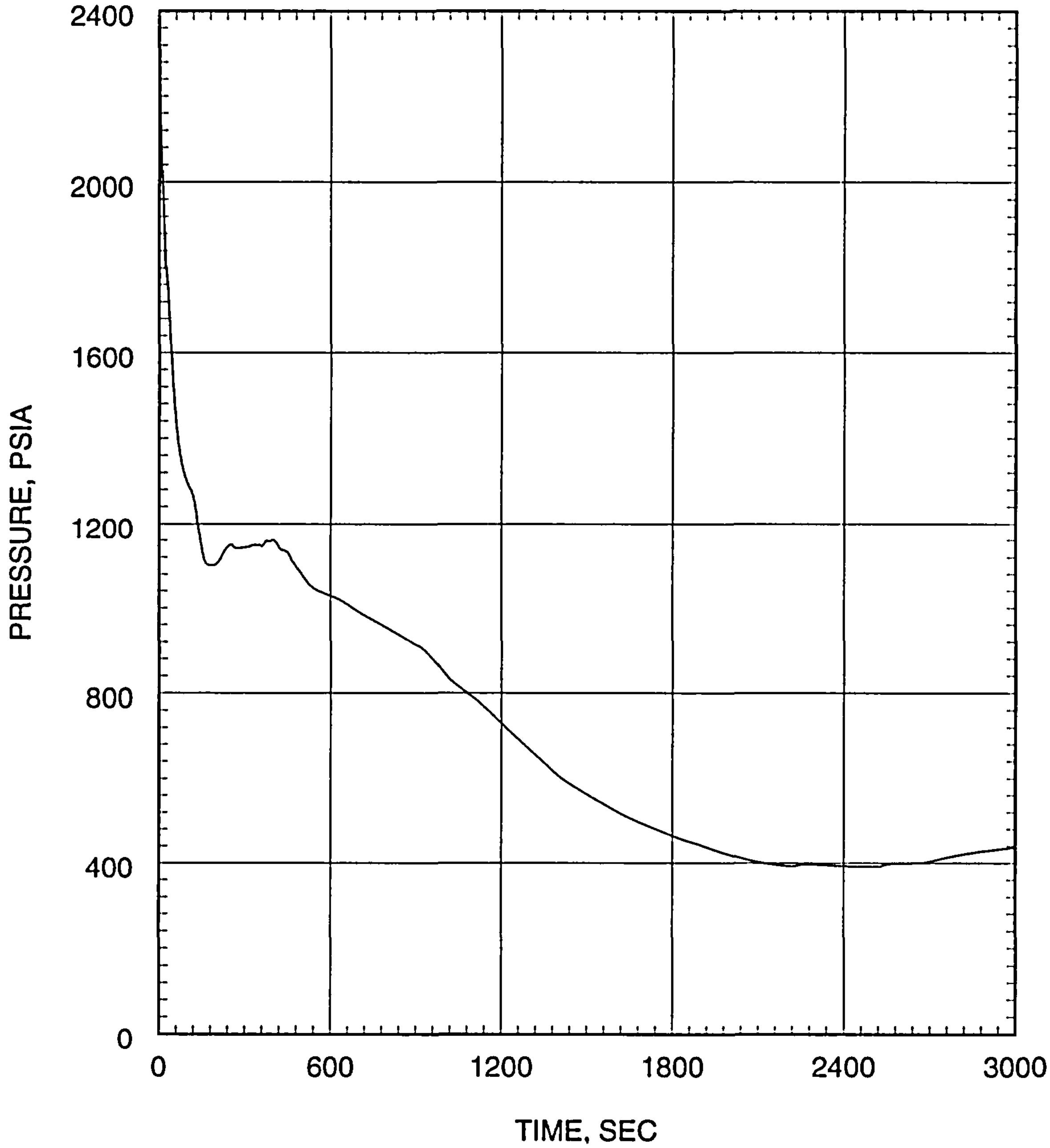

Figure 5.2.4.3-18
Small Break LOCA ECCS Performance Analysis
0.05 ft^2/PD Break
Inner Vessel Pressure

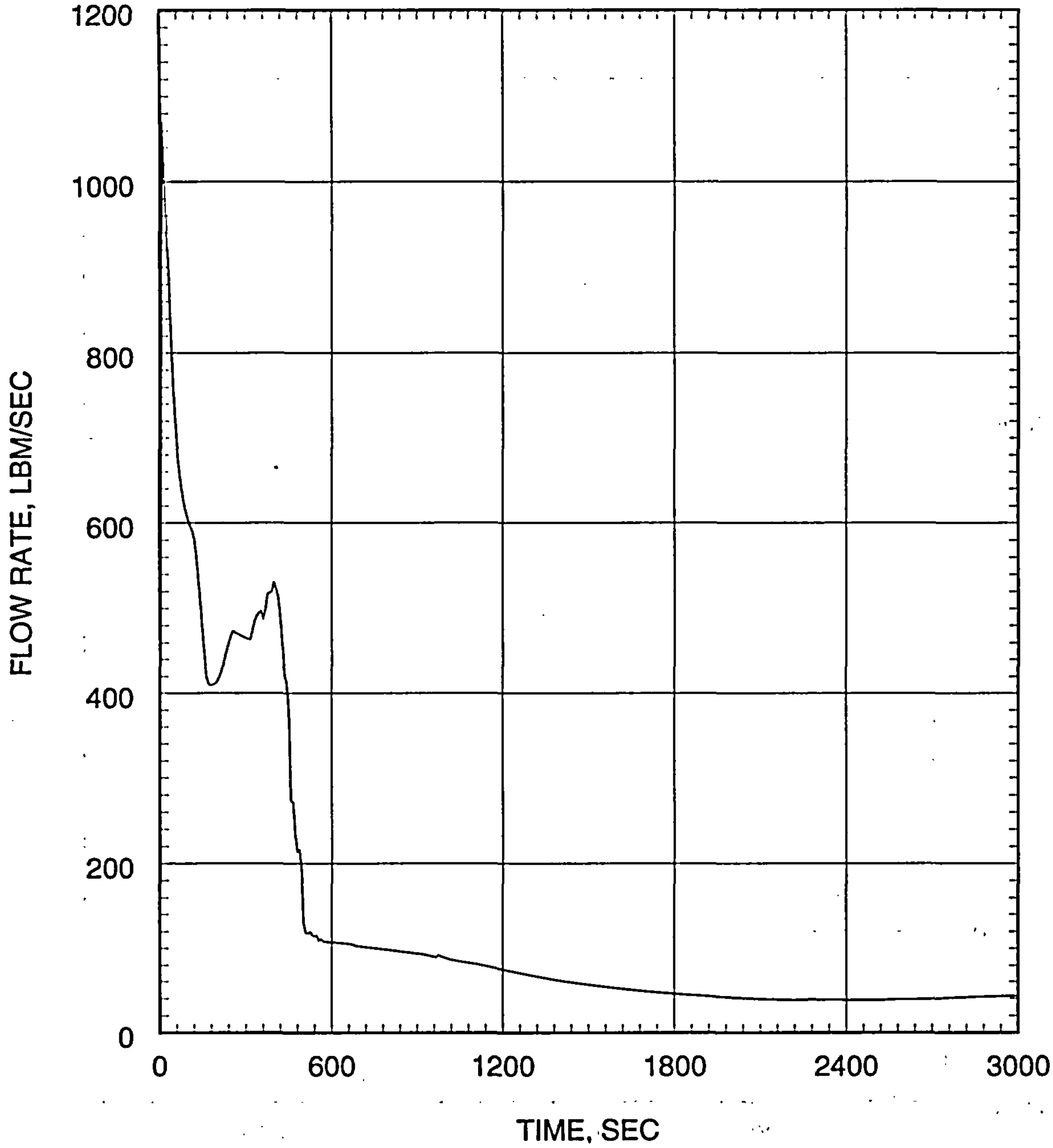

Figure 5.2.4.3-19
Small Break LOCA ECCS Performance Analysis
0.05 ft^2/PD Break
Break Flow Rate

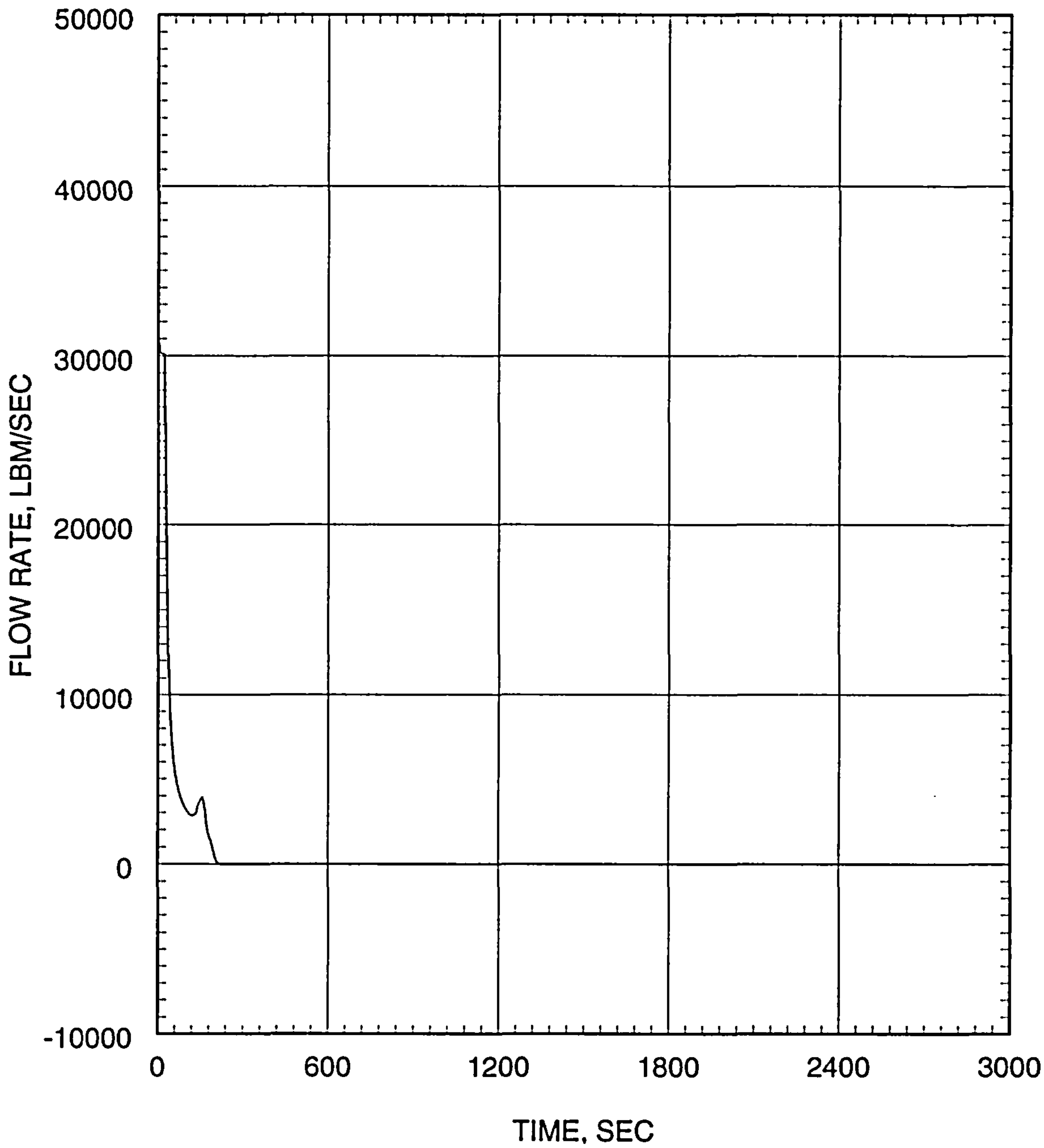

Figure 5.2.4.3-20
Small Break LOCA ECCS Performance Analysis
0.05 ft²/PD Break
Inner Vessel Inlet Flow Rate

