BALTIMORE
GAS AND
ELECTRIC

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ARTHUR E. LUNDVALL, JR.
VICE PRESIDENT
SUPPLY

November 17, 1982

Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

ATTENTION: MR. R. A. Clark, Chief
Operating Reactors Branch #3
Division of Licensing

SUBJECT: Calvert Cliffs Nuclear Power Plant
Unit 2, Docket No. 50-318
Amendment to Operating License DPR-69
Supplement 1 to Fifth Cycle License Application

REFERENCES: (A) A. E. Lundvall to R. A. Clark letter dated 10/15/82, "Unit 2 Fifth Cycle License Application"
(B) A. E. Lundvall to R. A. Clark letter dated 11/5/82, "Unit No. 2 Request for Amendment"

Gentlemen:

Baltimore Gas and Electric Company hereby supplements an earlier request (Reference (A)) for amendment to Operating License DPR-69. The enclosed Supplement 1 presents discussion in support of the conclusion that the Safety Analyses for an Auxiliary Feedwater Actuation System (Reference (B)) in Unit 2, Cycle 5 envelop and ensure conservative operation at a RATED THERMAL POWER OF 2700 MWth.

TECHNICAL SPECIFICATION CHANGES AND JUSTIFICATION

The proposed changes to the Standard Technical Specifications (STS) required by this Supplement 1 are presented in Section 4.0 of the Enclosure to this letter and justified by the discussions in Sections 1.0 through 3.0 of the Enclosure. Also included in Section 4.0 are all the proposed modifications to the STS included in Reference (B) in order that the staff may have a complete package of STS modifications associated with this Supplement 1.

Section 5.0 of the Enclosure proposes a one-time exemption to Technical Specification 3.7.1.2 in order to allow a thorough test of the Auxiliary Feedwater Actuation System (AFAS). Section 5.0 also presents the justification for that exemption.

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SAFETY ANALYSES AND REVIEW

This supplement and proposed STS changes constitute an unreviewed safety question since consequences of two previously analyzed Design Bases Events (DBE) are more severe, one new DBE is analyzed, and the margin of safety defined in the bases for one STS is slightly reduced from that discussed in Reference (A). However, the Enclosure presents analyses which demonstrate that acceptable limits on DNBR, Reactor Coolant System upset pressure, and 10CFR100 site boundary dose rate guidelines would not be exceeded during a Design Bases Event.

The Plant Operations and Safety Review Committee (POSRC) and Offsite Safety and Review Committee (OSSRC) have reviewed this proposed Amendment and these proposed changes to the Standard Technical Specifications and have concluded that although they constitute an unreviewed safety question they do not present an undue risk to the health and safety of the public.

Very truly yours,

BALTIMORE GAS AND ELECTRIC COMPANY

A. E. Lundvall, Jr.

A. E. Lundvall, Jr.
Vice-President - Supply

AEL/WJL/lmt

Enclosure (40 copies)

STATE OF MARYLAND, CITY OF BALTIMORE, TO WIT:

Arthur E. Lundvall, Jr., being duly sworn states that he is Vice President of the Baltimore Gas and Electric Company, a corporation of the State of Maryland; that he executed the foregoing Amendment for the purposes therein set forth; that the statements made in said Amendment are true and correct to the best of his knowledge, information, and belief; and that he was authorized to execute the Amendment on behalf of said Corporation.

WITNESS My Hand and Notarial Seal.

Ruth W. Grese
Notary Public

cc: J. A. Biddison, Esquire
G. F. Trowbridge, Esquire
D. H. Jaffe
P. W. Kruse

SUPPLEMENT 1

TO

CALVERT CLIFFS UNIT 2 CYCLE 5 REFUELING AMENDMENT

SAFETY ANALYSIS FOR THE SAFETY GRADE

AUXILIARY FEEDWATER ACTUATION SYSTEM

This supplement documents the results of the safety analysis performed for the safety grade Auxiliary Feedwater Actuation System (AFAS) and the associated Technical Specification changes. The safety grade AFAS consists of:

1. Automatic initiation of auxiliary feedwater to both steam generators based on a low level signal from either one of the steam generators. This signal is generated when the water level in either steam generator decreases below a nominal setpoint value of -172 inches based on wide range level indication. The safety analysis was performed by including appropriate uncertainties to the nominal setpoint.

2. Isolation logic to identify and isolate a ruptured steam generator. A steam generator with lower pressure (in comparison to the other steam generator) is identified as being ruptured and is isolated when the steam generator differential pressure (i.e., $\left| P_{SG}(A) - P_{SG}(B) \right|$) exceeds a nominal setpoint value of 130 psid. The safety analysis was performed by including appropriate uncertainties to the nominal setpoint.

The Design Basis Events (DBEs) impacted by the safety grade AFAS are: 1) the Loss of Feedwater event, 2) the Feed Line Break (FLB) event and 3) the Steam Line Break (SLB) event. These events were analyzed with and without Loss of AC power on turbine trip. In addition, a spectrum of break sizes were analyzed for the FLB and SLB events. Table 1 presents the reasons for analysis of each event, the acceptance criterion used in judging the results and a summary of results obtained. Detailed presentations of the results of the analysis are provided in Sections 1.0 through 3.0.

Section 4.0 presents the Technical Specification changes associated with the safety grade AFAS.

A summary of the analysis setpoints for the Reactor Protection System (RPS) and AFAS assumed in the analysis of each DBE is given in Table 2. For completeness, the table also presents the Technical Specification setpoints and the associated uncertainties.

Section 5.0 proposes a one time exemption to Technical Specification 3.7.1.2 in order to allow a thorough test of AFAS.

TABLE 1

EVENTS ANALYZED FOR SAFETY GRADE AUXILIARY FEEDWATER ACTUATION SYSTEM

Event	Reason for Reanalysis	Acceptance Criterion	Summary of Results
Loss of Feedwater	Determine acceptability of analysis setpoint to initiate auxiliary feedwater and analysis setpoint for flow controller.	Peak pressure less than upset pressure limit of 2750 psia and ensure that adequate heat sink is maintained during the event.	The peak pressure is 2574 psia. The steam generator water mass does not decrease below 37,500 lbm. Thus, results are acceptable. For further details see Section 1.0
Feed Line Break	Determine acceptability of analysis setpoint to initiate auxiliary feedwater and analysis setpoint for isolation logic to isolate ruptured steam generator.	Peak pressure less than upset pressure limit of 2750 psia. The 0-2 hr site doses are within 10CFR100 guidelines.	The peak pressure is 2749 psia*. The 0 to 2 hr thryroid dose (DEQ I-131) is 2.2 REM. For further details see Section 2.0
Steam Line Break	Determine acceptability of analysis setpoint for isolation logic to isolate ruptured steam generator.	For breaks outside containment, the site boundary doses are within 10CFR100 guidelines.	The 0 to 2 hr thyroid dose (DEQ I-131) is 67.0 REM.
		For breaks inside containment the post-trip DNBR is greater than 1.3 using McBeth correlation.	The minimum post-trip DNBR is 1.31. Thus, the results are acceptable. For further details see Section 3.0

*The peak pressure value quoted is for a FLB event with Loss of AC Power on turbine trip.

TABLE 2

RPS AND AFAS SETPOINTS ASSUMED IN SAFETY ANALYSIS

DBE	RPS and AFAS Function	Tech. Spec. Setpoint	Uncertainty	Analysis Setpoint
Loss of Feedwater	Steam Generator Low Level Trip	10" below top of feed ring	10"	20" below top of feed ring
	High Pressurizer Pressure Trip (HPPT)	2400 psia	22.3 psia	2422.3 psia
	Steam Generator Low Level Signal to Initiate Auxiliary Feedwater(1)	≥44.[illegible]% (-194 inches)	2.0% (9 inches)	42.4% (-203 inches)
	Auxiliary Feedwater Flow Controller	160 GPM	70 GPM	90 GPM
Feed Line Break	High Pressurizer Pressure Trip	2400 psia	67.4 psia	2467.4 psia
	Steam Generator Low Level Signal to Initiate Auxiliary Feedwater(1)	≥42.9% (-202 inches)	13.8% (64 inches)	29.1% (-266 inches)
	Auxiliary Feedwater Flow Controller	160 GPM	70 GPM	90 GPM
	Steam Generator Differential Pressure to Isolate Ruptured Steam Generator	130 psid	120 psid	10 psid(2)
Steam Line Break	Low Steam Generator Pressure Trip	685 psia	83.1 psia	600 psia

TABLE 2
(continued)

DBE	RPS and AFAS Function	Tech. Spec. Setpoint	Uncertainty	Analysis Setpoint
Steam Line Break	Steam Generator Differential Pressure to Isolate Ruptured Steam Generator	130.0 psid	120.0 psid	250.0 psid
	Steam Generator Low Level Signal to Initiate Auxiliary Feedwater(1)	<54.4% (-148 inches)	6.5% (30 inches)	60.9% (-118 inches)

(1)% of the distance between steam generator wide range upper and lower level instrument taps (-401 inches to +63.5 inches).

(2)For additional conservatism in the analysis, no auxiliary feedwater flow to the ruptured steam generator was assumed.

1.0 Loss of Feedwater Flow Event

The Loss of Feedwater Flow event was reanalyzed for Calvert Cliffs Unit 2 Cycle 5 to demonstrate that the RCS pressure limit of 2750 psia is not exceeded and that an adequate heat sink is maintained during the event. The event is reanalyzed to incorporate the effects of the safety grade Auxiliary Feedwater Actuation System. This system includes actuation of auxiliary feedwater based on wide range steam generator level indication and isolation logic to identify the ruptured steam generator based on steam generator differential pressure. The event was analyzed with and without loss of AC power on turbine trip.

Analysis Assumptions and Initial Conditions

Table 1-1 presents the initial conditions chosen to maximize the RCS pressure. A Moderator Temperature Coefficient (MTC) of $+0.5 \times 10^{-4} \Delta\rho / ^{\circ}F$ is assumed in the analysis. This MTC in conjunction with increasing coolant temperatures, adds positive reactivity and thus maximizes the rate of change of heat flux and pressure at the time of trip. A Fuel Temperature Coefficient (FTC) corresponding to beginning of cycle conditions was used in the analysis. This FTC causes the least amount of negative reactivity feedback, allowing higher increases in both the heat flux and RCS pressure. An uncertainty factor of 15% is used in the analysis. An initial pressure of 2154 psia is used in the analysis to maximize the rate of change of pressure at time of trip and thus the peak pressure obtained following a reactor trip. This initial pressure corresponds to the minimum allowed Technical Specification limit of 2200 psia and includes a conservatively high instrument uncertainty of 46 psia. An initial steam generator pressure of 815 psia is assumed in the analysis. This pressure delays the opening of the Main Steam Safety Valves (MSSVs), decreases the steam releases through the MSSVs and maximizes the peak RCS pressure. The Steam Dump and Bypass System (SDBS), the Pressurizer Pressure Control System (PPCS), the Pressurizer Level Control System (PLCS) and the Power Operated Relief Valves (PORV) are assumed to be in the manual mode of operation. This assumption enhances the RCS pressure increase since the automatic operation of these system mitigates the RCS pressure increase.

Table 1-3 presents the initial conditions chosen to analyze the Loss of Feedwater Flow to determine whether an adequate heat sink is maintained during the event. An MTC of $+0.5 \times 10^{-4} \Delta\rho / ^{\circ}F$ is assumed since this results in a greater rise in core power and heat flux prior to reactor trip. An EOC FTC was selected since it results in slower power rampdown after reactor trip, and thus maximizes rate of steam generator inventory depletion. The SDBS is assumed to be in the automatic mode of operation and an initial steam generator pressure of 915 psia is chosen. These assumptions increase the steam flow out of the secondary system via SDBS and MSSVs, and maximize the rate of steam generator inventory depletion.

An auxiliary feedwater actuation analysis setpoint of 42.4% of steam generator wide range span is assumed in this analysis. This represents a Technical Specification actuation setpoint of 44.4% and includes a 2.0% uncertainty. The actuation signal activates a motor driven auxiliary feedwater pump and a steam driven auxiliary feedwater pump which deliver auxiliary feedwater to both steam generators. The motor driven pump's auxiliary feedwater reaches the steam generator 18.0 seconds after low steam generator level signal is initiated. This includes 14.5 seconds for the pump to accelerate to speed including all signal processing delays and 3.5 seconds for water to travel through piping and reach the steam generator.

The flow from the motor driven pump to each steam generator is controlled by a flow control valve installed in the "leg" connecting the pump to the steam generator. A minimum flow of 90 gpm through each leg is conservatively assumed in the analysis. It represents the Technical Specification limit on AFW flow rate of 160 gpm through the flow control valve and an uncertainty of 70 gpm.

The steam driven pump's auxiliary feedwater reaches the steam generator 58.0 seconds after Auxiliary Feedwater Actuation setpoint is reached. This includes 50 seconds required to open steam admission valves to the pump, 4.5 seconds for the pump to accelerate to speed and 3.5 seconds for water to travel through piping and reach the steam generator. The flow from the steam driven pump to each steam generator is also controlled by a flow control valve installed in the flow "leg" connecting the pump to the steam generator. A flow of 90 gpm through each leg is assumed in the analysis. It represents the Technical Specification limit on AFW flow rate of 160 gpm through the flow control valve and an uncertainty of 70 gpm.

In case of loss of AC at turbine trip, there is an additional delay time involved for the motor driven pump. It includes 10 seconds for the diesel generators to start and reach speed following the LOAC and 30 seconds for the motor driven pump to be loaded on line.

Results

The results of the Loss of Feedwater event show that with respect to RCS peak pressure, the case with LOAC on turbine trip is more limiting than the case with no LOAC. Loss of AC power on turbine trip causes the RCS pumps to coastdown and dump and bypass valves to shut. Both effects contribute to the primary heatup and pressurization: the former by reducing the heat transfer rate from primary to secondary and the latter by temporarily suppressing the steam release out of the steam generators and raising the steam generator pressure before MSSVs open.

The sequence of events for the Loss of Feedwater Flow event with Loss of AC on turbine trip analyzed to determine the peak RCS pressure is presented in Table 1-2. Figures 1-1 through 1-5 present the transient behavior of core power, core average heat flux, RCS temperatures, RCS pressure and steam generator pressure. The results show that High Pressurizer Pressure analysis trip setpoint is reached at 21.5 seconds. Loss of AC power occurs at 22.9 seconds and RCS pumps start to coastdown. The primary safety valves begin to open at 24.3 seconds and the pressure reaches a maximum of 2574 psia at 25.3 seconds. The increase in secondary pressure is limited by the opening of MSSVs at 25.9 seconds. The steam generator pressure reaches a maximum of 1048 psia at 29.7 seconds.

The results of the analysis show that with respect to steam generator water inventory, the Loss of Feedwater event is less limiting when LOAC on turbine trip occurs. Loss of AC power causes Steam Dump and Bypass Valves to close, thereby reducing the total steam flow out of the steam generators and leaving more mass in them.

The sequence of events for the Loss of Feedwater Flow event without LOAC on turbine trip analyzed to maximize steam generator inventory depletion is given in Table 1-4. Figures 1-6 through 1-12 present the transient behavior of core power, core average heat flux, RCS temperatures, RCS pressure, steam generator pressure, steam generator water mass and auxiliary feedwater flow to the steam generator. The results of the analysis show that the low steam generator level trip setpoint is reached at 18.0 seconds and the CEAs begin to drop at 19.4 seconds. A signal to open Steam Dump and Bypass is generated at 19.0 seconds. At 21.2 seconds MSSVs begin to open to limit the increase in steam generator pressure. Maximum steam generator pressure of 1048 psia is reached at 25.0 seconds.

At 37.1 seconds the Auxiliary Feedwater Actuation setpoint is reached. The motor driven pump's auxiliary feedwater flow reaches the steam generator at 55.1 seconds. The steam driven pump's auxiliary feedwater flow reaches the steam generator at 95.1 seconds. Each pump delivers 90 gpm to each steam generator. The analysis shows that this flow rate is sufficient to maintain an adequate heat sink during the transient.

Conclusion

In conclusion, the results of the Loss of Feedwater Flow event with and without Loss of AC following the reactor trip demonstrate that the peak pressure does not exceed the upset limit of 2750 psia and that an adequate heat sink is maintained during the event.

TABLE 1-1

KEY PARAMETERS ASSUMED IN THE LOSS OF FEEDWATER ANALYSIS
TO MAXIMIZE CALCULATED RCS PEAK PRESSURE

Parameter	Units	Value
Initial Core Power Level	MWt	2754
Initial Core Coolant Inlet Temperature	^oF	550
Initial RCS Vessel Flow Rate	gpm	370,000
Initial Reactor Coolant System Pressure	psia	2154
Initial Steam Generator Pressure	psia	815
Initial Pressurizer Liquid Volume	ft^3	975
Moderator Temperature Coefficient	$x10^{-4}\Delta\rho/^oF$	+0.5
Doppler Coefficient Multiplier	-----	0.85
High Pressurizer Pressure Analysis Trip Setpoint	psia	2422.3
Reactor Regulating System	Operating Mode	Manual**
Steam Dump and Bypass System	Operating Mode	Manual**
Pressurizer Pressure Control System	Operating Mode	Manual**
Pressurizer Level Control System	Operating Mode	Manual**

**These modes of control system operation maximize the peak RCS pressure.

TABLE 1-2

SEQUENCE OF EVENTS FOR LOSS OF FEEDWATER FLOW ANALYSIS
TO MAXIMIZE CALCULATED RCS PEAK PRESSURE WITH LOAC

Time (sec)	Event	Setpoint or Value
0.0	Loss of Main Feedwater	----
21.5	High Pressurizer Pressure Trip Setpoint Reached	2422.3 psia
22.4	Trip Breakers Open	
22.8	Turbine Stop Valves Close	
22.9	CEAs Begin to Drop Into Core, Loss of AC Power	
24.3	Primary Safety Valves Begin to Open	2500 psia
25.3	Maximum RCS Pressure	2574* psia
25.9	Steam Generator Safety Valves Begin to Open	1000 psia
29.1	Primary Safety Valves Close	2400 psia
29.7	Maximum Steam Generator Pressure	1048 psia

*Pressure Includes Elevation Head

TABLE 1-3

KEY PARAMETERS ASSUMED IN THE LOSS OF FEEDWATER ANALYSIS TO MAXIMIZE STEAM GENERATOR INVENTORY DEPLETION

Parameter	Units	Value
Initial Core Power Level	MWt	2754
Initial Core Coolant Inlet Temperature	^oF	550
Initial RCS Vessel Flow Rate	gpm	370,000
Initial Reactor Coolant System Pressure	psia	2154
Initial Steam Generator Pressure	psia	915
Initial Pressurizer Liquid Volume	ft^3	975
Moderator Temperature Coefficient	$x 10^{-4} \Delta\rho / ^oF$	+0.5
Doppler Coefficient Multiplier	-----	0.85
Steam Generator Low Level Analysis Trip Setpoint	inches below top of feed ring	20.0
Auxiliary Feedwater Actuation Analysis Setpoint	% Wide Range Steam Generator Level Indication	42.4
Auxiliary Feedwater Flow Enthalpy	BTU/lbm	80.0
Reactor Regulating System	Operating Mode	Manual**
Steam Dump and Bypass System	Operating Mode	Automatic**
Pressurizer Pressure Control System	Operating Mode	Manual**
Pressurizer Level Control System	Operating Mode	Manual**

**These modes of control system operation maximize the steam generator water inventory depletion rate.

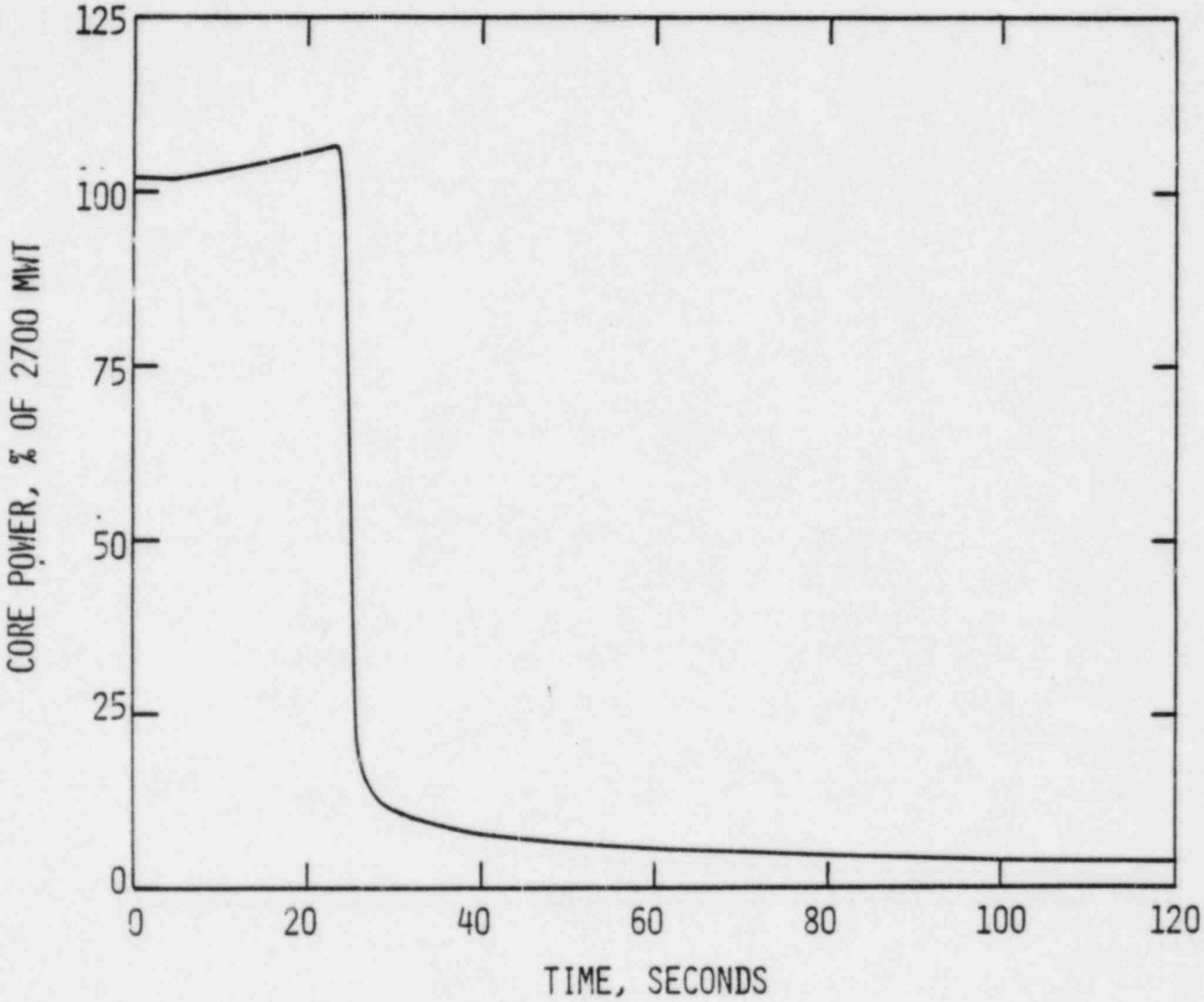
TABLE 1-4

SEQUENCE OF EVENTS FOR LOSS OF FEEDWATER FLOW ANALYSIS
TO MAXIMIZE STEAM GENERATOR INVENTORY DEPLETION

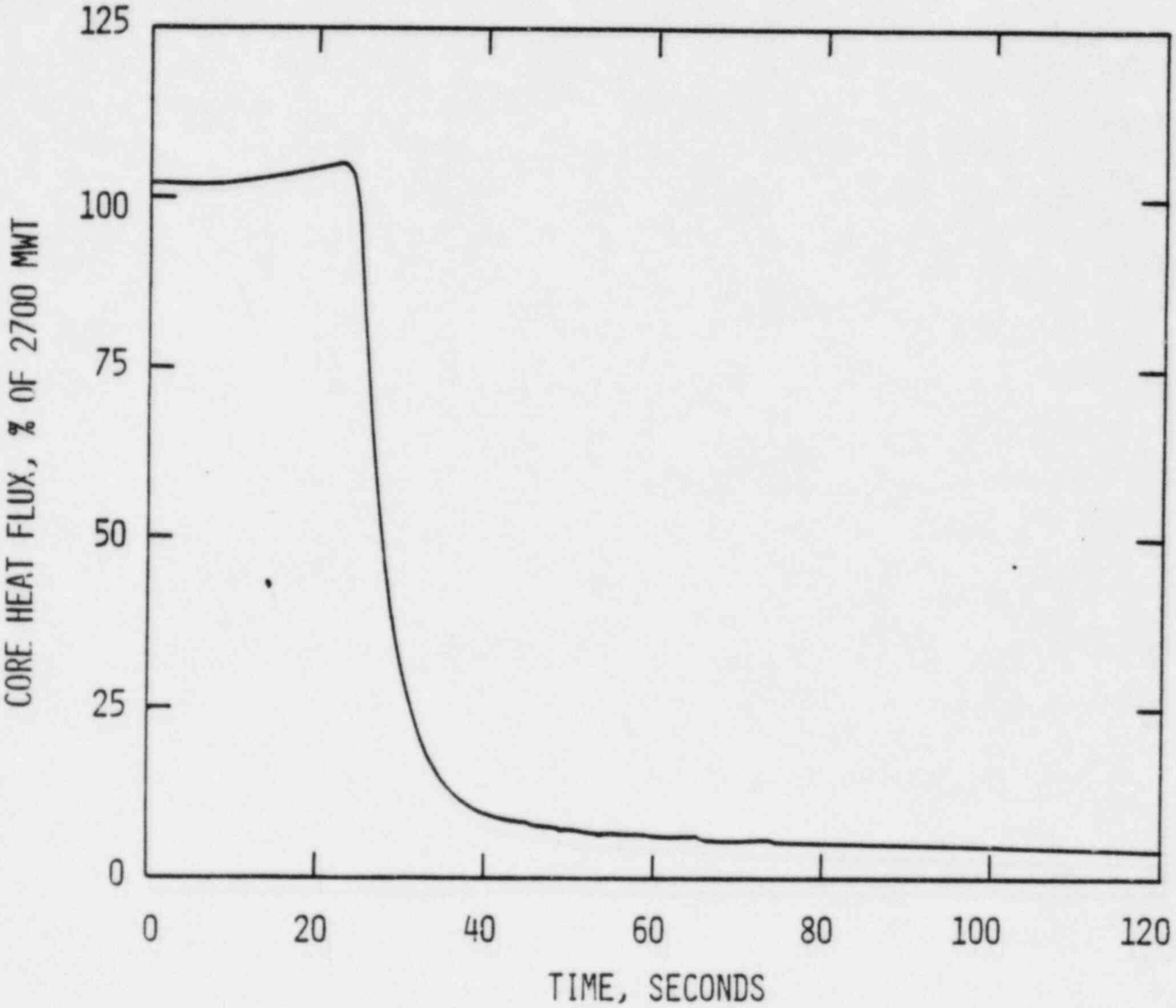
Time (sec)	Event	Setpoint or Value
0.0	Loss of Main Feedwater	---
2.0	S.G. Bypass Valve Opens	895 psia
18.0	Steam Generator Low Water Level Analysis Trip Setpoint is Reached	20 inches below the top of the feed ring
18.9	Trip Breakers Open	---
19.0	S.G. Dump Valve Opens	---
19.3	Turbine Valves Close	---
19.4	CEAs Begin to Drop Into Core	---
21.2	Steam Generator Safety Valves Begin to Open	1000 psia
22.6	Maximum RCS Pressure	2364* psia
25.0	Maximum Steam Generator Pressure	1048 psia
37.1	Auxiliary Feedwater Actuation Analysis Setpoint is Reached	42.4%**
51.6	Motor Driven Auxiliary Feed Pump Reaches Rated Speed	
55.1	Motor Driven Auxiliary Feedwater Enters Both Steam Generators	90 gpm/S.G.
87.1	Steam Admission Valves to Steam Driven Auxiliary Feedwater Pump Opens	
91.6	Steam Driven Auxiliary Pump Reaches Rated Speed	
95.1	Steam Driven Auxiliary Feedwater Enters Both Steam Generators	90 gpm/S.G.

