EVALUATION

OF THE

SYSTEM 80+ STANDARD DESIGN

FOR

STEAM GENERATOR TUBE RUPTURE EVENTS

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ABSTRACT

The probability that steam generator tube ruptures (SGTR) will result in containment bypass is reduced by current System 80+ design features. Two additional features will be added. A monitor for N-16 will be added to one steam line from each steam generator and modifications will be made to assure continuity of turbine steam bypass capability following a safety injection actuation signal. The resultant conditional probability for containment bypass via opening of the Main Steam Safety Valves (MSSVs) during a SGTR event becomes lower by two orders of magnitude than it was on the earlier System 80 design.

The System 80+ evolutionary ALWR was derived from the System 80 NSSS over an eight year period of design evaluations. Changes that were made concluding in the System 80+ systems and component configurations, have resulted in substantial increases in plant safety. Significant changes at this point in the design evolution to accommodate new bases for safety analyses and/or new acceptance criteria for Design Basis Events must be thoroughly evaluated if the effectiveness of the System 80+ integration is to be maintained. With these considerations in mind, and after considerable study involving tradeoffs and performance evaluations of the System 80+ Standard Plant we consider the following design features to best meet the goal of significantly reducing the probability of containment bypass due to SGTR. These features are:

1) A design change to add two N-16 monitors, one per steam generator, to assist in the diagnostics of the event. The signal would be latched to prevent loss of signal on reactor scram. These monitors would be in addition to the present System 80+ steamline area radiation monitors and sample and blowdown radiation monitors.

2) A design change to the System 80+ Component Cooling Water (CCW) system to permit the steam bypass system to continue to operate after SIAS is reached. It assures CCW to the air compressors following SIAS so that actuation air is available to the steam bypass valves indefinitely.

3) The main feedwater control system (FWCS) in the present System 80+ design automatically terminates main feedwater following a reactor trip with reduced primary coolant temperatures. This helps to offset the leak flow, extending the ruptured SG fill time.

4) The Rapid Depressurization System (RDS) discharging to the IRWST is actuated by the operator when MSSVs are challenged. The RDS is already a part of the System 80+ design.

5) The NUPLEX 80+ control room assists the operator in the diagnostics of events. NUPLEX 80+ is already a part of the System 80+ design.

6) The turbine bypass system for which all valves direct secondary flow to the condenser eliminates two paths to the atmosphere and is already part of the present System 80+ design.

7) The IRWST in the current System 80+ design is both a large source of safety injection water and a quench tank that confines blowdown fluids within the containment. It contains greater than 500,000 gallons of borated water and can be refilled by the CVCS from the Boric Acid Storage Tank which contains 250,000 gallons of borated water.

8) The large secondary side volume of the System 80+ SGs provides extra capacity and therefore extended operator action time before the MSSVs are challenged.

The above features have been evaluated in order to obtain a measure of their contribution to reducing the risk of containment bypass. It is estimated that the summation of the individual effects produce greater than two orders of magnitude reduction in risk of containment bypass from SGTR relative to the previous System 80 design.

Not factored into the above quantification is the very real prevention feature inherent in the System 80+ design due to the change of material in the SG tubes from Inconel 600 to Inconel 690 and the lowered operating temperatures.

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1.0 INTRODUCTION

1.1 Background

The System 80+ design is an evolutionary ALWR derived from the successful System 80 design. Changes incorporated into the System 80+ design provide significant increases in operating margins relative to those on System 80. Also, changes provide significantly greater capability in mitigating design basis events. Despite these improvements, the NRC staff (Reference 6-1) believes that greater improvement in the capability to prevent bypass of containment by primary coolant following a Steam Generator Tube Rupture (SGTR) event should be investigated. In particular, it is desired to reduce the reliance on manual operator actions to mitigate the event during the early post-trip period after the event.

In Chapter 15 of CESSAR-DC an analysis of a single SGTR event is presented assuming rupture of one tube and only automatic actuation of only safety grade systems and components for 30 minutes. After 30 minutes, operator action is assumed to mitigate the event. The offsite radiological dose acceptance criteria are satisfied, but the conservative Chapter 15 analysis methods predict the opening of main steam safety valves (MSSVs) on the secondary side that release primary coolant to atmosphere. The conservatively biased calculations required for these safety analyses yield an upper limit bound on the actual radiological release and are appropriate for their intended purposes.

A comprehensive study of candidate automatic systems was conducted to identify options which might substantially improve SGTR performance. In particular, the goal was set to try to significantly increase the time before the MSSVs would first lift, without credit for operator actions, following the rupture of five SG tubes. Those which were most promising were assessed by detailed performance anlayses and by system design evaluations. This report presents the results of these analyses and design evaluations including the attendant benefits and limitations of each candidate approach.

In meetings with the NRC (Reference 6-2), ABB-CE has presented more realistic analyses of the System 80+ design to survive a SGTR assuming only automatic actuation of components and systems which include both safety grade and non-safety grade equipment. Conclusions presented at the meetings indicated that the realistic response of the System 80+ design is to allow more than four hours for operator action following a single tube rupture and to allow more than 30 minutes following rupture of five tubes before MSSVs open to release to atmosphere.

To reduce reliance on operator action within 30 minutes or even within several hours, ABB-CE has evaluated a number of potential plant design changes. These changes were discussed at meetings with the NRC (References 6-2 and 6-3), where additional variations were also suggested.

1.2 Purpose of Report

This report presents the ABB-CE position on proposed mitigative design changes to the System 80+ Standard Design to prevent radiological release to the atmosphere following SGTR events. The report fulfills this purpose in three ways. First, the current System 80+ capability to mitigate SGTR events is evaluated. Second, proposed design changes are evaluated to determine their benefit. Third, the report establishes a criterion to use for measuring the benefits of the various design options. This criterion is the length of time from the initiation of the event until the operator must take action to prevent opening of the MSSVs.

1.3 Scope of Report

The report identifies the preventative and mitigative features of the current System 80+ design that prevent or limit radiological release following SGTR events. The report also identifies and describes eleven design changes proposed to enhance the plant response to SGTR. Methods employed to determine the realistic or best estimate responses of the plant are presented. These methods are employed to determine the response for the current plant design and for each of the proposed design changes. The intent is to provide realistic analytical estimates of the actual behavior, given the SGTR, so that valid comparisons may be made among the various proposed changes.

An evaluation of each plant configuration is provided, based upon the design and the plant response. As stated above, a criterion is established as the time to open the MSSVs assuming no operator action. In addition to this criterion, the evaluation bases include other considerations. The economics of the plant response consequences are considered. For example, the extent of cleanup required or the likelihood of significant equipment damage is evaluated. The complexity of the design change is considered along with the complexity of utilizing it during an event.

Proveness of the design change is considered. This is especially important at this stage in the System 80+ design process when much has already been done to confirm the effective integrated behavior of interacting systems and components. Uniqueness of the effects of a proposed change is cautiously reviewed to assure that unexpected equipment responses do not occur during other design basis events or operational evolutions.

A summary of the proposed design changes is given in Table 1.3-1 where the significant benefits and limitations are listed for each change.

TABLE 1.3-1
SUMMARY OF THE BENEFITS & LIMITATIONS OF POTENTIAL DESIGN CHANGES

SECTION NO. & DESIGN CHANGE	BENEFIT(S)	LIMITATION(S)
3.2. Automatically bypass MSIS on high SG level.	• Extends MSSV lift time from 30 to 50 minutes for 5 tubes ruptured. • Minimal hardware changes required.	• Redesign of the turbine bypass system is necessary. • Steam lines will flood causing significant equipment damage. • Conflicts with criterion 24 of Reg. Guide 1.153 which requires separation of Protection and Control Systems.
3.3 Automatically initiate auxiliary pressurizer spray (APS).	• Very small extension of MSSV lift time (1 minute) for 5 tubes ruptured. • Minimal hardware changes required.	• Reduces RCS subcooling • Increases pressurizer level early complicating diagnosis.
3.4 Automatically open the Reactor Coolant Gas Vent System (RCGVS).	• Very small extension of MSSV lift time (3 minutes) for 5 tubes ruptured. • Minimal hardware changes required.	• Reduces RCS subcooling • Increases pressurizer level early complicating diagnosis. • Conflicts with criterion 24 of Reg. Guide 1.153 which requires separation of Protection and Control Systems.

TABLE 1.3-1 (Cont'd)
SUMMARY OF THE BENEFITS & LIMITATIONS OF POTENTIAL DESIGN CHANGES

SECTION NO. & DESIGN CHANGE	BENEFIT(S)	LIMITATION(S)
3.5 Automatically open the SG liquid blowdown system.	• MSSV will not lift for 5 ruptured tubes beyond 10,000 seconds.	• New single failure safety analysis concerns. • New containment penetration piping & valves. • Will require exemption from regulatory isolation requirements for the containment.
3.6 Automatically reduce post-trip SBCS pressure to 900 psia (vs. 1100 psia).	• Small extension of MSSV lift time (3 minutes) for 5 tubes ruptured.	• Pressure reduction limited to remain above the low SG pressure MSIS setpoint (850 psia). • Complicates SBCS with potential impact on plant availability.
3.7 Automatic opening of Turbine Bypass System and Bypass of MSIS on low steam generator pressure.	• May extend MSSV lift time.	• Conflicts with required safety function for main steam line breaks. • High steam generator level MSIS still occurs. • Conflicts with criterion 24 of Reg. Guide 1.153 which requires separation of Protection and Control Systems.

TABLE 1.3-1 (Cont'd)
SUMMARY OF THE BENEFITS & LIMITATIONS OF POTENTIAL DESIGN CHANGES

SECTION NO. & DESIGN CHANGE	BENEFIT(S)	LIMITATION(S)
3.8 Automatically open the Rapid Depressurization System (RDS) on the pressurizer.	• Will prevent MSSV lift for >10,000 seconds for a five tube rupture.	• Core subcooling lost • Large reverse flow of unborated water. • Conflicts with criterion 24 of Reg. Guide 1.153 which requires separation of Protection and Control Systems. • RDS is not currently designed for design basis events. • Challenge to environmental qualification of containment equipment.
3.9 Increase main steam safety valve setpressure.	• Small extension of MSSV lift (5 minutes) for a five tube rupture.	• Will require a redesign of steam generator & secondary systems. • Higher RCS temperatures & pressures for decreased heat removal events. • The small break LOCA peak clad temperature will increase significantly.

TABLE 1.3-1 (Cont'd)
SUMMARY OF THE BENEFITS & LIMITATIONS OF POTENTIAL DESIGN CHANGES

SECTION NO. & DESIGN CHANGE	BENEFIT(S)	LIMITATION(S)
3.10 Automatic blowdown of steam generator liquid to IRWST.	• MSSV will not lift for 5 ruptured tubes beyond 10,000 seconds.	• New valves, piping supports, extensive first of a kind engineering. • Challenge to environmental qualification of containment equipment. • Overheating of the IRWST. • Potential for boron dilution.
3.11 Automatic initiation of the atmospheric dump valves.	• Minimal hardware changes required. • Extension of MSSV lift time.	• Steam lines will flood causing equipment damage. • Vents to atmosphere • Conflicts with criterion 24 of Reg. Guide 1.153 which require separation of protection and control systems.
3.12 Passive secondary cooling system.	• Extension of MSSV lift time.	• Steam lines will flood causing equipment damage. • Extensive redesign of containment and design of suppression tank. • Extensive first of a kind engineering.

2.0 Summary of Results

2.1 Design of the System 80+ Plant For SGTR Mitigation

The System 80+ evolutionary ALWR was derived from the System 80 NSSS over an eight year period of design evaluations. Changes that were made concluding in the System 80+ systems and component configurations, have resulted in substantial increases in plant safety. The plant changes that increase safety are evident in the plant design and the verifications of their safety benefit are evident in the increased operating margins and in the PRA evaluations presented in CESSAR-DC. Interactions among the plant systems and the control and protection systems have been studied and refined to yield the integrated System 80+ design. Significant changes at this point in the design evolution to accommodate new bases for safety analyses and/or new acceptance criteria for Design Basis Events must be thoroughly evaluated if the effectiveness of the System 80+ integration is to be maintained. With these considerations in mind, and after considerable study involving tradeoffs and performance evaluations of the System 80+ Standard Plant we consider the following design features to best meet the goal of significantly reducing the probability of containment bypass due to SGTR. These features are:

1) A design change to add two N-16 monitors, one per steam generator, to assist in the diagnostics of the event. The signal would be latched to prevent loss of signal on reactor trip. These monitors would be in addition to the present System 80+ steamline area radiation monitors and sample and blowdown radiation monitors.

2) A design change to the System 80+ Component Cooling Water (CCW) system to permit the steam bypass system to continue to operate after SIAS is reached. It assures CCW to the air compressors following SIAS so that actuation air is available to the steam bypass valves indefinitely.

3) The main feedwater control system (FWCS) in the present System 80+ design automatically terminates main feedwater following a reactor trip with reduced primary coolant temperatures. This helps to offset the leak flow, extending the ruptured SG fill time.

4) The Rapid Depressurization System (RDS) discharging to the IRWST is actuated by the operator when MSSVs are challenged. The RDS is already a part of the System 80+ design.

5) The NUPLEX 80+ control room assists the operator in the diagnostics of events. NUPLEX 80+ is already a part of

the System 80+ design.

6) The turbine bypass system for which all valves direct secondary flow to the condenser eliminates two paths to the atmosphere and is already part of the present System 80+ design.

7) The IRWST in the current System 80+ design is both a large source of safety injection water and a quench tank that confines blowdown fluids within the containment. It contains greater than 500,000 gallons of borated water and can be refilled by the CVCS from the Boric Acid Storage Tank which contains 250,000 gallons of borated water.

8) The large secondary side volume of the System 80+ SGs provides extra capacity and therefore extended operator action time before the MSSVs are challenged.

The above features have been evaluated in order to obtain a measure of their contribution to reducing the risk of containment bypass. It is estimated that the summation of the individual effects produce greater than two orders of magnitude reduction in risk of containment bypass from SGTR relative to the previous System 80 design.

Not factored into the above quantification is the very real prevention feature inherent in the System 80+ design due the change of material in the SG tubes from Inconel 600 to Inconel 690 and the lowered operating temperatures.

2.2 Response of System 80+ Plant to SGTR

The System 80+ plant design, as discussed in Section 2.1, was analyzed for the rupture of one to five steam generator tubes. The analyses, assumed only one change from the current System 80+ design. That is the change that assures continued operation of the steam turbine bypass system following a SIAS. The only other change to the current design that was proposed above in Section 2.1 is the addition of N-16 monitors to help the operator diagnose the SGTR event. Although N-16 monitors would aid the operator during this event, their addition would not change the analysis results presented here because the analysis assumes no operator action prior to MSSV opening.

The significant result of the analyses is the length of time between event initiation and opening of the MSSVs. With the above analysis assumption and only automatic response of plant systems this time varies from greater than four hours for rupture of one tube to one half hour for rupture of five tubes. Figure 2-1 shows the relationship between the number of ruptured tubes and the time

at which the MSSVs open. The times shown are adequate for the operator to diagnose the SGTR event and to initiate appropriate action to prevent release from the secondary system.

Operator actions following a SGTR event normally include minimization of the break flowrate and control of primary and secondary pressures and levels by using plant operating and emergency systems described in Section 3.1.1.

If the operator should fail to act prior to the opening of the MSSV or if the bypass system should fail and cause the MSSV to open much sooner, the current System 80+ design affords two additional contingency actions the operator can take to halt the release to atmosphere. One contingency action is actuation of the Reactor Coolant Gas Vent System (RCGVS) or the Rapid Depressurization System (RDS). The operator would manually open the RDS and blow down the primary side, discharging into the IRWST. After the MSSVs reseat, the primary pressure continues decreasing until the pressure differential at the SGTR break location is approximately zero, halting the release of primary coolant into the steam generator. Using the combination of throttling capabilities of the RCGVS or RDS and of the SIS (HPSI) pumps, the operator maintains both primary subcooling and minimum pressure differential at the tube break while holding secondary pressure below the MSSV setpoint. Figure 2-2 shows the transient pressures on the primary and secondary sides when the SDS is opened.

The other contingency available to the operator when the MSSVs open is the High Capacity Blowdown System. The current System 80+ design inlcudes the capability to blow down liquid from the steam generators during shutdown conditions at a variable rate with a maximum equivalent to 8% of the full power main steam mass flow rate. The operator would utilize the blowdown system to limit the maximum water level and/or to reduce the pressure in the steam generator. Figure 2-3 shows the transient pressures on the primary and secondary sides when the high capacity blowdown system is utilized to prevent release through the MSSVs.

Should a MSSV stick open these contingency actions would rapidly lower the secondary pressure minimizing the release rate and tending to reseat the stuck MSSV.

2.3 Probabilistic Evaluation of System 80+ Plant Containment Bypass Give A SGTR

Emphasis in this evaluation is on containment bypass via an assumed stuck open MSSV following a Steam Generator Tube Rupture (SGTR) event. System 80+ includes a number of design features that reduce the potential for lifting the MSSVs following an SGTR. These were listed in Section 2.1.

The purpose of this evaluation is to evaluate the impact of System 80+ design features on the potential for containment bypass via a stuck open MSSV. The evaluation is based on the following assumptions and conditions:

1) Best estimate transient analysis has shown that for a SGTR with 5 tubes ruptured, the operators have 30 minutes in which to take action to prevent lifting the MSSVs in the ruptured SG if the Turbine Bypass Control System (TBCS) is operating.

2) Best estimate transient analysis has shown that for a SGTR with 5 tubes ruptured, the MSSVs on the ruptured SG will lift if the TBCS fails to operate.

3) At 30 minutes for a five tube SGTR with the TBCS operating, the operators must establish RCS pressure control by throttling the HPSIs, and they must establish pressure and level control in the ruptured SG using either the ADVs or the blowdown system in order to preclude lifting the MSSVs.

4) If the Rapid Depressurization System (RDS) valves are opened within 30 minutes, they will depressurize the RCS sufficiently to preclude opening the MSSVs even if the Safety Injection pumps are not throttled.

5) If the TBCS fails, only the first two banks of MSSVs on the ruptured SG will lift.

6) If the MSSVs lift and pass steam, the probability that they fail to reclose is calculated as 7.0E-03 per valve.

7) If the MSSVs open and pass water, the probability that they fail to reclose is assumed as 1.0.

8) The N16 detectors, coupled with the NUPLEX 80+ Advanced Control Complex make it much easier for the operators to diagnose and respond to an SGTR. Therefore the operator error rate is significantly reduced. It was assumed the operator error rate would be 50 % less than for a plant without the NUPLEX 80+ Advanced Control Complex and the N16 detectors.

9) The base operator error rates used in this analysis are based on the single tube rupture case which has longer time available for operator action. These values were not recalculated for the 5 tube rupture case because only the changes in the conditional probabilities are of interest. Thus, the base conditional probabilities are purely figures of merit on which the deltas are based.

The SGTR analysis in the System 80+ PRA includes a model for failure to isolate/terminate the leak on the ruptured SG. Part of

this model represents opening of the MSSVs and a consequential failure to reseat. This portion of the model was modified slightly and converted to a stand-alone model (see Appendix A). This stand-alone model was used to evaluate the impact of the various design features. The model was first quantified using the System 80+ base failure rate data to generate the conditional probability for a stuck open MSSV for System 80+. Next, the TBCS portion of the model and the RDS portion of the model were set to "Failed" and the operator error rates were doubled to simulate not having the benefit of the N-16 monitors and the NUPLEX 80+ Advanced Control Complex to diagnose a SGTR. This represented the base case for a generic System 80 plant. This modified model was quantified to generate the conditional probability for a stuck open MSSV for a generic System 80 plant. Next, a set of three cases were run to evaluate the benefit of adding the various design features. These cases are as follows:

1) The TBCS portion of the System 80+ model was disabled (set to "Failed"), the SDS portion of model was disabled, and System 80+ operator error rates used. This evaluated the impact of adding N16 detectors and the NUPLEX 80+ Advanced Control Complex to the generic System 80.

2) The TBCS portion of model was enabled, the RDS portion of model was disabled, and operator error rates twice those of System 80+ were used. This evaluated impact of not isolating CCW to the IA compressors on SIAS for the generic System 80 plant.

3) The TBCS portion of model was disabled, the RDS portion of model was enabled, and operator error rates twice those of System 80+ were used. This evaluated the impact of adding the RDS to the generic System 80 plant.

The results of these cases are summarized in Table 2-1. The listings of the cutsets for all three cases are given in Appendix A.

Two improved design features were not directly evaluated. First, the System 80+ design has larger steam generators than System 80 plants. Transient analysis indicates that this additional SG size provides about 5 additional minutes to respond to the transient. This is a benefit, but the methodology used for quantifying operator error rates for the System 80+ PRA does not have sufficient resolution to calculate the benefit in terms of changes in the operator error rates. Second, For System 80, two of the TBVs dump directly to atmosphere. These valves tend to be in the last bank of TBVs that would open. If these valves are opened on an SGTR, there is the potential that they could fail to reclose. If the MSIV on the ruptured SG is not closed, this would present a bypass path, albeit a low probability one. For System 80+, all TBVs dump directly to the condenser, so there is minimal bypass via

the TBVs for System 80+. This was not directly evaluated because it would have required extensive model changes. Bypass of radiation to the atmosphere via the condenser is reduced by retention in the liquid condensate.

The results of this evaluation indicate that the conditional probability of a containment bypass via the MSSVs given an SGTR for System 80+ is about two orders of magnitude lower than for System 80. The most important design feature is ensuring that the TBCS continues to operate following SIAS.

TABLE 2-1

Evaluation of Benefit of Adding Design Features to System 80 to Preclude Lifting MSSVs on SGTR

PLANT	FEATURE	BENEFIT	Conditional Probability of Stuck Open MSSV	% Reduction
System 80 (Base)		n/a	6.96E-02	-
Add Only	N16 Detectors plus Advanced Control Room	Faster and more accurate identification of SGTR and status of equipment. Reduce operator error rates by 50%	6.30E-02	10%
Add Only	Cooling Water to Instrument Air Compressors not lost on SIAS	Turbine Bypass Control System not failed on SIAS	9.59E-03	86%
Add Only	Safety Depressurization System	Alternate Method to achieve RCS pressure control in time to prevent lifting of MSSVs	5.63E-02	19%
Add Only	Larger Steam Generators	Approximately 5 minutes longer before MSSVs lift. Slight increase in operator reliability	not quantified	
Add Only	All Turbine Bypass Valves discharge only to containment	Eliminate potential containment bypass path	not quantified	
System 80 +	Includes all added features above		2.28E-04	99.7%

FIGURE 2 - 1

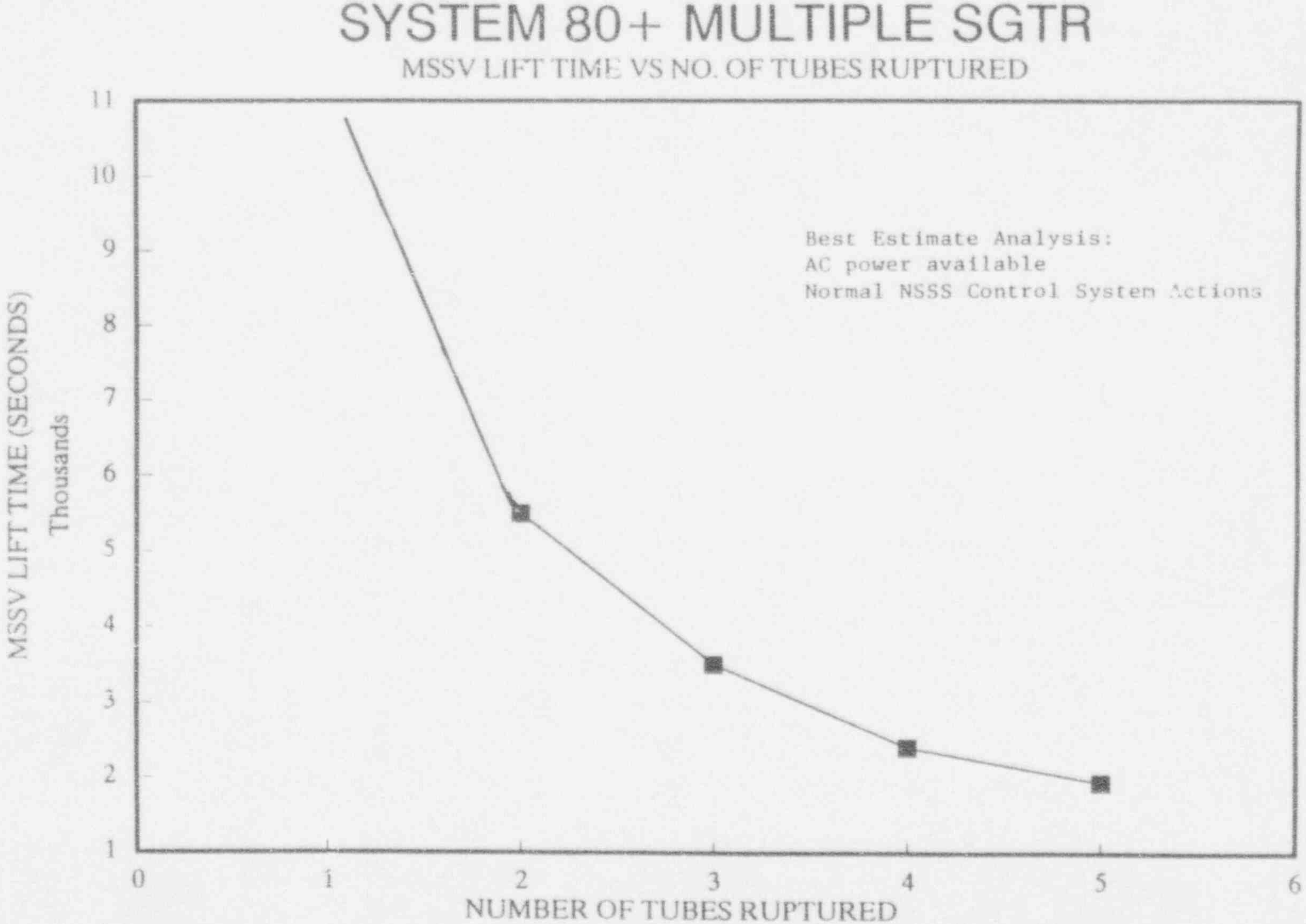

SYSTEM 80+ MULTIPLE SGTR
MSSV LIFT TIME VS NO. OF TUBES RUPTURED
Best Estimate Analysis:
AC power available
Normal NSSS Control System Actions
MSSV LIFT TIME (SECONDS)
Thousands
NUMBER OF TUBES RUPTURED
11
10
9
8
7
6
5
4
3
2
1
0
1
2
3
4
5
6

FIG. 2-2 RCS and SG Pressure vs. Time for 5 Tubes Ruptured and Automatic Rapid Depressurization System

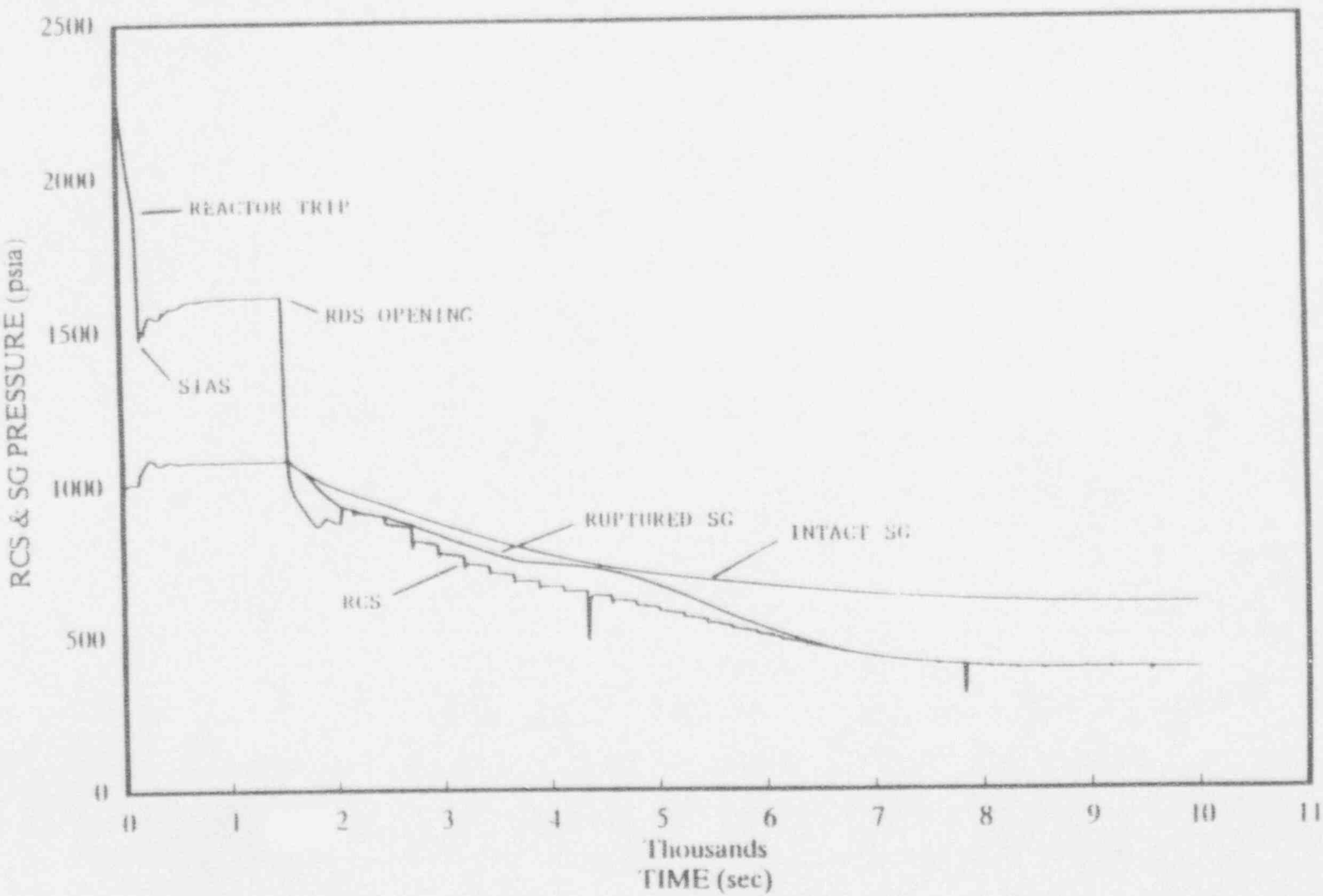
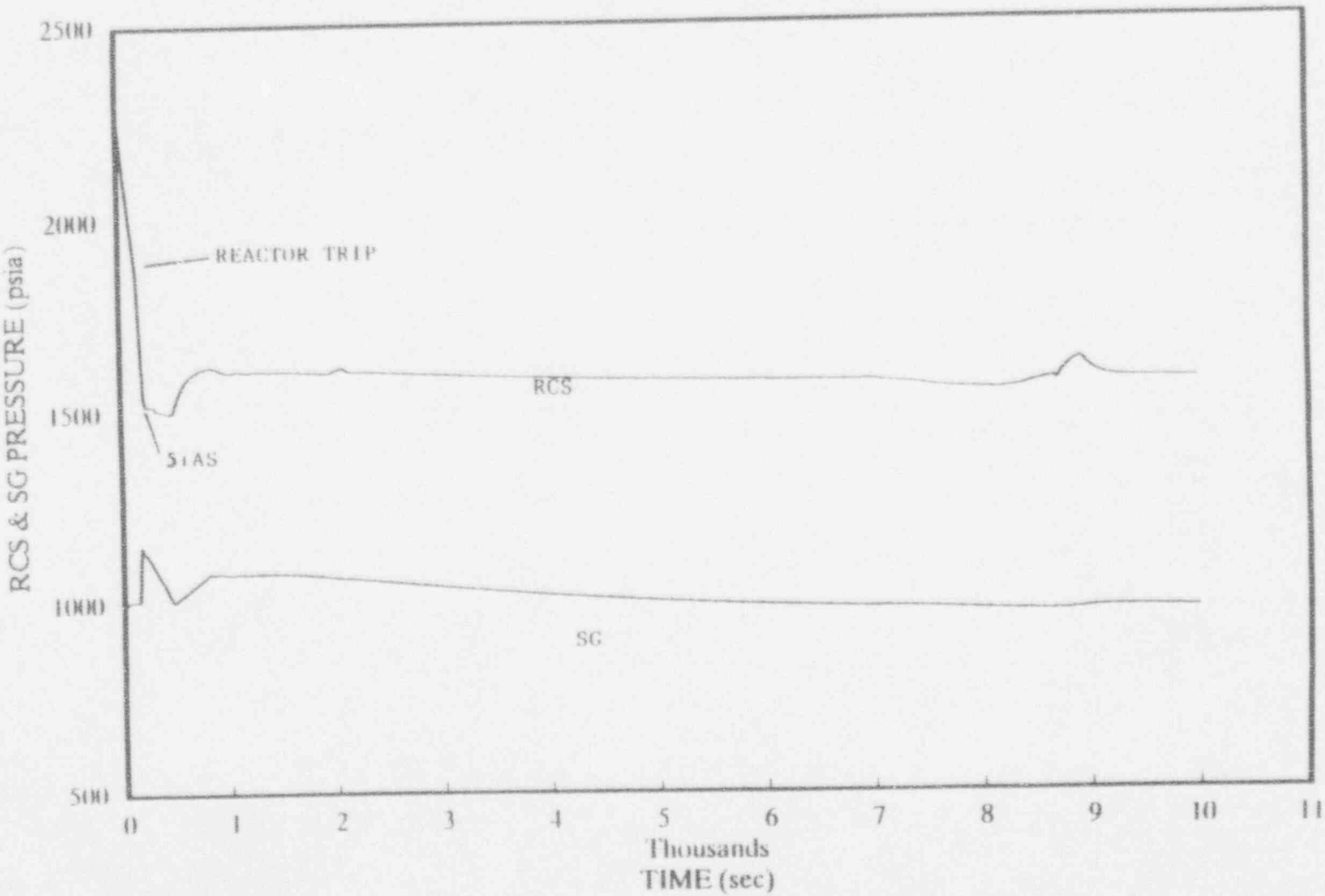


FIG. 2-3 RCS and SG pressures vs. Time for 5 Tubes Ruptured and Automatic SG Liquid Blowdown



3.0 DISCUSSION OF DESIGN CHANGES EVALUATED

Analysis and evaluations were performed on the current System 80+ design and on eleven proposed changes to the current design. This section presents a summary of the analytical results and an overview of the evaluation. Detailed analytical results are presented in Section 4.0.

