5.7.1.1.3 Description of Analyses and Evaluations

The structural evaluations are based on the results of structural analysis performed at 3425 MWt for the steam generators at Byron Unit 1 and Braidwood Unit 1. The following primary and secondary side design conditions apply:

1. Uprated NSSS power of 3600.6 MWt.
2. RCS vessel average temperature window of 577°F to 588.2°F
3. Maximum SGTP level up to 5%
4. Full power feedwater temperature of 446.6°F
5. Maximum and minimum steam pressure of 1024 psia and 913 psia.

The design and transient parameters evaluated in the previous analysis (3425 MWt) and those established for the uprate (3600.6 MWt) were compared for differences that could affect steam generator structural integrity. Differences in transients were reviewed for their impact on the design analysis, and conservative ratios were used to modify the previous analysis results to determine stresses and cumulative fatigue usage factors for the uprated conditions.

Structural evaluation of critical components in the replacement steam generators was used as the basis to justify operation at uprated conditions. The evaluations were performed to the requirements of the ASME Boiler and Pressure Vessel Code Section III, 1986 edition with no addenda, Reference 1.

5.7.1.1.4 Acceptance Criteria

The structural evaluations are based on the results of the previous structural analysis of the RSGs at a NSSS power level of 3425 MWt where the acceptance criteria for ASME Code Section III Class 1 components were met. Where load increases occurred for a power uprate to 3600.6 MWt, the replacement steam generator components were shown to still meet the acceptance criteria for ASME Code Section III Class 1 components.

5.7.1.1.5 Results

For ASME Code Design, Hydrotest and Level C and D Service Loading Conditions, the loads used in the previous analysis were found to be the same or to bound the loads developed for 5% power uprate conditions. For ASME Code Level A and B Service Conditions, the loads used in the previous analysis were found to be the same or to bound the loads developed for 5% power uprate conditions except for the feedwater temperature variation. For the affected RSG components (main and auxiliary feedwater nozzle), the stresses were prorated by the feedwater temperature variation and the fatigue usage factor recalculated. The new stresses and fatigue usage factors were less than the ASME Code acceptance criteria. The updated structural reports show that the ASME Code acceptance criteria for Level A and B Service Conditions were met for the RSGs at the 5% power uprate condition. Tables 5.7.1.1-2 to 5.7.1.1-5 summarize the results.

5.7.1.1.6 Conclusions

Results of the analyses performed on the Byron Unit 1 and Braidwood Unit 1 RSGs show that the ASME Code Section III limits are met at the uprated conditions (3600.6 MWt) for up to 5% steam generator tube plugging.

5.7.1.1.7 References

1. ASME Boiler and Pressure Vessel Code Section III, "Rules for the Construction of Nuclear Vessels," 1986 Edition, The American Society of Mechanical Engineers, New York, New York.

Table 5.7.1.1-1 Full Power Operating Conditions for RSG Structural Qualification at 5% Power Uprate	
NSSS Power Per SG, MWt	900.15
RCS Inlet Temperature, °F	608.0-618.4
RCS Outlet Temperature, °F	545.9-558
RCS Avg Temperature, °F	577-588.2(5)
RCS Pressure, psia	2250
RCS Flow (gpm)	99200(1) , 98289(2)
Steam Pressure (psia)	913(3) -1024(4)
Steam Temperature °F	533.7(3) -547.5(4)
Steam Flow (x 10^6lbm/hr)	4.0
Feedwater Temperature, °F	446.6
Feedwater Flow (x 10^6lbm/hr)	4.04
Zero Load Reactor Coolant Temperature °F	557
Zero Load Secondary Side Temperature °F	557

Notes:

1. The RCS flow of 99200 gpm is the best estimate flow at beginning of life (startup) conditions (0% tube plugging).
2. The RCS best estimate flow at end of life conditions (5% plugging) is 98289 gpm and therefore the above numbers may vary slightly from the PCWG values.
3. Steam pressure and saturated temperature for end-of-life conditions (5% tube plugging, 0.00005 °F-hr-ft2/Btu tube OD fouling) using best estimate flow.
4. Steam pressure and saturated temperature for beginning-of-life conditions (0% tube plugging, 0.00002 °F-hr-ft2/Btu tube OD fouling) using best estimate flow
5. RCS average temperature is based on the best estimate RCS flow and not the PCWG thermal design flow.

Table 5.7.1.1-2 Primary Side Components: Stress Intensity/Allowable for Design, Emergency, Faulted & Test Conditions				
Component	**Design[1]**	**Emergency[2]**	**Faulted[3]**	**Test[4]**
Primary Manway Pad/Shell	0.76	0.37 (P_L)	0.25 (P_L)	Bounded by Design
Primary Manway Bolts	0.8	0.96	0.61	-
Divider Plate	-	-	0.9 (P_m)	-
Primary Nozzle	0.82 (P_L+P_B)	Bounded by Design	0.92 (P_m)	Bounded by Design
Tubesheet and Shell Junction	0.97 (P_L+P_B)	0.75 (P_L+P_B)	0.77 (P_L+P_B)	0.78 (P_L+P_B)
Tubes	0.85 (P_m)	0.64 (P_m)	0.55 (P_m)	0.83 (P_m)
Support Pads	0.73 (P_L+P_B)	Bounded by Design	0.64 (P_L+P_B)	Bounded by Design

[1] Design Condition Limits: $P_M \leq S_M$; P_L, $P_L + P_B \leq 1.5\ S_M$

[2] Emergency Condition Limits: $P_M \leq$ Greater of (1.2 S_M, S_Y) P_L, $P_L + P_B \leq 1.5$ (Greater of (1.2 S_M, S_Y))

[3] Faulted Condition Limits: $P_M \leq$ Lesser of (2.4 S_M, 0.7S_U) P_L, $P_L + P_B \leq 1.5$ (Lesser of (2.4 S_M, 0.7S_U))

[4] Test Condition Limits: $P_M \leq 0.9S_Y$; P_L, $P_L + P_B \leq 1.35\ S_Y$

Table 5.7.1.1-3 Primary Side Components: Maximum Stress Intensity Range/Allowable, and Cumulative Fatigue Usage Factors for Normal/Upset Conditions					
Component	**Section or Location**	**Maximum Stress Range/ Allowable (Baseline)**	**Maximum Stress Range/ Allowable (Uprated)**	**Fatigue Usage Factor (Baseline)**	**Fatigue Usage Factor (Uprated)**
Primary Manway Pad/Shell	Cover	0.38	0.38	0.006	0.006
	Juncture	0.57	0.57	0.121	0.121
Primary Manway Bolts	-	0.8	0.8	0.871	0.871
Divider Plate	Drain Hole	0.45	0.45	0.904	0.904
	Fillet	0.91	0.91	0.039	0.039
Primary Nozzle	-	0.85	0.85	0.213	0.213
Tubesheet and Shell Junction	Juncture	0.98	0.98	0.741	0.741
	Tubesheet	0.96	0.96	0.387	0.387
Tubes	-	0.92	0.92	0.19	0.19
Acoustic Sensor Pad Location	-	-	-	0.839	0.839
Support Pads	-	0.99	0.99	0.670	0.670

Table 5.7.1.1-4

Secondary Side Components: Stress Intensity/Allowable for Design, Emergency, Faulted & Test Conditions

Component	Design[1]	Emergency[2]	Faulted[3]	Test[4]
Main Feedwater Nozzle	0.95 (P_L)	0.70 ($P_L + P_B$)	0.99 ($P_L + P_B$)	Bounded by Design
Auxiliary Feedwater Nozzle	0.93 (P_L+P_B)	0.97 (P_m)	0.99 ($P_L + P_B$)	Bounded by Design
Steam Outlet Nozzle	0.94 (P_L+P_B)	Bounded by Design	0.72 (P_L+P_B)	Bounded by Design
Secondary Shell/Transition Cone	0.99 (P_m)	Bounded by Design	0.72 ($P_L + P_B$)	Bounded by Design
Secondary Manway Cover, Pad, Shell	0.73 (P_L+P_B)	Bounded by Design	0.84 (P_M)	Bounded by Design
Secondary Manway Bolts	0.65	0.74	0.35	Bounded by Design
2.0 inch Inspection Port Opening	0.49	Bounded by Design	0.97 (P_M)	Bounded by Design
6.0 inch Hand Hole	0.78	0.72 ($P_L + P_B$)	0.62 (P_M)	Bounded by Design
8.0 inch Hand Hole	0.82	0.67 ($P_L + P_B$)	0.72 (P_M)	Bounded by Design
Small Nozzles	0.78 (P_M)	Bounded by Design	0.95 ($P_L + P_B$)	Bounded by Design

Table 5.7.1.1-5 Secondary Side Components: Cumulative Fatigue Usage Factors for Normal/Upset Conditions			
Component	**Section or Location**	**Fatigue Usage Factor (Baseline)**	**Fatigue Usage Factor (Uprated)**
Main Feedwater Nozzle	Transition Ring/Thermal Sleeve	0.945	0.967
Auxiliary Feedwater Nozzle	Transition Ring	0.929	0.970
Secondary Shell and Transition Cone	Cone/Lower Shell	0.021	0.021
Steam Outlet Nozzle	Shell Juncture	0.035	0.035
Secondary Manway	Shell	0.004	0.004
Secondary Manway Bolts	Bolt	0.752	0.752
2.0 inch Inspection Port Opening	Shell	0.205	0.205
	Bolt	0.807	0.807
6.0 inch Hand Hole	Shell	0.374	0.374
	Bolt	0.842	0.842
8.0 inch Hand Hole	Shell	0.222	0.222
	Bolt	0.975	0.975
Small Nozzles	-	0.938	0.938

5.7.1.2 Hardware Evaluation

5.7.1.2.1 Introduction

Evaluations were performed to determine the impact of the uprating conditions on the steam generator hardware, consisting of tube weld plugs, installed during fabrication.

5.7.1.2.2 Input Parameters and Assumptions

The input parameters used for the steam generator structural evaluation are given in Table 5.7.1.1-1.

5.7.1.2.3 Description of Analyses and Evaluations

The structural evaluations are based on the results of structural analysis of steam generators at Byron Unit 1 and Braidwood Unit 1 performed at 3425 MWt. The design loading and transient loadings for 3425 MWt were compared to those for 5% power uprate conditions.

5.7.1.2.4 Acceptance Criteria

ASME Code acceptance criteria are met if the power uprate loads are shown to be the same or bounded by the loads for the previous analysis performed at 3425 MWt. Where load increases occurred for a power uprate to 3600.6 MWt, the welded tube plugs were shown to still meet the ASME Code acceptance criteria.

5.7.1.2.5 Results

The comparison of the loadings indicated that the power uprate loads were that same as or bounded by the loads for 3425 MWt. Thus the ASME Code acceptance criteria are met for the tube plugs installed during RSG fabrication.

5.7.1.2.6 Conclusions

The ASME Code acceptance criteria are met for the tube plugs installed during RSG fabrication for the 5% power uprate conditions.

5.7.1.2.7 References

None.

5.7.1.3 Thermal Hydraulic Evaluation

5.7.1.3.1 Introduction

Secondary side steam generator performance characteristics such as circulation ratio, moisture carryover, hydrodynamic stability, heat flux and others are affected by increased thermal power and changes in steam pressure. Steam pressure, in turn, is determined by the power as well as primary temperature and tube plugging level.

5.7.1.3.2 Input Parameters and Assumptions

Applicable design parameters for operation at uprated conditions were used for the thermal-hydraulic evaluation. The input parameters used for the steam generator performance evaluation are given in Table 5.7.1.3-1.

5.7.1.3.3 Description of Analyses and Evaluations

Steam generator thermal-hydraulic operating characteristics were calculated using the CIRC Code. This Code calculates steady state thermal hydraulic performance for steam generators.

5.7.1.3.4 Acceptance Criteria

Where applicable, acceptance criteria are contained in the individual assessments in the results section.

5.7.1.3.5 Results

The secondary side operating characteristics for the current design and uprated operating conditions were compared to determine the impact of the uprated parameters. A summary is provided below.

Circulation Ratio - The circulation ratio is a measure of bundle liquid flow in relation to steam flow. The increase in power for the uprate (from 3425 MWt to 3600.6 MWt) causes the circulation ratio to decrease by approximately 9%. Bundle liquid flow minimizes accumulation of contaminants on the tube sheet and in the bundle. The small change in bundle liquid flow due to the uprating has minimal effect on this function.

Hydrodynamic Stability - The steam generator was evaluated for static and dynamic hydrodynamic stability at the 5% power uprate conditions. Hydrodynamic stability can be evaluated by showing that if the single-phase losses within the circulating loop are greater than 20% of the two-phase losses then the circulation is stable. The ratio of single-phase losses to two-phase losses is 0.45 (45%); and therefore, the steam generators remain hydrodynamically stable for 5% power uprate conditions.

Steam Generator Mass - As power increases, the circulation ratio decreases, resulting in a higher void fraction in the tube bundle. This change results in a 5% decrease in secondary side fluid mass due to power uprate. This small decrease in secondary mass has no significant effect on steam generator performance.

Peak Heat Flux - Peak heat flux will increase with power and tube plugging. For power uprating, the increased total heat load is passed through the same bundle heat transfer area, increasing the heat flux. For increased plugging, the same heat load is passed through a smaller heat transfer area, also increasing the heat flux. For the power uprate, the peak heat flux decreases since the increase in power is offset by the decrease in maximum tube plugging (20% for 3425 MWt versus 5% for 3600.6 MWt). The heat flux levels remain within the range of operating experience and are well below any nucleate boiling limits.

Steam Generator Pressure Drop - The steam generator total secondary pressure drops are seen to increase by less than 2 psi for 5% power uprate. These pressure drop increases represent a small fraction of the total feed circuit pressure drop and are not expected to have any effect on operation of the steam generators.

Moisture Carryover - Based on experimental data for prototype moisture separators, the moisture carryover is predicted to be below 0.1% for the replacement steam generators at Byron Unit 1 and Braidwood Unit 1 for power uprate conditions.

5.7.1.3.6 Conclusions

Based on the evaluation for uprated power, it is concluded that the thermal-hydraulic operating characteristics of the steam generators are within acceptable ranges and will not be adversely affected by the uprated conditions.

5.7.1.3.7 References

None.

Table 5.7.1.3-1

Thermal-Hydraulics Performance Parameters

105% Power NSSS Parameters	Startup (Beginning- of-Life Conditions)	Design (End-of–Life Conditions)
Power (MWt) (Note 1)	900.15	900.15
Reactor Coolant Pressure (psia)	2250	2250
RCS T_{hot} Temperature (°F)	608.0-618.4	608.0-618.4
RCS T_{cold} Temperature (°F)	546.5-558.0	545.9-557.5
RCS T_{avg} Temperature (°F) (Note 2)	577.3-588.2	577.0-587.9
RCS Thermal Design Flow (gpm/loop)	92000	92000
RCS Mechanical Design Flow (gpm/loop)	107000	107000
RCS Best Estimate Flow (gpm/loop)	99200	98289
Feedwater Temperature (°F)	446.6	446.6
Blowdown Flow (lbm/hr)	45000	45000
Tube Plugging (%)	0	5
Tube fouling (OD, °F-hr-ft^2/Btu)	0.00002	0.00005
Zero Power Reactor Coolant Temperature (°F)	557	557

Notes:

1. NSSS power per steam generator.
2. All thermal-hydraulic performance evaluation were based on the RCS best estimate flow and, therefore, the above numbers may vary slightly from the PCWG values.
3. The normal operating water level setpoint is 60% of the span of the narrow range water level taps. This water level applies for 0% to 100% reactor power.

5.7.1.4 Tube Degradation

Corrosion degradation of steam generator tubing has taken several forms: wastage, pitting, primary water stress corrosion cracking [PWSCC], and secondary side (outside diameter) stress corrosion cracking [ODSCC]. These forms of corrosion are influenced by several factors directly related to output power.

- temperature
- stress [differential thermal and differential pressure]
- heat flux [average and local]

An increase in any of these factors may have an adverse effect on corrosion degradation. The window for operating conditions at 5% power uprate (3600.6 MWt) is the same as or bounded by the window for operating conditions (3425 MWt) previously evaluated. For example, the maximum primary side T_{hot} (most important parameter with respect to tube degradation) is 618.4°F for both 3425 MWt and 3600.6 MWt. Hence, it is reasonable to state that the corrosion performance of tubing will be acceptable under the uprated conditions. The following paragraphs address the various forms of corrosion.

<u>Wastage and Pitting</u>

Wastage or pitting of tubing does not occur under normal secondary side water chemistry conditions. However, such corrosion is possible under deposits or in creviced regions where concentrated solutions can develop. Heat flux in particular exerts a significant influence on the degree of chemical concentration; however, a large change in heat flux would be necessary to produce a noticeable change in the potential for localized corrosion. Thus, the change in heat flux associated with a 5% power uprating is judged to have an insignificant effect on the potential for wastage or pitting.

<u>ODSCC and PWSCC</u>

Stress corrosion cracking [SCC] is a strong function of temperature. Since the maximum primary side T_{hot} 618.4°F is the same for both 3425 MWt and 3600.6 MWt, the potential for corrosion has not increased for the T_{hot} window defined for the 5% power uprate. The RSGs use alloy 690 tubing which has shown good resistance to both ODSCC and PWSCC.

SCC is also a strong function of stress. At startup (beginning-of-life with no tubes plugged), the operating primary-to-secondary side pressure difference is smaller (due to the higher operating T_{hot} value) and primary-to-secondary side temperature difference is higher (due to increased thermal power output) at the 5% power uprate conditions than for the operating conditions at 3425 MWt power level. The small increase in stress that could result from 5% power uprate would have a relatively small influence on the cracking rate compared to the temperature effect noted above. Because of the high SCC resistance of alloy 690, this effect is deemed negligible.

Power uprating will have no effect on the environment for PWSCC, but could increase the severity of environments for ODSCC. As noted for wastage and pitting, the expected change due to increased heat flux is relatively small. Coupled with the generally high SCC resistance of alloy 690, this effect is also deemed to be negligible.

Based on the review of the uprated power conditions on ODSCC and PWSCC in the Byron and Braidwood Unit 1 SGs, there is no significant impact due to the uprating.

5.7.1.5 U-Bend Fatigue Evaluation

5.7.1.5.1 Introduction

The potential for vibration in the U-bends (including the small radius U-bends) due to fluid elastic instability at the power uprate conditions was assessed. The tubes were also evaluated for fatigue at 5% power uprate conditions.

5.7.1.5.2 Input Parameters and Assumptions

The input parameters used for the steam generator flow induced vibration evaluation are given in Table 5.7.1.3-1. The input parameters used for the steam generator design and transient evaluation are given in Table 5.7.1.1-1.

5.7.1.5.3 Description of Analyses and Evaluations

For the flow induced vibration analysis, flow conditions for power uprate condition were simulated by the three-dimensional thermal-hydraulic analysis code ATHOSBWI. The code EasyFIV was used to determine the tube vibration response due to fluidelastic instability, vortex shedding resonance, and random turbulence excitation. For the design and transient loadings, the tubes were evaluated for 5% power uprate conditions as detailed in section 5.7.1.1.

5.7.1.5.4 Acceptance Criteria

For the flow induced vibration analysis, the fluid velocities were compared to the critical velocity ratio. For the fatigue evaluation, the fatigue usage factor was compared to the ASME Code acceptance criteria for Section III Class 1 components.

5.7.1.5.5 Results

The flow induced vibration evaluation at the fluid velocities for 5% power uprate conditions were less than the critical velocity ratio.

The fatigue evaluation of the tubes at 5% power uprate conditions resulted in a fatigue usage factor less than the ASME Code Subsection NB acceptance criteria. There was no increase in the cumulative fatigue usage factor for the power uprate (3600.6 MWt) since the loads were the same or bounded by the loads used in the previous analysis for a power level of 3425 MWt.

5.7.1.5.6 Conclusions

The conclusion of the flow induced vibration analysis is that the tubes are adequately supported for the prevention of detrimental flow-induced vibration over the full range of operating conditions at 5% power uprate conditions.

5.7.1.5.7 References

None.

5.7.1.6 Tube Wear from Support Structures

5.7.1.6.1 Introduction

Wear analysis of the RSGs has been performed to assess the impact of power uprate on support structure wear on steam generator tubes. The RSGs are shown to be of a design that has adequate resistance to tube wear.

5.7.1.6.2 Input Parameters and Assumptions

The input parameters used for the steam generator tube wear evaluation are given in Table 5.7.1.3-1.

5.7.1.6.3 Description of Analyses and Evaluations

In order to qualify tube wear rates for the U-bend region of the Byron 1/Braidwood 1 RSGs, a comparative method which presents normalized relative tube wear rates for various designs was used. The Byron 1/Braidwood 1 RSGs are compared against BWI designs as well as others operating in the field today, including both designs which have seen some tube fretting wear and some which have no evidence of fretting wear.

5.7.1.6.4 Acceptance Criteria

For the 5% power uprate conditions, the acceptance criteria was to show that the normalized relative tube wear rates had not increased from the previous power level of 3425 MWt.

5.7.1.6.5 Results

The susceptibility of wear is reduced at 5% power uprate conditions due to a lower circulation ratio and the increase in steam pressure caused by the increase in the nominal RCS average temperature.

5.7.1.6.6 Conclusions

Since the relative susceptibility for fretting wear is lower at 5% power (3600.6 MWt) uprate conditions than it is for 100% power (3425 MWt) conditions, the RSGs are expected to continue to operate without significant wear at either 100% power or 5% power uprate conditions.

5.7.1.6.7 References

None.

5.7.2 D5 Steam Generators

5.7.2.1 Structural Evaluation

5.7.2.1.1 Introduction

Uprating of Byron Unit 2 and Braidwood Unit 2 to 3600.6 MWt Nuclear Steam Supply System (NSSS) power will incorporate SG tube plugging (SGTP) from 0% to 10% in any SG. The power uprating will also include operation at high and low Reactor Coolant System (RCS) temperature conditions. These parameters were used for the SG structural evaluations at power uprated conditions.

5.7.2.1.2 Input Parameters and Assumptions

The PCWG parameters used for the SG structural evaluations are given in Section 2.0. Two sets of parameters were considered in the evaluation: high and low RCS temperatures. For primary side components, the bounding condition is that which results in the largest pressure differential between primary and secondary sides of the SG. For secondary side components, the bounding condition is that which results in the highest secondary side pressure.

The NSSS transients applicable to the power uprating conditions are provided in Section 3.0.

5.7.2.1.3 Descriptions of Analyses and Evaluations

The structural evaluations are based on the results of plant-specific structural analysis of steam generators at Byron Unit 2 and Braidwood Unit 2. The following primary and secondary side design conditions apply:

1. Uprated NSSS power of 3600.6 MWt
2. RCS vessel average temperature range of 575°F to 588°F
3. Westinghouse Model D5 SGs
4. Maximum SGTP level of 10%
5. Full power feedwater temperature of 446.6°F
6. Maximum and minimum nominal steam pressure of 953 psia and 827 psia, respectively

The design and transient parameters evaluated in both the design basis analysis and those established for the power uprate were compared for differences that could affect SG structural integrity. Differences in transients were reviewed for their impact on the design analysis. Conservative ratios, based on pressure range differences, were used to modify the original design analysis results to determine stresses and cumulative fatigue usage factors for the uprated conditions.

Structural evaluation of critical components in the Westinghouse Model D5 SGs was used to justify operation at uprated conditions. The evaluations were performed to the requirements of the ASME Boiler and Pressure Vessel Code Section III, 1971 edition with addenda through summer of 1972 (Reference 1).

Material strength properties from Reference 1 were used, except for those values not then available, which were taken from the 1986 edition (Reference 2).

The divider plate is a semi-circular plate welded to the SG tubesheet along the divider lane and to the inside surface of the channel head. Functionally it separates the primary coolant inlet and outlet chambers. It is not a pressure-retaining component and, as such, does not require a rigid Code analysis. The stress intensity ranges calculated elastically exceed the 3 S_m limits. Per paragraph NB-3228.1 of the ASME Code (Reference 1), a plastic analysis can be performed provided a shakedown is demonstrated. The tubesheet and channel head deformations drive the deformation in the divider plate and a shakedown does occur.

A simplified plastic analysis has been performed using techniques of Reference 3. This involved application of a modified Poisson's ratio, which is related to the yield strain and the alternating strain (half the strain range between the transients). The strain ranges were obtained from inelastic analyses. These strain ranges were amplified by scaling factors corresponding to the power uprating effects. From these strain ranges, elastic stress ranges were estimated and a fatigue evaluation performed. It was shown that the fatigue usage factor at the critical location (drain hole) would increase from 0.169 to 0.194 due to power uprating.

5.7.2.1.4 Acceptance Criteria

The primary and secondary side components were evaluated for the effects of changes to the thermal transients due to the power uprate. The acceptance criteria for each component are consistent with the criteria used in the design basis analysis for that component. The primary stresses were not affected by the power uprating. The maximum range of primary plus secondary stresses were compared with the corresponding $3S_m$ limits in the ASME Code. Where these limits were exceeded (as is the case with the divider plates), simplified elastic-plastic analyses were performed per NB 3228.1 of the ASME Code. The cumulative fatigue usage factor will remain below unity, thereby demonstrating adequacy for cyclic operation over a 40-year design life.

5.7.2.1.5 Results

Comparisons of primary side transients and RCS parameters were performed to determine scaling factors to apply to the baseline analyses for maximum stress range and fatigue usage factors. For primary side components, the scaling factors are ratios of primary to secondary pressure differentials for baseline and uprated scenarios, and they have been calculated over the entire time span of the applicable transients. The scaling factors are listed in Table 5.7.2.1-1. The primary stress analyses are unchanged from the baseline values and are listed in Table 5.7.2.1-3. Fatigue evaluations for these components are listed in Table 5.7.2.1-4.

Comparisons of secondary side transients and RCS parameters were performed to determine scaling factors to apply to the baseline analyses for maximum stress range and fatigue usage factors. For secondary side components, the scaling factors are ratios of secondary pressures for baseline and uprated scenarios, and have been calculated over the entire time span of the applicable transients. The scaling factors are listed in Table 5.7.2.1-2. The primary stress analyses are unchanged from the baseline values and are listed in Table 5.7.2.1-5. Fatigue evaluations for these components are listed in Table 5.7.2.1-6.

5.7.2.1.6 Conclusions

Results of the analyses performed on the Byron Unit 2 and Braidwood Unit 2 Westinghouse Model D5 SGs show that the ASME Code Section III limits are met at the power uprated conditions with up to 10 percent SG tube plugging.

5.7.2.1.7 References

1. ASME Boiler and Pressure Vessel Code Section III, "Rules for the Construction of Nuclear Vessels," 1971 Edition plus Addenda through Summer 1972, and Selected

Paragraphs of Winter 1974, The American Society of Mechanical Engineers, New York, New York.

2. ASME Boiler and Pressure Vessel Code Section III, "Rules for the Construction of Nuclear Vessels," 1986 Edition, The American Society of Mechanical Engineers, New York, New York.

3. B. F. Langer, "Design of Vessels Involving Fatigue," Chapter 2 of Pressure Vessel Engineering Technology, (R. W. Nichols, Editor), Elsevier Publishing Company, 1971.

Table 5.7.2.1-1

Power Uprating Scaling Factor Summary for Primary Side Components

Transient	Scale Factor
Unit Loading (15% - 100%)	1.149
Unit Unloading (100% - 15%)	1.141
Loading (0% -15%)	1.019
Unloading (15% - 0%)	1.019
Large Step Load Decrease with Steam Dump (100% - 5%)	1.141
Loss of Load	1.141
Inadvertent RCS Depressurization	1.141

Table 5.7.2.1-2 Power Uprating Scaling Factor Summary for Secondary Side Components	
Transient	**Scale Factor**
Unit Loading (15% - 100%)	1.079
Unit Unloading (100% - 15%)	1.097
Loading (0% -15%)	1.000
Unloading (15% - 0%)	1.000
Large Step Load Decrease with Steam Dump (100% - 5%)	1.078
Loss of Load	1.068
Inadvertent RCS Depressurization	1.068

Table 5.7.2.1-3 Primary Side Components: Stress Intensity/Allowable for Design, Emergency, Faulted & Test Conditions					
Component	**Design[1]**	**Emergency[2]**	**Faulted[3]**	**Test[4]**	**Comments**
Primary Manway Pad/Shell	0.51 (P_L)	0.29 (P_L)	0.25 (P_L)	0.41 (P_L)	Drain Hole is the critical location
Primary Manway Bolts	0.81	0.62	0.56	-	
Divider Plate	-	-	0.64 (P_m)	-	Non Pressure Boundary
Primary Nozzle	0.82	0.37	0.80	0.53	
Tubesheet and Shell Junction	0.85 (P_L+P_B)	0.65 (P_L+P_B)	0.67 (P_L+P_B)	0.97 (P_L+P_B)	Tubesheet Center
Tubes	0.97 (P_L+P_B)	0.67 (P_m/P_L)	0.95 (P_m/P_L)	0.91 (P_m/P_L)	
Tube to Tubesheet Weld	0.48 (P_M/P_L)	0.49 (P_M/P_L)	0.41 (P_M/P_L)	0.73 (P_M/P_L)	Location at 28° from vertical
Primary Chamber Drain	0.77 (P_M/P_L)	0.44 (P_M/P_L)	0.41 (P_M/P_L)	-	
Support Pads	0.61 (P_L+P_B)	0.61 (P_L+P_B)	0.82 (P_L+P_B)	0.5 (P_L+P_B)	At Channel Head Juncture

[1] Design Condition Limits: $P_M \le S_M$; P_L, $P_L + P_B \le 1.5\ S_M$

[2] Emergency Condition Limits: $P_M \le$ Greater of (1.2 S_M , S_Y). P_L, $P_L + P_B \le 1.5$ (Greater of (1.2 S_M , S_Y))

[3] Faulted Condition Limits: $P_M \le$ Lesser of (2.4 S_M , 0.7S_U). P_L, $P_L + P_B \le 1.5$ (Lesser of (2.4 S_M , 0.7S_U))

[4] Test Condition Limits: $P_M \le 0.9S_Y$; P_L, $P_L + P_B \le 1.35\ S_Y$

Table 5.7.2.1-4

Primary Side Components: Maximum Stress Intensity Range/Allowable, and Cumulative Fatigue Usage Factors for Normal/Upset Conditions

Component	Section or Location	Maximum Stress Range/ Allowable (Baseline)	Maximum Stress Range/ Allowable (Uprated)	Fatigue Usage Factor (Baseline)	Fatigue Usage Factor (Uprated)	Comments
Primary Manway Pad/Shell	Cover	0.30	0.34			
	Knuckle (Base Metal)	0.69	0.79	0.77	0.99	At Drain Hole
	Knuckle (Clad)	0.78	0.89			
Primary Manway Bolts		0.80	0.80	<1	<1	See Note 1
Divider Plate	Drain Hole			0.169	0.194	Plastic Analysis (see Note 2)
	Fillet			0.163	0.193	Plastic Analysis (see Note 2)
Primary Nozzle		0.91 (Near Safe End)	0.97 (Near Safe End)	<0.05 (In Shell)	0.075 (In Shell)	
Tubesheet and Shell Junction	Tubesheet Center	0.92	0.92	0.241	0.386	TS Center Upper Surface
T/TS Weld		-	-	0.32	0.379	Usage at Root
Primary Chamber Drain		0.78	0.85	0.47	0.59	Usage at Weld
Support Pads		0.81	0.81	0.455	0.684	

[1] Fatigue usage for the primary manway bolts exceeds 40 years based on test data for primary manway bolts.

[2] Per Section NB-3228.3 of ASME Code.

Table 5.7.2.1-5 Secondary Side Components: Stress Intensity/Allowable for Design, Emergency, Faulted & Test Conditions					
Component	**Design[1]**	**Emergency[2]**	**Faulted[3]**	**Test[4]**	**Comments**
Main Feedwater Nozzle	0.89 (P_L at D-D)	0.48 (P_L at D-D)	0.45 (P_L at D-D)	0.63 (P_L at D-D)	D-D is the knuckle
Auxiliary Feedwater Nozzle	0.69 (P_L+P_B @ Section 1)	0.76 (P_L at Section 1)	0.90 (P_L at Section 1)	0.23 (P_L at Section 1)	Section 1 is Nozzle to Adapter Weld
Steam Outlet Nozzle	0.53 (P_M at A-A)	0.27 (P_M at A-A)	0.53 P_L+P_B @ A-A	0.34 (P_M at A-A)	A-A is the minimum section
Secondary Shell/Transition Cone	1.00 (P_M at A-A)	0.50 (P_M at A-A)	0.49 (P_M at A-A)	0.67 (P_M at A-A)	A-A is on Upper Shell
Secondary Manway Cover, Pad, Shell	0.770 (P_M at A-A)	0.520 (P_M at A-A)	0.303 (P_M at A-A)	0.536 (P_M at A-A)	A-A is on the Shell
Secondary Manway Bolts	0.73	0.96	0.60	-	
6.0-inch Hand Hole	0.95 (P_M at A-A)	0.47 (P_M at A-A)	0.47 (P_M at A-A)	0.61 (P_M at A-A)	A-A is on the Shell
2.0-inch Instrumentation Opening	0.91 (P_M at A-A)	0.59 (P_M at A-A)	0.45 (P_M at A-A)	0.56 (P_M at A-A)	Section A-A is on Shell
2.5-in Access Opening	0.92 (P_M at A-A)	0.46 (P_M at A-A)	0.45 (P_M at A-A)	0.58 (P_M at A-A)	A-A is on the Shell
Small Bore Pipe taps	0.27 (P_M at H-H)	0.10 (P_M at H-H)	0.19 (P_M at H-H)	0.11 (P_M at H-H)	H-H is the minimum section

[1] Design Condition Limits: $P_M \leq S_M$; P_L, $P_L + P_B \leq 1.5\ S_M$

[2] Emergency Condition Limits: $P_M \leq$ Greater of ($1.2\ S_M$, S_Y), P_L, $P_L + P_B \leq 1.5$ (Greater of ($1.2\ S_M$, S_Y))

[3] Faulted Condition Limits: $P_M \leq$ Lesser of ($2.4\ S_M$, $0.7S_U$), P_L, $P_L + P_B \leq 1.5$ (Lesser of ($2.4\ S_M$, $0.7S_U$))

[4] Test Condition Limits: $P_M \leq 0.9S_Y$; P_L, $P_L + P_B \leq 1.35\ S_Y$

Table 5.7.2.1-6 Secondary Side Components: Cumulative Fatigue Usage Factors for Normal/Upset Conditions				
Component	**Section or Location**	**Fatigue Usage Factor (Baseline)**	**Fatigue Usage Factor (Uprated)**	**Comments**
Main Feedwater Nozzle	D-D	0.10	0.123	D-D is nozzle knuckle
	F-F	0.87	0.416	F-F is nozzle to liner weld
	A-A	0.23	0.349	A-A is nozzle safe end
Auxiliary Feedwater Nozzle	ASN 11	0.165	0.168	ASN 1 is nozzle to adapter weld; ASN 11 is nozzle to liner weld
	ASN 11	0.120	0.124	
	ASN 1	0.318	0.333	
Secondary Shell and Transition Cone	D-D	<0.03	0.029	D-D is at the Cone to Lower Shell Junction
Steam Outlet Nozzle	A-A	0.63	0.834	A-A is minimum section
Secondary Manway	E-E	0.409	0.658	E-E and F-F are at the Bolt Hole
	F-F	0.060	0.141	
Secondary Manway Bolts		<1	<1	See Note 1
2.5-inch Access Opening	B-B	0.619	0.641	B-B is the knuckle
	Bolt	0.977	0.99	
6.0-inch hand Hole	B-B	0.445	0.468	B-B is the knuckle
	Bolt	0.906	0.99	
Small Bore Pipe Taps	H-H	0.280	0.305	H-H is minimum section
2.0-inch Instrumentation Opening	B-B	0.200	0.180	B-B is the knuckle
	Bolt	0.999	0.984	

[1] Expected fatigue life of secondary manway bolts is greater than 40 years based on the test data for the primary manway bolts.

5.7.2.2 Hardware Evaluation

5.7.2.2.1 Introduction

Evaluations were performed to determine the impact of the power uprating conditions (as provided in Table 2.1-2) on the SG hardware repairs structural evaluations, which consist of:

- Tube mechanical plugs, including FTI and Westinghouse plugs
- Weld plugs
- Laser welded sleeves
- Baffle plate tube expansion
- Significant dispositioned non-conforming conditions
- Tube end machining (which is a modification related to roll plug or mechanical plug removal)
- Stabilizers.

These hardware repairs are either already installed or are licensed to be installed in the Byron and Braidwood Unit 2 Westinghouse Model D5 SGs.

5.7.2.2.2 Input Parameters and Assumptions

For the SG hardware evaluations, two sets of parameters were most important: high and low RCS temperatures. For both the tube mechanical plugs and the weld plugs, the enveloping condition is the one that results in the largest pressure differential between the primary and the secondary sides of the steam generator. The NSSS transients applicable to the uprating conditions were provided in Chapter 3 of this report. Both the parameter changes and the NSSS transients were used to determine the impact of the power uprating on the hardware repairs.

5.7.2.2.3 Descriptions of Analyses and Evaluations

The structural evaluations for the SG hardware changes were used as bases to justify operation at the uprated conditions. The evaluations were performed to the applicable requirements of the ASME Boiler and Pressure Vessel Code Section III (Reference 1, unless otherwise noted).

5.7.2.2.4 Acceptance Criteria

The tube mechanical plugs, the weld plugs, baffle plate tube expansion, and tube end machining were evaluated for the effects of changes to the thermal transients due to the uprate. The primary stresses due to design, emergency, faulted and test conditions will remain within the respective Code allowable values. The maximum range of primary plus secondary stresses were compared to the corresponding 3 S_m limits. The cumulative fatigue usage factor will remain less than or equal to unity, thereby demonstrating adequacy for cyclic operation over a 40-year design life.

For the laser welded sleeve design, a review was performed to the applicable ASME Code (Reference 2) to determine if the mechanical joint qualification, corrosion resistance, installation processes and nondestructive examination processes will continue to apply under power uprated conditions.

The methodology for the foreign objects evaluation was to calculate the impact-sliding wear time for the part to cause detectable wear on a tube and to compare this time to the time between plant refueling outages (cycle time). The situation where wear time exceeds cycle time is an acceptable condition.

5.7.2.2.5 Results

A summary of the results for each of the repairs follows:

<u>Steam Generator Tube Mechanical Plug</u>

The tube mechanical plug is adequately retained in the tube for all transients. There is adequate friction to prevent dislodging of the plug for the limiting transient loading. All of the stress/allowable ratios are less than unity, indicating that all primary stress limits are satisfied for the plug shell wall between the top land and the plug end cap. The plug shell meets the Class 1 fatigue exemption requirements per Section 3222.4 of the ASME Code (Reference 1).

Steam Generator Weld Plug

The weld plugs and the associated welded attachments have been shown to be adequate for installation in the SG tubesheet. The primary stress analysis was reviewed, and all of the stress/allowable ratios are less than unity, indicating that all primary stress limits are satisfied for the weld between the weld plug and tubesheet cladding. The cumulative fatigue usage remains at less than unity.

The primary degradation mechanism experienced in the model D5 steam generators at Byron and Braidwood Unit 2 is anti-vibration bar (AVB) wear. The small increase in wear anticipated due to power uprate conditions is not expected to challenge the tube structural limit. The increase in wear due to the power uprate will be assessed as a part of the operational assessment performed to determine the allowable operating interval between inspections. Eddy current inspection of active steam generator tubes will be performed in accordance with Technical Specifications during the refuel outage that follows operation at uprated conditions (3600.6 MWt).

Laser Welded Sleeves

The laser welded sleeves design, mechanical joint qualification, corrosion resistance, installation processes and nondestructive examination processes continue to apply for Byron and Braidwood Units 2, for the power uprated conditions.

Baffle Plate Tube Expansion

The power uprated conditions do not affect the previous acceptable fatigue results, and the mechanical stresses are unchanged from the previous acceptable results.

Significant Dispositioned Non-conforming Conditions

The main effect of the power uprate on foreign objects is a slightly higher secondary side fluid velocity. This affects the impact-sliding wear time for the part to cause detectable wear on a tube. The cycle time is acceptable and will be evaluated on a cycle-by-cycle basis for future operation where tube wear is present. All current evaluations addressing primary systems loose parts remain valid under uprating conditions, as RCS flow is unchanged. The previous fatigue evaluation of the Braidwood 2D steam generator auxiliary feedwater nozzle are not affected by power uprate.

Tube End Machining

The structural analysis for the tube end machining modification is related to mechanical plugging. It results from removal of mechanical plugs because part of the tube and tube weld is removed when the plug is removed by machining. The maximum amount of material removed, in terms of tube wall, was analyzed, and acceptable results were obtained based on stress and fatigue.

Stabilizers

Westinghouse-designed stabilizers installed in Byron 2 and Braidwood 2 are not adversely affected by the changes in fluid conditions associated with the power uprating. Therefore, there is no impact on those stabilizers due to uprating. The FTI-designed stabilizers were separately evaluated and met the applicable criteria at the power uprating conditions.

5.7.2.2.6 Conclusions

Results of the analyses performed on the Byron Unit 2 and Braidwood Unit 2 SG repairs show that the applicable acceptance criteria are met at the power uprated conditions.

5.7.2.2.7 References

1. ASME Boiler and Pressure Vessel Code Section III, "Rules for the Construction of Nuclear Vessels," 1971 Edition plus Addenda through Summer 1972, and Selected Paragraphs of Winter 1974, The American Society of Mechanical Engineers, New York, New York.

2. ASME Boiler and Pressure Vessel Code Section III and Section XI, "Rules for the Construction of Nuclear Power Plant Components," and "Rules for Inservice Inspection of Nuclear Power Plant Components," 1986 Edition, The American Society of Mechanical Engineers, New York, New York.

5.7.2.3 Thermal Hydraulic Evaluation

5.7.2.3.1 Introduction

Secondary side SG operating characteristics, including moisture separator performance, are affected by changes in thermal power (steam flow) and steam pressure. Steam pressure, in turn, is governed by thermal power, primary flow, primary temperature, and tube plugging level. A thermal power increase of 5.1% was evaluated for both Byron Unit 2 and Braidwood Unit 2. Additionally, operating conditions evaluated included a reduction in primary temperature and a bounding 10% tube plugging level. The effect of these changes on SG secondary side operating characteristics and moisture separator performance was assessed.

5.7.2.3.2 Input Parameters and Assumptions

Applicable design parameters for operation at uprated power (see Section 2) were used for the thermal-hydraulic evaluation. The uprated parameters require a minimum steam pressure of 827 psia. This pressure is bounded by Case 2, Table 2.1-2, which has the lowest steam pressure of the four cases, 811 psia.

5.7.2.3.3 Description of Analysis

SG thermal-hydraulic operating characteristics were calculated using the GEND5 Code. This Code calculates steady-state thermal hydraulic performance for Westinghouse Model D5 pre-heat SGs.

5.7.2.3.4 Acceptance Criteria

Where applicable, acceptance criteria are contained in the results section of the individual assessments.

5.7.2.3.5 Results

The secondary side operating characteristics for the current design and uprated operating conditions were compared to determine the impact of the uprated parameters. A summary is provided below.

Circulation Ratio - The circulation ratio is a measure of bundle liquid flow in relation to steam flow. It is primarily a function of steam flow (power). The 5.1% increase in power for the uprate causes the circulation ratio to decrease by 6-9%. The bundle liquid flow, given by the product (Circulation Ratio - 1) times (steam flow) changes slightly less. Bundle liquid flow minimizes accumulation of contaminants on the tube sheet and in the bundle. The small change in bundle liquid flow due to the power uprating has minimal effect on this function.

Damping Factor - The hydrodynamic stability of a SG is characterized by the damping factor. A negative damping factor indicates a stable unit. That is, small perturbations of steam pressure or circulation ratio will die out rather than grow in amplitude. The damping factors remain highly negative, at a level comparable to the current design, for all cases. The SGs remain hydrodynamically stable for all power uprated cases.

Steam Generator Mass - As power increases, the circulation ratio decreases, resulting in a higher void fraction in the tube bundle. The 5.1% increase in power for the uprate results in a 2-5% decrease in secondary mass. This small decrease in secondary mass has no significant effect on SG performance.

Peak Heat Flux - Peak heat flux will increase with power and tube plugging. For power uprating, the increased total heat load is passed through the same bundle heat transfer area, increasing the heat flux. For increased plugging, the same heat load is passed through a smaller heat transfer area, also increasing the heat flux. For the power uprate cases, the peak heat flux increases slightly. These heat flux levels remain within the range of operating experience and are well below any nucleate boiling limits.

Steam Generator Pressure Drop - The SG total secondary pressure drops will increase by 2-4 psi with power uprating. These pressure drop increases represent a small fraction of the total feed circuit pressure drop and will not affect operation of the SGs.

Moisture Carryover - Based on field data for moisture separator packages similar to those installed in the SGs of Byron Unit 2 and Braidwood Unit 2, the moisture carryover is projected to be near or below the design limit of 0.25% at the high end of the steam pressure range, 955 psia.

U-Bend Vibration – A study was previously performed for the Byron and Braidwood Unit 2 SGs, which concluded that, at the pre-uprating conditions, no tubes in either unit would require corrective action to preclude a North Anna type fatigue rupture. This study was reviewed and found to be still applicable at the uprated conditions. At the uprated power, the steam flow per SG will be less than $4.1X10^6$ lbm/hr. At this flow rate, any steam pressure above 700 psia is acceptable for both units. The minimum uprated steam pressure is greater than 800 psia (Table 2.1-2 of this report). Therefore, no corrective action to prevent U-bend fatigue needs to be considered for Byron Unit 2 or Braidwood Unit 2 SGs.

5.7.2.3.6 Conclusions

In summary, the thermal-hydraulic operating characteristics of the Byron Unit 2 and Braidwood Unit 2 SGs remain within acceptable ranges for the power uprated conditions.

5.7.2.3.7 References

None.

5.7.2.4 Tube Degradation

To minimize the potential impact of the power uprate on SG tube degradation, selection of the optimum point (best estimate steam pressure) at which to design the high pressure turbine modifications includes maintaining the post-uprate T_{hot} at the same value as the current T_{hot}. In addition, minimum steam pressure has been limited to the previously analyzed value, so that any contribution to SG tube degradation due to through wall pressure stress (due to primary to secondary differential pressure) has not been changed. Since T_{hot} and SG minimum pressure are the primary contributors to Primary Water Stress Corrosion Cracking (PWSCC) and Outside Diameter Stress Corrosion Cracking (ODSCC) and neither parameter (See Section 2.0) will change due to the power uprate, there is no impact to ODSCC or PWSCC due to the power uprate.

5.7.2.5 Preheater Vibration

5.7.2.5.1 Introduction

An evaluation was performed to determine if the increased feedwater flow associated with the uprated power level could result in an increase in SG preheater tube wear rates. The increase in feedwater flow associated with the uprating is approximately 5% of the design flow into the SGs.

5.7.2.5.2 Input Parameters and Assumptions

Design data parameters (See Table 2.1-2 of this report) were used to perform the original design analysis and were again used to perform the evaluation at the uprate conditions. However, a review of the actual plant operating data was performed to determine the current rate of feedwater flow into the SGs. The information reviewed included: total feed flow in each SG, along with the flow into the main feedwater nozzle and the auxiliary nozzle. This type of information is required to help define the baseline feedwater flow characteristics. These characteristics will change as a result of the uprate and therefore impact the flow induced wear rates. Other plant data used were eddy current test results of tubes within the preheater region of the SGs. This tube wear data was used to define the amount of wear actually experienced by the preheater tubes so that an assessment could be made of the potential impact of an increase in the feedwater flow and its impact on wear.

5.7.2.5.3 Description of Analysis/Acceptance Criteria

Wear time estimates were originally calculated using two methods:

- The g-delta method, in which the tube wear is defined to be proportional to the work performed by a tube in contact with, and moving relative to, a tube support hole under an applied force.

- The non-linear finite element model method, wherein the work rate is computed using forcing functions determined from scale model tests.

The increase in wear rates was evaluated considering the original wear calculations, the current rate of wear, the effects of increased flow, and the conservatively estimated consequence (in terms of required plugging of preheater tubes) of the increase in wear.

5.7.2.5.4 Results/Conclusions

The evaluation has determined that the increased main feedwater flow rates that would occur as a result of the uprate do not warrant immediate installation of orifice plates. There has been little to no growth in preheater wear indications prior to the uprate, and therefore, the increased degradation due to power uprate is not expected to be significant. With increased main feedwater flow, an increase in the rate of tube wear would also be projected. However, this increase is anticipated to be modest and not cause rapid wear.

Eddy current inspection will be performed in accordance with Technical Specifications during the first refueling outage for each unit after implementation of the power uprate program.

The evaluation has determined that the proposed power uprate conditions do not warrant the immediate installation of orifice plates. However, inspection data obtained from subsequent outages will be reviewed to determine if additional action is required, and to provide a basis for reducing the scope of the recommended eddy current inspection program.

5.7.2.5.5 References

None.

5.7.2.6 Steam Generator Tube Repair Criteria

An evaluation was performed to assess the impact of the uprated parameters on the tube repair criteria. Regulatory Guide 1.121 provides guidance for the determination of a repair limit for SG tubes undergoing localized tube wall thinning. Based on the conservative assumption of uniform wall thinning over an unlimited length the resulting structural limit $[(t_{nom} - t_{min})/t_{nom}]$, for the free-span region of the tube, for the Byron Unit 2 and Braidwood Unit 2 steam generators is 62.8%, based on low T_{avg} transient conditions and lower tolerance limit strength properties. As recommended in paragraph C.2.b. of the Regulatory Guide, an additional thickness degradation allowance must be added to the structural limit to establish the tube repair limit.
Paragraph C.3.f. of the Regulatory Guide specifies that the basis used in setting the operational degradation allowance include the method and data used in predicting the continuing degradation and consideration of eddy current measurement errors and other significant eddy current testing parameters. The corresponding repair limit is established by subtracting an allowance for eddy current uncertainty and continued growth from the structured limit.

5.8 Pressurizer

5.8.1 Introduction

The functions of the pressurizer are to absorb any expansion or contraction of the primary reactor coolant due to changes in temperature and pressure and to keep the reactor coolant system (RCS) at the desired pressure. The first function is accomplished by keeping the pressurizer approximately half full of water and half full of steam at normal conditions, by connecting the pressurizer to the RCS at the hot leg of one of the reactor coolant loops and allowing inflow to or outflow from the pressurizer as required. The second function is accomplished by keeping the temperature in the pressurizer at the water saturation temperature ($T_{pressurizer}$) corresponding to the desired pressure. The temperature of the water and steam in the pressurizer can be raised by operating electric heaters at the bottom of the pressurizer, and can be lowered by introducing relatively cool water into the steam space at the top of the pressurizer.

The limiting operating conditions of the pressurizer occur when the RCS pressure is high and the RCS hot leg (T_{hot}) and cold leg (T_{cold}) temperatures are low. This maximizes the temperature differential ΔT (between the pressurizer and hot or cold leg fluid) that is experienced by the pressurizer. Due to flow in and out of the pressurizer during various transients, the surge nozzle alternatively sees water at the pressurizer temperature ($T_{pressurizer}$) and water from the RCS hot leg at T_{hot}. If the RCS pressure is high (which means, correspondingly, that $T_{pressurizer}$ is high) and T_{hot} is low, then the surge nozzle will see maximum thermal gradients; and thus experience the maximum thermal stress. Likewise, the spray nozzle and upper shell temperatures alternate between steam at $T_{pressurizer}$ and spray which, for many transients, is at T_{cold}. Thus, if the RCS pressure is high ($T_{pressurizer}$ is high) and T_{cold} is low, then the spray nozzle and upper shell will also experience the maximum thermal gradients and thermal stresses.

5.8.2 Input Parameters and Assumptions

The pressurizer structural evaluation was performed by comparing the key inputs in the current pressurizers stress reports with the corresponding key inputs which would result from the uprating at the Byron and Braidwood Units 1 and 2. The following key inputs were included in the evaluation:

Design Transients [Section 3.0]

PCWG Parameters [Section 2.0]

Byron and Braidwood Units 1 and 2 Pressurizer Stress Reports [Refs. 1 through 4]

5.8.3 Evaluation

A review of the design transients for the uprating (Section 3.0) shows that the changes in the transients do not affect the pressurizer components. The maximum insurge flow rate is 1.11%. Based on a review of the temperature parameters, the maximum postulated temperature differential is 45°F. These parameters are the same as, or are bounded by, those parameters identified for the design basis analysis. Therefore, the design basis analysis remains valid for the uprate and no new analysis is required.

A review of Section 2.0 shows that the PCWG parameters affecting the pressurizer (hot leg temperature T_{hot} and cold leg temperature T_{cold}), revised for the uprating, are enveloped by the current analyses. These parameters are shown below, along with those used in the design stress reports [References 1 through 4]:

Parameter	4 Loop	Uprate	Ref 1-4
$T_{pressurizer}$ (°F)	653	653	653
T_{hot} (°F)	618.4	608.0[1]	---
T_{cold} (°F)	558.4	538.2[1]	---
$\Delta T_{hot} = T_{pressurizer} - T_{hot}$ (°F)	34.6	45.0	110
$\Delta T_{cold} = T_{pressurizer} - T_{cold}$ (°F)	94.6	114.8	135

(1) Plant operation limited to a minimum steam pressure of 827 psia, maximum T_{hot} of 618.4°F, and minimum T_{cold} of 538.2°F. Actual PCWG minimum T_{cold} is 542.0°F but administrative minimum is used for conservatism.

The above data show that for the surge nozzle, the differential temperature between the pressurizer fluid and the incoming hot leg fluid increases from 34.6 to 45.0°F for the uprating conditions. The existing analyses of References 1 through 4 envelop the uprating parameters, and therefore a new analysis is not required for the surge nozzle and other components in the lower part of the pressurizer.

For the spray nozzle, the differential temperature between the pressurizer fluid and the incoming cold leg fluid increases from 94.6 to 114.8°F for the conditions. The existing analyses of References 1 through 4 consider a minimum ΔT_{cold} of 135°F during sprays, thus enveloping the uprating parameters. Therefore a new analysis is not required for the spray nozzle and other components in the upper part of the pressurizer.

5.8.4 Acceptance Criteria

If the input data were unchanged or if revised input data for the uprating remained within the design envelope, the current pressurizer structural analysis remains applicable. However, for any uprating inputs outside of the design envelope, additional structural analysis is performed. The acceptance criteria for any additional analysis is the same as is documented in the design reports, References 1 through 4.

The applicable ASME Code Edition and Addenda for all units is provided in Reference 5.

5.8.5 Results and Conclusion

Based upon the evaluation results, it is concluded that the current stress reports, References 1 through 4, present analyses that envelop the uprating parameters and design transients. In addition, the revised design transients do not affect the pressurizer components. Therefore, no additional stress/fatigue/fracture mechanics analyses are required, and the pressurizer components meet the requirements of the applicable ASME Code, Section III (Reference 5) considering the uprating program.

5.8.6 References

1. Stress Report: WNET-130(CAE), Volume 1, Rev. 3, dated: August 1989, "Model D Series 84 Pressurizer Stress Report for Commonwealth Edison Company Byron Generating Station Unit 1."

2. Stress Report: WNET-130(CBE), Volume 1, Rev. 3, dated: August 1989, "Model D Series 84 Pressurizer Stress Report for Commonwealth Edison Company Byron Generating Station Unit 2."

3. Stress Report: WNET-130(CCE), Volume 1, Rev. 3, dated: August 1989, "Model D Series 84 Pressurizer Stress Report for Commonwealth Edison Company Braidwood Generating Station Unit 1."

4. Stress Report: WNET-130(CDE), Volume 1, Rev. 2, dated: August 1989, "Model D Series 84 Pressurizer Stress Report for Commonwealth Edison Company Braidwood Generating Station Unit 2."

5. ASME Boiler and Pressure Vessel Code, Section III, "Rules for Construction of Nuclear Power Plant Components," 1971 Edition, Summer 1973 Addendum, The American Society of Mechanical Engineers, New York, NY.

5.9 NSSS Auxiliary Equipment

5.9.1 Introduction

The purpose of this section is to evaluate the Byron and Braidwood auxiliary tanks, heat exchangers, pumps, and valves for the uprating parameters. Specifically, the equipment was evaluated for impact of thermal transients and maximum operating temperatures, pressures, and flow rates.

5.9.2 Input Parameters and Assumptions

The PCWG parameters (Section 2.0) document the NSSS operating temperatures and pressures. This information was applied where applicable for evaluation of the auxiliary equipment maximum operating temperatures and pressures. Sections 3.1 and 3.2 define the transients for the auxiliary tanks, heat exchangers, pumps, and valves based on the uprating conditions.

5.9.3 Description of Analyses and Evaluations

The design parameters and transients were reviewed for the auxiliary tanks, heat exchangers, pumps, and valves. They were compared to those used in the uprating (Sections 2.0 and 3.0) to confirm that they remain bounding. This review documents the acceptability of the uprate conditions for the auxiliary system components.

<u>Auxiliary System Tanks</u>

The design temperature, pressure, design transients, and design criteria for the auxiliary tanks were reviewed. The only tanks that have transients identified are the safety injection accumulators. The operating temperatures and pressures for these vessels remain within the design basis. The thermal transients for the safety injection accumulators remain bounded by the original design transients.

<u>Auxiliary System Heat Exchangers</u>

For the NSSS auxiliary heat exchangers, the applicable design transients and design temperature and pressures were identified. Based on PCWG parameters in Section 2.0 and an evaluation of the effects of flow induced vibration (FIV), there is no impact on the auxiliary system heat exchangers as a result of the uprating. The operating temperature and pressure ranges for these vessels remain bounded by the original design parameters. The original design transients for the auxiliary equipment remain bounding for the transients associated with the uprating.

Auxiliary System Pumps

Based upon Section 2.0, there is no impact upon the NSSS auxiliary system pumps as a result of the uprating. The operating temperature and pressure ranges for these pumps remain bounded by the original design parameters. Section 3.2 indicates that the original design transients for the auxiliary equipment bound the transients associated with the uprating.

Since the uprated service conditions for the auxiliary system pumps remain within the design basis for these pumps, there are no operability issues resulting from the uprating.

Auxiliary System Valves

As shown in Section 2.0, the operating temperature and pressure ranges for the auxiliary system valves remain bounded by the original design parameters. Section 3.2 indicates that the original design transients for the auxiliary equipment remain bounding for the transients associated with the uprating. The impact of uprating on motor-operated valves (MOVs) operation and testing is addressed in Section 10.0.

5.9.4 Acceptance Criteria

If the uprating program conditions are bounded by the original system design conditions, then no further effort would be required to qualify the auxiliary tanks, heat exchangers, pumps, and valves for this aspect of the uprating. Any values in excess of the design values will be addressed in this report.

If the original design transients bound the revised auxiliary tank, heat exchanger, pump, and valve transients for the uprating program, then no further effort would be required to qualify the equipment for this aspect of the uprating. If the revised transients are not bounded by the original equipment design, then each affected piece of equipment would need to be re-qualified for the new transient conditions on a case-by-case basis.

5.9.5 Results

A comparison of the conditions given in Section 2.0 shows that all maximum operating temperatures and pressures for NSSS auxiliary systems components are bounded by the existing design basis. Since all tanks, heat exchangers, pumps, and valves were designed and manufactured consistent with the system design and applicable Codes and standards requirements, all of the NSSS tanks, heat exchangers, pumps, and valves are acceptable for the maximum system operating temperatures and pressures resulting from the uprating. Sections 3.1 and 3.2 confirm that the auxiliary equipment and NSSS thermal transients resulting from the uprating are bounded by the original Byron and Braidwood design parameters. Therefore the auxiliary tanks, heat exchangers, pumps, and valves remain acceptable for the thermal transients resulting from the uprating.

For the heat exchangers, FIV is a function of the shell-side flow rates. Shell-side flow rates have been reviewed and do not change significantly because of the uprating. Thus, FIV is not a problem as a result of the uprating.

5.9.6 Conclusions

The Byron and Braidwood auxiliary tanks, heat exchangers, pumps, and valves are acceptable for the uprating conditions since there is no change to the auxiliary system operating conditions identified as a consequence of the uprating.

5.9.7 References

None

5.10 Loop Stop Isolation Valves (LSIVS)

5.10.1 Introduction

This section addresses the ASME Code of record structural considerations for the pressure boundary components of the Westinghouse primary system loop stop isolation valves. The valves were evaluated for the Byron and Braidwood Uprating Program Performance Capability Working Group (PCWG) parameters (Section 2.0) and Nuclear Steam Supply System (NSSS) design transients (Section 3.0).

5.10.2 Input Parameters and Assumptions

The reactor coolant system (RCS) LSIVs were designed and analyzed to meet the Byron and Braidwood plant design specification (Reference 1), the valve general equipment specification (Reference 2), and the ASME Code (References 3 and 4). The Byron and Braidwood Uprating parameters evaluated are given in Section 2.0, Section 3.0, and Table 5.10.3.1-1.

The LSIVs are used to isolate a reactor coolant loop from the rest of the system. Two valves are required for each loop, one in the hot leg and one in the cold leg. The LSIVs are evaluated for hot leg transients, which are more severe than cold leg transients.

All maintenance and repair activities on the LSIVs have been performed in accordance with the original design requirements. Therefore, the LSIVs continue to meet those requirements.

The original design Byron and Braidwood Loss of Coolant Accident (LOCA) vessel and loop piping hydraulic forcing functions remain bounding for the Uprating conditions per Section 6.6. The Byron and Braidwood Uprating seismic loads remain bounded by the original design operating conditions.

5.10.3 Description of Evaluations and Acceptance Criteria

5.10.3.1 Transient Discussion

The Uprating PCWG parameters for reactor coolant pressure (2250 psia) and hot leg temperature (T_{hot}) limit (618.4°F maximum) equal those of the original design. Therefore, the Uprating PCWG parameters are acceptable for the LSIVs. The Uprating ranges for the hot leg and cold leg temperatures are bounded by the original design operating range.

The only primary side thermal or pressure transient modified in Section 3.0 that may effect the hot leg is the Loss of Load transient. Only the Low T_{avg} (average coolant temperature) case was revised. Because the High T_{avg} case is more severe, the change has no effect on evaluation of the LSIVs.

Table 5.10.3.1-3 lists the resultant usage factors and code allowable values for various LSIV components. These usage factors include the effects of the Uprating parameters (Table 5.10.3.1-1) and the applicable design transients and cycle count (Table 5.10.3.1-2).

The design transients listed in Section 3.0 were used as a basis for this evaluation. Note that the RCS cold overpressurization transient (see Table 5.10.3.1-2) was not added because of the Uprating but was an addition to the original design transients and has been considered in all evaluations in this section.

5.10.4 Acceptance Criteria

Acceptance criteria is listed in the ASME Code (References 3 and 4).

5.10.5 Results

The review of the effects of the Byron and Braidwood Uprating PCWG parameters and NSSS design transients on the site-specific and generic LSIV reports, as described in Section 5.10.3, indicates that the appropriate edition of record for the pertinent sections of the ASME Code (References 3 and 4) are still met.

5.10.6 Conclusions

The new PCWG parameters and NSSS design transients for the Uprating are acceptable for the LSIVs from a structural standpoint. The valve pressure boundary parts still satisfy the LSIV specifications (References 1 and 2) and the ASME Code of record (References 3 and 4). Therefore, the results are consistent with and continue to comply with the original licensing basis/acceptance requirements for Byron Units 1 and 2, and Braidwood Units 1 and 2.

5.10.7 References

1. Plant Design Specification 679018, Revision 3, "Commonwealth Edison Company Byron Station Units 1 and 2 Braidwood Station Units 1 and 2 Public Service of Indiana Marble Hill Station Units 1 and 2, Primary System Loop Isolation Valves ASME Boiler & Pressure Vessel Code, Section III Class 1," Westinghouse Nuclear Energy Systems, Pittsburgh, PA, By I. P. Hochman, February, 1976.

2. General Equipment Specification G-678874, Revision 2, "Primary System Loop Isolation Valves Class 1 Motor Operated Gate Valves ASME Boiler & Pressure Vessel Code, Section III," Westinghouse Nuclear Energy Systems, Pittsburgh, PA, By J. C. DiPerna, Revised by J. C. DiPerna, April 15, 1975.

3. "ASME Boiler and Pressure Vessel Code, Section III, Nuclear Power Plant Components," American Society of Mechanical Engineers, NY, Winter 1973 and Winter 1975 (generic reports only) Addenda.

4. "ASME Boiler and Pressure Vessel Code, Code Cases 1552 (generic reports only) and 1552-1," American Society of Mechanical Engineers, NY, NY.

Table 5.10.3.1-1 PCWG Conditions Used to Bracket All Operating Conditions for Byron and Braidwood Uprating				
	Original Basis		Uprating	
	High T_{avg}	Low T_{avg}	High T_{avg}	Low T_{avg}
T_{hot}, °F	618.4	600.0	618.4	608.0
T_{cold}, °F	558.4	538.2	555.7	538.2

P = 2235 psig

T = 556°F to 619°F

P = 2250 psia for all cases

T_{hot} = 618.4°F Original Basis

T_{hot} = 608.0°F Cases 1 and 2 for Byron and Braidwood Units 1 & 2

T_{hot} = 620.3°F[1] Cases 3 and 4 for Byron and Braidwood Units 1 & 2

T_{cold} = 558.4°F Original Basis

T_{cold} = 542.0°F[2] Cases 1 and 2 for Byron and Braidwood Units 1 & 2

T_{cold} = 555.7°F Cases 3 and 4 for Byron and Braidwood Units 1 & 2

(1) Plant operation limited to a maximum T_{hot} of 618.4°F as indicated in Section 2.0 footnotes.

(2) Plant operation limited to a minimum T_{cold} of 538.2°F as indicated in Section 2.0 footnotes.

Table 5.10.3.1-2 Applicable Design Transients and Cycle Count Comparison		
Plant Condition	**Equipment Specification No. G-678874 Revision 2**	**Uprating**
Normal Conditions		
1. Plant Heatup	200 open 80 closed	200 open 80 closed
2. Plant Cooldown	200 open 80 closed	200 open 80 closed
3. Unit Loading at 5%/min	13,200	13,200
4. Unit Unloading at 5%/min	13,200	13,200
5. 10% Step Load Increase	2000	2000
6. 10% Step Load Decrease	2000	2000
7. Large Step Load Decrease	200	200
8. Steady State Fluctuations – A – B	1.5E5 3.0E6	1.5E5 3.0E6
9. Feedwater Cycling	2000	2000
10. 0-15% Unit Loading	500	500
11. 15-0% Unit Unloading	500	500
12. Loop Out of Service – Shutdown – Startup	80 70	Not Applicable Not Applicable
13. Boron Concentration Equal.	26,400	26,400
14. Refueling	80	80
Upset Conditions		
1. Loss of Load	80	80
2. Loss of Power	40	40
3. Partial Loss of Flow	80	80
4. Reactor Trip Case A Case B Case C	 230 160 10	 230 160 10
5. Inadvertent RCS Depressurization	20	20
6. Inadvertent Startup of Inactive Loop	10	0

Table 5.10.3.1-2 (cont.) Applicable Design Transients and Cycle Count Comparison		
Plant Condition	**Equipment Specification No. G-678874 Revision 2**	**Uprating**
7. Control Rod Drop	80	80
8. Inadvertent Safety Injection	60	60
9. OBE	400	400
10. RCS Cold Overpressurization	Not Applicable	10[1]
Emergency Conditions		
1. Small LOCA	5	5
2. Small Steam Line Break	5	5
3. Complete Loss of Flow	5	5
Faulted Conditions		
1. Large LOCA	1	1
2. Large Steam Line Break	1	1
3. Feedwater Steam Line Break	1	1
4. RCP Locked Rotor	1	1
5. Control Rod Ejection	1	1
6. Steam Generator Tube Rupture	Covered by Reactor Trip	-
7. Safe Shutdown Earthquake (SSE)	1	1
Test Conditions		
1. Turbine Roll Test	20	20
2. Primary Side Hydrostatic Test	10	10
3. Primary Side Leak Test	200	200

(1) There are 600 pressure cycles for each transient cycle for a total of 6000 pressure cycles.

Table 5.10.3.1-3 Results		
Component	**Usage Factor**	**Code Allowable**
Valve Body Weld Prep	0.353	< 1.0
Main Flange Blending Region	0.660	< 1.0
Valve Bypass Nozzle	0.793	< 1.0
Valve Bonnet	0.570	< 1.0
Main Flange Studs	0.572	< 1.0
Valve Disc	0.140	< 1.0
Valve Seat Rings	0.179	< 1.0
Valve Canopy Seal Weld Ring	0.274	< 1.0
Valve Backseat Ring	0.930	< 1.0
Valve Torque Arm	0.010	< 1.0
Valve Torque Key	0.016	< 1.0
Valve Stuffing Box	0.133	< 1.0
Valve Disc Guide	0.020	< 1.0
Valve Stem	0.010	< 1.0
Yoke Bolting	0.444	< 1.0

6.0 NSSS ACCIDENT ANALYSES

This section provides the results of the analyses and/or evaluations that were performed for the Nuclear Steam Supply System (NSSS) accident analyses in support of the Power Uprate Program. The accident analysis areas addressed in this section include:

- Small-Break Loss-of-Coolant Accident (LOCA), Hot Leg Switchover, and Post-LOCA Long Term Cooling
- Non-LOCA Events
- Steam Generator Tube Rupture Transient
- LOCA Containment Integrity
- Main Steamline Break Consequences
- LOCA Hydraulic Forces
- Radiological Consequences (Doses)

The Large-Break LOCA submittal, using Best Estimate Methodology, is being prepared separately from this report and will be provided later.

The detailed results and conclusions of each analysis are presented within each subsection.

6.1 Loss-of-Coolant Accident (LOCA) Transients

6.1.1 Small-Break LOCA

6.1.1.1 Introduction

This section contains information regarding the Small-Break Loss-of-Coolant Accident (SBLOCA) analysis and evaluations performed in support of the uprate project for Byron and Braidwood Units 1 and 2. The purpose of analyzing the Small-Break LOCA is to demonstrate conformance with the 10 CFR 50.46 (Reference 1) requirements for the conditions associated with the uprating. Important input assumptions, as well as analytical models and analysis methodology for the Small-Break LOCA, are contained in subsequent sections. Analysis results are provided in the form of tables and figures, as well as a more detailed description of the limiting transient. The analysis has shown that no design or regulatory limit related to the Small-Break LOCA would be exceeded due to the uprated power and assumed plant parameters.

6.1.1.2 Input Parameters and Assumptions

The important plant conditions and features are listed in Table 6.1.1-1. Several additional considerations that are not identified in Table 6.1.1-1 are discussed below.

Figure 6.1.1-1 depicts the hot rod axial power shape modeled in the Small-break LOCA analysis. This shape was chosen because it represents a distribution with power concentrated in the upper regions of the core (the axial offset is +13%). Such a distribution is limiting for Small-break LOCA since it minimizes coolant swell while maximizing vapor superheating and fuel rod heat generation at the uncovered elevations. The chosen power shape has been conservatively scaled to a 2-line segment K(Z) envelope based on the peaking factors shown in Table 6.1.1-1.

Figure 6.1.1-2 provides the SI flow versus pressure curve modeled in the Small-break LOCA analysis. The flows shown in Figure 6.1.1-2 account for a 5% flow reduction to account for future pump degradation. The flow from one Safety Injection (SI) pump and one Centrifugal Charging (CV) pump were assumed in this analysis.

6.1.1.3 Description of Analyses/Evaluations Performed

<u>Analytical Model</u>

For Small-breaks, the NOTRUMP computer code (References 2 and 3) is employed to calculate the transient depressurization of the Reactor Coolant System (RCS), as well as to describe the mass and energy release of the fluid flow through the break. The NOTRUMP computer code is a one-dimensional general network code incorporating a number of advanced features. Among these advanced features are: calculation of thermal non-equilibrium in all fluid volumes, flow regime-dependent drift flux calculations with counter-current flooding limitations, mixture level tracking logic in multiple-stacked fluid nodes, regime-dependent drift flux calculations in multiple-stacked fluid nodes and regime-dependent heat transfer correlations. The NOTRUMP Small-break LOCA Emergency Core Cooling System (ECCS) Evaluation Model was developed to determine the RCS response to design basis Small-break LOCAs, and to address NRC concerns expressed in NUREG-0611 (Reference 4).

The RCS model is nodalized into volumes interconnected by flow paths. The broken loop is modeled explicitly, while the intact loops are lumped together into a second loop. Transient behavior of the system is determined from the governing conservation equations of mass, energy, and momentum. The multi-node capability of the program enables explicit, detailed spatial representation of various system components which, among other capabilities, enables a calculation of the behavior of the loop seal during a Small-break LOCA. The reactor core is represented as heated control volumes with associated phase separation models to permit transient mixture height calculations.

Fuel cladding thermal analyses are performed with a version of the LOCTA-IV code (Reference 5) using the NOTRUMP calculated core pressure, fuel rod power history, uncovered core steam flow and mixture heights as boundary conditions. Figure 6.1.1-3 illustrates the code interface for the Small-break Model.

Analysis

This uprate analysis has considered 16 different break cases as indicated by the result Tables 6.1.1-7 through 6.1.1-10. A break spectrum of 1.5, 2, 3, and 4-inch breaks was considered for both Units 1 and Units 2 at Hi and Low T_{avg} conditions. The uprate analysis did not result in a break shift for either units. The Low T_{avg} 2 inch break remained limiting for Units 1 and the Hi T_{avg} 3 inch break remained limiting for the Units 2.

The most limiting single active failure assumed for a Small-break LOCA is that of an emergency power train failure which results in the loss of one complete train of ECCS components. In addition, a Loss-of-Offsite Power (LOOP) is assumed to occur coincident with reactor trip. This means that credit may be taken for at most one high head safety injection (HHSI) pump, one charging pump (CV/SI), and one low head, or residual heat removal (RHR) pump. In this analysis, one HHSI pump and one CV/SI pump are modeled. The RHR is not considered in Small-break LOCA analyses because the shutoff head is lower than the RCS pressure during the portion of the transient considered here. The Small-break LOCA analysis performed for the Byron/Braidwood uprate project assumes ECCS flow is delivered to both the intact and broken loops at the RCS backpressure. The broken and intact loop SI flows are illustrated in Figure 6.1.1–2. The assumption of LOOP and the failure of a diesel generator to start as the limiting single failure for Small-break LOCA is part of the NRC approved methodology and does not change as a result of the uprated conditions. The single failure assumption is extremely limiting due to the fact that one train of ECCS, one motor driven auxiliary feedwater (AF) pump, and power to the reactor coolant pumps (RCPs) are all lost. Any other active single failure would not result in a more limiting scenario since increased SI flow would improve the overall transient results.

