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Ken Peters
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Waterford 3

W3F1-2004-0096

October 18, 2004

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

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

REFERENCES:
1. Entergy Letter dated November 13, 2003, "License Amendment Request NPF-38-249 Extended Power Uprate"
2. Entergy Letter dated May 7, 2004, "Supplement to Amendment Request NPF-38-249, Extended Power Uprate"
3. Entergy Letter dated July 14, 2004, "Supplement to Amendment Request NPF-38-249, Extended Power Uprate"

Dear Sir or Madam:

By letter (Reference 1), Entergy Operations, Inc. (Entergy) proposed a change to the Waterford Steam Electric Station, Unit 3 (Waterford 3) Operating License and Technical Specifications to increase the unit's rated thermal power level from 3441 megawatts thermal (MWt) to 3716 MWt.

On August 25, 2004, Entergy and members of your staff held a call to discuss the results of the analysis submitted in Reference 1 and the assumptions used for these analyses. As a result of the call, Entergy agreed to reanalyze the main steam line break return to power event with a revised assumption regarding fuel failures and also to provide an additional analysis of the loss of feedwater event that maximizes pressurizer level. Also, during the August 25, 2004, call, the staff requested additional assurance that the emergency operating procedures support the operator action time assumed in the analysis for securing charging flow.

The results for the reanalyzed main steam line break return to power event are provided in Attachment 1 and supersede the results previously submitted in Section 2.13.1.3.1, "Steam System Piping Failures Post-Trip Analysis," of Attachment 5 in Reference 1. Additionally, Sections 2.13.1.3.3.2 and 2.13.1.3.3.5 have been revised to be consistent with the reanalyzed main steam line break return to power event. The revised sections are provided in Attachment 6 and supersede the information previously submitted in these sections in Attachment 5 of Reference 1.

The additional analysis of the loss of feedwater event that maximizes pressurizer level is provided in Attachment 2. A discussion regarding the emergency operating procedure and the operator action time is provided in Attachment 3.

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Subsequent to the August 25, 2004, call, Entergy identified that the steam generator tube rupture event analysis submitted in Reference 1 assumed that cooldown was achieved using only one of the two atmospheric dump valves when operating procedures specify the use of two atmospheric dump valves. This issue was entered into Entergy's 10 CFR 50 Appendix B corrective action program at Waterford 3. As a result, the steam generator tube rupture event was reanalyzed assuming both atmospheric dump valves were used during the cooldown. The results of this reanalysis are provided in Attachment 4 and supersede the results submitted in Section 2.13.6.3.2, "Steam Generator Tube Rupture," of Attachment 5 in Reference 1.

As a result of the steam generator tube rupture re-analysis, information provided in the response to Question 14 in Reference 2 has changed. That supplement provided the detailed calculation results for offsite doses in support of information contained in Reference 1. The revised information for steam generator tube rupture offsite dose superseding that previously provided in Reference 2 is:

Event	PUR Section	Fuel Failure Limit (%)	2 Hour EAB Whole Body (rem)	2 Hour EAB Thyroid (rem)	Duration LPZ Whole Body (rem)	Duration LPZ Thyroid (rem)
Steam Generator Tube Rupture – GIS case (accident generated iodine spike)	2.13.6.3.2	0%	0.64	1.19	0.24	1.29
Steam Generator Tube Rupture – PIS case (pre-existing iodine spike)	2.13.6.3.2	0%	0.65	21.92	0.24	4.61

Reference 1 and Attachment 4 of this letter report consequences for these events meet the appropriate acceptance limits of the Standard Review Plan (NUREG-0800). As stated in Reference 1 and again in Attachment 4, this will become the new licensing basis for these events and be the dose information described in the Waterford 3 Final Safety Analysis Report.

Finally, Attachment 5 contains minor miscellaneous corrections that were not included in Section 2.13 of Attachment 5 (Power Uprate Report) of Reference 1. None of these corrections affect the Power Uprate Report conclusions and are being provided for completeness.

The no significant hazards consideration included in Reference 3 is not affected by any information contained in the supplemental letter. There are no new commitments contained in this letter.

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

I declare under penalty of perjury that the foregoing is true and correct. Executed on October 18, 2004.

Sincerely,

KJP/DBM/cbh

Attachments:
1. Revised Section 2.13.1.3.1, Steam System Piping Failures Post-Trip Analysis
2. Analysis of Loss of Feedwater Event that Maximizes Pressurizer Level
3. Emergency Operating Procedure and Operator Action Time to Secure Charging
4. Revised Section 2.13.6.3.2, Steam Generator Tube Rupture
5. Minor Miscellaneous Corrections to Section 2.13
6. Revised Sections 2.13.1.3.3.2, Purpose of Analysis and Acceptance Criteria and 2.13.1.3.3.5, Radiological Consequences

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Attachment 1

To

W3F1-2004-0096

Revised Section 2.13.1.3.1, Steam System Piping Failures Post-Trip Analysis

2.13.1.3.1 Steam System Piping Failures Post-Trip Analysis

The objective of the main steam line break (MSLB) with or without a concurrent LOOP event analysis is to document the impact of:

An increase in rated power to 3716 MWt

A decrease in the LSGP trip and MSIS actuation setpoints

A reduction in CEA worth at trip

Transition to the CENTS transient simulation code

Change in most negative MTC from -4.0×10^{-4} $\Delta\rho/°F$ to -4.2×10^{-4} $\Delta\rho/°F$

The return to power MSLB analysis is presented in FSAR Section 15.1.3.1.

2.13.1.3.1.1 General Description

A MSLB is defined as a pipe break in the Main Steam Safety System (MSSS). The increased steam flow resulting from a pipe break in the MSSS causes an increased energy removal from the affected steam generator, which causes a decrease in the overall Reactor Coolant System (RCS) temperatures and RCS pressure. In the presence of a negative moderator temperature coefficient (MTC), the cooldown causes positive reactivity to be added to the core. A highly negative MTC in conjunction with a large break size (guillotine breaks) can combine to degrade shutdown margin and result in a potential post-trip return to power.

With a loss-of-offsite power (LOOP) concurrent with the break, reactor coolant pumps (RCPs) begin to coast down and certain Engineered Safety Features (ESF) Systems are actuated.

In all guillotine break cases, the low steam generator pressure initiates both a reactor trip and a main steam isolation signal (MSIS), which causes closure of the main steam isolation valves (MSIVs) and main feed isolation valves (MFIVs). The steam flow from the intact SG is terminated by the complete closure of the MSIVs. Since the pipe break is assumed to occur upstream of the MSIV, the steam flow from the affected SG is not terminated until the affected SG dries out. The large cooldown of the RCS results in the reduction of the RCS pressure, which will empty the pressurizer and initiate a safety injection actuation signal (SIAS). The emptying of the affected SG and the initiation of boron injection terminates the return to power and causes the core reactivity to decrease. The operator, via the appropriate emergency procedures, may initiate plant cooldown by manual control of ADVs anytime after reactor trip occurs. The plant is then cooled to the shutdown cooling temperature, at which time shutdown cooling can be initiated.

In the analysis of record (AOR), four MSLB events were chosen to maximize the potential for a post-trip return-to-power. The events were:

A guillotine break MSLB at hot-full power (HFP) with LOOP

A guillotine break MSLB at HFP with offsite power available

A guillotine break MSLB at hot-zero power (HZP) with LOOP

A guillotine break MSLB at HZP with offsite power available

In addition, the above combinations were analyzed for both inside containment (IC) and outside containment (OC) break locations. The outside containment break locations are in general more benign with the blowdown flow being limited by the inline venturi flow restrictors.

2.13.1.3.1.2 Purpose of Analysis and Acceptance Criteria

The purpose of the analysis is to determine that the radiological doses are within their respective limits and that a coolable geometry is maintained. This is accomplished by iterating on SCRAM worth to determine that which results in 2% fuel failure due to DNB SAFDL violation for the inside containment LOOP cases and no SAFDL violation for the inside containment no-LOOP cases. Limits on SCRAM are selected so that no SAFDL violation is predicted for any of the outside containment cases.

The criteria for the MSLB with and without LOOP events are the following:

Maintain a coolable geometry

Radiological Doses	≤ small fraction (10%) of 10CFR100 limits for an event generated iodine spike and no iodine spike, and ≤ 10CFR100 limits for a pre-existing iodine spike or fuel failure
Control Room Doses	≤ 5 rem whole body ≤ 75 rem skin ≤ 30 rem thyroid

The MSLB with or without a concurrent LOOP event is described in Chapter 15.1.3.1 of the SAR (Reference 2.13-1).

2.13.1.3.1.3 Impact of Changes

The increase in rated power maximizes the amount of energy that is removed by the broken steam line and the cooldown effect on the RCS temperature.

The LSGP trip and MSIS actuation setpoints were decreased due to lower operating SG pressures. This delays somewhat the action of the MSIVs in stopping steam flow from the unaffected SG.

The more negative MTC results in the addition of additional positive reactivity by MTC effects during the cooldown.

The impact of the above changes, along with the iterated SCRAM worth results in a small number of fuel pins predicted to experience DNB SAFDL violation for inside containment (IC) break location LOOP cases. No violation of SAFDLs occurs for inside containment no-LOOP cases or the outside containment (OC) break locations. The radiological doses remain less than the 10CFR100 limits.

2.13.1.3.1.4 Analysis Overview

The methodology used in this analysis is the same as that used in the analysis of record.

This analysis utilized the CENTS computer code (Reference 2.13-2) for the transient analysis simulation. The minimum DNBR evaluation was determined using the HRISE code (Reference 2.13-10), which employed the MacBeth correlation. ROCS/HERMITE were used to assess reactivity feedback and core power distribution.

Input parameters for HFP and HZP from Tables 2.13.1.3.1-1 through 2.13.1.3.1-4 and the bounding physics data from Section 2.13.0.2 have been incorporated in this analysis with the following clarifications:

- A double-ended IC guillotine break (7.88 ft^2) causes the greatest cooldown of the RCS and the most severe degradation of shutdown margin. Flow from the other SG was limited to the 3.14 ft^2 area of the inline flow restrictors.
- A break inside or outside the containment building, upstream of the MSIVs causes a non-isolatable condition in the affected SG.
- A SIAS is actuated when the pressurizer pressure drops below 1560 psia. Time delays associated with the safety injection pump acceleration and valve opening are taken into account. An 18.5-second HPSI response time was assumed for the offsite power available case while a 30-second delay (conservatively greater than the 27 seconds to be specified in the Technical Requirements Manual [TRM]) was assumed for the LOOP case. Additionally, the event was initiated from the highest pressure allowed by the Technical Specifications to delay the effect of the safety injection boron.
- The cooldown of the RCS is terminated when the affected steam generator blows dry. As the coolant temperatures begin increasing, positive reactivity insertion from moderator reactivity feedback decreases. The decrease in moderator reactivity combined with the negative reactivity inserted via boron injection cause the total reactivity to become more negative.
- CENTS is used to model the reactor coolant pump (RCP) coast down on a LOOP.
- Low SG pressure trip setpoint of 576 psia was assumed with a 0.9-second response time.
- MSIS is actuated on a LSGP setpoint of 576 psia. The MSIVs and Main Feedwater Isolation Valves (MFIVs) all receive an MSIS signal to close. A response time of 8.0 seconds was assumed for the MSIVs.
- The HERMITE code (Reference 2.13-4) was used to calculate the reactivity for the post-trip return to power portion of the analysis. This was done since the HERMITE code, which is a three-dimensional, coupled neutronics, open channel thermal hydraulics code, can more accurately model the effects of moderator temperature feedback on the power distribution and reactivity for the critical configuration existing during the return to power. The HERMITE results used in the Waterford 3 analysis were actually obtained from a parametric study performed for Calvert Cliffs Unit 1 Cycle 7. Waterford 3-specific ROCS

calculations were used to confirm the applicability of these parametric results to Waterford 3.

- Three-dimensional power distribution peaks (Fq) were determined with the ROCS and HERMITE evaluations mentioned above. Axial profiles consistent with these conservative power distribution peaks were utilized in the analysis.
- Reactor core thermal margin (DNBR) was simulated using the HRISE computer program, which employed the MacBeth critical heat flux (CHF) correlation and a 1.3 DNBR limit described in Reference 2.13-10. RCS conditions from CENTS (RCS temperature, pressure, flow, and power) are used in the HRISE thermal margin calculations.
- An EOC Doppler coefficients was assumed. This was based on the most negative fuel temperature coefficient (FTC). This FTC, in conjunction with the decreasing fuel temperatures, causes the greatest positive reactivity insertion during the steam line break event.
- The delayed neutron fraction assumed is the maximum value including uncertainties for EOC conditions (total delayed neutron fraction, β, 0.005662).
- A minimum initial RCS flow of 148,000,000 lbm/hr was assumed.
- A maximum initial RCS temperature results in the greatest increase in density of the coolant during the event. This maximizes the positive reactivity added by the moderator. The analytical value of 552°F was used in this analysis.

The conservative assumptions included in the HZP and HFP simulations are discussed below.

The post trip steam line break analysis done for power uprate is performed with a combination of reactivity parameters that are expected to bound cycle specific core design parameters. A review of these parameters is done for every fuel cycle Reload Analysis to ensure the analysis of record remains bounding. Acceptable results can still be obtained if one cycle specific parameter (for example MTC) is non-conservative relative to the analysis of record, provided that other cycle specific parameters (for example SCRAM worth) are adequately conservative to compensate for any non-conservative parameter. The Reload Analysis process automatically performs this assessment to ensure the acceptability of the cycle specific reactivity behavior.

A negative MTC results in the greatest positive reactivity addition during the RCS cooldown caused by the steam line break. Since the coefficient of reactivity associated with moderator feedback varies significantly over the range of moderator density covered in the analysis, a curve of reactivity insertion versus moderator density rather than a single value of MTC is assumed in the analysis. A typical moderator cooldown curve is seen in Figure 2.13-1 and includes the direct change in moderation as well as variation in the worth of the tripped CEAs as moderator density changes. It was conservatively calculated assuming that on reactor trip, the highest worth control element assembly is stuck in the fully withdrawn position. The effect of uneven temperature distribution on the moderator reactivity is accounted for by assuming that the moderator reactivity is a function of the lowest cold leg temperature. Each cycle, the reload assessment process generates the appropriate cooldown curve.

For conservatism, the full steam generator heat transfer surface area is assumed to always be covered by the 2-phase level until a steam generator becomes essentially empty.

Due to differences in the magnitudes of reactivity feedback mechanisms, the rates of heat removal associated with different break areas and LOOP assumptions, the minimum acceptable SCRAM worth would be different for each of the eight RTP steamline break (SLB) scenarios examined. Restrictions will be incorporated in future reload core designs to ensure that the most limiting of the requirements are verified for actual power uprate core designs.

The HFP cases assume that feedwater delivery to the affected SG reached the capacity of the Main Feedwater (MFW) System until the MFIVs act to terminate MFW delivery.

2.13.1.3.1.5 Radiological Consequences

Based upon the required scram worths, the maximum fuel failure for the inside containment LOOP RTP MSLB is 2% via the mechanism of DNB SAFDL violation. No fuel failure is allowed for the inside containment no-LOOP cases or for the outside containment RTP main steamline break (MSLB). Similar limited fuel failure during the RTP SLB has been licensed for Calvert Cliffs and St Lucie 2. The radiological consequences and fuel failure limits of the RTP SLB scenario are combined with those of the pre-trip SLB scenario. Refer to Section 2.13.1.3.3.5 for the discussion.

2.13.1.3.1.6 Analysis Results

The results of all four of the inside containment RTP SLB scenarios are presented. The input assumptions for the HFP, LOOP case, the HFP no-LOOP case, the HPP LOOP case and the HZP no-LOOP case are seen in Tables 2.13.1.3.1-1 through 2.13.1.3.1-4, respectively.

The sequences of events for the scenarios are seen in Tables 2.13.1.3.1-5 through 2.13.1.3.1-8. Figures 2.13.1.3.1-1 though 2.13.1.3.1-13 present the transient response of key parameters for the HFP LOOP case. The same parameters are plotted in Figures 2.13.1.3.1-14 through 2.13.1.3.1-25 for the HFP no-LOOP case, in Figures 2.13.1.3.1-26 through 2.13.1.3.1-38 for the HZP LOOP case and in Figures 2.13.1.3.1-39 through 2.13.1.3.1-50 for the HZP no-LOOP case.

It is seen that the response for the power uprate is slightly more adverse than the current power level. A limited extent of SAFDL violation is seen to occur for these inside containment steam line breaks.

Table 2.13.1.3.1-1
HFP, LOOP Assumption Table

Parameter	Power Uprate Assumption	Current Power Level Assumption
Initial Core Power, MWt	3716	3478
Core Inlet Coolant Temperature, °F	552	560
RCS Flowrate, $x10^6$ lbm\hr	148.0	148.0
Pressurizer Pressure, psia	2310	2300
Pressurizer Level, %	21	---
SG Pressure, psia	867	969
SG Level, % NR	90	---
Doppler Coefficient Multiplier	1.15	1.15
SBCS	Inoperative	Inoperative
PPCS	Automatic	Automatic
High Pressure Safety Injection Pumps	1 pump inoperative	1 pump inoperative
Blowdown Fluid	100% steam	100% steam
Break Area, ft^2	7.88	7.88
Core Burnup	End of Cycle	End of Cycle

Table 2.13.1.3.1-2
HFP, no-LOOP Assumption Table

Parameter	Power Uprate Assumption	Current Power Level Assumption
Initial Core Power, MWt	3716	3478
Core Inlet Coolant Temperature, °F	552	560
RCS Flowrate, x106 lbm/hr	148.0	148.0
Pressurizer Pressure, psia	2310	2300
Pressurizer Level, %	21	---
SG Pressure, psia	867	969
SG Level, % NR	90	---
Doppler Coefficient Multiplier	1.15	1.15
SBCS	Inoperative	Inoperative
PPCS	Automatic	Automatic
High Pressure Safety Injection Pumps	1 pump inoperative	1 pump inoperative
Blowdown Fluid	100% Steam	100% Steam
Break Area, ft2	7.88	7.88
Core Burnup	End of Cycle	End of Cycle

Table 2.13.1.3.1-3
HZP, LOOP Assumption Table

Parameter	Power Uprate Assumption	Current Power Level Assumption
Initial Core Power, MWt	37.16	34.78
Core Inlet Coolant Temperature, °F	552	551
RCS Flowrate, $x10^6$ lbm/hr	148.0	148.0
Pressurizer Pressure, psia	2310	2300
Pressurizer Level, %	21	---
SG Pressure, psia	1054	1044
SG Level, % NR	90	---
Doppler Coefficient Multiplier	1.15	1.15
SBCS	Inoperative	Inoperative
PPCS	Automatic	Automatic
High Pressure Safety Injection Pumps	1 pump inoperative	1 pump inoperative
Blowdown Fluid	100% steam	100% steam
Break Area, ft^2	7.88	7.88
Core Burnup	End of Cycle	End of Cycle

Table 2.13.1.3.1-4
HZP, no-LOOP Assumption Table

Parameter	Power Uprate Assumption	Current Power Level Assumption
Initial Core Power, MWt	37.16	34.78
Core Inlet Coolant Temperature, °F	552	551
RCS Flowrate, x106 lbm/hr	148.0	148.0
Pressurizer Pressure, psia	2310	2300
Pressurizer Level, %	21	---
SG Pressure, psia	1054	1044
SG Level, % NR	90	---
Doppler Coefficient Multiplier	1.15	1.15
SBCS	Inoperative	Inoperative
PPCS	Automatic	Automatic
High Pressure Safety Injection Pumps	1 pump inoperative	1 pump inoperative
Blowdown Fluid	100% Steam	100% Steam
Break Area, ft2	7.88	7.88
Core Burnup	End of Cycle	End of Cycle

Table 2.13.1.3.1-5
HFP, LOOP, Inside Containment Sequence of Events

EPU Time (sec)	Current Power Level Time (sec)	Event	EPU Setpoint/Value	Current Power Level Setpoint/Value
0.0	0.0	Steam line break upstream of MSIV, loss of power to RCPs	7.88 ft^2	7.88 ft^2
1.9	1.7	LSGP trip and MSIS setpoint reached	576 psia	675 psia
2.8	2.6	Trip breakers open	---	---
2.8	2.6	MSIVs begin to close	---	---
3.4	3.2	Shutdown CEAs begin dropping into the core	---	---
11.4	---	MSIVs closed	---	---
19.4	12.6	MFIVs closed	---	---
44.2	15.8	Pressurizer empties	---	---
50.4	19.8	Low RCS pressure initiates SIAS	1560 psia	1560 psia
69.5	---	Minimum pressurizer pressure, psia	873.3	---
80.4	49.8	HPSI pump reaches full speed	---	---
153.2	142.3	Maximum post-trip fission power	6.1% of 3716 MWt	5.2% of 3410 MWt
169.3	152.3	Minimum post-trip MacBeth DNBR	1.03	>1.30
183.8	143.5	Maximum post-trip reactivity	+.006%$\Delta\rho$	-.056%$\Delta\rho$
269.0	112.7	Affected SG empties	---	---
1800	1800	Plant cooldown initiated by manual control of the ADV associated with the intact SG	---	---
28,800	---	SDC initiated	---	---

Table 2.13.1.3.1-6
HFP, no LOOP, Inside Containment Sequence of Events

Power Uprate Time (sec)	Current Power Level Time (sec)	Event	Power Uprate Setpoint / Value	Current Power Level Setpoint / Value
0.0	0.0	Steam Line Break Upstream of main Steam Isolation Valve, Loss of Power to Reactor Coolant Pumps	7.88 ft^2	7.88 ft^2
1.9	1.7	Low Steam Generator Pressure Trip and MSIS Setpoint Reached	576 psia	675 psia
2.8	2.6	Trip Breakers Open	---	---
2.8	2.6	MSIVs Begin to Close	---	---
3.4	3.2	Shutdown CEAs Begin Dropping into the Core	---	---
11.0	12.6	MSIVs Closed	---	---
13.6	15.8	Pressurizer Empties	---	---
14.7	18.2	Low RCS Pressure Initiates SIAS	1560 psia	1560 psia
33.2	36.7	High Pressure Safety Injection Pump Reaches Full Speed	---	---
69.8	72.8	Maximum Post Trip Fission Power	6.4% of 3716 MWt	5.6% of 3410 MWt
69.8	72.8	Maximum Post Trip LHGR	22.8	20.7
101.6	74.4	Affected Steam Generator Empties	---	---
103.4	74.4	Maximum Post Trip Reactivity	-.147%$\Delta\rho$	-.318%$\Delta\rho$
1800.0	1800.0	Plant Cooldown Initiated by Manual Control of the Atmospheric Dump Valve Associated with the Intact Steam Generator	---	---

Table 2.13.1.3.1-7
HZP, LOOP, Inside Containment Sequence of Events

EPU Time (sec)	Current Power Level Time (sec)	Event	EPU Setpoint/Value	Current Power Level Setpoint/Value
0.0	0.0	Steam line break upstream of MSIV, loss of power to RCPs	7.88 ft^2	7.88 ft^2
3.2	2.2	LSGP trip and MSIS setpoint reached	576 psia	675 psia
4.1	3.1	Trip breakers open	- - -	- - -
4.7	3.7	Shutdown CEAs begin dropping into the core	- - -	- - -
11.6	---	Pressurizer empties	---	---
12.2	11.6	Low RCS pressure initiates SIAS	1560 psia	1560 psia
12.2	13.1	MSIVs closed	---	---
19.8	---	MFIVs closed	---	---
40.0	94.5	Maximum post-trip reactivity	+0.19%$\Delta\rho$	+0.19%$\Delta\rho$
42.2	41.6	HPSI pump reaches full speed	---	---
123.6	---	Minimum RCS pressure, psia	580.1	---
226.1	229.6	Maximum post-trip fission power	4.4% of 3716 MWt	4.2% of 3478 MWt
228.0	249.4	Minimum post-trip DNBR	1.18	>1.30
>600	311.4	Affected SG empties	---	---
1800	1800	Plant cooldown initiated by manual control of the ADV associated with the intact SG	---	---
28,800	---	SDC initiated	---	---

Table 2.13.1.3.1-8
HZP, no LOOP, Inside Containment Sequence of Events

Power Uprate Time (sec)	Current Power Level Time (sec)	Event	Power Uprate Setpoint / Value	Current Power Level Setpoint / Value
0.0	0.0	Steam Line Break Upstream of main Steam Isolation Valve, Loss of Power to Reactor Coolant Pumps	---	---
3.2	2.2	Low Steam Generator Pressure Trip and MSIS Setpoint Reached	576 psia	675 psia
4.1	3.1	Trip Breakers Open	---	---
4.7	3.7	Shutdown CEAs Begin Dropping into the Core	---	---
11.3	10.6	Low RCS Pressure Initiates SIAS	1560 psia	1560 psia
12.2	13.1	MSIVs Closed	---	---
46.3	88.5	Maximum Post Trip Reactivity	+0.2004%$\Delta\rho$	+0.187%$\Delta\rho$
29.8	29.1	High Pressure Safety Injection Pump Reaches Full Speed	---	---
228.2	145.7	Maximum Post Trip Fission Power	5.7% of 3716 MWt	5.9% of 3478 MWt
228.2	145.7	Maximum Post-Trip LHGR	20.6	20.6
396.7	143.7	Affected Steam Generator Empties	---	---
1800.0	1800.0	Plant Cooldown Initiated by Manual Control of the Atmospheric Dump Valve Associated with the Intact Steam Generator	---	---

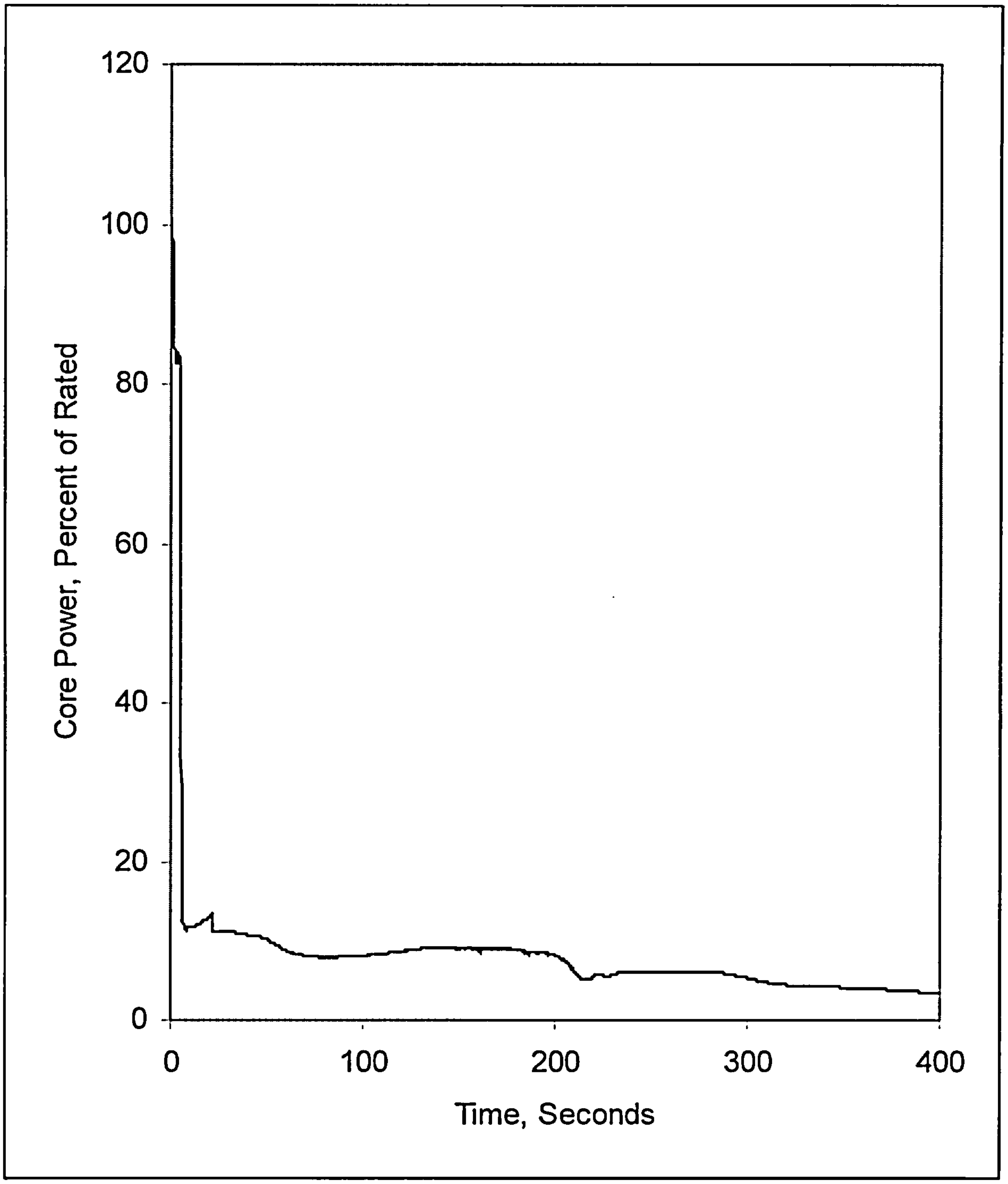


Figure 2.13.1.3.1-1
Inside Containment, HFP SLB with LOOP
Core Power vs. Time

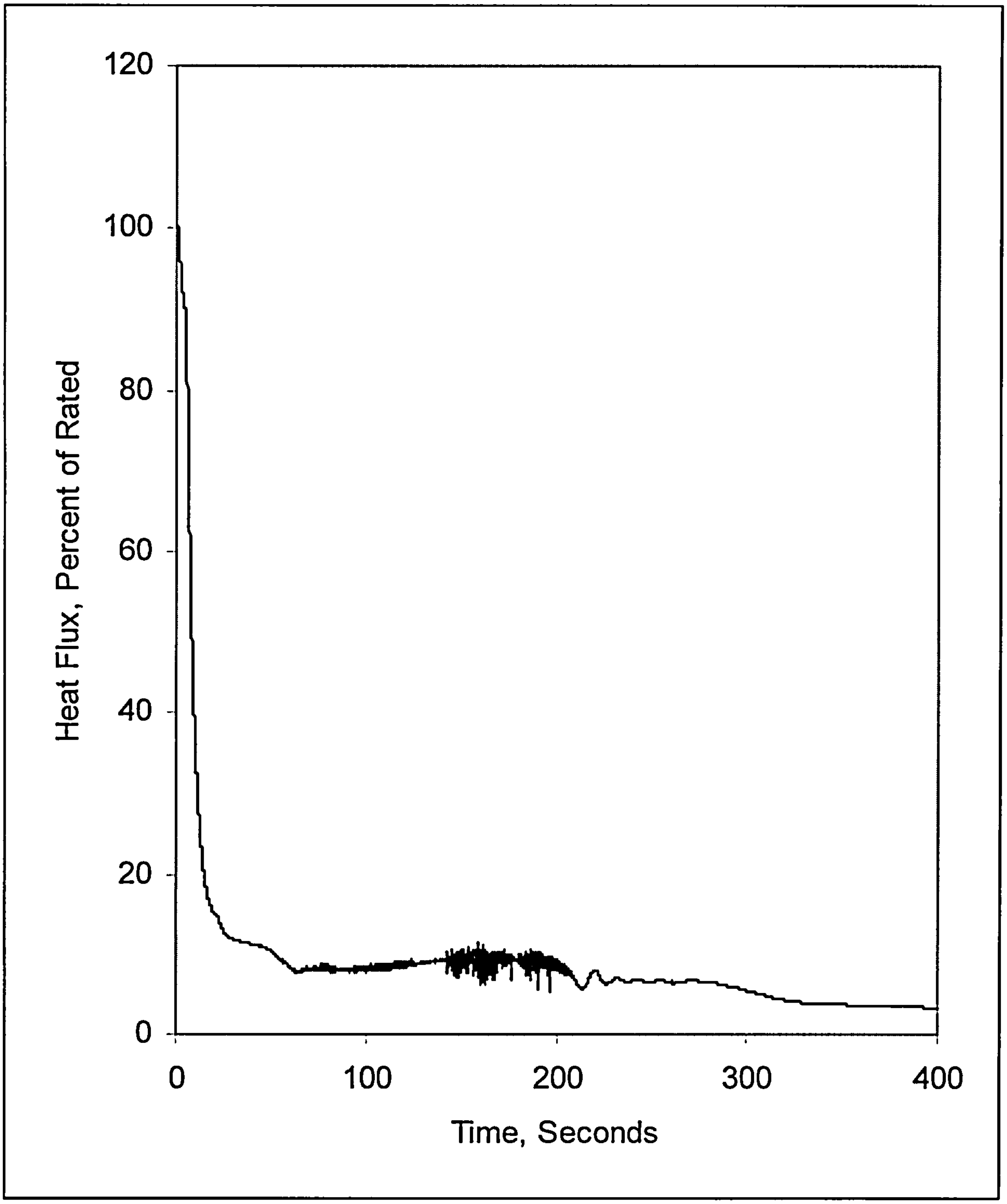


Figure 2.13.1.3.1-2
Inside Containment, HFP SLB with LOOP
Core Heat Flux vs. Time

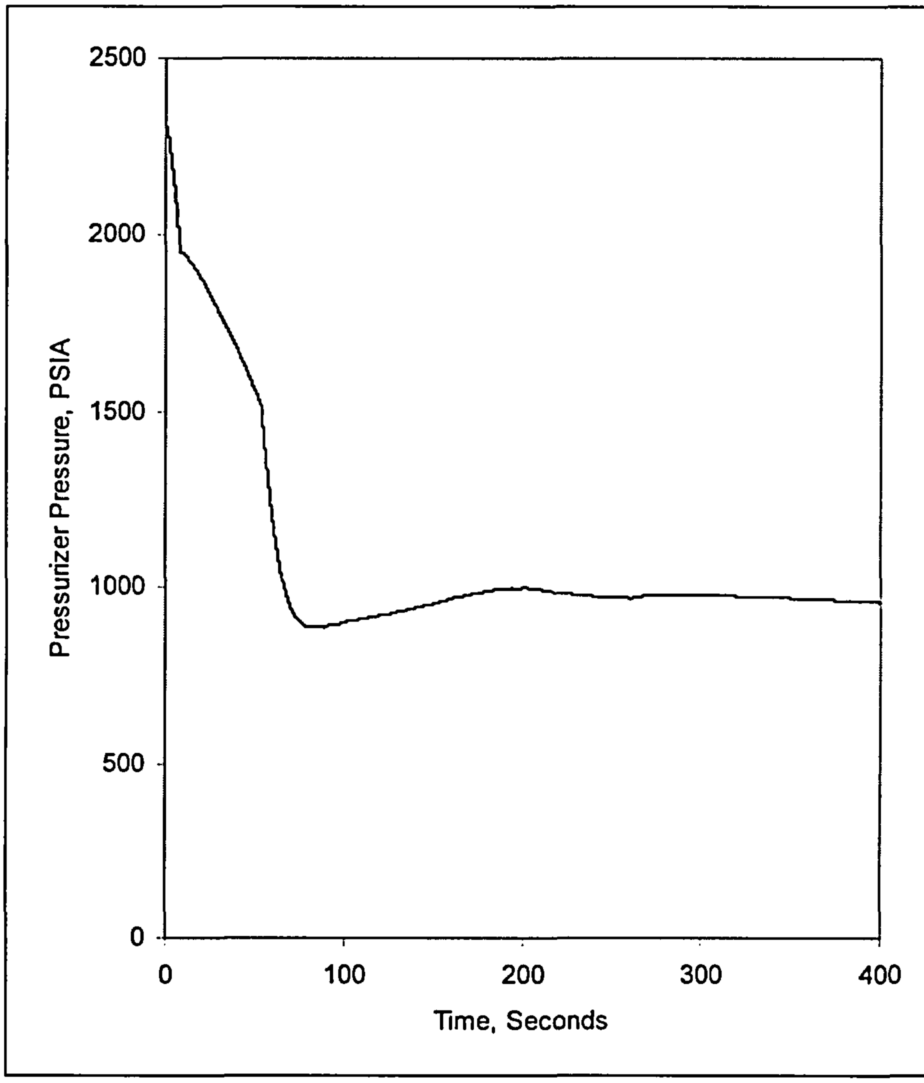


Figure 2.13.1.3.1-3
Inside Containment, HFP SLB with LOOP
Pressurizer Pressure vs. Time

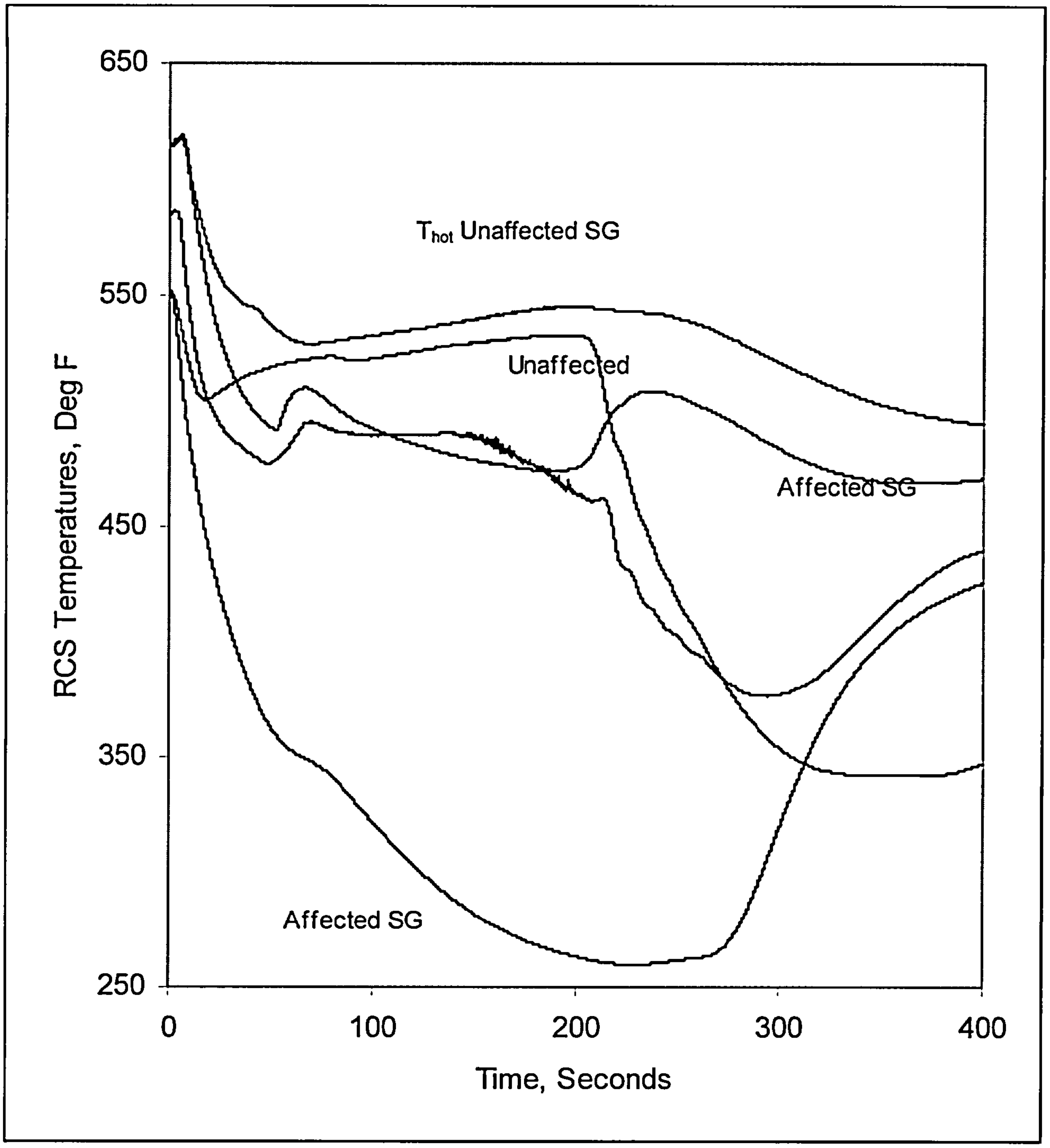


Figure 2.13.1.3.1-4
Inside Containment, HFP SLB with LOOP
RCS Temperatures vs. Time

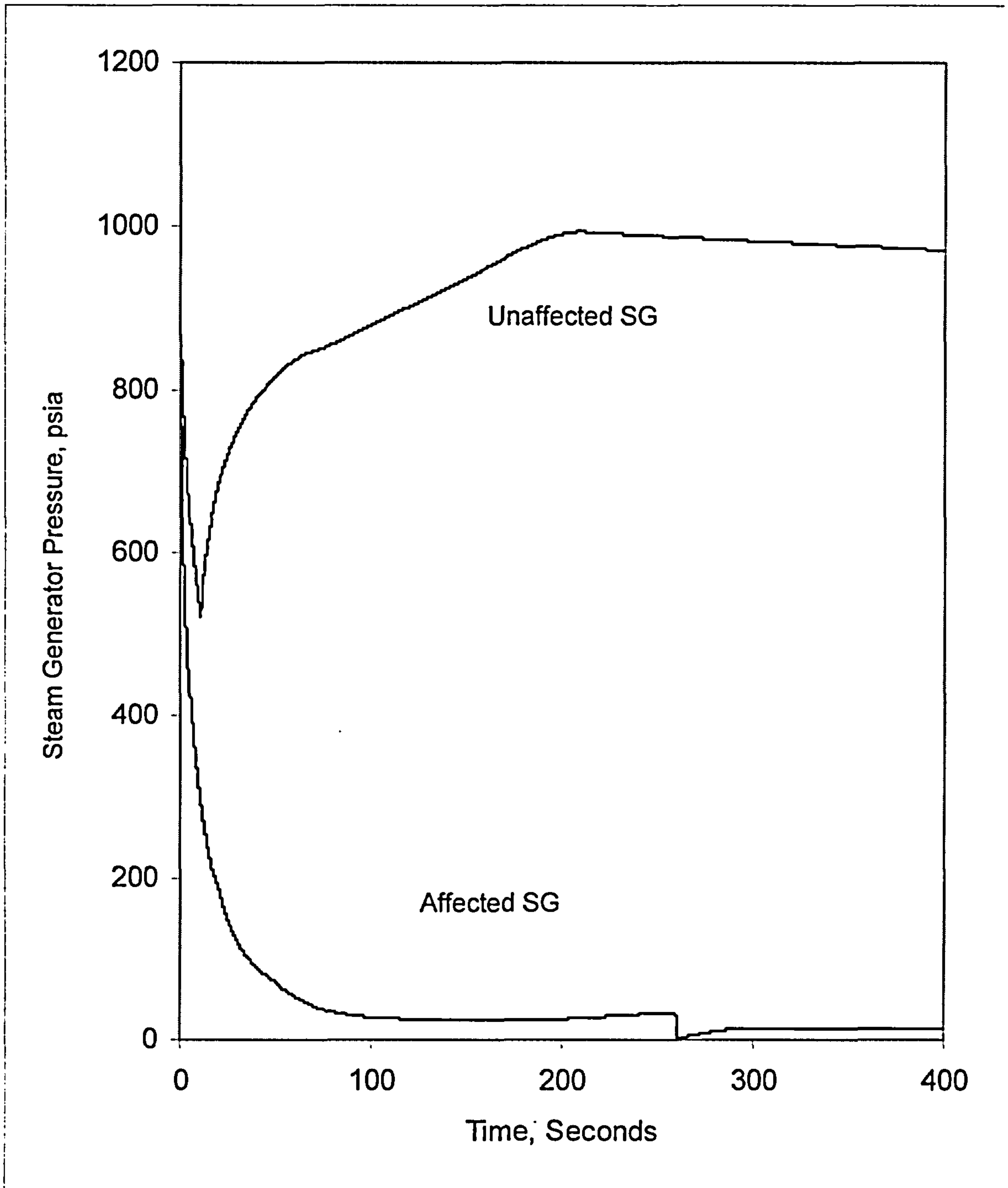


Figure 2.13.1.3.1-5
Inside Containment, HFP SLB with LOOP
SG Pressure vs. Time

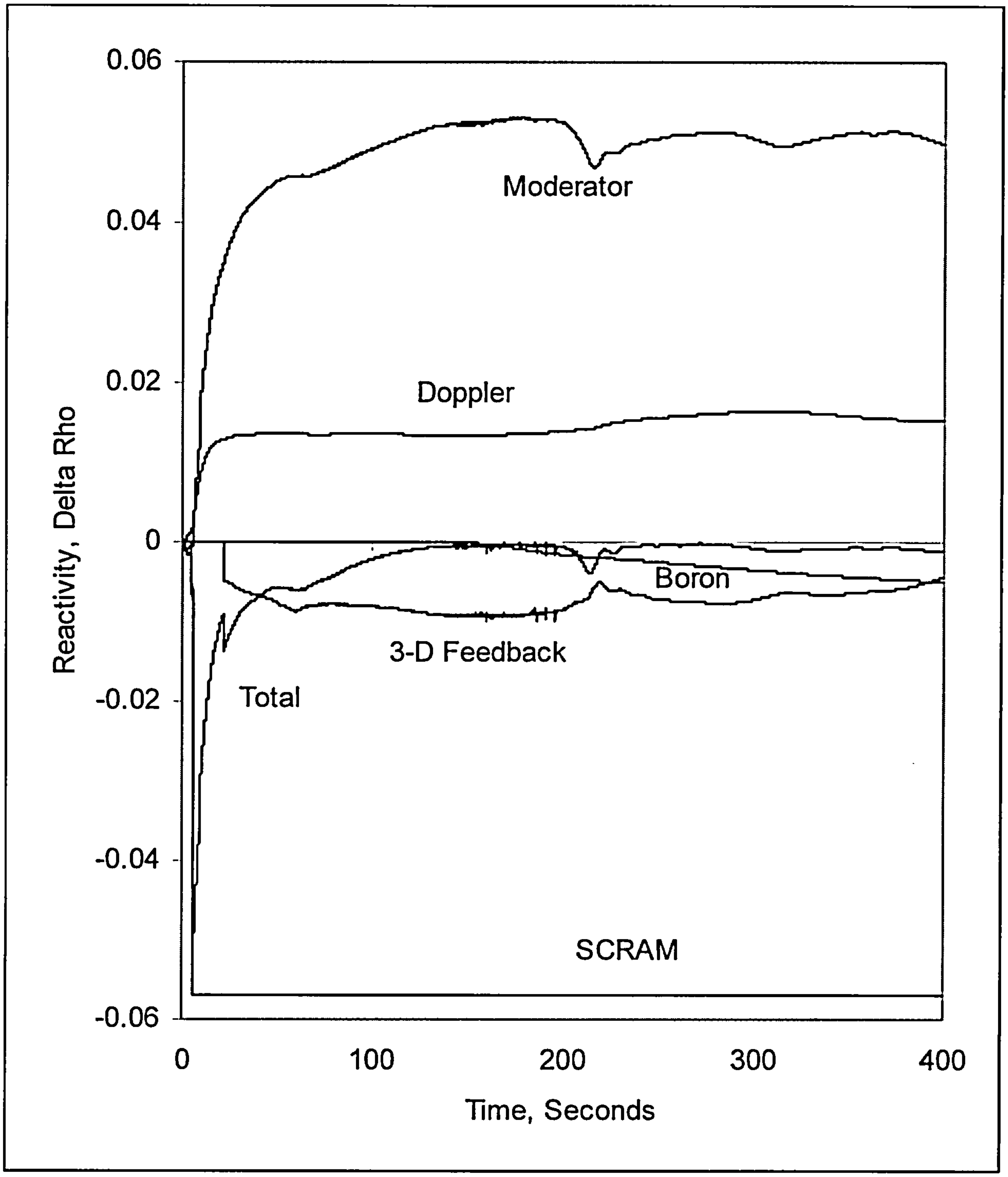
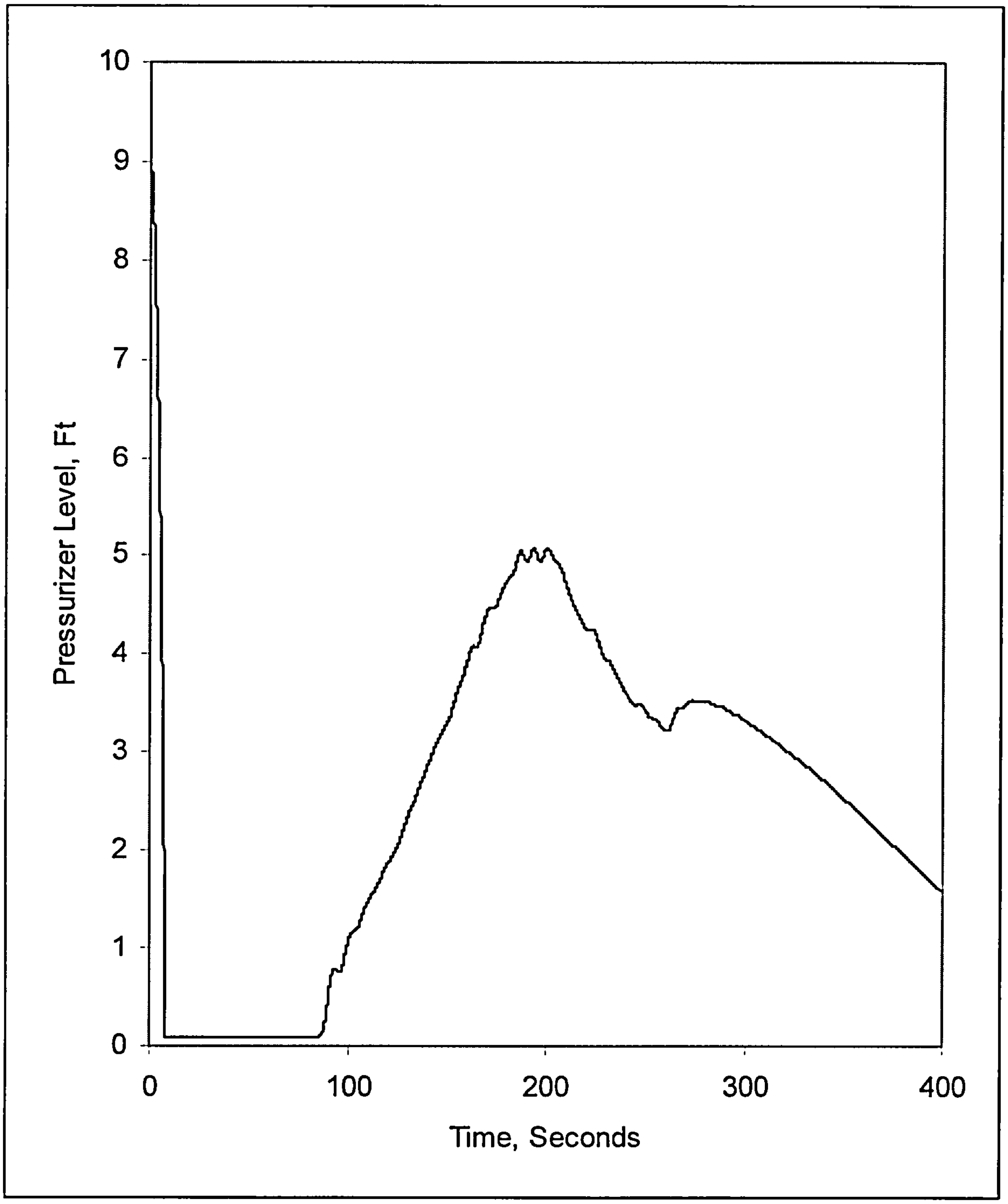


Figure 2.13.1.3.1-6
Inside Containment, HFP SLB with LOOP
Reactivity vs. Time



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Inside Containment, HFP SLB with LOOP
Pressurizer Level vs. Time

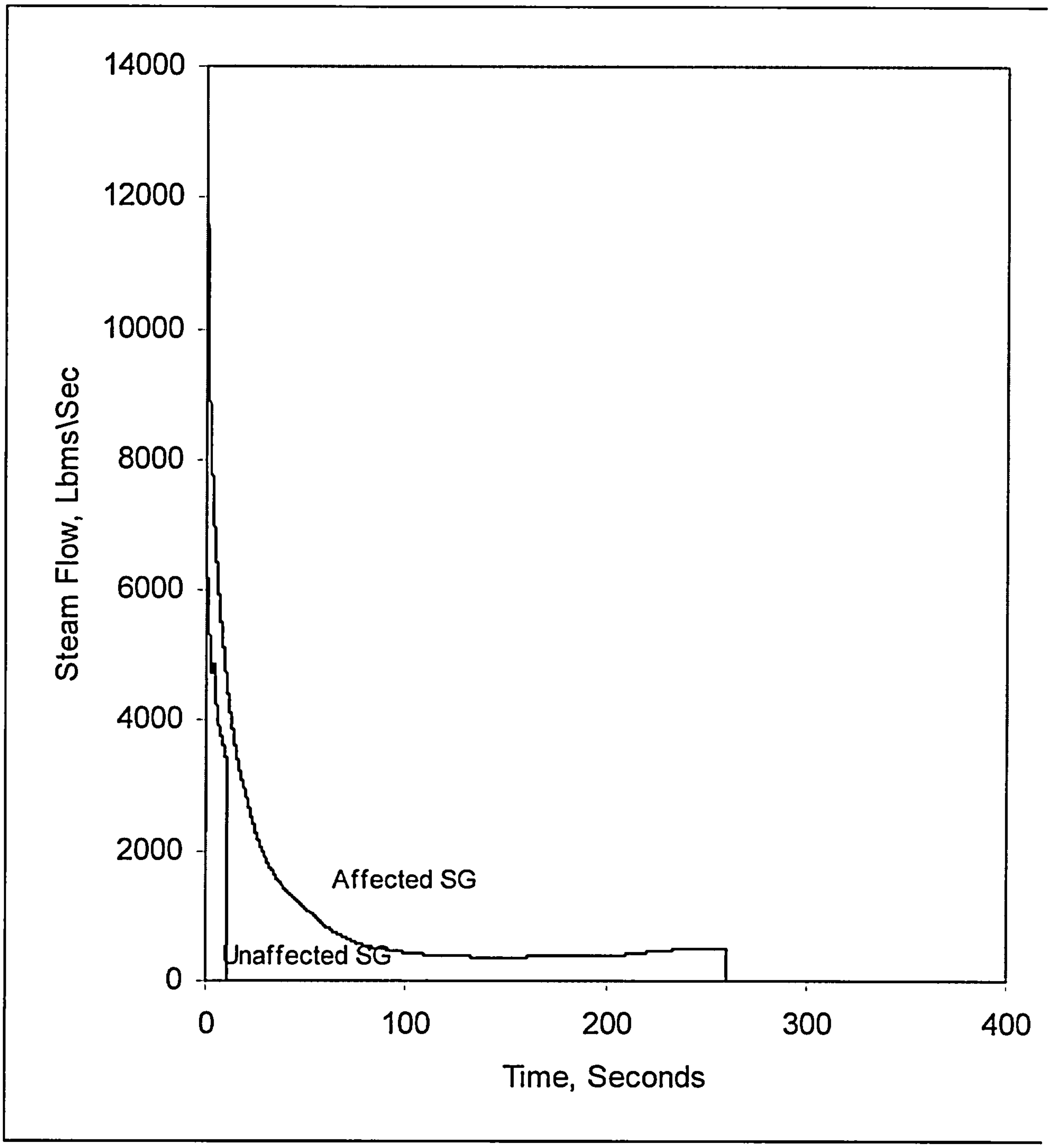


Figure 2.13.1.3.1-8
Inside Containment, HFP SLB with LOOP
Steam Flow vs. Time

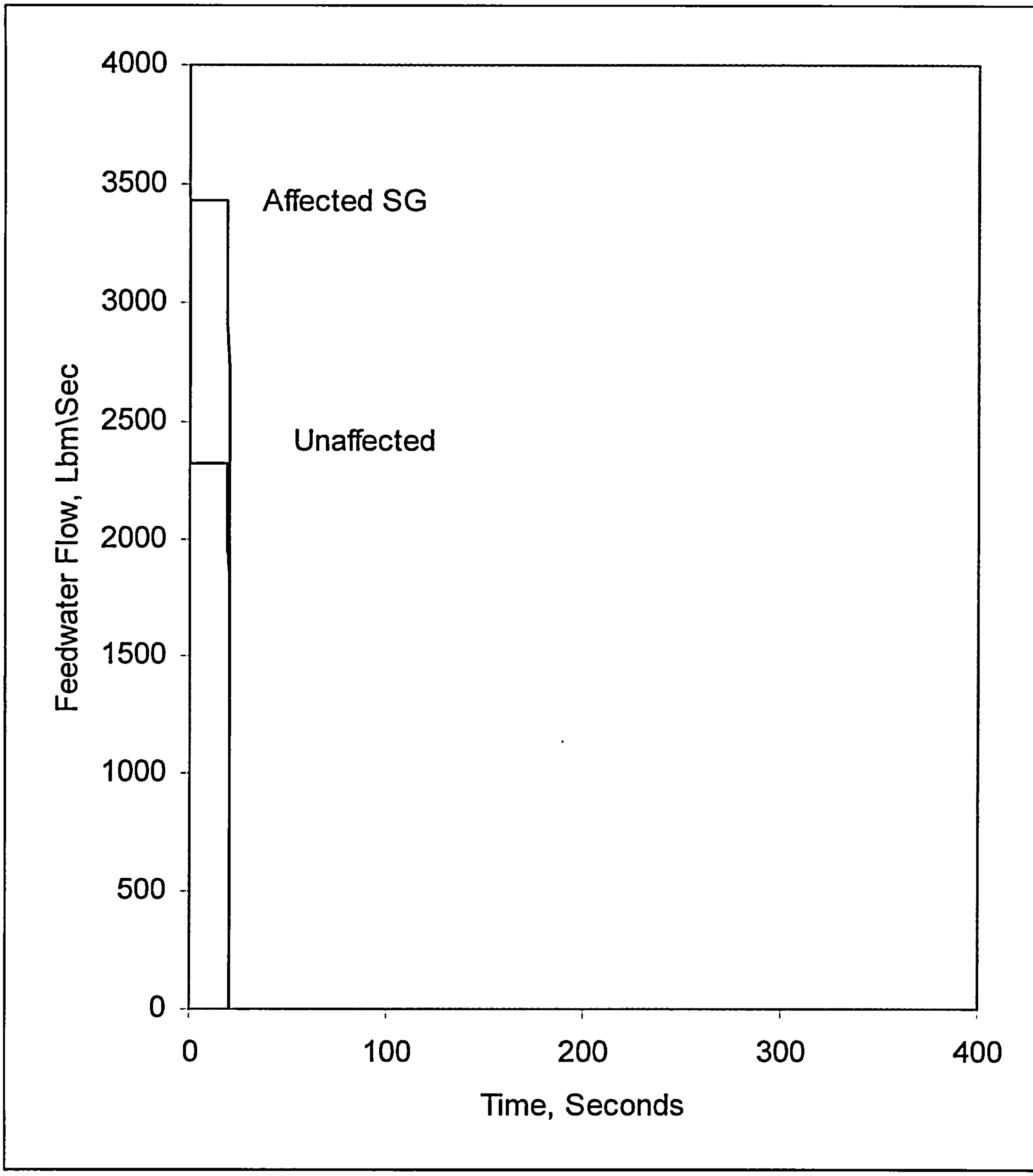
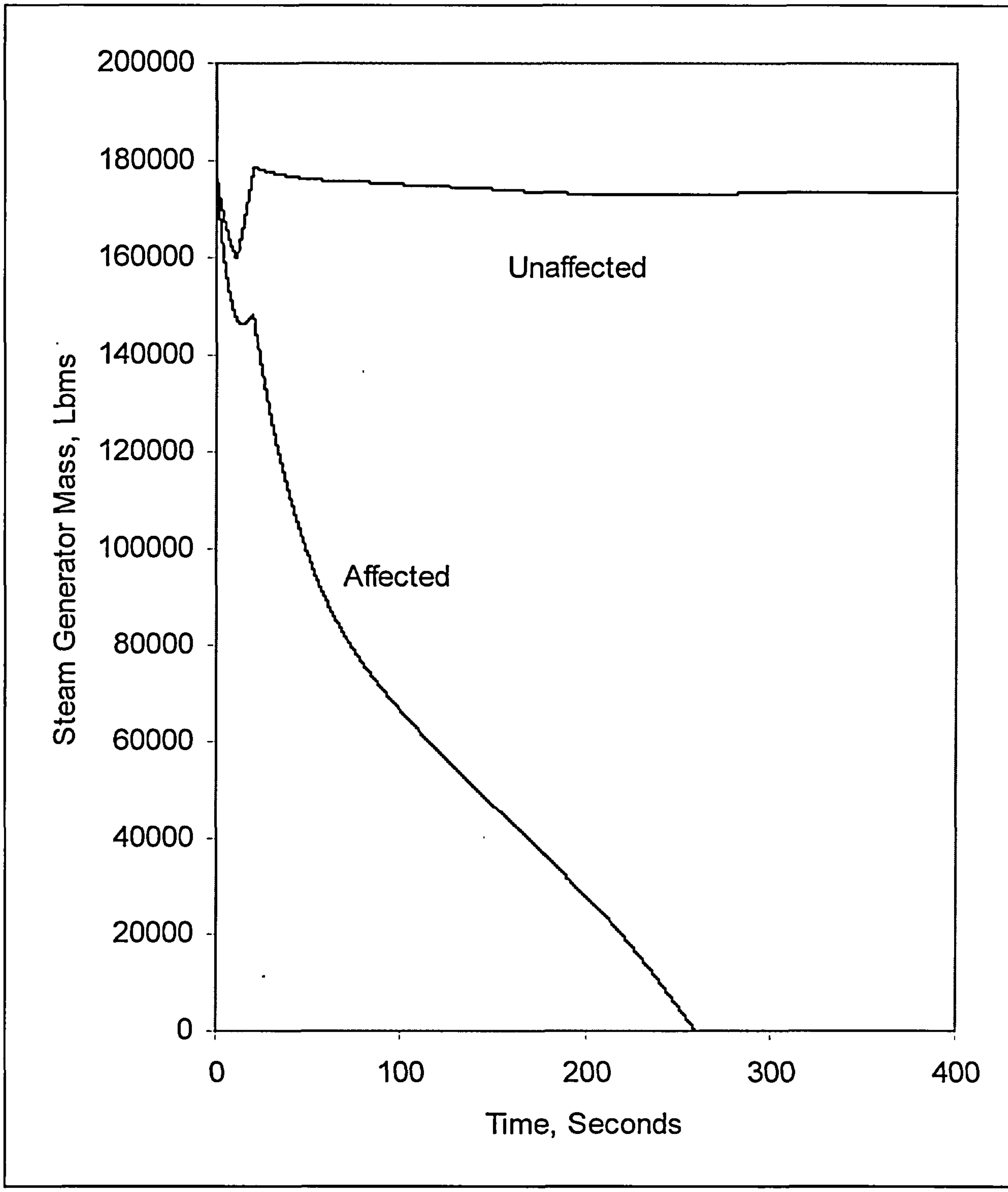