A description of each change is given. These changes have been carried through design process sufficiently to support the conclusions of the evaluations.

Benefits of each design change are highlighted, followed by the limitations.

3.1 Current System 80+ Design

3.1.1 Description of Current Design

The current System 80+ design provides a number of systems for use in mitigation of a tube rupture event. The design basis of these systems are not typically for the prevention or mitigation of a steam generator tube rupture event, however, their use, whether automatic or manual, decreases the probability of a main steam safety valve from lifting. The following systems will help mitigate the consequences of a tube rupture event:

1 - The Turbine Bypass System is an automatic system which provides a path to remove steam from the steam generators. In the event of steam generator tube rupture, the TBS will automatically relieve secondary pressure and dump steam to the condenser (See Section 5.5 for more detailed description). This system will regulate the pressure in the secondary system below the MSSV setpoint and remains effective until a MSIS is generated on high steam generator level.

2 - The operator has the capability to initiate pressurizer spray if the Reactor Coolant pumps are operating or auxiliary pressurizer spray if the RCPs are tripped. The pressurizer spray will reduce the primary pressure, thus, decreasing the primary to secondary leakage

3 - The operator has the capability to throttle the safety injection pumps in order to lower the primary system pressure. This, if used in conjunction with the main or auxiliary spray, will allow the operator to reduce primary pressure, even to the point where there is almost zero leakage.

4 - The operator has the capability to use high capacity steam generator blowdown to remove secondary inventory and reduce pressure. The blowdown system dumps to the condenser limiting radioactive releases.

5 - The operator has the capability to operate the manually controlled atmospheric dump valves. These valves vent to atmosphere, however, their use allows for a controlled vent to atmosphere unlike a MSSV lift. They also have upstream block valves which are used to isolate unwanted atmospheric discharges.

6 - In the event that the non-safety main and auxiliary pressurizer spray systems are unavailable, the operator can use the RCGVS to vent the pressurizer and lower RCS pressure. This may also be used in-conjunction with throttling the SI pumps to minimize leakage.

7 - If the RCS requires quick depressurization to prevent the MSSVs from opening, the operator can use the Rapid Depressurization System to blow down the RCS to the IRWST in Containment. This will limit the primary to secondary leakage. The RDS can also be used in conjunction with throttling the SI pumps to terminate primary to secondary leakage through the tube rupture.

8 - N-16 radiation monitors are being added in the secondary system to provide a quicker indication that a steam generator tube rupture has occurred. These are additional to the area radiation monitors currently located near each steam line upstream of the MSSVs.

The current System 80+ design allows a number of options for the operator to prevent the MSSVs from lifting.

3.1.2 Benefits

If no operator action is assumed, the Turbine Bypass System will continue to prevent MSSV opening for more than four hours for a one tube rupture case. In the unlikely event that a five tube double ended guillotine rupture occurs, the operator has approximately 30 minutes before the steam generator will become isolated by high level and the MSSVs will lift shortly thereafter.

The operator has a number of options to limit secondary system pressure to prevent the MSSVs from lifting and creating a containment bypass.

3.1.3 Limitations

The System 80+ design does not have the capability to prevent MSSV lift without operator action for an extended period of time (> 30 minutes) following rupture of 5 tubes.

3.2 Automatic Bypass of Main Steam Isolation Signal on High Steam Generator Level

3.2.1 Description of Change

A Main Steam Isolation Signal (MSIS) is an Emergency Safety Feature Actuation Signal (ESFAS) generated on either high steam generator level or low steam generator pressure. In the current System 80+ design, when a high steam generator water level occurs (approximately 95% narrow range level indication), the Plant Protection System (PPS) generates a MSIS signal which closes the MSIVs and the MSIV bypass valves, the MFIVs, the EFW isolation valves, the Blowdown Isolation Valves and the Sampling System Isolation Valves. These valves are containment isolation valves (See Table 5-1). The isolation valves close or are confirmed closed (sampling and MSIV bypass), effectively isolating the affected steam generator. This function isolates paths which may provide escape routes for radioactivity and also prevents steam generator water level from reaching the steam lines downstream of the MSSVs.

Bypassing the MSIS to the MSIVs on high steam generator level is an option being considered to help mitigate the consequences of the tube rupture event. If a tube rupture event occurs, a signal will be generated from the N-16 radiation monitors on the steam lines. This signal, coincident with a reactor trip signal and high steam generator level signal, will bypass the MSIS to the MSIVs preventing the valves from closing and isolating the steam lines. With the steam lines unisolated, the Turbine Bypass valves in the Steam Bypass Control System are still available to remove steam and regulate the secondary pressure below the main steam safety valve setpoint.

3.2.2 Benefits

No new hardware is required to implement the change and extend the time before operator action is required

The high level MSIS is not credited in the Chapter 6 or 15 Safety Analyses, therefore, it would not have an impact on these Analyses

3.2.3 Limitations

The affected steam generator will eventually overfill. The main steam piping is not designed to accommodate flowing water. Stress analysis for the piping and nozzles and water hammer analyses would need to be done. This may result in additional piping supports making the design more complex.

The turbine bypass system is not designed to accommodate water. Re-evaluation of the sizing of the turbine bypass valves and system piping may result in different turbine bypass valves, and new piping supports. Two phase flow to the condenser will affect its structural design as a result of the higher flow loads.

The design of the turbine stop valves will have to be assessed to determine the effects of water and two phase flow on water hammer events.

The impacts of water flowing in the main steam system will have to be addressed for other main steam system branches such as extraction steam for the EFW turbine driven pump and feedwater heaters. The possibility of boron depositing in the secondary system due to water flow will have to be analyzed.

In addition, redesign of the control systems for this function may impact the Probability Risk Assessment (PRA) or plant availability. The ultimate configuration will be a first of a kind with unproven performance and additional complexity.

New instrumentation will be a first-of-a-kind design.

3.3 Automatic Initiation of Auxiliary Pressurizer Spray

3.3.1 Description of Change

The Chemical and Volume Control System (CVCS) auxiliary spray is currently designed to provide auxiliary spray for control of pressurizer pressure and to allow for pressurizer cooling during final stages of normal shutdown when the RCPs are not operating to provide main spray capability. The auxiliary spray design consists of a pipe connection from the charging pumps that ties into the main pressurizer spray lines. A normally closed isolation valve prevents flow during normal operation. Operator action is required to initiate auxiliary spray to depressurize the RCS. Auxiliary spray is not required to perform any accident mitigation or safe shutdown functions for design basis events.

A design change considered to mitigate the consequences of a steam generator tube rupture event is to provide a signal to open the auxiliary spray isolation valve based on radiation detection (N-16) coincident with a reactor trip signal. In the event of a tube rupture, the reactor will trip and the N-16 monitor will generate a signal which will open the auxiliary spray isolation valve, start a charging pump if one is not already operating, align a source of water and start to depressurize the RCS. Lower RCS pressures will decrease the primary to secondary leakage and delay or possibly prevent the secondary pressure from reaching the MSSV setpoint.

3.3.2 Benefits

This design change requires minimal hardware changes but may require modification of control systems.

3.3.3 Limitations

In order to maximize auxiliary spray flow to obtain a rapid depressurization, the charging pumps would have to be isolated from the RCS. This would require additional changes to the control system including interfacing safety and non safety control signals

A similar design has been used in Europe (Reference 6-4) where rapid depressurization minimizes the primary to secondary flow. However, the European design receives a SIAS with a coincident low pressurizer pressure and low pressurizer level. In the System 80+ design a SIAS occurs only on low pressurizer pressure. Therefore, the Safety Injection pumps will actuate and keep the RCS pressure high effectively defeating the auxiliary pressurizer spray from depressurizing the RCS. If the pressurizer goes solid, there is no benefit for auxiliary spray. Controlling or terminating SI flow using pressurizer level was not considered for System 80+ over

concerns for level measurement inaccuracies and increased core damage frequency (PRA).

3.4 Automatic Opening of the Reactor Coolant Gas Vent System on the Pressurizer

3.4.1 Description of Change

The System 80+ Reactor Coolant Gas Vent System (RCGVS) is a safety grade system designed to manually vent steam and non-condensible gases from either the pressurizer and/or the reactor vessel upper head. The RCGVS consists of piping and valves which come off of the pressurizer and the reactor vessel upper head and normally vent to the IRWST. During operation of the system, the operator manually aligns the piping train from either the reactor vessel or the pressurizer and depressurizes the RCS by venting to the IRWST. The RCGVS is designed and required to be operable during all design basis events

A change considered to prevent MSSVs from opening during a tube rupture event is to automatically open the RCGVS valve train off of the pressurizer. If a tube rupture occurs, a N-16 monitor in the secondary system will generate a signal which, coincident with a reactor trip signal, will actuate the RCGVS valves providing a vent path from the pressurizer to the IRWST. This will cause a depressurization of the RCS and lower the primary to secondary leak rate, effectively extending the time before operator action is required to prevent MSSV lifting.

3.4.2 Benefits

There are minimal hardware and software changes.

3.4.3 Limitations

The RCGVS function is required for design basis events. Supplying non-safety grade signals from a new instrument control system to these valves for actuation will complicate the design of the system and may impact the availability of the system for use during other required operations.

Depressurization is similar t~ using auxiliary pressurizer spray in that the safety injection pumps will acuate and increase the RCS pressure. The RCGVS does not have the required capacity to remove adequate safety injection flow to prevent the RCS from repressurizing above the MSSV lift pressure.

3.5 Automatic Initiation of Steam Generator Blowdown System

3.5.1 Description of Change

The System 80+ steam generator blowdown system is designed to operate manually and on a continuous basis as required to maintain acceptable steam generator secondary side water chemistry. Each steam generator is equipped with its own blowdown line with the capability of blowing down the hot leg and/or the economizer regions of the steam generator shell side. The liquid blowdown effluent is routed outside containment to a blowdown flash tank and/or the condenser. During normal operation the blowdown system removes either 0.2% or 1% (depending of water chemistry) of the main steam rate from the steam generators. High capacity blowdown (approximately 8% of the main steam rate) is used periodically to remove any corrosion products on the tube sheet. The blowdown system is isolated automatically on a Containment Isolation Signal, a Main Steam Isolation Signal, or a Emergency Feedwater Actuation Signal. For a more detailed description see Section 5.4.

The blowdown system provides a potential pathway to remove mass and energy during a steam generator tube rupture event, thus, preventing the MSSVs from opening. Because the isolation function of the blowdown system is credited in the safety analysis, the direct pathway to the condenser is unavailable (without manual override) during a tube rupture event. However, a modification in the design of the system could help mitigate the consequences of a tube rupture event (see Figure 3.5-1). A new pipe line would tee off of the common blowdown line upstream of the first containment isolation valve and bypass the containment isolation valves through a new containment penetration. Outside containment, the pipe line would tee back into the blowdown line just outside of containment to minimize new piping. Two normally closed isolation valves in series would be provided to isolate this bypass route during normal operation. A control system using coincident signal from a N-16 monitor, a high steam generator level and a reactor trip would open the bypass isolation valves and the high capacity blowdown control valve to the condenser. This action would remove mass and energy from the affected steam generator and prevent MSSV lift.

3.5.2 Benefits

Major benefit from this design change is realized for the high capacity blowdown rate (8% full power steam flow rate). This rate is adequate to accommodate the break flow from a 5 tube rupture. Draining the steam generator fluid via the blowdown delays the generation of an MSIS on a high steam generator level (greater than 10000 seconds) and actuation of the MSSVs subsequent to isolation of the steam bypass system.

Figure 3.5-2 illustrates the secondary side transient pressure for a rupture of 5 tubes. It shows that automatic actuation of the

steam bypass system and the high capacity steam generator blowdown system maintains the secondary side pressure well below the MSSV actuation setpoint of about 1200 psia.

3.5.3 Limitations

The current design of the blowdown system is able to accommodate 3 blowdown rates, 0.2%, 1.0% and 8% of the main steam rate. The 8% blowdown rate is needed to remove the energy from multiple tube ruptures (up to five tubes). For a one tube rupture case, 8% blowdown is sufficient to cause emergency feedwater to actuate and still dry out the steam generator. Automatic actuation of blowdown without operator intervention results in a large pressure differential between primary and secondary and a high flow rate from the break into the secondary and then out of containment unless a level control system were also added.

The CIAS which isolates the blowdown cannot be interfaced with the control grade N-16 signal per Regulatory Guide 1.75 and IEEE 384. Therefore, this redesign requires the addition of new containment penetrations, one for each steam generator. The impacts of new containment penetrations that are not isolated on a Containment Isolation Signal, or a Main Steam Isolation Signal or a Emergency Feedwater Actuation Signal, will have to be assessed with regard to Containment design, Safety Analyses, Inservice Test and Inspection, etc,.

Automatic blowdown to the condenser during a tube rupture event still provides an indirect path for radioactivity to reach the atmosphere. To transport the 8% flow continuously to the condenser, modifications are needed in the blowdown system.

If the condenser is unavailable the radioactive effluent will go to the flash tank which has a limited capacity (approximately 2 minutes of high capacity). Eventually the flash tank safety valve set pressure will be reached and the tank will vent directly to atmosphere.

FIGURE 3.5-1

AUTOMATIC STEAM GENERATOR LIQUID BLOWDOWN TO CONDENSER

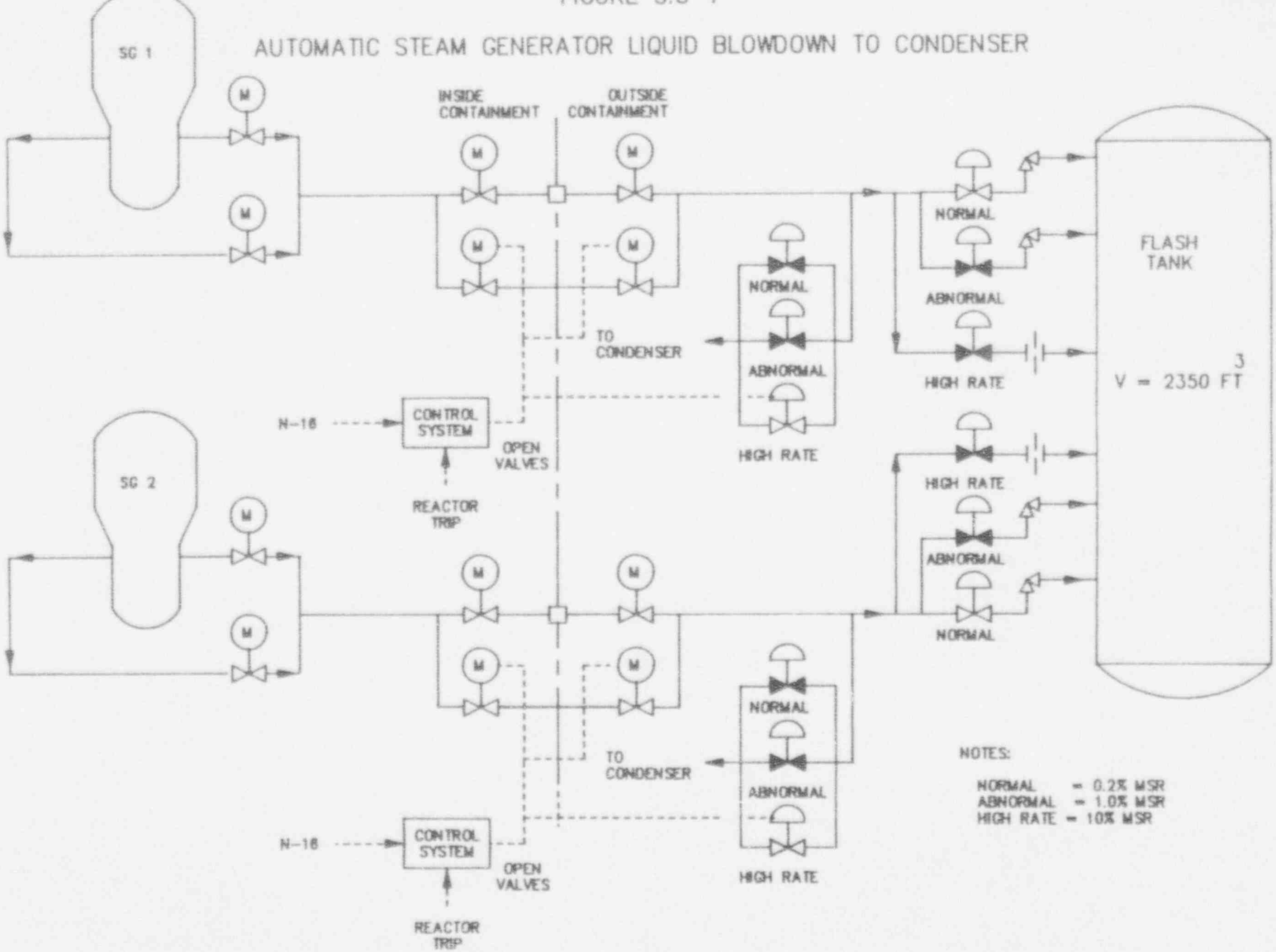
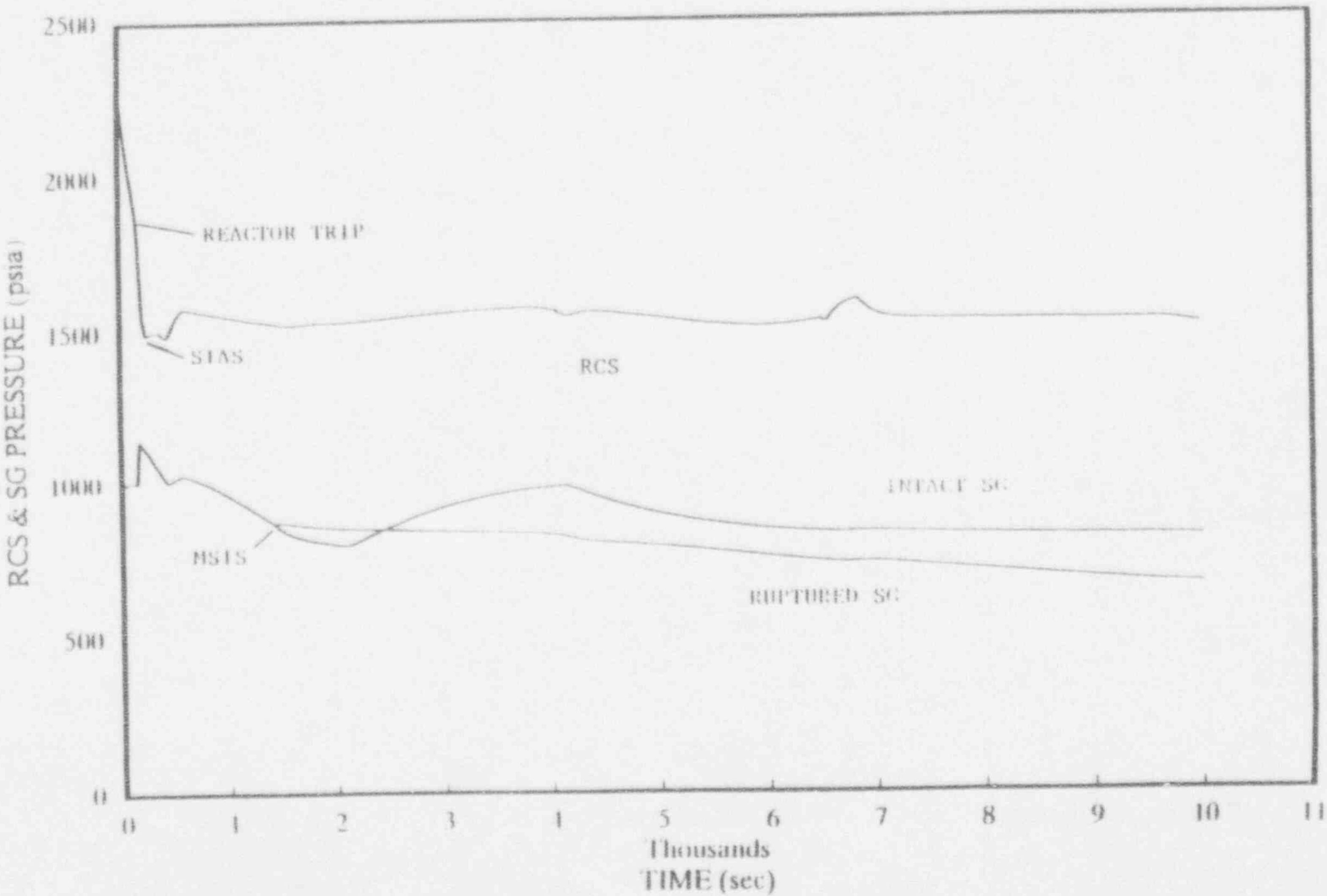


FIG. 3.5-2 RCS and SG Pressures vs. Time for 5 Tubes Ruptured and Automatic SG Liquid Blowdown to Condenser



3.6 Automatic Reduction of Post Trip Turbine Bypass Control System Set Pressure from 1100 psia to 900 psia

3.6.1 Description of Change

The non safety grade Turbine Bypass System (TBS) is provided to accommodate load rejection in conjunction with the Reactor Power Cutback System without tripping the reactor or lifting tne primary safety valves or the MSSVs. Eight valves tee off of the main steam header and vent to the condenser. The valves are actuated by the Steam Bypass Control System which uses steam flow, steam header pressure, and primary pressure as inputs. For a more detailed description see section 5.4

A change considered to help mitigate the consequences of a steam generator tube rupture event is to lower the current post trip secondary pressure setpoint from 1100 psia to 900 psia automatically based on a signal generated from a N-16 radiation detector in the main steam lines. In a normal post trip scenario, the TBS would open and remove the required steam to maintain the RCS average temperature at a no load condition. In a SGTR post trip condition the TBS would remain open until the secondary pressure is reduced to approximately 900 psia, essentially lowering the RCS temperature.

3.6.2 Benefits

There are no difficulties interfacing the non 1E N-16 signal with the non 1E SBCS.

3.6.3 Limitations

This design change prevents pressure buildup in the steam generators, however, for a five tube rupture, the level in the steam generator would increase until a MSIS on high SG water level occurs. An MSIS would isolate the TBS from the affected steam generator which would allow the pressure to increase and the safety valve set pressure to be reached.

During a five tube SGTR event, the System 80+ design with a lowered pressure setpoint in the TBS gains only an added 3 minutes in delaying MSSV lift.

With a low setpoint and a single failure, there is a possibility of blowing steam to the condenser until 900 psia is reached in the steam generators. This scenario is not addressed in the design of the TBS or the condenser.

3.7 Automatic Opening of Turbine Bypass System and Bypass of MSIS on Low Steam Generator Pressure

3.7.1 Description of Change

This change proposes automatic opening of the turbine bypass system to relieve pressure in the affected steam generator and bypassing the main steam isolation signal on low pressure in order to allow continued use of the turbine bypass system.

The current TBS valves open when a low steam flow and high pressure is sensed in the steam lines. The design change would require a new control system which would use a signal generated from an N-16 monitor on the main steam line coincident with a reactor trip to automatically open the TBS valves to the condenser (as opposed to the current TBS which modulates the TBS valves based on system pressure). This would reduce secondary system pressure.

The second change in this option is to bypass the MSIS on low steam generator pressure. If a MSIS is generated, the MSIVs will isolate the TBS causing the MSSVs to lift. If the MSIS is bypassed, the MSIVs will remain open allowing the TBS to reduce the steam generator pressure.

3.7.2 Benefits

This design change will extend the time before operator action is required to prevent MSSVs from lifting.

3.7.3 Limitations

Similar to Change 3.2, this design change will not prevent water from eventually entering the steam lines if the operator does not take action. This will require the steam system and the TBS to be designed for steam, water and two phase flow conditions which require "first of a kind" engineering.

Adding a non 1E controller to bypass the safety grade MSIS requires an interface between 1E and non 1E signals which must be isolated based on the design guidance in IEEE Standards 279, 603, 384 and Regulatory Guides 1.153 and 1.75.

Reducing the secondary pressure without any method of reducing the primary pressure will cause an increase in the primary to secondary pressure drop and leak rate.

3.8 Automatic Opening of the Rapid Depressurization System

3.8.1 Description of Change

The System 80+ Rapid Depressurization System (RDS) provides a manual means of quickly depressurizing the RCS when normal and emergency feedwater are unavailable for core cooling. Two independent pipe trains are connected to the pressurizer steam space and discharge directly to the IRWST. In each train, there are remote manually operated isolation and control valves. The failure of any one component will not prevent the RDS from fulfilling its design basis. During a total loss of feedwater event, the operator opens the isolation and control valves to depressurize the RCS and allow Safety Injection pumps to feed the RCS.

A potential change considered to prevent MSSVs from opening during a SG tube rupture event is to automatically open the RDS valves and depressurize the RCS. This would require a new control system to open the valves for unique symptoms of a tube rupture event. If a tube rupture occurs, N-16 monitors on the steam lines will generate a signal which, coincident with a reactor trip signal will open the RDS valves providing a vent path from the pressurizer to the IRWST. This will cause a rapid depressurization of the RCS which will lower the primary to secondary leak rate, effectively extending the time before operator action is required. The capacity of the RDS is such that it can remove the safety injection flow to an extent where primary and secondary pressures are approximately equal. This prevents primary to secondary flow and secondary pressure buildup and subsequent MSSV lift.

3.8.2 Benefits

The major benefit of this design change is the elimination of the damaged SG level buildup and subsequent challenge to the MSSVs. As shown in Figure 3.8-1, actuation of the RDS prior to generation of an MSIS causes a rapid depressurization of the RCS resulting in the RCS pressure decreasing below the steam generator pressure. This would cause the break flow to decrease to zero and then reverse the direction (i.e., flow from secondary side to primary side).

As long as the RDS is open, the differential pressure between the secondary and primary sides would remain positive resulting in a decrease in the damaged steam generator level and pressure. Hence, no challenge to the MSSVs occurs.

3.8.3 Limitations

The Rapid Depressurization System was designed to be manually operated for a beyond design basis event of a total loss of feedwater. Use of this system takes into account operator action to trip the Reactor Coolant pumps to prevent damage if the RCS

pressure drops below the NPSH requirements, operator action to align cooling systems to remove heat from the IRWST, operator action to throttle the RDS valves based on changing RCS parameters, etc. Automating the RDS would require all the manual tasks required with a use of the system to also be automated. The complexity of the transient the RDS is designed for, constrains the design to manual operation.

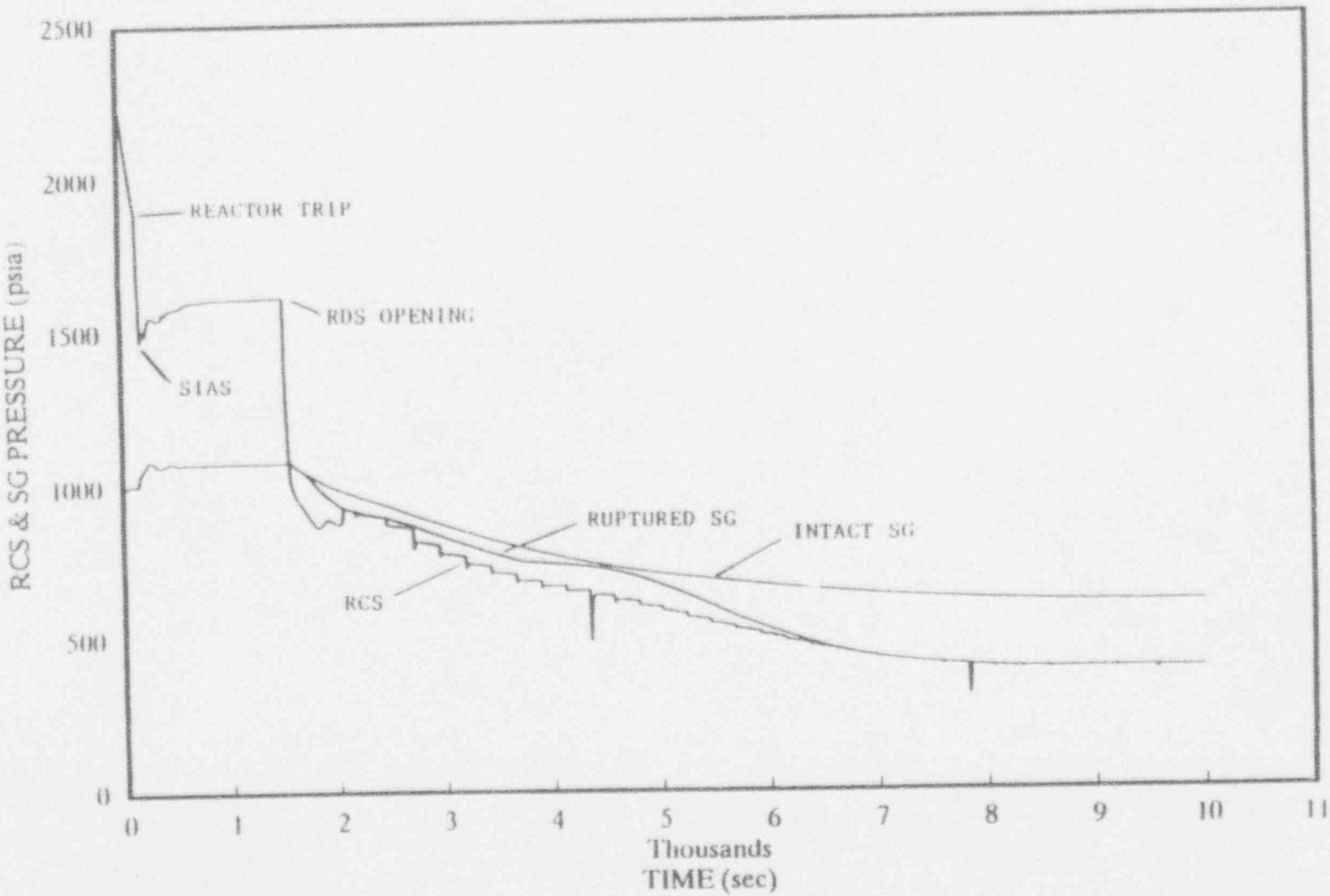
Similar to the new blowdown option into the IRWST, this design change will cause environmental conditions inside containment, including the risk from containment spray actuation, to exceed the design limitations of the non qualified hardware in containment. This has the potential to result in pre-mature replacement of the hardware. This may also challenge the lifetime of the qualified hardware by increasing the cumulative exposure of the equipment to high temperatures, high pressures, and high radiation resulting from the RCS blowdown.