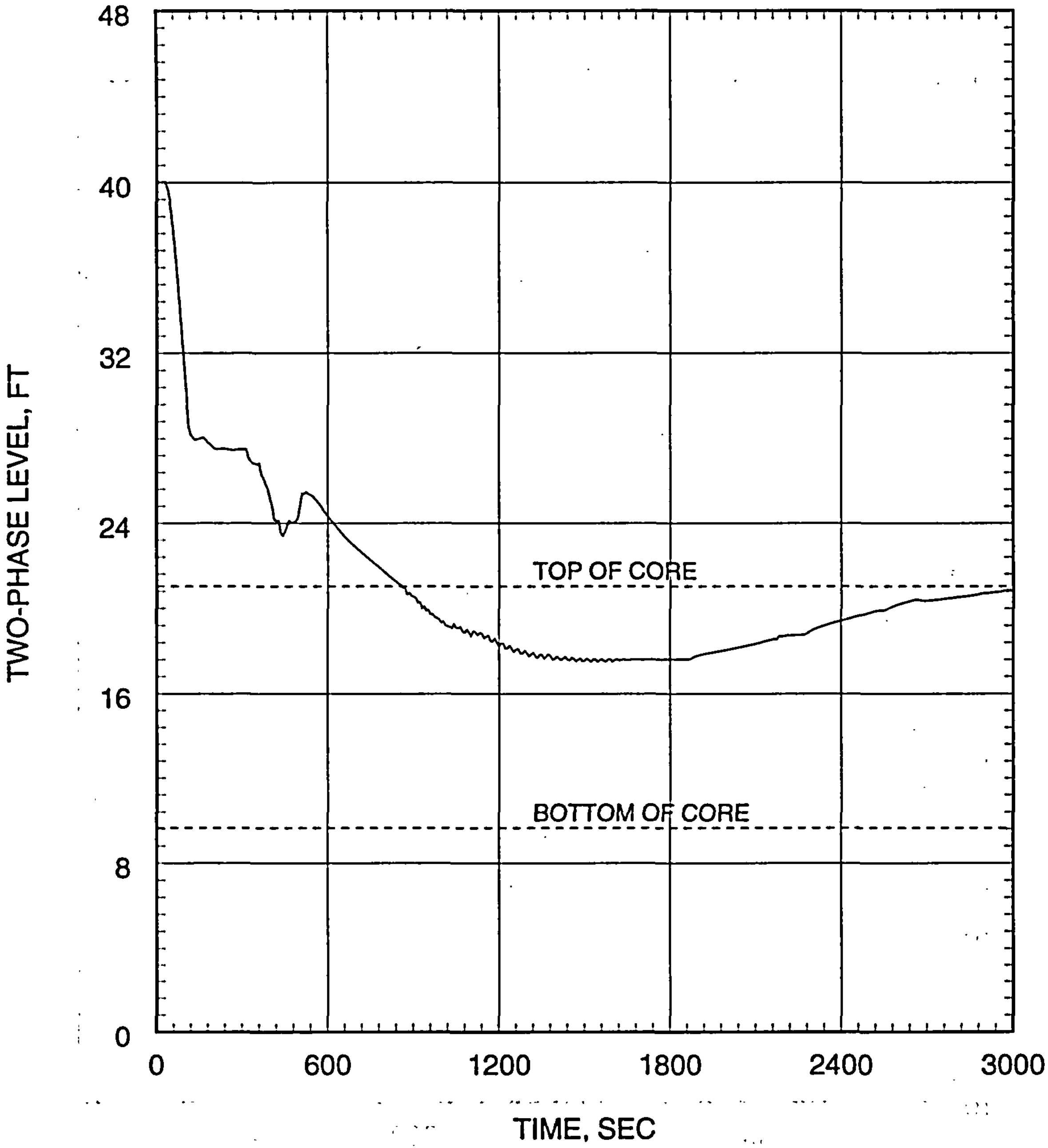

Figure 5.2.4.3-21
Small Break LOCA ECCS Performance Analysis
0.05 ft^2/PD Break
Inner Vessel Two-Phase Mixture Level

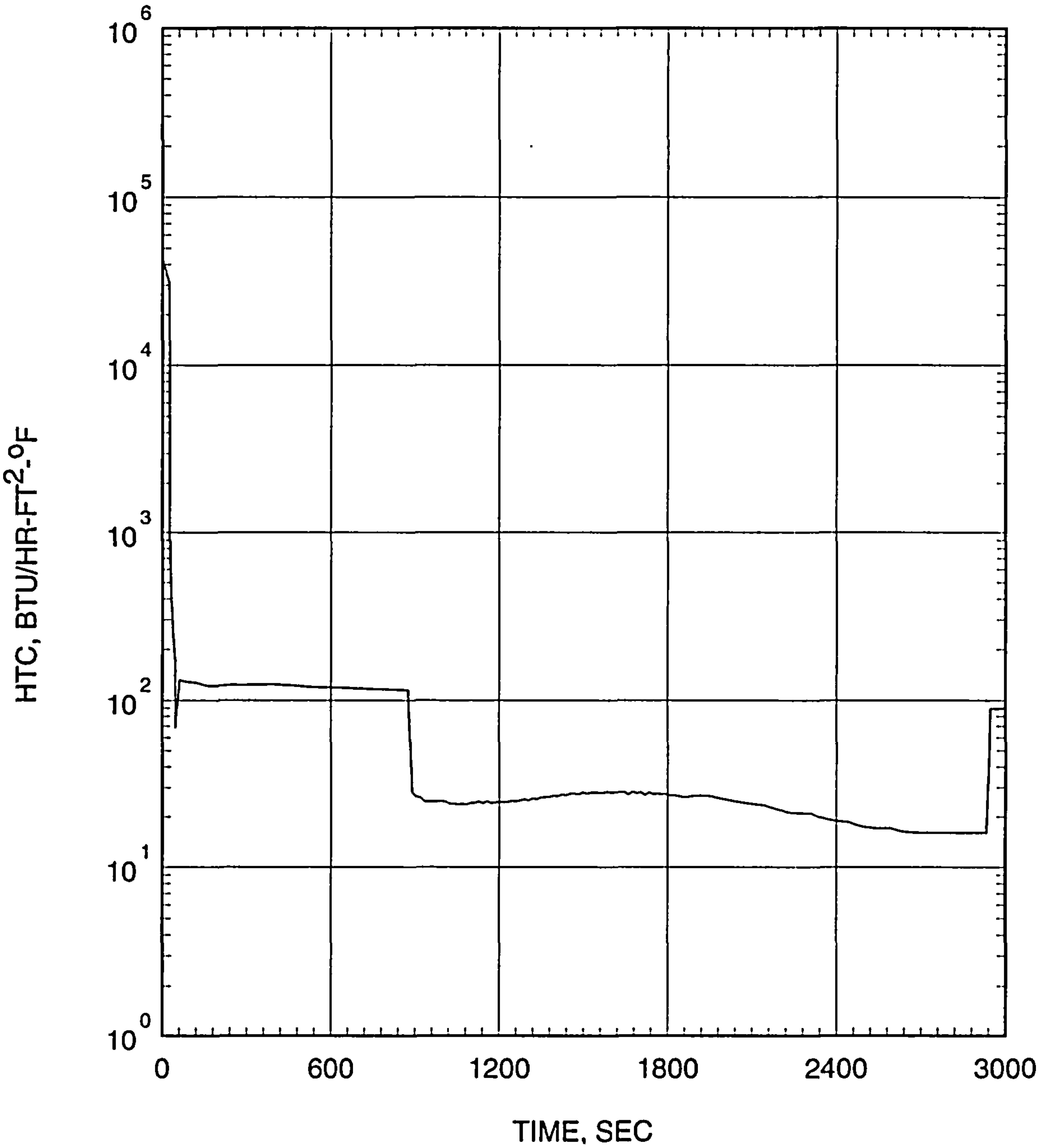

Figure 5.2.4.3-22
Small Break LOCA ECCS Performance Analysis
0.05 ft^2/PD Break
Heat Transfer Coefficient at Hot Spot

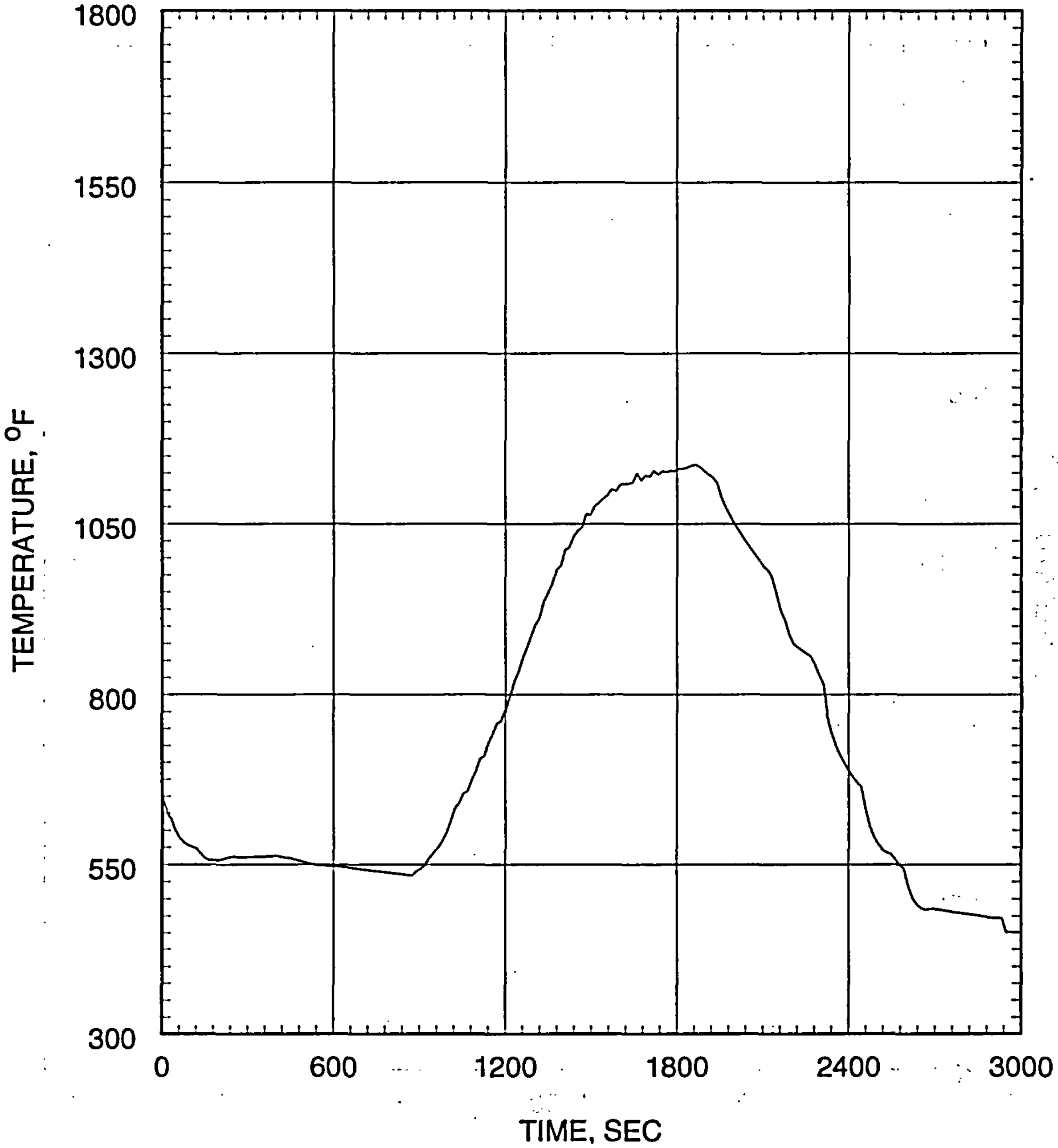

Figure 5.2.4.3-23
Small Break LOCA ECCS Performance Analysis
0.05 ft^2/PD Break
Coolant Temperature at Hot Spot