Figure 2.13.1.3.1-9
Inside Containment, HFP SLB with LOOP
Feedwater Flow vs. Time



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Inside Containment, HFP SLB with LOOP
SG Mass vs. Time

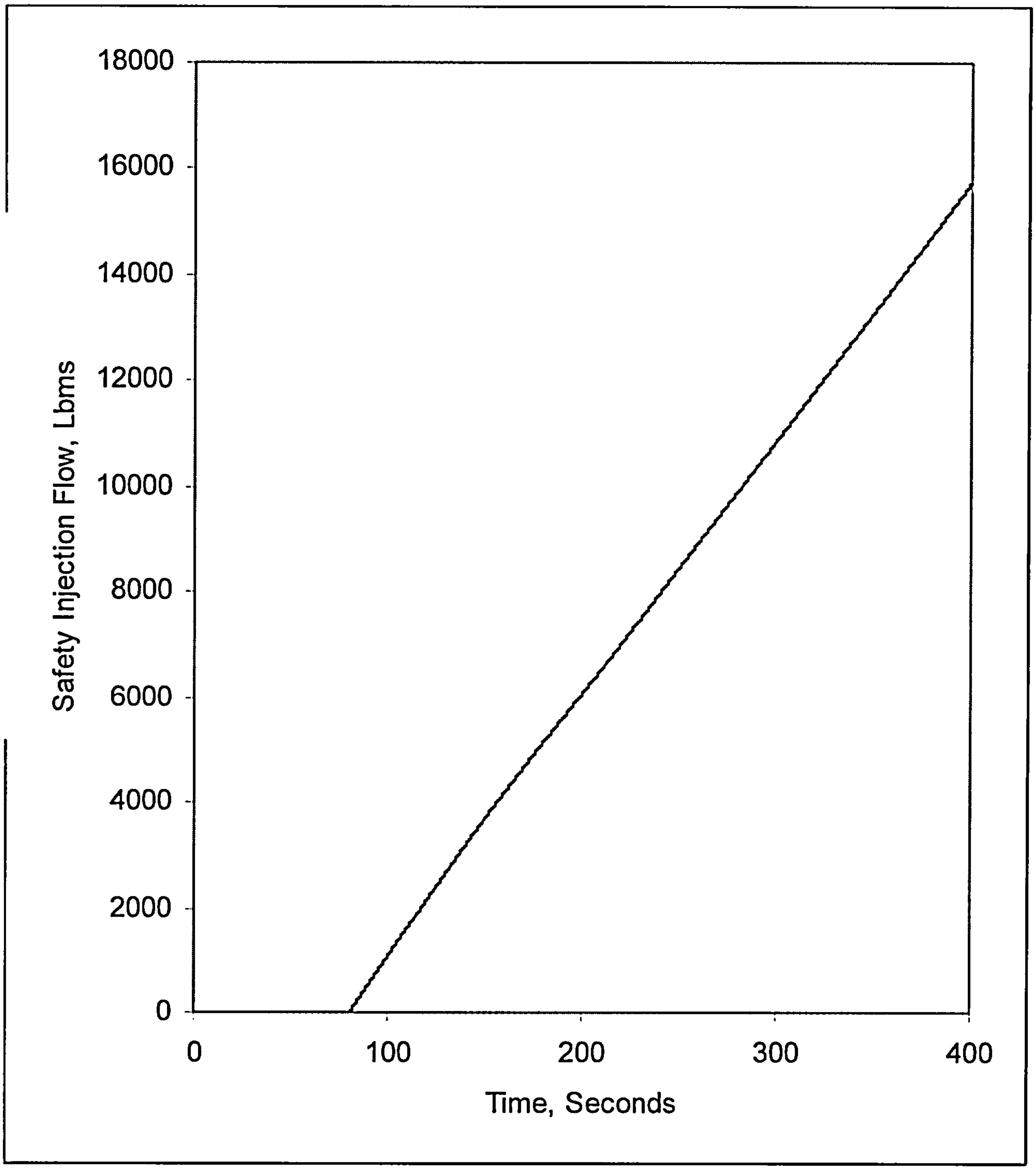


Figure 2.13.1.3.1-11
Inside Containment, HFP SLB with LOOP
Integrated Safety Injection Flow vs. Time

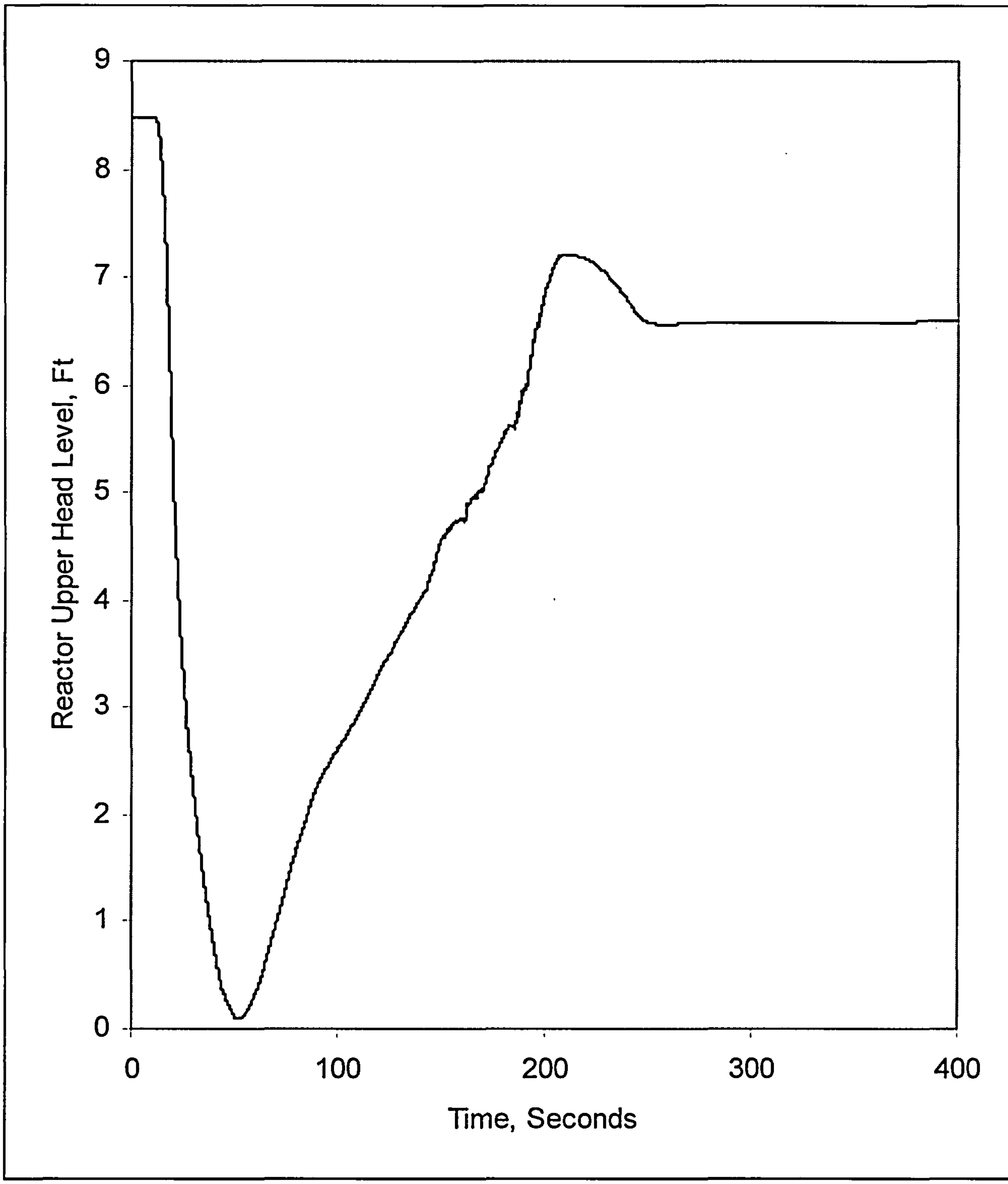


Figure 2.13.1.3.1-12
Inside Containment, HFP SLB with LOOP
Reactor Vessel Level vs. Time

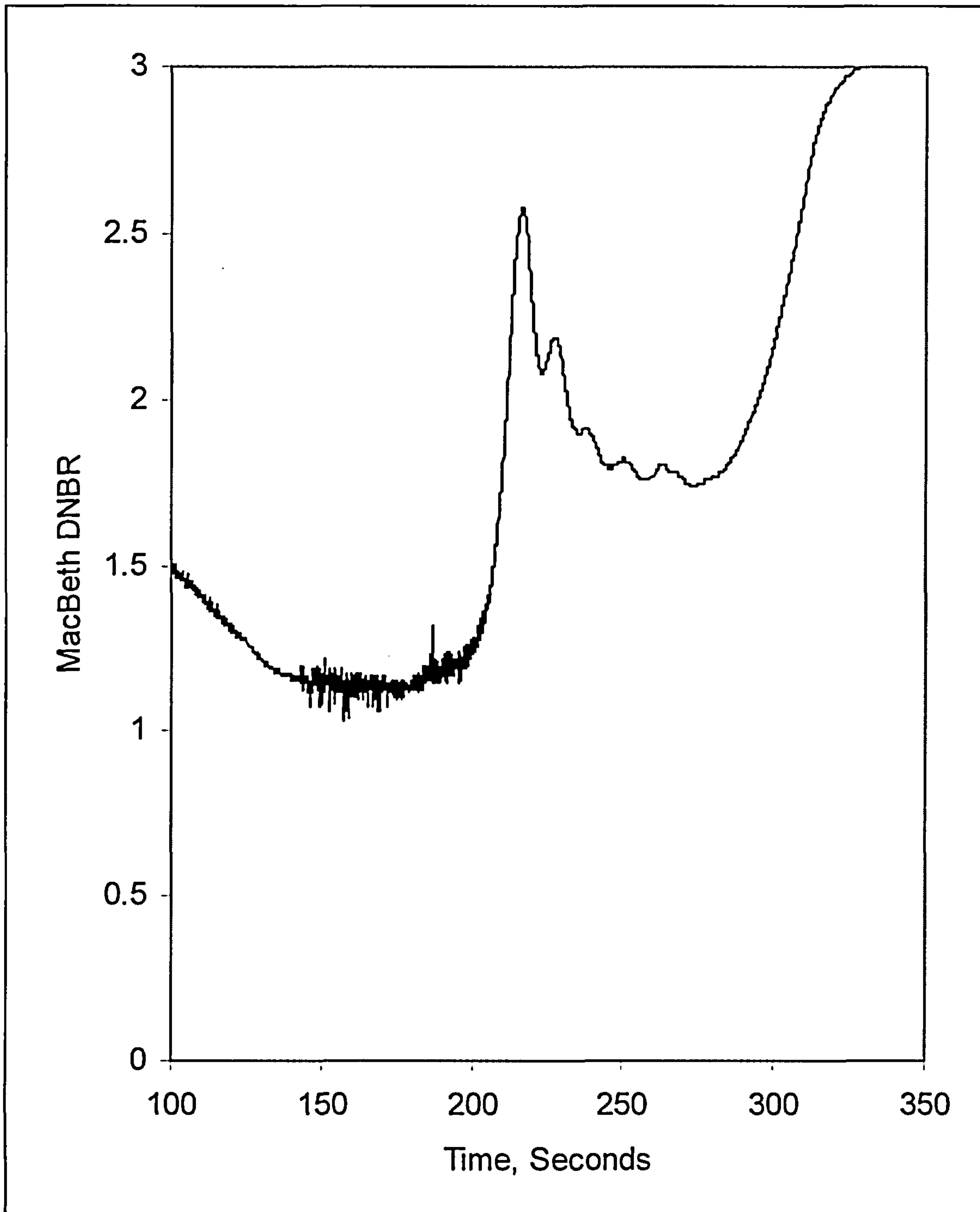


Figure 2.13.1.3.1-13
Inside Containment, HFP SLB with LOOP
DNBR vs. Time

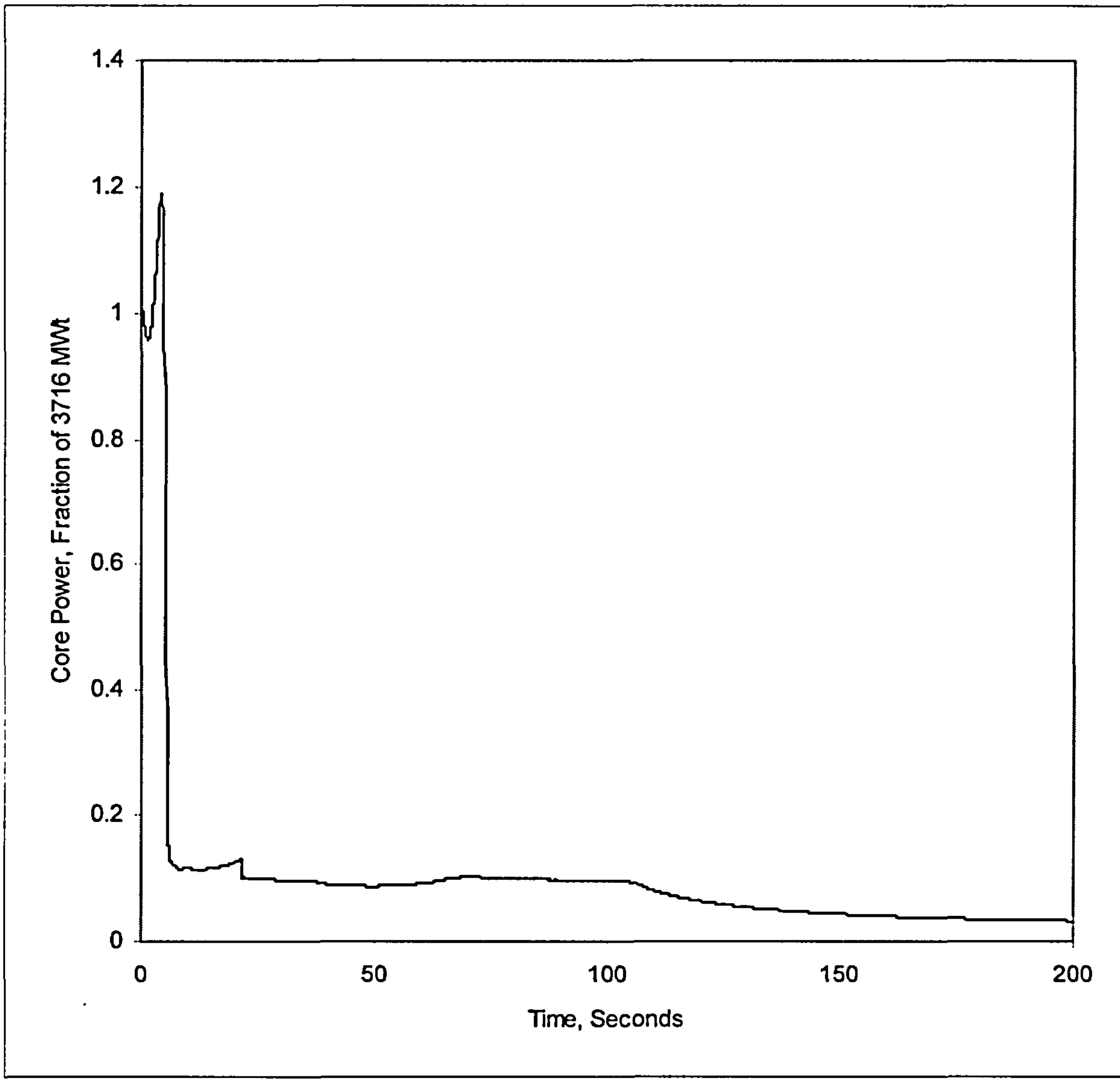


Figure 2.13.1.3.1-14
Return-to-power Steam Line Break
Hot Full Power, No Loss of Offsite Power
Core Power vs. Time

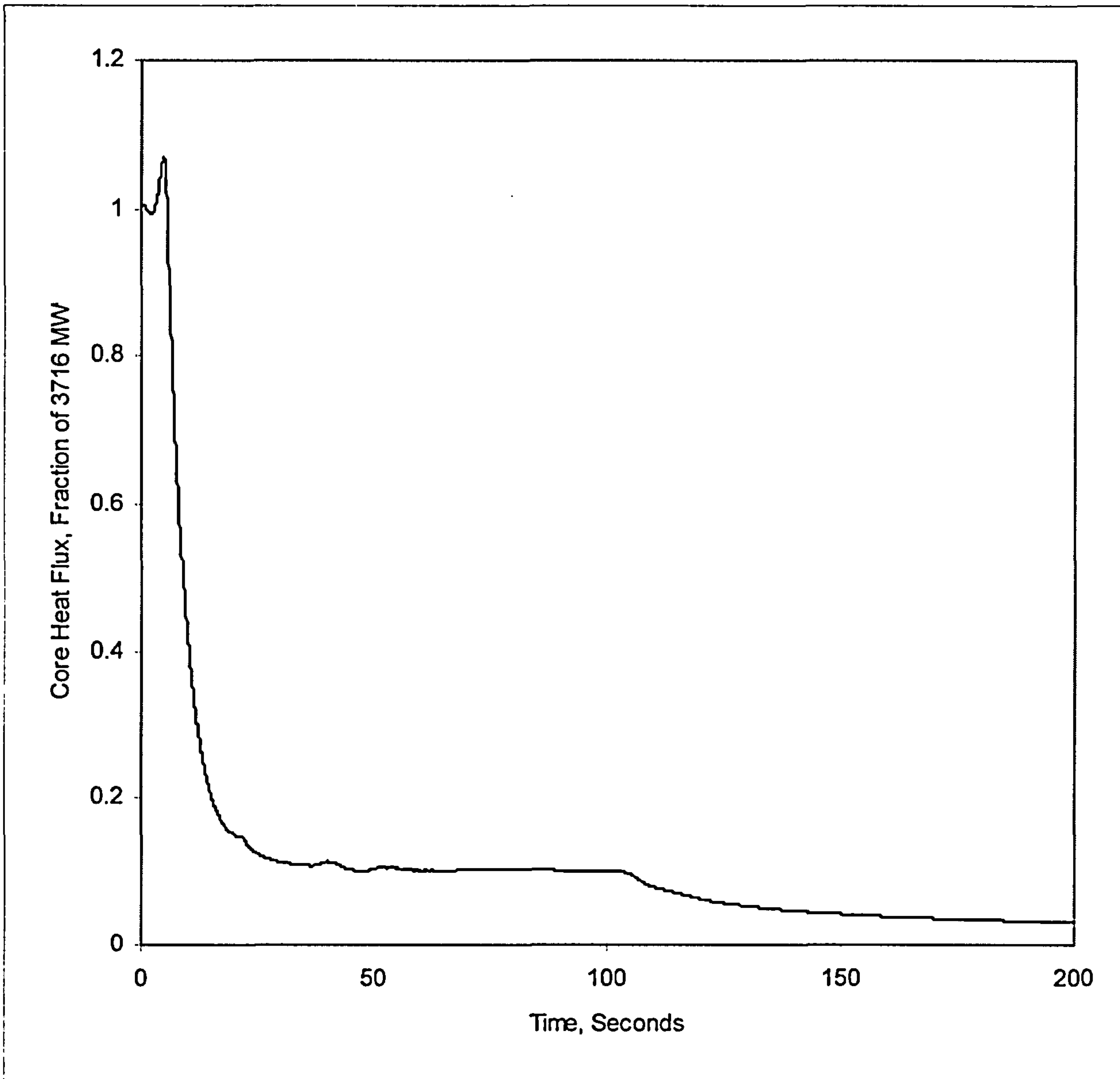


Figure 2.13.1.3.1-15
Return-to-power Steam Line Break
Hot Full Power, No Loss of Offsite Power
Core Heat Flux vs. Time

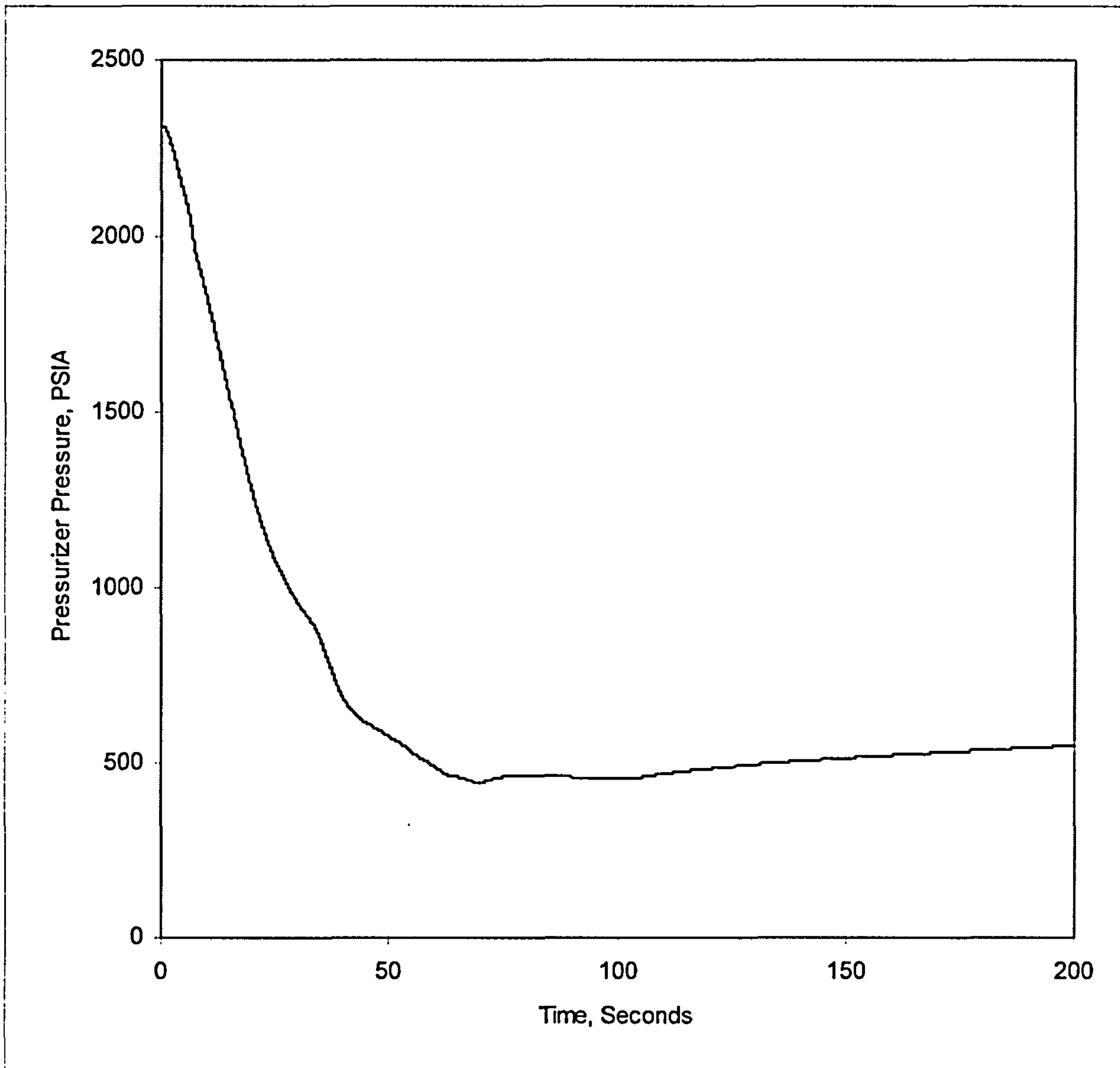


Figure 2.13.1.3.1-16
Return-to-power Steam Line Break
Hot Full Power, No Loss of Offsite Power
Pressurizer Pressure vs. Time

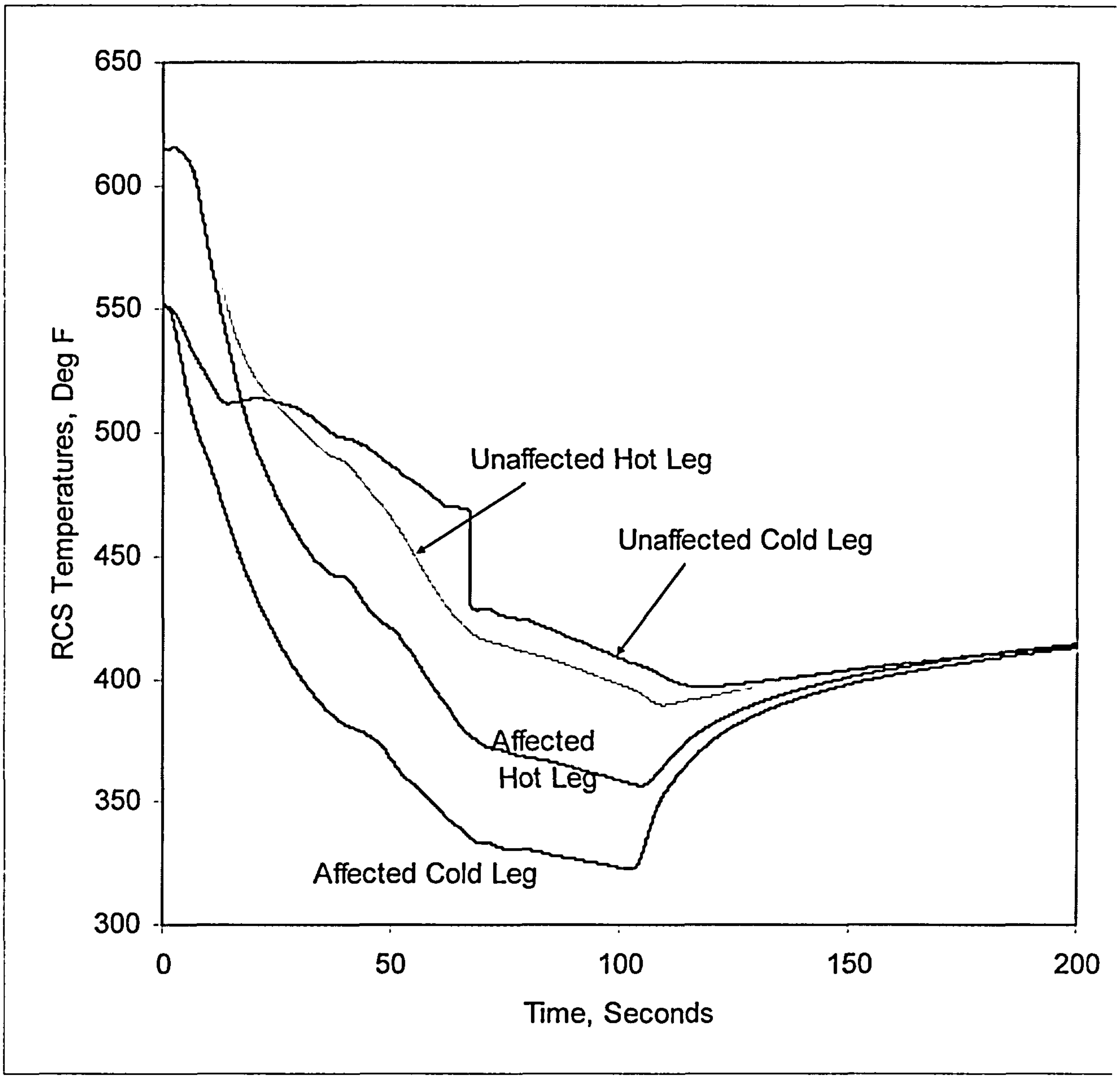


Figure 2.13.1.3.1-17
Return-to-power Steam Line Break
Hot Full Power, No Loss of Offsite Power
Reactor Coolant System Temperatures vs. Time

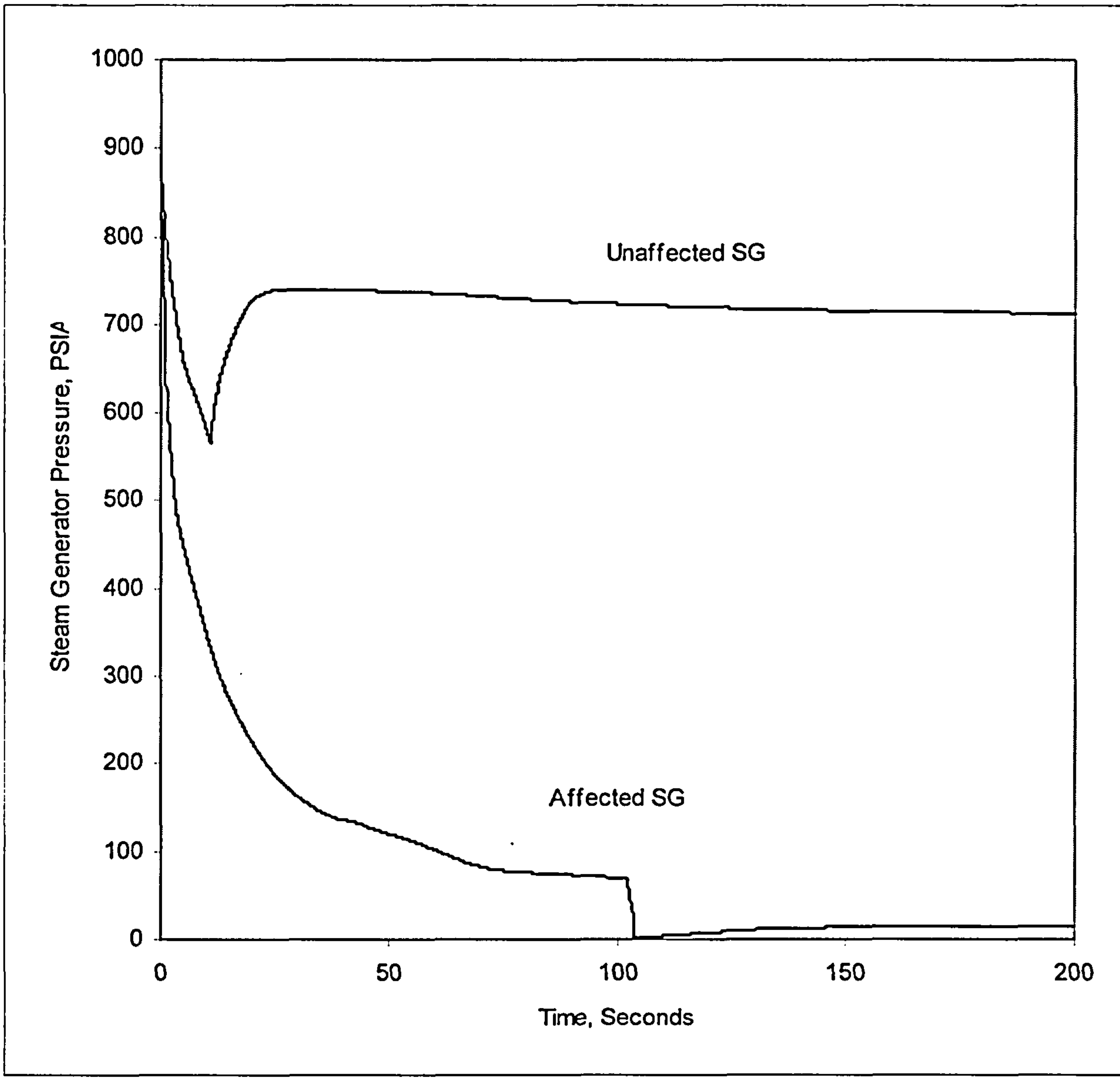


Figure 2.13.1.3.1-18
Return-to-power Steam Line Break
Hot Full Power, No Loss of Offsite Power
Steam Generator Pressure vs. Time

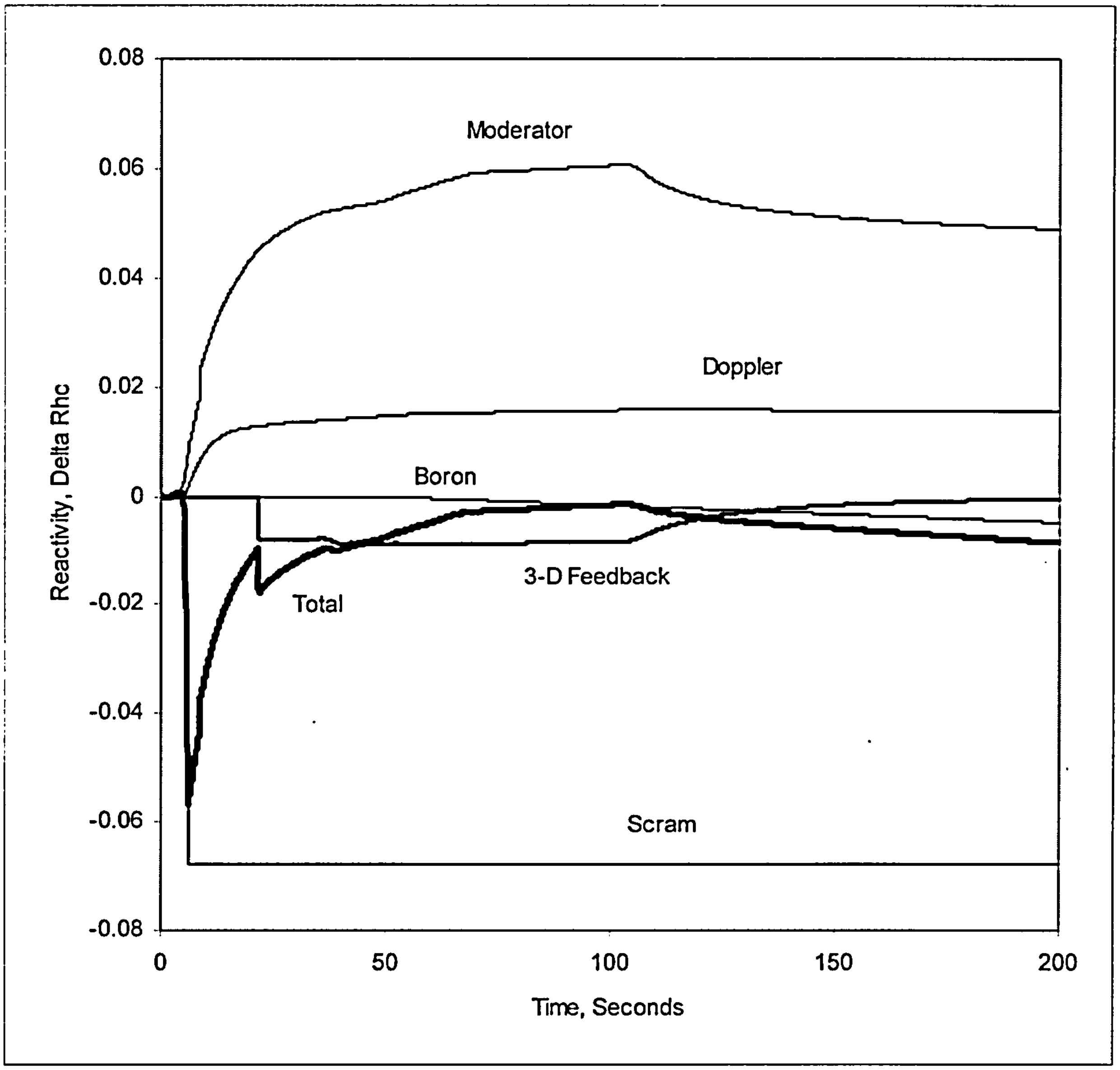


Figure 2.13.1.3.1-19
Return-to-power Steam Line Break
Hot Full Power, No Loss of Offsite Power
Reactivity vs. Time

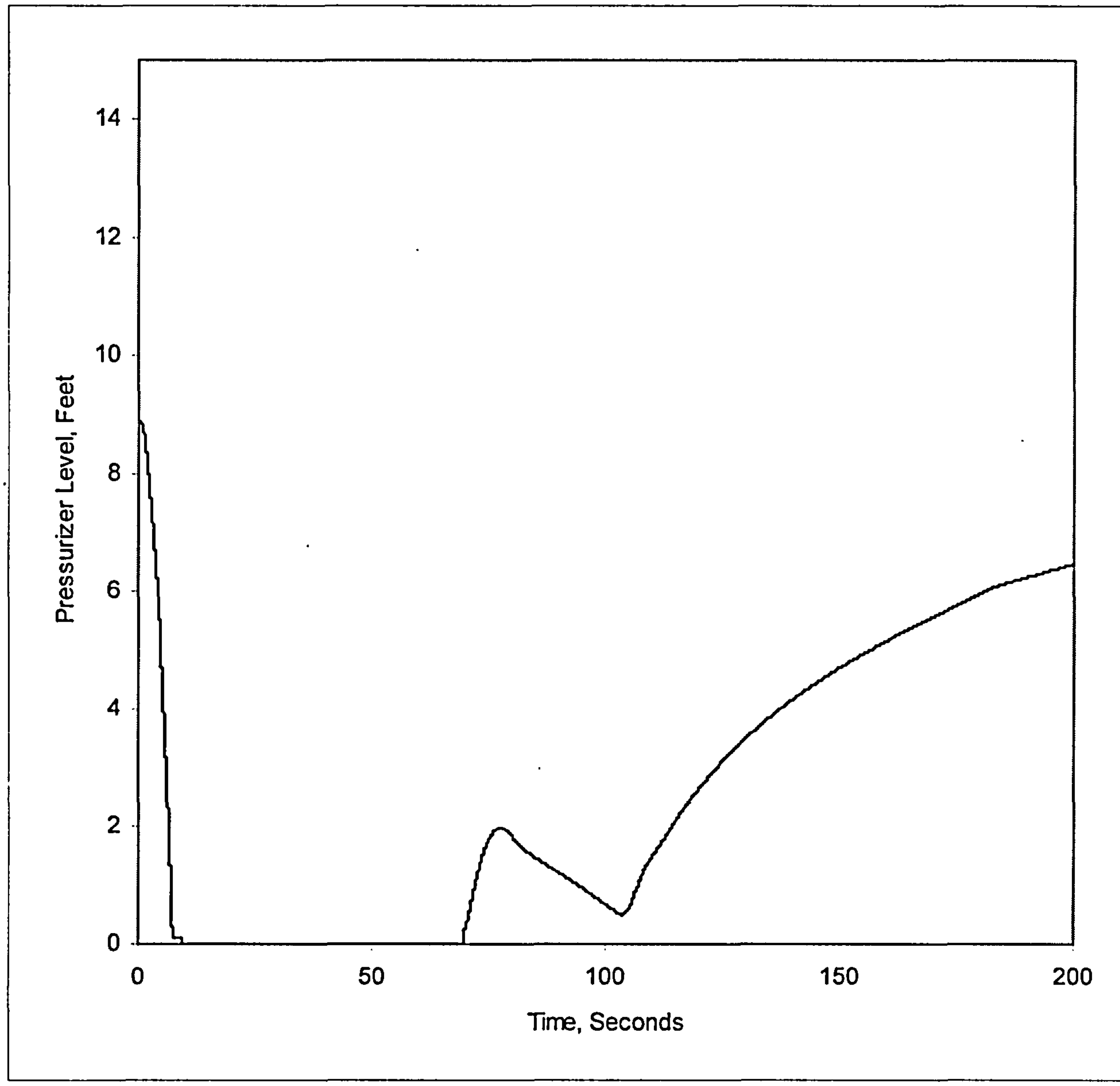


Figure 2.13.1.3.1-20
Return-to-power Steam Line Break
Hot Full Power, No Loss of Offsite Power
Pressurizer Level vs. Time

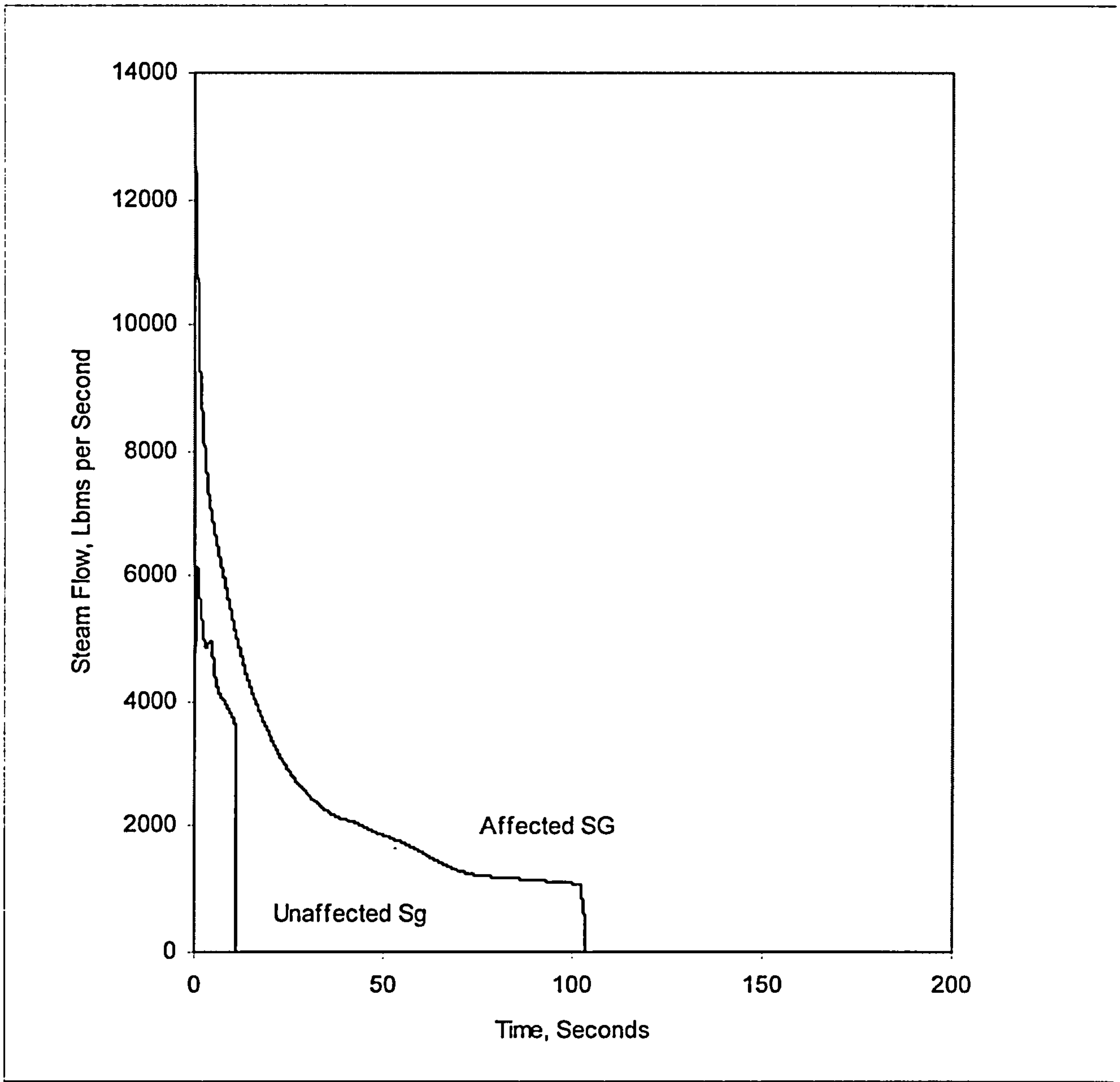


Figure 2.13.1.3.1-21
Return-to-power Steam Line Break
Hot Full Power, No Loss of Offsite Power
Steam Flow vs. Time

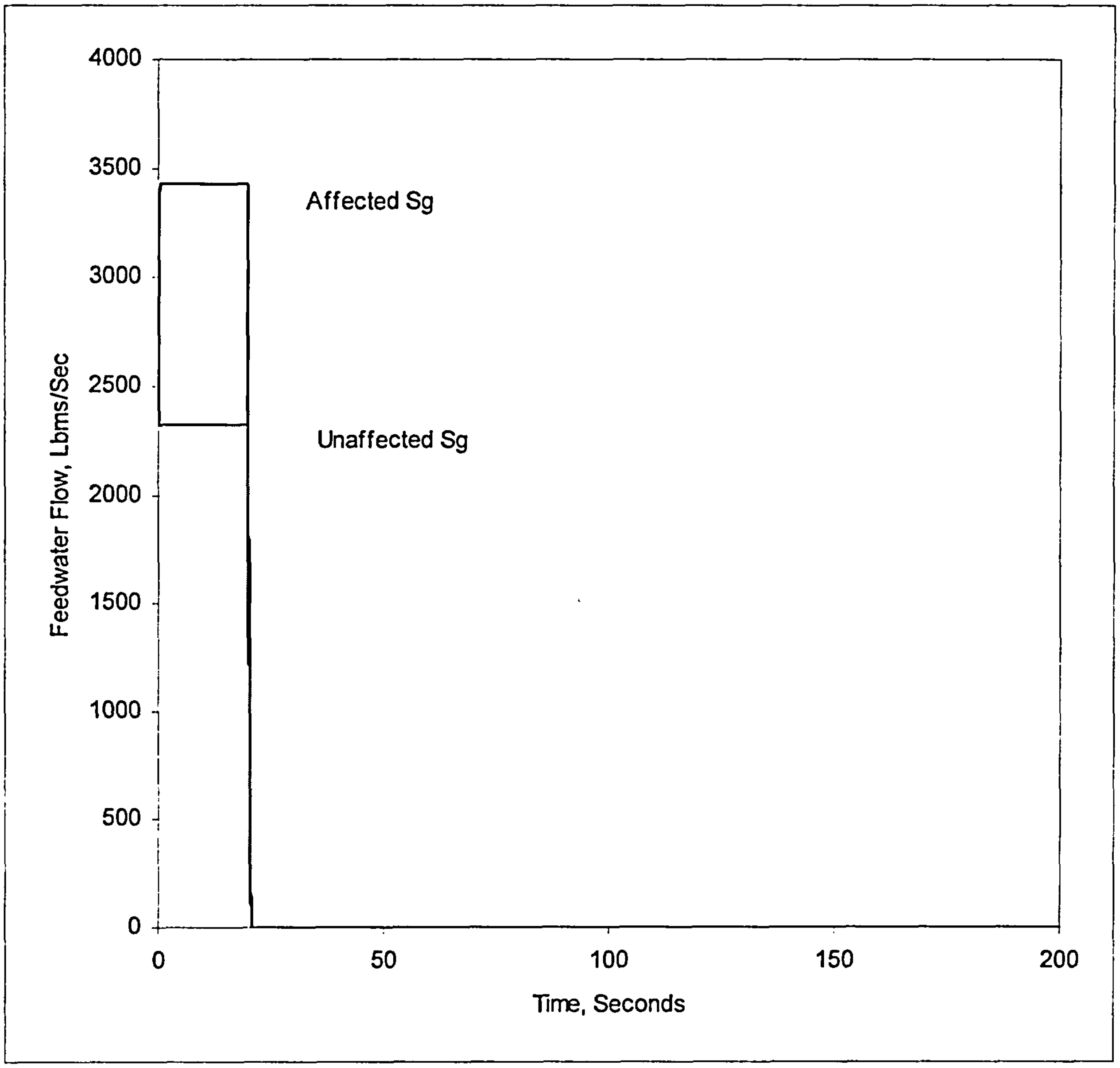


Figure 2.13.1.3.1-22
Return-to-power Steam Line Break
Hot Full Power, No Loss of Offsite Power
Feedwater Flow vs. Time

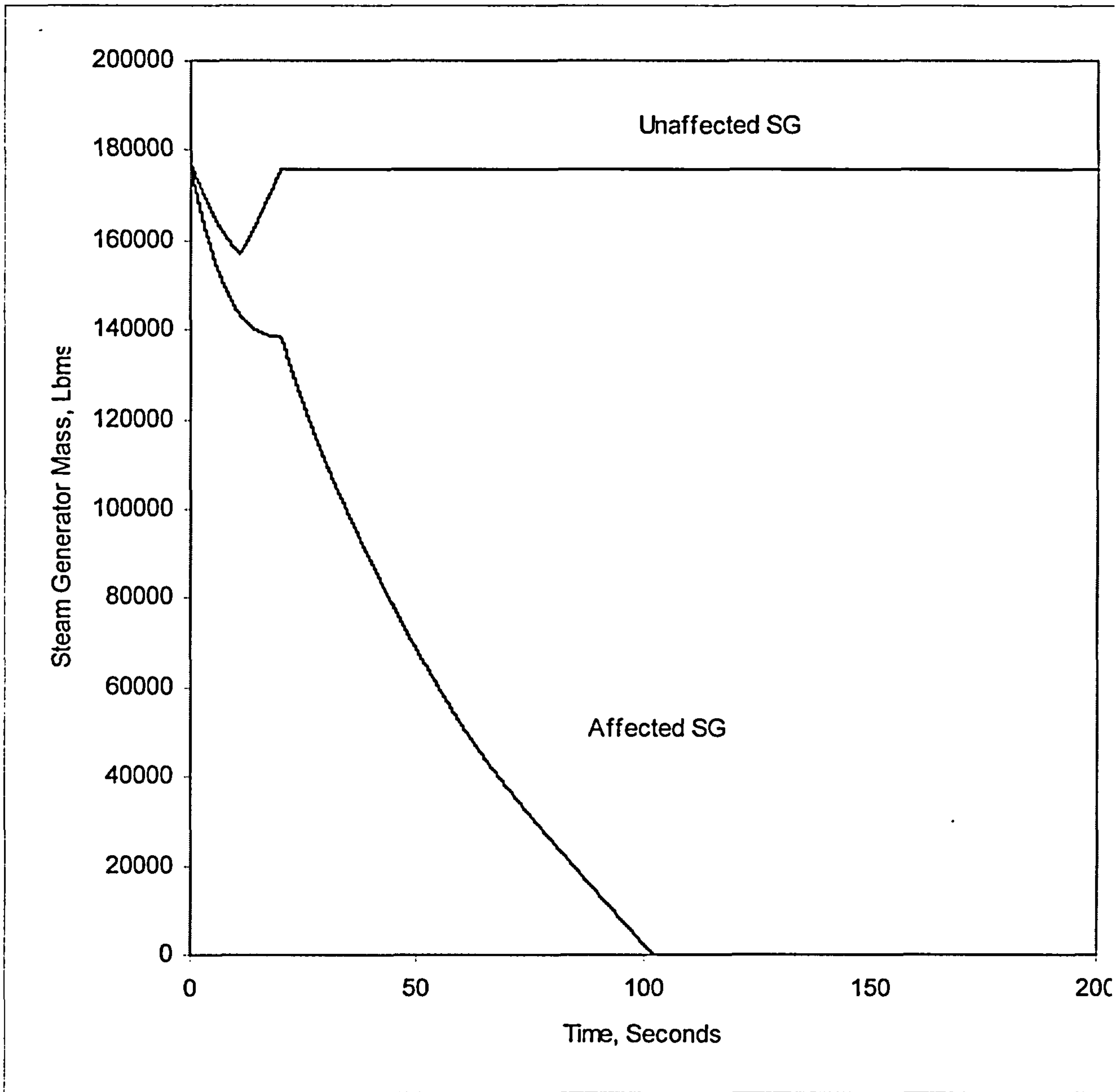


Figure 2.13.1.3.1-23
Return-to-power Steam Line Break
Hot Full Power, No Loss of Offsite Power
Steam Generator Mass vs. Time

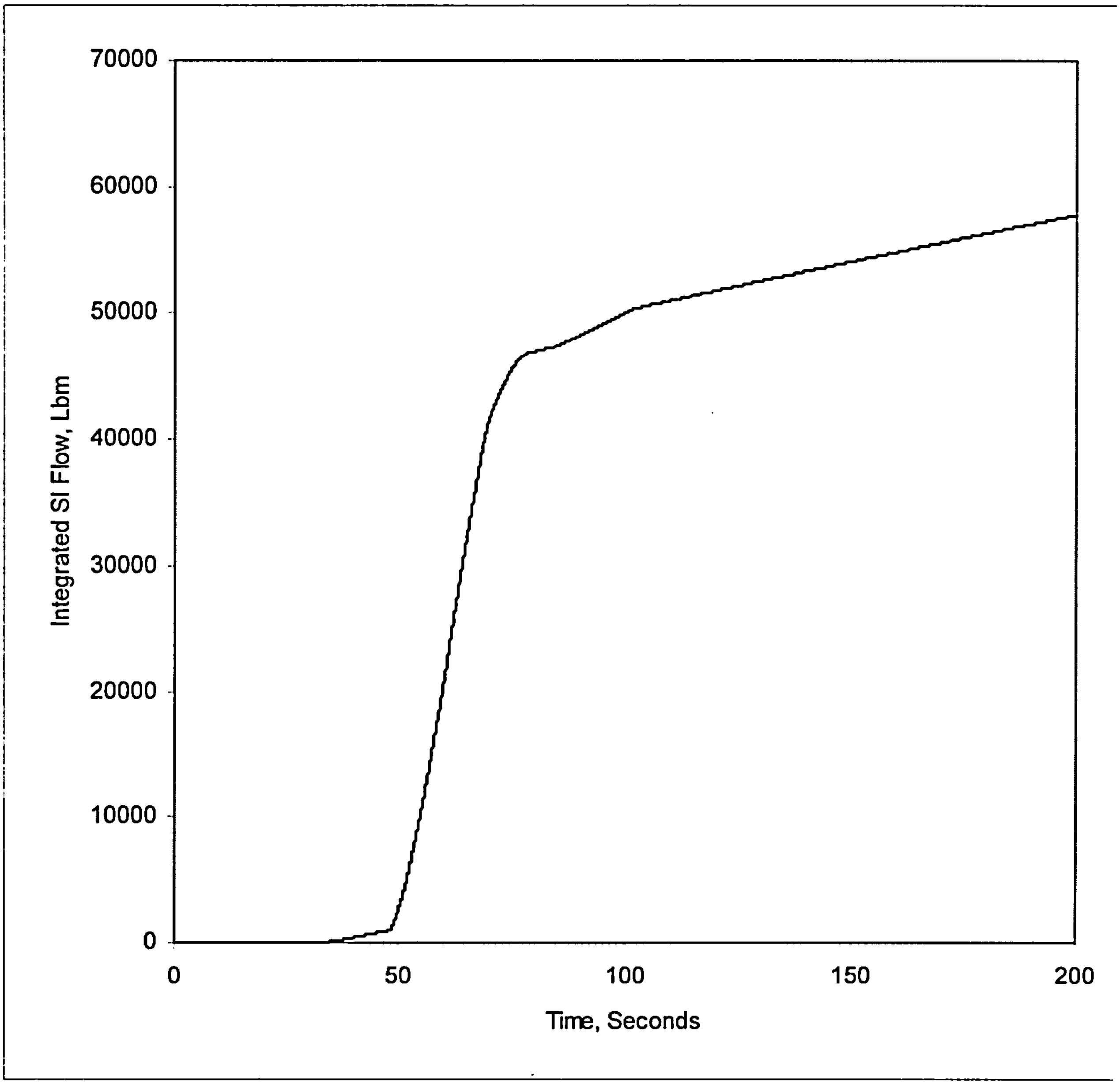


Figure 2.13.1.3.1-24
Return-to-power Steam Line Break
Hot Full Power, No Loss of Offsite Power
Integrated Safety Injection Flow vs. Time

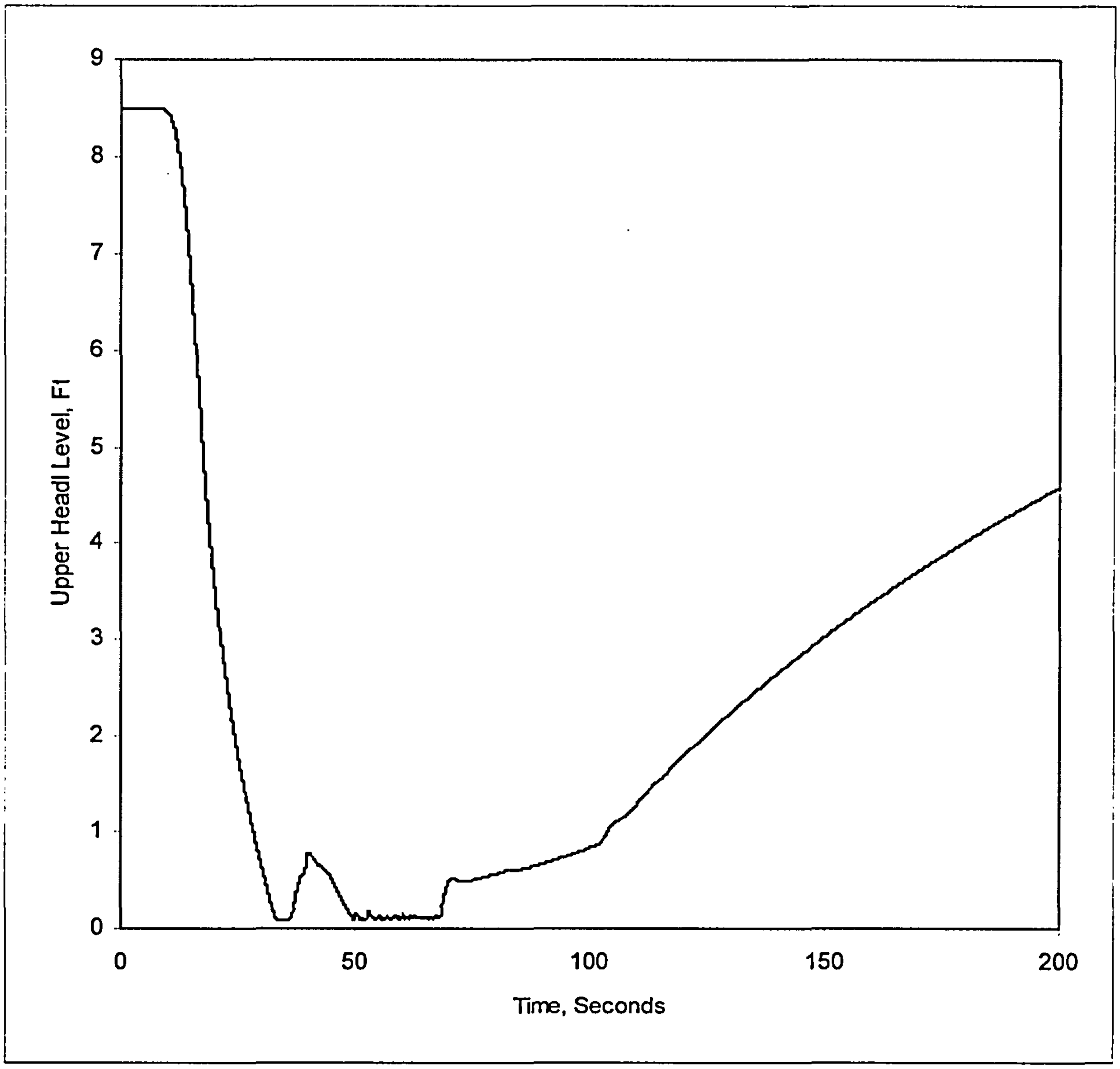


Figure 2.13.1.3.1-25
Return-to-power Steam Line Break
Hot Full Power, No Loss of Offsite Power
Reactor Vessel Upper Head Level vs. Time