Inadvertant and/or automatic operation of this new system can clearly result in a loss of RCS subcooling with attendent fuel damage. This would exacerbate the possible radiation releases to be controlled during the SGTR event and risk investment protection for an inadvertant actuation.

If the RDS is going to be considered for design basis events, new thermal and hydraulic loads will impact the design of the RDS nozzles, piping, support system. These transient loads will impact the design of the RCGVS and the IRWST and may impose additional transients on RCS components.

Reverse leakage that is caused by the actuation of the RDS has the potential for boron dilution within the RCS. The original inventory in the damaged steam generator does not contain boron and mixing of this water with the RCS fluid causes the dilution.

FIG. 3.8-1   RCS and SG Pressures vs. Time for 5 Tubes Ruptured and Automatic Rapid Depressurization System



3.9 Increase Main Steam Safety Valve Setpressure

3.9.1 Description of Change

Each steam line in the System 80+ design has five main steam safety valves (MSSVs) to provide overpressure protection for the secondary side of the steam generators and the Main Steam System (MSS). The setpoints for the MSSV are staggered to limit the number of valves that will open dependent upon the severity of the accident. One valve in each steam line is set to actuate at 1185 psia, one valve in each steam line is set to actuate at 1220 psia and the last three valves in each steam line are set to actuate at 1245 psia. All MSSVs discharge directly to atmosphere.

Consideration was given to increasing the Main Steam Safety Valve (MSSV) setpoint by up to 300 psia to help mitigate the consequences of a steam generator tube rupture event. A higher pressure setpoint would increase the margin between the normal operating pressure and the relief valve setpoint which will extend the time before the operator must take action to prevent MSSV opening. Limitations from the impact on the small break LOCA prohibit an increase as large as 300 psi (see discussion below in Section 3.9.3).

3.9.2 Benefits

No new functional requirements or new kinds of equipment to implement the change which would delay opening of the MSSVs.

3.9.3 Limitations

This change would require the secondary system design pressure to be increased by 300 psia. Consequently, the weight of the steam generators would increase by up to 100 tons each. The added weight would require an increase in containment heat sinks. These factors would likely impact the volume and arrangement of the containment.

The RCS supports would need to be redesigned and/or re-evaluated to accommodate the increased loads. Any contribution to containment sizing must also be assessed.

For decreased heat removal events, RCS temperature and pressure would rise to a much higher value than in current plants. Pressurizer safety valve actuation would be more likely.

Unless the entire steam system and turbine are upgraded to 1500 psia, a second set of secondary side relief valves would be required downstream of the MSIVs to protect the lower pressure portion of the steam system whenever the MSIVs are open and the pressure is below 1500 psia but exceeds the downstream design pressure.

Feedwater systems would have to be designed to accommodate a higher design pressure.

The peak clad temperature calculated for the Design Basis small break LOCA would increase significantly as described in paragraph 4.3.9. The higher MSSV lift pressures would significantly reduce the SI flow during the small break LOCA unless the SI pump discharge head is increased accordingly. However, this is undesirable for the SGTR.

3.10 AUTOMATIC BLOWDOWN OF STEAM GENERATOR LIQUID TO IRWST

3.10.1 Description of Change

Each System 80+ steam generator is provided with both hot side and cold side blowdown lines. The blowdown system from each steam generator includes a 6-inch nozzle for hot leg blowdown and a 6 inch nozzle for the economizer blowdown. Both lines combine downstream of its respective isolation valve and is routed to the blowdown flash tank and/or the condenser, see Section 5.3 for a detailed description.

This design change is the addition of a new blowdown line connected to the common line downstream of the first set of blowdown isolation valves. This new line is routed to the In-Containment Refueling Water Storage Tank (IRWST) (see Figure 3.10-1). This new line (one per generator) contains two motor operated isolation valves in series that are normally closed. The system is designed to prevent the main steam safety valves from lifting in the event of a SGTR or to sufficiently delay the opening permiting operator intervention and the new system is designed to limit any impact on the existing blowdown system and IRWST. The isolation valves would be opened on coincident signals from the N-16 radiation monitors in the steam line, high steam generator water level, and a reactor trip. The IRWST would receive and cool the secondary system blowdown effluent by thermal mixing. In the event a low water level (approximately the Emergency Feedwater Actuation Setpoint) is reached in the affected steam generator, the isolation valves would close to prevent dryout of the steam generator. This design would effectively cycle the water level in the affected steam generator between the Emergency Feedwater low level setpoint and normal steam generator water level.

3.10.2 Benefits

The benefits of this change are the delay in actuation of the high SG level MSIS which causes isolation of the steam bypass system and the delay in opening of the MSSVs which causes release to the atmosphere. The magnitude of the delay is dependent on the blowdown flowrate and the number of ruptured tubes. For a blowdown rate equal to 7% (selected to be within current System 80+ design capability yet yielding several hours delay) of the full power main steam flowrate and with 5 ruptured tubes, the MSIS actuation is delayed for more than 10000 seconds (2.8 hours) and the MSSV lift is delayed longer. For the one ruptured tube case, the damaged steam generator level remains below the normal steam generator water level for more than 10000 seconds (2.8 hours). Therefore, blowdown actuation will not occur until a later time (greater than 15000 seconds) when the damaged steam generator level would reach the normal water level. Figure 3.10-2 shows the secondary side

transient pressure for a rupture of 5 tubes. Additional analysis details are given for this option in Section 4.3.10.

Another benefit of this design change is the elimination of the containment bypass by containing most of the break flow within the IRWST for a larger number of tube ruptures.

3.10.3 Limitations

Implementation of this design requires new valves, piping and control systems. The valves and piping would have to be designed for high energy liquid and two phase conditions. New high energy lines inside containment would require new supports and shields to satisfy separation requirements. This leads to extensive first-of-a-kind engineering.

For long blowdown periods, there is the potential of heating up the IRWST. With the selected 7% blowdown rate, the IRWST will become saturated approximately one hour after initiation of blowdown (at shutdown, the design value of blowdown is higher; the actual value will depend upon fluid conditions in the steam generator [see Section 5.4]). In about two hours, 6% of the IRWST will have evaporated. The high temperatures and evaporation of the heat sink will have an adverse impact on core cooling by reducing the subcooling of the injected flow.

Secondary contaminents (such as chlorides) will be transported into the IRWST (an open tank) and eventually pass into the RCS by way of the safety injection pumps. The new pipe train, when actuated, will direct secondary fluid into the IRWST, which will be transported to the RCS via the safety injection pump. Experience has shown that adding chlorides with oxygen present (oxygen ingress from the open tank atmosphere) and elevated temperatures can lead to stress corrosion cracking of stainless steel.

If the new blowdown system is designed for rupture of 5 tubes, it will exceed the break flowrate from a single ruptured tube. In the event the control system fails, the steam generator will reach the Emergency Feedwater actuation setpoint (approximately 25% Wide range (WR) SG level). The emergency feed system will then feed up to 800 gpm of unborated water into the IRWST resulting in a potential loss of reactivity control.

Discharging into the IRWST will require analysis of the loads due to potential concurrent SDS and steam generator blowdown. This may result in a redesign of the IRWST or a redesign of the sparger for the blowdown line. Addition of another large blowdown quench tank within containment has been suggested to prevent contamination of the IRWST and to prevent degradation of the SIS performance. Limitations would include space and supports within containment for a large enough tank, given that even the IRWST with 500,000 gallons of water would heat up. Adding a large tank would reduce

containment free volume which will have a detrimental impact on results for MSLB and LOCA events. Secondly, the ECCS coolant and primary coolant would be lost out the break to the new tank and could not be recirculated without additional piping interfaces.

Operation of the system may cause an increased radiation exposure to personnel and may cause environmental conditions inside containment to exceed the design limitations of the non-qualified hardware in containment. This will result in pre-mature replacement of the hardware. This may also challenge the lifetime of the qualified hardware by increasing the cumulative exposure of high temperature, pressures, and radiation resulting from a containment blowdown.

FIGURE 3.10-1
NEW SYSTEM FOR AUTOMATIC STEAM GENERATOR LIQUID BLOWDOWN TO IRWST

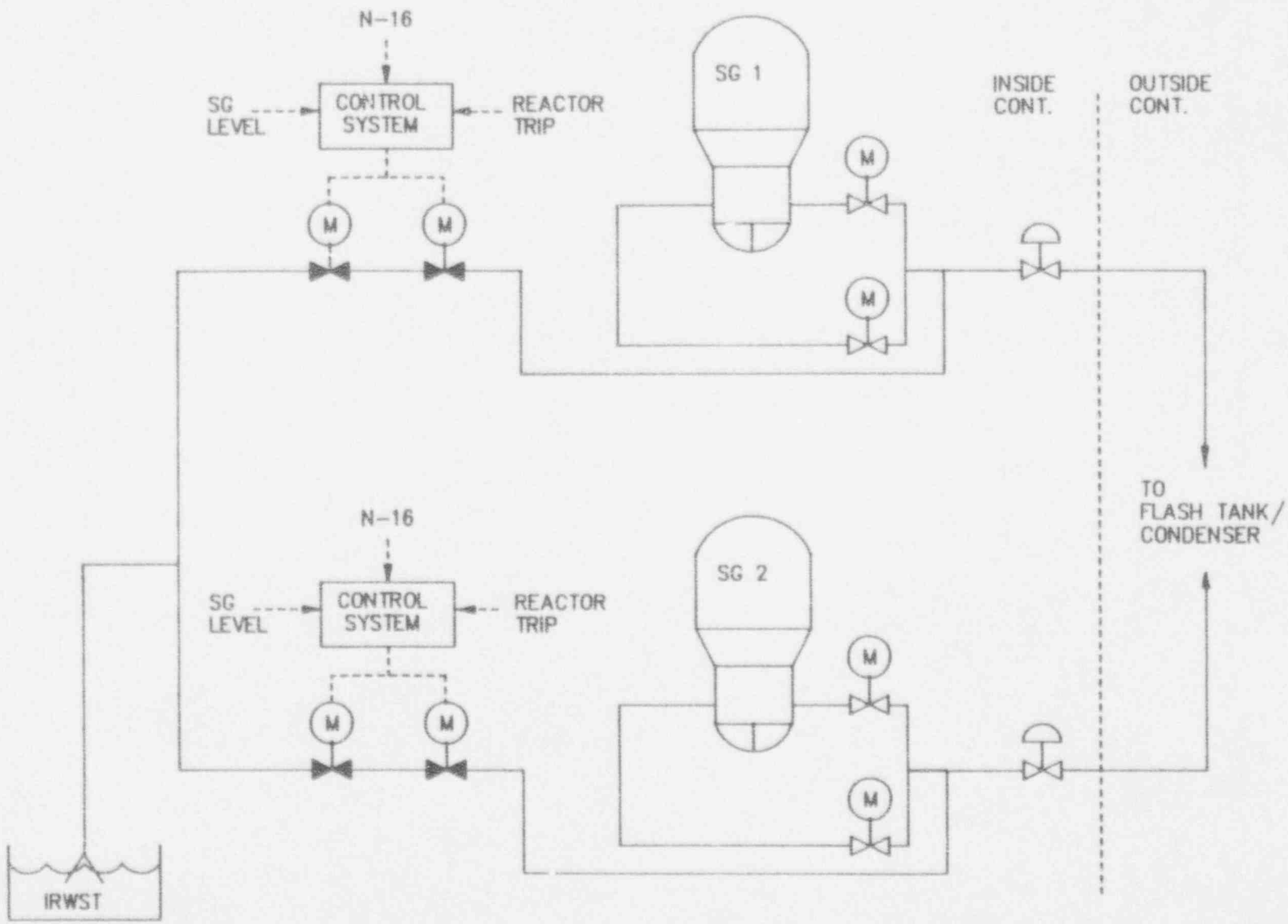
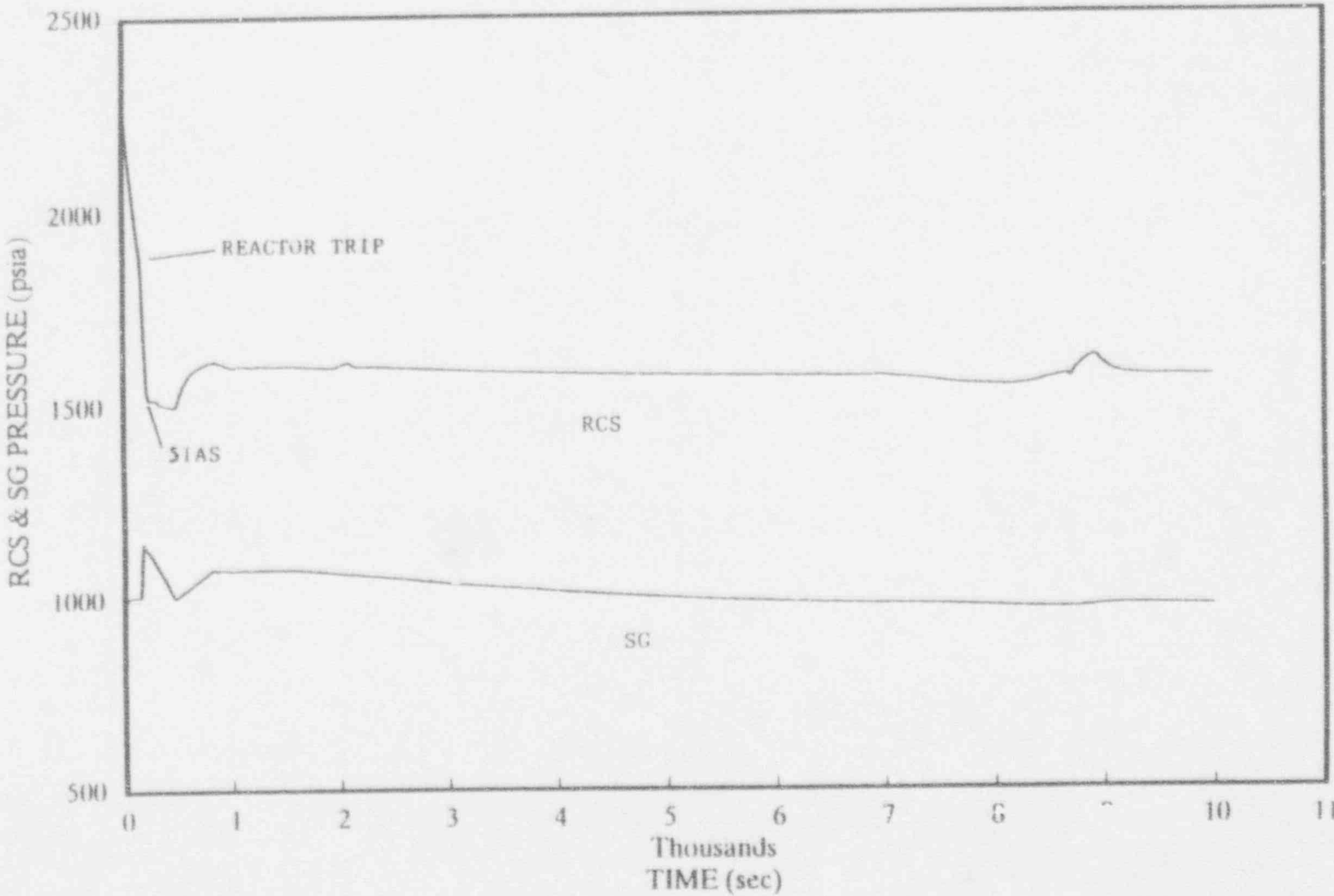


FIG. 3.10-2 RCS and SG Pressures vs. Time for 5 Tubes Ruptured and Automatic SG Liquid Blowdown to IRWST



3.11 Automatic Initiation of the Atmospheric Dump Valves

3.11.1 Description of Change

Each main steam line in the current System 80+ design is provided with one manually operated atmospheric dump valve (ADV) to allow cooldown of the steam generators when the main steam isolation valves are closed, or when the main condenser is not available as a heat sink (see Figure 3.11-1). The ADVs are designed to maintain the steam pressure below the lowest setting of the main steam safety valves during emergency shutdowns or plant hot standby conditions. Each valve is sized to allow a controlled plant cooldown in the event of a line break or tube rupture, which renders one steam generator unavailable for heat removal, concurrent with a loss of normal AC power and a single active failure of one of the remaining two ADVs.

The current ADVs are remote manually operated from the main control room or the remote shutdown panel. Isolation valves are provided upstream of each ADV which are capable of being remotely and manually positioned from the Main Control Room or from the Remote Shutdown Panel to isolate the ADVs.

This design change includes a new control system which will cause the ADVs to automatically open to remove mass and energy from the steam generators and would prevent the main steam safety valves from lifting. The new control system would actuate the automatic ADV on coincidence of high steam generator secondary pressure (approximately 1140 psia) and N-16 and either a reactor trip or an SIAS. The safety grade status of the valves and the capability for remote manual operation would be retained.

3.11.2 Benefits

Changing the current remote manual operation of the ADV to automatic operation requires minimal hardware change.

One of the benefits from automatic actuation of the ADVs is the prevention of uncontrolled steam releases through the MSSVs, should these valves be challenged and opened during an SGTR event. As seen from Figure 3.11-2, the ADVs cycle open and close to maintain the steam generator pressure below the MSSV setpoint subsequent to the generation of an MSIS on a high steam generator level, for five tube ruptures in one steam generator.

Single tube rupture events will not challenge the automatic ADV operation for more than four hours. Rupture of 5 tubes causes a high SG level MSIS at about 1600 sec, (see Figure 3.11-2), which is prior to automatic actuation of the ADVs at a pressure of 1140 psia, selected to be above the steam bypass pressure and below the MSSV pressure. After about 1700 sec, the automatic ADV would cycle

to control steam generator pressure below the MSSV opening pressure.

A similar system (steam bypass control system) has already been incorporated into the System 80+ design using different control signal inputs for actuation.

3.11.3 Limitations

For a five tube rupture event, the pressure will be controlled by the automatic ADVs, however, without operator intervention, the level in the steam generator would increase until water and two phase flow are exiting the valve. This will require the steam line, the automatic ADV, and downstream piping be designed for steam, water and two phase flow condition. Although the steam lines upstream of the MSIVs are qualified, this is a radical departure for the ADV and discharge piping design. It would result in significant first-of-a-kind engineering to develop an atmospheric steam dump system for two phase and water conditions. There may also be a need to demonstrate performance of these valves to pass the various types of fluid.

Automating the ADVs may provide protection from opening the MSSVs, but the valves still are routed to atmosphere, creating an intermittant (isolable) direct containment bypass.

The System 80+ design utilizes an automatic Steam Bypass Control System (with a capacity of 55% total of full power steam flow) for control of overpressure conditions. In conjunction with the Reactor Power cutback System, the design can accommodate 100% load rejections. Therefore, automatic ADVs are not necessary. Using the Steam bypass control system as opposed to an automatic ADV retains the secondary system condensate instead of discharging the steam to atmosphere. This offers a significant radiation decontamination benefit (a factor of about 10,000) relative to direct discharge of water through the ADV's.

FIGURE 3.11-1

AUTOMATIC ATMOSPHERIC DUMP VALVE SYSTEM

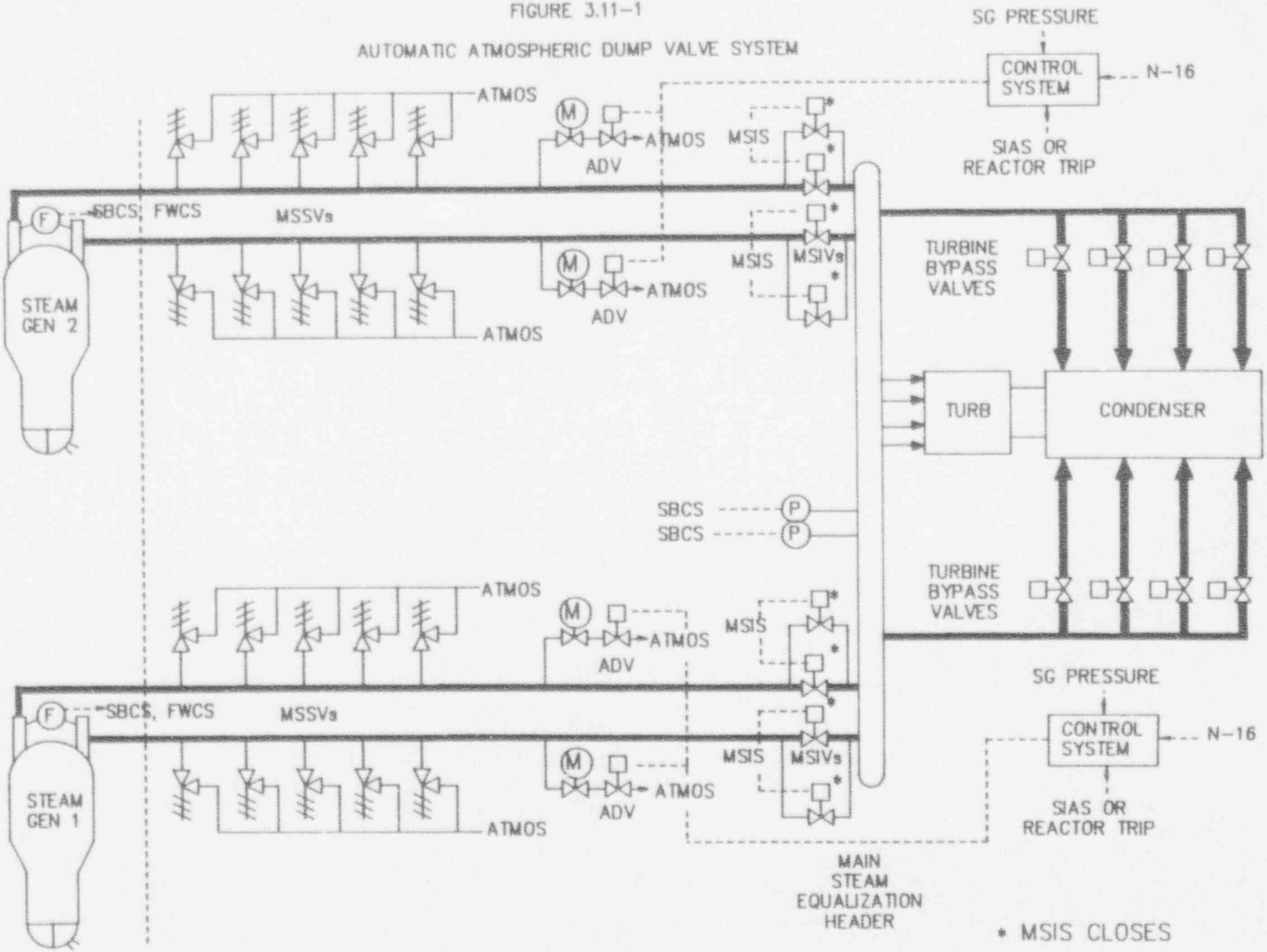
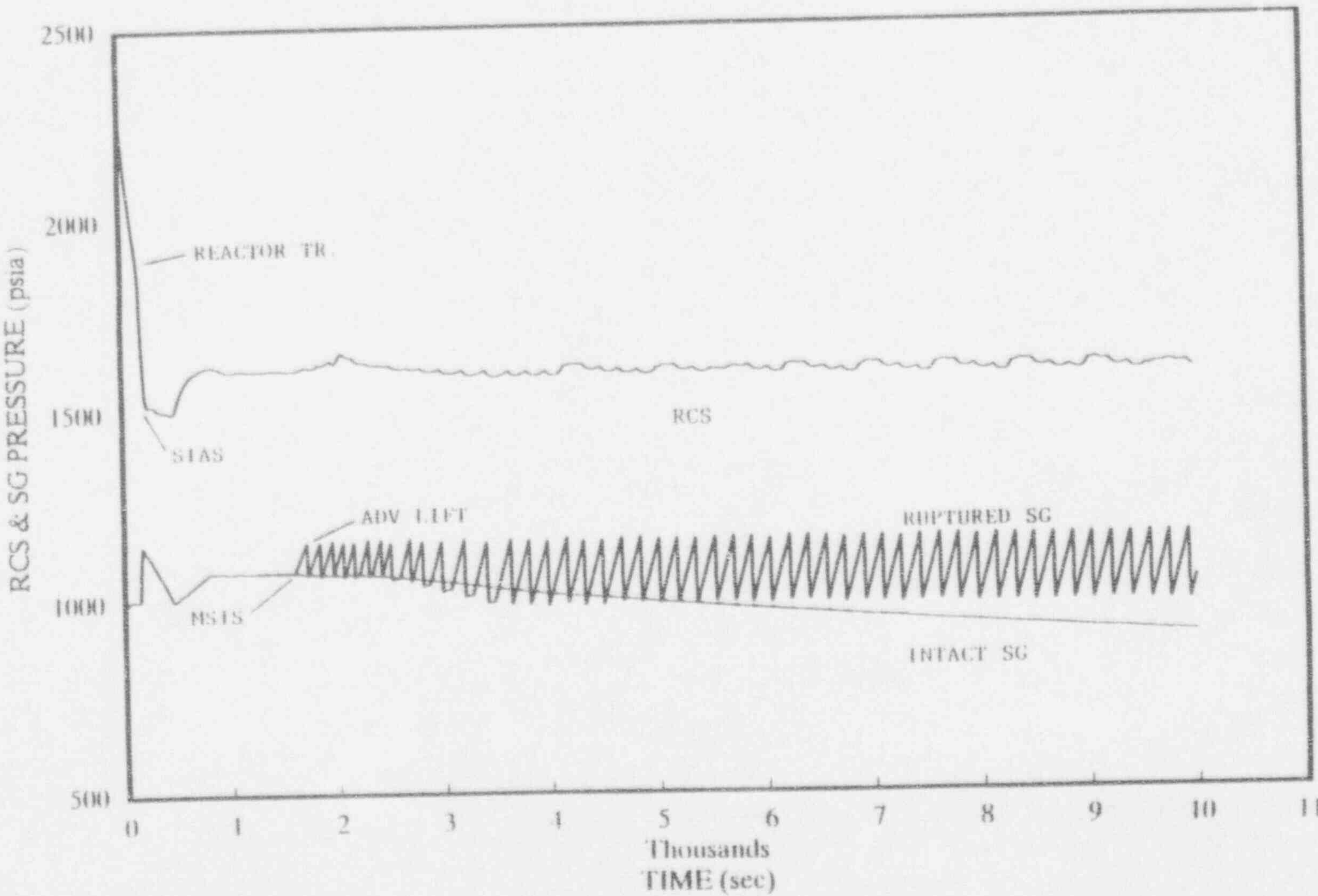


FIG. 3.11-2 RCS and SG pressures vs. Time for 5 Tubes Ruptured and Automatic ADVs



3.12 Passive Secondary Cooling System

3.12.1 Description

An option considered was to include a passive secondary cooling system which would remove energy from the steam generators. This system would include pipe lines teeing off each steam generator main steam line that are routed to a suppression tank. The tank would condense the steam and the condensate would be returned to the steam generators. This would allow for natural convection cooling of the steam generators which would keep the pressure from increasing to the main steam safety valve setpoint. This passive heat removal system provides system cooling after the MSIVs have isolated the steam generator. Obviously, the addition of such a major new system into the System 80+ design would require very extensive plant layout and equipment changes. While the concept may be possible; the details would have to wait for a demonstrated need and commitment to make the change.

3.12.2 Benefits

This system will continue to cool the secondary side after a MSIS signal occurs.

3.12.3 Limitations

For a five tube rupture case, the water level, due to the large primary to secondary leakage, will eventually fill the affected steam generator causing an MSIS. This will lead to water eventually flowing out the MSSVs.

A new suppression pool at an elevation that allows for natural convection cooling must be designed and incorporated into the limited space inside containment or outside in an auxiliary building. This pool will require cooling capabilities

There is no current design which includes a natural circulation cooling system for the steam generators. A lengthy first of a kind design effort is required to incorporate this design into the evolutionary ALWR. New piping, new isolation valves, new steam generator nozzle penetrations and new containment design features, all are required to incorporate this option into the system 80+ design.

4.0 SGTR ANALYSIS AND EVALUATION METHOD

4.1 Methods of Analysis

The SGTR events presented in this report were analyzed with best estimate analysis methods and assumptions. In addition, the analysis required the capability to actuate various plant systems/components based on specific conditions being reached in the plant during the transient. For these reasons the CEPAC interactive computer code was chosen to analyze the SGTR events with varying number of tubes being ruptured.

A technical description of the CEPAC code is provided in Reference 6-4. An overview of the primary system components that are modeled by the CEPAC is shown in Figure 1. The code models the key nuclear steam supply system components such as the steam generators, reactor vessel and core, hot and cold legs, pressurizer, and reactor coolant pumps. For the primary system, key safety and control systems/components are modeled. These systems include the pressurizer sprays, heaters, relief and safety valves, safety injection pumps, charging and letdown flows, and reactor regulating and shutdown rods. Initial conditions and other plant design parameters pertaining to these models are provided by the user to initialize the code and to initiate transient calculations.

The secondary system models include key components from the main feedwater valve to the turbine admission valves as shown in Figure 2. The steam generators are modeled to receive feedwater from main and auxiliary feedwater systems and a steam generator liquid blowdown system is included. The main steam lines contain atmospheric dump, main steam safety, main steam isolation, turbine admission, and steam dump valves. Again, initial conditions and other plant design parameters relevant to the secondary system models are provided by the user to initialize and initiate transient calculations.

The CEPAC code is an interactive code which allows for inputting equipment and control system disposition as well as specific operator actions. The outputs from the code includes time-dependent graphical display, hard copy printouts of major transient parameter values, and transient parameter plots.