Prior to break initiation, the plant is assumed to be in a full power (102%) equilibrium condition, i.e., the heat generated in the core is being removed via the secondary system. Other initial plant conditions assumed in the analysis are given in Table 6.1.1-1. Subsequent to the break opening, a period of reactor coolant system blowdown ensues in which the heat from fission product decay, the hot reactor internals, and the reactor vessel continues to be transferred to the RCS fluid. The heat transfer between the RCS and the secondary system may be in either direction and is a function of the relative temperatures of the primary and secondary. In the case of continuous heat addition to the secondary during a period of quasi-equilibrium, an increase in the secondary system pressure results in steam relief via the steam generator safety valves.

When a Small-break LOCA occurs, depressurization of the RCS causes fluid to flow into the loops from the pressurizer resulting in a pressure and level decrease in the pressurizer. The reactor trip signal subsequently occurs when the pressurizer low-pressure reactor trip setpoint, conservatively modeled as 1857 psia, is reached. LOOP is assumed to occur coincident with reactor trip. A safety injection signal is generated when the pressurizer low-pressure safety injection setpoint, conservatively modeled as 1715 psia, is reached. Safety injection is delayed 40 seconds after the occurrence of the low pressure condition. This delay accounts for signal processing, diesel generator start up and emergency power bus loading consistent with the assumed loss-of-offsite power coincident with reactor trip, as well as the pump acceleration delays.

The following countermeasures limit the consequences of the accident in two ways:

1. Reactor trip and borated water injection supplement void formation in causing a rapid reduction of nuclear power to a residual level corresponding to the delayed fission and fission product decay. No credit is taken in the Small-break LOCA analysis for the boron content of the injection water. In addition, credit is taken in the Small-break LOCA analysis for the insertion of Rod Cluster Control Assemblies (RCCAs) subsequent to the reactor trip signal, while assuming the most reactive RCCA is stuck in the full out position. A rod drop time of 2.7 seconds was assumed while also considering an additional 2 seconds for the signal processing delay time. An additional 1.3 second delay has also been modeled for added conservatism. Therefore, a total delay time of 6.0 seconds from the time of reactor trip signal to full rod insertion was used in the Small-break LOCA analysis.

2. Injection of borated water ensures sufficient flooding of the core to prevent excessive cladding temperatures.

During the earlier part of the Small-break transient (prior to the assumed loss-of-offsite power coincident with reactor trip), the loss of flow through the break is not sufficient to overcome the positive core flow maintained by the reactor coolant pumps. During this period, upward flow through the core is maintained. However, following the reactor coolant pump trip (due to a LOOP) and subsequent pump coastdown, a period of core uncovery occurs. Ultimately, the Small-break transient analysis is terminated when the ECCS flow provided to the RCS exceeds the break flow rate.

The core heat transfer mechanisms associated with the Small-break transient include the break itself, the injected ECCS water, and the heat transferred from the RCS to the steam generator secondary side. Main Feedwater (MFW) is conservatively assumed to be isolated in 8 seconds following the generation of the low pressurizer pressure SI signal, consisting of a 2 second signal delay time and a 6 second main feedwater control valve stroke time. Additional makeup water is also provided to the secondary using the auxiliary feedwater (AF) system. An AF actuation signal is modeled off the low pressurizer pressure SI signal, resulting in the delivery of AF system flow 90 seconds after the generation of the SI signal. The heat transferred to the secondary side of the steam generator aids in the reduction of the RCS pressure.

Should the RCS depressurize to approximately 600 psia (minimum), as is the case in the limiting 3-inch and 4-inch break cases, the cold leg accumulators begin to inject borated water into the reactor coolant loops. In the case of the 1.5 and 2-inch breaks however, the transient is terminated without the aid of accumulator injection.

6.1.1.4 Acceptance Criteria for Analyses/Evaluations

The acceptance criteria for the LOCA are described in 10 CFR 50.46 (Reference 1) as follows:

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

2. The calculated total oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation.

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

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

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

Criteria 1 through 3 are explicitly covered by the Small Break LOCA analysis at uprated conditions.

For criterion 4, the appropriate core geometry was modeled in the analysis. The results based on this geometry satisfy the Peak Clad Temperature (PCT) criterion of 10 CFR 50.46 and consequently, demonstrate the core remains amenable to cooling.

For criterion 5, Long-Term Core Cooling (LTCC) considerations are not directly applicable to the Small Break LOCA transient, but are assessed in Section 6.1.3 as part of the evaluation of ECCS performance.

The criteria were established to provide a significant margin in emergency core cooling system (ECCS) performance following a LOCA.

6.1.1.5 Results

In order to determine the conditions that produced the most limiting Small Break LOCA case (as determined by the highest calculated peak cladding temperature), a total of 8 break cases were examined for each of the Units 1 and Units 2. These cases included the investigation of variables, including break size and RCS average temperature, to ensure that the most severe postulated Small Break LOCA event was analyzed. The following discussions provide insight into the analyzed conditions.

<u>Limiting Temperature Conditions</u>

For Byron/Braidwood Units 1 and Units 2, the temperature window analyzed was based on a nominal vessel average temperature range of 565°F to 598°F, which includes ±10°F to bound uncertainties. The analysis showed that for Units 1, the Low T_{avg} 2-inch case is limiting. For Units 2, the High T_{avg} 3-inch case was found to be limiting. The limiting case transient for each pair of units will be discussed below.

<u>Byron/Braidwood Units 1 SBLOCA Results Discussion</u>

The results of Reference 6 demonstrate that the cold leg break location is limiting with respect to postulated cold leg, hot leg and pump suction leg break locations. The PCT results are shown in Tables 6.1.1-2 and 6.1.1-3. Inherent in the limiting Small Break analysis are several input assumptions (see Section 6.1.1.2 and Table 6.1.1-1), while Tables 6.1.1-7 and 6.1.1-8 provide the key transient event times.

For the Small Break LOCA uprate analysis, the limiting case for Units 1 was the Low T_{avg} 2-inch break case. A summary of the transient response for the limiting Units 1 case is shown in Figures 6.1.1-4 through 6.1.1-14. These figures present the response of the following parameters.

- RCS Pressure
- Core Mixture Level
- Top Core Node Vapor Temperature
- Broken Loop and Intact Loop Secondary Side Pressure
- Break Vapor Flow Rate
- Break Liquid Flow Rate
- Broken Loop and Intact Loop Accumulator Flow
- Pumped Safety Injection Mass Flow Rate for the Intact and Broken Loops
- Peak Cladding Temperature
- Hot Spot Fluid Temperature
- Hot Spot Rod Surface Heat Transfer Coefficient

Upon initiation of the limiting Low T_{avg} 2-inch break for Units 1, there is an initial rapid depressurization of the RCS followed by an intermediate equilibrium at around 1250 psia (see Figure 6.1.1-4). Following the equilibrium, the RCS pressure gradually depressurizes but never reaches the accumulator injection setpoint of 600 psia (see Figure 6.1.1-10). During the initial period of the Small Break transient, the effect of the break flow rate is not sufficient to overcome the flow rate maintained by the reactor coolant pumps as they coast down. As such, normal upward flow is maintained through the core and core heat is adequately removed. Following reactor trip, the removal of the heat generated as a result of fission products decay is accomplished via a two-phase mixture level covering the core. The core mixture level and cladding temperature transient plots for the Units 1 Low T_{avg} 2-inch break calculations are illustrated in Figures 6.1.1-5 and 6.1.1-12. These figures show that the peak cladding temperature occurs near the time when the core is most deeply uncovered and the top of the core is being cooled by steam. This time is characterized by the highest vapor superheating above the mixture level (refer to Figure 6.1.1-6).

A comparison of the flow provided by the safety injection system to the intact and broken loops can be found in Figure 6.1.1-11. The cold leg break vapor and liquid mass flow rates are provided in Figures 6.1.1-8 and 6.1.1-9 respectively. Figures 6.1.1-13 and 6.1.1-14 provide additional information on the fluid temperature at the hot spot and hot rod surface heat transfer coefficient at the hot spot, respectively. Figure 6.1.1-7 depicts the secondary side pressure for both the intact and broken loops for the Units 1 Low T_{avg} 2-inch break case.

Additional Break Cases

Studies documented in Reference 6 have determined that the limiting small-break transient occurs for breaks of less than 10 inches in diameter in the cold leg. To ensure that the 2-inch diameter break was the most limiting, calculations were also performed with break equivalent diameters of 1.5, 3, and 4 inches. The results of the break spectrum cases are given in Tables 6.1.1-2 and 6.1.1-3. Figures 6.1.1-15 through 6.1.1-23 refer to the non-limiting break cases analyzed for Units 1 at the Low T_{avg} conditions. Figures 6.1.1-24 through 6.1.1-35 refer to the non-limiting break cases analyzed for Units 1 at the High T_{avg} conditions. The following plots have been included in Figures 6.1.1-15 through 6.1.1-35.

1. RCS Pressure Transient
2. Core Mixture Level
3. Peak Cladding Temperature

The PCTs for each of the breaks considered are shown in Tables 6.1.1-2 and 6.1.1-3, these PCTs are less than the limiting 2-inch Low T_{avg} break case.

The 10 CFR 50.46 criteria continue to be satisfied beyond the end of the calculated transient due to the following conditions:

1. The RCS pressure is gradually decaying
2. The net mass inventory is increasing
3. The core mixture level is recovered, or recovering due to increasing mass inventory

4. As the RCS inventory continues to gradually increase, the core mixture level will continue to increase and the fuel cladding temperatures will continue to decline indicating that the temperature excursion is terminated.

Byron/Braidwood Units 2 SBLOCA Results Discussion

The Units 2 PCT results are shown in Tables 6.1.1-4 and 6.1.1-5. Inherent in the limiting Small Break analysis are several input assumptions (see Section 6.1.1.2 and Table 6.1.1-1), while Tables 6.1.1-9 and 6.1.1-10 provide the key transient event times. For the Small Break LOCA uprate analysis, the limiting case for Units 2 was the Hi T_{avg} 3-inch break case. A summary of the transient response for the limiting Units 2 case is shown in Figures 6.1.1-36 through 6.1.1-46. These figures present the response of the following parameters.

- RCS Pressure
- Core Mixture Level
- Top Core Node Vapor Temperature
- Broken Loop and Intact Loop Secondary Side Pressure
- Break Vapor Flow Rate
- Break Liquid Flow Rate
- Broken Loop and Intact Loop Accumulator Flow
- Pumped Safety Injection Mass Flow Rate for the Intact and Broken Loops
- Peak Cladding Temperature
- Hot Spot Fluid Temperature
- Hot Spot Rod Surface Heat Transfer Coefficient

Upon initiation of the limiting Hi T_{avg} 3-inch break for Units 2, there is an initial rapid depressurization of the RCS followed by an intermediate equilibrium at around 1300 psia (see Figure 6.1.1-36). Following the equilibrium, the RCS pressure depressurizes to the accumulator injection setpoint of 600 psia (see Figure 6.1.1-42) at approximately 1700 seconds. The core mixture level and cladding temperature transient plots for the Units 2 Hi T_{avg} 3-inch break calculations are illustrated in Figures 6.1.1-37 and 6.1.1-44. These figures show that the peak cladding temperature occurs near the time when the core is most deeply uncovered and the top of the core is being cooled by steam. This time is characterized by the highest vapor superheating above the mixture level (refer to Figure 6.1.1-38).

A comparison of the flow provided by the safety injection system to the intact and broken loops can be found in Figure 6.1.1-43. The cold leg break vapor and liquid mass flow rates are provided in Figures 6.1.1-40 and 6.1.1-41, respectively. Figures 6.1.1-45 and 6.1.1-46 provide additional information on the fluid temperature at the hot spot and hot rod surface heat transfer coefficient at the hot spot, respectively. Figure 6.1.1-39 depicts the secondary side pressure for both the intact and broken loops for the Hi T_{avg} 3-inch break case.

Additional Break Cases

Studies documented in Reference 6 have determined that the limiting small-break transient occurs for breaks of less than 10 inches in diameter in the cold leg. To ensure that the 3-inch diameter break was the most limiting, calculations were also performed with break equivalent diameters of 1.5, 2, and 4 inches. The results of the break spectrum cases are given in Tables 6.1.1-4 and 6.1.1-5. Figures 6.1.1-47 through 6.1.1-55 refer to the non-limiting break cases analyzed for Units 2 at the High T_{avg} conditions. Figures 6.1.1-56 through 6.1.1-67 refer to the non-limiting break cases analyzed for Units 2 at the Low T_{avg} conditions. The following plots have been included in Figures 6.1.1-47 through 6.1.1-67.

1. RCS Pressure Transient

2. Core Mixture Level

3. Peak Cladding Temperature

The PCTs each of the breaks considered are shown in Tables 6.1.1-4 and 6.1.1-5. In each case, the PCTs are less than the limiting 3-inch break case.

The 10 CFR 50.46 criteria continue to be satisfied beyond the end of the calculated transient due to the following conditions:

1. The RCS pressure is gradually decaying

2. The net mass inventory is increasing

3. The core mixture level is recovered

4. As the RCS inventory continues to gradually increase, the core mixture level will continue to increase and the fuel cladding temperatures will continue to decline indicating that the temperature excursion is terminated.

ZIRLO/Zirc-4 Cladding Evaluation

Since ZIRLO and Zirc-4 fuel have different physical characteristics as modeled by the SBLOCTA code, explicit calculations for Zirc-4 fuel have been performed for each limiting case (See Table 6.1.1-6). The Zirc-4 fuel was found to be non-limiting at beginning of life (BOL) conditions for the Units 1 Low T_{avg} 2-inch case. Figure 6.1.1-68 illustrates the PCT plot for the Unit 1 Low T_{avg} Zirc-4 case.

The Zirc-4 fuel was found to be slightly (~1°F) limiting for the Units 2 Hi T_{avg} case. A burnup credit of 6,000 MWD/MTU was taken in order to make the Zirc-4 fuel non-limiting compared to the ZIRLO fuel. This burnup restriction will be tracked in the SPIL current limits from this point forward. The calculated PCT for Zirc-4 fuel at 6000 MWD/MTU was found to be 1601°F (see Figure 6.1.1-69), which is less limiting than the ZIRLO fuel PCT for the Units 2 Hi T_{avg} 3-inch case.

At the time at which this analysis is implemented, no new Zirc-4 fuel is expected to be inserted into the core. All of the Zirc-4 fuel will be burned for at least one cycle, if not more, if ZIRLO fuel is implemented at non-uprate conditions. The Zirc-4 minimum, core-wide, fuel-pin burnup is expected to be well in excess of 6000 MWD/MTU. Therefore, assuming that this is the case, the ZIRLO fuel will be considered more limiting with a PCT of 1614°F in comparison to the 1601°F PCT for the Zirc-4 fuel at 6000 MWD/MTU. This confirmation will have to be explicitly verified as part of the SPIL process when the uprated ZIRLO fuel is being implemented. If this burnup criterion can be satisfied during the reload, as is expected, then no additional PCT penalty will be needed for Zirc-4 fuel.

The fuel temperatures/pressures used in these calculations were based on NRC approved fuel performance code (PAD 3.4) which addresses all the helium release related issues. This analysis has been performed using the most limiting temperature/pressure as calculated for non-IFBA VANTAGE 5 fuel. The standard Westinghouse position is that non-IFBA fuel bounds IFBA fuel for SBLOCA analyses.

6.1.1.6 Conclusions

A break spectrum of 1.5, 2, 3, and 4 inch diameters have been considered at both high and low vessel average temperatures for all Byron and Braidwood Units. A peak cladding temperature of 1602°F was calculated to be limiting for Units 1. This limiting PCT occurred for the 2-inch low T_{avg} break case. Zirc-4 fuel is bounded by ZIRLO fuel for Units 1.

A peak cladding temperature of 1614°F was calculated to be limiting for Units 2. This limiting PCT occurred for the 3-inch high T_{avg} break case. Beyond 6000 MWD/MTU, PCT for Zirc-4 fuel is bounded by PCT for ZIRLO fuel.

The analyses presented in this section show that the accumulator and safety injection subsystems of the Emergency Core Cooling System, together with the heat removal capability of the steam generator, provide sufficient core heat removal capability to maintain the calculated peak cladding temperatures below the required limit of 10 CFR 50.46.

6.1.1.7 References

1. "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Cooled Nuclear Power Reactors," 10 CFR 50.46 and Appendix K of 10 CFR 50, Federal Register, Volume 39, Number 3, January 1974, as amended in Federal Register, Volume 53, September 1988.

2. Meyer, P. E., "NOTRUMP - A Nodal Transient Small Break and General Network Code," WCAP-10079-P-A, (proprietary) and WCAP-10080-NP-A (non-proprietary), August 1985.

3. Lee, N. et al., "Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code," WCAP-10054-P-A (proprietary) and WCAP-10081-NP-A (non-proprietary), August 1985.

4. "Generic Evaluation of Feedwater Transients and Small Break Loss-of-Coolant Accidents in Westinghouse - Designed Operating Plant," NUREG-0611, January 1980.

5. Bordelon, F. M. et al., "LOCTA-IV Program: Loss-of-Coolant Transient Analysis," WCAP-8301 (proprietary) and WCAP-8305 (non-proprietary), June 1974.

6. Rupprecht, S. D. et al., "Westinghouse Small Break LOCA ECCS Evaluation Model Generic Study with the NOTRUMP Code," WCAP-11145-P-A (proprietary), October 1986.

Table 6.1.1-1

Input Parameters Used in the Small Break LOCA Analysis

Input Parameter	Value	
Core Rated Thermal Power-100%	3586.6	
Fuel Type	17 X 17 V5+	
Total Core Peaking Factor, F_Q	2.6	
FDH	1.7	
FNZ	1.53	
PHA	1.514	
Maximum Axial Offset	+13%	
Initial RCS Loop Flow	92,000 gpm/loop	
Initial Vessel T_{avg}	Max: 598.0 °F Min: 565.0 °F	
Initial Pressurizer Pressure	2300 psia	
Pump Type	With RCP Weir	
Low Pressurizer Pressure Reactor Trip Signal	1857 psia	
Trip Signal Processing Time	2.0 seconds	
Reactor Trip Delay Time	6.0 seconds	
Aux. Feedwater Temp. (Maximum)	125 °F	
Number and Types of Pumps Available Following a LOOP	1 Diesel Driven	
AF Flow (Minimum)	560 gpm Total to 4 SGs (at 1284 psia or less)	
AF Delay Time (Maximum)	90 seconds	
AF Actuation Signal	LPP SI	
STEAM GENERATORS	BWI SG	D5 SG
Max AF Enthalpy Switchover Purge Volumes, ft^3	160 ft^3	60 ft^3
SGTP (Maximum)	5%	10%
Max. MFW Isolation Delay Time	2 seconds	
MFW Isolation Ramp Time	6 seconds	
MFW Isolation Signal	LPP SI	
Isolation of Steam Line	LPP RT/LOOP	

Table 6.1.1-1 (cont.) Input Parameters Used in the Small Break LOCA Analysis		
Input Parameter	**Value**	
Steam Generator Secondary Water Mass, lbm/SG	111,000	79,194
Pressure Drop from SG to Steam Header	20 psi	
Containment Spray Flowrate for 2 Pumps (Maximum)	9255 gpm	
RWST Deliverable Volume (Minimum)	180888 gallons	
SI Temp at Cold Leg Recirc.	212 °F	
ECCS Configuration	1 IHSI Pump and 1 Charging Pump spill to RCS Pressure	
ECCS Water Temp.	Max: 120 °F	
Safety Injection Signal	1715 psia	
SI Signal Delay Time	40 seconds	
ECCS Flow vs Pressure	See Table 6.1.1-1A	
Initial Accumulator Water/Gas Temperature	130 °F	
Initial Nominal Acc. Water Vol.	950 ft^3	
Min Acc. Cover Press. (With Uncertainty Consideration)	600 psia	

Table 6.1.1-1a

Safety Injection Flows Used in the Small Break LOCA Analysis

(Flows Account for 5% Reduction Due to Pump Degradation)

RCS Pressure (psia)	Intact Loop (lbm/sec)	Broken Loop (lbm/sec)
15	92.8	37.1
100	90.1	36.0
200	86.6	34.6
300	83.4	33.3
400	80.1	32.0
500	76.5	30.5
600	72.7	29.0
700	68.9	27.5
800	64.6	25.8
900	59.9	23.9
1000	54.1	21.6
1100	47.2	18.8
1200	37.9	15.1
1300	25.5	10.1
1400	20.5	8.1
1500	19.0	7.5
1600	17.3	6.8
1700	15.4	6.1
1800	13.5	5.4
1900	11.5	4.6
2000	9.3	3.7
2100	7.0	2.8
2200	3.3	1.3
2300	0.0	0.0

Table 6.1.1-2 Units 1 Hi T_{avg} Case SBLOCTA Results				
	1.5 Inch	2 Inch	3 Inch	4 Inch
PCT (°F)	765	1570	1514	1428
PCT Time (s)	22680.6	3434.5	1834.7	1019.1
PCT Elevation (ft)	11.25	11.75	11.5	11.25
Burst Time (s)	N/A	N/A	N/A	N/A
Burst Elevation (ft)	N/A	N/A	N/A	N/A
Max. Local ZrO_2 (%)	0.01	1.17	0.89	0.29
Max. Local ZrO_2 Elev (ft)	11.25	11.75	11.50	11.25
Core-Wide Avg. ZrO_2 (%)	0.00	0.17	0.14	0.05

Table 6.1.1-3 Units 1 Low T_{avg} Case SBLOCTA Results				
	1.5 Inch	2 Inch	3 Inch	4 Inch
PCT (°F)	731	1602	1457	1292
PCT Time (s)	22894.8	3495.8	2013.5	1099.7
PCT Elevation (ft)	11.50	11.75	11.5	11.25
Burst Time (s)	N/A	N/A	N/A	N/A
Burst Elevation (ft)	N/A	N/A	N/A	N/A
Max. Local ZrO2 (%)	0.00	1.30	0.62	0.11
Max. Local ZrO2 Elev (ft)	11.50	11.75	11.50	11.25
Core-Wide Avg. ZrO2 (%)	0.00	0.19	0.10	0.02

Table 6.1.1-4 Units 2 Hi T_{avg} Case SBLOCTA Results				
	1.5 Inch	**2 Inch**	**3 Inch**	**4 Inch**
PCT (°F)	912	1086	1614	1537
PCT Time (s)	16234.8	2804.5	1618.5	889.0
PCT Elevation (ft)	11.25	11.25	11.50	11.25
Burst Time (s)	N/A	N/A	N/A	N/A
Burst Elevation (ft)	N/A	N/A	N/A	N/A
Max. Local ZrO2 (%)	0.03	0.06	1.48	0.65
Max. Local ZrO2 Elev (ft)	11.25	11.25	11.50	11.25
Core-Wide Avg. ZrO2 (%)	0.00	0.01	0.23	0.11

Table 6.1.1-5 Units 2 Low T_{avg} Case SBLOCTA Results				
	1.5 Inch	**2 Inch**	**3 Inch**	**4 Inch**
PCT (°F)	874	1604	1452	1313
PCT Time (s)	17491.8	3159.5	1805.6	992.3
PCT Elevation (ft)	11.00	11.50	11.50	11.25
Burst Time (s)	N/A	N/A	N/A	N/A
Burst Elevation (ft)	N/A	N/A	N/A	N/A
Max. Local ZrO2 (%)	0.03	1.42	0.61	0.14
Max. Local ZrO2 Elev (ft)	11.00	11.75	11.50	11.25
Core-Wide Avg. ZrO2 (%)	0.00	0.21	0.09	0.02

Table 6.1.1-6 ZIRC-4 SBLOCTA Results			
	Units 1 Low T_{AVG} 2 Inch	Units 2 Hi T_{AVG} 3 Inch BU = BOL	Units 2 Hi T_{AVG} 3 Inch BU = 6000 MWD/MTU
PCT (°F)	1601	1615	1601
PCT Time (s)	3494.5	1618.5	1624.7
PCT Elevation (ft)	11.75	11.50	11.75
Burst Time (s)	N/A	N/A	N/A
Burst Elevation (ft)	N/A	N/A	N/A
Max. Local ZrO2 (%)	1.30	1.5	1.48
Max. Local ZrO2 Elev (ft)	11.75	11.5	11.50
Core-Wide Avg. ZrO2 (%)	0.19	0.23	0.45

Table 6.1.1-7 Units 1 Hi T_{avg} Case NOTRUMP Results				
Event Time (sec)	**1.5 Inch**	**2 Inch**	**3 Inch**	**4 Inch**
Break Initiation	0	0	0	0
Reactor Trip Signal	147.1	82.3	54.4	24.7
S-Signal	159.3	93.9	66.5	35.6
SI Delivered	199.3	133.9	106.5	75.6
Loop Seal Clearing*	2692	1362	586	350
Core Uncovery	15020	2112	863	637
Accumulator Injection	N/A	N/A	2002	920
RWST Switchover Time	1146.7	1143.3	1136.1	1114.8
PCT Time	22680.6	3434.5	1834.7	1019.1
Core Recovery**	>TMAX	>TMAX	2960	2200

Table 6.1.1-8 Units 1 Low T_{avg} Case NOTRUMP Results				
Event Time (sec)	**1.5 Inch**	**2 Inch**	**3 Inch**	**4 Inch**
Break Initiation	0	0	0	0
Reactor Trip Signal	79.0	41.8	17.7	10.2
S-Signal	123.3	65.2	27.1	14.1
SI Delivered	163.3	105.2	67.1	54.1
Loop Seal Clearing*	2845	1457	647	380
Core Uncovery	16040	2290	1032	731.1
Accumulator Injection	N/A	N/A	2119	991
RWST Switchover Time	1146.8	1143.1	1137.5	1116.3
PCT Time	22894.8	3495.8	2013.5	1099.7
Core Recovery**	>TMAX	>TMAX	2955	2150

* Loop seal clearing is defined as break vapor flow > 1 lb/s

** For the cases, where core recovery is > TMAX, basis for transient termination can be concluded based on the following arguments: (1) The RCS system pressure is decreasing which will increase SI flow, (2) Total RCS system mass is increasing due to SI flow exceeding break flow, (3) Core mixture level has begun to increase and is expected to continue for the remainder of the accident.

Table 6.1.1-9
Units 2 Hi T_{avg} Case
NOTRUMP Results

Event Time (sec)	1.5 Inch	2 Inch	3 Inch	4 Inch
Break Initiation	0	0	0	0
Reactor Trip Signal	142.1	80.2	59.0	24.6
S-Signal	154.6	91.8	71.6	36.4
SI Delivered	194.6	131.8	111.6	76.4
Loop Seal Clearing*	2254	1114.2	485	292
Core Uncovery	9810	1809.3	771	510
Accumulator Injection	N/A	N/A	1732	990.8
RWST Switchover Time	1147.4	1144.3	1132.9	1111.3
PCT Time	16234.8	2804.5	1618.5	889.0
Core Recovery**	37098	4740	2754	2378

Table 6.1.1-10
Units 2 Low T_{avg} Case
NOTRUMP Results

Event Time (sec)	1.5 Inch	2 Inch	3 Inch	4 Inch
Break Initiation	0	0	0	0
Reactor Trip Signal	77.7	41.3	17.6	10.2
S-Signal	117.8	59.6	27.2	14.3
SI Delivered	157.8	67.2	96.6	54.3
Loop Seal Clearing*	2381	1215.5	549.3	311.9
Core Uncovery	10750	1938	717.9	614.5
Accumulator Injection	N/A	N/A	1928.1	882.6
RWST Switchover Time	1147.5	1144.0	1133.9	1112.7
PCT Time	17491.8	3159.5	1805.6	992.3
Core Recovery**	36950	5740	2826	2103

* Loop seal clearing is defined as break vapor flow > 1 lb/s

** For the cases, where core recovery is > TMAX, basis for transient termination can be concluded based on the following arguments: (1) The RCS system pressure is decreasing which will increase SI flow, (2) Total RCS system mass is increasing due to SI flow exceeding break flow, (3) Core mixture level has begun to increase and is expected to continue for the remainder of the accident.

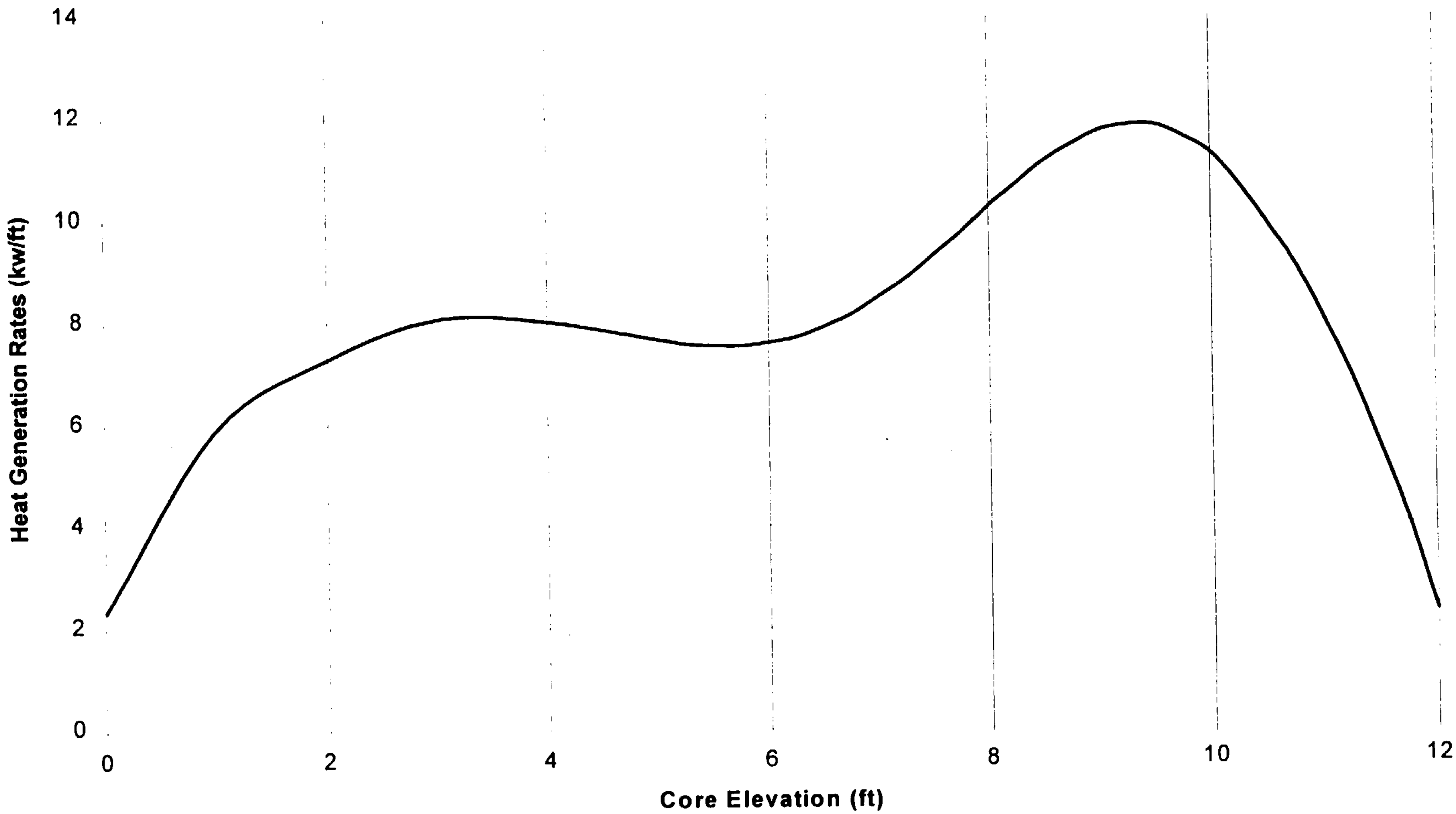


Figure 6.1.1–1

Small Break Hot Rod Power Shape

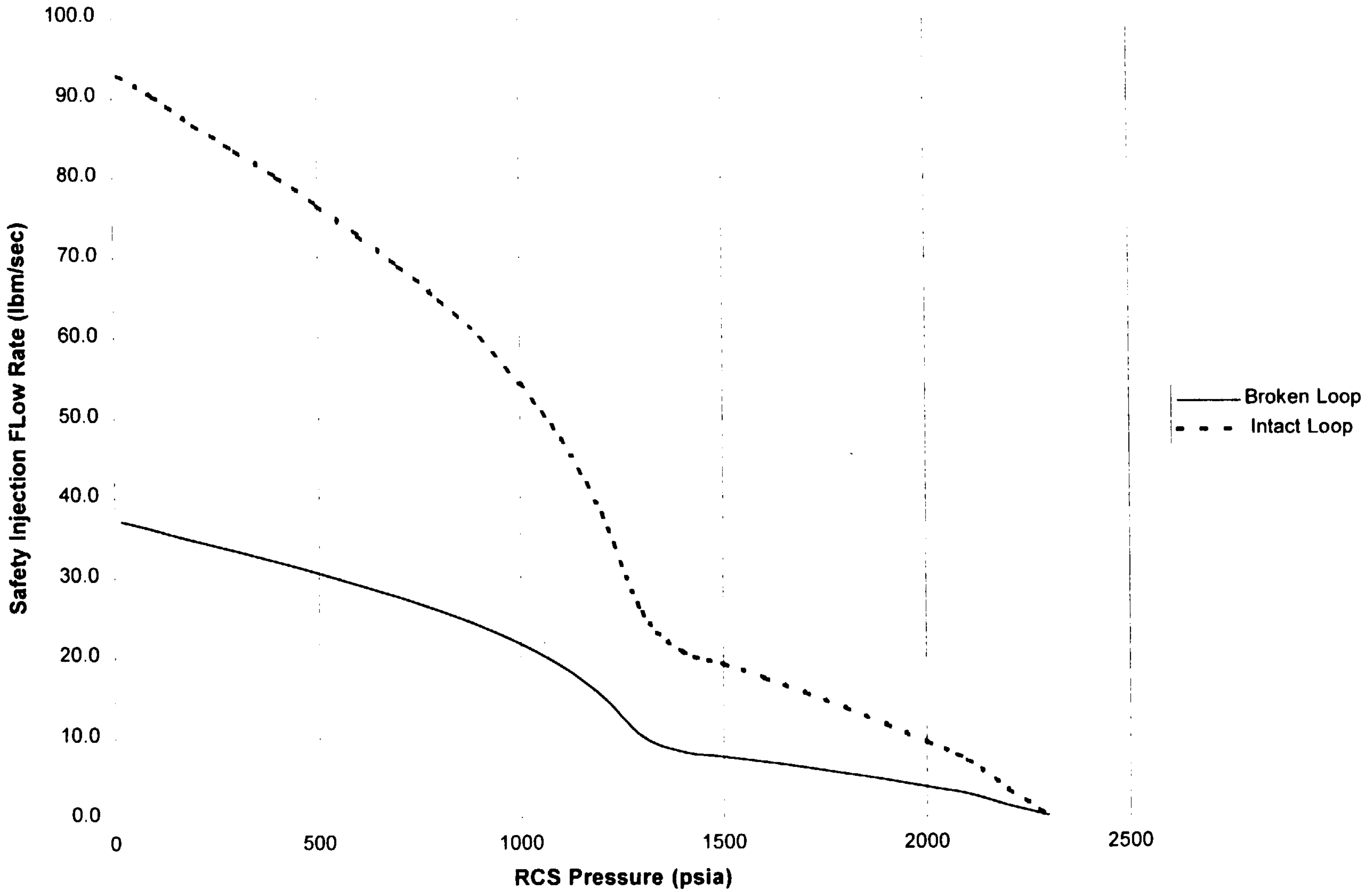


Figure 6.1.1–2

Small Break LOCA Safety Injection Flows

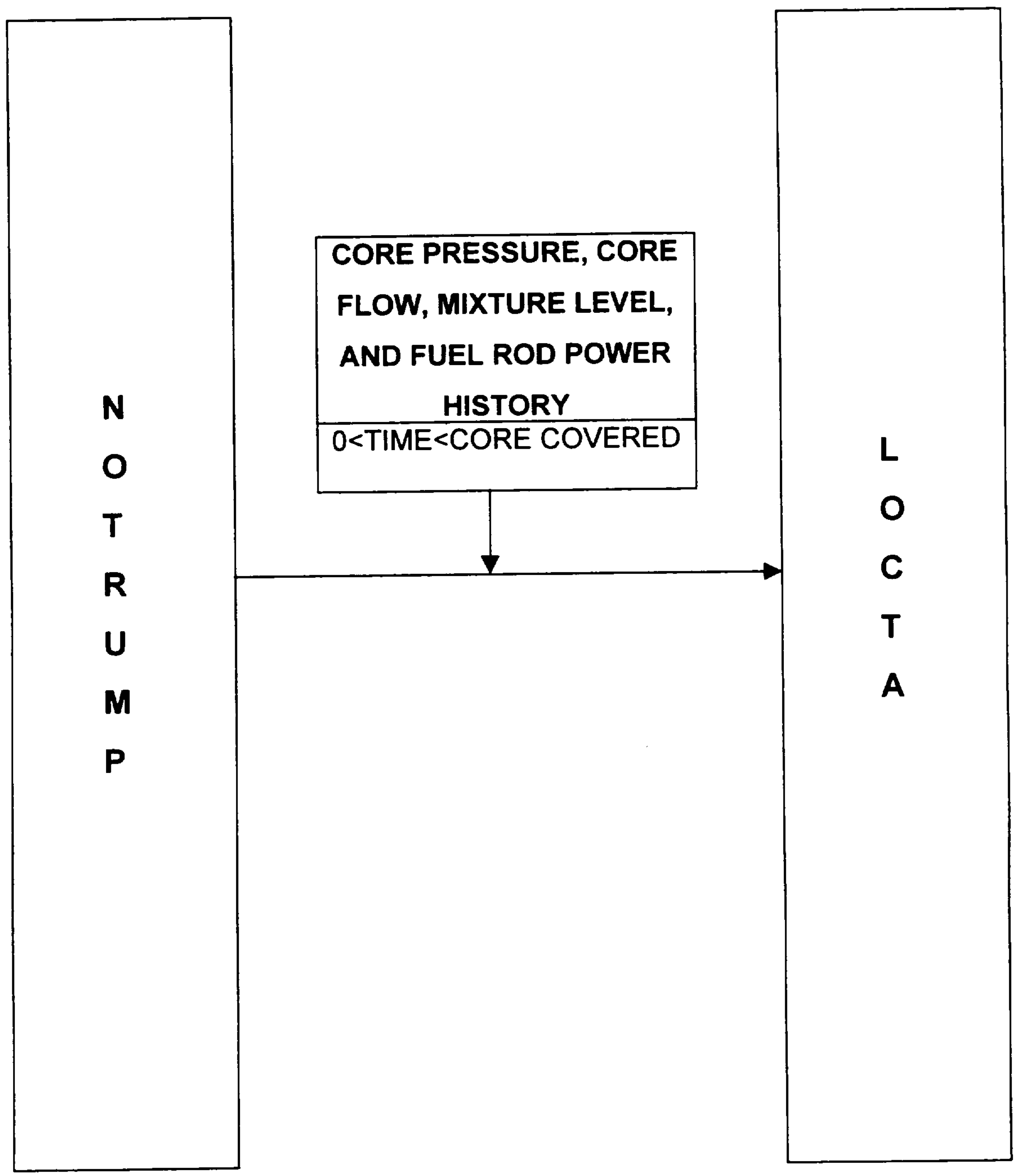


Figure 6.1.1–3
Code Interface Description
for Small Break Model

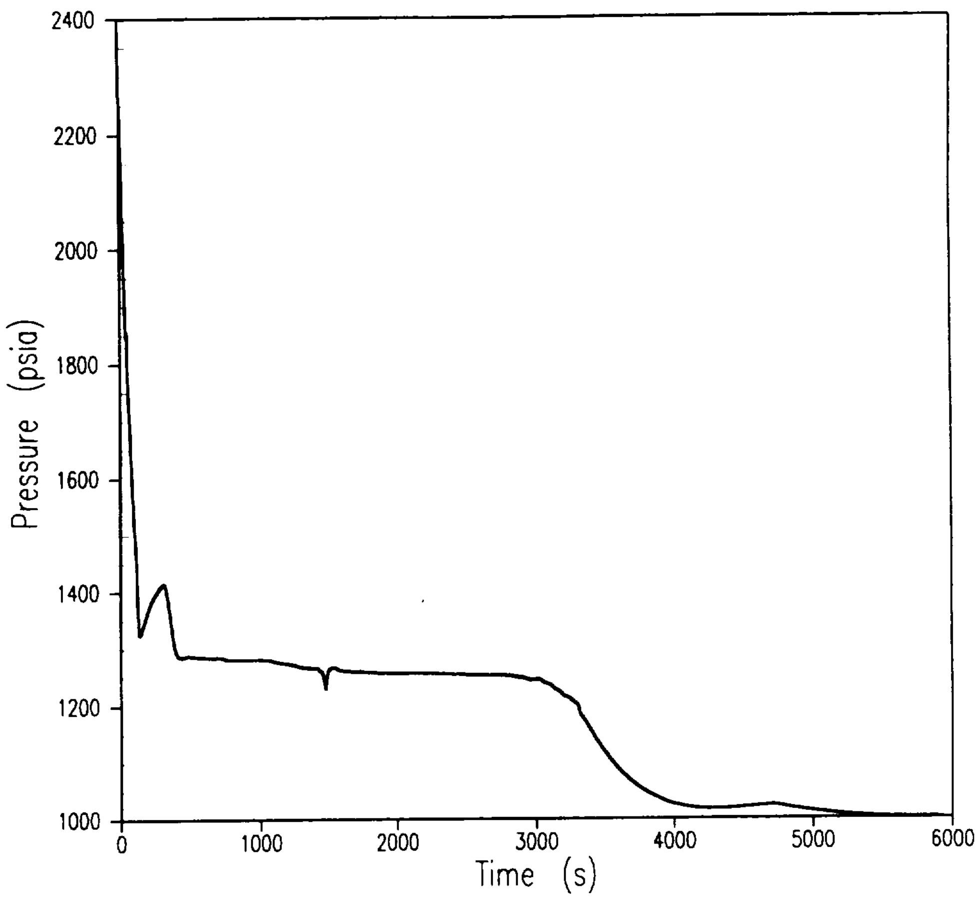


Figure 6.1.1–4

Units 1 Low T_{avg} 2-Inch

RCS Pressure

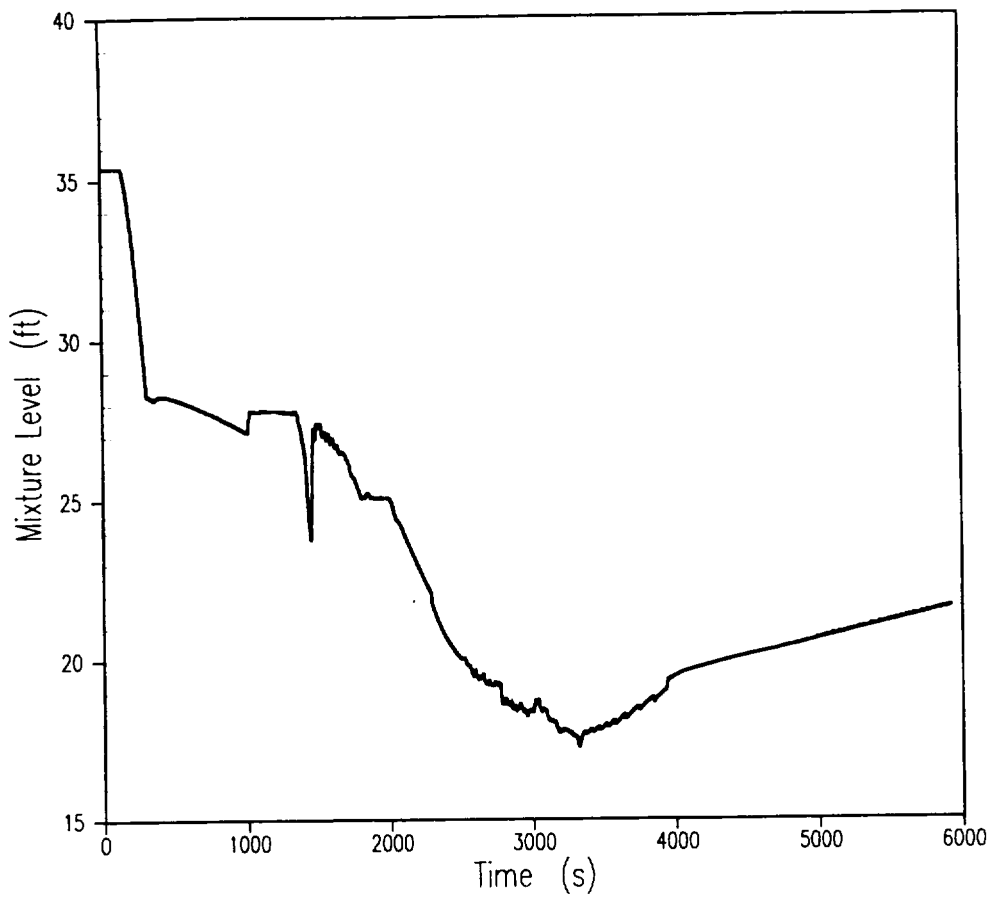


Figure 6.1.1–5

Units 1 Low T_{avg} 2-Inch

Core Mixture Level

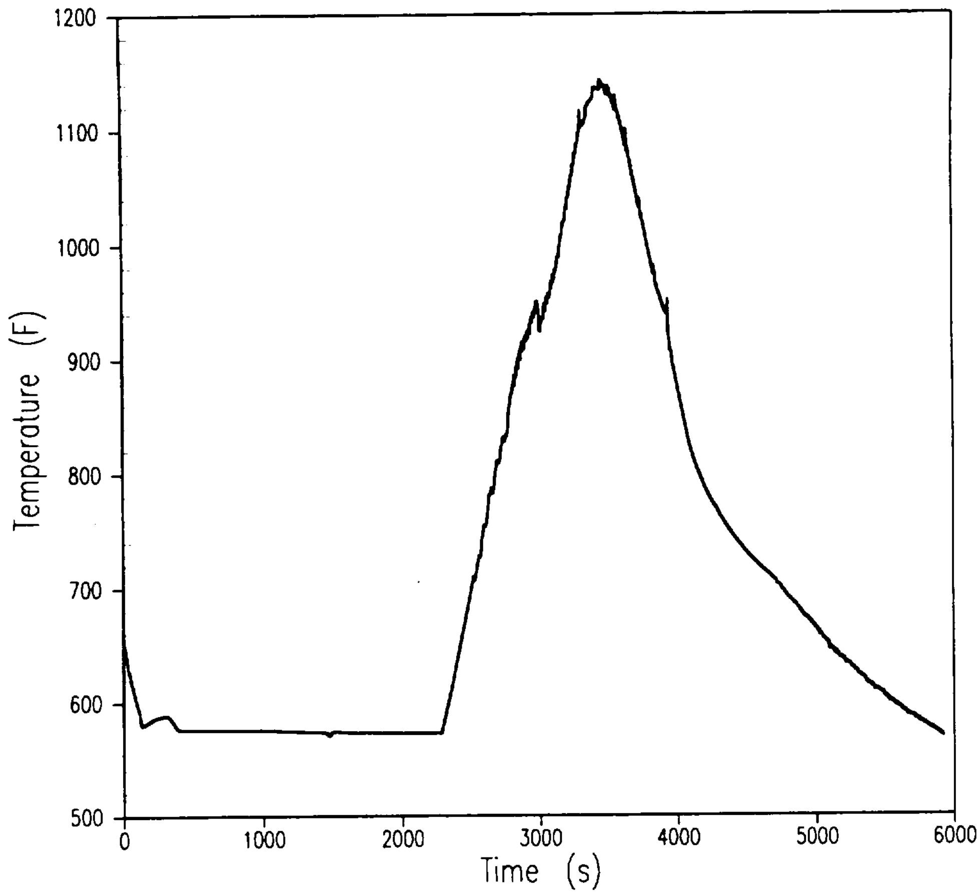


Figure 6.1.1–6

Units 1 Low T_{avg} 2-Inch

Core Exit Vapor Temperature

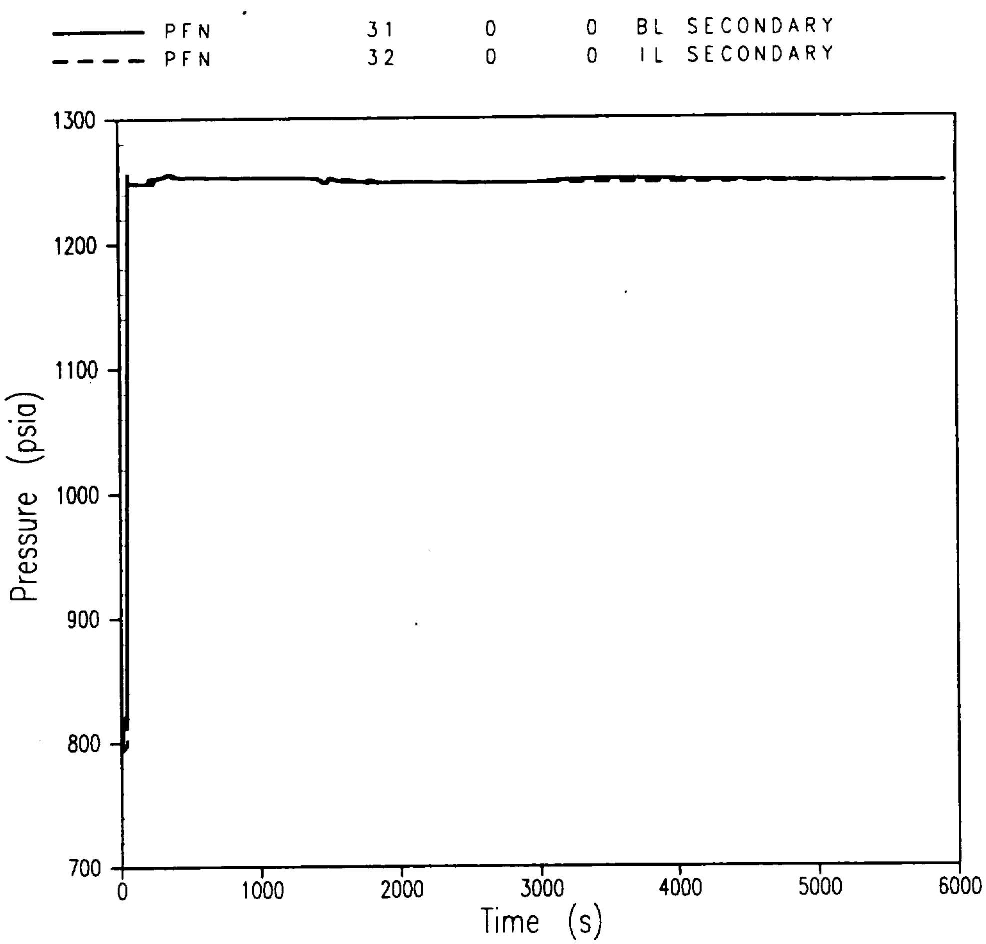


Figure 6.1.1–7

Units 1 Low T_{avg} 2-Inch

Broken Loop and Intact Loop Secondary Pressure

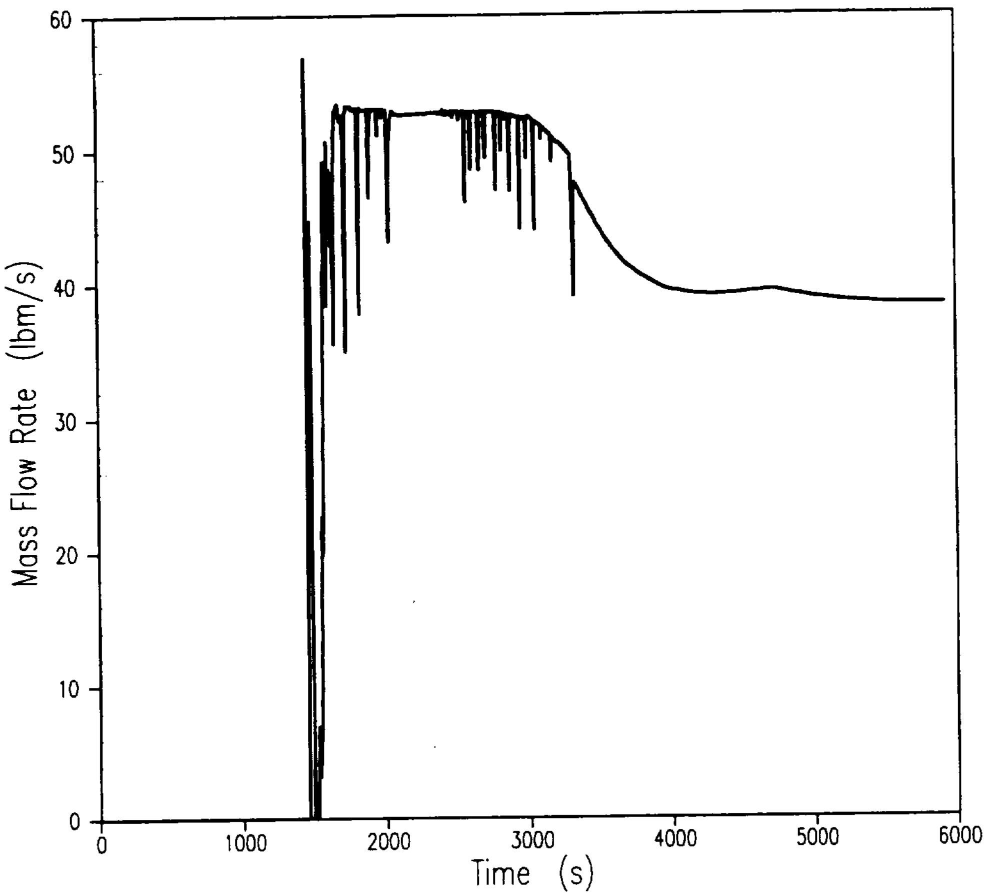


Figure 6.1.1–8

Units 1 Low T_{avg} 2-Inch

Break Vapor Flow Rate

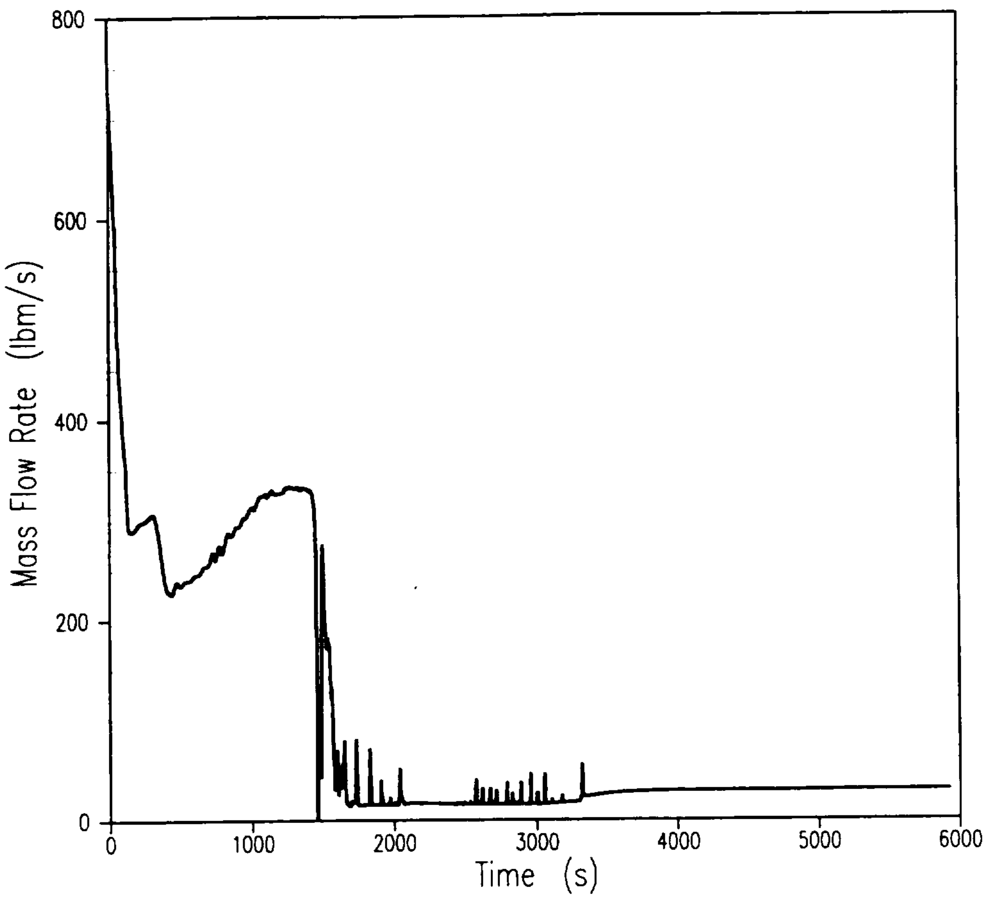


Figure 6.1.1–9

Units 1 Low T_{avg} 2-Inch

Break Liquid Flow Rate

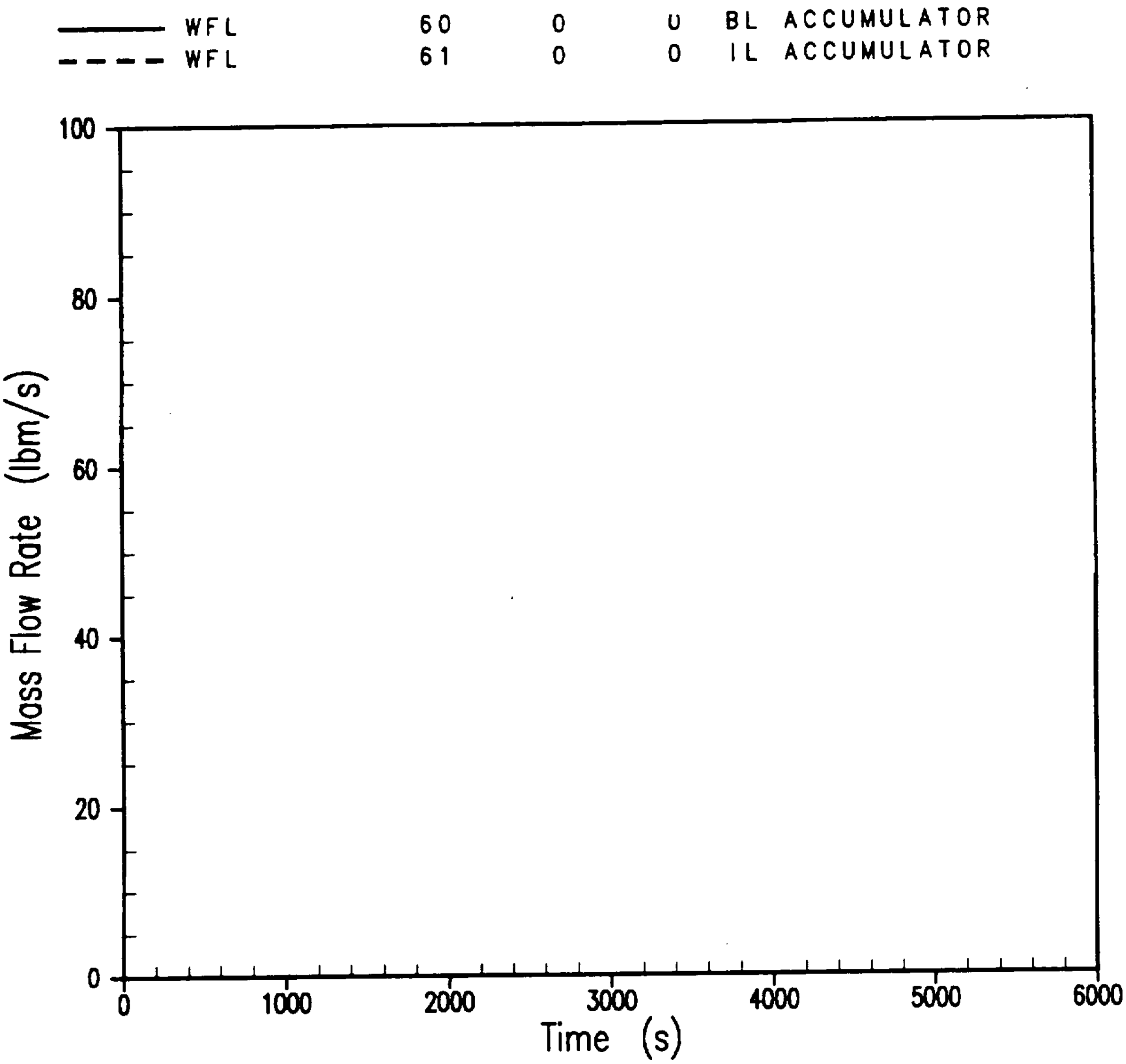


Figure 6.1.1-10

Units 1 Low T_{avg} 2-Inch

Broken Loop and Intact Loop Accumulator Flow Rate

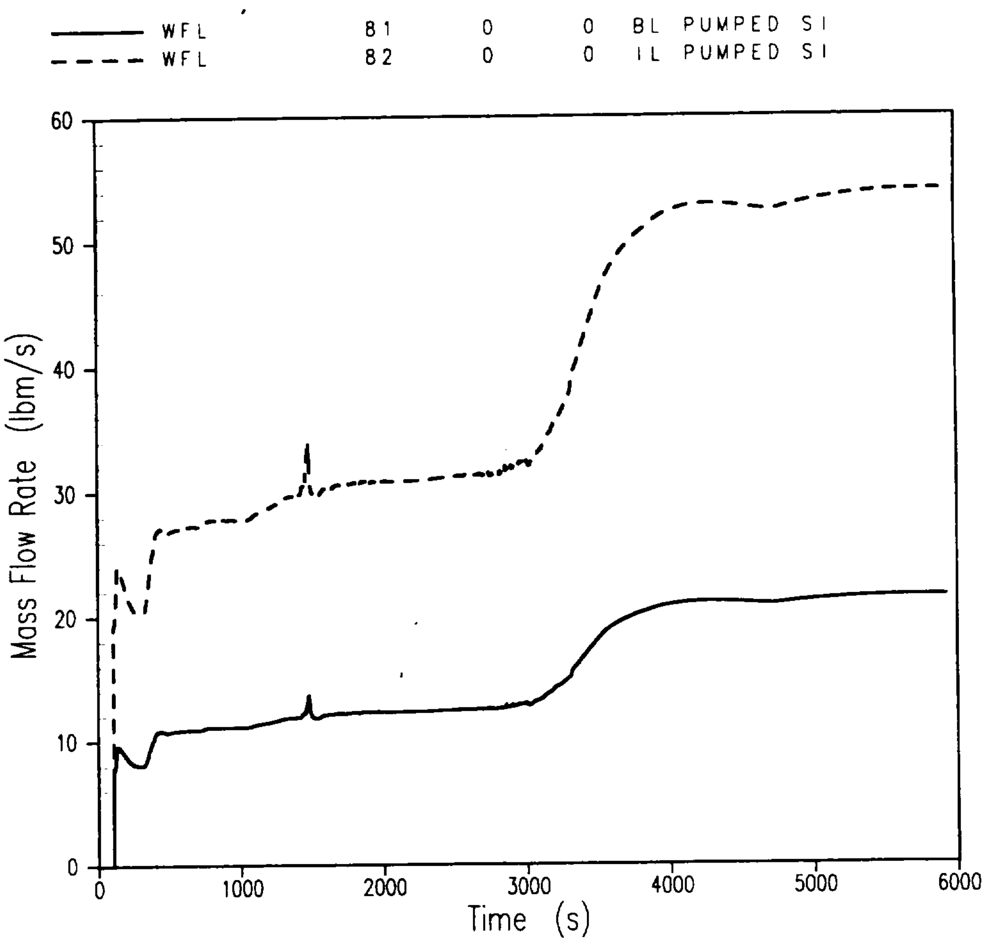


Figure 6.1.1-11

Units 1 Low T_{avg} 2-Inch

Broken Loop and Intact Loop Pumped Safety Injection Flow

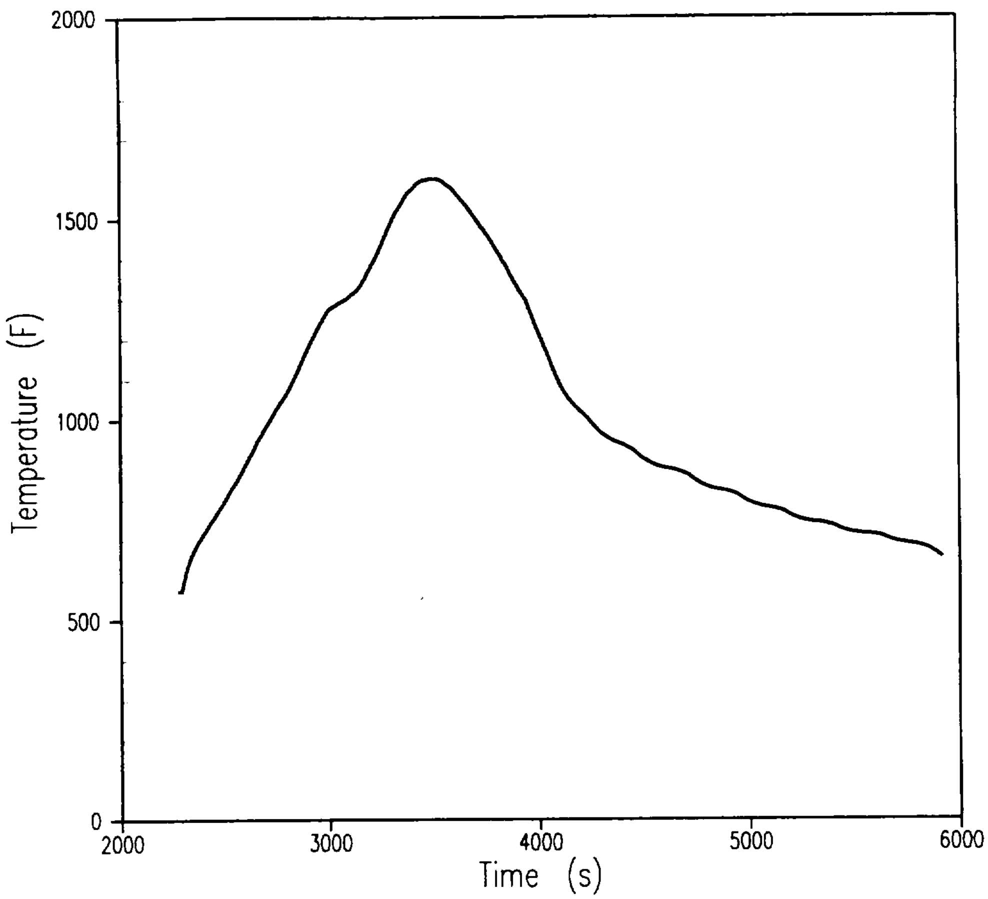


Figure 6.1.1-12

Units 1 Low T_{avg} 2-Inch

Peak Clad Temperature at 11.75 ft.

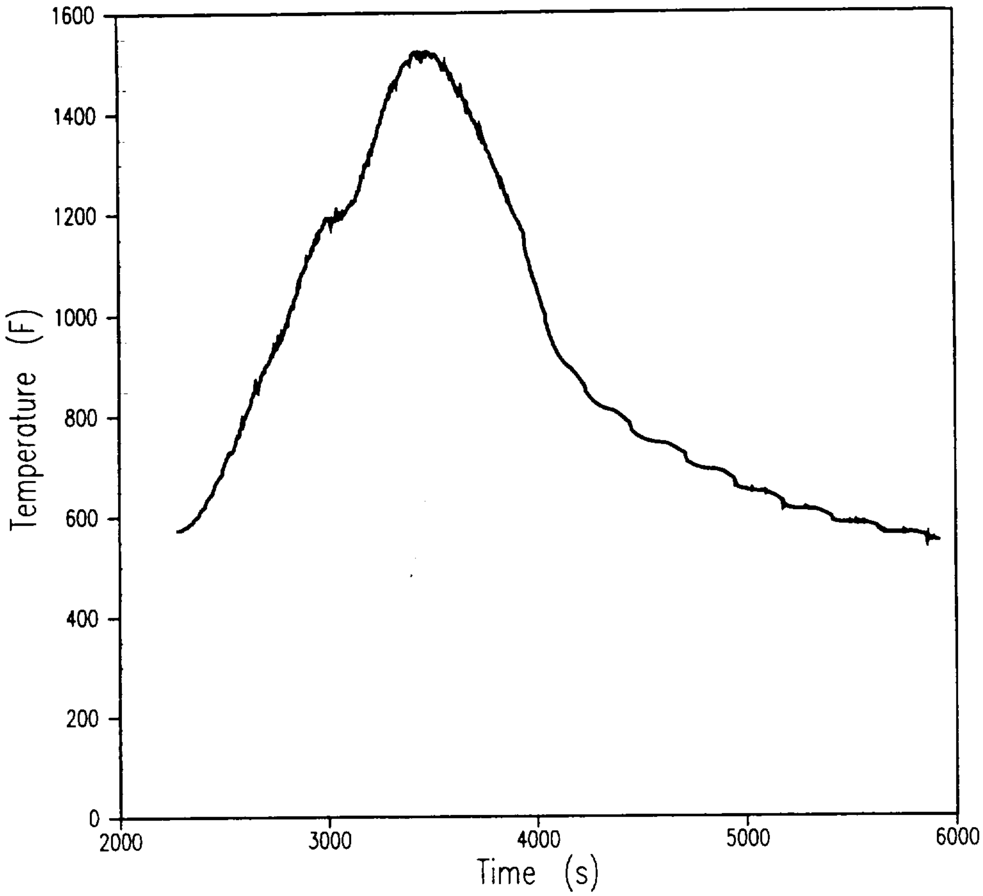


Figure 6.1.1-13

Units 1 Low T_{avg} 2-Inch

Hot Spot Fluid Temperature

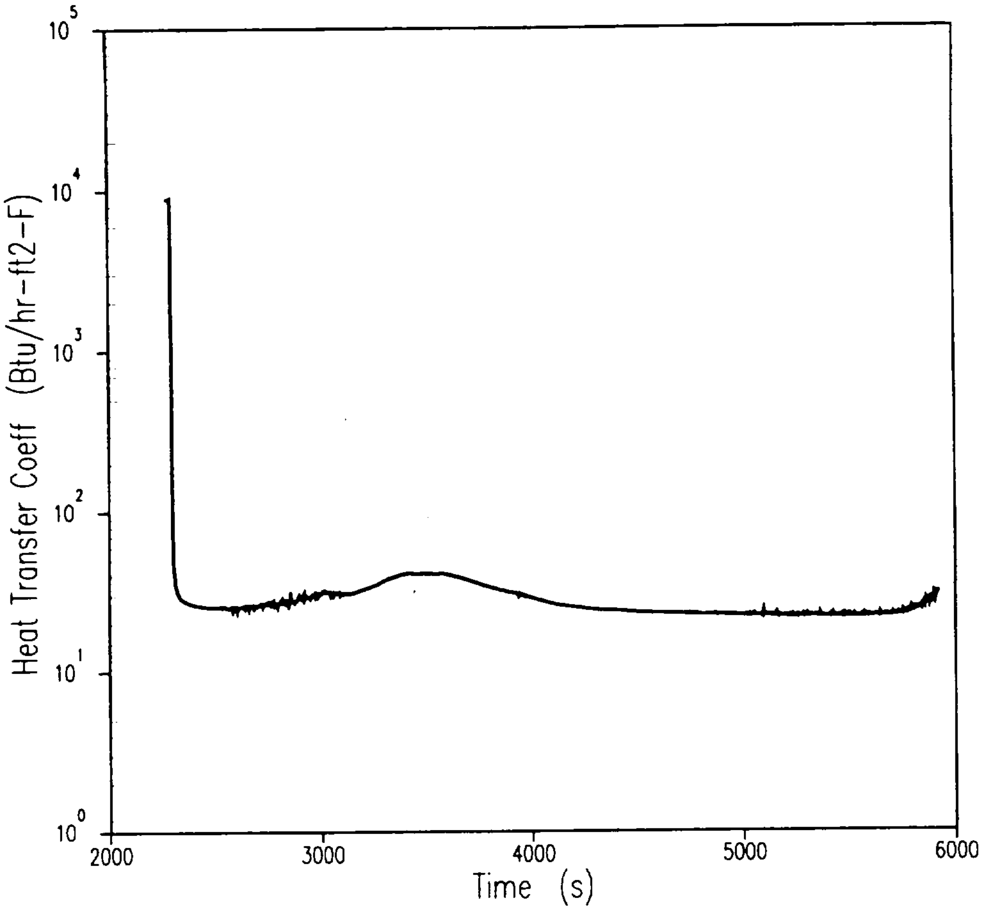


Figure 6.1.1-14

Units 1 Low T_{avg} 2-Inch

Rod Film Heat Transfer Coefficient at 11.75 ft.