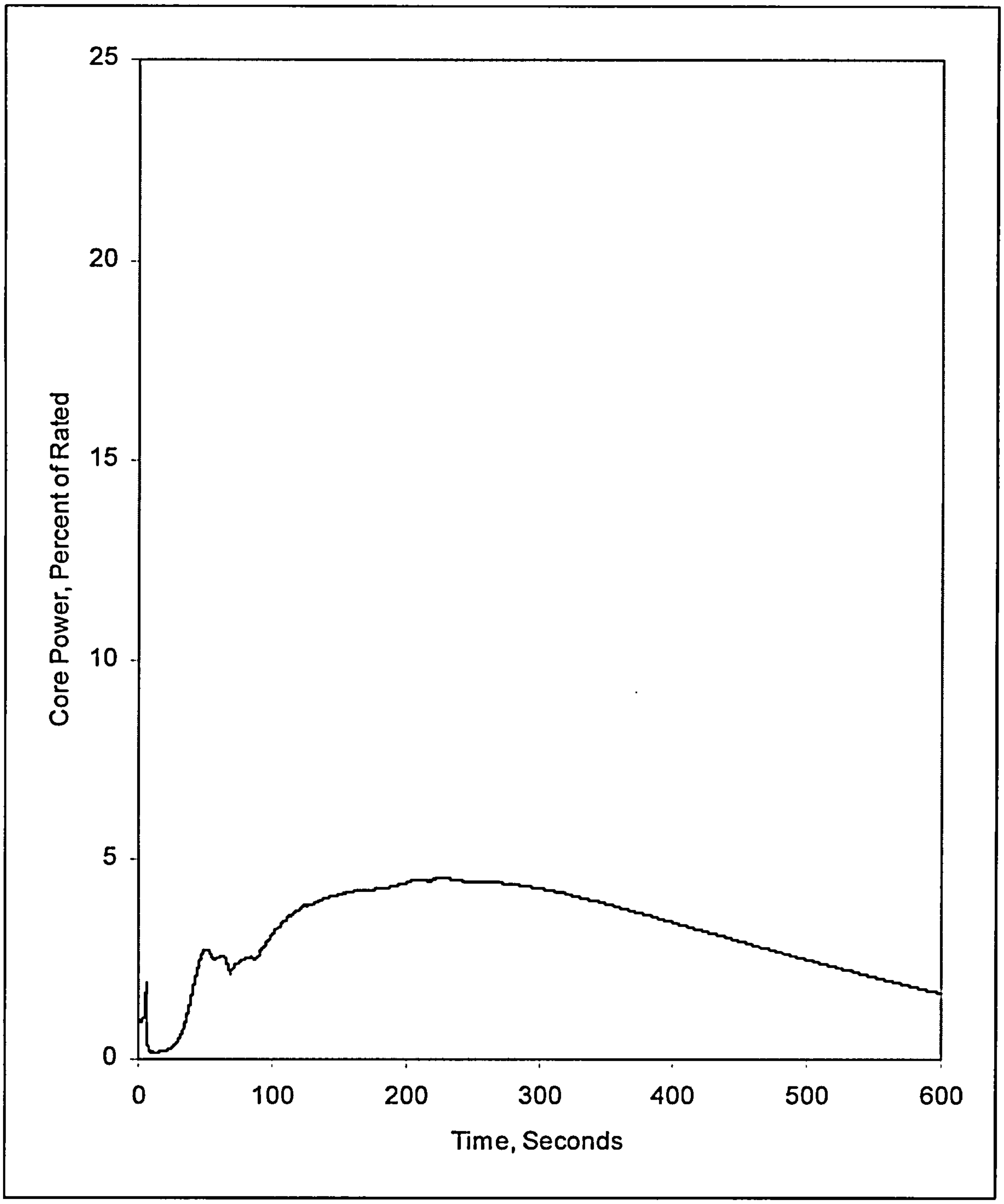


Figure 2.13.1.3.1-26
Inside Containment, HZP SLB with LOOP
Core Power vs. Time

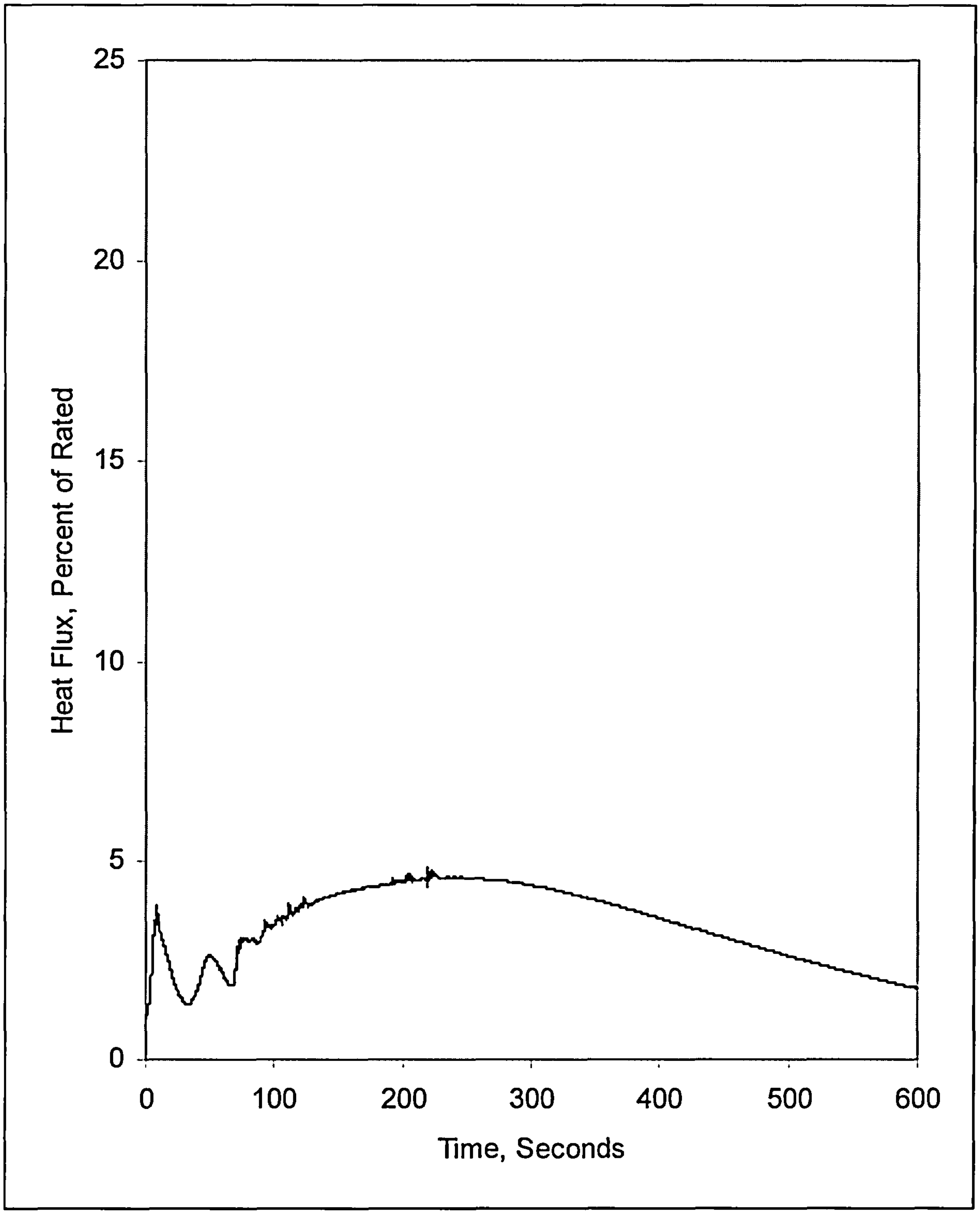


Figure 2.13.1.3.1-27
Inside Containment, HZP SLB with LOOP
Core Heat Flux vs. Time

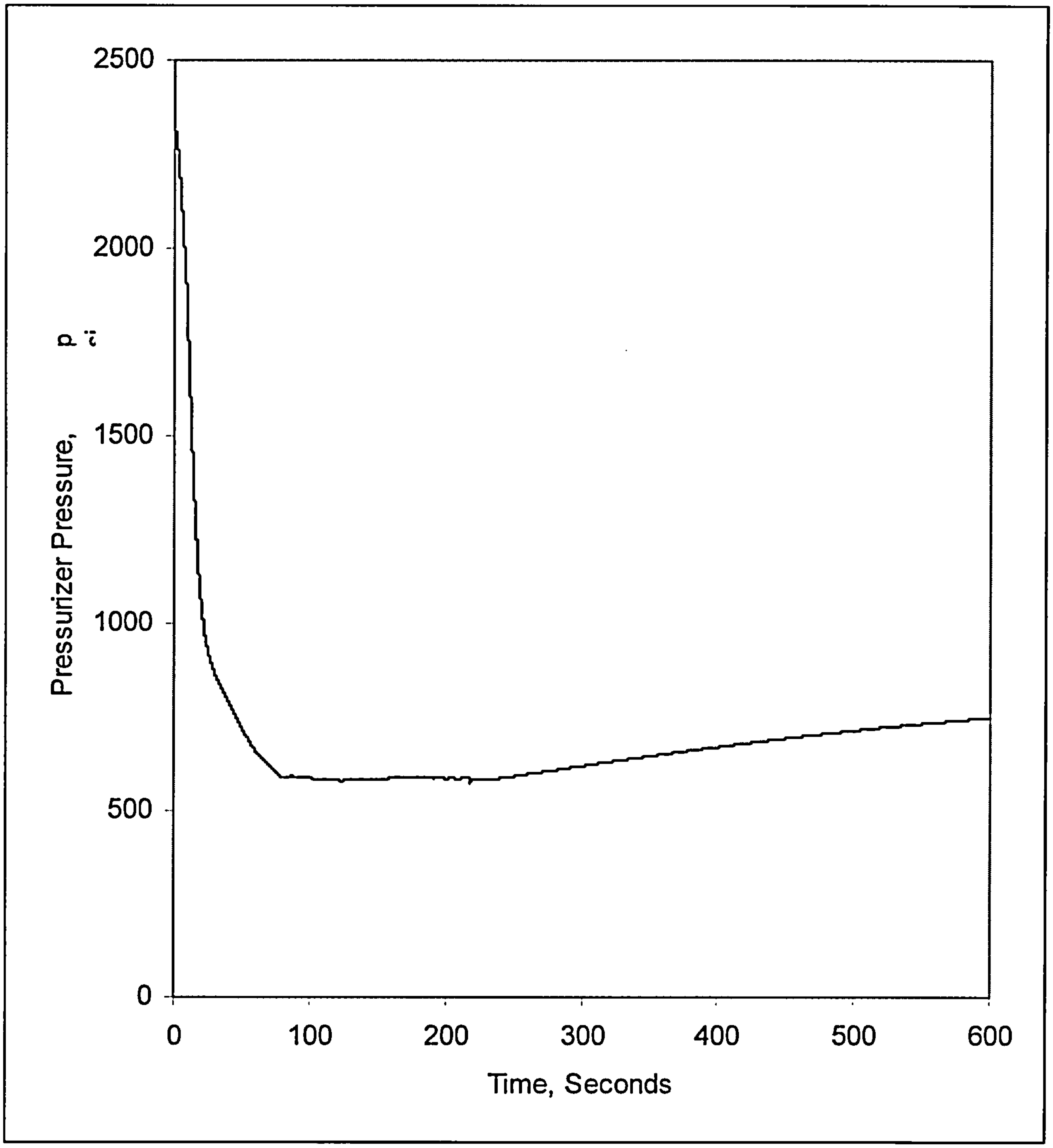


Figure 2.13.1.3.1-28
Inside Containment, HZP SLB with LOOP
Pressurizer Pressure vs. Time

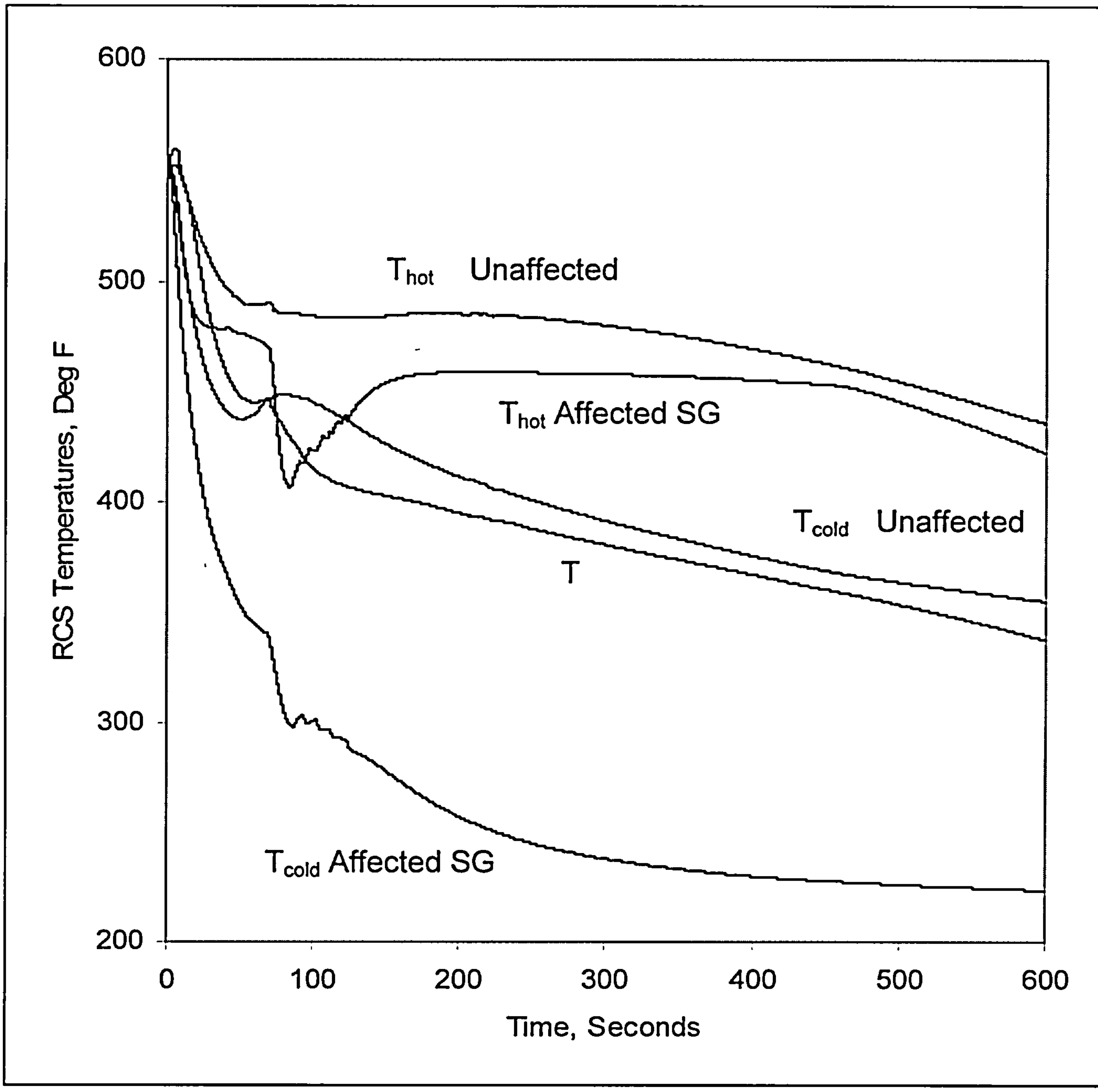


Figure 2.13.1.3.1-29
Inside Containment, HZP SLB with LOOP
RCS Temperature vs. Time

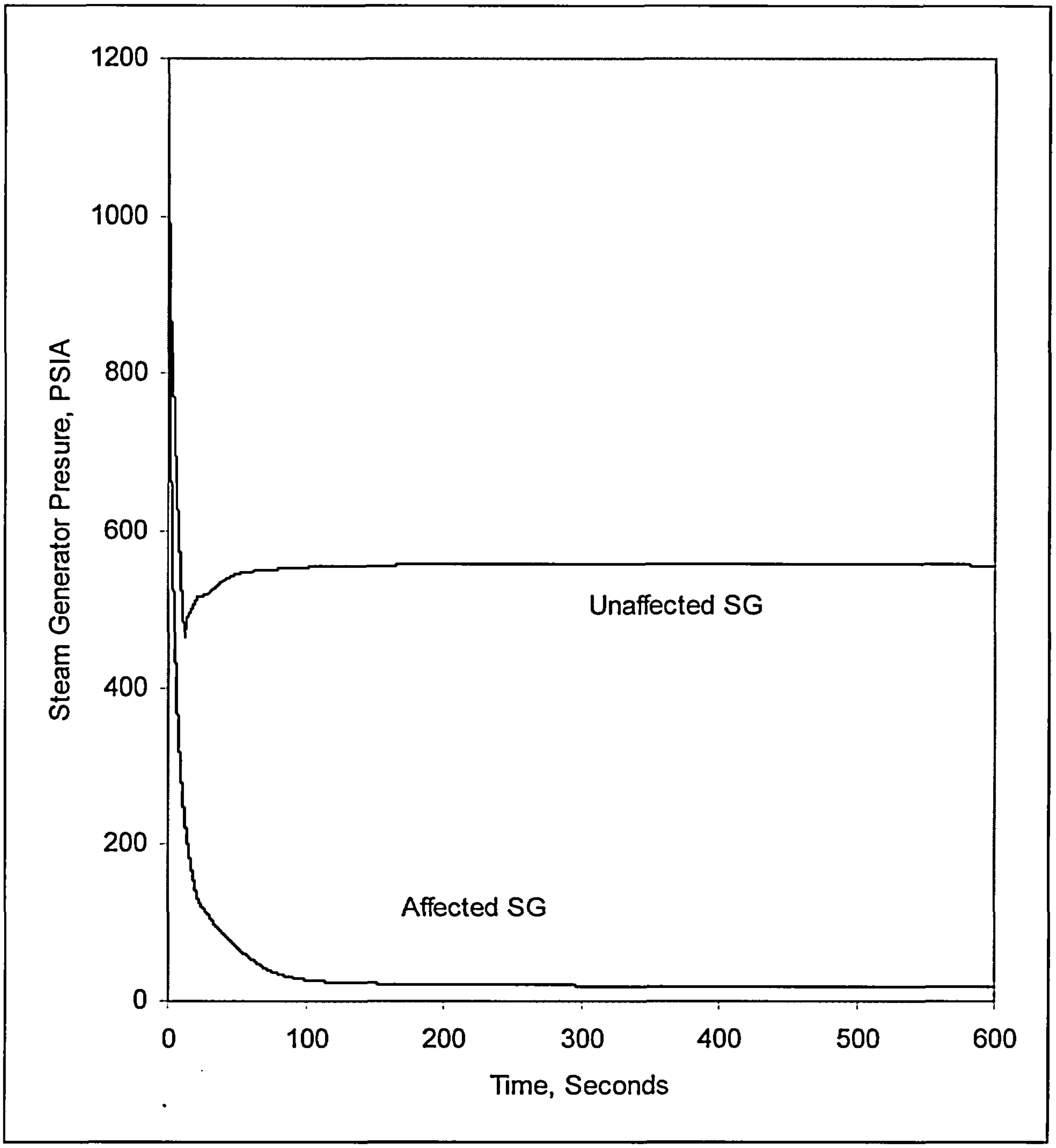


Figure 2.13.1.3.1-30
Inside Containment, HZP SLB with LOOP
SG Pressure vs. Time

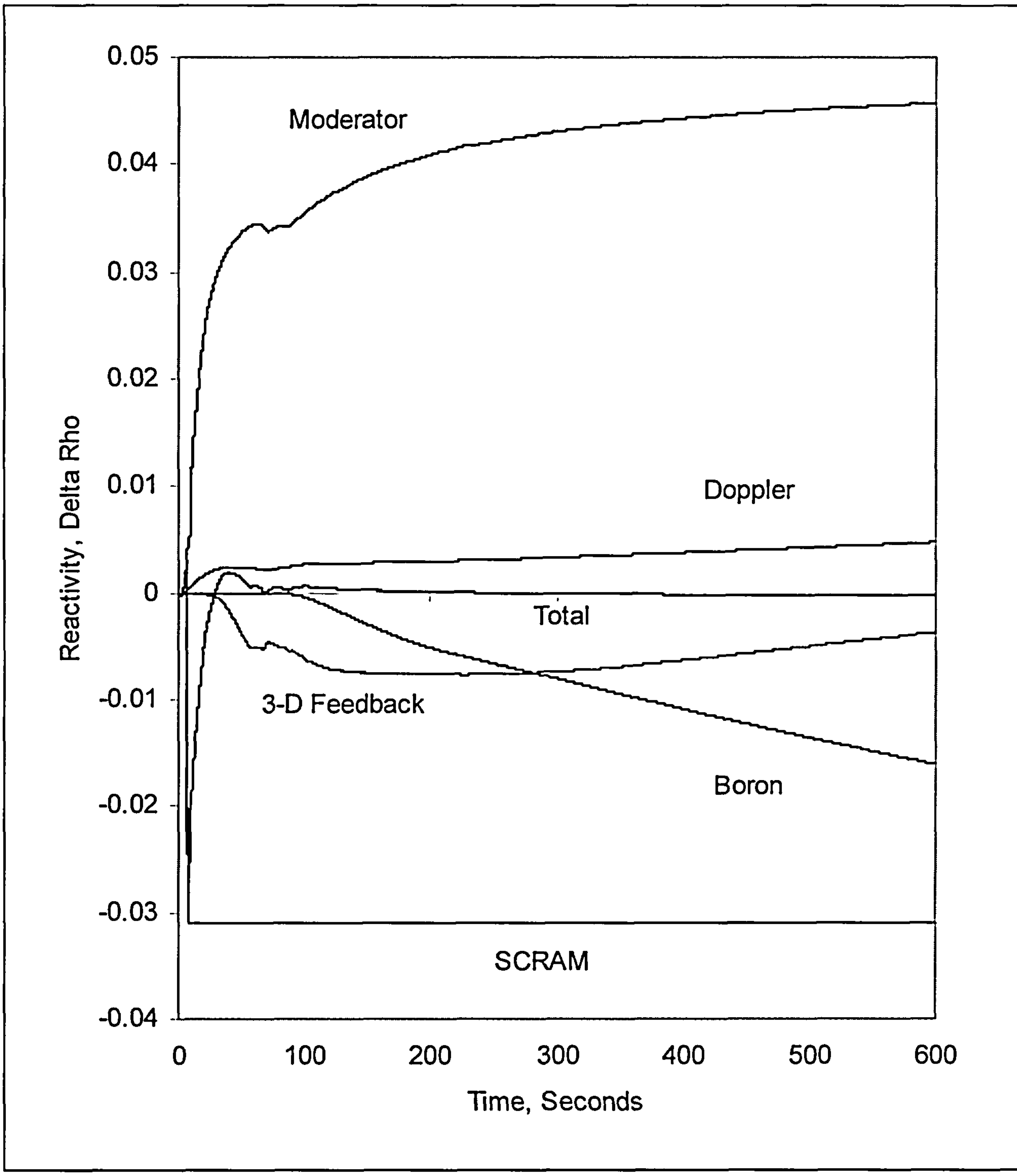


Figure 2.13.1.3.1-31
Inside Containment, HZP SLB with LOOP
Reactivity vs. Time

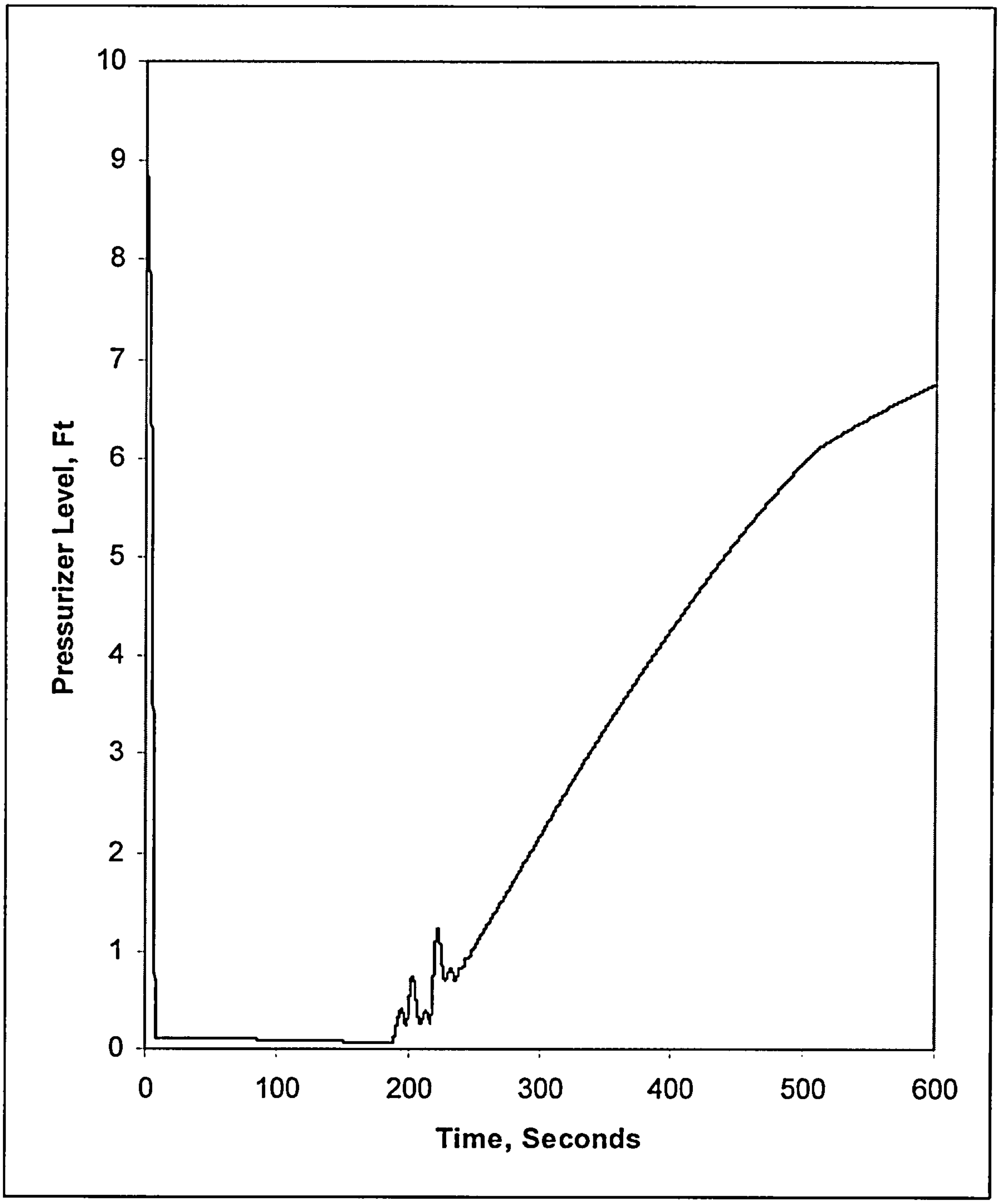


Figure 2.13.1.3.1-32
Inside Containment, HZP SLB with LOOP
Pressurizer Level vs. Time

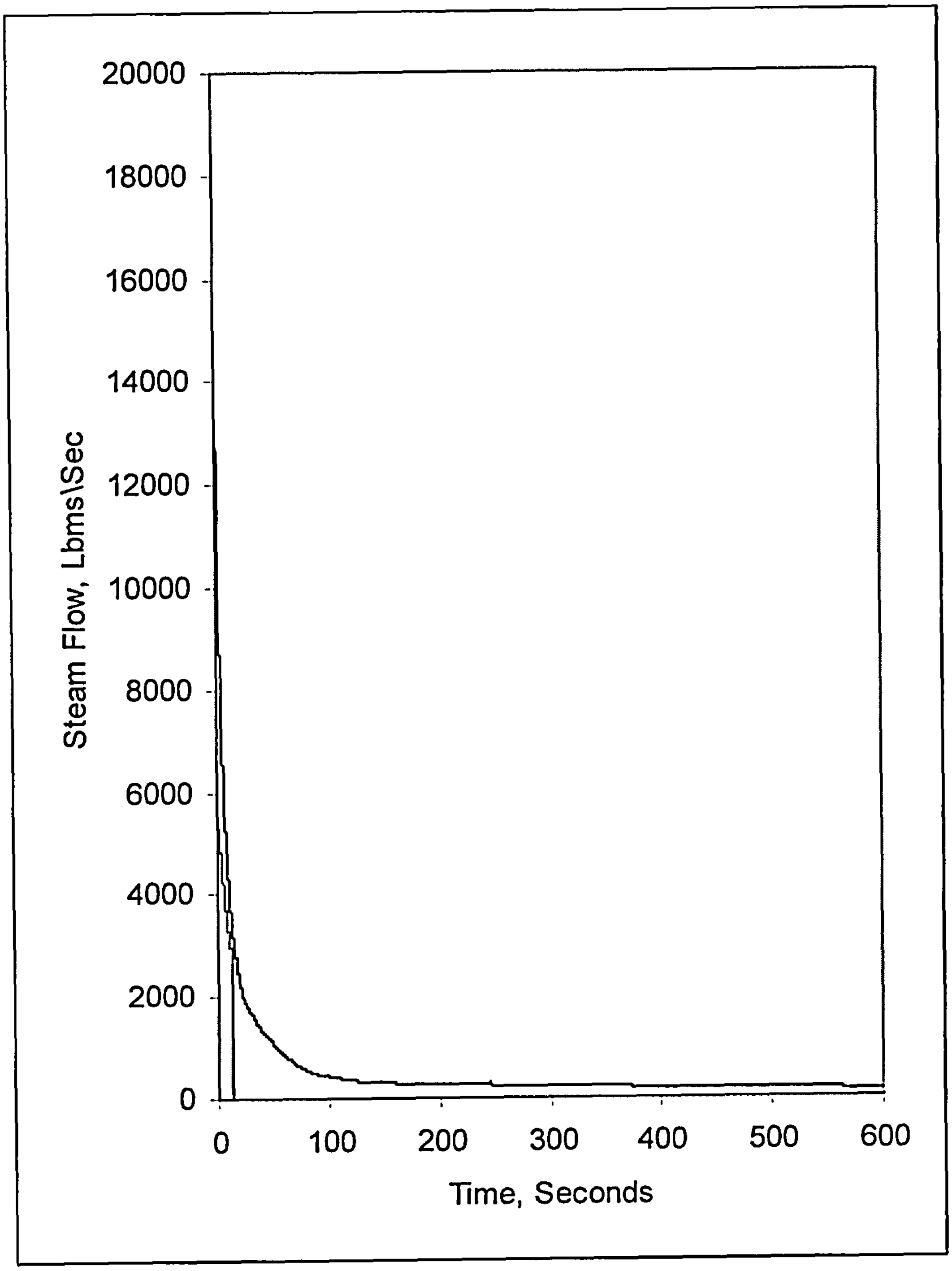


Figure 2.13.1.3.1-33
Inside Containment, HZP SLB with LOOP
Steam Flow vs. Time

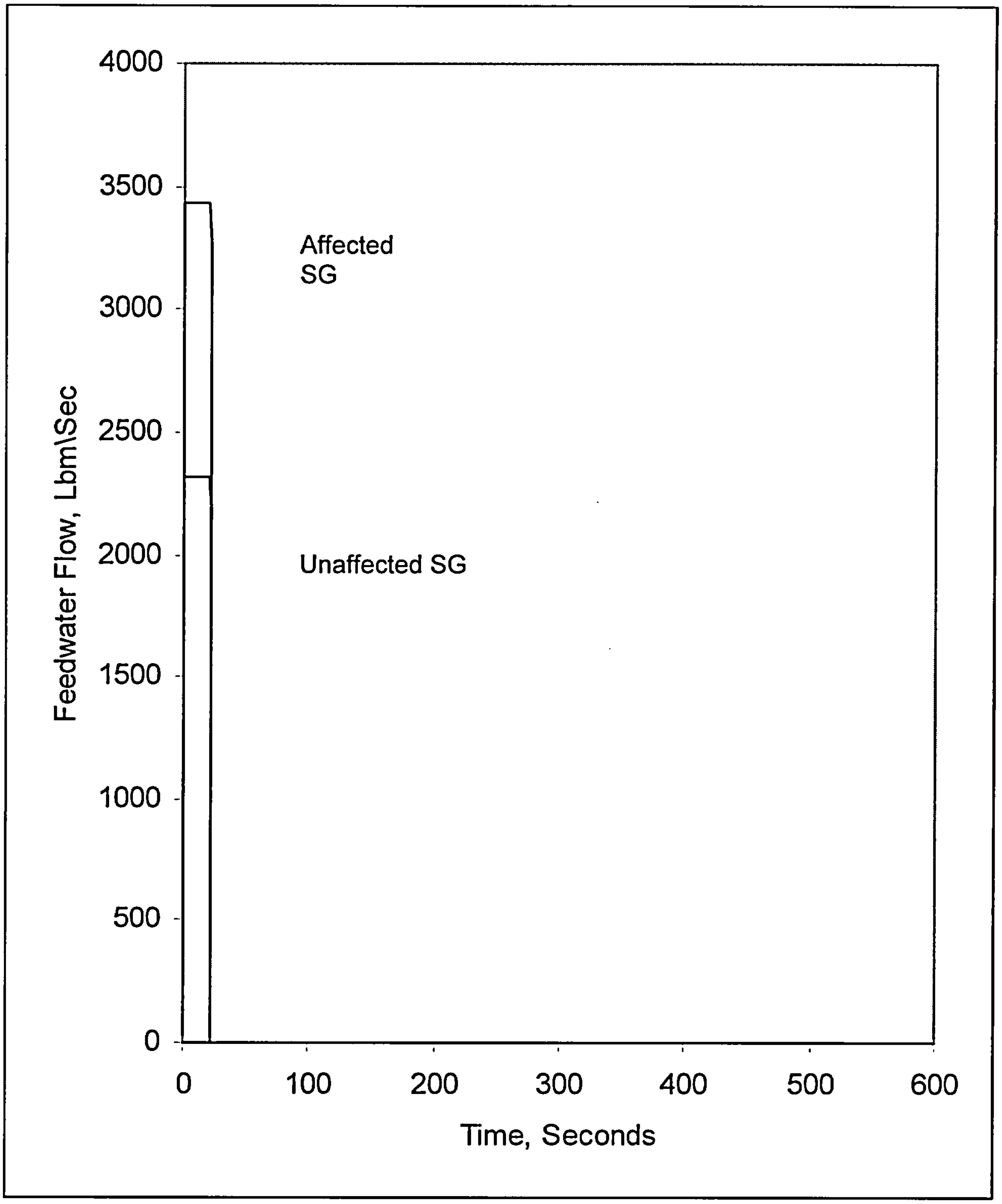


Figure 2.13.1.3.1-34
Inside Containment, HZP SLB with LOOP
Feedwater Flow vs. Time

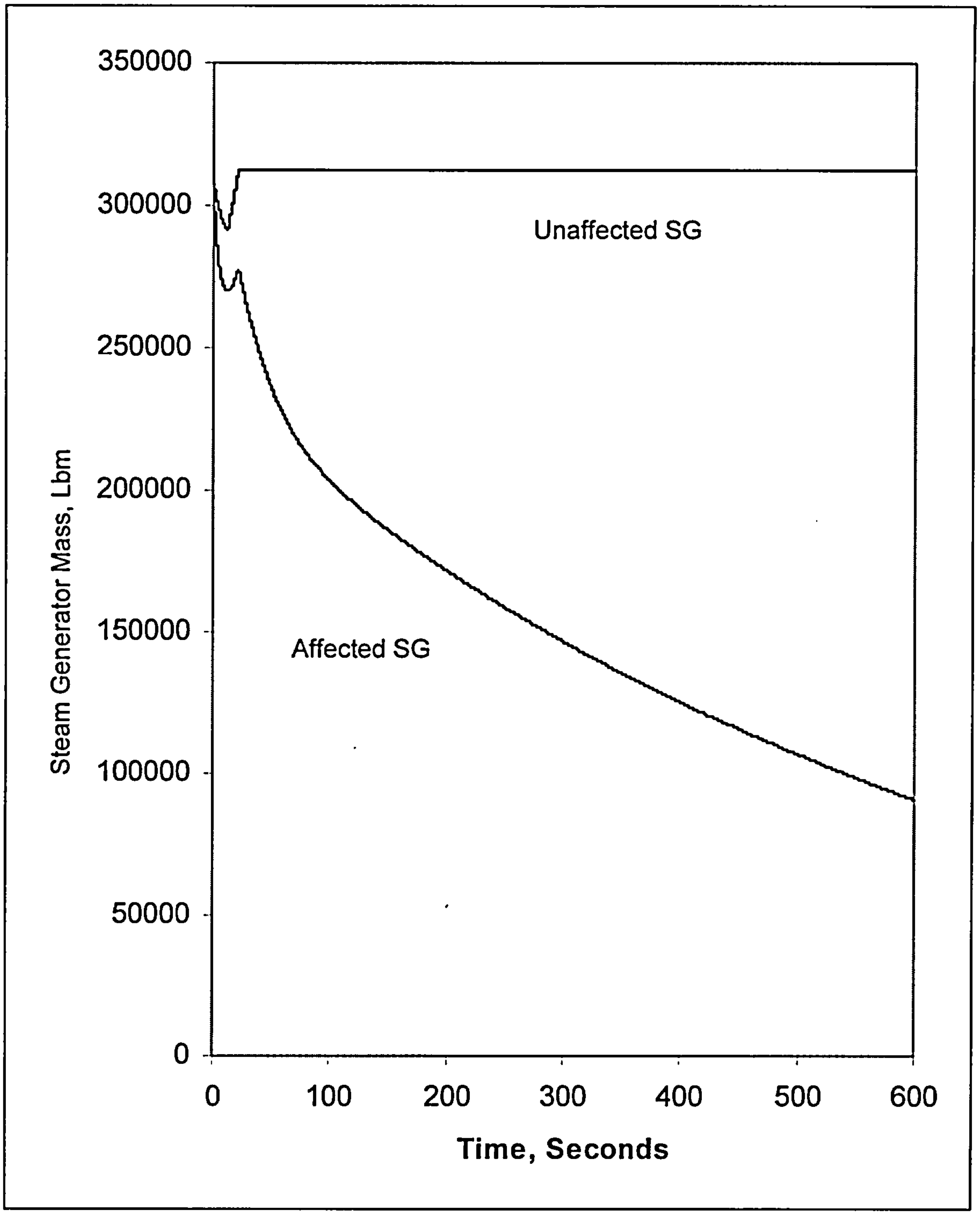


Figure 2.13.1.3.1-35
Inside Containment, HZP SLB with LOOP
SG Mass vs. Time

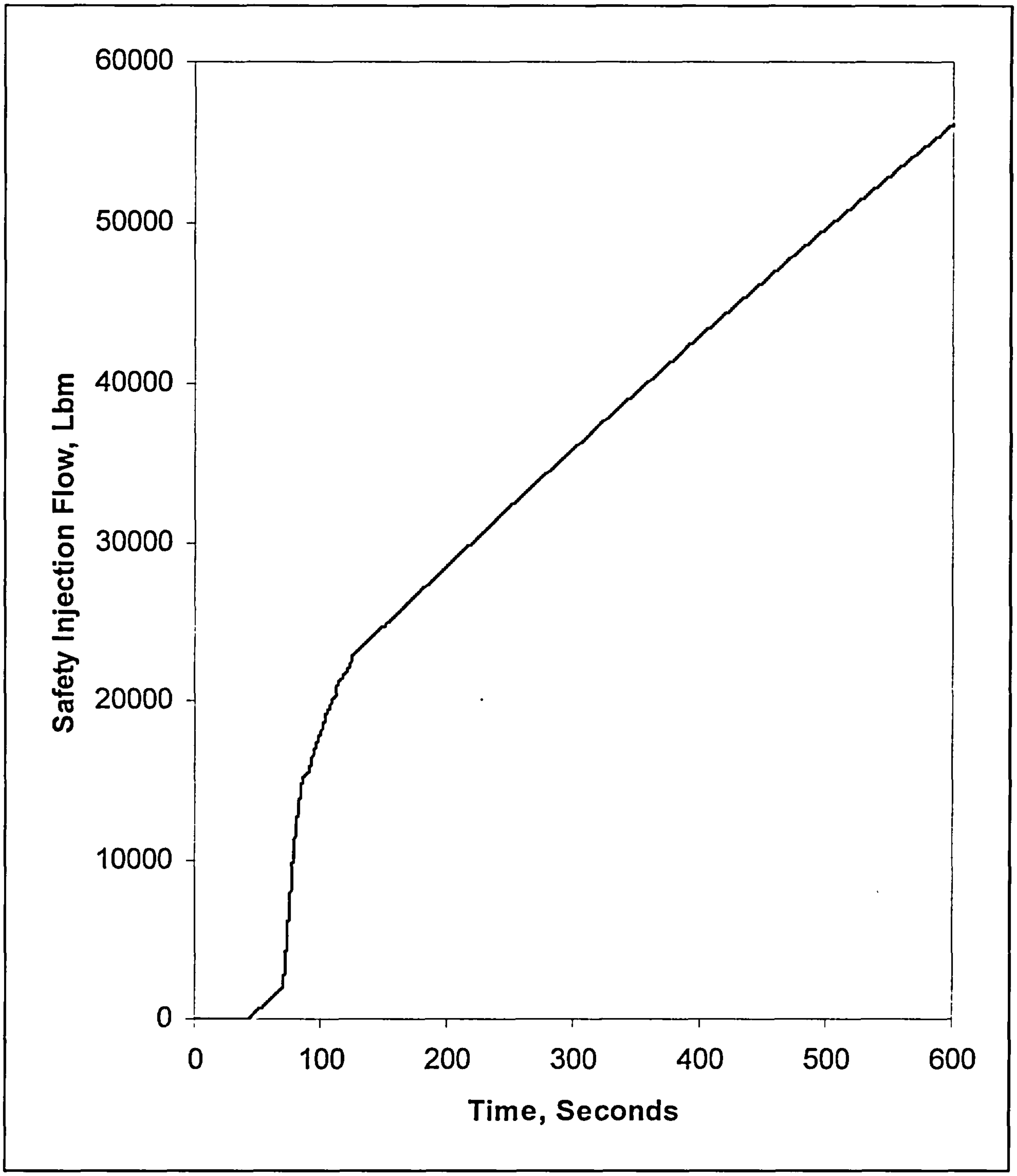


Figure 2.13.1.3.1-36
Inside Containment, HZP SLB with LOOP
Integrated Safety Injection Flow vs. Time

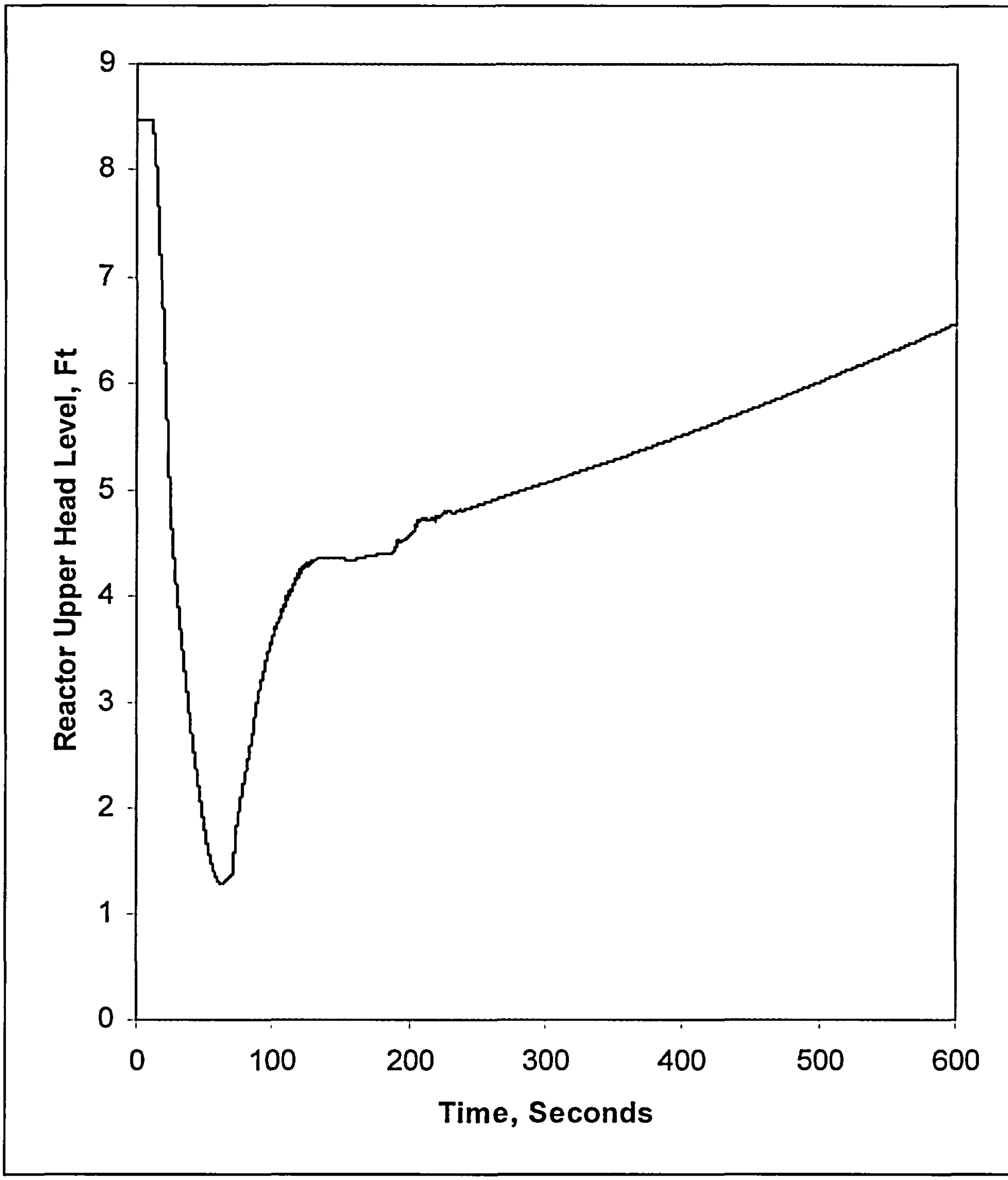


Figure 2.13.1.3.1-37
Inside Containment, HZP SLB with LOOP
Reactor Vessel Level vs. Time

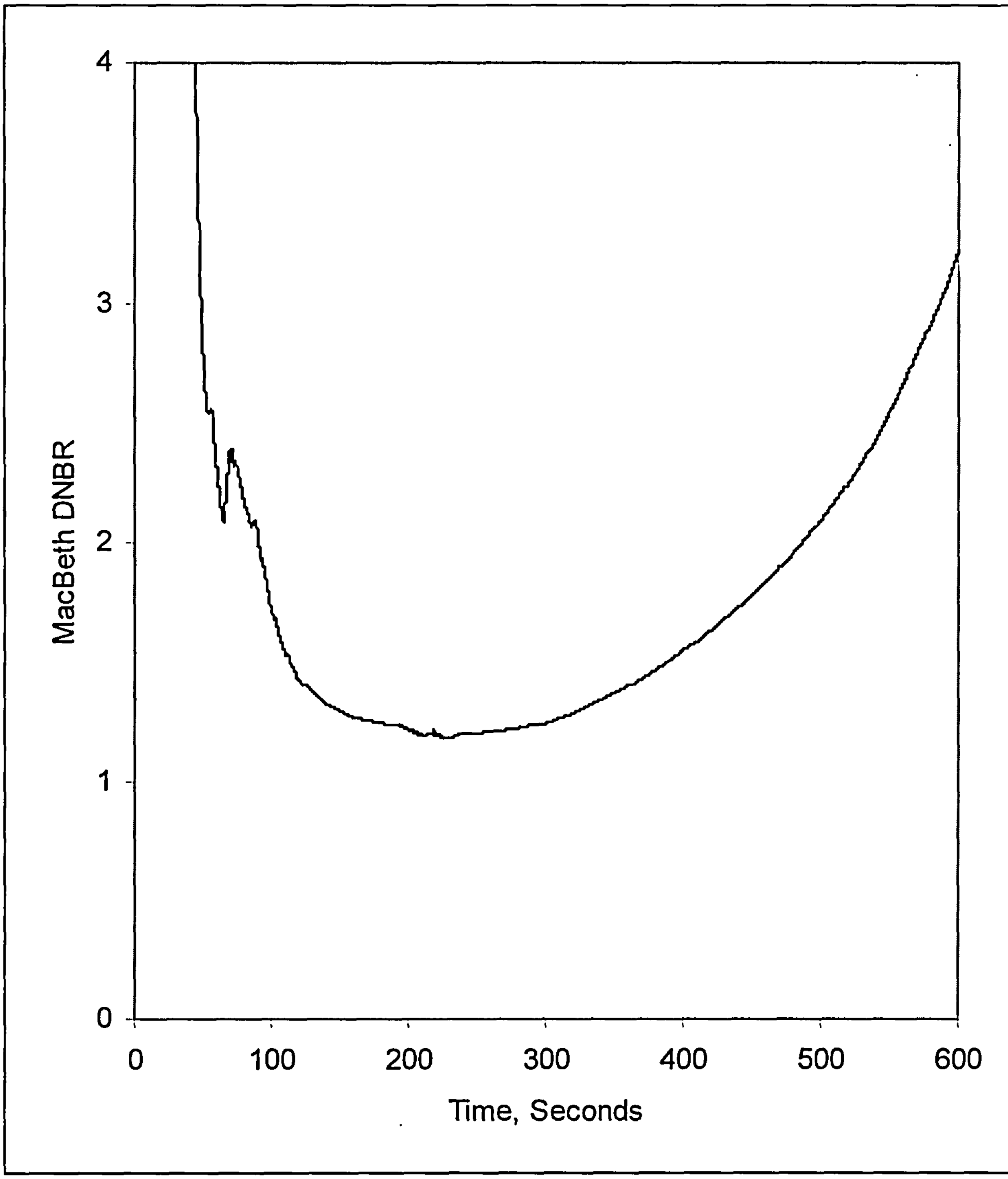


Figure 2.13.1.3.1-38
Inside Containment, HZP SLB with LOOP
DNBR vs. Time

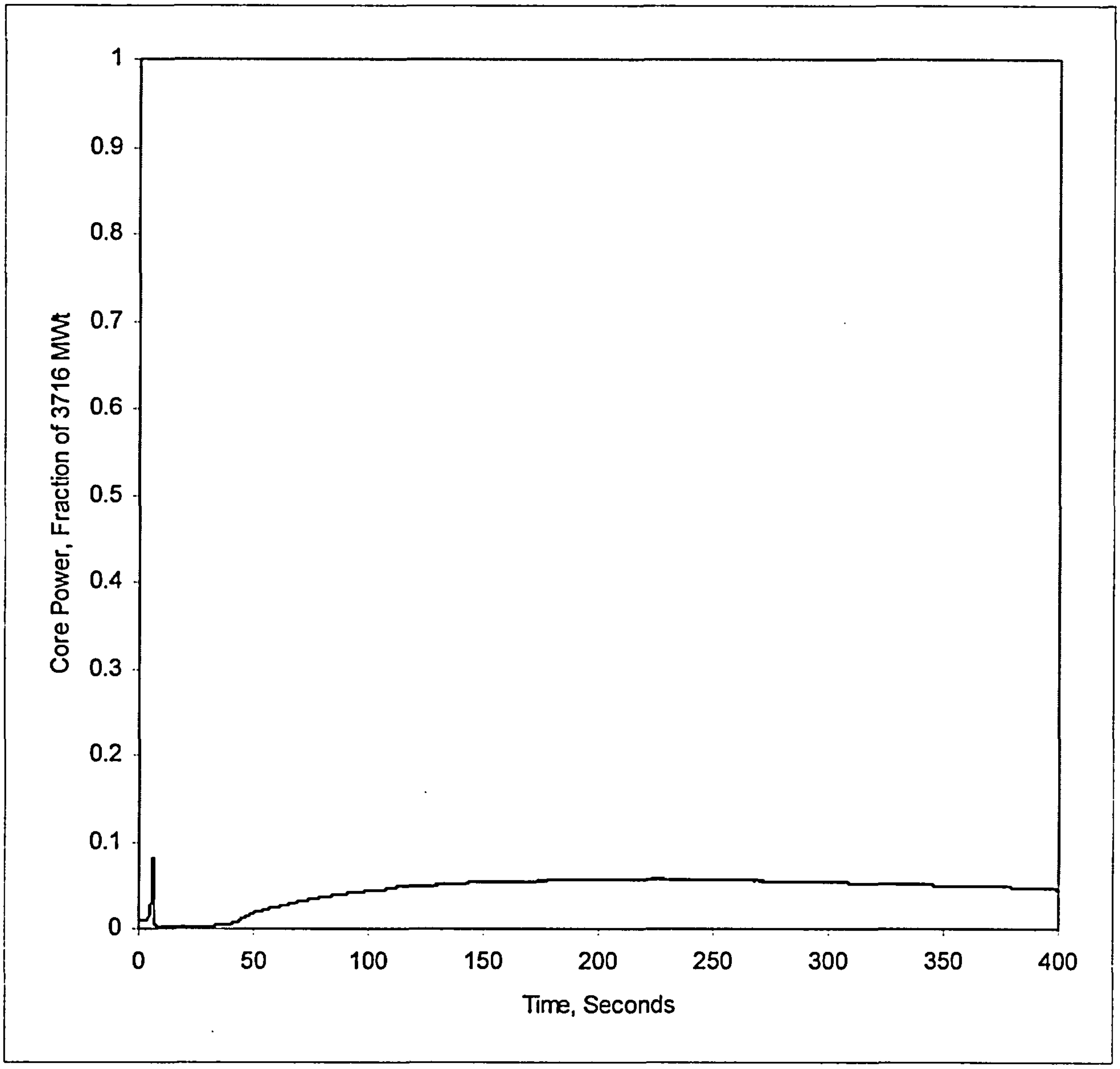


Figure 2.13.1.3.1-39
Return-to-power Steam Line Break
Hot Zero Power, No Loss of Offsite Power
Core Power vs. Time

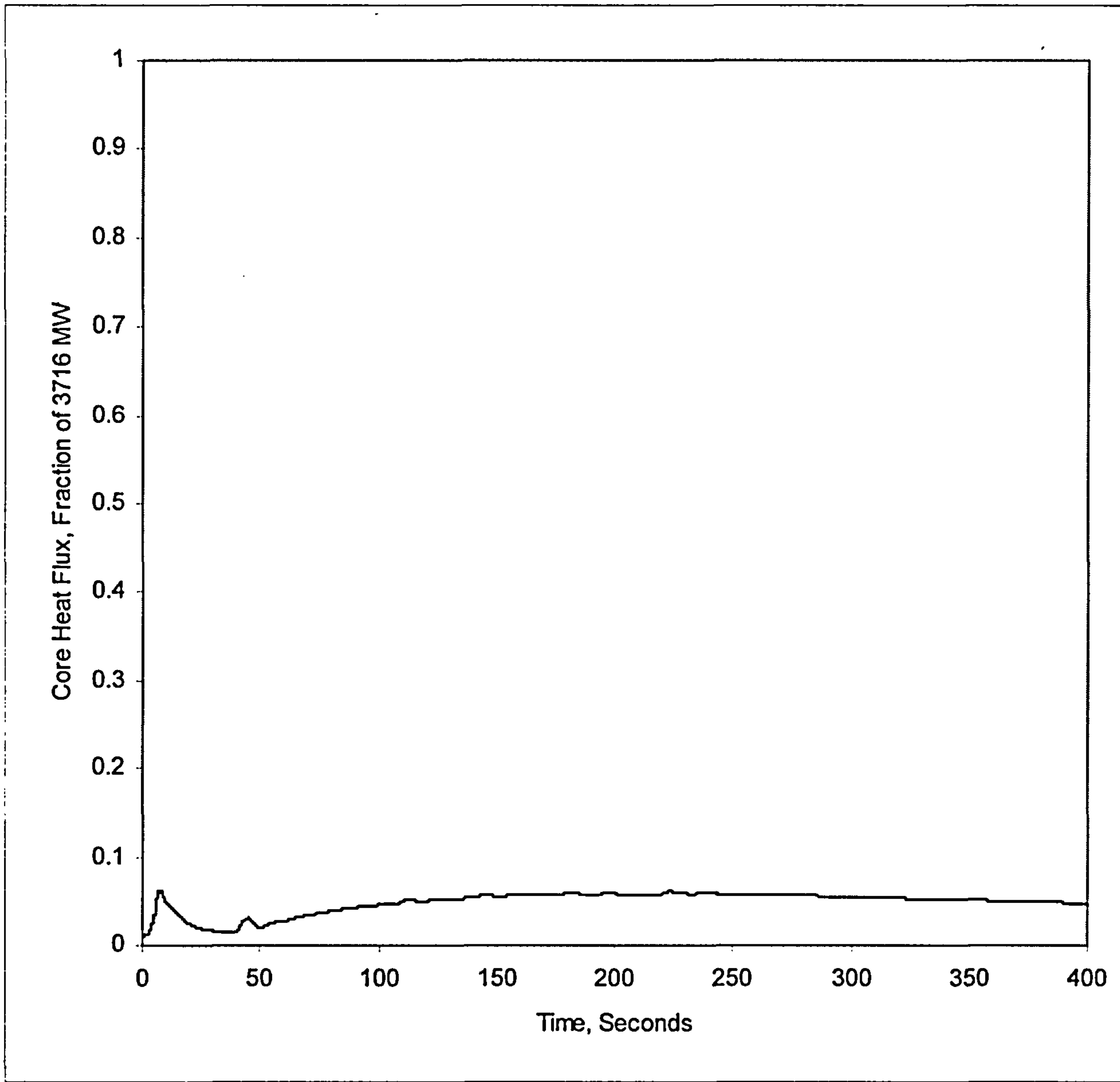


Figure 2.13.1.3.1-40
Return-to-power Steam Line Break
Hot Zero Power, No Loss of Offsite Power
Core Heat Flux vs. Time

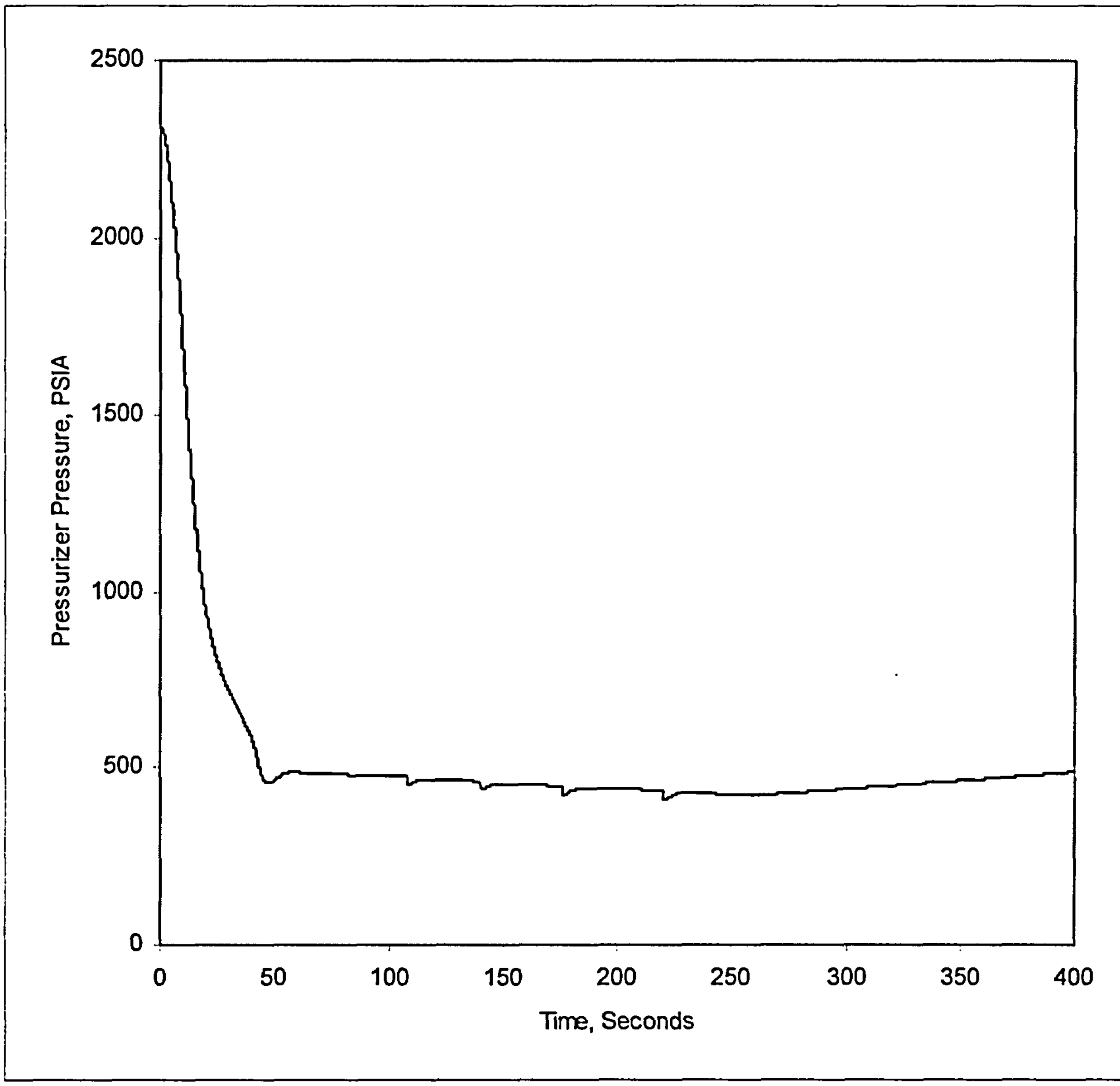


Figure 2.13.1.3.1-41
Return-to-power Steam Line Break
Hot Zero Power, No Loss of Offsite Power
Pressurizer Pressure vs. Time