*Pressure includes elevation head

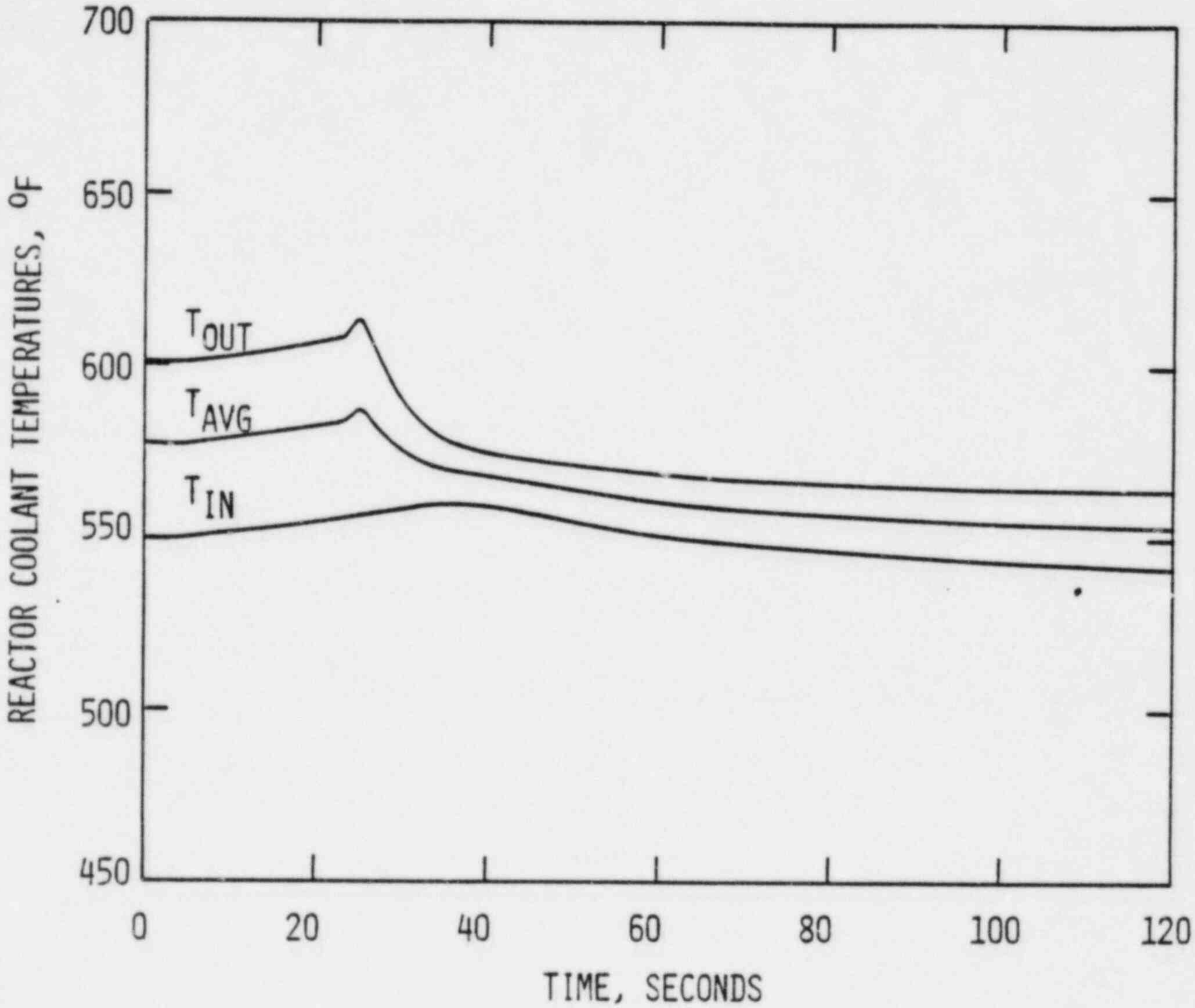
**% of distance between steam generator wide range upper and lower level instrument taps.



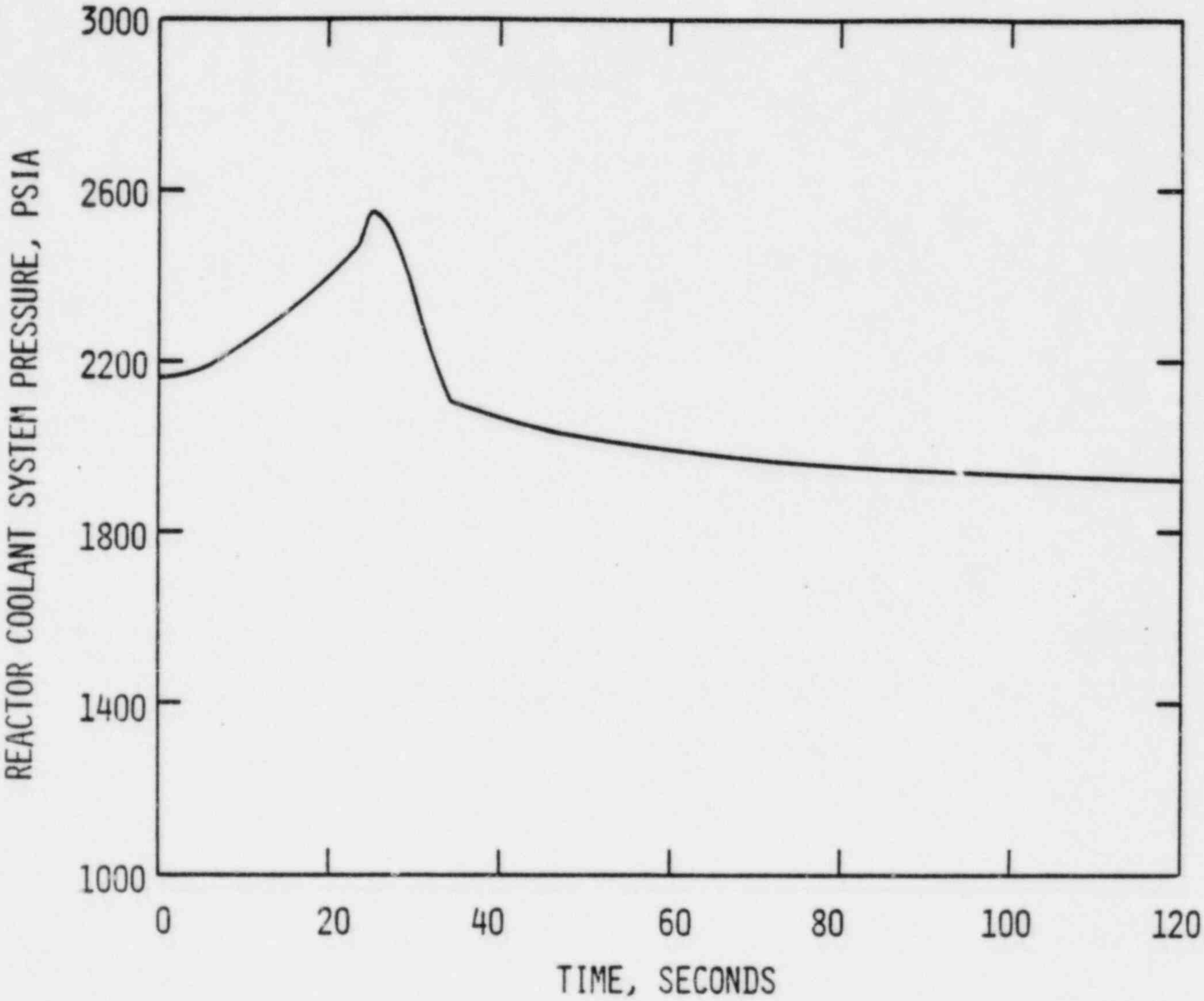
BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	LOSS OF FEEDWATER FLOW EVENT/MAXIMIZE RCS PEAK PRESSURE WITH LOAC FOLLOWING REACTOR TRIP CORE POWER VS TIME	FIGURE 1-1



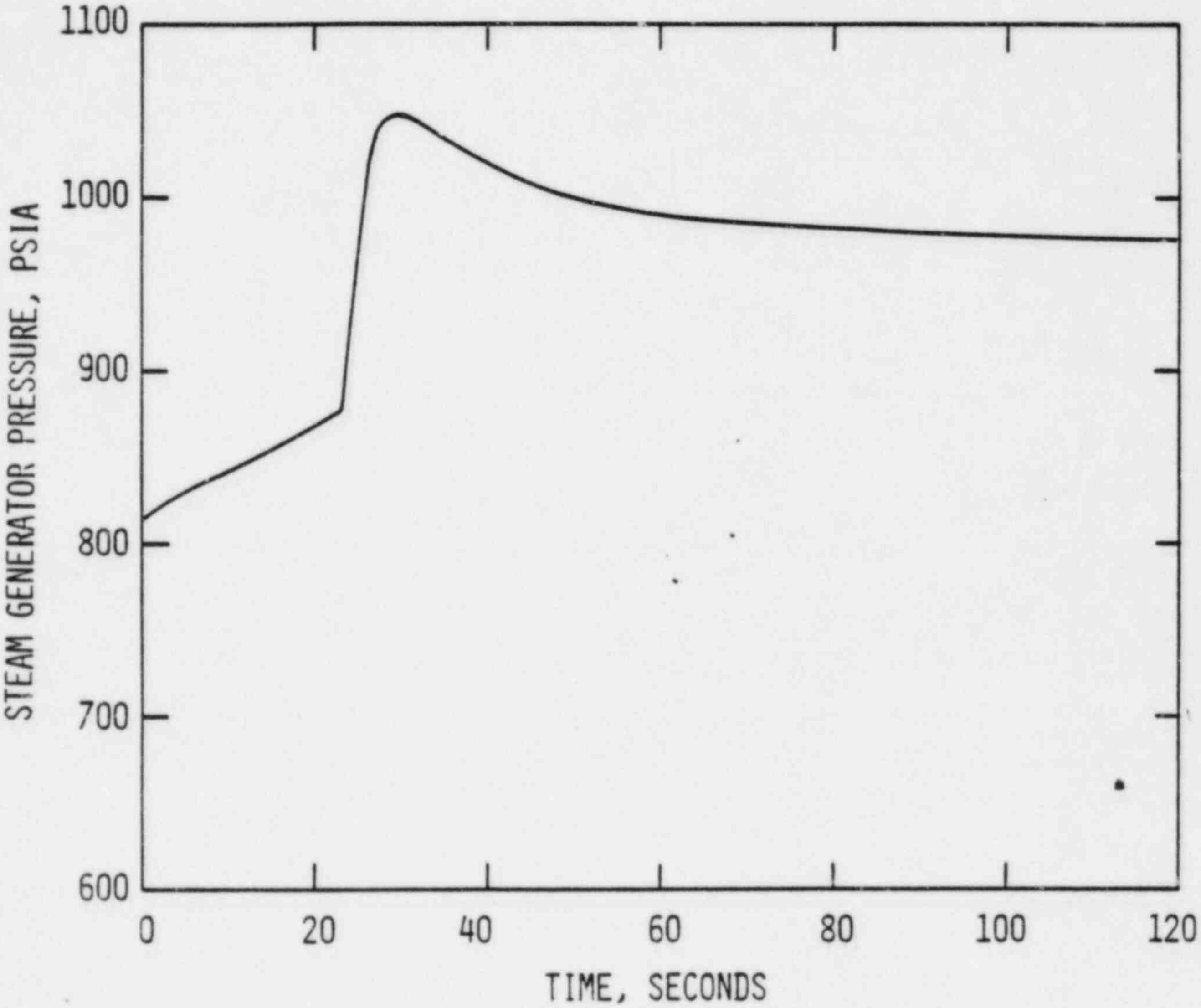
BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	LOSS OF FEEDWATER FLOW EVENT/MAXIMIZE RCS PEAK PRESSURE WITH LOAC FOLLOWING REACTOR TRIP CORE HEAT FLUX VS TIME	FIGURE 1-2



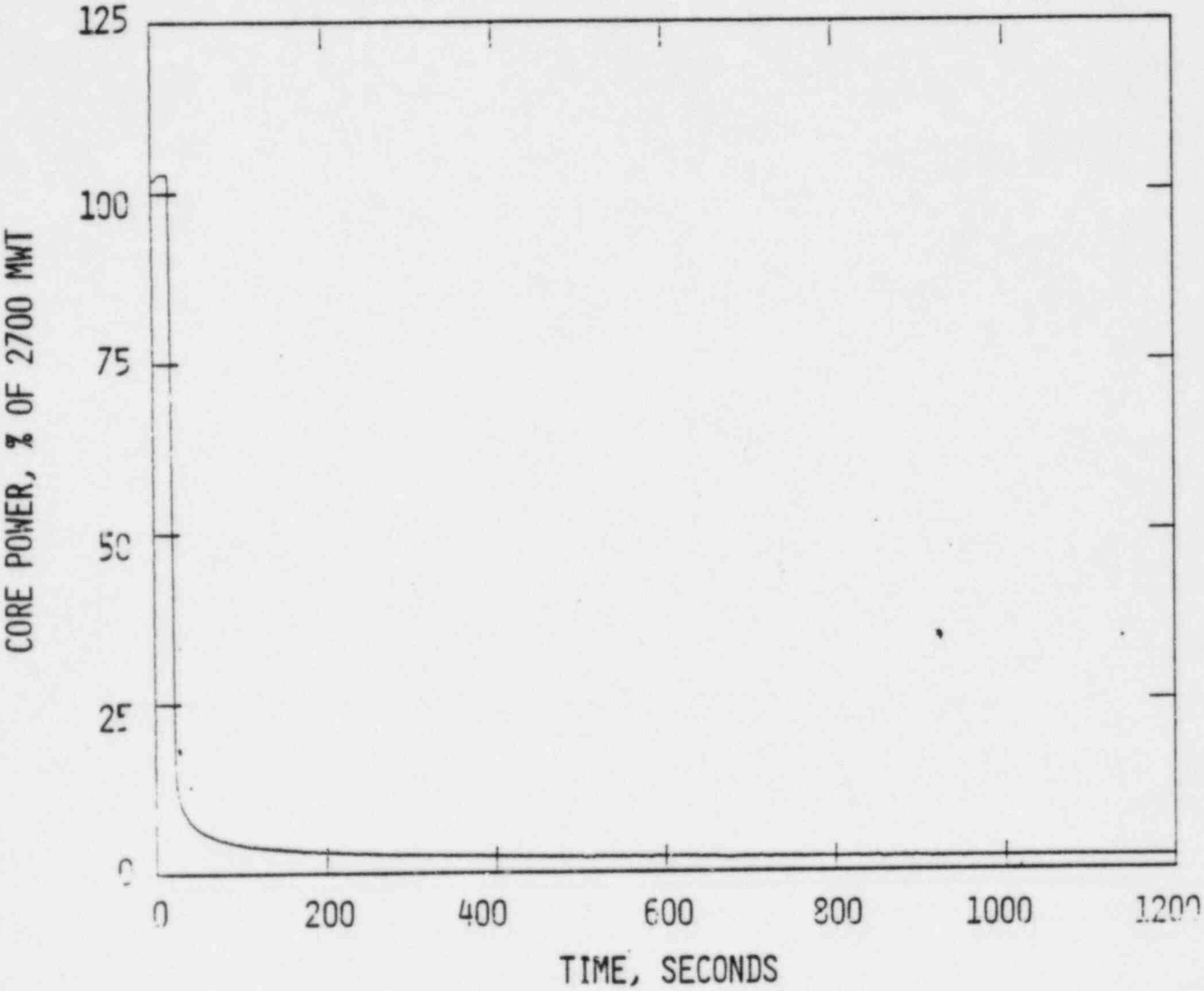
BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	LOSS OF FEEDWATER FLOW EVENT/MAXIMIZE RCS PEAK PRESSURE WITH LOAC FOLLOWING REACTOR TRIP REACTOR COOLANT SYSTEM TEMPERATURES VS TIME	FIGURE 1-3



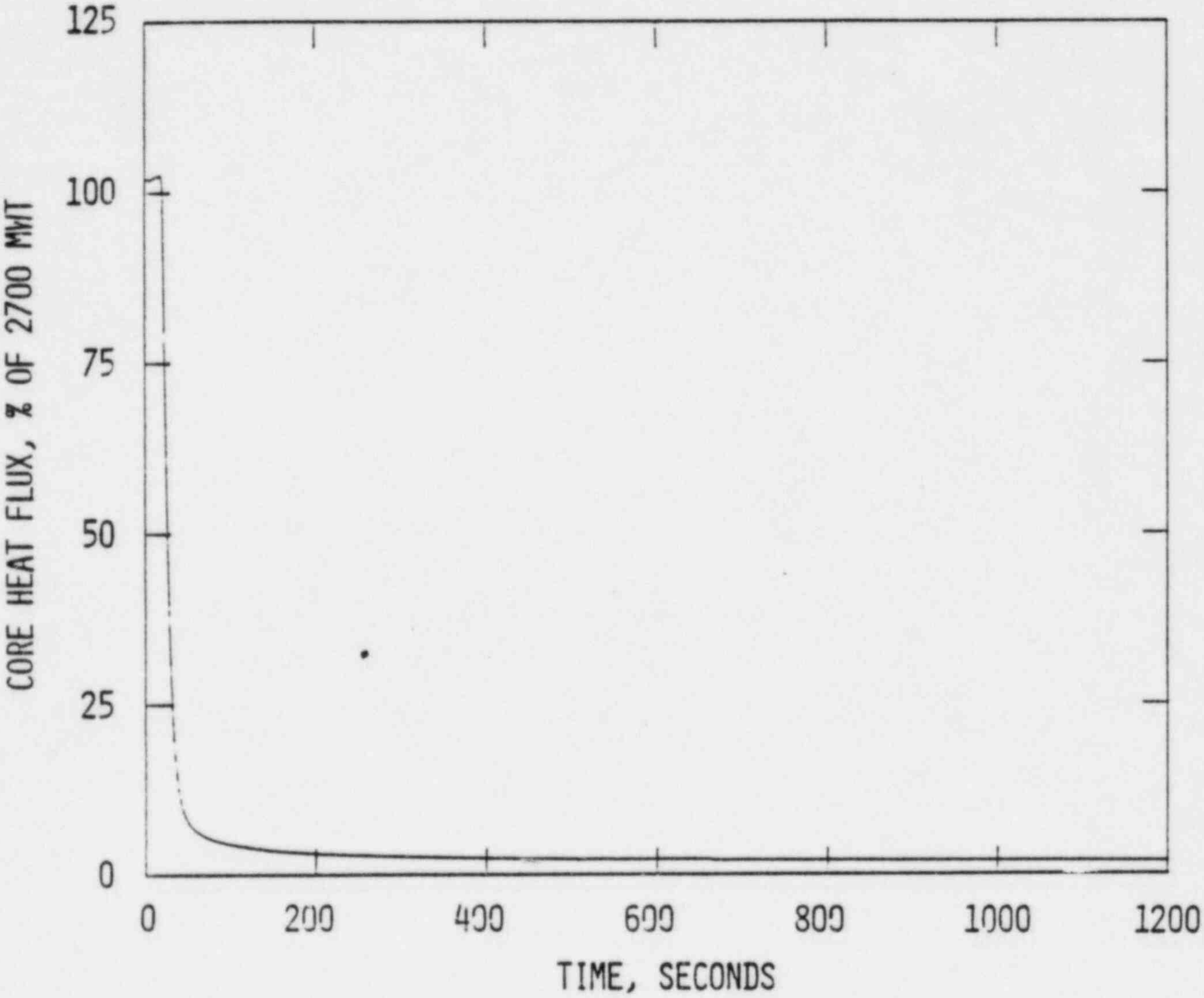
BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	LOSS OF FEEDWATER FLOW EVENT/MAXIMIZE RCS PEAK PRESSURE WITH LOAC ..LLOWING REACTOR TRIP REACTOR COOLANT SYSTEM PRESSURE VS TIME	FIGURE 1-4



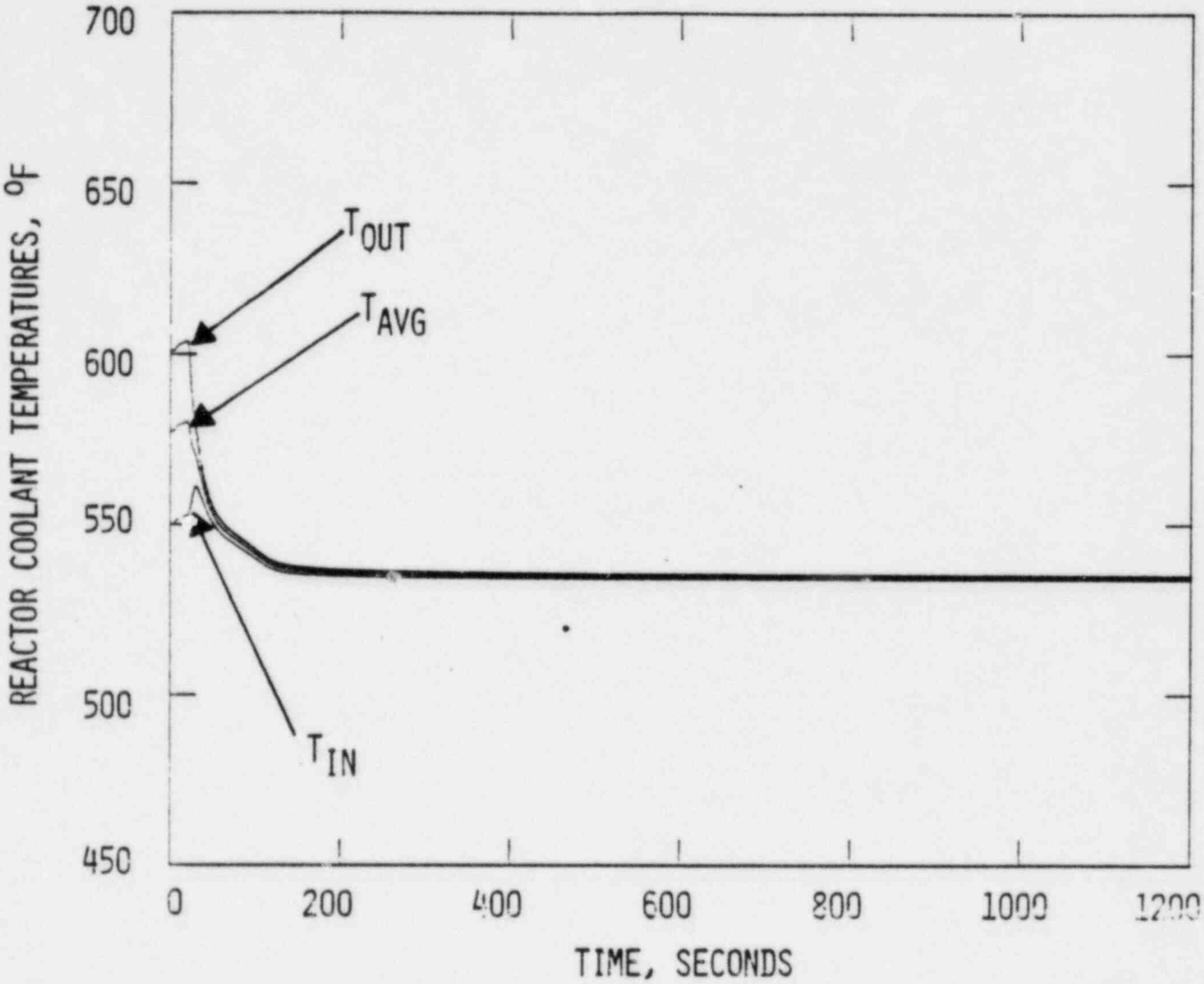
BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	LOSS OF FEEDWATER FLOW EVENT/MAXIMIZE RCS PEAK PRESSURE WITH LOAC FOLLOWING REACTOR TRIP STEAM GENERATOR PRESSURE VS TIME	FIGURE 1-5



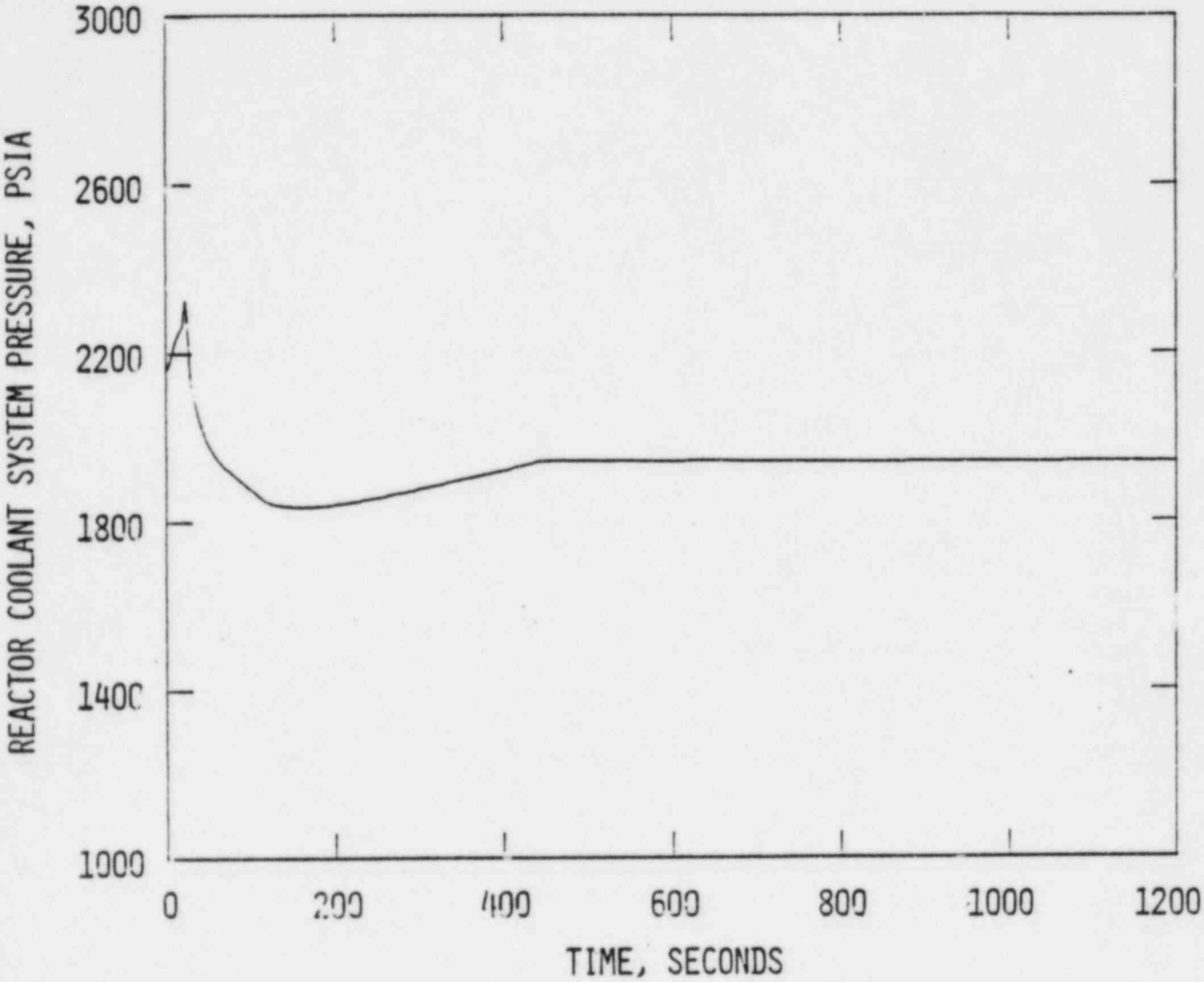
BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	LOSS OF FEEDWATER FLOW EVENT/MAXIMIZE S.G. INVENTORY DEPLETION WITHOUT LOAC CORE POWER VS TIME	FIGURE 1-6