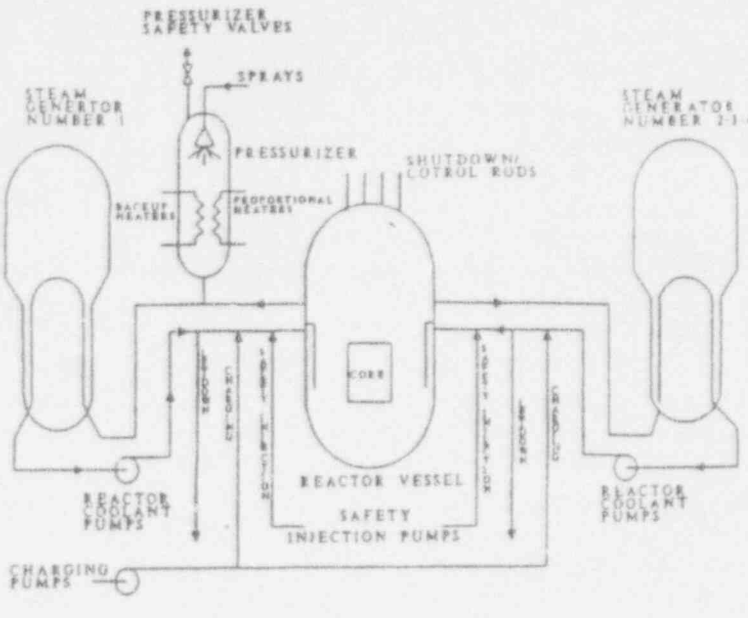


Figure 4.1-1 Primary System Components

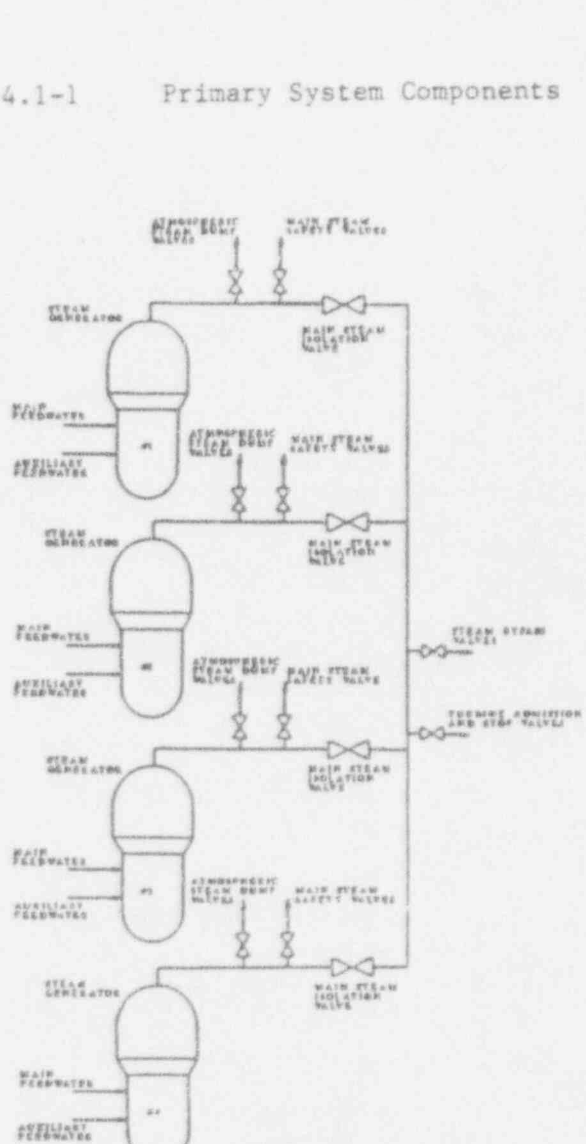


Figure 4.1-2 Secondary System Components

4.2 Analysis Assumptions

4.2.1 Initial Conditions

Normal, full power plant conditions are assumed for the analyses (except intitial power is 102%). See Table 4.2.1-1 for parameter values used in the analyses.

4.2.2 Best Estimate Assumptions

The following best estimate assumptions are made in the transient analyses presented in this report.

(1) Offsite power is available during the transient.

(2) All control systems are assumed to be in the automatic mode.

(3) No operator actions are included in the analysis.

(4) Normal plant protection systems are assumed to be available.

(5) Control system actuations during the transient are assumed to be at nominal setpoint values. Table 4.2.1-1 gives the setpoints.

(6) The condenser is assumed to be available for receiving steam flowing through the steam bypass valves from the steam generators and steam generator liquid that flows through the blowdown piping.

(7) The plant protection systems are assumed to be functioning to provide automatic protection during the transient.

TABLE 4.2.1-1

PARAMETER VALUES FOR ANALYSES

INITIAL CONDITIONS & SETPOINTS

1.	INITIAL RCS PRESSURE, PSIA	2250
2.	INITIAL SG PRESSURE (100% POWER), PSIA	1000
3.	INITIAL POWER LEVEL	102%
4.	INITIAL CORE INLET TEMPERATURE	558°F
5.	INITIAL RCS FLOW RATE	100% OF DESIGN FLOW
6.	INITIAL STEAM GENERATOR LEVEL	76.4% WIDE RANGE
7.	SIAS SETPOINT PRESSURE, PSIA	1835
8.	CHARGING PUMP SHUTOFF PRESSURE, PSIA	3025
9.	SAFETY INJECTION PUMP SHUTOFF PRESSURE, PSIA	1835
10.	SBCS SETPOINT PRESSURE, PSIA	1078
11.	MSIS SETPOINT - SG LOW PRESSURE, PSIA	870
12.	MSIS SETPOINT - SG HIGH LEVEL, % WIDE RANGE	98
13.	MSSV SETPOINT PRESSURE FOR FIRST VALVE BANK, PSIA	1200

SYSTEM/COMPONENT CAPACITIES

1.	SGTR FLOW, LBM/SEC - 1 TUBE 5 TUBES	44 @ 1800 PSIA 173 @ 1600 PSIA
2.	SAFETY INJECTION FLOW PER PUMP, LBM/SEC	25 @ 1800 PSIA 168 @ 1600 PSIA
3.	CHARGING PUMP FLOW, LBM/SEC	17 @ 2250 PSIA
4.	AUX. SPRAY FLOW, LBM/SEC	17 @ 2250 PSIA
5.	RCGVS FLOW, LBM/SEC	14 @ 2500 PSIA
6.	RDS FLOW, LBM/SEC	238 @ 2500 PSIA
7.	ADV FLOW PER VALVE, LBM/SEC (MIN)	264 @ 1000 PSIA

4.3 Results of Analysis

This section provides descriptions of the results of steam generator tube rupture (SGTR) analyses for various design options that are evaluated as potential fixes to minimize challenges to the MSSVs and extend MSSV lift times during an SGTR event. Both one tube ruptured in one steam generator as well as five tube ruptures in one steam generator are considered. The design options considered are as follows:

(1) Base case with no automatic actuations other than those currently included in the design,

(2) Automatic bypass of MSIS on high steam generator level,

(3) Automatic initiation of auxiliary pressurizer spray to reduce RCS pressure in order to reduce break flow,

(4) Automatic opening of the reactor coolant gas vent system (RCGVS) to reduce RCS pressure and thereby reduce break flow,

(5) Automatic blowdown (high capacity) of steam generator liquid to the condenser to remove mass and energy from the damaged steam generator (SG) and thereby reduce SG pressure and level,

(6) Automatic reduction of post-trip steam bypass control system initiation pressure from 1078 psia to 900 psia to reduce the damaged steam generator pressure and level,

(7) Automatic opening of the rapid depressurization system (RDS) to depressurize the RCS and to terminate or reverse break flow,

(8) Increase main steam safety valve (MSSV) lift setpoint by 200 psia to delay MSSV opening,

(9) Automatic blowdown of steam generator liquid to IRWST to control SG pressure and level,

(10) Automatic initiation of the atmospheric dump valves to reduce SG pressure, and

(11) Natural convection cooling system for steam generator secondary.

The analyses results are compared against the results for the base case to quantify the benefits in terms of delaying MSSV lifting (containment bypass) which results in additional time available for appropriate operator actions to stabilize the plant subsequent to a tube rupture event. In addition the results are used to demonstrate the differences in benefits and/or limitations between the one tube and five tube ruptures.

The key measure in terms of eliminating or delaying uncontrolled containment bypass for each of the design changes described below is the MSSV lift time. Table 4.3.0-1 summarizes the results for each of the design changes in terms of this measure.

TABLE 4.3.0-1
SUMMARY OF CASES ANALYZED FOR MULTIPLE STEAM GENERATOR TUBE RUPTURE

Case #	# of Tubes	SBCS[1]	Auto[2] Bypass MSIS (HSGL)	Auto[3] APS	Auto[4] RCGV	Auto SG[5] Blowdown	Auto[6] RDS	Auto[7] ADV	MSSV Lift Setpoint (psia)	Approximate MSSV Lift Time (Minutes)
1	1	Auto @ 1100 psia	no	no	no	no	no	no	1200	167+
2	5	Auto @ 1100 psia	no	no	no	no	no	no	1200	30
3	1	Auto @ 1100 psia	yes	no	no	no	no	no	1200	167+
4	5	Auto @ 1100 psia	yes	no	no	no	no	no	1200	167+ ... SG overfills at 50 minutes
5	1	Auto @ 1100 psia	no	yes	no	no	no	no	1200	167+
6	5	Auto @ 1100 psia	no	yes	no	no	no	no	1200	31
7	1	Auto @ 1100 psia	no	no	yes	no	no	no	1200	167+
8	5	Auto @ 1100 psia	no	no	yes	no	no	no	1200	33
9	1	Auto @ 1100 psia	no	no	no	yes, high capacity	no	no	1200	167+ ... SG empties at 30 minutes
10	5	Auto @ 1100 psia	no	no	no	yes, high capacity	no	no	1200	167+ ... Intact SG nearly empties at 10 mins.

TABLE 4.3.0-1
SUMMARY OF CASES ANALYZED FOR MULTIPLE STEAM GENERATOR TUBE RUPTURE

Case #	# of Tubes	SBCS[1]	Auto[2] Bypass MSIS (HSGL)	Auto[3] APS	Auto[4] RCGV	Auto SG[5] Blowdown	Auto[6] RDS	Auto[7] ADV	MSSV Lift Setpoint (psia)	Approximate MSSV Lift Time (Minutes)
11	1	Auto @ 900 psia	no	no	no	no	no	no	1200	167+
12	5	Auto @ 900 psia	no	no	no	no	no	no	1200	33
13	5	Auto @ 1100 psia	no	no	no	no	yes	no	1200	167+
14	5	Auto @ 1100 psia	no	no	no	yes, blowdown to IRWST	no	no	1200	167+
15	5	Auto @ 1100 psia	no	no	no	no	no	yes	1200	No MSSV lift ADV lifts at 28 mins.
16	5	Auto @ 1100 psia	no	no	no	no	no	no	1400	35

1. SBCS ... Steam Bypass Control System

2. Auto Bypass MSIS (HSGL) ... Automatic Bypass of the High SG Level Initiation of Main Steam Line Isolation

3. Auto APS ... Automatic Initiation of Auxiliary Pressurizer Spray

4. Auto RCGVS ... Automatic Initiation of the Reactor Coolant Gas Vent System

5. Auto SG Blowdown ... Automatic Initiation of the SG Liquid Blowdown System (to condenser)

6. Auto RDS ... Automatic Initiation of the Rapid Depressurization System (to IRWST)

7. Auto ADV ... Automatic Initiation of the ADV on High SG Pressure (setpoint of 1160 psia)

4.3.1 Current System 80+ Design

The analyses of the current design are aimed at quantifying the system performance under SGTR conditions and determine MSSV lift times for two SGTR cases, case 1 with one tube rupture and case 2 with five tubes ruptured in one steam generator. Figures 4.3.1-1 through 4.3.1-5 presents the results for one tube rupture and Figures 4.3.1-6 through 4.3.1-10 illustrate the results for the five tubes ruptured case. The results consists of transient plots for (a) RCS and SG pressures, (2) break, safety injection, and steam bypass flow rates, (3) steam generator level, (4) pressurizer level, and (5) hot and cold leg temperatures. The sequences of events occurring during the transients are presented in Tables 4.3.1-1 and 4.3.1-2.

The RCS pressure transients for both cases illustrate that the pressure decreases very rapidly following the rupture(s) resulting in an increse in the charging flow and actuation of the pressurizer heaters. The major difference is that the changes in parameter values are more rapid for the five tubes ruptured case. This is because of the large break flow rates for this case. As the pressure decreases, a reactor trip on hot leg saturation is obtained at 1289 seconds for the one tube case and at 149 seconds for the five tube case. A turbine trip occurs immediately afterwards and the steam bypass system is opened within two seconds after reactor trip. The safety injection actuation signal is generated upon reaching a low RCS pressure (at 1294 seconds for one tube rupture, and 165 seconds for five tube rupture) subsequent to the reactor trip. The safety injection flow eventually causes an increase in RCS pressure and as the break flow is balanced by this flow and charging flow, the RCS pressure reaches a quasi-steady state value (about 1800 psia for one tube rupture and about 1600 psia for 5 tubes ruptured).

For case 1, the steam generator pressure (Figure 4.3.1-1) decreases rapidly after the initial quick opening of the bypass valves and the pressure remains at about 1078 psia (opening setpoint for the bypass valves) subsesequently reaching bypass valve modulation mode. The bypass system remains open for the one tube rupture case during most of the remainder of the transient up to 10,000 seconds (167 minutes). The damaged steam generator level (Figure 4.3.1-3) is controlled prior to the reactor trip on steam generator level control and decreases rapidly subsequent to the reactor trip (due to termination of main feedwater on low T_{avg} and level collapse due to increase in the steam generator pressure). Despite the break flow (Figure 4.3.1-2) into the secondary side of the damaged steam generator, the level continues decrease for the one tube rupture case, since the steam bypass system remains open removing inventory from the generator. The intact steam generator level also decreases up to the time the auxiliary feedwater is initiated on low steam generator level. Subsequently, the level in this steam

generator continues to increase until a high steam generator level signal shuts off auxiliary feedwater flow. As a result, the steam generator level begins to decrease.

For the one tube rupture case (case 1), the RCS subcooling decreases prior to the reactor trip due to the decrease in RCS pressure that accompanies the tube rupture. The subcooling increases thereafter due to cooling of the RCS and the increase in the RCS pressure to the quasi-steady state value resulting from safety injection flow (Figure 4.3.1-2). Throughout the transient, subcooling of the RCS is maintained, thereby precluding core damage. The pressurizer level (Figure 4.3.1-4) decreases rapidly prior to the reactor trip and the pressurizer almost empties at the time of reactor trip. The level increases to about 10% following sustained safety injection flow into the RCS.

For the five tubes ruptured case (case 2), the reactor trip and turbine trip occurs very early in the transient due to the large amount of break flow (about five times as much as the one tube rupture case). Subsequent to reactor trip the safety injection flow (Figure 4.3.1-7) causes the RCS pressure (Figure 4.3.1-6) to reach the quasi-steady state value of about 1600 psia. The cooling effect of the safety injection flow maintains RCS subcooling and core cooling. The steam generator pressure (Figure 4.3.1-6) increases rapidly following the reactor trip and reaches the steam bypass valve opening setpoint of 1078 psia. The bypass valves quick open to relieve the pressure and close as the pressure decreases below the opening setpoint. The valves reopen under modulation control as the SG pressure increases again. The damaged steam generator level (Figure 4.3.1-8) builds up very rapidly prior to the reactor trip since the steam generator level control system cannot keep up with the large amount of break flow. The level decreases immediately after reactor trip due to the collapse of the two phase steam generator level on high SG pressure, termination of the main feedwater on low T_{avg}, and opening of the steam bypass valves. The SG level increases subsequently as the break flow continues to be large and the bypass flow (Figure 4.3.1-8) is terminated on low SG pressure at about 1625 seconds. The level continues to increase and a Main Steam Isolation Signal (MSIS) is generated on high level at 1540 seconds. The MSIS terminates the steam bypass flow and results in an increase in the damaged SG pressure (Figure 4.3.1-6). As this pressure reaches 1200 psia the MSSVs of the damaged SG lifts relieving the pressure. The MSSVs close following the pressure relief. Subsequently the MSSVs cycle open and closed to remove mass and energy from the damaged steam generator.

Thus, for the one tube rupture case (case 1), the damaged steam generator MSSVs remain unchallenged for longer than 10,000 seconds (167 minutes) due to the availability of the steam bypass system (no MSIS signal) and the relatively smaller break flow. However, for the five tube rupture case (case 2), the damaged steam

generator MSSVs are challenged as an MSIS is generated on a high steam generator level. MSSVs open at about 1800 seconds (30 minutes) and cycle open and close to relieve steam generator mass and energy. The steam generator level is expected to increase even after the MSSV opening since the break flow rate is larger than the MSSV release rate to maintain the steam generator pressure around 1200 psia.

TABLE 4.3.1-1

SEQUENCE OF EVENTS FOR CASE 1
STEAM GENERATOR TUBE RUPTURE (BASE CASE FOR 1 TUBE)

TIME (Sec)	EVENT	SETPOINT
0.0	Tube Rupture Occurs	
1100	Pressurizer Backup Heaters Actuated on Low Pressurizer Pressure, psia	2200
1289	Reactor Trips on Hot Leg Saturation Trip Signal	--
1290	Turbine Trips	--
1291	Steam Bypass System Actuated on High Steam Generator Pressure, psia	1078
1294	Pressurizer Pressure Reaches Safety Injection Actuation (SIAS) Setpoint, psia	1835
1295	Main Feedwater Terminated on Low T_{avg}	--
1296	Peak Steam Generator Pressure occurs, psia	1138
2370	Auxiliary Feedwater to Intact Steam Generator Actuated on Low Level, ft. above tube sheet	20.09
5680	Auxiliary Feedwater to Intact Steam Generator Terminated on High Level, ft. above tube sheet	40.46
*	Main Steam Isolation Signal (MSIS) Generated on High Level in the Damaged Steam Generator, % wide range level	98
*	Main Steam Safety Valves (MSSVs) on Damaged Steam Generator Actuated on High Steam Generator Pressure, psia	1200

* Event does not occur during the 10000 seconds of transient simulation.

TABLE 4.3.1-2

SEQUENCE OF EVENTS FOR CASE 2
STEAM GENERATOR TUBE RUPTURE (BASE CASE FOR 5 TUBES)

TIME (Sec)	EVENT	SETPOINT
0.0	Tube Rupture Occurs	--
130	Pressurizer Backup Heaters Actuated on Low Pressurizer Pressure, psia	2200
149	Reactor Trips on Hot Leg Saturation Trip Signal	--
150	Turbine Trips	--
152	Steam Bypass System Actuated on High Steam Generator Pressure, psia	1078
165	Pressurizer Pressure Reaches Safety Injection Actuation Signal (SIAS) Setpoint, psia	1835
166	Main Feedwater Terminated on Low T_{avg}	--
1590	Main Steam Isolation Signal (MSIS) Generated on High Level in the Damaged Steam Generator, % wide range level	98
1800	Main Steam Safety Valves (MSSVs) on Damaged Steam Generator Actuated on High Steam Generator Pressure, psia	1200

FIG. 4.3.1-1 RCS and SG Pressures vs. Time

Case 1 for 1 Tube Ruptured and Current System 80+ Design

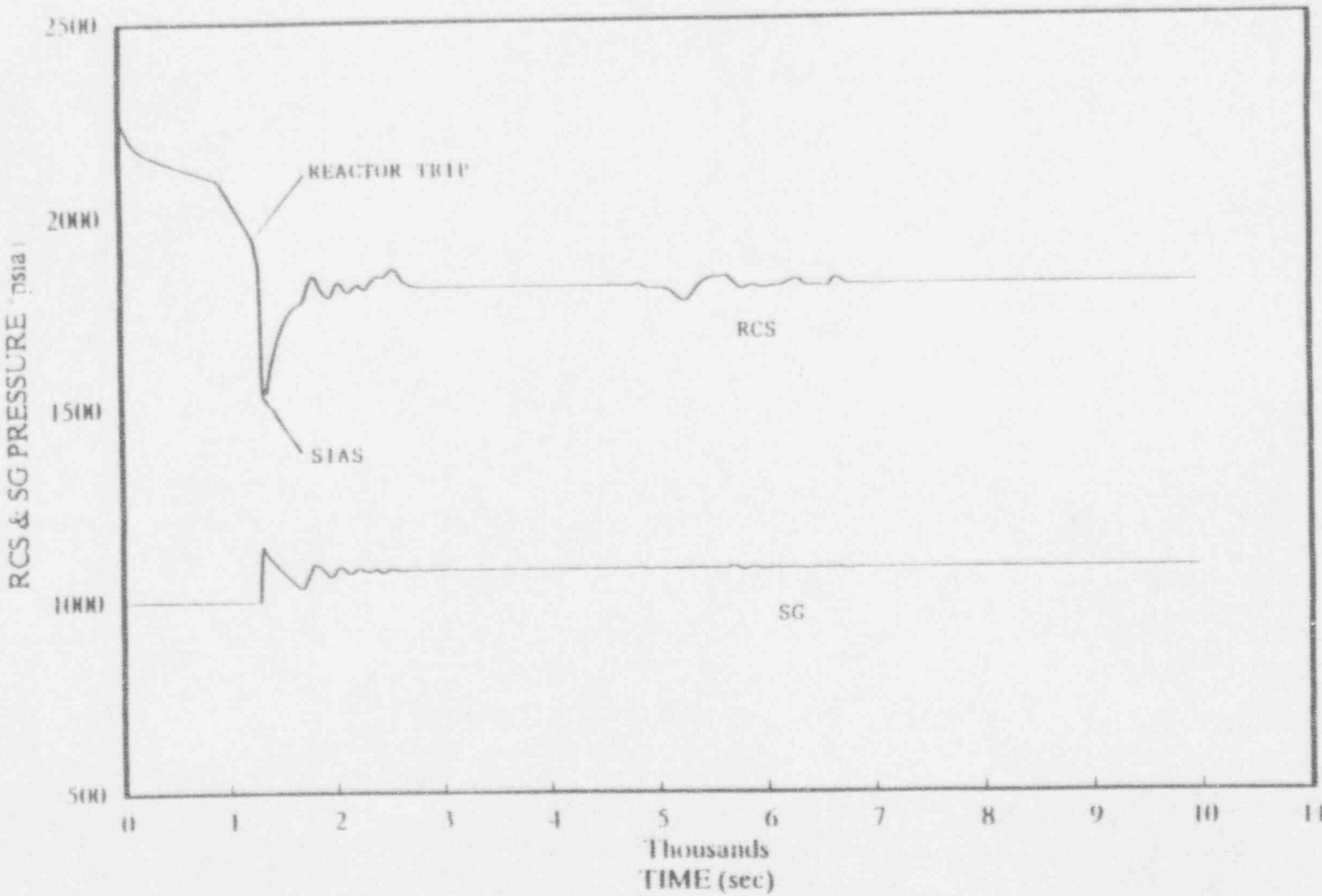


FIG. 4.3.1-2 Leak, HPSI and Bypass Flow Rates vs. Time
Case 1 for 1 Tube Ruptured and Current System 80+ Design