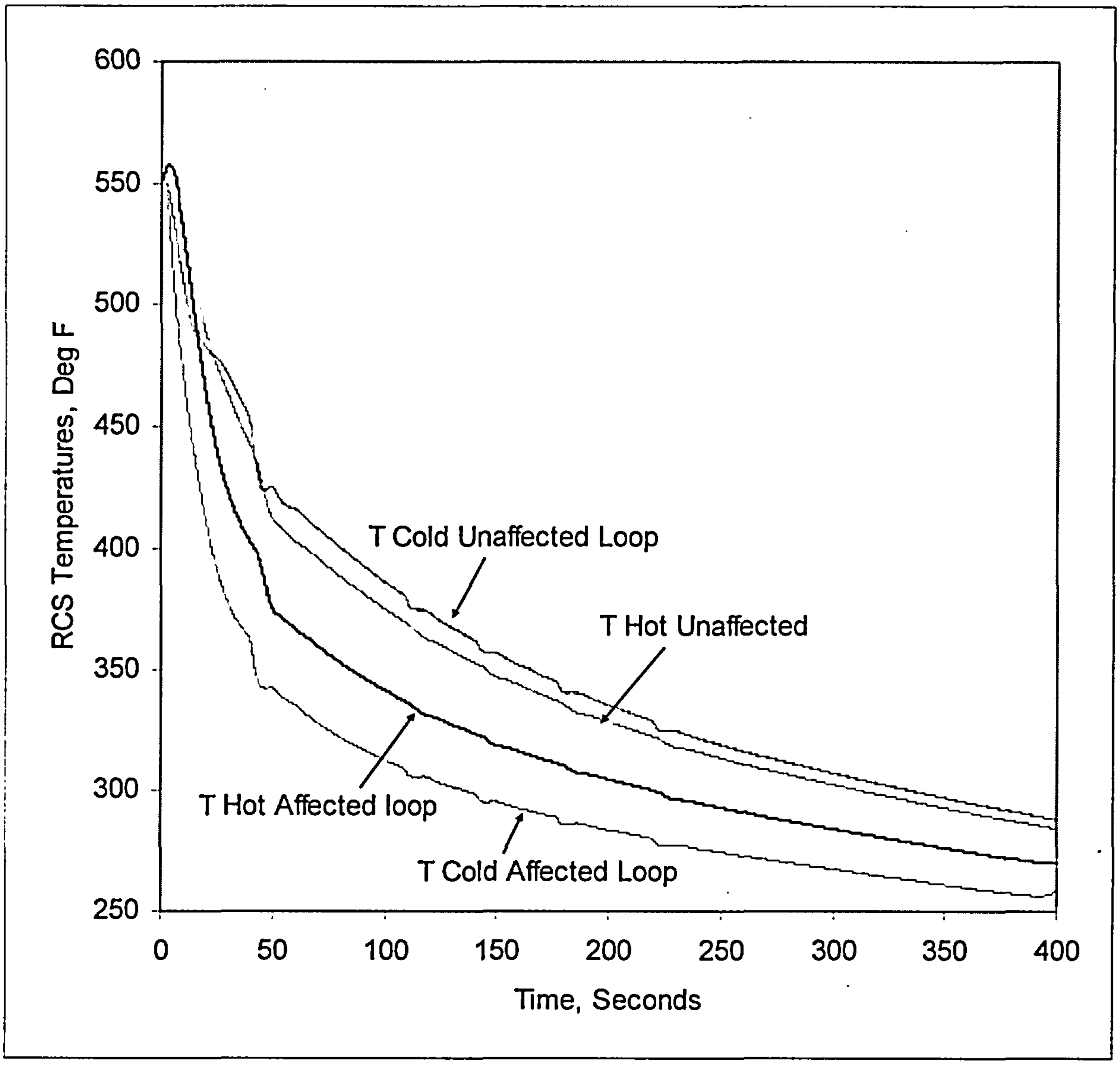


Figure 2.13.1.3.1-42
Return-to-power Steam Line Break
Hot Zero Power, No Loss of Offsite Power
Reactor Coolant System Temperatures vs. Time

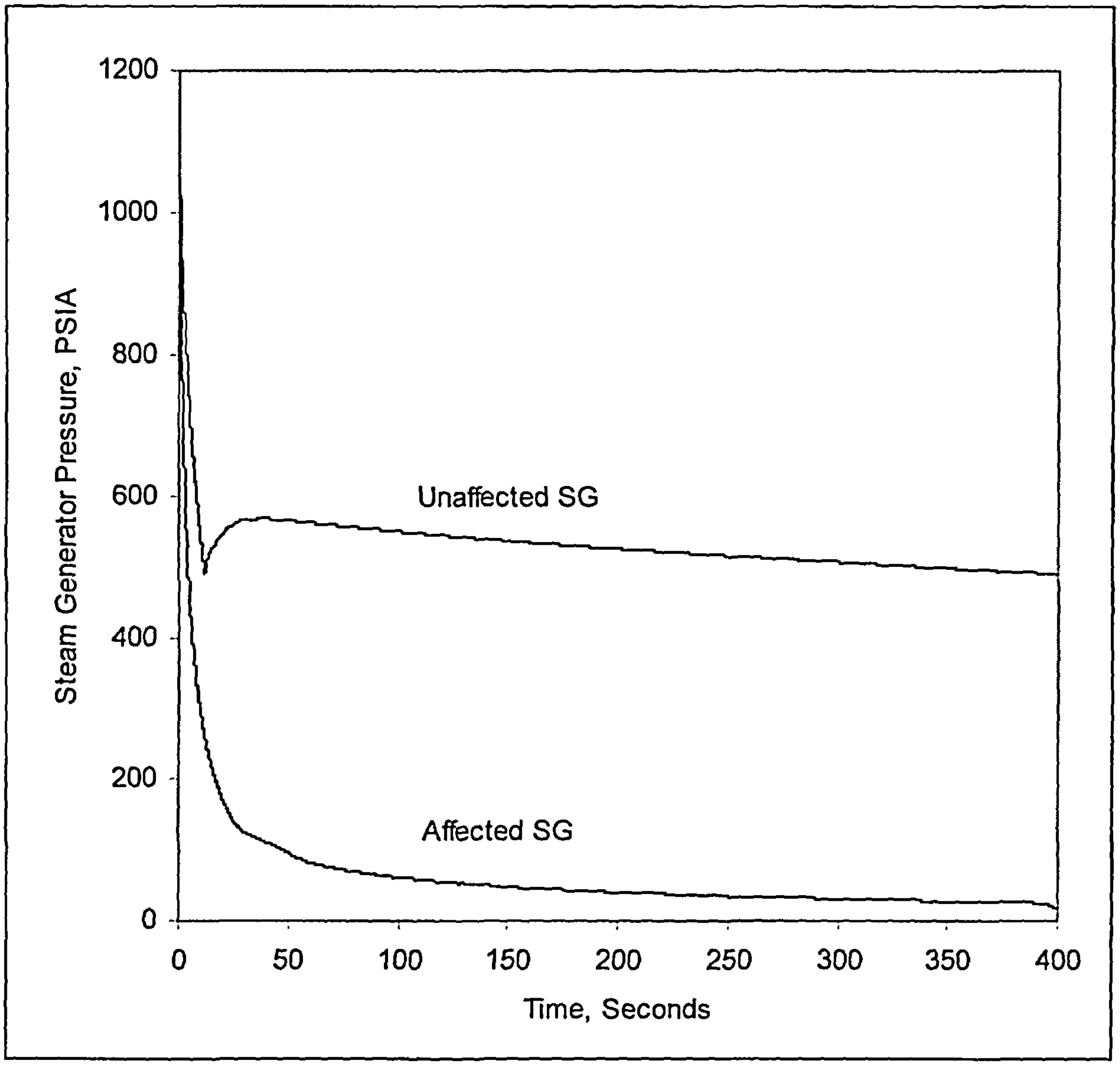


Figure 2.13.1.3.1-43
Return-to-power Steam Line Break
Hot Zero Power, No Loss of Offsite Power
Steam Generator Pressure vs. Time

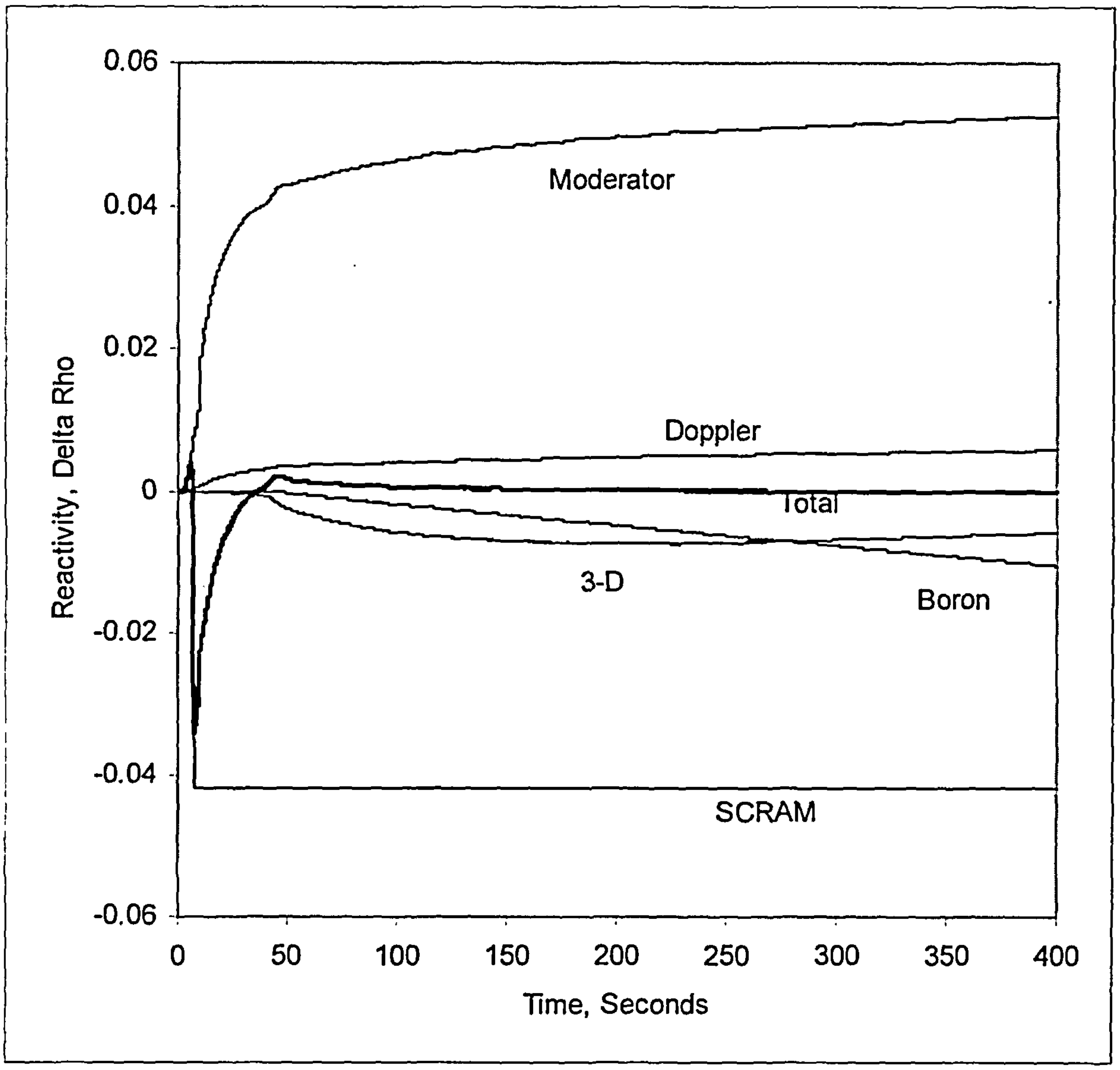


Figure 2.13.1.3.1-44
Return-to-power Steam Line Break
Hot Zero Power, No Loss of Offsite Power
Reactivity vs. Time

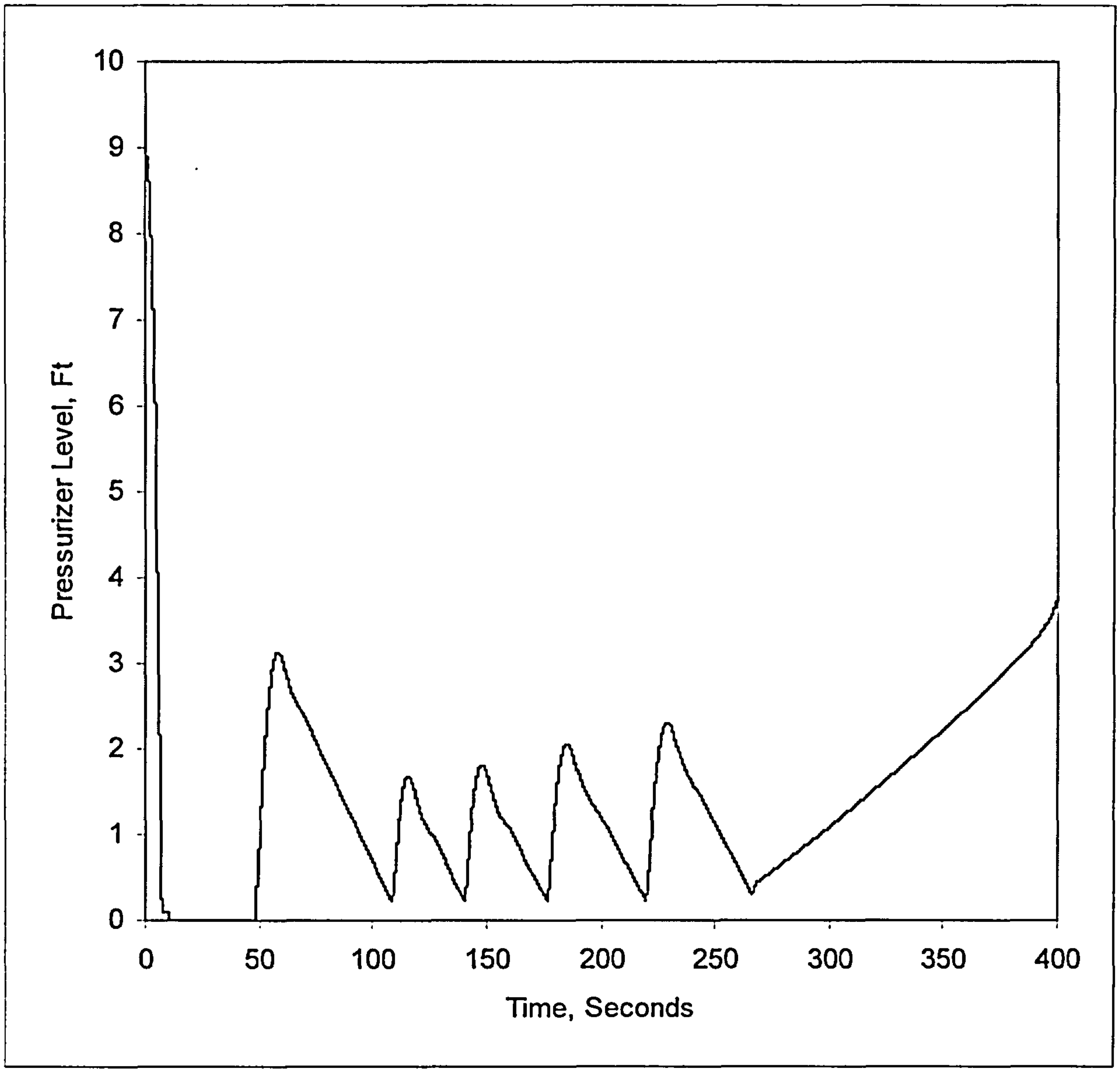


Figure 2.13.1.3.1-45
Return-to-power Steam Line Break
Hot Zero Power, No Loss of Offsite Power
Pressurizer Level vs. Time

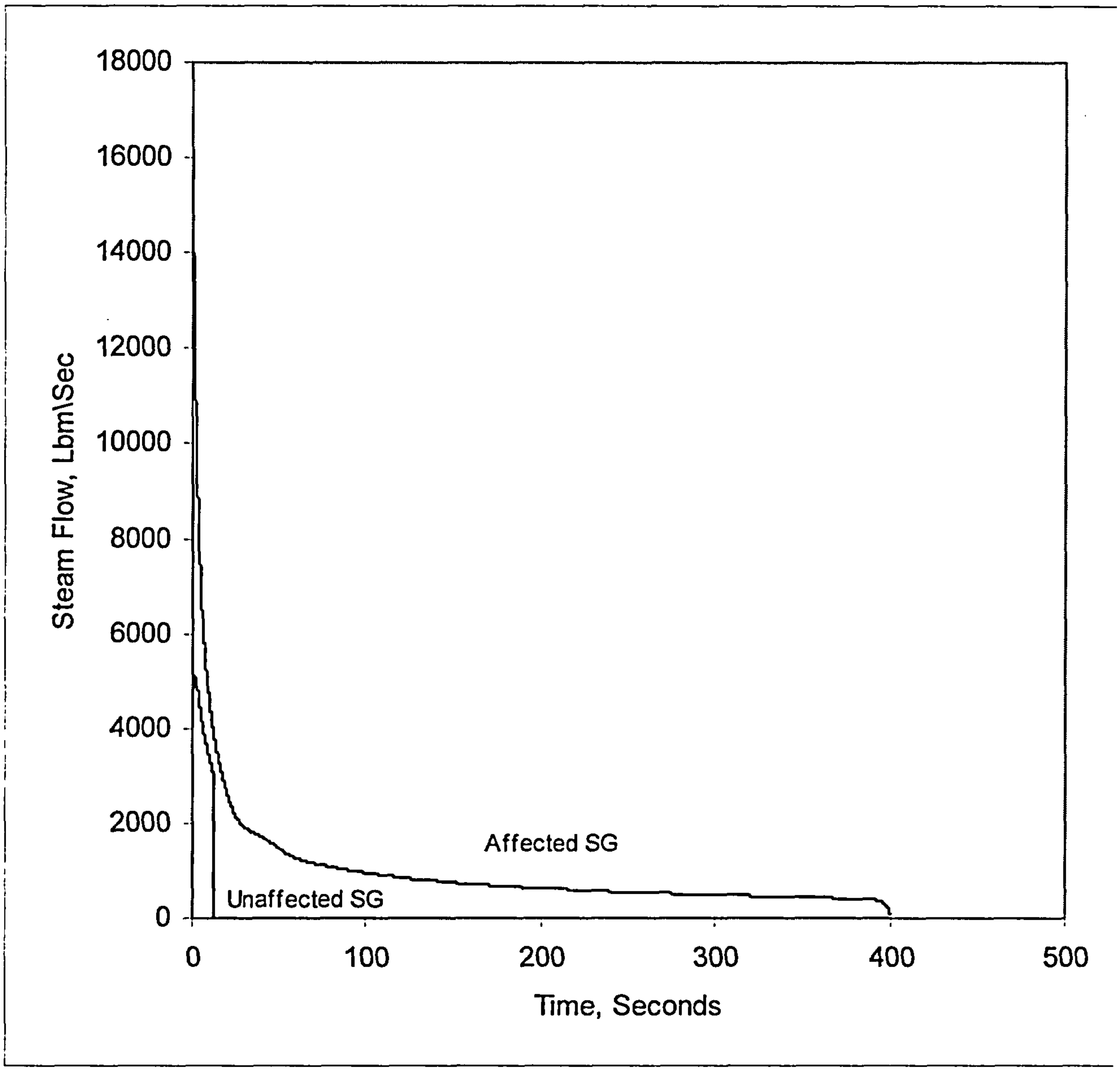


Figure 2.13.1.3.1-46
Return-to-power Steam Line Break
Hot Zero Power, No Loss of Offsite Power
Steam Flow vs. Time

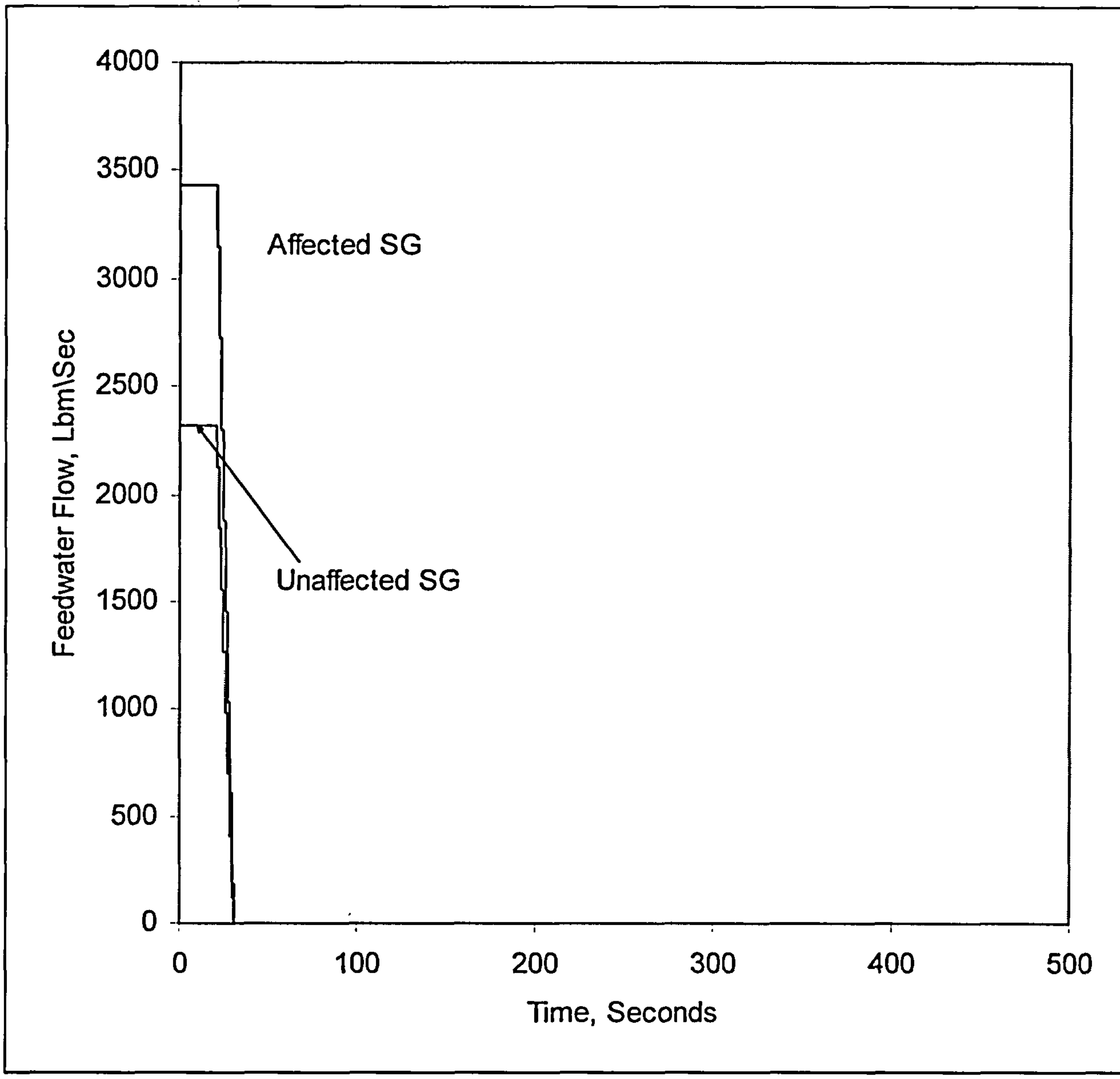


Figure 2.13.1.3.1-47
Return-to-power Steam Line Break
Hot Zero Power, No Loss of Offsite Power
Feedwater Flow vs. Time

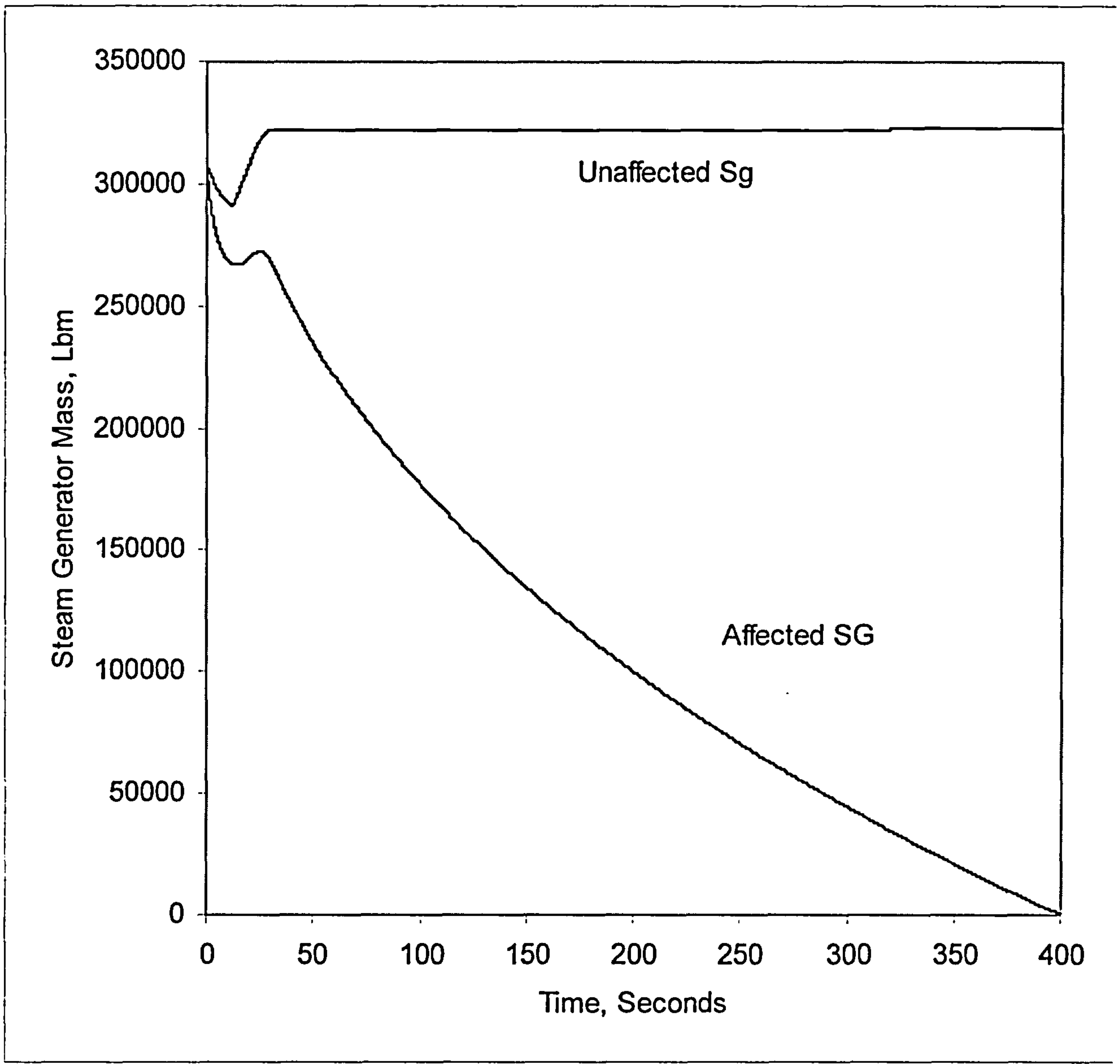


Figure 2.13.1.3.1-48
Return-to-power Steam Line Break
Hot Zero Power, No Loss of Offsite Power
Steam Generator Mass vs. Time

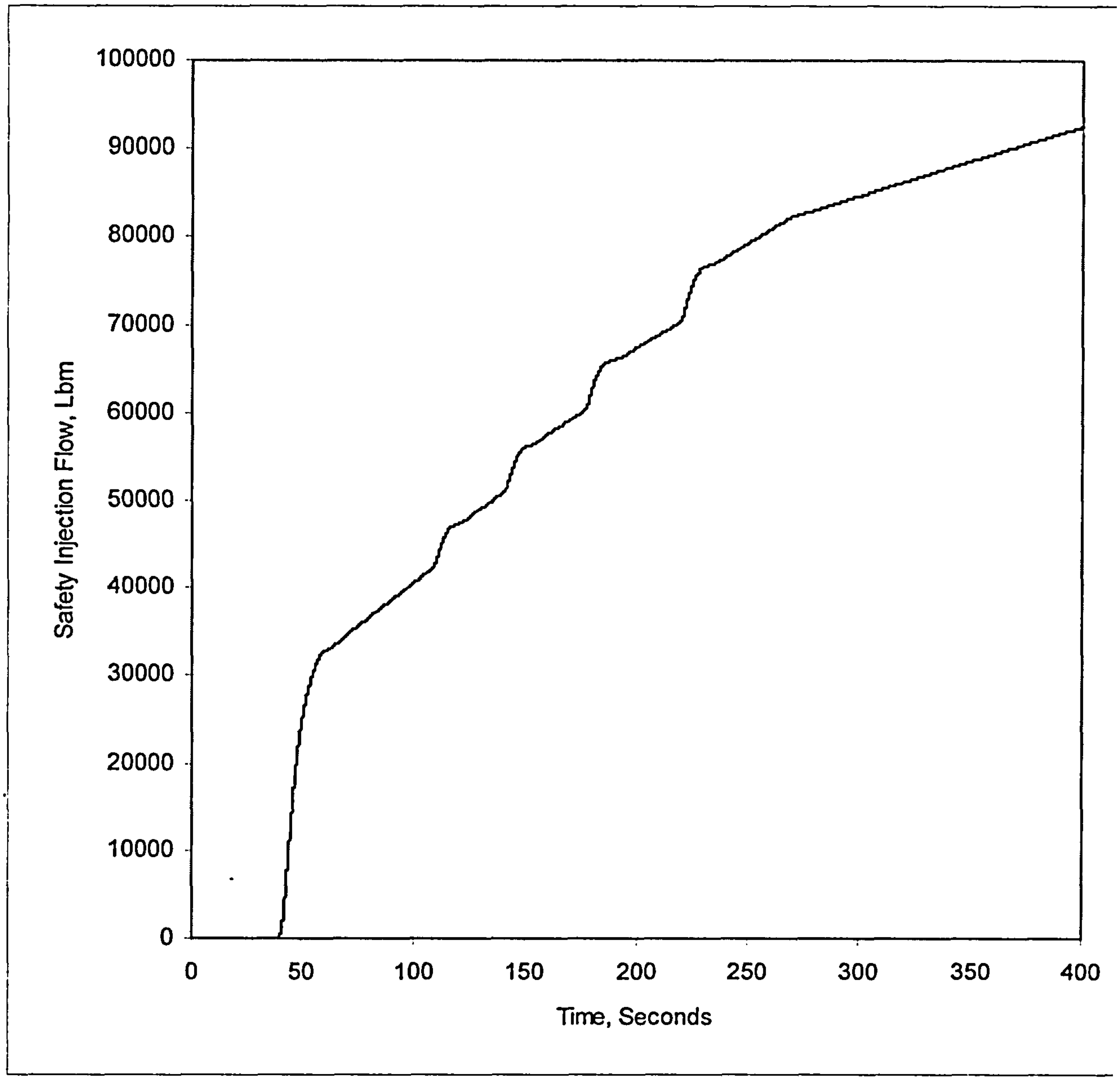


Figure 2.13.1.3.1-49
Return-to-power Steam Line Break
Hot Zero Power, No Loss of Offsite Power
Integrated Safety Injection Flow vs. Time

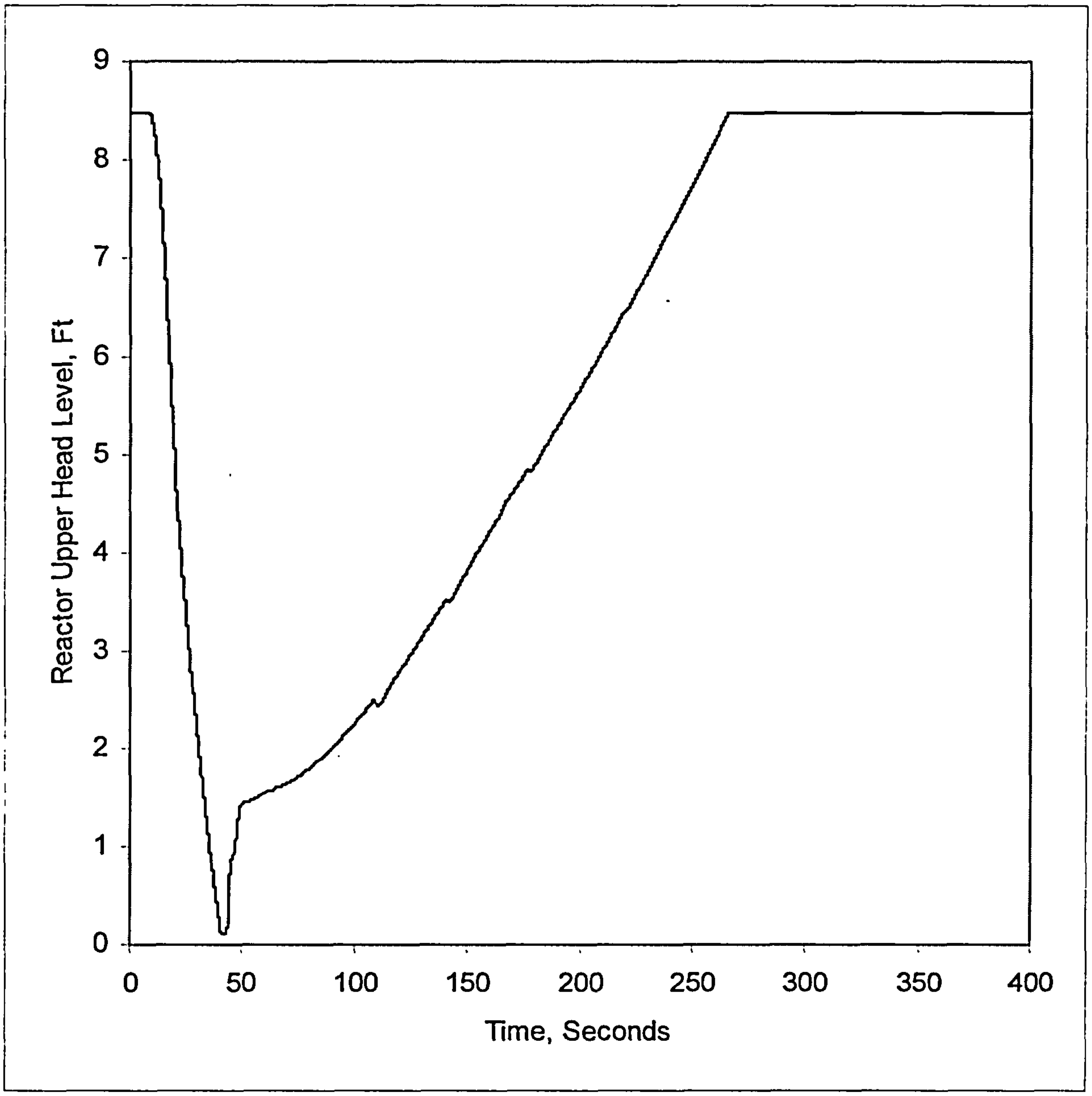


Figure 2.13.1.3.1-50
Return-to-power Steam Line Break
Hot Zero Power, No Loss of Offsite Power
Reactor Vessel Upper Head Level vs. Time

Attachment 2

To

W3F1-2004-0096

Analysis of Loss of Feedwater Event that Maximizes Pressurizer Level

Purpose of Analysis

During the review of the Waterford-3 3716 MWt extended power uprate report, the Reactor Systems Branch asked for a confirmatory demonstration that the pressurizer will not become totally filled with liquid following a loss of feedwater plus a single failure. This report presents the results of the requested analysis and demonstrates that adequate time exists for the operators to identify conditions which are leading to a solid system and take compensatory actions. Two potential active failures are considered: Failure of the Pressurizer Level Control System (PLCS), and Reduction of the Emergency Feedwater Flow (EFW).

Cases Analyzed

Case 1: Loss of Feedwater with PLCS failure, long-term, 1800 sec run

The loss of feedwater plus the single failure of the pressurizer level control system (PLCS) was the first scenario to be examined. The failure in the PLCS is assumed to result in termination of letdown flow and starting all charging pumps. This first set of results determines the time at which the system would become solid with no operator intervention and determines the timing when discharge of liquid through the pressurizer safety valves begins.

Results of Case 1 show that operator action is required no earlier than 15 minutes after reactor trip, in order to prevent discharge of liquid through the pressurizer safety valves.

Major assumptions for this case are presented in Table 1-1. Sequence of events is presented in Table 1-2, and figures are presented in Figure 1-1 through Figure 1-13.

Case 2: Loss of Feedwater with PLCS failure, long-term, operator action 15 min after reactor trip, 1800 sec run

Case 2 is the same as Case 1 but with operator action being modeled to occur at 15 minutes. The operator action consists of tripping 2 out of 3 charging pumps and reestablishing letdown flow. Results of Case 2 show that that with operator action at this time, significant margin exists to a solid pressurizer condition.

Major assumptions for this case are presented in Table 2-1. Sequence of events is presented in Table 2-2, and figures are presented in Figure 2-1 through Figure 2-13.

Case 3: Loss of Feedwater with Reduced EFW flow, long-term, 1800 sec run

The other scenario examined is a single active failure in the emergency feedwater system. This failure results in a minimum EFW flow of 575 gpm being delivered to the steam generators. Examining the results, it is seen that this scenario does not result in the discharge of liquid through the pressurizer safety valves or pressurizer fill.

Major assumptions for this case are presented in Table 3-1. Sequence of events is presented in Table 3-2, and figures are presented in Figure 3-1 through Figure 3-13.

Analysis Overview

This evaluation examined the analysis of the loss of feedwater analysis documented in the Power

Uprate Report (PUR) with the following input differences (to exacerbate the potential for pressurizer fill):

1. Most positive (least negative) MTC of 0.5×10^{-4} $\Delta\rho$.
2. A PSV tolerance of -3% was applied.
3. An MSSV tolerance of +3% was applied.
4. Main Steam Isolation Signal (MSIS) setpoint of 725 psia was used. However, it was not initiated, since secondary safety valves were cycling, and SG pressure did not drop below this setpoint.

Analysis Results

The LOFW with an active failure in the PLCS event does not result in pressurizer overfill, since operators take action in 15 minutes after reactor trip, tripping 2 out of 3 charging pumps and initiating letdown flow.

The NSSS, PPS, and EFW system responses for the LOFW with PLCS failure event are shown in Table 1-2 and Figures 1-1 through 1.-13.

The NSSS, PPS, and EFW system responses for the LOFW with PLCS failure and operator action in 15 minutes after trip event are shown in Table 2-2 and Figures 2-1 through 2-13.

The LOFW with reduced EFW flow event does not result in pressurizer overfill. The NSSS, PPS, and EFW system responses for this event are shown in Table 3-2 and Figures 3-1 through 3-13.

Table 1-1

Assumptions for 1800 seconds Long-Term LOFW with PLCS Failure Event (Case 1)	
Parameter	Power Uprate Assumption
Initial Core Power level, MWt	3735
Core Inlet Temperature, °F	533
RCS Flowrate, 10^6 lbm/hr	148
Pressurizer Pressure, psia	2090
Pressurizer Level, %	67.5
SG Pressure, psia	742
SG Level, %NR	90
MTC, $10^{-4}\Delta\rho/°F$	0.5
Doppler Coefficient Multiplier	0.85
CEA Worth for Trip, $10^{-2}\Delta\rho$	-6
SBCS	Inoperative
PLCS	Manual
PPCS	Automatic
Single Failure	PLCS: maximum charging flow and zero letdown flow
Operator Action	None

Table 1-2. Sequence of Events for 1800 seconds Long-Term LOFW with PLCS Failure Event (Case 1)

Time (sec)	Event	Setpoint or value
0.0	Termination of all feedwater flow	---
0.0	PLCS failure: Maximum charging flow Minimum letdown flow	 144 gpm 0 gpm
32.1	Low steam generator water level trip signal	5% NR
33.0	Trip breakers open	---
33.6	CEAs begin to drop into core	---
33.6	Maximum core power (% of 3716 MWt)	101.3%
48.3	Steam generator safety valves open	1117 psia
49.8	Maximum steam generator pressure	1118.6 psia
82.5	Emergency feedwater reaches steam generators	---
360.4	Minimum steam generator water inventory	52,110 lbm
932	Time when operator would be required to trip charging pumps	15 minutes after reactor trip
961.1	Minimum RCS pressure	1972.4 psia
1111.9	Time when liquid starts to discharge through the PSVs (if operator did not trip charging pumps 15 minutes after trip)	PSV quality < 1.0
1297.1	Pressurizer safety valves begin to open	2424 psia
1705.2	Maximum RCS pressure	2484 psia
1705.4	Maximum pressurizer liquid volume	1468.7 ft^3
1800	End of analysis	---

Table 2-1

Assumptions for 1800 seconds Long-Term LOFW Event with Operator Action 15 min After Reactor Trip (Case 2)	
Parameter	Power Uprate Assumption
Initial Core Power level, MWt	3735
Core Inlet Temperature, °F	533
RCS Flowrate, 10^6 lbm/hr	148
Pressurizer Pressure, psia	2090
Pressurizer Level, %	67.5
SG Pressure, psia	742
SG Level, %NR	90
MTC, $10^{-4}\Delta\rho$/°F	0.5
Doppler Coefficient Multiplier	0.85
CEA Worth for Trip, $10^{-2}\Delta\rho$	-6
SBCS	Inoperative
PLCS	Manual
PPCS	Automatic
Single Failure	PLCS: maximum charging flow and zero letdown flow
Operator Action	15 min after reactor trip operator trips 2 out of 3 charging pumps & initiates letdown flow

Table 2-2. Sequence of Events for the Loss of Normal Feedwater Long-Term Case with Operator Action 15 min After Reactor Trip (Case 2)

Time (sec)	Event	Setpoint or value
0.0	Termination of all feedwater flow	---
0.0	PLCS failure: Maximum charging flow Minimum letdown flow	 144 gpm 0 gpm
32.1	Low steam generator water level trip signal	5% NR
33.0	Trip breakers open	---
33.6	CEAs begin to drop into core	---
33.6	Maximum core power (% of 3716 MWt)	101.3%
40.6	Maximum RCS pressure	2379 psia
48.3	Steam generator safety valves open	1117 psia
49.8	Maximum steam generator pressure	1118.6 psia
82.5	Emergency feedwater reaches steam generators	---
432.1	Minimum steam generator water inventory	50,990 lbm
932	Operator trips 2 out of 3 charging pumps; initiates letdown flow Charging flow Letdown flow	15 minutes after reactor trip 48 gpm 78 gpm
963.8	Minimum RCS pressure	1932.7 psia
1033.1	Maximum pressurizer liquid volume	1369 ft^3
1800	End of analysis	---

Table 3-1

Assumptions for 1800 seconds Long-Term LOFW Event with Reduced AFW Flow (Case 3)	
Parameter	Power Uprate Assumption
Initial Core power level, MWt	3735
Core Inlet Temperature, °F	533
RCS Flowrate, 10^6 lbm/hr	148
Pressurizer Pressure, psia	2090
Pressurizer Level, %	67.5
SG Pressure, psia	742
SG Level, %NR	90
MTC, $10^{-4}\Delta\rho/°F$	0.5
Doppler Coefficient Multiplier	0.85
CEA Worth for Trip, $10^{-2}\Delta\rho$	-6
SBCS	Inoperative
PLCS	Automatic
PPCS	Automatic
Single Failure	EFW flow: one-half emergency feedwater capacity, 575 gpm
Operator Action	None

Table 3-2. Sequence of Events for 1800 seconds Long-Term LOFW Event with Reduced AFW Flow (Case 3)

Time (sec)	Event	Setpoint or value
0.0	Termination of all feedwater flow	---
32.1	Low steam generator water level trip signal	5% NR
33.0	Trip breakers open	---
33.6	CEAs begin to drop into core	---
33.6	Maximum core power (% of 3716 MWt)	101.4%
40.6	Maximum RCS pressure	2366 psia
47.4	Maximum pressurizer liquid volume	1081 ft^3
47.7	Steam generator safety valves begin to open	1117 psia
52.3	Maximum steam generator pressure	1120 psia
96.5	Emergency feedwater reaches steam generators	---
504	Minimum steam generator water inventory	46,120 lbm
1026.4	Minimum RCS pressure	1939 psia
1800	End of analysis	---

Figure 1-1
Loss of Normal Feedwater Flow with PLCS Failure, Long-Term
Core Power vs. Time

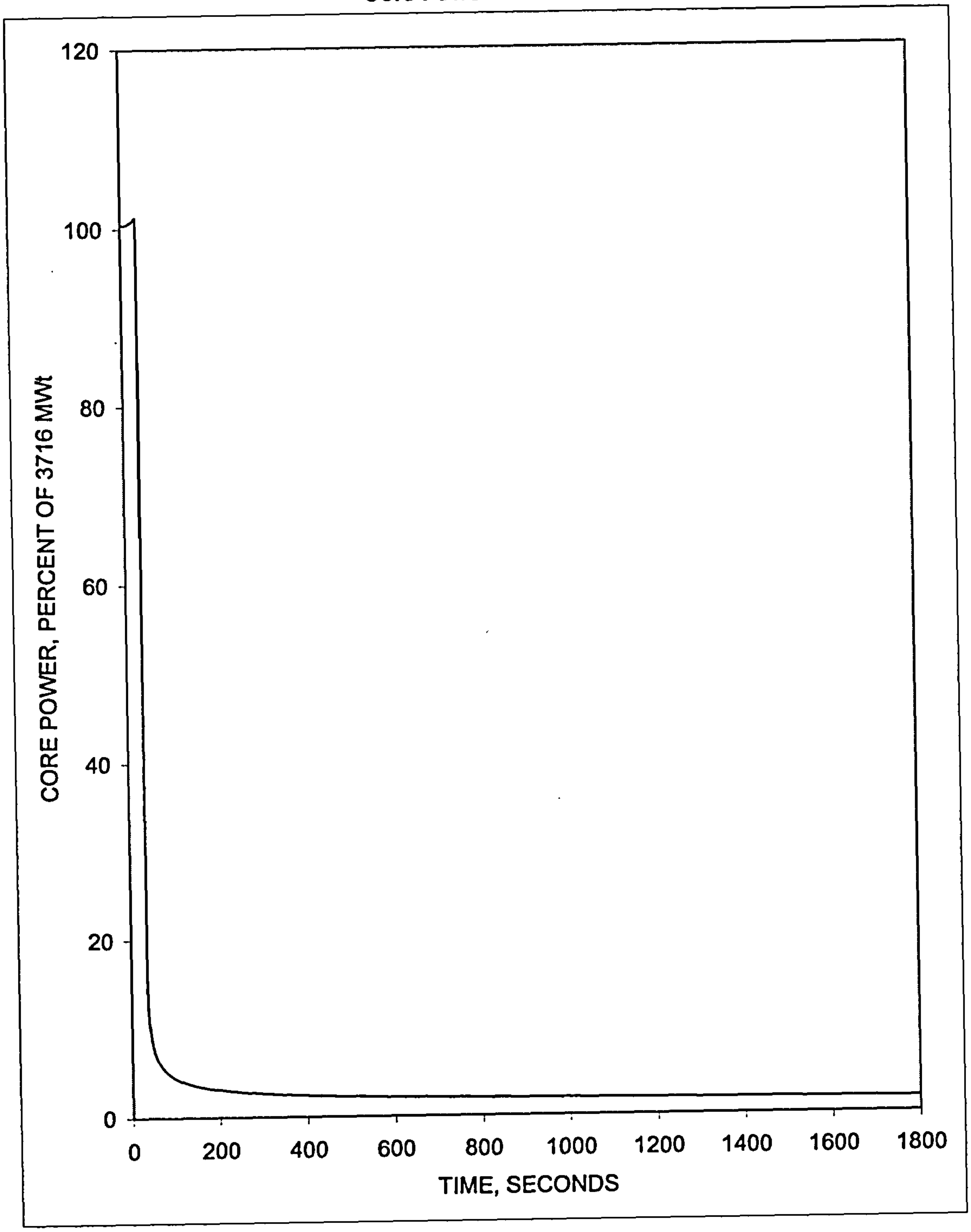


Figure 1-2
Loss of Normal Feedwater Flow with PLCS Failure, Long-Term
Core Heat Flux vs. Time

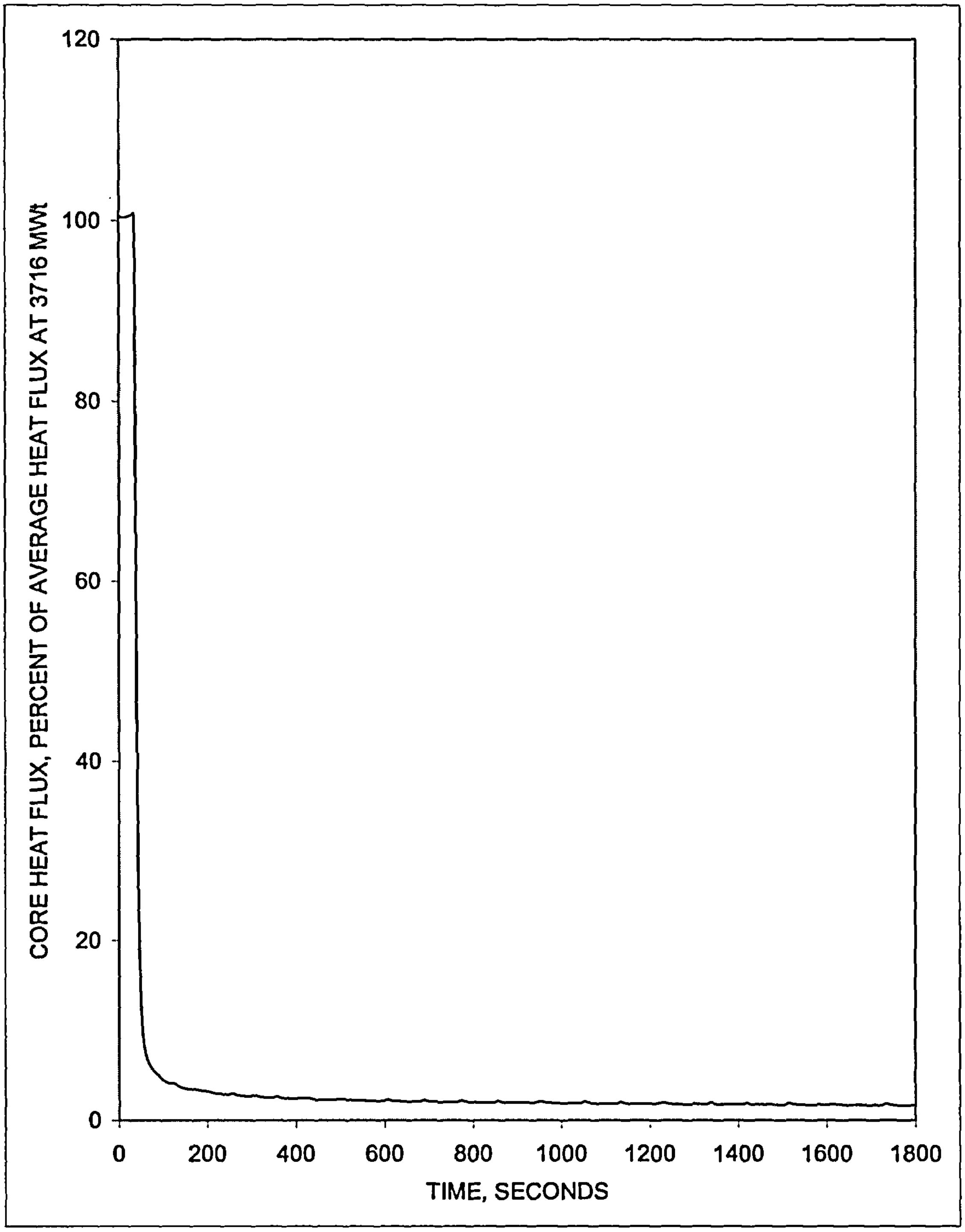


Figure 1-3
Loss of Normal Feedwater Flow with PLCS Failure, Long-Term
Reactor Coolant System (Cold Leg Discharge) Pressure vs. Time

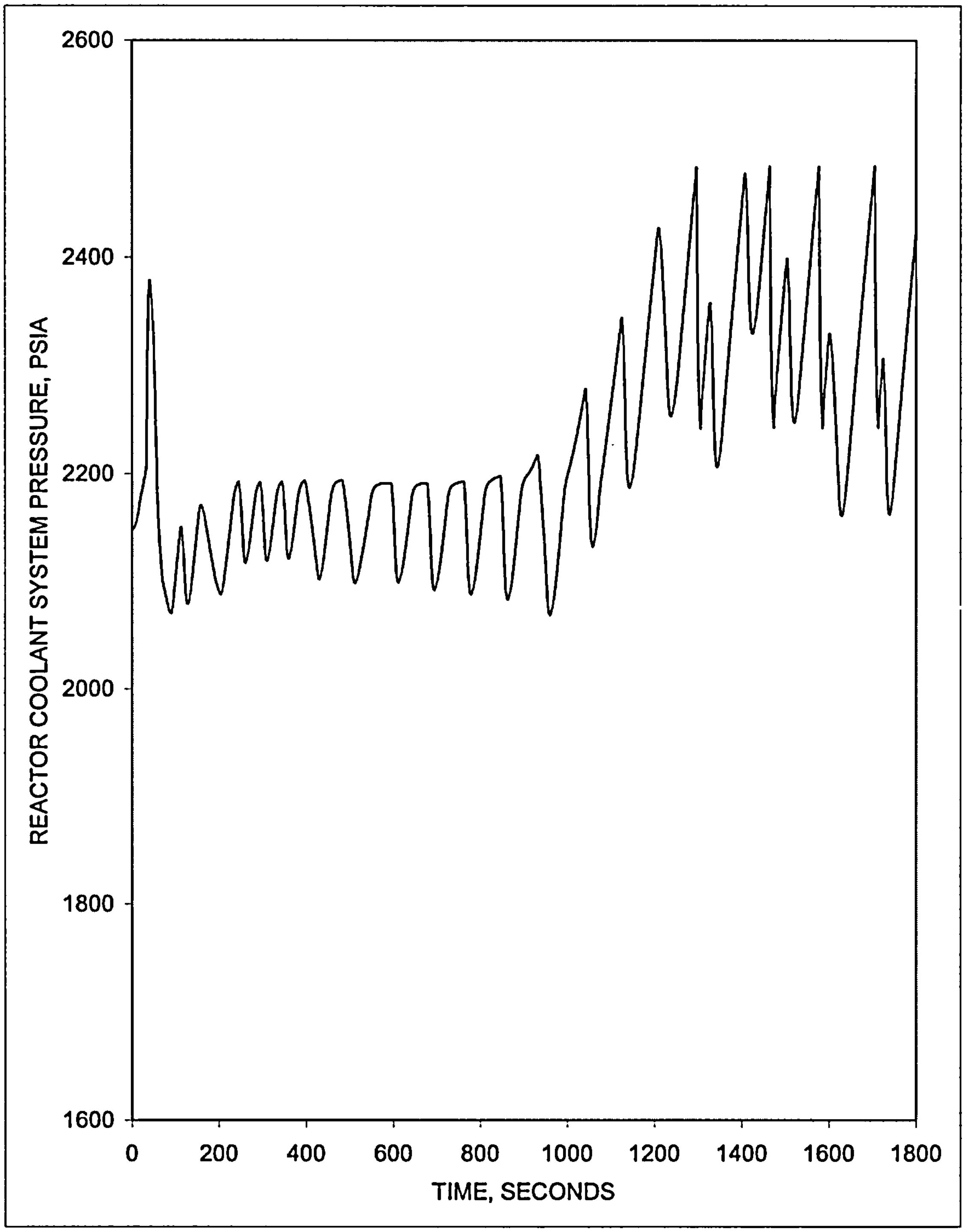


Figure 1-4
Loss of Normal Feedwater Flow with PLCS Failure, Long-Term
Reactor Coolant System Temperatures vs. Time

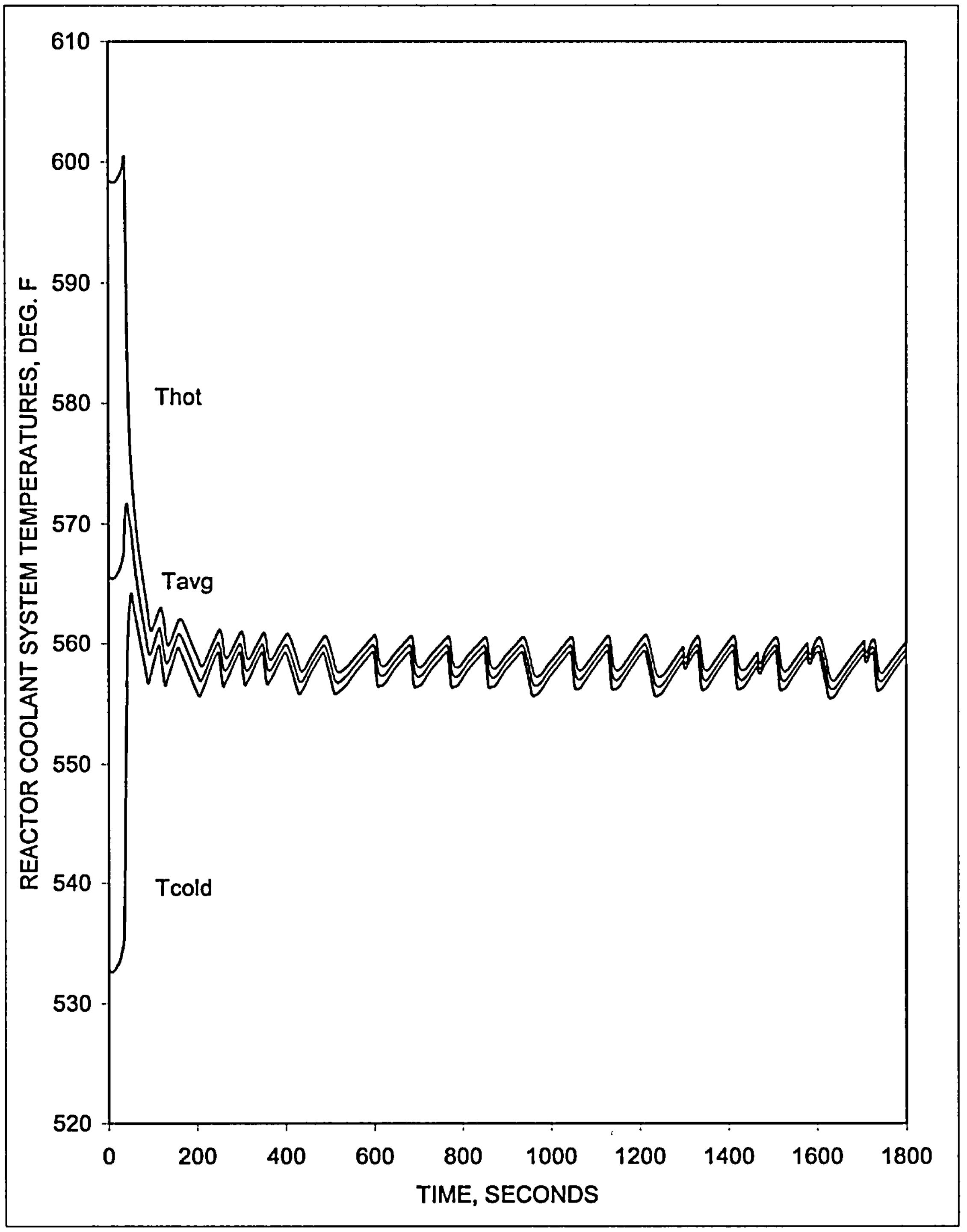


Figure 1-5
Loss of Normal Feedwater Flow with PLCS Failure, Long-Term
Pressurizer Water Volume vs. Time