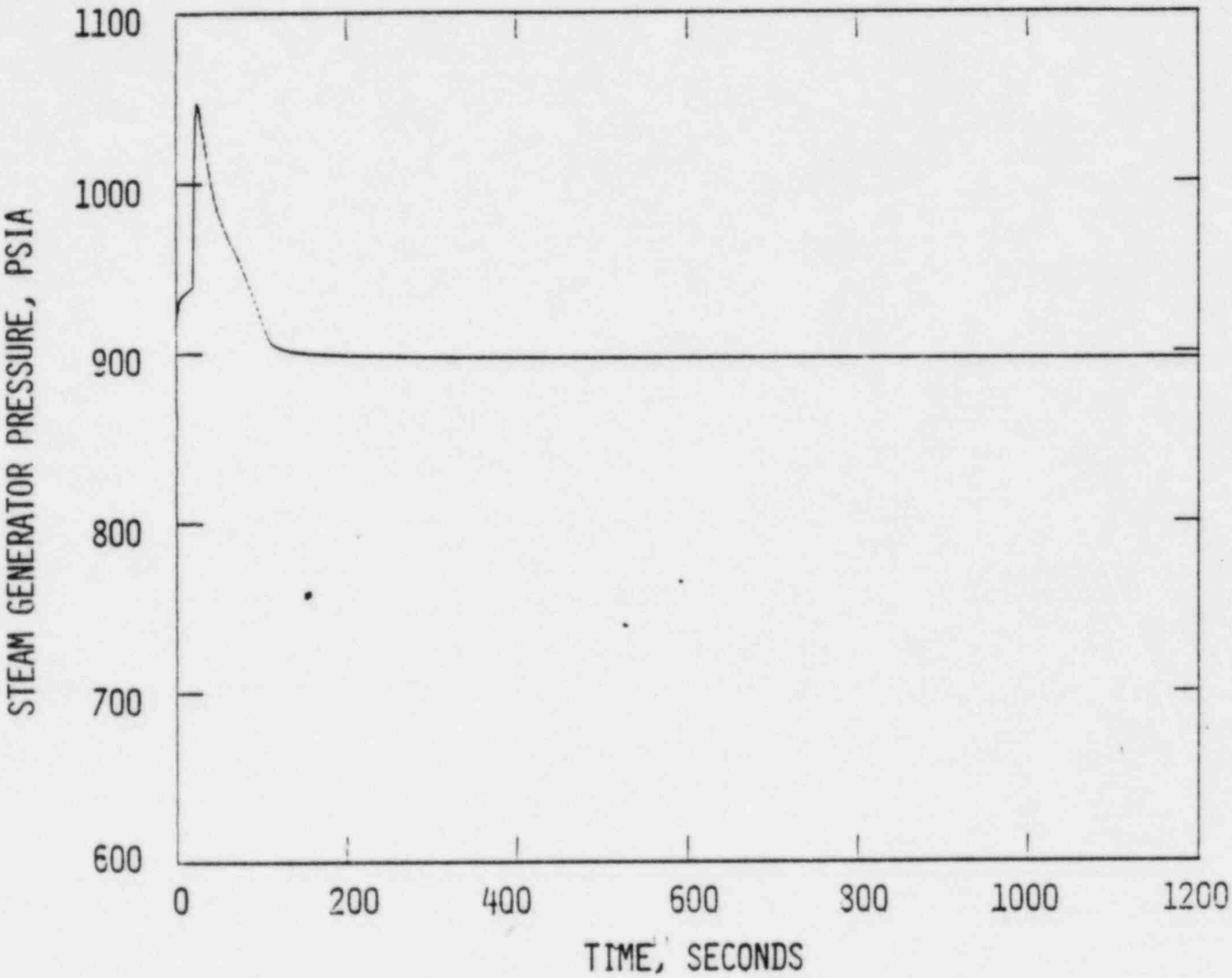
BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	LOSS OF FEEDWATER FLOW EVENT/MAXIMIZE S.G. INVENTORY DEPLETION WITHOUT LOAC CORE HEAT FLUX VS TIME	FIGURE 1-7



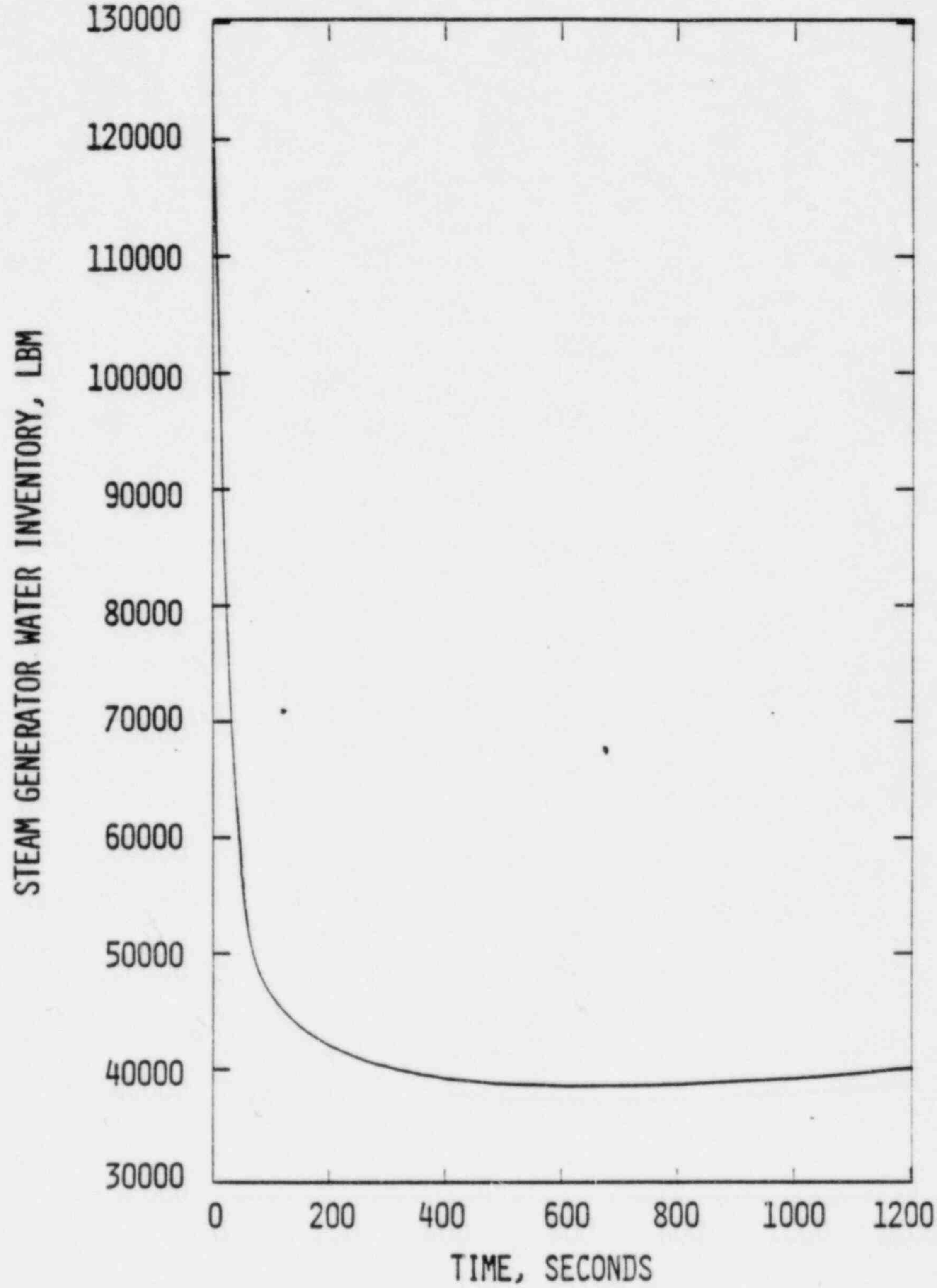
BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	LOSS OF FEEDWATER FLOW EVENT/MAXIMIZE S.G. INVENTORY DEPLETION WITHOUT LOAC REACTOR COOLANT TEMPERATURES VS TIME	FIGURE 1-8



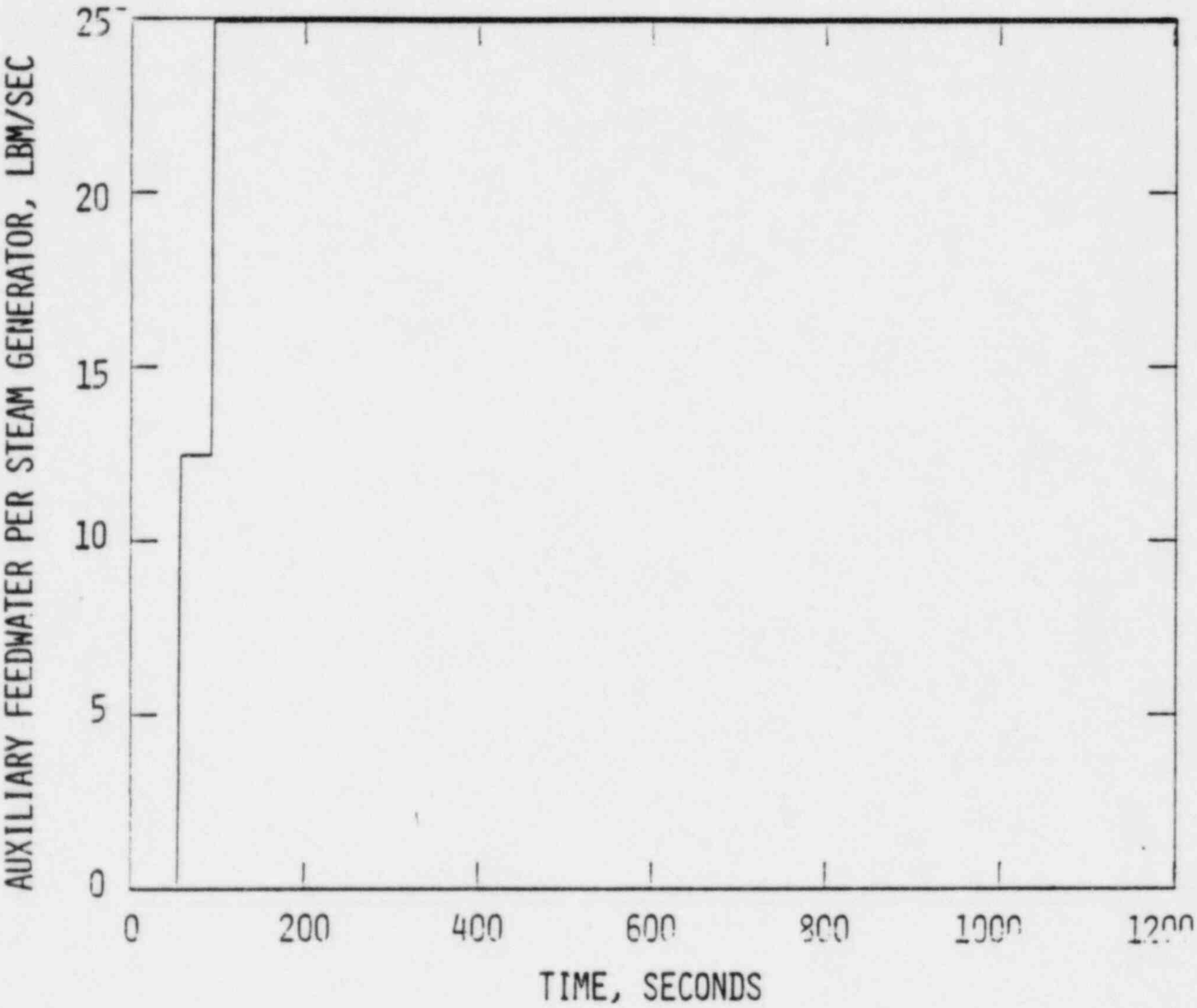
BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	LOSS OF FEEDWATER FLOW EVENT/MAXIMIZE S.G. INVENTORY DEPLETION WITHOUT LOAC REACTOR COOLANT SYSTEM PRESSURE VS TIME	FIGURE 1-9



BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	LOSS OF FEEDWATER FLOW EVENT/MAXIMIZE S.G. INVENTORY DEPLETION WITHOUT LOAC STEAM GENERATOR PRESSURE VS TIME	FIGURE 1-10



BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	LOSS OF FEEDWATER FLOW EVENT/MAXIMIZE S.G. INVENTORY DEPLETION WITHOUT LOAC STEAM GENERATOR WATER INVENTORY VS TIME	FIGURE 1-11



BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	LOSS OF FEEDWATER FLOW EVENT/MAXIMIZE S.G. INVENTORY DEPLETION WITHOUT LOAC AUXILIARY FEEDWATER FLOW TO S.G. VS TIME	FIGURE 1-12

2.0 Feedline Break Event

Introduction

The Feed Line Break (FLB) event was analyzed for Calvert Cliffs Unit 2 Cycle 5 to demonstrate that the RCS pressure limit of 2750 psia is not exceeded and that the site boundary doses do not exceed 10CFR100 guidelines. The event is analyzed to incorporate the effects of the safety grade auxiliary feedwater actuation system. This system includes actuation of auxiliary feedwater based on wide range steam generators differential pressure. The event was analyzed with and without Loss of AC Power on turbine trip. A spectrum of break sizes were considered in the analysis and the results of the limiting break size is presented herein.

Discussion

The FLB event is initiated by a break in the main feedwater system (MFS) piping. Depending on the break size and location and the response of the MFS, the effects of a break can vary from a rapid heatup to a rapid cooldown of the Nuclear Steam Supply System (NSSS). In order to discuss the possible effects breaks are categorized as small, if the associated discharge flow is within the excess capacity of the MFS, and as large, otherwise. Break locations are identified with respect to the feedwater line reverse flow check valve. There is one reverse flow check valve per feed line and it is located between the steam generator feedwater nozzle and the containment penetration. Closure of the check valve to prevent reverse flow from the steam generator maintains the heat removal capability of that generator in the presence of a break upstream of the check valve.

Feed line breaks upstream of the reverse flow check valve can initiate one of the following transients. A break of any size with MFS unavailable will result in a Loss of Feedwater Flow (LOFW) event. A small pipe break with MFS available will result in no reduction in feedwater flow. Depending on the break size, a large break with MFS available will result in either a partial or a total LOFW event. Since FLBs upstream of the reverse flow check valve result in transients no more severe than a LOFW event (see Section 1.0 for the results of the LOFW event), these FLBs were not analyzed.

In addition to the possibility of partial or total LOFW, FLBs downstream of the check valve have the potential to establish reverse flow from the ruptured steam generator back to the break. Reverse flow occurs whenever the MFS is not operating subsequent to a pipe break or when the MFS is operating but without sufficient capacity to maintain pressure at the break above the steam generator pressure. FLBs which develop reverse flow through the break are limiting with respect to primary overpressure. Thus, only these FLBs were considered in the analysis.

FLBs downstream of the check valve with reverse flow may result in either a RCS heatup or a RCS cooldown event depending on the enthalpy of the reverse flow and the heat transfer characteristics of the ruptured steam generator. However, excessive heat removal through the feed line break is not considered in the analysis because the cooldown potential is less than that for the Steam Line Break (SLB) event (see Section 3.0 for the results of the SLB event). This occurs because SLBs have a greater potential for discharging high enthalpy fluid due to the location of the steam piping which is located above the feedwater piping within a steam generator. In addition, the maximum break area for a FLB is 1.4 ft^2 in comparison to 6.305 ft^2 for a SLB.

Unlike SLBs, FLBs cause a decrease in feedwater flow, resulting in lower steam generator liquid inventory which reduces the heat removal capacity. The reduced heat transfer capability results in a rapid RCS overpressurization and, thus, it is the heatup potential of a FLB which is analyzed and reported herein.

A general description of the FLB event downstream of the check valves, with the MFS unavailable and with low enthalpy break discharge is given below. The loss of subcooled feedwater flow to both steam generators causes increasing steam generator temperatures, decreasing liquid inventories and decreasing water levels. The rising secondary temperature reduces the primary-to-secondary heat transfer which results in a heatup and pressurization of the RCS. The heatup becomes more severe as the ruptured steam generator experiences a further reduction in its heat transfer capability due to decreasing liquid inventory as the discharge through the break continues. The heatup of the RCS and the depletion of liquid inventory in the steam generator will initiate a reactor trip on either High Pressurizer Pressure or Steam Generator Low Water Level. The RCS heatup can continue even after a reactor trip due to a total loss of heat transfer in the ruptured steam generator as the liquid inventory is completely depleted. The rise in RCS pressure causes the Pressurizer Safety Valves (PSVs) to open. The rise in secondary pressure is limited by the opening of the Main Steam Safety Valves (MSSVs). The opening of the PSVs and the MSSVs in conjunction with the reactor trip (which reduces core power to decay level) mitigates the RCS overpressurization.

The reduction in liquid inventory in the undamaged steam generator initiates auxiliary feedwater flow to both steam generators. As the steam generator differential pressure reaches the AFW isolation logic setpoint, AFW flow to the ruptured steam generator is terminated. The automatic initiation of AFW flow to the undamaged steam generator in conjunction with operator action to increase the AFW flow rate is sufficient to remove decay heat.

Analysis Assumptions and Initial Conditions

The following is a discussion of the conservative assumptions and initial conditions chosen to maximize RCS pressure. Blowdown of the steam generator nearest the feedwater line break is modeled assuming frictionless critical flow as calculated by the Henry-Fauske correlation (Reference 1). The feed line break location is conservatively modeled to be near the bottom of the steam generator, even though in reality, the feed line nozzle is at a much higher elevation within the steam generator. The analysis assumes that saturated liquid is discharged through the break until the liquid mass reaches 5000 lbm, at which time saturated steam discharge is assumed. This assumption maximizes the liquid inventory discharge through the break and minimizes the energy removal from the steam generator through the break. It also minimizes the ruptured steam generator heat transfer capacity and thereby maximizes the RCS overpressurization.

The analysis also assumed that the effective heat transfer area is decreased linearly as the steam generator liquid mass decreases. The mass interval over which the rampdown is assumed to occur is conservatively chosen to model a rapid loss of heat transfer in the ruptured steam generator.

To maximize RCS pressure, the analysis conservatively credited only the high pressurizer pressure trip. This assumption maximizes the rate of change of pressure at the time of trip and thus the peak pressure obtained following the trip. The analysis did not credit either the high containment pressure trip or the steam generator low water level trip.

Table 2-1 presents the initial conditions chosen to maximize the RCS pressure. A Moderator Temperature Coefficient curve corresponding to beginning of cycle conditions is assumed. This MTC in conjunction with increasing coolant temperatures adds positive reactivity and, thus, maximizes the rate of change of heat flux and pressure at the time of trip. A Fuel Temperature Coefficient (FTC) corresponding to beginning of cycle conditions was used in the analysis. This FTC causes the least amount of negative reactivity feedback, allowing higher increases in both the heat flux and RCS pressure. An uncertainty factor of 15% is used in the analysis.

An initial pressure of 2154 psia is used in the analysis to maximize the rate of change of pressure at time of trip and, thus, the peak pressure obtained following a reactor trip. This initial pressure corresponds to the minimum allowed Technical Specification limit of 2200 psia and includes a conservatively high instrument uncertainty of 46 psia. An initial steam generator pressure of 815 psia is assumed in the analysis. This pressure delays the opening of the Main Steam Safety Valves (MSSVs) and maximizes the peak RCS pressure.

The Steam Dump and Bypass System (SDBS), the Pressurizer Pressure Control System (PPCS), the Pressurizer Level Control System (PLCS) and the Power Operated Relief Valves (PORV) are assumed to be in the manual mode of operation. This assumption enhances the RCS pressure increase since the automatic operation of these systems mitigates the RCS pressure increase.

Auxiliary feedwater actuation analysis setpoint of 29.1% of steam generator wide range span is assumed in this analysis. This represents a Technical Specification actuation setpoint of 42.9% and includes a 13.8% uncertainty. The actuation signal activates a motor driven auxiliary feedwater pump and a steam driven auxiliary feedwater pump which deliver auxiliary feedwater to both steam generators. The motor driven pump's auxiliary feedwater reaches the steam generator 18.0 seconds after low steam generator level signal is initiated. This includes 14.5 seconds for the pump to accelerate to speed including all signal processing delays and 3.5 seconds for water to travel through piping and reach the steam generator.

The flow from the motor driven pump to each steam generator is controlled by a flow control valve installed in the "leg" connecting the pump to the steam generator. A minimum flow of 90 gpm through each leg is conservatively assumed in the analysis. It represents the Technical Specification limit on AFW flow rate of 160 gpm through the flow control valve and an uncertainty of 70 gpm.

The steam driven pump's auxiliary feedwater reaches the steam generator 58.0 seconds after Auxiliary Feedwater Actuation setpoint is reached. This includes 50 seconds required to open steam admission valves to the pump, 4.5 seconds for the pump to accelerate to speed and 3.5 seconds for water to travel through piping and reach the steam generator. The flow from the steam driven pump to each steam generator is also controlled by a flow control valve installed in the flow "leg" connecting the pump to the steam generator. A flow of 90 gpm through each leg is assumed in the analysis. It represents the Technical Specification limit on AFW flow rate of 160 gpm through the flow control valve and an uncertainty of 70 gpm.

In case of loss of AC at turbine trip, there is an additional delay time involved for the motor driven pump. It includes 10 seconds for the diesel generators to start and reach speed following the LOAC and 30 seconds for the motor driven pump to be loaded on line.

The assumptions made to maximize the boundary site dose are given in Table 2-2. During the event, two sources of radioactivity contribute to the site boundary dose. The initial activity in the steam generator and the activity associated with primary to secondary leakage. The leakage through the steam generator tubes is assumed to be the Technical Specification limit of 1.0 GPM. The initial primary and secondary activities are assumed to be at the Technical Specification limits of 1.0 μCi/gm and 0.1 μCi/gm, respectively. The analysis assumes that all of the initial activity in the steam generators and the primary activity due to the tube leakage are released to the atmosphere with a decontamination factor of 1.0, resulting in the maximum site boundary dose.

Results

The FLB event with Loss of AC (LOAC) power on turbine trip results in the maximum RCS pressure. This occurs because LOAC power causes the Reactor Coolant Pumps to coastdown. The reduced core flow decreases the rate of heat removal and, thus, maximizes the primary heatup and overpressurization. Thus, only the results of the FLB event with LOAC power on turbine trip are presented herein.

Figure 2-1 presents the results of the parametric study to determine the break size which leads to the highest RCS peak pressure. Figure 2-1 shows that, initially as the break size increases, so does the peak RCS pressure. This is due to faster water drainage out of the ruptured generator, which will cause a more rapid primary to secondary heat transfer rampdown. However, as the break size increases further, the greater steam relieving capacity of larger breaks once the ruptured steam generator feedwater nozzle uncovers will offset the faster heat transfer rampdown and will result in lower peak pressure. The highest peak pressure was obtained for a break size of 0.275 ft^2.

The sequence of events for a 0.275 ft^2 Feed Line Break downstream of the reverse flow check valve with LOAC on turbine trip is given in Table 2-3. Figures 2-2 through 2-7 present the transient behavior of core power, core average heat flux, RCS temperatures, RCS pressure, steam generator pressure and steam generator liquid inventory for 1800 seconds of transient.

A 0.275 ft^2 break in the main feedwater line is assumed to instantaneously terminate feedwater flow to both steam generators and establish critical flow from the steam generator nearest the break. During the first 24.6 seconds of the event, the absence of subcooled feedwater flow causes the secondary pressure and temperature to increase, which reduces the primary to secondary heat transfer. This causes the primary pressures and temperatures to increase. At 24.6 seconds, the liquid inventory in the ruptured steam generator is sufficiently depleted to cause a further rampdown in the heat transfer rate. This causes the primary pressure and temperature to rapidly increase and at the same time causes the secondary pressure to decrease.

The rapid increase in primary pressure initiates a High Pressurizer Pressure trip at 27.1 seconds. At 27.7 seconds, the pressure reaches 2500 psia, at which time the Pressurizer Safety Valves (PSVs) open to mititage the increase in primary pressure. At 28.4 seconds, the turbine stop valves close, increasing the secondary pressure. At 28.5 seconds, the CEAs begin to drop into the core, inserting negative reactivity which mitigates the primary heatup. However, at this time, the Reactor Coolant Pumps (RCPs) are assumed to initiate flow coastdown due to LOAC power on turbine trip. The rapid decrease in core flow slows down the rate of heat removal from the primary. At 28.6 seconds, the feed line break is uncovered and steam is discharged through the break, which mitigates the primary heatup. These competing effects results in a peak RCS pressure of 2749 psia at 31.2 seconds. The increase in secondary pressure is mitigated by the opening of the Main Steam Safety Valves in the undamaged and ruptured steam generator at 35.1 and 36.3 seconds respectively.

A low steam generator level in the undamaged steam generator initiates AFAS at 60.0 seconds. The AFW flow from the motor driven pump reaches the undamaged steam generator at 86.5 seconds. The AFW flow from the steam driven pump reaches the undamaged steam generator at 118.0 seconds. (It should be noted that AFW flow at these times would also have been fed to the ruptured steam generator but no credit was taken for this in the analysis.) The AFW flow in conjunction with the steam release through the break causes the secondary and primary temperatures and pressure to decrease.

At 188.5 seconds a Steam Generator Isolation Signal is generated. After appropriate delays, the Main Steam Isolation Valves (MISVs) close at 201.4 seconds. This causes the pressure in the undamaged steam generator to increase rapidly and the pressure in the ruptured steam generator to decrease. An AFW isolation signal based on steam generator differential pressure is initiated at 202.0 seconds and the AFW block (i.e., isolation) valve completely closes at 222.0 seconds.

The water level in the undamaged steam generator continues to decrease as a result of boil-off. At about 250.0 seconds the liquid inventory in the undamaged steam generator is sufficiently depleted that there is no heat transfer from primary to secondary. This causes the primary pressure and temperature to increase again. The increase in primary pressure results in the opening of PSVs at 579.5 seconds.

The analysis conservatively assumed that the operator takes the necessary action to increase AFW flow at 10 minutes following reactor trip. Thus, at 628.5 seconds, AFW flow is increased to the undamaged steam generator, which slowly reduces the primary heatup. The PSVs close at 688.0 seconds.

The resultant site boundary dose calculated with the assumptions given in Table 2-2 is:

Thyroid (DEQ I-131) = 2.2 REM

Conclusion

The results of the FLB event with LOAC power on turbine trip shows tht the peak pressure does not exceed the pressure upset limit of 2750 psia and that the site boundary doses are within 10CFR100 guidelines.