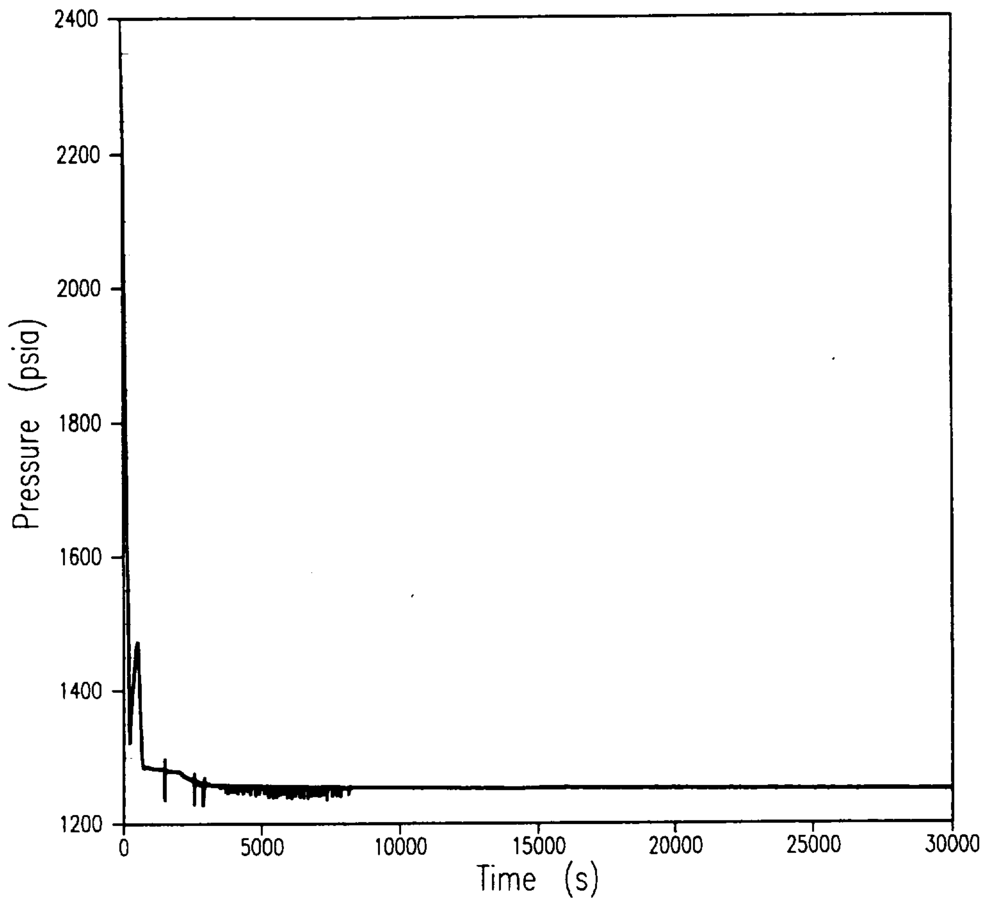


Figure 6.1.1-15

Units 1 Low T_{avg} 1.5-Inch

RCS Pressure

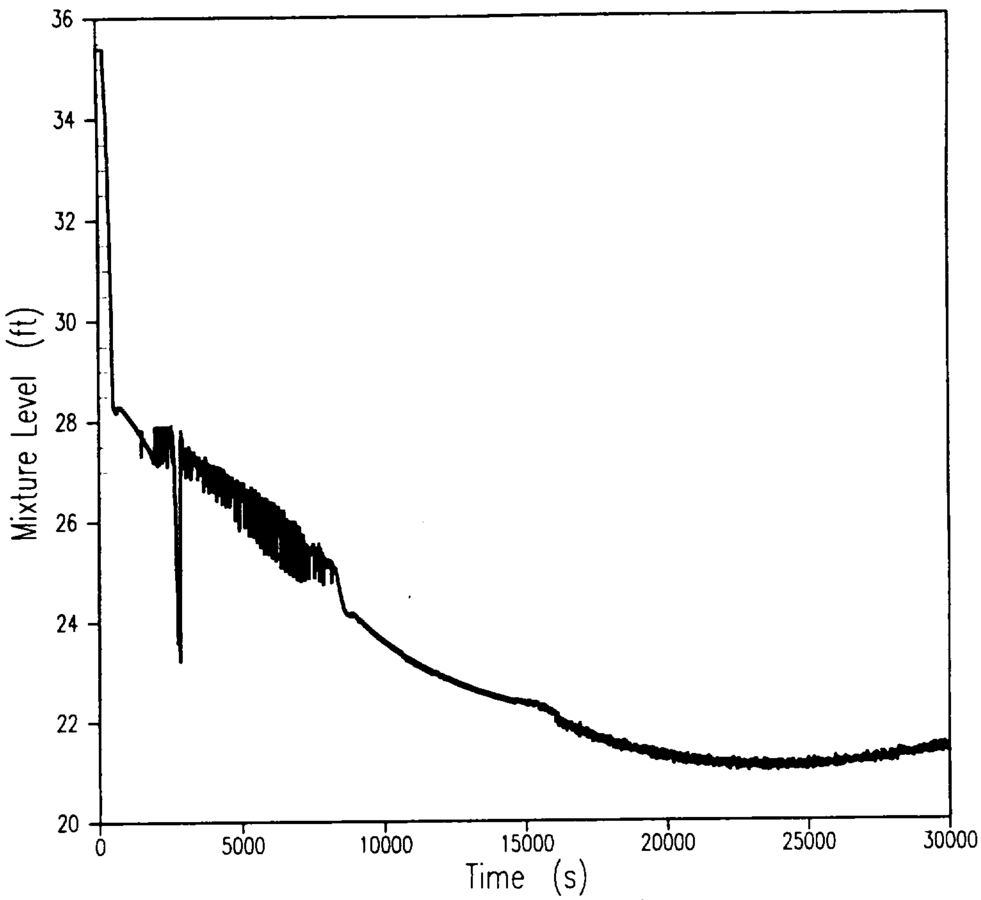


Figure 6.1.1-16

Units 1 Low T_{avg} 1.5-Inch

Core Mixture Level

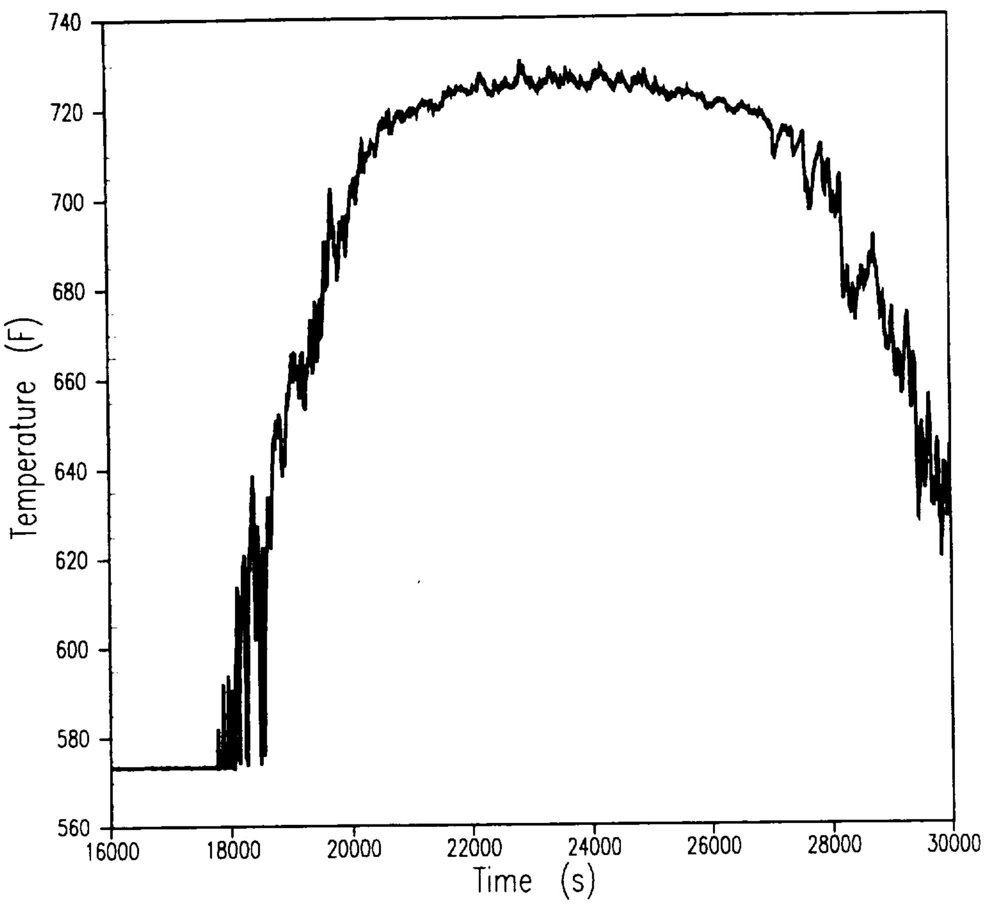


Figure 6.1.1-17

Units 1 Low T_{avg} 1.5-Inch

Peak Clad Temperature at 11.5 ft.

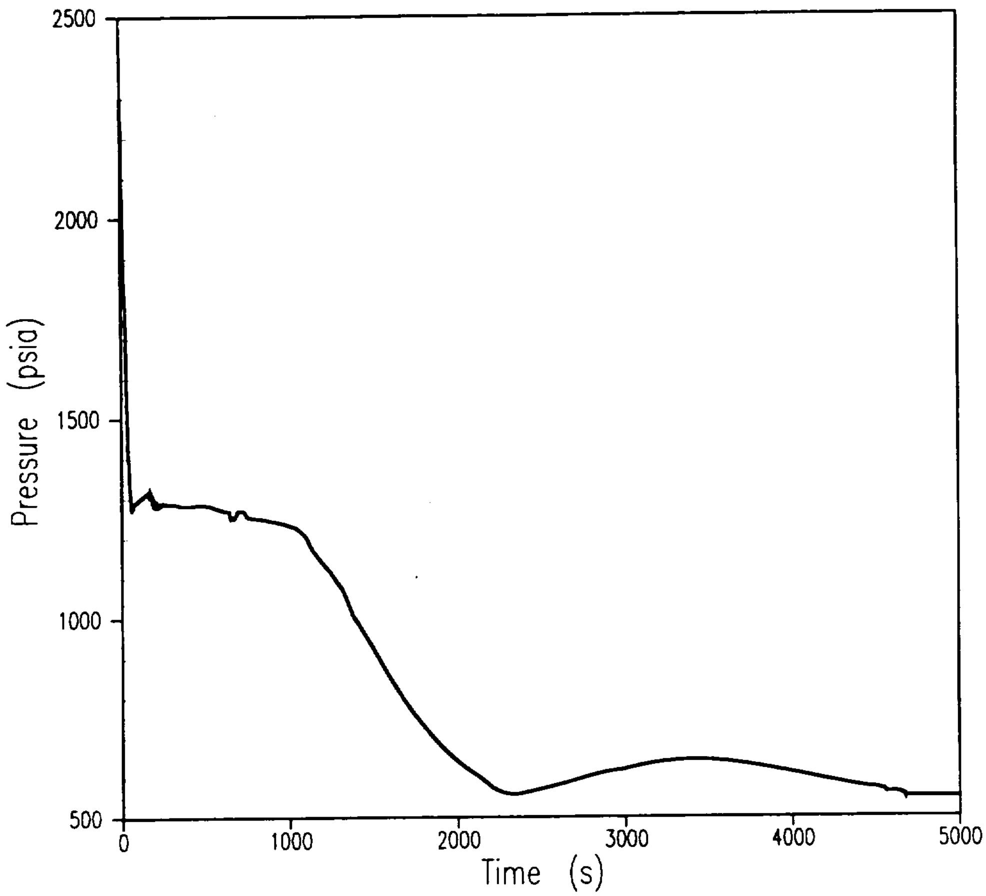


Figure 6.1.1-18

Units 1 Low T_{avg} 3-Inch

RCS Pressure

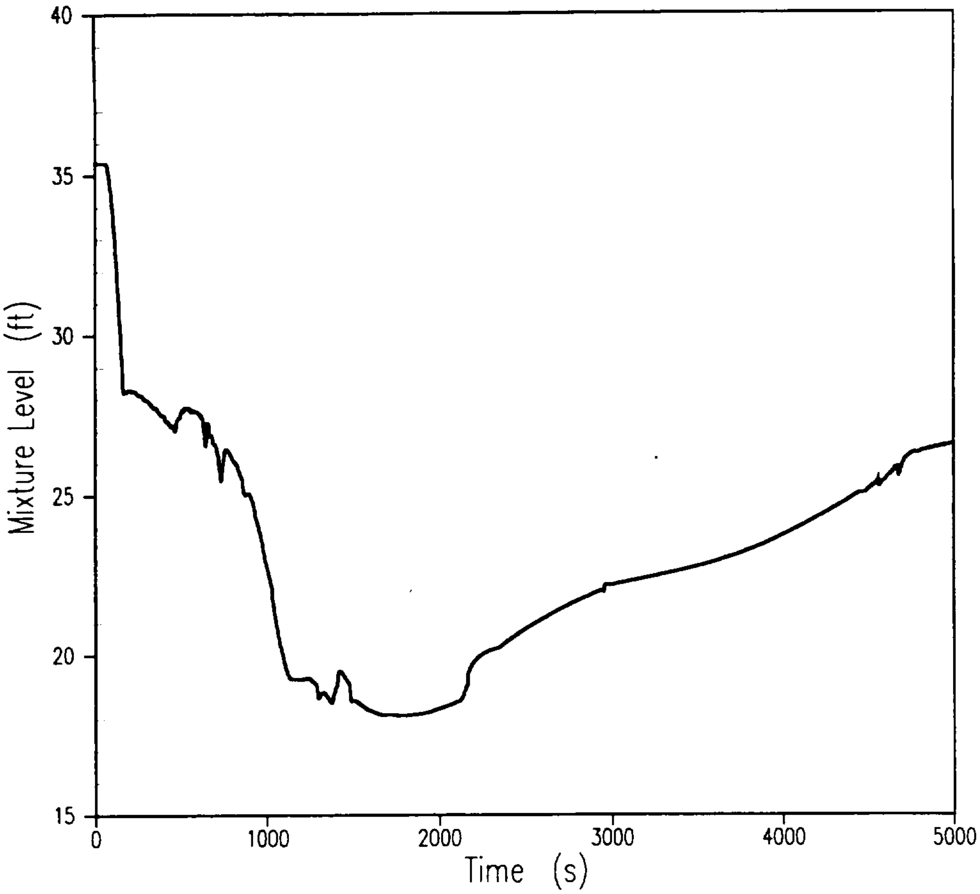


Figure 6.1.1-19

Units 1 Low T_{avg} 3-Inch

Core Mixture Level

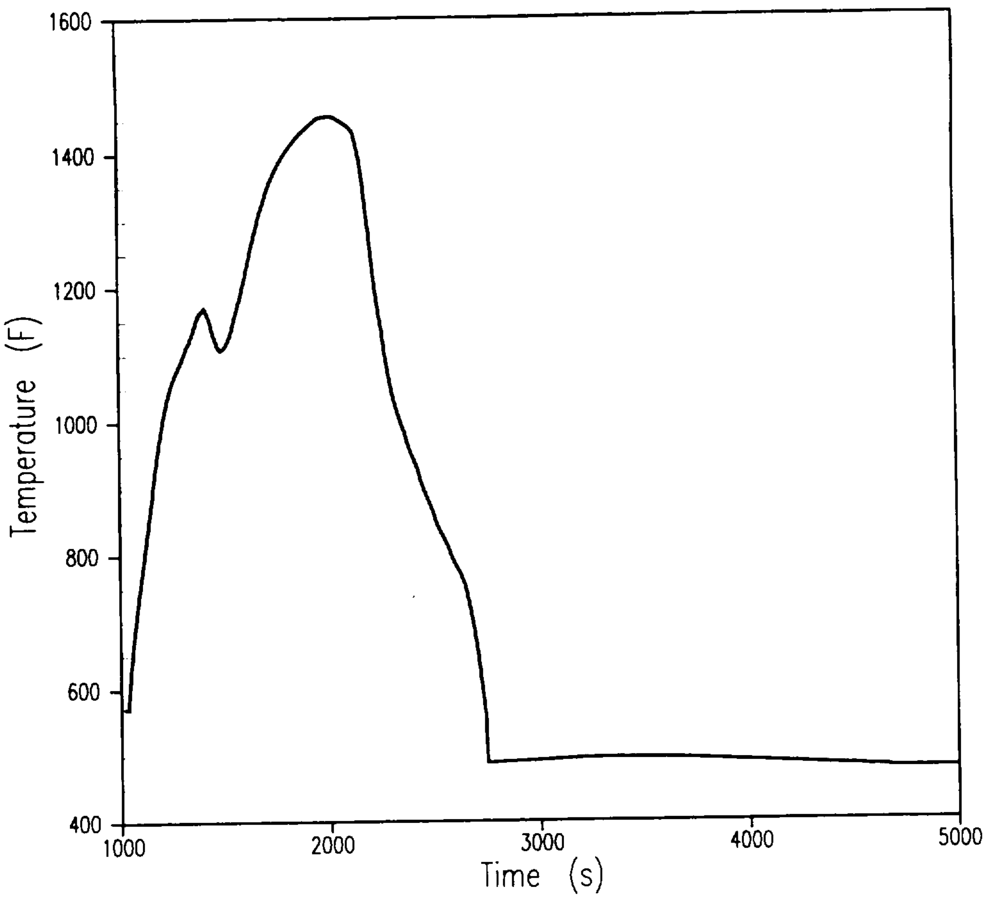


Figure 6.1.1-20

Units 1 Low T_{avg} 3-Inch

Peak Clad Temperature at 11.5 ft.

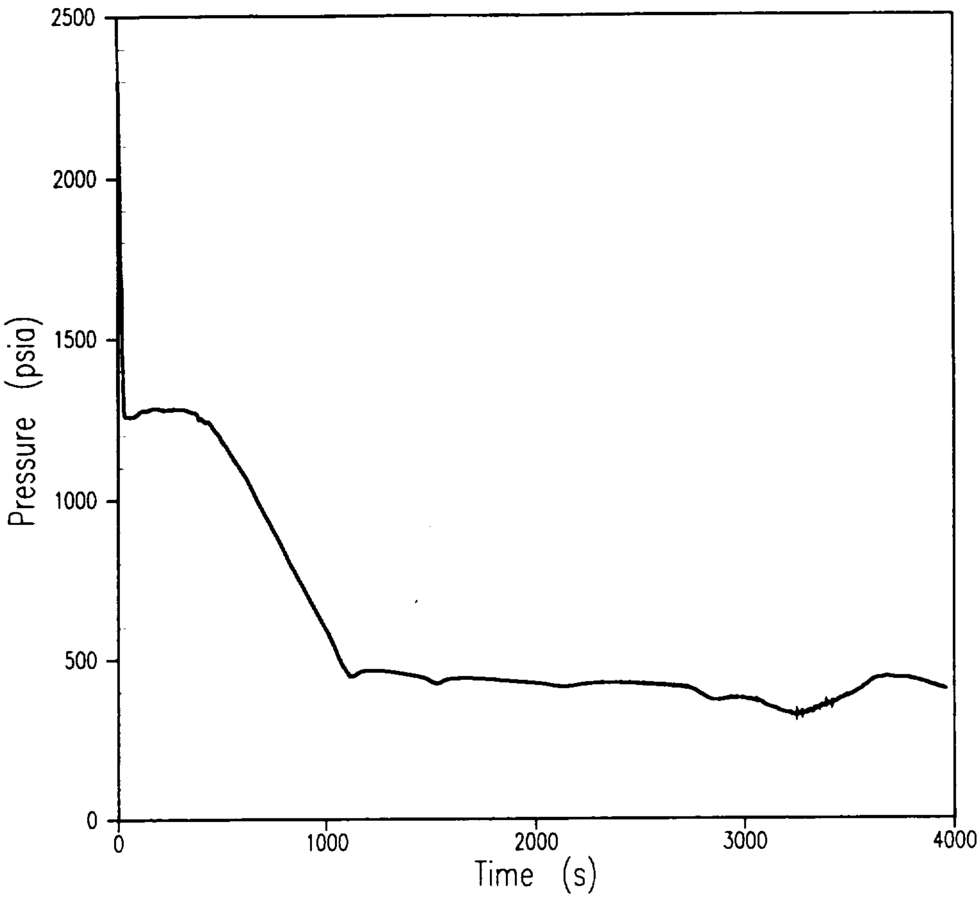


Figure 6.1.1-21

Units 1 Low T_{avg} 4-Inch

RCS Pressure

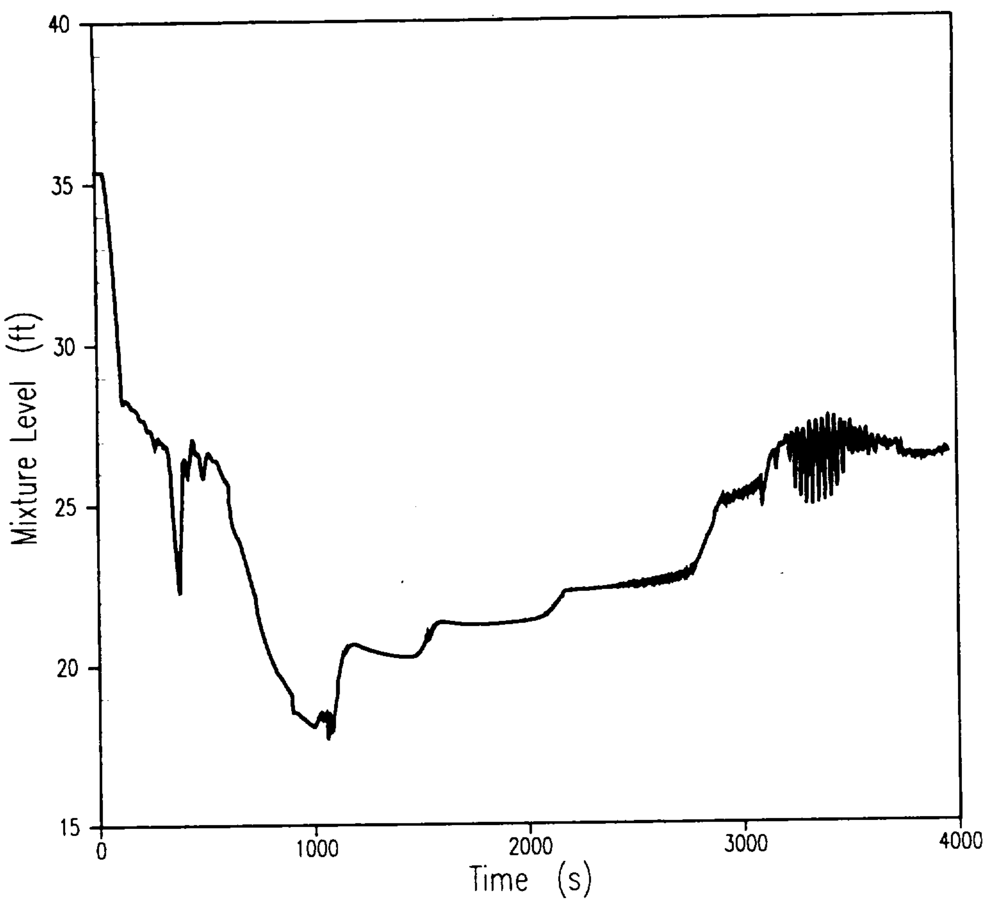


Figure 6.1.1-22

Units 1 Low T_{avg} 4-Inch

Core Mixture Level

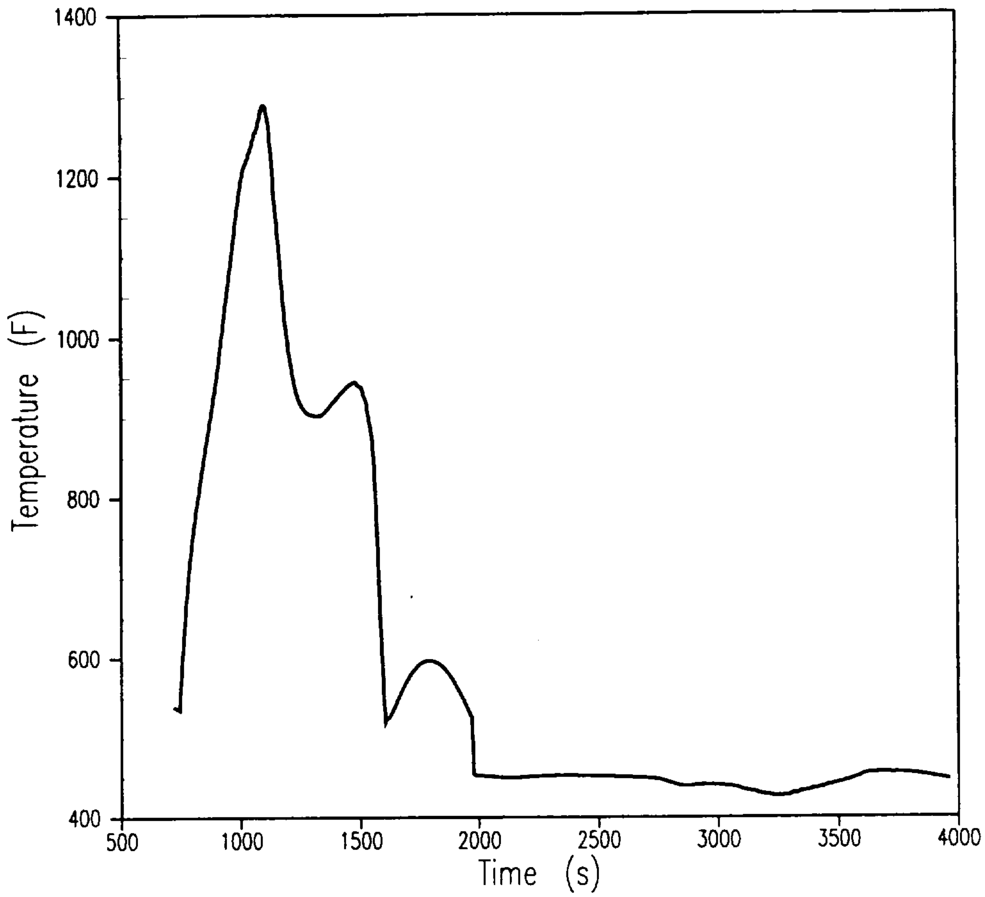


Figure 6.1.1-23

Units 1 Low T_{avg} 4-Inch

Peak Clad Temperature at 11.25 ft.

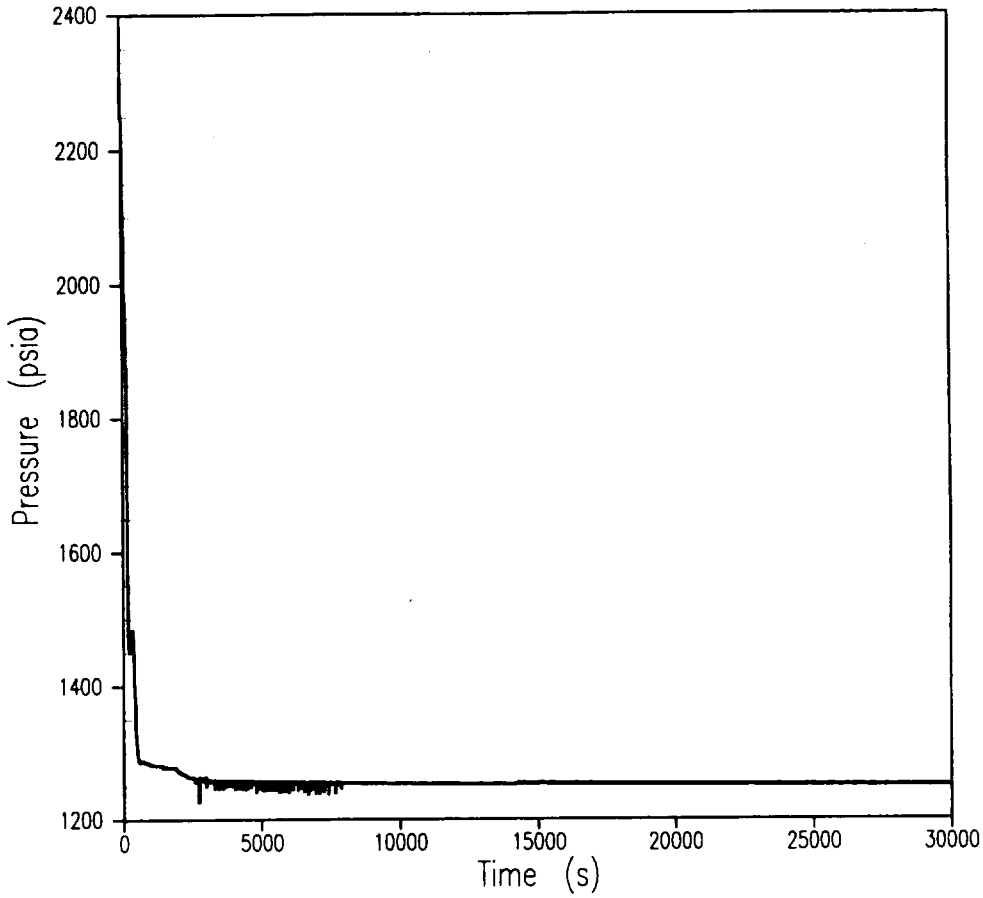


Figure 6.1.1-24

Units 1 High T_{avg} 1.5-Inch

RCS Pressure

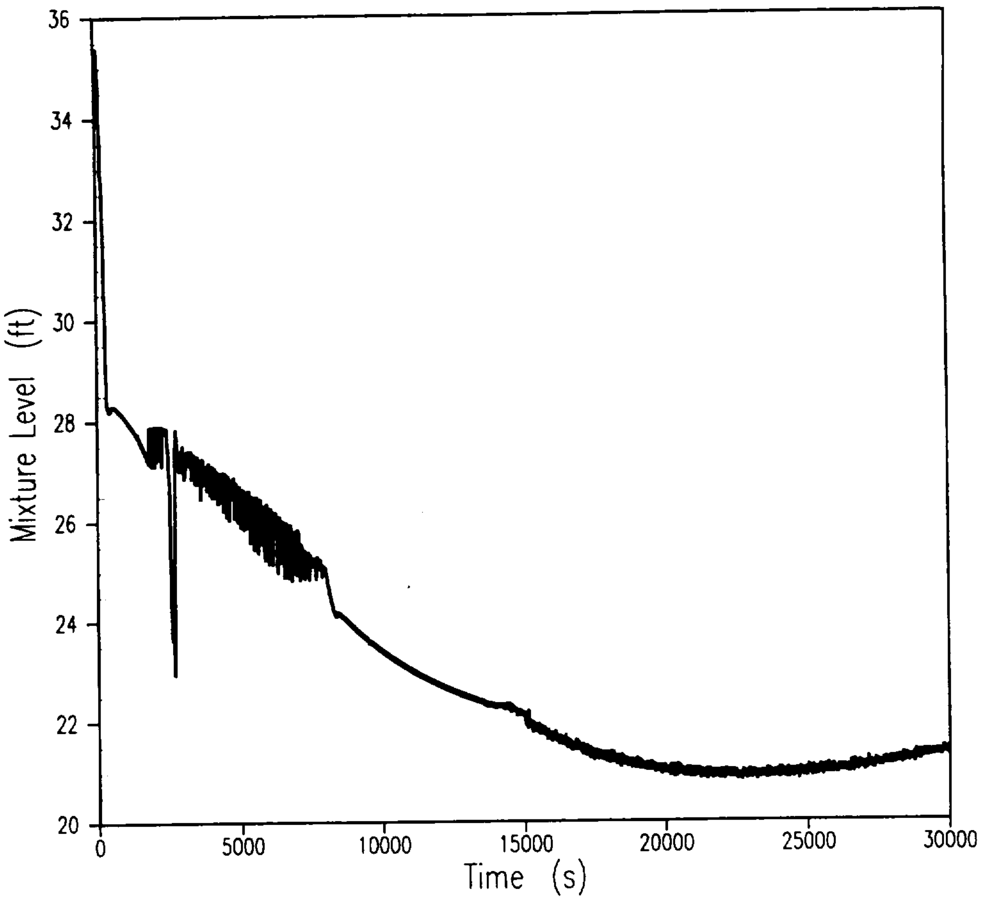


Figure 6.1.1-25

Units 1 High T_{avg} 1.5-Inch

Core Mixture Level

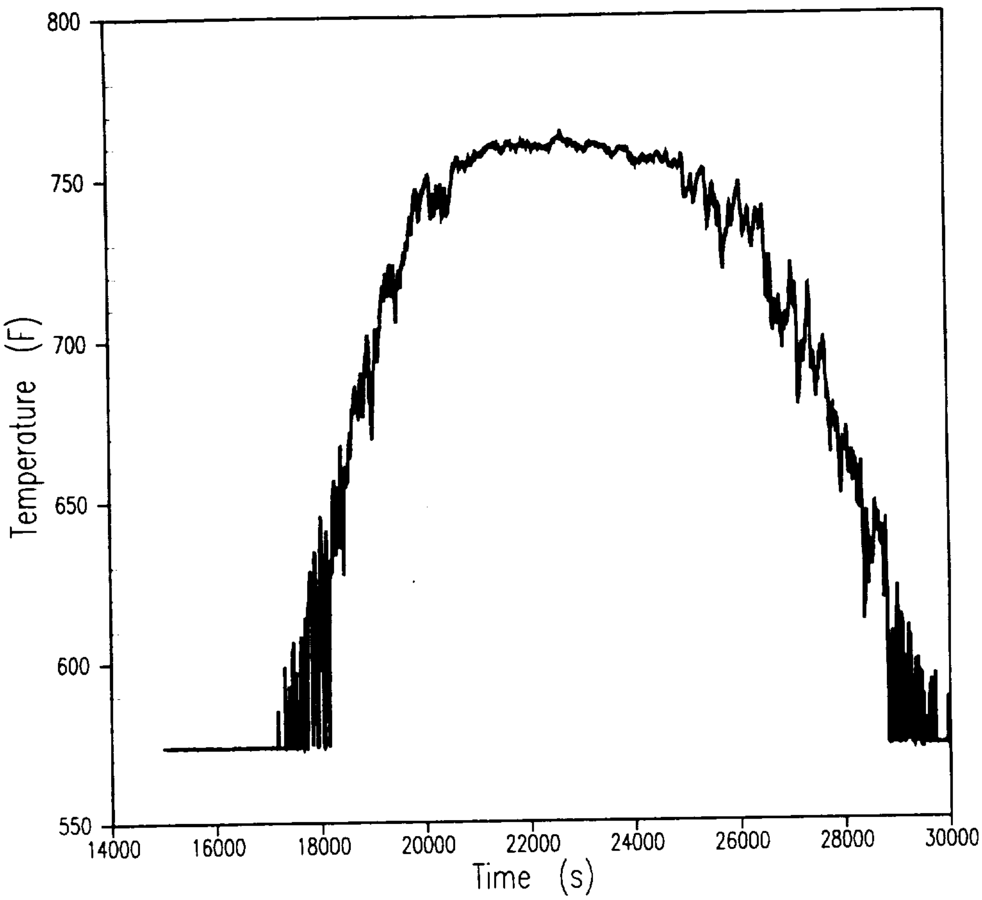


Figure 6.1.1-26

Units 1 High T_{avg} 1.5-Inch

Peak Clad Temperature at 11.25 ft.

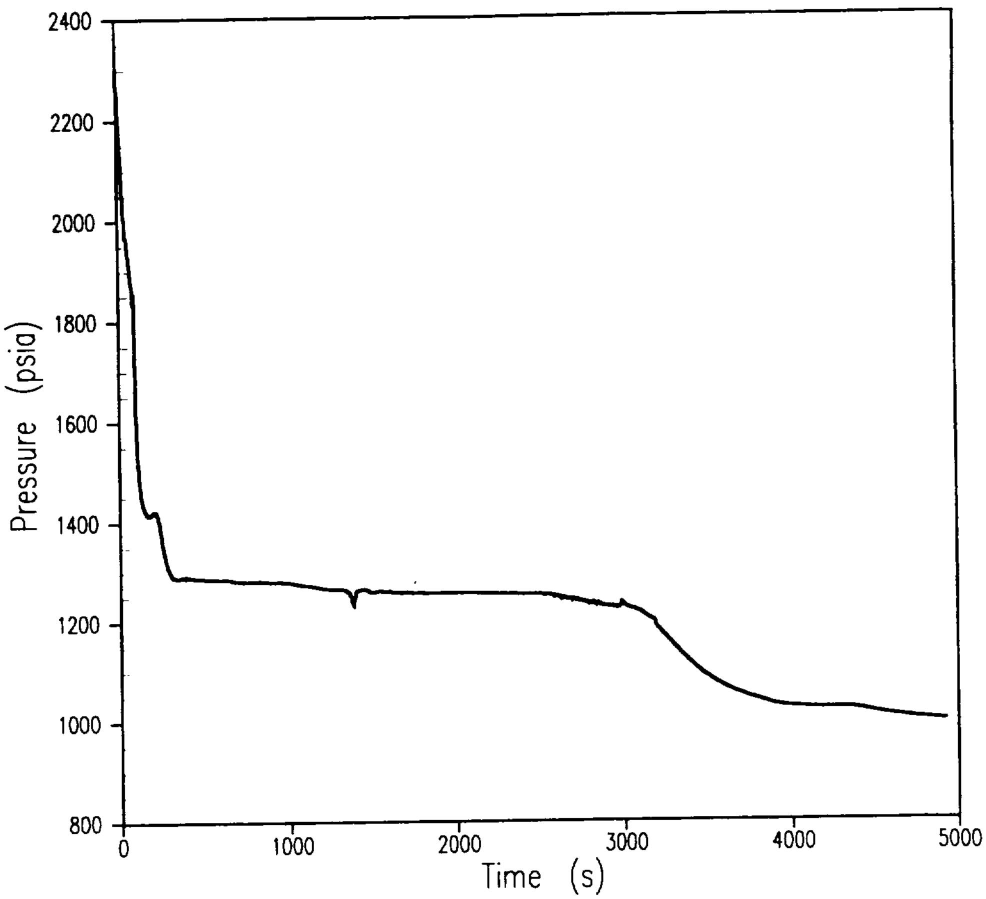


Figure 6.1.1-27

Units 1 High T_{avg} 2-Inch

RCS Pressure

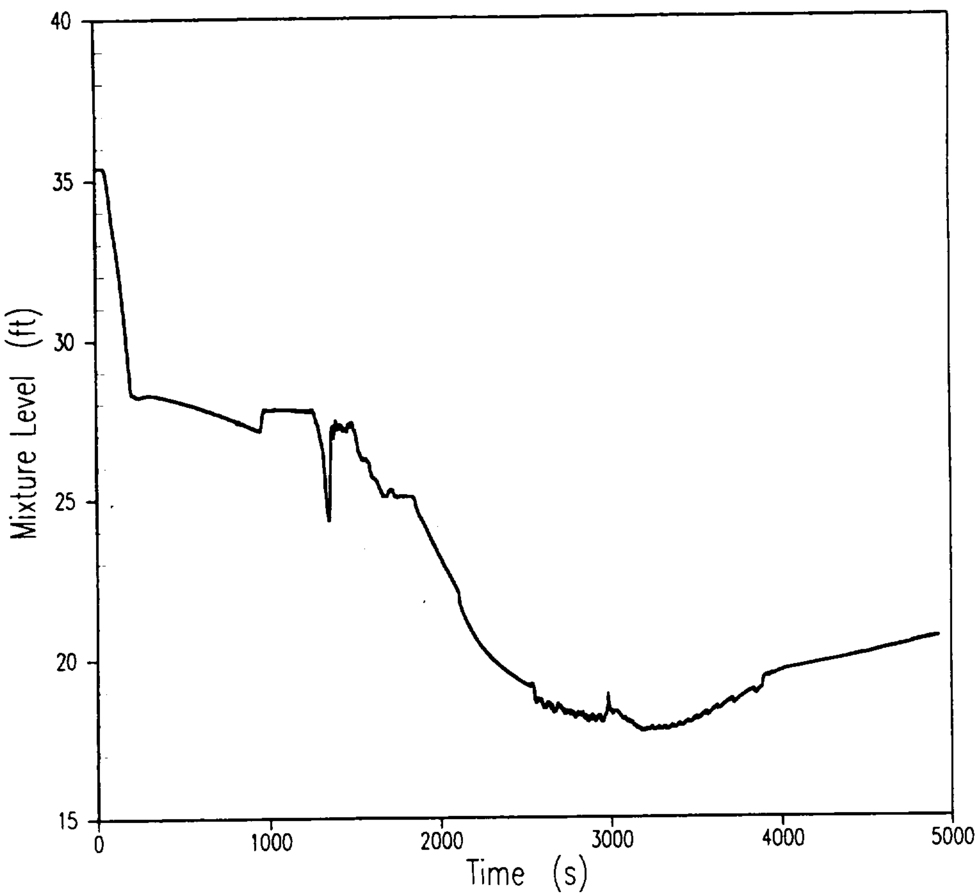


Figure 6.1.1-28

Units 1 High T_{avg} 2-Inch

Core Mixture Level

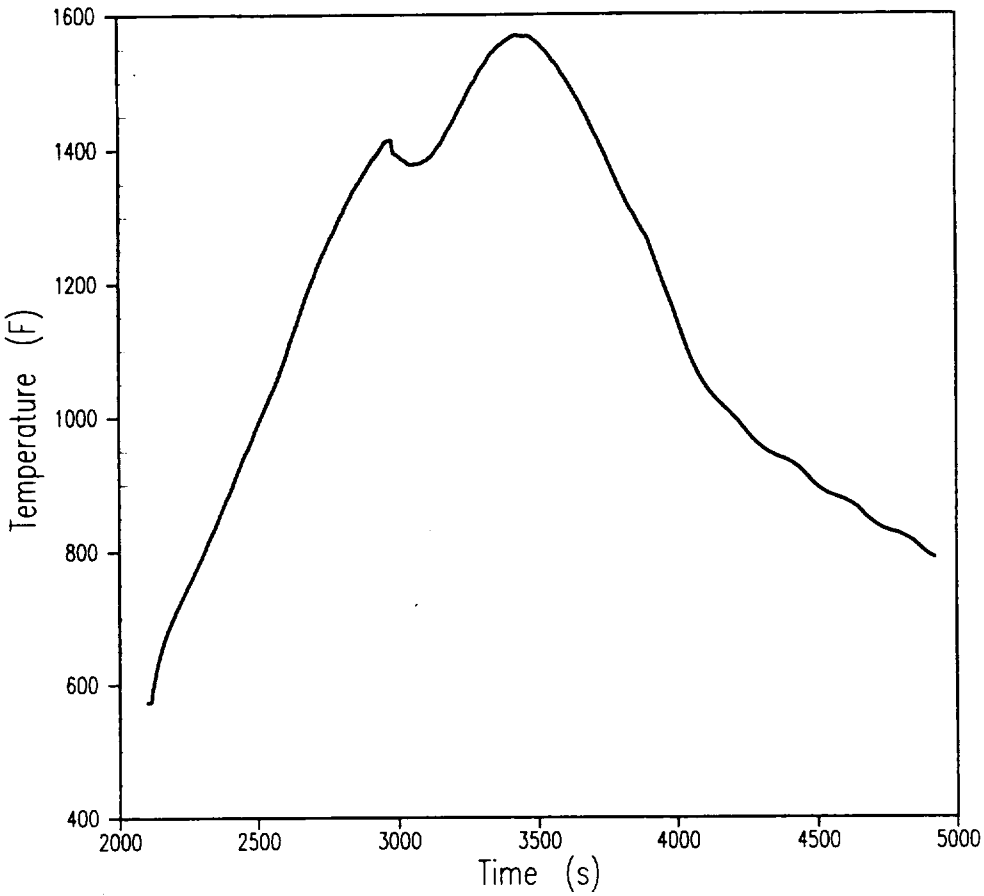


Figure 6.1.1-29

Units 1 High T_{avg} 2-Inch

Peak Clad Temperature at 11.75 ft.

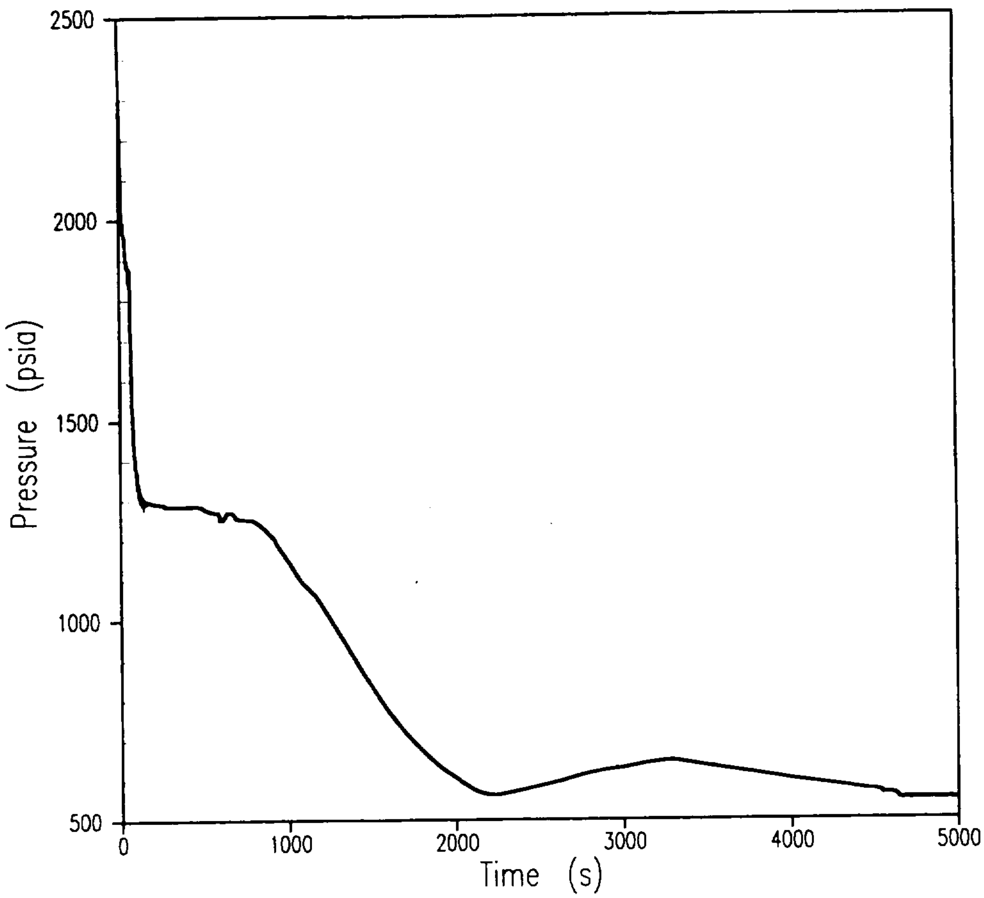


Figure 6.1.1-30

Units 1 High T_{avg} 3-Inch

RCS Pressure

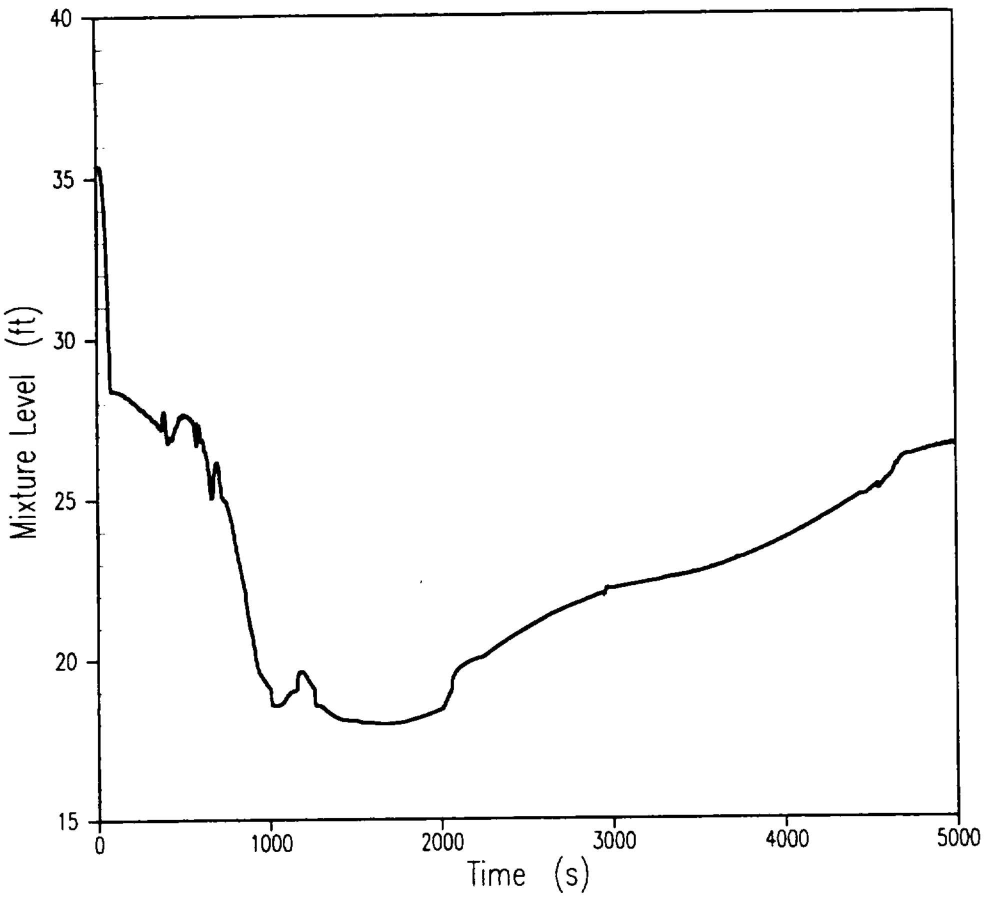


Figure 6.1.1-31

Units 1 High T_{avg} 3-Inch

Core Mixture Level

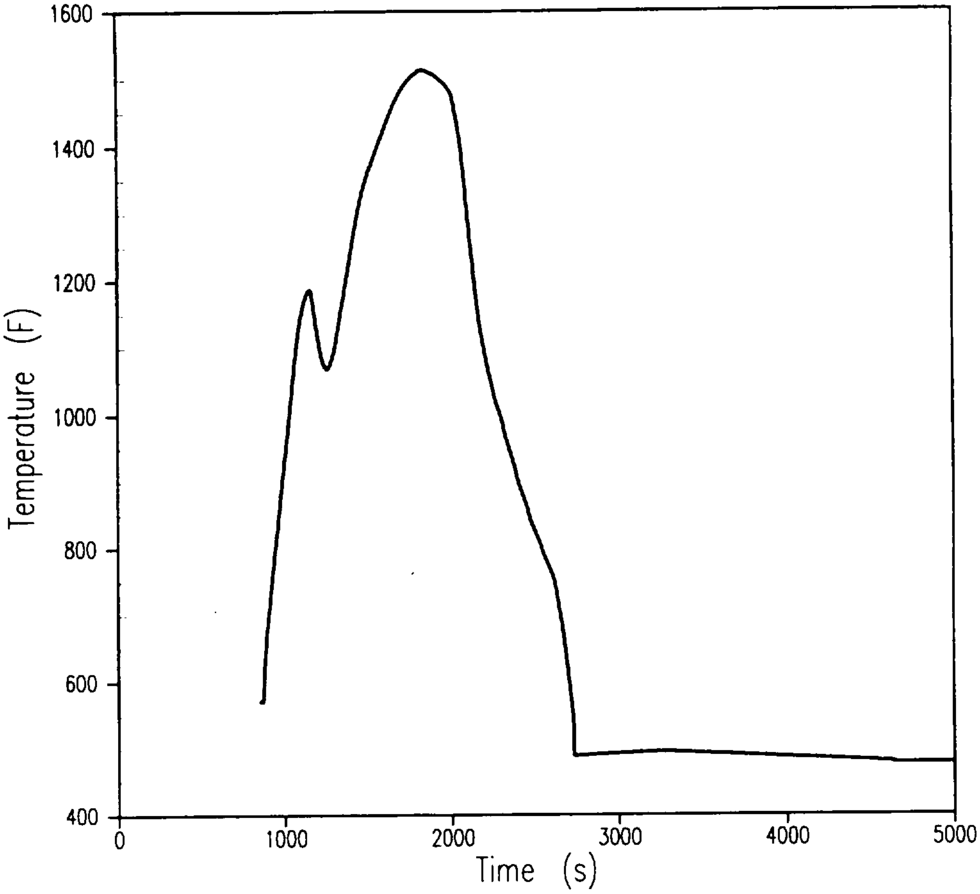


Figure 6.1.1-32

Units 1 High T_{avg} 3-Inch

Peak Clad Temperature at 11.5 ft.

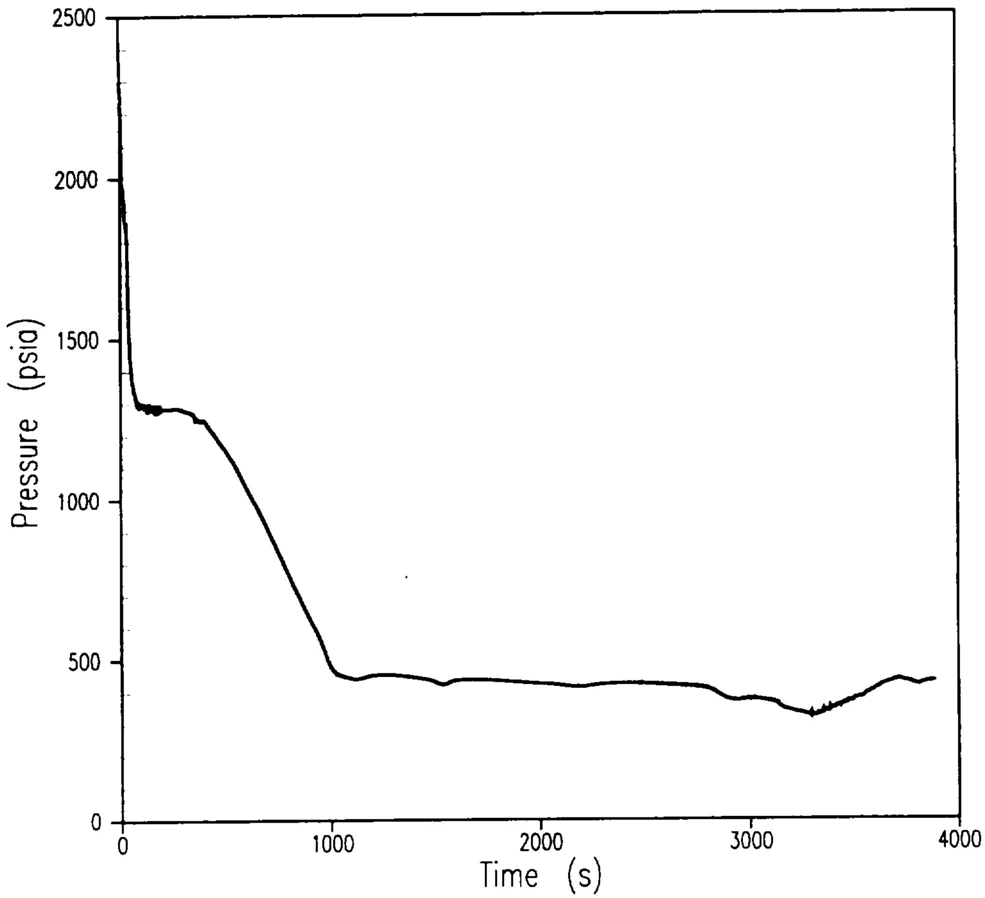


Figure 6.1.1-33

Units 1 High T_{avg} 4-Inch

RCS Pressure

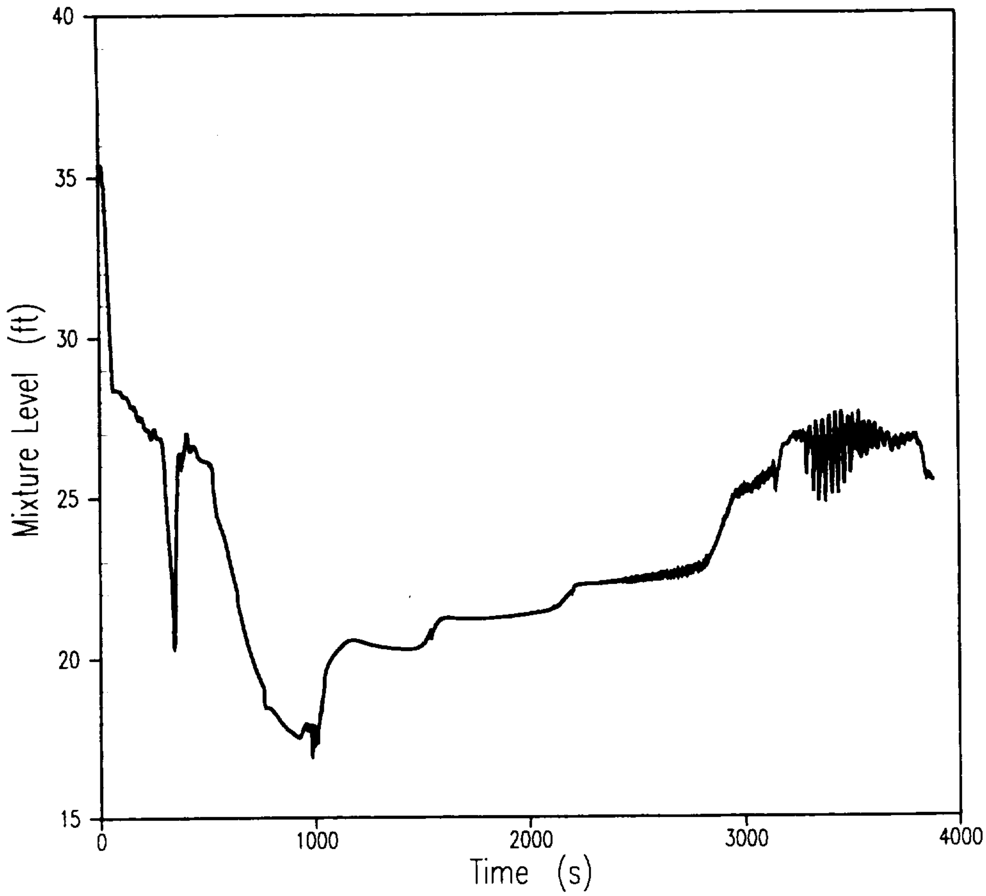


Figure 6.1.1-34

Units 1 High T_{avg} 4-Inch

Core Mixture Level

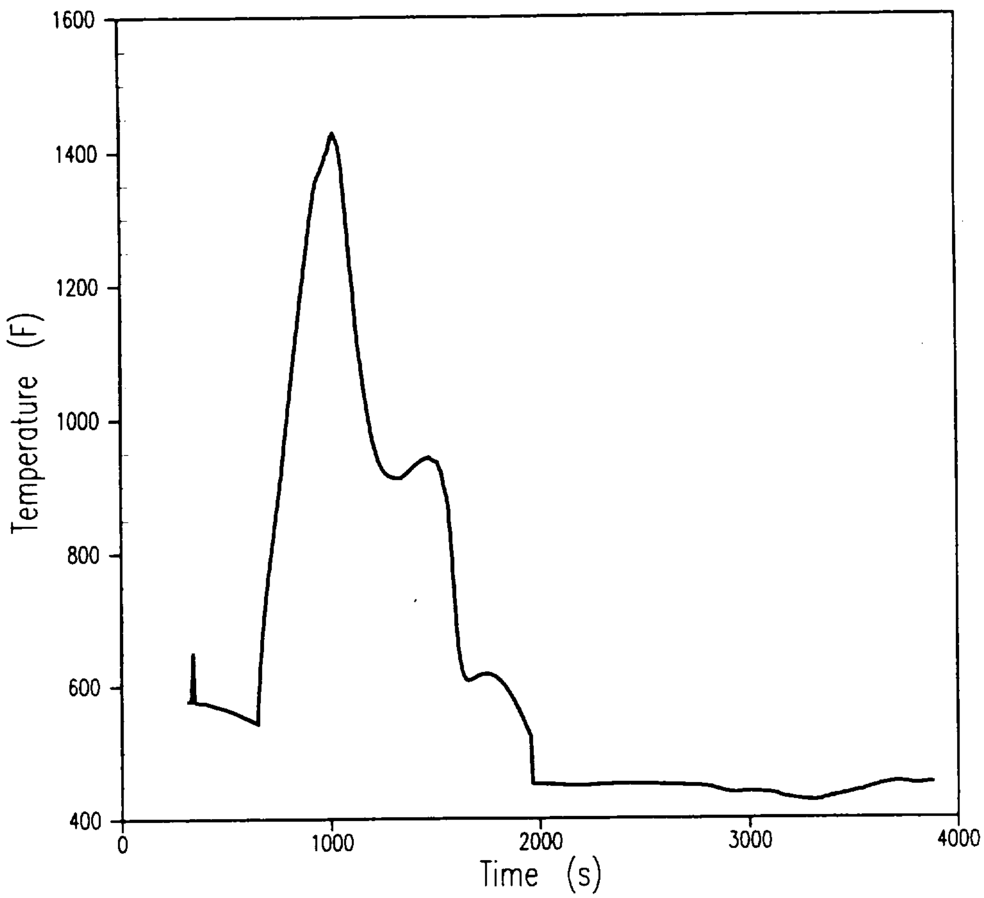


Figure 6.1.1-35

Units 1 High T_{avg} 4-Inch

Peak Clad Temperature at 11.25 ft.