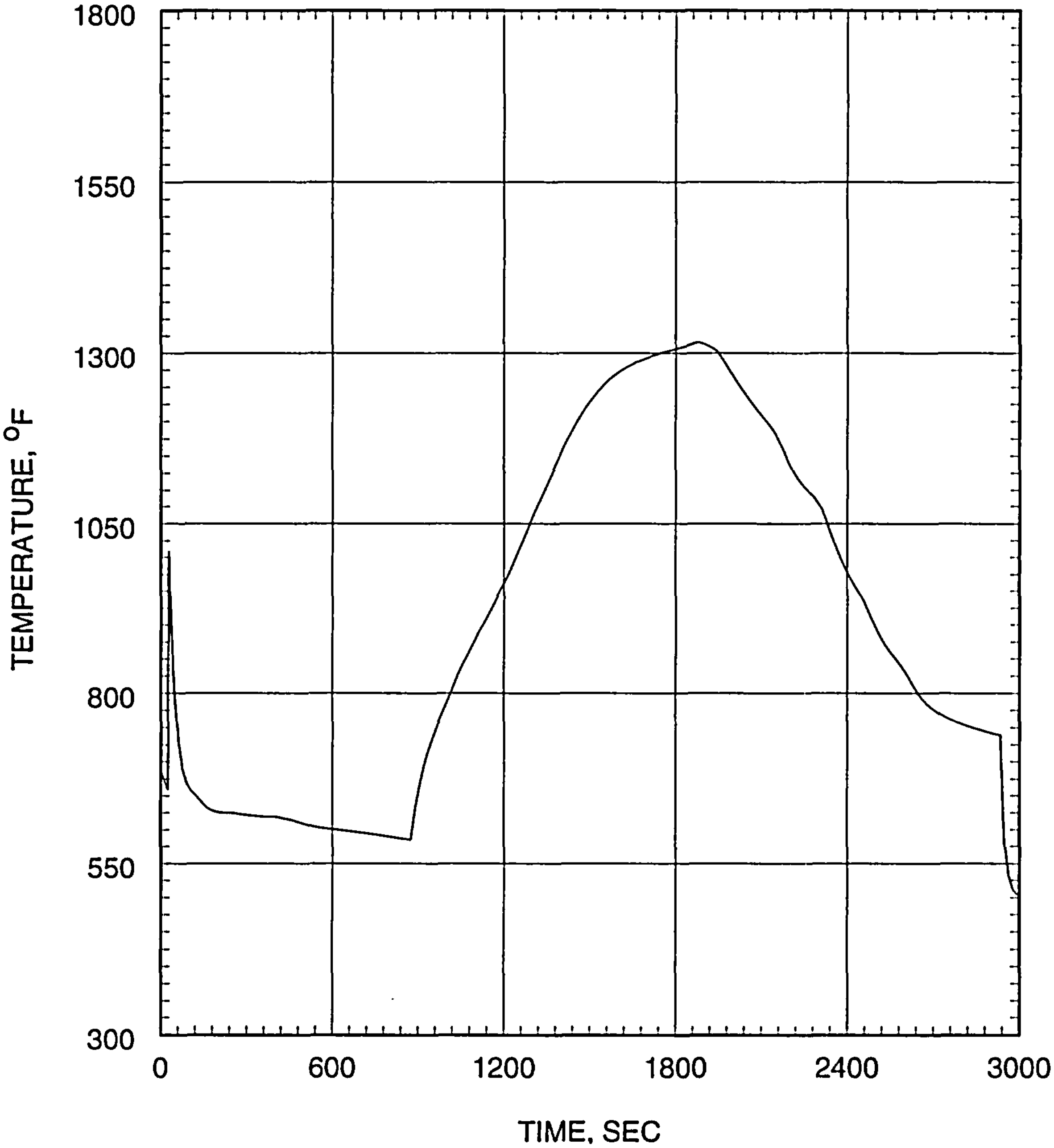

Figure 5.2.4.3-24
Small Break LOCA ECCS Performance Analysis
0.05 ft²/PD Break
Cladding Temperature at Hot Spot

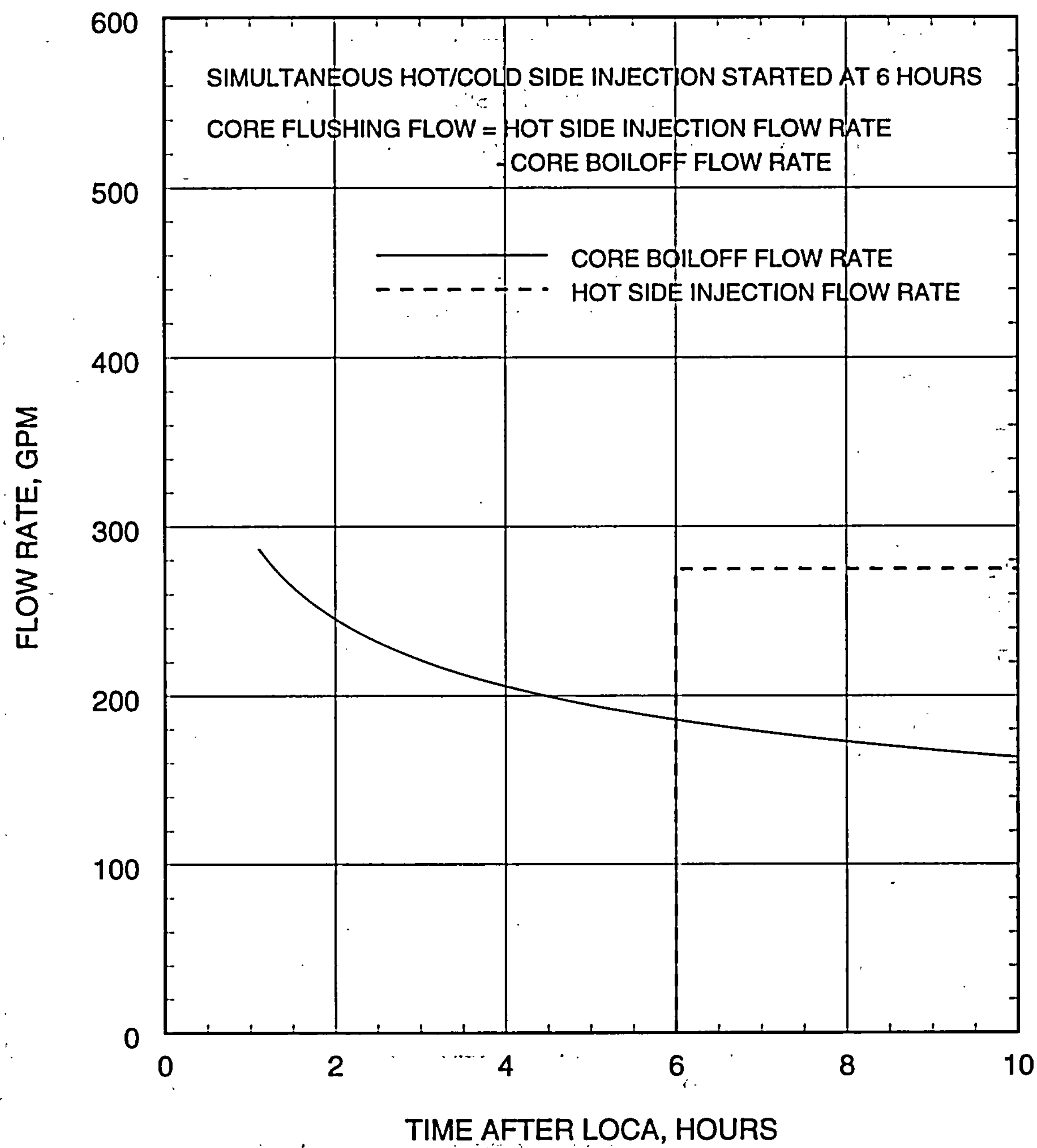

Figure 5.2.5.3-1a
Long-Term Cooling Analysis
Comparison of Core Boil-off Rate and the Minimum Simultaneous Hot and Cold Side Injection Flow Rate with a Decay Heat Multiplier of 1.1 after 1000 Seconds

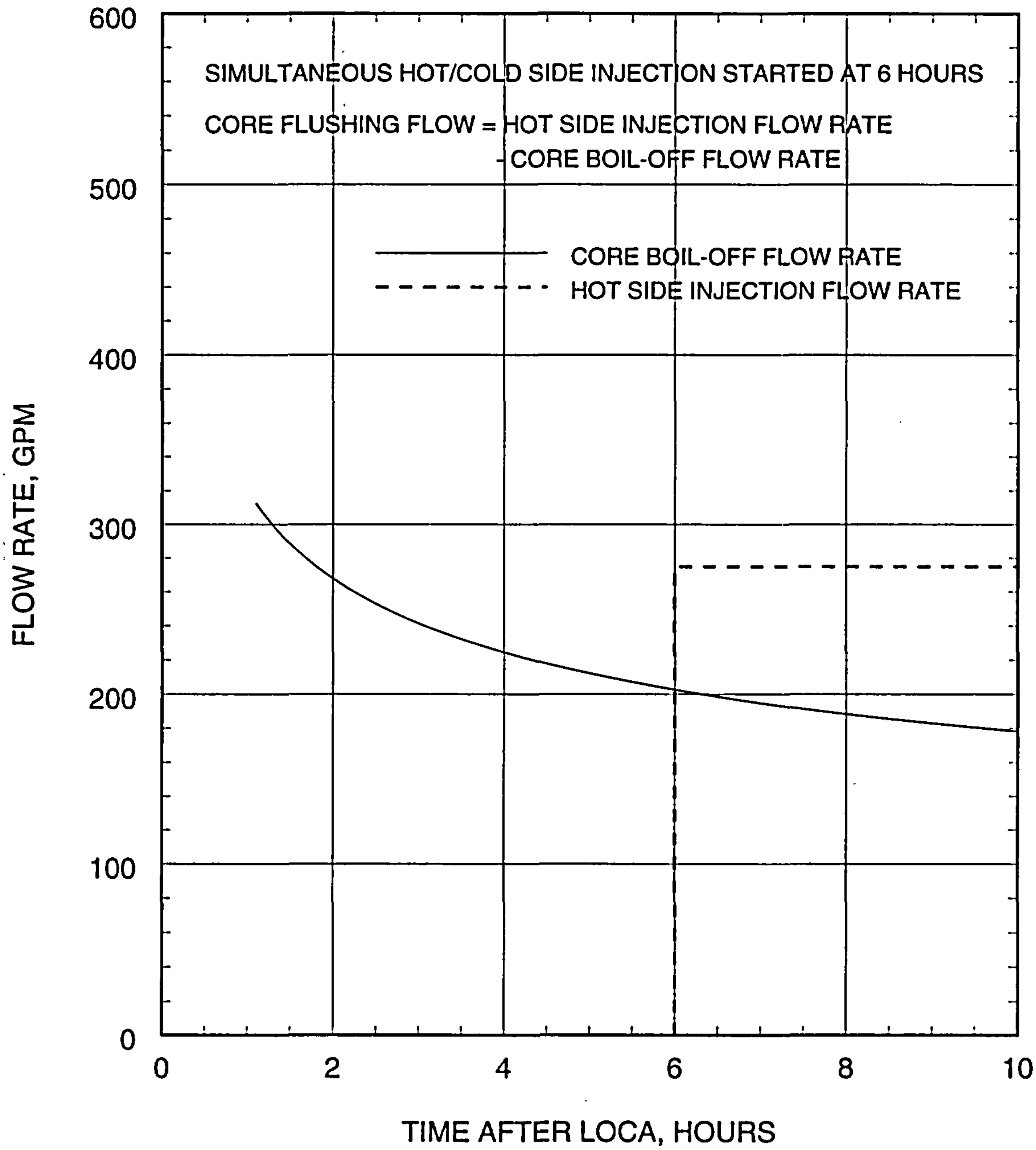

Figure 5.2.5.3-1b
Long-Term Cooling Analysis
Comparison of Core Boil-off Rate and the Minimum Simultaneous
Hot and Cold Side Injection Flow Rate
with a Decay Heat Multiplier of 1.2 after 1000 Seconds