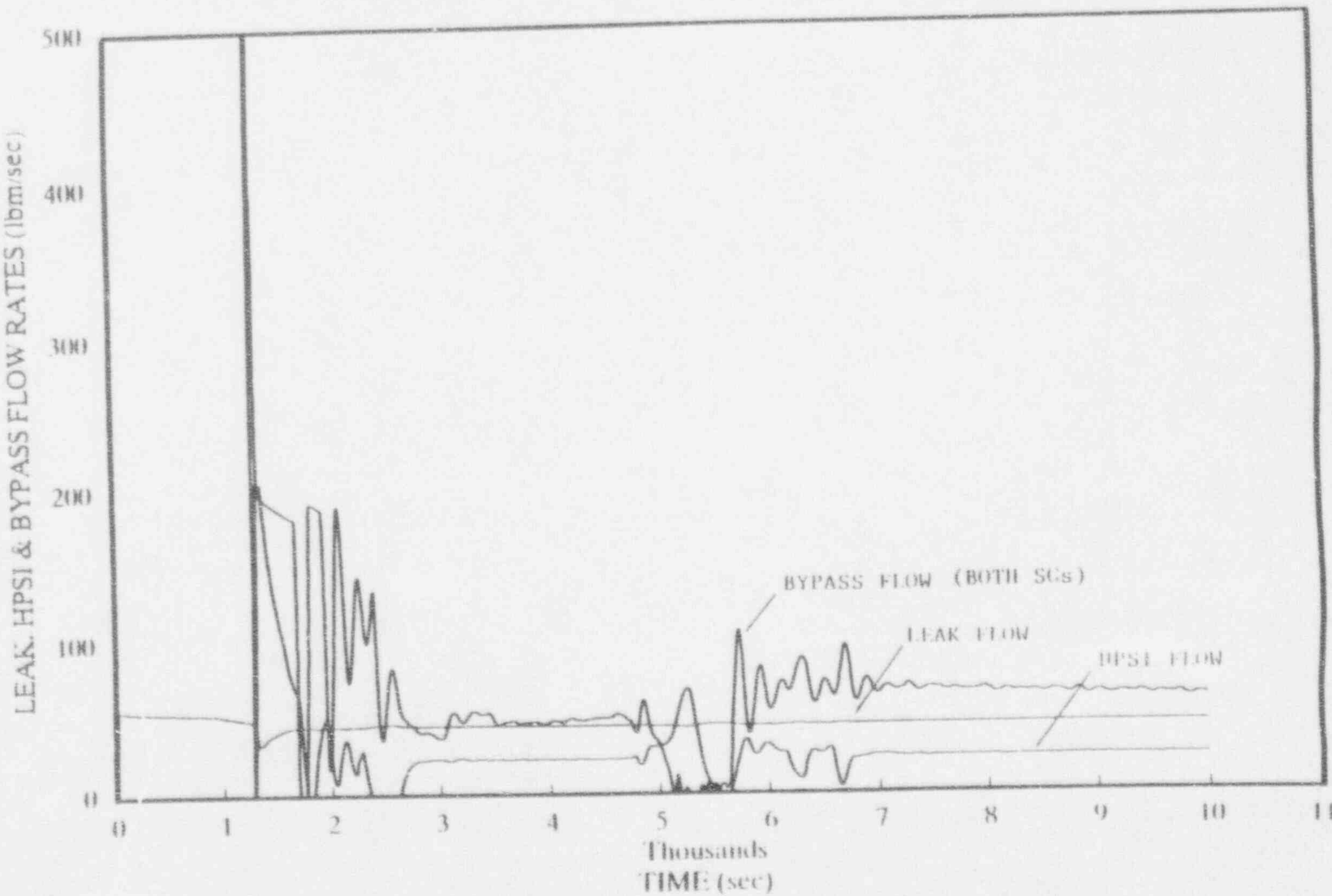


FIG. 4.3.1-3 Steam Generator Level vs. Time

Case 1 for 1 Tube Ruptured and Current System 80+ Design

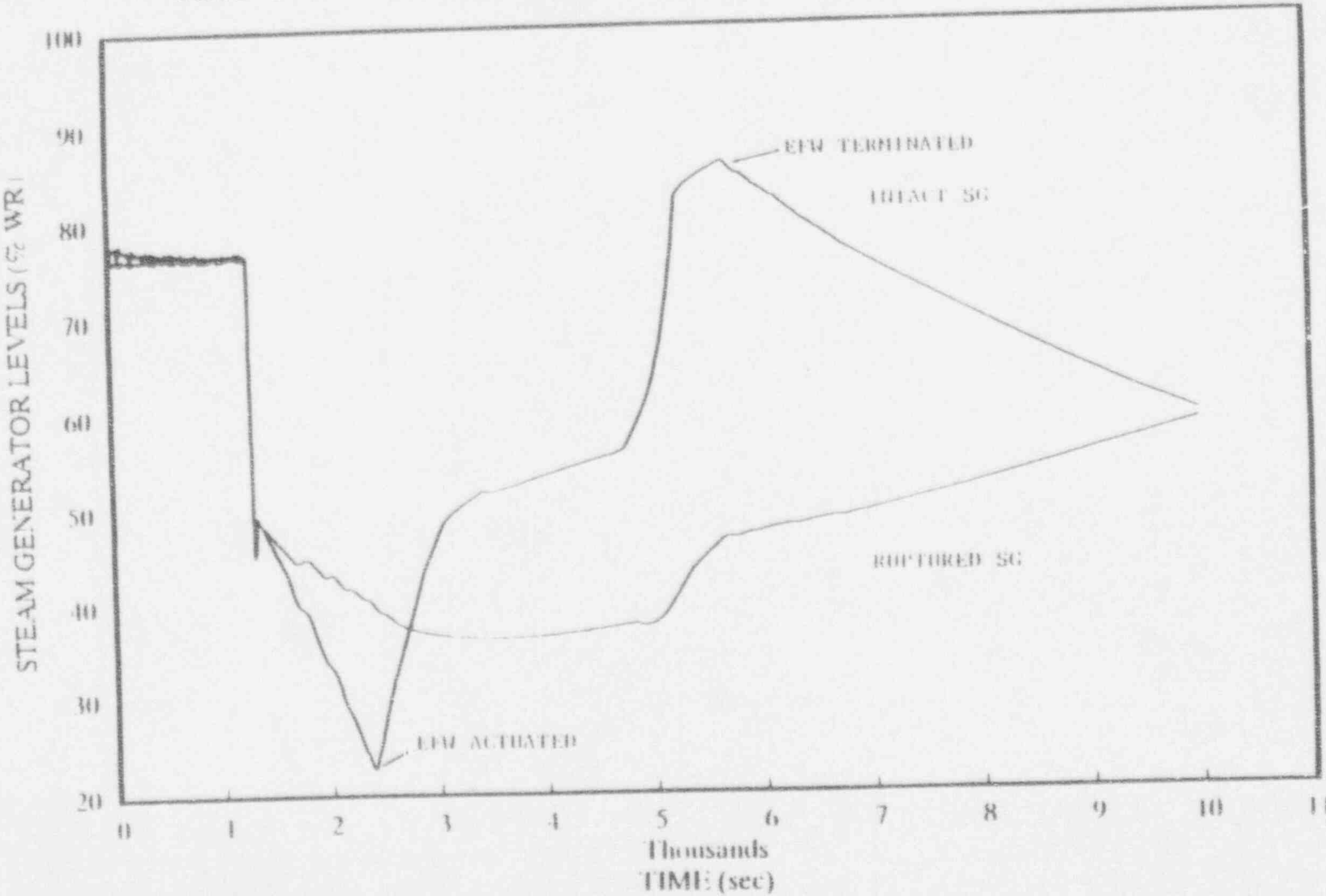


FIG. 4.3.1-4 Pressurizer Level vs. Time

Case 1 for 1 Tube Ruptured and Current System 80+ Design

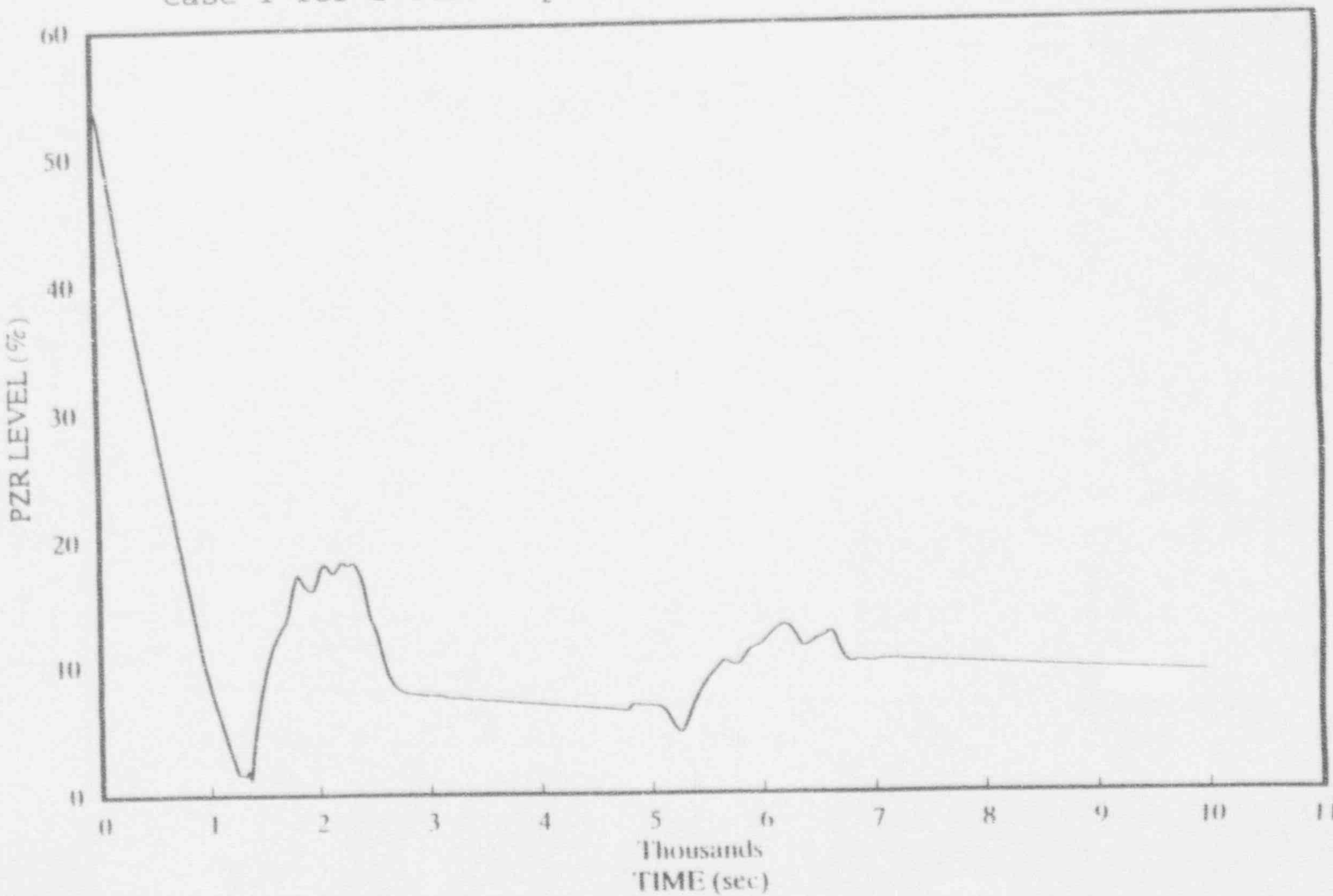


FIG. 4.3.1-5 Hot and Cold Leg Temperatures vs. Time

Case 1 for 1 Tube Ruptured and Current System 80+ Design

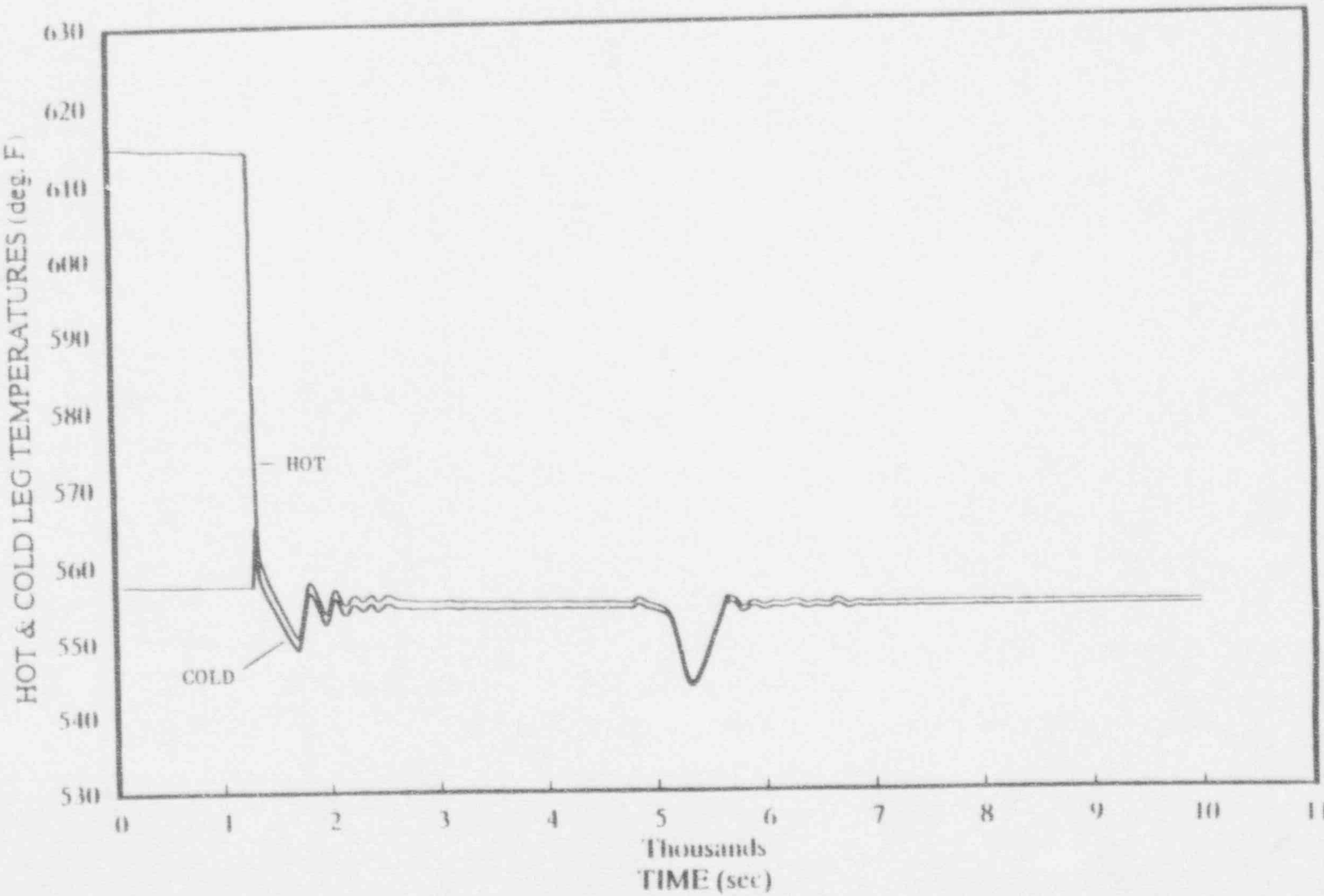


FIG. 4.3.1-6 RCS and SG Pressures vs. Time

Case 2 for 5 Tubes Ruptured and Current System 80+ Design

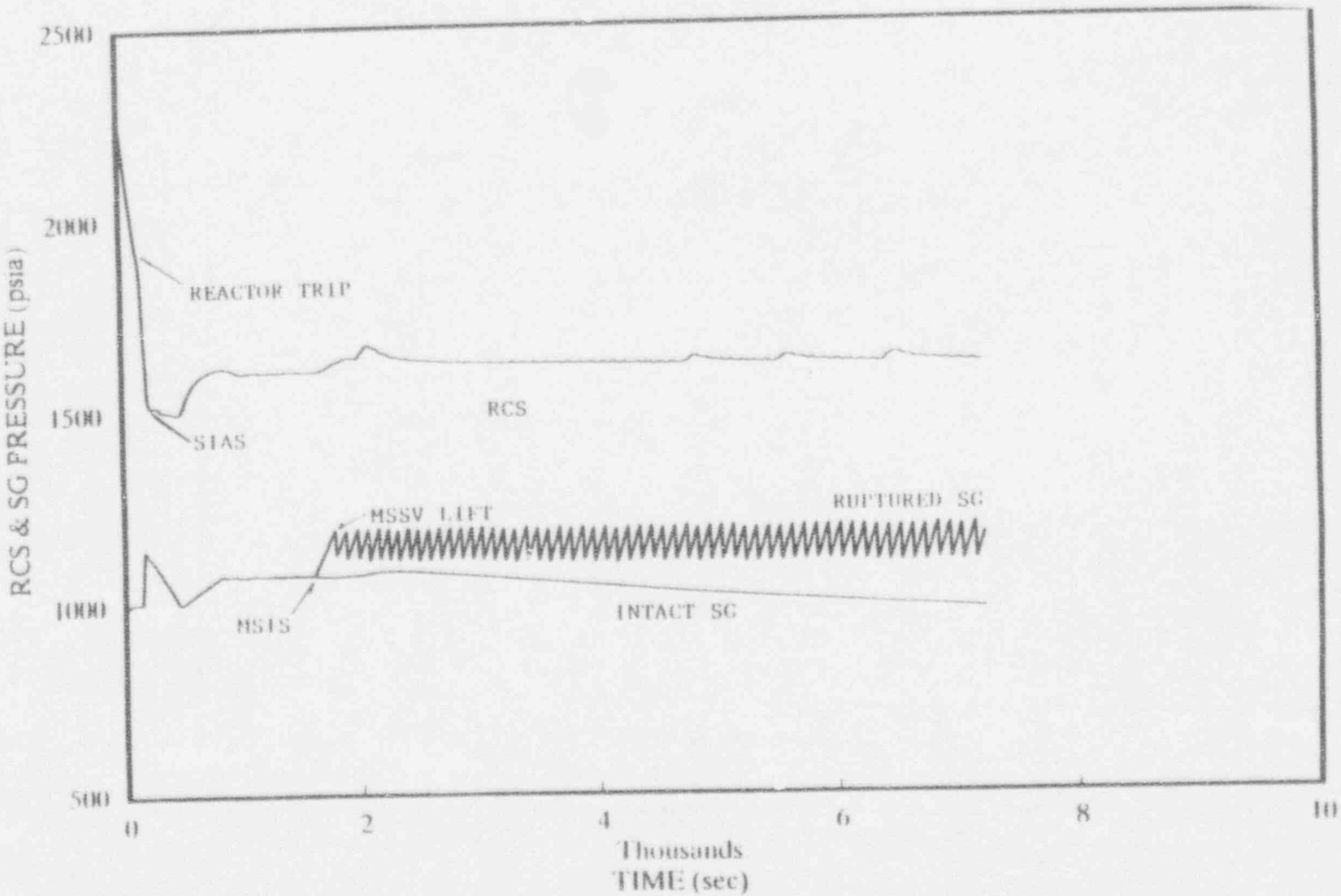


FIG. 4.3.1-7 Leak, HPSI and Bypass Flow Rates vs. Time
Case 2 for 5 Tubes Ruptured and Current System 80+ Design

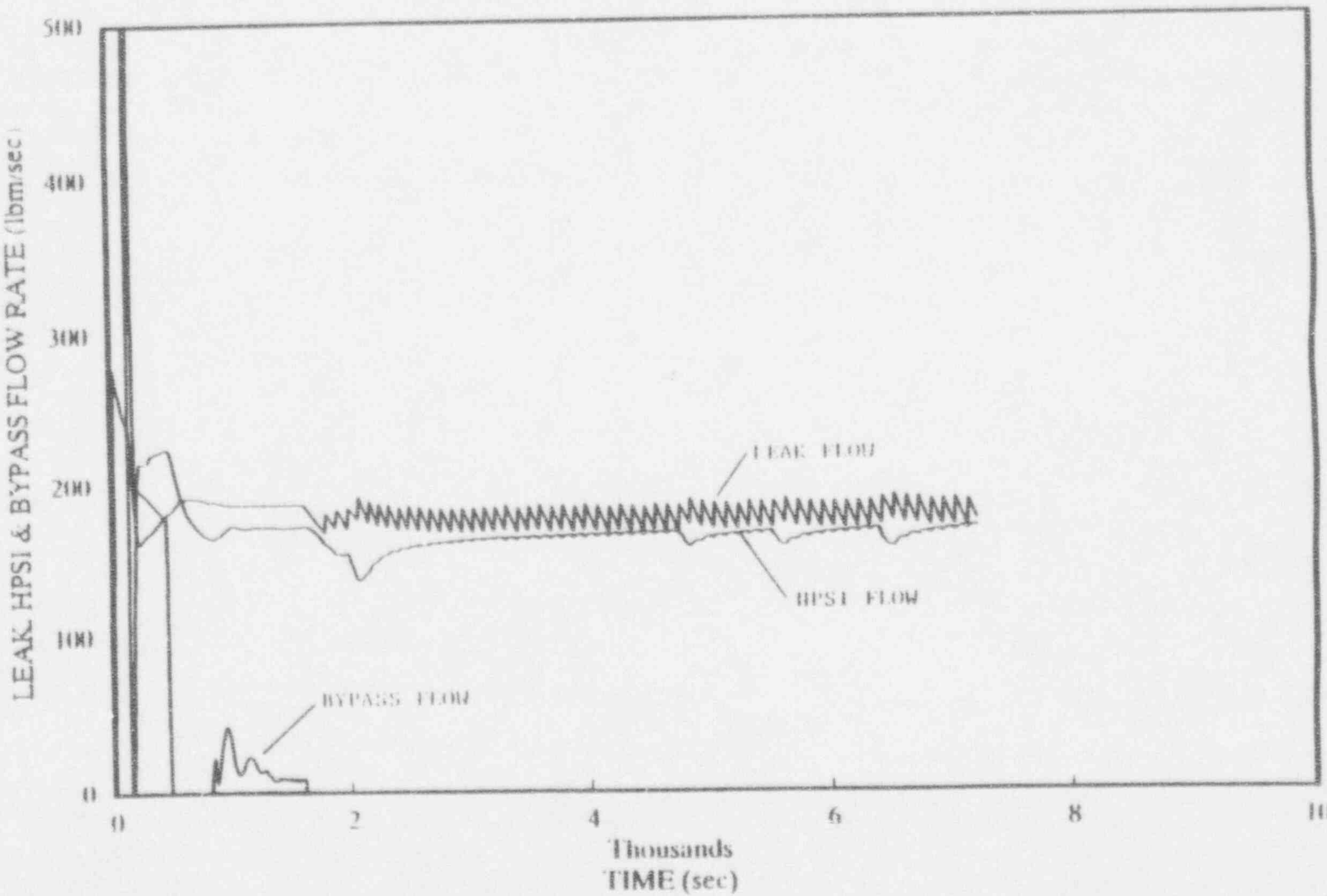


FIG. 4.3.1-8 Steam Generator Level vs. Time
Case 2 for 5 Tubes Ruptured and Current System 80+ Design

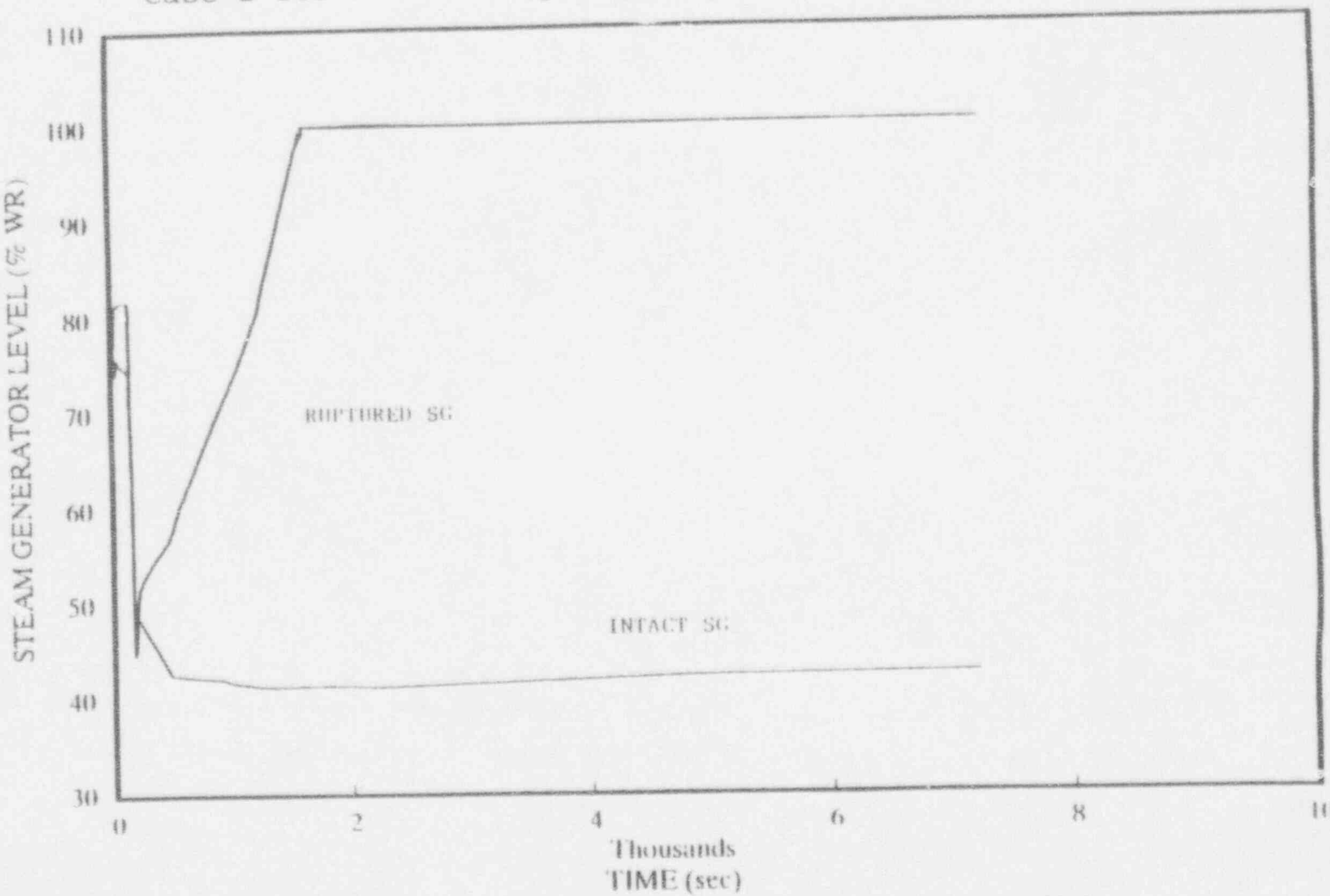


FIG. 4.3.1-9 Pressurizer Level vs. Time

Case 2 for 5 Tubes Ruptured and Current System 80+ Design

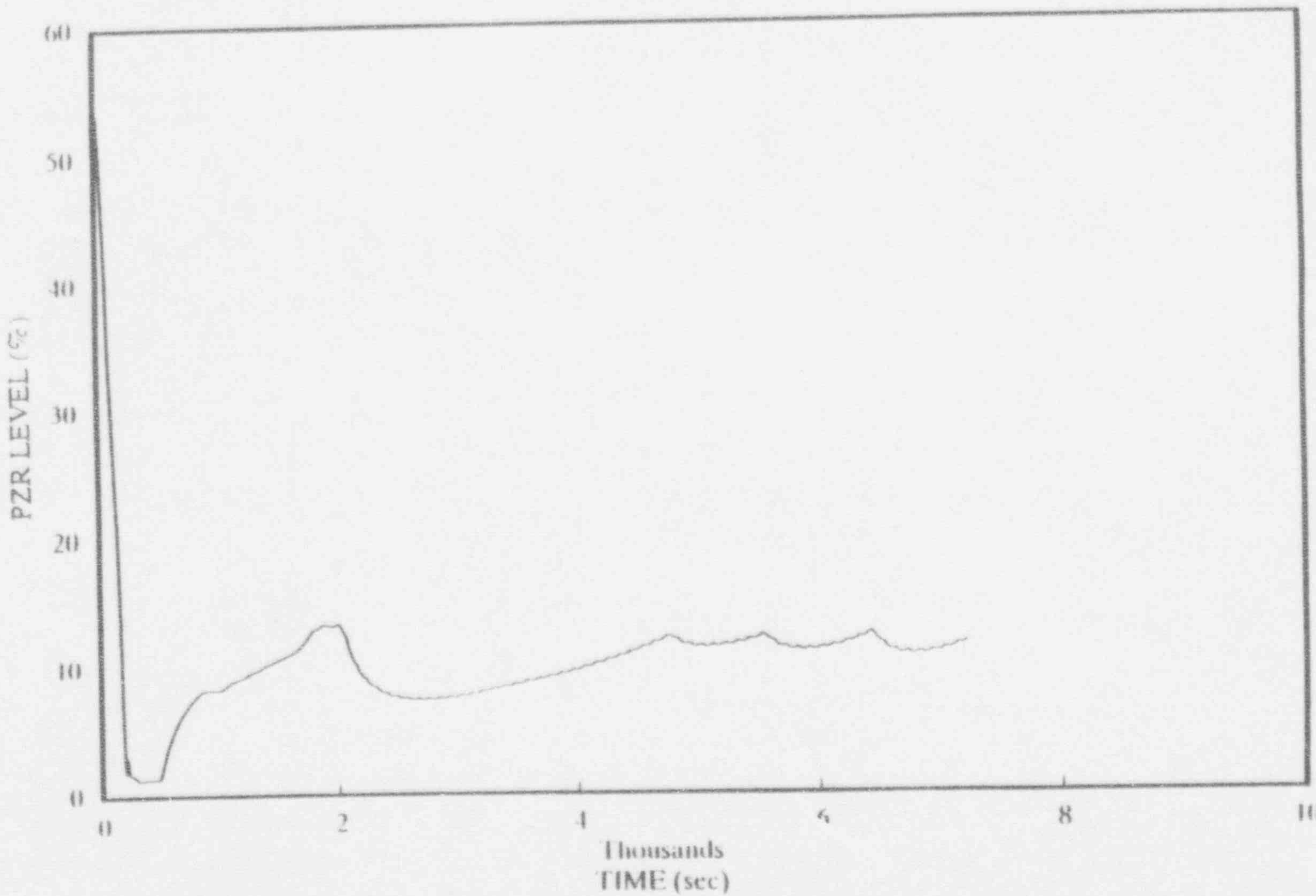
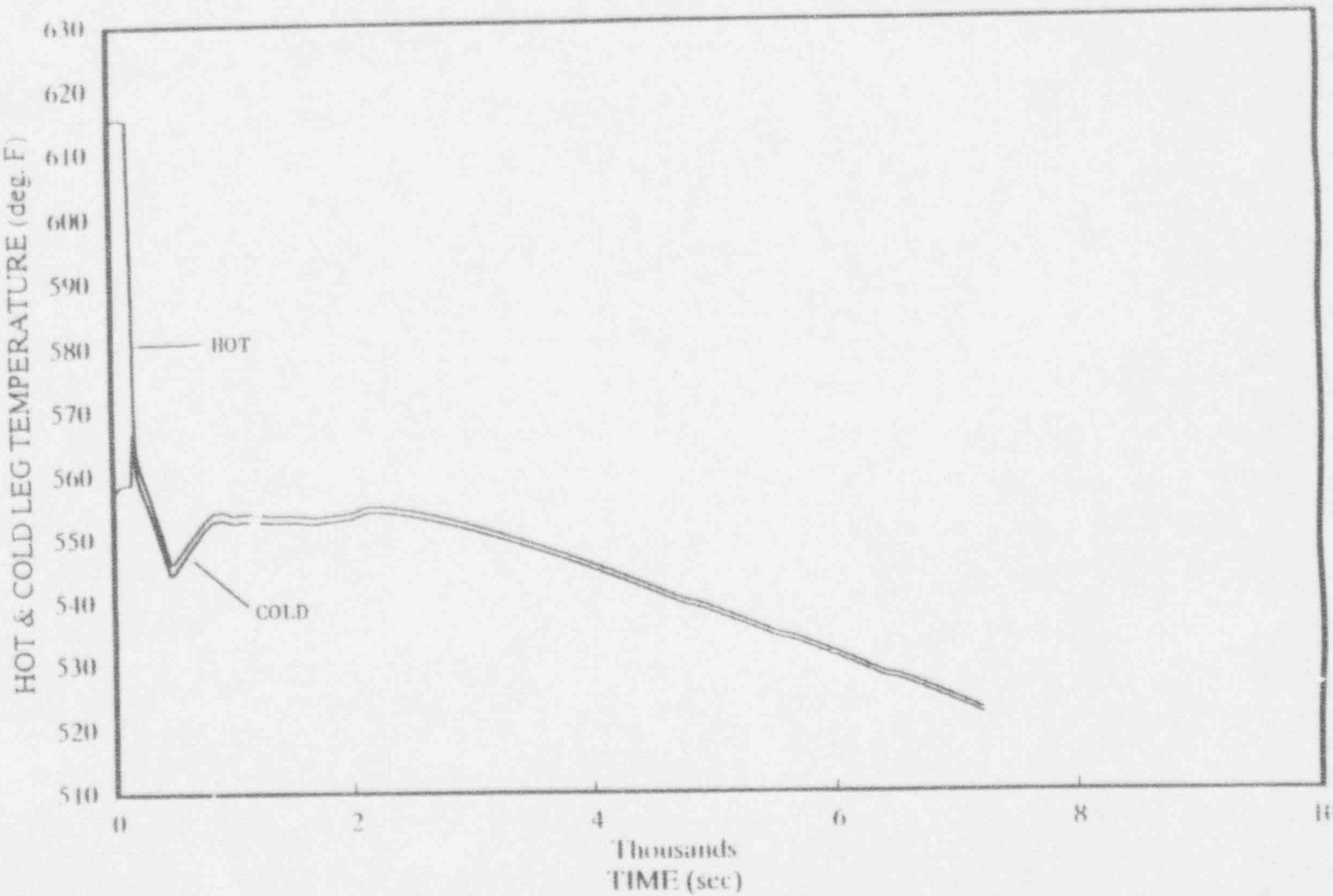


FIG. 4.3.1-10 Hot and Cold Leg Temperatures vs. Time

Case 2 for 5 Tubes Ruptured and Current System 80+ Design



4.3.2 Automatic Bypass of MSIS on High Steam Generator Level

This design modification considers a potential change to the MSIS such that a coincident 2 of 4 channel reactor trip signal and a 2 of 2 channel N-16 SG radiation detector signals cause a bypass of the MSIV closure signal on high level in the damaged steam generator. This modification allows for steam bypass flow capability as long as possible. Since a high steam generator level is not reached for the one tube rupture case (case 3) for up to and beyond 10,000 seconds (167 minutes), this design change would not have any impact on the transient behavior for this case. Hence for one tube rupture with this modification Figures 4.3.1-1 through 4.3.1-5 and the sequence of events table, Table 4.3.1-1, are applicable for the 10,000 seconds (167 minutes) transient simulation time. Although not presented, the single tube rupture case was run for 15,000 seconds (more than four hours) and the MSSV's were still not challenged.

For the five tubes ruptured case (case 4), the transient behavior would be similar to that for case 2 up to the time when the steam generator level has increased to the MSIS setpoint. Subsequent to this time frame (about 1590 seconds), the transient behavior will be different than that for case 2 as shown in Figures 4.3.2-1 through 4.3.2-5. A sequence of events for this case is provided in Table 4.3.2-1.

As seen from Figure 4.3.2-1, the steam generator pressure remains at about 1078 psia even after the high level setpoint for MSIS is reached. This is a consequence of the bypassing of the MSIS signal which makes the bypass system available for steam relief resulting in no challenge to the damaged SG MSSVs. Figure 4.3.2-1 indicates that the MSSV lift time is extended beyond 10,000 seconds (167 minutes). Even though the bypass allows for steam flow out of the steam generators, it is seen that the break flow rate (Figure 4.3.2-2) is significantly higher than the bypass flow capability and hence for case 4, the steam generator level is expected to increase rapidly and enter the steam lines after 30 minutes and the lines would be solid after about 50 minutes. The steam lines upstream of the MSIVs are designed for carrying water, but not the downstream piping and equipment. Thus, this approach risks significant damage to the plant piping and equipment.

TABLE 4.3.2-1

SEQUENCE OF EVENTS FOR CASE 3
STEAM GENERATOR TUBE RUPTURE (1 TUBE)
WITH MSIS ON HIGH SG LEVEL BYPASSED

TIME (Sec)	EVENT	SETPOINT
0.0	Tube Rupture Occurs	--
1100	Pressurizer Backup Heaters Actuated on Low Pressurizer Pressure, psia	2200
1289	Reactor Trips on Hot Leg Saturation Trip Signal	--
1290	Turbine Trips	--
1291	Steam Bypass System Actuated on High Steam Generator Pressure, psia	1078
1294	Pressurizer Pressure Reaches Safety Injection Actuation Signal (SIAS) Setpoint, psia	1835
1295	Main Feedwater Terminated on Low T_{avg}	--
1296	Peak Steam Generator Pressure occurs, psia	1138
2370	Auxiliary Feedwater to Intact Steam Generator Actuated on Low Level, ft. above tube sheet	20.09
5680	Auxiliary Feedwater to Intact Steam Generator terminated on High Level, ft. above tube sheet	40.46
*	Main Steam Isolation Signal (MSIS) Generated on High Level in the Damaged Steam Generator, % wide range level	98
*	Main Steam Safety Valves (MSSVs) on Damaged Steam Generator Actuated on High Steam Generator Pressure, psia	1200

* Event does not occur during the 10000 seconds of transient simulation.

TABLE 4.3.2-2

SEQUENCE OF EVENTS FOR CASE 4
STEAM GENERATOR TUBE RUPTURE (5 TUBES)
WITH MSIS ON HIGH SG LEVEL BYPASSED

TIME (Sec)	EVENT	SETPOINT
0.0	Tube Rupture Occurs	--
130	Pressurizer Backup Heaters Actuated on Low Pressurizer Pressure, psia	2200
149	Reactor Trips on Hot Leg Saturation Trip Signal	--
150	Turbine Trips	--
152	Steam Bypass System Actuated on High Steam Generator Pressure, psia	1078
165	Pressurizer Pressure Reaches Safety Injection Actuation Signal (SIAS) Setpoint, psia	1835
1[illegible]	Main Feedwater Terminated on Low T_{avg}	--
1590	Main Steam Isolation Signal (MSIS) would have been generated on High Level in the Damaged Steam Generator, % wide range level (signal bypassed for this case)	98
*	Main Steam Safety Valves (MSSVs) on Damaged Steam Generator Actuated on High Steam Generator Pressure, psia	1200

* Event does not occur during the first 10000 seconds of transient simulation.