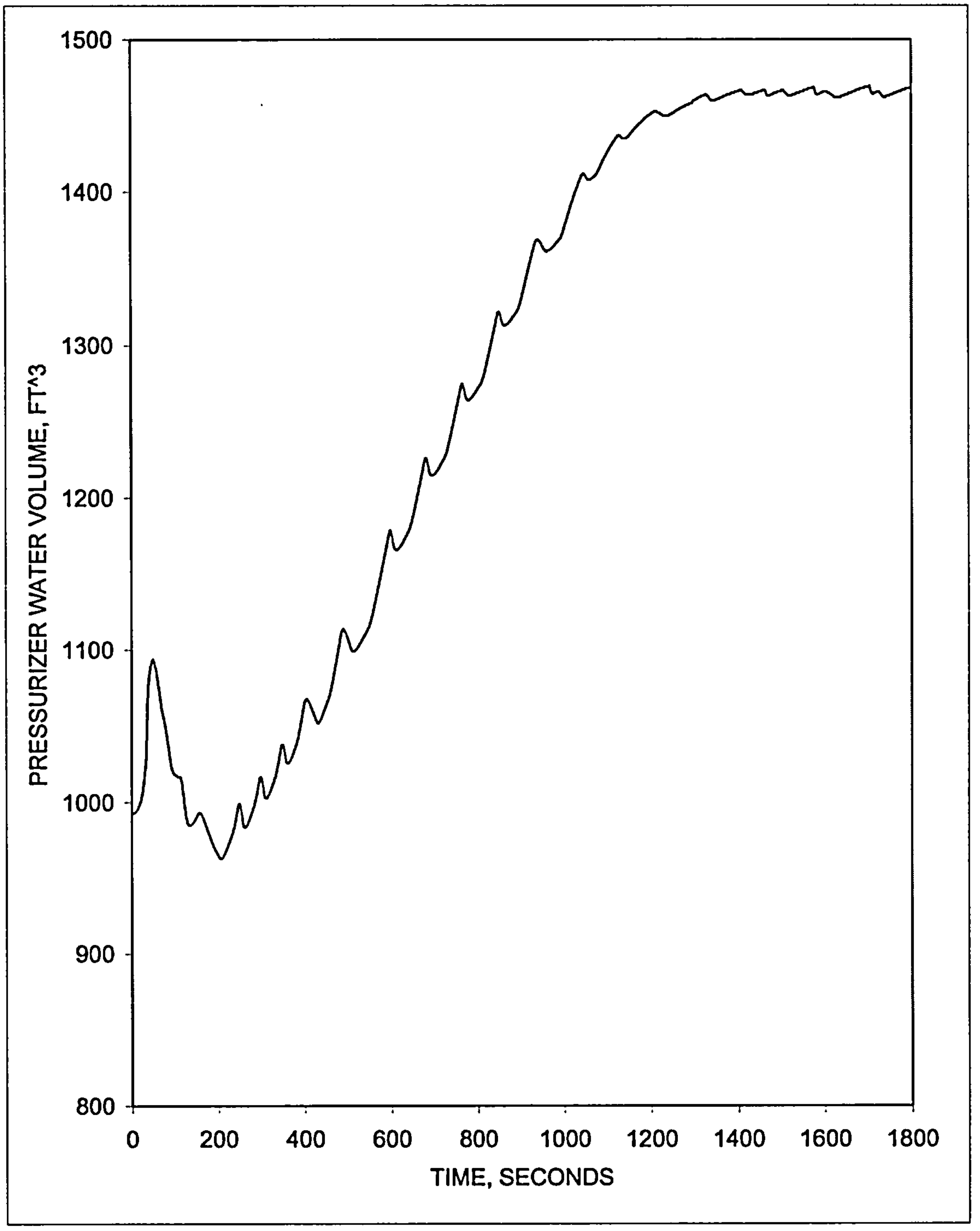


Figure 1-6
Loss of Normal Feedwater Flow with PLCS Failure, Long-Term
Steam Generator Pressure vs. Time

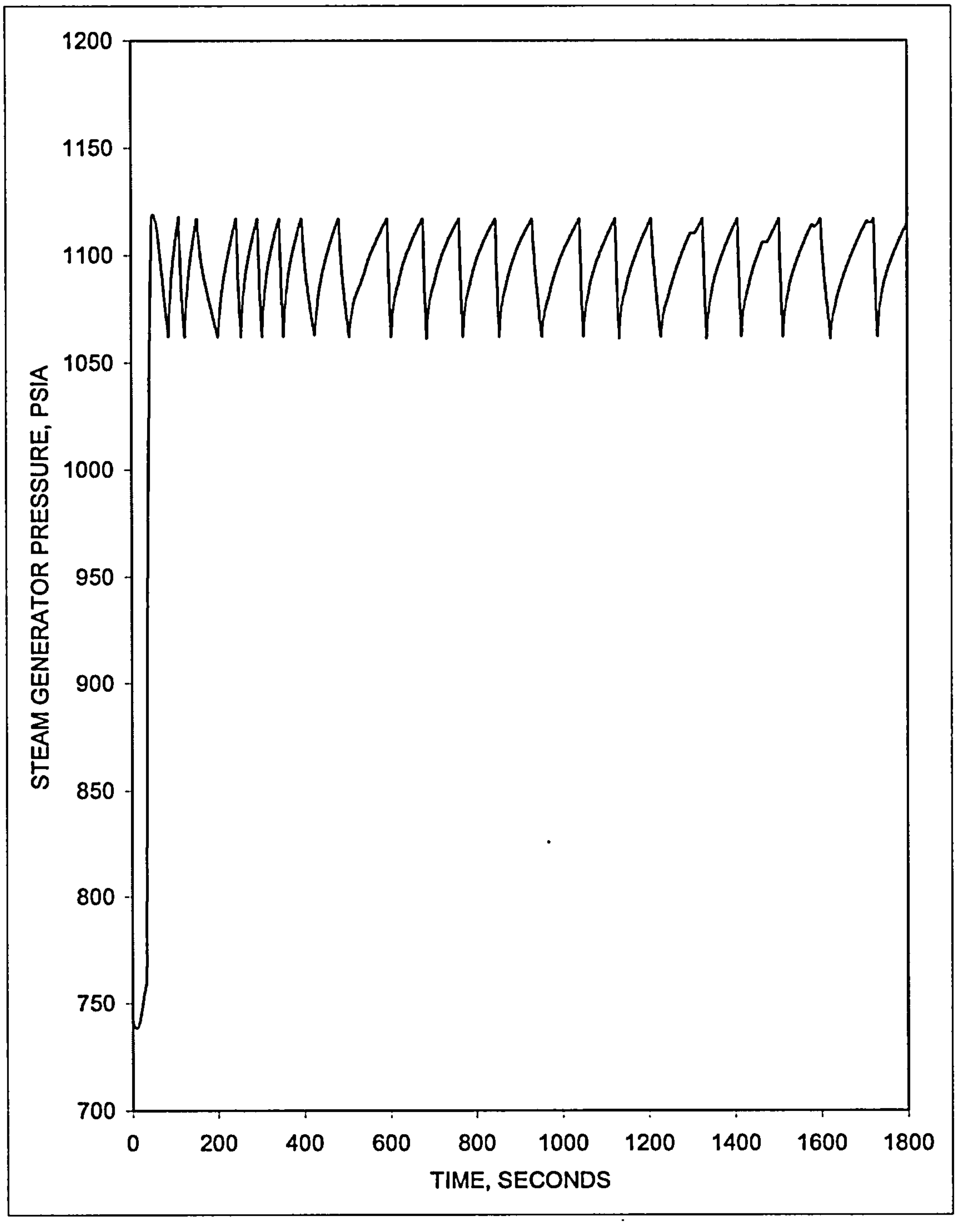


Figure 1-7
Loss of Normal Feedwater Flow with PLCS Failure, Long-Term
Total Secondary Steam Flowrate vs. Time

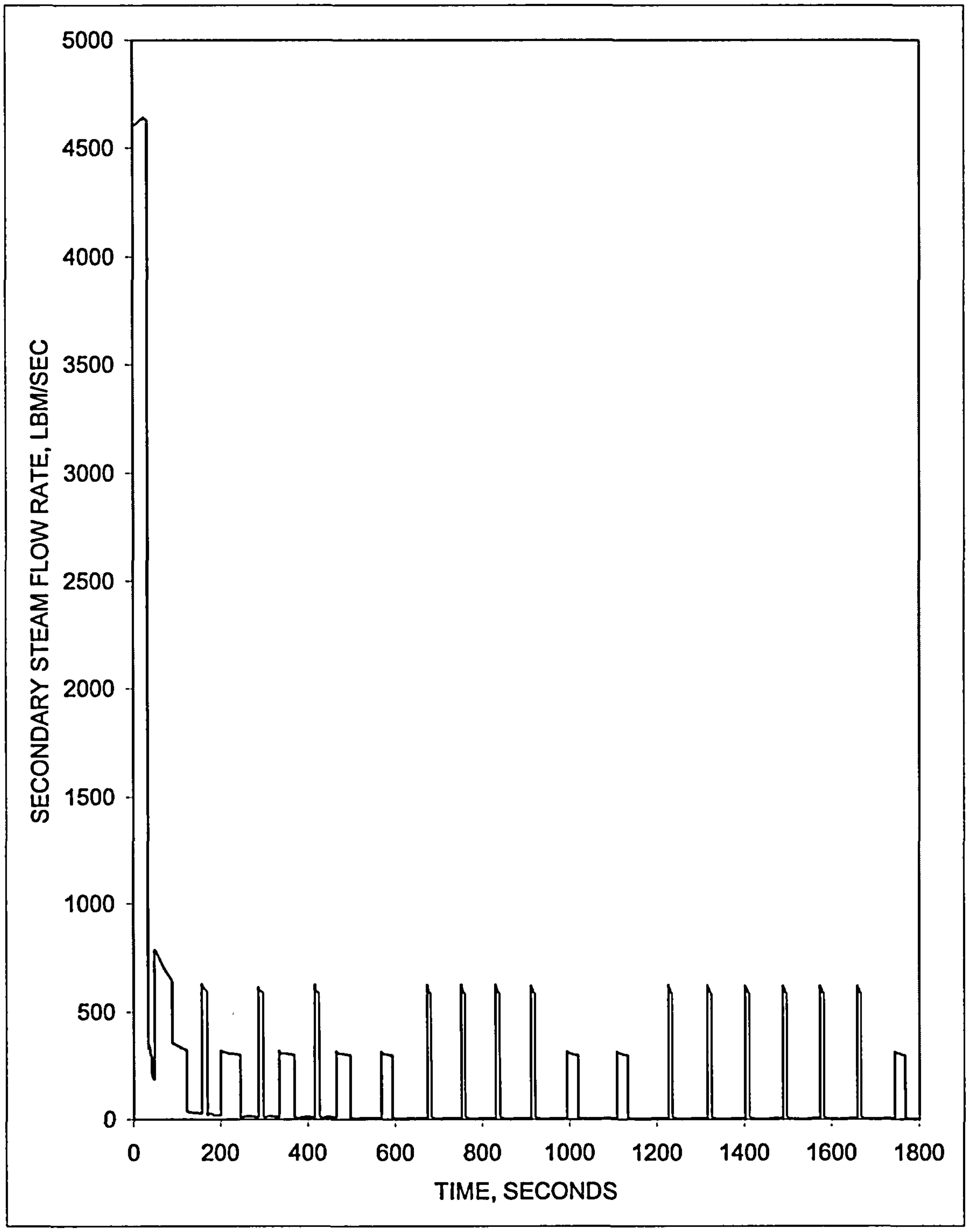


Figure 1-8
Loss of Normal Feedwater Flow with PLCS Failure, Long-Term
Emergency Feedwater Flowrate per Steam Generator vs. Time

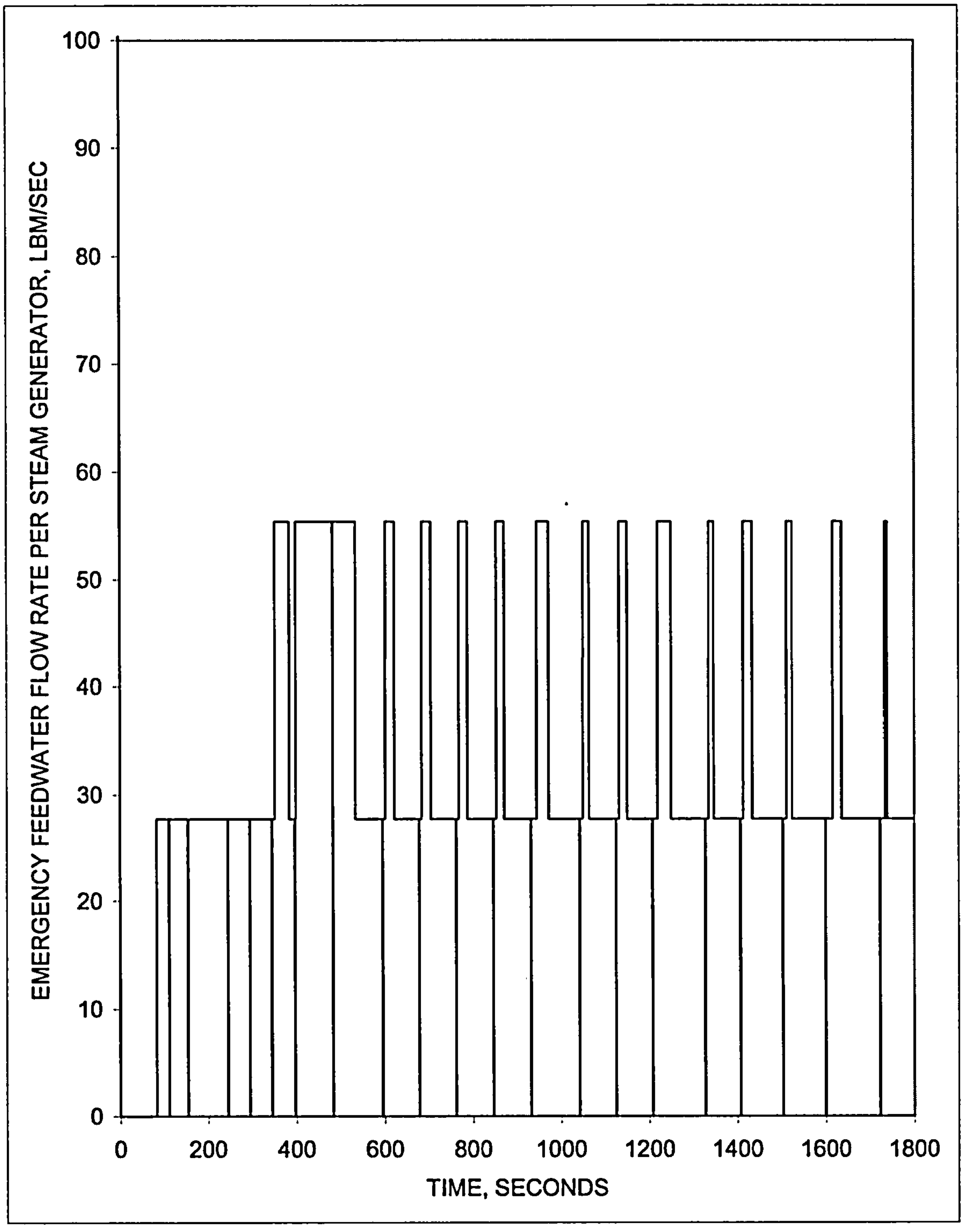


Figure 1-9
Loss of Normal Feedwater Flow with PLCS Failure, Long-Term
Emergency Feedwater Enthalpy vs. Time

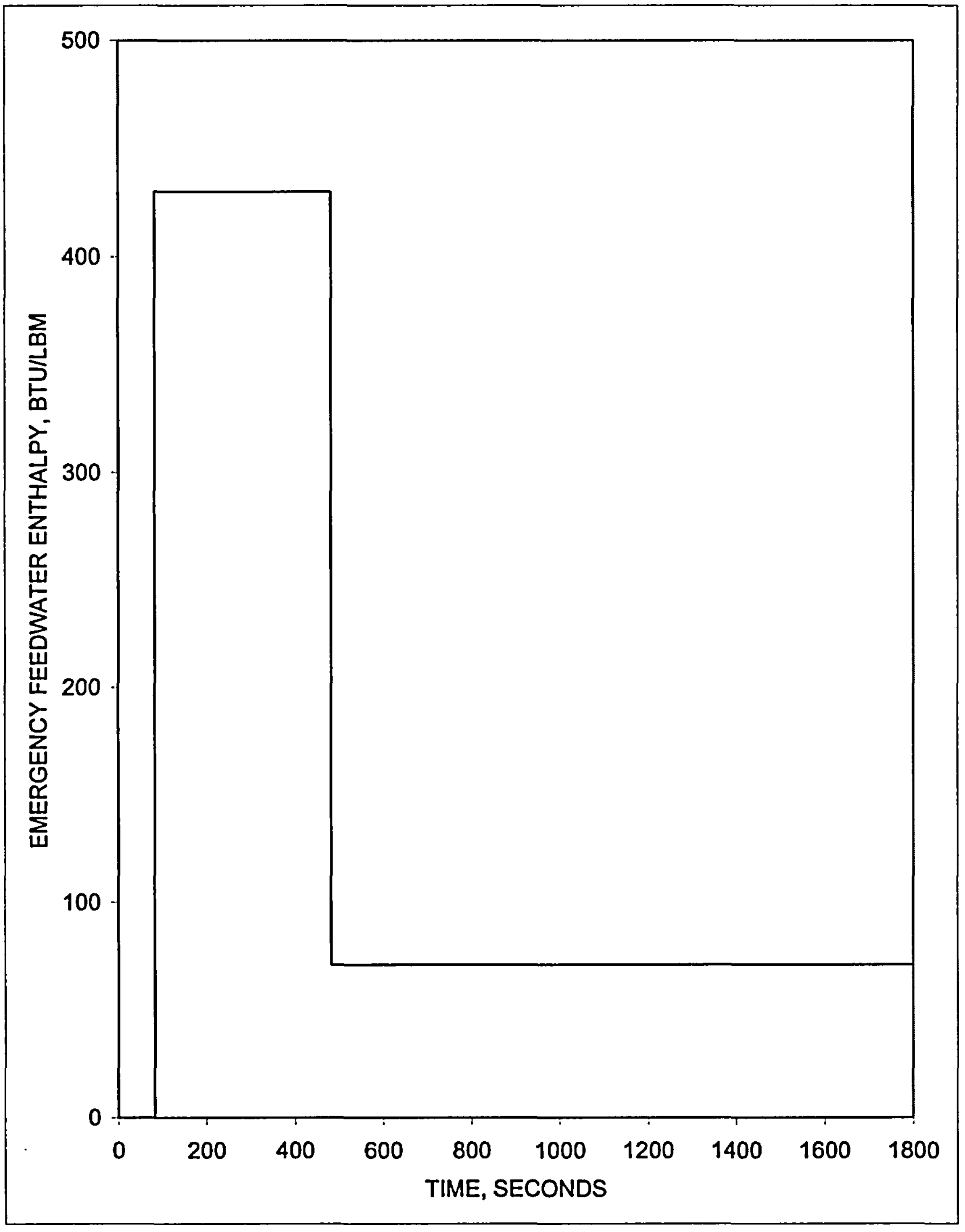


Figure 1-10
Loss of Normal Feedwater Flow with PLCS Failure, Long-Term
Secondary Liquid Mass vs. Time

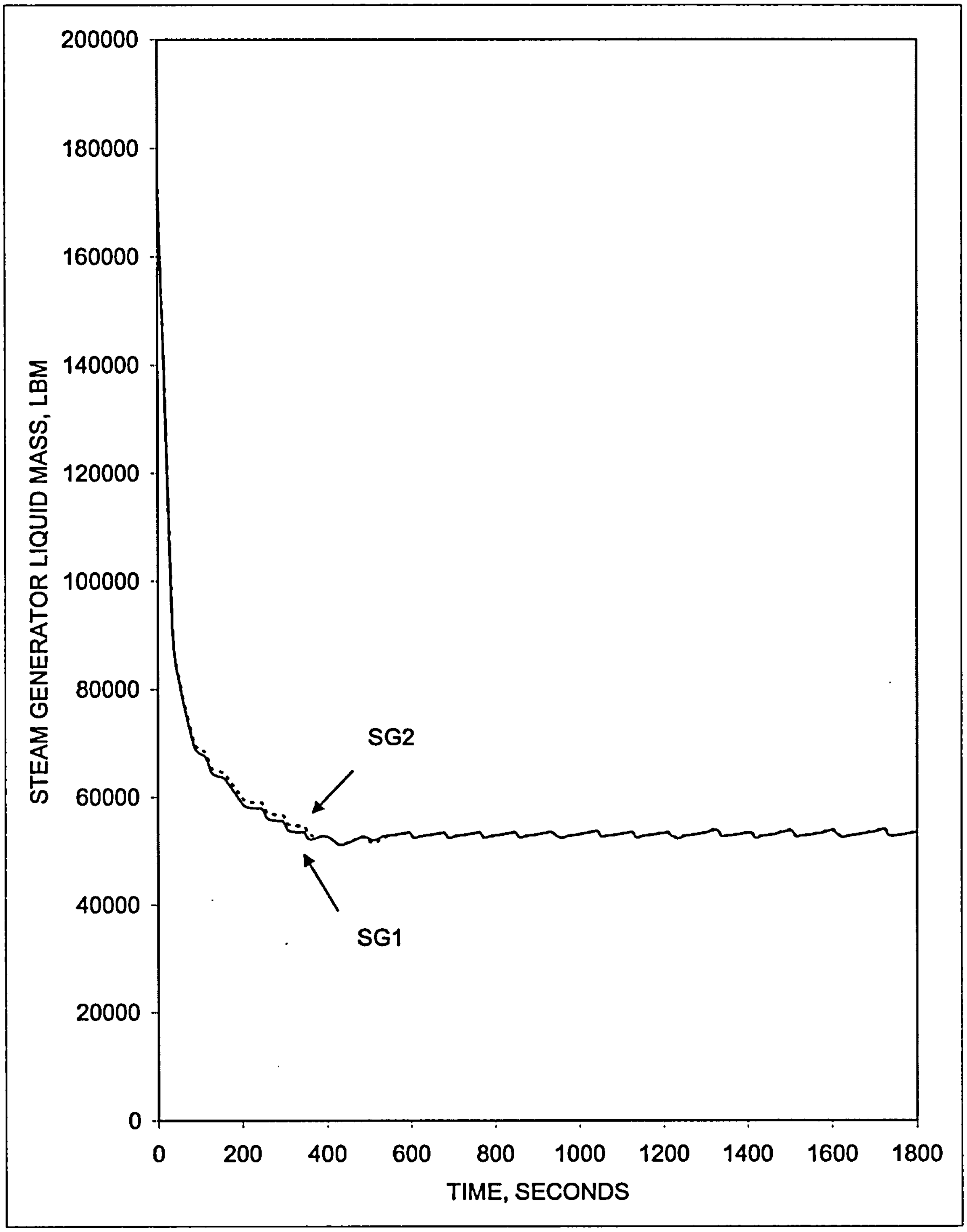


Figure 1-11
Loss of Normal Feedwater Flow with PLCS Failure, Long-Term
Safety Valve Flowrate per Steam Generator vs. Time

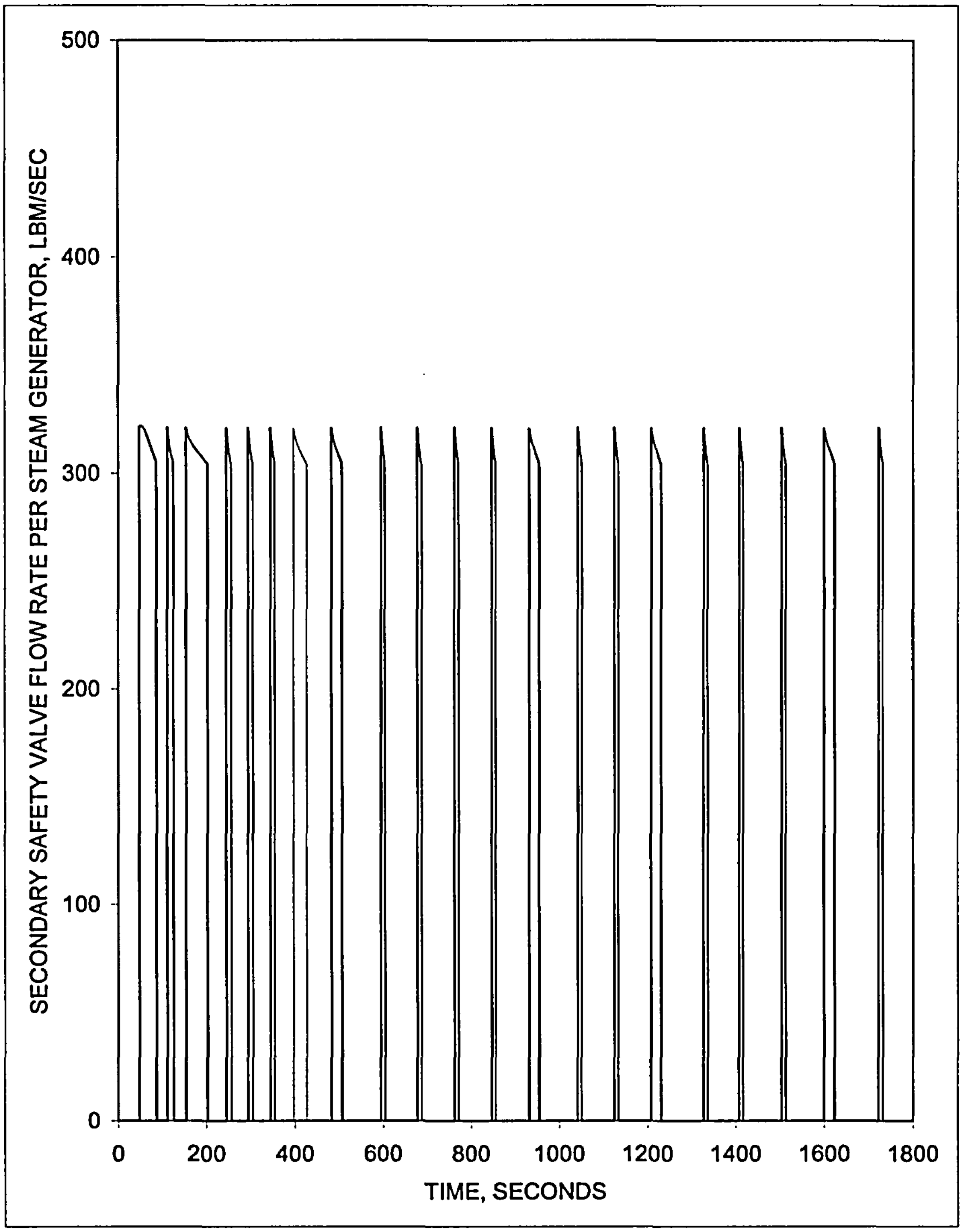


Figure 1-12
Loss of Normal Feedwater Flow with PLCS Failure, Long-Term
Primary Safety Valve Flow Rate vs. Time

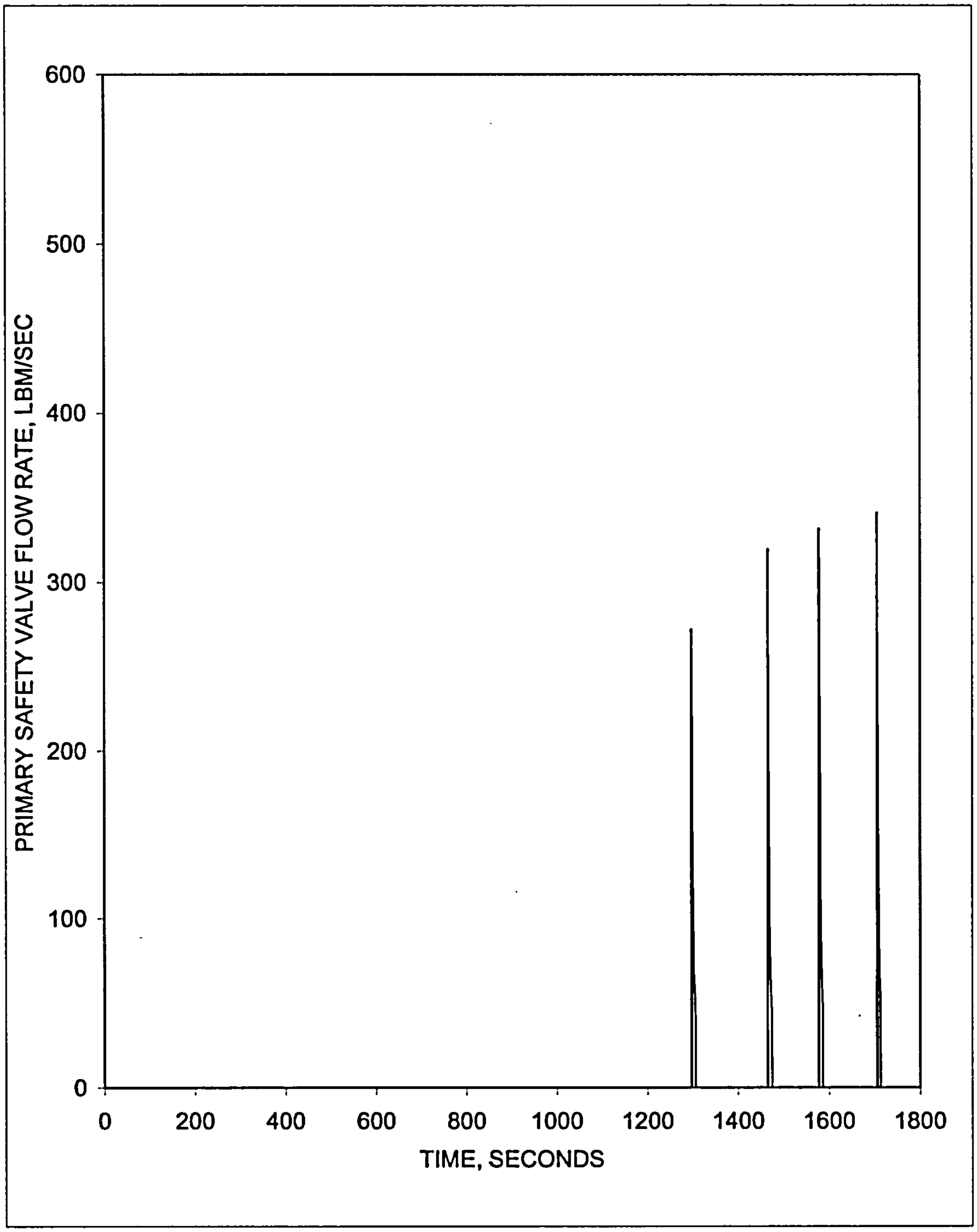


Figure 1-13
Loss of Normal Feedwater Flow with PLCS Failure, Long-Term
Primary Safety Valve Quality vs. Time

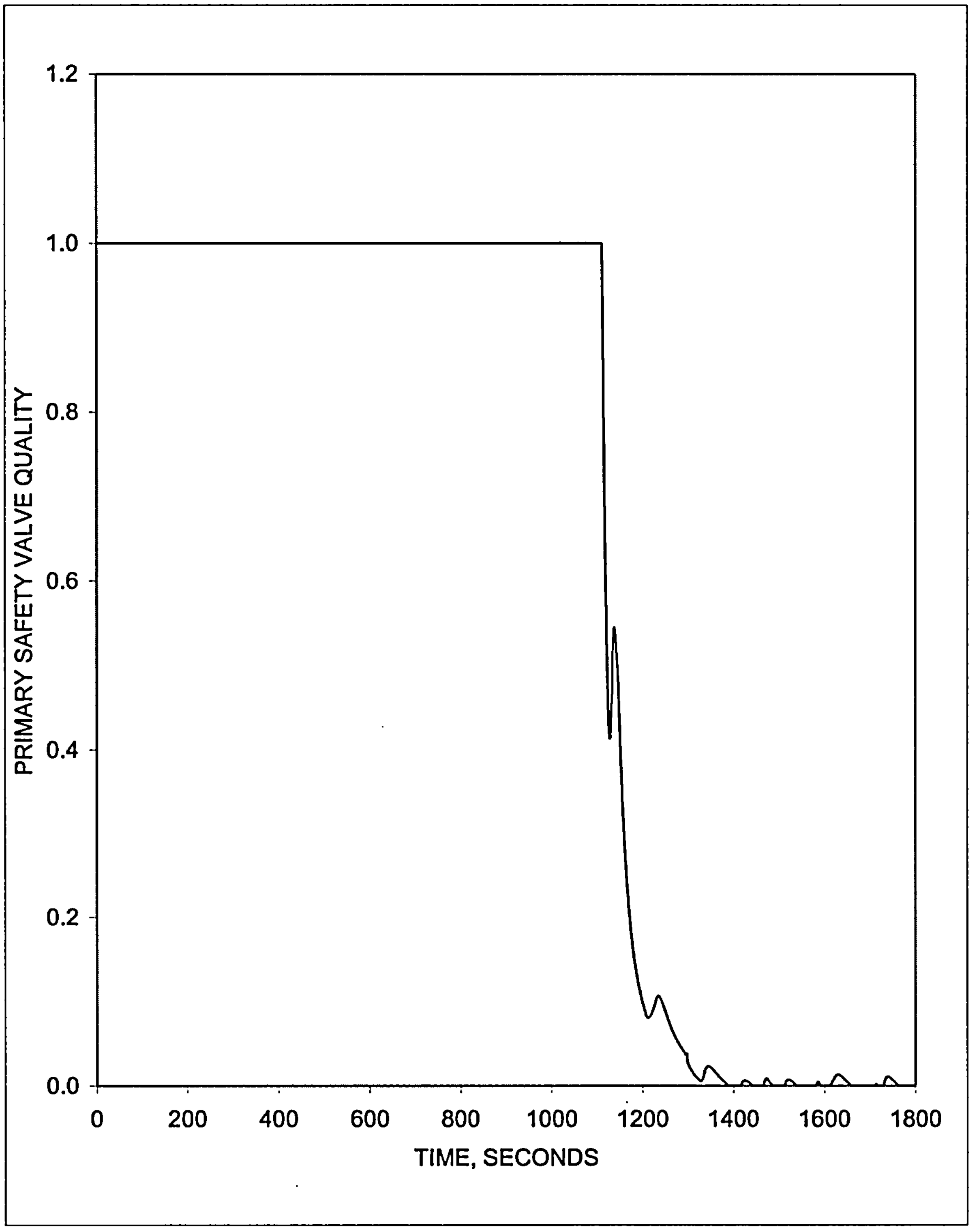


Figure 2-1
Loss of Normal Feedwater Flow with Operator Action 15 min After Reactor Trip, Long-Term Core Power vs. Time

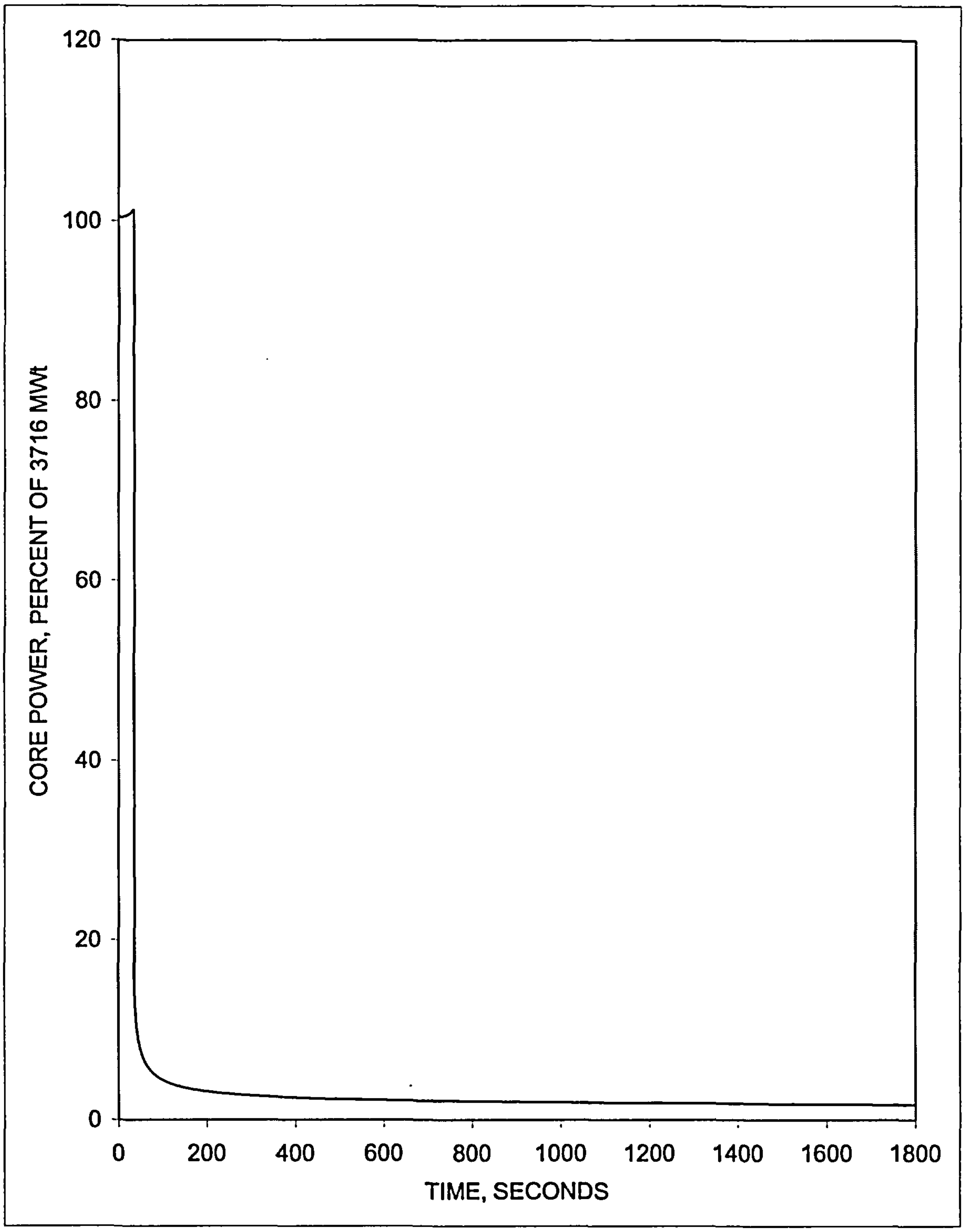


Figure 2-2
Loss of Normal Feedwater Flow with Operator Action 15 min After Reactor Trip, Long-Term Core Heat Flux vs. Time

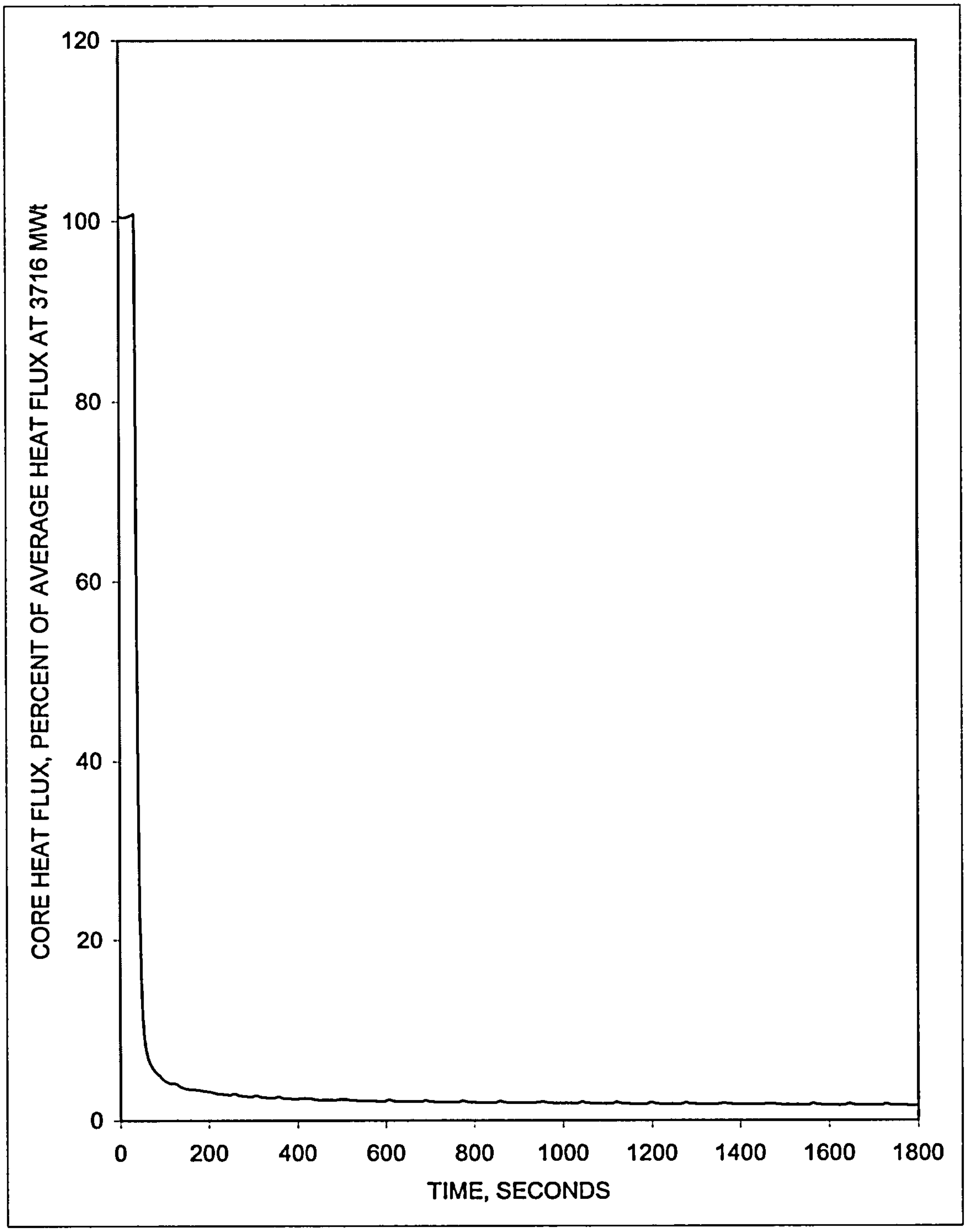


Figure 2-3
Loss of Normal Feedwater Flow with Operator Action 15 min After Reactor Trip, Long-Term Reactor Coolant System (Cold Leg Discharge) Pressure vs. Time

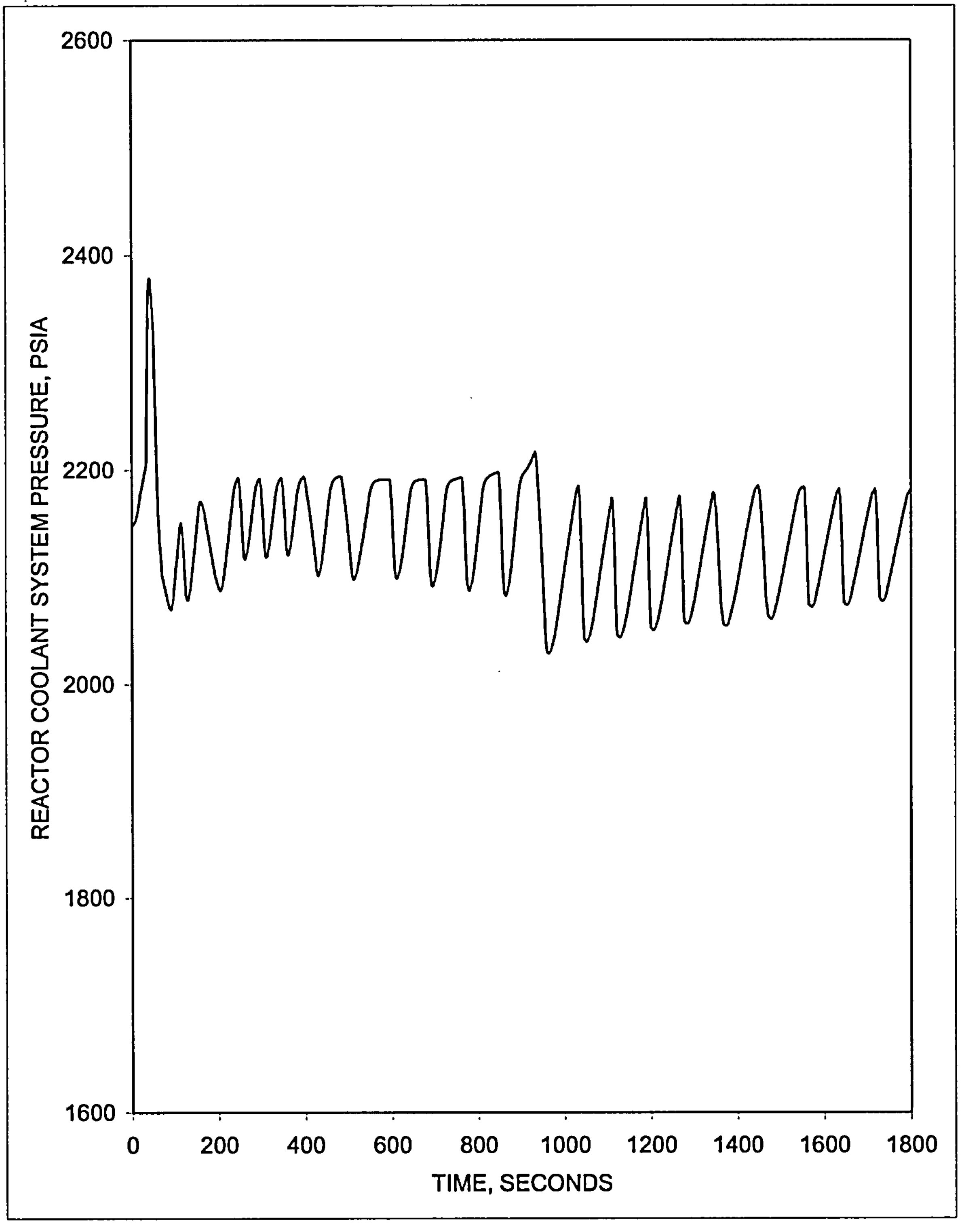


Figure 2-4
Loss of Normal Feedwater Flow with Operator Action 15 min After Reactor Trip, Long-Term Reactor Coolant System Temperatures vs. Time

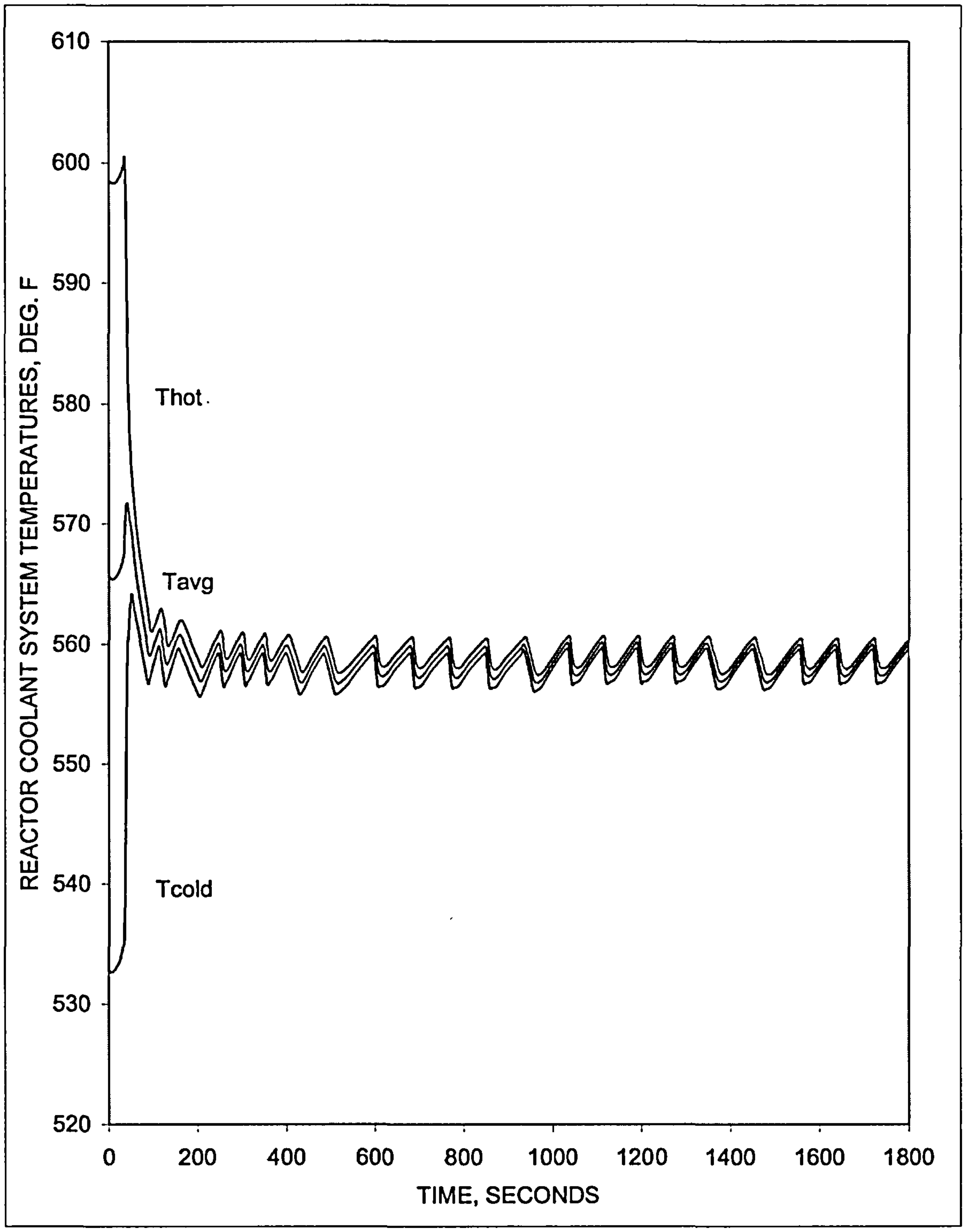


Figure 2-5
Loss of Normal Feedwater Flow with Operator Action 15 min After Reactor Trip, Long-Term Pressurizer Water Volume vs. Time

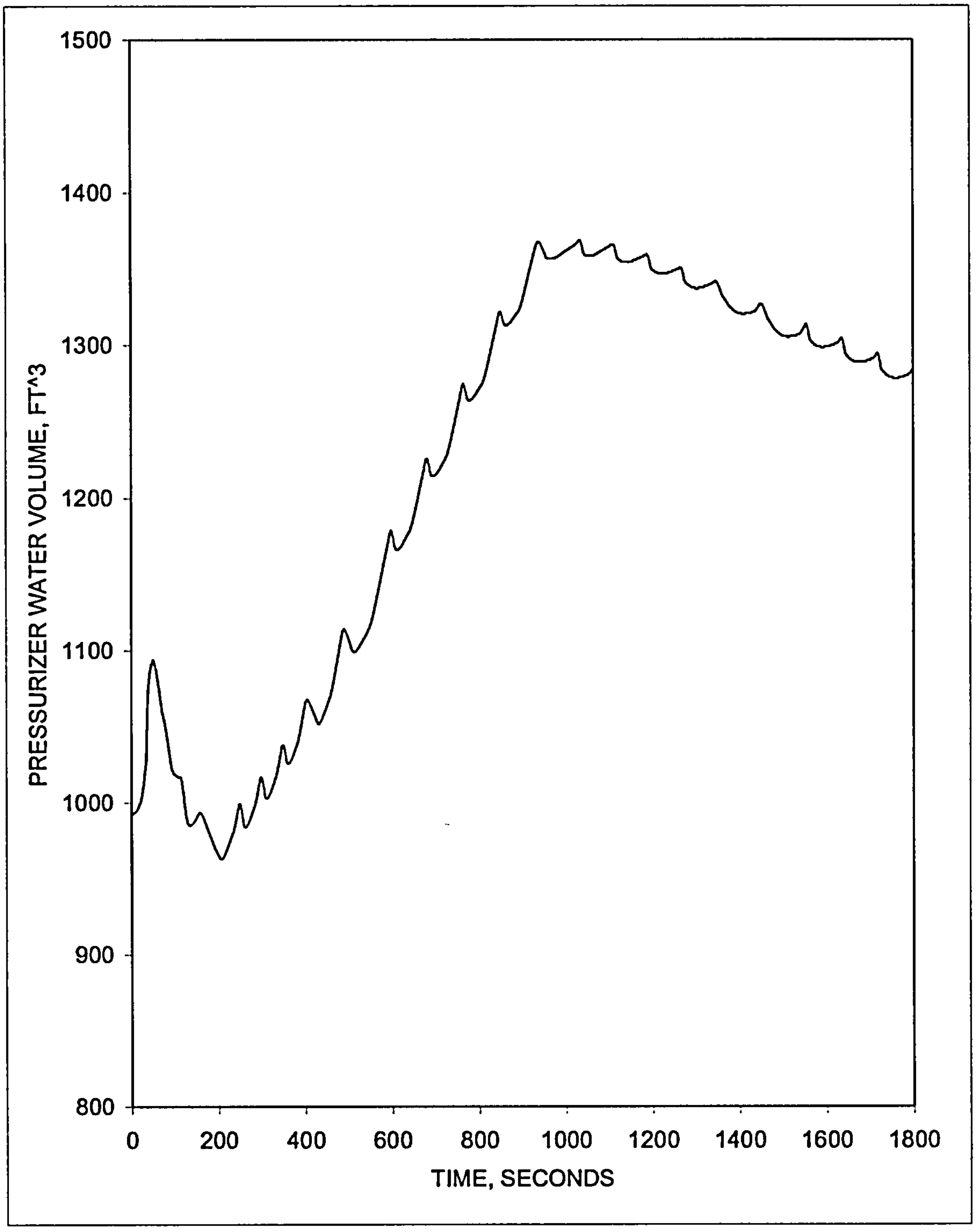


Figure 2-6
Loss of Normal Feedwater Flow with Operator Action 15 min After Reactor Trip, Long-Term Steam Generator Pressure vs. Time

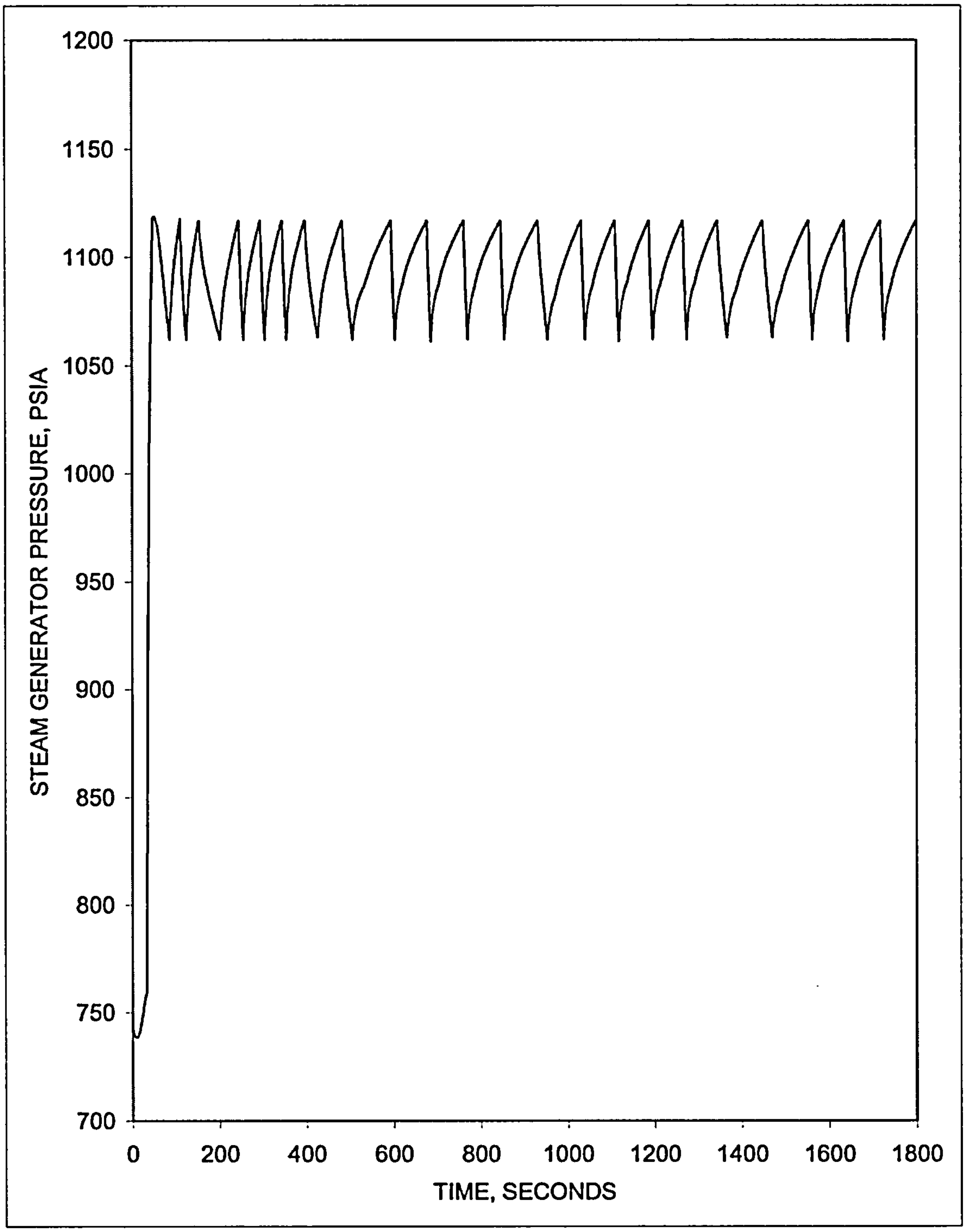


Figure 2-7
Loss of Normal Feedwater Flow with Operator Action 15 min After Reactor Trip Long-Term
Total Secondary Steam Flowrate vs. Time

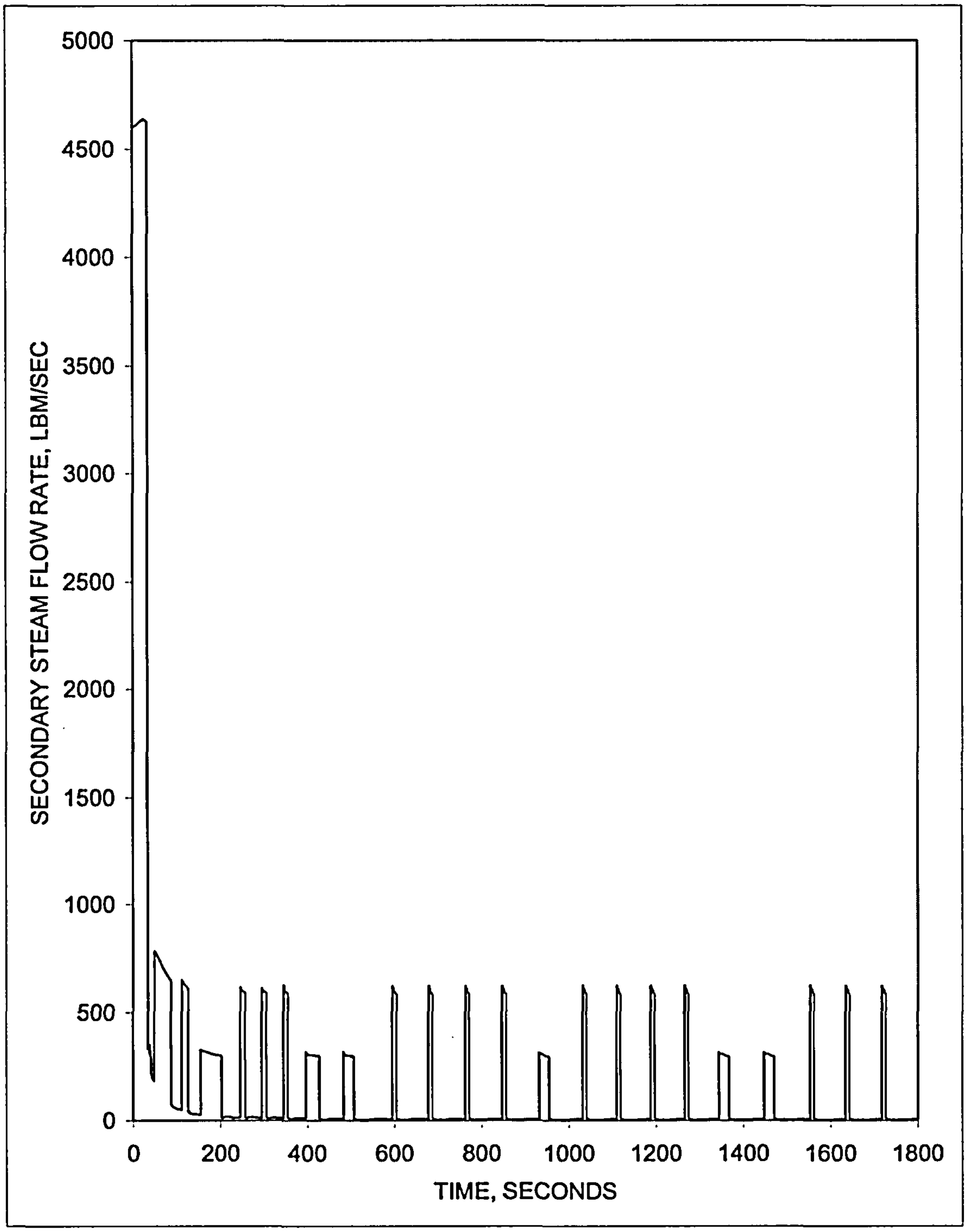


Figure 2-8
Loss of Normal Feedwater Flow with Operator Action 15 min After Reactor Trip, Long-Term Emergency Feedwater Flowrate per Steam Generator vs. Time