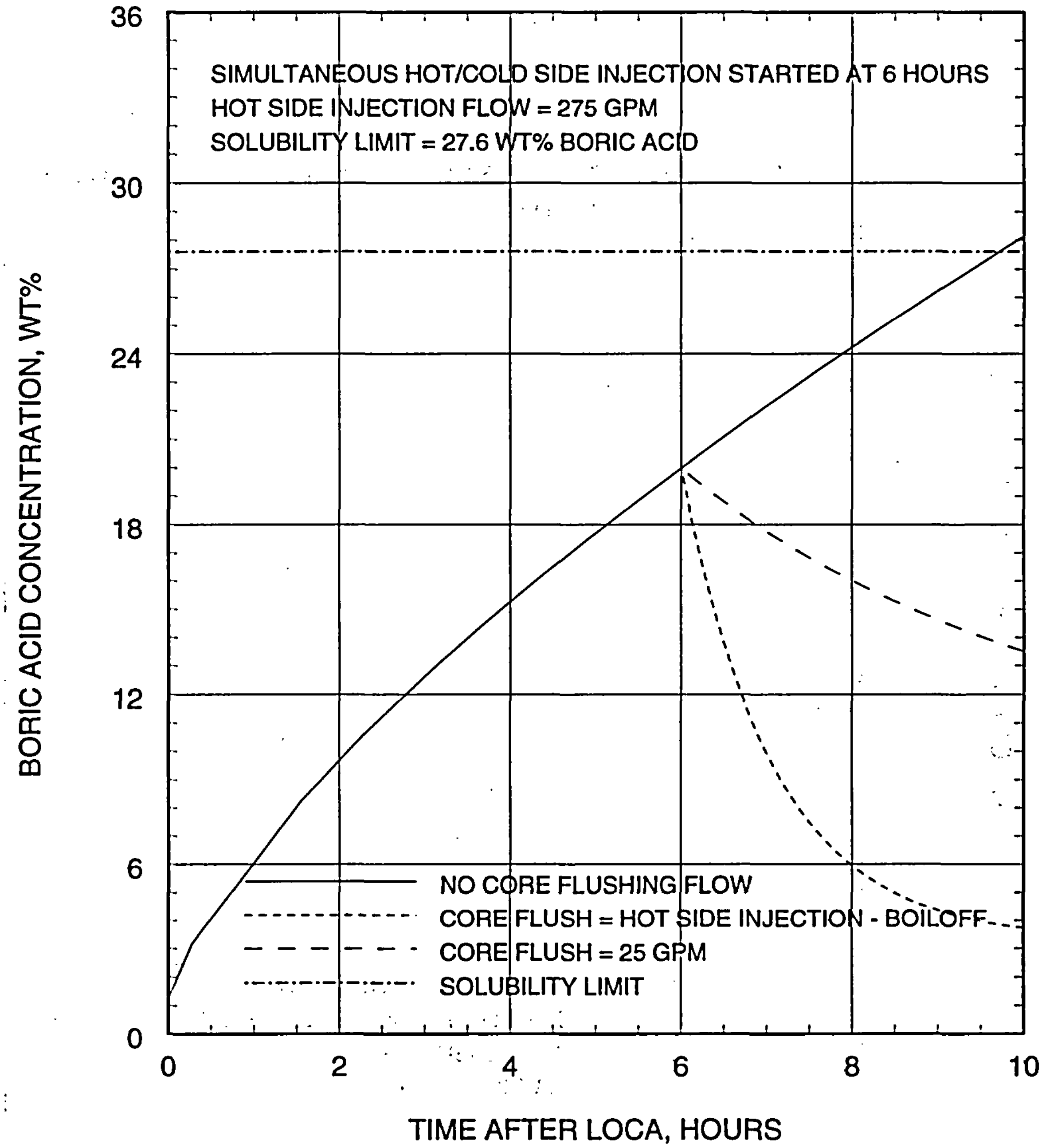

Figure 5.2.5.3-2a
Long-Term Cooling Analysis
Boric Acid Concentration in the Core versus Time
with a Decay Heat Multiplier of 1.1 after 1000 Seconds

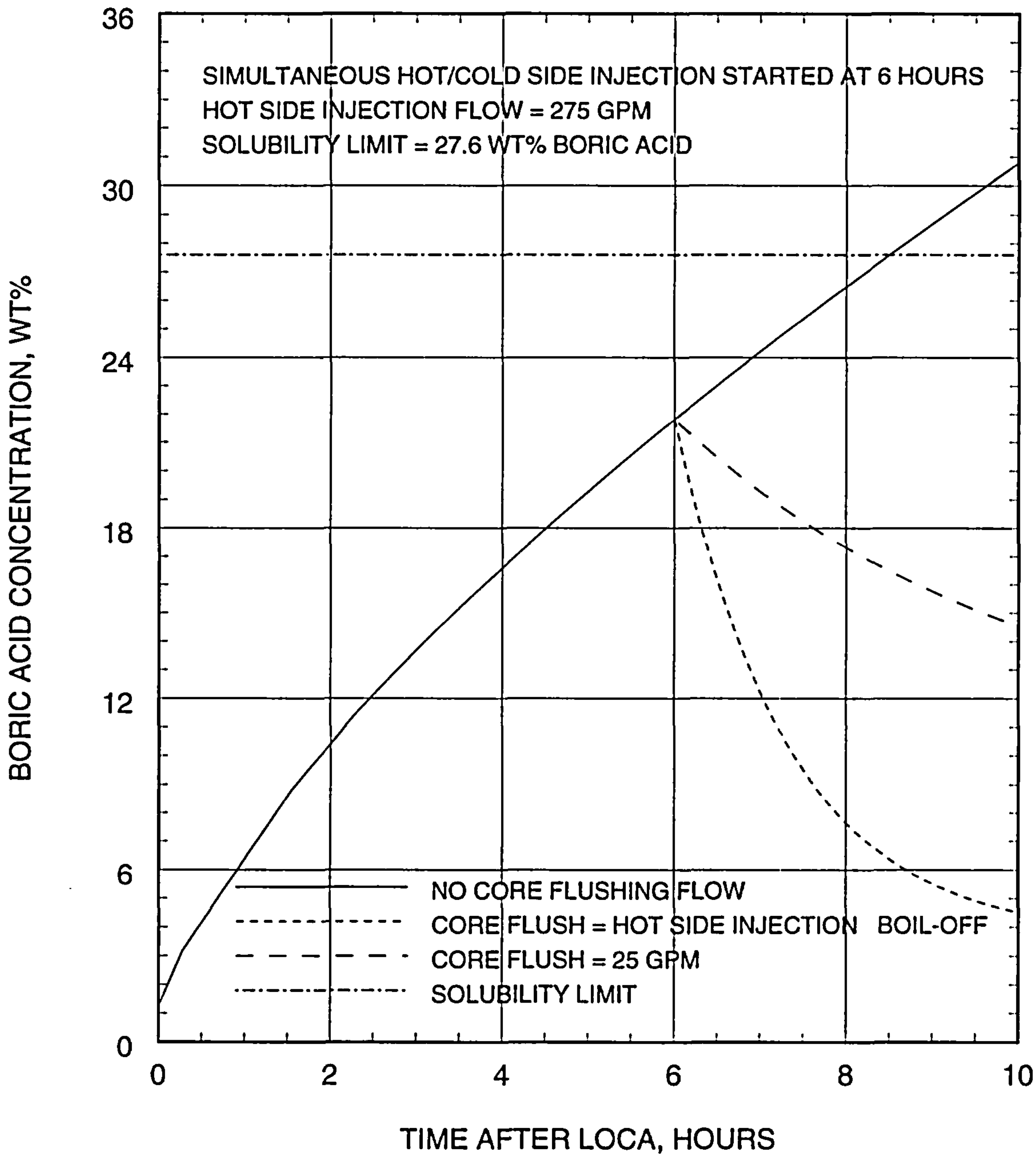

Figure 5.2.5.3-2b
Long-Term Cooling Analysis
Boric Acid Concentration in the Core versus Time
with a Decay Heat Multiplier of 1.2 after 1000 Seconds

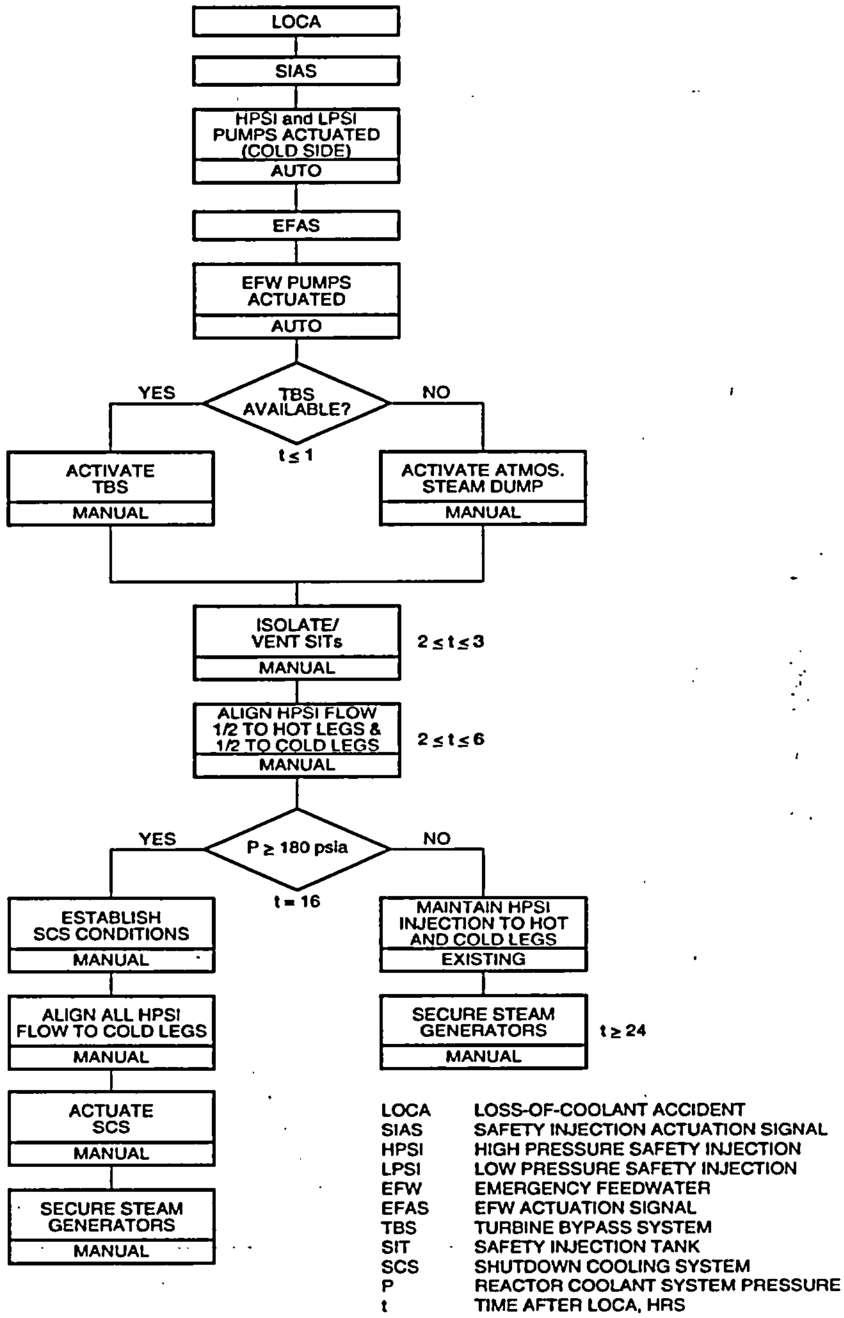

Figure 5.2.5.3-3
Long-Term Cooling Analysis
Long-Term Cooling Plan with a Decay Heat Multiplier of 1.1 or 1.2 after 1000 Seconds