TABLE 2-1

KEY PARAMETERS ASSUMED IN THE FEEDWATER LINE BREAK ANALYSIS

Parameter	Units	Value
Initial Core Power Level	MWt	2754.0
Initial Core Coolant Inlet Temperature	^{o}F	550.0
Initial RCS Vessel Flow Rate	gpm	370,000.0
Initial Reactor Coolant System Pressure	psia	2154.0
Initial Steam Generator Pressure	psia	815.0
Initial Pressurizer Liquid Volume	ft	975.0
Effective Moderator Temperature Coefficient	$x10^{-4}\Delta\rho/^{o}F$	+0.2
Doppler Coefficient Multiplier	-----	0.85
High Pressurizer Pressure Analysis Trip Setpoint	psia	2467.4
Auxiliary Feedwater Actuation Analysis Setpoint	% Wide Range Steam Generator Level Indication	29.1
Steam Generator Differential Pressure Analysis Setpoint	psid	10.0
CEA Worth at Trip	$\%\Delta\rho$	-5.2
Reactor Regulating System	Operating Mode	Manual**
Steam Dump and Bypass System	Operating Mode	Manual**
Pressurizer Pressure Control System	Operating Mode	Manual**
Pressurizer Level Control System	Operating Mode	Manual**

**These modes of control system operation maximize the peak RCS pressure.

TABLE 2-2

ASSUMPTIONS FOR THE RADIOLOGICAL EVALUATION FOR
THE FEED LINE BREAK EVENT

Parameter	Units	Value
Reactor Coolant System Maximum Allowable Concentration (DEQ I-131)[1]	μCi/gm	1.0
Steam Generator Maximum Allowable Concentration (DEQ I-131)[1]	μCi/gm	0.1
Partition Factor Assumed for All Doses	----	1.0
Atmospheric Dispersion Coefficient[2]	sec/M^3	1.80×10^{-4}
Breathing Rate	M^3/sec	3.47×10^{-4}
Dose Conversion Factor (I-131)	REM/Ci	1.48×10^{6}

[1]Tech Spec limits

[2]0-2 hour accident condition

TABLE 2-3

SEQUENCE OF EVENTS FOR FEED LINE BREAK ANALYSIS
WITH LOAC FOLLOWING REACTOR TRIP

Time (sec)	Event	Setpoint or Value
0.0	Break in the Main Feedwater Line	0.275 ft^2
	Instantaneous Loss of All Feedwater Flow to Both Steam Generators	
24.6	Heat Transfer Rampdown Begins in the Ruptured Steam Generator	19691 lbm
27.1	High Pressurizer Pressure Trip Setpoint is Reached	2467.4 psia
27.7	Primary Safety Valves Open	2500 psia
28.0	Trip Breakers Open	
28.4	Turbine Stop Valves Close	
28.5	CEAs Begin to Drop Loss of AC Power on Turbine Power; Diesel Generators Start Coming On Line; RCPs Coastdown Begins	
28.6	Level in the Ruptured Steam Generator Goes Below the Assumed Nozzle Level Steam Will Be Blown Out of the Break	5000 lbm
31.2	Maximum RCS Pressure	2749* psia
35.1	Undamaged Steam Generator Safety Valves Open	1000 psia
36.3	Ruptured Steam Generator Safety Valves Open	1000 psia
38.5	Diesel Generators Reach Rated Speed and Voltage Following LOAC Power	
38.7	Maximum Steam Generator Pressure, Undamaged/Ruptured	1022/1009 psia
43.5	Primary Safety Valves Close	2400 psia

*Pressure Includes Elevation Head

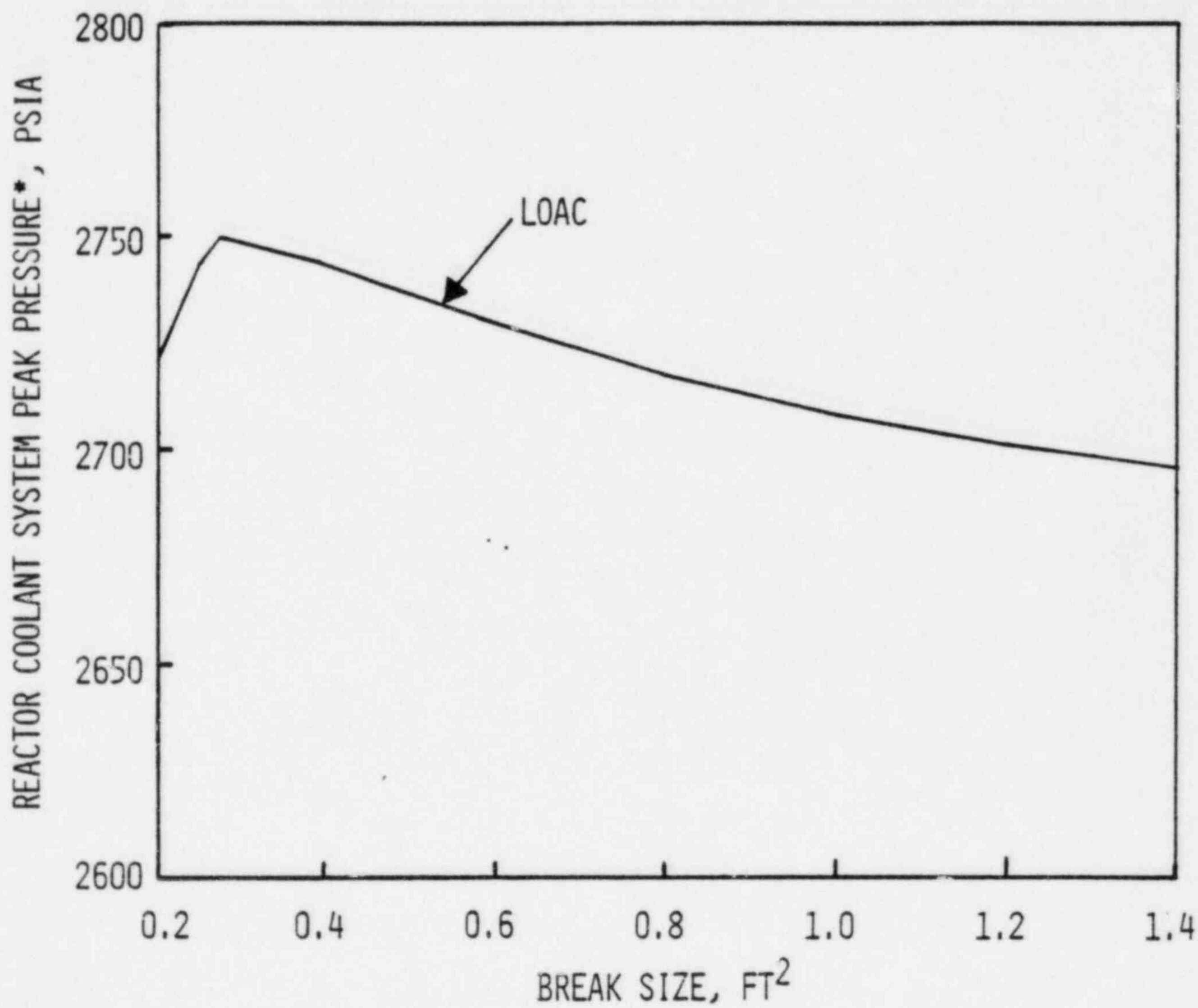
TABLE 2-3
(continued)

Time (sec)	Event	Setpoint or Value
55.5	Steam Generator Safeties are Closed	1000 psia
60.0	Auxiliary Feedwater Actuation Analysis Setpoint is Reached in Undamaged Steam Generator	29.1%**
68.5	Motor Driven AFW Pump is Loaded on Diesel Generator	
83.0	Motor Diven Auxiliary Feed Pump Reaches Rated Speed	
86.5	Motor Driven Auxiliary Feedwater Enters Undamaged S.G.	90.0 GPM
110.0	Steam Admission Valves to Steam Driven Auxiliary Feedwater Pump Open	
114.5	Steam Driven Auxiliary Pump Reaches Rated Speed	
118.0	Steam Driven Auxiliary Feedwater Flow Enters Undamaged Steam Generator	90.0 GPM
138.5	Heat Transfer Rampdown Begins in Undamaged Steam Generator	19691 lbm
188.5	Steam Generator Isolation Analysis Setpoint is Reached	600.0 psia
189.4	Main Steam Isolation Valves Start to Close	
201.4	Main Steam Isolation Valves are Completely Closed	
202.0	Steam Generator Differential Pressure Analysis Setpoint is Reached	$\Delta P = 10.0$ psid
222.0	AFW Block Valve Completely Closed	
250.0	Undamaged Steam Generator Empties	

**% of distance between steam generator wide range upper and lower level instrument taps.

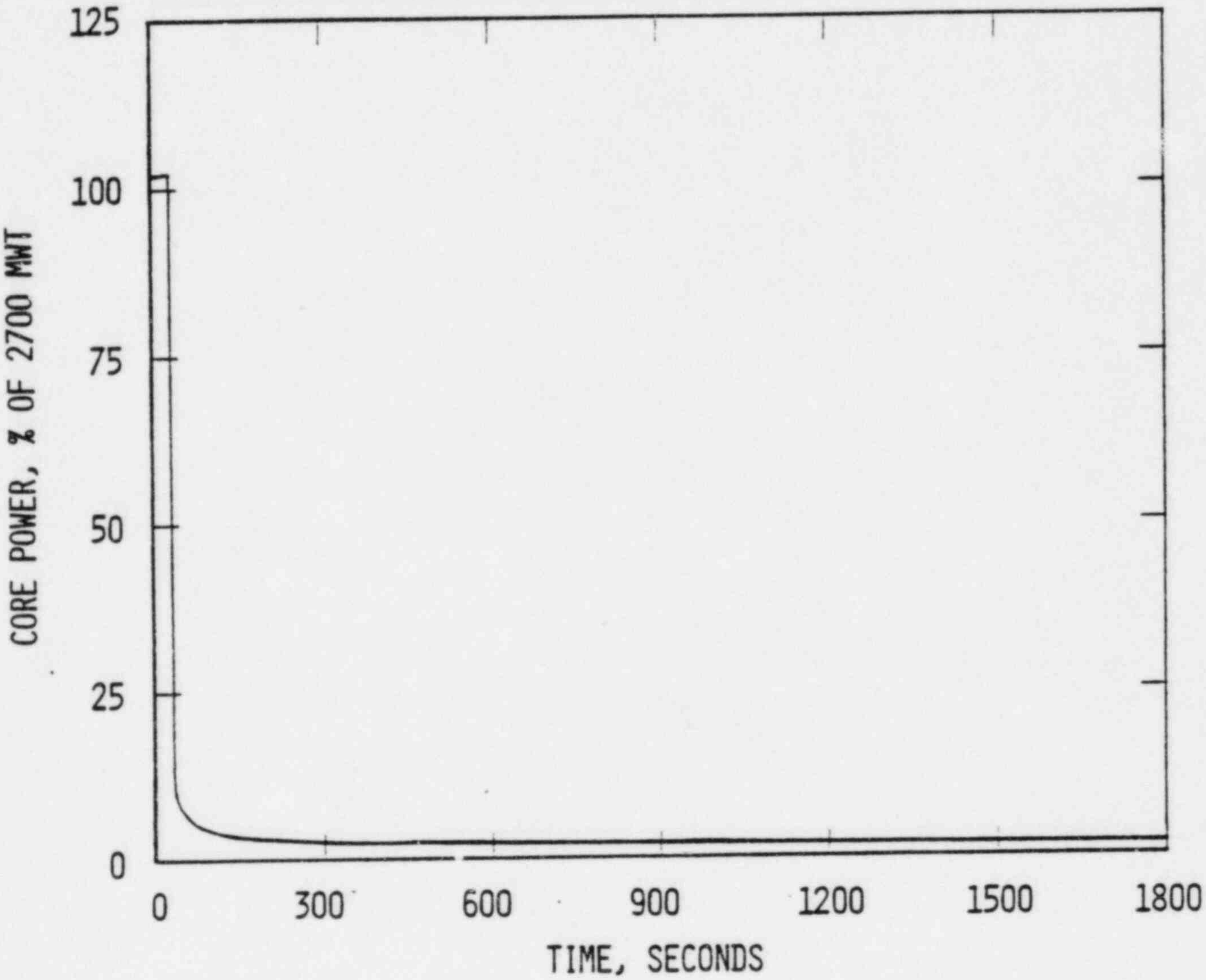
TABLE 2-3
(continued)

Time (sec)	Event	Setpoint or Value
445.0	Undamaged Steam Generator Safety Valves Open	1000.0 psia
519.5	Primary Safety Valves Open	2500.0 psia
628.5	Operator Increases Auxiliary Feedwater Flow to Undamaged Steam Generator	400.0 GPM
688.0	Primary Safety Valves Close	

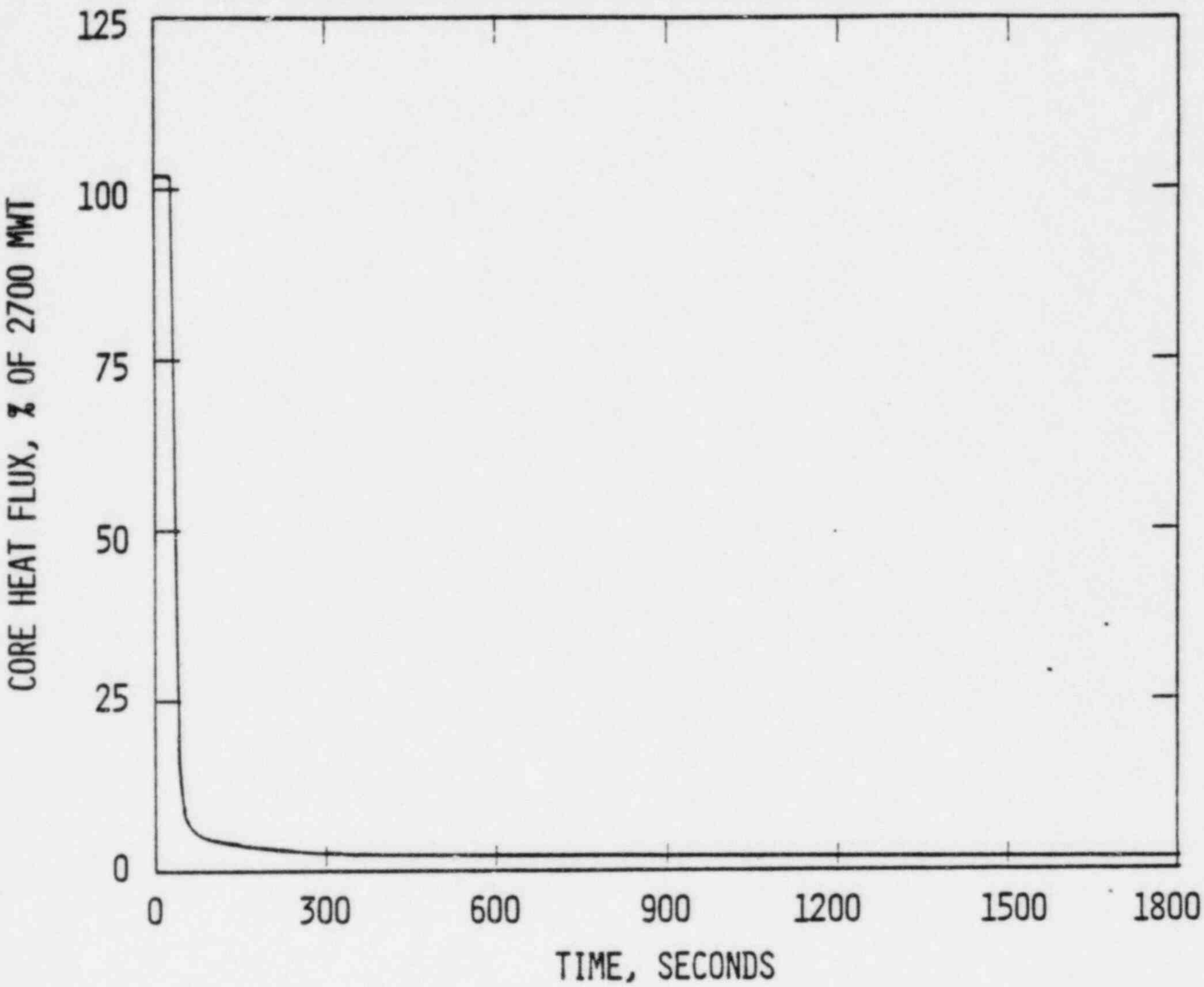


*PRESSURE INCLUDES ELEVATION HEAD

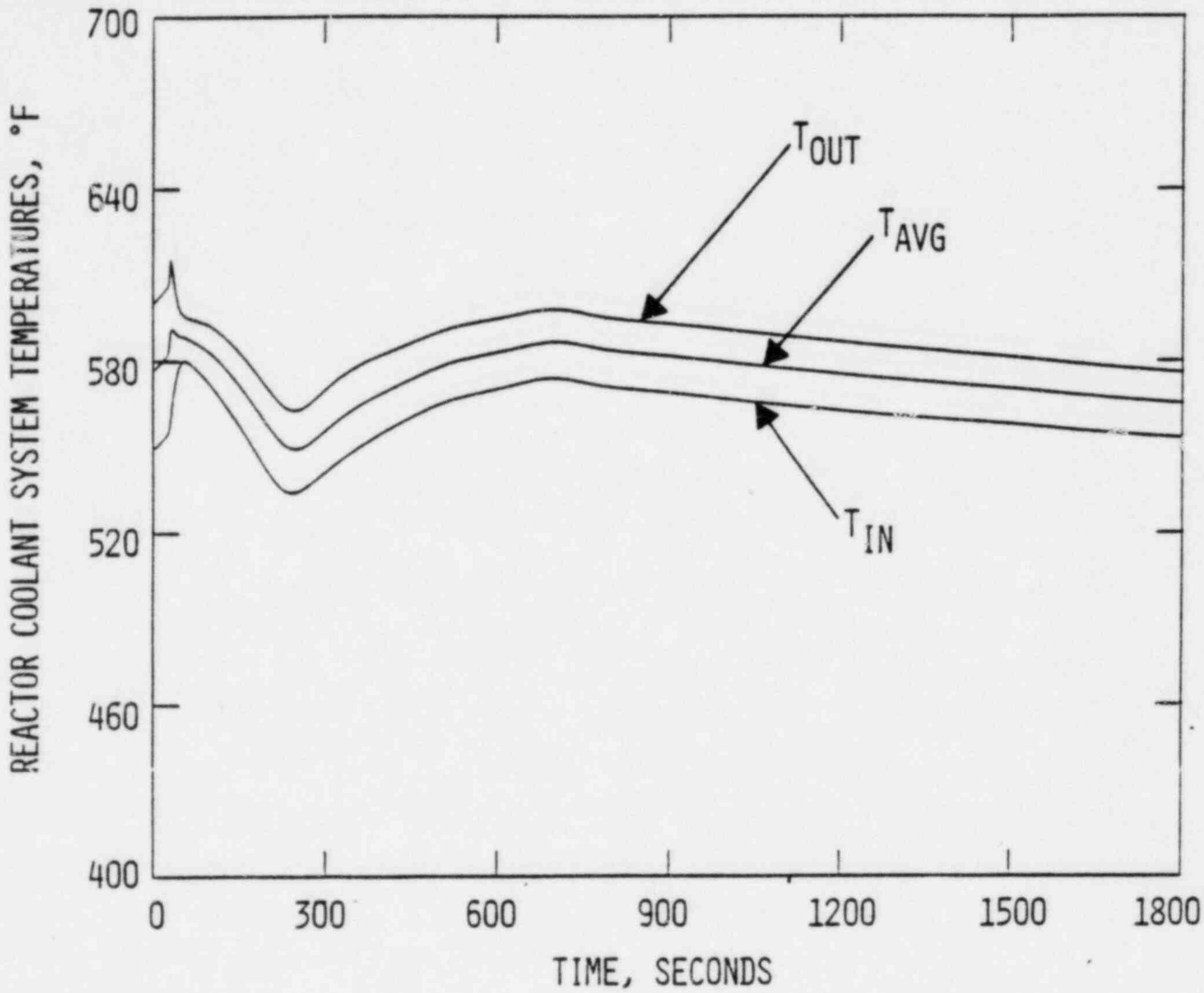
BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	FEED LINE BREAK EVENT REACTOR COOLANT SYSTEM PEAK PRESSURE VS BREAK SIZE	FIGURE 2-1



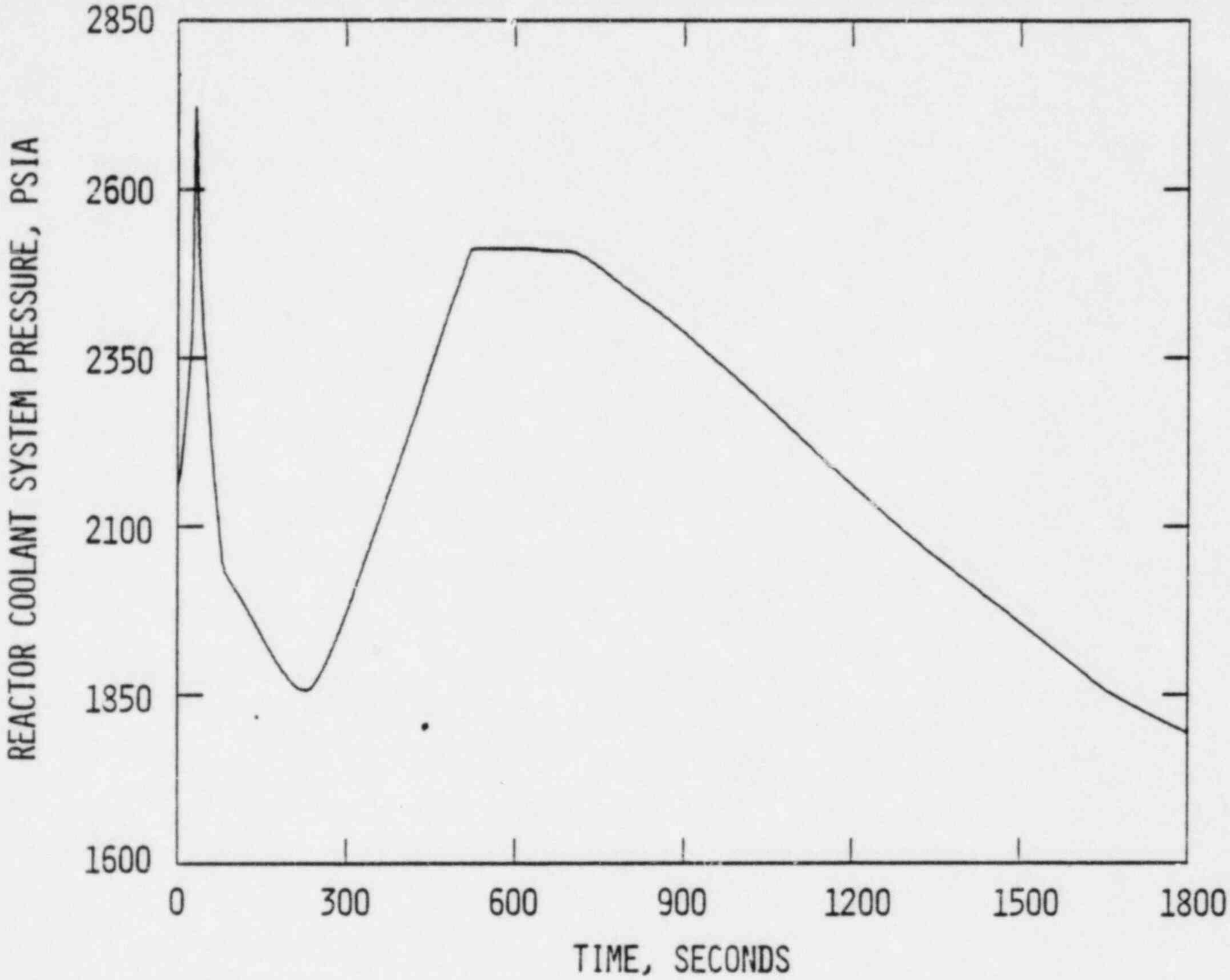
BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	FEED LINE BREAK EVENT WITH LOAC FOLLOWING REACTOR TRIP CORE POWER VS TIME	FIGURE 2-2



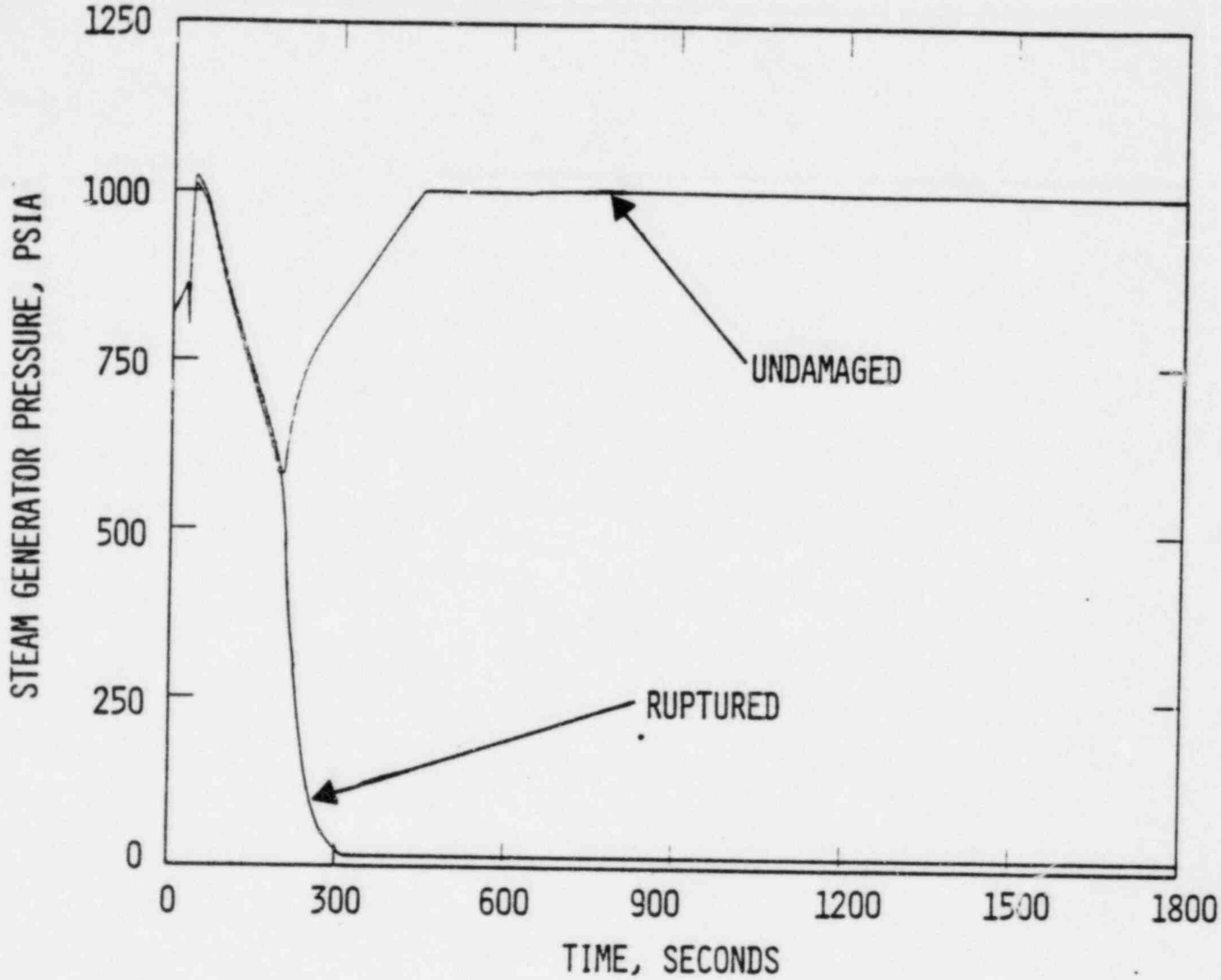
BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	FEED LINE BREAK EVENT WITH LOAC FOLLOWING REACTOR TRIP CORE HEAT FLUX VS TIME	FIGURE 2-3



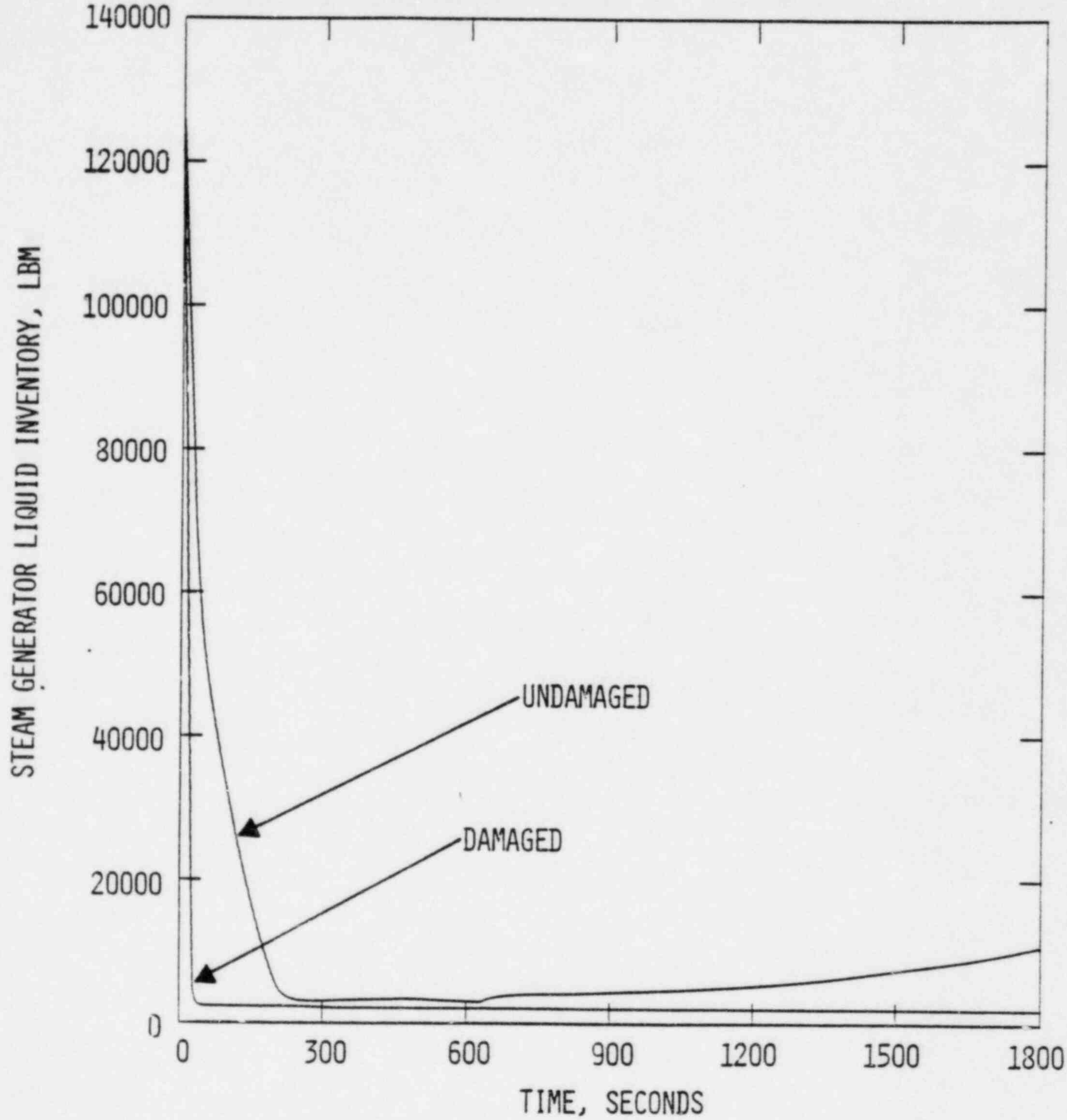
BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	FEED LINE BREAK EVENT WITH LOAC FOLLOWING REACTOR TRIP REACTOR COOLANT SYSTEM TEMPERATURES VS TIME	FIGURE 2-4



BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	FEED LINE BREAK EVENT WITH LOAC FOLLOWING REACTOR TRIP REACTOR COOLANT SYSTEM PRESSURE VS TIME	FIGURE 2-5



BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	FEED LINE BREAK EVENT WITH LOAC FOLLOWING REACTOR TRIP STEAM GENERATOR PRESSURE VS TIME	FIGURE 2-6



BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	FEED LINE BREAK EVENT WITH LOAC FOLLOWING REACTOR TRIP STEAM GENERATOR WATER INVENTORY VS TIME	FIGURE 2-7

3.0 Steam Line Break

Introduction

The Steam Line Break event was reanalyzed for Calvert Cliffs Unit 2 Cycle 5 to demonstrate that the post-trip minimum DNBR will not exceed the limit of 1.3 (MacBeth correlation) and that the site boundary doses will be within the 10CFR100 guidelines. The event was reanalyzed to incorporate the effects of the safety grade Auxiliary Feedwater Actuation Systeam (AFAS). This includes actuation of auxiliary feedwater based on wide range steam generator level indication and isolation logic to identify the ruptured steam generator based on steam generator differential pressure. A spectrum of steam line break sizes, both inside and outside containment initiated from Hot Full Power (HFP) and Hot Zero Power (HZP) were analyzed. In addition, the analysis was performed with and without Loss of AC (LOAC) power on turbine trip. The results of the limiting steam line break size, inside and outside containment is presented herein.