FIG. 4.3.2-1 RCS and SG Pressures vs. Time

Case 3 for 1 Tube Ruptured and Automatic Bypass of MSIS on High SG Level

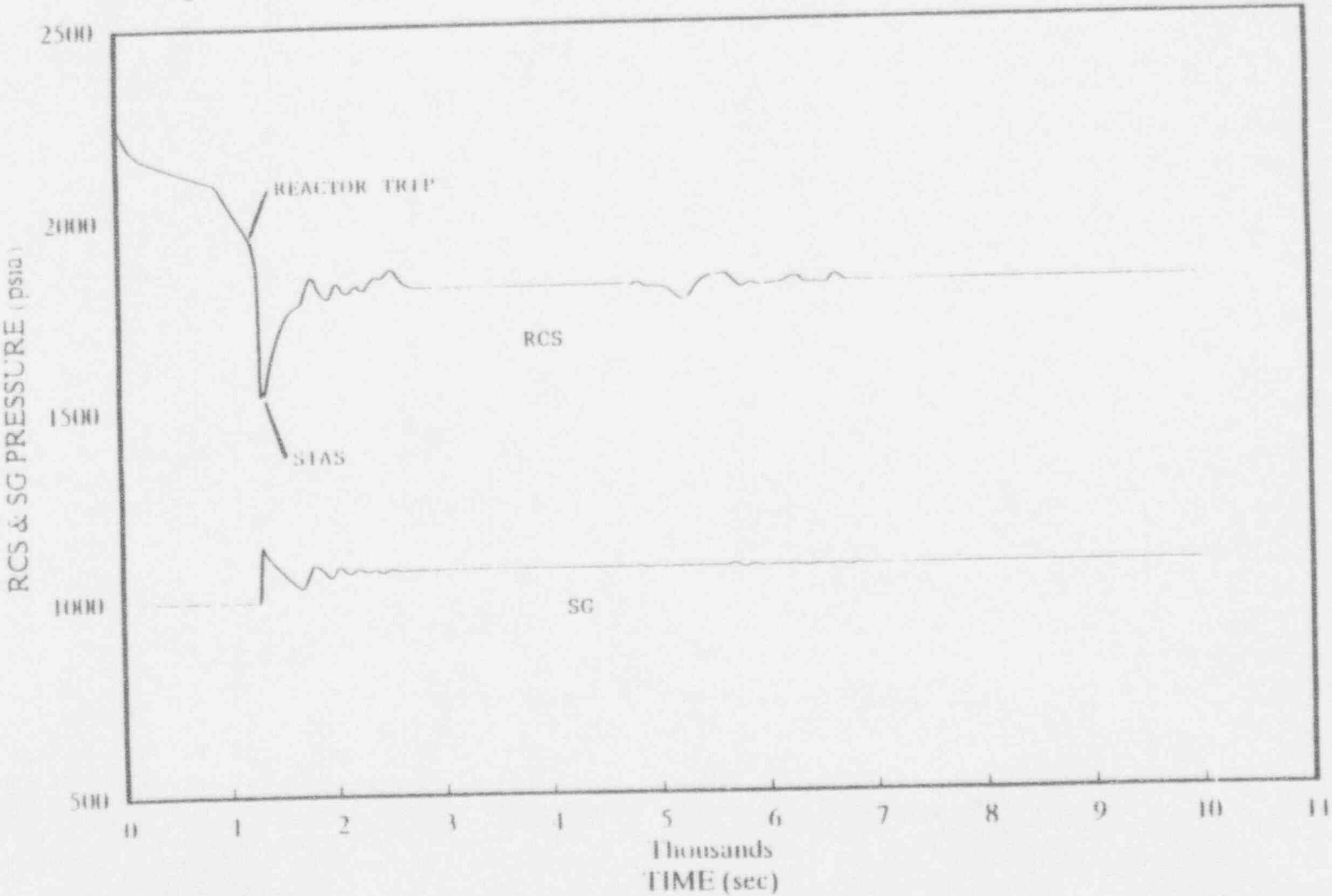


FIG. 4.3.2-2 Leak, HPSI and Bypass Flow Rates vs. Time

Case 3 for 1 Tube Ruptured and Automatic Bypass of MSIS on High SG Level

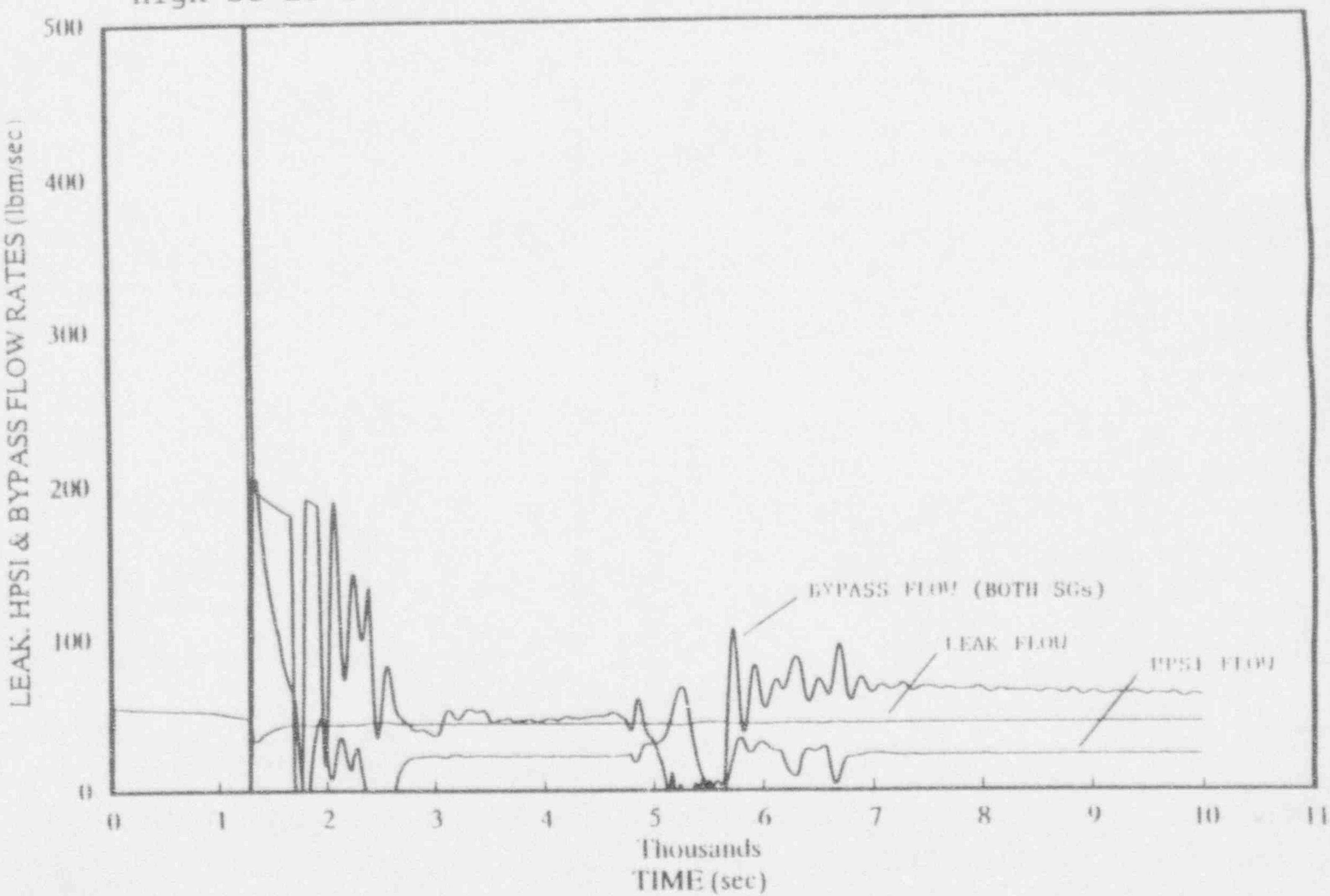


FIG. 4.3.2-3 Steam Generator Level vs. Time

Case 3 for 1 Tube Ruptured and Automatic Bypass of MSIS on High SG Level

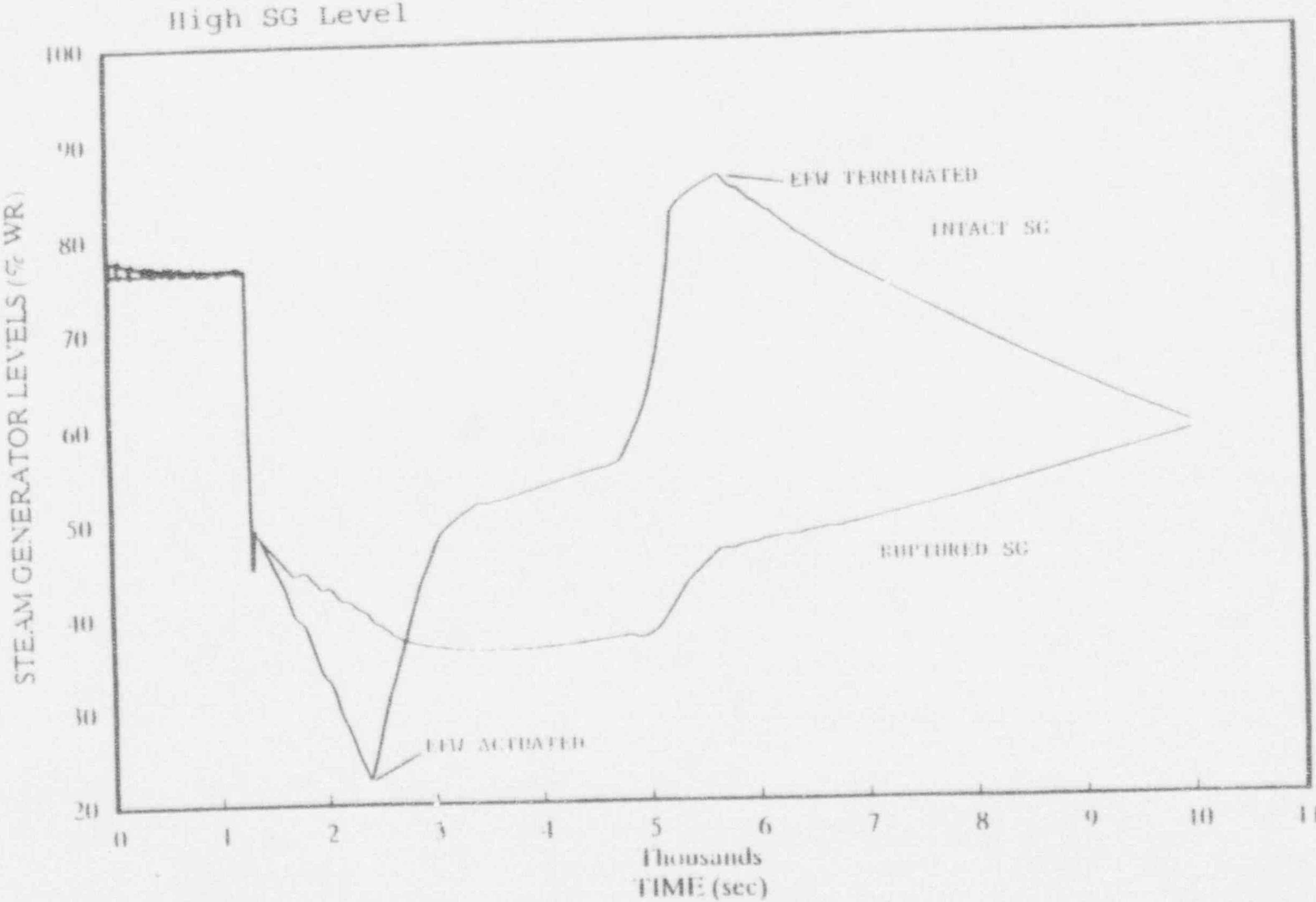


FIG. 4.3.2-4 Pressurizer Level vs. Time

Case 3 for 1 Tube Ruptured and Automatic Bypass of MSIS on High SG Level

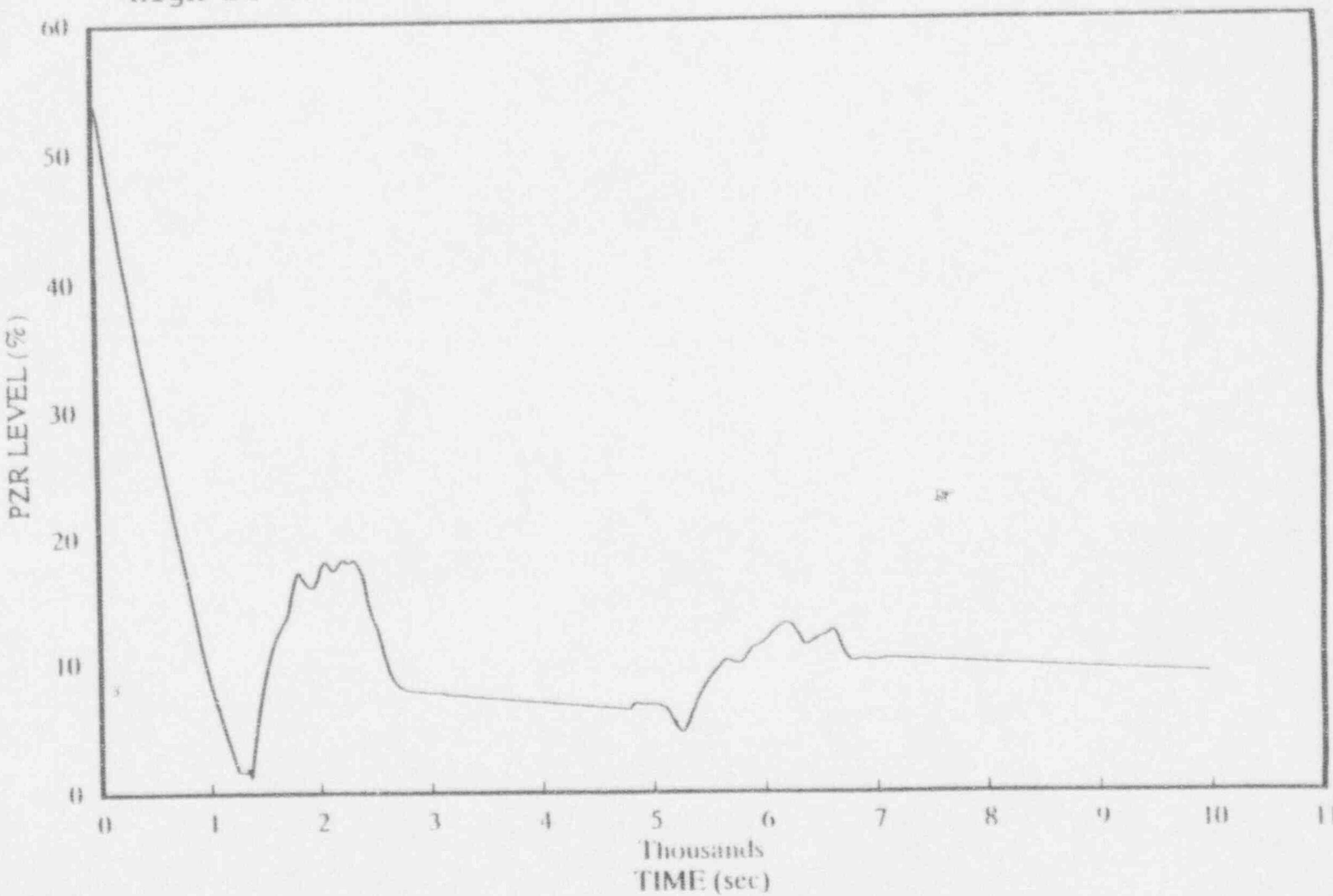


FIG. 4.3.2-5 Hot and Cold Leg Temperatures vs. Time
Case 3 for 1 Tube Ruptured and Automatic Bypass of MSIS on High SG Level

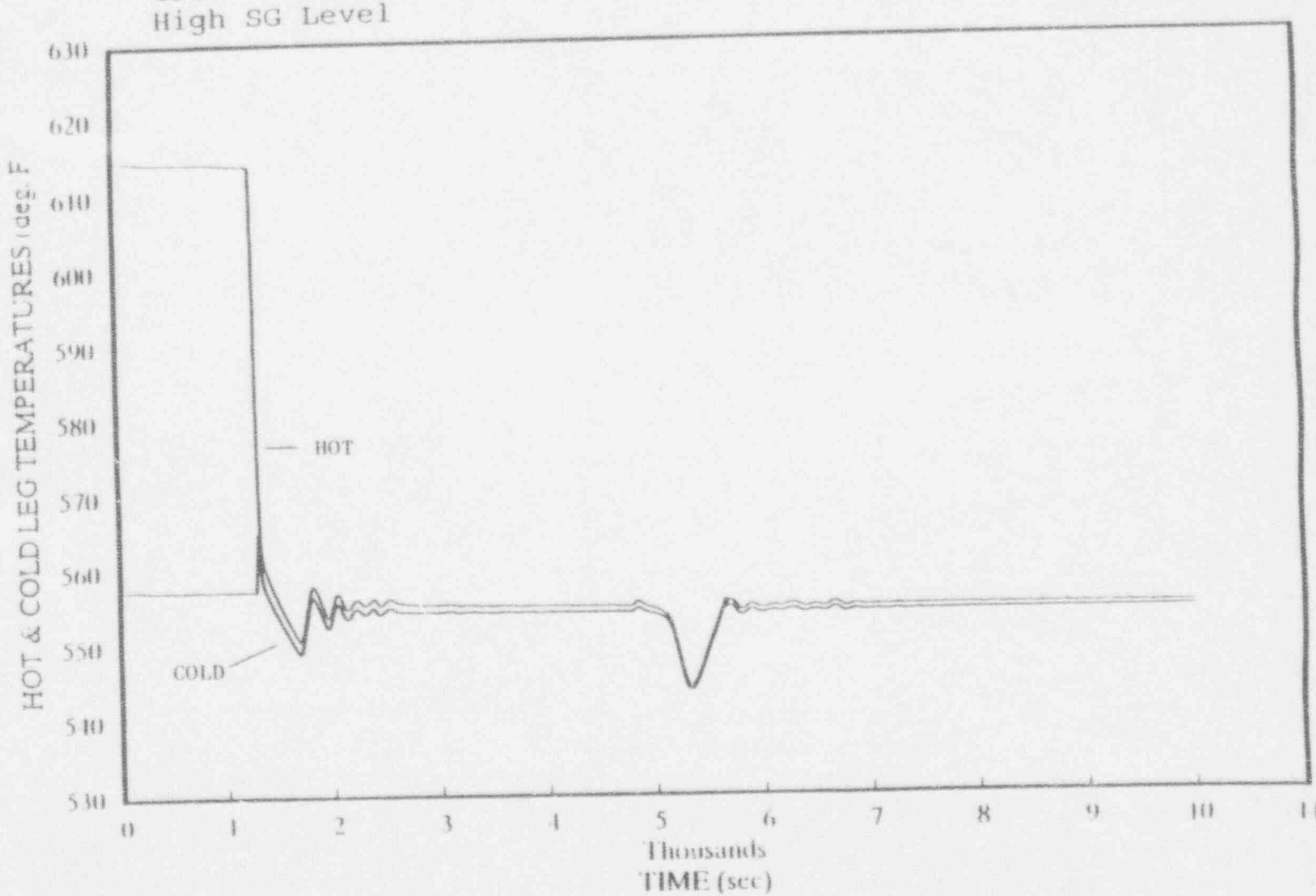


FIG. 4.3.2-6 RCS and SG Pressures vs. Time

Case 4 for 5 Tubes Ruptured and Automatic Bypass of MSIS on High SG Level

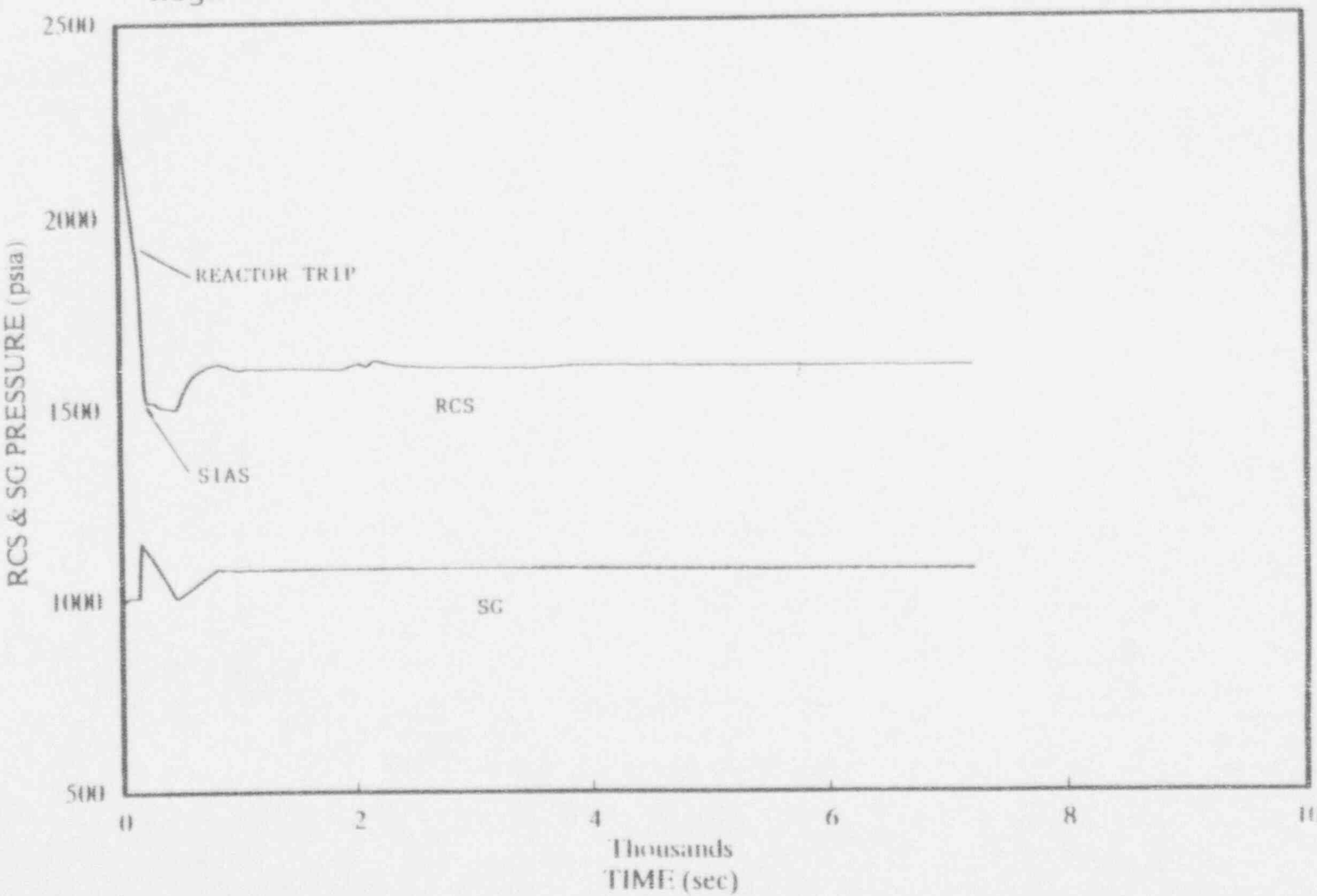


FIG. 4.3.2-7 Leak, HPSI and Bypass Flow Rates vs. Time

Case 4 for 5 Tubes Ruptured and Automatic Bypass of MSIS on High SG Level

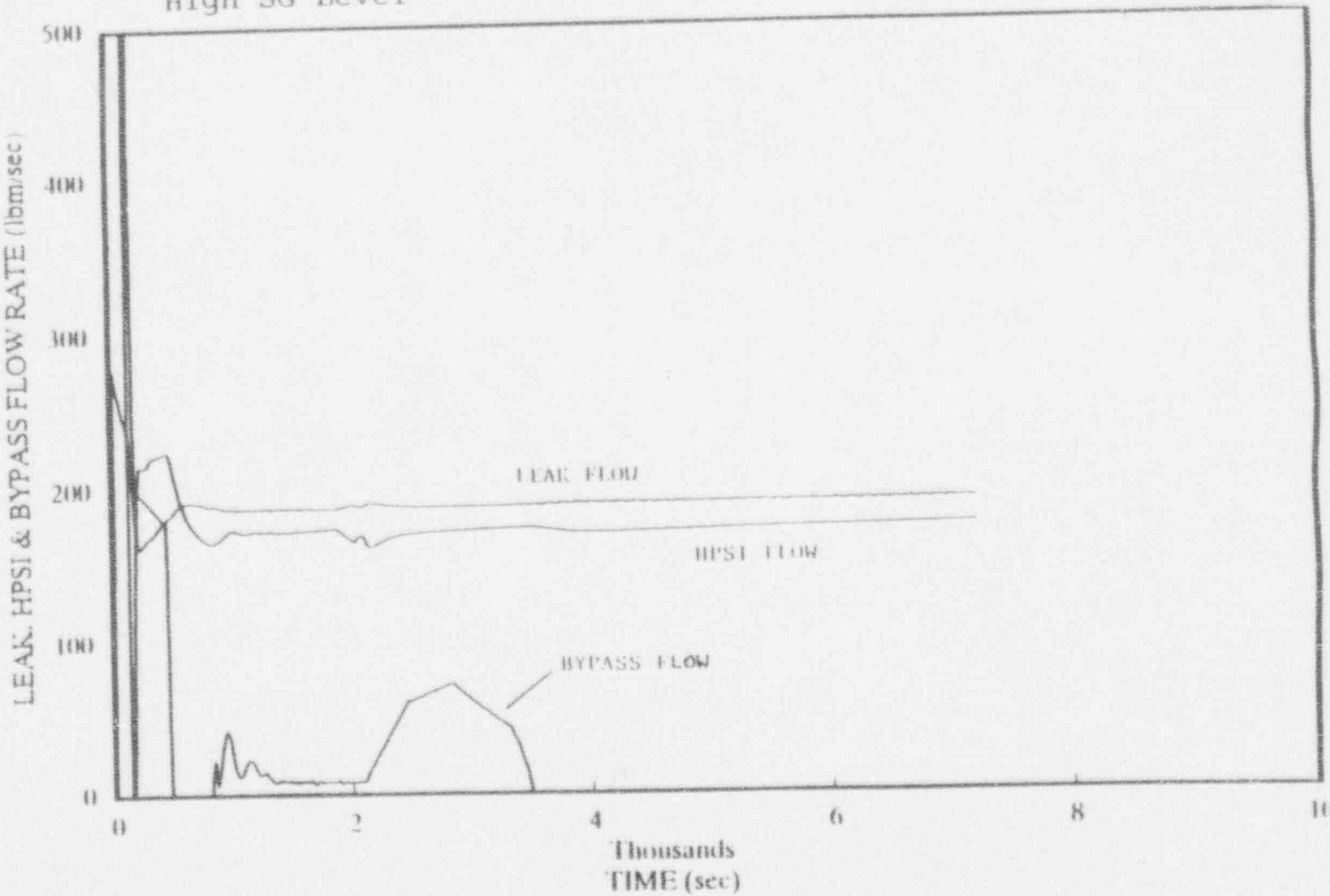


FIG. 4.3.2-8 Steam Generator Level vs. Time

Case 4 for 5 Tubes Ruptured and Automatic Bypass of MSIS on High SG Level

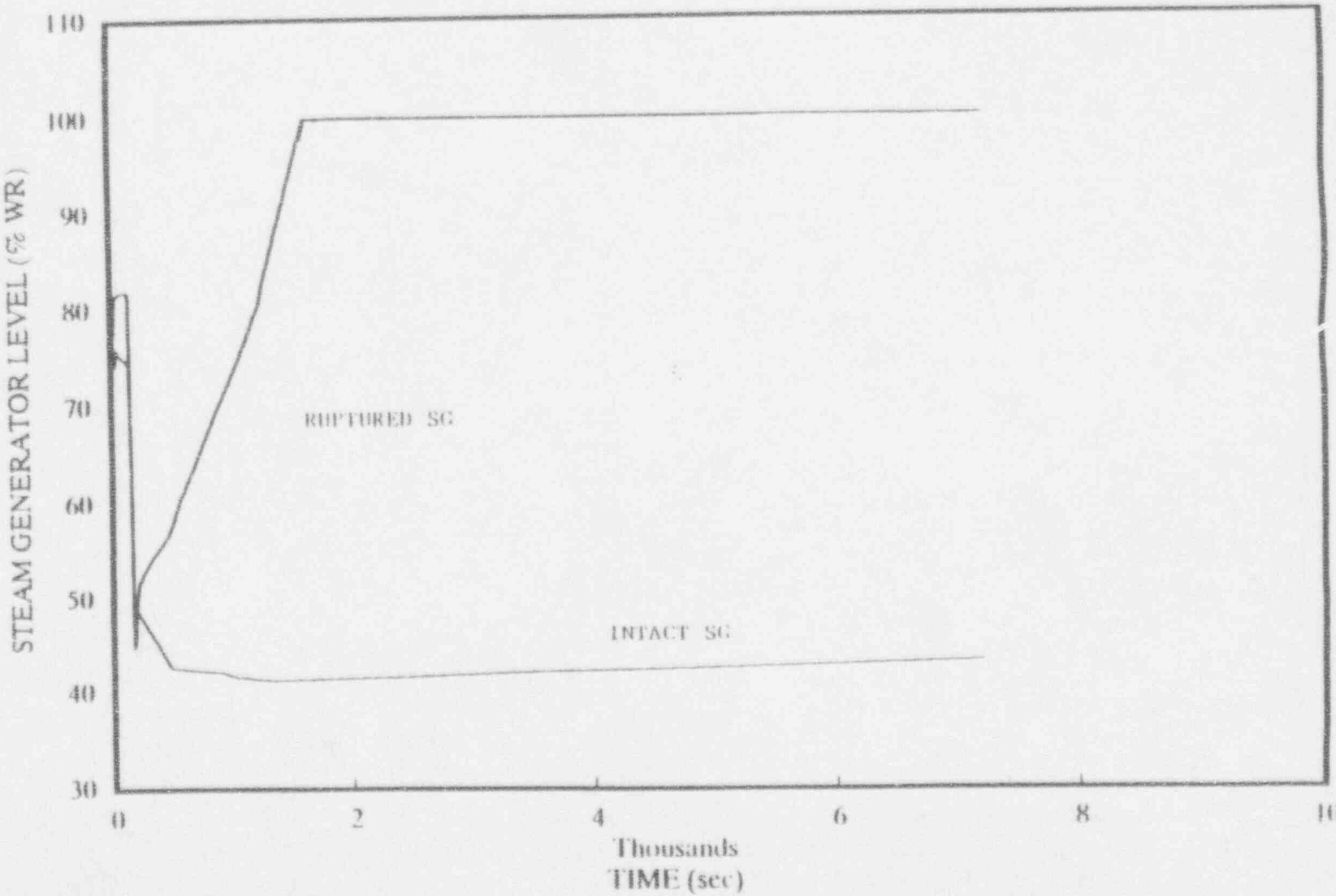


FIG. 4.3.2-9 Pressurizer Level vs. Time

Case 4 for 5 Tubes Ruptured and Automatic Bypass of MSIS on High SG Level

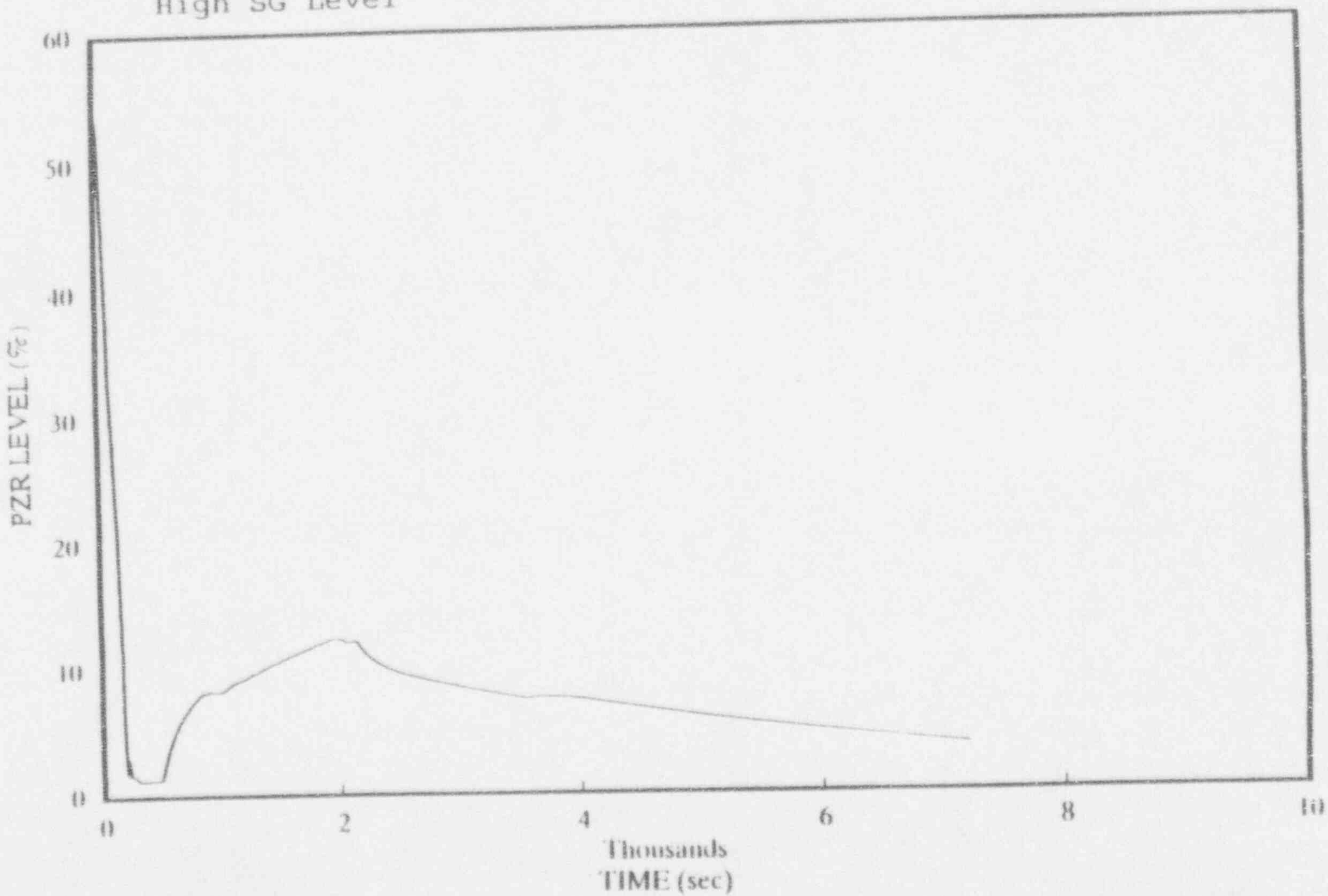
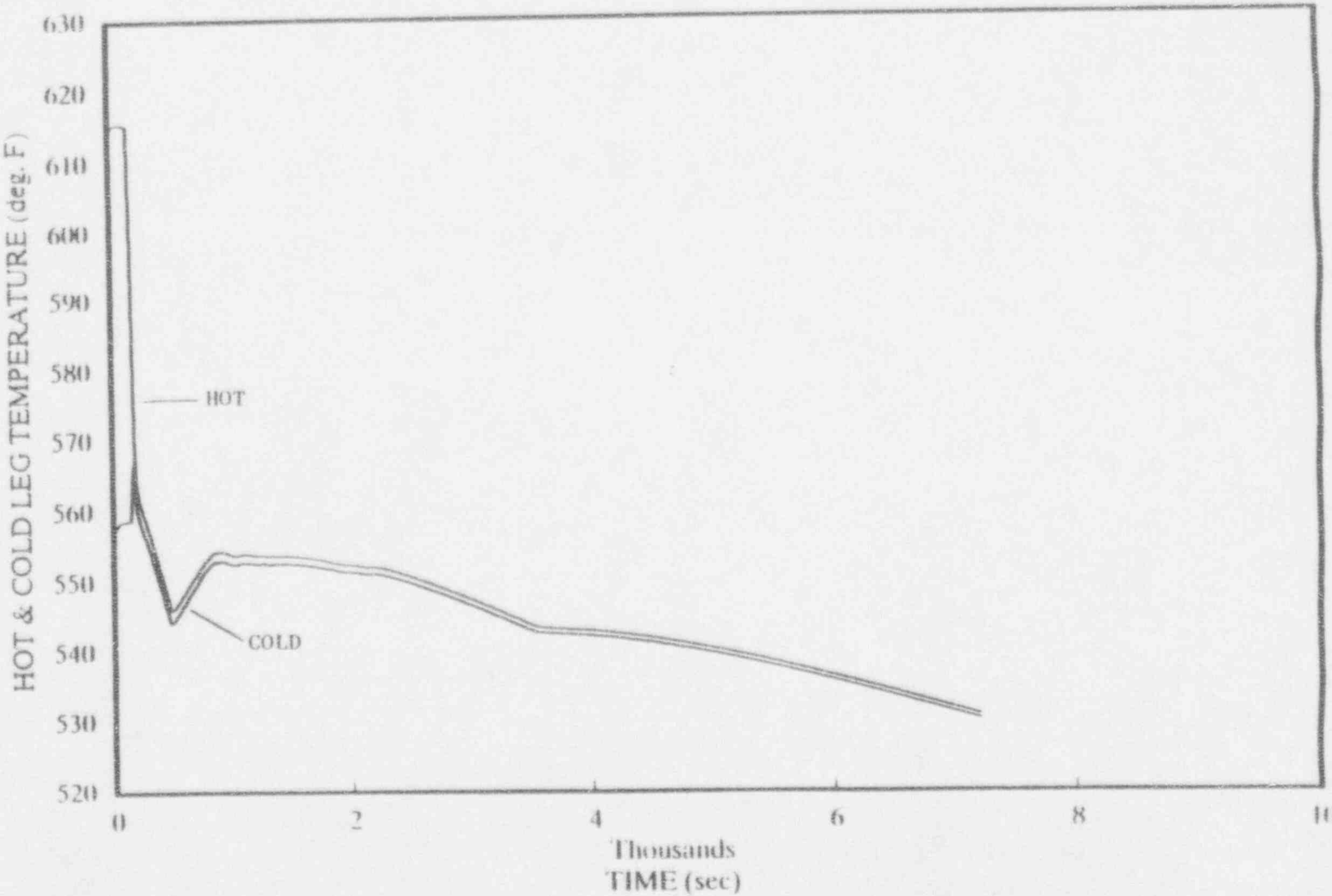


FIG. 4.3.2-10 Hot and Cold Leg Temperatures vs. Time

Case 4 for 5 Tubes Ruptured and Automatic Bypass of MSIS on High SG Level



4.3.3 Automatic Initiation of Auxiliary Pressurizer Spray

This design change considers automatic initiation of the auxiliary pressurizer spray. The objective is to reduce the RCS pressure in order to reduce the break flow rate. This would cause a reduction in the rate of increase in the damaged SG level, delaying MSIS signal and the resulting MSSV lift. The auxiliary spray actuation is envisioned to take place on a 2 out of 4 channel reactor trip signal and a 2 of 2 channel N-16 SG radiation detector signals.