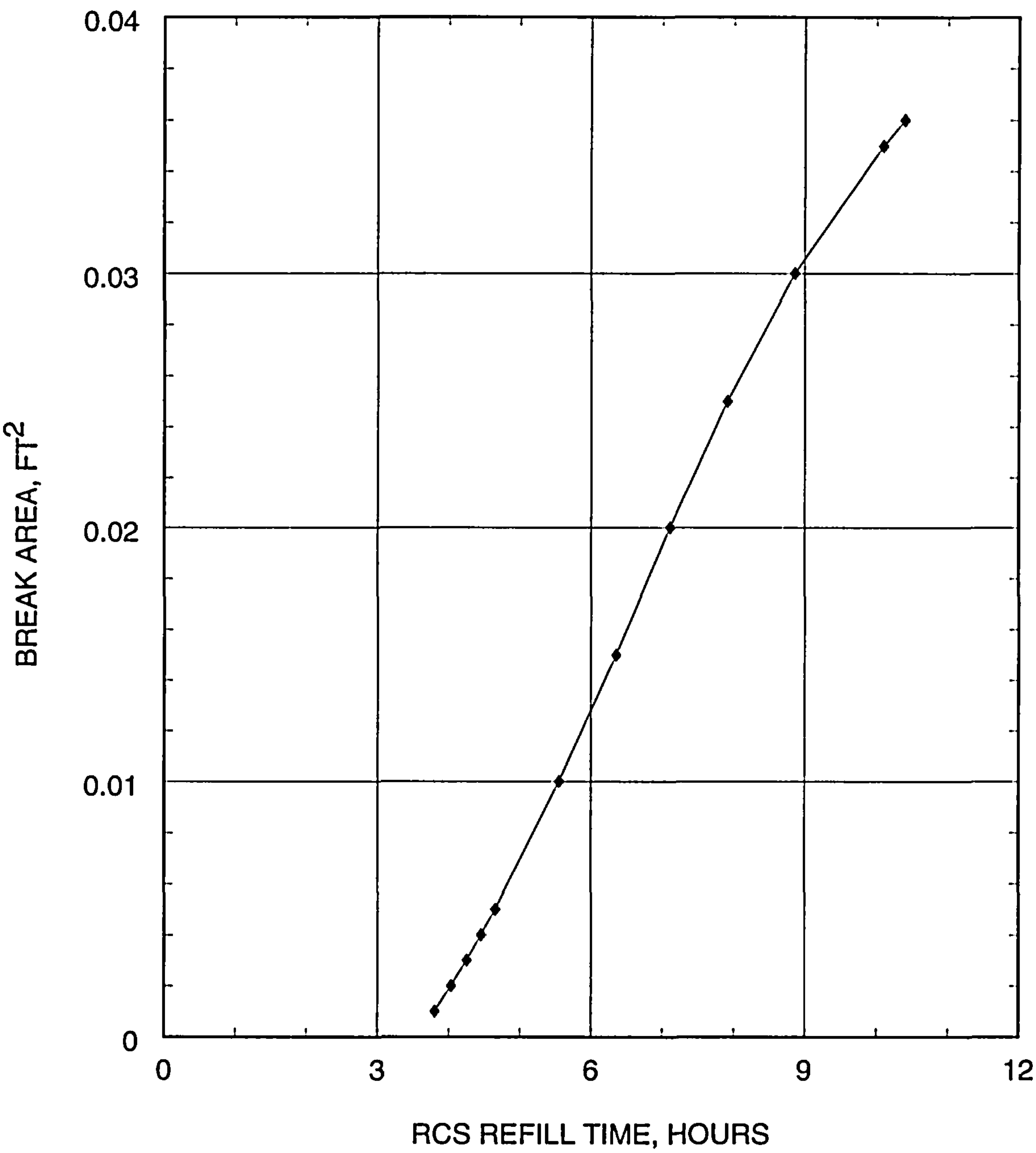

Figure 5.2.5.3-4
Long-Term Cooling Analysis
Break Area versus RCS Refill Time
with a Decay Heat Multiplier of 1.1 after 1000 Seconds

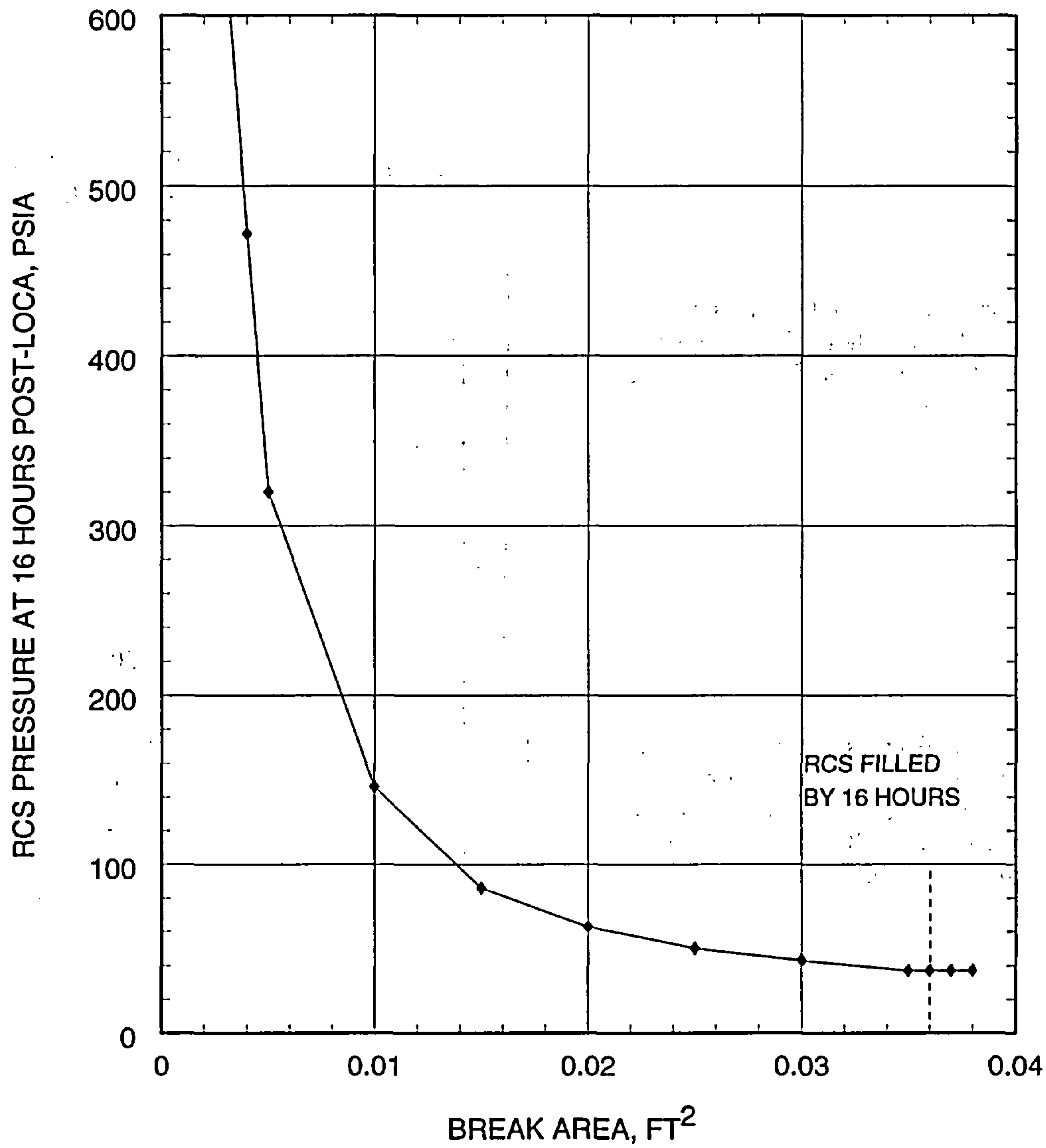

Figure 5.2.5.3-5
Long-Term Cooling Analysis
RCS Pressure at the Decision Time versus Break Area
with a Decay Heat Multiplier of 1.1 after 1000 Seconds

For break areas 0.005 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 and natural circulation disperses boric acid throughout the RCS and the SGs cool the RCS to the SDC entry temperature.

Break Size (ft^2)	RCS Pressure at 16 Hours Post-LOCA (psia)
0.038	37
0.037	37
0.036	37
0.035	37
0.030	43
0.025	50
0.020	63
0.015	86
0.010	146
0.005	320
0.004	472
0.003	635
0.002	851
0.001	1074

Figure 5.2.5.3-6
Long-Term Cooling Analysis
Overlap of Acceptable Procedures in Terms of Break Size
with a Decay Heat Multiplier of 1.1 after 1000 Seconds

5.3 MASS AND ENERGY RELEASE, CONTAINMENT INTEGRITY

5.3.1 Introduction

The containment building encloses the primary and secondary plant and is the final barrier against the release of significant amounts of radioactive fission products in the event of an accident. The containment structure must be capable of withstanding the pressure and temperature conditions resulting from a postulated Loss of Coolant Accident (LOCA) or Main Steam Line Break (MSLB). The containment response analysis is performed to demonstrate that the design pressure and temperature conditions for the containment structure are not exceeded. The Equipment Qualification (EQ) analysis defines a temperature envelope within which the operability of all inside containment Class 1E Safety Related Equipment must be ensured.

St. Lucie Unit 2 has a current containment design pressure of 44 psig.

The containment mass and energy release and pressure and temperature response analyses conform to the requirements of the NRC's Standard Review Plan (SRP), Reference 1, which invokes the requirements of the General Design Criteria (GDC) 50.

5.3.2 Evaluation Approach

The planned increase in the steam generator tube plugging (SGTP) up to 42% with a corresponding reduction in the Reactor Coolant System (RCS) flow rate, reduction in the core power and reduction in the RCS primary cold leg inlet temperature (Tcold), impacts the LOCA and MSLB mass and energy releases to the containment. Consequently, the containment pressure and temperature conditions resulting from postulated LOCA and MSLB events will potentially be impacted. The discussion in this section evaluates the effect of individual parameters on the mass and energy releases as well as their combined effect on the containment pressure and temperature response.

5.3.3 Acceptance Criteria

The acceptance criteria are that the calculated peak containment atmosphere pressure and temperature should remain below the original design basis values. However, FPL has set a conservative limit on the containment pressure of 41.8 psig for the LOCA events. This criterion corresponds to the current Integrated Leak Rate Test (ILRT) pressure. Another criterion set by FPL is to remain within the existing St. Lucie 2 long term Equipment Qualification (EQ) temperature.