Analysis Assumptions and Initial Conditions

SLB Inside Containment

The HFP SLB event was initiated from the conditions listed in Table 3-1. The Moderator Temperature Coefficient (MTC) of reactivity assumed in the analysis corresponds to end of life, since this MTC results in the greatest positive reactivity change during the RCS cooldown caused by the Steam Line Rupture. Since the reactivity change associated with moderator feedback varies significantly over the moderator density covered in the analysis, a curve of reactivity insertion versus density rather than a single value of MTC, is assumed in the analysis. The moderator cooldown curve assumed in the analysis is given in Figure 3-1. This moderator cooldown curve was conservatively calculated assuming that on reactor scram the Control Element Assembly is stuck in the fully withdrawn position which yields the most severe combination of scram worth and reactivity insertion.

The reactivity defect associated with the fuel temperature decrease is also based on an end of life Doppler defect. The Doppler defect based on an end of life Fuel Temperature Coefficient (FTC), in conjunction with the decreasing fuel temperatures, causes the greatest positive reactivity insertion during the Steam Line Rupture event. The uncertainty on the FTC assumed in the analysis is given in Table 3-1. The β fraction assumed is the maximum absolute value including uncertainties for end of life conditions. This too is conservative since it maximizes subcritical multiplication and thus, enhances the potential for Return-To-Power (R-T-P). The analysis also assumed a conservatively low value of boron reactivity worth of -1.0%$\Delta\rho$ per 95 PPM for safety injection flow from the High and Low Pressure Safety Injection pumps.

The minimum CEA worth assumed to be available for shutdown at the time of reactor trip at the maximum allowed power level is 6.89%$\Delta\rho$. This available scram worth was calculated for the stuck rod which produced the moderator cooldown curve in Figure 3-1.

During a return-to-power, negative reactivity credit was assumed in the analysis. This negative reactivity credit is due to the local heatup of the inlet fluid in the hot channel, which occurs near the location of the stuck CEA. This credit is based on three-dimensional coupled neutronic-thermal-hydraulic calculations performed with the HERMITE/TORC code (References 9 and 10) for St. Lucie Unit 2 Cycle 1 (Reference 11). It should be noted that only a small fraction of the negative reactivity credit justified for St. Lucie Unit 2 was included in the SLB event analysis for Calvert Cliffs Unit 2 Cycle 5.

The analysis only credited the low steam generator pressure trip. An analysis trip setpoint of 600.0 psia was assumed in the analysis. This represents the Technical Specification setpoint of 685.0 psia and an uncertainty of 85.0 psia. The analysis also assumed that a Steam Generator Isolation Signal (SGIS) is generated when secondary pressure reaches 600.0 psia. This represents the Technical Specification setpoint of 685.0 psia and an uncertainty of 85.0 psia. A Main Steam Isolation Valve (MSIV) closure time of 12.9* seconds (includes valve closure time and signal processing delay time) was conservatively assumed in the analysis.

The analysis conservatively assumed that following reactor trip, the main feedwater flow is ramped down to 8% of full power feedwater flow in 20 seconds and that the main feedwater isolation valves are completely closed in 80 seconds after a low steam generator pressure or a main steam isolation signal. These assumptions are consistent with Technical Specification limits.

The analysis assumptions regarding auxiliary feedwater actuation analysis setpoint, the associated time delays, and the AFW flow through eachg leg are given below. They were conservatively chosen to initiate AFW flow sooner and deliver the maximum AFW flow to the ruptured steam generator, which maximizes the primary cooldown and enhances the potential R-T-P.

An auxiliary feedwater actuation analysis setpoint of 60.9% of steam generator wide range span is assumed in this analysis. This represents a Technical Specification actuation setpoint of 54.4% and includes a 6.5% uncertainty. The actuation signal activates a motor driven auxiliary feedwater pump and a steam driven auxiliary feedwater pump which deliver auxiliary feedwater to both steam generators. The motor driven pump's auxiliary feedwater flow reaches the steam generator 9.5 seconds after low steam generator level signal is initiated. This is the minimum time delay associated with the motor driven pump to accelerate to full speed and other signal processing delay times. The analysis conservatively assumed that the AFW flow legs are filled with water and, thus, no time delay associated with AFW flow through the piping was included in the analysis.

The flow from the motor driven pump to each steam generator is controlled by a flow control valve installed in the "leg" connecting the pump to the steam generator. A maximum flow of 217 gpm through each leg is conservatively assumed in the analysis. It represents the Technical Specification limit on AFW flow rate of 160 gpm through the flow control valve and an uncertainty of 57 gpm.

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*Conservative with respect to Technical Specification limit

The steam driven pump's auxiliary feedwater reaches the steam generator 9.5 seconds after auxiliary feedwater actuation setpoint is reached. This includes a minimum time delay of 5.0 seconds required to open steam admission valves to the AFW pump, and 4.5 seconds for the pump to accelerate to speed. The analysis conservatively assumed that the AFW flow legs are filled with water and, thus, no time delay associated with AFW flow through the piping was included in the analysis. The flow from the steam driven pump to each steam generator is also controlled by a flow control valve installed in the flow "leg" connecting the pump to the steam generator. A minimum flow of 217 gpm through each leg is assumed in the analysis. It represents the Technical Specification limit on AFW flow rate of 160 gpm throught the flow control valve and an uncertainty of 57 gpm.

In case of loss of AC power on turbine trip, there is an additional delay time involved for the motor driven pump. It includes 10 seconds for the diesel generators to start and reach speed following the LOAC and 15.0 seconds for the motor driven AFW pump to be loaded on line if shutdown sequencer is initiated. A 30.0 second time delay is assumed for the motor driven AFW pump to be loaded on line if the LOCA sequencer is initiated. The LOCA sequencer is initiated when SIAS is generated.

The analysis also included isolation of the ruptured steam generator when the steam generator differential pressure reached the analysis setpoint of 250.0 psid. This represents a Technical Specification setpoint of 130.0 psid and an uncertainty of 120.0 psid. In addition, a 20.0 second time delay was assumed in the analysis to close the AFW isolation (i.e., block) valves. These assumptions are conservative since it delays the isolation of AFW to the ruptured steam generator.

A safety injection actuation analysis setpoint of 1645.0 psia was assumed in the analysis. This represents a Technical Specification setpoint of 1725.0 psia and an uncertainty of 80.0 psia. The analysis conservatively assumed that on a Safety Injection Actuation Signal (SIAS), only one High Pressure Safety Injection (HPSI) pump starts. In addition, a maximum time delay of 30 seconds for HPSI pumps to accelerate to full speed was assumed in the analysis. In case of LOAC power, additional time delays are included in the analysis. It includes 10.0 seconds for the diesel generators to start and reach speed following the LOAC and 5.0 seconds for the HPSI pump to be loaded on line regardless of which sequencer (i.e., shutdown or LOCA) is initiated.

The HZP inside containment SLB event was initiated at the conditions given in Table 3-2. The moderator cooldown curve is given in Figure 3-2. The cooldown curve corresponds to an end of life MTC. An end of life FTC was also used for the reasons previously discussed in connection with the HFP SLB event. The minimum CEA worth assumed to be available for shutdown at the time of reactor trip at the zero power level is 5.2% $\Delta\rho$. This available scram worth was calculated for the stuck rod which produced the moderator cooldown curve in Figure 3-2. The maximum inverse boron worth of 90 PPM/% $\Delta\rho$ was conservatively assumed for the safety injection flow during the HZP SLB event.

The post-trip minimum DNBR for both the HFP and HZP inside containment SLBs were calculated using the MacBeth correlation (Reference 4) with the Lee non-uniform mixing correlation factor (Reference 5).

SLB Outside Containment

The HFP and HZP outside containment SLB events were initiated from conditions listed in Tables 3-3 and 3-4, respectively. All assumptions except for the moderator cooldown curve, the initial primary pressure, and the reactor trip credited in the analysis are identical to those for the inside containment SLB event. The reasons for these differences are given below.

The moderator cooldown curve assumed in the analysis is given in Figure 3-3. This cooldown curve corresponds to an effective MTC of $-2.5 \times 10^{-4}\ \Delta\rho\ /{}^{o}F$ in comparison to the EOC Technical Specification MTC limit of $-2.2 \times 10^{-4}\ \Delta\rho\ /{}^{o}F$. An effective MTC of $-2.5 \times 10^{-4}\ \Delta\rho\ /\ {}^{o}F$ was used in the outside containment SLB event analysis to envelope future cycles.

An initial primary pressure of 2154 psia was conservatively assumed in the analysis. This represents the minimum Technical Specification allowed pressure of 2200 psia and an uncertainty of 46.0 psia. The lower initial pressure results in lower primary pressures at time of minimum DNBR and, thus, a lower minimum DNBR during the event.

For a SLB outside containment, a reactor trip on either Thermal Margin/Low Pressure (TM/LP), low stem generator pressure or high power is credited in the anlaysis.

The assumptions made to maximize the site boundary dose are given in Table 3-5. During the event, two sources of radioactivity contribute to the site boundary dose; the initial activity in the steam generator and the activity associated with primary to secondary leakage. The primary activity which leaked through the tubes included the initial activity in the primary allowed by the Technical Specifications and activity released to the coolant due to any additional fuel failure. The analysis conservatively assumed that all fuel pins with minimum DNBR below the design limit of 1.23 (CE-1 correlation) failed. The minimum DNBR during the transient was calculated using the thermal-hydraulic code CETOP (Reference 6). In calculating the site boundry dose, the analysis conservatively assumed that all activity is released to the atmosphere with a decontamination factor of 1.0.

Results

SLB Inside Containment

The SLB event with Loss of AC (LOAC) power on turbine trip results in the maximum post trip R-T-P and, thus, the minimum post trip transient DNBR. This occurs because LOAC power causes the Reactor Coolant Pumps (RCPs) to coastdown. The decreasing coolant flow is asssumed to result in no flow mixing at the core inlet plenum. Thus, cold edge temperatures were used to calculate the moderator reactivity insertion. This resulted in more positive reactivity being inserted and produced the maximum post trip

R-T-P. In addition, the lower core flows resulted in minimizing the transient minimum DNBR.

The results of the parametric analysis in break size indicated that the largest break size resulted in the maximum post trip R-T-P and, thus, the minimum post trip DNBR. This occurs because the largest break size caused the greatest temperature reduction and, thus, inserted the greatest magnitude of positvie reactivity due to moderator reactivity feedback. This resulted in a higher R-T-P and minimum post trip DNBR. Therefore, the results of the largest inside containment SLB with LOAC on turbine trip are presented herein.

The sequence of events for the 6.305 ft^2 SLB with LOAC on turbine trip initiated from HFP conditions is given in Table 3-6. The reactivity insertion as a function of time is presented in Figure 3-4. The NSSS responses during the transient are given in Figures 3-5 through 3-9.

The results of the analysis show that the HFP SLB causes the secondary pressure to rapidly decrease until a reactor trip on low steam generator pressure is initiated at 1.7 seconds. The CEAs drop into the core at 3.1 seconds and terminate the power and heat flux increases.

A LOAC power on turbine trip is assumed to occur at 3.1 seconds. At this time, RCPs start coasting down and the diesel generators start coming on line. At 13.1 seconds, the diesel generators reach full speed and shutdown sequencer is initiated to load emergency systems. At 17.7 seconds the safety injection actuation analysis setpoint is reached and diesel generators switch from shutdown sequencer to LOCA sequencer to load emergency systems. At 22.7 seconds HPSI pump is loaded on line and at 52.7 seconds the HPSI pump reaches full speed.

The Steam Generator Isolation Analysis Setpoint is reached at 1.7 seconds. At 2.6 seconds, the MSIVs begin to close and are completely closed at 14.6 seconds. The blowdown from the intact steam generator is terminated at this time.

An AFW isolation signal based on steam generator differential pressure is initiated at 2.9 seconds. At 22.9 seconds, the AFW block valve associated with the steam generator with lowest pressure (i.e., ruptured steam generator) is completely closed.

At 13.4 seconds, an AFAS is generated based on low steam generator level. The steam admission valve to the AFW pump is opened at 18.4 seconds and the steam driven AFW pump reaches full speed and delivers AFW flow to the intact steam generator at 22.9 seconds. The motor driven AFW pump is loaded on line by diesel generators at 47.7 seconds and is assumed to reach full speed and deliver AFW flow to the intact steam generator instantaneously.

The continued blowdown from the ruptured steam generators causes the core reactivity to approach criticality. The ruptured steam generator blows dry at 100.5 seconds, which terminates the cooldown of the RCS. A peak reactivity of -0.044% at 131.4 seconds is obtained. A peak R-T-P of 8.6%, consisting of 5.2% fission power and 3.4% decay power, is produced at 136.8 seconds. A transient minimum DNBR of 1.31 at 136.8 seconds is obtained.

The negative reactivity inserted due to boron injection via the HPSI pump terminates the approach to criticality and the core becomes more subcritical.

The sequence of events for the 6.305 ft^2 SLB with LOAC on turbine trip initiated from HZP conditions is given in Table 3-7. The reactivity insertion as a function of time is presented in Figure 3-10. The NSSS response during the transient are given in Figures 3-11 through 3-15.

The results of the analysis show that the HZP SLB causes the secondary pressure to rapidly decrease until a reactor trip on low steam generator pressure is initiated at 1.5 seconds. The CEAs drop into the core at 2.9 seconds and terminate the power and heat flux increases.

A LOAC power turbine trip is assumed to occur at 2.9 seconds. At this time, RCPs start coasting down and the diesel generators start coming on line. At 12.9 seconds, the diesel generators reach full speed and shutdown sequencer is initiated to load emergency systems. At 22.4 seconds, the safety injection actuation analysis setpoint is reached and the diesel generators switch from shutdown sequencer to LOCA sequencer to reload the emergency systems. At 27.4 seconds, the diesel generators load the HPSI pump on line and 30.0 seconds later (i.e., at 57.4 seconds) the HPSI pump reaches full speed.

The Steam Generator Isolation Analysis Setpoint is reached at 1.5 seconds. At 2.4 seconds, the MSIVs begin to close and are completely closed at 14.4 seconds. The blowdown from the intact steam generator is terminated at this time.

At 11.1 seconds, an AFAS is generated based on low steam generator level. The steam admission valve at the AFW pump is opened at 16.1 seconds and the steam driven AFW pump reaches full speed and delivers AFW flow to both steam generators at 20.5 seconds.

An AFW isolation signal based on steam generator differential pressure is initiated at 3.1 seconds. At 23.1 seconds, the AFW block valve associated with the steam generator with lowest pressure (i.e., ruptured steam generator) is completely closed. AFW flow to the ruptured steam generator is terminated. The motor driven AFW pump is loaded on line by diesel generators at 52.4 seconds and is assumed to reach full speed and deliver AFW flow to the intact steam generator instantaneously.

The continued blowdown from the ruptured steam generators causes the core reactivity to approach criticality. The ruptured steam generator blows dry at 98.5 seconds, which terminates the cooldown of the RCS. A peak reactivity of $-0.075\%\Delta\rho$ at 150.0 seconds is obtained. No R-T-P occurs and consequently, critical heat fluxes are not exceeded.

The negative reactivity inserted due to boron injection via the HPSI pump terminates the approach to criticality and the core becomes more subcritical.

SLB Outside Containment

The outside containment SLB event with LOAC power on turbine trip initiated from HFP resulted in the maximum site boundary dose. This occurs because the LOAC power causes RCPs to coastdown and minimizes the core flow following turbine trip. The lower core flows result in a lower transient DNBR which maximizes the predicted number of fuel pin failures.

The results of the parametric analysis in break sizes indicated that a 0.33 ft^2 SLB resulted in the maximum number of predicted fuel pin failures. This break size is limiting since it delays the time of reactor trip on high power and thereby maximizes the power and heat flux overshoot after trip. The higher peak heat flux resulted in minimizing the DNBR and, thus, maximizing the fuel failure. Therefore, the results of the 0.33 ft^2 SLB outside containment with LOAC on turbine trip initiated from HFP is presented herein.

The sequence of events for a 0.33 ft^2 SLB outside containment with LOAC on turbine trip initiated from HFP conditions is given in Table 3-8. The reactivity insertion as a function of time is presented in Figure 3-16. The NSSS response during the transient are given in Figures 3-17 through 3-21.

The results of the analysis show that the SLB causes the core power to rapidly increase until a reactor trip on high power is initiated at 14.7 seconds. The CEAs drop into the core at 15.6 seconds and terminate the power and heat flux increases.

A LOAC power on turbine trip is assumed to occur at 15.6 seconds. At this time, RCPs start coasting down and the diesel generators start coming on line. At 25.6 seconds, the diesel generators reach full speed and shutdown sequencer is initiated to load emergency systems. At 30.6 seconds, the HPSI pump is loaded on line and at 40.6 seconds, the motor driven AFW pump is loaded on line.

At 15.7 seconds, an AFAS is generated based on low steam generator level. The steam admission valve to the AFW pump is opened at 20.7 seconds, and the steam driven AFW pump reaches full speed and delivers AFW flow to both steam generators at 25.2 seconds. The motor driven AFW pump is loaded on line by diesel generators at 40.6 seconds and is assumed to reach full speed and deliver AFW flow to both steam generators instantaneously.

The Steam Generator Isolation Analysis Setpoint is reached at 88.5 seconds. At 89.4 seconds, the MSIVs begin to close and are completely closed at 101.4 seconds. The blowdown from the intact steam generator is terminated at this time.

An AFW isolation signal based on steam generator differential pressure is initiated at 172.0 seconds. At 192.0 seconds, the AFW block valve associated with the steam generator with lowest pressure (i.e., ruptured steam generator) is completely closed. Thus, AFW flow to ruptured steam generator is terminated, while AFW flow to intact steam generator continues.

The 0.33 ft^2 SLB outside containment shows that 2.0% of fuel pins experience DNB. The resultant site boundary dose is:

Thyroid (DEQ I-131) = 67.0 REM
Whole Body (DEQ Xe-133) = 0.055 REM

Conclusions

The results of the Steam Line Break inside containment shows that post-trip minimum DNBR is above the design limit of 1.3. The SLB outside containment results in a site boundary dose which is within 10CFR100 guidelines. Therefore, the results of the inside and outside containment SLB events with LOAC power on turbine trip is acceptable for Unit 2 Cycle 5.

TABLE 3-1

KEY PARAMETERS ASSUMED IN THE INSIDE CONTAINMENT
STEAM LINE BREAK EVENT INITIATED FROM HFP

Parameter	Units	Cycle 5
Initial Core Power	MWt	2754.0
Initial Core Inlet Temperature	^{o}F	550.0
Initial RCS Pressure	psia	2300.0
Initial Steam Generator Pressure	psia	860.0
Low Steam Generator Pressure Analysis Trip Setpoint	psia	600.0
Auxiliary Feedwater Actuation Analysis Setpoint	% Wide Range Steam Generator Level Indication	60.9
Steam Generator Differential Pressure Analysis Setpoint	psid	250.0
Safety Injection Actuation Signal	psia	1645.0
Minimum CEA Worth Available at Trip	% $\Delta\rho$	-6.89
Doppler Multiplier		1.15
Moderator Cooldown Curve	% vs. density	See Figure 3-1
Inverse Boron Worth	PPM/% $\Delta\rho$	95.0
Effective MTC	$x10^{-4}\ \Delta\rho/^{o}F$	-2.2
β Fraction (including uncertainty)		.0060

TABLE 3-2

KEY PARAMETERS ASSUMED IN THE INSIDE CONTAINMENT
STEAM LINE BREAK EVENT INITIATED FROM HZP

Parameter	Units	Cycle 5
Initial Core Power	MWt	1.0
Initial Core Inlet Temperature	^{o}F	532.0
Initial RCS Pressure	psia	2300.0
Initial Steam Generator Pressure	psia	900.0
Low Steam Generator Pressure Analysis Trip Setpoint	psia	600.0
Auxiliary Feedwater Actuation Analysis Setpoint	% Wide Range Steam Generator Level Indication	60.9
Steam Generator Differential Pressure Analysis Setpoint	psid	250.0
Safety Injection Actuation Signal	psia	1645.0
Minimum CEA Worth Available at Trip	$\%\Delta\rho$	-5.2
Doppler Multiplier		1.15
Moderator Cooldown Curve	% vs. density	See Figure 3-2
Inverse Boron Worth	PPM/$\%\Delta\rho$	90.0
Effective MTC	$x10^{-4}\Delta\rho/^{o}F$	-2.2
β Fraction (including uncertainty)		.0060

TABLE 3-3

KEY PARAMETERS ASSUMED IN THE OUTSIDE CONTAINMENT STEAM LINE BREAK EVENT INITIATED FROM HFP

Parameter	Units	Cycle 5
Initial Core Power	MWt	2754.0
Initial Core Inlet Temperature	^{o}F	550.0
Initial RCS Pressure	psia	2154.0
Initial Steam Generator Pressure	psia	860.0
Low Steam Generator Pressure Analysis Trip Setpoint	psia	600.0
Auxiliary Feedwater Actuation Analysis Setpoint	% Wide Range Steam Generator Level Indication	60.9
Steam Generator Differential Pressure Analysis Setpoint	psid	250.0
Safety Injection Actuation Signal	psia	1645.0
Minimum CEA Worth Available at Trip	$\%\Delta\rho$	-6.89
Doppler Multiplier		1.15
Moderator Cooldown Curve	% vs. density	See Figure 3-3
Inverse Boron Worth	PPM/% $\Delta\rho$	95.0
Effective MTC	$x10^{-4}\Delta\rho/^{o}F$	-2.5
β Fraction (including uncertainty)		.0060

TABLE 3-4

KEY PARAMETERS ASSUMED IN THE OUTSIDE CONTAINMENT STEAM LINE BREAK EVENT INITIATED FROM HZP

Parameter	Units	Cycle 5
Initial Core Power	MWt	1.0
Initial Core Inlet Temperature	°F	532.0
Initial RCS Pressure	psia	2154.0
Initial Steam Generator Pressure	psia	900.0
Low Steam Generator Pressure Analysis Trip Setpoint	psia	600.0
Auxiliary Feedwater Actuation Analysis Setpoint	% Wide Range Steam Generator Level Indication	60.9
Steam Generator Differential Pressure Analysis Setpoint	psid	250.0
Safety Injection Actuation Signal	psia	1645.0
Minimum CEA Worth Available at Trip	$\%\Delta\rho$	-5.2
Doppler Multiplier		1.15
Moderator Cooldown Curve	% vs. density	See Figure 3-2
Inverse Boron Worth	PPM/$\%\Delta\rho$	90.0
Effective MTC	$x 10^{-4} \Delta\rho /^{\circ}F$	-2.5
β Fraction (including uncertainty)		.0060

TABLE 3-5

ASSUMPTIONS FOR THE RADIOLOGICAL EVALUATION FOR THE STEAM LINE BREAK EVENT

Parameter	Units	Value
Reactor Coolant System Maximum Allowable Concentration (DEQ I-131)[1]	μCi/gm	1.0
Steam Generator Maximum Allowable Concentration (DEQ I-131)[1]	μCi/gm	0.1
Partition Factor Assumed for All Doses	----	1.0
Atmospheric Dispersion Coefficient[2]	sec/M^3	1.80×10^{-4}
Breathing Rate	M^3/sec	3.47×10^{-4}
Dose Conversion Factor (I-131)	REM/Ci	1.48×10^{6}

[1]Tech Spec limits

[2]0-2 hour accident condition

TABLE 3-6

SEQUENCE OF EVENTS FOR INSIDE CONTAINMENT
STEAM LINE BREAK EVENT WITH
LOSS OF AC POWER ON TURBINE TRIP INITIATED FROM HFP

Time (sec)	Event	Setpoint or Value
0.0	Steam Line Break Occurs	6.305 ft^2
1.7	Low Steam Generator Pressure Analysis Trip Setpoint is Reached; Steam Generator Isolation Analysis Setpoint is Reached	600.0 psia
2.6	Trip Breakers Open; Main Steam Isolation Valves Begin to Close; Main Feedwater Isolation Valves Begin to Close	
2.9	Steam Generator Differential Pressure Analysis Setpoint is Reached	ΔP = 250.0 psid
3.1	CEAs Enter Core; Loss of AC Power on Turbine Trip; RCPs Coastdown Begins; Diesel Generator Start Coming On Line; Main Feedwater Rampdown Begins	
13.1	Diesel Generators Reach Rated Speed Following LOAC Power; Shutdown Sequencer Initiated	
13.4	Auxiliary Feedwater Actuation Analysis Setpoint is Reached	60.9%**
14.6	Main Steam Isolation Valves Completely Closed	---
17.7	Safety Injection Actuation Analysis Setpoint is Reached; LOCA Sequencer Initiated	1645.0 psia
18.4	Steam Admission Valves to Steam Driven AFW Pump Completely Open	
19.7	Pressurizer Empties	---

**% of distance between steam generator wide range upper and lower level instrument taps.

TABLE 3-6
(continued)

Time (sec)	Event	Setpoint or Value
22.7	Power Provided to High Pressure Safety Injection Pumps	
22.9	AFW Block Valve Completely Closed; Steam Driven AFW Pump at Full Speed and Delivers AFW Flow to Intact Steam Generator	217.0 gpm
23.1	Main Feedwater Rampdown Completed	8% of Full Power Feedwater Flow
47.7	Power Provided to Motor Driven AFW Pump	
47.7	Motor Driven AFW Pump at Full Speed and Delivers AFW Flow to Intact Steam Generator	217.0 gpm
52.7	High Pressure Safety Injection Pump at Full Speed	---
82.6	Main Feedwater Isolation Valve Completely Closed	---
100.5	Affected Steam Generator Blows Dry	---
131.4	Peak Reactivity	$-0.044\%\Delta\rho$
136.8	Peak Return to Power	8.6% of 2700 MWt

TABLE 3-7

SEQUENCE OF EVENTS FOR INSIDE CONTAINMENT
STEAM LINE BREAK EVENT WITH
LOSS OF AC POWER ON TURBINE TRIP INITIATED FROM HZP

Time (sec)	Event	Setpoint or Value
0.0	Steam Line Break Occurs	6.305 ft^2
1.5	Low Steam Generator Pressure Analysis Trip Setpoint is Reached; Steam Generator Isolation Analysis Setpoint is Reached	600.0 psia
2.4	Trip Breakers Open; Main Steam Isolation Valves Begin to Close; Main Feedwater Isolation Valves Begin to Close	---
2.9	CEAs Enter Core; Loss of AC Power on Turbine Trip; RCPs Coastdown Begins; Diesel Generators Start Coming On Line	
3.1	Steam Generator Differential Pressure Analysis Setpoint is Reached	ΔP = 250.0 psid
11.1	Auxiliary Feedwater Actuation Analysis Setpoint is Reached	60.9%**
12.9	Diesel Generators Reach Rated Speed Following LOAC Power; Shutdown Sequencer Initiated	
14.4	Main Steam Isolation Valves Completely Closed	---
16.1	Steam Admission Valves to Steam Driven AFW Pump Completely Open	---
20.6	Steam Driven Auxiliary Feedwater Pump at Full Speed and Delivers AFW Flow to Both Steam Generators	217.0 gpm/S.G.