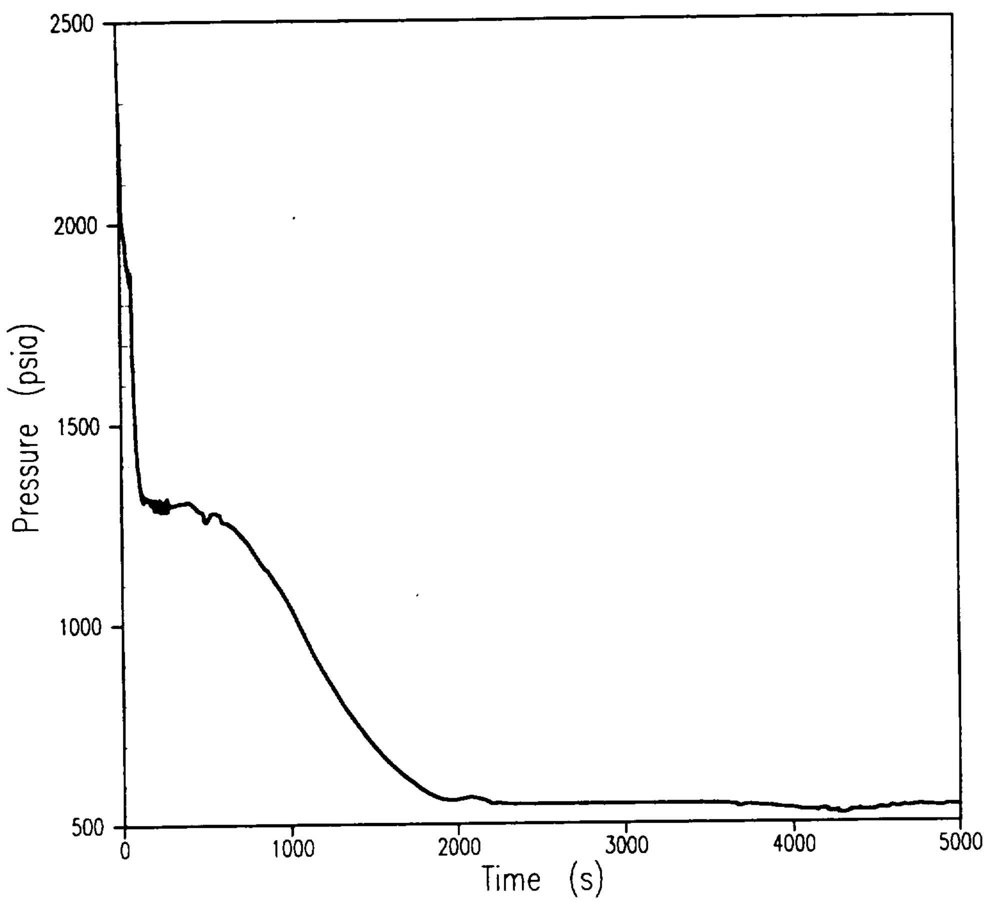


Figure 6.1.1-36

Units 2 High T_{avg} 3-Inch

RCS Pressure

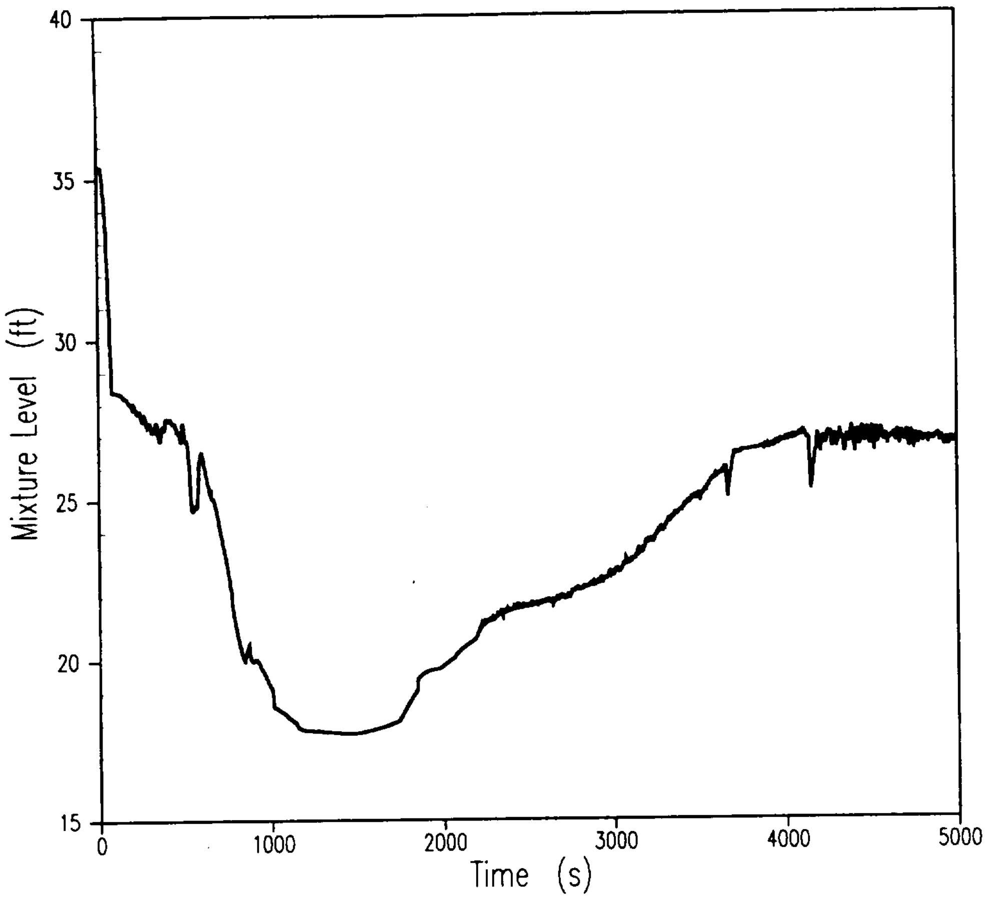


Figure 6.1.1-37

Units 2 High T_{avg} 3-Inch

Core Mixture Level

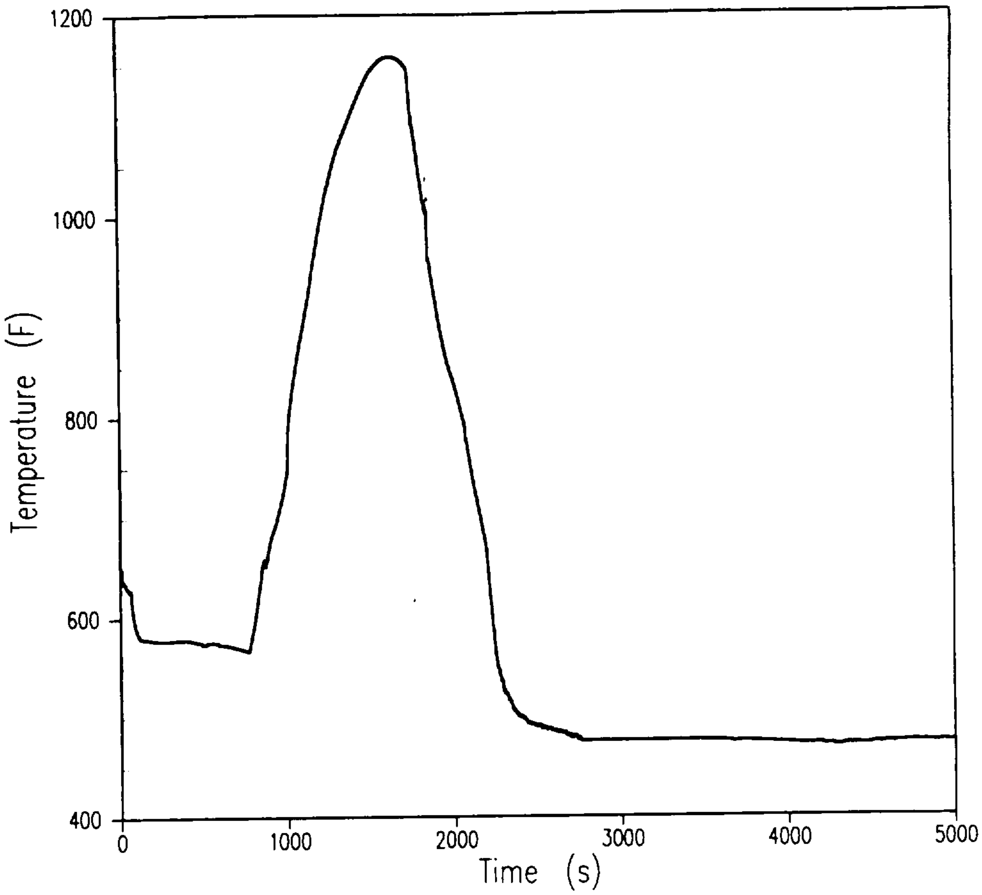


Figure 6.1.1-38

Units 2 High T_{avg} 3-Inch

Core Exit Vapor Temperature

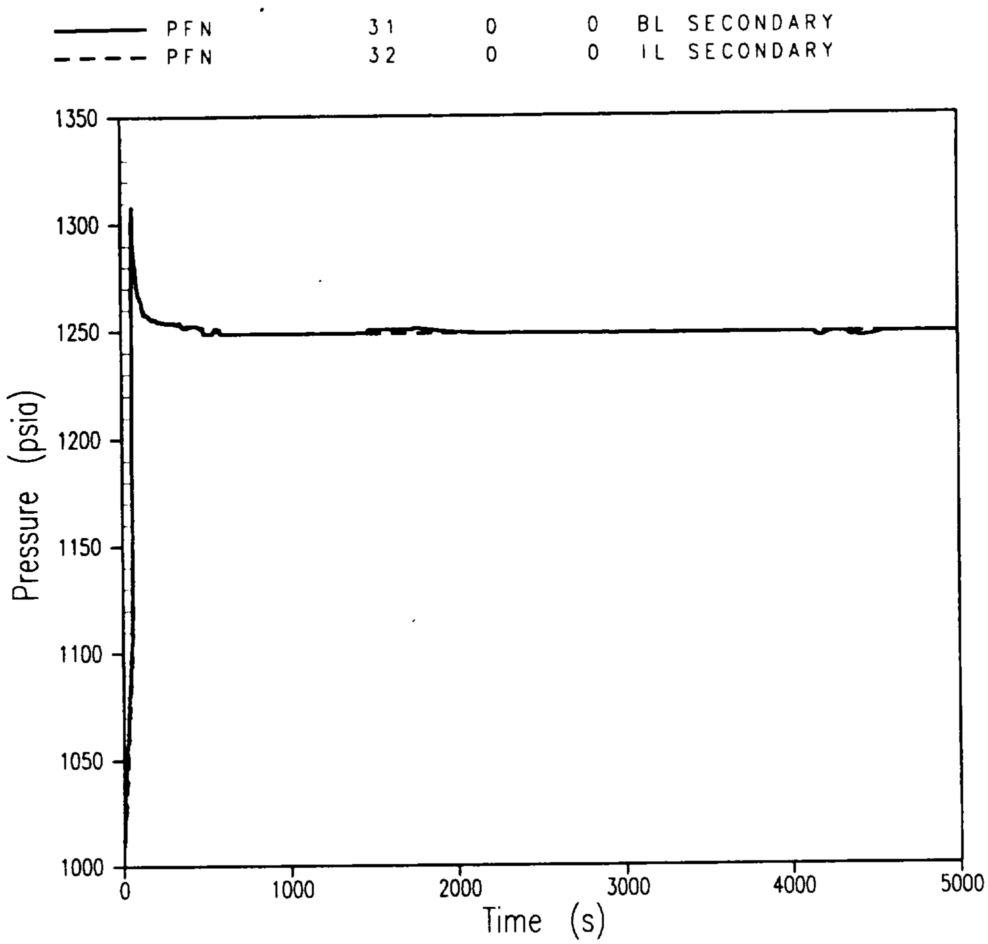


Figure 6.1.1-39

Units 2 High T_{avg} 3-Inch

Broken Loop and Intact Loop Secondary Pressure

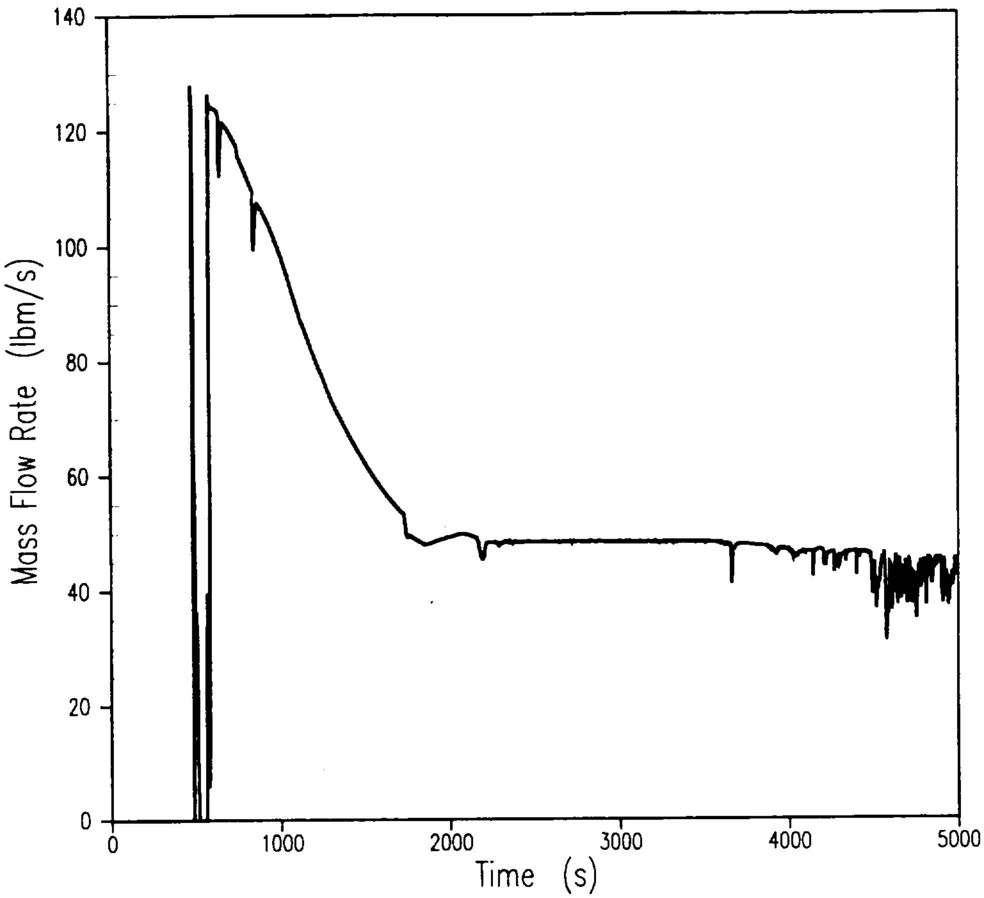


Figure 6.1.1-40

Units 2 High T_{avg} 3-Inch

Break Vapor Flow Rate

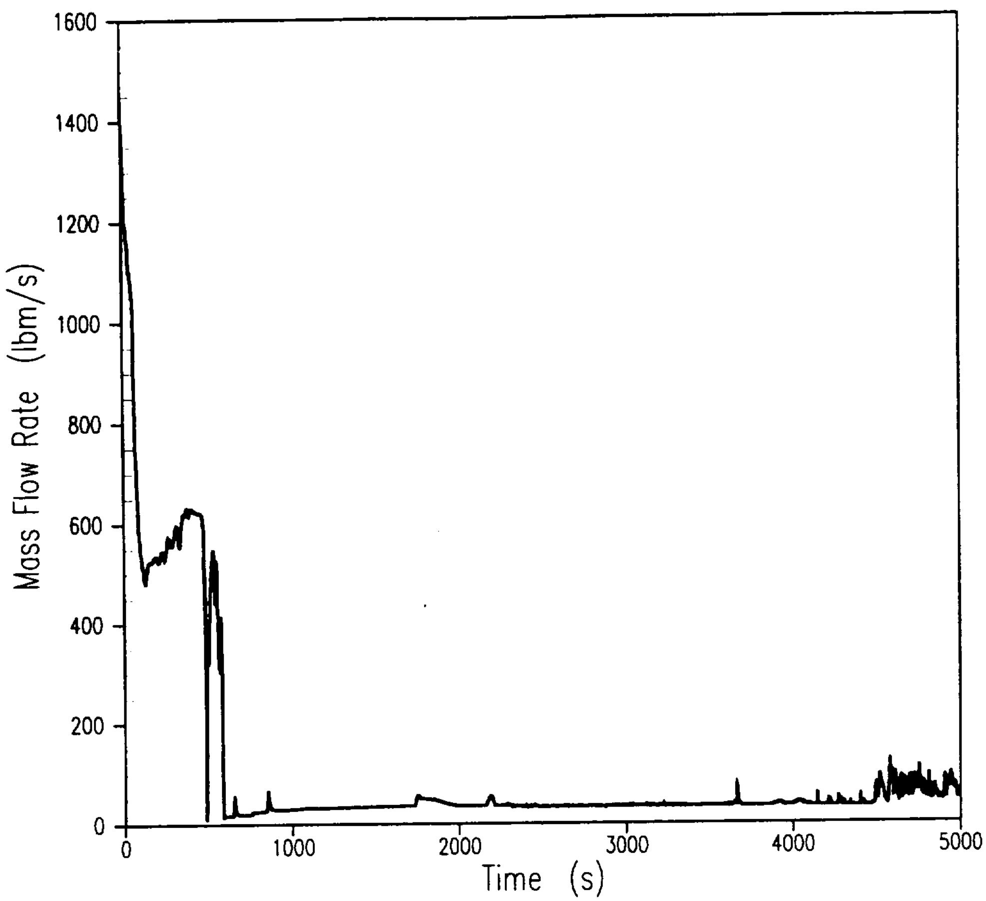


Figure 6.1.1-41

Units 2 High T_{avg} 3-Inch

Break Liquid Flow Rate

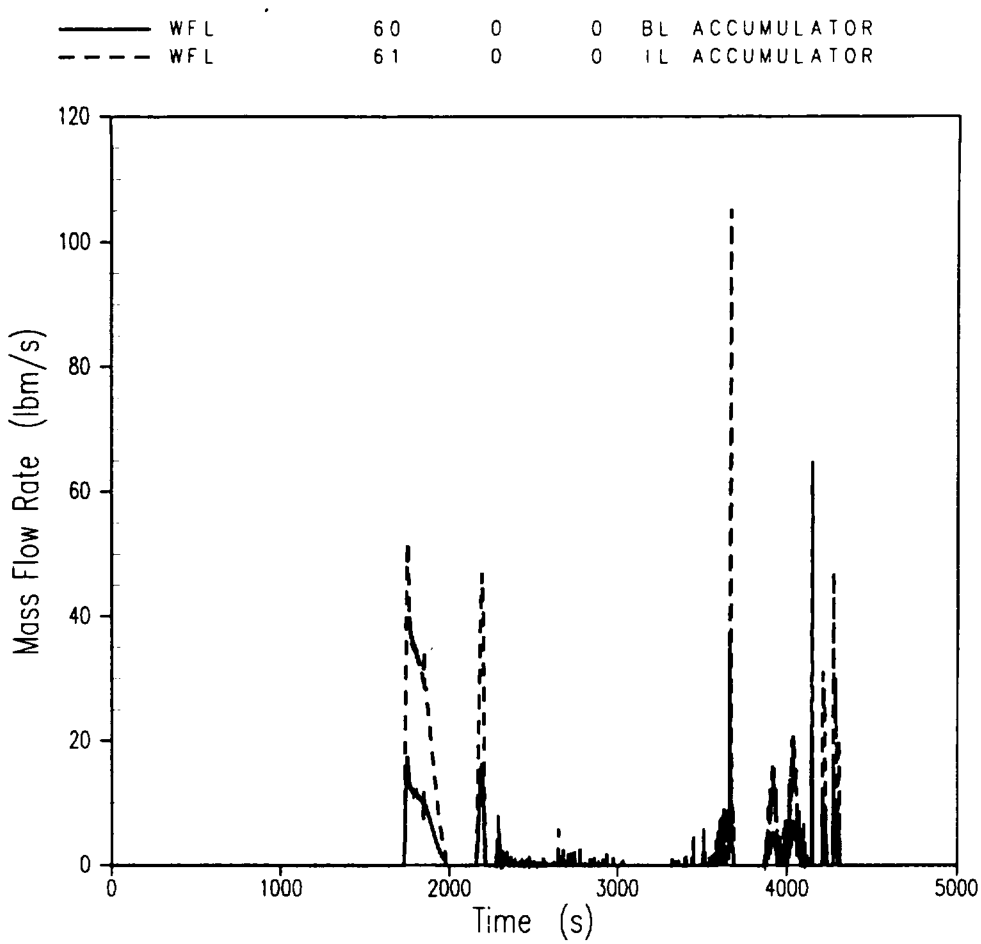


Figure 6.1.1-42

Units 2 High T_{avg} 3-Inch

Broken Loop and Intact Loop Accumulator Flow Rate

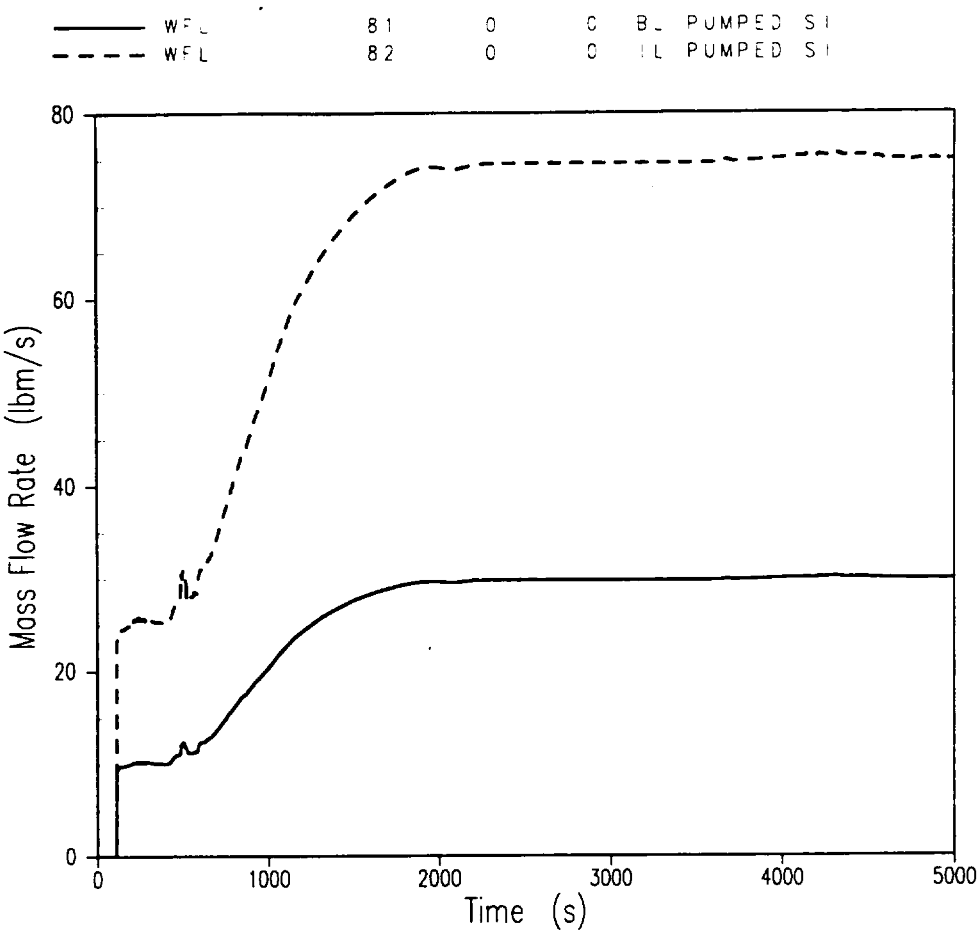


Figure 6.1.1-43

Units 2 High T_{avg} 3-Inch

Broken Loop and Intact Loop Pumped Safety Injection Flow Rate

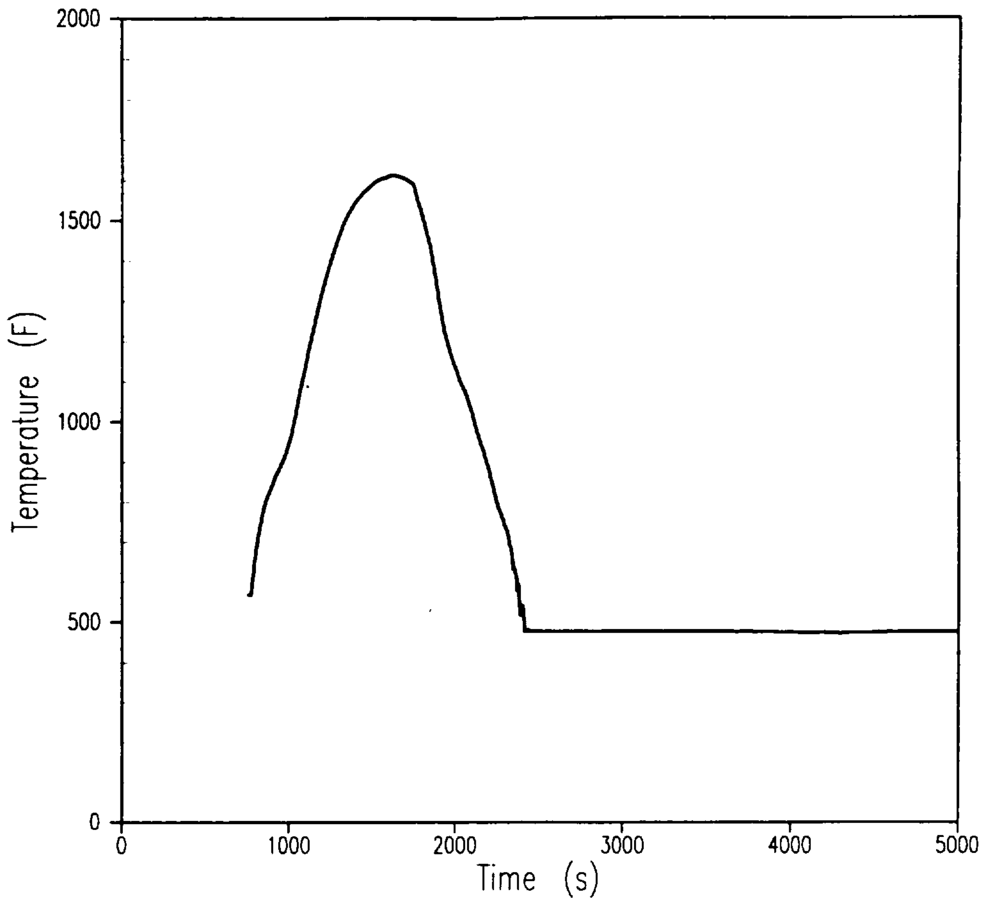


Figure 6.1.1-44

Units 2 High T_{avg} 3-Inch

Peak Clad Temperature at 11.5 ft.

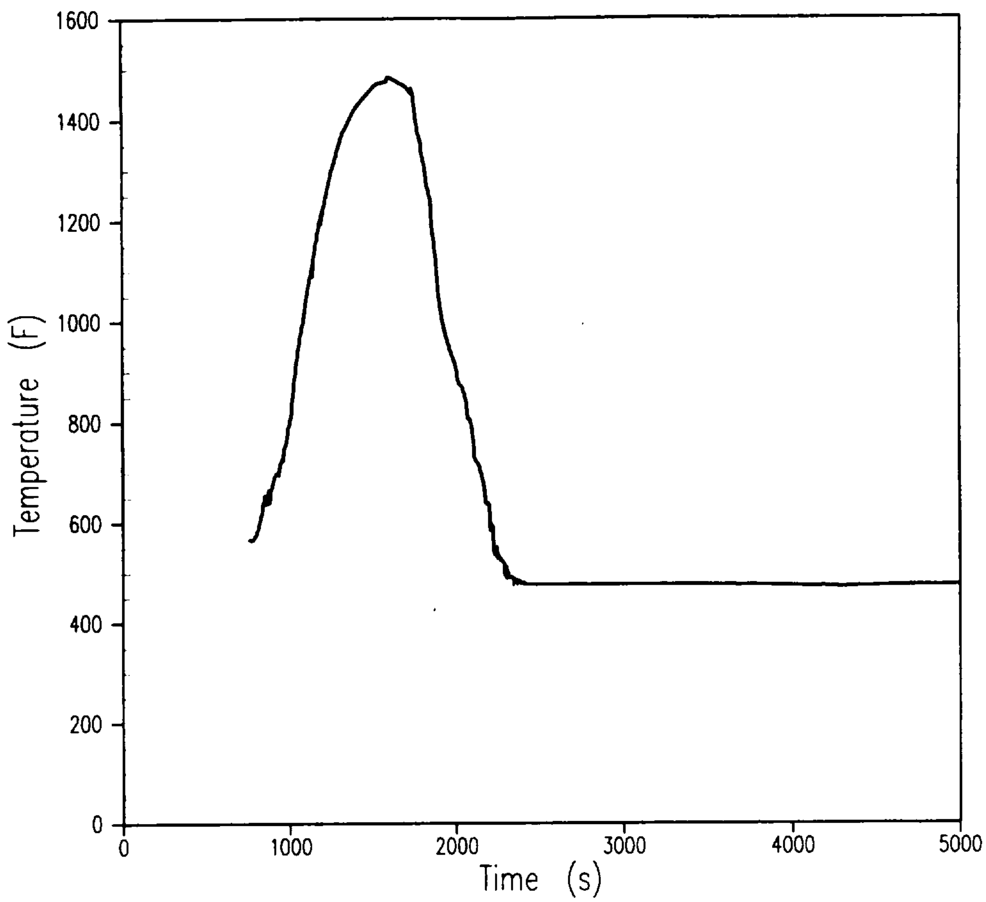


Figure 6.1.1-45

Units 2 High T_{avg} 3-Inch

Hot Spot Fluid Temperature

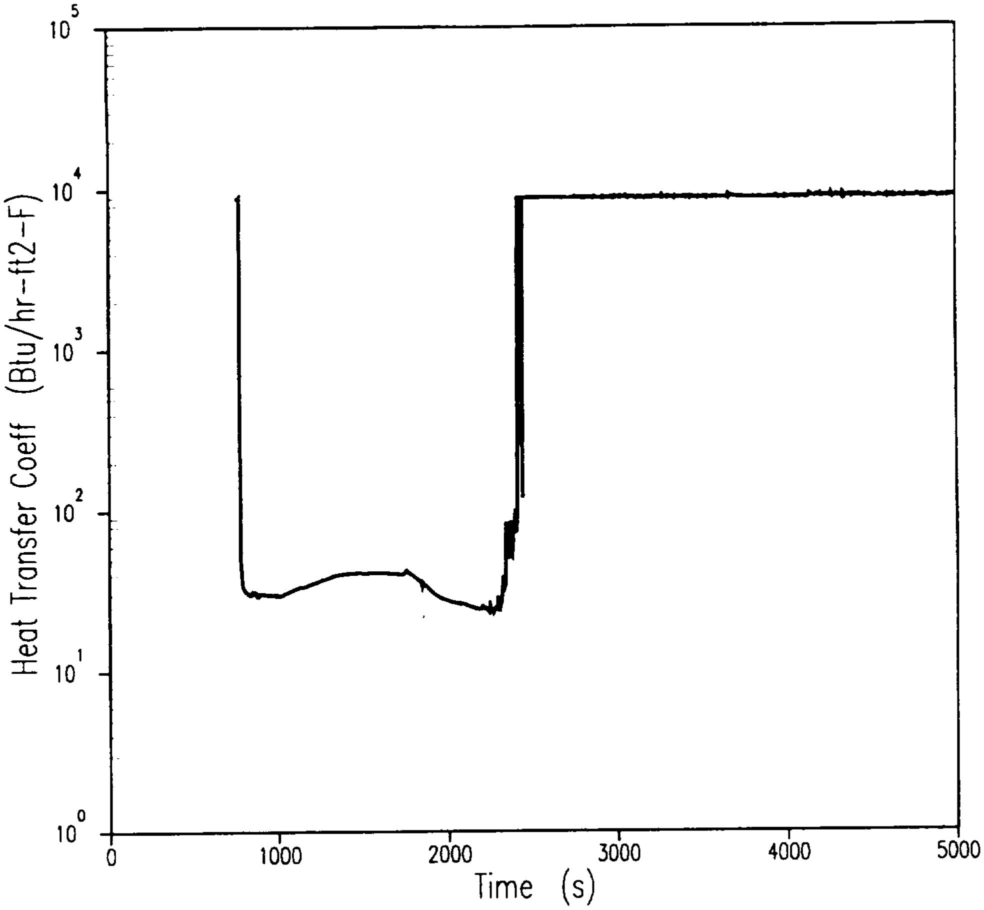


Figure 6.1.1-46

Units 2 High T_{avg} 3-Inch

Rod Film Heat Transfer Coefficient at 11.5 ft.

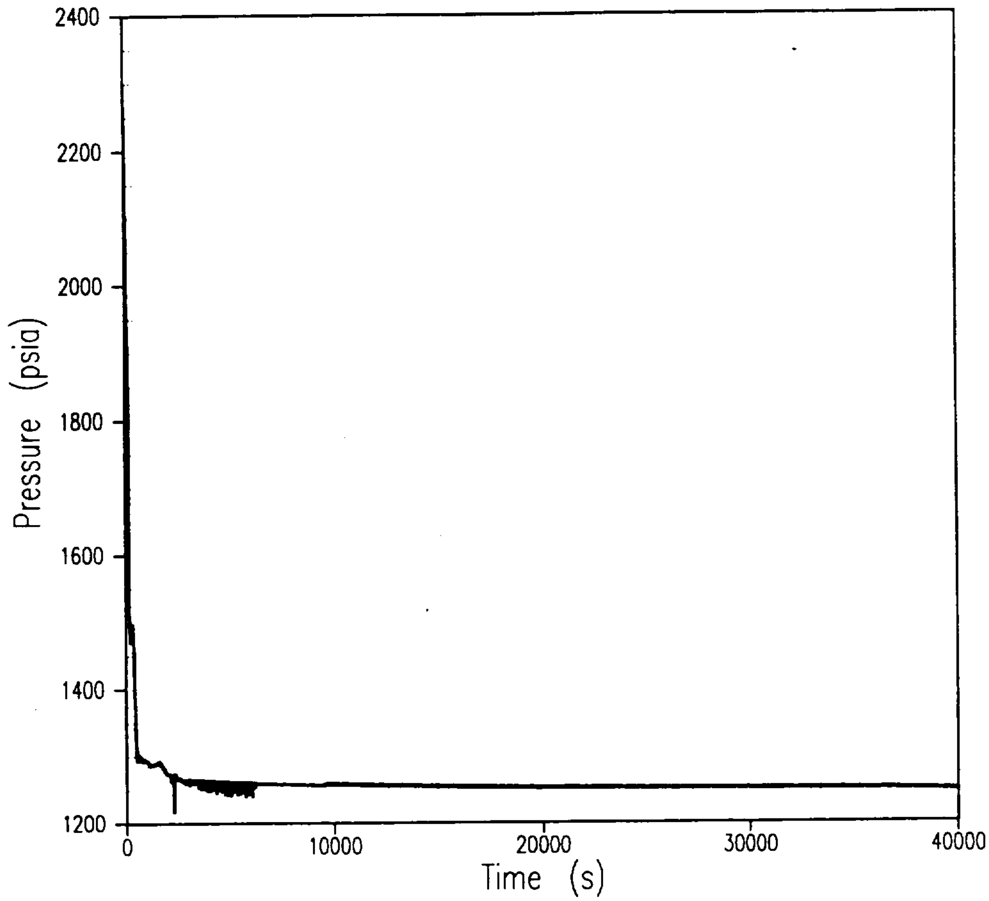


Figure 6.1.1-47

Units 2 High T_{avg} 1.5-Inch

RCS Pressure

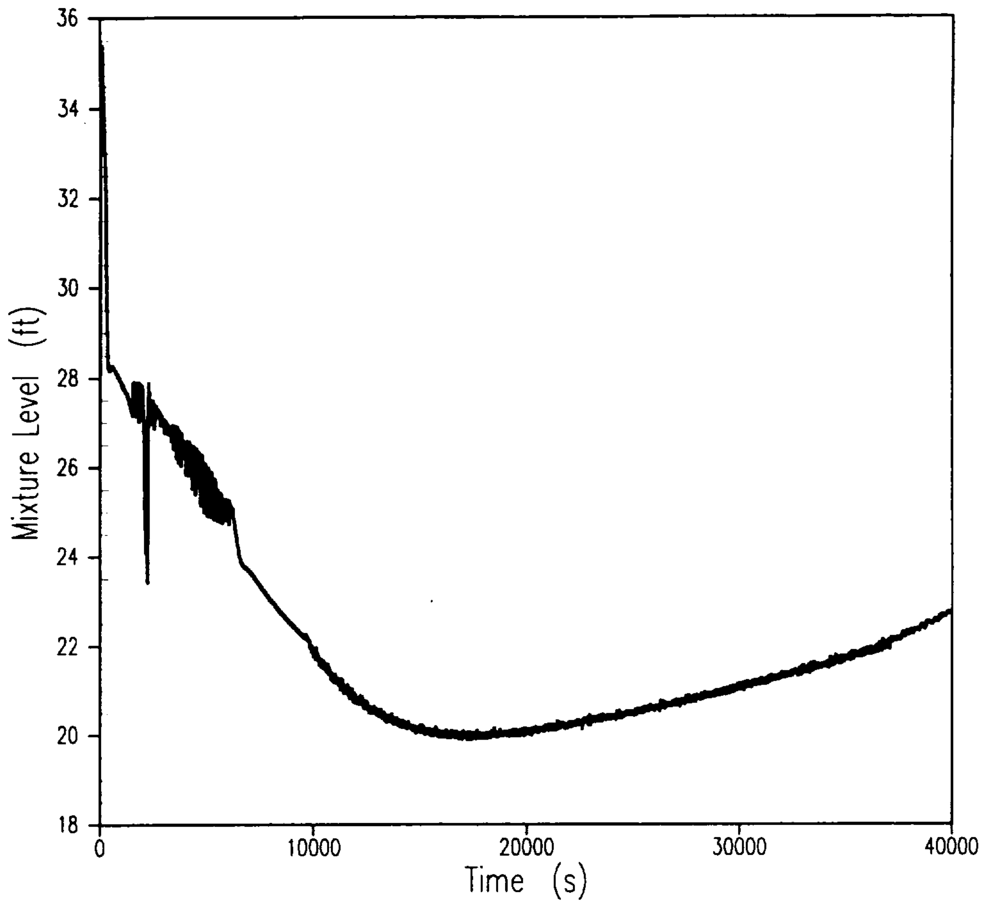


Figure 6.1.1-48

Units 2 High T_{avg} 1.5-Inch

Core Mixture Level

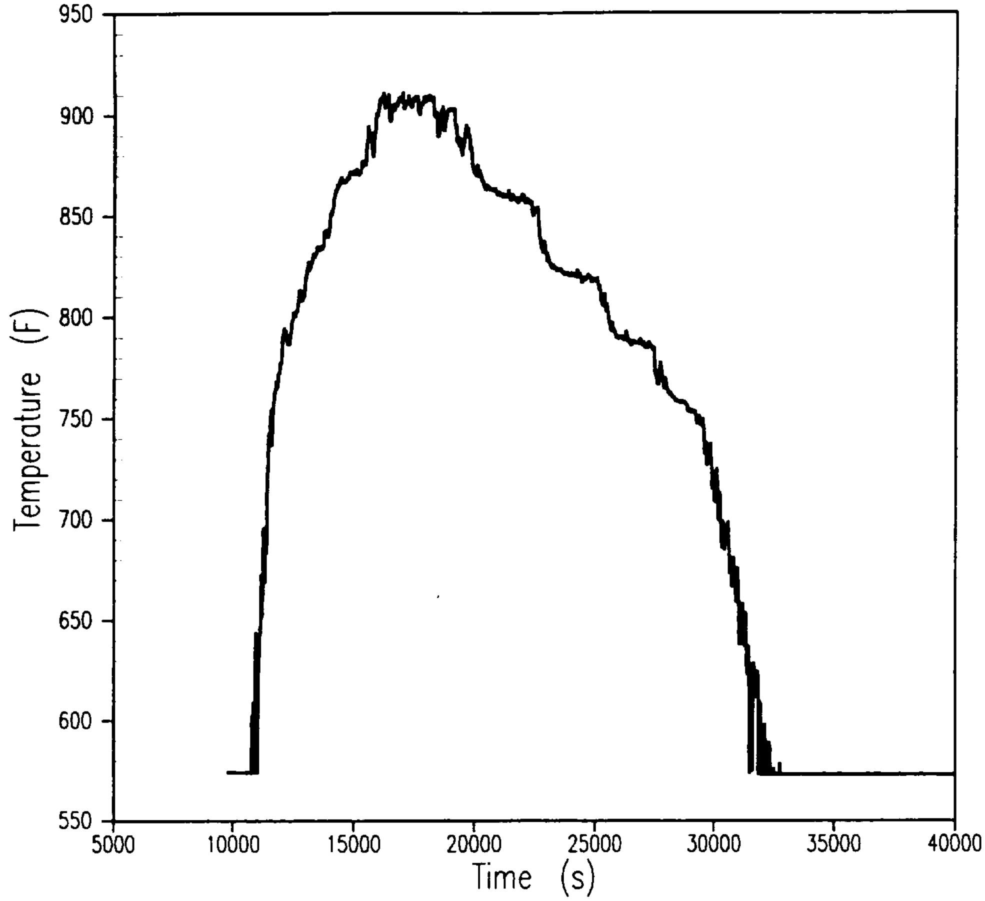


Figure 6.1.1-49

Units 2 High T_{avg} 1.5-Inch

Peak Clad Temperature at 11.25 ft.

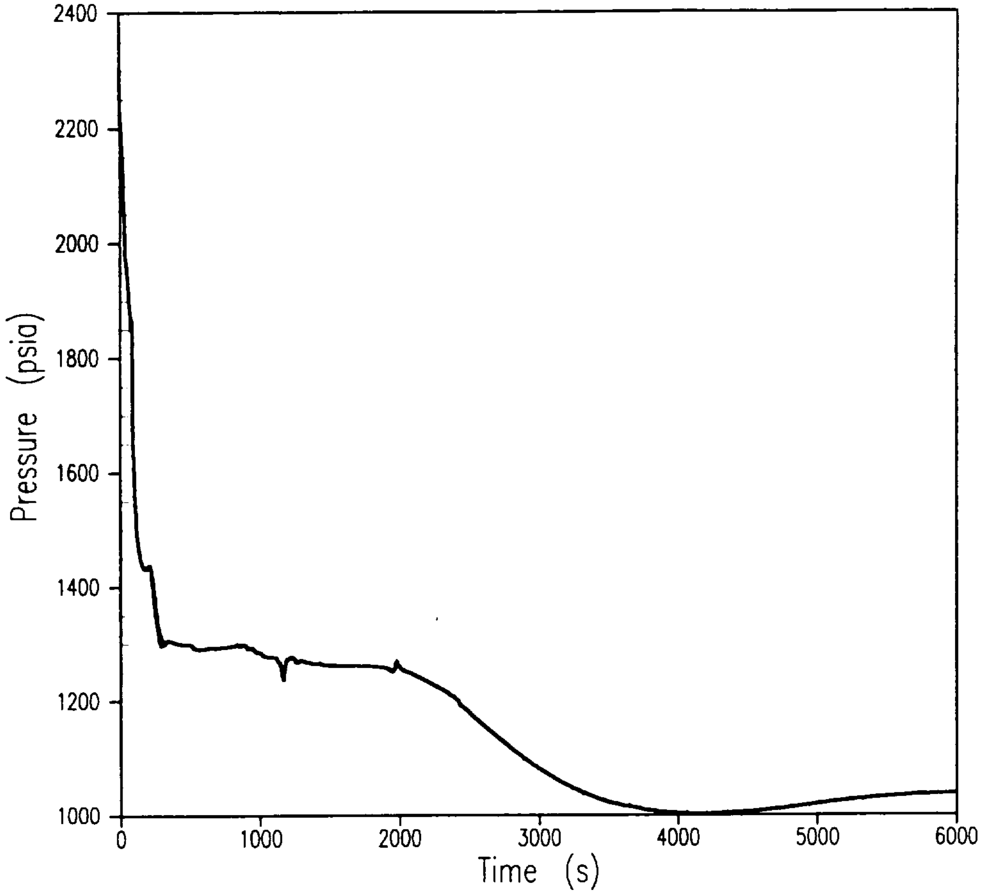


Figure 6.1.1-50

Units 2 High T_{avg} 2-Inch

RCS Pressure

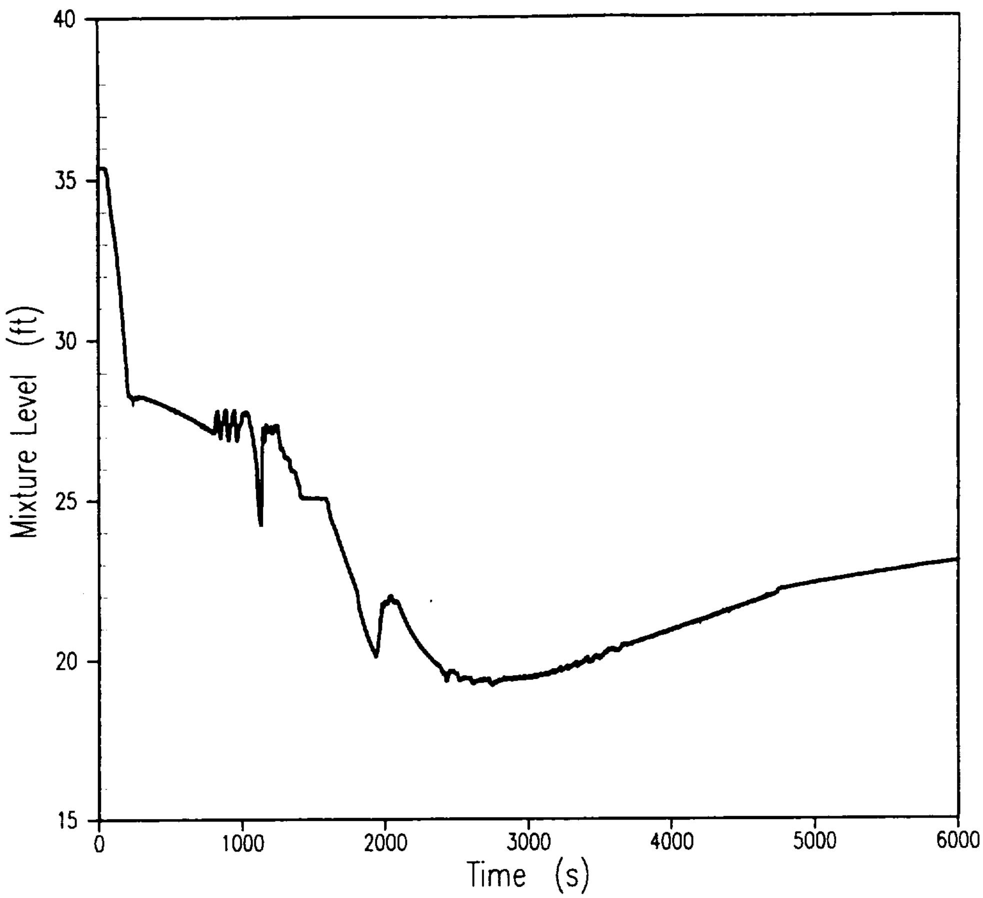


Figure 6.1.1-51

Units 2 High T_{avg} 2-Inch

Core Mixture Level

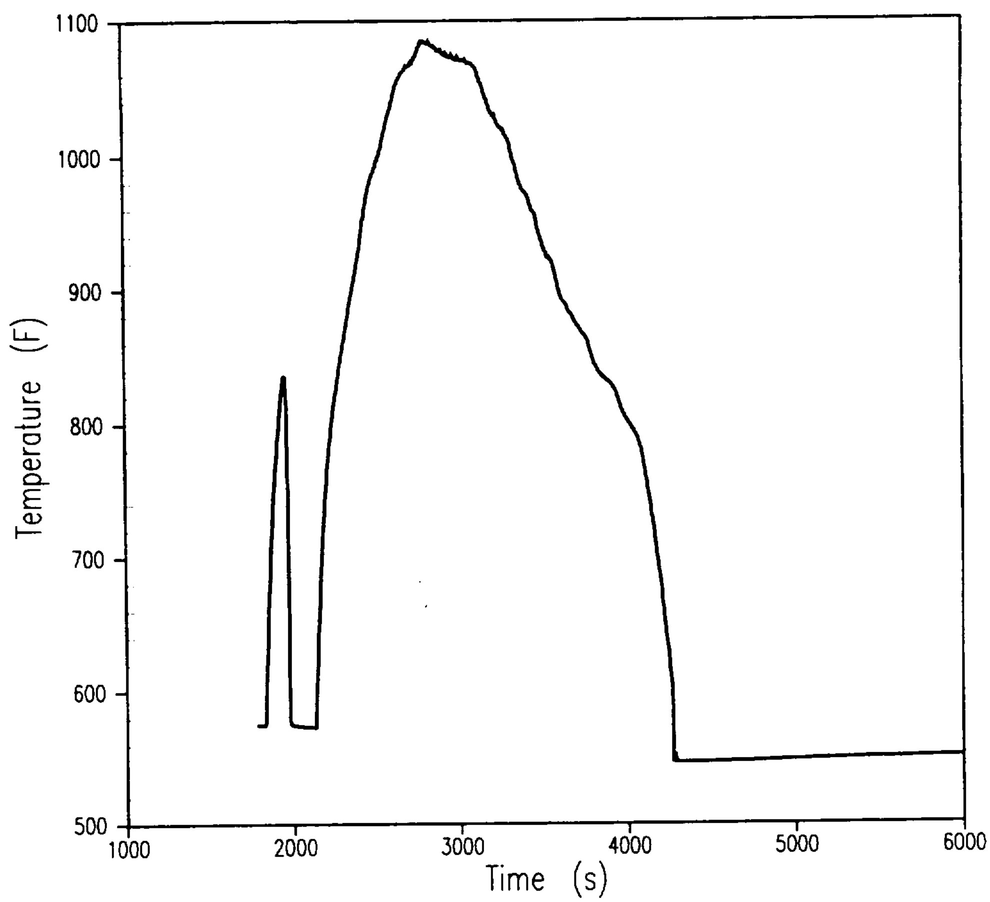


Figure 6.1.1-52

Units 2 High T_{avg} 2-Inch

Peak Clad Temperature at 11.25 ft.

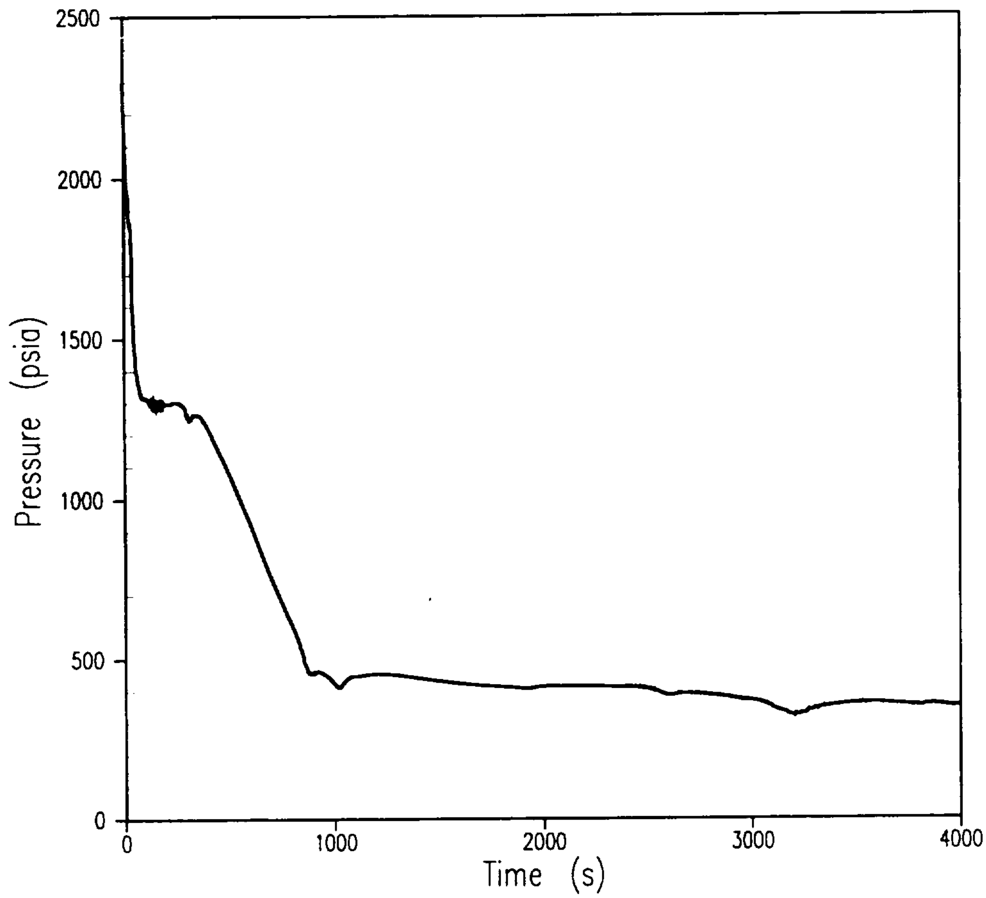


Figure 6.1.1-53

Units 2 High T_{avg} 4-Inch

RCS Pressure

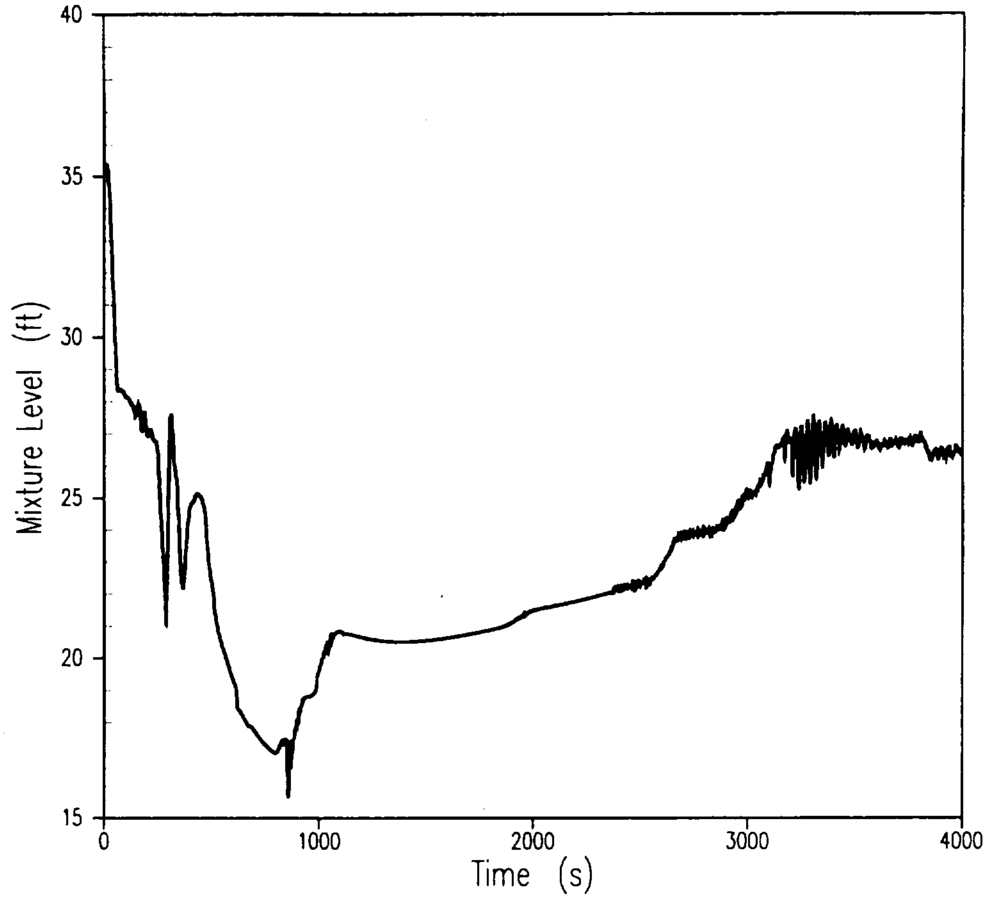


Figure 6.1.1-54

Units 2 High T_{avg} 4-Inch

Core Mixture Level

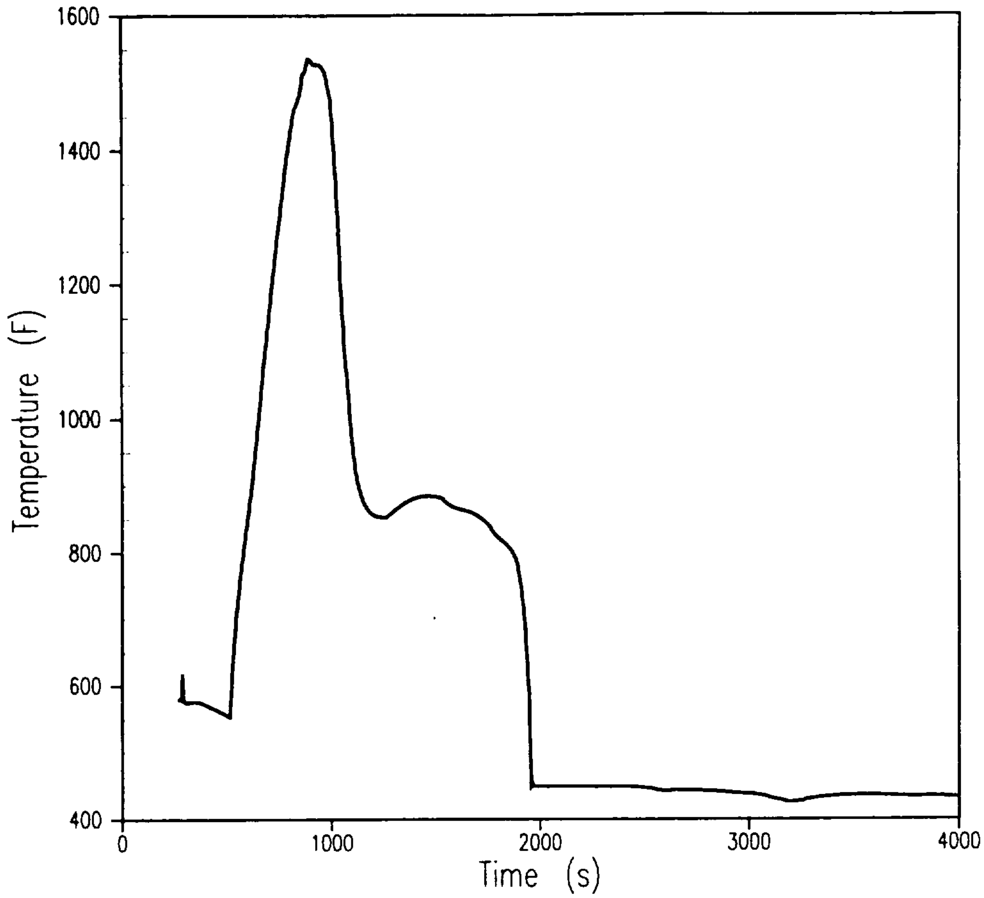


Figure 6.1.1-55

Units 2 High T_{avg} 4-Inch

Peak Clad Temperature at 11.25 ft.

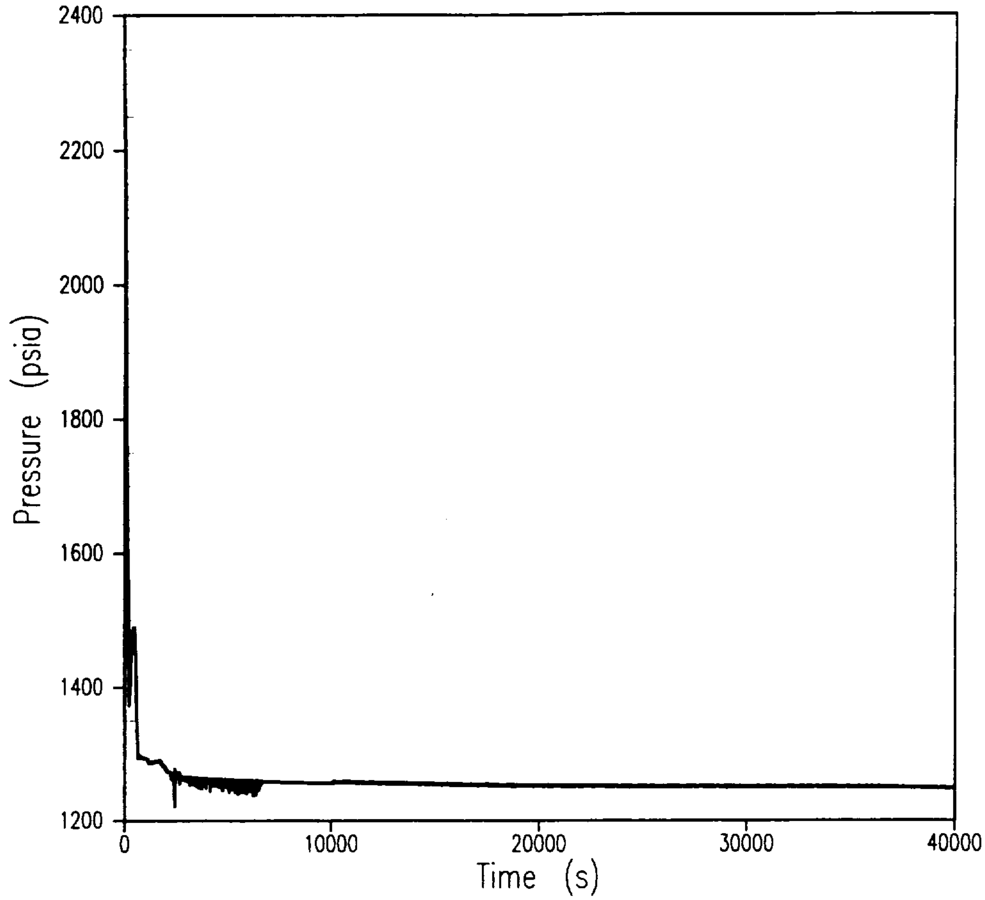


Figure 6.1.1-56

Units 2 Low T_{avg} 1.5-Inch

RCS Pressure

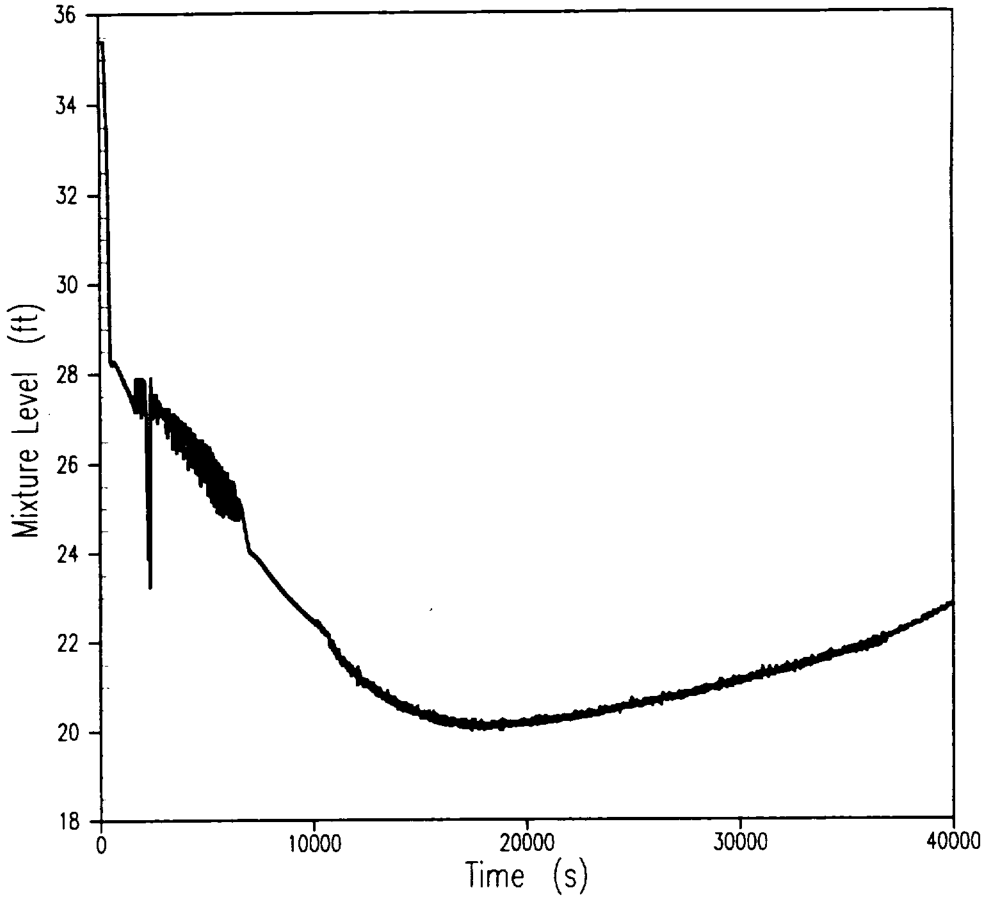


Figure 6.1.1-57

Units 2 Low T_{avg} 1.5-Inch

Core Mixture Level

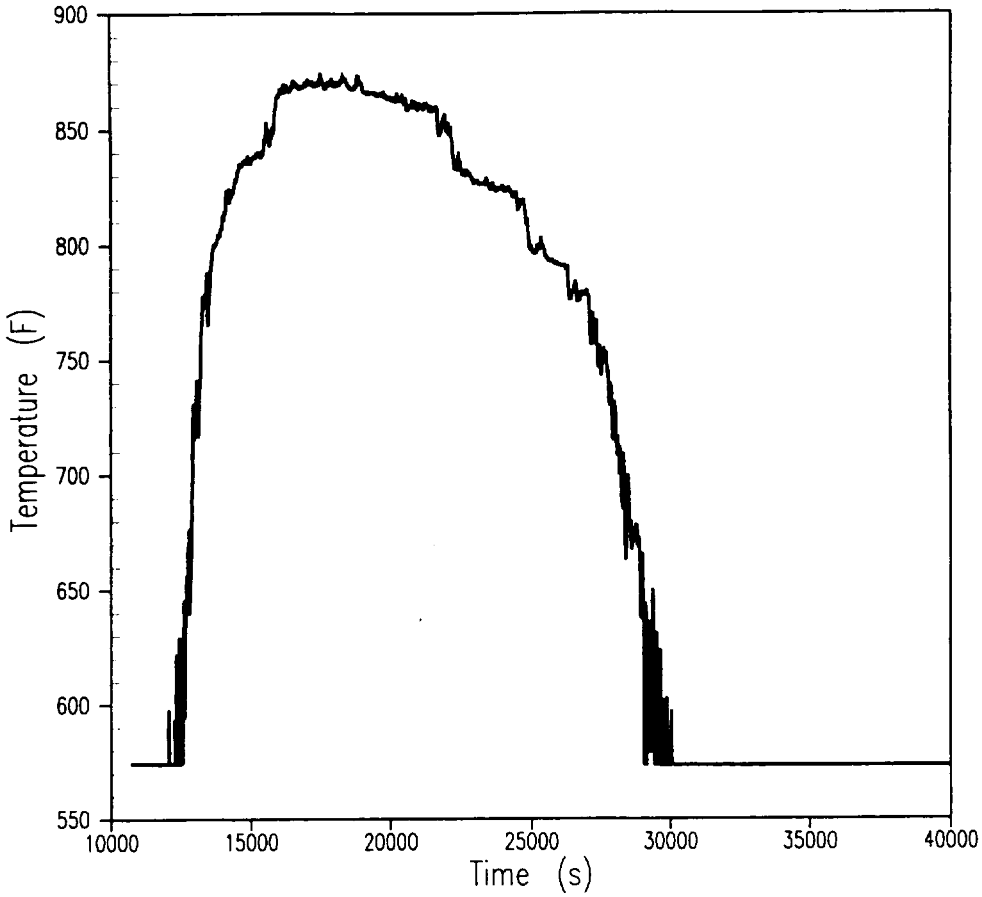


Figure 6.1.1-58

Units 2 Low T_{avg} 1.5-Inch

Peak Clad Temperature at 11.00 ft.

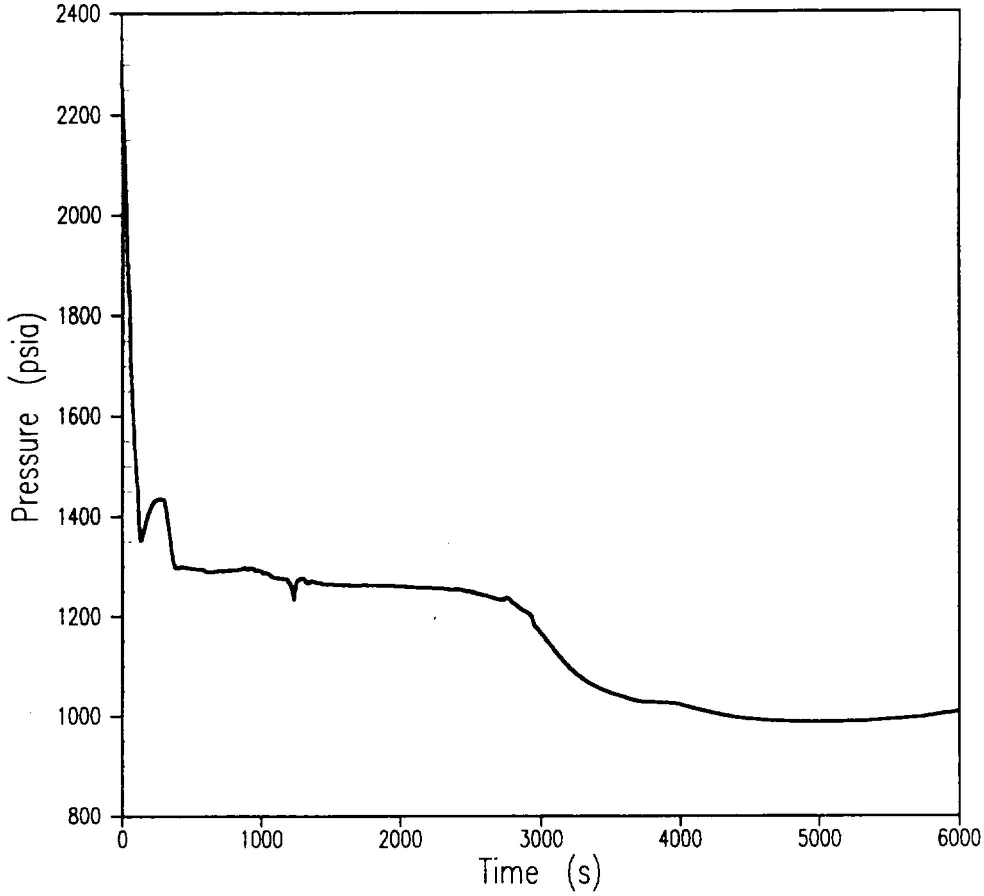


Figure 6.1.1-59

Units 2 Low T_{avg} 2-Inch

RCS Pressure

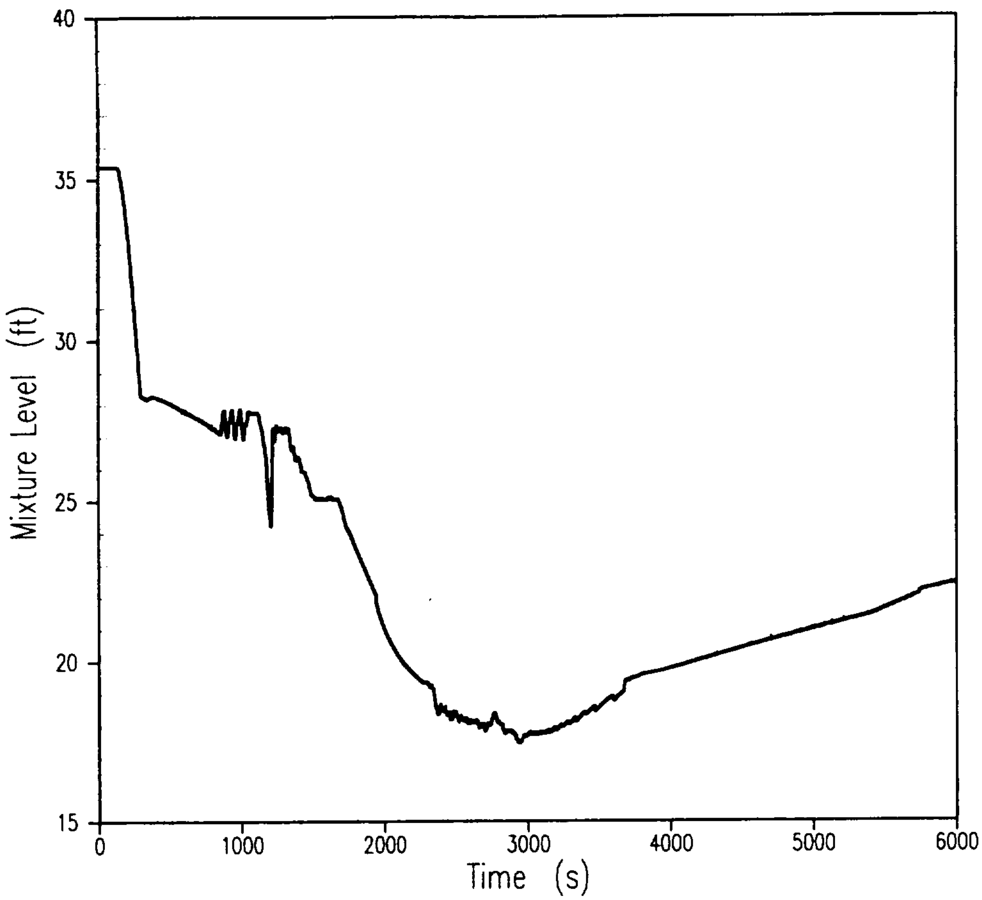


Figure 6.1.1-60

Units 2 Low T_{avg} 2-Inch

Core Mixture Level

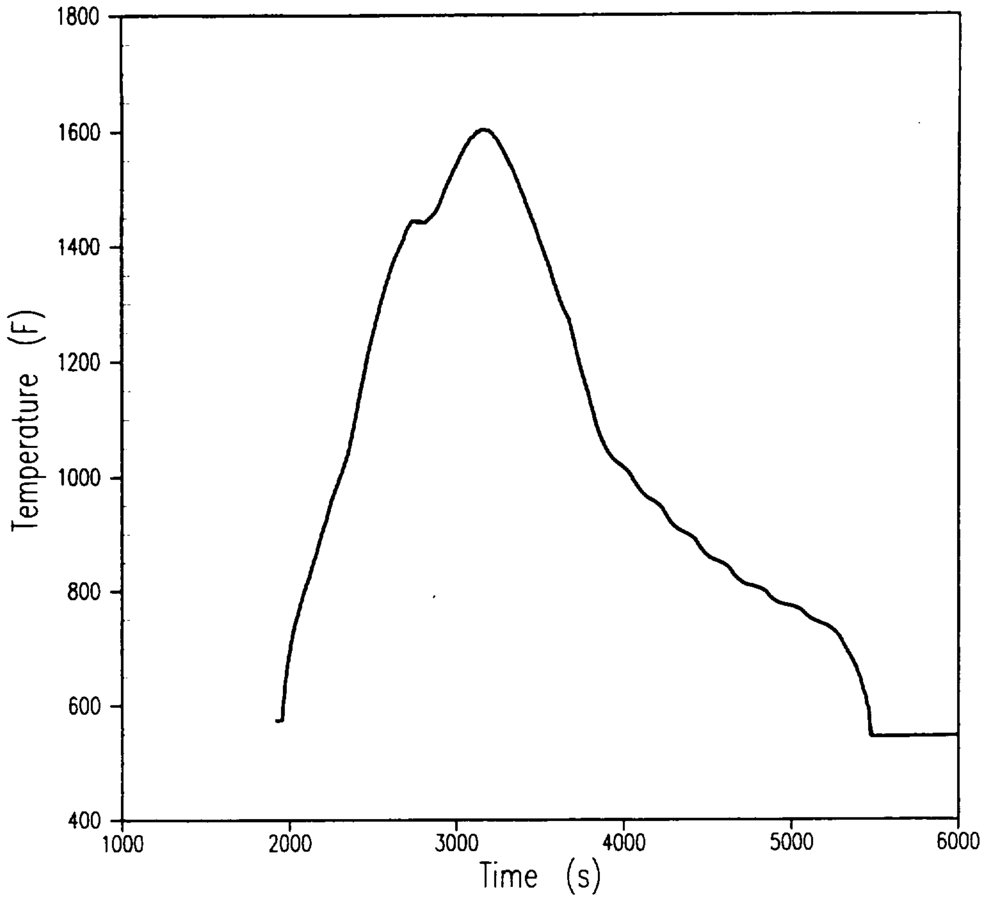


Figure 6.1.1-61

Units 2 Low T_{avg} 2-Inch

Peak Clad Temperature at 11.50 ft.

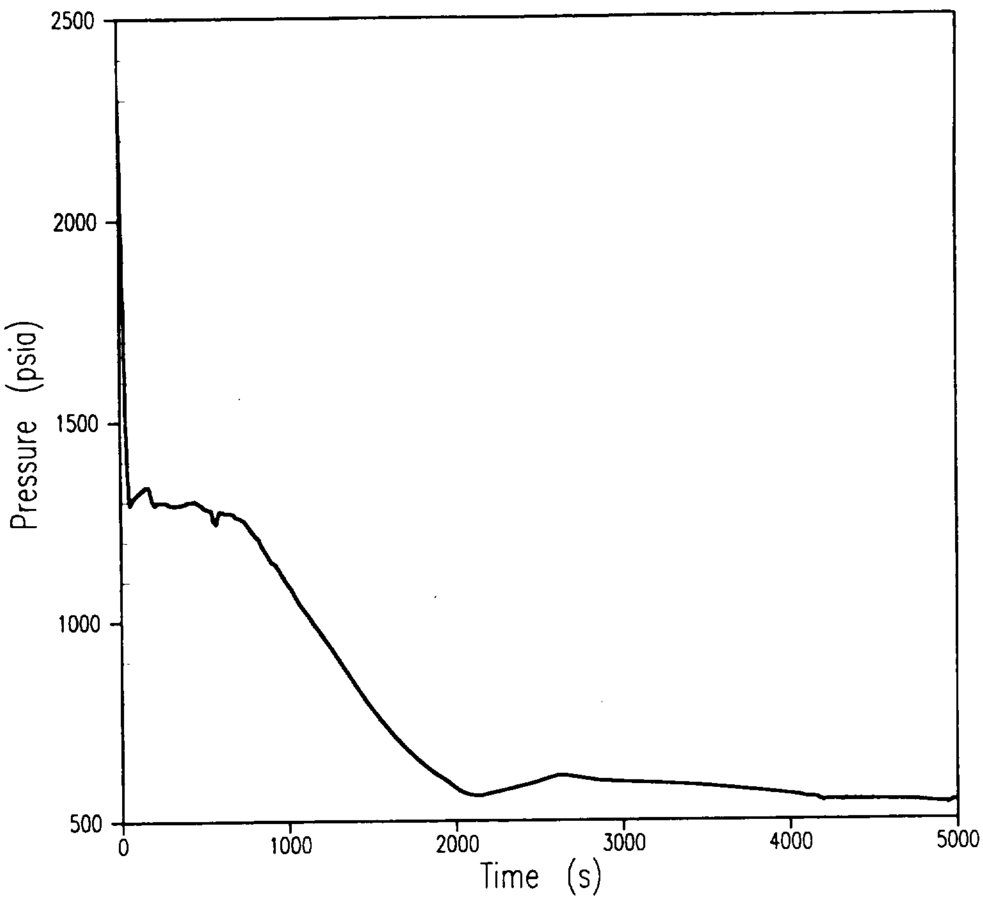


Figure 6.1.1-62

Units 2 Low T_{avg} 3-Inch

RCS Pressure

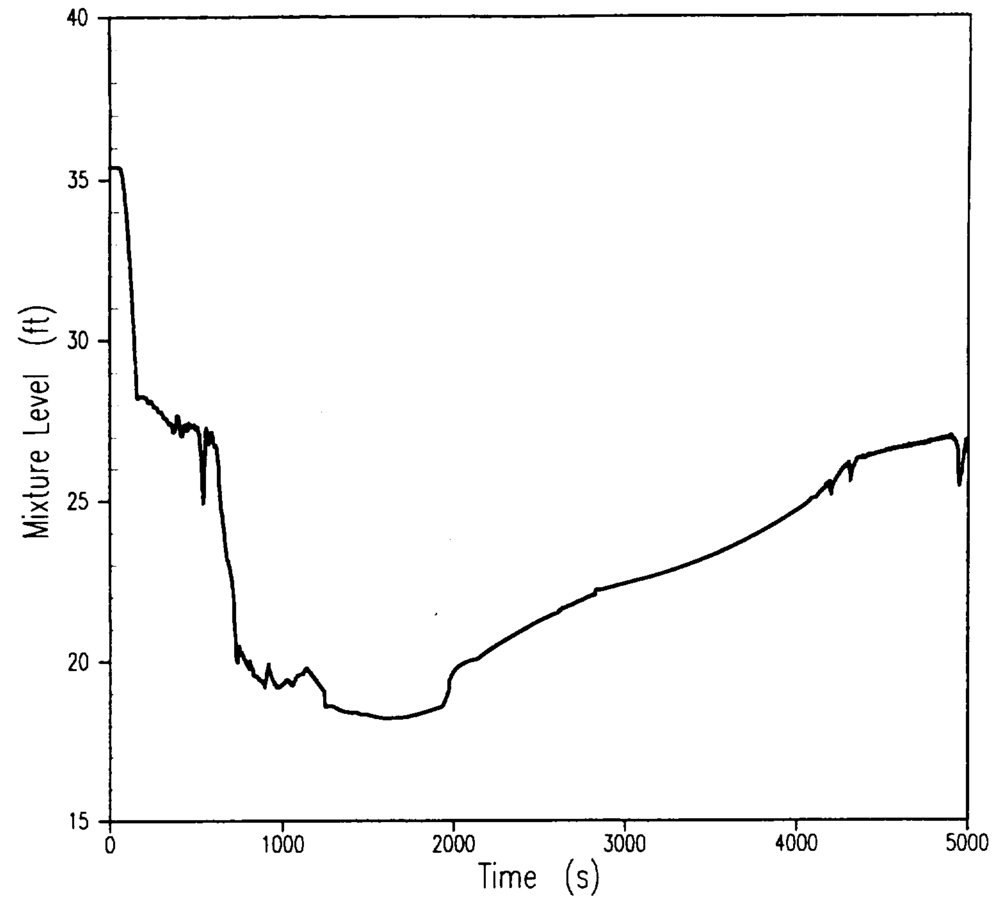


Figure 6.1.1-63

Units 2 Low T_{avg} 3-Inch

Core Mixture Level

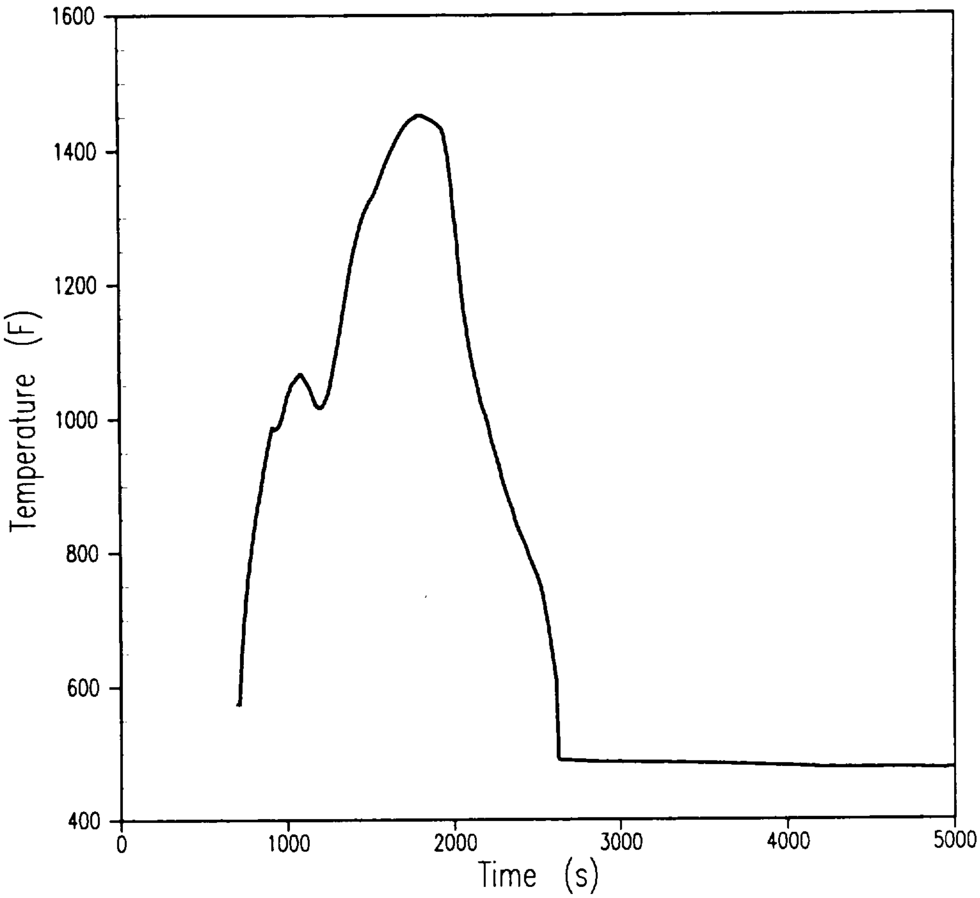


Figure 6.1.1-64

Units 2 Low T_{avg} 3-Inch

Peak Clad Temperature at 11.5 ft.