5.3.4 Description of Evaluation and Assessment of the Impact

5.3.4.1 Loss of Coolant Accident Mass and Energy Release

The significant RCS parameters that determine the severity of the mass and energy release due to a postulated LOCA and, consequently, the containment pressure and temperature response are (1) core power, (2) RCS flow rate and (3) RCS inlet temperature. Table 5.5-1 provides a comparison of the significant input parameters between the 30% SGTP and 42% SGTP conditions for the LOCA containment mass and energy release evaluation.

The LOCA mass and energy release analysis is performed utilizing the minimum RCS flow rate, and maximum RCS inlet temperature. Therefore, the reduced RCS inlet temperature and core power will tend to reduce the severity of the results. This is so because reducing the core power but keeping the primary (RCS) inlet temperature and the RCS flow rate the same, results in a lower RCS outlet temperature (T_{hot}). Although the mass flow rate may slightly increase, the leak energy will be lower due to the lower enthalpy of the flow. Similarly, reducing the RCS inlet temperature but keeping the core power and the RCS flow rate the same, results in a lower RCS outlet temperature (T_{hot}) and the total energy released into the containment will be reduced. However, the reducing the RCS flow rate but keeping the core power and RCS inlet temperature the same will tend to increase the severity of the energy release since it results in a higher RCS outlet temperature (T_{hot}). For the planned steam generator tube plugging of up to 42%, the RCS flow rate, core power and RCS inlet temperature are all reduced. The overall effect of these changes is a slight decrease in RCS outlet temperature. Consequently, based on the discussion above, the LOCA mass and energy release to the containment for the 42% SGTP conditions is deemed to be less severe than those documented in the FSAR for the 30% SGTP conditions. The steam generator secondary side parameters have a secondary effect on the LOCA mass and energy release to the containment and, therefore, the impact of the changes in the SG secondary side parameters is deemed to be insignificant.

5.3.4.2 Main Steam Line Break Mass and Energy Release

The significant RCS parameters that determine the severity of the mass and energy releases due to a postulated MSLB are (1) core power, (2) RCS flow rate, (3) RCS inlet temperature and (4) steam generator tube plugging. The MSLB mass and energy release analysis is performed utilizing the maximum RCS flow rate, maximum RCS inlet temperature, maximum steam generator pressure and no SG tube plugging. Therefore, the effects of the lower RCS flow rate, reduced core power, reduced RCS inlet temperature and increased steam generator tube plugging up to 42% will tend to reduce the severity of the results. This is so because the decay heat, primary to secondary heat transfer and secondary steam pressure are reduced. At lower core power, the steam generator liquid mass will be slightly higher, resulting in slightly more steam released through the break to the containment. However, the beneficial impact of three parameters (decay heat, primary-to-secondary heat transfer and steam pressure) more than offsets the impact of the slight increase in secondary side inventory. Hence, overall MSLB mass and energy releases to the containment will be less severe. Consequently, the impact of these changes on the MSLB mass and energy release results is deemed to be no more adverse than those original analysis documented in the FSAR.

5.3.4.3 Containment Pressure and Temperature Response

As discussed above, the overall impact of the changes associated with the proposed steam generator tube plugging of up to 42% on the containment LOCA and MSLB mass and energy release is deemed to be no more adverse than that documented in the original analysis provided in the FSAR. Consequently, the resulting containment pressure and temperature response is deemed to be less severe than the current analysis of record.

5.3.5 Conclusions

Based on the discussion above, the containment pressure and temperature response following postulated LOCA and MSLB events with steam generator tube plugging of up to 42% and reductions in the RCS flow rate, core power and RCS primary cold leg inlet temperature, remains bounded by the results of the containment response from the original analysis documented in the FSAR.

5.3.6 References

1. U.S. Nuclear Regulatory Commission NUREG-0800, Revision 1, Standard Review Plan, July 1981.

Table 5.3-1 Comparison of Significant Parameters - Containment LOCA Mass and Energy Release			
Parameter and Units	Input / Operating Conditions		Impact
	42% SGTP	30% SGTP	
Core Power, MWt (including uncertainty)	2452	2754	No adverse
Primary Cold Leg Inlet Temperature, T_{cold}, (maximum), °F	550.1	552.0	No adverse
Primary Flow Rate (minimum), gpm	300,000	335,000	Negligible
Steam Generator Pressure (maximum), psia	780.0	930.0	No adverse
Feedwater Enthalpy (maximum), BTU/lbm	420.0	410.9	Negligible
Liquid Mass per Steam Generator, lbm	135,700	134,130	Negligible

5.4 RADIOLOGICAL DOSE EVALUATION

Recently, Non-LOCA safety analyses supporting operation of the Florida Power and Light (FP&L) St. Lucie Unit 2 plant at 89% power with up to 42% of the steam generator tubes plugged (SGTP) has been completed. This section presents an evaluation of the impact of these two changes on the radiological consequences calculation, with the exception of the steam generator (SG) tube rupture event (which was re-analyzed in Section 5.1.24).

5.4.1 Method of Evaluation

The method of this evaluation is to compare key inputs from the 89% power with up to 42% SGTP set of analyses to those used in the existing radiological consequences analysis of record (AOR, Reference 5.4-1). Changes to the inputs are examined and are either sufficient to demonstrate the continued applicability of the radiological consequences or the margin between the existing results and the regulatory limit are judged to be greater than the impact of the adverse consequences. For non-LOCA safety analyses, the dose consequences are dominated by the amount of fuel failures and the primary-to-secondary leakage.

5.4.2 Parameters Unaffected By Tube Plugging

The majority of the parameters which are part of the radiological consequences AOR (Reference 5.4-1) are governed by regulation, Technical Specifications, or agreed upon analytical assumptions in licensing interactions. Table 5.4-1 lists these key parameters. These parameters are not impacted by operating at 89% power with up to 42% SGTP.

5.4.3 Parameters Affected By Tube Plugging and Reduced Power

This section discusses parameter changes that might impact radiological consequences calculations with up to 42% SGTP at 89% of rated thermal power. However, since the radiological consequences calculations are performed separately from the transient analyses, the discussion in this section evaluates the impact of these parameter changes as opposed to performing explicit radiological calculations. Table 5.4-2 lists the key parameters affected by increasing tube plugging and reducing core power.

The impact of each key parameter change is discussed in the subsections that follow. [Note that increasing SGTP will reduce RCS volume and increase RCS specific activity for fuel failure cases. This is addressed on an event-by-event basis in Section 5.4.5.]

5.4.3.1 Core Power

Decreasing core power from 2700 MWt (rated thermal power) to 2404 MWT (89% power) will benefit radiological consequence calculations because it will reduce decay heat. The decay heat is reduced by 11% at 89% power because the inventory of fission byproducts in the fuel is reduced by about 11%. In other words, applying the source terms associated with 100% operation to 89% power operation remains applicable. Thus, at 89% power the decay heat will drop by 11% and the steam releases used in the radiological consequence calculations will drop by about the same amount. Reduced steaming is a direct benefit to radiological consequence calculations. Reduced inventory of fission byproducts is also a direct benefit to the radiological consequences determined for those analyses that predict fuel failure.

Operation at 89% power will not adversely affect the isotopes and/or activities assumed for the RCS as the T.S. limit on primary activity will not change for reduced power operation.

5.4.3.2 RCS Flow

Decreasing RCS flow from 335,000 gpm to 300,000 gpm in the RCS will not have any direct impact on radiological consequences. However, the reduction in flow associated with the 89% power and 42% plugged SG tube scenario will reduce SG pressure. See Section 5.4.3.4 for further discussion.

5.4.3.3 RCS Temperature

Decreasing T_{COLD} from 549.0°F to 547.1°F will benefit radiological consequence calculations because it will reduce the flashing fraction for a given transient. Flashing fraction measures the amount of RCS leakage from primary to secondary that immediately flashes to steam as a result of thermodynamic expansion in percent leak. Flashing fraction is calculated as:

$$\text{Flashing Fraction} = \frac{\text{Leak Enthalpy} - \text{SG Saturated Liquid Enthalpy}}{\text{SG Saturated Vapor Enthalpy} - \text{SG Saturated Liquid Enthalpy}} = \frac{h_1 - h_{SG}{}^l}{h_{SG}{}^v - h_{SG}{}^l}$$

Thus, as RCS temperature decreases, leak enthalpy will decrease and reduce flashing fraction. As an example, Table 5.4-3 calculates flashing fractions at a primary pressure of 2250 psia and a secondary pressure of 800 psia for T_{COLD} values of 549.0°F, 547.1°F, and 546.0°F.

Thus, decreasing T_{COLD} from 549.0°F to the range of 546.0 to 547.1°F will reduce flashing fraction. [Note that Table 5.4-3 is used as an example and the leak enthalpy is based upon cold leg temperatures as opposed to hot leg temperatures. The SG pressure in Table 5.4-3 is arbitrary and used for illustration only.]

5.4.3.4 SG Pressure

Decreasing minimum SG pressure from 810 psia to 724 psia will have mixed effects on radiological consequence calculations. Reducing SG pressure will increase the heat of vaporization of water (H_{FG}) and will increase SG density at saturated conditions. These effects will consequently reduce steaming and reduce SG concentration. However, reducing SG pressure will increase flashing fraction. The impact of each of the effects is discussed in the subsections that follow.

Reduced Steaming due to SG Density Changes

Increasing steam generator tube plugging and reducing core power reduces heat transfer area in the steam generator and drops secondary pressure. This reduction results in the decrease in secondary system pressure listed in Table 5.4-4. [Note that the SG pressure values used in Table 5.4-4 are arbitrary and are used for illustration only.]

Decreasing secondary pressure benefits radiological consequence calculations because the heat of vaporization of water varies with pressure. Table 5.4-4 demonstrates that for any steam generator pressure, a lower pressure resulting from the plugged tubes will result in a greater heat of vaporization. Therefore, slightly lowered steaming would be necessary to remove core decay heat and stored energy in the RCS metal and liquid mass during the cooldown.

Reduced SG Concentration due to SG Density Changes

Another consideration due to the reduction in SG pressure is the mass of secondary system liquid. The iodine activity leaking from the primary to secondary mixes with the mass in the steam generator. Thus a greater

steam generator mass would lead to a more dilute concentration for any given amount of primary-to-secondary system leakage. Table 5.4-5 demonstrates that lower saturation pressure results in an increase in the density of the liquid in the steam generator. [Note that the SG pressure values used in Table 5.4-5 are arbitrary and are used for illustration only.]

Increased Flashing Fraction due to Reduced SG Pressure

Another consideration due to the reduction in SG pressure is the increase in flashing fraction associated with a reduced SG pressure. By reducing the pressure of the SG, the saturated liquid enthalpy in the SG decreases and the saturated vapor enthalpy of the SG increases. This will increase flashing fraction. As an example, Table 5.4-6 calculates flashing fractions at a primary pressure of 2250 psia and a leak temperature of 549.0°F for SG pressure values of 810, 732, and 724 psia.

5.4.3.5 Conclusions for Parameters Affected By Tube Plugging and Reduced Power

The majority of the parameters found in radiological consequences do not change as a result of the tube plugging or power level as they are governed by regulation, technical specifications or agreed upon analytical assumptions in licensing interactions (Section 5.4.2). The only effect found to adversely impact radiological consequence calculations was that flashing fraction will increase due to reduced SG pressure. However, the impact of this non-conservatism will be more than offset by the following:

- Decreasing core power to 89% power will benefit radiological consequence calculations because it will reduce decay heat by 11% and consequently reduce steaming by approximately 11%.
- Decreasing RCS temperature will benefit radiological consequence calculations because it will reduce flashing fraction.
- Decreasing SG pressure will: reduce steaming due to SG density changes, and reduce SG concentration due to SG density changes.