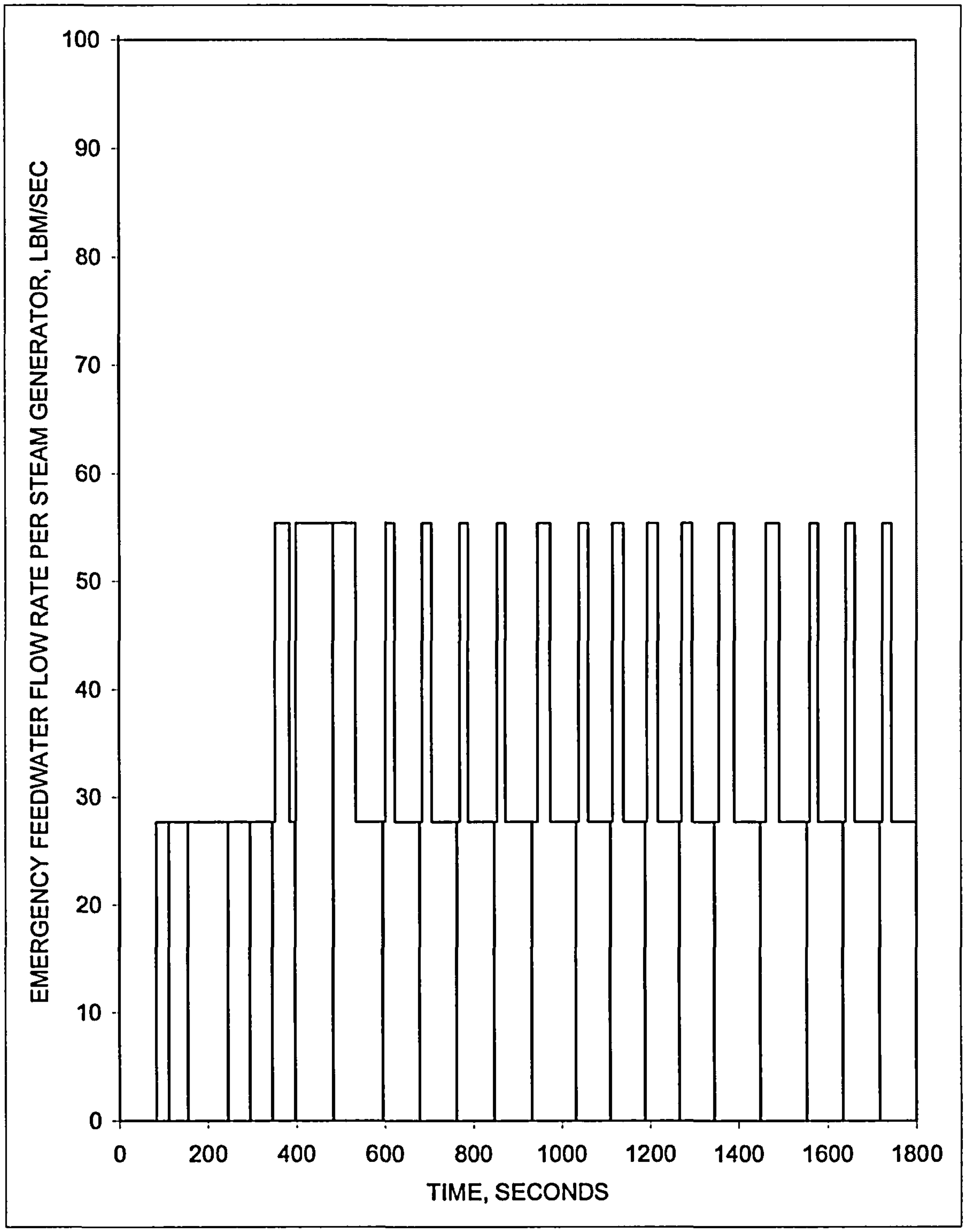


Figure 2-9
Loss of Normal Feedwater Flow with Operator Action 15 min After Reactor Trip, Long-Term Emergency Feedwater Enthalpy vs. Time

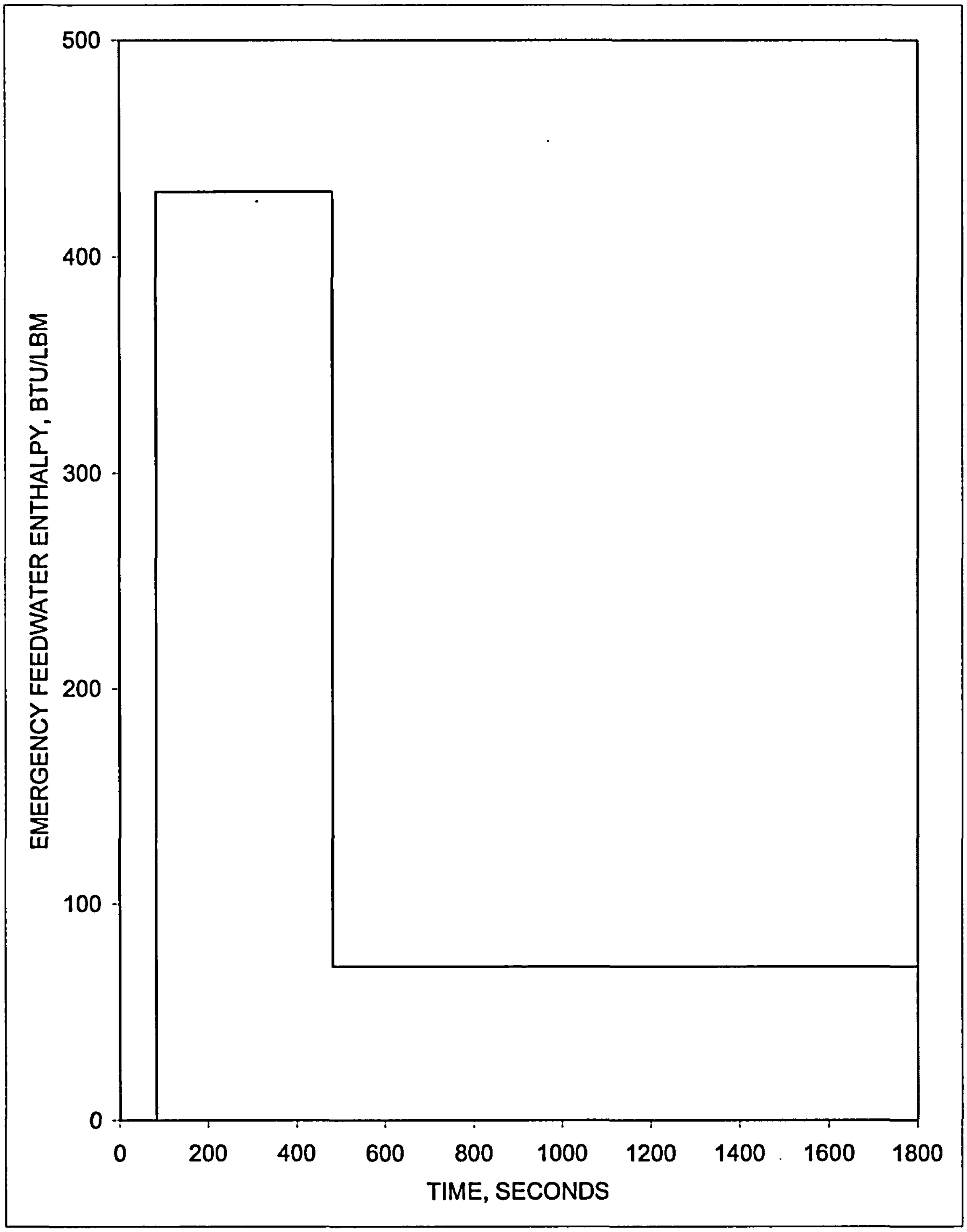


Figure 2-10
Loss of Normal Feedwater Flow with Operator Action 15 min After Reactor Trip, Long-Term Secondary Liquid Mass vs. Time

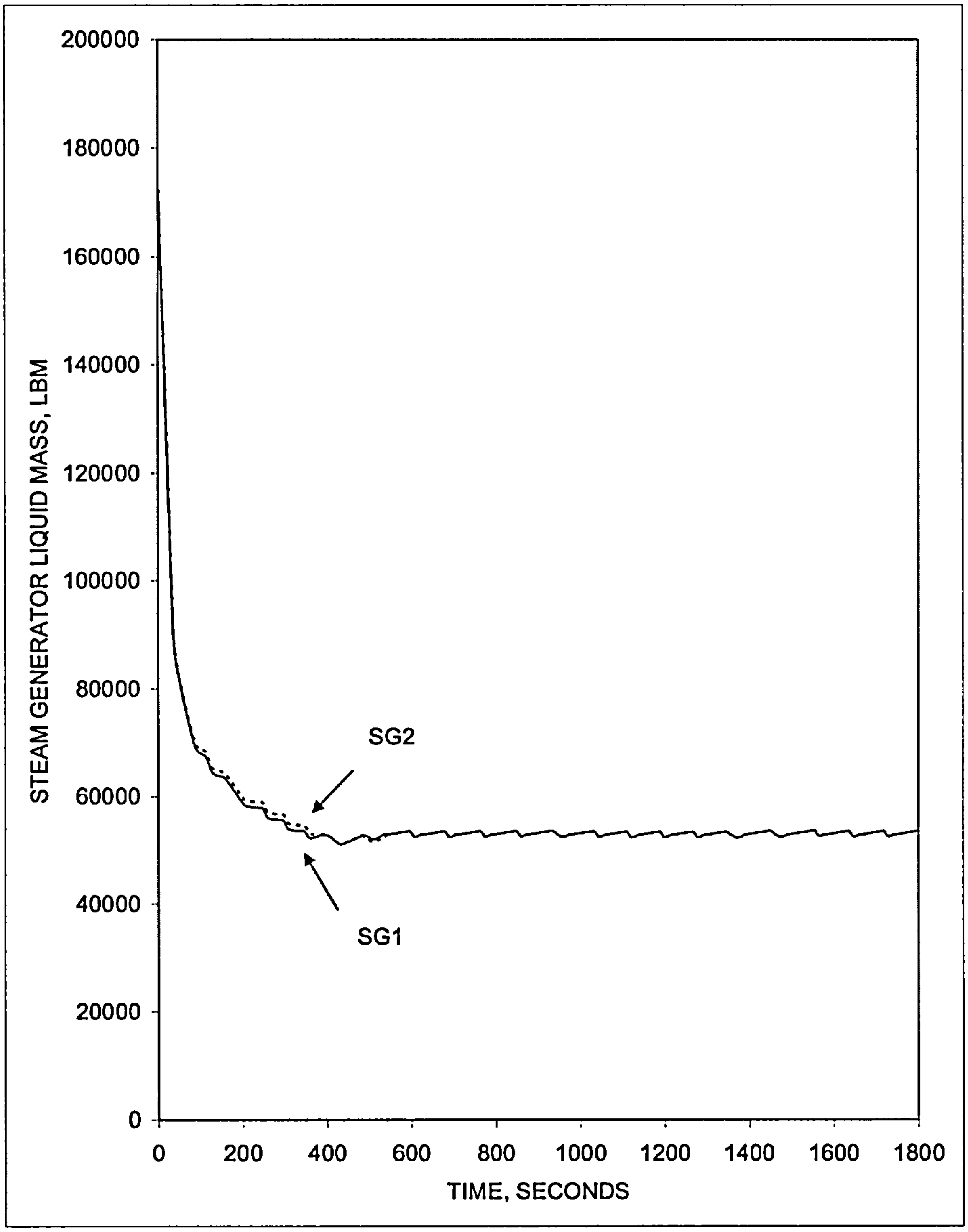


Figure 2-11
Loss of Normal Feedwater Flow with Operator Action 15 min After Reactor Trip, Long-Term Safety Valve Flowrate per Steam Generator vs. Time

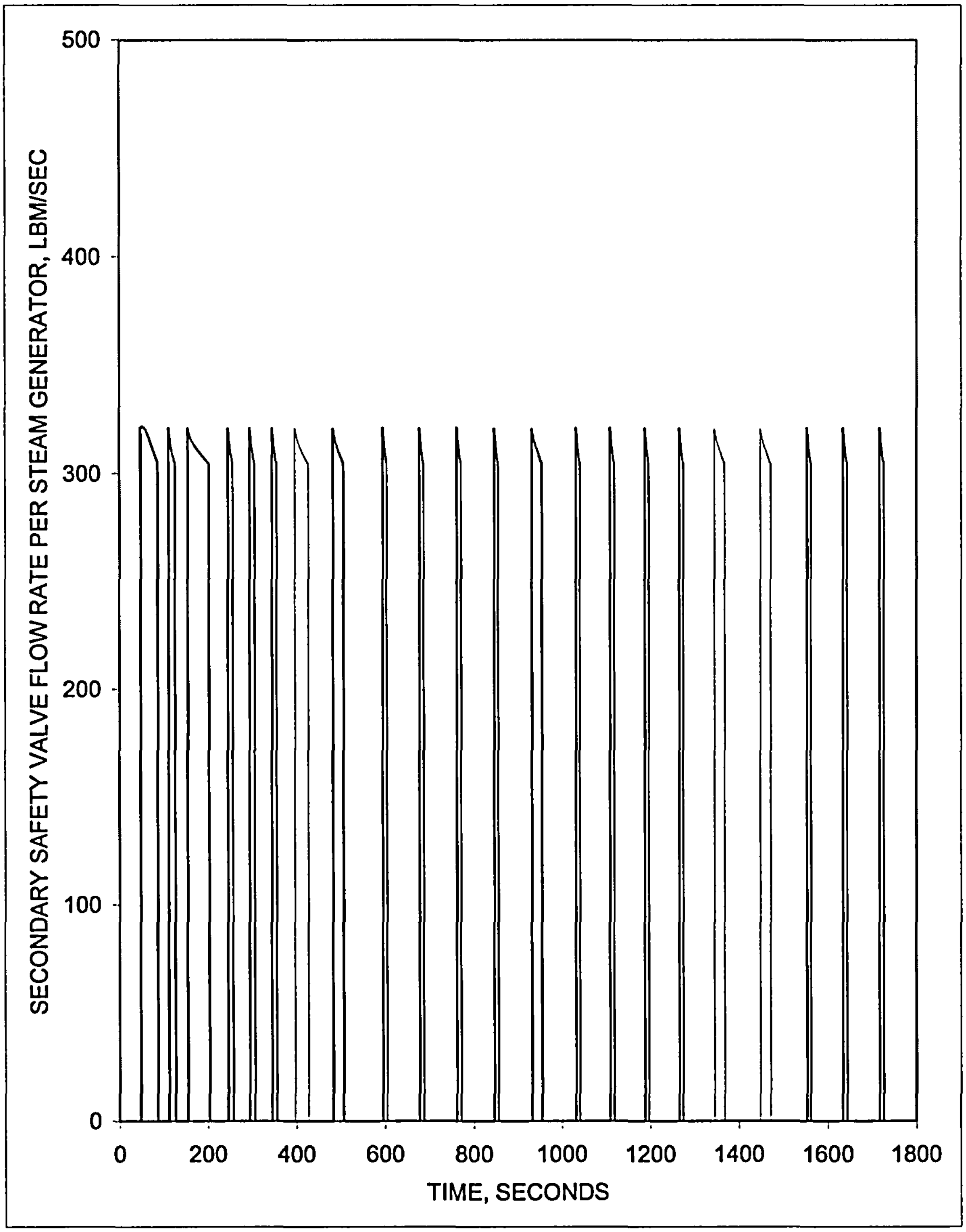


Figure 2-12
Loss of Normal Feedwater Flow with Operator Action 15 min After Reactor Trip, Long-Term
Primary Safety Valve Flow Rate vs. Time

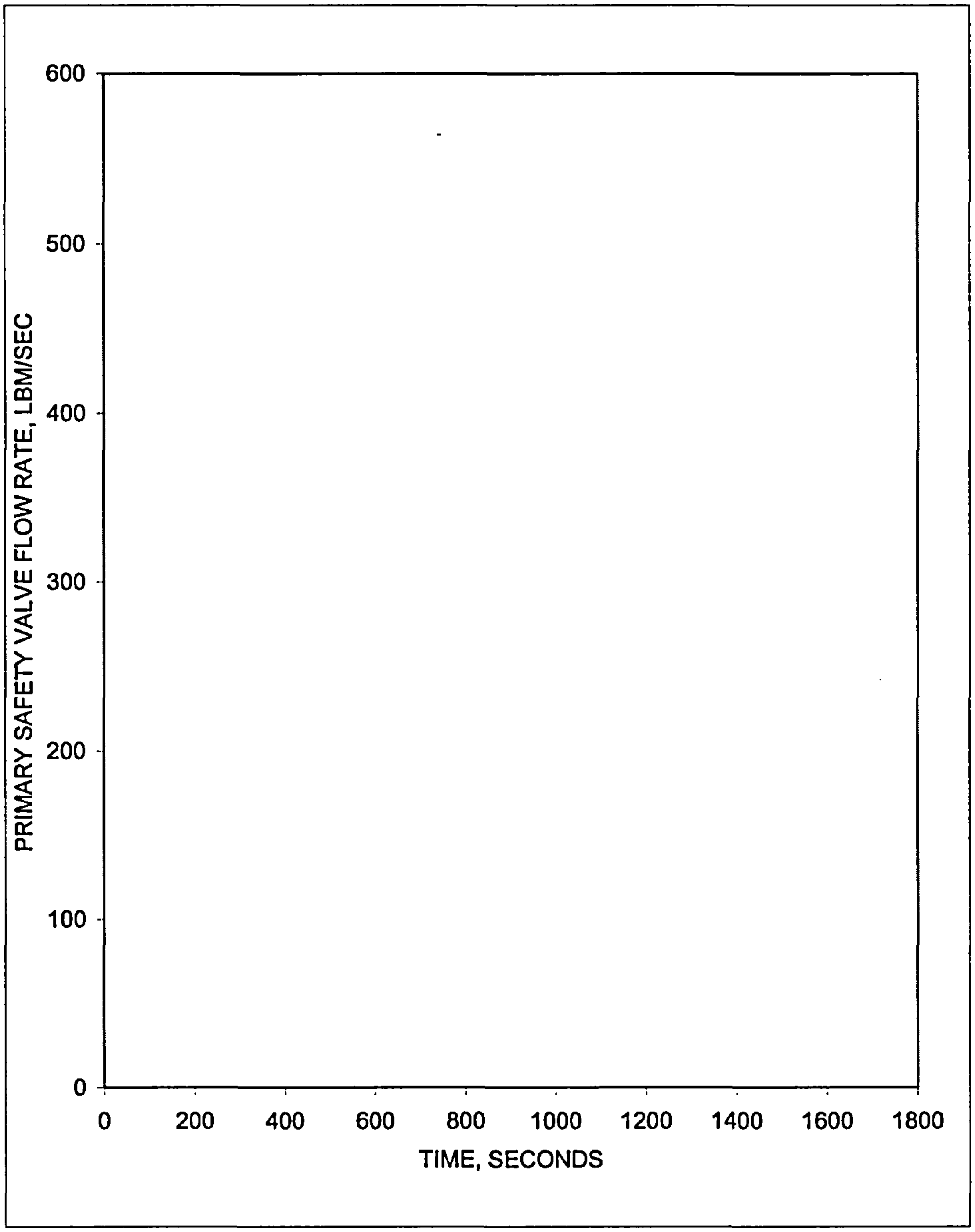


Figure 2-13
Loss of Normal Feedwater Flow with Operator Action 15 min After Reactor Trip Long-Term
Primary Safety Valve Quality vs. Time

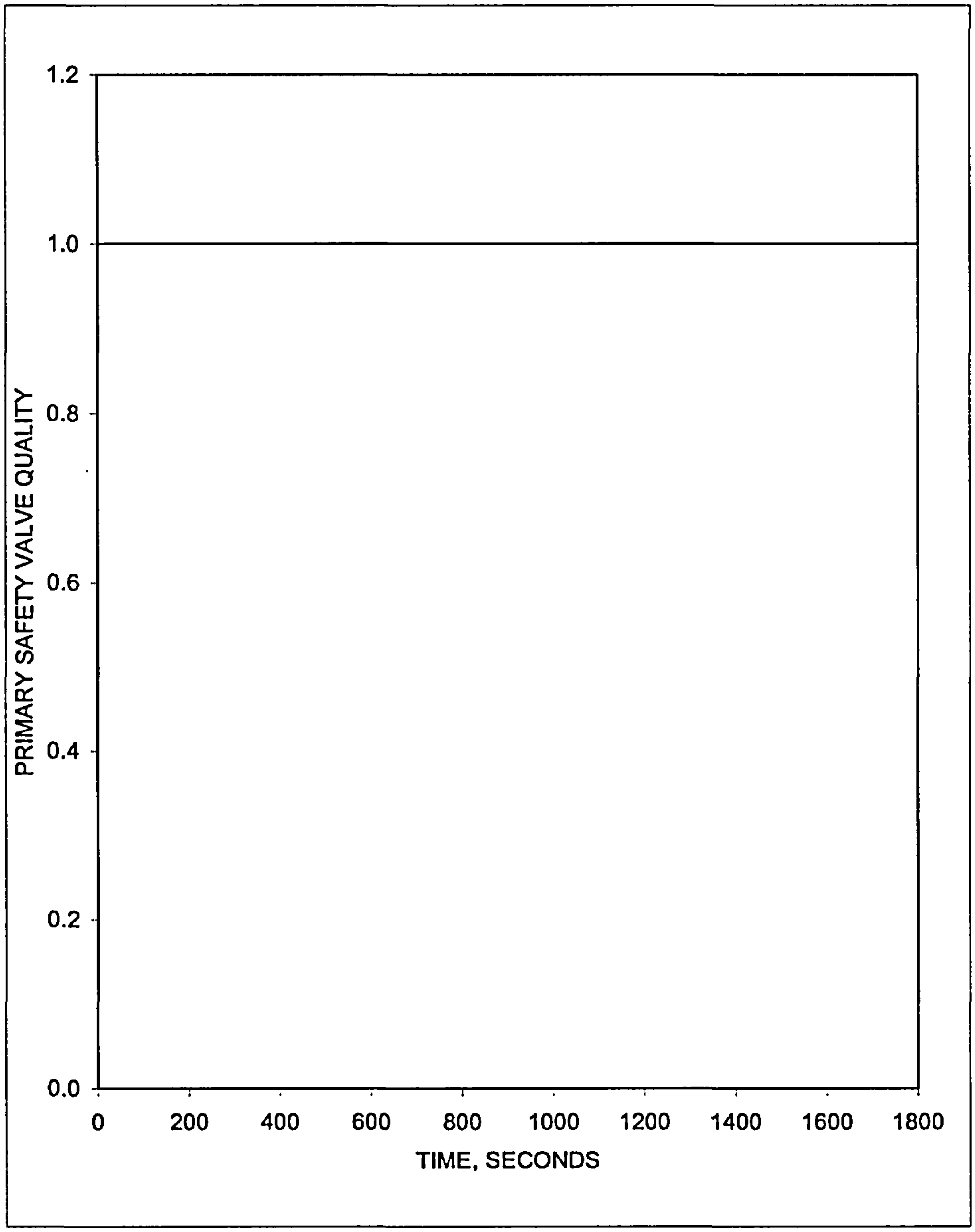


Figure 3-1
Loss of Normal Feedwater Flow with Reduced EFW Flow, Long-Term
Core Power vs. Time

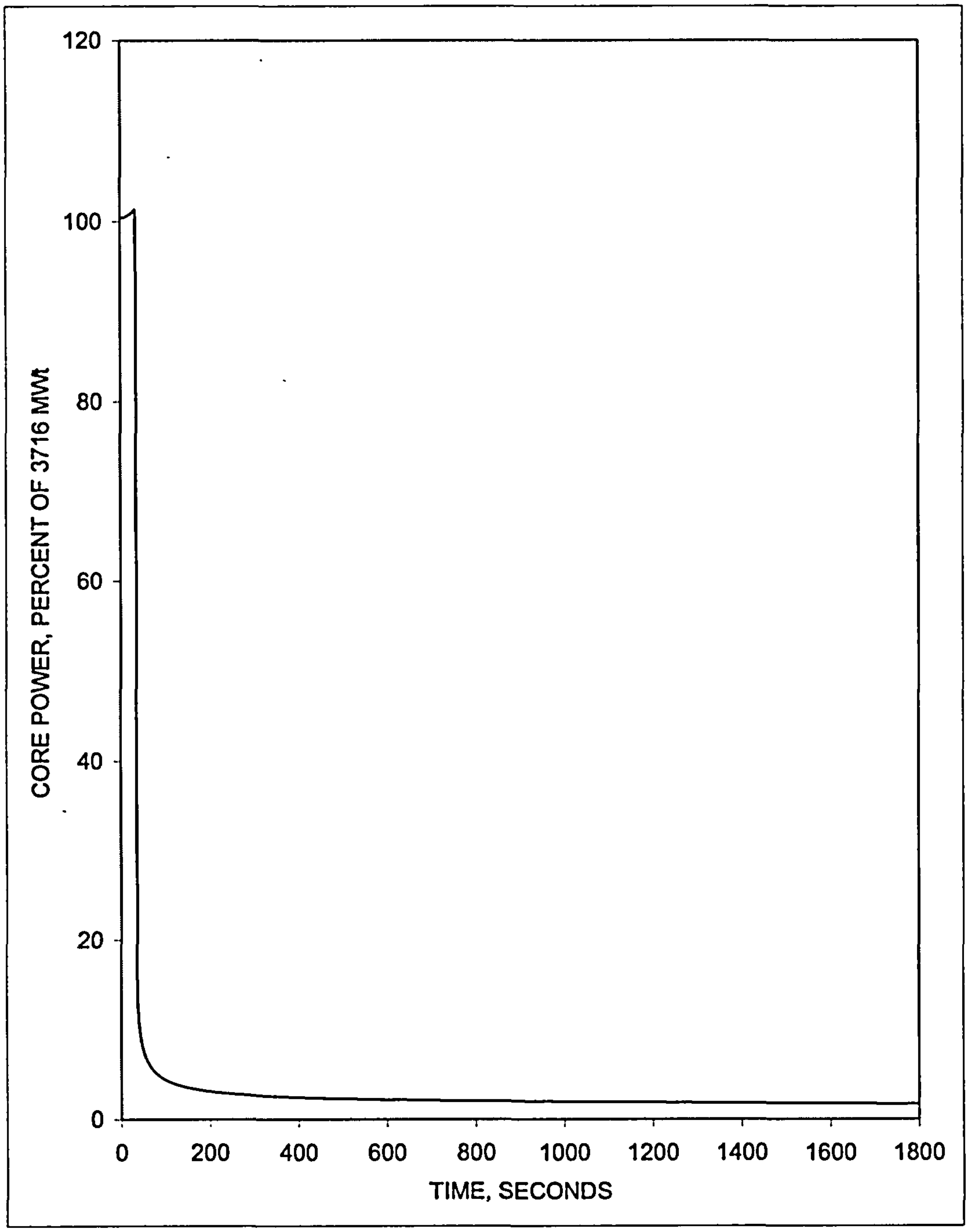


Figure 3-2
Loss of Normal Feedwater Flow with Reduced EFW Flow, Long-Term
Core Heat Flux vs. Time

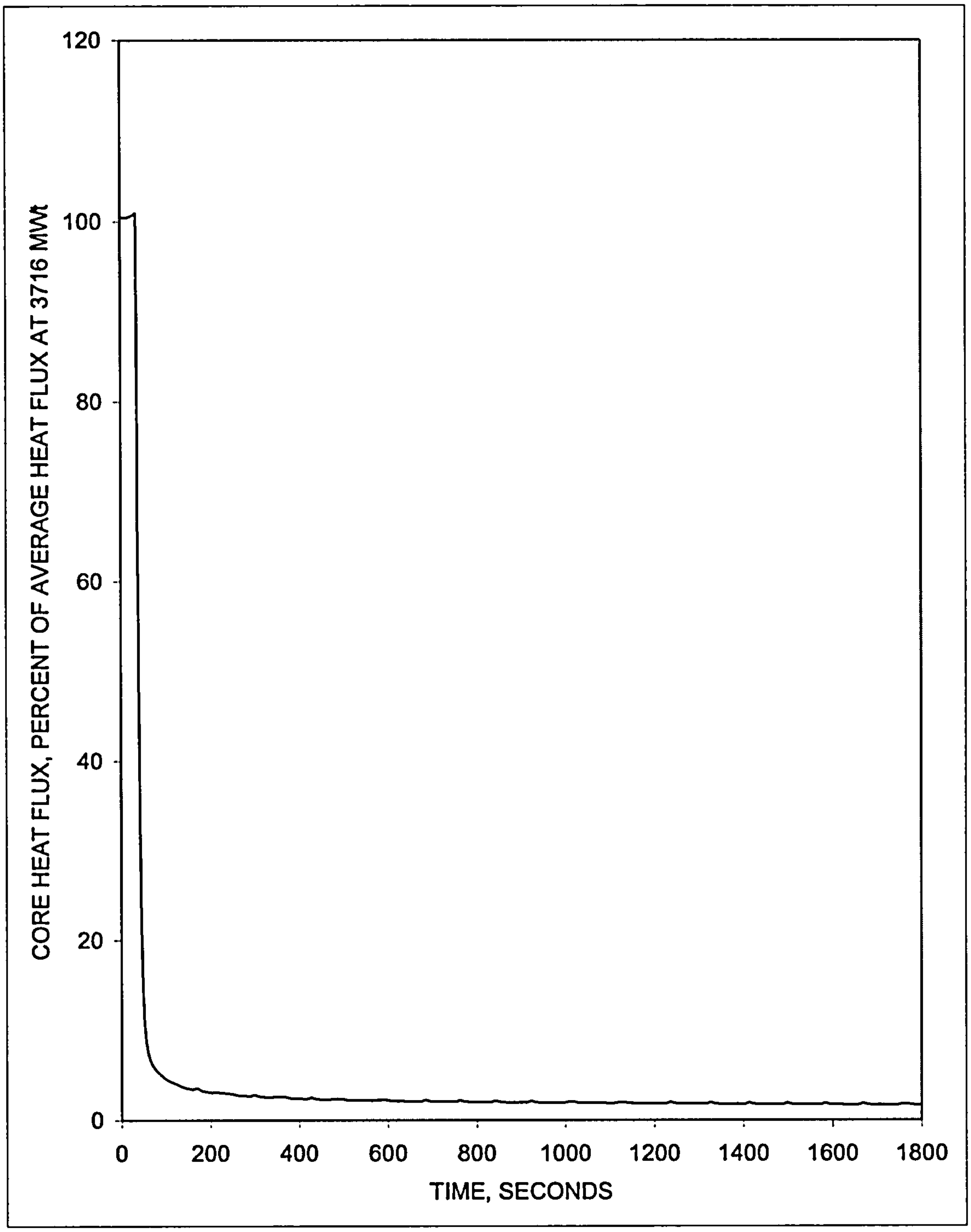


Figure 3-3
Loss of Normal Feedwater Flow with Reduced EFW Flow, Long-Term
Reactor Coolant System (Cold Leg Discharge) Pressure vs. Time

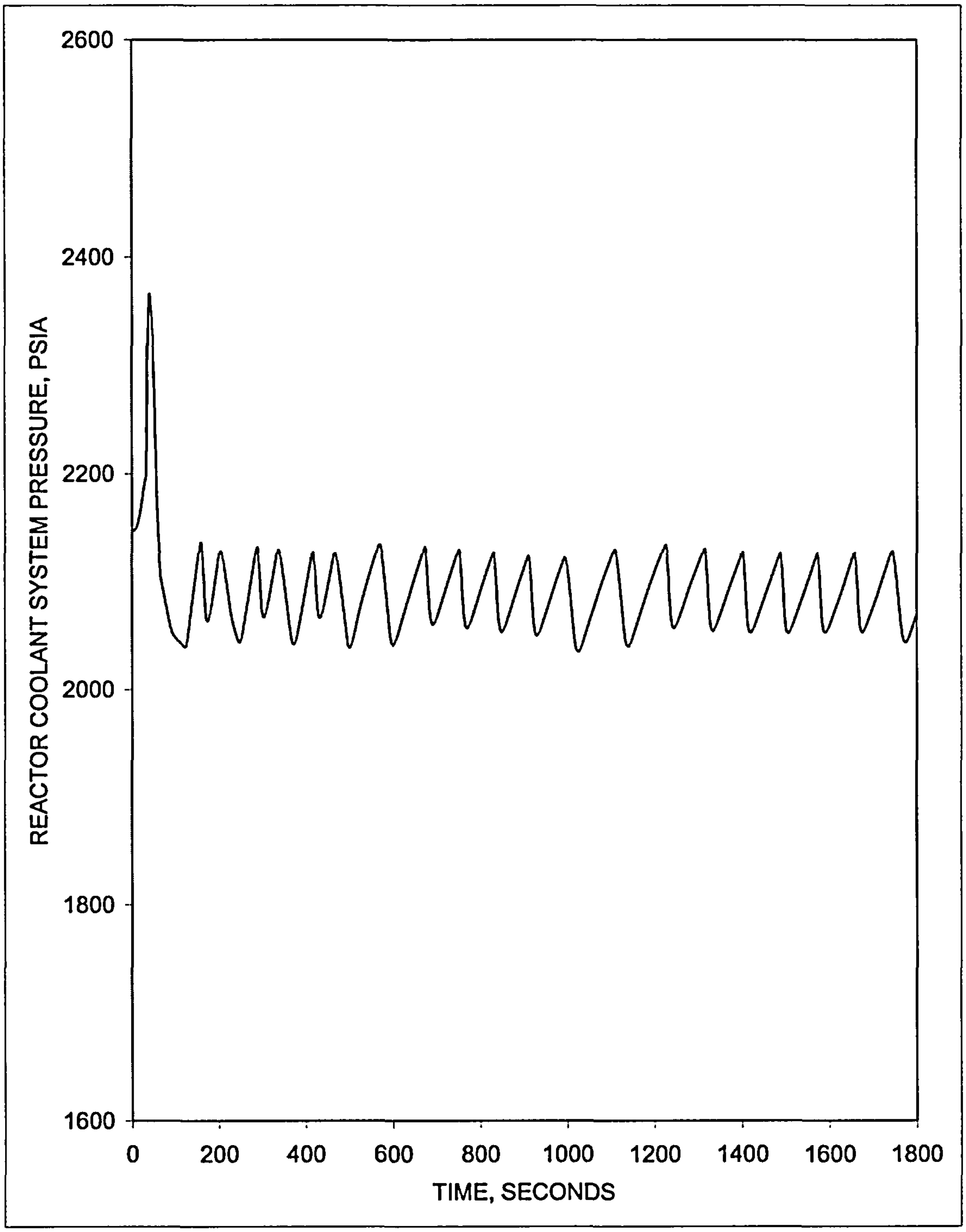


Figure 3-4
Loss of Normal Feedwater Flow with Reduced EFW Flow, Long-Term
Reactor Coolant System Temperatures vs. Time

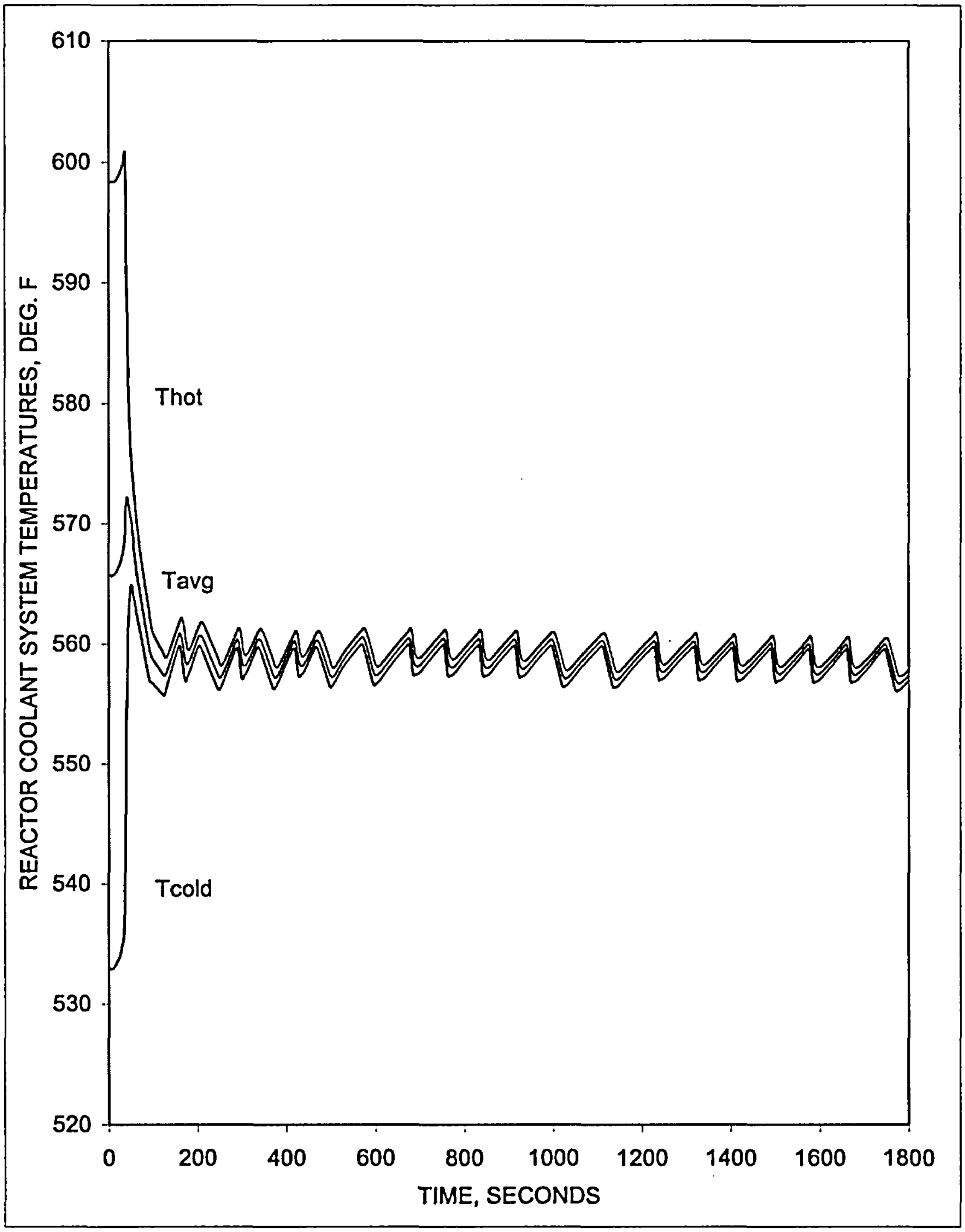


Figure 3-5
Loss of Normal Feedwater Flow with Reduced EFW Flow, Long-Term
Pressurizer Water Volume vs. Time

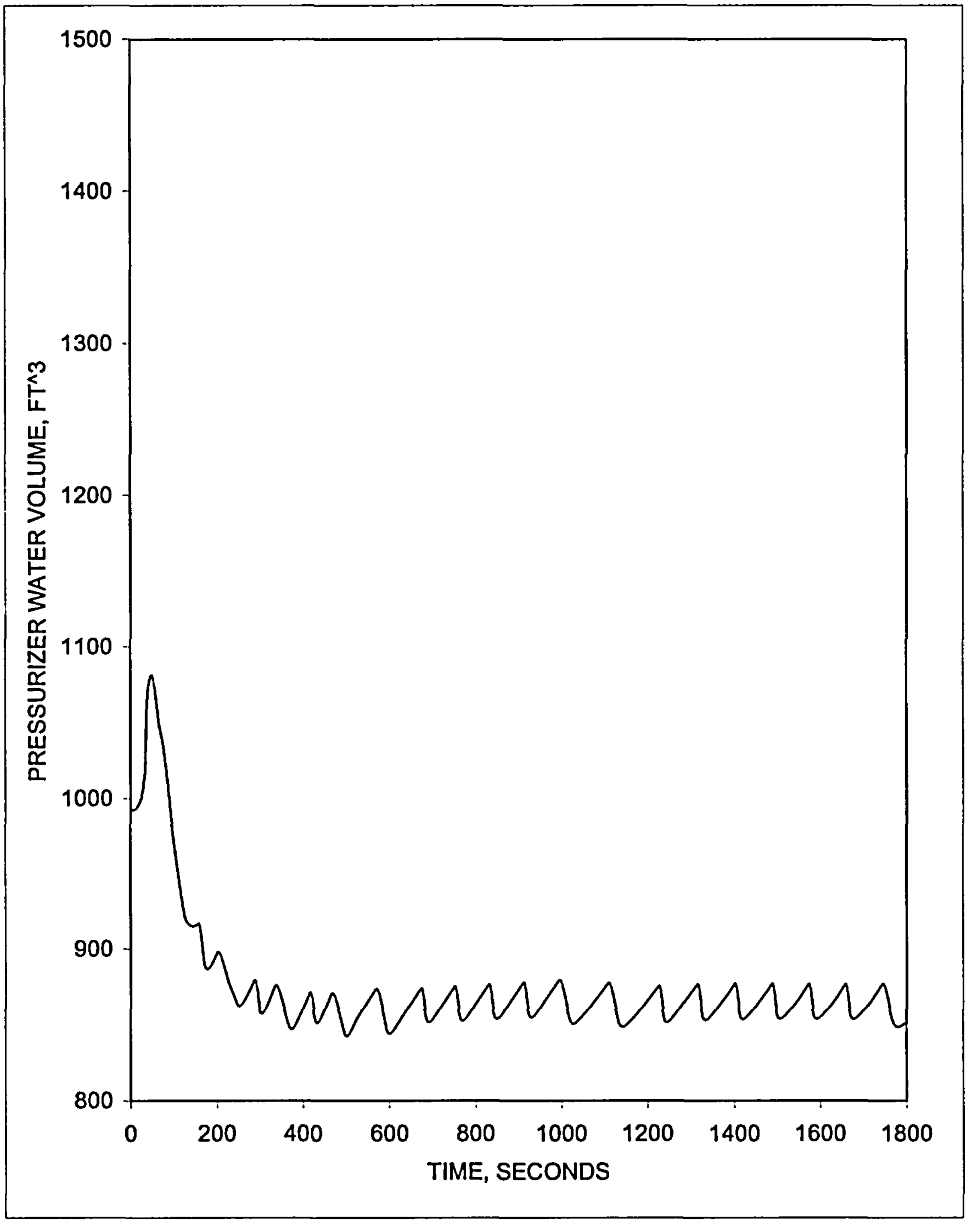


Figure 3-6
Loss of Normal Feedwater Flow with Reduced EFW Flow, Long-Term
Steam Generator Pressure vs. Time

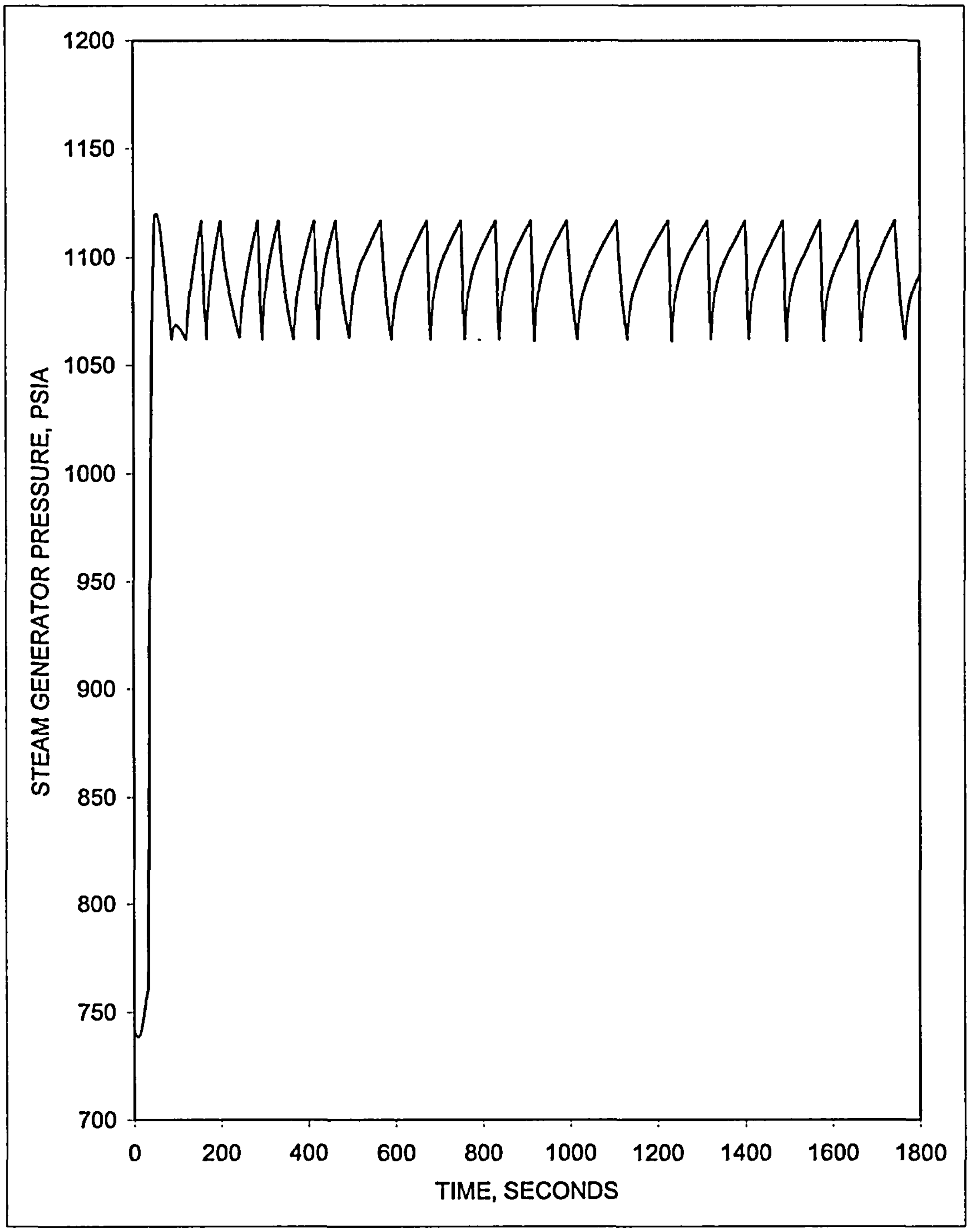


Figure 3-7
Loss of Normal Feedwater Flow with Reduced EFW Flow, Long-Term
Total Secondary Steam Flowrate vs. Time

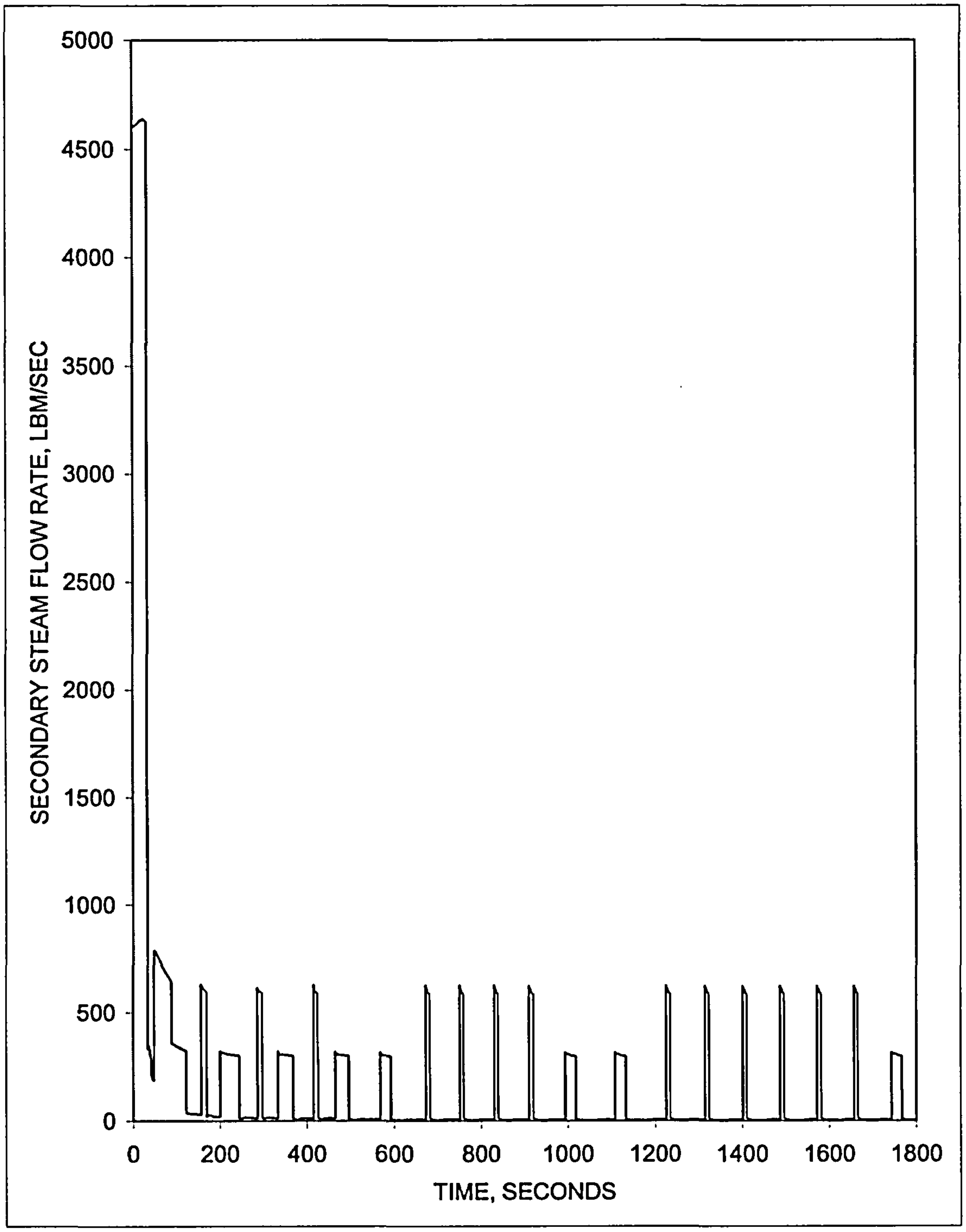


Figure 3-8
Loss of Normal Feedwater Flow with Reduced EFW Flow, Long-Term
Emergency Feedwater Flowrate per Steam Generator vs. Time

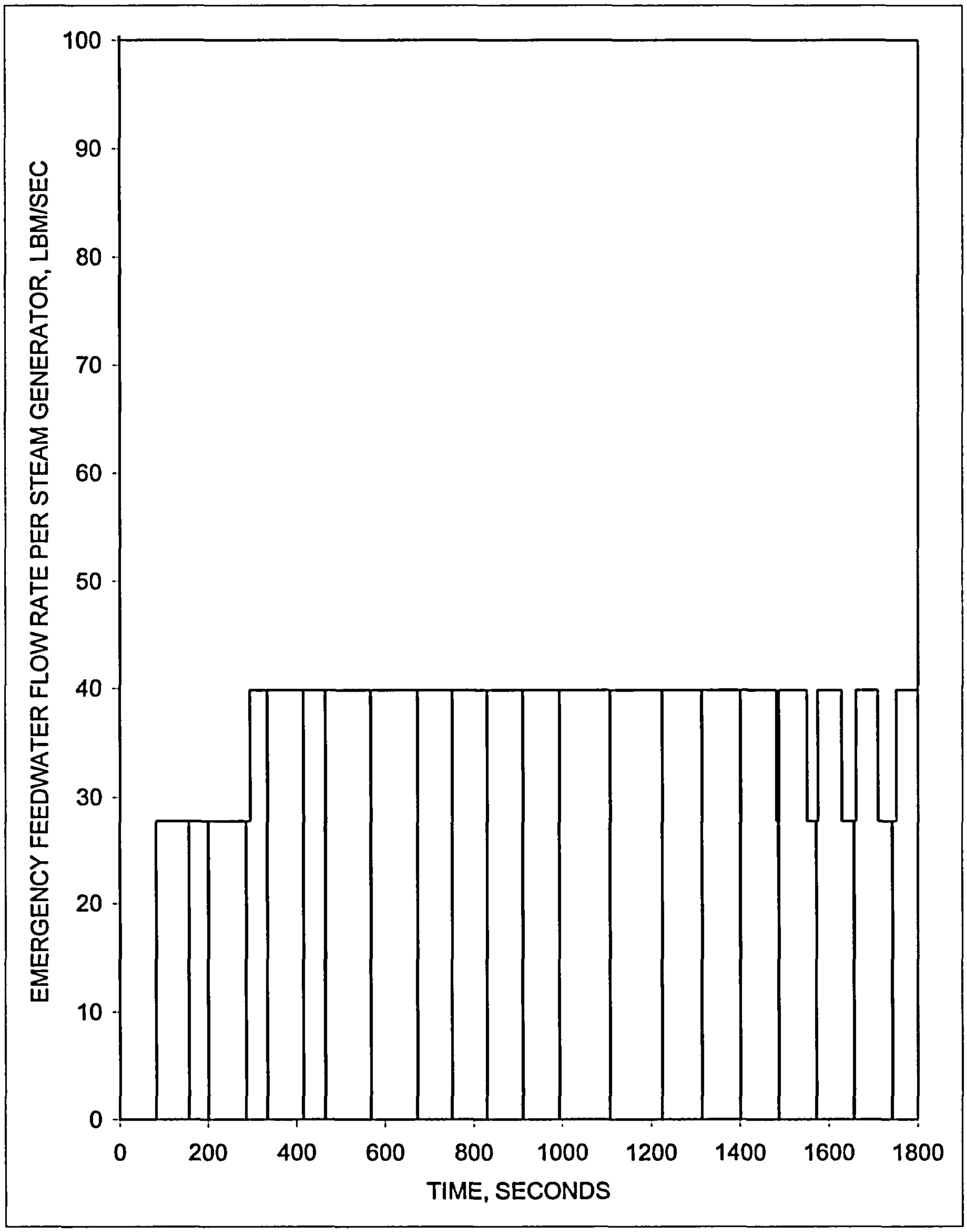


Figure 3-9
Loss of Normal Feedwater Flow with Reduced EFW Flow, Long-Term
Emergency Feedwater Enthalpy vs. Time

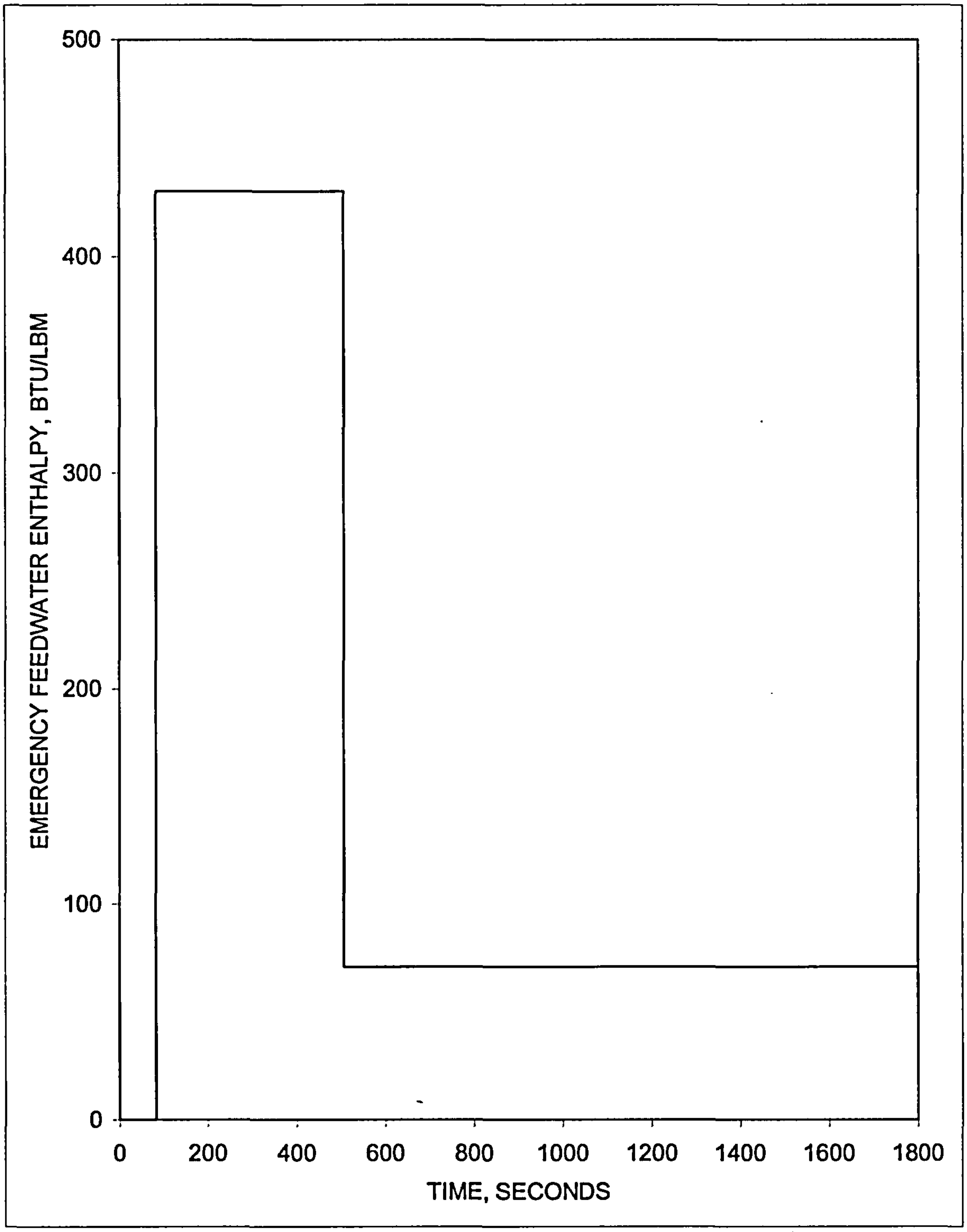


Figure 3-10
Loss of Normal Feedwater Flow with Reduced EFW Flow, Long-Term
Secondary Liquid Mass vs. Time

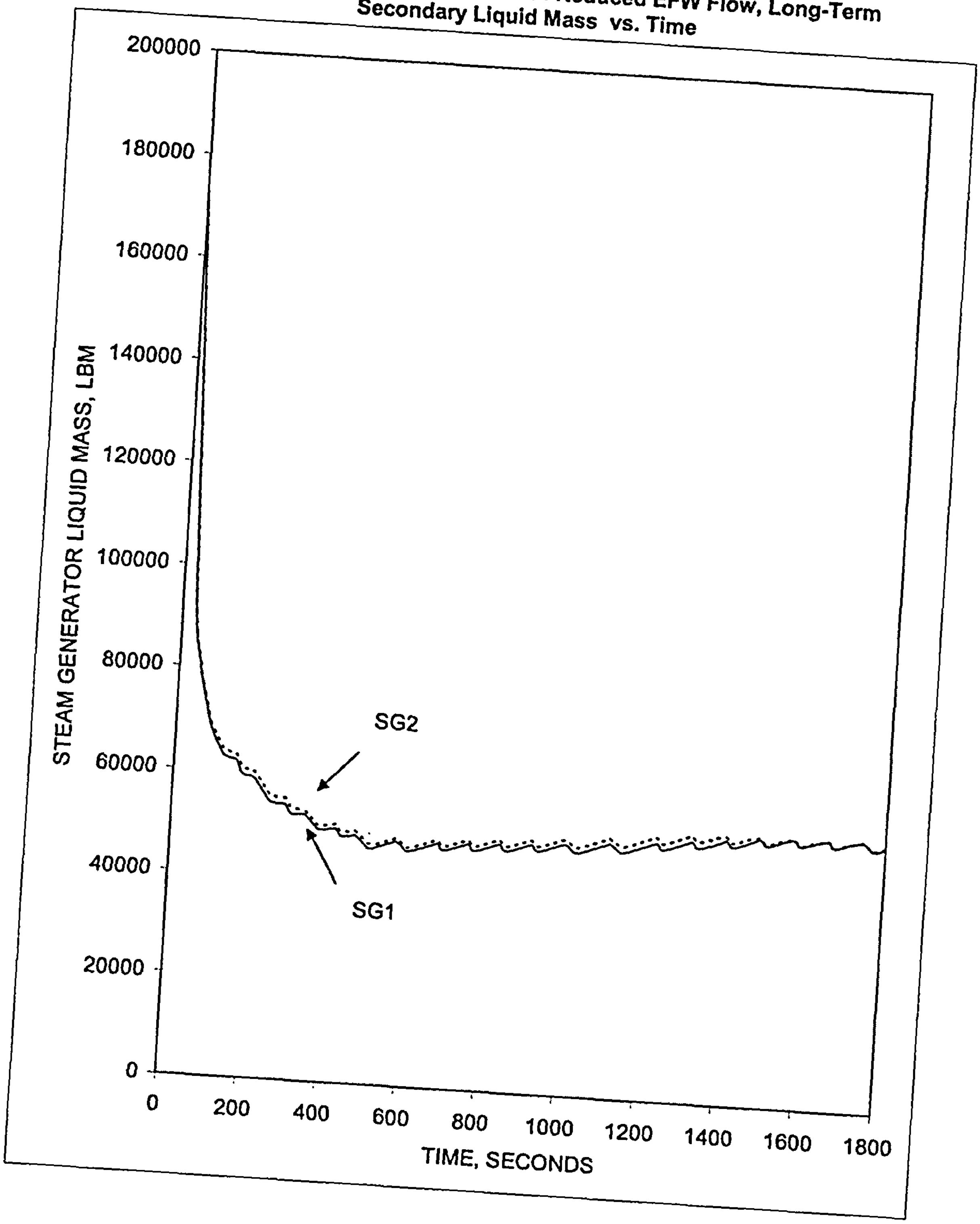


Figure 3-11
Loss of Normal Feedwater Flow with Reduced EFW Flow, Long-Term
Safety Valve Flowrate per Steam Generator vs. Time