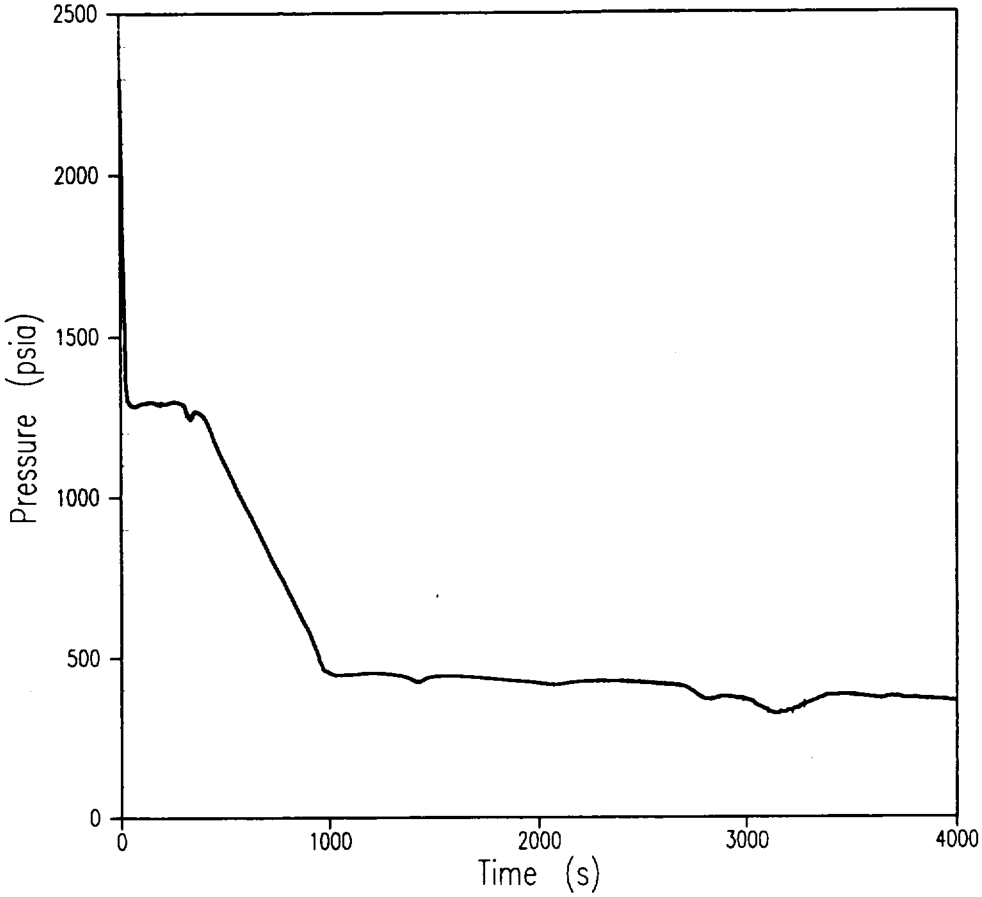


Figure 6.1.1-65

Units 2 Low T_{avg} 4-Inch

RCS Pressure

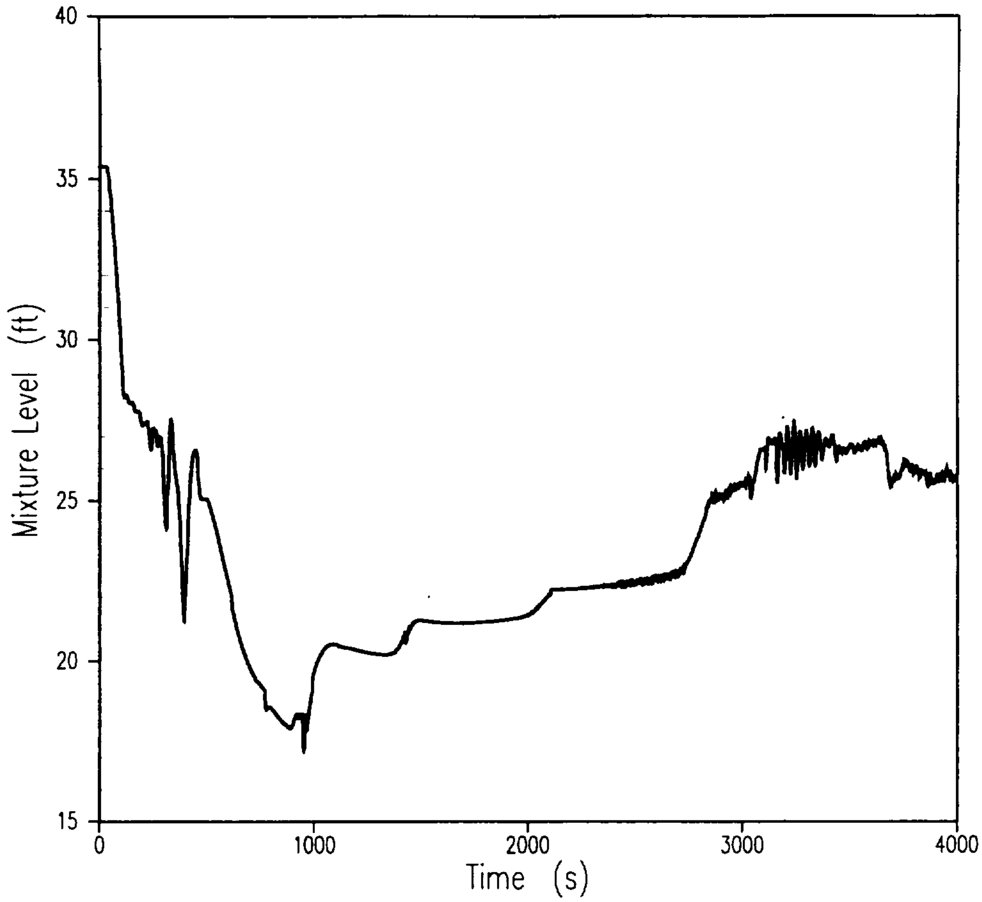


Figure 6.1.1-66

Units 2 Low T_{avg} 4-Inch

Core Mixture Level

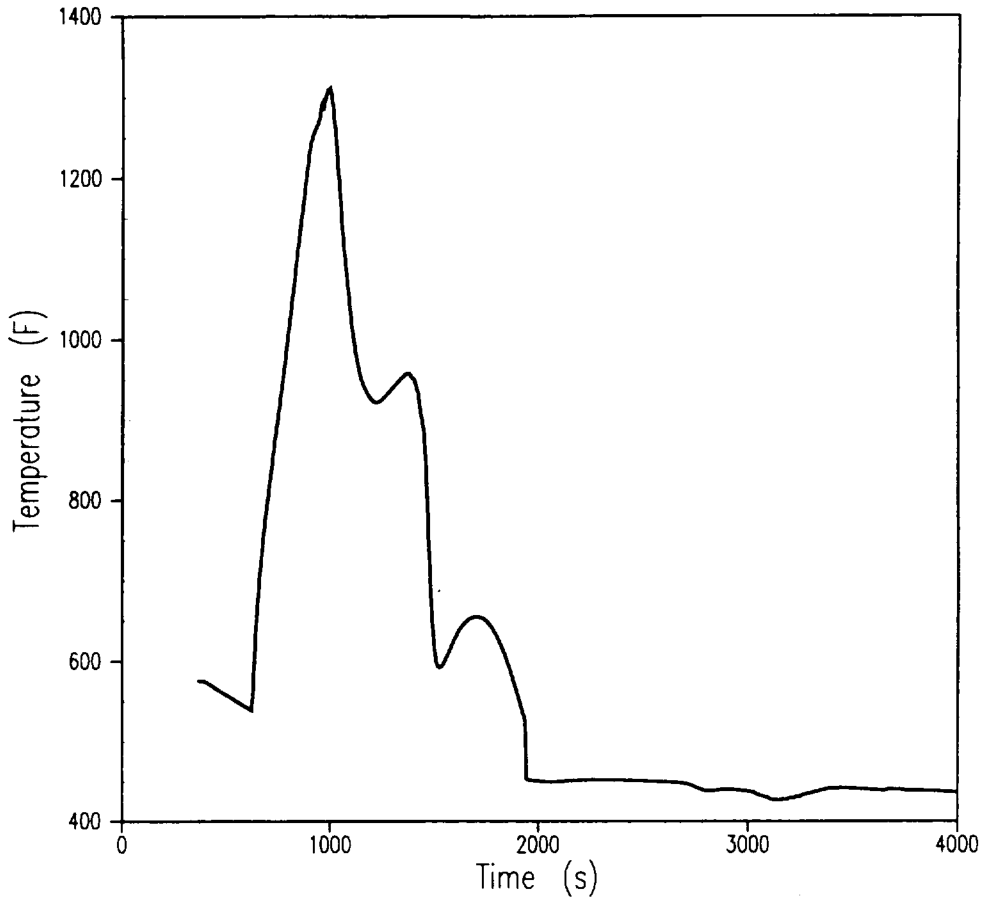


Figure 6.1.1-67

Units 2 Low T_{avg} 4-Inch

Peak Clad Temperature at 11.25 ft.

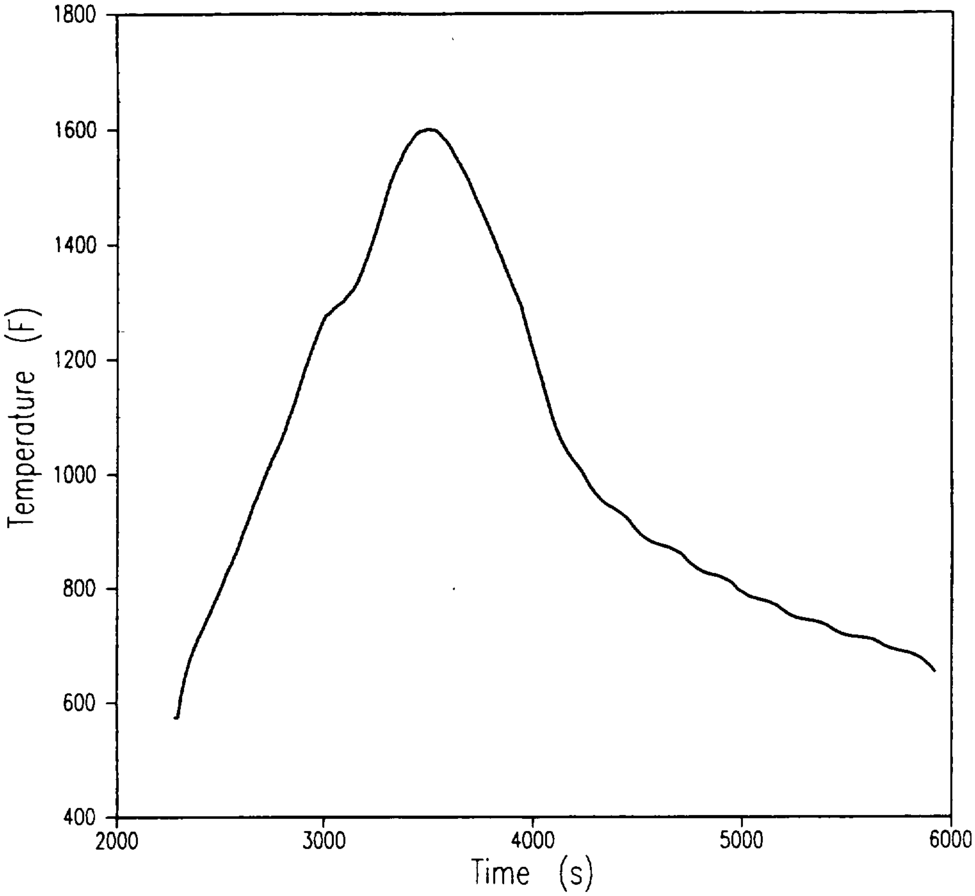


Figure 6.1.1-68

Units 1 Low T_{avg} 2-Inch Zirc-4

Peak Clad Temperature at 11.75 ft.

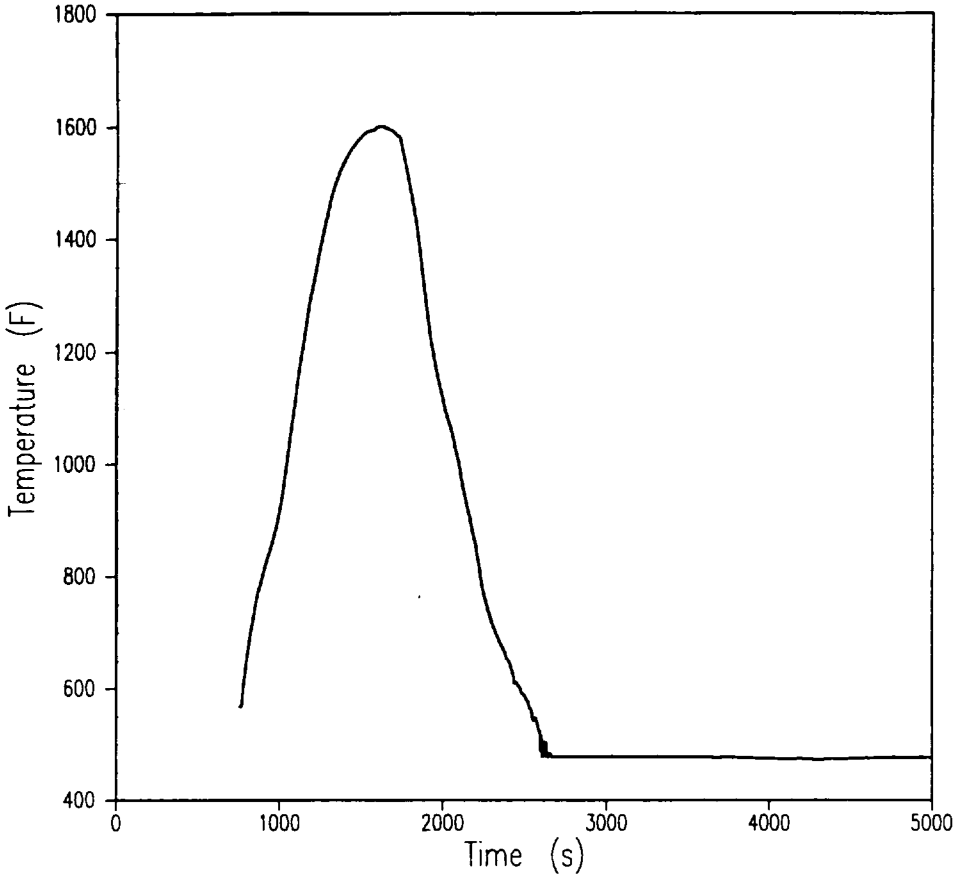


Figure 6.1.1-69

Units 2 High T_{avg} 3-Inch Zirc-4, BU = 6K

Peak Clad Temperature at 11.75 ft.

6.1.2 Hot Leg Switchover

6.1.2.1 Introduction

Post-LOCA maximum allowable time before Hot Leg Switchover (HLSO) is calculated for inclusion in the emergency operating procedures to ensure there is no boron precipitation in the reactor vessel following boiling in the core after a large-break LOCA. This calculation is dependent upon power level and the various boron concentrations of the Reactor Coolant System (RCS) and Emergency Core Cooling System (ECCS).

6.1.2.2 Input Parameters/Assumptions and Description of Analysis

Currently, a HLSO time of 8.5 hours is calculated for Byron/Braidwood Units 1 and 2 based on a core power level of 3411 MWt and a conservatively calculated core volume. Although boron concentrations of the RCS and ECCS have not changed due to the uprating, the increase in core power to 3586.6 MWt requires recalculation of the HLSO time and hot leg recirculation minimum required flow.

An increase in core power alone would reduce the HLSO time. However, the new HLSO time calculation was based on a more accurate core mixing volume than previously used.

With the more accurate core mixing volume, the maximum HLSO time for an uprated core power of 3586.6 MWt was found to be 9.5 hours. Because 8.5 hours to Hot Leg Switchover is conservative with respect to the new maximum HLSO time, 8.5 hours is an acceptable HLSO time.

Minimum flow requirements are calculated at the hot leg switchover time to ensure that sufficient flow exists in the hot leg recirculation flow configuration to stop the buildup of boron in the vessel and to ensure adequate core cooling is maintained. For the large-break LOCA's, the minimum required flow delivered to the hot legs is 1.3 times the calculated core boiloff rate, and the minimum required flow delivered to the cold legs must equal or exceed 1.5 times the calculated core boiloff rate.

In the event of a small hot leg break where RCS pressure can remain high, there are two means of demonstrating the adequacy of flow at hot leg switchover time. Credit may be taken for operator action to cool down and depressurize the RCS, using safety grade SG PORV's, prior to entering hot leg recirculation mode. Alternatively, it may be demonstrated that available flows at high pressures meet or exceed the calculated core boiloff rate, which is known to be conservative relative to the actual maximum calculated flow through the break. Core boiloff rates at high RCS pressures are calculated for the minimum required flow delivered to both the hot and cold legs for a small hot leg break.

6.1.2.3 Acceptance Criteria

Boron precipitation may result in a change in core geometry which would make it not amenable to cooling, or reduce the heat transfer capability such that heat cannot be sufficiently removed for the extended period required by long-lived radioactivity remaining in the core. To ensure that boron does not precipitate in the core, the HLSO calculation was performed to show the acceptance criteria of 10 CFR 50.46 continue to be met for the increase in core power from 3411 to 3586.6 MWt. Specifically, a new maximum allowable time before HLSO was established at the uprate conditions, based upon the boron concentrations being four percent lower than the boron solubility limit.

The available flow rates must meet or exceed the minimum required flow criteria.

6.1.2.4 Results

A revised set of hot leg recirculation minimum required flows were calculated at the uprate power conditions. Table 6.1.2-1 provides the required ECCS flow rates for four different accident scenarios.

6.1.2.5 Conclusions

The acceptance criteria of 10 CFR 50.46 continue to be met at the uprate power conditions.

6.1.2.6 References

1. "Byron & Braidwood Station, Updated Final Safety Analysis Report," Revision 7, Docket Nos. STN-454/455/456/457, as amended through December 1998.

Table 6.1.2-1 ECCS Minimum Required Flow Rates for Byron/Braidwood Uprating to 3586.6 MWt						
Break Location and Size	**ECCS Flow Spilling Assumption**	**Source of Flow to Meet Criteria**	**Pressure at Delivery Location**	**Flow Criteria at 8.5 Hr. HLSO (lbm/sec)**	**Flow Criteria at 9.5 Hr. HLSO (lbm/sec)**	**Available Flow (lbm/sec)**
Cold Leg Large Break	One Cold Leg Spills to Containment Pressure.	Total Hot Leg Flow. (No lines spilling.)	Atmospheric Pressure	42.8 (1.3 x boiloff)	41.5 (1.3 x boiloff)	$\geq$ 42.8
Hot Leg Large Break	One Hot Leg Spills to Containment Pressure.	Total Cold Leg Flow. (No lines spilling.)	Atmospheric Pressure	49.4 (1.5 x boiloff)	47.9 (1.5 x boiloff)	$\geq$ 49.4
Hot Leg Small Break	One Hot Leg Spills to RCS Pressure.	Total of Hot and Cold Leg Delivered Flow.	1000 psi	31.7[1,2]	Not calculated — bounded by 8.5 hr. criteria.	$\geq$ 31.7[2]
Hot Leg Small Break	One Hot Leg Spills to RCS Pressure.	Total of Hot and Cold Leg Delivered Flow.	1300 psi	32.1[1,2]	Not calculated — bounded by 8.5 hr. criteria.	$\geq$ 32.1[2]

[1]Based on 1.0 x boiloff which greatly exceeds maximum break flow rates for break cases of one inch or smaller.

[2]These flows must be met where credit is not taken for operation of steam generator PORVs.

6.1.3 Post-LOCA Long Term Core Cooling

6.1.3.1 Introduction

The Long Term Core Cooling (LTCC) analysis is performed to demonstrate that during post-LOCA the core will remain subcritical. During post-LOCA long term cooling, safety injection flow is drawn from the containment sump following switchover from the Refueling Water Storage Tank (RWST). The Byron/Braidwood long term cooling analysis at the uprate conditions was performed based on the assumption that two different amounts of ECCS water will be drained from the RWST to the sump, i.e., two curves were generated as shown in Figure 6.1.3-1.

6.1.3.2 Input Parameters/Assumptions and Description of Analysis

As stated in the introduction section, two post-LOCA sump boron curves were generated. The amount of ECCS water which was assumed to drain from the RWST for each curve was dependent upon the break size. For small break LOCAs (break sizes $\leq 1.0\ ft^2$), the amount of water assumed to be drained from the RWST to the containment was 169,608 gallons (LO-2 level alarm, 46.7% level). For large break LOCAs (break sizes $> 1.0\ ft^2$), the amount of water assumed to be drained from the RWST to the containment was 326,972 gallons (LO-3 level alarm, 12% level).

This approach in support of the LTCC analysis can be justified by the fact that for SBLOCA the control rods will insert and at least 169,608 gallons of ECCS water from the RWST will be drained to the containment. Credit for the effect of control rods on subcriticality generally results in the SBLOCA break being less limiting than the LBLOCA despite the difference in RWST volume drained. For the LBLOCA, the control rods may not insert, however the containment sprays will be actuated and at least 326,972 gallons of ECCS water from the RWST will be drained to the containment. Analyses were performed by Westinghouse to demonstrate that control rods will insert for break sizes up to 1 ft^2. An analysis was performed for the uprate conditions to demonstrate that containment sprays will actuate for break sizes greater than 1 ft^2 area. The analysis included conservative modeling appropriate for this application.

6.1.3.3 Acceptance Criteria

The Westinghouse licensing position for satisfying the requirements of 10 CFR 50.46 Paragraph (b) Item (5), "Long-Term Cooling," is documented in Reference 1. The Westinghouse position is that the core will remain subcritical post-LOCA by borated water from various ECCS water sources residing in the RCS and containment sump. Since credit for control rod insertion is not taken for a LOCA of greater than 1 ft^2 area (a "large break"), the borated ECCS water provided by the accumulators and RWST must have a sufficiently high boron concentration that, when mixed with other sources of borated and non-borated water, the core will remain subcritical should all control rods remain withdrawn from the core.

6.1.3.4 Results

Figure 6.1.3-1 depicts the two post-LOCA sump boron concentration curves generated. One sump boron curve was based on RWST volume drained only to the low level signal (169,608 gallons), the other was based on RWST volume drained below the low level signal (326,972 gallons). This amount of RWST volume drained reduced Sump Boron Concentration by approximately 141 ppm (to 1812 ppm) at 1250 ppm Pre-Trip RCS Boron Concentration, Peak Xenon.

6.1.3.5 Conclusions

In summary, the post-LOCA long term core cooling boron limit curve will be used to qualify the fuel and core loading arrangement on a cycle-by-cycle basis during the fuel reload process. Provided that the maximum critical Boron concentration remains below the post-LOCA sump boron concentration curve (for all rods out, no Xenon, 68°F – 212°F), it is concluded that the core will remain subcritical post-LOCA, and that decay heat can be removed for the extended period required by the remaining long-lived radioactivity.

6.1.3.6 References

1. Bordelon, F. M., et al., "Westinghouse ECCS Evaluation Model - Summary," WCAP-8339 (Non-Proprietary), July 1974.

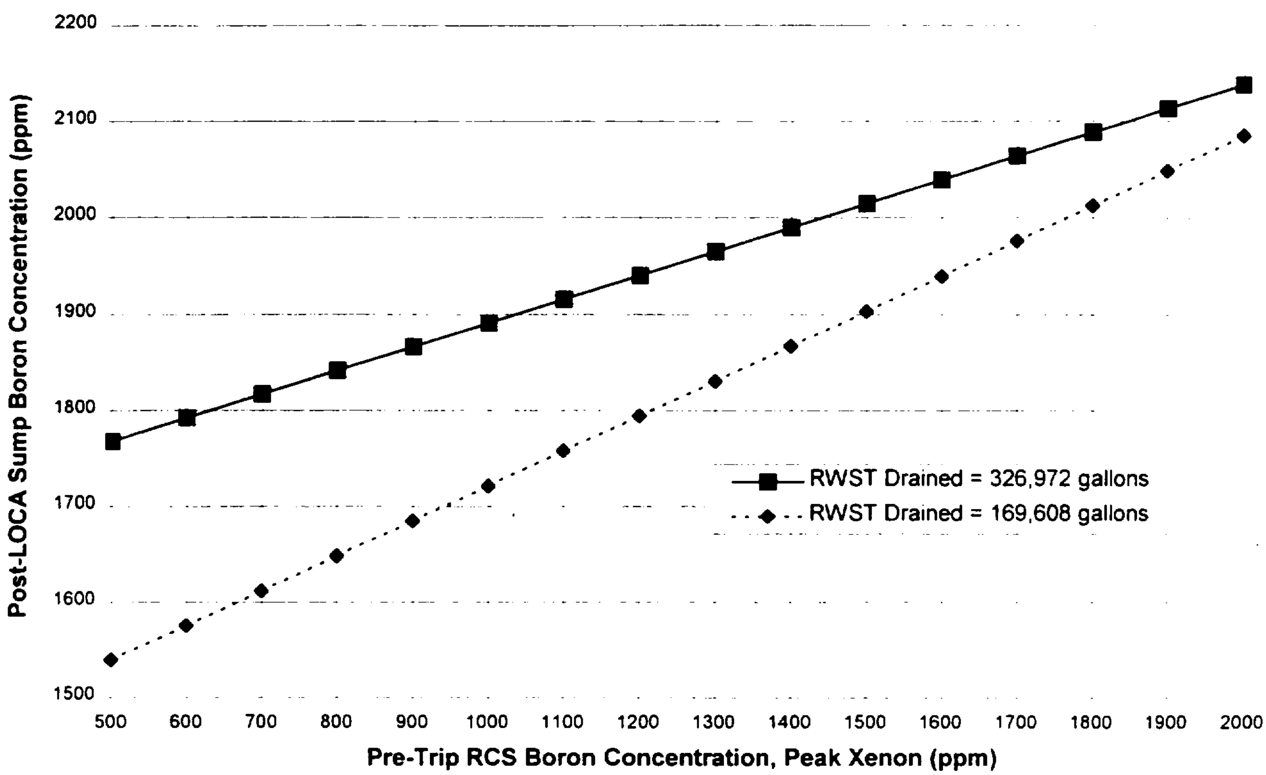


Figure 6.1.3-1

Post-LOCA Sump Boron Concentration, Peak Xenon Curve

6.2 Non-LOCA Analyses and Evaluations

6.2.0 Introduction

To support the Byron/Braidwood Power Uprating Project, all UFSAR Chapter 15 Non-LOCA analyses were evaluated to determine the acceptability of plant operation at the uprated conditions. The uprated conditions are those defined in Table 2.1-1 for the Byron 1 and Braidwood 1 units with BWI steam generators and in Table 2.1-2 for the Byron 2 and Braidwood 2 units with D5 steam generators. The Non-LOCA events considered herein are listed in Table 6.2.0-1, along with the corresponding section number in this report and the applicable UFSAR section(s).

Where applicable, the Non-LOCA analyses continue to employ the Revised Thermal Design Procedure (RTDP) methodology (Reference 1). The RTDP methodology statistically convolutes the uncertainties of the plant operating parameters (power, temperature, pressure and flow) into the design limit Departure from Nucleate Boiling Ratio (DNBR) value. These design limit DNBR values are then utilized to determine the safety analysis limit DNBR values that are assumed as an acceptance criterion in the DNBR-related non-LOCA analyses.

The safety analysis values of the Overtemperature ΔT and Overpower ΔT (OTΔT/OPΔT) setpoint values applicable to the plant uprate are as follows.

OTΔT	OPΔT
$K1_{Analysis}$ = 1.50	$K4_{Analysis}$ = 1.155
K2 = 0.0297	K6 = 0.00245
K3 = 0.00181	f(ΔI) = 0
f(ΔI) + wing = 10%, %ΔI = 3.47%	
- wing = -26%, %ΔI = 2.61%	

These setpoints were determined based on revised Safety Analysis DNBR limits and Core Thermal Limits applicable for the uprated power conditions defined in Tables 2.1-1 and 2.1-2.

In conjunction with support of the plant uprate, the Non-LOCA safety analyses have also been performed to support several other changes that directly affect the UFSAR Chapter 15

Non-LOCA safety analyses. These changes, including those directly associated with the power uprate conditions, are summarized in the sections that follow.

Power Uprating

The changes in plant conditions that are considered to be directly associated with the subject power uprating, and are reflected in Tables 2.1-1 and 2.1-2, are discussed below.

NSSS power is increased from 3425 MWt to 3600.6 MWt. This results in an increase in reactor power from 3411 MWt to 3586.6 MWt and a corresponding increase in rod average linear power from 5.45 kW/ft to 5.73 kW/ft.

Thermal Design Flow (TDF) is increased from 358,800 gpm to 368,000 gpm as a result of reductions in the assumed maximum steam generator tube plugging levels (see below). Corresponding to the increase in TDF, the Minimum Measured Flow (MMF) used in conjunction with the statistical Revised Thermal Design Procedure (RTDP) DNBR methodology is increased from 366,000 gpm to 380,900 gpm. Core bypass flow of 8.3% (non-statistical) and 7.6% (statistical) are assumed. These core bypass flow conditions are consistent with those currently supporting Thimble Plug Elimination and, as such, are not a change.

The maximum Reactor Vessel Average Coolant Temperature (T_{avg}) is decreased from 588.4°F to 588.0°F. The minimum T_{avg} is increased from 569.1°F to 575.0°F.

Feedwater temperature at full power conditions is increased from 440°F to 446.6°F. The feedwater temperature at a hot-zero power conditions remains at 100°F. Feedwater temperatures at part-power conditions increase proportionally with power between hot-zero power and full power conditions.

The maximum steam generator tube plugging levels are decreased from 20% to 5% for the BWI steam generators and from 24% uniform/30% peak to 10% uniform for the D5 steam generators. A maximum 5% loop-to-loop flow asymmetry continues to be considered in the safety analysis consistent with the current licensing basis analyses.

As previously indicated, revised OTΔT and OPΔT setpoints were determined based on revised Safety Analysis DNBR limits and Core Thermal Limits applicable for the uprated power conditions. For the uprate, the Safety Analysis Limit DNBR was revised from 1.40 (Typical & Thimble cell) to 1.33 (Typical & Thimble cell). With the exception of the f(ΔI) function setpoints for the OTΔT trip, the OTΔT and OPΔT trip setpoints remain unchanged. For the OTΔT f(ΔI) function, the deadband intercept with the negative wing of the f(ΔI) function changed from -24% ΔI to -26% ΔI. The slope of the negative gain on f(ΔI) changed from 3.35 to 2.61%/%ΔI while the slope on the positive gain changed from -4.11 to -3.47 %/%ΔI. It should be noted that the determination of these trip setpoints includes consideration of a 1°F loop-to-loop temperature variation.

Automatic Rod Control

The uprating analyses also include changes to the automatic rod control system parameters to optimize rod control system performance. Specifically, the non-LOCA analyses support a change in the lead/lag compensation on the measured T_{avg} from 80 seconds/5 seconds to 40 seconds/10 seconds. Also, the rod control deadband is decreased from ±4°F to ±1.5°F.

Pressurizer Heater Modeling

The pressurizer deviation setpoint for the backup heaters is changed from -25 psi to -10 psi to improve pressurizer heater response to plant normal transient and the pressurizer water volume heater-off setpoint is changed from an overly conservative value of 180 $ft.^3$ to an actual calculated value of 358.6 $ft.^3$

Safety Injection

Several changes to the modeling of Safety Injection (SI) system response are included in the Non-LOCA safety analyses supporting the uprating program. The SI flow rates as a function of RCS pressure used in the power uprating analysis are illustrated in Figure 6.2.0-1. The delay time for SI actuation without offsite power is increased from 37 seconds to 40 seconds. The safety analysis setpoint for actuation of SI and steamline isolation on low steamline pressure used in the steamline break core response analysis is revised from 364 psia to 450 psia.

Auxiliary Feedwater

To support the uprating program, several changes in the modeling of the Auxiliary Feedwater (AF) System response are included in the Non-LOCA safety analyses. The AF actuation delay time with offsite power available is reduced from 60 seconds to 55 seconds in the Feedline Break (FLB) and Loss of Normal Feedwater (LONF) analyses. The AF actuation delay time without offsite power available is increased from 60 seconds to 63 seconds. The minimum constant AF flow rate, assuming operation of the AF control valves (AF005), is increased from 140 gpm per loop to 151 gpm per loop for the Unit 2 plants with D5 steam generators but remains at 140 gpm per loop for the Unit 1 plants with BWI steam generators. The AF flow as a function of steam generator pressure with the AF control valves (AF005) inoperable is also slightly increased. The resulting AF flow rates are illustrated in Figure 6.2.0-2.

Neutronics/Reactivity Modeling

To support future reload design activities with uprated core power and to support several event-specific uprating analyses, several neutronics related analysis input assumptions are changed to support the uprate.

To facilitate future reload design activities, the maximum critical boron concentration for the Mode 2 (Startup) boron dilution analysis is revised from 1496 ppm to 1730 ppm. The Mode 2 boron dilution analysis is presented in Section 6.2.17.

For the Rod Ejection analysis, the End-of-Life Hot Zero Power (EOL HZP) maximum ejected rod worth and F_Q are revised from 900 pcm and 21.0 to 800 pcm and 23.0, respectively. The Beginning-of-Life Hot Full Power (BOL HFP) maximum ejected rod worth is reduced from 250 pcm to 200 pcm. The Rod Ejection analysis is presented in Section 6.2.19.

To support the Uncontrolled RCCA Withdrawal at Power analysis, the maximum reactivity insertion rate is limited to $\leq$50 pcm/sec (66.66 pcm/in) corresponding to maximum differential RCCA worth at maximum RCCA withdrawal rate. This is discussed in Section 6.2.14.

Revised HZP stuck rod moderator density coefficients and Doppler-only power coefficients were generated and used in the HZP steamline break core response analysis supporting the power uprating. These are discussed in Section 6.2.4.

To facilitate future reload core designs, the end-of-life maximum moderator density coefficient was revised from 0.43 Δk/gm/cc to 0.54 Δk/gm/cc except for the HFP feedwater malfunction (FWM) and steamline break (SLB) analyses presented in Sections 6.2.1 and 6.2.5, respectively. For the HFP FWM and SLB analyses, the end-of-life maximum moderator density coefficient is limited to a value of 0.33 Δk/gm/cc and a minimum end-of-life Doppler-only power coefficient with a power defect of 1200 pcm at 100% power is used. The Doppler-only power coefficients used in the Non-LOCA safety analyses are illustrated in Figure 6.2.0-3.

The least negative boron worth is revised from -7 pcm/ppm to -5 pcm/ppm.

MSSV Tolerance

The Non-LOCA licensing basis analyses for the Byron/Braidwood units currently support a maximum Main Steam Safety Valve (MSSV) tolerance of ±3%. For the uprating, the Non-LOCA analyses are performed to support an increase in the MSSV tolerance to ±4%.

Fuel Temperatures

Revised fuel temperatures generated in support of the uprated power conditions are applied as appropriate in the Non-LOCA safety analyses. These fuel temperatures reflect the use of 17x17 Vantage+ IFBA and non-IFBA fuel with Zirlo™ fuel rods and assembly components.

Feedwater Isolation Interlock

Also considered under the scope of the Non-LOCA analyses is an additional plant operational related item. This item is the re-instatement of the feedwater isolation interlock on low RCS T_{avg} and is addressed for the feedline break (FLB) event as presented in Section 6.2.9.

Methodology Changes

The Non-LOCA safety analysis methodology used to support the power uprate is the same as that applied for the current licensing basis Non-LOCA analyses with one exception. This exception is the use of a RCS thick-metal mass model for heat absorption in the LOFTRAN computer program. The RCS thick-metal mass model was applied in the analysis for the FLB event as presented in Section 6.2.9. Credit for heat absorption by the thick-metal masses within the primary and secondary-sides of the RCS is needed to demonstrate adequate post-trip residual and decay heat removal capacity of the AF system for this event.

Reactor Trip

There are various instrumentation delays associated with each reactor trip function that are modeled directly and considered in the non-LOCA safety analyses. The total delay time is defined as the time from when trip conditions are reached to the time the rods are free to fall. The safety analysis trip setpoint and maximum time delay assumed for each reactor trip function are as follows. These values are the same as those applicable to the current licensing basis Non-LOCA safety analyses and remain applicable for the power uprate.

Reactor Trip Function	Time Delay (seconds)	Maximum Trip Setpoint Assumed for Analysis
Power Range Flux (high setting)	0.5	118%
Power Range Flux (low setting)	0.5	35%
Overtemperature ΔT	8.0	Variable (see above)
Overpower ΔT	8.0	Variable (see above)
High Pressurizer Pressure	2.0	2471 psia
Low Pressurizer Pressure	2.0	1860 psia
Low Reactor Coolant Flow	1.0	85.1% of loop flow
Low-Low Steam Generator Water Level (LONF/LOOP events) (Feedline Break event)	 2.0 2.0	 28.6% NRS (D5 SG) 10.0% NRS (BWI SG) 18.6% NRS (D5 SG) 0% NRS (BWI SG)
High-High Steam Generator Water Level (Feedwater Isolation) (Turbine Trip)	 7.0 2.5	 100% NRS 100% NRS
Reactor Trip (following Turbine Trip)	2.5	N/A

Table 6.2.0-2 summarizes key analysis assumptions considered in the Byron/Braidwood Uprate non-LOCA analyses and evaluations.

The non-LOCA accidents are considered either American Nuclear Society (ANS) Condition II, III, or IV events. The ANS categorizes events based upon expected frequency of occurrence and severity as follows.

Condition I: Normal Operation and Operational Transients

Condition II: Faults of Moderate Frequency

Condition III: Infrequent Faults

Condition IV: Limiting Faults

Condition I events are normal operation incidents which are expected to occur frequently or regularly. These occurrences are accommodated with margin between any plant parameter and the value of that parameter which would require either automatic or manual protective action.

Condition II events (which are the majority of the Non-LOCA events) are incidents of moderate frequency that may reasonably occur during a calendar year of operation. These faults, at worst, result in a reactor trip with the plant capable of returning to power operations after corrective actions. Condition II incidents shall not generate a more serious accident (Condition III or IV) without other incidents occurring independently.

Condition III events are infrequent faults that may reasonably occur during the lifetime of a plant. These faults shall not cause more than a small fraction of fuel elements to be damaged. No consequential loss of function of the RCS or containment as fission product barriers can occur. The release of radioactive materials to unrestricted areas may exceed 10 CFR Part 20 limits; however, they shall not be sufficient to interrupt or restrict public use of those areas beyond the exclusion radius. Condition III incidents shall not generate a more serious accident (Condition IV) without other incidents occurring independently.

Condition IV events are limiting faults that are not expected to occur but are postulated because their consequences would include the potential for significant radioactive releases. The release of radioactive material shall not result in an undue risk to public health and safety exceeding the guidelines of 10 CFR 100. No consequential loss of function of systems required to mitigate the event may occur.

The results of all analyses and evaluations demonstrate that applicable safety analysis acceptance criteria are satisfied at the uprated conditions detailed in Tables 2.1-1 and 2.1-2.

References

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

Table 6.2.0-1 List of Non-LOCA Events		
Licensing Report Section	**Event**	**UFSAR Section**
6.2.1	Excessive Heat Removal Due to Feedwater System Malfunctions	15.1.1 & 15.1.2
6.2.2	Excessive Increase in Secondary Steam Flow	15.1.3
6.2.3	Inadvertent Opening of a Steam Generator Relief or Safety Valve	15.1.4
6.2.4	Steam System Piping Failure at Zero Power	15.1.5
6.2.5	Steam System Piping Failure at Full Power	15.1.6
6.2.6	Loss of External Electrical Load and/or Turbine Trip	15.2.2 to 15.2.5
6.2.7	Loss of Non-emergency AC Power to the Plant Auxiliaries	15.2.6
6.2.8	Loss of Normal Feedwater	15.2.7
6.2.9	Feedwater System Pipe Break	15.2.8
6.2.10	Partial Loss of Forced Reactor Coolant Flow	15.3.1
6.2.11	Complete Loss of Forced Reactor Coolant Flow	15.3.2
6.2.12	Single Reactor Coolant Pump Locked Rotor/Shaft Break	15.3.3 to 15.3.5
6.2.13	Uncontrolled RCCA Withdrawal From a Subcritical or Low Power Startup Condition	15.4.1
6.2.14	Uncontrolled RCCA Bank Withdrawal at Power	15.4.2
6.2.15	Rod Cluster Control Assembly Misoperation	15.4.3
6.2.16	Startup of an Inactive Reactor Coolant Pump at an Incorrect Temperature	15.4.4
6.2.17	Chemical and Volume Control System Malfunction That Results in a Decrease in Boron Concentration in the Reactor Coolant	15.4.6
6.2.18	Inadvertent Loading of a Fuel Assembly into an Improper Position	15.4.7
6.2.19	Rod Cluster Control Assembly Ejection	15.4.8
6.2.20	Inadvertent Operation of the Emergency Core Cooling System (ECCS) During Power Operation	15.5.1
6.2.21	Inadvertent Opening of a Pressurizer Safety or Relief Valve	15.6.1

Note: No evaluations were performed for UFSAR Section 15.2.1, "Steam Pressure Regulator Malfunction or Failure That Results in Decreasing Steam Flow" or 15.5.2, "Chemical and Volume Control System Malfunction that Increases Reactor Coolant Inventory." The event described in Section 15.5.2 is bounded by Section 15.5.1. For Section 15.2.1, there are no pressure regulators whose failure or malfunction could cause a steam flow transient. See UFSAR Sections 15.2.1 and 15.5.2.

Table 6.2.0-2 Non-LOCA Key Accident Analysis Assumptions for Byron/Braidwood Uprate	
NSSS Power	3600.6 MWt
Reactor Power	3586.6 MWt
NSSS Thermal Design Flow (per Loop)	92,000 gpm
Minimum Measured Flow (per Loop)	95,225 gpm
Core Bypass Flow Fraction (Non-Statistical) (Statistical)	8.3% 7.6%
Programmed Full Power RCS Average Temperature	588.0°F maximum 575.0°F minimum
Steam Generator Design (Byron 1/Braidwood 1) (Byron 2/Braidwood 2)	BWI SG D5 SG
Maximum Steam Generator Tube Plugging Level	10% average/peak (D5 SG) 5% average/peak (BWI SG)
Max $F_{\Delta H}$(Non-statistical) (Statistical)	1.70 1.635
Max F_Q	2.60
DNB Methodology (where applicable)	RTDP
Max EOL MDC	0.54 Δk/gm/cc (0.33 Δk/gm/cc for SLB/FWM)
Max BOL MTC	+7 pcm/°F ≤ 70% RTP ramping to 0 at 100% RTP
Initial Condition Uncertainties: Power RCS Flow Temperature Pressure Steam Generator Water Level Pressurizer Water Level	 ± 2% RTP ± 3.5% ± 7.6°F, + 1.5°F bias ± 43 psi ± 5% NRS ± 5% span

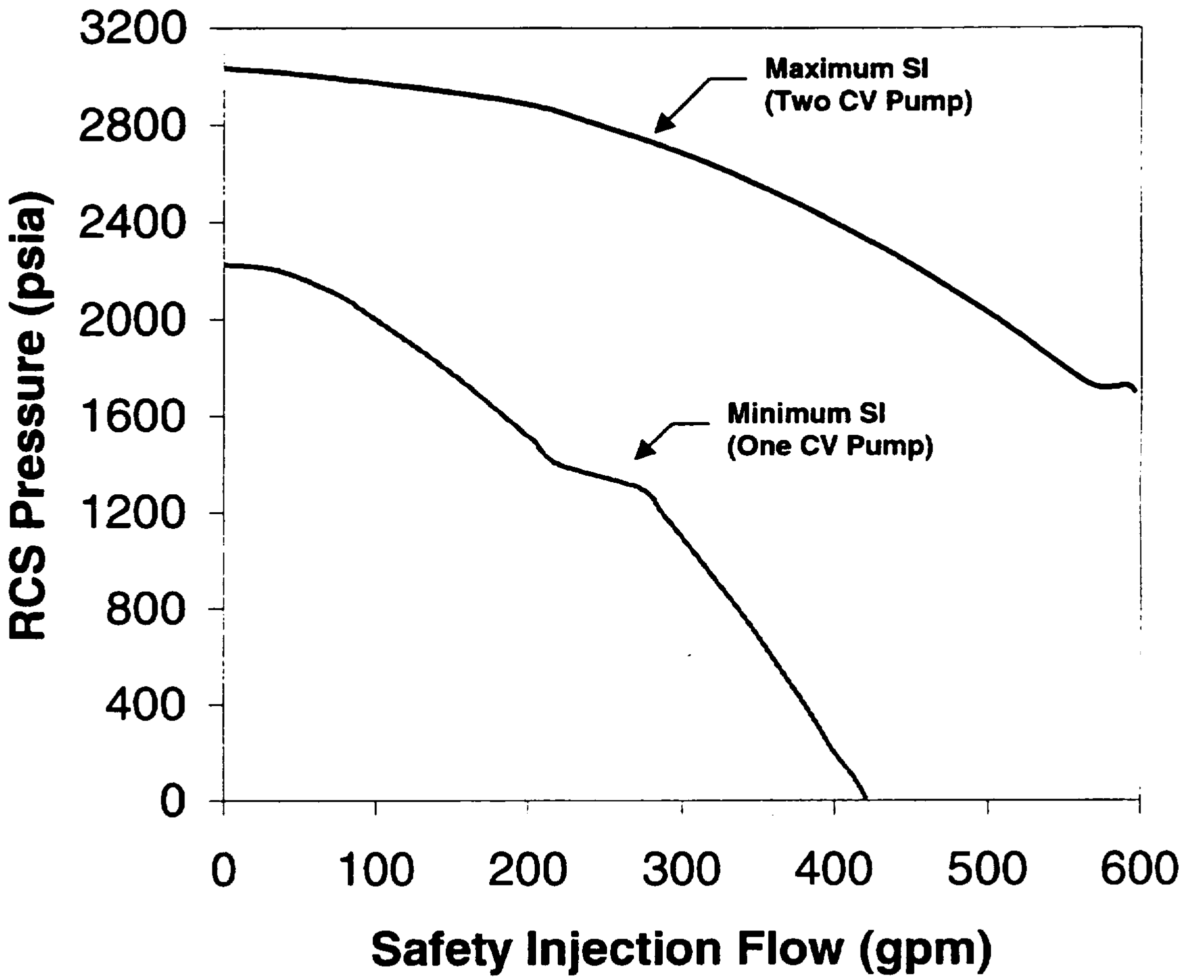
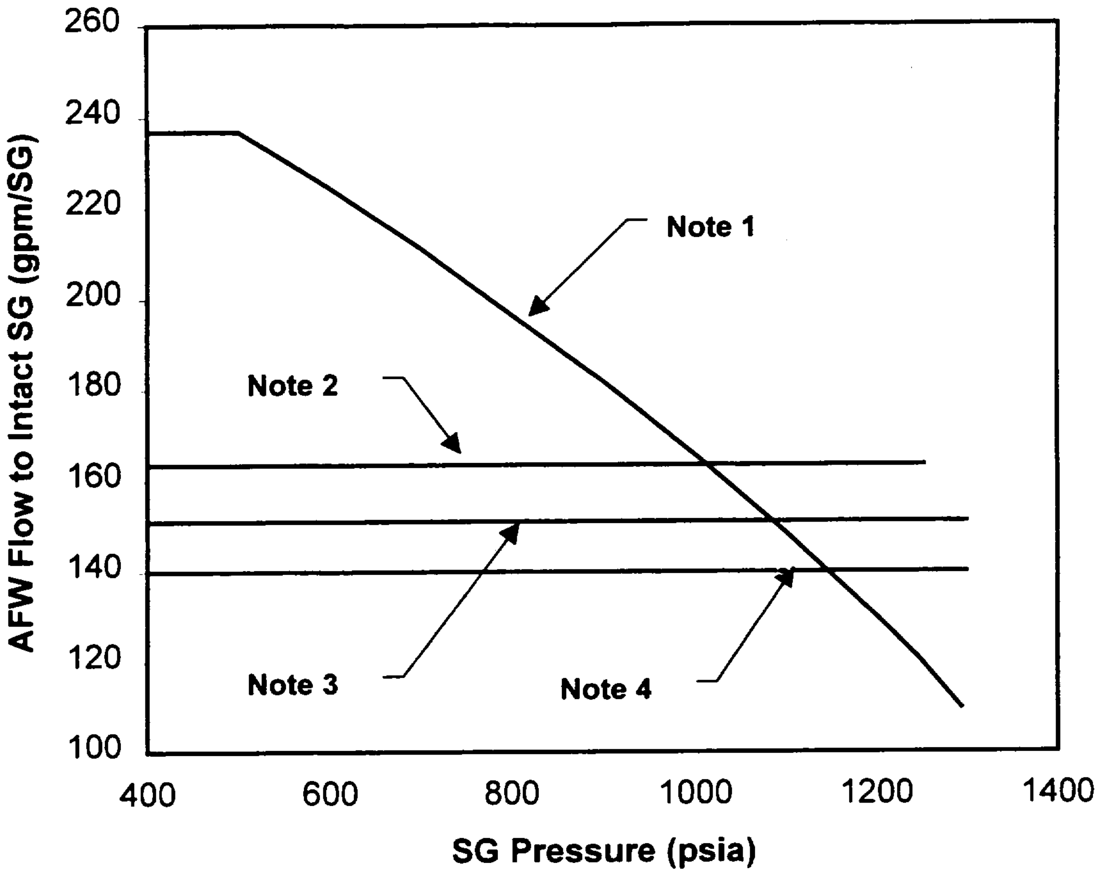


Figure 6.2.0-1

High-Head Safety Injection Flow vs. RCS Pressure



Note 1 - FLB AF Flow - AF005 Valves Inoperable

Note 2 - FLB AF Flow - Faulted SG Isolated (≤ 1253 psia)

Note 3 - FLB AF Flow - AF005 Valves Operable – D5 SGs

Note 4 - FLB AF Flow - AF005 Valves Operable – BWI SGs
& LONF/LOOP Flow (all cases, ≤ 1285.4 psia)

Figure 6.2.0-2

Auxiliary Feedwater Flow vs. SG Pressure

NOTE 1 – "UPPER CURVE" LEAST NEGATIVE DOPPLER ONLY

POWER DEFECT = -0.78 $\Delta\rho$ (0 TO 100% POWER)

NOTE 2 – LEAST NEGATIVE END-OF-LIFE DOPPLER ONLY

POWER DEFECT = -1.2 $\Delta\rho$ (0 TO 100% POWER)

NOTE 3 – "LOWER CURVE" MOST NEGATIVE DOPPLER ONLY

POWER DEFECT = -1.6 $\Delta\rho$ (0 TO 100% POWER)

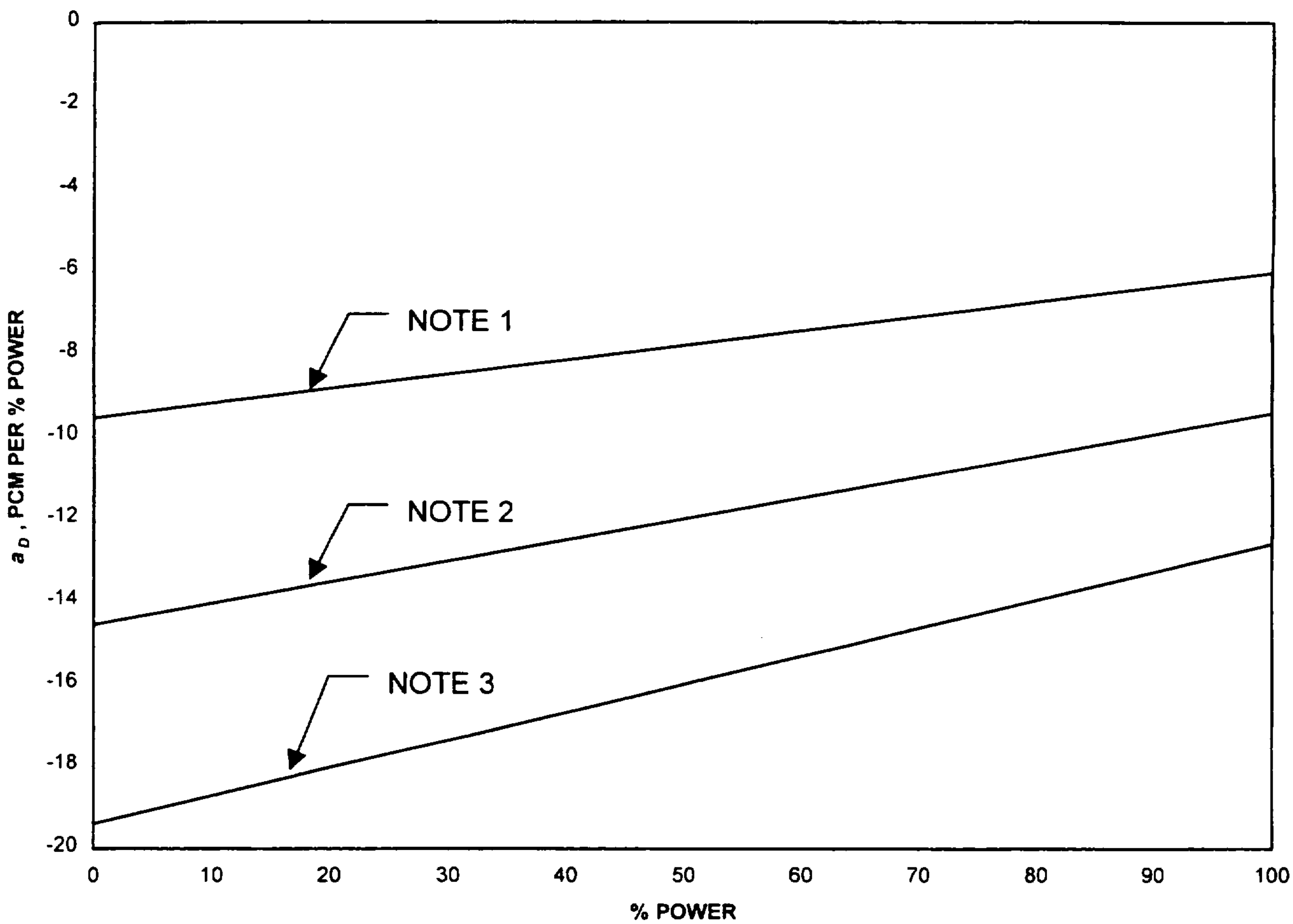


Figure 6.2.0-3

Doppler Power Coefficients

Used in Non-LOCA Safety Analyses

6.2.1 Excessive Heat Removal Due to Feedwater System Malfunctions

6.2.1.1 Introduction

Reductions in feedwater temperature or excessive feedwater additions result in an increase in core power above full power. Such transients are attenuated by the thermal capacity of the RCS and the secondary side of the plant. The overpower/overtemperature protection functions (neutron high flux, overtemperature ΔT, and overpower ΔT trips) prevent any power increase that could lead to a DNBR that is less than the limit value.

An example of excessive feedwater flow would be a full opening of a feedwater control valve due to a feedwater control system malfunction or an operator error. At power, this excess flow causes a greater load demand on the RCS due to increased subcooling in the steam generator. With the plant at no-load conditions, the addition of cold feedwater may cause a decrease in RCS temperature and thus a reactivity insertion due to the effects of the negative moderator temperature coefficient of reactivity. However, the excessive feedwater flow at no-load conditions is a less severe transient than at full power. Therefore, only the full power case is analyzed. Continuous excessive feedwater addition is prevented by the steam generator high-high water level trip.

A second example of excess heat removal is the transient associated with failure of one or more of the low pressure feedwater bypass valves which diverts flow around a portion of the feedwater heaters. In the event of an accidental opening of a bypass valve, there could be an immediate reduction in feedwater temperature to the steam generators. At power, this increased subcooling will create a greater load demand on the RCS.

6.2.1.2 Input Parameters and Assumptions

The reactivity insertion rate following a feedwater system malfunction, attributed to the cooldown of the RCS, is calculated with the following assumptions.

- The excessive feedwater flow and feedwater temperature events are analyzed with the Revised Thermal Design Procedure as described in Reference 1. Therefore, the initial reactor power, pressure, and RCS average temperature are assumed to be at their nominal values. Uncertainties in initial conditions are included in the DNBR limit calculated using the methodology described in Reference 1.

- In determining the most limiting conditions for the excessive feedwater flow and temperature reduction feedwater malfunction events, both the BWI SG (Unit 1) and the D5 SGs (Unit 2) are considered in the analysis.

- For the single-loop, feedwater control valve malfunction event at full-power conditions, one feedwater control valve is assumed to fail open resulting in a step increase in feedwater flow to one steam generator. For the BWI SGs (Unit 1), this step increase is to 167% nominal full power feedwater flow and feedwater temperature is reduced from 446.6°F to 385°F. For the D5 SGs (Unit 2) this step increase is to 175% nominal full power feedwater flow and feedwater temperature is reduced from 446.6°F to 381°F.

- For the multi-loop, feedwater control valve malfunction event at full-power conditions, all four feedwater control valves are assumed to fail open resulting in a step increase in feedwater flow to all four steam generators. For the BWI SGs (Unit 1), this step increase is to 129% nominal full power feedwater flow and feedwater temperature is reduced from 446.6°F to 360°F. For the D5 SGs (Unit 2) this step increase is to 132% nominal full power feedwater flow and feedwater temperature is reduced from 446.6°F to 354°F.

- For the temperature reduction feedwater malfunction event, the failure resulting in the temperature reduction is conservatively assumed to be the loss of an entire train of feedwater heaters. To conservatively bound this failure, a loss of multiple trains of feedwater heaters is modeled along with the opening of the feedwater heater bypass valves. This is conservative since the loss of multiple heater strings could only result from multiple initiating failures. For this event, which is analyzed assuming hot full power initial conditions, the feedwater temperature is conservatively assumed to drop from the nominal temperature of 446.6°F to 200°F.

- The initial water level in all the steam generators is a conservatively low level.

- No credit is taken for the heat capacity of the RCS and steam generator metal mass in attenuating the resulting plant cooldown.

- For the feedwater malfunction event resulting in excessive feedwater flow, a maximum EOL moderator density coefficient of 0.54 Δk/gm/cc is assumed. A maximum EOL moderator density coefficient of 0.33 Δk/gm/cc is assumed in the analysis for the temperature reduction feedwater malfunction event.

- The feedwater flow resulting from a fully open control valve is terminated by the steam generator high-high water level signal that closes all feedwater main control and feedwater isolation valves, trips the main feedwater pumps, and trips the turbine generator.

The reactor protection system features, including Power-Range High Neutron Flux, Overpower ΔT, and Turbine Trip on High-High Steam Generator Water Level, are available to provide mitigation of the feedwater system malfunction transient.

Normal reactor control systems and engineered safety systems (e.g., SI) are not assumed to function. The reactor protection system may actuate to trip the reactor due to an overpower condition. No single active failure in any system or component required for mitigation will adversely affect the consequences of this event.

6.2.1.3 Description of Analysis

The excessive flow and temperature reduction transients are analyzed with the LOFTRAN (Reference 2) computer code. This code simulates a multi-loop system, neutron kinetics, the pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and main steam safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level.

The excessive feedwater flow event assumes an accidental opening of one or more feedwater control valves with the reactor at full power conditions with both automatic and manual rod control.

The feedwater temperature reduction analysis conservatively assumes the loss of multiple trains of feedwater heaters as previously described along with the opening of the feedwater heater bypass valves. This event is analyzed at full power considering operation in both automatic and manual rod control. The feedwater temperature is conservatively assumed to drop from the nominal temperature of 446.6°F to 200°F.

6.2.1.4 Acceptance Criteria

Based on its frequency of occurrence, the feedwater system malfunction event is considered a Condition II event as defined by the American Nuclear Society. The following items summarize the acceptance criteria associated with this transient.

The critical heat flux shall not be exceeded. This is ensured by demonstrating that the minimum DNBR does not go below the limit value at any time during the transient.

Pressure in the reactor coolant and main steam systems shall be maintained below 110% of the design pressures.

The peak linear heat generation rate should not exceed a value that would cause fuel centerline melt.

6.2.1.5 Results

For the excessive feedwater flow at full-power event, the single-loop, manual rod control case, with the D5 steam generator design, results in the largest reactivity feedback and the greatest power increase. With the reactor in automatic rod control, the transient conditions are less severe. When the steam generator water level in the faulted loop reaches the high-high level setpoint, all feedwater isolation valves and feedwater pump discharge valves are automatically closed and the main feedwater pumps trip. This prevents continuous addition of feedwater. In addition, a turbine trip and reactor trip are generated at this time.

Figures 6.2.1-1 through 6.2.1-2 show the increase in nuclear power and ΔT associated with the increased load on the reactor. Since the power level rises during the excessive feedwater flow event, the fuel temperatures will also rise until after the reactor trip occurs. The core heat flux lags behind the neutron flux due to fuel rod thermal time constant and the peak linear rod power reached is limited to a value below that which would result in exceeding the fuel melting temperature. Hence, fuel melting is precluded for this event.

For the temperature reduction at full power event, the feedwater temperature reduction is modeled to occur in all four loops. For this event, the case modeling manual rod control and the D5 steam generator design results in the greatest power increase. This reduction in feedwater temperature increases the thermal load on the primary system. The resultant temperature and power transient causes a reactor trip on an overpower ΔT signal. Following reactor trip, pressurizer pressure decreases and a feedwater isolation signal occurs when the low pressurizer pressure safety injection system setpoint is reached. Following this feedwater isolation signal, the feedwater control and isolation valves are closed, and feedwater isolation occurs. Figures 6.2.1-3 through 6.2.1-4 show the increase in nuclear power and loop ΔT associated with the increased thermal load on the reactor. Since the power level rises during the feedwater temperature reduction event, the fuel temperatures will also rise until after the reactor trip occurs. The results of the analysis for this case demonstrate that this event is bounded by the limiting excessive feedwater flow case previously described. Hence, fuel melting is also precluded for the feedwater temperature reduction event.

In all cases, the DNBR remains above the applicable safety analysis limit throughout the transient and, therefore, the applicable DNB criterion is met. Furthermore, since the feedwater malfunction events are primarily cooldown events, overpressurization limits for the primary and secondary-side system are not challenged for these events.

The sequence of events for the limiting excessive feedwater flow and temperature reduction cases are presented in Table 6.2.1-1.

6.2.1.6 Conclusions

The results of the excessive feedwater flow and feedwater temperature reduction events show that the DNBR remains above the limit value at all times; therefore, no fuel or clad damage is predicted.

6.2.1.7 References

1. Friedland, A. J., and Ray, S., "Revised Thermal Design Procedure," WCAP-11397-P-A (Proprietary), WCAP-11397-A (Non-proprietary), April 1989

2. Burnett, T. W. T. et al., "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary) and WCAP-7907-A (Non-proprietary), April 1984

Table 6.2.1-1 Sequence of Events-Feedwater System Malfunction Events		
Case	**Event**	**Time (Sec)**
Limiting Excessive FW Flow Case Single-Loop Excessive FW Flow to D5 steam generator – manual rod control	One main feedwater valve fails open	0.0
	High-High steam generator water level setpoint reached	61.7
	Turbine trip occurs	64.2
	Minimum DNBR occurs	64.4
	Reactor trip on turbine trip occurs	66.7
	Feedwater isolation occurs	68.7
Limiting Feedwater Temperature Reduction Case Feedwater Temperature Reduction to D5 steam generator – manual rod control	Feedwater heater bypass valves fail open and a loss of multiple trains of feedwater heaters occurs	0.0
	Overpower ΔT reactor trip setpoint reached	6.2
	Rod motion occurs	14.2
	Minimum DNBR occurs	8
	Low Pressurizer Pressure SI setpoint reached	38.8
	Feedwater isolation occurs	45.8

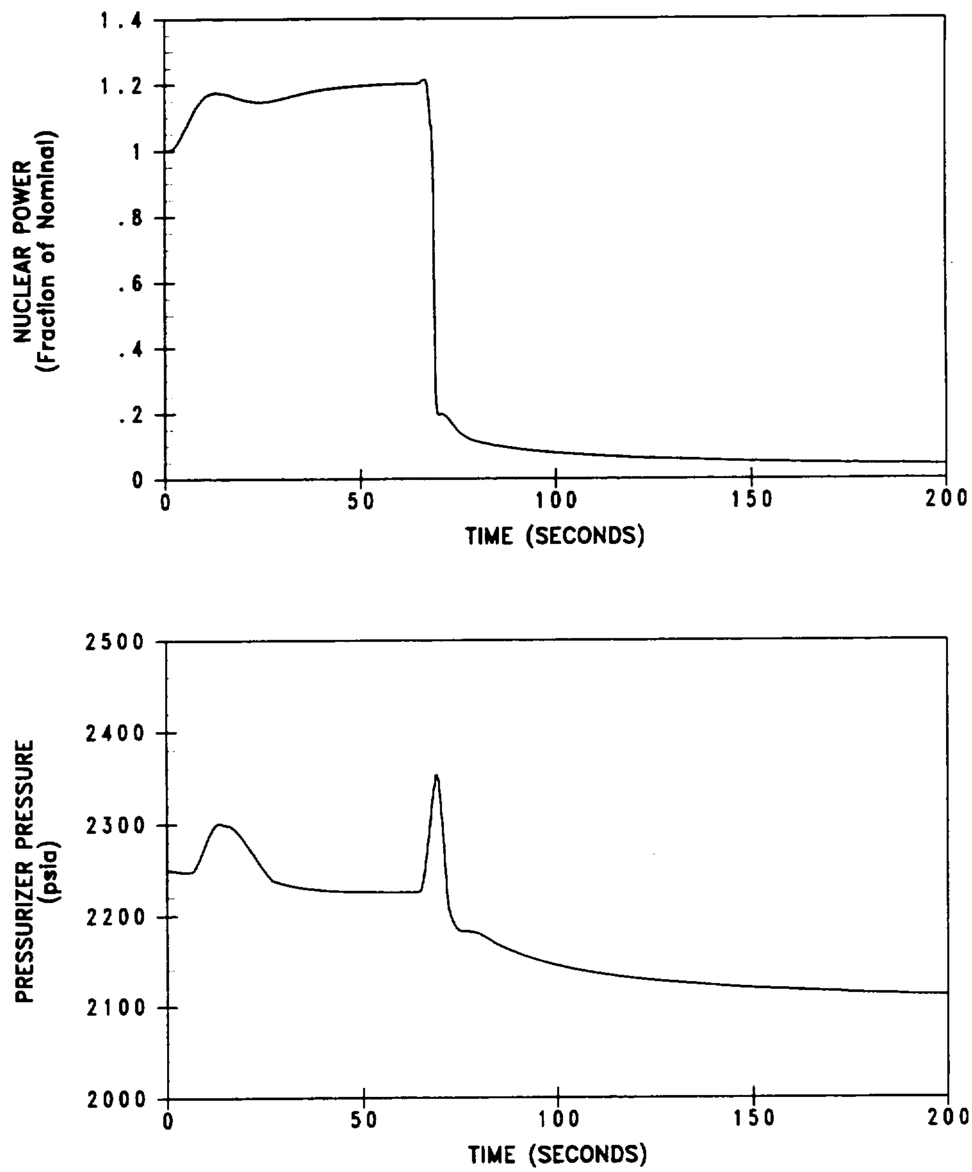


Figure 6.2.1-1

Nuclear Power and Pressurizer Pressure for Excessive Feedwater Flow Event

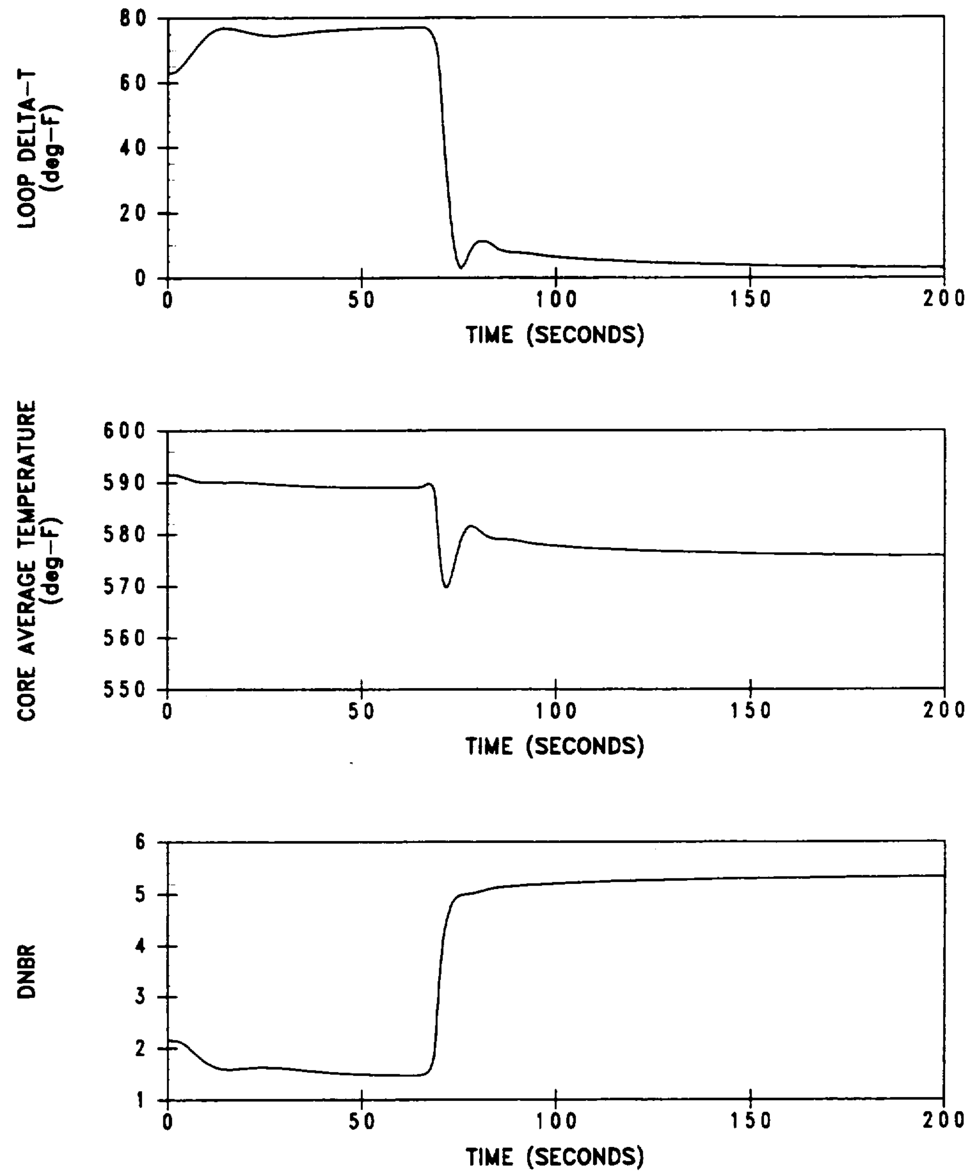


Figure 6.2.1-2

Reactor Coolant Loop ΔT, Core Average Temperature, and DNBR for Excessive Feedwater Flow Event

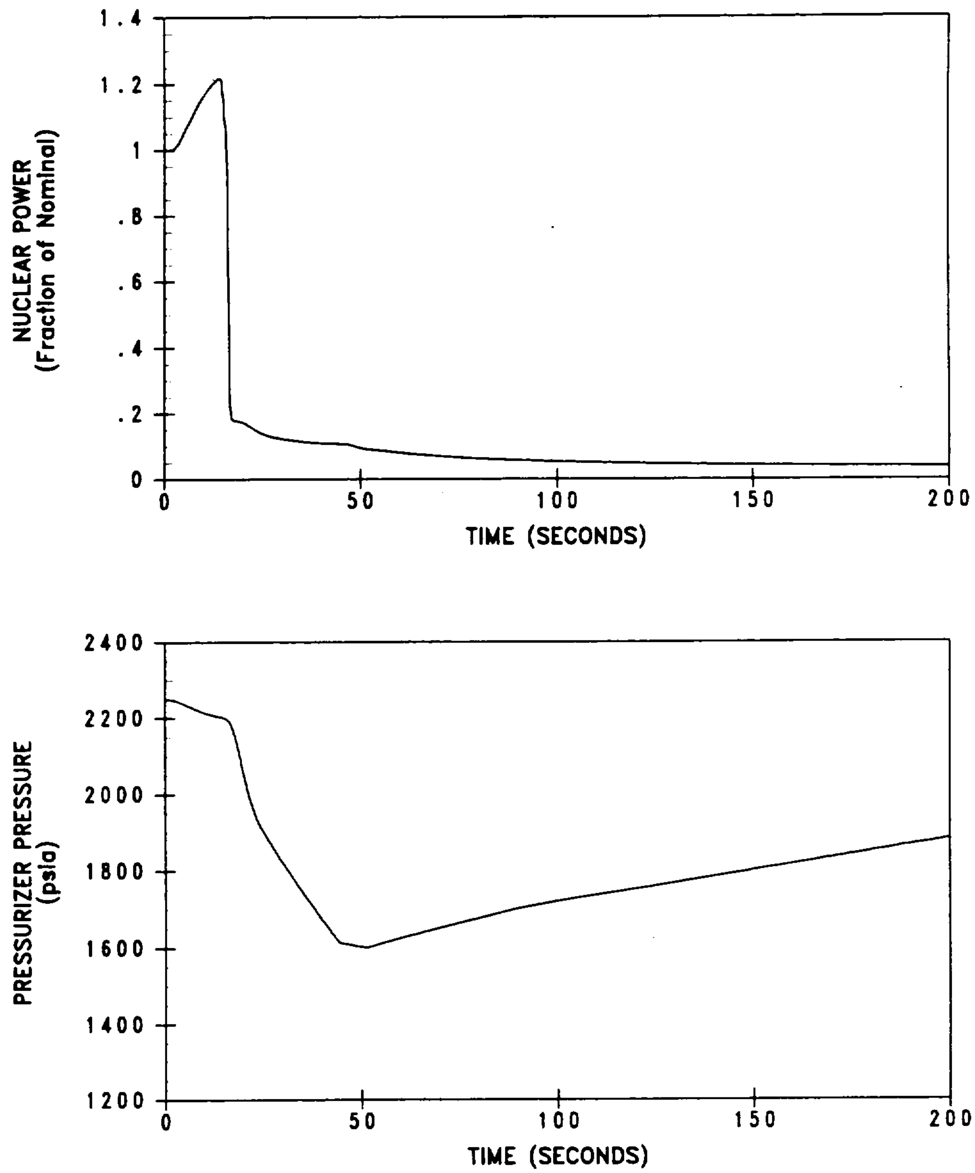


Figure 6.2.1-3

Nuclear Power and Pressurizer Pressure for Feedwater Temperature Reduction Event

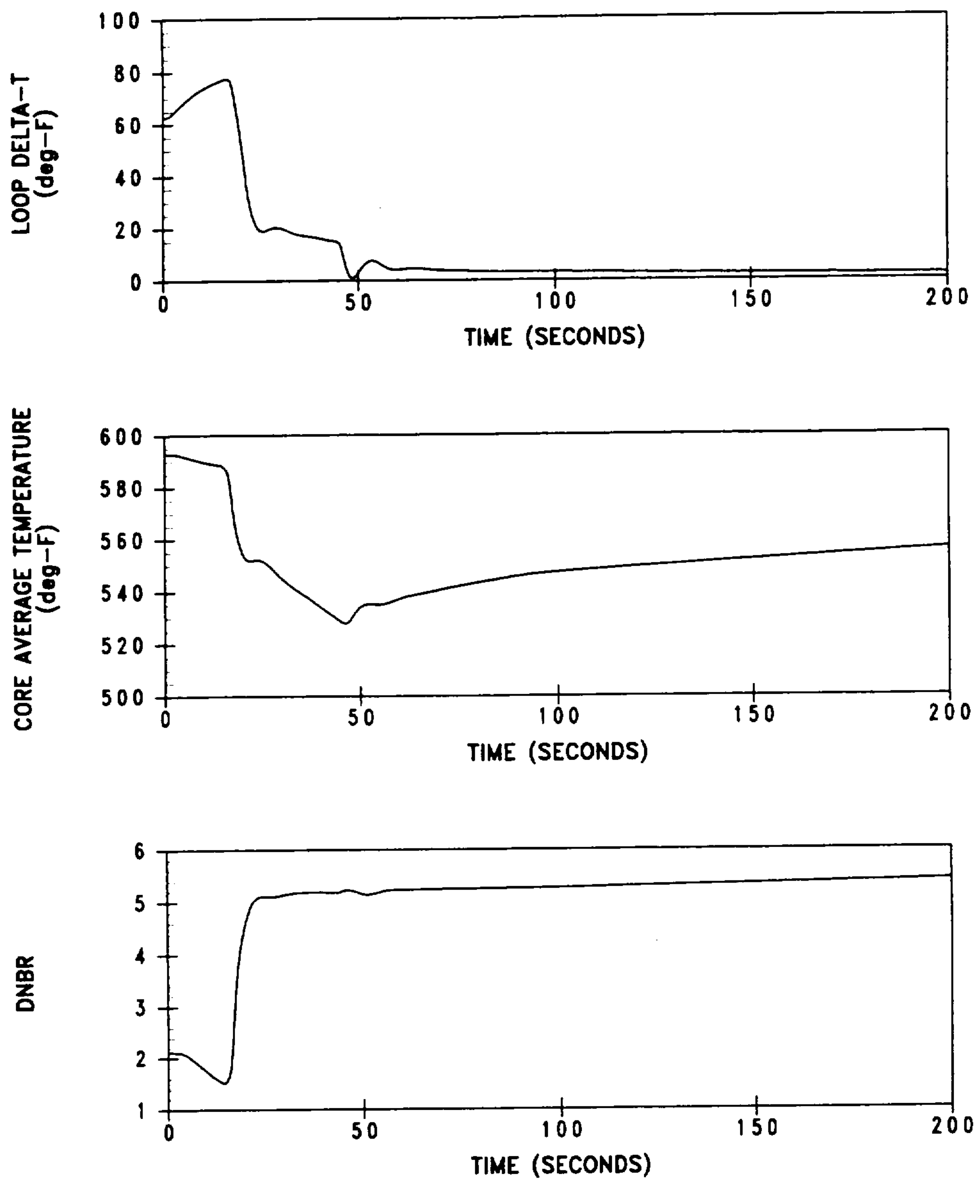


Figure 6.2.1-4

Reactor Coolant Loop ΔT, Core Average Temperature, and DNBR for Feedwater Temperature Reduction Event

6.2.2 Excessive Load Increase Incident

6.2.2.1 Introduction

An excessive load increase incident 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. The reactor control system is designed to accommodate a 10% step-load increase or a 5% per minute ramp-load increase in the range of 15 to 100% full power. Any loading rate in excess of these values may cause a reactor trip actuated by the reactor protection system. If the load increase exceeds the capability of the reactor control system, the transient would be terminated in sufficient time to prevent violating the DNB design basis.

This incident could result from either an administrative violation such as excessive loading by the operator, or an equipment malfunction in the steam bypass control or turbine speed control systems.