Thus, the combined effects of reducing core power, reducing core flow, reducing RCS temperature, and reducing SG pressure will not adversely impact radiological consequences. Further discussions of radiological consequences are discussed in Sections 5.4.4 and Section 5.4.5.

5.4.4 Parameters Affected By WCAP-9272 Process

The current safety analysis AORs for St. Lucie Unit 2 were performed for Cycle 15 with 30% SGTP and are based upon the WCAP-9272 reload methodology. However, while the transition to the WCAP-9272 reload methodology was made for Cycle 15, the current radiological consequences calculation was performed using the Combustion Engineering analytical process. Since this evaluation performs an assessment of the current radiological consequences calculation, the transition to the WCAP-9272 methodology is still discussed herein. Transition to the WCAP-9272 reload methodology has the potential to produce changes in the analytical results which impact a radiological consequences calculation. As the WCAP-9272 based analyses for Cycle 16 also include modeling with 42% SGTP at 89% power, some of the changes listed are the result of the combined effect. In addition to the changes associated with the change in reload philosophy, a technical specification change reduced the primary-to-secondary steam generator tube leakage limit from 1.0 GPM to 0.3 GPM total for the two steam generators. Further discussion follows in Section 5.4.5.

5.4.5 Evaluation of AOR Dose Analyses against the 42% SGTP and 89% Power Program

The following sections provide an event-by-event discussion of each event for which a dose analysis is performed. This will demonstrate the applicability of the current radiological consequence AOR (Reference 5.4-1) to operation at 89% power with up to 42% SGTP.

5.4.5.1 Pre-Trip Steam Line Break (Inside and Outside Containment)

The radiological consequences analysis of the Pre-Trip Steam Line Break (using the Combustion Engineering methodology) determined the 10CFR100 limits for fuel failure during the Pre-Trip Steam Line Break are 33% (DNB, Reference 5.4-2, Section 15.1.5.4) for an Inside Containment event, and 10.5% fuel failure limit (DNB, Reference 5.4-2, Section 15.1.5.4) for an Outside Containment event. The analysis presented in Section 5.1.5 for 42% SGTP and the corresponding Cycle 16 core design has verified that the fuel failures for Cycle 16 are well below these limits. Nevertheless, this assessment will not credit the reduction in fuel failure in judging acceptability.

The radiological consequence AOR used a conservatively high initial steam generator inventory corresponding to the High SG Level Trip setpoint when calculating dose consequences for the Pre-Trip Steam Line Break; Most of this inventory is assumed to be released to the environment resulting in increased doses. However, this is conservative because the Pre-Trip Steam Line Break initializes at a lower SG level. In addition, the primary system mass should also be considered. The difference in primary system mass associated with operation at 89% power with 42% steam generator tube plugging is negligible. This is because the primary system volume reduction associated with 42% steam generator tube plugging tends to decrease primary system mass while the decreased primary temperature associated with 89% power tends to increase primary density and increase primary mass. However, the release to the atmosphere is the product of the tube leakage and the concentration in the primary coolant resulting from fuel failures. Due to the lowered Technical Specification limit for the primary-to-secondary leakage (from 1.0 gpm to 0.3 gpm, Reference 5.4-3, Section 3.4.6.2), the steam generator tube leakage will decrease by 70%. Thus, the decrease in the activity carried by the steam generator tube leakage would have a beneficial effect which overwhelms the slight increase in the specific RCS activity due to the smaller primary system mass with increased plugged tubes.

Based upon the above, the current radiological consequences AOR remains bounding. [Note that loss of offsite power (LOOP) assumptions (LOOP at reactor trip or 3 seconds later) will not make the current AOR dose consequences more adverse.]

5.4.5.2 Post-Trip Steam Line Break (Inside and Outside Containment)

The radiological consequences analysis of the Post-Trip Steam Line Break (using the Combustion Engineering methodology) determined the 10CFR100 fuel failure limits for dose consequences during a Post-Trip Steam Line Break are 3.4% (centerline melt, Reference 5.4-2, Section 15.1.6.5) for Outside Containment and 13.5% (centerline melt, Reference 5.4-2, Section 15.1.6.5) for Inside Containment. The analysis presented in Section 5.1.6 for 42% SGTP and the corresponding Cycle 16 core design has verified that the fuel failures for Cycle 16 are well below this limit. Nevertheless, this assessment will not credit the reduction in fuel failure in judging acceptability.

The radiological consequence AOR used a conservatively high initial steam generator inventory corresponding to the High SG Level Trip setpoint when calculating dose consequences for the Post-Trip Steam Line Break; Most of this inventory is assumed to be released to the environment resulting in increased doses. However, this is conservative because the Post-Trip Steam Line Break initializes at a lower SG level.

In addition, the primary system mass should also be considered. The difference in primary system mass associated with operation at 89% power with 42% steam generator tube plugging is negligible. This is because the primary system volume reduction associated with 42% steam generator tube plugging tends to decrease primary system mass while the decreased primary temperature associated with 89% power tends to increase primary density and increase primary mass. However, the release to the atmosphere is the product of the tube leakage and the concentration in the primary coolant resulting from fuel failures. Due to the lowered Technical Specification limit for the primary-to-secondary leakage (from 1.0 gpm to 0.3 gpm, Reference 5.4-3, Section 3.4.6.2), the steam generator tube leakage will decrease by 70%. Thus, the decrease in the activity carried by the steam generator tube leakage would have a beneficial effect which overwhelms the slight increase in the specific RCS activity due to the smaller primary system mass with increased plugged tubes.

Based upon the above, the current radiological consequences AOR remains bounding. [Note that loss of offsite power (LOOP) assumptions (LOOP at reactor trip or 3 seconds later) will not make the current AOR dose consequences more adverse.]

5.4.5.3 Feedwater Line Break

Both the current radiological consequences analysis (Reference 5.4-1) and the analysis presented in Section 5.1.12 for 42% SGTP model the discharge of the inventory from one steam generator through the break. However, the two models have a different initial steam generator liquid inventory and thus a different initial secondary system iodine activity for discharge from this source. The radiological consequences AOR accounts for the discharge of the CESEC based steam generator activity along with the discharge of tube leakage at the technical specification concentration without iodine partitioning through the affected steam generator.

Discharge from the intact steam generator accounts for tube leakage into that steam generator and discharge during steaming with iodine partitioning. The radiological consequence AOR used a conservatively high initial steam generator inventory corresponding to the High SG Level Trip setpoint when calculating dose consequences for the Feedwater Line Break; Most of this inventory is assumed to be released to the environment resulting in increased doses. However, Reference 5.4-2, Section 15.2.8.2 discusses that the Feedwater Line Break analysis initializes at a SG level consistent with the low-level alarm. Since the radiological consequences AOR calculated less than 10% of the 10CFR100 limits, the current AOR remains bounding. The decrease in primary to secondary leakage from 1.0 gpm to 0.3 gpm (Reference 5.4-3, Section 3.4.6.2) provides additional conservatism in the current AOR.

Also note that loss of offsite power (LOOP) assumptions (LOOP at reactor trip or 3 seconds later) will not make the current AOR dose consequences more adverse.]

5.4.5.4 CEA Ejection

The CEA Ejection event is a result of a complete break of the control element drive mechanism (CEDM) housing or CEDM nozzle on the reactor vessel head. Fuel failure, which would lead to radiological consequences, occurs when specific enthalpy threshold values are violated. These include a Clad Damage Threshold which states that the Total Average Enthalpy must remain below 200 cal/gm and maximum fuel melting must be limited to the innermost 10% of the fuel pellet at the hot spot independent of pellet enthalpy (Section 5.1.20.1).

The above mentioned threshold values were met for the current radiological consequences analysis, therefore no fuel failure was predicted. Radiological consequences, which are limited to a small fraction of the 10 CFR 100 guidelines, however have assumed 0.05% of the rods are in centerline melt and 9.5% of the rods are in DNB (Section 15.4.8.4).

The 42% SGTP at 89% core power analysis found that the average fuel pellet enthalpy remained below 200 cal/g for all cases (Section 5.1.20.3). Thus this analysis is bounded by the current AOR.

During a CEA Ejection, 0.5 weight % / day is released to the environment via the containment leakage, which is not impacted by the SGTP. A second source is Steam Generator Tube leakage; the steaming from the SGs during cooldown. Since this leakage rate has been reduced from 1.0 gpm to 0.3 gpm (Reference 5.4-3, Section 3.4.6.2) the 42% SGTP at 89% core power analysis becomes less limiting.

5.4.5.5 Inadvertent Opening of an MSSV

According to the current radiological consequences analysis (Reference 5.4-1), the Feedwater Line Break event is analyzed to the same dose criteria as that of the Inadvertent Opening of an MSSV. The Inadvertent Opening of an MSSV is bounded by the Feedwater Line Break since, similar to the Feedwater Line Break, no fuel failure was predicted. Bounding this event by a Feedwater Line Break is possible because once the steam generator has run dry, radiological doses will steam out of the break in the Feedwater Line in the same manner that they would steam out of the MSSV.

Since the 42% SGTP at 89% core power analysis has concluded no fuel failure for a Feedwater Line Break event, the initial RCS and steam generator concentrations remain at the Technical Specifications limits similar to the current analysis (Reference 5.4-1). Reducing the primary to secondary leakage from 1.0 gpm to 0.3 gpm (Reference 5.4-3, Section 3.4.6.2) gives additional conservatism to the radiological consequences predicted by the AOR for this event.

5.4.5.6 Locked Rotor/Sheared Shaft

The radiological consequences analysis of the Locked Rotor/Sheared Shaft determined the 10CFR100 fuel failure limits for dose consequences due to DNBR criteria as 13.6% (Reference 5.4-2, Section 15.3.3.4, with a stuck open atmospheric dump valve) and 2.5% (Reference 5.4-2, Section 15.3.3.4, without a stuck open atmospheric dump valve). Since the 89% power with up to 42% SGTP analysis shows that the maximum percent of Rods-in-DNB is less than 2.5% (Section 15.1.15.6), the current dose consequences remain bounding. Reducing the primary to secondary leakage from 1.0 gpm to 0.3 gpm (Reference 5.4-3, Section 3.4.6.2) gives additional conservatism to the radiological consequences predicted by the AOR for this event.

5.4.5.7 Letdown (Primary) Line Break

A Letdown (Primary) Line Break may result from a break in a letdown line, instrument line, or sample line. The current analysis (Section 5.1.23) selects the double ended break of the letdown line outside containment upstream of the outside containment isolation valve as it is the largest line and results in the largest release of reactor coolant to the environment. The analysis of this event does not directly challenge any DNBR criterion.

Total activity released due to a Primary Line Break is a resultant of the break itself in conjunction with any doses steamed from the steam generator. Since there is no fuel failure in this event, the primary system activity is governed by the Technical Specification limit of 1 μCi/cc. Since this limit is unchanged, a

reduction in primary system mass will provide a beneficial effect on the calculated doses. Reducing decay heat associated with a reduction in core power to 89% and the reduction in primary to secondary leakage from 1 gpm to 0.3 gpm will reduce the dose component from the steam releases. The dose consequences from the current analysis would thus remain bounding for the 42% SGTP and 89% power case.

5.4.6 Loss of Coolant Accident (LOCA)

The assumptions and parameters used to calculate the radiological source terms and dose consequences for a LOCA, as described in the UFSAR (Reference 5.4-2) are not changed at 89% core power with 42% SGTP. As such, the doses as given in the UFSAR remain unchanged at 89% core power with 42% SGTP.