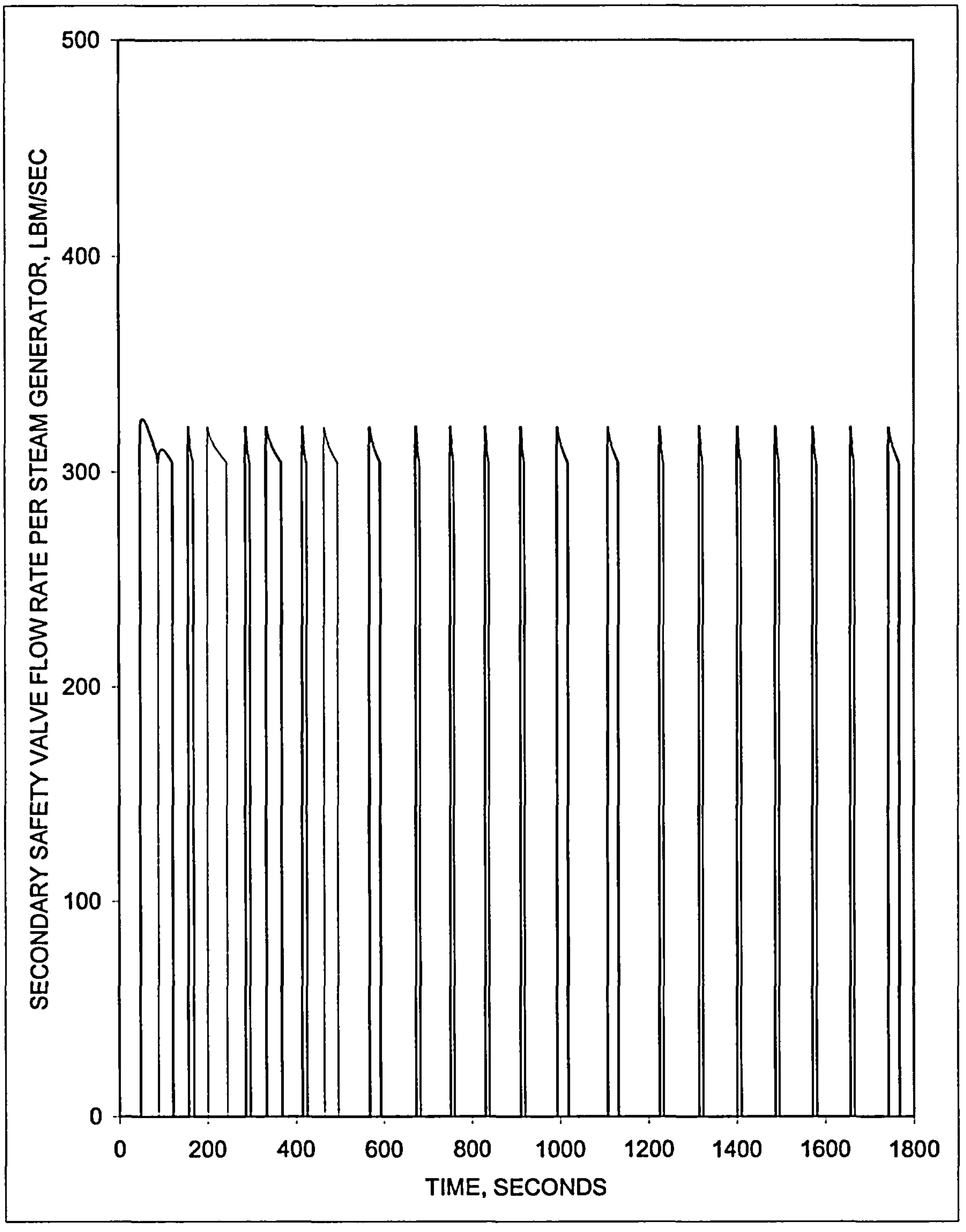


Figure 3-12
Loss of Normal Feedwater Flow with Reduced EFW Flow, Long-Term
Primary Safety Valve Flow Rate vs. Time

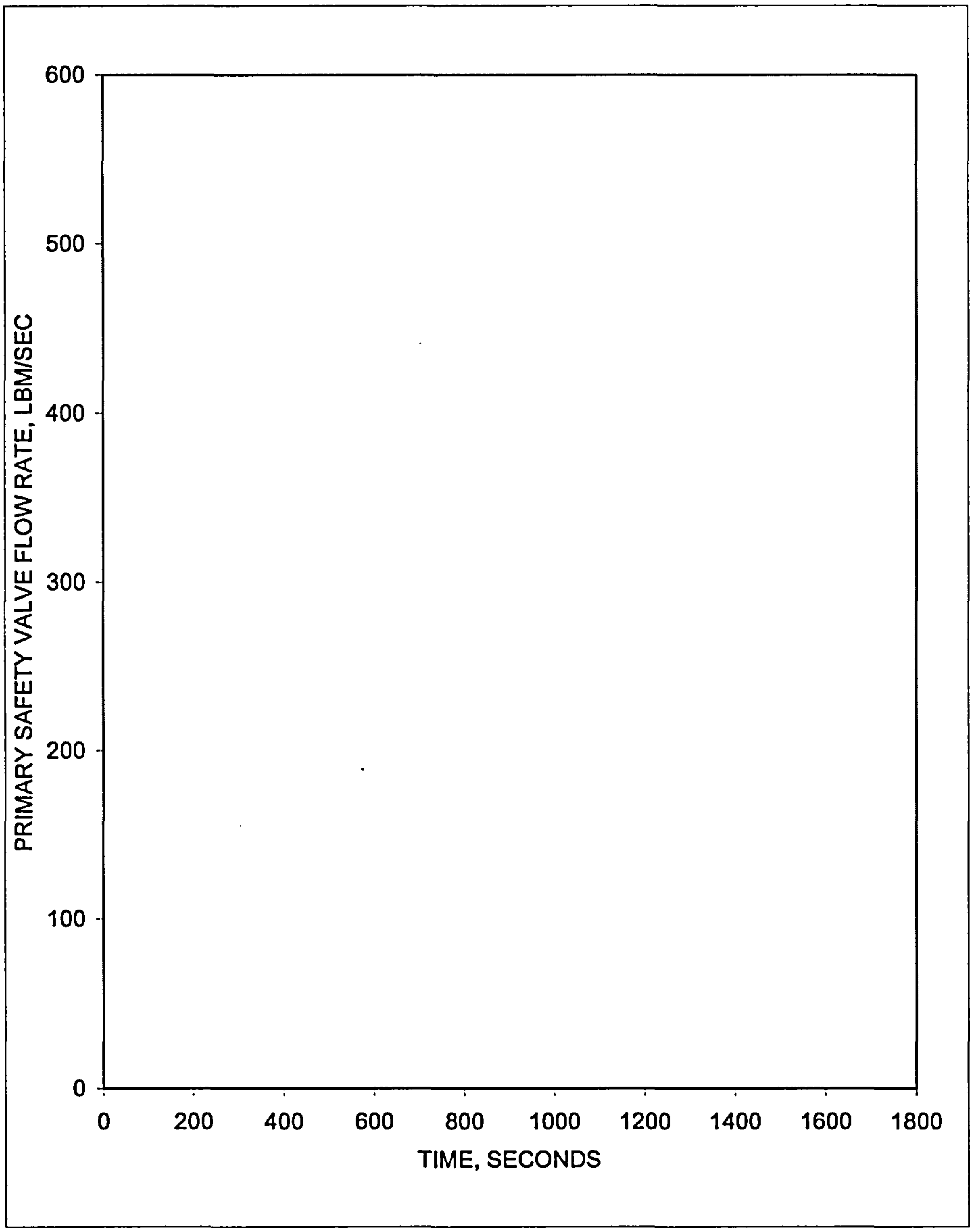
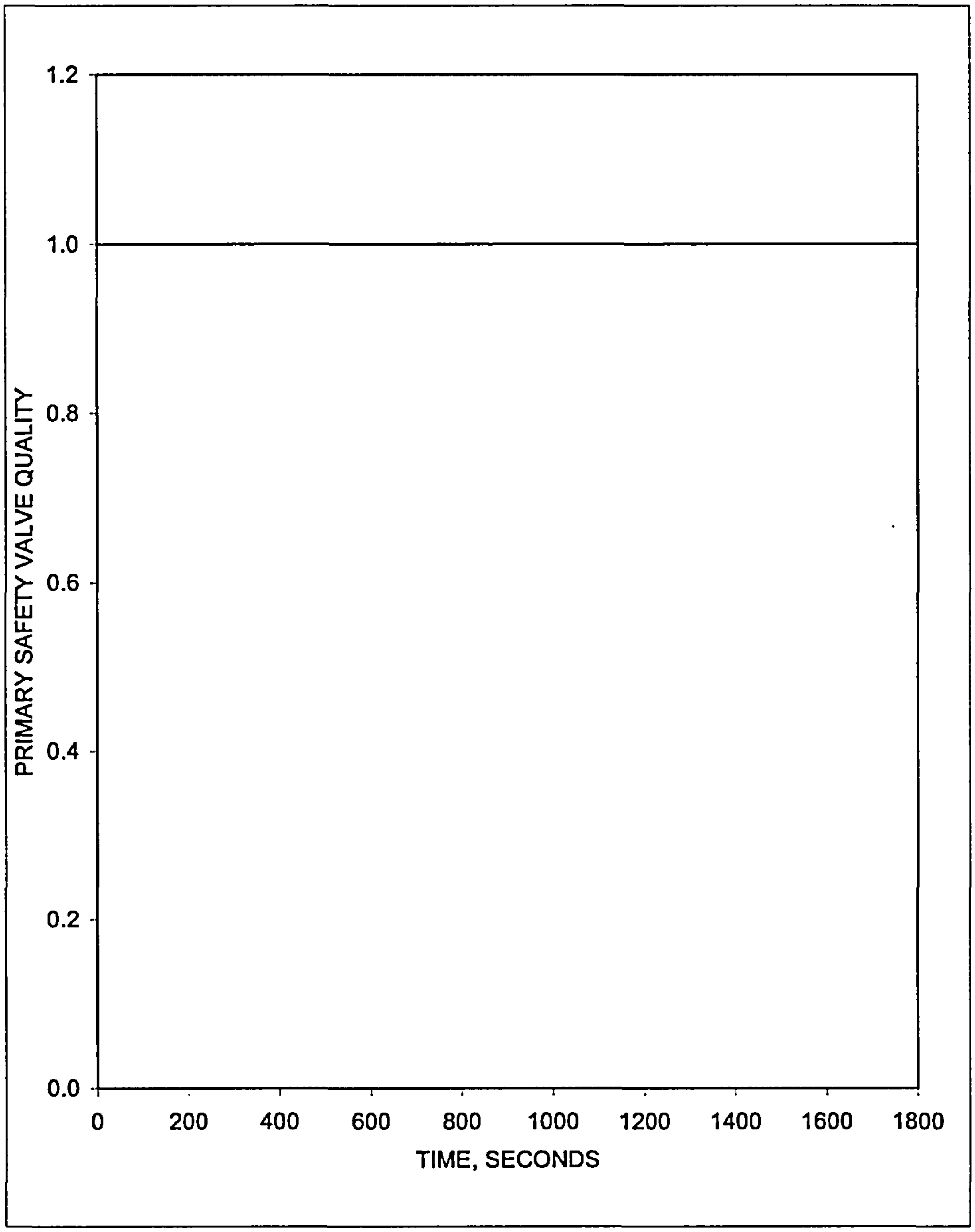


Figure 3-13
Loss of Normal Feedwater Flow with Reduced EFW Flow, Long-Term
Primary Safety Valve Quality vs. Time



Attachment 3

To

W3F1-2004-0096

Emergency Operating Procedure and Operator Action Time to Secure Charging

Emergency Operating Procedure and Operator Action Time to Secure Charging

Question:

During a Feedwater Line Break (FWLB) event, a Safety Injection Actuation Signal (SIAS) (generated on a high containment pressure signal) would further challenge the long-term cases. Among other things, a SIAS starts safety injection pumps, starts all three charging pumps, and isolates letdown. While the High Pressure Safety Injection (HPSI) pumps and letdown isolation have little effect, the mass addition associated with three charging pumps will quickly fill the pressurizer solid. For the FWLB event, the depletion of secondary side inventory and the subsequent Reactor Coolant System (RCS) heatup had previously challenged criteria to prevent the pressurizer going solid and Pressurizer Safety Valve (PSV) liquid discharge criteria. Now with the mass addition of 3 charging pumps, it would be impossible to demonstrate compliance during the first 30 minutes. The Waterford 3 Extended Power Uprate (EPU) FWLB calculation requires operator action to secure charging flow within 12 minutes. The staff should verify that Emergency Operating Procedures (EOPs) instruct operators to perform this function and that this action will be completed within 12 minutes. Note that the LOAC will direct operators to the Functional Recovery procedures, which may delay this required action.

Response:

Per NUREG-0800 Standard Review Plan (SRP) 15.2.8 Section II, an operator action time greater than 10 minutes may be assumed. This time is reasonable to assume for all non-LOCA events for non-ECCS non-ESF actions such as securing charging to prevent pressurizer overfill.

An SIAS only auto starts two charging pumps not three as assumed in the question above.

Standard post reactor trip actions instruct the Operator to maintain pressurizer level within 33% and 60% by, among other things, operating charging pumps as necessary. This is a continuous action performed throughout the EOPs whenever pressurizer level is challenged and regardless of which individual EOP is being used. Since Operators continuously monitor pressurizer level during the accident and a high pressurizer level alarm exists, there is high confidence that charging pumps can be secured within the required time to prevent filling the pressurizer. The standard post trip actions also include instructions to stabilize RCS temperature in the event of an Excess Steam Demand, as would exist for a Feedwater line break, by either the steam dump valves to the condenser or the Atmospheric Dump Valve on the intact steam generator and feeding with emergency feedwater. This action, which is not credited in the analysis, typically occurs in simulator scenarios as pressurizer pressure starts to rise after the initial cooldown. This action limits the pressurizer refill effects due to RCS heat up and provides more time to fill the pressurizer than is predicted in the analysis. The implementation of this step is not time based, but is indication based (pressurizer pressure or core exit thermocouple temperature starts to rise). Since EPU has little effect on the time for the faulted steam generator to blow down, the timing of the EOP action to stabilize temperature will not change appreciably. Operators will stabilize temperature and pressure when the faulted steam generator has lost its RCS cooling capability. RCS temperature will be controlled at a lower temperature than at the start of the accident, thus giving a relatively long time with two charging pumps running before pressurizer level would be high in the level band.

Attachment 4

To

W3F1-2004-0096

Revised Section 2.13.6.3.2, Steam Generator Tube Rupture

2.13.6.3.2 Steam Generator Tube Rupture

The objective of the steam generator tube rupture (SGTR) with loss-of-offsite power (LOOP) analysis is to document the impact of the following changes:

- Change from CESEC to CENTS as the primary simulation tool
- A decrease in secondary system pressures due to the uprate
- Associated lowering of the MSIS setpoint

The impact of the EPU resulted in no violation of maximum RCS and SG pressure limits for the SAR events.

2.13.6.3.2.1 General Description of the Event

The SGTR accident is a penetration of the barrier between the Reactor Coolant System (RCS) and the Main Steam Supply System (MSSS), which results from the failure of a steam generator (SG) U-tube. Integrity of the barrier between the RCS and MSSS is significant from a radiological release standpoint. The primary coolant activity from the leaking SG tube mixes with the shell side water in the affected SG. After the reactor trip and turbine trip, the radioactive fluid will be released through the ADVs as a result of the LOOP.

A SGTR event results in a depressurization of the RCS. Prior to reactor trip, the radioactivity is transported through the turbine to the condenser where noncondensable radioactive materials would be released via the condenser air ejectors. Because of the reactor trip, the turbine/generator trips and normal offsite power is assumed to be lost. It is assumed that electrical power would then be unavailable for the station auxiliaries such as reactor coolant pumps (RCPs) main feedwater pumps (MFPs), and main circulating water pumps. Under such circumstances, the plant would experience a loss of load, normal feedwater flow, forced RCS flow, condenser vacuum, and SG blowdown. A LOOP after the reactor and turbine/generator trip results in the greatest releases of radioactivity to the atmosphere, therefore, it is assumed for a limiting analysis. The plant is brought to SDC entry conditions through the use of SG ADVs, pressurizer heaters, auxiliary spray, the Safety Injection System (SIS), charging and the Emergency Feedwater System (EFS).

Diagnosis of the SGTR accident is facilitated by radiation monitors that initiate alarms and inform the operator of abnormal activity levels and that corrective operator action is required. These radiation monitors are located in the condenser air ejector discharge, SG blowdown lines, and main steam lines. Additional diagnostic information is provided by the RCS pressure and pressurizer level response and by the level response in the affected SG.

2.13.6.3.2.2 Purpose of Analysis and Acceptance Criteria

The purpose of the analysis was to determine whether the peak primary and secondary system pressures remain below their respective acceptance criteria, DNBR remained above the DNB SAFDL, and to provide input for the offsite dose analysis.

The following criteria apply to the SGTR event:

- DNBR ≥ DNB SAFDL
- Peak RCS pressure ≤ 2750 psia
- Peak secondary pressure ≤ 1210 psia
- Radiological doses are within 10CFR100 limits

The SGTR w/LOOP event is described in Chapter 15.6.3.2 of the FSAR (Reference 2.13-1).

2.13.6.3.2.3 Impact of Changes

In the reanalysis of the SGTR, the CENTS code is used in the same fashion as the CESEC code.

The decreased secondary system pressures associated with the EPU conditions tend to increase the primary-to-secondary system leakage predicted in the early phases of the event.

The increase in rated thermal power (RTP), and resulting decay heat load tend to increase the amount of steaming necessary to perform plant cooldown.

2.13.6.3.2.4 Analysis Overview

This analysis utilized the CENTS computer code (Reference 2.13-2) for the transient analysis simulation. The minimum DNBR evaluation was determined using the CETOP code (Reference 2.13-3). As stated in the FSAR, the LOOP case is bounding for offsite doses. This is due to the fact that the release path for the LOOP is direct to the atmosphere rather than through the condenser when offsite power is available. This analysis assumes that the LOOP occurs 3.0 seconds after reactor trip which is a conservative assumption as discussed in Reference 2.13-13. This assumption is consistent with the SGTR with LOOP assumptions made on other plants and included in CESSAR FSAR Chapter 15.

The input parameters from Table 2.13.6.3.2-1 and the bounding physics data from Section 2.13.0.2 of this report were incorporated with the following clarifications:

- The BOC Doppler curve was assumed.
- A BOC delayed neutron fraction and neutron lifetime consistent with those defined in Section 2.13.0.2 were assumed.
- An initial core power of 3735 MWt, based on a rated power of 3716 MWt and a 0.5% uncertainty, was assumed.
- A most positive (least negative) MTC of $-0.2 * 10^{-4}$ $\Delta\rho/°F$ at HFP was used.
- The maximum HFP core inlet temperature of 552 °F was assumed.
- A minimum RCS flow of $1.48x10^{8}$ lbm/hr was assumed.

2.13.6.3.2.5 Radiological Consequences

During the SGTR, a total of 325,702 lbm of primary coolant passes through the rupture into the affected SG. Prior to reactor trip, both SGs are steaming normally to the condenser. The high partition factor associated with the condenser makes releases from this source insignificant. Following reactor trip, both SGs are steamed through the ADVs. The affected SG is then isolated until it is necessary to bring the affected SGs ADV back into service for reaching equilibrium for shutdown cooling entry and SG inventory control. A total of 245,600 lbm of steam is released to the atmosphere through the affected SGs ADV. Of this 138,969 lbm are released during the initial steaming prior to isolation.

The majority of the cooldown of the plant is performed by steaming the unaffected SG. A total of 910,107 lbm of steam are released through the unaffected generator's ADV during the cooldown of the plant. Radioactivity release through this intact SG is assumed due to primary to secondary tube leakage.

The radiological consequences for the SGTR with LOOP were calculated for both a pre-existing iodine spike and an event generated iodine spike.

The radiological consequences resulting from the SGTR with LOOP are:

	2-Hour EAB (PIS)	8-Hour LPZ (PIS)
Thyroid	< 300 rem	< 300 rem
Whole Body	< 25 rem	< 25 rem

	2-Hour EAB (GIS)	8-Hour LPZ (GIS)
Thyroid	< 30 rem	< 30 rem
Whole Body	< 2.5 rem	< 2.5 rem

Note:
GIS – generated iodine spike
PIS – pre-existing iodine spike

2.13.6.3.2.6 Analysis Results

The peak RCS and SG pressures remained below their respective criterion of 2750 psia and 1210 psia. The NSSS and RPS responses for the SGTR event are shown in Table 2.13.6.3.2-2 and in Figures 2.13.6.3.2-1 through 2.13.6.3.2-13.

Table 2.13.6.3.2-1
Assumptions for 3716 MWt
SGTR with LOOP

Parameter	3716-MWt Power Uprate Assumption	Current Power Level Assumption
Initial Core Power, MWt	3735	3478
Core Inlet Temperature, °F	552	560
RCS Flowrate, 10^6 lbm/hr	148	141
Pressurizer Pressure, psia	2090	2000
Pressurizer Level, %	33	---
SG Pressure, psia	872	949
SG Level, % NR	26.5	88.5
MTC 10^{-4} $\Delta\rho$/°F	-0.2	N/A
Doppler Coefficient Multiplier	.85	N/A
CEA Worth for Trip, % $\Delta\rho$	-6.0	N/A
SBCS	Inoperative	Inoperative
Feedwater Regulation System	Inoperative	Inoperative
EFS	Automatic	Automatic
SG ADVs	Automatic	Automatic
ADV Setpoint, psia	980	1050
SIAS Setpoint, psia	1560	1560

Table 2.13.6.3.2-2
Sequence of Events for 3716 MWt
SGTR with LOOP

EPU Time (Sec.)	Current Power Level Time (Sec.)	Event	3716-MWt EPU Setpoint/Value	Current Power Level Setpoint/Value
0.0	0.0	Tube rupture occurs	---	---
45	40	Second charging pump turned on, on pressurizer level error, ft	-0.75	-0.75
70	70	Third charging pump turned on, on pressurizer level error, ft	-1.17	-1.17
445	109.3	CPC hot leg saturation trip condition reached, °F	13	13
446		CEAs begin to drop	---	---
448	109.7	LOOP	---	---
445	112.1	SG ADVs open, psia	980	1050
450	113.5	SG MSSVs open, psia	1085	1085
455	142	SG MSSVs close, psia	1041.6	1041.6
485	170.1	SIAS actuated on pressurizer pressure, psia	1560	1560
515	645	Safety injection flow begins to enter RCS	---	---
595	138.1	Pressurizer empties	---	---

Table 2.13.6.3.2-2 (cont.)
Sequence of Events for 3716 MWt
Steam Generator Tube Rupture with Loss of Offsite Power

EPU Time (Sec.)	Current Power Level Time (Sec.)	Event	3716 MWt EPU Setpoint/Value	Current Power Level Setpoint/Value
875	530	Operator initiates EFW flow to unaffected SG	225	225
Operator control with 2-minute interval between actions begins.	650	Operator takes manual control of the SG ADVs. Initiates plant cooldown by steaming through both of the ADVs	---	---
	4190	Operator initiates auxiliary spray in order to depressurize the RCS below 1000 psia and regain level control in the pressurizer.	---	---
	3350	Operator manually controls EFW flow to the intact SG to maintain 68% to 71% WR.	71	77
	4310	Operator manually controls safety injection, auxiliary spray flow and the pressurizer backup heater output to try to maintain subcooling (28°F) and pressurizer level (33%-60%)	---	---
1980	4070	Operator isolates the affected SG	---	---
23630	8270	Operator opens ADV to the affected SG as needed to maintain level below 94% WR.	---	---
28800.	28800	Shutdown cooling entry conditions reached, RCS pressure, psia/Temperature, °F	392/350	392/350

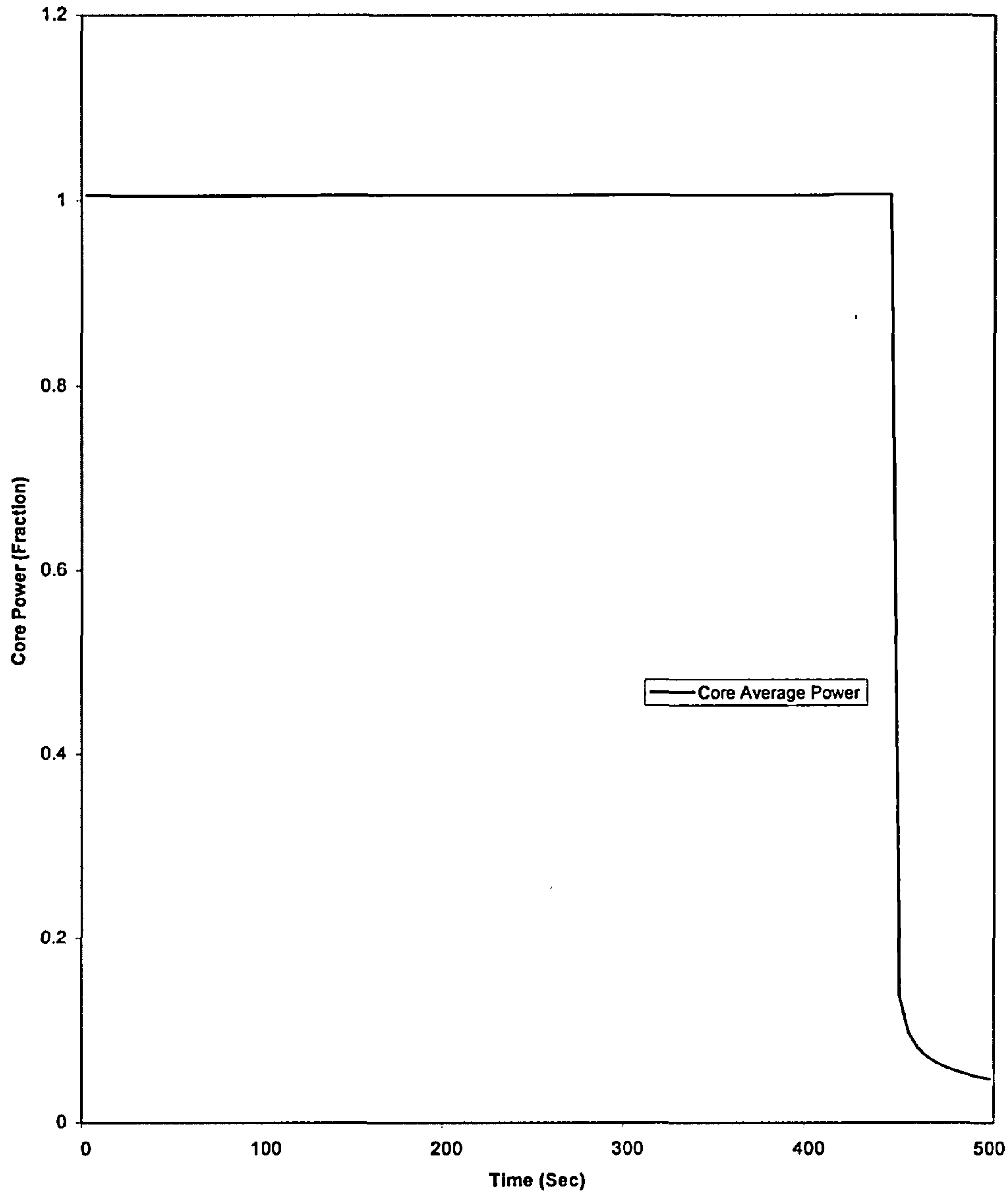


Figure 2.13.6.3.2-1
SGTR with LOOP
Core Power vs. Time

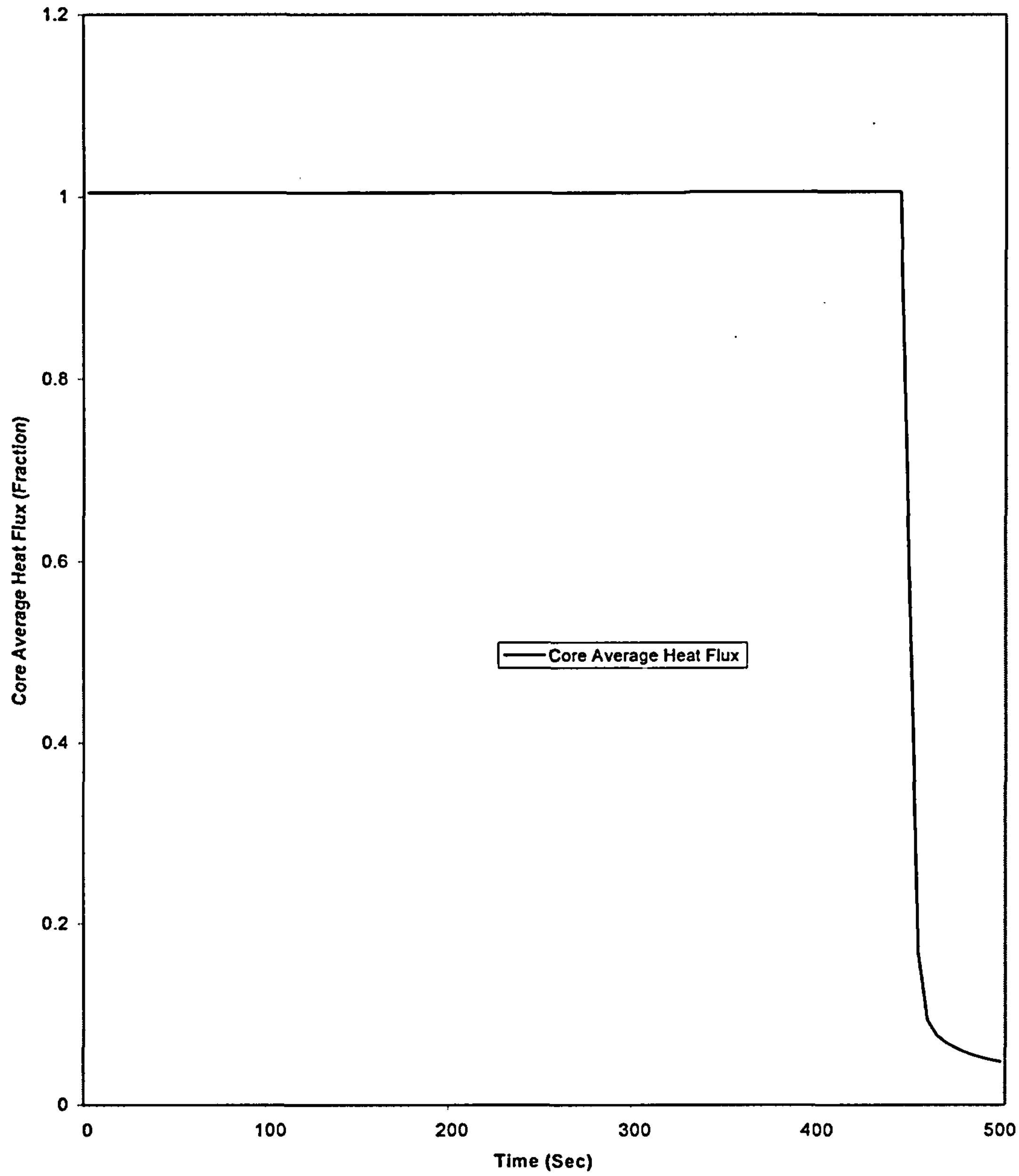


Figure 2.13.6.3.2-2
SGTR with LOOP
Core Heat Flux vs. Time

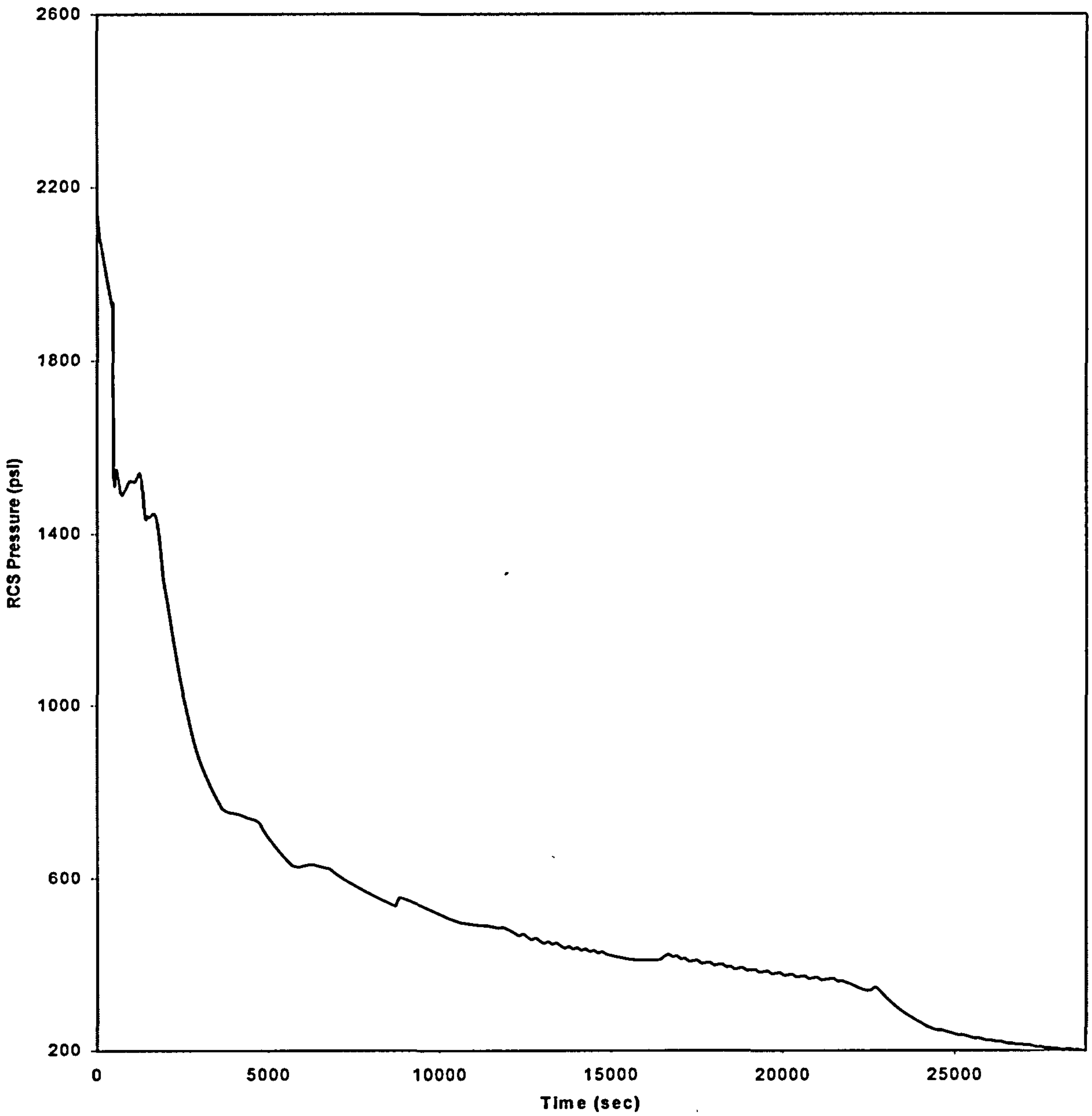


Figure 2.13.6.3.2-3
SGTR with LOOP
RCS Pressure vs. Time

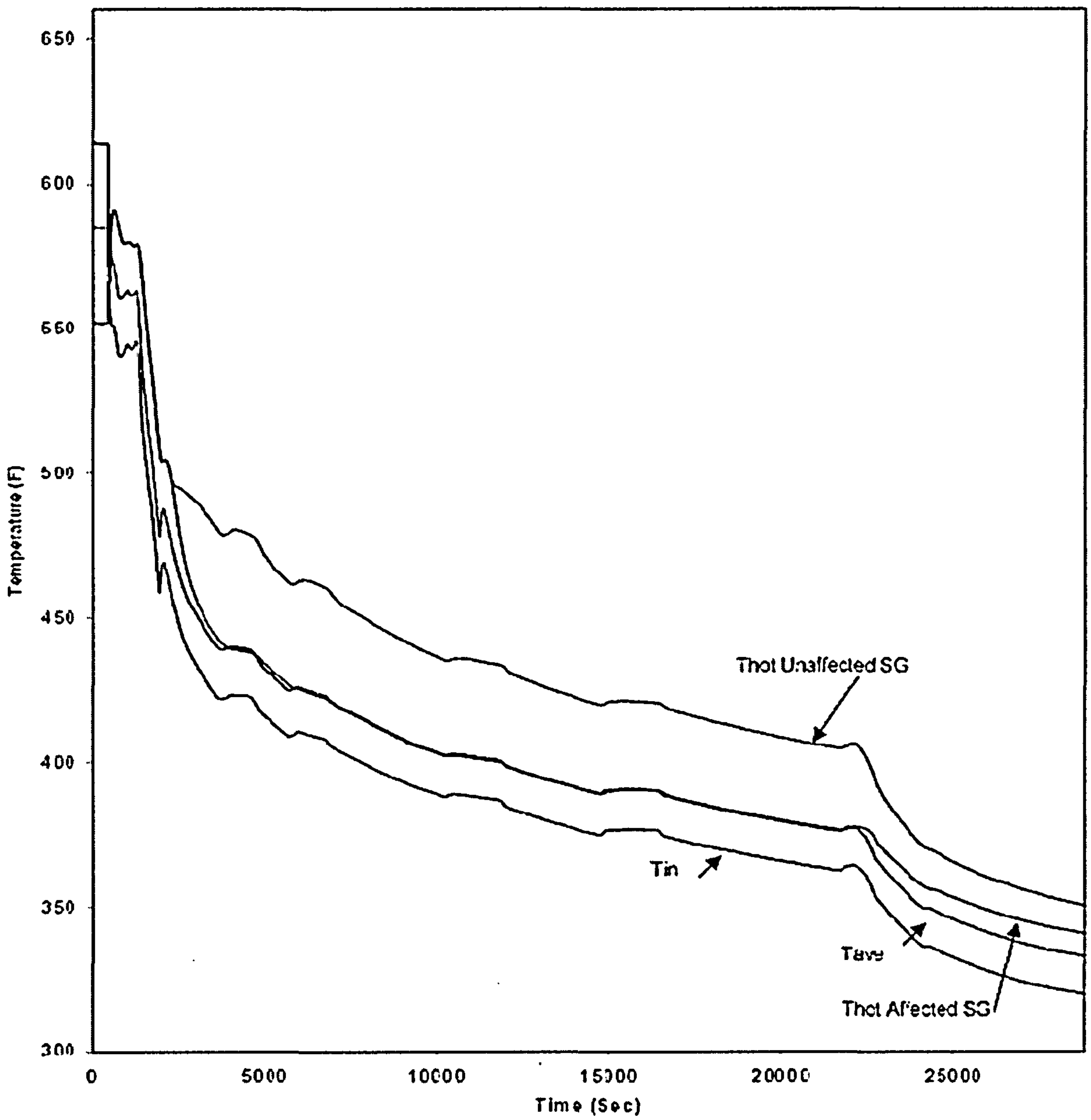


Figure 2.13.6.3.2-4
SGTR with LOOP
RCS Temperatures vs. Time

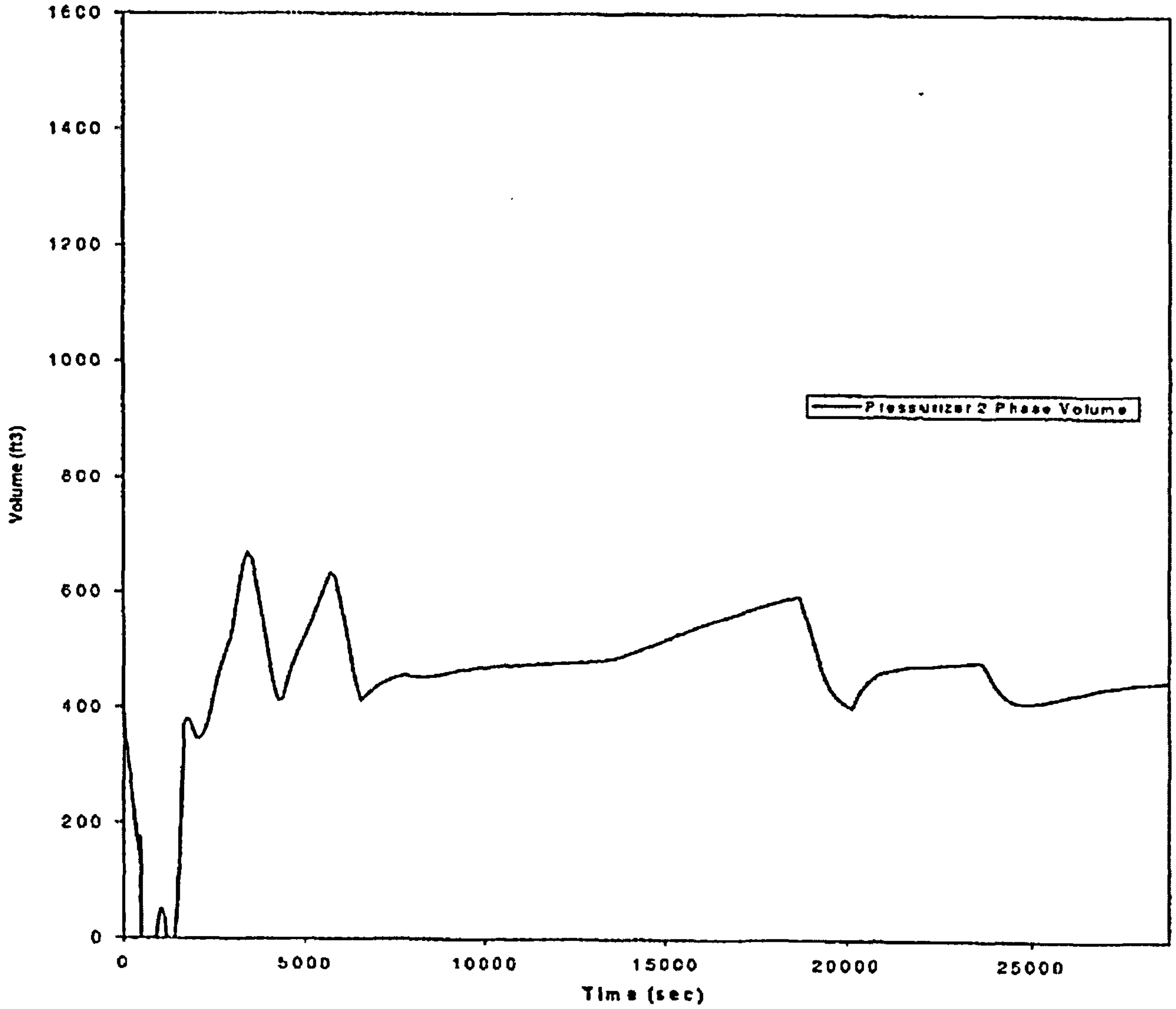


Figure 2.13.6.3.2-5
SGTR with LOOP
Pressurizer Water Volume vs. Time

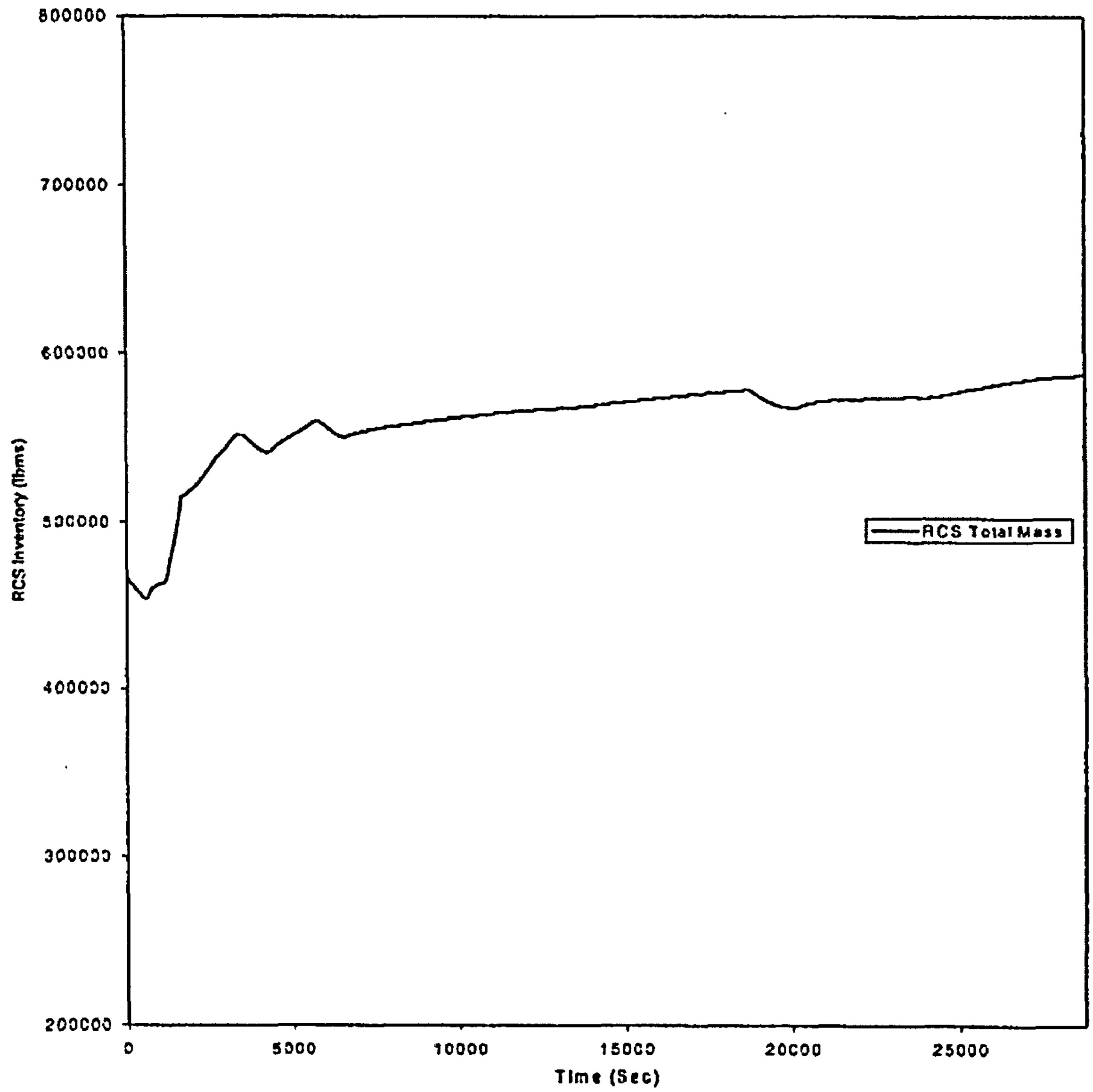


Figure 2.13.6.3.2-6
SGTR with LOOP
RCS Inventory vs. Time

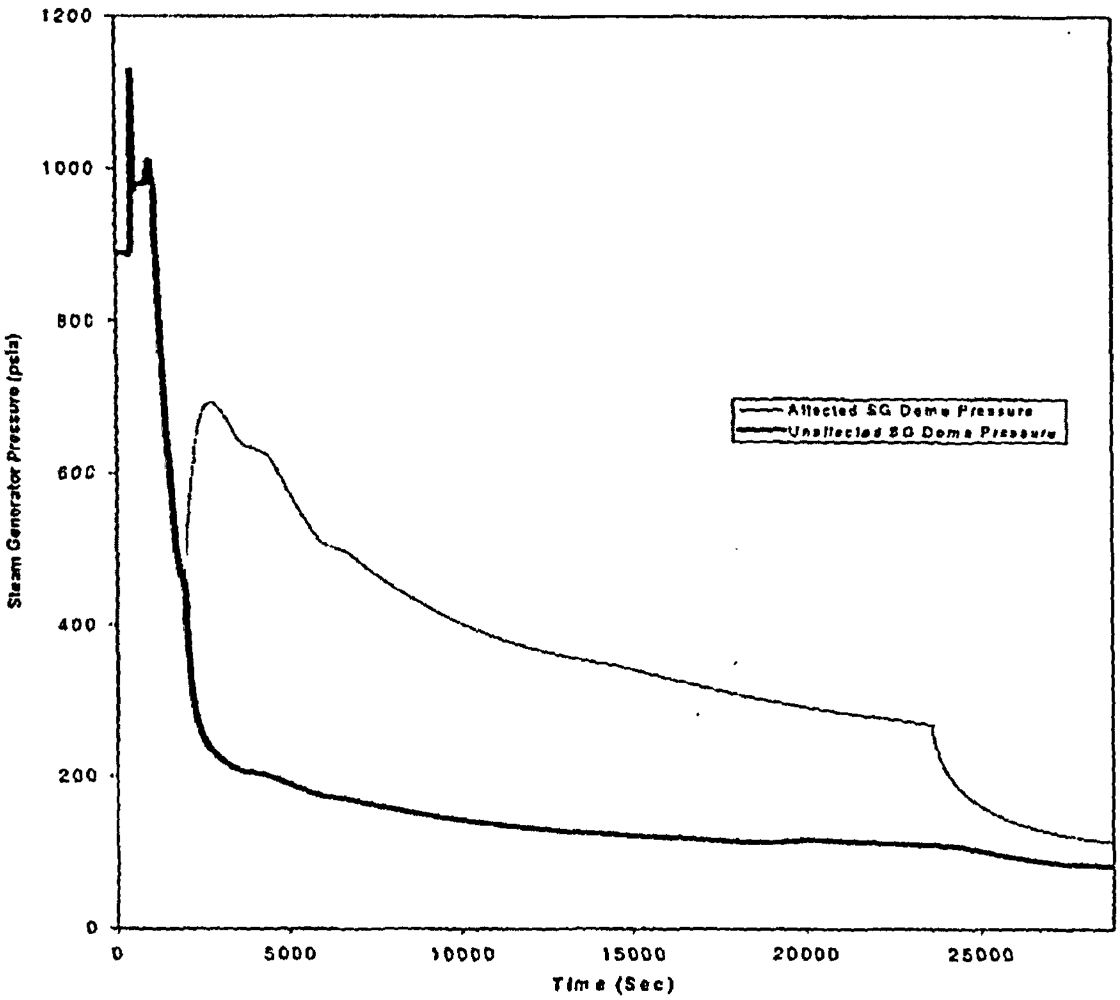


Figure 2.13.6.3.2-7
SGTR with LOOP
SG Pressure vs. Time

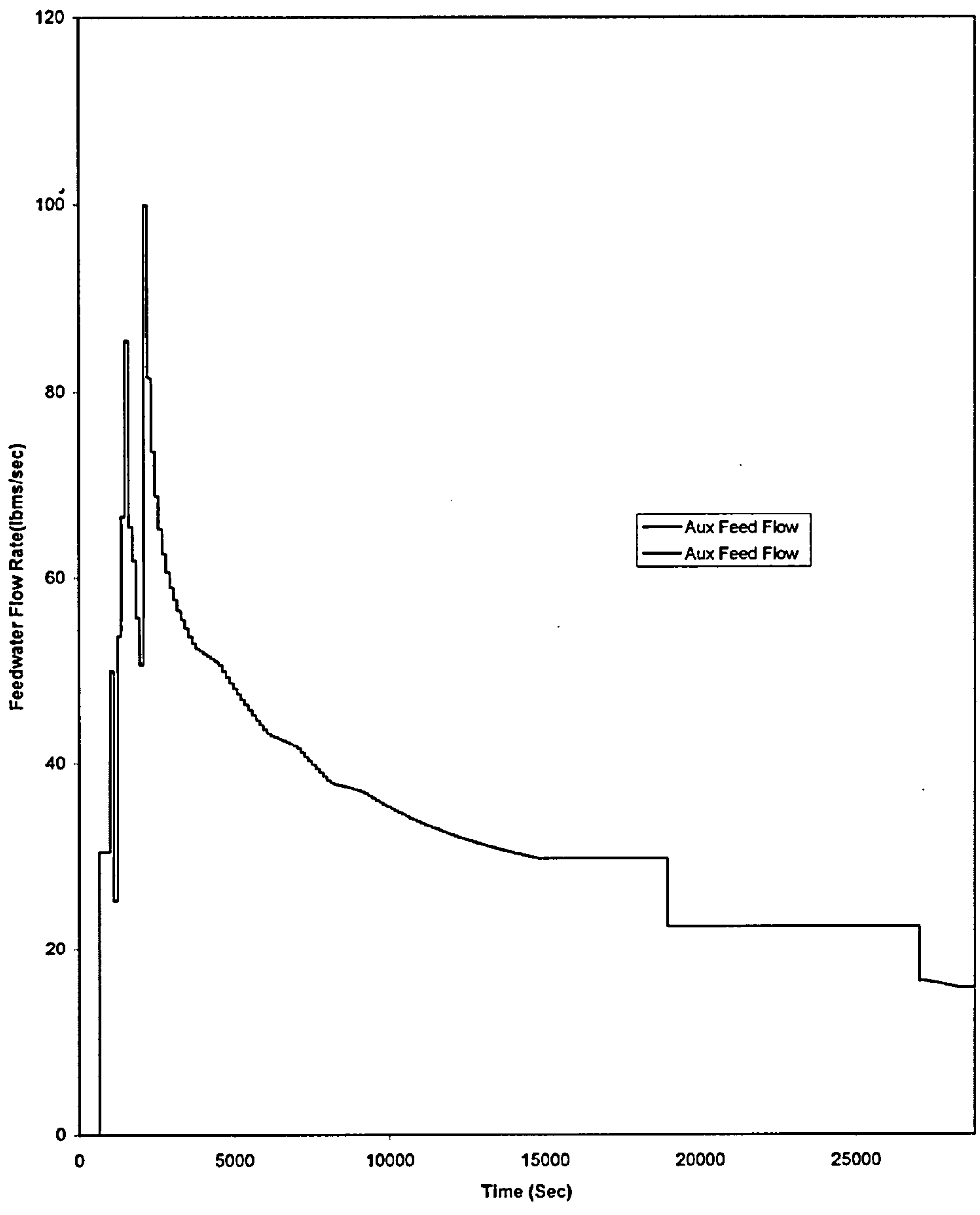


Figure 2.13.6.3.2-8
SGTR with LOOP
Feedwater Flowrate per SG vs. Time

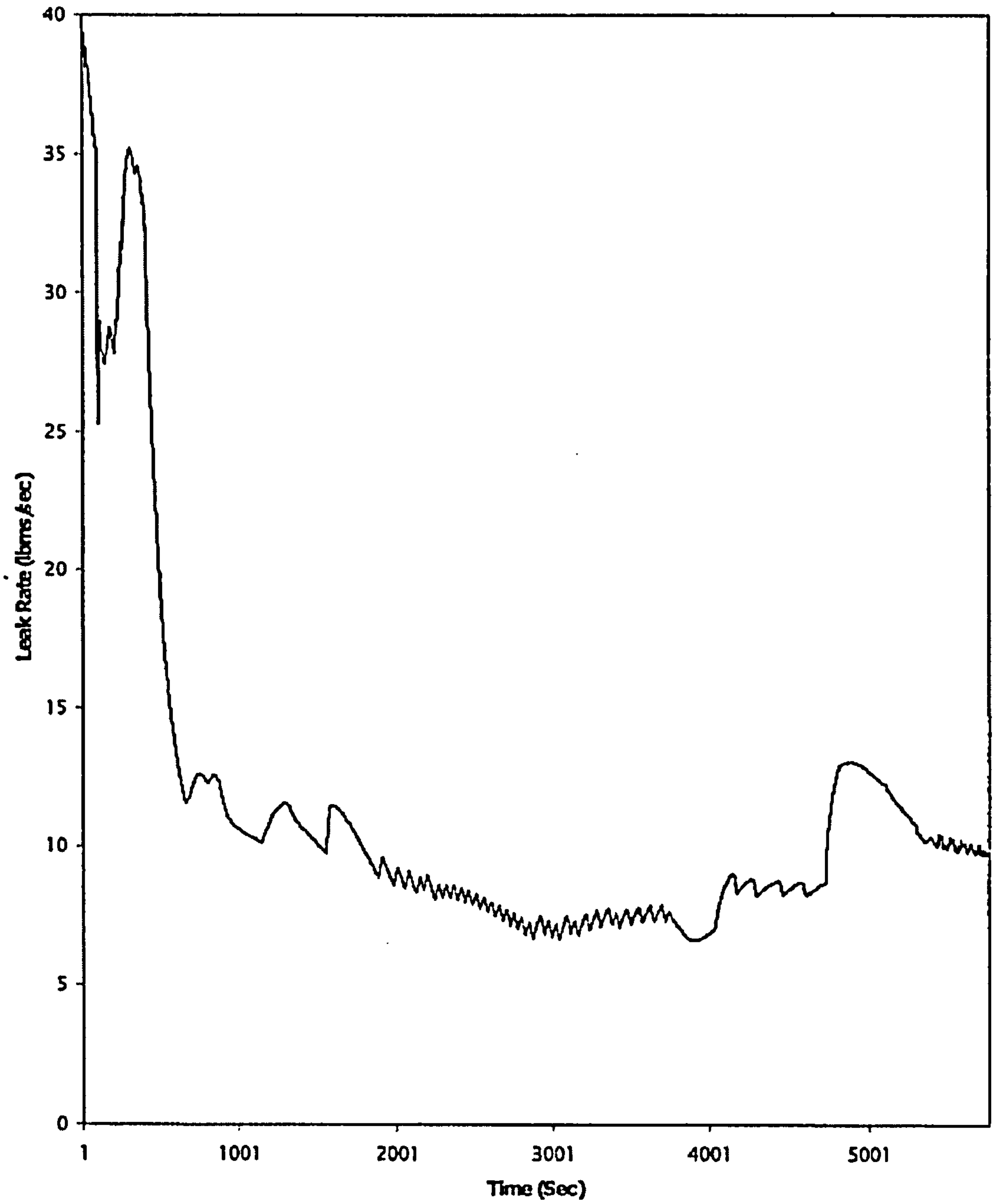


Figure 2.13.6.3.2-9
SGTR with LOOP
Primary-to-Secondary Leak Rate vs. Time

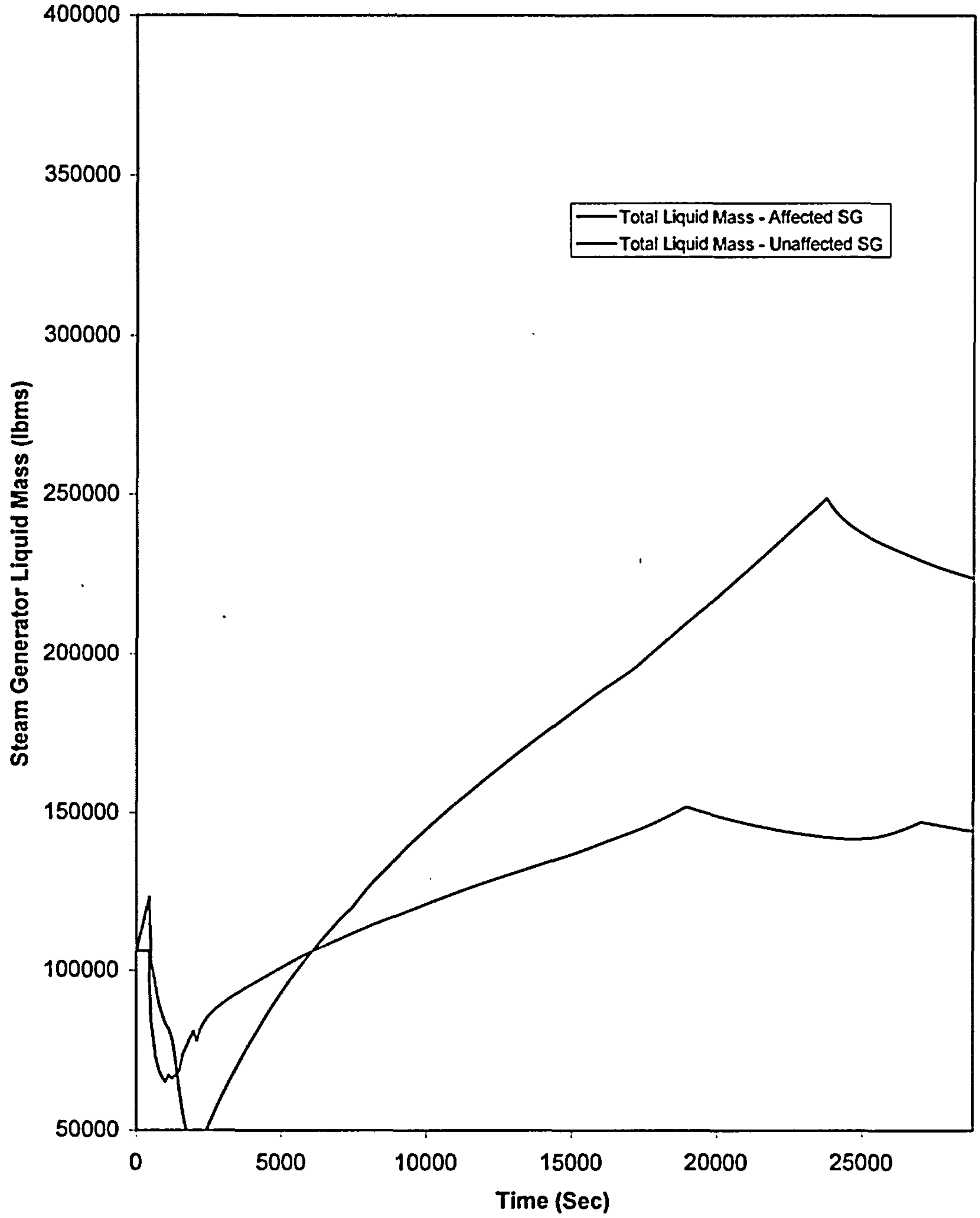


Figure 2.13.6.3.2-10
SGTR with LOOP
SG Liquid Mass vs. Time

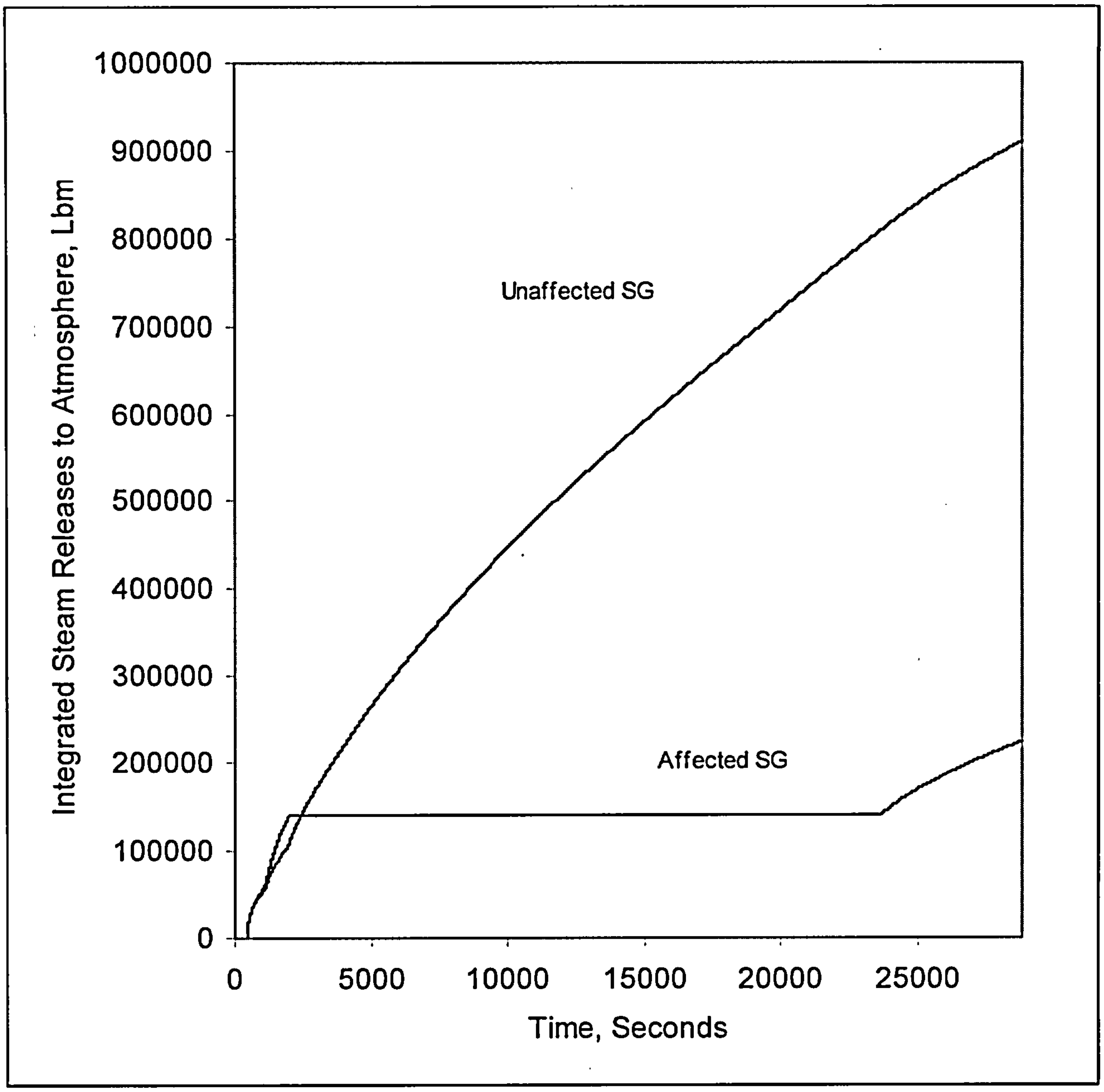


Figure 2.13.6.3.2-11
SGTR with LOOP
Integrated Steam Mass Through ADVs vs. Time

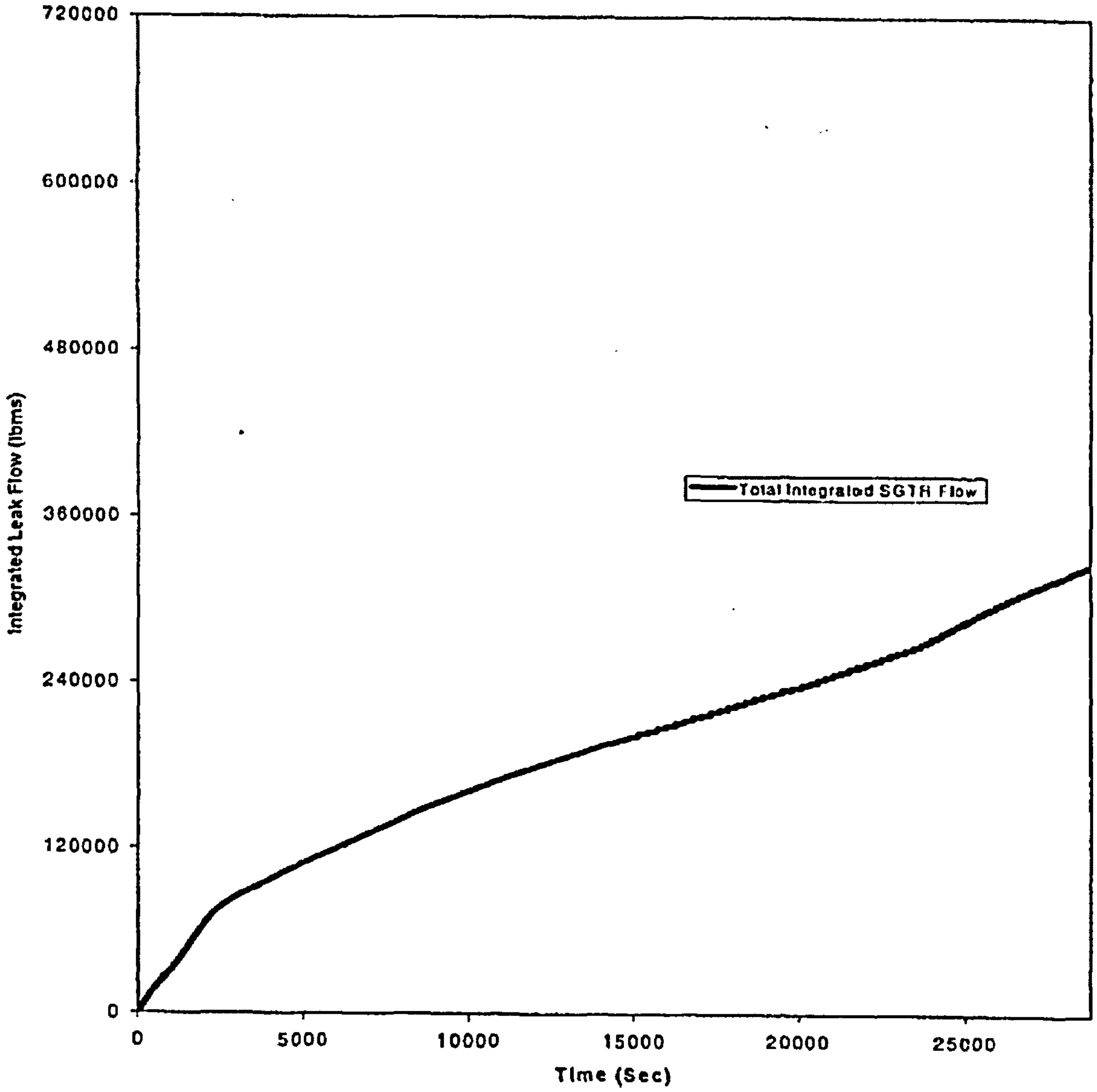


Figure 2.13.6.3.2-12
SGTR with LOOP
Integrated Primary-to-Secondary Leak Flow vs. Time