During power operation, steam dump to the condenser is controlled by comparing the RCS temperature to a reference value based on turbine power. A high temperature difference in conjunction with a loss of load or turbine trip indicates a need for steam dump. A single controller malfunction will not cause the steam dump valves to open. Interlocks block opening of the valves unless a large turbine load decrease or a turbine trip has occurred.

Regardless of the rate of load increase, the reactor protection system will trip the reactor in time to maintain the DNBR above the limit value. Increases in steam load to more than design flow are analyzed as a main steam line rupture (Section 6.2.4).

Protection against an excessive load increase incident, if necessary, is provided by the following reactor protection system signals.

- Overtemperature ΔT
- Power range high neutron flux
- Low pressurizer pressure

6.2.2.2 Input Parameters and Assumptions

The analysis includes the following conservative assumptions.

1. This event is analyzed with the Revised Thermal Design Procedure (Reference 1). Initial reactor power and RCS pressure and temperature are assumed to be at their nominal values. Uncertainties in initial conditions are included in the DNBR limit.

2. The evaluation is performed for a step-load increase of 10 percent steam flow from 100 percent Rated Thermal Power.

3. This event is analyzed in both automatic and manual rod control.

4. The excessive load increase event is analyzed for both beginning-of-life (minimum reactivity feedback) and end-of-life (maximum reactivity feedback) conditions. A small (zero) moderator density coefficient at beginning-of-life (BOL) and a large positive value at end-of-life (EOL) are used. A positive moderator temperature coefficient is not assumed since this would benefit the analysis.

6.2.2.3 Description of Analysis

Historically, four cases are analyzed, and presented in the UFSAR (Reference 2), to demonstrate plant behavior following a 10% step-load increase from rated load. These cases are as follows.

- Reactor in manual rod control with BOL (minimum moderator) reactivity feedback
- Reactor in manual rod control with EOL (maximum moderator) reactivity feedback
- Reactor in automatic rod control with BOL (minimum moderator) reactivity feedback
- Reactor in automatic rod control with EOL (maximum moderator) reactivity feedback

This accident is analyzed using the LOFTRAN computer code (Reference 3) to determine the plant transient conditions following the excessive load increase. The code models the core neutron kinetics, RCS including natural circulation, pressurizer, pressurizer power-operated relief valves and spray, steam generators, main steam safety valves, and the auxiliary feedwater system. The code computes pertinent plant variables including DNBR, temperatures, pressures, and power level.

For BOL (minimum moderator feedback) cases, the core has the least-negative moderator temperature coefficient of reactivity and the least-negative Doppler-only power coefficient curve; therefore, the least-inherent transient response capability. Since a positive moderator temperature coefficient would benefit the analysis, a zero moderator temperature coefficient was assumed. For EOL (maximum moderator feedback) cases, the moderator temperature coefficient of reactivity has its most-negative value and the most-negative Doppler-only power coefficient curve. This results in maximum reactivity feedback due to changes in coolant temperature.

A 10% step increase in steam demand is assumed. Normal reactor control systems and engineered safety systems are not required to function. The analysis does not take credit for operation of the pressurizer heaters. The cases that assume automatic rod control are analyzed to ensure that the worst case is presented; the automatic function is not required. The reactor protection system is assumed operable; however, reactor trip is not encountered for the cases analyzed. No single active failure in any system or component required for mitigation will adversely affect the consequences of this accident.

6.2.2.4 Acceptance Criteria

Based on its frequency of occurrence, the excessive load increase accident is considered a Condition II event as defined by the American Nuclear Society. The following items summarize the acceptance criteria associated with this event.

The critical heat flux should not be exceeded. This is ensured by demonstrating that the minimum DNBR remains above the limit value throughout the transient.

Pressure in the reactor coolant and main steam systems should remain below 110% of the design pressures.

The peak linear heat generation rate (expressed in kw/ft) should remain below the value that would cause fuel centerline melt.

6.2.2.5 Results

The results of the excessive load increase analysis confirm that the DNBR limit is met for this transient at Byron and Braidwood Units 1 and 2 under uprated power conditions. Representative results are shown in Figures 6.2.2-1 through 6.2.2-4, which show nuclear power, pressurizer pressure, pressurizer water volume, core average temperature and DNBR for the cases analyzed. Manual rod control mode cases are shown in Figures 6.2.2-1 (minimum reactivity feedback) and 6.2.2-2 (maximum reactivity feedback) conditions. Automatic rod control mode cases are shown in Figures 6.2.2-3 (minimum reactivity feedback) and 6.2.2-4 (maximum reactivity feedback) conditions. Table 6.2.2-1 lists the sequence of events for the cases considered.

With respect to peak pressure, the excessive load increase accident is bounded by the loss of electrical load/turbine trip analysis (Section 6.2.6).

6.2.2.6 Conclusions

The results of the excessive load increase analysis show that all acceptance criteria for this event are met at Byron and Braidwood Units 1 and 2 under uprated power conditions. The minimum DNBR remains above the safety analysis limit value, and peak linear heat generation remains below the limit value; thus ensuring the applicable acceptance criteria for critical heat flux and fuel centerline melt are met. In addition, RCS and main steam system pressures do not exceed 110% of design. Following the initial load increase response, the plant returns to a stabilized condition.

6.2.2.7 References

1. Friedland, A. J., and Ray, S., "Revised Thermal Design Procedure," WCAP-11397-P-A, (Proprietary), WCAP-11397-A (Non-proprietary), April 1989.

2. "Byron & Braidwood Station, Updated Final Safety Analysis Report," Revision 7, Docket Nos. STN-454/455/456/457, as amended through December 1998.

3. Burnett, T. W. T., et al., "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary) and WCAP-7907-A (Non-proprietary), April 1984.

Table 6.2.2-1

Sequence of Events-Excessive Increase in Secondary Steam Flow

Case	Event	Time (sec)
Manual Reactor Control (Minimum Reactivity Feedback)	10% Step Load Increase	0.0
	Equilibrium conditions reached (approximate time)	400
Manual Reactor Control (Maximum Reactivity Feedback)	10% Step Load Increase	0.0
	Equilibrium conditions reached (approximate time)	150
Automatic Reactor Control (Minimum Reactivity Feedback)	10% Step Load Increase	0.0
	Equilibrium conditions reached (approximate time)	300
Automatic Reactor Control (Maximum Reactivity Feedback)	10% Step Load Increase	0.0
	Equilibrium conditions reached (approximate time)	200

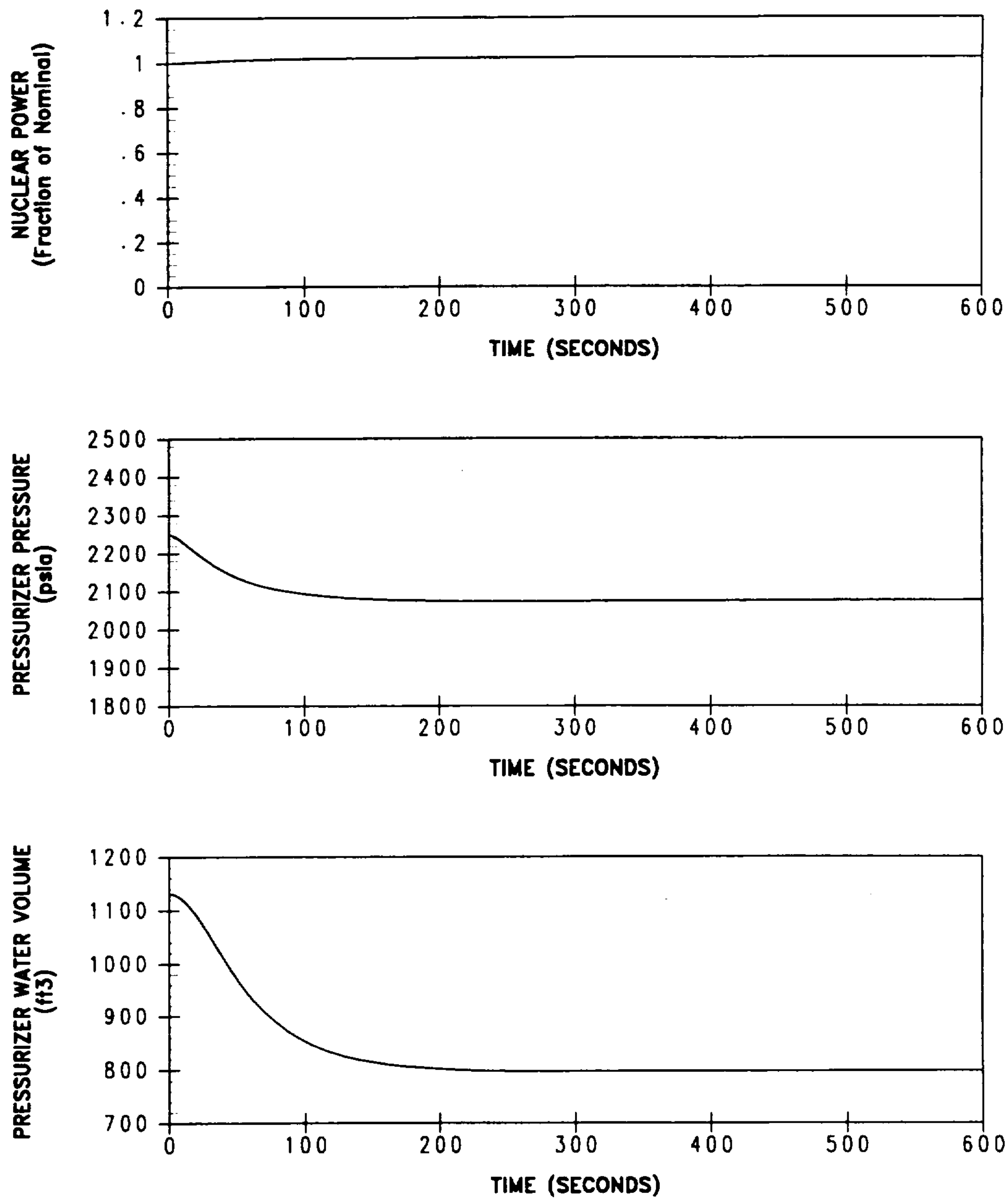


Figure 6.2.2-1 (Sheet 1)

Excessive Load Increase, Minimum Reactivity Feedback, Manual Rod Control

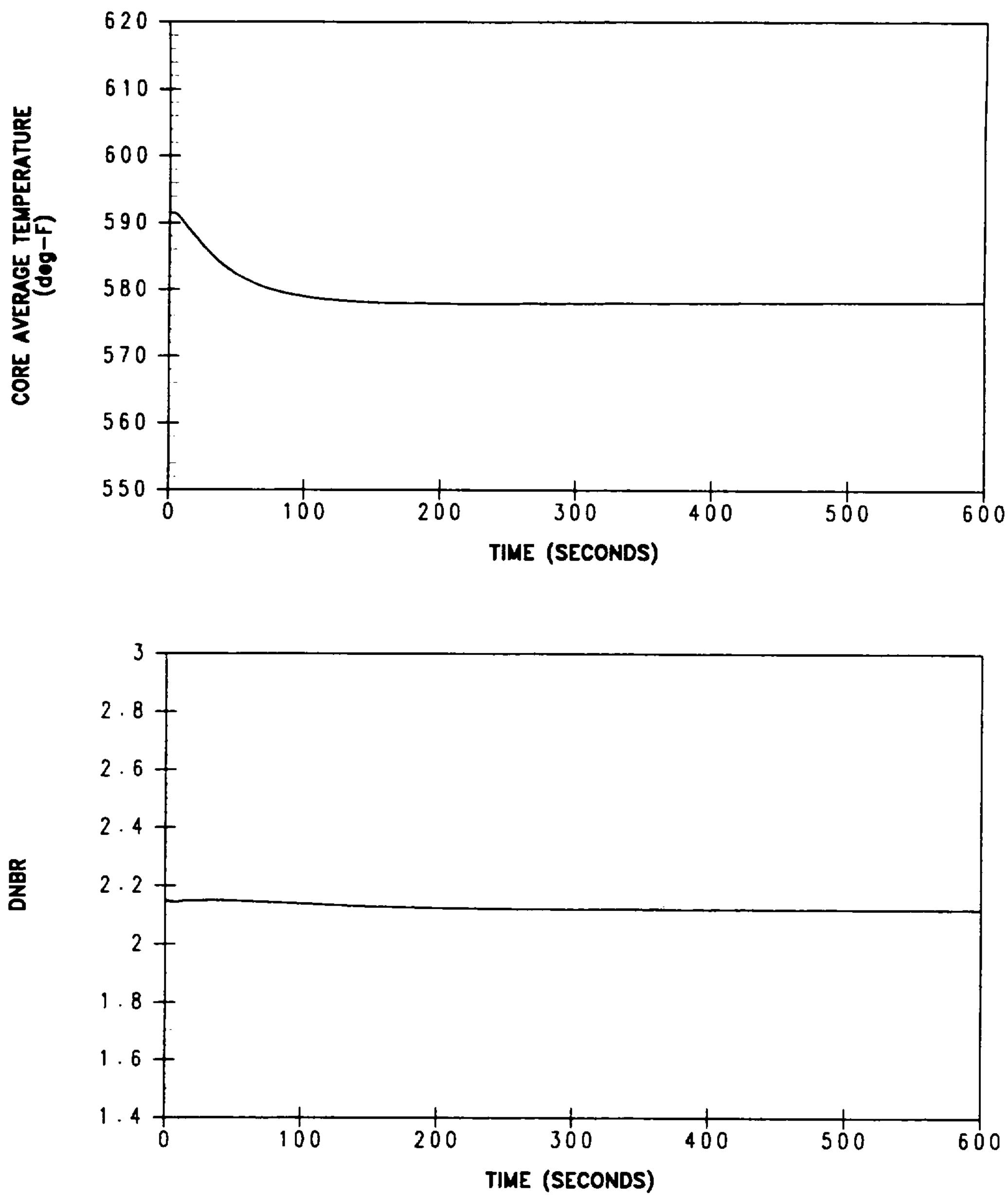


Figure 6.2.2-1 (Sheet 2)

Excessive Load Increase, Minimum Reactivity Feedback, Manual Rod Control

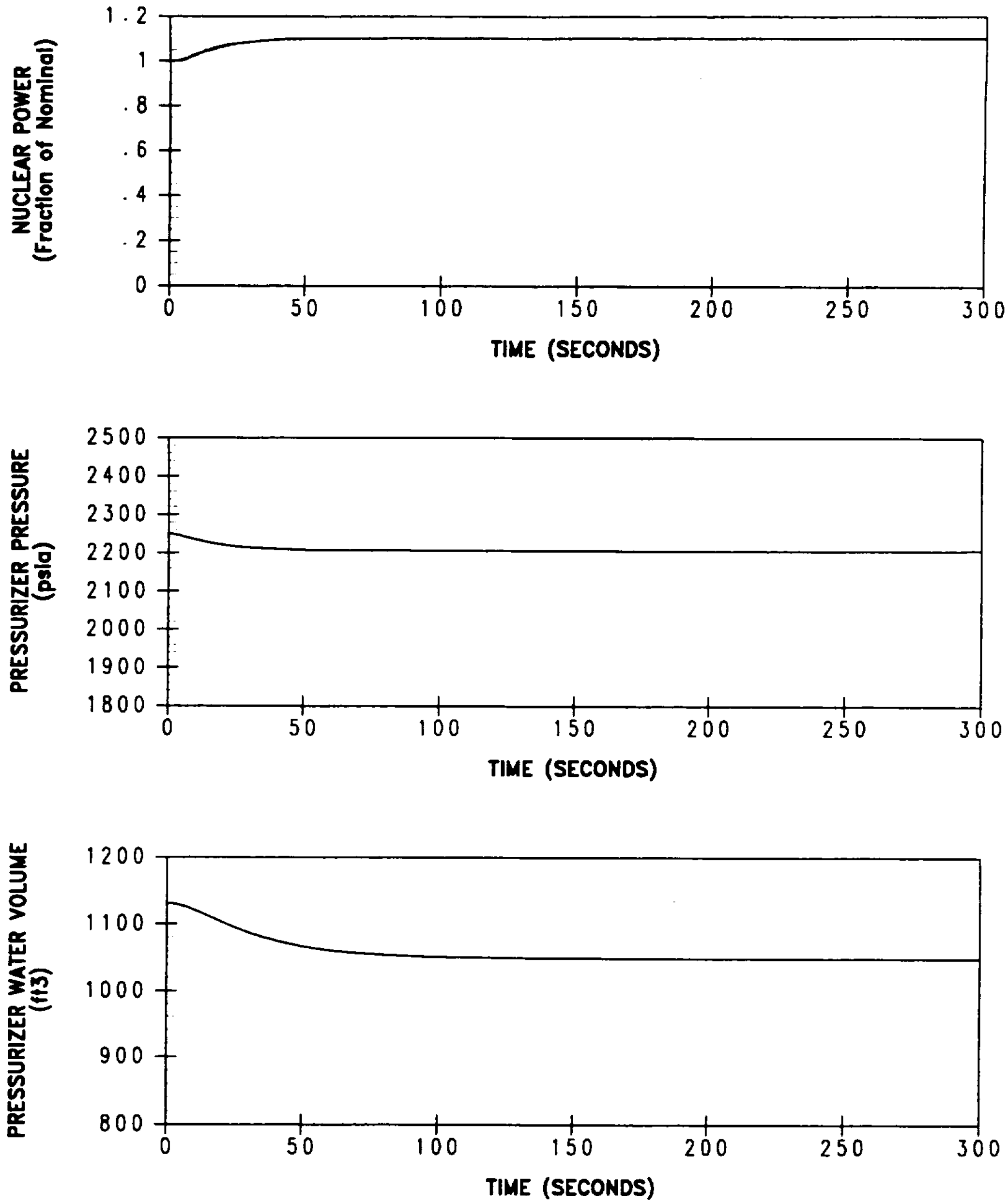


Figure 6.2.2-2 (Sheet 1)

Excessive Load Increase, Maximum Reactivity Feedback, Manual Rod Control

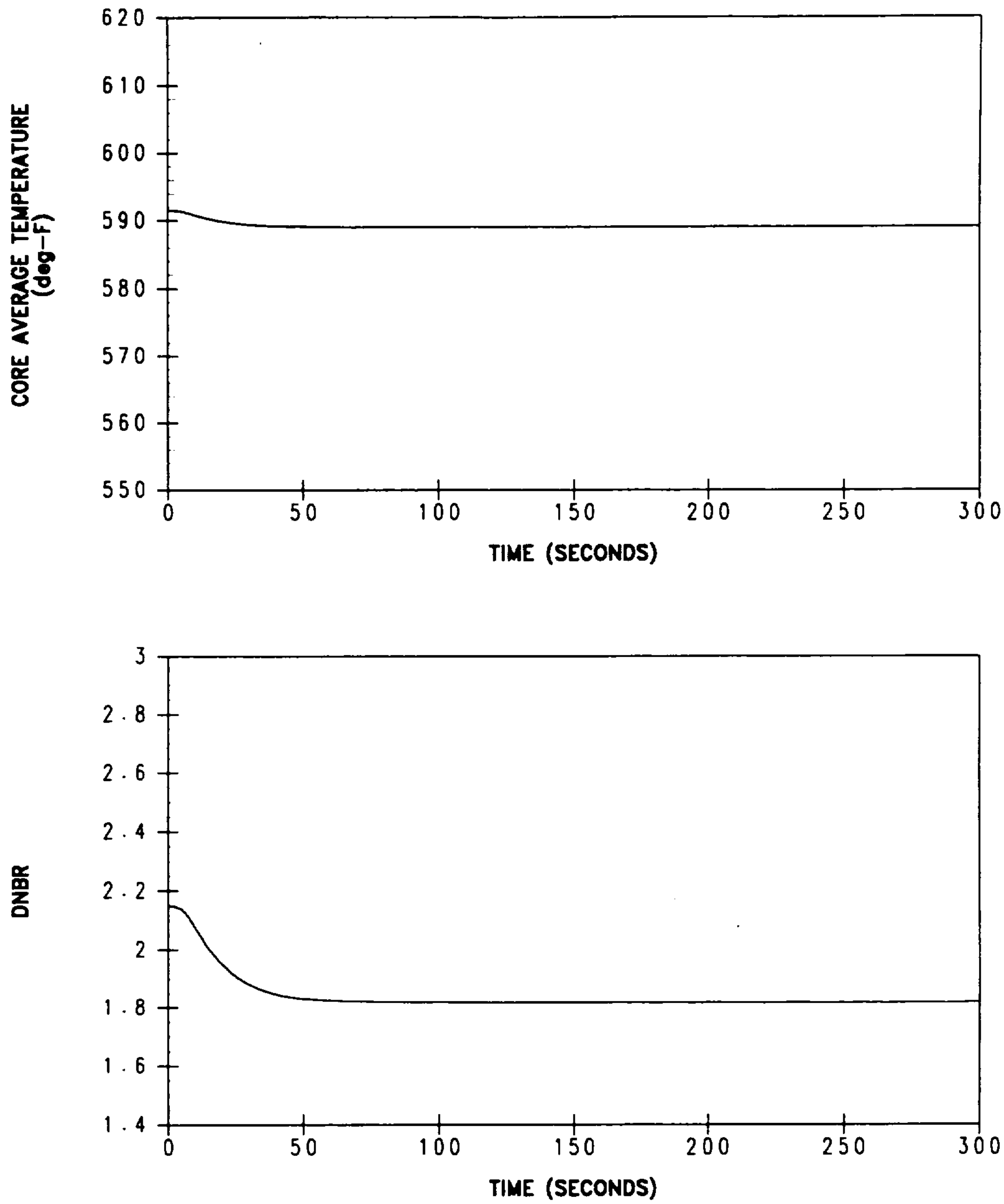


Figure 6.2.2-2 (Sheet 2)

Excessive Load Increase, Maximum Reactivity Feedback, Manual Rod Control

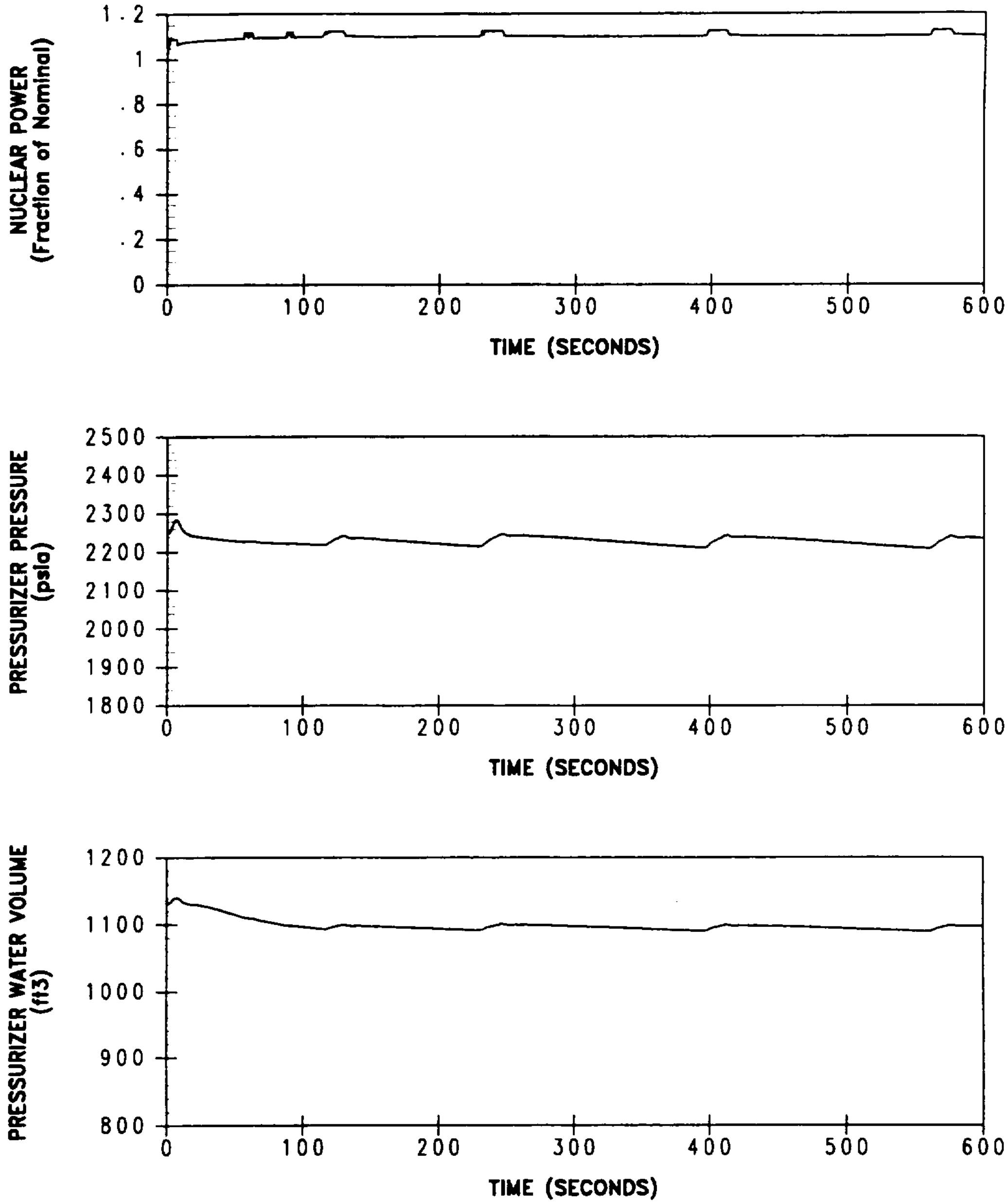


Figure 6.2.2-3 (Sheet 1)

Excessive Load Increase, Minimum Reactivity Feedback, Automatic Rod Control

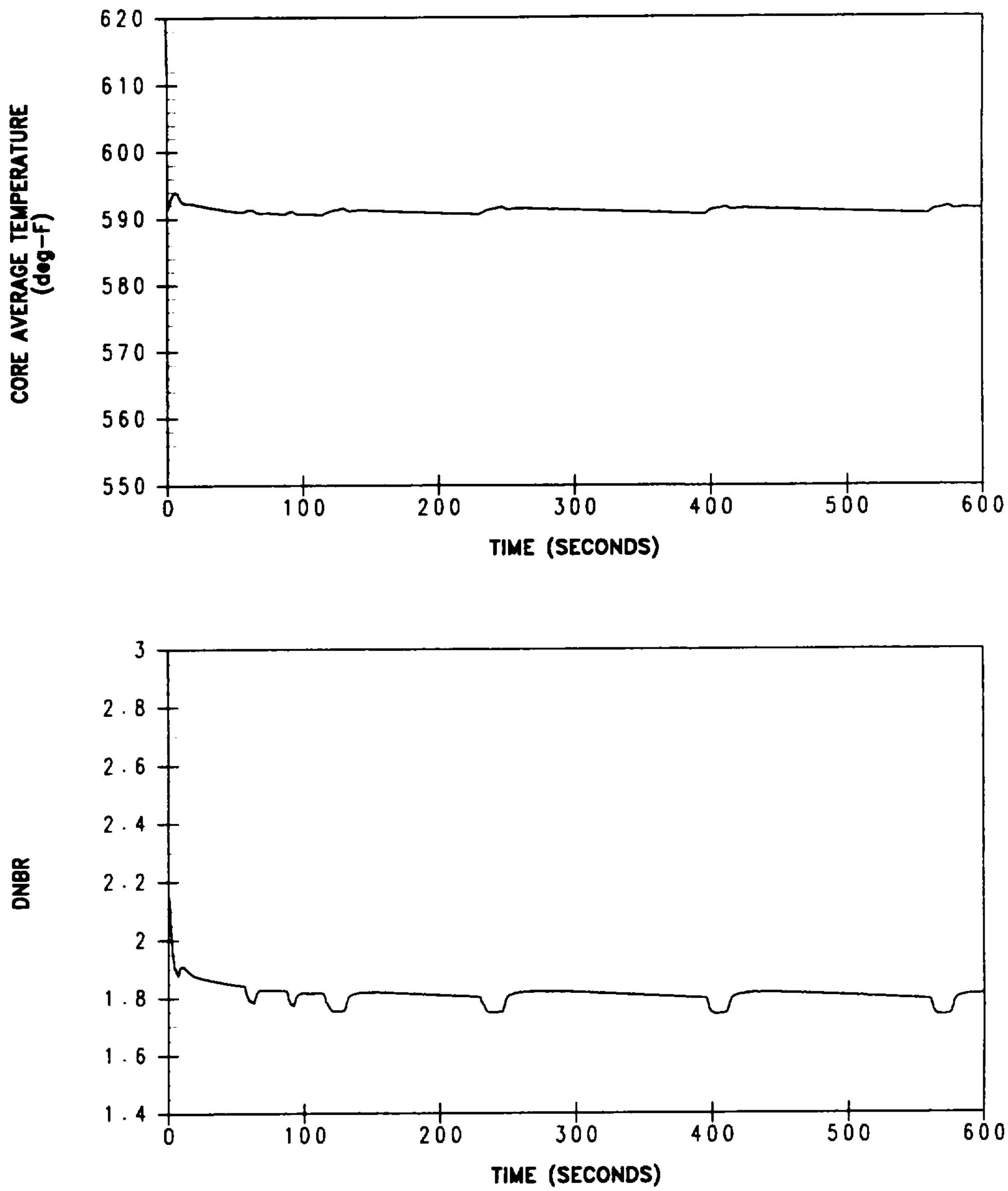


Figure 6.2.2-3 (Sheet 2)

Excessive Load Increase, Minimum Reactivity Feedback, Automatic Rod Control

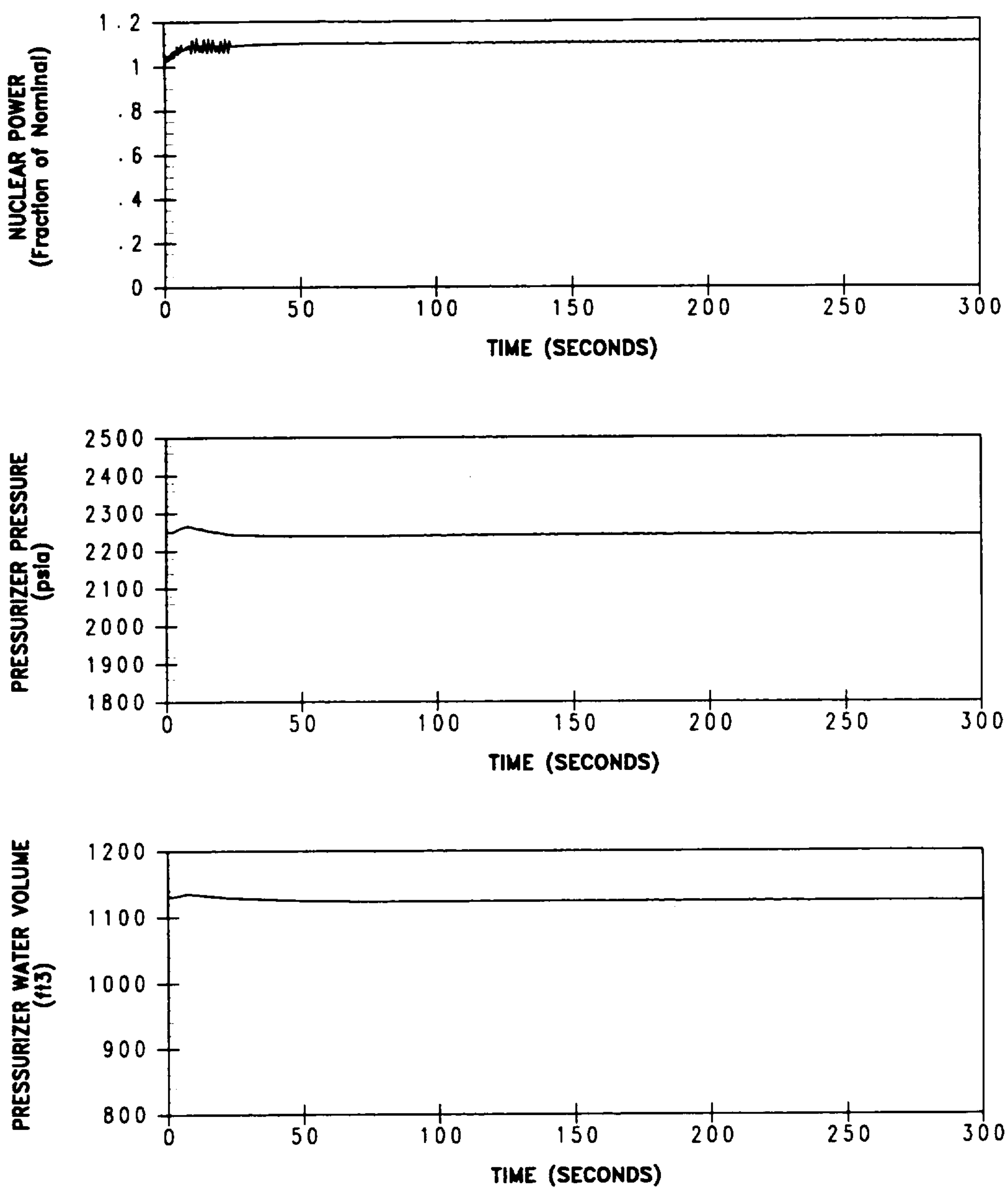


Figure 6.2.2-4 (Sheet 1)

Excessive Load Increase, Maximum Reactivity Feedback, Automatic Rod Control

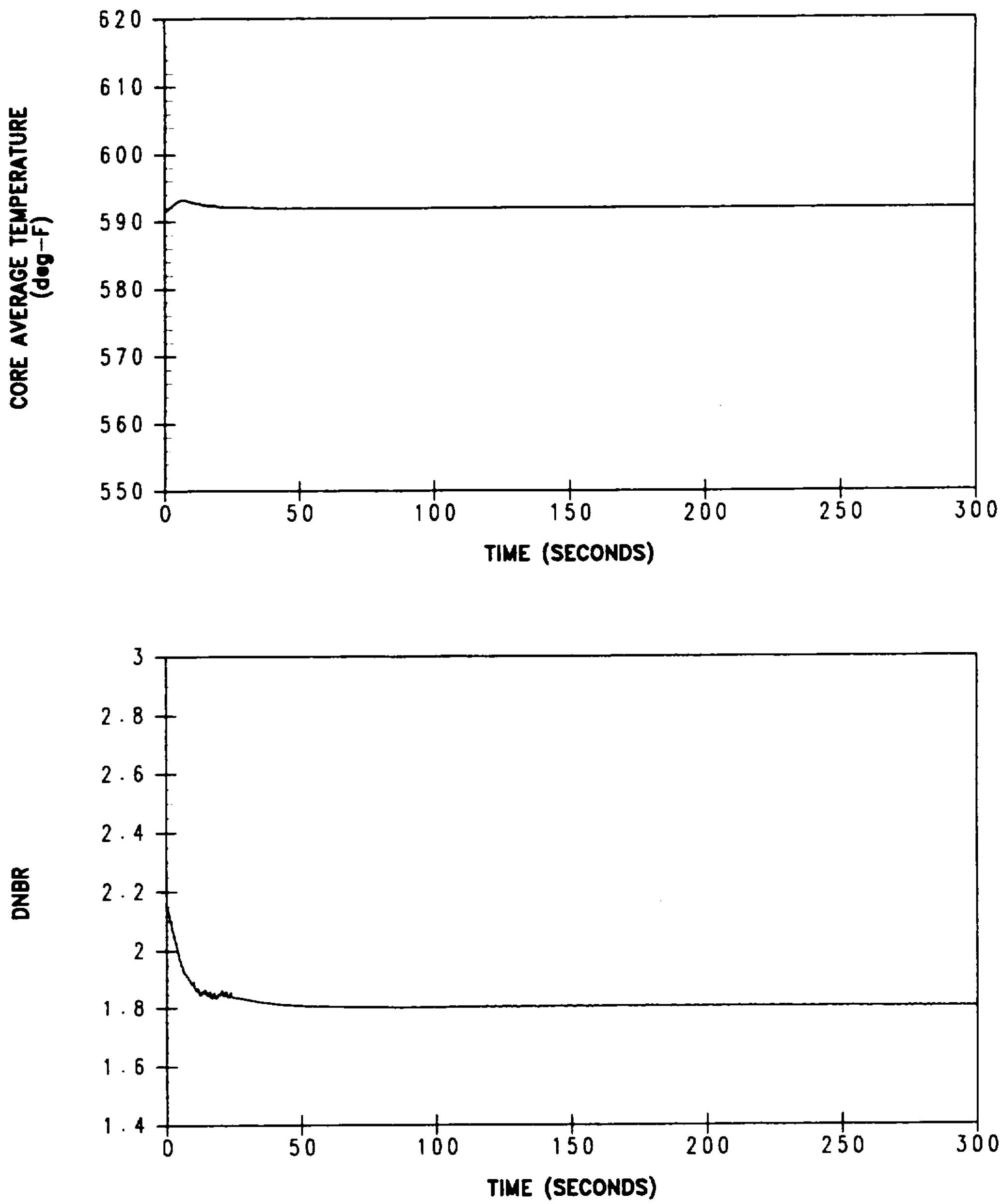


Figure 6.2.2-4 (Sheet 2)

Excessive Load Increase, Maximum Reactivity Feedback, Automatic Rod Control

6.2.3 Inadvertent Opening of a Steam Generator Relief or Safety Valve

The inadvertent opening of a steam generator relief or safety valve event (i.e., credible steamline break) creates a depressurization of the secondary-side with an effective opening size that is within the spectrum of break sizes analyzed by the hypothetical steamline break event. Therefore, the credible steamline break is bounded by the hypothetical steamline break discussed in Sections 6.2.4 and 6.2.5.

6.2.4 Steam System Piping Failure at Zero Power

6.2.4.1 Introduction

The rupture of a main steamline would result in an initial increase in steam flow that then decreases during the accident as the steam pressure falls. The energy removal from the Reactor Colant System (RCS) causes a reduction of coolant temperature and pressure. In the presence of a negative moderator temperature coefficient, the cooldown results in a positive reactivity insertion and subsequent reduction in core shutdown margin. If the most reactive Rod Cluster Control Assembly (RCCA) is assumed stuck in its fully withdrawn position after reactor trip, there is an increased possibility that the core will become critical and return to power. A return to power following a steamline break is a potential problem mainly because of the high power peaking factors that would exist assuming the most-reactive RCCA is stuck in its fully withdrawn position. The core is ultimately shut down by boric acid injection delivered by the safety injection system.

The following functions provide the necessary protection against a steam pipe rupture.

a. Safety injection system actuation from any of the following:

    1. Two-out-of-three low steamline pressure signals in any one loop

    2. Two-out-of-four low pressurizer pressure signals

    3. Two-out-of-three high-1 containment pressure signals.

b. The overpower reactor trips (neutron flux and ΔT) and the reactor trip occurring in conjunction with receipt of the Safety Injection (SI) signal.

c. Redundant isolation of the main feedwater lines. Sustained high feedwater flow would cause additional cooldown; therefore, in addition to the normal control action which will close the main feedwater valves, a safety injection signal will rapidly close all feedwater control valves and backup feedwater isolation valves, trip the main feedwater pumps, and close the feedwater pump discharge valves.

d. Trip of the fast-acting steamline stop valves (designed to close in less than 5 seconds) on:

1. Two-out-of-three low steamline pressure signals in any one loop

2. Two-out-of-three high-2 containment pressure signals

3. Two-out-of-three high negative steamline pressure rate signals in any one loop (used only during cooldown and heatup operations).

For breaks downstream of the isolation valves, closure of all valves will completely terminate the blowdown. For any break, in any location, no more than one steam generator would experience an uncontrolled blowdown even if one of the isolation valves fails to close.

Steam flow is measured by monitoring the dynamic head in nozzles located in the throat of the steam generator. The effective throat area of the flow restrictor nozzles is 1.1 ft^2 for Unit 1 (with BWI replacement steam generators) and 1.4 ft^2 for Unit 2 (with Westinghouse D5 steam generators). These flow areas are considerably less than the main steam pipe area. Thus, the flow restrictor nozzles serve to limit the maximum steam flow for a break at any location.

6.2.4.2 Input Parameters and Assumptions

The following conditions were assumed to exist at the time of a main steamline break accident.

a. End-of-Life (EOL) shutdown margin at no-load, equilibrium xenon conditions, and the most reactive RCCA stuck in its fully withdrawn position. Operation of the control rod banks during core burnup is restricted in such a way that addition of positive reactivity in a steamline break accident will not lead to a more adverse condition than the case analyzed.

b. The negative moderator coefficient corresponding to EOL rodded core with the most-reactive RCCA withdrawn. The variation of the coefficient with temperature and pressure has been included. The K_{eff} versus coolant average temperature at 1150 psia, corresponding to the negative moderator temperature coefficient used, is shown in

Figure 6.2.4-1. The effect of power generated in the core on overall reactivity is shown in Figure 6.2.4-2.

The core properties associated with the sector nearest the affected steam generator and those associated with the remaining sector were conservatively combined to obtain average core properties for reactivity feedback calculations. Further, it was conservatively assumed that the core power distribution was uniform. These two conditions cause an underprediction of the reactivity feedback in the high power region near the stuck rod. To verify the conservatism of this method, the reactivity and power distribution was checked for the limiting statepoints for the cases analyzed.

This core analysis considered the Doppler reactivity from the high fuel temperature near the stuck RCCA, moderator feedback from the high water enthalpy near the stuck RCCA, power redistribution and non-uniform core inlet temperature effects. For cases in which steam generation occurs in the high flux regions of the core, the effect of void formation was also included. It was determined that the reactivity employed in the kinetics analysis was always larger than the reactivity calculated including the above local effects for the statepoints. These results verify conservatism, i. e., an underprediction of negative reactivity feedback from power generation.

c. Minimum capability for injection of high concentration boric acid (2300 ppm) solution corresponding to the most restrictive single failure in the High-Head Safety Injection (HHSI) system. The Emergency Core Cooling System (ECCS) consists of three systems: (1) the passive accumulators, (2) the Residual Heat Removal (RHR) System, and (3) the Low-Head Safety Injection (LHSIS) and HHSI system. Only the HHSI system is modeled for the steamline break accident analysis.

The actual modeling of the HHSI system in LOFTRAN is described in Reference 1. The flow corresponds to that delivered by one charging pump delivering its full flow to the cold leg header. No credit has been taken for the low concentration borated water, which must be swept from the lines downstream of the refueling water storage tank prior to the delivery of concentrated boric acid to the reactor coolant loops.

For the case where offsite power is assumed, the sequence of events in the HHSI system is the following. After the generation of the safety injection (SI) signal (appropriate delays for instrumentation, logic, and signal transport included), the appropriate valves begin to operate and the charging pump starts. In 17 seconds, the valves are assumed to be in the final position and the pump is assumed to be at full speed. Transfer of the pump suction would be completed in 27 seconds. The volume containing the low concentration borated water is swept from the ECCS before the 2300 ppm borated water reaches the core. This delay described above is inherently included in the LOFTRAN modeling.

In cases where offsite power is not available, an additional 13-second delay is assumed to start the diesels and to load the necessary SI equipment onto them.

d. Design value of the steam generator heat transfer coefficient including allowance for fouling factor.

e. Since the steam generators have integral flow restrictors with a 1.1 ft^2 throat area for Unit 1 and 1.4 ft^2 for Unit 2, any rupture with a break area greater than the area of the flow restrictor, regardless of the location, would have the same effect on the Nuclear Steam Supply System (NSSS) as the break equal to the area of the flow restrictor. The following cases have been considered in determining the core power and RCS transients.

   Case 1: Complete severance of a pipe, with the plant initially at no-load conditions, and full reactor coolant flow with offsite power available

   Case 2: Case 1 with loss of offsite power coincident with the steamline break. Loss of offsite power results in reactor coolant pump coastdown, which is assumed to begin at 3 seconds.

f. Power peaking factors corresponding to one stuck RCCA and non-uniform core inlet coolant temperatures are determined at EOL. The coldest core inlet temperatures are assumed to occur in the sector with the stuck rod. The power peaking factors account for the effect of the local void in the region of the stuck control assembly during the return-to-power phase following the steamline break. This void, in conjunction with the large negative moderator coefficient, partially offsets the effect of the stuck assembly. The power peaking factors depend on the core conditions for power, temperature, pressure, and flow, and thus are different for each case studied.

The core conditions used for both with and without offsite power cases correspond to values determined from the respective transient analyses.

Both cases assume initial hot shutdown conditions at event initiation since this represents the most conservative initial condition. These hot shutdown initial conditions were considered for cases assuming full power operation at both the high (588°F) and low (575°F) Hot Full Power (HFP) T_{avg} conditions. Should the reactor be just critical or operating at power at the time of a steamline break, the reactor will be tripped by the normal overpower protection system when the power level reaches a trip setpoint. Following a trip at power, the RCS contains more stored energy than at no-load, the average coolant temperature is higher than at no-load, and there is appreciable energy stored in the fuel. Thus, the additional stored energy is removed via the cooldown caused by the steamline break before the no-load conditions of RCS temperature and shutdown margin assumed in the analyses are reached. After the additional stored energy has been removed, the cooldown and reactivity insertions proceed in the same manner as in the analysis, which assumes no-load conditions at time zero. In addition, since the initial steam generator water inventory is greatest at no-load, the magnitude and duration of the RCS cooldown are less for steamline breaks occurring at power. A spectrum of steamline breaks at various power levels has been analyzed in Reference 2.

g. In computing the steam flow during a steamline break, the Moody Curve (Reference 3) for f(L/D) = 0 is used.

h. Perfect moisture separation in the steam generator is assumed.

6.2.4.3 Description of Analysis

The rupture of a major steamline is the most-limiting cooldown transient. It is analyzed at zero power with no decay heat since decay heat would retard the cooldown, thereby reducing the return to power. A detailed discussion of this transient for the most limiting break size (a double-ended rupture) is presented here.

The analysis of the steam pipe break has been performed to determine:

a. The core heat flux and RCS temperature and pressure resulting from the cooldown following the steamline break. The LOFTRAN code (Reference 1) has been used.

b. The thermal-hydraulic behavior of the core following a steamline break. A detailed thermal-hydraulic digital computer code, THINC, has been used to determine if DNBR falls below the safety analysis limit for the core conditions computed in item (a) above.

6.2.4.4 Acceptance Criteria

A major steamline break is classified as an ANS Condition IV event. Effects of minor secondary system pipe breaks, which are classified as Condition III events, are bounded by the analysis presented in this section.

Conservatively assuming a stuck RCCA with or without offsite power, and assuming a single failure in the engineered safety features, the core remains in place and intact. Although DNB and possible clad perforation following a steam pipe break are not necessarily unacceptable, the following analysis in fact shows that the DNBR never falls below the safety analysis limit for any break assuming the most reactive assembly stuck in its fully withdrawn position. This analysis will conservatively meet the radiological dose criteria set forth in the Standard Review Plan.

6.2.4.5 Results

The calculated sequence of events for the limiting case (Unit 2, Low T_{avg} with offsite power available) is shown in Table 6.2.4-1.

The results presented are a conservative indication of the events that would occur assuming a steamline break since it is postulated that all of the conditions described above occur simultaneously.

Core Power and Reactor Coolant System Transient

Figure 6.2.4-3 shows the core heat flux, core average temperature, and steam flow following a main steamline break (complete severance of a steam pipe) at initial no-load conditions. Figure 6.2.4-4 shows the corresponding pressurizer pressure and pressurizer water volume and Figure 6.2.4-5 shows the boron concentration and reactivity transients for this event. Offsite power is assumed available so that full reactor coolant flow exists. The transient shown assumes an uncontrolled steam release from only one steam generator. Should the core be critical at near zero power when the break occurs, the initiation of safety injection by low steamline pressure will trip the reactor. Steam release from more than one steam generator will be prevented by automatic closure of the fast-acting isolation valves in the steam lines by low steamline pressure signals, high containment pressure signals, or high negative steamline pressure rate signals. Even with the failure of one valve, release is limited to no more than 10 seconds for the other steam generators while the one generator blows down. The steamline stop valves are designed to be fully closed in less than 5 seconds from receipt of a closure signal.

The core attains criticality with the RCCAs inserted (with the design shutdown assuming one stuck RCCA) before boron solution at 2300 ppm enters the RCS. A peak core power lower than the nominal full power value is attained.

The calculation assumes the boric acid is mixed with, and diluted by, the water flowing in the RCS prior to entering the reactor core. The concentration after mixing depends upon the relative flow rates in the RCS and in the HHSI system. The variation of mass flow rate in the RCS due to water density changes is included in the calculation as is the variation of flow rate in the HHSI system due to changes in the RCS pressure. The HHSI system flow calculation included the line losses in the system as well as the pump head curve.

For the case assuming coincidental loss of offsite power when the SI signal is generated, the SI system delay time includes 13 seconds to start the diesel in addition to the 17 seconds to start the SI pump and open the valves. An additional 10 seconds is required to transfer the HHSI pump suction from the Volume Control Tank (VCT) to the Refueling Water Storage Tank (RWST). Therefore, in 40 seconds, the diesel and pump are assumed to start and the valves are assumed to be in their final position with the pump suction transferred from the VCT to the RWST. Criticality is achieved later, and the core power increase is slower, than in the case with offsite power available. The ability of the emptying steam generator to extract heat from the RCS is reduced by the decreased flow in the RCS. The peak power remains well below the nominal full power value.

It should be noted that following a steamline break only one steam generator blows down completely. Thus, the remaining steam generators are still available for dissipation of decay heat after the initial transient is over. In the case of loss of offsite power, this heat is removed to the atmosphere via the steamline safety valves.

Margin to Critical Heat Flux

DNB analyses were performed for both units with and without offsite power and High and Low T_{avg} programs. The minimum DNBR is greater than the limit value in all cases, with the limiting case being Unit 2 (D5 SGs), Low HFP T_{avg} case, with offsite power available. The results of this case are presented herein.

6.2.4.6 Conclusions

The analysis has shown that the acceptance criteria stated in Subsection 6.2.4.4 are satisfied. Although DNB and possible cladding perforation following a steam pipe break are not necessarily unacceptable and not precluded by the criteria, the above analysis shows that the DNBR never falls below the safety analysis limit.

6.2.4.7 References

1. Burnett, T. W. T., et al, "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary), WCAP-7907-A (Non-proprietary), April 1984.

2. Hollingsworth, S. D. and Wood, D. C., "Reactor Core Response to Excessive Secondary Steam Releases," WCAP-9226, Revision 1 (Proprietary), January 1978, and WCAP-9227, Revision 1 (Non-Proprietary), January 1978.

3. Moody, F. S., "Transactions of the ASME," *Journal of Heat Transfer*, Page 134, February 1965.

Table 6.2.4-1 Time Sequence of Events for the Rupture of a Main Steamline	
Event	**Time (sec)**
Limiting Case: Unit 2, offsite power available, Low T_{avg}	
Steamline ruptures	0.0
Low steamline pressure setpoint reached (SI signal generated)	0.8
Steamline isolation occurs	8.8
Criticality attained	24.8
Pressurizer empties	25.2
SI injection begins	27.8
Borated water from the RWST reaches the core*	98.0
Peak core heat flux occurs	151.6

* One ppm of boron was arbitrarily chosen to represent an appreciable amount of boron to be considered for this item.

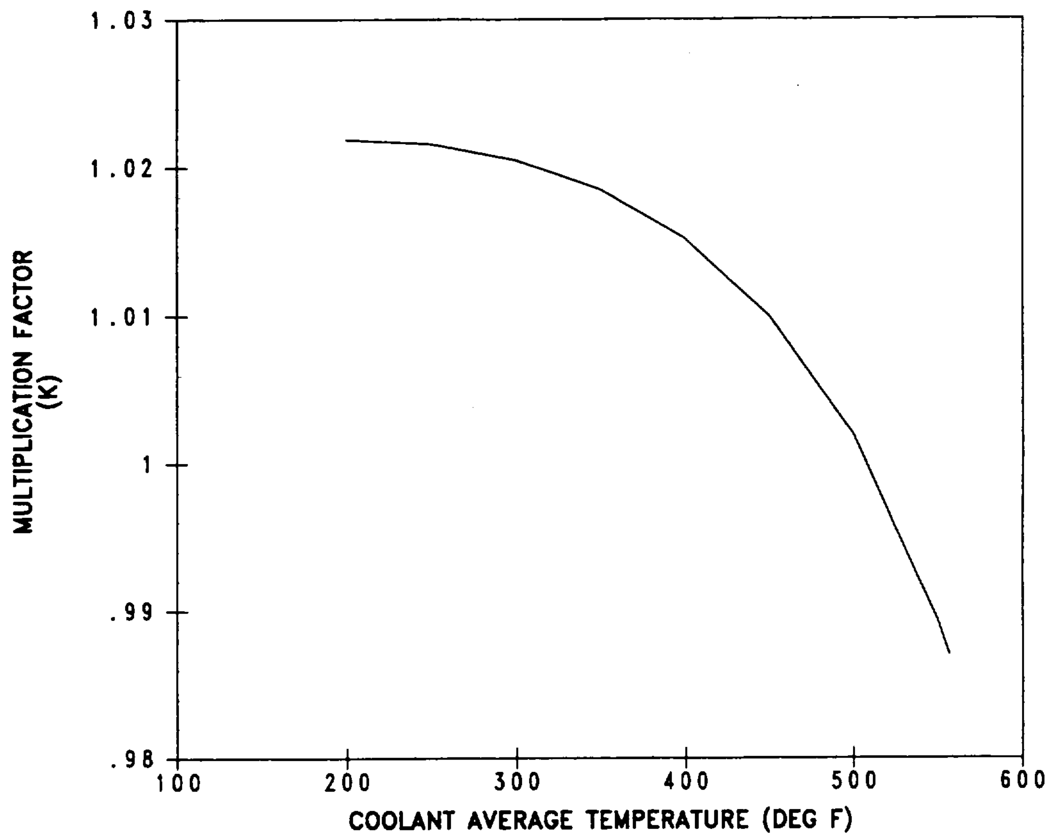


Figure 6.2.4-1

HZP SLB Moderator Density Model

K_{eff} vs. Coolant Average Temperature

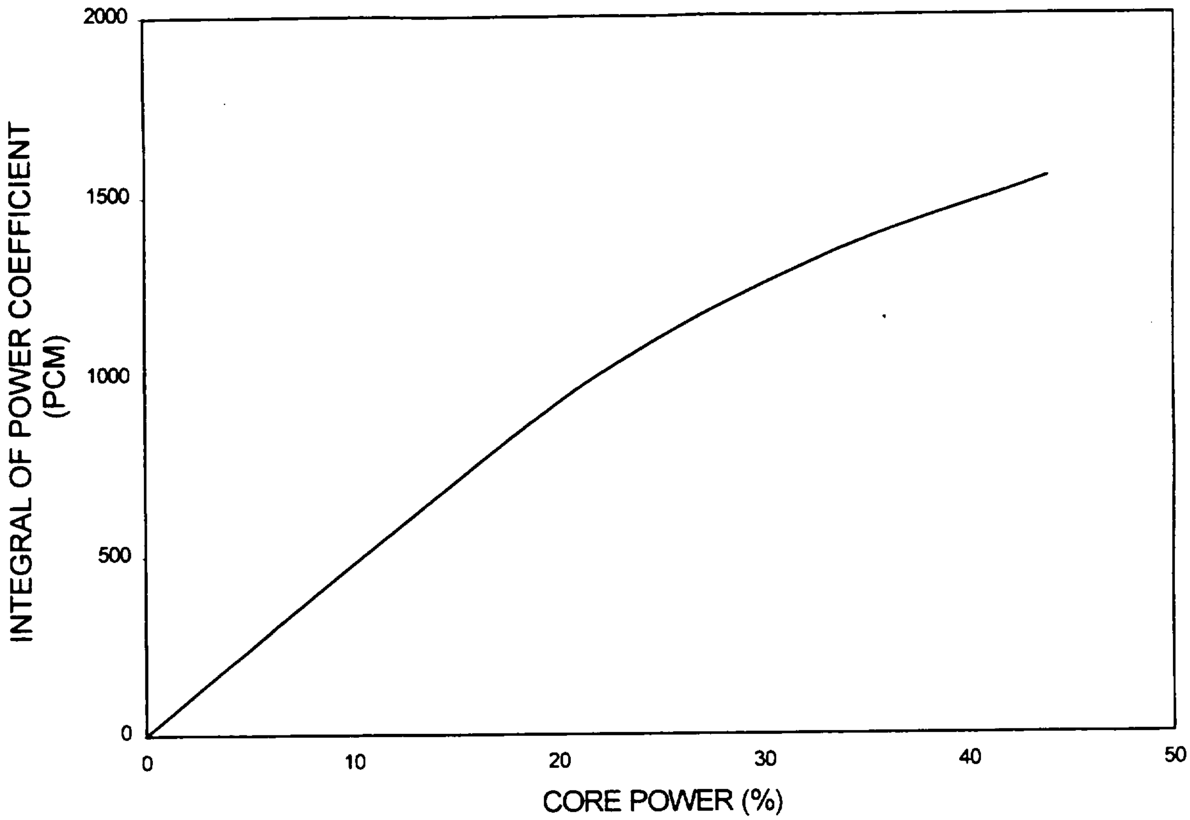


Figure 6.2.4-2

HZP SLB Doppler-Only Power Feedback Model

Integral of Doppler-Only Power Coefficient vs. Core Power

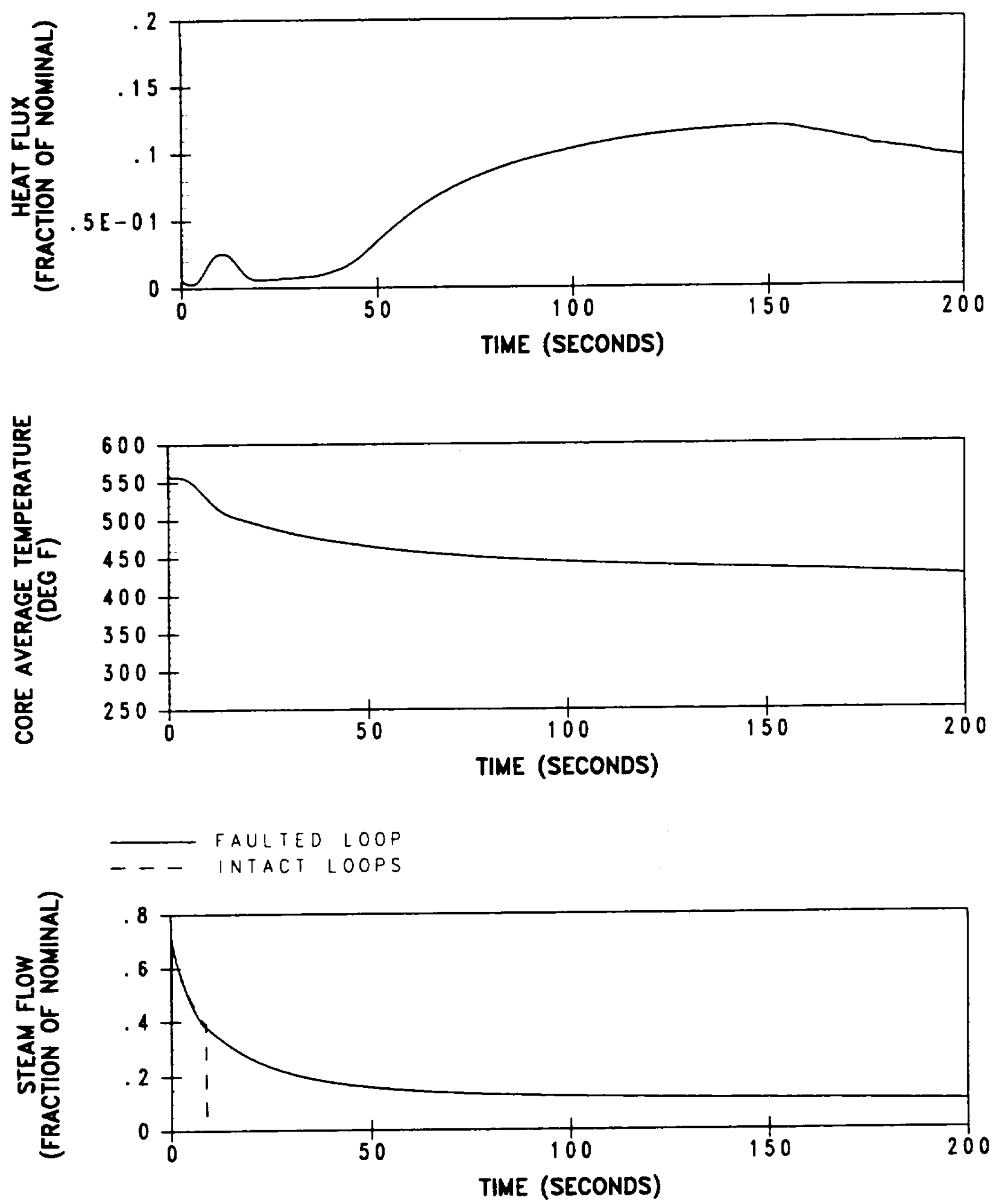
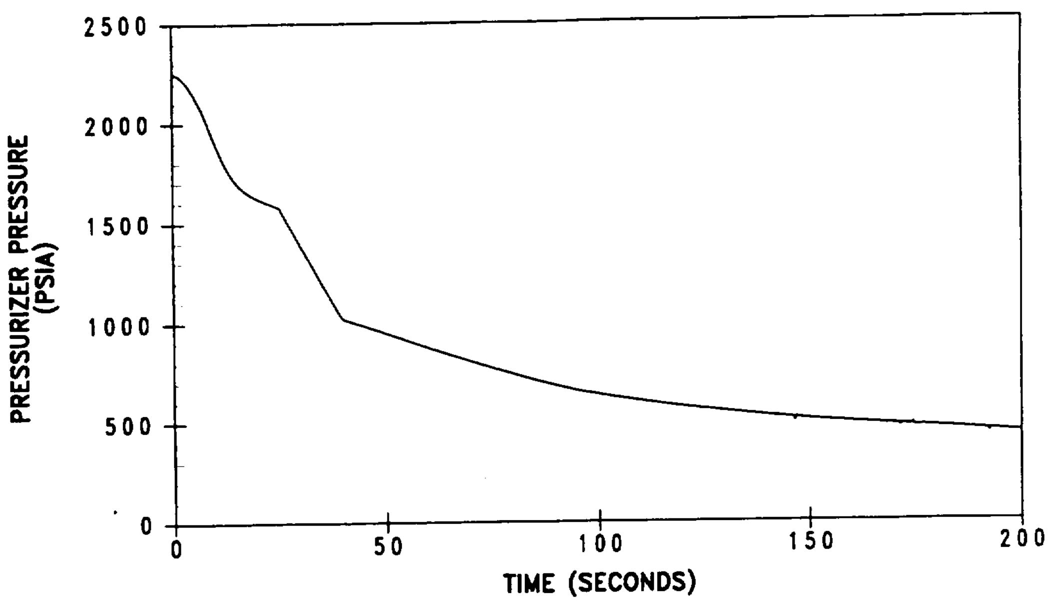


Figure 6.2.4-3

1.4 ft^2 Steamline Break, Offsite Power Available, Unit 2

Core Heat Flux, Core Average Coolant Temperature, and Steam Flow vs. Time



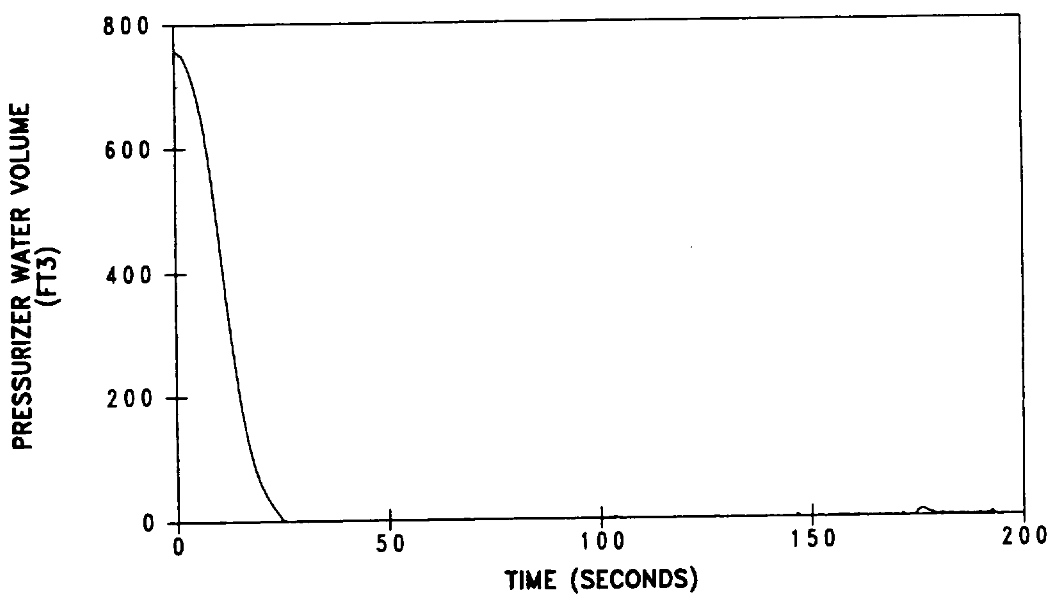


Figure 6.2.4-4

1.4 ft^2 Steamline Break, Offsite Power Available, Unit 2

Pressurizer Pressure and Pressurizer Water Volume vs. Time

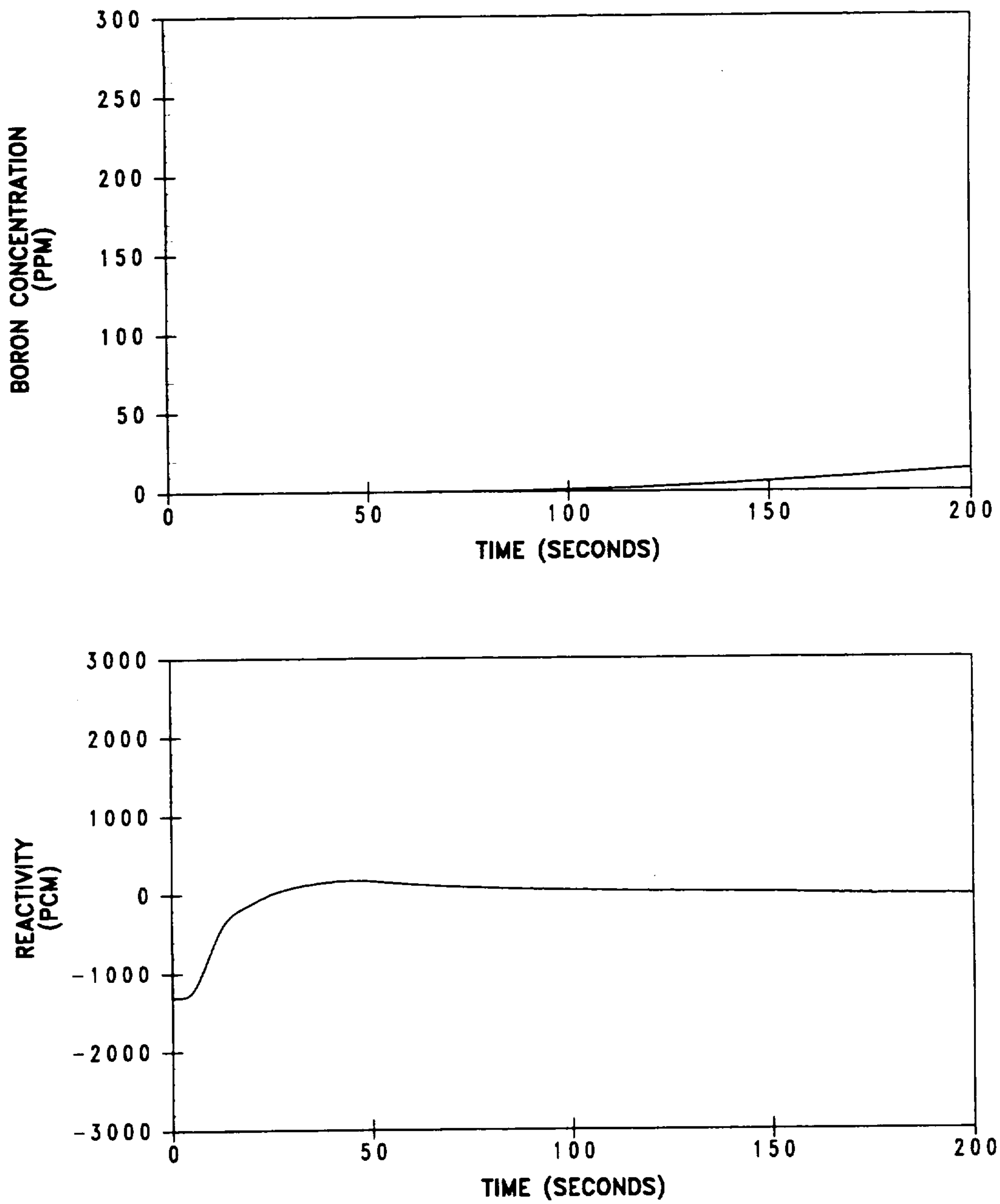


Figure 6.2.4-5

1.4 ft^2 Steamline Break, Offsite Power Available, Unit 2

Boron Concentration and Reactivity vs. Time

6.2.5 Steam System Piping Failure at Full Power

6.2.5.1 Introduction

The steam system piping failure accident analysis described in Section 6.2.4 is performed assuming hot-zero power initial conditions with the control rods inserted in the core with the exception of the most reactive rod. Such a condition could occur while the reactor is at hot shutdown at the minimum required shutdown margin or after the plant has been tripped automatically by the reactor protection system or manually by the operator. For an at-power steamline break, the analysis of Section 6.2.4 represents 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 at-power initial conditions to demonstrate that core protection is maintained prior to and immediately following reactor trip.

6.2.5.2 Input Parameters and Assumptions

The following assumptions are made in the analysis of the steamline break event at power.

a. Initial conditions - The initial core power, reactor coolant temperature, and reactor coolant system pressure are assumed to be at their nominal full-power values at uprated power conditions. Cases for both uniform and asymmetric initial loop flow conditions are considered. The latter cases consider a maximum 5% loop-to-loop asymmetric flow variation.

b. Cases are analyzed with various break sizes considering both steam generator designs (i.e., BWI SGs for Unit 1, D5 SGs for Unit 2). The limiting case is determined in the analysis to be that for a 0.967 ft2 break for Unit 1. The results of this case bound all other break sizes for both Unit 1 and Unit 2.

c. Break flow - In computing the steam flow during a steamline break, the Moody curve for f(L/D) = 0 is used.

d. Reactivity coefficients - The analysis assumed maximum moderator reactivity feedback and minimum Doppler power feedback to maximize the power increase following the break. The maximum moderator density coefficient assumed is 0.33 Δk/gm/cc.

e. Protection system - The protection system features that mitigate the effects of a steamline break are described in Section 6.2.4. This analysis only considers the initial phase of the transient from at-power conditions. Protection in this phase of the transient is provided by reactor trip, if necessary. Section 6.2.4 presents the analysis of the bounding transient following reactor trip, where other protection system features are actuated to mitigate the effects of the steamline break.

f. Control systems - The pressurizer sprays are modeled to minimize RCS pressure, which is conservative with respect to DNBR. No other control systems are modeled.

6.2.5.3 Description of Analysis

The analysis of the steamline break at power is performed as follows:

a. The LOFTRAN code (Reference 1) is used to calculate the nuclear power, core heat flux, and reactor coolant system temperature and pressure transients resulting from the cooldown following the steamline break.

b. The core radial and axial peaking factors are determined using the thermal-hydraulic conditions from LOFTRAN as input to the nuclear core models. A detailed thermal-hydraulic code, THINC, is then used to calculate the DNBR for the limiting time during the transient.

The analysis was performed using the Revised Thermal Design Procedure as described in WCAP-11397-P-A (Reference 2). Uncertainties on RCS initial conditions (temperature, pressure, and power) are included in the development of the DNBR limit value.

6.2.5.4 Acceptance Criteria

A major steamline break is classified as an ANS Condition IV event. Effects of minor secondary system pipe breaks, which are classified as Condition III events, are bounded by the analysis presented in this section.

Conservatively assuming a stuck RCCA with or without offsite power, and assuming a single failure in the engineered safety features, the core remains in place and intact. Although DNB and possible clad perforation following a steam pipe break are not necessarily unacceptable, the following analysis in fact shows that the DNBR never falls below the safety analysis limit for any break assuming the most reactive assembly stuck in its fully withdrawn position. This analysis will conservatively meet the radiological dose criteria set forth in the Standard Review Plan.

6.2.5.5 Results

The sequence of events for the limiting case (Unit 1, High T_{avg} program, uniform flow) is shown in Table 6.2.5-1. Although a spectrum of break sizes was analyzed, only the transient conditions from the limiting case (0.967 ft^2 break) are provided here, as shown in Figures 6.2.5-1 through 6.2.5-3. The 0.967 ft^2 break with symmetric (uniform) RCS flow for Unit 1 is the most limiting case for both kW/ft and DNBR considerations. The Unit 1 results bound those for Unit 2. For this limiting case, a reactor trip on overpower ΔT occurs. The results of the analysis demonstrate that this trip function provides the necessary protection required to ensure that the minimum DNBR remains above the applicable safety analysis DNBR limit throughout the transient and that the peak linear rod power (kW/ft) does not exceed that required for the occurrence of fuel centerline melt.

6.2.5.6 Conclusions

The results of the hot full power steamline break analysis show that all applicable acceptance criteria are met. Hence, it is concluded that operation of the Byron/Braidwood units at uprated power conditions is acceptable for this event.

6.2.5.7 References

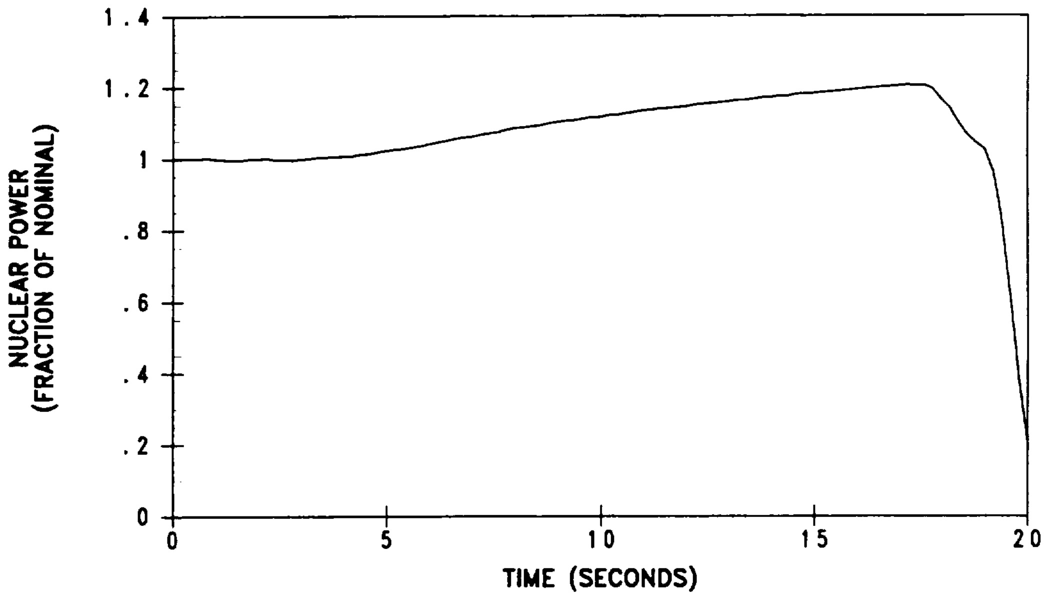
1. Burnett, T. W. T., et al, "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary), WCAP-7907-A (Non-proprietary), April 1984.