5.4.7 Fuel Handling Accidents and the Waste Gas Decay Tank Rupture

These events are not affected at 89% core power with 42% SGTP. Fuel handling accidents are not impacted by changes in tube plugging or core power as these events occur outside the RCS. Since there is no change to the RCS Technical Specification activity and RCS volume is reduced due to the increased SG tube plugging, the current waste gas decay tank rupture analysis remains bounding at 89% core power with 42% SGTP.

5.4.8 Conclusions

A set of non-LOCA safety analyses that support operation at 89% core power with 42% SGTP have recently been completed for Florida Power and Light. In order to determine whether or not the current radiological calculations are valid at 89% core power with 42% SGTP, evaluations of key input parameters has been performed.

The majority of the parameters found in radiological consequences do not change as a result of the tube plugging or power level as they are governed by regulation, technical specifications or agreed upon analytical assumptions in licensing interactions (Section 5.4.2). The only effect found to adversely impact radiological consequence calculations was that flashing fraction will increase due to reduced SG pressure. However, the impact of this non-conservatism will be more than offset by the following:

- Decreasing core power to 89% power will benefit radiological consequence calculations because it will reduce decay heat by 11% and consequently reduce steaming by approximately 11%.
- Decreasing RCS temperature will benefit radiological consequence calculations because it will reduce flashing fraction.
- Decreasing SG pressure will: reduce steaming due to SG density changes, and reduce SG concentration due to SG density changes.
- Reducing the steam generator tube leakage Technical Specification from the current 1 GPM to 0.3 GPM will reduce secondary activity levels.

After key inputs from the radiological consequences calculation from the recent set of (non-LOCA) analyses were compared to the at 89% core power with 42% SGTP analyses, it was found that there were no dose violations in accordance to 10CFR100 limits. The radiological dose calculations from the current analysis of records for the above mentioned transients remain valid at 89% core power with 42% SGTP.

5.4.9 References

5.4-1. Letter No. L-2005-004 from William Jefferson (FPL) to the NRC Document Control Desk, "Supplemental Information Alternate Source Term (AST) License Amendment," dated January 7, 2005.

5.4-2. "St. Lucie Unit 2 Updated Final Safety Analysis Report," Amendment 16, Docket No. 50-389.

5.4-3. "St. Lucie Unit 2 Technical Specifications," Amendment 138, Docket No. 50-389.

Table 5.4-1 Parameters Unaffected By Tube Plugging
Parameter
Atmospheric Dispersion Factor, 0-2 Hour Exclusion Area Boundary
Atmospheric Dispersion Factor, 0-8 Hour Low Population Zone
Iodine Spiking Factor
Iodine Partitioning at Steam-Liquid Interface
Breathing Rate
Dose Conversion Factors
Technical Specification Primary Iodine Activity
Technical Specification Secondary Iodine Activity
Technical Specification Noble Gas Activity

Table 5.4-2
Parameters Affected By Tube Plugging and Reduced Power

100% Power & 0-1500 Plugged SG Tubes		89% Power & 42% Plugged SG Tubes (Table 5.1.0-3)	
Parameter	**Value**	**Parameter**	**Value**
Core Power (MWt)	2700	Core Power (MWt)	2404
RCS Flow (gpm)	335,000	RCS Flow (gpm)	300,000
HFP T_{COLD} (°F)	549.0	HFP T_{COLD} (°F)	547.1
Minimum SG Pressure (psia)	810	Minimum SG Pressure (psia)	732

Table 5.4-3
Sensitivity of Flashing Fraction to RCS Temperature

SG Pressure (psia)	Saturated Enthalpy - Vapor (BTU/lbm)	Saturated Enthalpy - Liquid (BTU/lbm)	T_{COLD} (°F)	RCS Pressure (psia)	Leak Enthalpy (BTU/lbm)	Flashing Fraction (%)
800	1199.30	509.90	549.0	2250	545.96	5.23%
			547.1		543.60	4.89%
			546.0		542.25	4.69%

Table 5.4-4 Sensitivity of Steam Flow to SG Pressure				
100% Power & 0-1500 Plugged SG Tubes		89% Power & 42% Plugged SG Tubes		Reduction in Steam Flow (%)
SG Pressure (psia)	H_{FG} (BTU/lbm)	SG Pressure (psia)	H_{FG} (BTU/lbm)	
900	669.375	850	679.301	1.4829
800	689.4	750	699.698	1.4938
700	710.218	650	721.001	1.5183

Table 5.4-5 Sensitivity of Steam Generator Liquid Mass to SG Pressure				
100% Power & 0-1500 Plugged SG Tubes		89% Power & 42% Plugged SG Tubes		Increase in SG Liquid Mass (%)
SG Pressure (psia)	Density (lbm/ft^3)	SG Pressure (psia)	Density (lbm/ft^3)	
900	47.0813	850	47.4842	0.8558
800	47.8956	750	48.3166	0.879
700	48.7487	650	49.1937	0.9128
Note that the impact of having a different steam generator mass which is discharged through a break is dealt with in the specific event section later in this report.				

Table 5.4-6 Sensitivity of Flashing Fraction to SG Pressure						
SG Pressure (psia)	Saturated Enthalpy - Liquid (BTU/lbm)	Saturated Enthalpy - Vapor (BTU/lbm)	T_{COLD} (°F)	RCS Pressure (psia)	Leak Enthalpy (BTU/lbm)	Flashing Fraction (%)
810	511.645	1199.01	549.0	2250	545.96	4.99%
732	497.669	1201.12				6.86%
724	496.185	1201.32				7.06%

APPENDIX A

EVALUATIION of 42% SG TUBE PLUGGING

ON INSTALLED ALLOY 800 SLEEVES

Evaluation of 42% SG Tube Plugging on Installed Alloy 800 Sleeves

A.1 Introduction

WCAP-15918-P, Reference 1, establishes the structural and licensing basis for Alloy 800 steam generator tube sleeves installed in Westinghouse and CE-designed steam generators with 3/4-inch tubing. Installation of sleeves reduces the flow area available to the primary coolant, thus consideration must be given to the total quantity of sleeves and plugs installed in a steam generator. The St. Lucie Unit 2 Steam Generator (SG) plugging level may exceed 30% in the next refueling outage resulting in operating conditions potentially exceeding the current differential operating pressure between primary and secondary pressure (e.g., ΔP = 1460 psi). The evaluation summarized below assumes that both sleeves and plugs are installed during the St. Lucie Unit 2 Cycle 16 refueling outage such that the combination of sleeves and plugs is equivalent to 42% plugging.

The table on page 3-1 (Section 3.0 Acceptance Criteria) of Reference 1 was updated (see Table A-1) to present the operating, design, and accident conditions for both the CE Plants discussed in Reference 1 and for St. Lucie Unit 2 with 42% SGTP.

A.2 Technical Basis

Section 8.1.1 of Reference 1 calculates the tentative pressure thickness required per Paragraph NB-3324.1 of the ASME Pressure Vessel Code, Section III to determine the minimum wall thickness required for the Alloy 800 tube sleeves. The minimum wall thickness is based on the design value of primary pressure and is unaffected by the 42% tube plugging program.

Section 8.1.2 of Reference 1 calculates the maximum sleeve loads from accident conditions and assumes a maximum primary to secondary differential pressure of 2520 psi for a main steam line break and 2850 psi for a feedwater line break. In both cases, these loads are well below the acceptance criterion and have a safety factor in excess of 2.5. A review of these accidents for the 42% tube plugging program shows that the feedwater line break is limiting and results in limiting pressures less than those analyzed in Reference 1. Loads on the Alloy 800 sleeves resulting from a LOCA are based on the maximum secondary to primary differential pressure of the secondary side design pressure minus the zero primary pressure, and are less than the loads occurring during normal operation. Hence, the faulted loads calculated in Reference 1 remain bounding for the 42% tube plugging program.

The minimum operating steam generator pressure for the 42% tube plugging program will be 724 psia. This pressure is less than the value assumed, 790 psia, in Section 8.2.1 of Reference 1. This results in a differential operating pressure of 1526 psi vs. the 1460 psi value discussed earlier. Therefore, the allowable sleeve wall degradation will be slightly lower (by approximately 3%) than that described in WCAP-15918 but remains in excess of the 45% detection level described in Section 5.1 of that report. The lower secondary pressure will also reduce the allowable degradation in the parent tube. Nevertheless, this degradation is still in excess of the 50% detection level demonstrated for the tube in the region of the sleeve roll/expansion joints. Any defects in the sleeved region are plugged on detection, thus the allowable degradation calculated in WCAP-15918 provides a guide to assess the eddy current detectability limit. Since all tubes will have a plus-point examination of the roll/expansion joint zones before sleeving, there will be no detectable defects in these regions when the sleeve is installed. Hence the probability of a crack growing to a point where it could leak

within one cycle, to which the tubesheet sleeves are limited, is minimal. It is therefore concluded that the reduction in secondary pressure resulting from 42% tube plugging is inconsequential when compared with the conclusions of Reference 1.

The maximum axial load on the tube/sleeve assembly results from differential thermal expansion during normal operation. WCAP-15918 assumed a primary steam generator inlet temperature (T-hot) of 611°F and a secondary fluid temperature of 506°F. For the 42% tube plugging program, T-hot is 600.8°F and the respective secondary fluid temperature is 506.9°F, resulting in a maximum temperature difference of 93.9°F, which is less than that evaluated in Reference 1. As a result, the axial loads resulting from thermal expansion calculated in Reference 1 bound those loads that would occur for the 42% SGTP program.

Although the 42% tube plugging program will result in higher secondary fluid velocities, a sleeved tube is stiffer and therefore less susceptible to vibration than a virgin tube. Since the vibration analysis documented in Section 8.4 of Reference 1 is acceptable, the sleeved tube will also have acceptable vibration characteristics.

A.3 Conclusion:

Evaluation of the Alloy 800 sleeve rolled joints is based on qualification testing that bounds the 42% tube plugging program. Based on a review of these conditions, Westinghouse concludes that the design of the Alloy 800 sleeve in the Reference 1 bounds the operating conditions applicable to the 42% tube plugging program at St. Lucie Unit 2. Hence, the sleeve design of Reference 1 remains applicable to, and bounds the operating conditions for, the 42% tube plugging program.

A.4 Reference

A-1 WCAP 15918-P, Rev. 02, Steam Generator Tube Repair for Combustion Engineering and Westinghouse Designed Plants with 3/4 Inch Inconel 600 Tubes Using Leak Limiting Alloy 800 Sleeves, July 2004.

Table A-1
Alloy 800 SG Sleeving
Operating, Design & Accident Conditions

	All CE Plants		**St. Lucie Unit 2 with 42% SGTP**	
Primary Side	608.6°F (operating)	2250 psia (operating)	600.8°F (operating)	2250 psia (operating)
	650°F (design)	2500 psia (design)	650°F (design)	2500 psia (design)
Secondary Side	505.8°F (operating)	790 psia (operating)	506.9°F (operating)	724 psia (operating)
	560°F (design)	1100 psia (design)	560°F (design)	1100 psia (design)
Accident Conditions	Primary to Secondary Δ Pressure	2520 psi (MSLB) 2560 psi (FLB) Note 1	Primary to Secondary Δ Pressure	2520 psi (MSLB) 2560 psi (FLB) Note 1
	Secondary to Primary Δ-Pressure	1170 psi (LOCA)	Secondary to Primary Δ Pressure	1170 psi (LOCA)

Note 1: From Reference 1, the FLB pressure differential for the Westinghouse "D" and "E" Plants is 2850 psi., which was used in the Section 8.1.2 stress calculations.