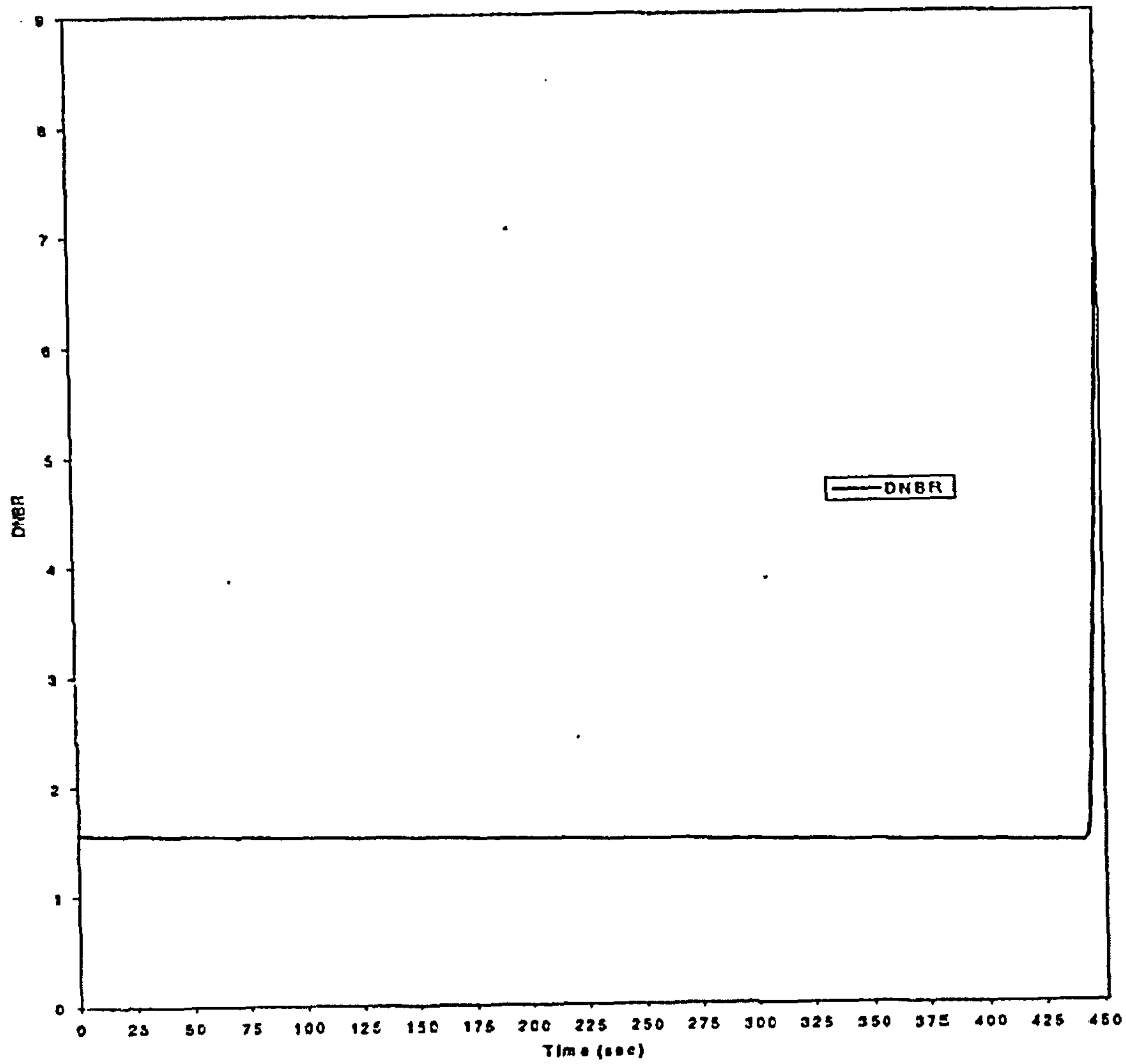


Figure 2.13.6.3.2-13
SGTR with LOOP
Minimum DNBR vs. Time

Attachment 5

To

W3F1-2004-0096

Minor Miscellaneous Corrections to Section 2.13

Minor Miscellaneous Corrections to Section 2.13

The revisions to Power Uprate Report (PUR) Section 2.13 consist of minor corrections that were not included in the initial submittal of the report. None of these changes affect the report's conclusions. The changes are:

1. Editorial revision to the entry for Section 2.13.2.2.3 in Table 2.13.0-1 to use terminology consistent with other sections in the PUR. Reference to an additional bounding event has been added to the table for the LOOP event. The additional event (Inadvertent Opening of a Steam Generator ADV in PUR Section 2.13.2.1.4) bounds the radiological consequences of the LOOP. Consistent with this change, the text of PUR Section 2.13.2.1.4 has been revised to cite the bounding event for LOOP radiological consequences.

2. Revisions to figures that reflect slight changes in the transient behavior of various parameters or changes to labeling. The figures affected are: 2.13.1.1.4-4; 2.13.1.3.3-7; 2.13.2.2.5-8; 2.13.4.1.3-3; 2.13.4.1.3-5; 2.13.4.1.3-7; 2.13.4.3.2-12.

3. Replacement of Figure 2.13.1.2.3-5 to show the T_{avg} trace that did not reproduce in the printed version of the existing figure.

4. Editorial change to Table 2.13.1.3.3-1 to change the units for RCS flowrate from m/hr to lbm/hr.

5. Minor changes to Sequence of Events Table 2.13.1.3.3-3 to correct some timing and parameter values. The initially reported minimum DNBR is more conservative (closer to the DNBR limit) than the corrected value.

6. Two revisions to Section 2.13.1.3.3.6. One revision incorporates the revised minimum DNBR in Table 2.13.1.3.3-3 noted above, and the other revises a minimum DNBR value to the correct value presently reported in Table 2.13.1.3.3-4 (i.e., a correction to achieve internal consistency in the PUR).

7. In Table 2.13.2.3.1-2, the maximum SG pressure has been changed from 1122 psia to 1123 psia. The change is due to roundoff.

8. In Table 2.13.2.3.1-3, the initial intact SG inventory has been corrected from 98.280 to 98,280.

9. In Table 2.13.2.3.1-4, the time of emergency feedwater activation has been changed from 60 sec. to 50 sec. to achieve internal consistency with event timings provided in the table.

10. In Table 2.13.3.2.1-2, the time of the low RCP shaft speed trip has been changed from 0.48 sec. to 0.49 sec. The change results from roundoff.

11. In Table 2.13.3.3.1-1, the assumed pressurizer level has been corrected from 44 to 54 percent, and the narrow range SG level has been corrected from 68 to 71 percent.

12. In Table 2.13.4.1.4-1, the RCS flowrate for power uprate has been changed from lb/hr to gpm for consistency with the value presented for the current power level assumption. Correspondingly, the units for RCS flowrate have been changed to gpm.

13. Correction of the time of RCS peak pressure in Table 2.13.4.3.2-4 from 2.9 sec. to 3.41 sec. In addition, Figure 2.13.4.3.2-2 has been replaced to show peak core power as a fraction of full power.

Table 2.13.0-1 (cont.)
Non-LOCA Transient Events

Section	Event	Category	Result
2.13.1.2.3	Increased Main Steam Flow with Loss-of-offsite Power (LOOP)	Infrequent Event	EPU analysis provided
2.13.1.2.4	IOSGADV with LOOP	Infrequent Event	EPU analysis provided
2.13.1.3.1	Steam System Piping Failures Post-Trip Analysis	Limiting Fault	EPU analysis provided
2.13.1.3.2	Mode 3 and 4 All Rods In (ARI) Steam Line Break (SLB)	Limiting Fault	Event is bounded by current FSAR
2.13.1.3.3	Steam System Piping Failures Pre-Trip Power Excursion	Limiting Fault	EPU analysis provided
Decrease in Heat Removal by the Secondary System (Turbine Plant)			
2.13.2.1.1	Loss of External Load	Moderate Frequency	Event is bounded by 2.13.2.1.3
2.13.2.1.2	Turbine Trip	Moderate Frequency	Event is bounded by 2.13.2.1.3
2.13.2.1.3	Loss of Condenser Vacuum (LOCV)	Moderate Frequency	EPU analysis provided
2.13.2.1.4	LOOP	Moderate Frequency	Event is bounded by 2.13.2.1.3 and 2.13.3.2.1 2.13.1.1.4,
2.13.2.1.5	Steam Pressure Regulator Failure	Moderate Frequency	Event is bounded by 2.13.2.1.3
2.13.2.2.1	Loss of External Load with SAF	Infrequent Event	Event is bounded by 2.13.2.2.3
2.13.2.2.2	Turbine Trip with SAF	Infrequent Event	Event is bounded by 2.13.2.2.3
2.13.2.2.3	LOCV with ~~LOOP~~ SAF	Infrequent Event	Event with SAF is bounded by event with no SAF, 2.13.2.1.3
2.13.2.2.4	Loss-of-Normal AC Power with SAF	Infrequent Event	Event is bounded by 2.13.3.2.1
2.13.2.2.5	Loss-of-Normal Feedwater Flow	Infrequent Event	EPU analysis provided
2.13.2.3.1	Feedwater System Pipe Breaks	Limiting Fault	EPU analysis provided

Table 2.13.1.3.3-1
Key Parameters Assumed for the Steam Piping Failures Event
IC Pre-Trip Power Excursions

Parameter	Power Uprate Assumption	Current Power Level Assumption
Initial Core Power, MWt	3735	3482
Core Inlet Temperature, °F	552	560
Pressurizer Pressure, psia	2310	2000
RCS Flowrate, 10^6 lbm/hr	148.0	137.0
Pressurizer Level, %	35.8	---
SG Pressure, psia	878	976
SG Level, % NR	65 (36.1 ft)	---
MTC, 10^{-4} $\Delta\rho$/°F	-4.2	-4.0
Doppler Coefficient Multiplier	0.85 (BOC)	0.85 (BOC)
Kinetics	Minimum β	Minimum β
CEA Worth at Trip, %$\Delta\rho$	-6.0	-6.0
Break Size ft^2	5.5	5.25

2.13.1.3.3.6 Analysis Results

The primary reactor trip for the pre-trip SLB event is the CPCS VOPT. The initial thermal margin was selected to ensure no fuel failure occurs for the OC breaks. This margin, in conjunction with the input parameters from Tables 2.13.1.3.3-1 and 2.13.1.3.3-2 and the physics data from Section 2.13.0.2 resulted in the lowest calculated DNBR.

1.1689 at 6.5

Table 2.13.1.3.3-3 delineates the sequence of events for the pre-trip SLB IC event. A CPCS VOPT occurs at 3.63 seconds, which results in a minimum DNBR of ~~1.1602 at 6.7~~ seconds. Figures 2.13.1.3.3-1 through 2.13.1.3.3-7 illustrate the behavior of key parameters associated with the pre-trip SLB event.

As shown in Table 2.13.1.3.3-4 for the pre-trip SLB outside-containment event, a CPCS VOPT occurs at 3.73 seconds, which results in a minimum DNBR of ~~1.2879 at 6.7~~ seconds. The minimum DNBR remains greater than the SAFDL value of 1.26.

1.2754 at 6.3

Table 2.13.1.3.3-3
Sequence of Events for the Steam System Piping Failure Event
IC Pre-Trip Power Excursion with LOOP

3716 MWt EPU Time (sec)	Current Power Level Time (sec)	Event	3716 MWt EPU Setpoint/Value	Current Power Level Setpoint/Value
0.0	0.0	Failure in the MSSS Piping	5.5 ft^2	5.25 ft^2
3.63	4.57	CPCS VOPT trip occurs	113.63% of 3716 MWt	117.14% of 3482 MWt
4.06	5.2	Trip breakers open	---	--
4.35	6.0	LOOP occurs, RCPs begin coastdown	---	--
4.66	5.8	CEAs begin to drop	---	--
~~5.42~~5.2	6.0	Maximum core power	~~136.06~~134% of 3716 MWt	137.53% of 3482 MWt
~~5.96~~5.8	6.35	Maximum core heat flux	~~119.73~~118% of 3716 MWt	119.4% of 3482 MWt
~~6.7~~6.5	6.9	Minimum DNBR	~~1.1602~~1.1689	1.1617

2.13.2.1.4 Loss-of-Normal AC Power

The thermal margin consequences of this event are bounded by the loss of flow, Section 2.13.3.2.1 of this report. The peak pressure consequences of this event are bounded by the LOCV, Section 2.13.2.1.3 of this report. Radiological consequences of this event are bounded by the Inadvertent opening of a Steam Generator ADV, Section 2.13.1.1.4 of this report.

Table 2.13.2.3.1-2
Comparison of the Sequence of Events for the Limiting Large FWLB Event

EPU Time (sec)	Current Power Level Time (sec) Reference 3, Table 15.2-8	Event	EPU Setpoint/ Value	Current Power Level Setpoint/Value Reference 3, Table 15.2-8
0.0	0.0	Break of main feedwater line. Complete loss of feed flow.	0.12 ft^2	0.2 ft^2
24.1	---	Low SG trip condition (SG liquid mass)	9000 lbm (2 ft)	5% NR
24.1	---	EFW actuation signal generated by low water level trip condition (SG liquid mass)	9000 lbm (2 ft)	5% NR
24.6	17.3	High pressurizer trip condition	2422 psia	2474 psia
25.0	18.2	Trip breakers open	---	---
25.0	18.2	Turbine trip	---	---
25.0	18.2	LOOP	---	---
25.01	18.2	Turbine admission valves closed	---	---
25.6	18.8	CEAs begin to drop	---	---
26.95	16.6	SG connected to the ruptured feed line empties	2000 lbm	---
27.0	18.7	PSVs open	2575 psia	2575 psia
27.85	20.7	Maximum, pressurizer surge line flow	1914 lbm/sec	1637 lbm/sec
28.2	21.3	Maximum RCS pressure	2753 psia	2750 psia
34.5	22.8	SG safety valves open	1117 psia	1117.6 psia
35.0	26.7	Maximum SG pressure	1123~~2~~ psia	1165 psia
84.1	70.1	Emergency feedwater flow initiated*	---	---
100	26.0	Minimum pressurizer steam volume	225.2 ft^3	391 ft^3
1800	1800	Opertor takes control of plant	---	---
28,800	---	SDC initiated	---	---

*EFW flow is initially diverted to the break.

Table 2.13.2.3.1-3
Comparison of Assumptions for the Small FWLB Event

Parameter	Power Uprate Assumption	Current Power Level Assumption
Initial core power level, MWt	3735	3478*
Core inlet temperature, °F	552	560
Core mass flow rate, 10^6 lbm/hr	148	128.55
RCS pressure, psia	2310	2200
SG pressure, psia	867	964
MTC, $10^{-4}\Delta\rho$/°F	-0.2	0
Doppler coefficient multiplier	0.85	0.85
CEA worth for trip, $10^{-2}\Delta\rho$	-6	-6.0
SBCS	Inoperative	Inoperative
PPCS	Inoperative	Inoperative
PLCS	Automatic	Inoperative
FWLB area, ft^2	0.17	0.2
Initial intact SG liquid inventory, lbm	98,280	144,300
SG safety valve setpoint tolerance, percent	+3%	+3%
PSV setpoint tolerance, percent	+3%	+3%
EFW flow, gpm	575	700

* Includes pump heat

Table 2.13.2.3.1-4 (cont.)
Comparison of the Sequence of Events for the Limiting Small FWLB Event

EPU Time (sec)	Current Power Level Time (sec) Reference 3, Table 15.2-8	Event	EPU Setpoint/Value	Current Power Level Setpoint/Value Reference 3, Table 15C.1-3
44	28.1	SG safety valves open	1117.2 psia	1117.6 psia
46.05	30.5	Maximum SG pressure	1129.1 psia	1152.5 psia
51.8	35.8	Minimum pressurizer steam volume	345.4 ft^3	443.2 ft^3
86.6	---	EFW flow initiated	emergency feedwater flow activation (EFWA) + 50~~60~~ sec	---
100.	---	End of analysis	100.0	---

Table 2.13.3.2.1-2
Sequence of Events for the Loss of Flow

EPU Time (sec)	Current Power Level Time (sec)	Event	EPU Setpoint/Value	Current Power Level Setpoint/Value
0.0	0.0	Loss of power to all RCPs	---	---
0.498	0.622	Low RCP shaft speed trip condition	96.5% of initial shaft speed	96.5% of initial shaft speed
0.78	0.85	Reactor trip breakers open	---	---
1.38	1.45	CEAs begin to drop	---	---
2.60	2.20	Minimum DNBR	$\geq$ 1.26	$\geq$ 1.26
7.9	4.5	Maximum RCS pressure, psia	2395	2523
183.5*	15*	SG safety valves open, psia	1117	1100
183.5*	19*	Maximum SG pressure, psia	1117	1116
212.8*	24*	SG safety valves close, psia	1062	1056

* These are typical values for the loss-of-forced RCS flow event.

Table 2.13.3.3.1-1
RCP Seized/Sheared Shaft Assumption Table

Parameter	Power Uprate Assumption	Current Power Level Assumption
Initial Core Power, MWt	3735	3478
Core Inlet Temperature, °F	533	560
Pressurizer Pressure, psia	2098	2300
RCS Flowrate, 10^6 lbm/hr	170.2	141.7
Pressurizer Level, %	<u>54</u>~~44~~	---
SG Pressure, psia	733	---
SG Level, % NR	<u>71</u>~~68~~	---
MTC, $x10^{-4}$ $\Delta\rho$/°F	-0.20	+0.5
Doppler Coefficient Multiplier	0.85	0.85
Kinetics	Maximum β	Maximum β
CEA Worth at Trip, %$\Delta\rho$	-5.0	-8.55

Table 2.13.4.1.4-1

Comparison of Assumptions for the CEA Drop Event

Parameter	3716 MWt Power Uprate Assumption	Current Power Level Assumption Reference 3, Table 15.4-9
Initial core power, MWt	3735	3441
Core inlet temperature, °F	543	553
Pressurizer pressure, psia	2250	2250
Pressurizer level, %	67.5	---
RCS flowrate, gpm ~~x 10^6 lb/hr~~	417640~~158.4~~	396000
Dropped CEA reactivity worth, %$\Delta\rho$	-0.15	-0.05
Time for CEA to be fully inserted, sec.	1	1
MTC, $10^{-4}\Delta\rho$/°F	-4.2	-3.3
Doppler coefficient multiplier	1.15	1.15
Prompt CEA radial distortion upon drop	1.147	1.09
15 minute Xenon radial distortion	1.097	1.043
PPCS	Auto	---
PLCS	Auto	---

Table 2.13.4.3.2-4
CEA Ejection Peak RCS Pressure Sequence of Events

3716 MWt EPU Time (sec)	Event	3716-MWt EPU Setpoint/Value
0.00	Mechanical failure of CEDM causes CEA to eject	---
0.00	CEA fully ejected	---
0.07	CPC VOPT, % of full power	159
0.08	Maximum core power occurs, % of full power	187.0
0.699	Trip breakers open	---
1.299	CEAs begin to drop into core	---
3.41~~2.9~~	Maximum RCS pressure, psia	2519*
4.8	CEA fully inserted, core power reduced to below 10% power	---

* 2597 psia for BOC cycle 1 HFP CEA ejection.

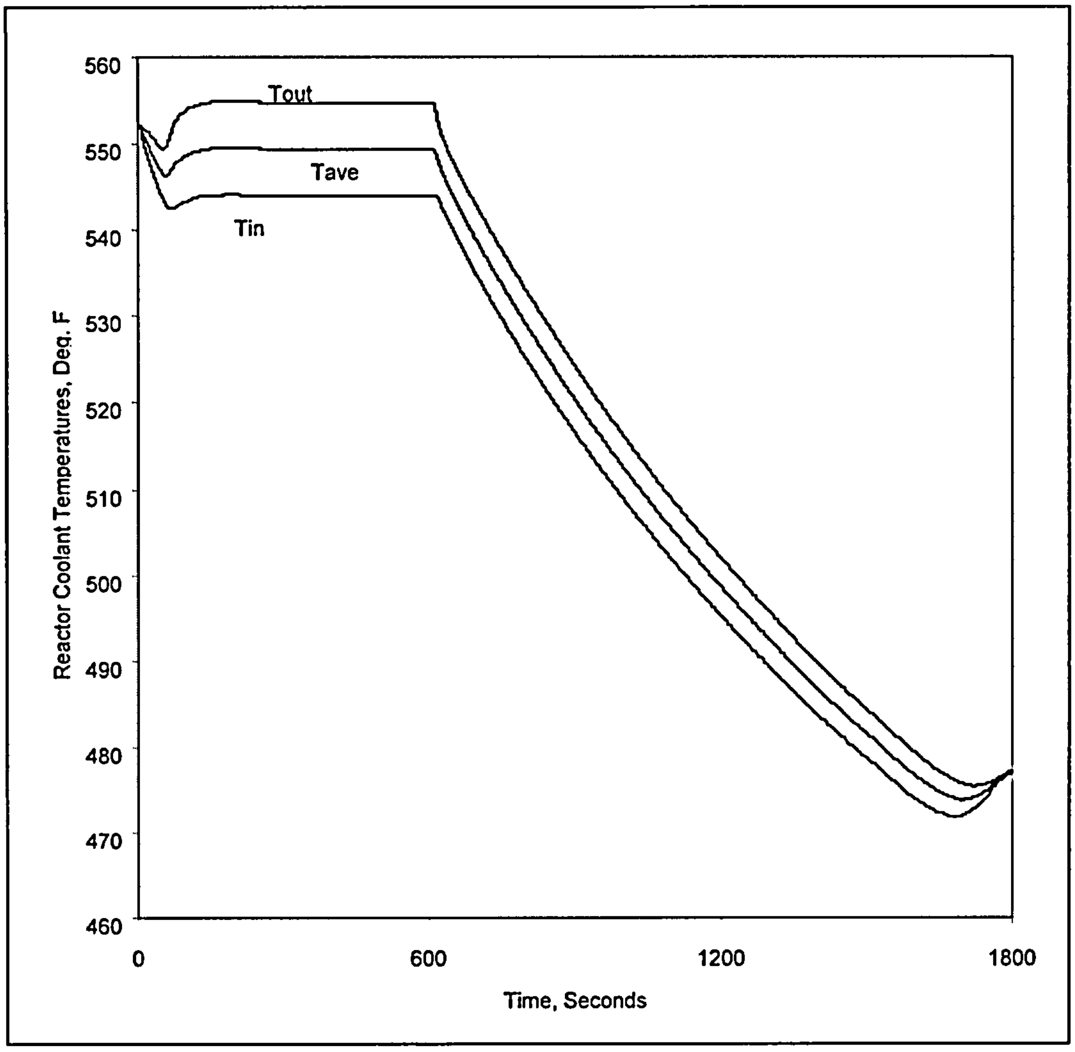


Figure 2.13.1.1.4-4
Inadvertent Opening of a Steam Generator Atmospheric Dump Valve
Reactor Coolant Temperature vs. Time

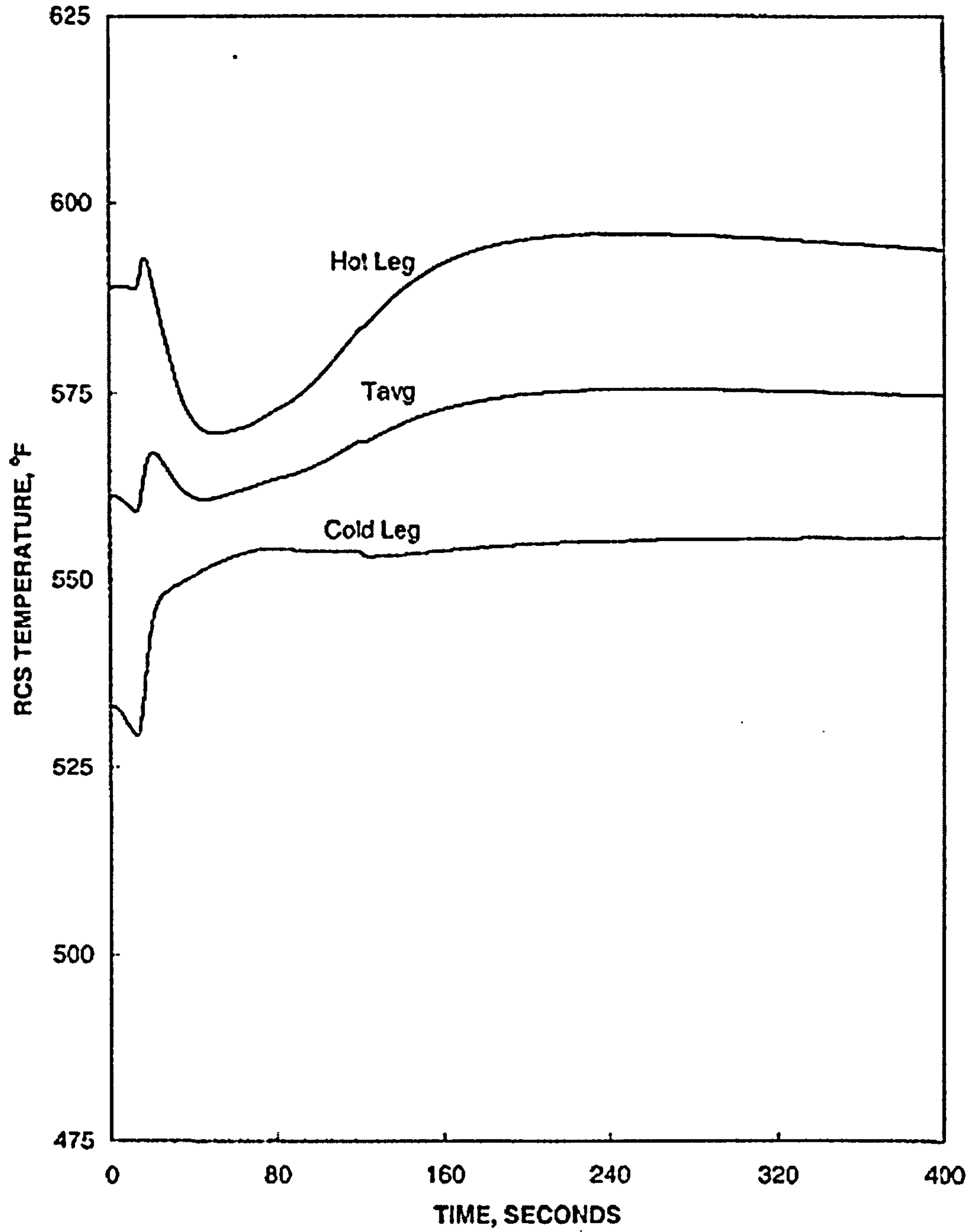


Figure 2.13.1.2.3-5
Increased Main Steam Flow with Concurrent Single Failure
Reactor Coolant Temperatures vs. Time

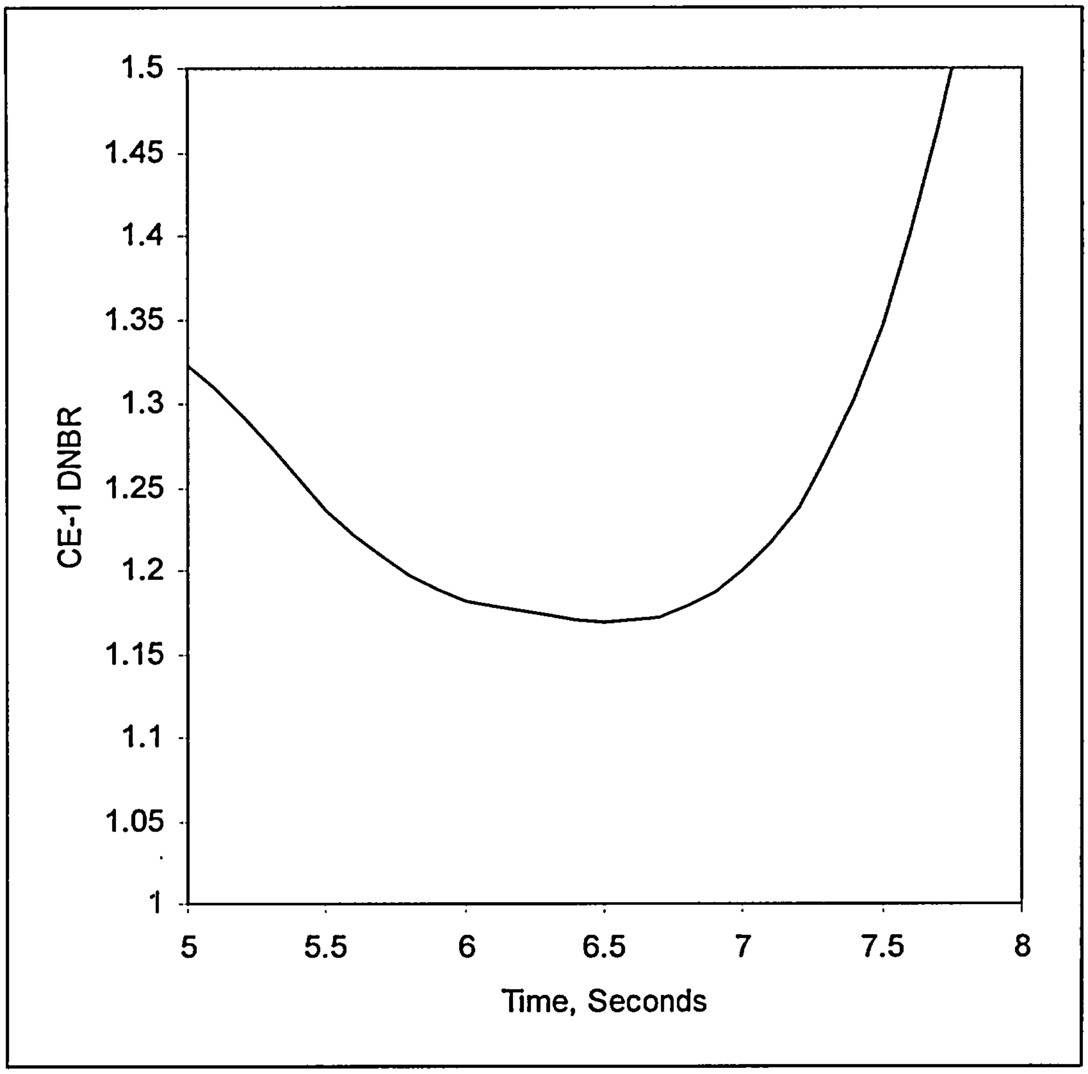


Figure 2.13.1.3.3-7
IC, SLB, Pre-Trip Power Excursions
DNBR vs. Time

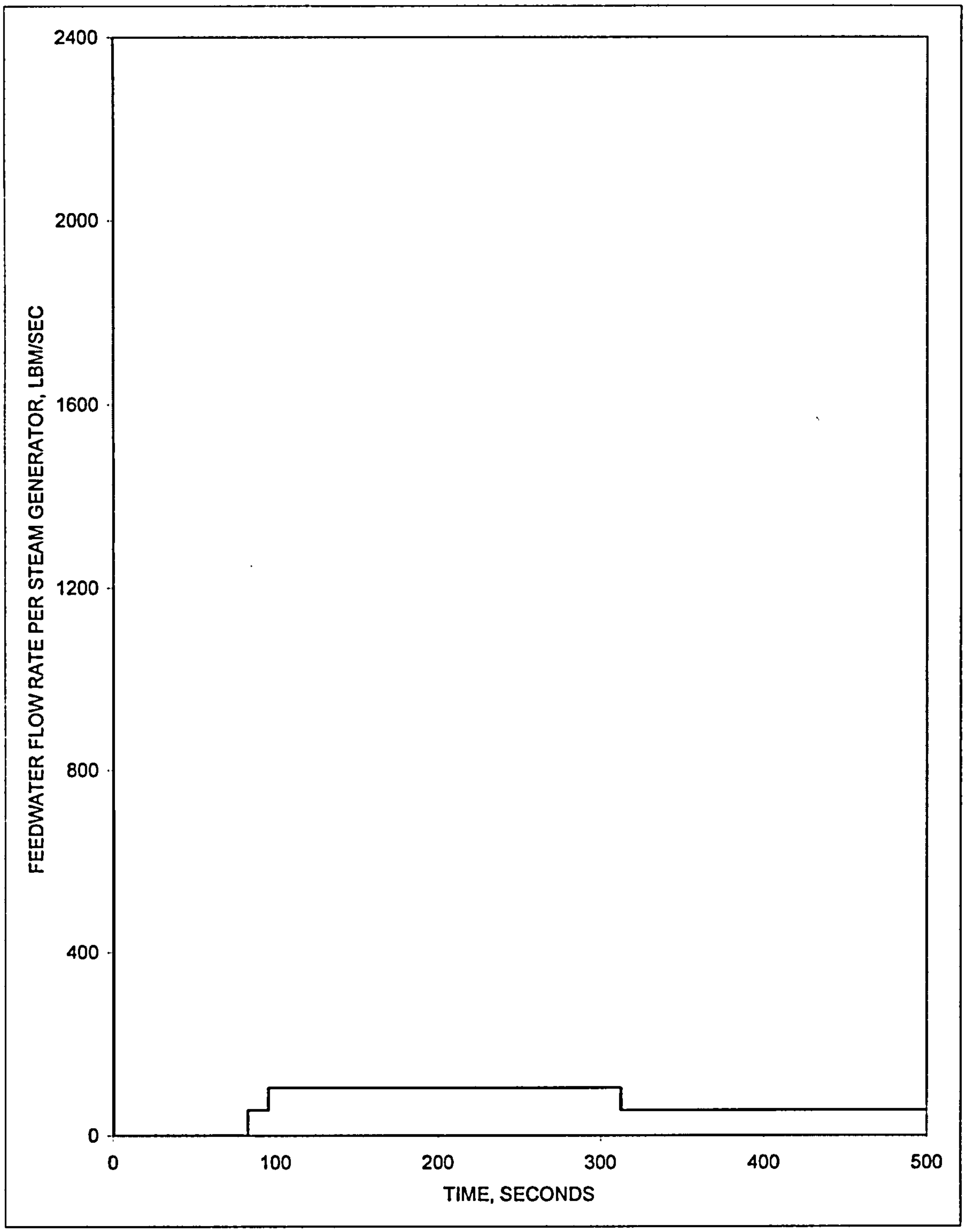


Figure 2.13.2.2.5-8
Loss of Normal Feedwater Flow
Feedwater Flowrate per Steam Generator vs. Time

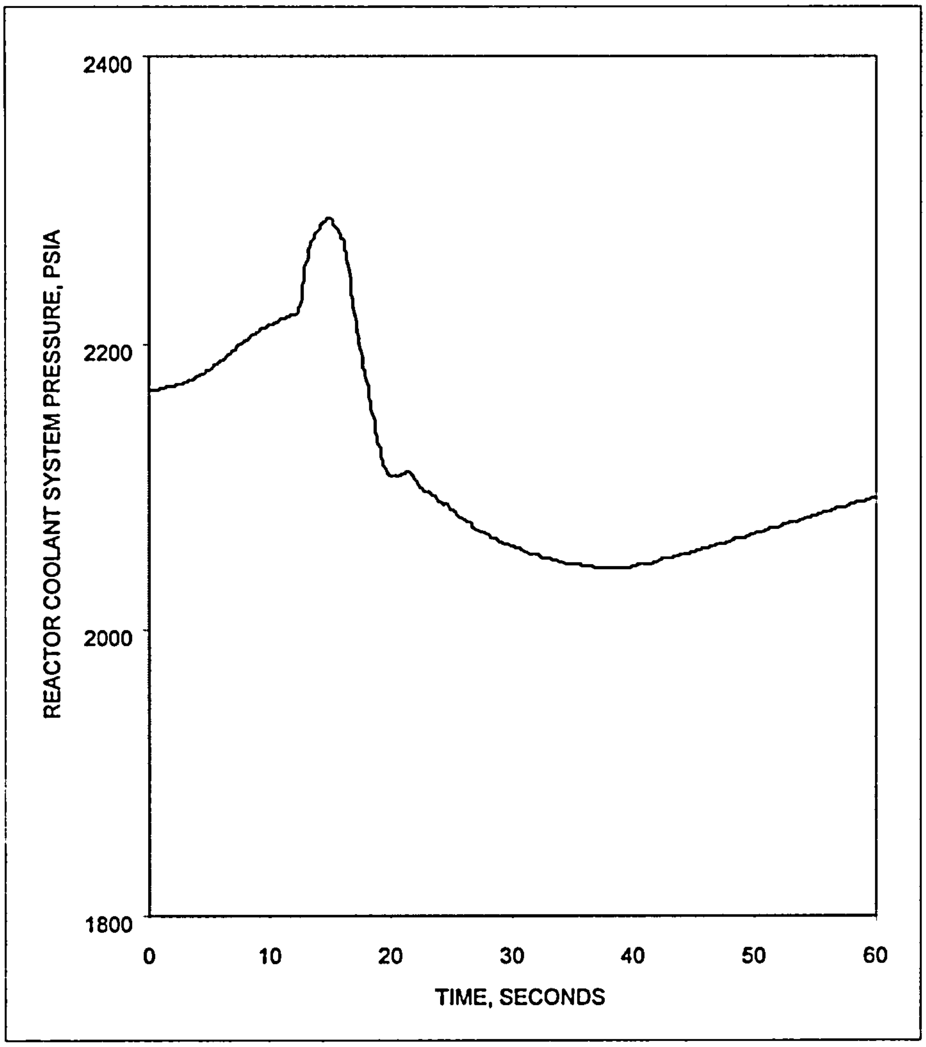


Figure 2.13.4.1.3-3
Control Element Assembly Withdrawal at Power
RCS Pressure vs. Time

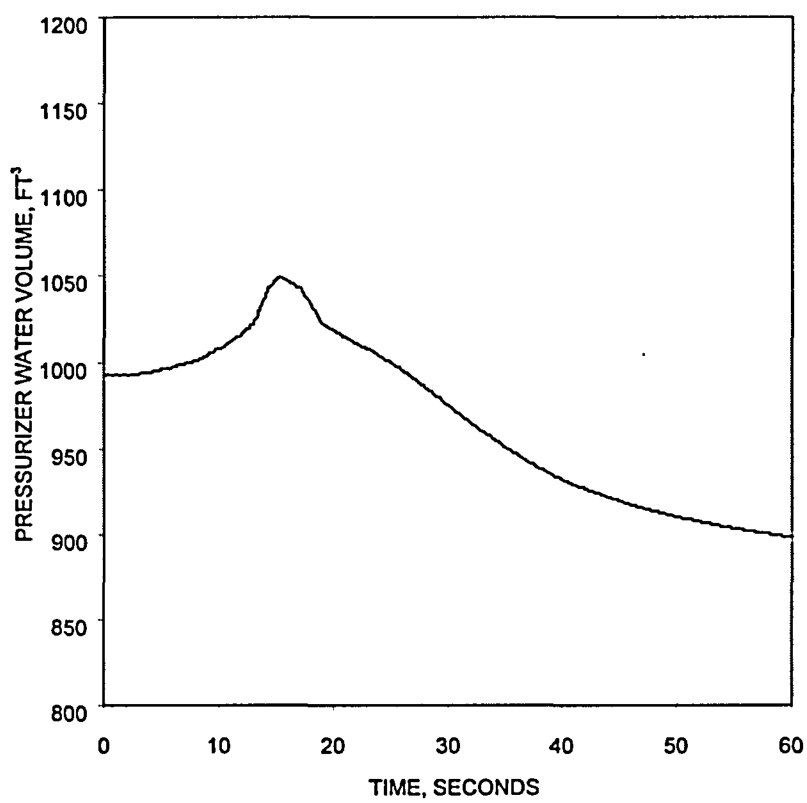


Figure 2.13.4.1.3-5
Control Element Assembly Withdrawal at Power
Pressurizer Water Volume vs. Time

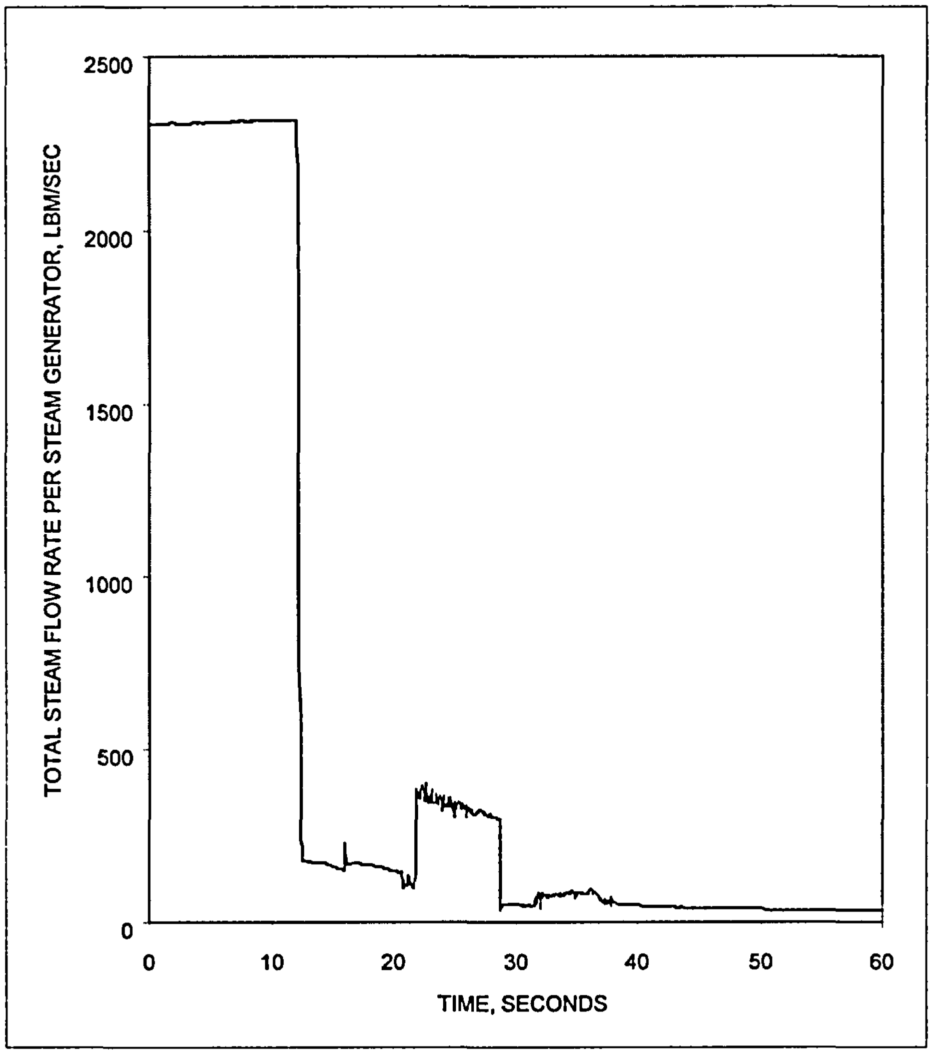


Figure 2.13.4.1.3-7
Control Element Assembly Withdrawal at Power
Steam Flow vs. Time

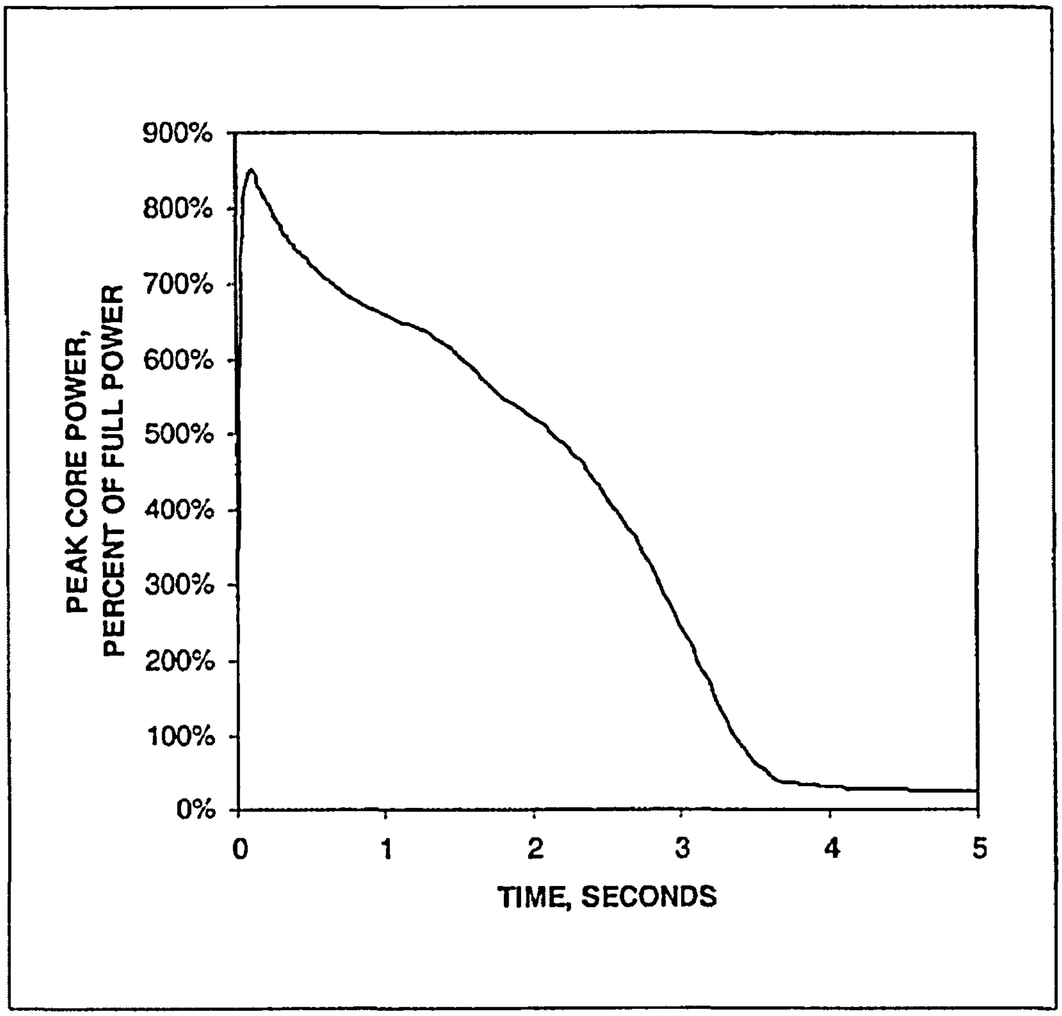


Figure 2.13.4.3.2-2
CEA Ejection Peak Core Power vs. Time

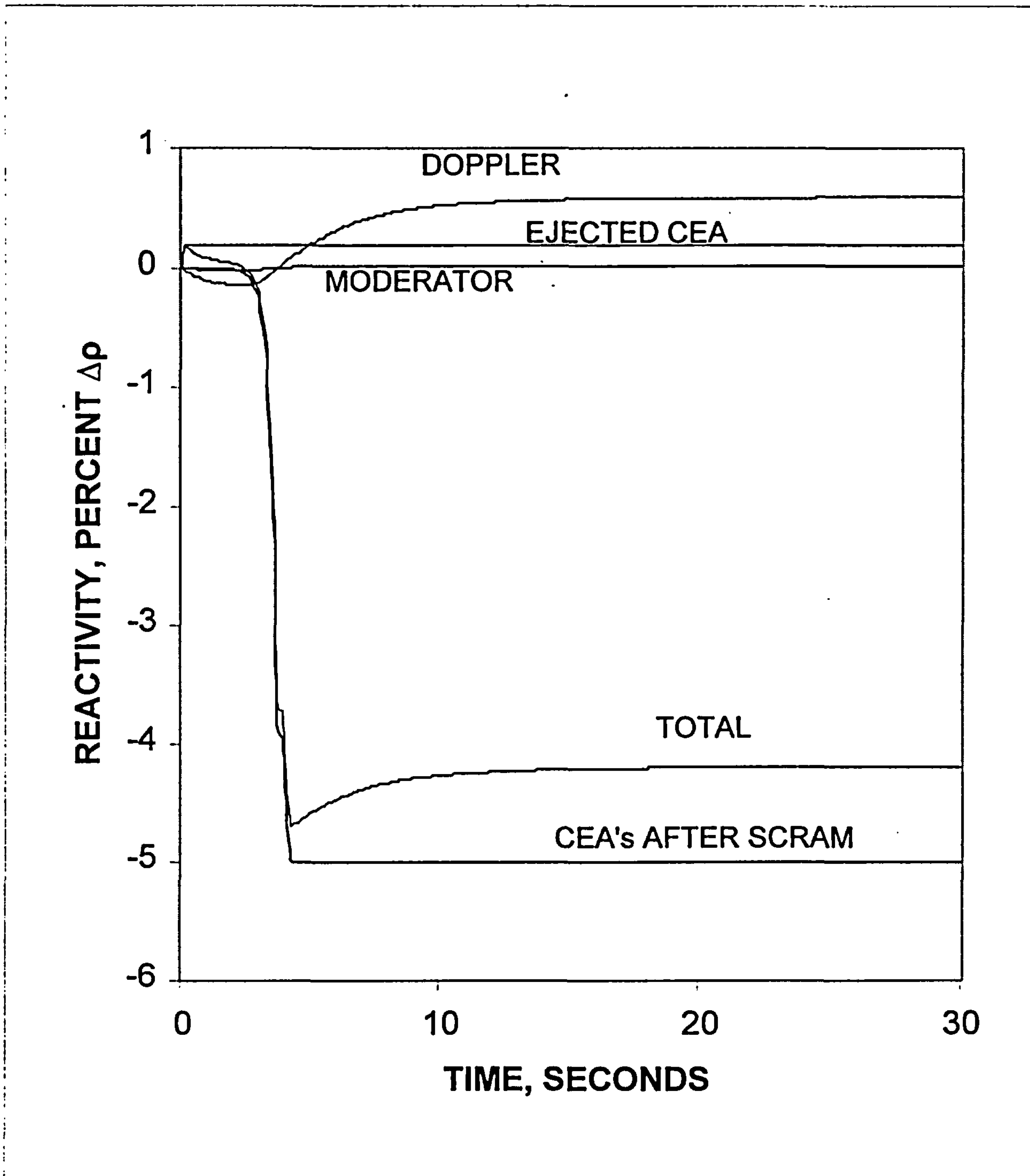


Figure 2.13.4.3.2-12
CEA Ejection Reactivity Components vs. Time for Peak RCS Pressure

Attachment 6

To

W3F1-2004-0096

Revised Sections
2.13.1.3.3.2, Purpose of Analysis and Acceptance Criteria
and
2.13.1.3.3.5, Radiological Consequences

2.13.1.3.3.2 Purpose of Analysis and Acceptance Criteria

The purpose of this analysis is to examine the thermal margin degradation and fuel failure immediately before and after trip during a steam line break event. Longer term effects are discussed in the return to power SLB event. (Section 2.13.1.3.1) Two break locations were analyzed: an inside containment (IC) break and an outside containment (OC) break. The OC break, due to the smaller flow area, does not result in SAFDL violation. The IC break cases do allow some fuel failure.

The criteria for the pre-trip SLB are the following:

- Minimum DNBR ≥1.26 for no fuel failure (OC). If the IC minimum DNBR < 1.26 then a fuel failure analysis must be performed
- Radiological doses ≤ 10CFR100 limits
- Fuel temperature ≤ fuel centerline melt temperature, as demonstrated by peak LHR ≤ 21.0 kW/ft.

This event is described in Section 15.1.3.3 of the Safety Analysis Report (SAR) (Reference 2.13-1).

2.13.1.3.3.5 Radiological Consequences

With the release path resulting from inside containment SLB's, the fuel failure that would result in the 10CFR100 limits being reached is well in excess of 10% of the pins in DNB (MSLB with LOOP).

The pre-trip SLB event with no LOOP does not result in violation of the DNBR SAFDL. The pre-trip SLB with LOOP, discussed in this section, results in a limited violation of the DNBR SAFDL. The thermal hydraulic conditions present in the core at the time of minimum DNBR in this analysis will be evaluated in combination with the cycle-specific pin census each reload cycle. It will be verified that fewer than 8.0% of the fuel pins will be predicted to experience DNB via the method of statistical convolution.

Similarly, a limited amount of SAFDL violation will occur during the RTP SLB with LOOP (Section 2.13.1.3.1). The extent of this SAFDL violation will be confirmed each reload cycle. The LOOP RTP SLB will be limited to less than 2% of the pins in violation of the MacBeth DNBR SAFDL.

The fuel pin census applicable to the Pre-Trip phase of the SLB is typical of the HFP power distribution. The fuel pin census applicable to the RTP phase of the SLB is governed by the power distribution that would be present in the core in the N-1 configuration. As these two power distributions are independent of each other, the total fuel failure associated with the SLB event is taken as the summation of the fuel failure for these two scenarios.

The SLB event with no LOOP does not result in SAFDL violations. For the SLB event with LOOP, the total fuel failure is ≤10.0% of the pins experiencing DNB. Of these, 8.0% are attributable to the pre-trip phase and 2% are attributable to the RTP phase. The radiological consequences resulting from these fuel failure results are:

	2-Hour EAB	**8-Hour LPZ**
Thyroid	< 300 rem	< 300 rem
Whole Body	< 25 rem	< 25 rem