**% of distance between steam generator wide range upper and lower level instrument taps.

TABLE 3-7
(continued)

Time (sec)	Event	Setpoint or Value
22.4	Safety Injection Actuation Analysis Setpoint is Reached LOCA Sequencer Initiated	1645.0 psia
23.1	AFW Block Valve Completely Closed; AFW Flow to Ruptured Steam Generator is Terminated	---
27.4	Power Provided to HPSI Pump	
28.9	Pressurizer Empties	
52.4	Power Provided to Motor Driven AFW Pump; Motor Driven AFW Pump Reaches Full Speed and Delivers AFW Flow to Intact Steam Generator	217.0 gpm
57.4	High Pressure Safety Injection Pump Reaches Full Speed	---
98.5	Affected Steam Generator Blows Dry	---
150.0	Peak Reactivity	-0.075%$\Delta\rho$

TABLE 3-8

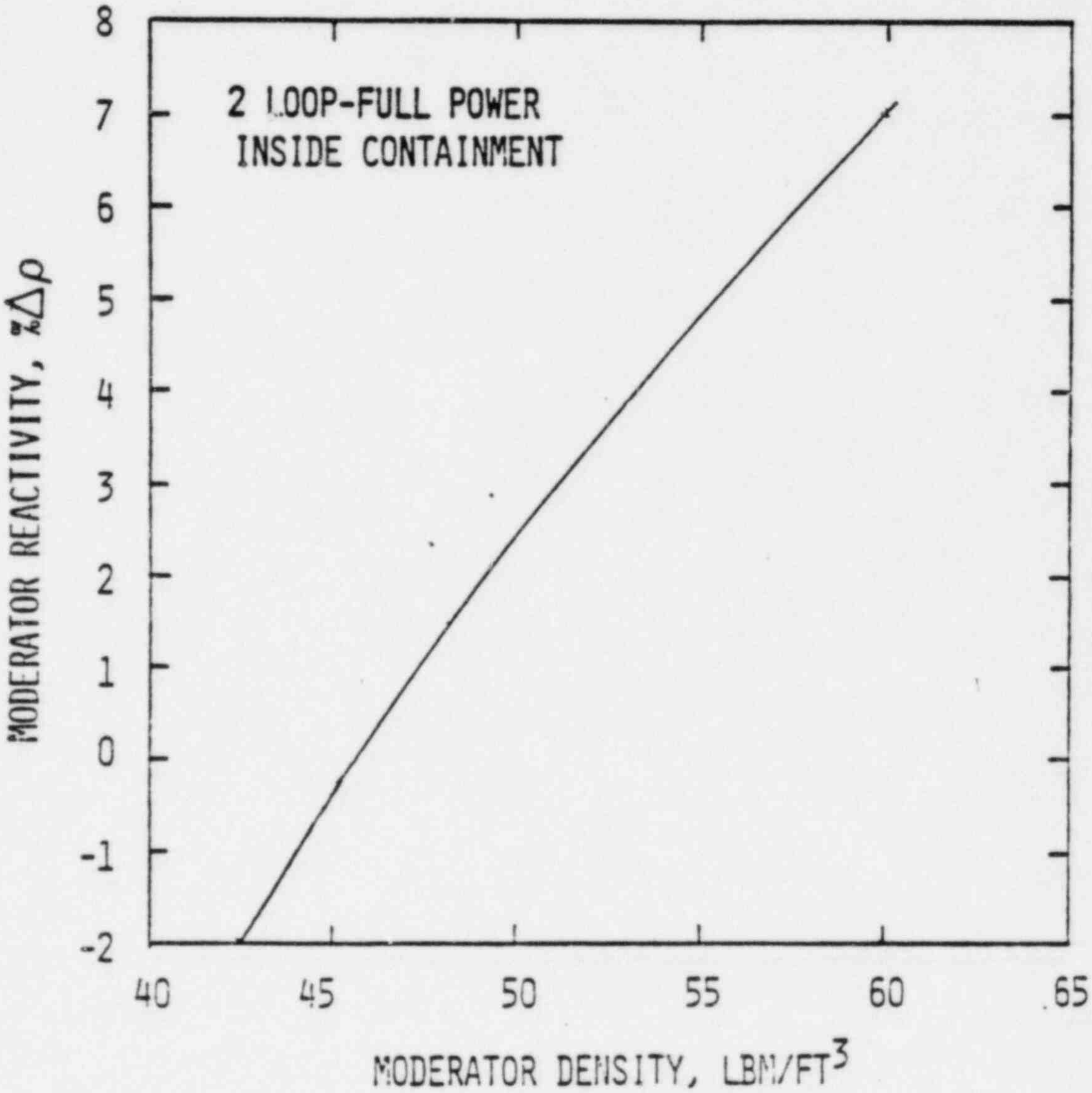
SEQUENCE OF EVENTS FOR OUTSIDE CONTAINMENT
STEAM LINE BREAK EVENT WITH
LOSS OF AC POWER ON TURBINE TRIP INITIATED FROM HFP

Time (sec)	Event	Setpoint or Value
0.0	Steam Line Break Occurs	0.33 ft^2
14.7	High Power Analysis Trip Setpoint is Reached	112% of 2700 MWt
15.1	Trip Breakers Open	---
15.6	CEAs Enter Core; Loss of AC Power on Turbine Trip; RCPs Coastdown Begins; Main Feedwater Rampdown Begins; Diesel Generators Start Coming On Line	---
15.7	Peak Core Average Power Peak Core Averge Heat Flux	118.1% of 2700 MWt 113.4% of 2700 MWt
15.7	Auxiliary Feedwater Actuation Analysis Setpoint is Reached	60.9%**
20.7	Steam Admission Valves to Steam Driven AFW Pump Completely Open	---
25.2	Steam Driven AFW Pump Reaches Full Speed and Delivers AFW to Both Steam Generators	217.0 gpm/S.G.
25.6	Diesel Generators Reach Rated Speed Following LOAC Power; Shutdown Sequencer Initiated	---
30.6	Power Provided to High Pressure Safety Injection Pump	---
35.6	Main Feedwater Rampdown Completed	8% of full power feedwater flow
40.6	Power Provided to Motor Driven AFW Pump; Motor Driven AFW Pump at Full Speed and Delivers AFW Flow to Both Steam Generators	217.0 gpm/S.G.
88.5	Steam Generator Isolation Analysis Setpoint is Reached	600.0 psia

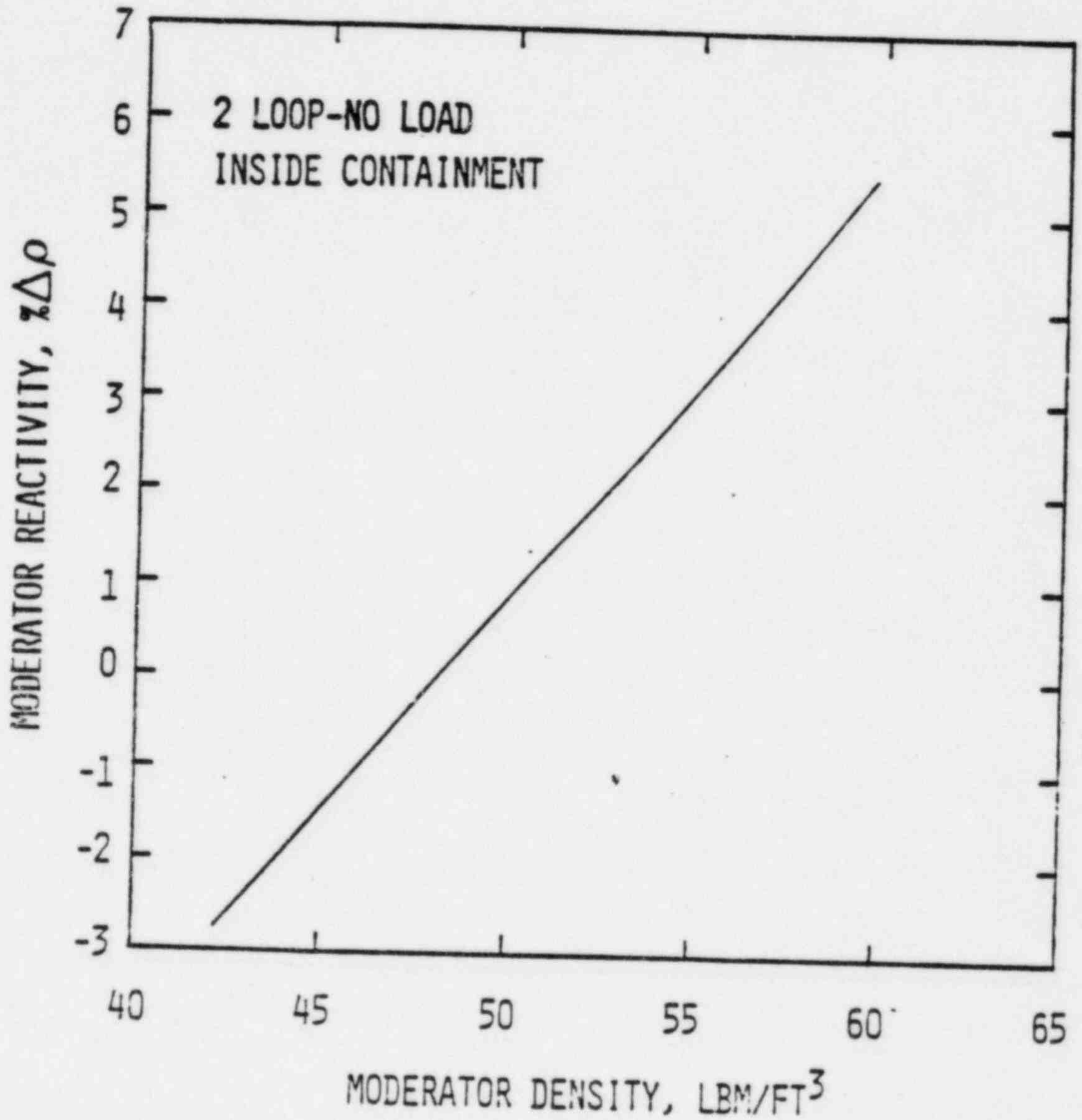
**% of distance between steam generator wide range upper and lower level instrument taps.

TABLE 3-8
(continued)

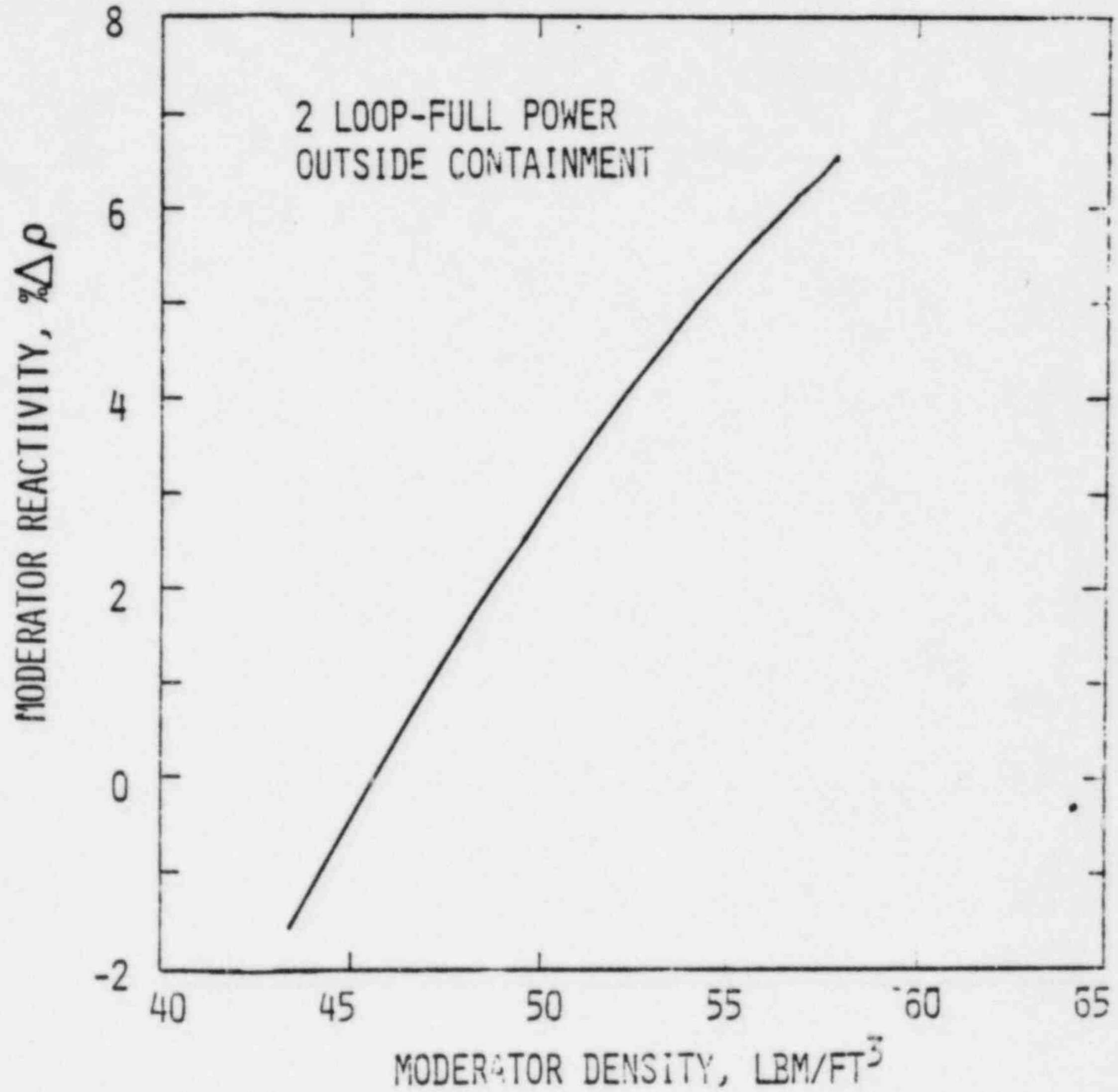
Time (sec)	Event	Setpoint or Value
89.0	Safety Injection Actuation Analysis Setpoint is Reached	1645.0 psia
89.4	Main Steam Isolation Valves Begin to Close; Main Feedwater Isolation Valves Begin to Close	---
101.4	Main Steam Isolation Valves Completely Closed	---
119.0	High Pressure Safety Injection Pump Reaches Full Speed	---
122.5	Pressurizer Empties	---
169.4	Main Feedwater Isolation Completely Closed	---
172.0	Steam Generator Differential Pressure Analysis Setpoint is Reached	ΔP = 250.0 psid
192.0	AFW Block Valve Completely Closed; AFW Flow to Ruptured Steam Generators is Terminated	---



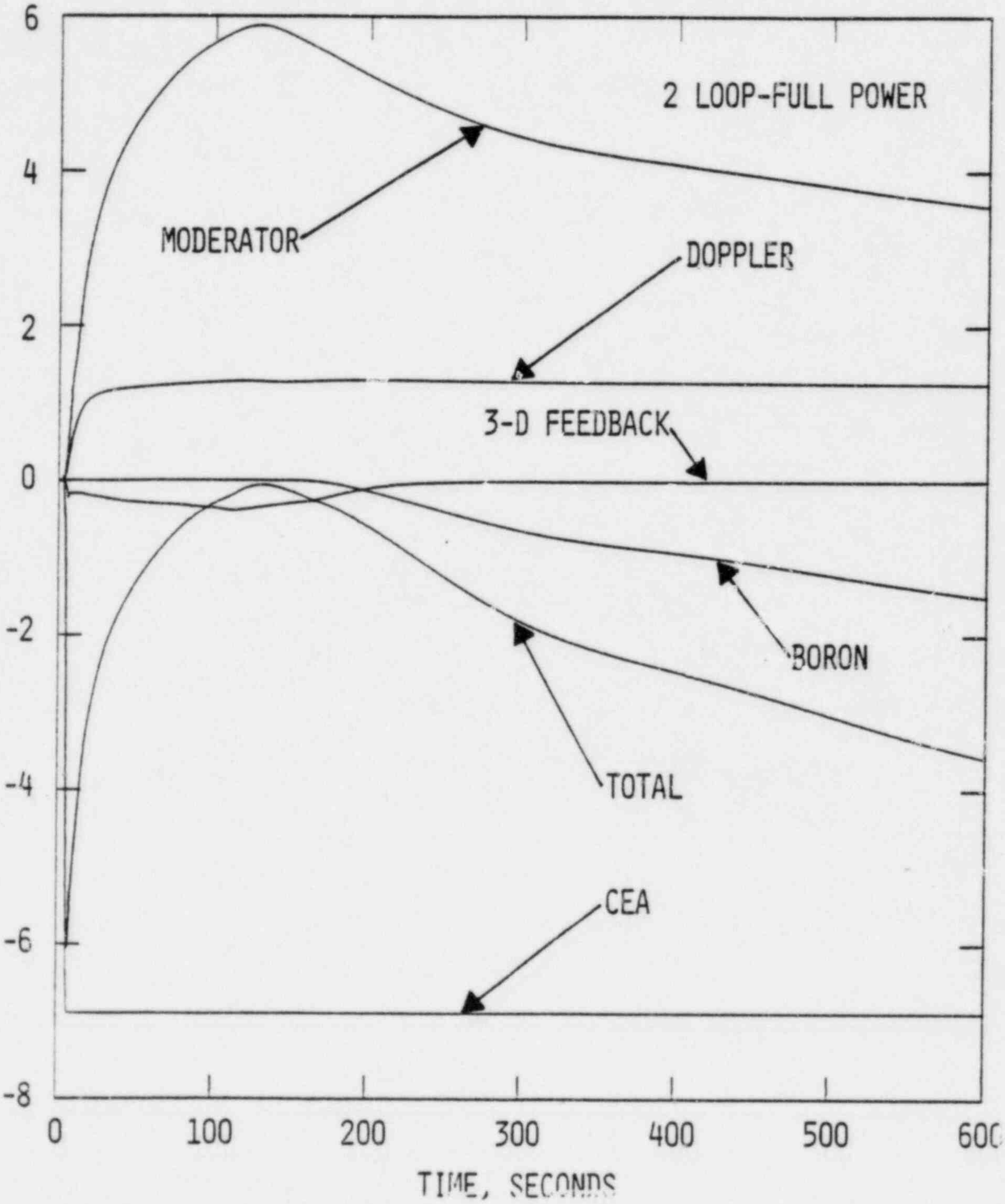
BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	STEAM LINE BREAK EVENT MODERATOR REACTIVITY VS MODERATOR DENSITY	FIGURE 3-1



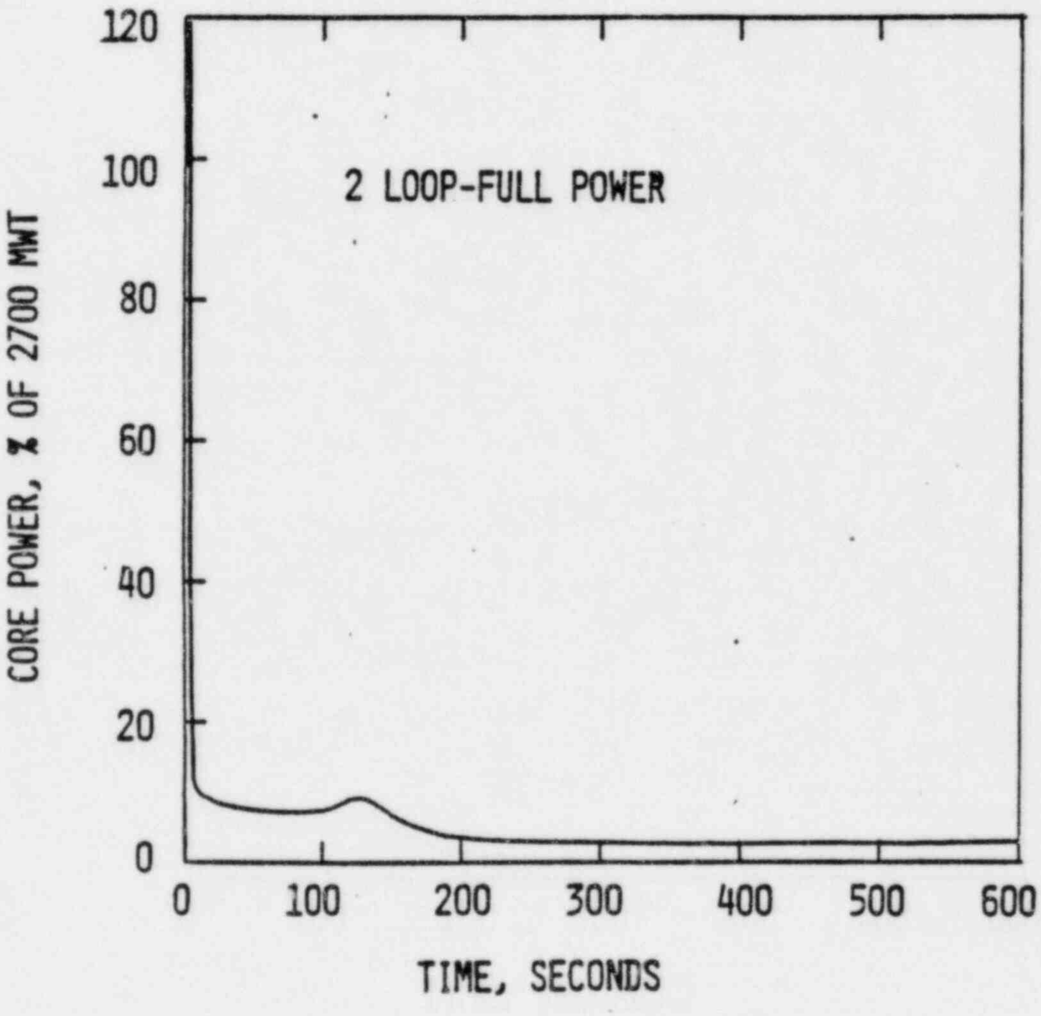
BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	STEAM LINE BREAK EVENT MODERATOR REACTIVITY VS MODERATOR DENSITY	FIGURE 3-2



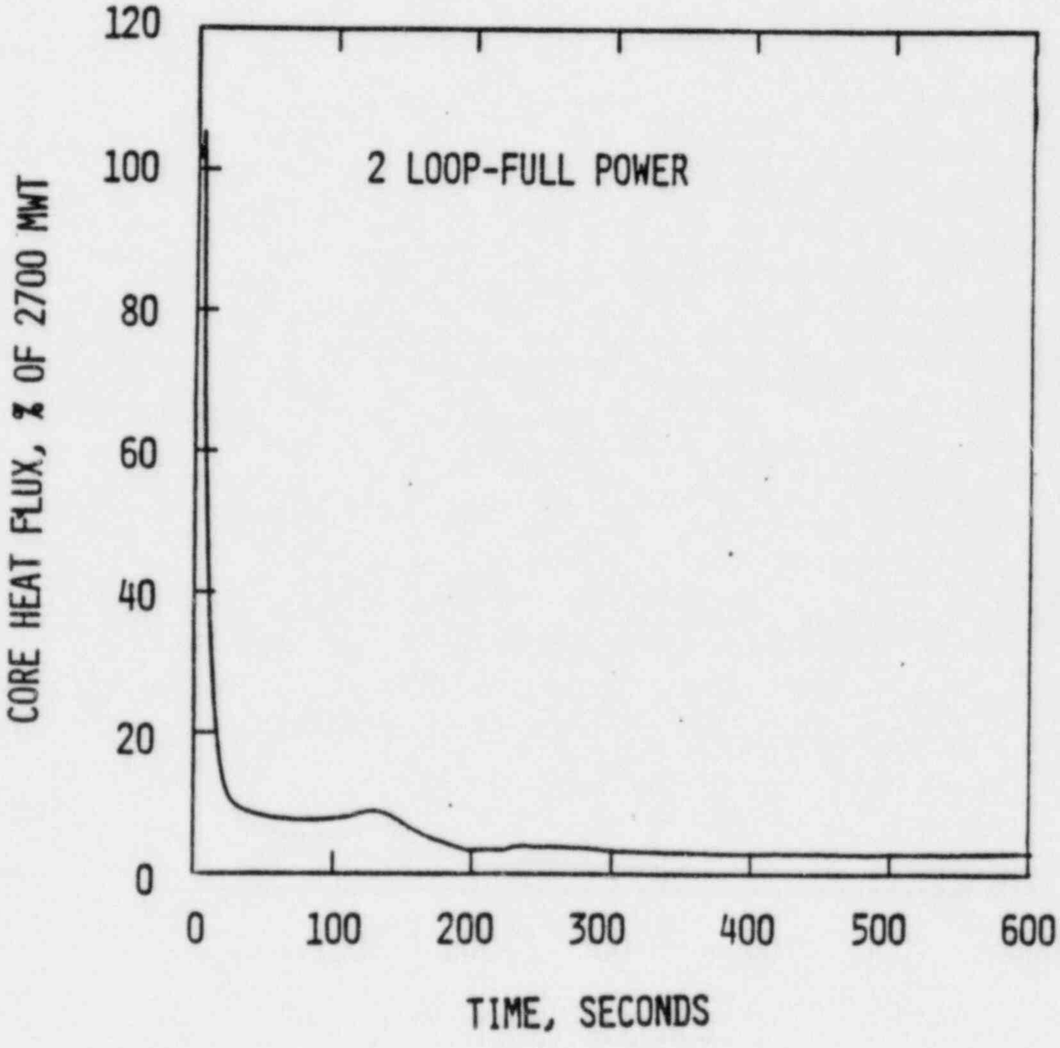
BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	STEAM LINE BREAK EVENT OUTSIDE CONTAINMENT MODERATOR REACTIVITY VS MODERATOR DENSITY	FIGURE 3-3