Case 5 identifies the one tube rupture with auxiliary spray actuation subsequent to the reactor trip. Figures 4.3.3-1 through 4.3.3-5 show the transient behavior for key RCS and SG parameters for this case with Table 4.3.3-1 containing the sequence of major events occurring during the transient. Up until reactor trip these parameters behave similar to those for the base case (case 1). Subsequent to reactor trip the pressurizer level (Figure 4.3.3-4) increases very rapidly due to the actuation of the spray. The spray flow rate is about 150 gpm. The pressurizer fills up with water and becomes solid at about 1810 seconds. The RCS pressure (Figure 4.3.3-1) decreases following the reactor trip allowing the safety injection fluid to reach the core. The safety injection flow (Figure 4.3.3-2) causes cooling of the RCS as well as subsequent RCS repressurization to a quasi-steady state value of about 1800 psia. The safety injection flow assures RCS subcooling and core covery. Subsequent to fillup of the pressurizer, the break flow (Figure 4.3.3-2) is essentially matched by the combination of charging flow and safety injection flow such that the pressurizer remains filled for the remainder of the transient.

For Case 5, the steam bypass valves remains open subsequent to turbine trip at about 1290 seconds. Initially, the bypass system functions in the quick open mode relieving large amounts of steam. Subsequently, as the SG pressure (Figure 4.3.3-1) decreases and then increases to a quasi-steady state value around 1078 psia, the bypass functions in the modulation mode relieving enough steam to maintain this constant pressure. This bypass flow rate is smaller than the break flow rate (Figure 4.3.3-2) and hence the damaged steam generator level increases [Note that the bypass flow shown in Figure 4.3.3-2 is the flow from both steam generators; bypass flow from one generator is about half this flow rate.]. The damaged steam generator level (Figure 4.3.3-3) slightly decreases up to about 5000 seconds and increases later on as the bypass flow rate decreases drastically and the break flow rate remains essentially constant. The bypass flow rate increases again as the steam generator pressure increases and this causes a reduction in the rate of increase of the damaged steam generator level after 600 seconds. The intact steam generator level decreases due to the high bypass flow rate (Figure 4.3.3-2) initially and the termination of the main feedwater flow. Auxiliary feedwater flow is actuated when the low SG level setpoint of 20.09 ft is reached.

This causes an increase in the intact SG level. The rate of increase of this level is more rapid when the bypass flow rate is reduced at about 5500 seconds. Subsequently when the bypass flow rate increases, the rate of increase of the SG level is reduced. At about 6045 seconds the auxiliary feedwater to the intact SG was terminated on high level at which time the SG level begins decrease.

Case 6 denotes the five tube rupture case with auxiliary spray actuation. The results for the analysis of this case are presented in Figures 4.3.3-6 through 4.3.3-10. The sequence of major events occurring during the transient is listed in Table 4.3.3-2. The auxiliary spray actuation causes a sustained RCS pressure decrease subsequent to the reactor trip (Figure 4.3.3-6). This develops a large amount of safety injection flow (Figure 4.3.3-7) resulting in a pronounced decrease in the RCS temperatures (Figure 4.3.3-10). The pressurizer fills under the combined action of the auxiliary spray and safety injection flow. Subsequently, the RCS pressure remains at a large quasi-steady state value resulting in a reduced safety injection flow rate. Since the break flow rate (Figure 4.3.3-7) is higher than the bypass flow rate the damaged steam generator level (Figure 4.3.3-8) builds up rapidly and reaches the MSIS setpoint at about 1600 seconds and the bypass flow is terminated. The damaged steam generator pressure (Figure 4.3.3-6) increases subsequently and the MSSVs on this SG lifts at about 1750 seconds. The MSSVs cycle open and close to control the SG pressure at about 1200 psia.

Thus, a design change that automatically actuates the auxiliary spray system does not result in a significant benefit for either the one tube rupture (case 5) or the five tube ruptures (case 6). For the one tube case the damaged SG does not overfill or the MSSVs are not challenged for more than 10,000 seconds (167 minutes) as in the base case (case 1). However, the actuation of the sprays results in the fill up of the pressurizer with water, which is undesirable from an RCS pressure and inventory control point of view. For the five tube rupture case (case 6), the auxiliary spray actuation hastens the fill up of the damaged SG. Hence the use of automatic actuation of the auxiliary spray does not delay the challenge to the damaged SG MSSVs.

TABLE 4.3.3-1

SEQUENCE OF EVENTS FOR CASE 5
STEAM GENERATOR TUBE RUPTURE (1 TUBE)
WITH AUXILIARY SPRAY ON N-16 INDICATION

TIME (Sec)	EVENT	SETPOINT
0.0	Tube Rupture Occurs	--
1100	Pressurizer Backup Heaters Actuated on Low Pressurizer Pressure, psia	2200
1289	Reactor Trips on Hot Leg Saturation Trip Signal	--
1290	Turbine Trips	--
1291	Steam Bypass System Actuated on High Steam Generator Pressure, psia	1078
1294	Pressurizer Pressure Reaches Safety Injection Actuation Signal (SIAS) Setpoint, psia	1835
1295	Main Feedwater Terminated on Low T_{avg}	--
1296	Auxiliary Pressurizer Spray Actuated on Reactor Trip and N-16 Radiation Detector Signals	--
1810	Pressurizer Fills , Level (%)	100
2820	Auxiliary Feedwater to Intact Steam Generator Actuated on Low Level, ft. above tube sheet	20.09
6020	Auxiliary Feedwater to Intact Steam Generator Terminated on High Level, ft. above tube sheet	40.46
*	Main Steam Isolation Signal (MSIS) Generated on High Level in the Damaged Steam Generator, % wide range level	98
*	Main Steam Safety Valves (MSSVs) on Damaged Steam Generator Actuated on High Steam Generator Pressure, psia	

* Event does not occur during the first 10000 seconds of transient simulation.

TABLE 4.3.3-2

SEQUENCE OF EVENTS FOR CASE 6
STEAM GENERATOR TUBE RUPTURE (5 TUBES)
WITH AUXILIARY SPRAY ON N-16 INDICATION

TIME (Sec)	EVENT	SETPOINT
0.0	Tube Rupture Occurs	--
130	Pressurizer Backup Heaters Actuated on Low Pressurizer Pressure, psia	2200
149	Reactor Trips on Hot Leg Saturation Trip Signal	--
150	Turbine Trips	--
152	Steam Bypass System Actuated on High Steam Generator Pressure, psia	1078
165	Pressurizer Pressure Reaches Safety Injection Actuation Signal (SIAS) Setpoint, psia	1835
166	Main Feedwater Terminated on Low T_{avg}	--
167	Auxiliary Pressurizer Spray Actuated on Reactor Trip and N-16 Radiation Detector Signals	--
1177	Pressurizer Fills, Level (%)	100
1730	Main Steam Isolation Signal (MSIS) Generated on High Level in the Damaged Steam Generator, % wide range level	98
1860	Main Steam Safety Valves (MSSVs) on Damaged Steam Generator Actuated on High Steam Generator Pressure, psia	1200

FIG. 4.3.3-1 RCS and SG Pressures vs. Time

Case 5 for 1 Tube Ruptured and Automatic Initiation of Auxiliary Pressurizer Spray

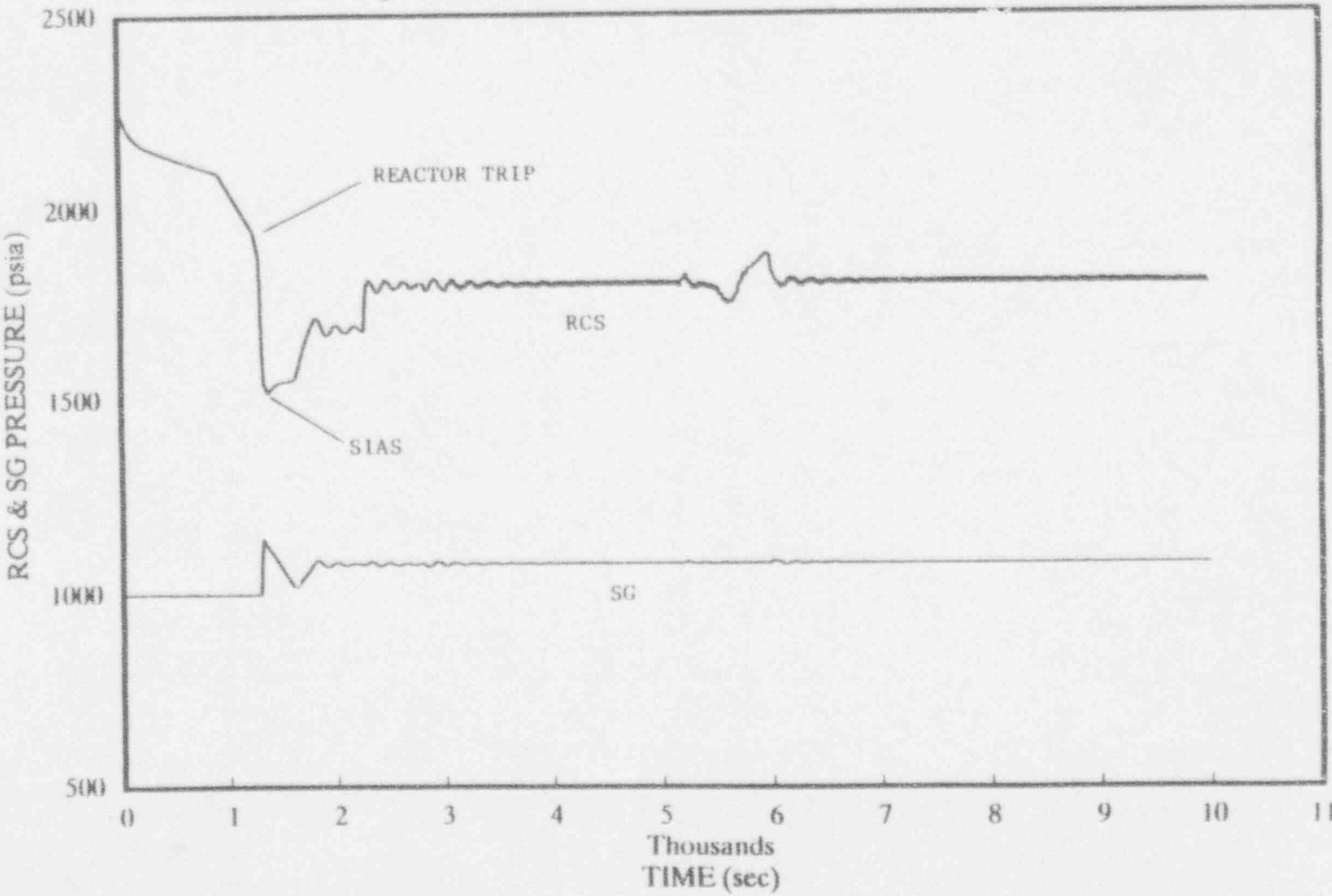


FIG. 4.3.3-2 Leak, HPSI and Bypass Flow Rates vs. Time

Case 5 for 1 Tube Ruptured and Automatic Initiation of Auxiliary Pressurizer Spray

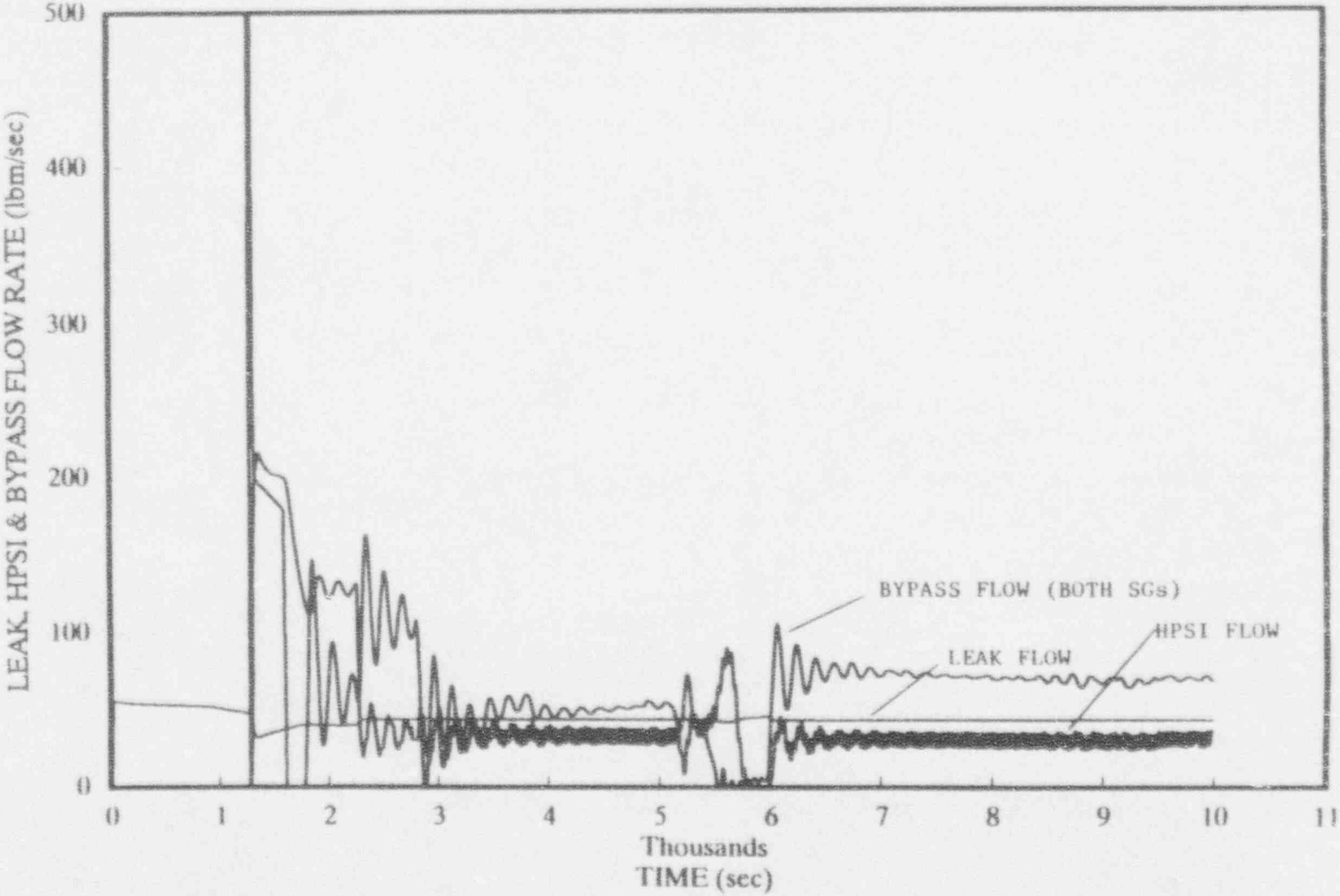


FIG. 4.3.3-3 Steam Generator Level vs. Time

Case 5 for 1 Tube Ruptured and Automatic Initiation of Auxiliary Pressurizer Spray

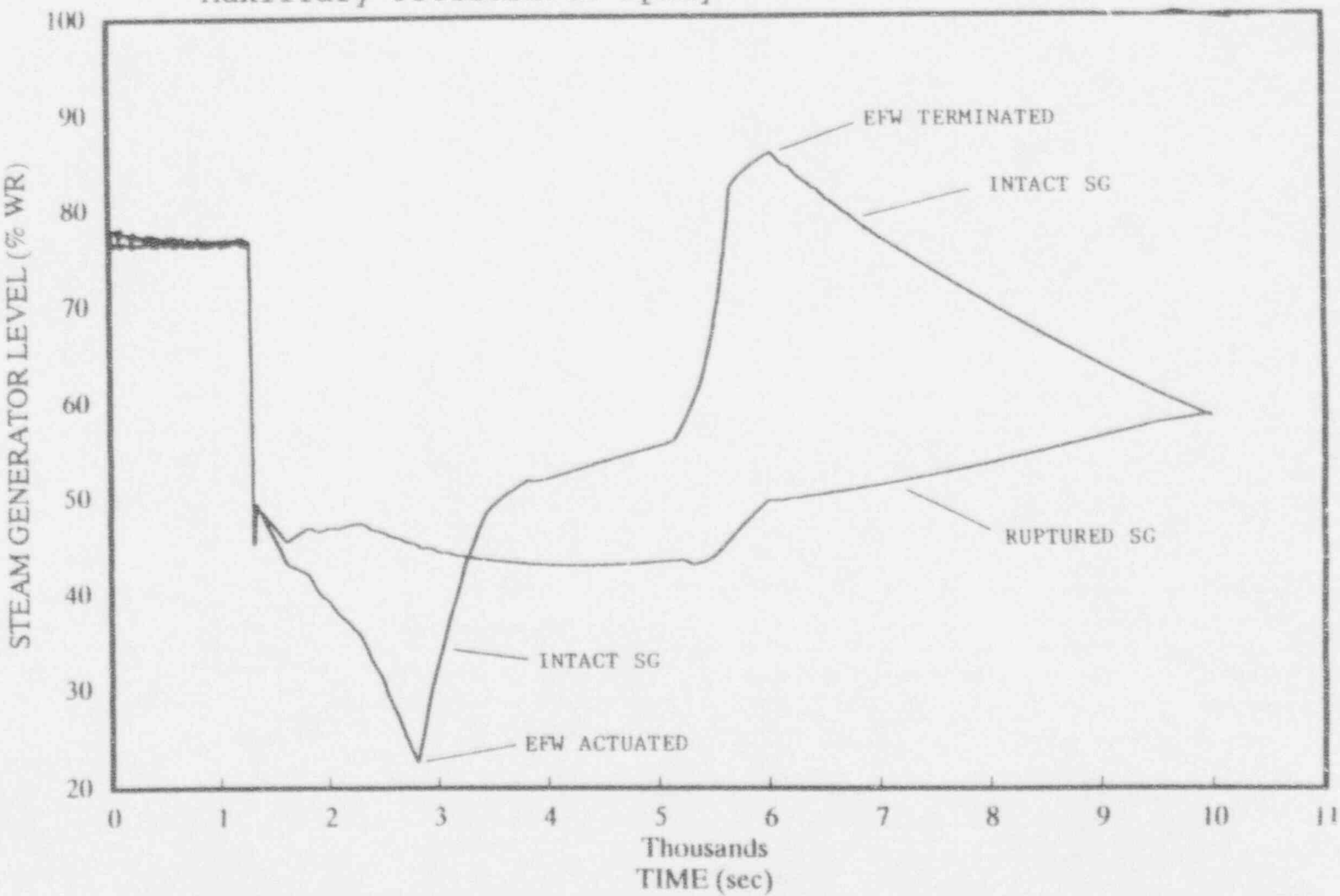


FIG. 4.3.3-4 Pressurizer Level vs. Time

Case 5 for 1 Tube Ruptured and Automatic Initiation of Auxiliary Pressurizer Spray

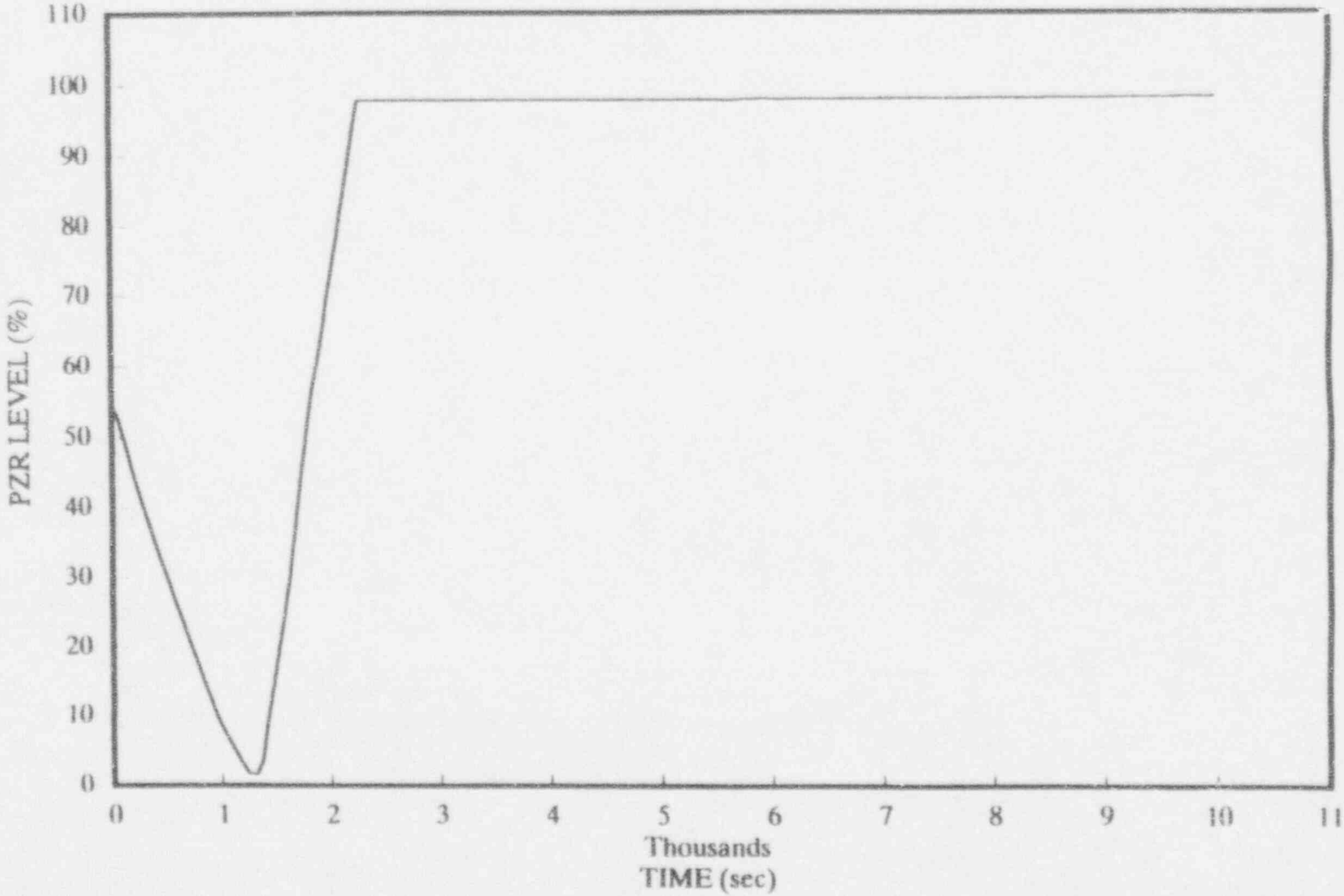


FIG. 4.3.3-5 Hot and Cold Leg Temperatures vs. Time

Case 5 for 1 Tube Ruptured and Automatic Initiation of Auxiliary Pressurizer Spray

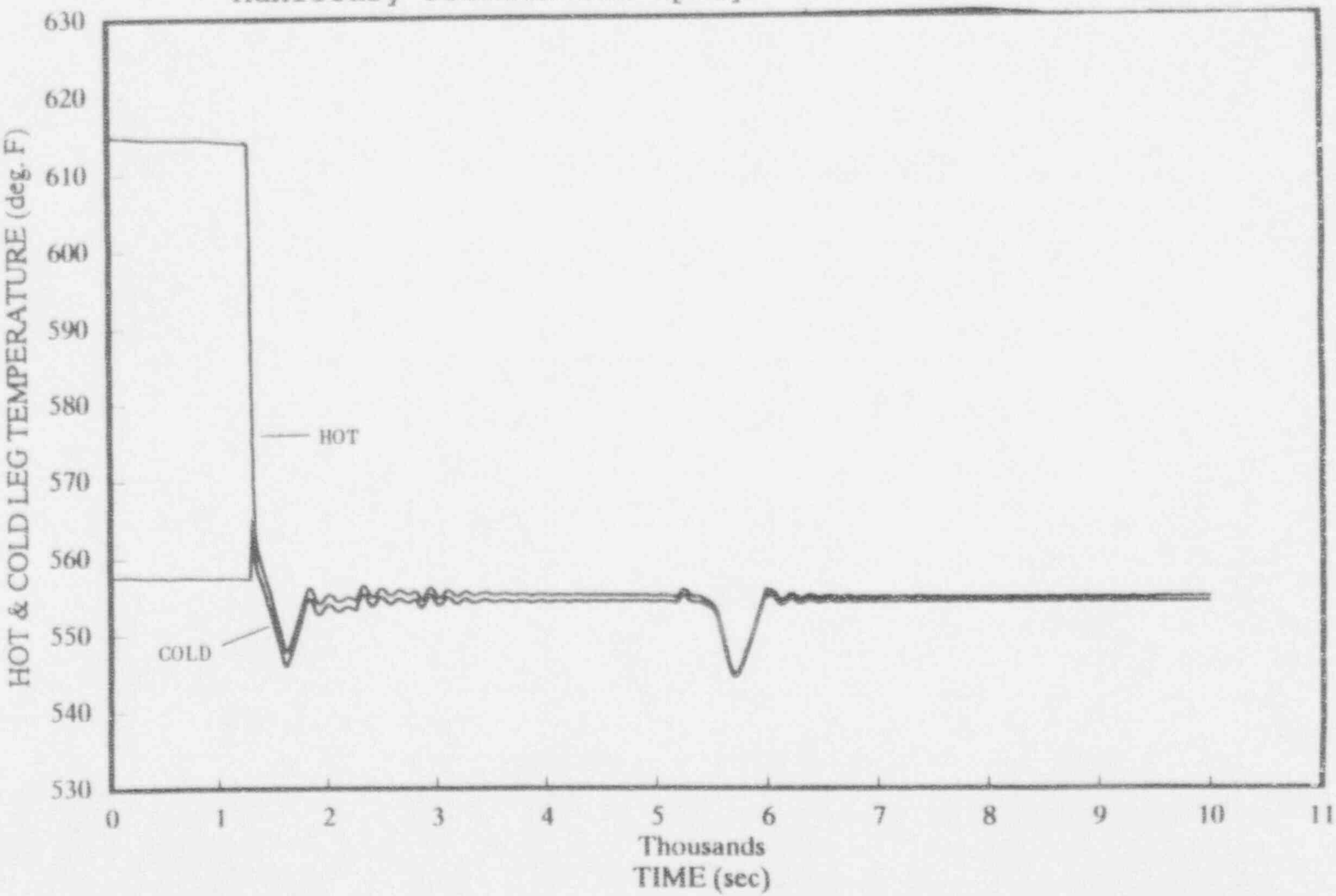


FIG. 4.3.3-6 RCS and SG Pressures vs. Time

Case 6 for 5 Tubes Ruptured and Automatic Ini iation of Auxiliary Pressurizer Spray