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

Table 6.2.5-1

Time Sequence of Events for the Main Steam Line Break Core Response at Full Power

Event	Time (sec)
Steam line ruptures (0.967 ft^2)	0.0
Overpower ΔT reactor trip setpoint reached	9.1
Rods begin to drop	17.1
Peak core heat flux occurs (minimum DNBR)	17.8



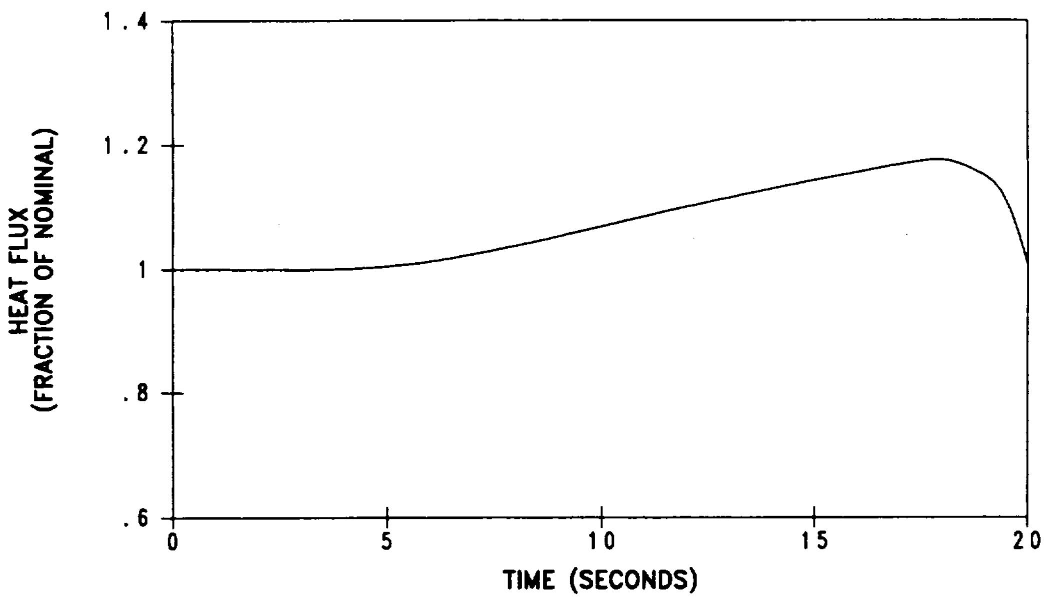


Figure 6.2.5-1

Steam System Piping Failure at Full Power - 0.967 ft^2 Break, Unit 1

Nuclear Power and Core Heat Flux vs. Time

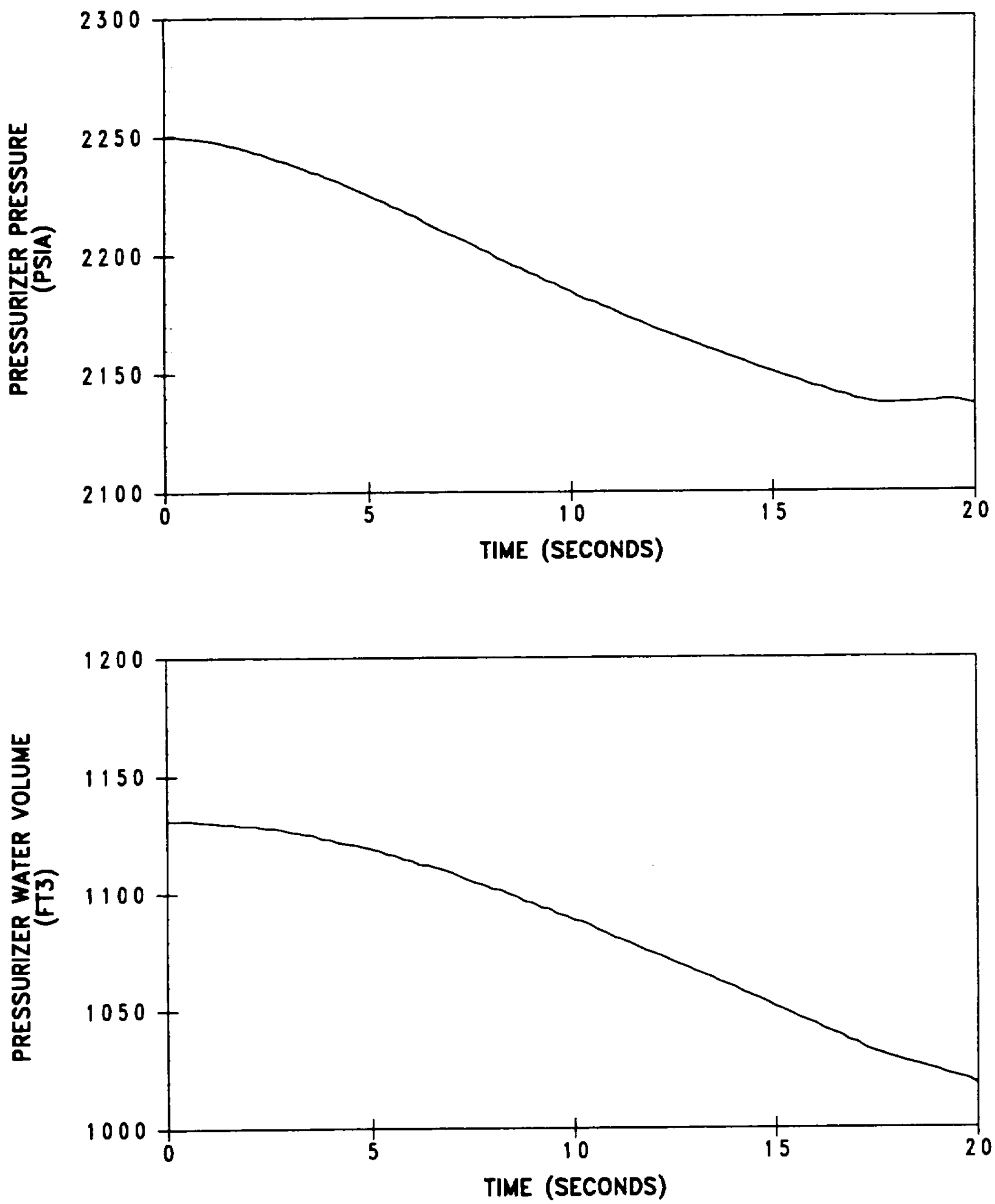


Figure 6.2.5-2

Steam System Piping Failure at Full Power - 0.967 ft^2 Break, Unit 1

Pressurizer Pressure and Pressurizer Water Volume vs. Time

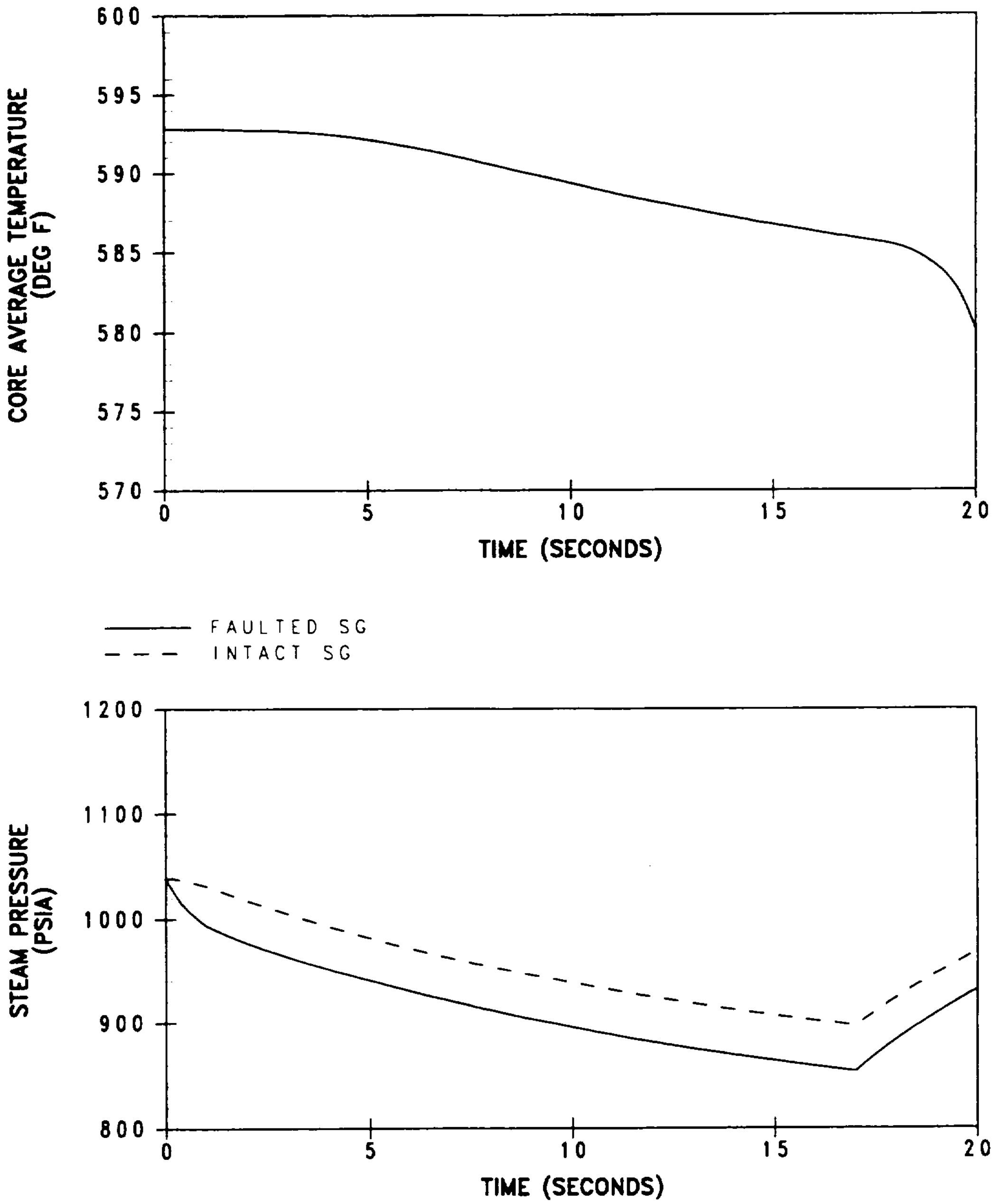


Figure 6.2.5-3

Steam System Piping Failure at Full Power - 0.967 ft² Break, Unit 1

Core Average Coolant Temperature and Steam Pressure vs. Time

6.2.6 Loss of External Electrical Load and/or Turbine Trip

6.2.6.1 Introduction

A major load loss on the plant can result from either a loss of external electrical load or from a turbine trip. A loss of external electrical load may result from an abnormal variation in network frequency or other adverse network operating condition. For either case, offsite power is available for the continued operation of plant components such as the reactor coolant pumps. The case of loss of all non-emergency ac power is presented in Section 6.2.7.

For a loss of external electrical load without subsequent turbine trip, no direct reactor trip signal would be generated, as the plant would be expected to trip from the reactor protection system if a safety limit were approached. A continued steam load of approximately 5% would exist after total loss of external electrical load because of the steam demand of plant auxiliaries.

For a turbine trip, the reactor would be tripped directly (unless below approximately 30% (P-8) power) on a signal from the turbine auto stop oil pressure or turbine stop valves.

If the steam dump valves fail to open following a large loss of load, the steam generator safety valves may lift and the reactor may be tripped by the high pressurizer pressure signal, high pressurizer water level signal or overtemperature ΔT signal. If feedwater flow is also lost, the reactor may be tripped by a steam generator low-low water level signal. The steam generator shell-side pressure and reactor coolant temperatures will increase rapidly following a large loss of load. The pressurizer and steam generator safety valves are sized to protect the RCS and steam generators against overpressure for all load losses without assuming operation of the steam dump system, pressurizer spray, pressurizer power-operated relief valves, automatic rod control, or direct reactor trip on turbine trip.

The pressurizer safety valve capacity is sized based on a complete loss of heat sink with the plant initially operating at the maximum calculated turbine load along with operation of the steam generator safety valves. The pressurizer and steam generator safety valves are then able to maintain the RCS and Main Steam System pressures within 110% of the corresponding design pressure without a direct reactor trip on turbine trip.

6.2.6.2 Input Parameters and Assumptions

The Loss of External Electrical Load/Turbine Trip accident is analyzed for two specific cases:

- maximum RCS and secondary side pressures
- minimum DNBR

Since the Byron/Braidwood Nuclear Power Stations operate with different steam generator models (BWI for Units 1 and D5 for Units 2), this accident is analyzed separately for Units 1 and Units 2. The major assumptions used in the analyses are summarized below.

Initial Operating Conditions

The peak pressure case without pressure control is analyzed using the Standard Thermal Design Procedure. Initial reactor power and RCS temperatures are assumed to be at their nominal values plus uncertainties. Initial RCS pressure is assumed to be at its nominal value minus uncertainties. The analysis models Thermal Design Flow.

The minimum DNBR case with pressure control is analyzed using the Revised Thermal Design Procedure (Reference 1). Initial reactor power, pressure, and RCS average temperature are assumed to be at their nominal values. Uncertainties in initial conditions are included in the departure from nucleate boiling ratio (DNBR) limit. Minimum Measured Flow is modeled.

Reactivity Coefficients

Minimum reactivity feedback (BOL) conditions are conservatively assumed for both cases. The analysis is performed at full power conditions assuming a MTC of 0 pcm/°F. Least negative Doppler-only power and temperature coefficients are also assumed.

Reactor Control

From the standpoint of the maximum pressures and minimum DNBR attained, it is conservative to assume that the reactor is in manual rod control. If the reactor were in automatic rod control, the control rod banks would move prior to trip and reduce the severity of the transient.

Pressurizer Spray and Power-Operated Relief Valves

The pressurizer power-operated relief valves and pressurizer spray portion of the automatic pressure control system are assumed in the minimum DNBR case since each serve to limit the RCS pressure increase, which is conservative for the DNBR calculation. In the peak pressure case, the pressurizer power-operated relief valves and spray are not assumed. Safety valves are assumed operable in each case.

Feedwater Flow

Main feedwater flow to the steam generators is assumed to be lost at the time of turbine trip. No credit is taken for auxiliary feedwater flow; however, eventually auxiliary feedwater flow would be initiated and a stabilized plant condition would be reached.

Reactor Trip

Reactor trip is actuated by the first reactor protection system trip setpoint reached. Trip signals are expected due to high pressurizer pressure and overtemperature ΔT.

Steam Release

No credit is taken for operation of the steam dump system or steam generator power-operated relief valves. This assumption maximizes secondary pressure.

6.2.6.3 Description of Analyses

For the Loss of External Electrical Load/Turbine Trip Event, the behavior of the unit is analyzed for a complete loss of steam load from full power without a direct reactor trip. This assumption is made to show the adequacy of the pressure-relieving devices and to demonstrate core protection margins by delaying reactor trip until conditions in the RCS result in a trip due to other signals. Thus, the analysis assumes a worst-case transient. In addition, no credit is taken for steam dump. Main feedwater flow is terminated at the time of turbine trip, with no credit taken for auxiliary feedwater (except for long-term recovery) to mitigate the consequences of the transient.

A detailed analysis using the LOFTRAN (Reference 2) computer code is performed to determine the plant transient conditions following a total loss of load. The code models the core neutron kinetics, RCS including natural circulation, pressurizer, pressurizer PORVs and spray, steam generators, main steam safety valves, and the auxiliary feedwater system; and computes pertinent variables, including pressurizer pressure, steam generator pressure, steam generator mass, and reactor coolant average temperature.

6.2.6.4 Acceptance Criteria

Based on its frequency of occurrence, the Loss of External Electrical Load/Turbine Trip accident is considered a Condition II event as defined by the American Nuclear Society. The criteria are as follows.

1. Pressure in the reactor coolant and main steam systems should remain below 110% of the design values.

2. Fuel cladding integrity shall be maintained by ensuring that the minimum DNBR remains above the 95/95 DNBR limit.

3. An incident of moderate frequency in combination with any single active component failure, or single operator error, shall be considered an event for which an estimate of the number of potential fuel failures shall be provided for radiological dose calculations. For such accidents, fuel failure must be assumed for all rods for which the DNBR falls below those values cited above for cladding integrity unless it can be shown, based on an acceptable fuel damage model, that fewer failures occur. There shall be no loss of function of any fission product barrier other than the fuel cladding.

6.2.6.5 Results

The calculated sequence of events for the Loss of External Electrical Load/Turbine Trip cases are presented in Table 6.2.6-1.

Peak Pressure Case

The transient responses for the total loss of steam load from full power are shown in Figure 6.2.6-1 for Byron 1/Braidwood 1 and Figure 6.2.6-3 for Byron 2/Braidwood 2. No credit is taken for the pressurizer spray, pressurizer power-operated relief valves, or for the steam dump. The reactor is tripped by the high pressurizer pressure trip channel. The pressurizer safety valves are actuated and the primary system pressure remains below the 110% design value. The steam generator safety valves maintain the secondary side steam pressure below 110% of the steam generator shell design pressure.

Minimum DNBR Case

The transient responses for the total loss of steam load from full power are shown in Figure 6.2.6-2 for Byron 1/Braidwood 1 and Figure 6.2.6-4 for Byron 2/Braidwood 2. Full credit is taken for the pressurizer spray and pressurizer power-operated relief valves. No credit is taken for the steam dump. The reactor is tripped by the overtemperature T trip channel. The minimum DNBR remains well above the limit value.

6.2.6.6 Conclusions

The results of this analysis show that the plant design is such that a total loss of external electrical load without a direct reactor trip presents no hazard to the integrity of the RCS or the main steam system at uprated power conditions. All of the applicable acceptance criteria are met. The minimum DNBR for each case is greater than the safety analysis limit value. The peak primary and secondary system pressures remain below 110% of design at all times. The protection features presented in Section 6.2.6.2 provide mitigation of the Loss of External Electrical Load/Turbine Trip transient such that the above criteria are satisfied.

6.2.6.7 References

1. Friedland, A. J. and Ray, S., "Revised Thermal Design Procedure," WCAP-11397 (Proprietary), April 1989.

2. Burnett, T. W. T., et al., "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary), WCAP-7907-A (Non-proprietary), April 1984.

Table 6.2.6-1

Sequence of Events-Loss of Load/Turbine Trip Event

Case	Event	Time (Sec)
Byron 1/Braidwood 1: Peak Pressure Case	Loss of Electrical Load/Turbine Trip	0.0
	High Pressurizer Pressure Reactor trip Setpoint reached	5.3
	Rods begin to drop	7.3
	Peak pressurizer pressure occurs	7.5
	Minimum DNBR occurs	*
Byron 1/Braidwood 1: Minimum DNBR Case	Loss of Electrical Load/Turbine Trip	0.0
	Overtemperature T Reactor trip Setpoint reached	6.0
	Peak pressurizer pressure occurs	9.9
	Rods begin to drop	14.0
	Minimum DNBR occurs	15.1
Byron 2/Braidwood 2: Peak Pressure Case	Loss of Electrical Load/Turbine Trip	0.0
	High Pressurizer Pressure Reactor trip Setpoint reached	4.5
	Peak pressurizer pressure occurs	6.3
	Rods begin to drop	6.5
	Minimum DNBR occurs	*
Byron 2/Braidwood 2: Minimum DNBR Case	Loss of Electrical Load/Turbine Trip	0.0
	Overtemperature T Reactor trip Setpoint reached	4.0
	Peak pressurizer pressure occurs	9.7
	Rods begin to drop	12.0
	Minimum DNBR occurs	13.1

* Never falls below initial value

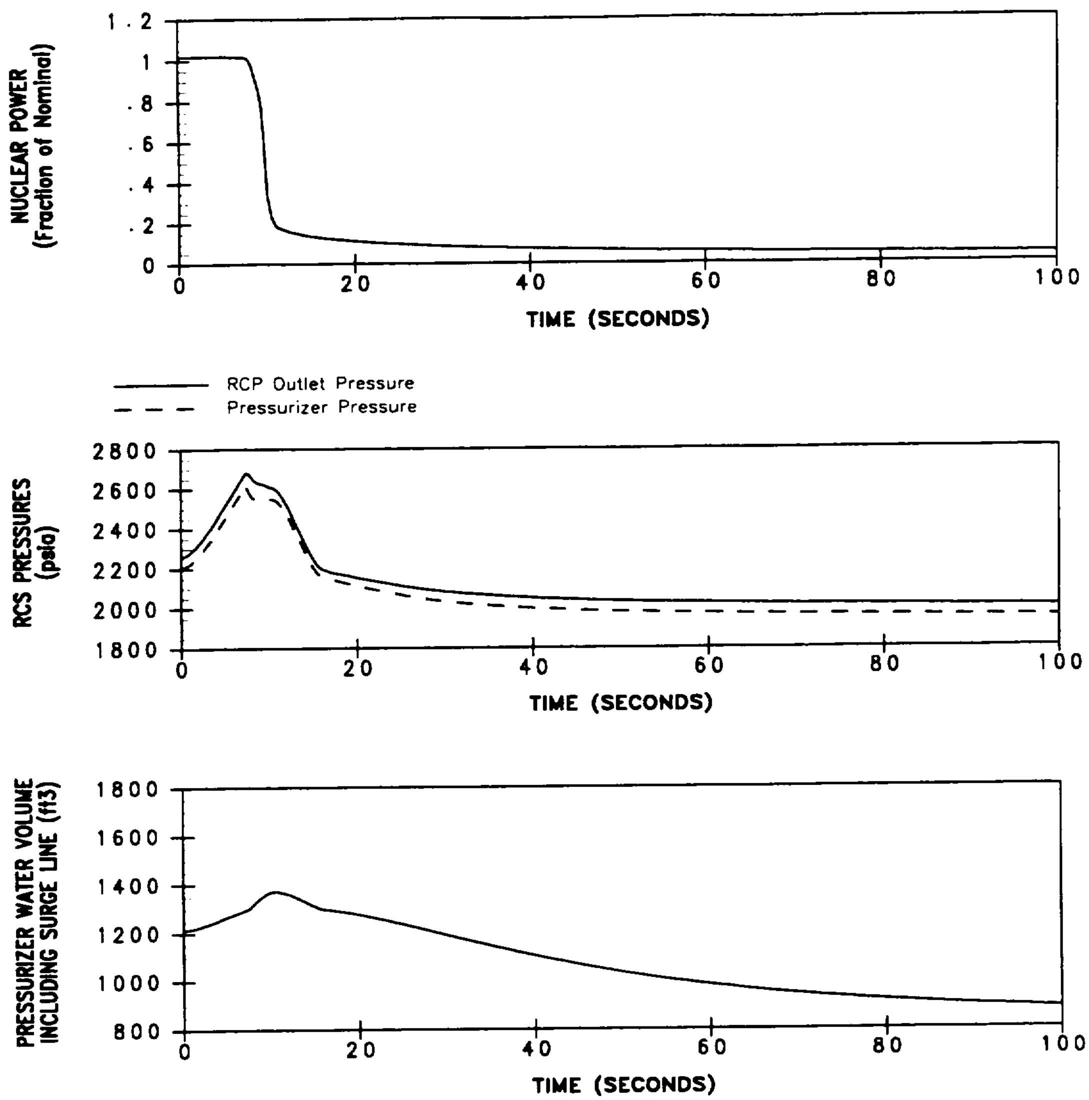


Figure 6.2.6-1 (Sheet 1)

Loss of Load/Turbine Trip, Peak Pressure Case, Unit 1

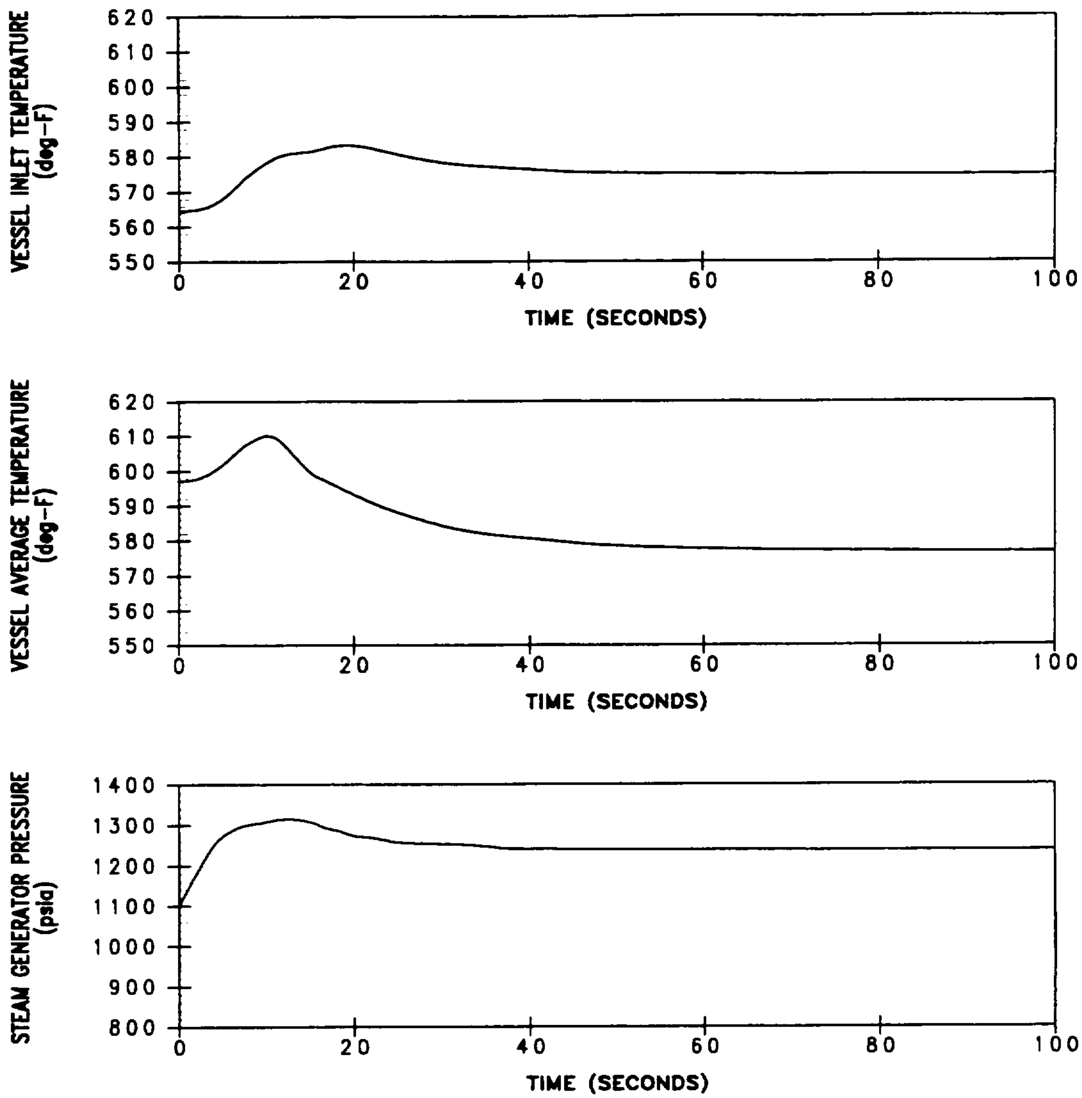


Figure 6.2.6-1 (Sheet 2)

Loss of Load/Turbine Trip, Peak Pressure Case, Unit 1

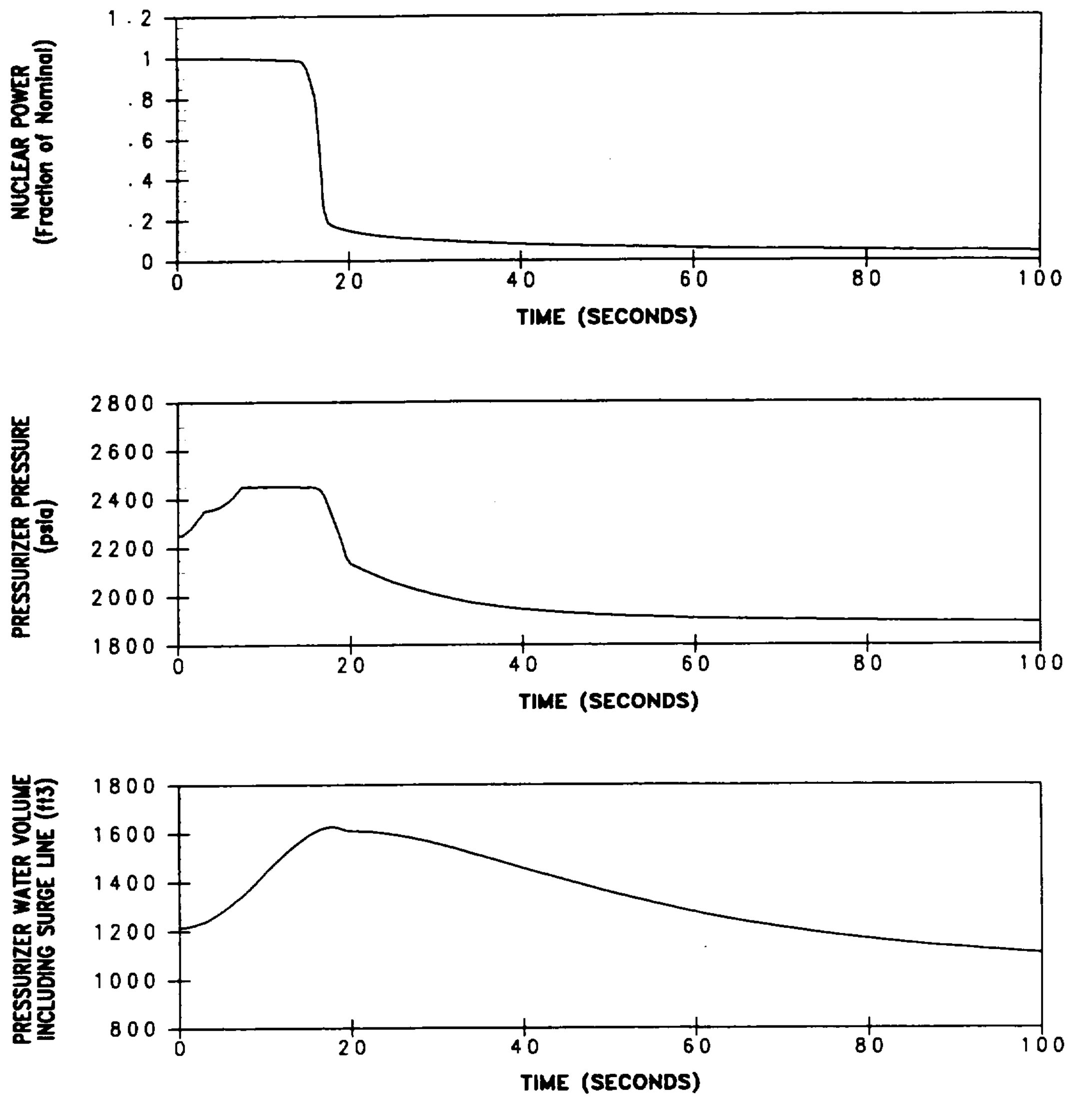


Figure 6.2.6-2 (Sheet 1)

Loss of Load/Turbine Trip, Minimum DNBR Case, Unit 1

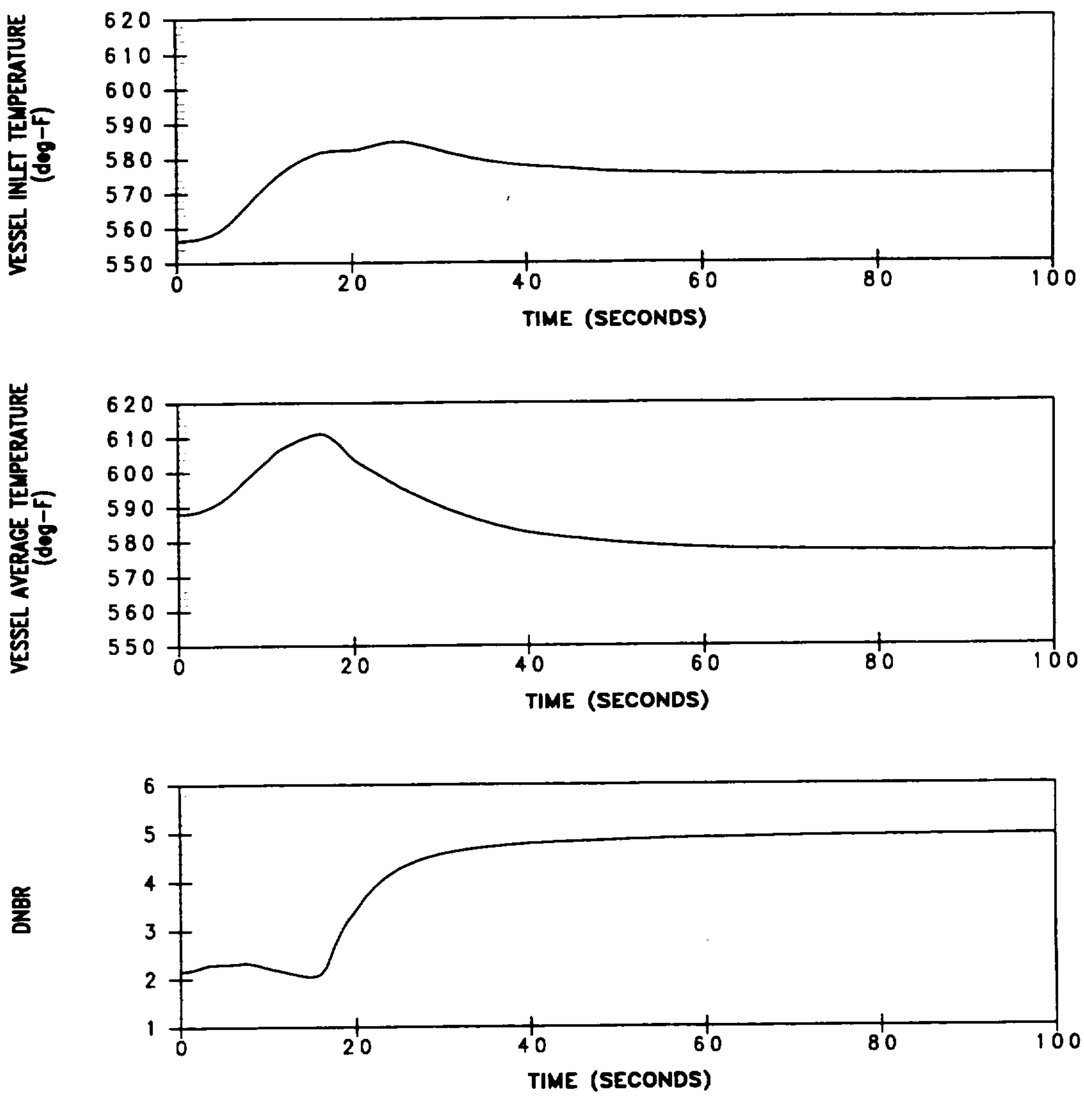


Figure 6.2.6-2 (Sheet 2)

Loss of Load/Turbine Trip, Minimum DNBR Case, Unit 1

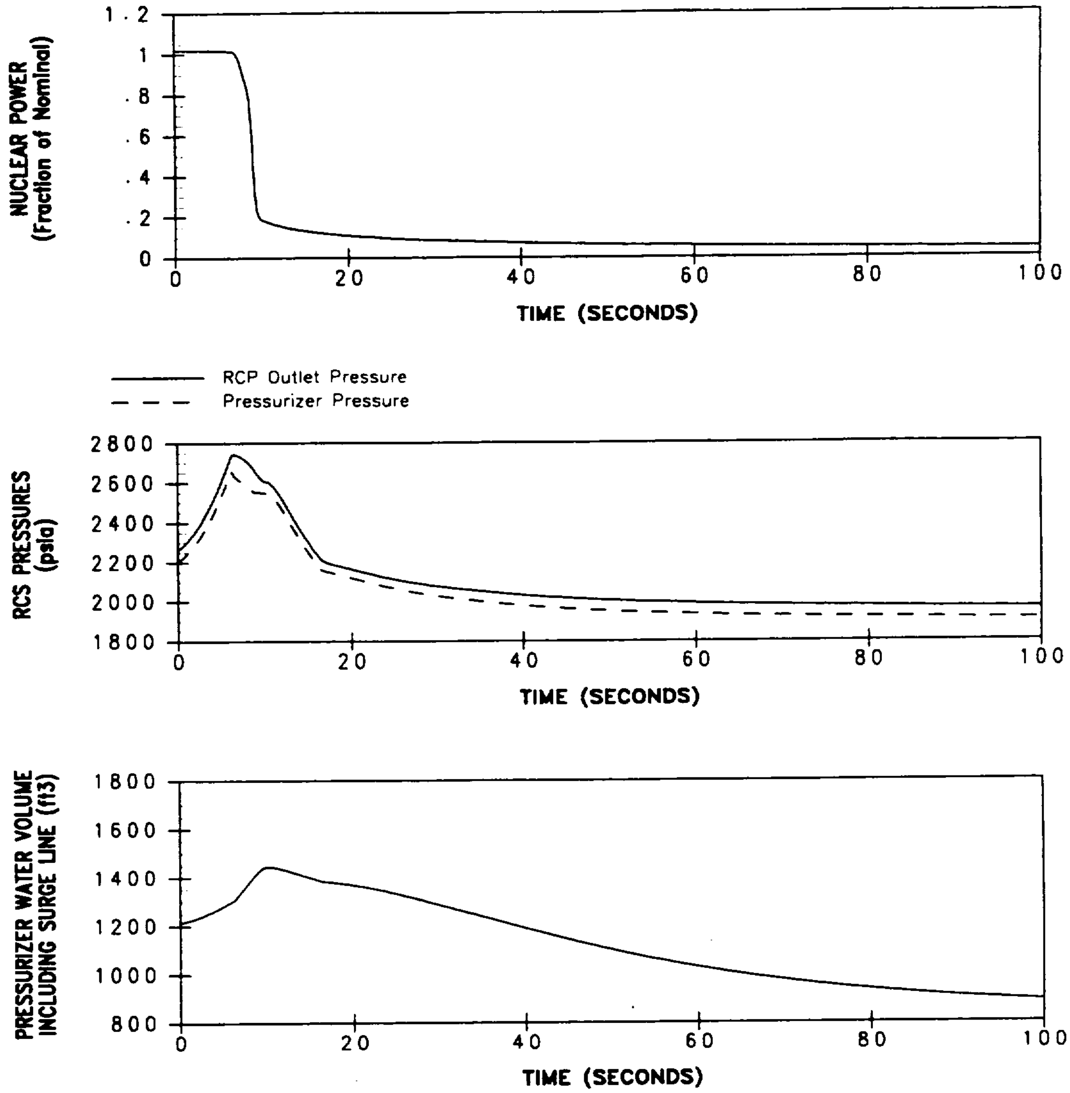


Figure 6.2.6-3 (Sheet 1)

Loss of Load/Turbine Trip, Peak Pressure Case, Unit 2

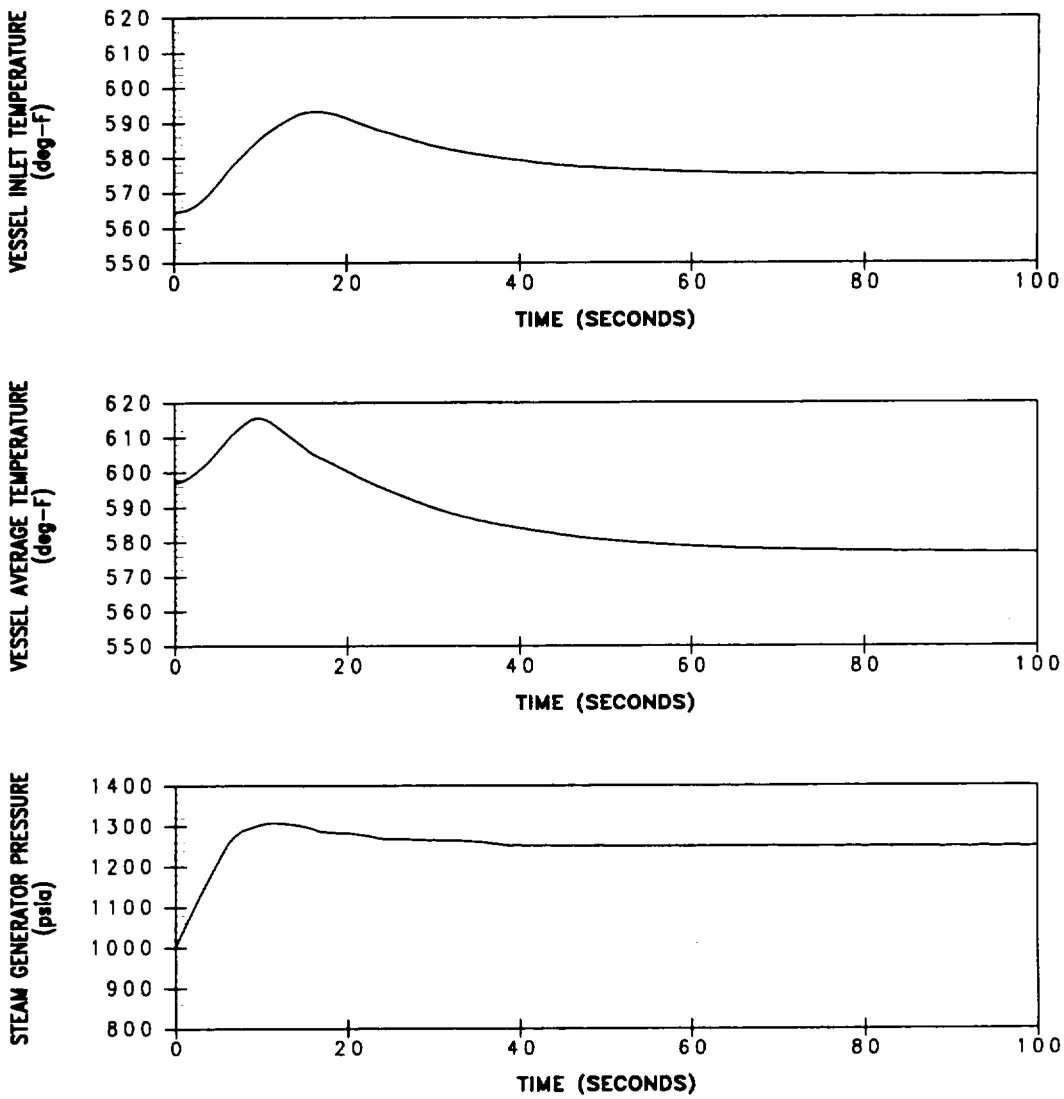


Figure 6.2.6-3 (Sheet 2)

Loss of Load/Turbine Trip, Peak Pressure Case, Unit 2

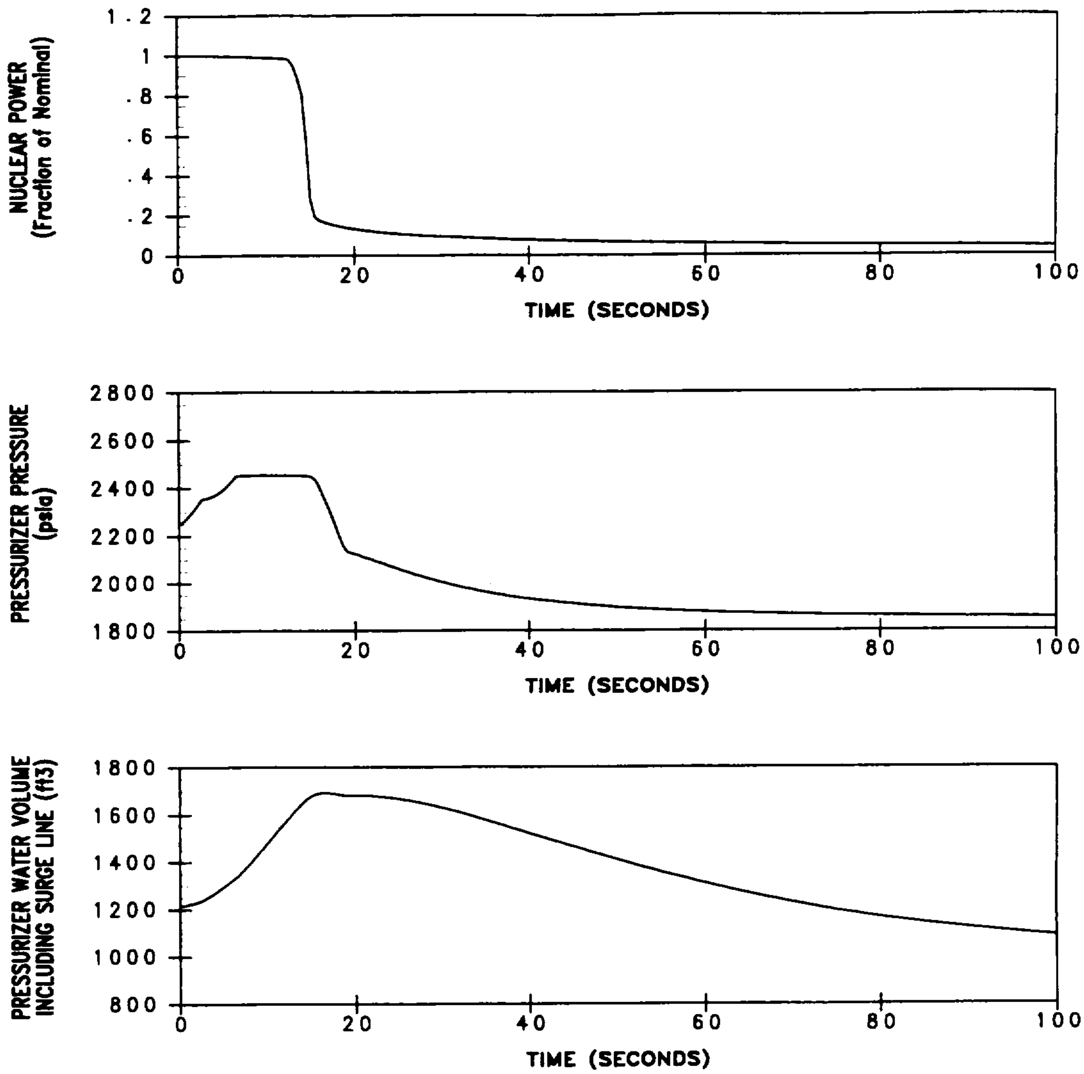


Figure 6.2.6-4 (Sheet 1)

Loss of Load/Turbine Trip, Minimum DNBR Case, Unit 2

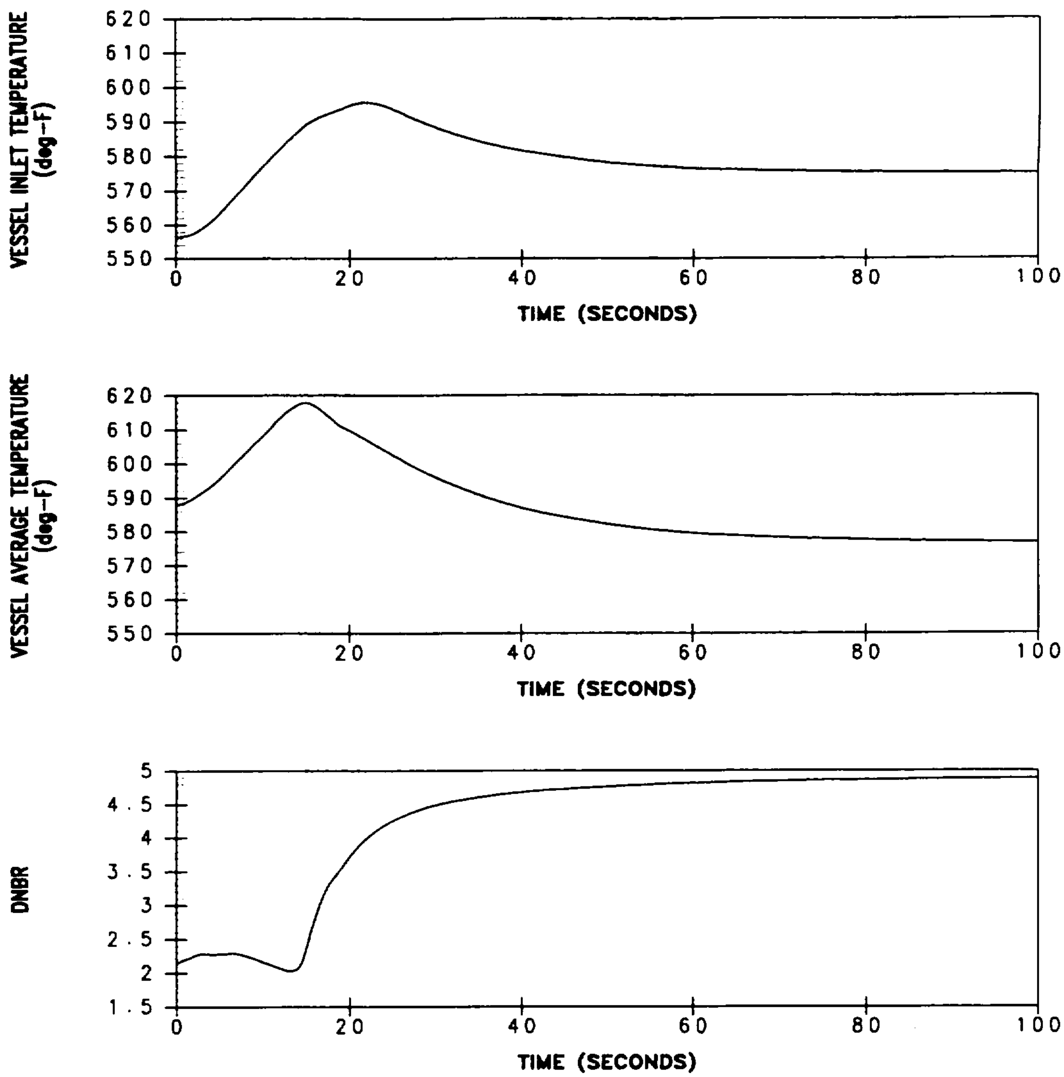


Figure 6.2.6-4 (Sheet 2)

Loss of Load/Turbine Trip, Minimum DNBR Case, Unit 2

6.2.7 Loss of Nonemergency AC Power to the Plant Auxiliaries

6.2.7.1 Identification of Causes and Accident Description

A complete loss of non-emergency AC power may result in the loss of all power to the plant auxiliaries, i.e., the reactor coolant pumps, condensate pumps, etc. The loss of power to the condensate pumps results in a loss of normal feedwater. The loss of power may be caused by a complete loss of the offsite grid accompanied by a turbine generator trip at the station or by a loss of the onsite AC distribution system.

Following a loss of AC power with turbine and reactor trips, the sequence described below will occur:

a. The emergency diesel generators will start on a loss of voltage on the plant emergency buses and begin to supply plant vital loads.

b. Plant vital instruments are supplied from emergency DC power sources.

c. As the steam system pressure rises following the trip, the steam generator power-operated relief valves may be automatically opened to the atmosphere. The condenser is assumed not to be available for steam dump. If the steam generator power-operated relief valves are not available, the steam generator safety valves may lift to dissipate the sensible heat of the fuel and coolant plus the residual decay heat produced in the reactor.

d. As the no-load temperature is approached, the steam generator power-operated relief valves (or the safety valves, if the power-operated relief valves are not available) are used to dissipate the residual decay heat and to maintain the plant at the hot standby condition.

The following provides the necessary protection against a loss of all AC power.

a. Reactor trip on low-low water level in any steam generator.

b. One motor-driven auxiliary feedwater pump and one diesel-driven auxiliary feedwater pump is started on any of the following:

    1. Low-low level in any steam generator,

    2. Any safety injection signal,

    3. Loss of offsite power (automatic transfer to diesel generators), or

    4. Manual actuation.

The motor-driven auxiliary feedwater pump is supplied power by the emergency diesel generators. The diesel-driven auxiliary feedwater pump is driven by its own diesel engine. Both pumps are designed to supply rated flow within approximately one minute of the initiating signal even if a loss of all nonemergency AC power occurs simultaneously with loss of normal feedwater. The pumps take suction from the condensate storage tank for delivery to the steam generators.

Following the loss of power to the reactor coolant pumps (RCPs), coolant flow is necessary for core cooling and the removal of residual and decay heat. Heat removal is maintained by natural circulation in the RCS loops. Following RCP coastdown, the natural circulation capability of the RCS will remove decay heat from the core, aided by AF flow in the secondary system. Demonstrating that acceptable results can be obtained for this event proves that the natural circulation flow in the RCS is adequate to remove decay heat from the core.

The first few seconds after a loss of AC power to the RCPs closely resembles the analysis of the complete loss of flow event (see Section 6.2.11, where it is shown that the DNBR is maintained above the limit value) in that the RCS would experience a rapid flow reduction transient. This aspect of the loss of AC power event is bounded by the analysis performed for the complete loss of flow event that demonstrates that the DNB design basis is met. Therefore, the DNB aspects of this event were not reevaluated for this analysis.

The analysis of the loss of AC power event is performed to demonstrate that RCS natural circulation and the AF system are capable of removing the stored and residual heat, and consequently will prevent RCS or main steam system overpressurization, water relief from the pressurizer, and uncovery of the reactor core.

6.2.7.2 Input Parameters and Assumptions

The analysis is performed for both Unit 1 (with BWI RSGs) and Unit 2 (with D5 SGs) at uprated power conditions.

The major assumptions used in this analysis are as follow:

a. The plant is initially operating at 102% of the NSSS power (3600.6 MWt), which includes a maximum reactor coolant pump heat of 20.0 MWt.

b. The initiating event is a loss of all non-emergency AC power that results in the loss of power supply for the condensate pumps. The loss of the condensate pumps results in a loss of normal feedwater.

c. The RCPs are conservatively assumed to operate until the time of reactor trip providing a constant reactor coolant volumetric flow equal to the Thermal Design Flow value. This is to maximize the amount of stored energy in the RCS. The loss of power to the RCPs is not assumed to occur until after the start of rod motion following the reactor trip on a low-low steam generator water level condition.

d. No credit is taken for the immediate insertion of the control rods because of the loss of AC power to the station auxiliaries.

e. Cases are analyzed assuming initial HFP reactor vessel average coolant temperatures at the upper and lower ends of the uprated operating range. The vessel average temperature assumed at the upper end of the range is 588°F plus an uncertainty of 9.1°F, which includes a bias of 1.5°F. The average temperature assumed at the lower end of the range is 575°F minus an uncertainty of 7.6°F.

f. Initial pressurizer pressure is assumed to be 2250 psia with an uncertainty of ±43 psi. Cases are considered with the pressure uncertainty applied in both the positive and negative direction to conservatively bound the potential operating conditions.

g. Reactor trip occurs on steam generator low-low water level at 10% of narrow range span for the Unit 1 BWI RSGs and 28.6% of narrow range span for the Unit 2 D5 SGs.

h. The worst single failure modeled in the analysis is the loss of the diesel-driven AF pump. This results in the availability of one motor-driven AF pump supplying a minimum total AF flow of 560 gpm, distributed equally to each of the four steam generators.

i. AF flow is assumed to be initiated 63 seconds following a low-low steam generator water level signal.

j. The pressurizer sprays and PORVs are assumed to be operable to maximize pressurizer water volume. These control systems are not credited for event mitigation since the pressurizer safety valves alone would prevent the RCS pressure from exceeding the RCS design pressure limit during this transient.

k. Secondary system steam relief is achieved through the self-actuated main steam safety valves that are modeled assuming a +4% lift point tolerance.

l. A conservative core residual heat generation based upon long term operation at the initial power level preceding the trip is assumed in the analysis. This core residual heat generation model is based on the 1979 version of ANS 5.1 (Reference 2). ANSI/ANS-5.1-1979 is a conservative representation of the decay energy release rates.

m. A maximum steam generator tube plugging level of 5% for the Unit 1 BWI RSGs and 10% for the Unit 2 D5 SGs is modeled.

n. A maximum AF enthalpy of 91.12 Btu/lbm is conservatively assumed in the analysis. An AF line purge volume of 160 ft^3 for the Unit 1 BWI RSGs and 60 ft^3 for the Unit 2 D5 SGs is modeled.

o. A heat transfer coefficient in the steam generators associated with RCS natural circulation is assumed following RCP coastdown.

6.2.7.3 Description of Analysis

A detailed analysis using the LOFTRAN (Reference 1) computer code is performed to determine the plant transient following a loss of all AC power. The code describes the core neutron kinetics, RCS including natural circulation, pressurizer, pressurizer PORVs and sprays, steam generators, main steam safety valves, and the auxiliary feedwater system, and computes pertinent variables, including pressurizer pressure, pressurizer water level, and reactor coolant average temperature.

6.2.7.4 Acceptance Criteria

Based on its frequency of occurrence, the loss of non-emergency AC power accident is considered a Condition II event as defined by the American Nuclear Society. The following items summarize the acceptance criteria associated with this event:

- The critical heat flux shall not be exceeded. This is demonstrated by ensuring that the applicable safety analysis DNBR limit is met.
- Pressure in the reactor coolant and main steam systems shall be maintained below 110% of the design pressures.

With respect to DNB, the loss of non-emergency AC power accident is bounded by the loss of flow accident reported in Section 6.2.11.

6.2.7.5 Results

Analyses were performed for both Unit 1 with BWI RSGs and Unit 2 with D5 SGs at the uprate power conditions. However, for the Loss of Nonemergency AC Power to the Plant Auxiliaries event, the Unit 1 analysis is more limiting and therefore presented herein.

Figures 6.2.7-1 through 6.2.7-4 present the transient response of plant conditions and parameters of interest following a loss of non-emergency AC power with the assumptions listed in Section 6.2.7.2. The calculated sequence of events for this accident is listed in Table 6.2.7-1.

The first few seconds after the loss of non-emergency AC power to the RCPs, the flow transient closely resembles the complete loss of flow incident, where core damage due to rapidly increasing core temperature is prevented by reactor trip, which, for a loss of non-emergency AC power event, is on a low-low steam generator water level signal. After reactor trip, stored and residual heat must be removed to prevent damage to the core and the reactor coolant and main steam systems. The LOFTRAN code results show that the natural circulation and AF flow available is sufficient to provide adequate core decay heat removal following reactor trip and RCP coastdown.

The water level in the pressurizer (see Figure 6.2.7-1, which includes the volume of the pressurizer surge lines) never reaches a water-solid condition. Hence, no water relief from the pressurizer occurs. The peak RCS and secondary-side pressures remain below the applicable design limits throughout the transient.

6.2.7.6 Conclusions

With respect to DNB, the loss of non-emergency AC power event is bounded by the complete loss of flow event which demonstrated that the minimum DNBR is greater than the safety analysis limit value.

The results of the analysis show that pressurizer does not reach a water-solid condition and that the applicable RCS and secondary-side pressure limits are met. Therefore, the loss of offsite power event does not adversely affect the core, the RCS, or the main steam system.

6.2.7.7 References

1. Burnett, T. W. T., et al, "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary), WCAP-7907-A (Non-proprietary), April 1984.

2. ANSI/ANS-5.1 - 1979, "American National Standard for Decay Heat Power in Light Water Reactors," August 1979.

TABLE 6.2.7-1

TIME SEQUENCE OF EVENTS FOR LOSS OF NON-EMERGENCY AC POWER

Event	Time (seconds)
Loss of Non-emergency AC Power occurs and main feedwater flow stops	10
Low-low steam generator water level reactor trip setpoint reached	65.5
Rods begin to drop	67.5
Reactor coolant pumps begin to coastdown	69.5
AF flow from one motor-driven AF pump is initiated	128.5
Core decay heat decreases to AF heat removal capacity	~345.0
Feedwater lines are purged and cold AF is delivered to four steam generators	682.0
Peak water level in pressurizer occurs (post reactor trip)	742.0

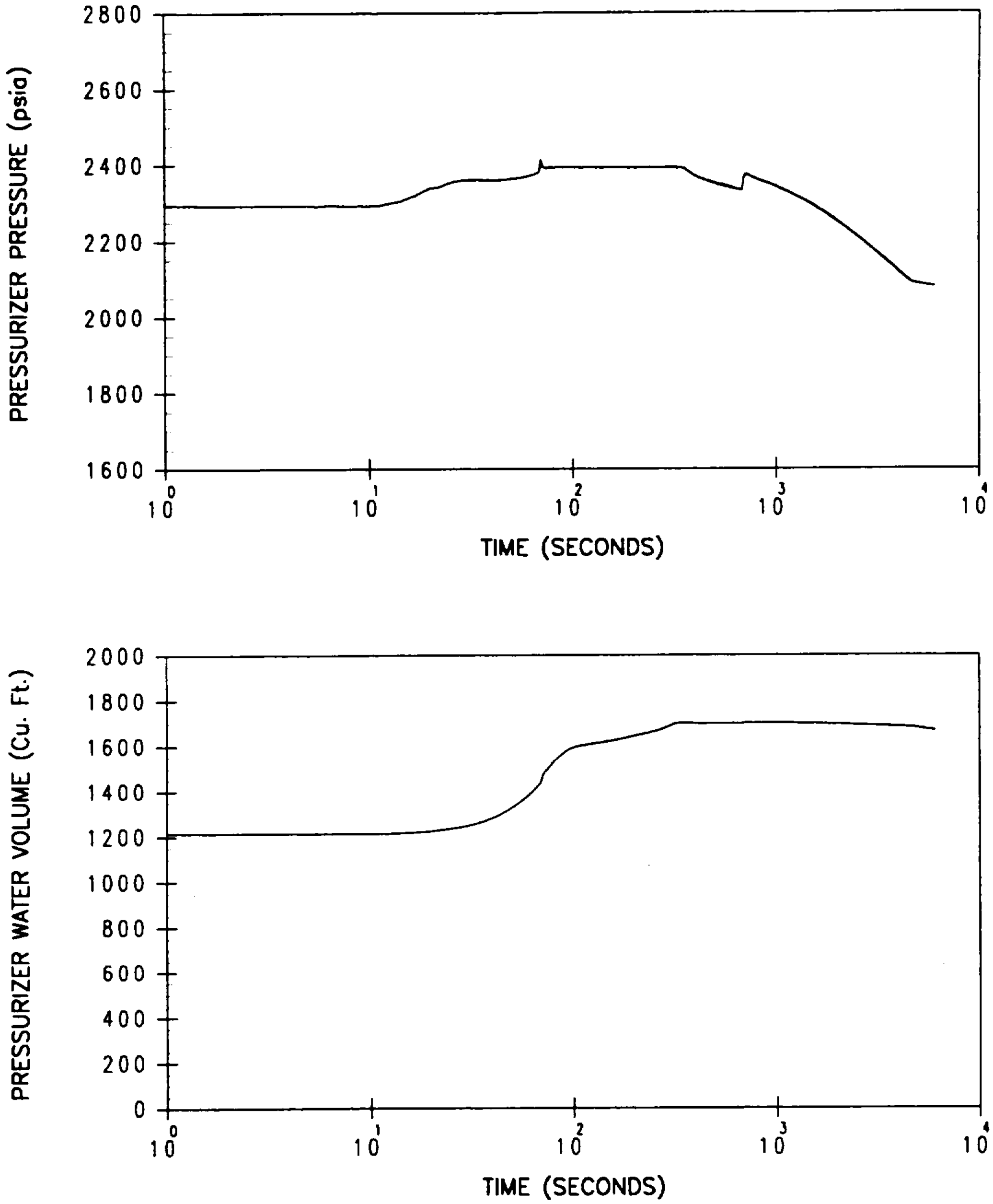


Figure 6.2.7-1

Loss of AC Power to the Plant Auxiliaries

Pressurizer Pressure and Water Volume versus Time

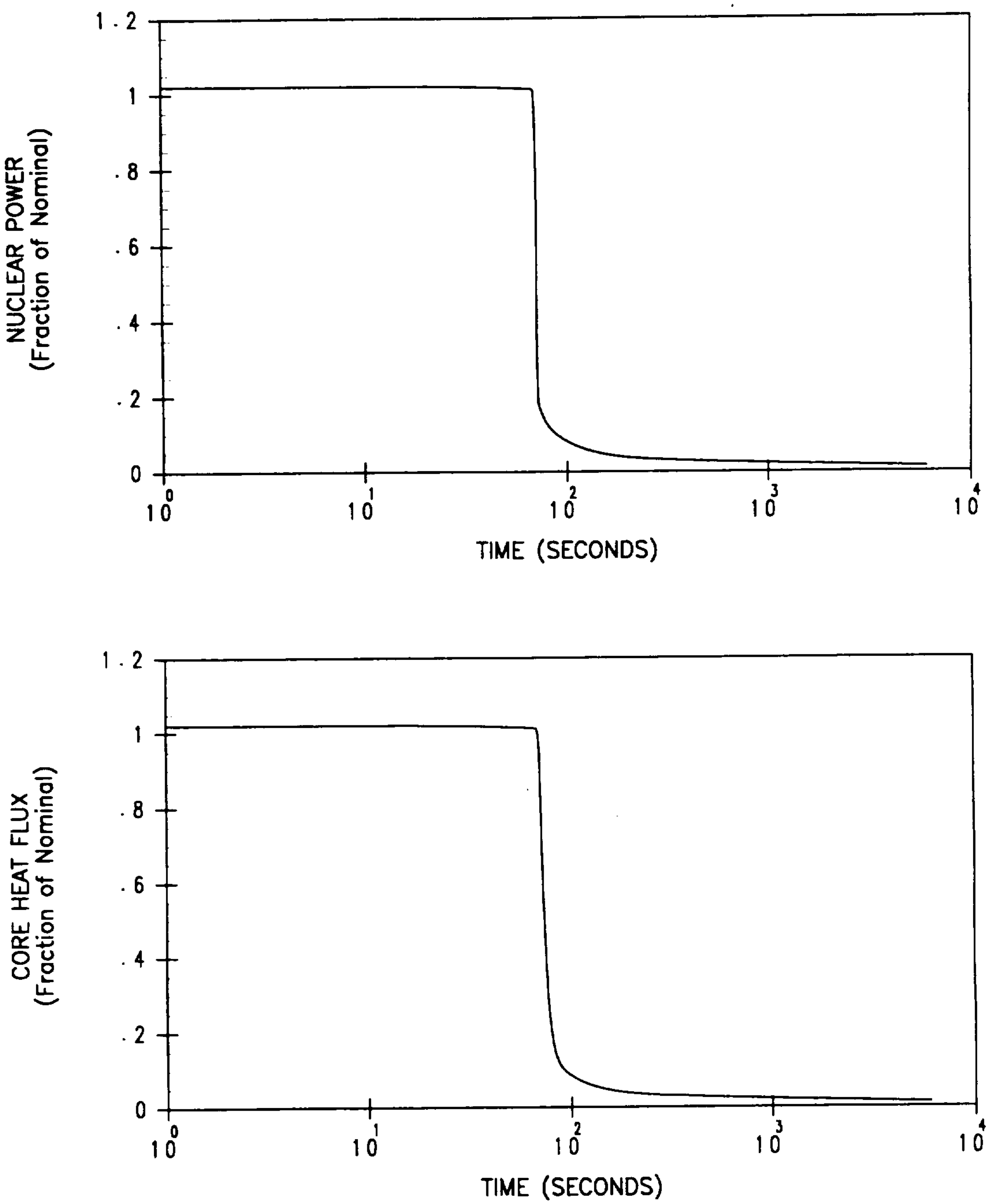


Figure 6.2.7-2

Loss of AC Power to the Plant Auxiliaries

Nuclear Power and Core Heat Flux versus Time

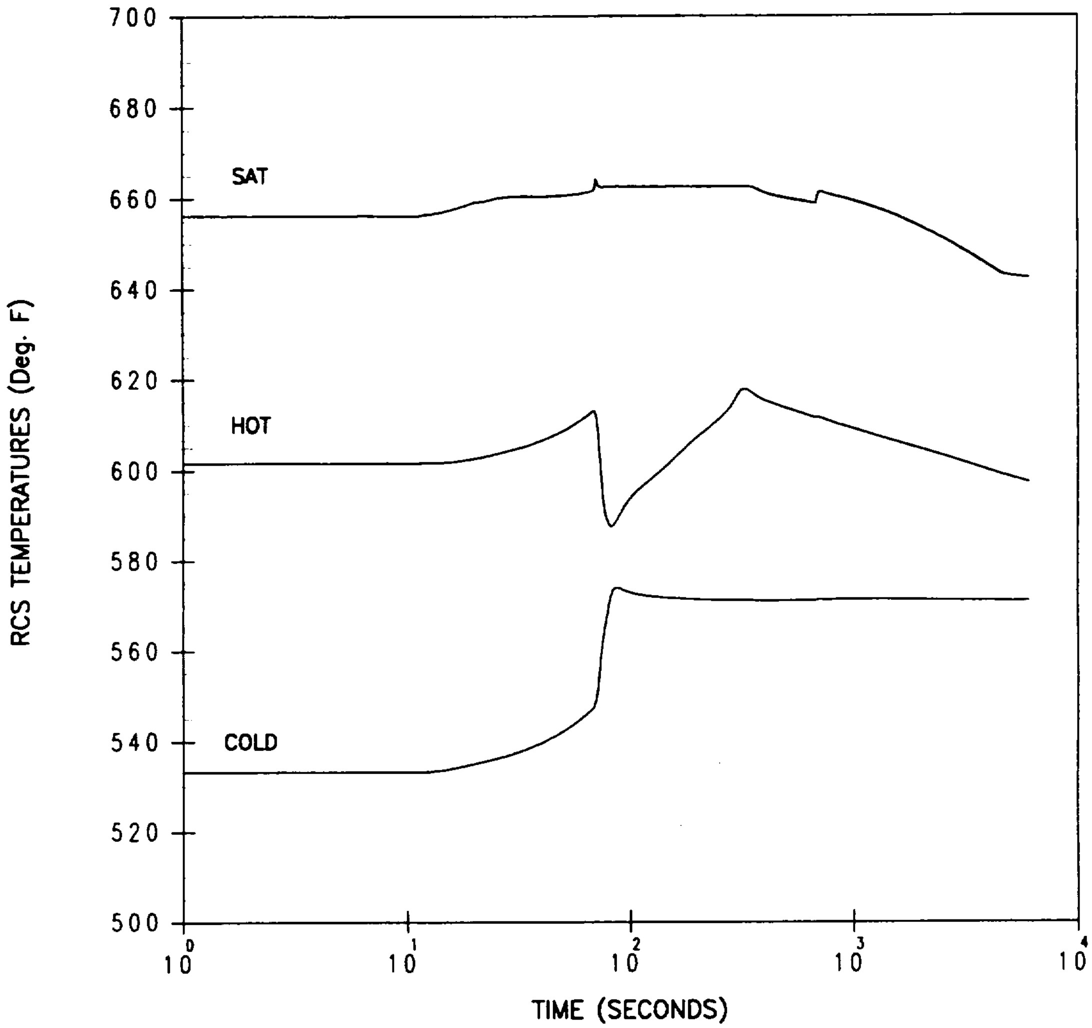


Figure 6.2.7-3

Loss of AC Power to the Plant Auxiliaries

RCS Loop Temperatures versus Time

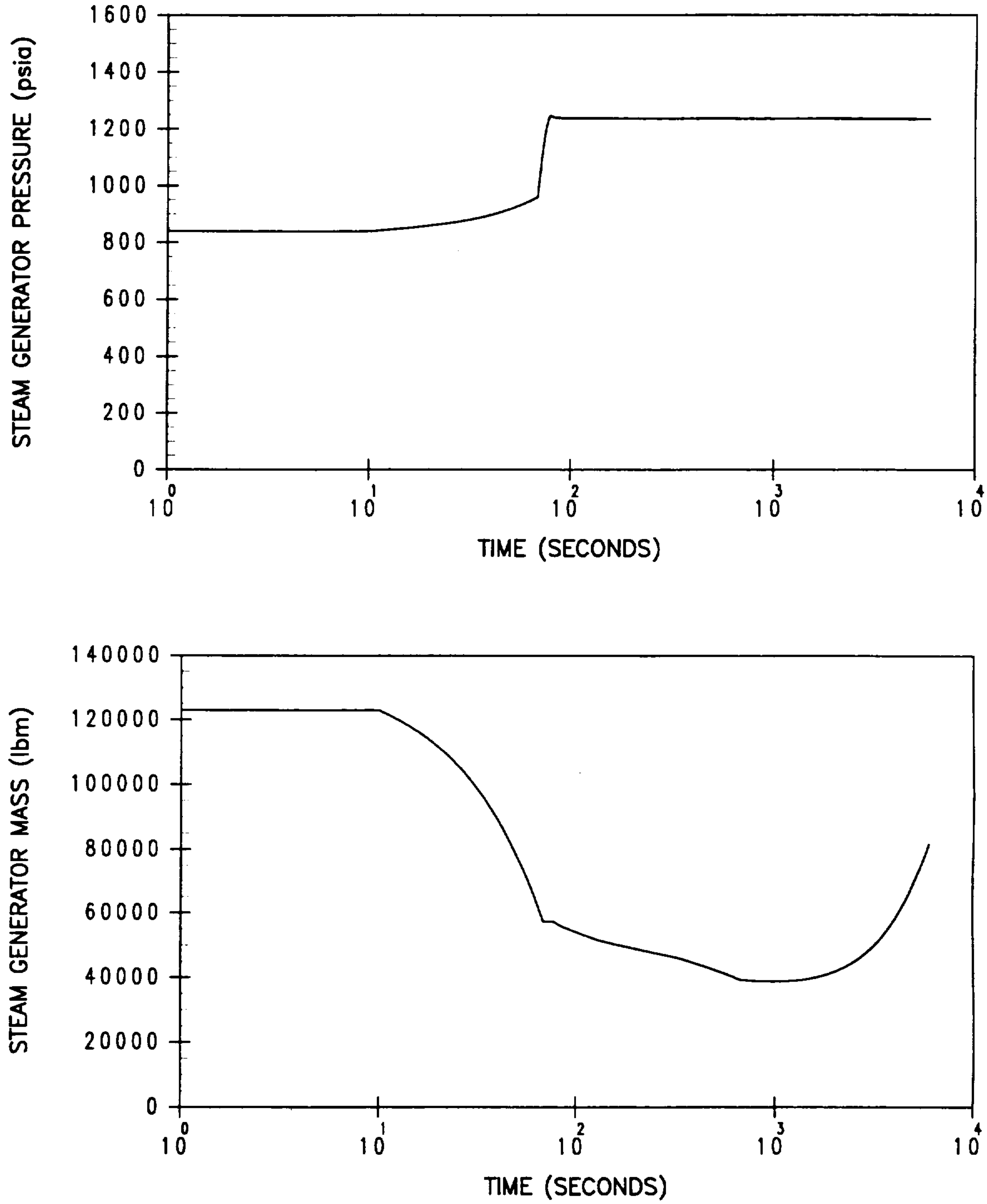


Figure 6.2.7-4

Loss of AC Power to the Plant Auxiliaries

Steam Generator Pressure and Mass versus Time

6.2.8 Loss of Normal Feedwater

6.2.8.1 Introduction

A loss of normal feedwater (from pump failures, valve malfunctions, or loss of offsite AC power) results in a reduction in capability of the secondary system to remove the heat generated in the reactor core. If the reactor were not tripped during this accident, core damage would possibly occur as a result of the loss of heat sink while at power. If an alternative supply of feedwater is not supplied to the plant, residual heat following a reactor trip may heat the primary system water to the point where water relief from the pressurizer could occur. A significant loss of water from the RCS could lead to core uncovery and subsequent core damage. However, since a reactor trip occurs well before the steam generator heat transfer capability is reduced, the primary system conditions never approach those that would result in a DNB condition.