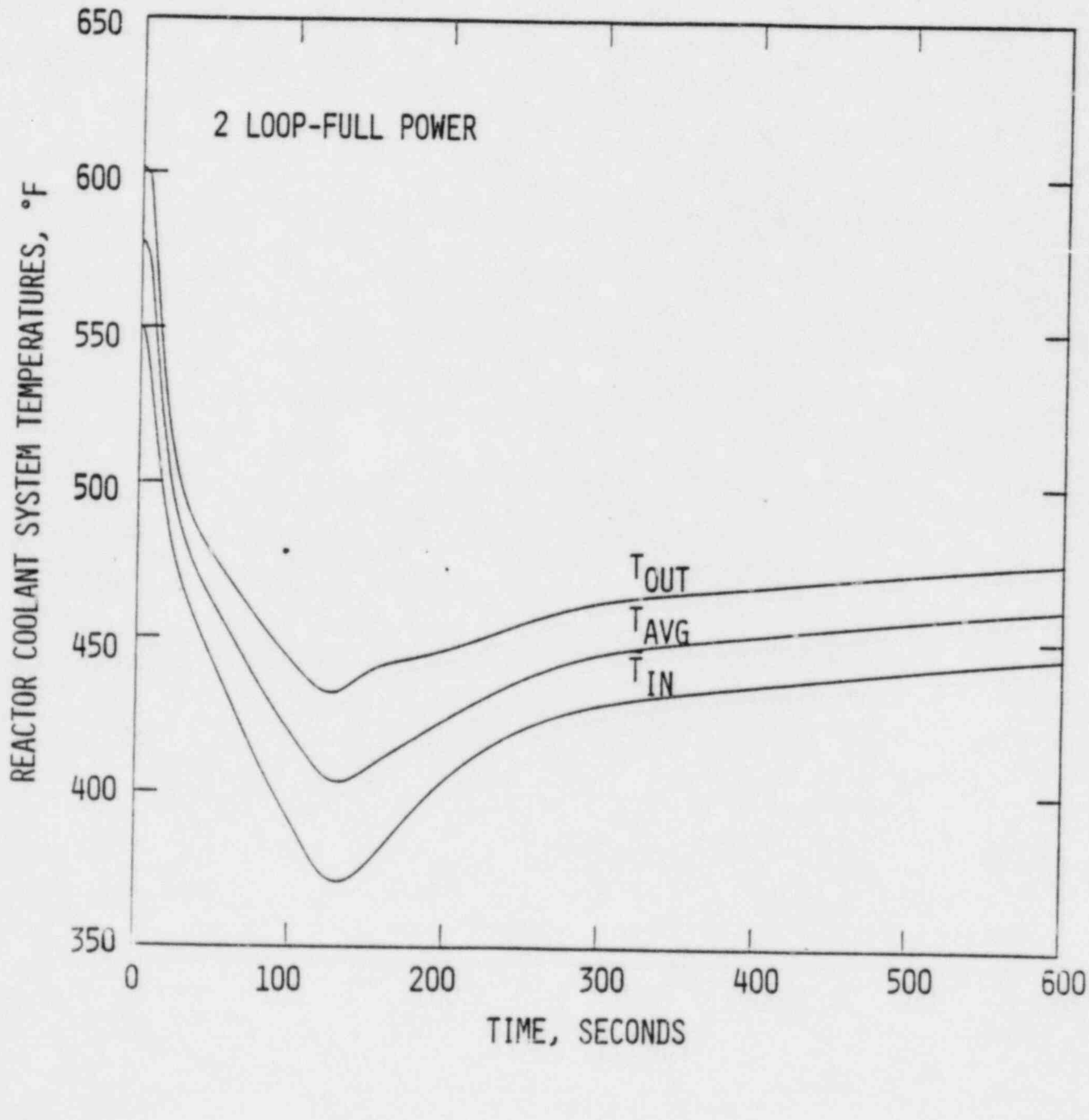
BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	STEAM LINE BREAK EVENT REACTIVITIES VS TIME	FIGURE 3-4



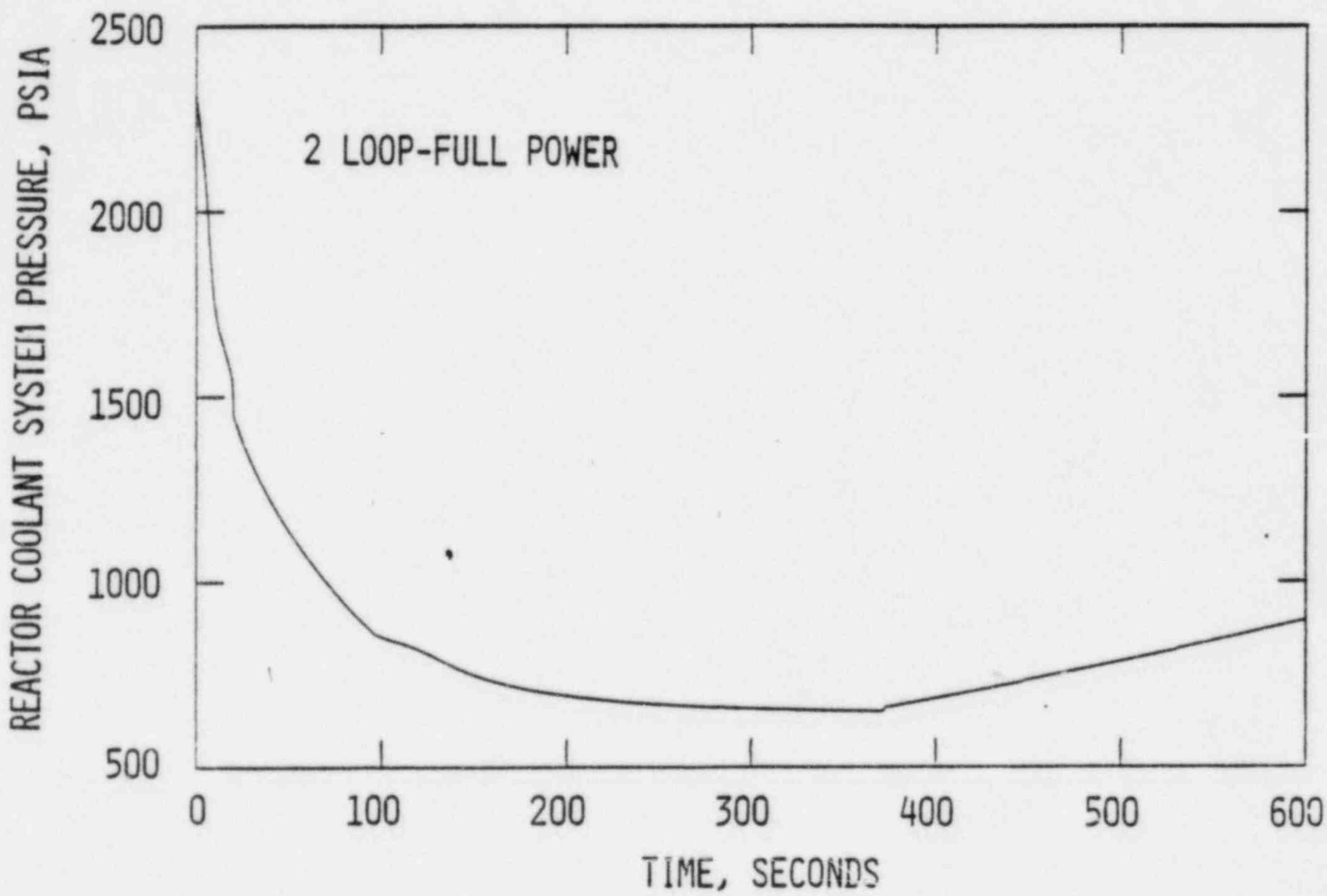
BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	STEAM LINE BREAK EVENT CORE POWER VS TIME	FIGURE 3-5



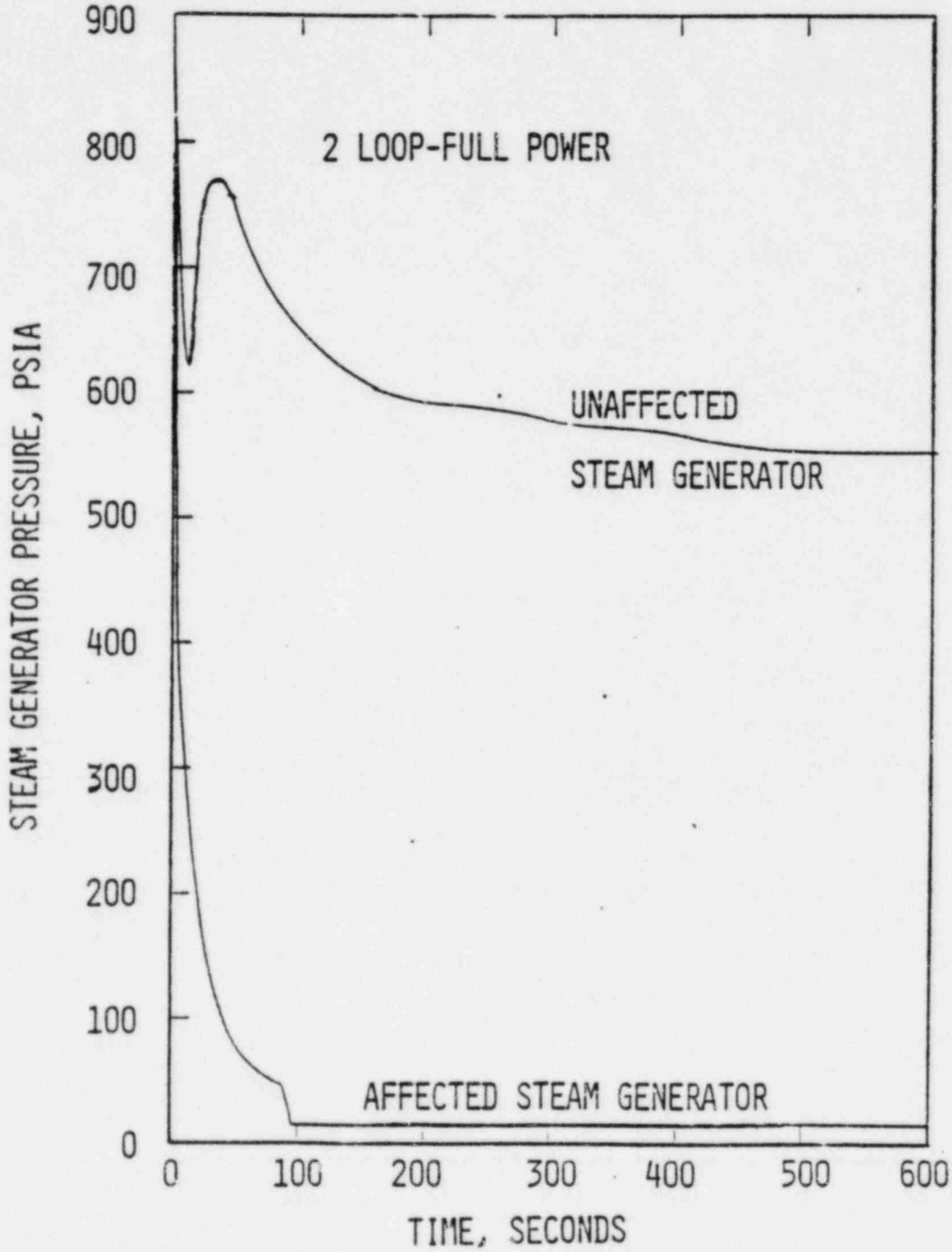
BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	STEAM LINE BREAK EVENT CORE HEAT FLUX VS TIME	FIGURE 3-6



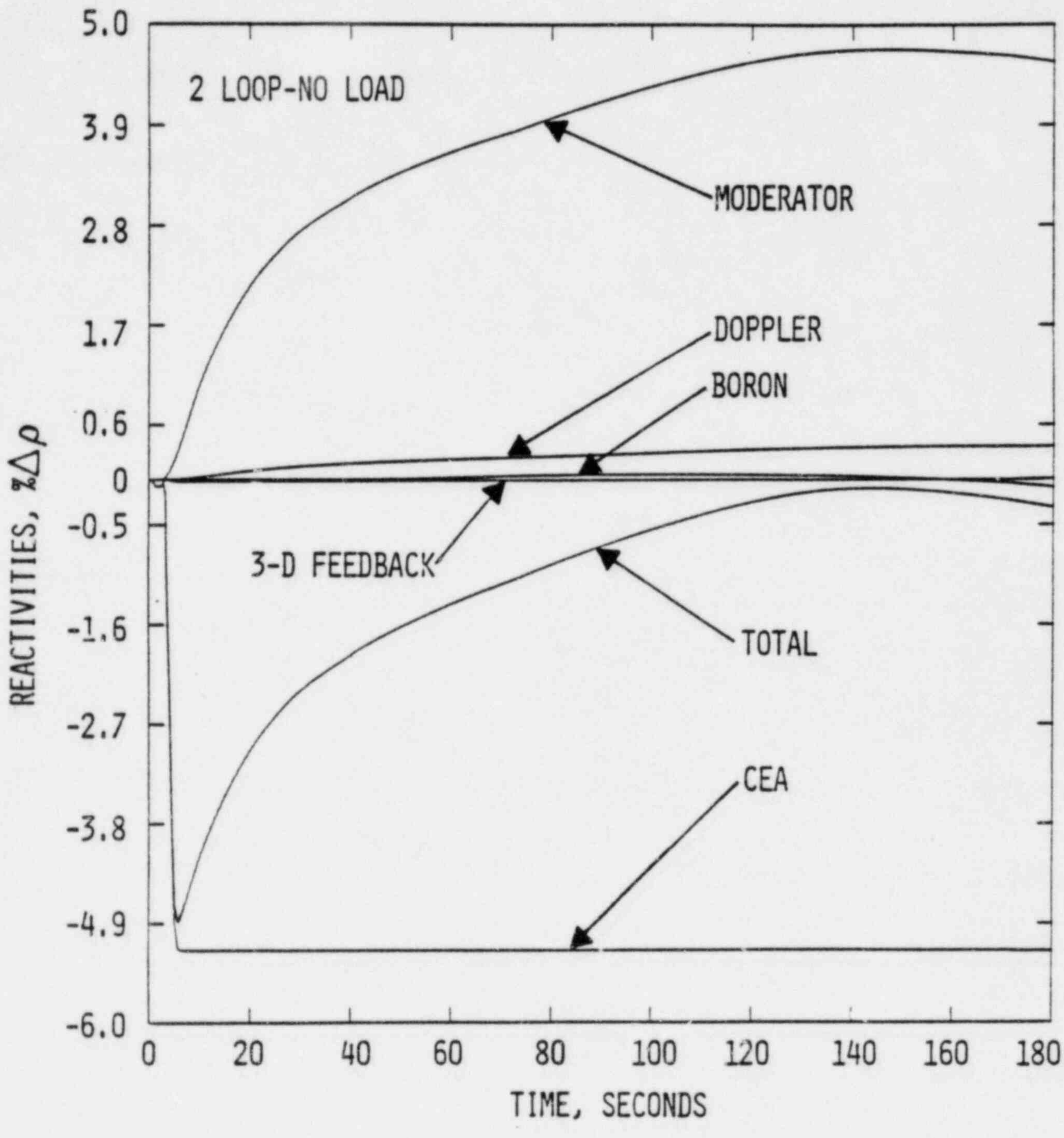
BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	STEAM LINE BREAK EVENT REACTOR COOLANT SYSTEM TEMPERATURES VS TIME	FIGURE 3-7



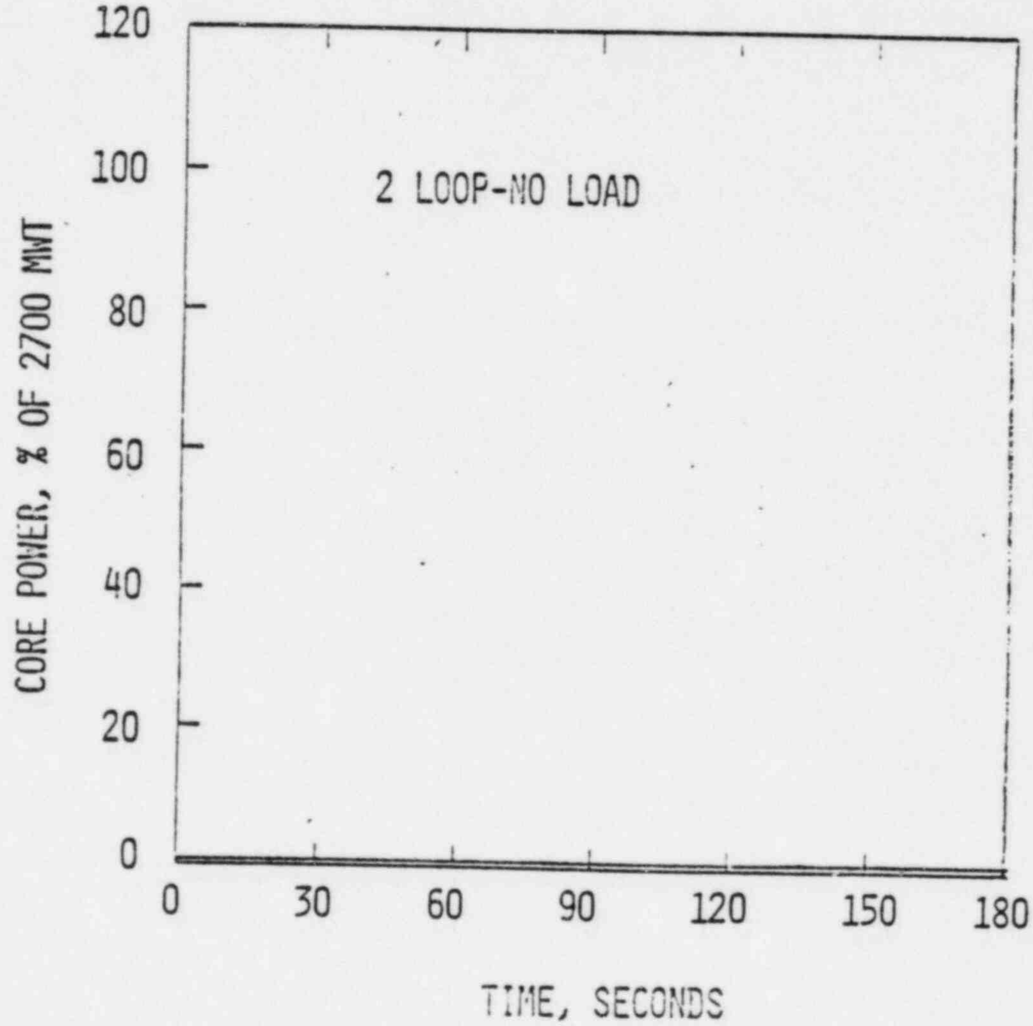
BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	STEAM LINE BREAK EVENT REACTOR COOLANT SYSTEM PRESSURE VS TIME	FIGURE 3-8



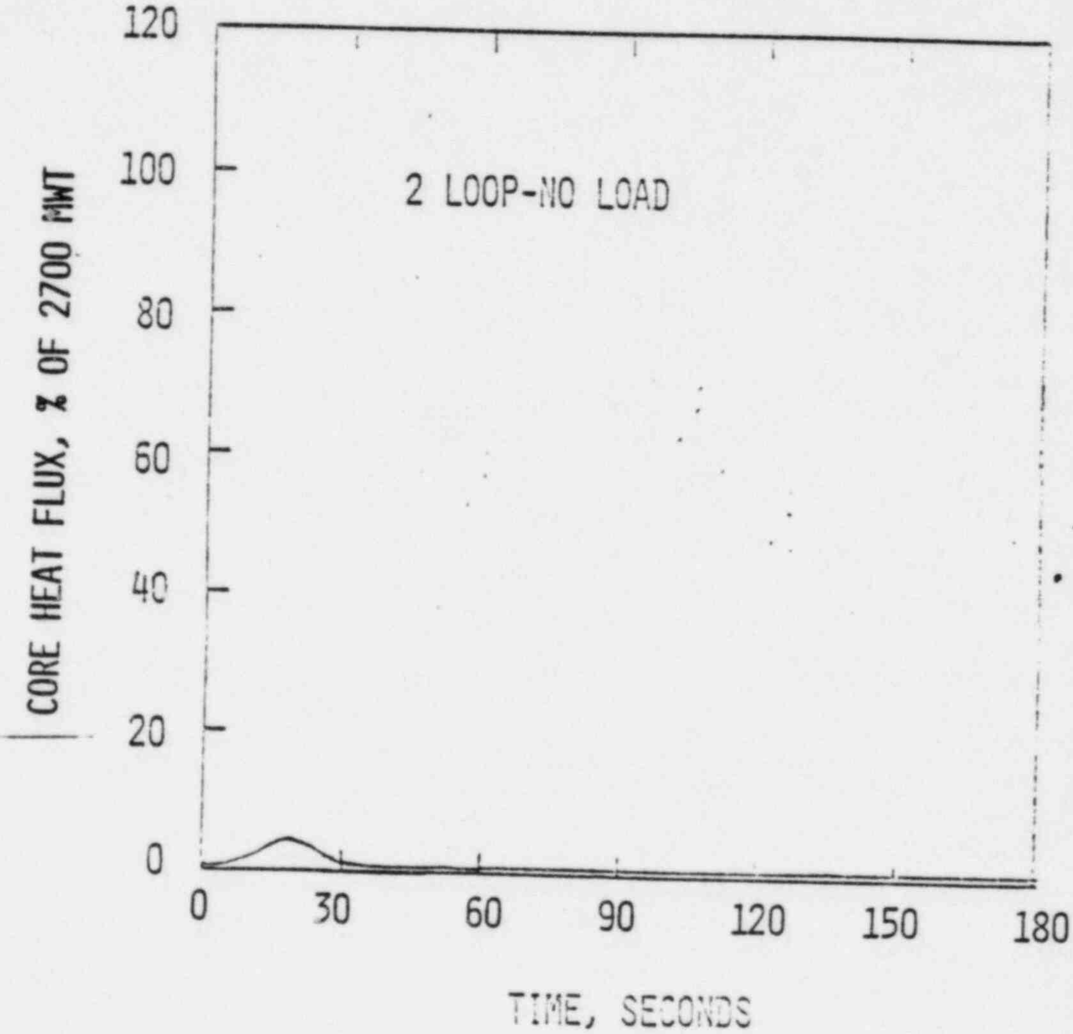
BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	STEAM LINE BREAK EVENT STEAM GENERATOR PRESSURE VS TIME	FIGURE 3-9



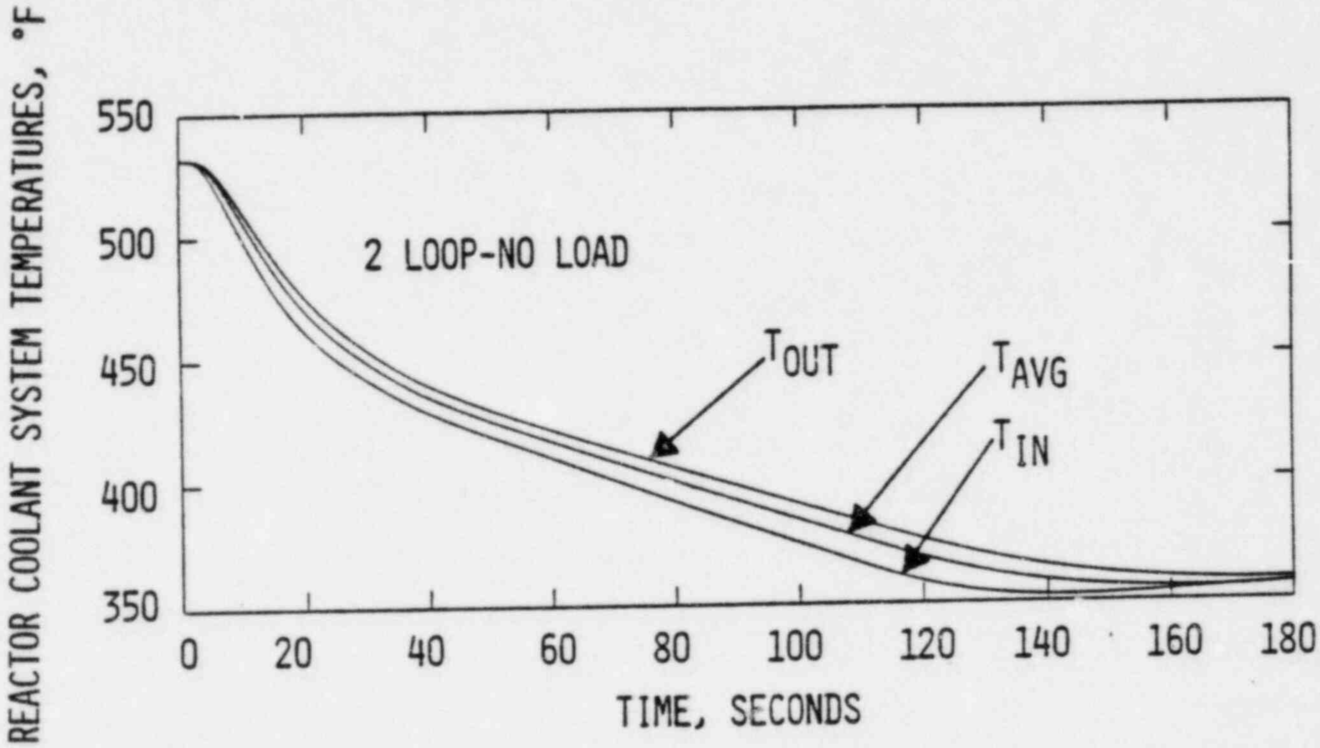
BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	STEAM LINE BREAK EVENT REACTIVITIES VS TIME	FIGURE 3-10



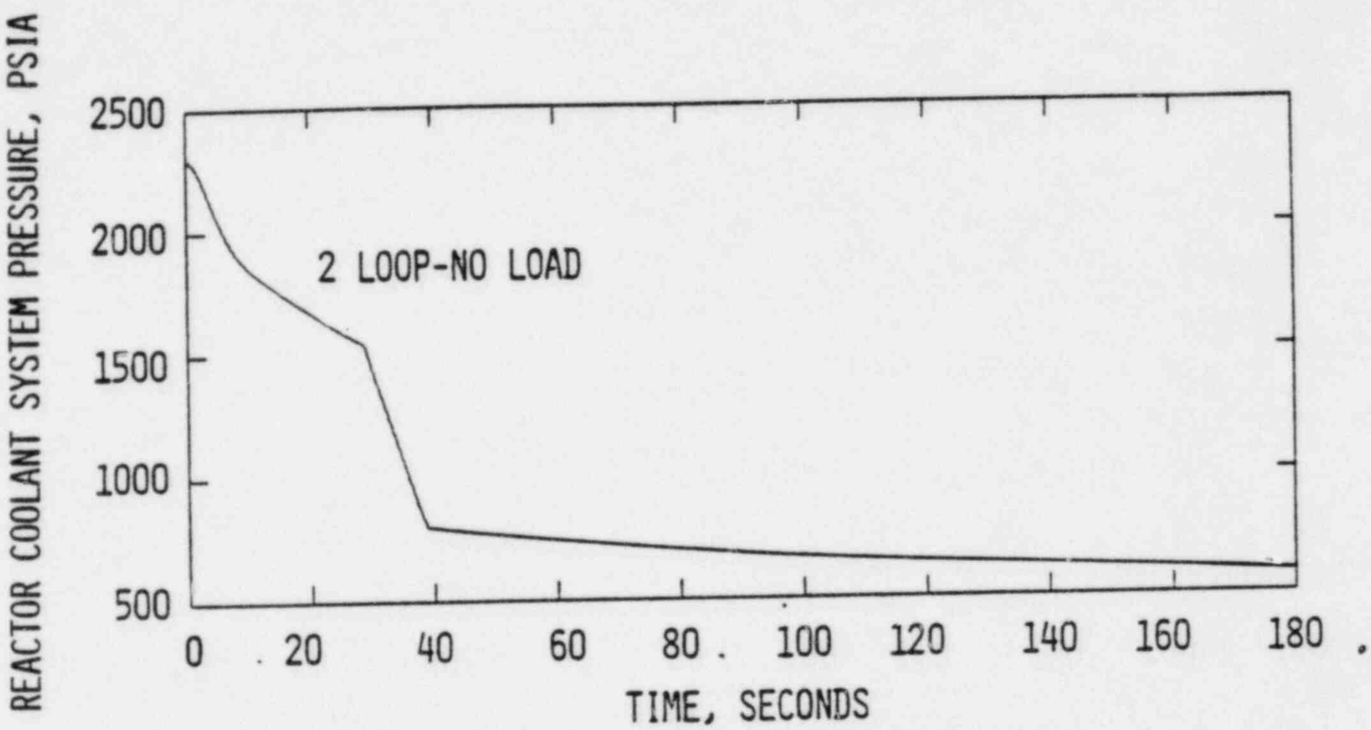
BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	STEAM LINE BREAK EVENT CORE POWER VS TIME	FIGURE 3-11