The loss of normal feedwater that occurs as a result of the loss of AC power is discussed in Section 6.2.7.

The following events occur following the reactor trip for the loss of normal feedwater resulting from main feedwater pump failures or valve malfunctions.

a. As the steam system pressure rises following the trip, the steam generator power-operated relief valves are automatically opened. Steam dump to the condenser is assumed not available. If the power-operated relief valves are not available, the steam generator safety valves will lift to dissipate the sensible heat of the fuel and coolant, and the residual decay heat produced in the reactor.

b. As the no-load temperature is approached, the steam generator power-operated relief valves (or the steam generator safety valves, if the power operated relief valves are not available) are used to dissipate the residual heat and to maintain the plant at the hot standby condition.

The following provide the necessary protection against core damage in the event of a loss of normal feedwater.

a. Reactor trip on low-low water level in any steam generator.

b. One motor-driven auxiliary feedwater pump and one diesel-driven auxiliary feedwater pump is started on any of the following:

   1. Low-low water level in any steam generator;

   2. Any safety injection signal;

   3. Loss of offsite power (automatic transfer to diesel generators); or

   4. Manual actuation.

The analysis shows that following a loss of normal feedwater, the AF system is capable of removing the stored and residual heat thus preventing overpressurization of the RCS and the SG secondary side, water relief from the pressurizer, and uncovery of the reactor core.

6.2.8.2 Input Parameters and Assumptions

The analysis is performed for both Unit 1 (with BWI RSGs) and Unit 2 (with D5 SGs) at uprated power conditions.

The major assumptions used in this analysis are as follows:

a. The plant is initially operating at 102% of the NSSS power (3600.6 MWt), which includes a maximum reactor coolant pump heat of 20.0 MWt.

b. The RCPs are assumed to operate continuously throughout the transient providing a constant reactor coolant volumetric flow equal to the Thermal Design Flow.

c. Cases are analyzed assuming initial HFP reactor vessel average coolant temperatures at the upper and lower ends of the. The vessel average temperature assumed at the upper end of the range is 588°F plus an uncertainty of 9.1°F, which includes a bias of

1.5°F. The average temperature assumed at the lower end of the range is 575°F minus an uncertainty of 7.6°F.

d. Initial pressurizer pressure is assumed to be 2250 psia with an uncertainty of ±43 psi. Cases are considered with the pressure uncertainty applied in both the positive and negative direction to conservatively bound the potential operating conditions.

e. Reactor trip occurs on steam generator low-low water level at 10% of narrow range span for the Unit 1 BWI RSGs and 28.6% of narrow range span for the Unit 2 D5 SGs.

f. The worst single failure modeled in the analysis is the loss of the diesel-driven AF pump. This results in the availability of one motor-driven AF pump supplying a minimum total AF flow of 560 gpm, distributed equally among each of the four steam generators.

g. AF flow is assumed to be initiated 55 seconds following a low-low steam generator water level signal.

h. The pressurizer sprays and PORVs are assumed to be operable to maximize the pressurizer water volume. These control systems are not credited for event mitigation since the pressurizer safety valves alone would prevent the RCS pressure from exceeding the RCS design pressure limit during this transient.

i. Secondary system steam relief is achieved through the self-actuated main steam safety valves that are modeled assuming a +4% lift point tolerance.

j. A conservative core residual heat generation based upon long term operation at the initial power level preceding the trip is assumed in the analysis. This core residual heat generation model is based on the 1979 version of ANS 5.1 (Reference 2). ANSI/ANS-5.1-1979 is a conservative representation of the decay energy release rates.

k. A maximum steam generator tube plugging level of 5% for the Unit 1 BWI RSGs and 10% for the Unit 2 D5 SGs is modeled.

I. A maximum AF enthalpy of 91.12 Btu/lbm is conservatively assumed in the analysis. An AF line purge volume of 160 ft^3 for the Unit 1 BWI RSGs and 60 ft^3 for the Unit 2 D5 SGs is modeled.

6.2.8.3 Description of Analysis

A detailed analysis using the LOFTRAN (Reference 1) computer code is performed to determine the plant transient conditions following a loss of normal feedwater. The code models the core neutron kinetics, RCS including natural circulation, pressurizer, pressurizer PORVs and sprays, steam generators, main steam safety valves, and the auxiliary feedwater system, and computes pertinent variables, including pressurizer pressure, pressurizer water level, steam generator mass, and reactor coolant average temperature.

6.2.8.4 Acceptance Criteria

Based on its frequency of occurrence, the loss of normal feedwater accident is considered a Condition II event as defined by the American Nuclear Society. The following items summarize the acceptance criteria associated with this event:

- The critical heat flux shall not be exceeded. This is demonstrated by ensuring that the applicable safety analysis DNBR limit is met.
- Pressure in the reactor coolant and main steam systems shall be maintained below 110% of the design pressures.

With respect to DNB, the loss of normal feedwater accident is bounded by the loss of load accident reported in Section 6.2.6.

6.2.8.5 Results

Analyses were performed for both Unit 1 with BWI RSGs and Unit 2 with D5 SGs at the uprate power conditions. However, for the Loss of Normal Feedwater event, the Unit 2 analysis is more limiting and therefore presented herein.

The calculated sequence of events for this accident is listed in Table 6.2.8-1. Figures 6.2.8-1 through 6.2.8-4 present the transient response of plant conditions and parameters of interest following a loss of normal feedwater with the assumptions listed in Section 6.2.8.2.

Following the reactor and turbine trip from full load, the water level in the steam generators will fall due to reduction of the steam generator void fraction and because steam flow through the safety valves continues to dissipate the stored and generated heat. Approximately one minute following the initiation of the low-low level trip, the motor-driven AF pump automatically starts, consequently reducing the rate at which the steam generator water level decreases.

The capacity of the motor-driven AF pump enables sufficient heat transfer from the four steam generators receiving auxiliary feedwater to dissipate the core residual heat. The water level in the pressurizer (see Figure 6.2.8-1) never reaches a water-solid condition. Hence, no water relief from the pressurizer occurs. The peak RCS and secondary-side pressures remain below the applicable design limits throughout the transient.

Since the plant is tripped well before the steam generator heat transfer capability is reduced, the primary system variables never approach a DNB condition.

6.2.8.6 Conclusions

With respect to DNB, the loss of normal feedwater accident is bounded by the loss of load accident, which demonstrates that the minimum DNBR is greater than the safety analysis limit value.

The results of the analysis show that the pressurizer does not reach a water-solid condition and that the applicable RCS and secondary-side pressure limits are met. Therefore, the loss of normal feedwater event does not adversely affect the core, RCS, or main steam system.

6.2.8.7 References

1. Burnett, T. W. T., et al, "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary), WCAP-7907-A (Non-Proprietary), April 1984.

2. ANSI/ANS-5.1 - 1979, "American National Standard for Decay Heat Power in Light Water Reactors," August 1979.

Table 6.2.8-1

Time Sequence of Events for Loss of Normal Feedwater Flow

Event	Time (seconds)
Loss of main feedwater occurs	10
Low-low steam generator water level reactor trip setpoint reached	47.2
Rods begin to drop	49.2
AF flow from one motor-driven AF pump is initiated	102.2
Feedwater lines are purged and cold AF is delivered to four steam generators	298.0
Total of core decay and RCP heat decreases to AF heat removal capacity	~ 1950.0
Peak water level in pressurizer occurs	2044.0

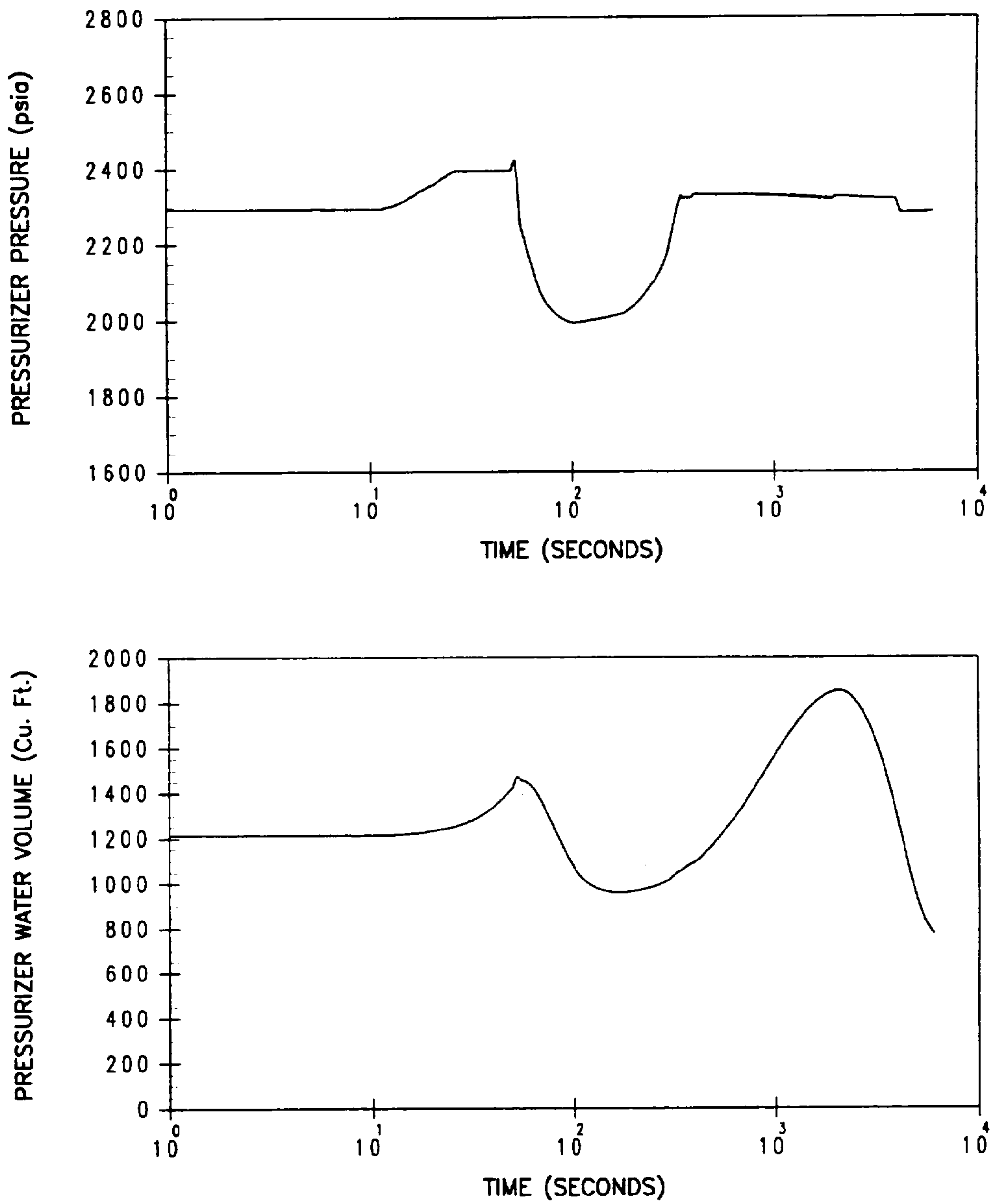


Figure 6.2.8-1

Loss of Normal Feedwater

Pressurizer Pressure and Water Volume versus Time

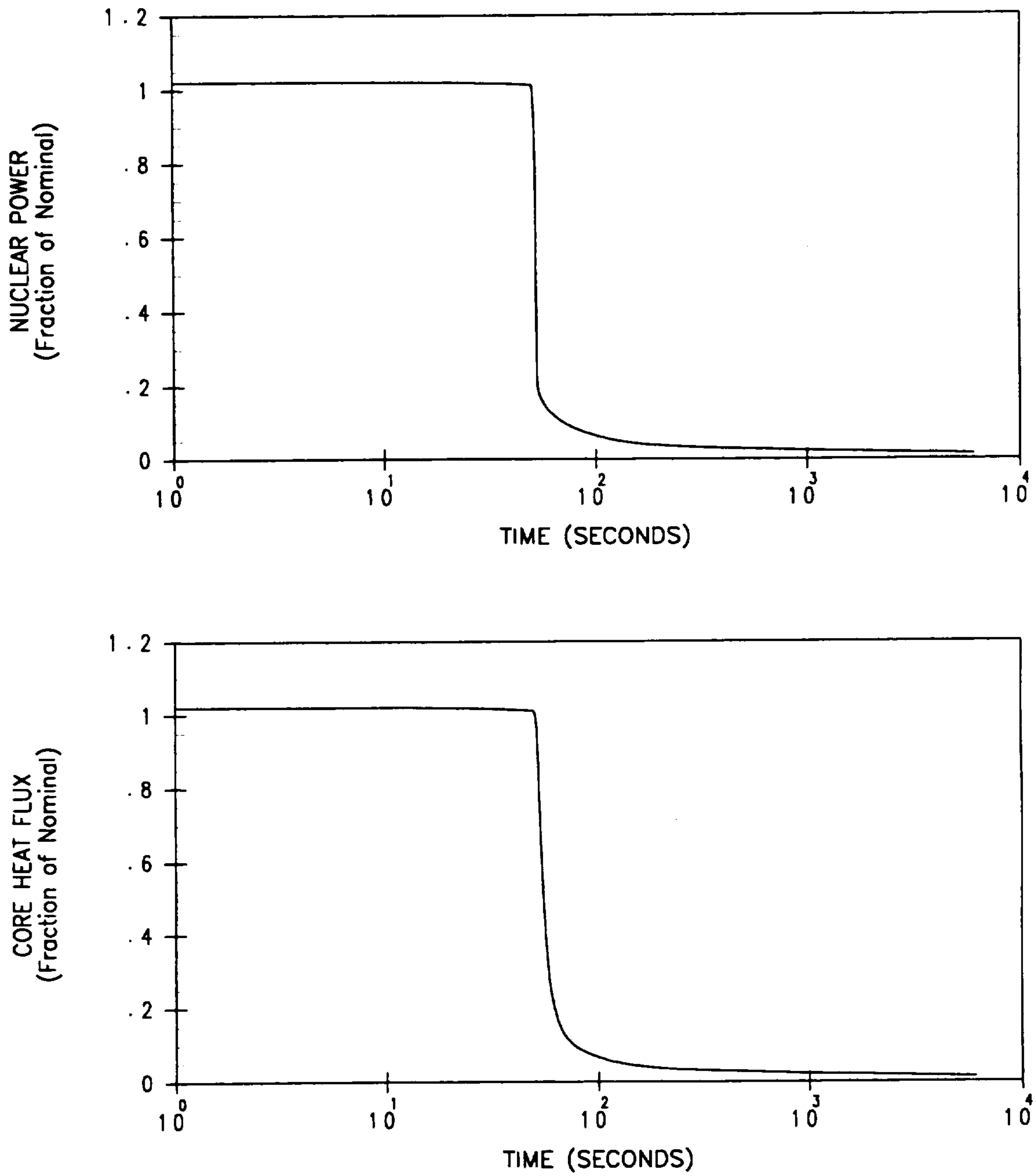


Figure 6.2.8-2

Loss of Normal Feedwater

Nuclear Power and Core Heat Flux versus Time

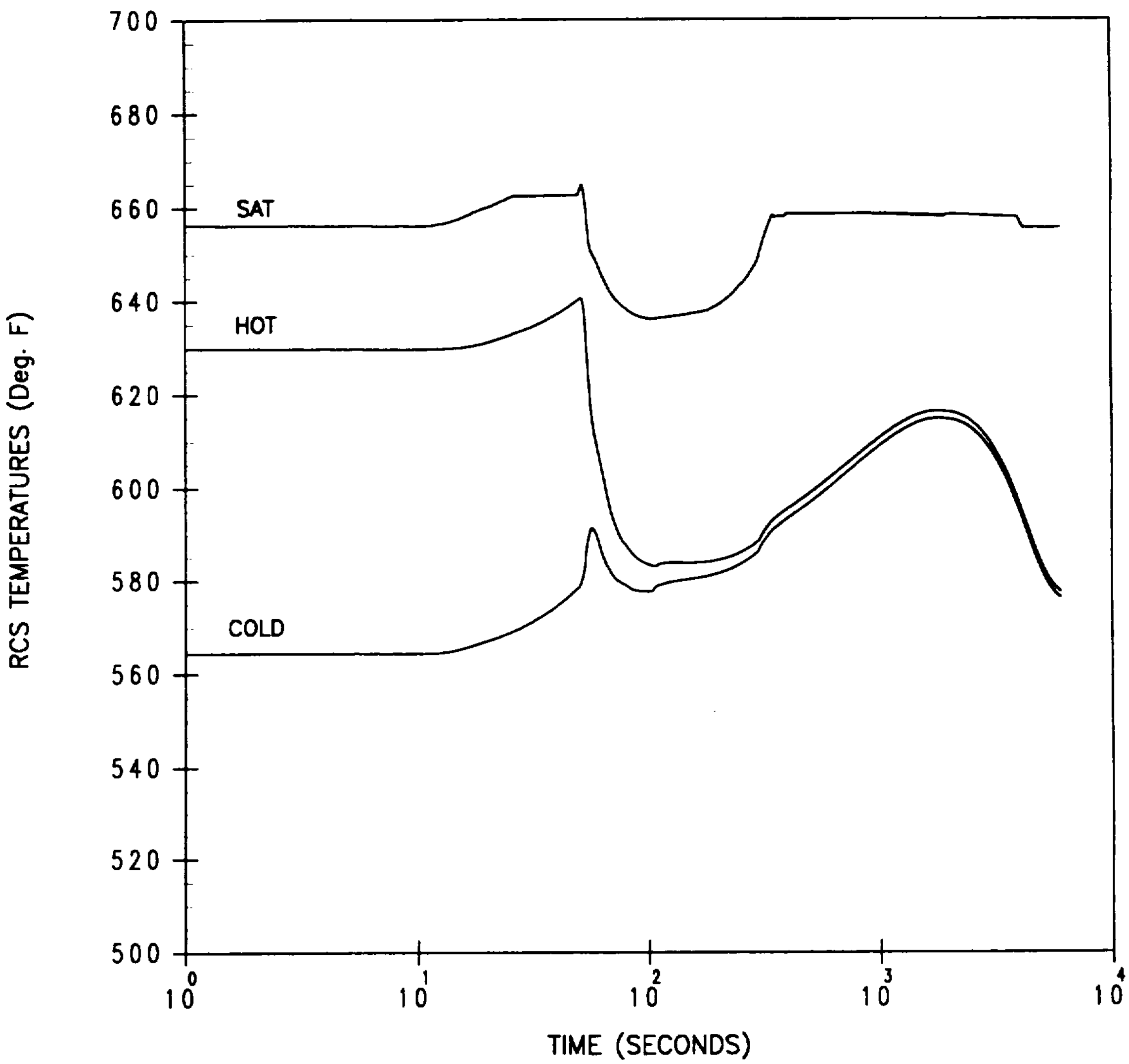
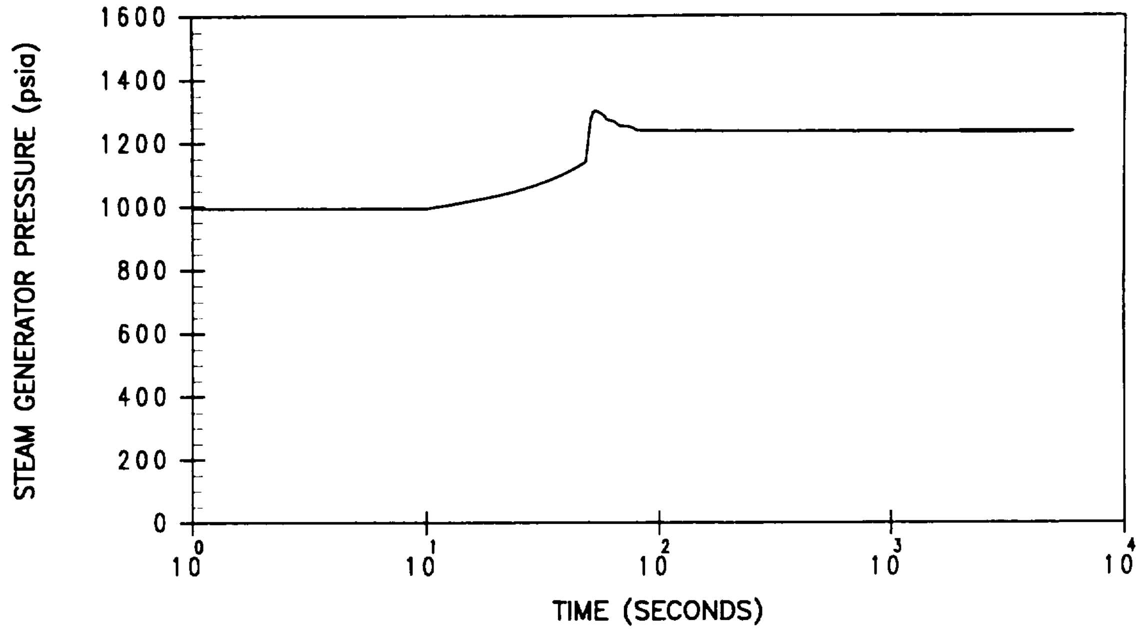


Figure 6.2.8-3

Loss of Normal Feedwater

RCS Loop Temperatures versus Time



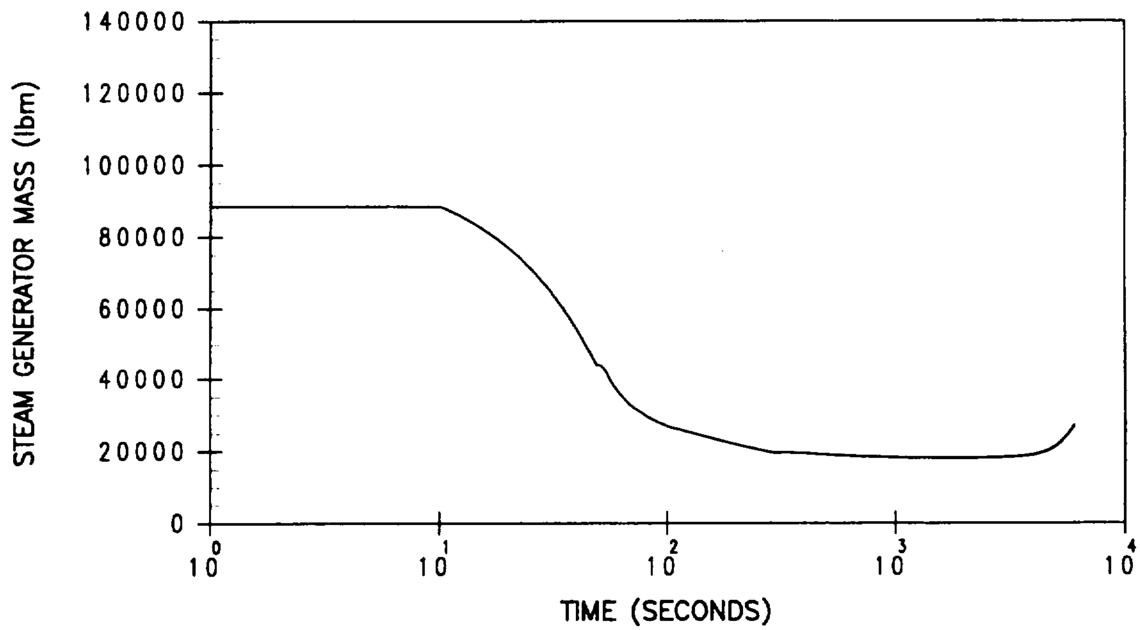


Figure 6.2.8-4

Loss of Normal Feedwater

Steam Generator Pressure and Mass versus Time

6.2.9 Major Rupture of a Main Feedwater Pipe

6.2.9.1 Introduction

A major feedwater line rupture is defined as a break in a feedwater pipe large enough to prevent addition of sufficient feedwater to the steam generators to maintain shell-side fluid inventory. If the break is postulated in a feedline between the check valve and the steam generator, fluid from the steam generator may also be discharged through the break. Further, a break in this location could preclude subsequent addition of auxiliary feedwater to the affected steam generator. A break upstream of the feedline check valve would affect the NSSS only as a loss of feedwater. This case is covered by the evaluation in Section 6.2.8.

Depending upon the size of the break and the plant operating conditions at the time of the break, the break could cause either an RCS cooldown (by excessive energy discharge through the break) or an RCS heatup. The potential RCS cooldown resulting from a secondary-side pipe break (i.e., a steamline rupture) is evaluated in Section 6.2.4 and 6.2.5. Steam blowdown through a rupture of a main steamline will result in a more excessive cooldown than water blowdown through a rupture in the main feedline. Therefore, only the RCS heatup effects are evaluated for a feedline break.

A feedwater line break reduces the ability of the steam generators to remove heat from the RCS for the following reasons:

a. Feedwater flow to the steam generators is reduced. Since feedwater is subcooled, its loss may cause reactor coolant temperature to increase prior to reactor trip.

b. Fluid in the steam generator may be discharged through the break, and would then not be available for decay heat removal after trip.

c. The break may be large enough to prevent the addition of any main feedwater to the steam generators.

An auxiliary feedwater system is provided to assure that adequate feedwater will be available such that:

a. No substantial overpressurization of the RCS shall occur.

b. Sufficient liquid inventory shall be maintained in the RCS to provide adequate decay heat removal.

The severity of the feedwater line break transient depends on a number of system parameters including break size, initial reactor power, and operation of various control and safety systems. A number of feedwater line break cases have been analyzed. These analyses show that the most limiting feedwater line breaks are double-ended breaks of the largest feedwater line, occurring at full power with and without loss of offsite power. These cases are discussed below.

The following provide the necessary protection for a main feedwater line break:

1. A reactor trip on any of the following conditions:

    a. High pressurizer pressure

    b. Overtemperature ΔT

    c. Low-low steam generator water level in any loop,

    d. Safety injection signals from any of the following:

        i.) 2/3 low steamline pressure in any loop.

        ii.) 2/3 high containment pressure.

2. An auxiliary feedwater system to provide an assured source of feedwater to the steam generators for decay heat removal.

Receipt of a low-low steam generator water level signal in any loop starts the motor-driven and diesel-driven auxiliary feedwater pumps, which then deliver auxiliary feedwater to the steam generators. Similarly, receipt of a low steamline pressure signal in any loop initiates a steamline isolation signal that closes all main steam isolation valves. This signal also gives a safety injection signal, which initiates flow of borated water into the RCS. The amount of safety injection is a function of RCS pressure.

6.2.9.2 Input Parameters and Assumptions

The primary assumptions for the major feedwater rupture analysis are as follows. These inputs are consisent with the Unit 2 analysis, which has been determined to be substantially limiting compared to Unit 1. Only Unit 2 results are presented here.

a. The plant is initially operating at 102% of the uprated NSSS power (3600.6 MWt).

b. Initial coolant average temperature is assumed to be 597.1°F, which is 9.1°F (7.6°F uncertainty plus 1.5°F bias) above the nominal high T_{avg} program value of 588.0°F. The initial pressurizer pressure is 43 psi below its nominal value.

c. No credit is taken for pressurizer spray or the high pressurizer pressure reactor trip. However, to ensure that sufficient decay heat removal capability is maintained, the analysis assumes operation of the pressurizer power operated relief valves to minimize RCS pressure (i.e., T_{sat}).

d. Initial pressurizer level is assumed to be the nominal programmed value. The initial steam generator water level is assumed to be the nominal value plus 5% narrow range span (NRS) in the faulted steam generator and the nominal level minus 5% NRS in the intact steam generators.

e. Main feedwater to all steam generators is assumed to stop at the time the break occurs (i.e., all main feedwater spills).

f. A maximum double-ended break area of 0.223 ft2 is modeled in the Unit 2 analysis. These break flow areas correspond to the flow area of the respective steam generator flow orifices in the feedwater inlet nozzle.

g. Steam generator heat transfer area is assumed to decrease as the shell-side liquid inventory decreases.

h. Conservative core residual heat generation is assumed based upon long term operation at the initial power level preceding the trip (Reference 1).

i. A conservative feedline break discharge quality is assumed prior to reactor trip, thereby maximizing the time until the trip setpoint is reached. After the trip occurs, a saturated liquid discharge (no steam) is assumed from the faulted steam generator through the feedline rupture. This minimizes the heat removal capability of the faulted steam generator.

j. Reactor trip is modeled to occur when the steam generator water level reaches the low-low setpoint of 18.6% NRS in the faulted steam generator.

k. The auxiliary feedwater (AF) system is actuated by the low-low steam generator water level signal. The AF System is assumed to supply a minimum constant flow of 151 gpm per steam generator to each of the three intact steam generators at all pressures. This is consistent with the AF System control valves functioning as designed.

   Since these control valves are not safety related, the case in which the valves fail (open) is also considered in the analysis. For this case, more AF flow may be diverted out the break via the faulted loop. However, more flow is also provided to the intact steam generators at lower pressures. The analysis of this case credits operator action to isolate AF flow to the faulted steam generator (and break) after 20 minutes. This case is found to be less limiting than the case assuming operation of the control valves.

l. For the case with offsite power available, a 55-second delay is assumed after reaching the low-low steam generator water level reactor trip setpoint to allow time for sensor response, signal processing, and startup of the AF pumps. For the case where offsite power is lost, the delay time after reaching the low-low steam generator water level reactor trip setpoint is assumed to be 63 seconds to include startup of the emergency diesel generators. An additional 181 seconds is assumed before the feedwater lines are purged and the relatively cold (120°F) auxiliary feedwater entered the intact steam generators.

m. Credit is taken for heat energy deposited in a portion of the reactor coolant system metal during the reactor coolant system heatup.

n. For the case that assumes no offsite power, the loss of offsite electrical power is assumed to occur after the reactor trip, and reactor coolant flow decreases to natural circulation.

o. No credit is taken for charging and letdown.

p. No credit is taken for the following potential protection signals to mitigate the consequences of the accident:

1. High pressurizer pressure,
2. Overtemperature ΔT,
3. High pressurizer level, and
4. High containment pressure.

q. To account for potential variations associated with steam generator tube plugging, analysis considers a maximum loop-to-loop flow variation of 7% and a maximum tube plugging level of 10% in any steam generator.

r. Pressurizer heaters are modeled since operation of the heaters slightly reduces the margin to the acceptance criterion.

The only reactor control systems assumed to function are the pressurizer power-operated relief valves and the pressurizer heaters. The reactor protection system is required to function following a feedwater line break as analyzed here. No single active failure will prevent operation of this system.

The engineered safety systems assumed to function are safety injection (SI) and auxiliary feedwater (AF). One train of SI has been assumed available. For the AF system, the worst-case configuration is assumed, i.e., three intact steam generators receive AF following the break. One auxiliary feedwater pump is also assumed to fail. The other auxiliary feedwater pump is assumed to deliver flow to each intact steam generators with the AF control valves operating properly.

Following the trip of the reactor coolant pumps for the feedline break with a loss of offsite power, RCS flow coastdown occurs until flow in the loops reaches a natural circulation condition.

6.2.9.3 Description of Analysis

The transient response following a feedwater pipe rupture event is calculated by a detailed digital simulation of the plant. The analysis models a simultaneous loss of main feedwater to all steam generators and subsequent reverse blowdown of the faulted steam generator. The analysis is performed using the LOFTRAN code (Reference 2). The code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer heaters, steam generators, and main steam safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level.

6.2.9.4 Acceptance Criteria

The feedline rupture accident is an ANS Condition IV occurrence. Condition IV events are faults that are not expected to occur, but are postulated because their consequences would include the potential for release of significant amounts of radioactive material.

The Standard Review Plan (Rev. 1) requires that the specific criteria used in evaluating the consequences of the feedline rupture shall be:

1. Pressure in the reactor coolant and main steam systems should be maintained below 110% of the design pressures;

2. Any fuel damage that may occur during the transient should be limited such that the core remains in place and geometrically intact, with no loss of core cooling capability; and

3. Any activity release must be such that the calculated doses at the site boundary are within a small fraction of the guidelines of 10 CFR Part 100.

Although the maximum pressures are reported, the reactor coolant and main steam systems pressure transients for a feedline rupture event are bounded by the Loss of Load/Turbine Trip event, as analyzed in Section 6.2.6, in which assumptions are made to conservatively calculate the RCS and MSS pressure transient. The assumptions made for the feedline break transient are made to conservatively calculate the minimum margin to hot leg saturation. To conservatively assure meeting this criterion, the internal criterion established within

Westinghouse is that no bulk boiling occurs in the primary coolant system following a feedline rupture prior to the time that the heat removal capability of the steam generators, being fed auxiliary feedwater, exceeds NSSS residual heat generation.

6.2.9.5 Results

The results presented herein are for the more limiting Unit 2 with Westinghouse Model D5 preheat steam generators and are not representative for Unit 1 with BWI replacement steam generators. As described in Section 6.2.9.1, only the RCS heatup effects following a feedline break are evaluated for this analysis since the potential RCS cooldown effects are bounded by the steamline break events evaluated in Section 6.2.4 and 6.2.5. The initial cooldown that occurs following a Unit 1 feedline break event is significantly larger than that for a Unit 2 feedline break. This is due to the large difference in steam generator inventory and differences in main feedwater system design between the larger Unit 1 feedring type steam generators and the smaller Unit 2 preheat steam generators. For both steam generator designs, the cooldown portion of the event is bounded by the steamline break event, as analyzed in Sections 6.2.4 and 6.2.5. The results of the heatup portion of the feedline break show that the Unit 2 analysis is more limiting than the Unit 1 analysis with respect to margin to hot leg saturation. Therefore, only the more limiting Unit 2 results are presented herein.

Calculated plant parameters following a major feedwater line break analyzed to maximize the potential for losing RCS inventory are shown in Figures 6.2.9-1 through 6.2.9-8. Results for the case with offsite power available are presented in Figures 6.2.9-1 through 6.2.9-4. Results for the case where offsite power is lost are presented in Figures 6.2.9-5 through 6.2.9-8. The calculated sequence of events for both cases analyzed are listed in Table 6.2.9-1.

For the cases analyzed, RCS pressure is maintained at the power-operated relief valve setpoint until the operator terminates safety injection flow. However, the reactor core remains covered with water throughout the transient, as water relief due to thermal expansion is limited by the heat removal capability of the auxiliary feedwater system and makeup is provided by the safety injection system.

The major difference in the two cases can be seen in the figures of hot and cold leg temperatures, Figure 6.2.9-3 (with offsite power available) and Figure 6.2.9-7 (without offsite power). The case with offsite power results in a more severe rise in temperature. The pressurizer fills for the case with power due to the increased coolant expansion resulting from the reactor coolant pump heat addition, hence water is relieved for the case with power. As previously stated, however, the core remains covered with water for both cases.

6.2.9.6 Conclusions

Results of this analysis show that the assumed AF system capacity is adequate to remove core decay heat and to prevent uncovering the reactor core for the postulated feedline rupture at the uprated power conditions.

6.2.9.7 References

1. ANSI/ANS-5.1-1979, "American National Standard for Decay Heat Power in Light Water Reactors," August 29, 1979

2. Burnett, T.W.T et al., "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary), WCAP-7907-A (Non-proprietary), April 1984

Table 6.2.9-1 Sequence of Events – Feedwater System Pipe Break Events		
Case	**EVENT**	**Time (Sec)**
Main Feedline Break with offsite power available	Main feedline break occurs	10
	Low-low steam generator water level setpoint reached in faulted loop	32
	Rods begin to drop	34
	One motor-driven AF pump starts and supplies auxiliary feedwater to three intact steam generators	87
	Low steamline pressure setpoint reached in faulted loop	204
	All main steamline isolation valves close	212
	Cold auxiliary feedwater reaches intact steam generators	268
	Main steam safety valve set pressure reached in intact steam generators	510
	Pressurizer water relief begins	1234
	Core decay heat and pump heat decrease to auxiliary feedwater heat removal capacity	~4900
Main Feedline Break with loss of offsite power	Main feedline break occurs	10
	Low-low steam generator water level setpoint reached in faulted loop	32
	Rods begin to drop	34
	One motor-driven AF pump starts and supplies auxiliary feedwater to three intact steam generators	95
	Low steamline pressure setpoint reached in faulted loop	256
	All main steamline isolation valves close	264
	Cold auxiliary feedwater reaches intact steam generators	276
	Main steam safety valve set pressure reached in intact steam generators	795
	Core decay heat and pump heat decrease to auxiliary feedwater heat removal capacity	~1800

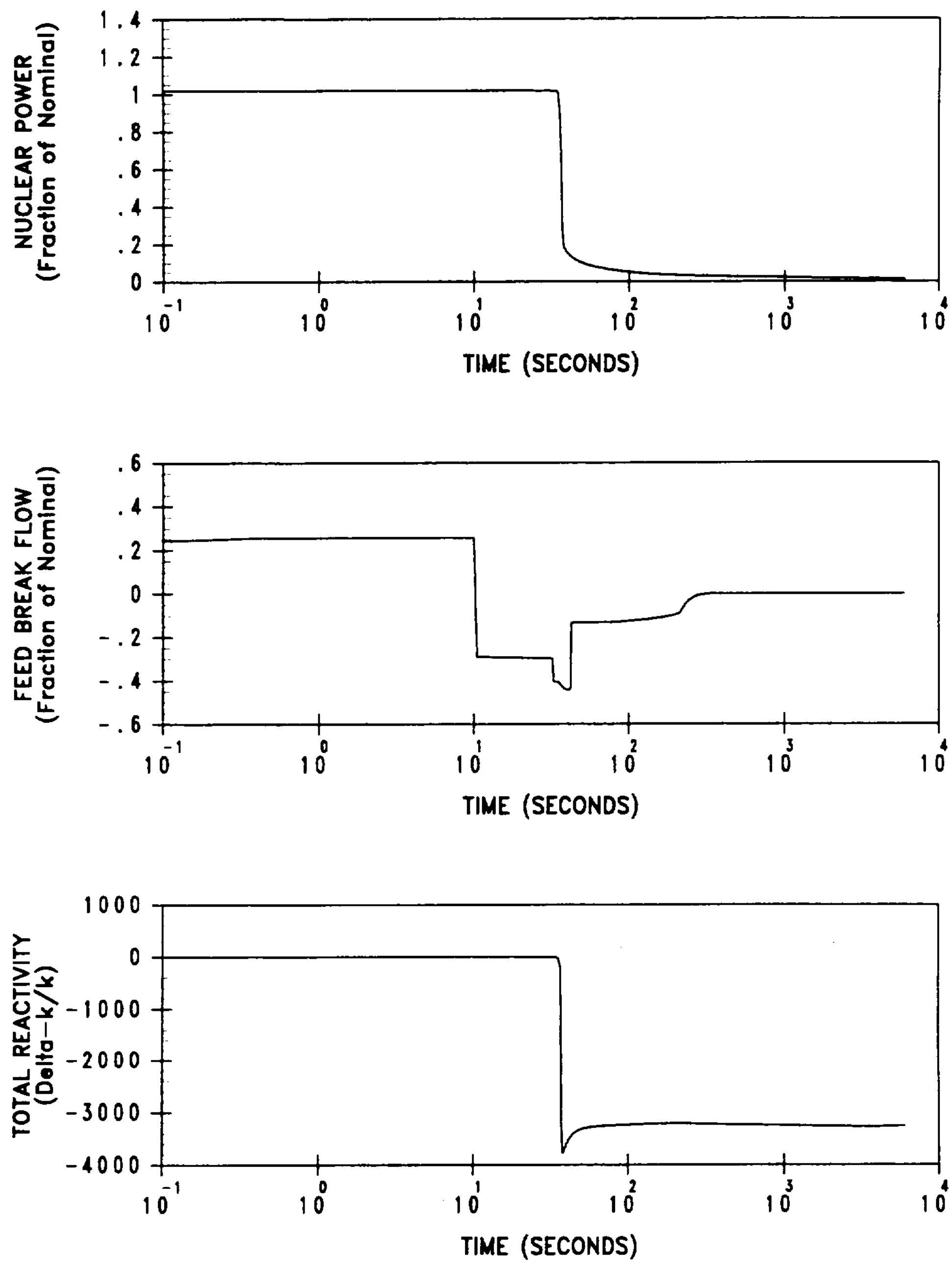


Figure 6.2.9-1: Nuclear Power, Total Core Reactivity and Feedline Break Flow Transients for Main Feedline Break with Offsite Power Available

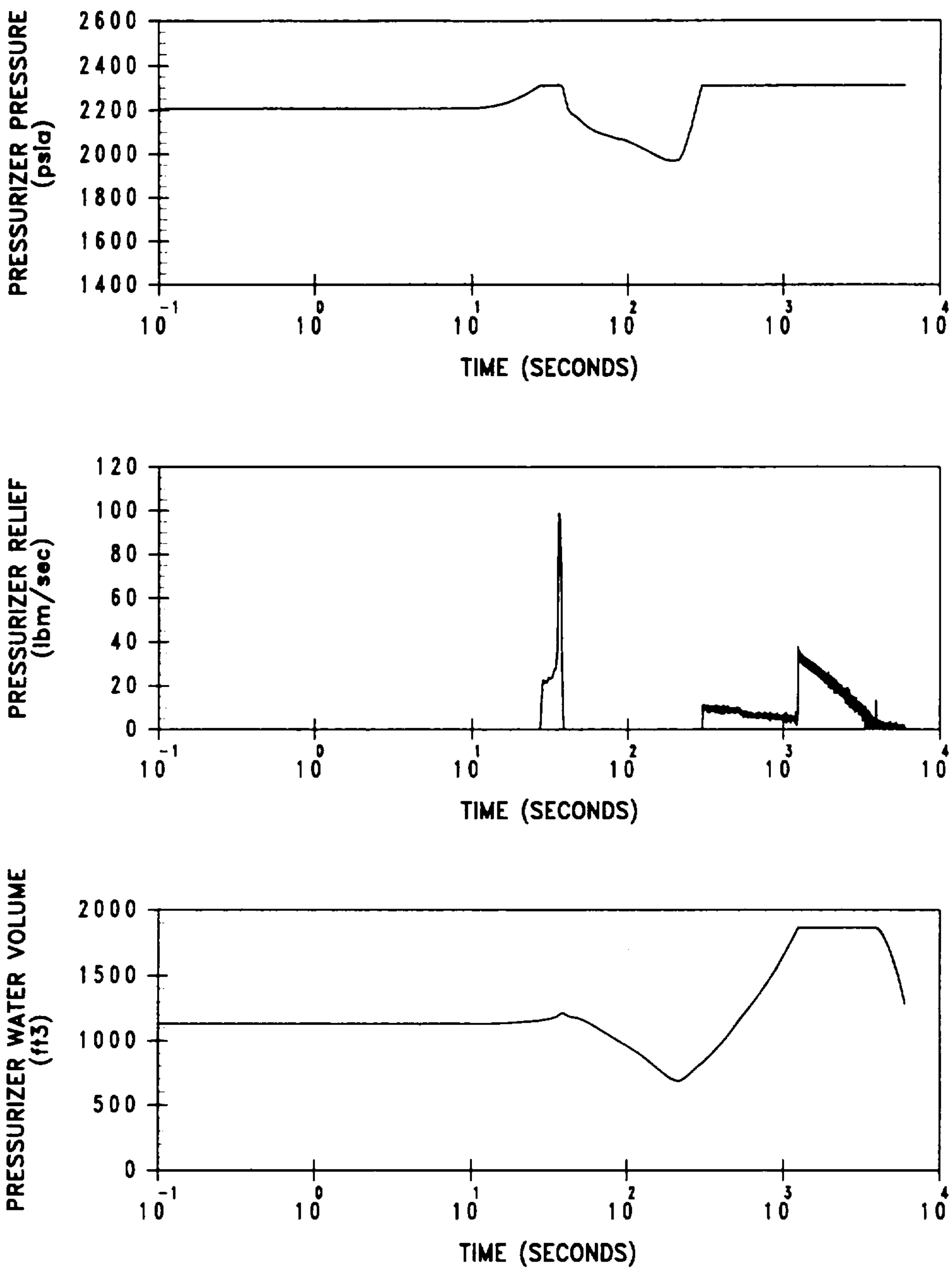


Figure 6.2.9-2: Pressurizer Pressure, Pressurizer Relief and Pressurizer Water Volume Transients for Main Feedline Break with Offsite Power Available

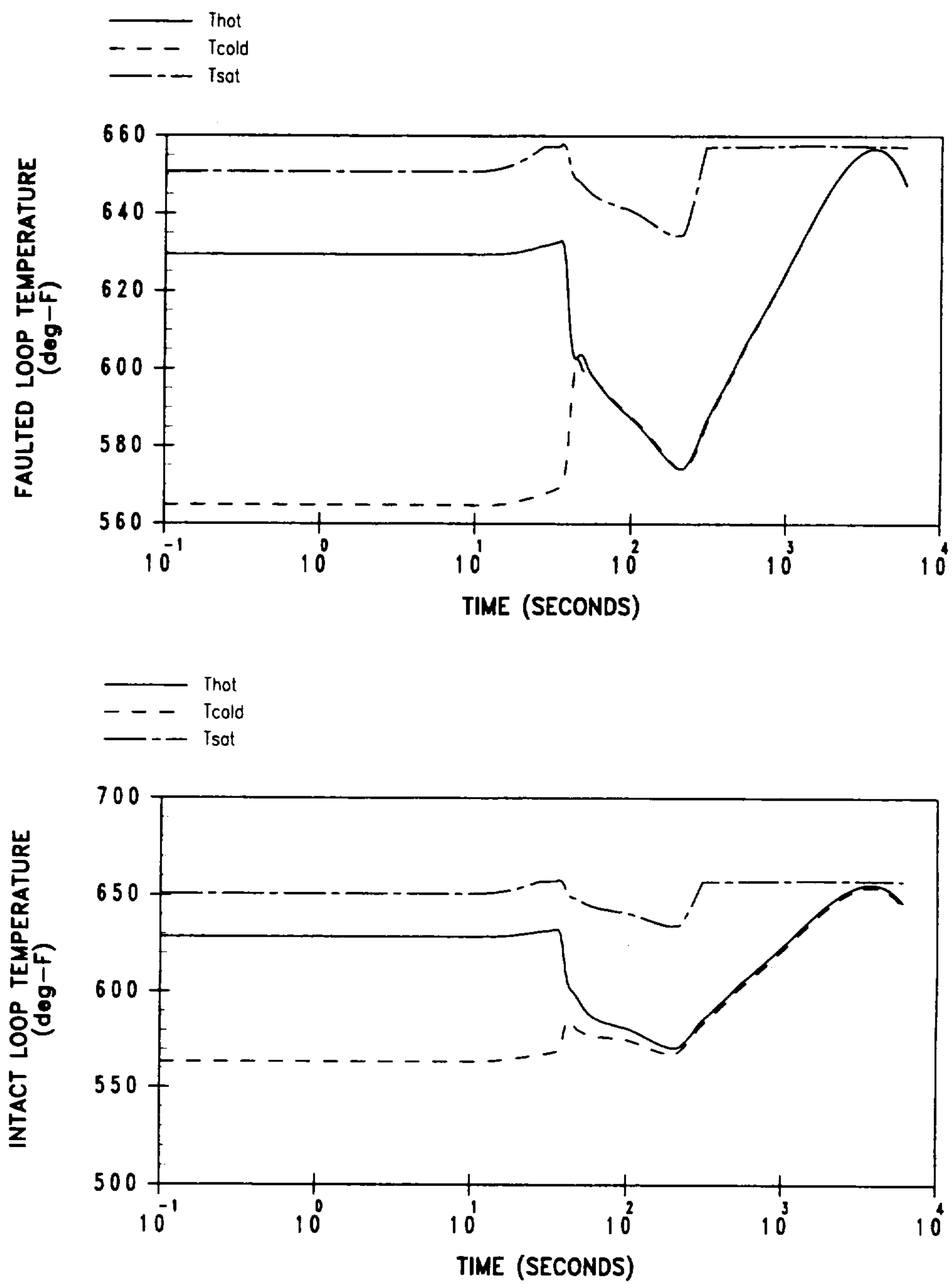


Figure 6.2.9-3: Faulted and Intact Loop Coolant Temperature Transients for Main Feedline Break with Offsite Power Available

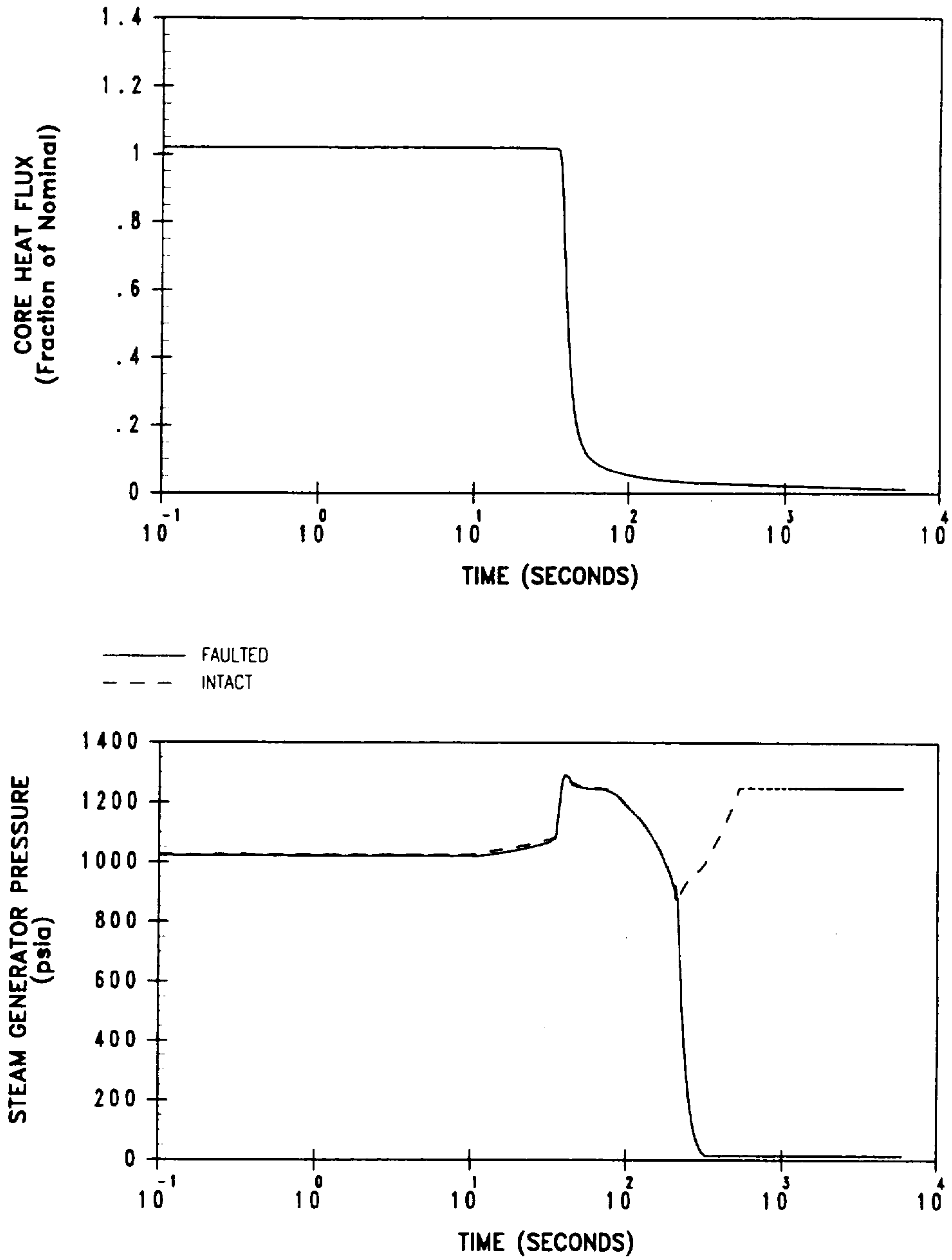


Figure 6.2.9-4: Core Heat Flux and Steam Generator Pressure Transients for Main Feedline Break with Offsite Power Available

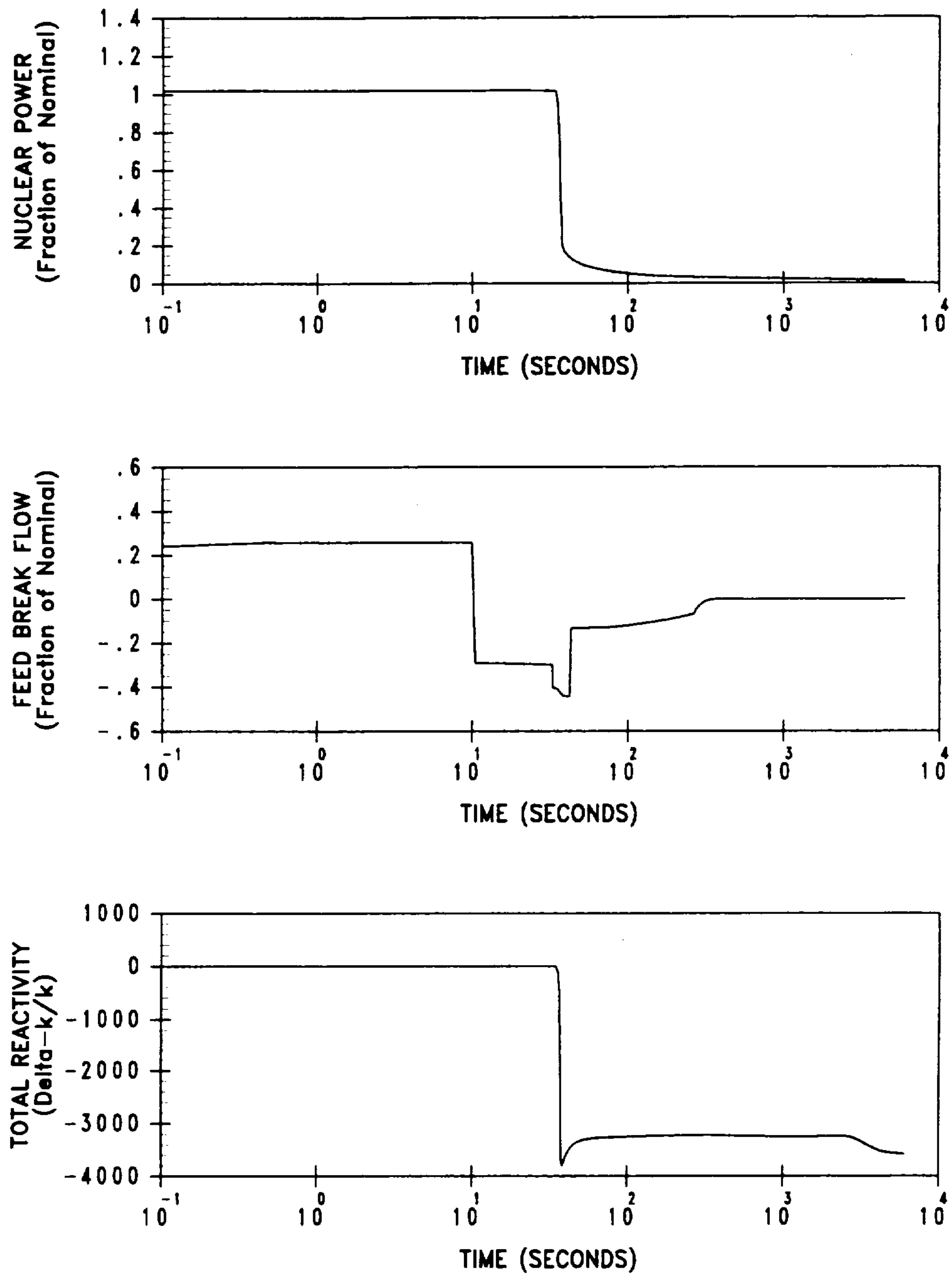


Figure 6.2.9-5: Nuclear Power, Total Core Reactivity and Feedline Break Flow Transients for Main Feedline Break without Offsite Power Available

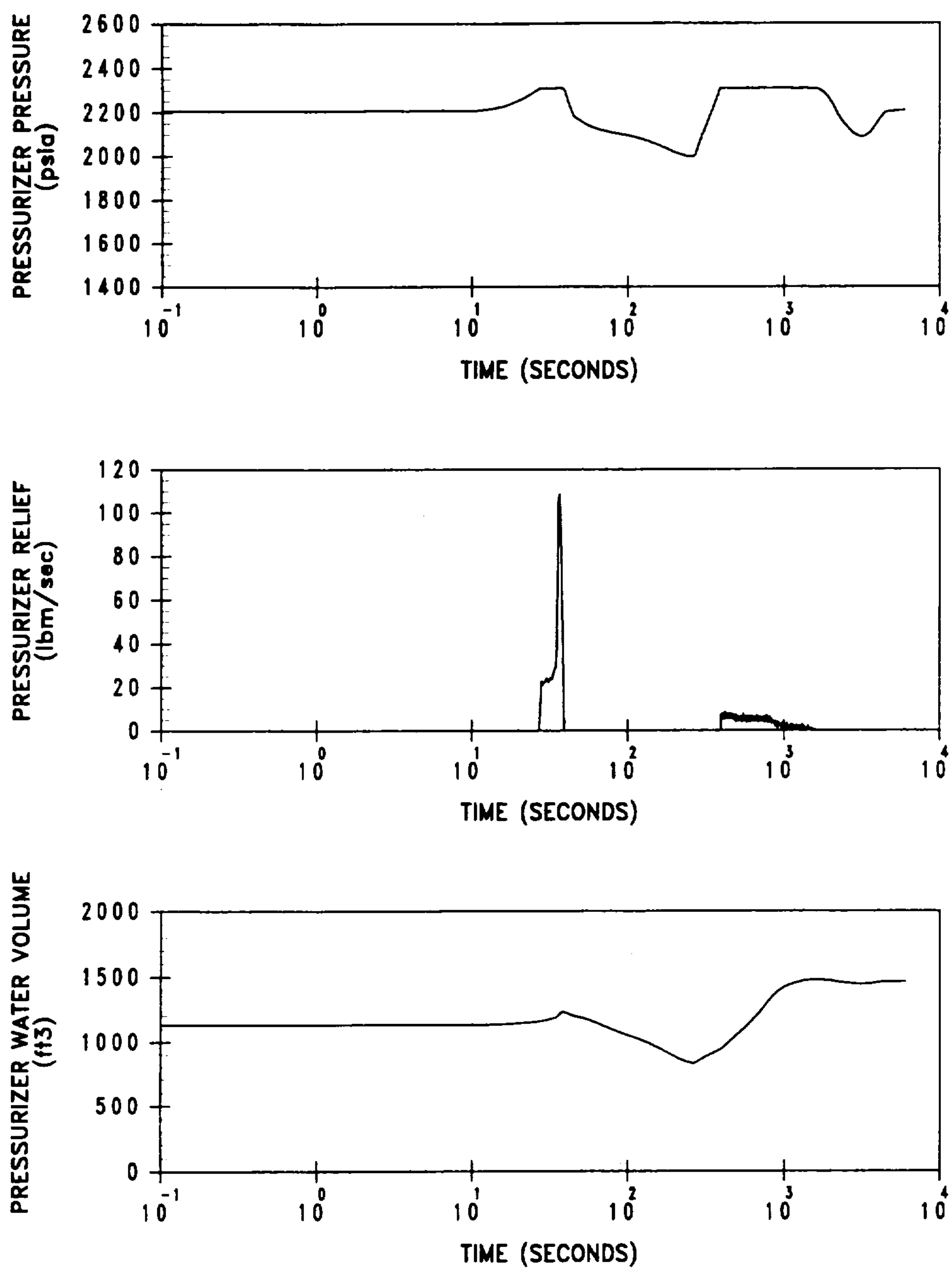


Figure 6.2.9-6: Pressurizer Pressure, Pressurizer Relief and Pressurizer Water Volume Transients for Main Feedline Break without Offsite Power Available

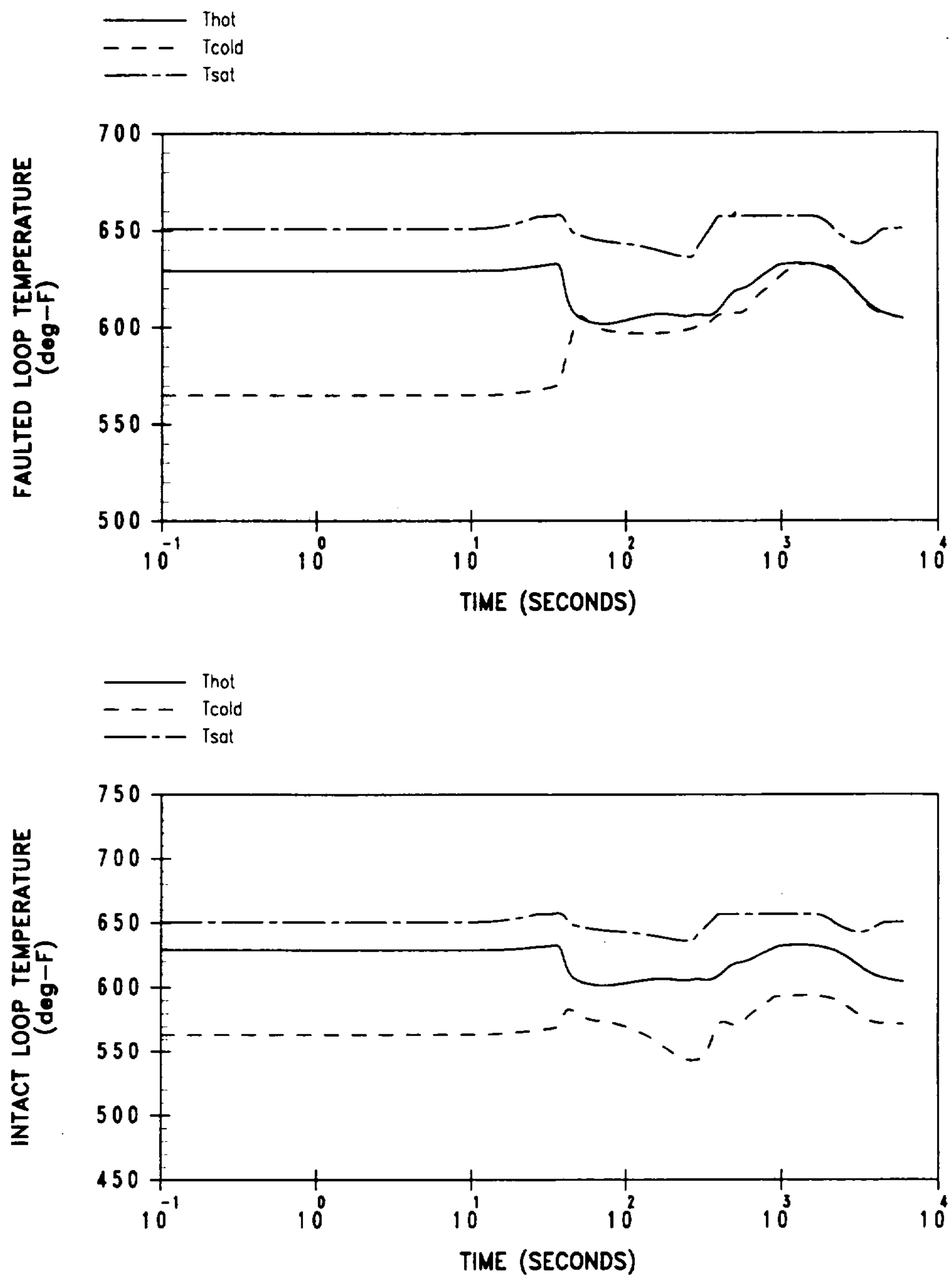


Figure 6.2.9-7: Faulted and Intact Loop Coolant Temperature Transients for Main Feedline Break without Offsite Power Available

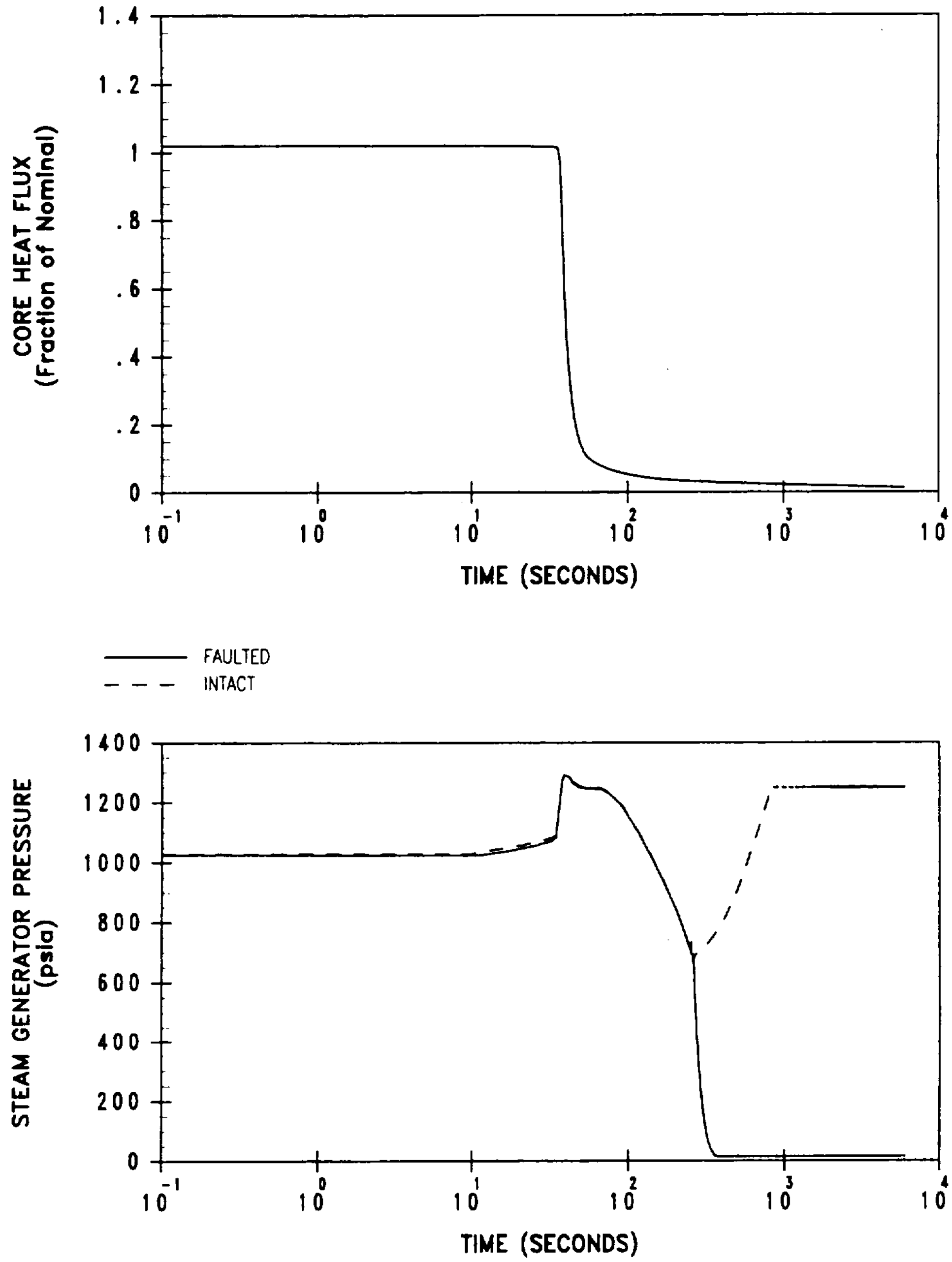


Figure 6.2.9-8: Core Heat Flux and Steam Generator Pressure Transients for Main Feedline Break without Offsite Power Available

6.2.10 Partial Loss of Forced Reactor Coolant Flow

6.2.10.1 Introduction

A partial loss of forced reactor coolant flow accident may result from a mechanical or electrical failure in a reactor coolant pump (RCP), or from a fault in the power supply to these pumps. If the reactor is at power at the time of the event, the immediate effect is a rapid increase in coolant temperature. This increase in coolant temperature could result in departure from nucleate boiling (DNB), with subsequent fuel damage, if the reactor is not promptly tripped.

The following signals provide protection against a partial loss of forced reactor coolant flow incident:

- Low primary coolant flow;
- RCP circuit breakers opening will actuate the corresponding undervoltage relays.

The reactor trip on low primary coolant flow provides protection against loss of flow conditions. This function is generated by two-out-of-three low flow signals per reactor coolant loop. Above Permissive P-8, low flow in any loop will actuate a reactor trip. Between approximately 10 percent power (Permissive P-7) and the power level corresponding to Permissive P-8, low flow in any two loops will actuate a reactor trip. Reactor trip on low flow is blocked below Permissive P-7. A reactor trip signal from the pump breaker position is provided as a backup to the low flow signal. When operating above Permissive 7, a breaker open signal from any two pumps will actuate a reactor trip. Reactor trip on reactor coolant pump breakers open signal is blocked below Permissive 7.

6.2.10.2 Input Parameters and Assumptions

This accident is analyzed using the Revised Thermal Design Procedure (Reference 1). Initial core power (consistent with uprated power conditions) and reactor coolant pressure are assumed to be at their nominal values for steady-state, full-power operation. Reactor coolant temperature is assumed to be at the nominal value for the High T_{avg} Program plus a 1.5°F bias. Uncertainties in initial conditions are included in the departure from nucleate boiling ratio (DNBR) limit as described in Reference 1. The analysis also considers a maximum Reactor Coolant System (RCS) loop-to-loop flow asymmetry of 7%.

The analysis is performed assuming a moderator temperature coefficient (MTC) of 0 pcm/°F and a conservatively large (absolute value) Doppler-only power coefficient. The use of a 0 pcm/°F MTC is consistent with the analysis initial condition assumptions and corresponds to the applicable MTC limit at hot full power (HFP). The HFP analysis results using a 0°pcm/°F MTC bound those for part-power initial conditions with a positive MTC at the licensed allowable MTC limit. The negative reactivity from control rod insertion/scram is conservatively based on 4.0% Δk trip reactivity from HFP.

Normal reactor control systems and engineered safety systems (e.g., Safety Injection) are not required to function. No single active failure in any system or component required for mitigation will adversely affect the consequences of this event.

6.2.10.3 Description of Analysis

A partial loss of flow involving the loss of two reactor coolant pumps with four loops in operation was analyzed to confirm that the conclusions in the UFSAR (Reference 2) remain valid for the plant uprate.

The transient was analyzed using three digital computer codes. First, the LOFTRAN code (Reference 3) was used to calculate the loop and core flow transients, nuclear power transient, and primary system pressure and temperature transients. This code simulates a multi-loop system, neutron kinetics, the pressurizer, pressurizer relief and safety valves, pressurizer spray, the steam generators, and main steam safety valves. The flow coastdown analysis performed by LOFTRAN 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 as-built pump characteristics, and is based on conservative system pressure loss estimates.

The FACTRAN code (Reference 4) was then used to calculate the heat flux transient based on the nuclear power and flow from LOFTRAN. Finally, the THINC code (References 5 and 6) was used to calculate the DNBR during the transient based on the heat flux from FACTRAN and the flow from LOFTRAN. The DNBR results are based on the minimum of the typical and thimble cells.

6.2.10.4 Acceptance Criteria

A partial loss of forced reactor coolant flow incident is classified by the American Nuclear Society (ANS) as a Condition II event. The immediate effect is a rapid increase in reactor coolant temperature and subsequent increase in RCS pressure. The primary acceptance criterion for this event is that the critical heat flux should not be exceeded. This is ensured by demonstrating that the minimum DNBR does not go below the applicable safety analysis limit at any time during the transient. The analysis results also demonstrate that pressure in the reactor coolant and main steam systems remains below 110% of the respective design pressures to ensure that the applicable Condition II pressure criteria are met.

6.2.10.5 Results

The partial loss of forced reactor coolant flow event is the least DNB-limiting transient among all loss of flow cases. Reactor trip for the partial loss of flow case occurs on a low primary coolant flow signal. The THINC-IV (Reference 6) analysis confirms that the minimum DNBR is greater than the safety analysis limit. Fuel clad damage criteria are not challenged in the partial loss of forced reactor coolant flow event since the DNB criterion is met.

The analysis of the partial loss of flow event also demonstrates that the peak Reactor Coolant System and Main Steam System pressures are well below their respective limits.

The sequence of events for the partial loss of flow transient is presented in Table 6.2.10-1. The transient results for this case are presented in Figures 6.2.10-1 and 6.2.10-2.

6.2.10.6 Conclusions

The analysis performed at uprated conditions demonstrates that for the partial loss of flow incident, the DNBR does not decrease below the safety analysis limit at any time during the transient; thus, no fuel or clad damage is predicted. The peak primary and secondary system pressures remain below their respective limits at all times. All applicable acceptance criteria are therefore met.

6.2.10.7 References

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

2. "Byron & Braidwood Station, Updated Final Safety Analysis Report," Revision 7, Docket Nos. STN-454/455/456/457, as amended through December 1998.

3. Burnett, T.W.T, et al., "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary), WCAP-7907-A (Non-proprietary), April 1984.

4. Hargrove, H.G., "FACTRAN -- A FORTRAN-IV Code for Thermal Transients in a UO_2 Fuel Rod," WCAP-7908-A, December 1989.

5. Hochreiter, L. E., Chelemer, H., "Application of THINC IV Program to PWR Design," WCAP-8054-P-A, February 1989.

6. Friedland, A. J., Ray, S., "Improved THINC IV Modeling for PWR Core Design," WCAP-12330-A, September 1991.

Table 6.2.10-1 Sequence of Events-Partial Loss of Forced Reactor Coolant Flow Event		
Case	**Event**	**Time (sec)**
Partial loss of forced reactor coolant flow (Four loops operating, two loops coasting down)	Coastdown begins	0.0
	Low flow reactor trip	1.7
	Rods begin to drop	2.7
	Minimum DNBR occurs	3.9