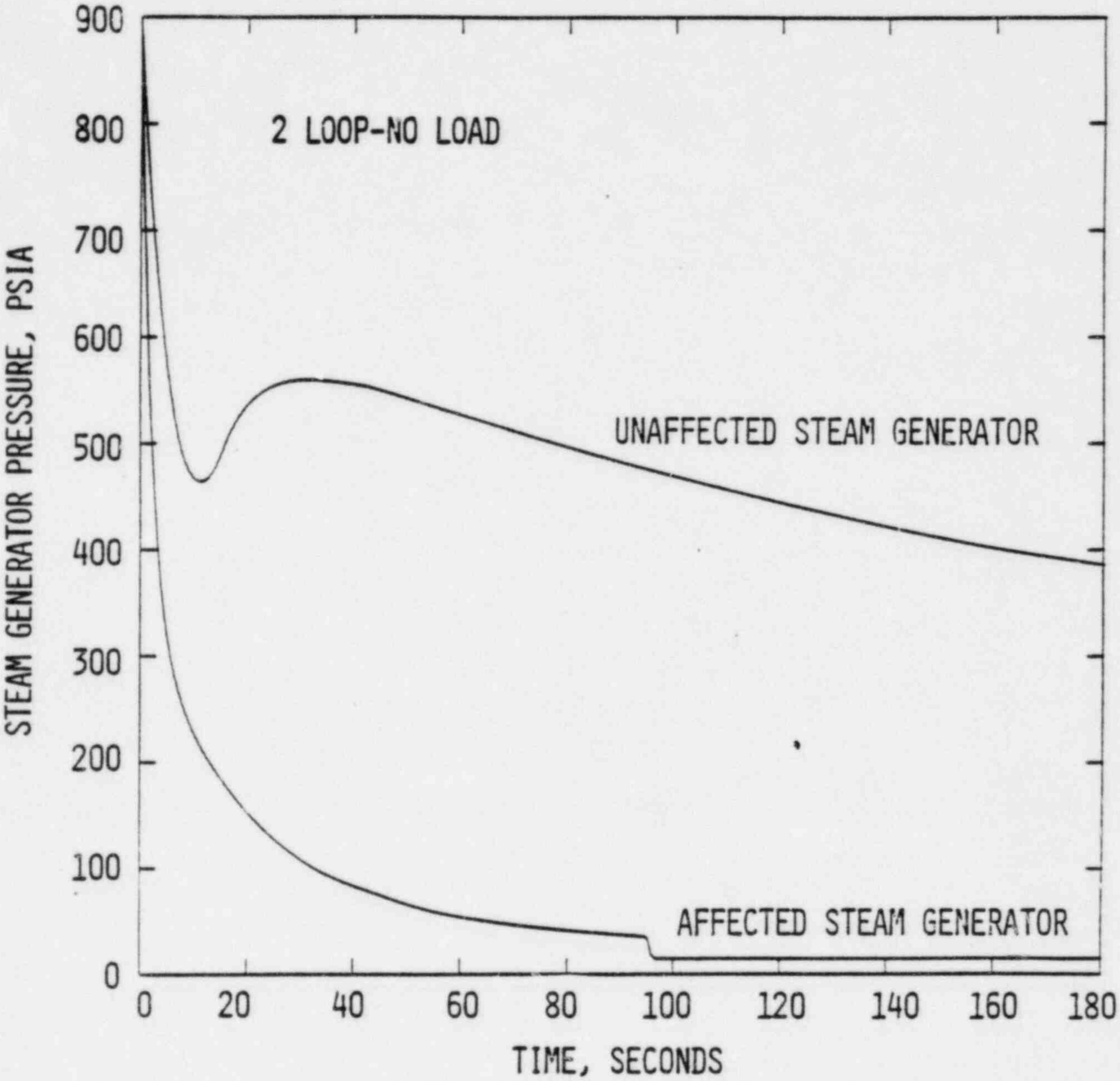
BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	STEAM LINE BREAK EVENT CORE HEAT FLUX VS TIME	FIGURE 3-12



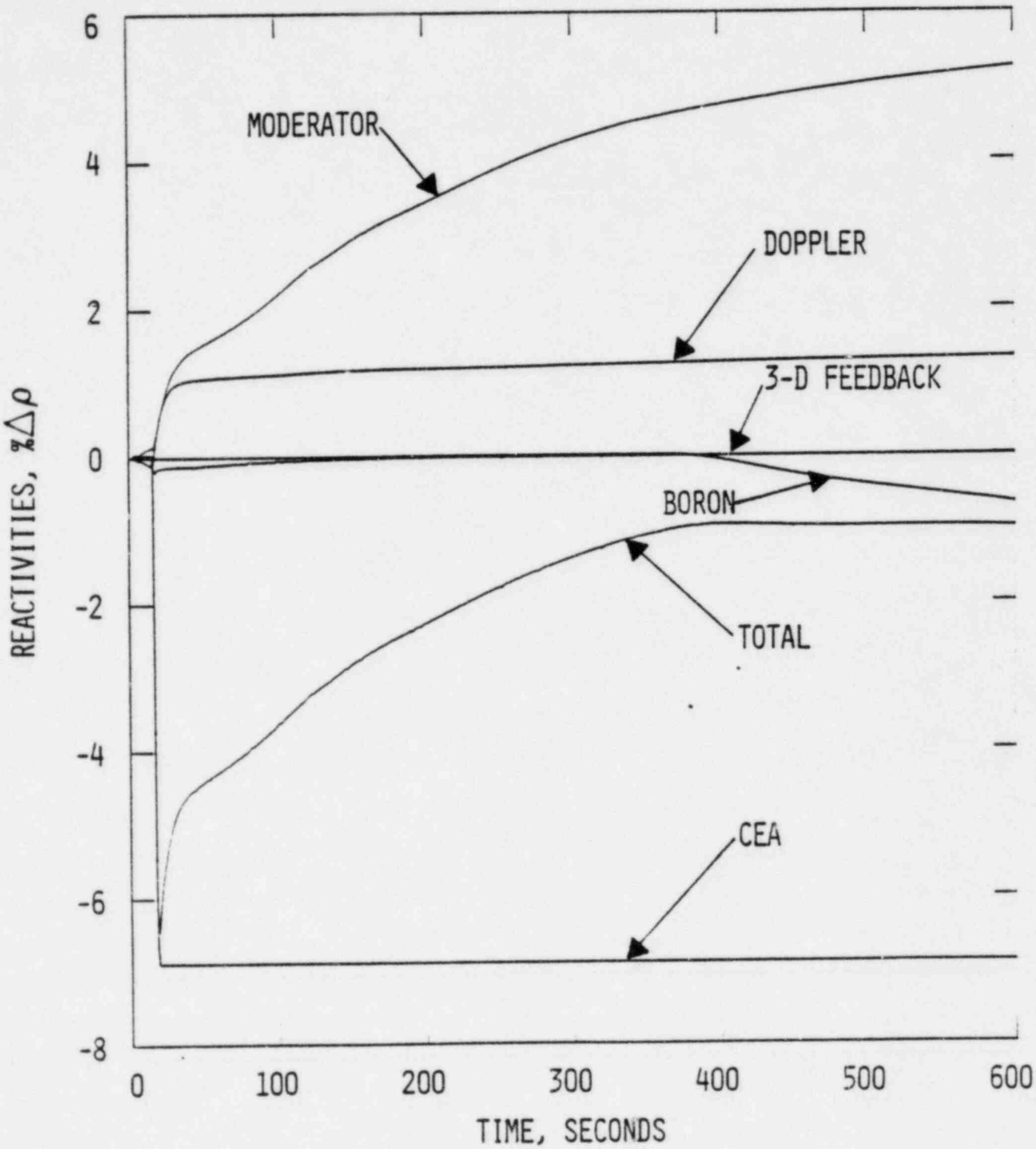
BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	STEAM LINE BREAK EVENT REACTOR COOLANT SYSTEM TEMPERATURES VS TIME	FIGURE 3-13



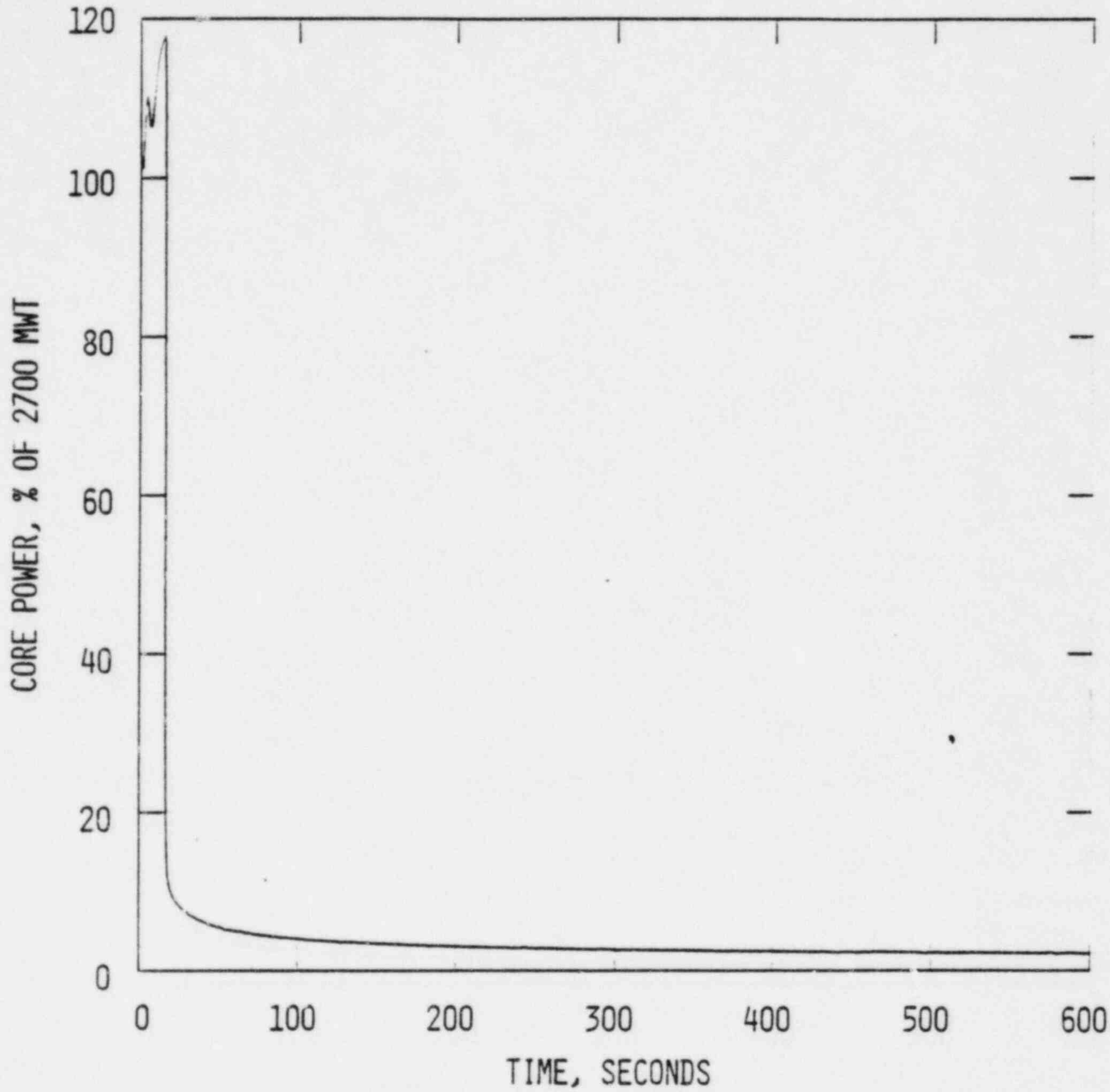
BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	STEAM LINE BREAK EVENT REACTOR COOLANT SYSTEM PRESSURE VS TIME	FIGURE 3-14



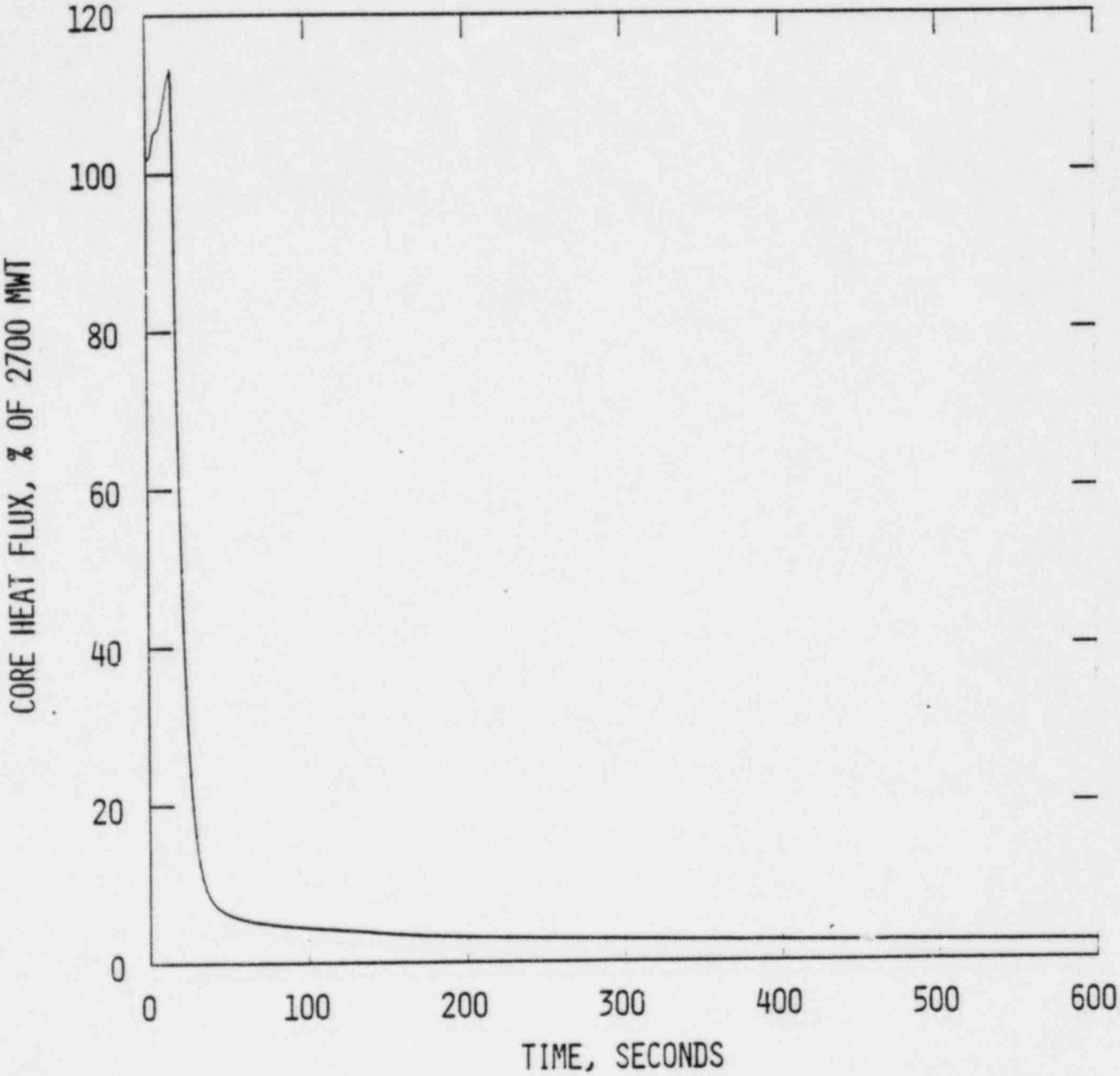
BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	STEAM LINE BREAK EVENT STEAM GENERATOR PRESSURE VS TIME	FIGURE 3-15



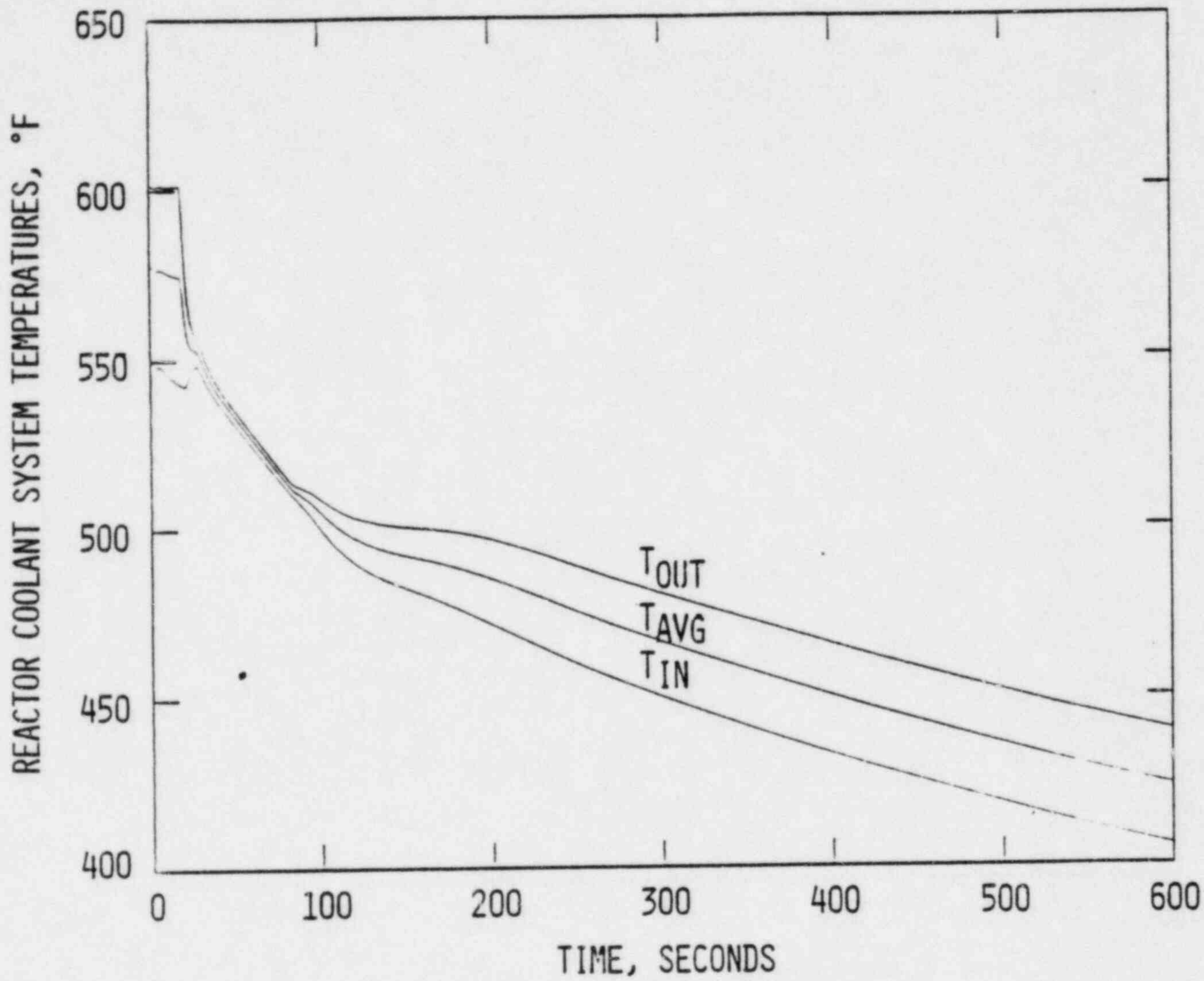
BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	STEAM LINE BREAK EVENT OUTSIDE CONTAINMENT REACTIVITIES VS TIME	FIGURE 3-16



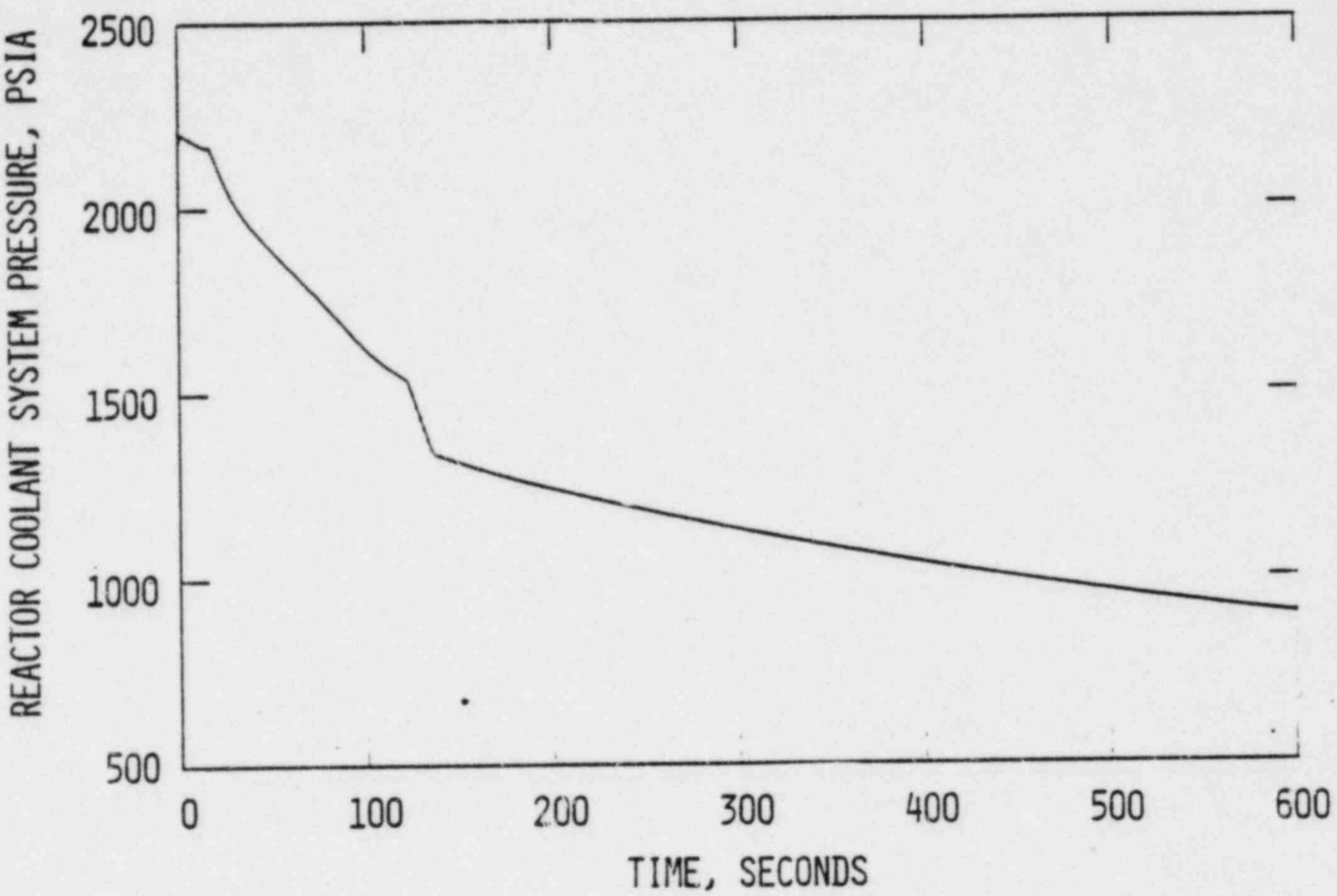
BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	STEAM LINE BREAK EVENT OUTSIDE CONTAINMENT CORE POWER VS TIME	FIGURE 3-17



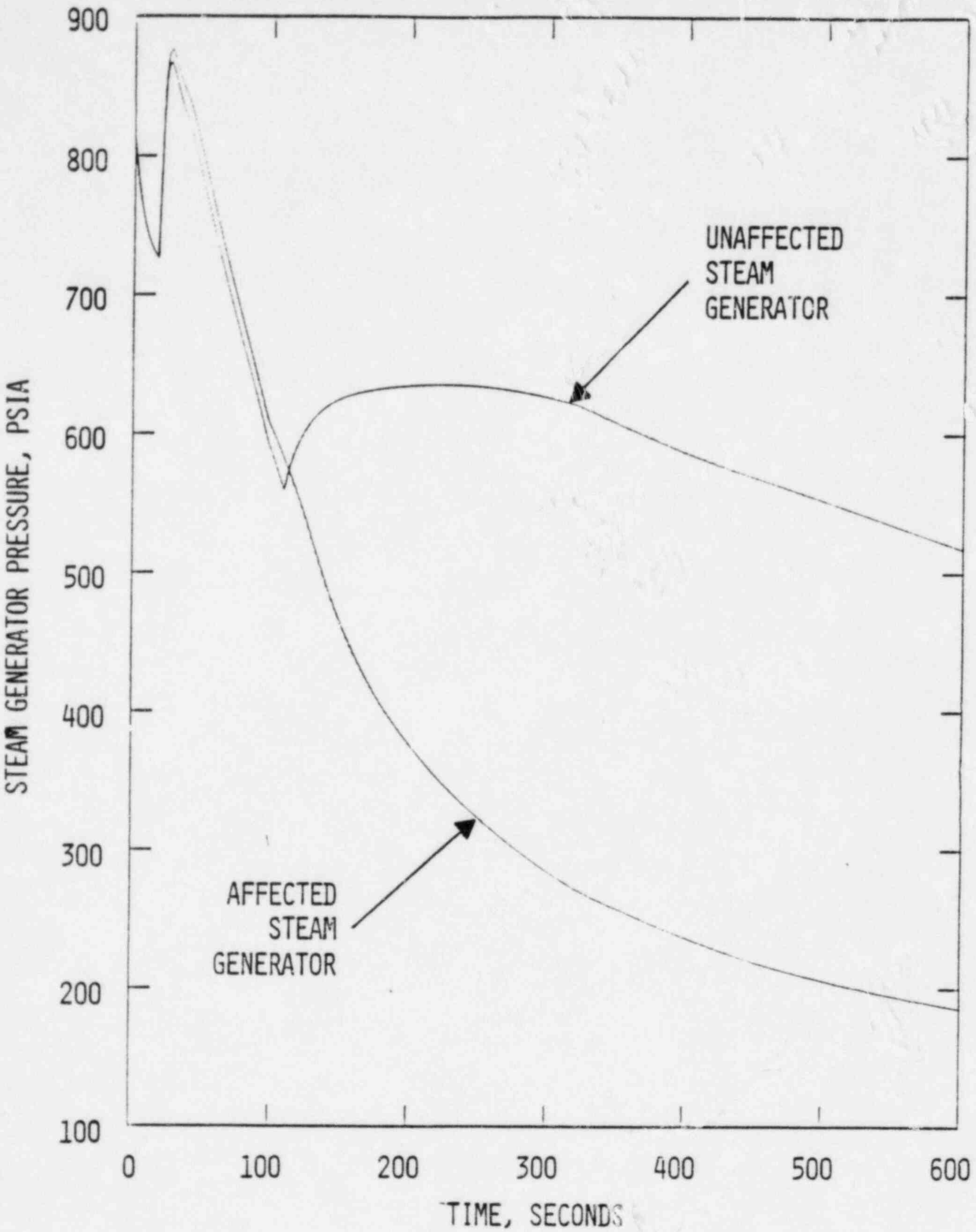
BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	STEAM LINE BREAK EVENT OUTSIDE CONTAINMENT CORE HEAT FLUX VS TIME	FIGURE 3-18



BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	STEAM LINE BREAK EVENT OUTSIDE CONTAINMENT REACTOR COOLANT SYSTEM TEMPERATURES VS TIME	FIGURE 3-19



BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	STEAM LINE BREAK EVENT OUTSIDE CONTAINMENT REACTOR COOLANT SYSTEM PRESSURE VS TIME	FIGURE 3-20



BALTIMORE GAS & ELECTRIC CO. Calvert Cliffs Nuclear Power Plant	STEAM LINE BREAK EVENT OUTSIDE CONTAINMENT STEAM GENERATOR PRESSURE VS TIME	FIGURE 3-21

4.0 Technical Specifications

The Technical Specification changes and/or additions which are required to validate the safety analysis performed for the safety grade AFAS are presented in this section. The changes and/or additions for the safety grade AFAS are denoted by an asterisk (*).