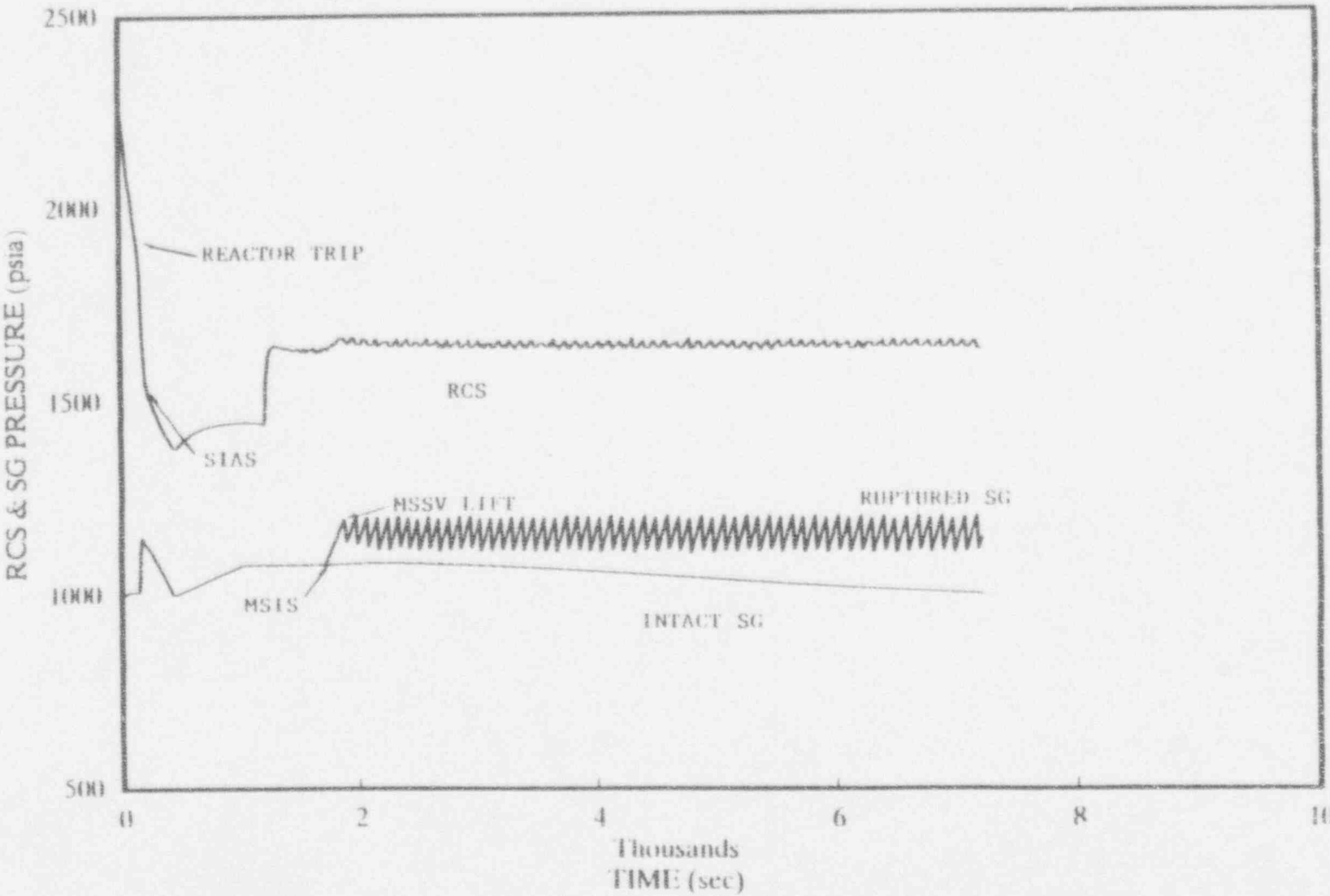


FIG. 4.3.3-7 Leak, HPSI and Bypass Flow Rates vs. Time
Case 6 for 5 Tubes Ruptured and Automatic Initiation of Auxiliary Pressurizer Spray

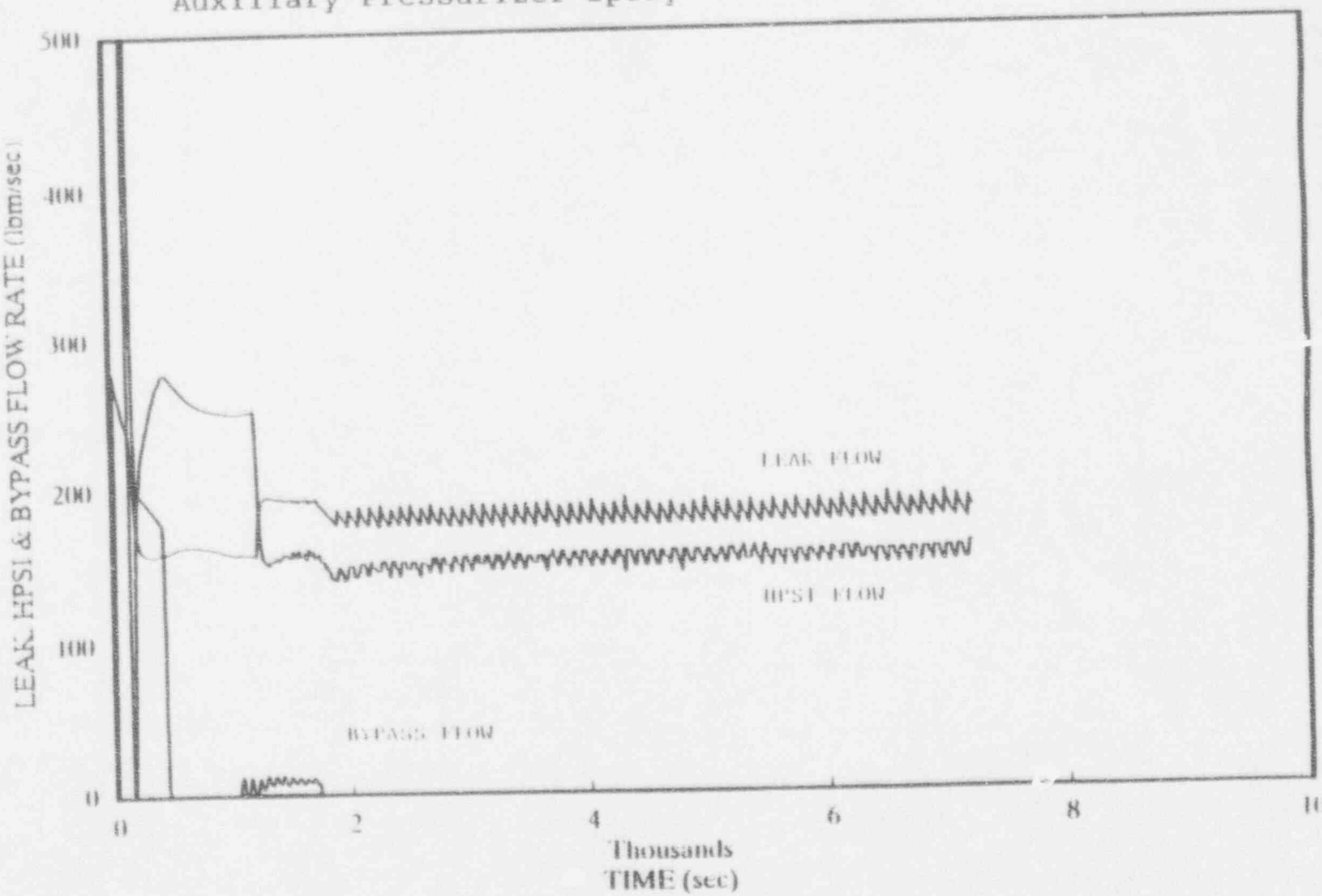


FIG. 4.3.3-8 Steam Generator Level vs. Time

Case 6 for 5 Tubes Ruptured and Automatic Initiation of Auxiliary Pressurizer Spray

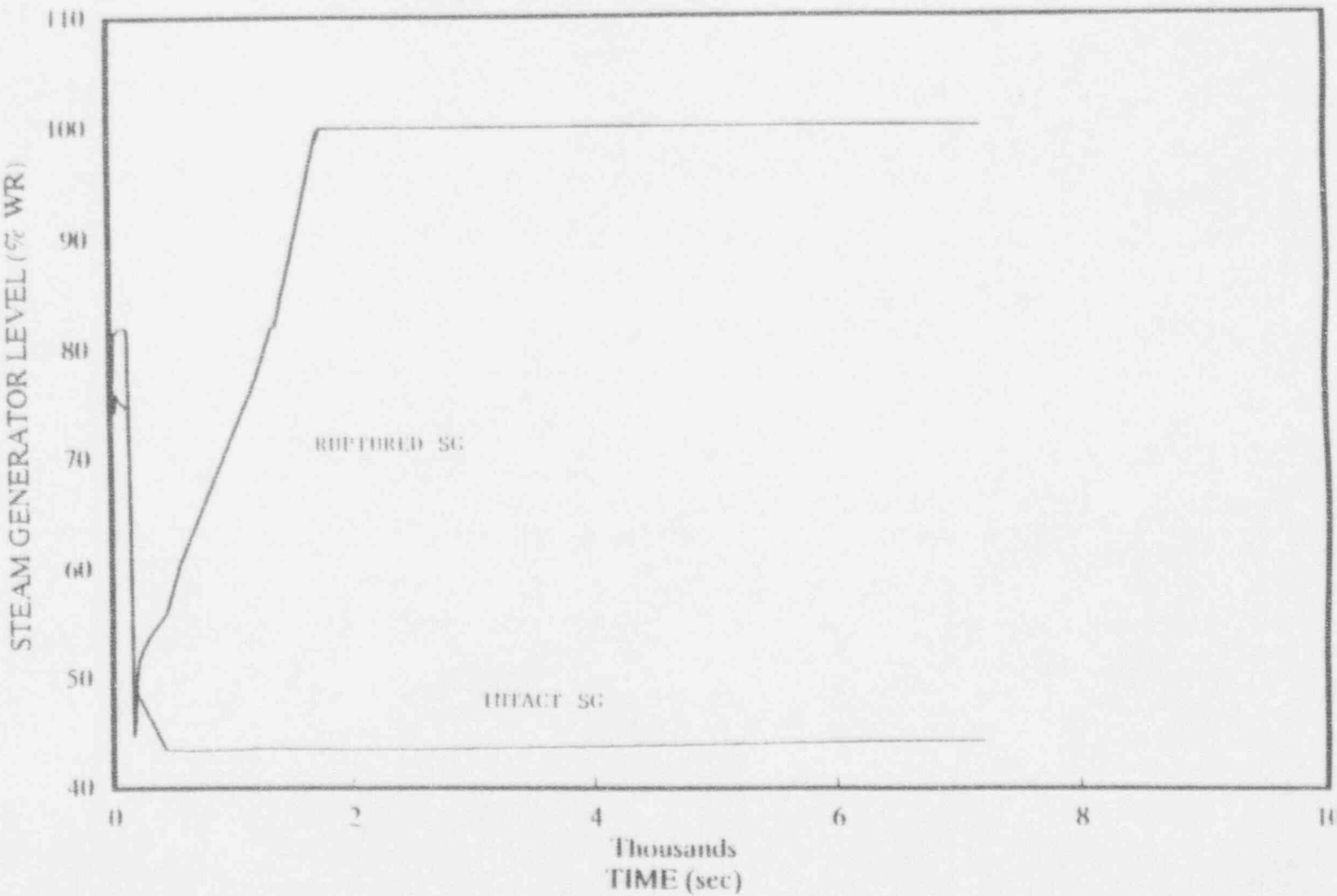


FIG. 4.3.3-9 Pressurizer Level vs. Time
Case 6 for 5 Tubes Ruptured and Automatic Initiation of Auxiliary Pressurizer Spray

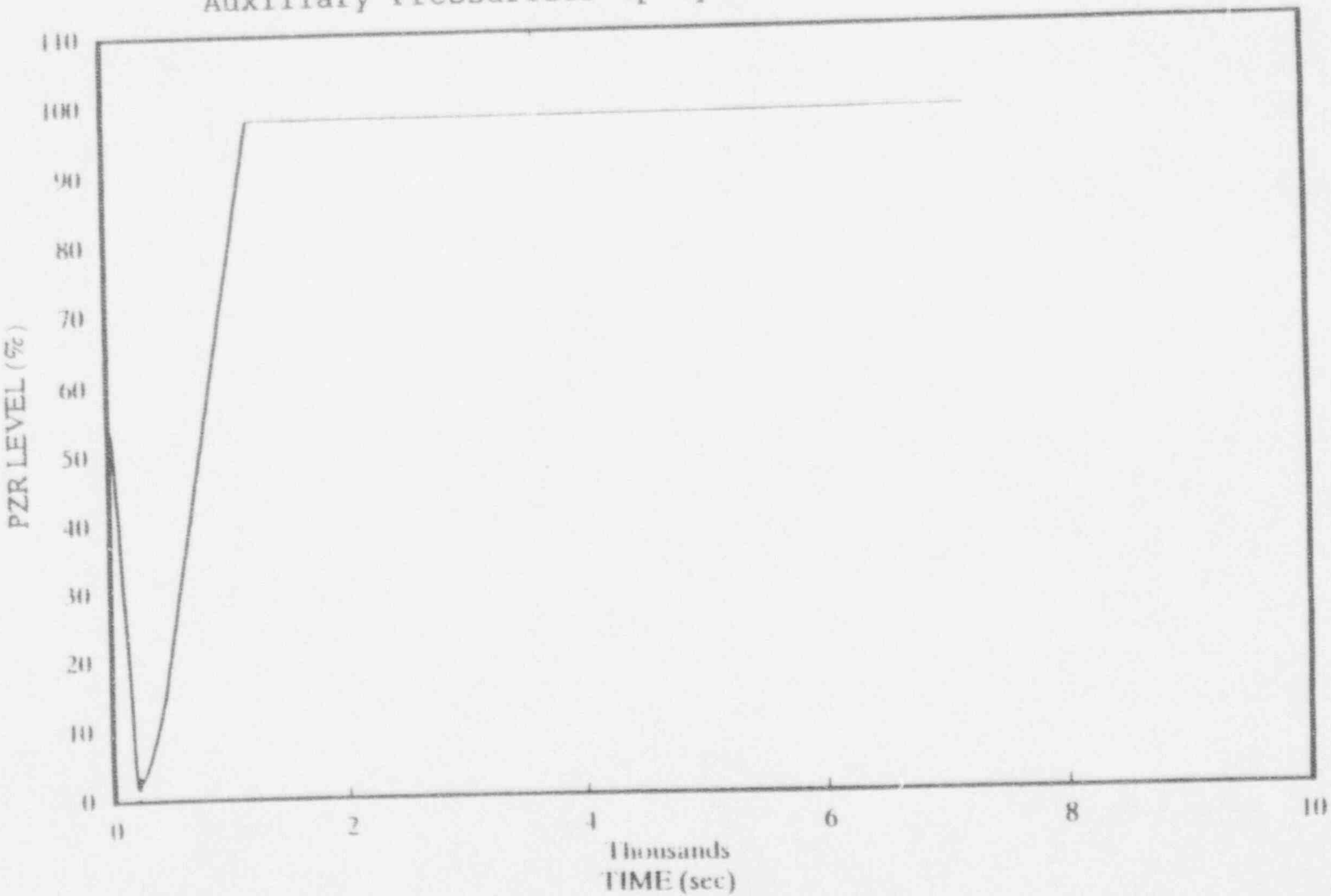
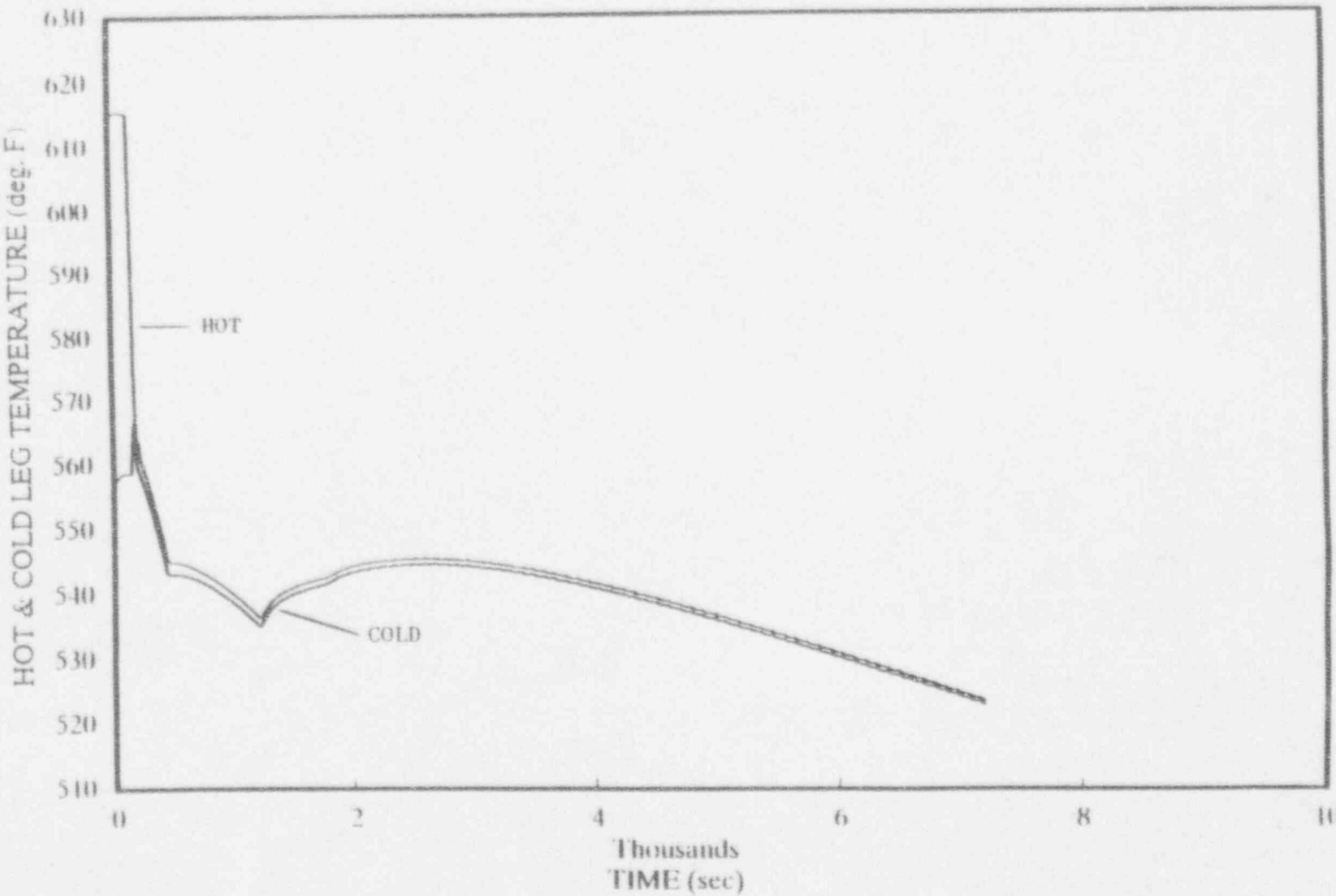


FIG. 4.3.3-10 Hot and Cold Leg Temperatures vs. Time

Case 6 for 5 Tubes Ruptured and Automatic Initiation of Auxiliary Pressurizer Spray



4.3.4 Automatic Opening of the Reactor Coolant Gas Vent System

This design change considers automatic opening of the reactor coolant gas vent system (RCGVS) valves to lower the RCS pressure and thereby reduce the break flow. This in turn may reduce the rates at which the damaged SG pressure and level increase so as to delay the challenge to MSSVs. The RCGVs would depressurize the RCS by blowing steam into the In-containment Refueling Water Storage Tank (IRWST). In the analysis it is assumed that the automatic opening of the RCGVS valves takes place on a 2 out of 4 channel reactor trip signal and a 2 of 2 channel N-16 SG radiation detector signals.

The results for one tube rupture case with this design change (Case 7) are provided in Figures 4.3.4-1 through 4.3.4-5 and the corresponding sequence of major events are listed in Table 4.3.4-1. The results for case 7 appears to be similar to those for case 5 (case with automatic auxiliary spray actuation). For case 7, the RCGVS flow and the break flow combined with safety injection flow (Figure 4.3.4-2) remove decay heat from the system subsequent to reactor trip. For case 5 , decay heat removal is accomplished by the cooling effect of the cold auxiliary spray water and the safety injection flow and the mass and energy removal through the break. Thus, for case 7, safety injection flow tends to be slightly higher to compensate for the lack of the auxiliary spray flow. This flow assures that RCS subcooling is maintained, thereby precluding core damage. In addition, for case 7, RCS heat removal through the steam bypass system is lower since the RCGVS removes some of the decay heat. Since the steam bypass system flow rate is slightly smaller than that is for case 5, the damaged SG level (Figure 4.3.4-3 vs 4.3.3-3) remains at a relatively higher value during the transient and the SG fills up slightly faster. However, the damaged steam generator level remains below the MSIS setpoint even at 10,000 seconds. As in case 5, the pressurizer fills early in the transient (at about 2270 seconds) due to the relatively large safety injection flow.

For the five ruptured tubes case with RCGVS valves actuated (case 8), the results are presented in Figures 4.3.4-6 through 4.3.4-10 and the sequence of major events that occur during the transient is listed in Table 4.3.4-2. These results are also similar to those for case 6 which is the base case with automatic actuation of the auxiliary pressurizer sprays. Major difference is in the safety injection flow rate (Figure 4.3.4-7) which is larger for case 8 in comparison to case 6. This is because of the RCS pressure (Figure 4.3.4-6) reaching a lower quasi-steady state value for case 8 due to the RCGVS opening. Since the larger safety injection flow (Figure 4.3.4-7) removes a larger portion of the decay heat for case 8, the break flow rate is smaller for case 8 than for case 6. This results in a slower increase in the damaged SG level (Figure 4.3.4-8), slightly longer duration in reaching the MSIS setpoint (1850 seconds) and opening of the MSSVs (2000

seconds) for case 8. The pressurizer fills up (Figure 4.3.4-9) for this case at about 1325 seconds due to the safety injection flow and the opening of the RCGVS valves.

Thus, a design change that automatically actuates the RCGVS valves flow does not result in a significant benefit for either the one tube rupture (case 7) or the five tube ruptures (case 8). For the one tube case the damaged SG does not overfill or the MSSVs are not challenged for more than 10,000 seconds (167 minutes) as in the base case (case 1). However, the actuation of the RCGVS valves results in the fill up of the pressurizer with water, which is undesirable from an RCS pressure and inventory control point of view. For the five tube rupture case (case 8), the RCGVS valves actuation delays the fill up of the damaged SG only slightly (1590 seconds for the base case vs 1850 for case 8). Hence the automatic actuation of the RCGVS valves does not appreciably delay the challenge to the damaged SG MSSVs.

TABLE 4.3.4-1

SEQUENCE OF EVENTS FOR CASE 7
STEAM GENERATOR TUBE RUPTURE (1 TUBE)
WITH RCGVS ACTUATED ON N-16 INDICATION

TIME (Sec)	EVENT	SETPOINT
0.0	Tube Rupture Occurs	--
110[illegible]	Pressurizer Backup Heaters Actuated on Low Pressurizer Pressure, psia	2200
1289	Reactor Trips on Hot Leg Saturation Trip Signal	--
1290	Turbine Trips	--
1291	Steam Bypass System Actuated on High Steam Generator Pressure, psia	1078
1294	Pressurizer Pressure Reaches Safety Injection Actuation Signal (SIAS) Setpoint, psia	1835
1295	Main Feedwater Terminated on Low T_{avg}	--
1296	Reactor Coolant Gas Vent System Valves Actuated on Reactor Trip and N-16 Radiation Detector Signals	--
2270	Pressurizer Fills, Level (%)	100
3250	Auxiliary Feedwater to Intact Steam Generator Actuated on Low level, ft. above tube sheet	20.09
6570	Auxiliary Feedwater to Intact Steam Generator Terminated on High Level, ft. above tube sheet	40.46
*	Main Steam Isolation Signal (MSIS) Generated on High Level in the Damaged Steam Generator, % wide range level	98
*	Main Steam Safety Valves (MSSVs) on Damaged Steam Generator Actuated on High Steam Generator Pressure, psia	1200

* Event does not occur during the 10000 seconds of trasient simulation.

TABLE 4.3.4-2

SEQUENCE OF EVENTS FOR CASE 8
STEAM GENERATOR TUBE RUPTURE (5 TUBES)
WITH RCGVS ACTUATED ON N-16 INDICATION

TIME (Sec)	EVENT	SETPOINT
0.0	Tube Rupture Occurs	--
130	Pressurizer Backup Heaters Actuated on Low Pressurizer Pressure, psia	2200
149	Reactor Trips on Hot Leg Saturation Trip Signal	--
150	Turbine Trips	--
152	Steam Bypass System Actuated on High Steam Generator Pressure, psia	1078
165	Pressurizer Pressure Reaches Safety Injection Actuation Signal (SIAS) Setpoint, psia	1835
166	Main Feedwater Terminated on Low T_{avg}	--
167	Reactor Coolant Gas Vent System Actuated on Reactor Trip and N-16 Detector Signals	--
1325	Pressurizer Fills, Level (%)	100
1850	Main Steam Isolation Signal (MSIS) Generated on High Level in the Damaged Steam Generator, % wide range level	98
2000	Main Steam Safety Valves (MSSVs) on Damaged Steam Generator Actuated on High Steam Generator Pressure, psia	1200

FIG. 4.3.4-1 RCS and SG Pressures vs. Time

Case 7 for 1 Tube Ruptured and Automatic Opening of RCGVS on Pressurizer

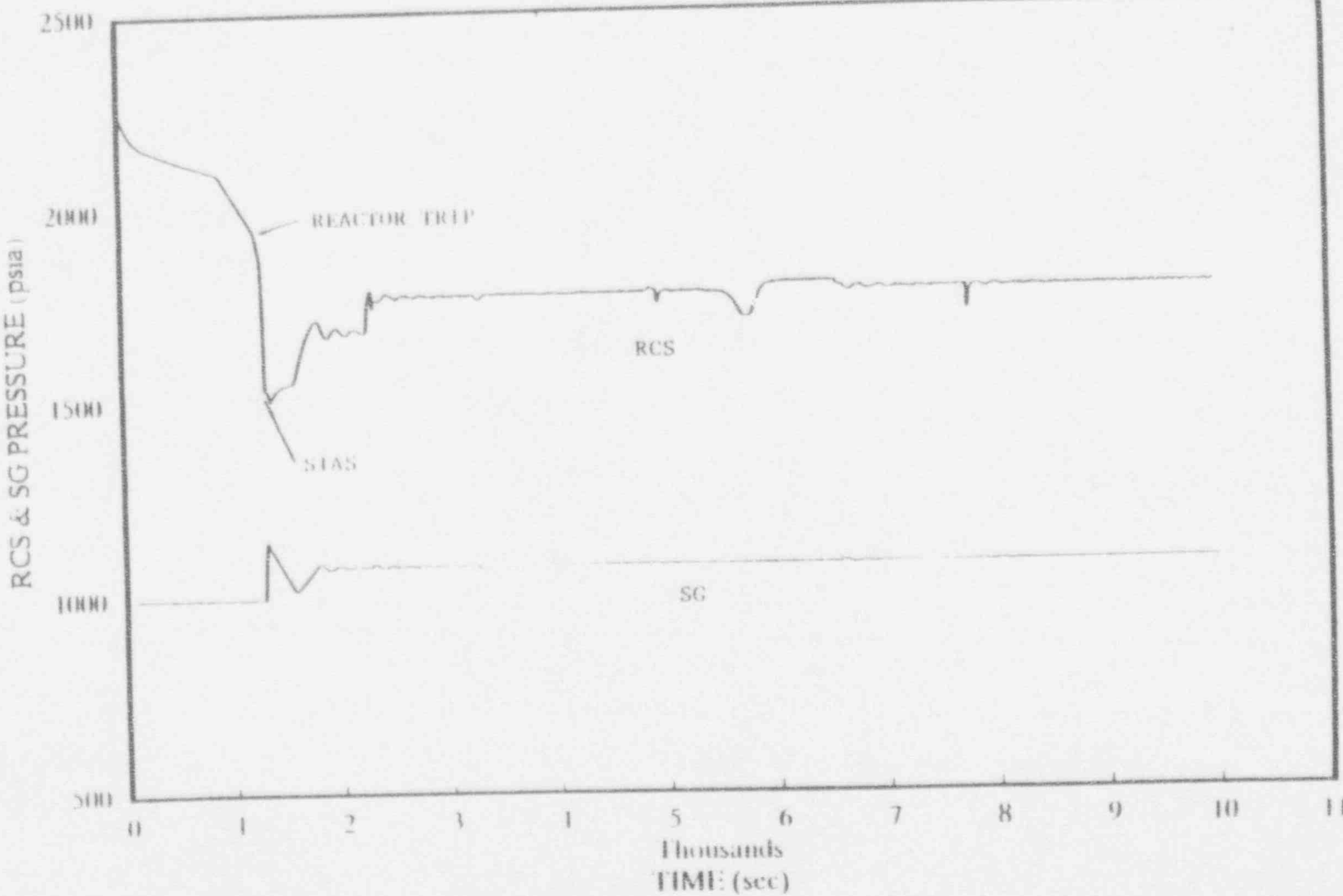


FIG. 4.3.4-2 Leak, HPSI and Bypass Flow Rates vs. Time
Case 7 for 1 Tube Ruptured and Automatic Opening of RCGVS on Pressurizer

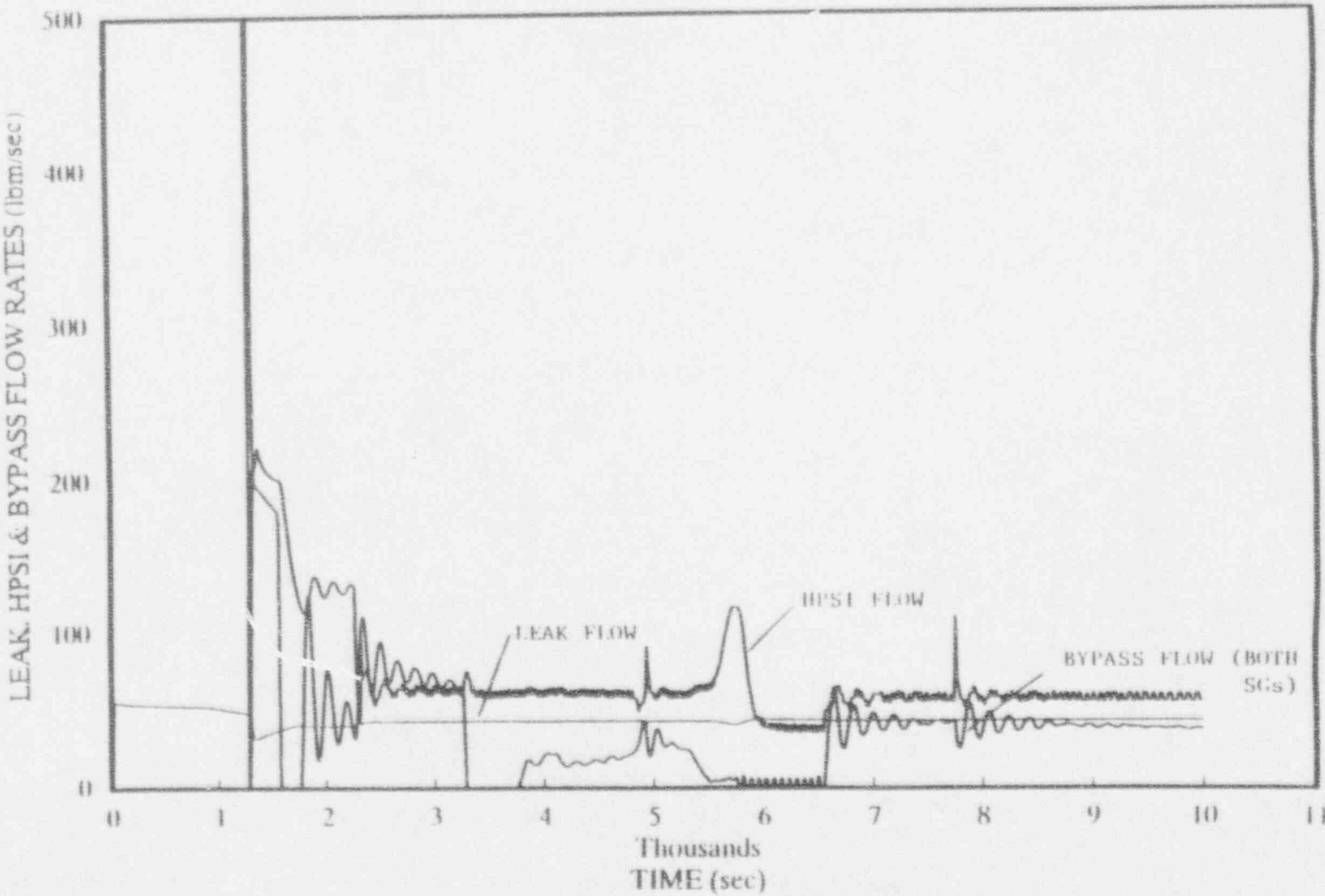


FIG. 4.3.4-3 Steam Generator Level vs. Time

Case 7 for 1 Tube Ruptured and Automatic Opening of RCGVS on Pressurizer

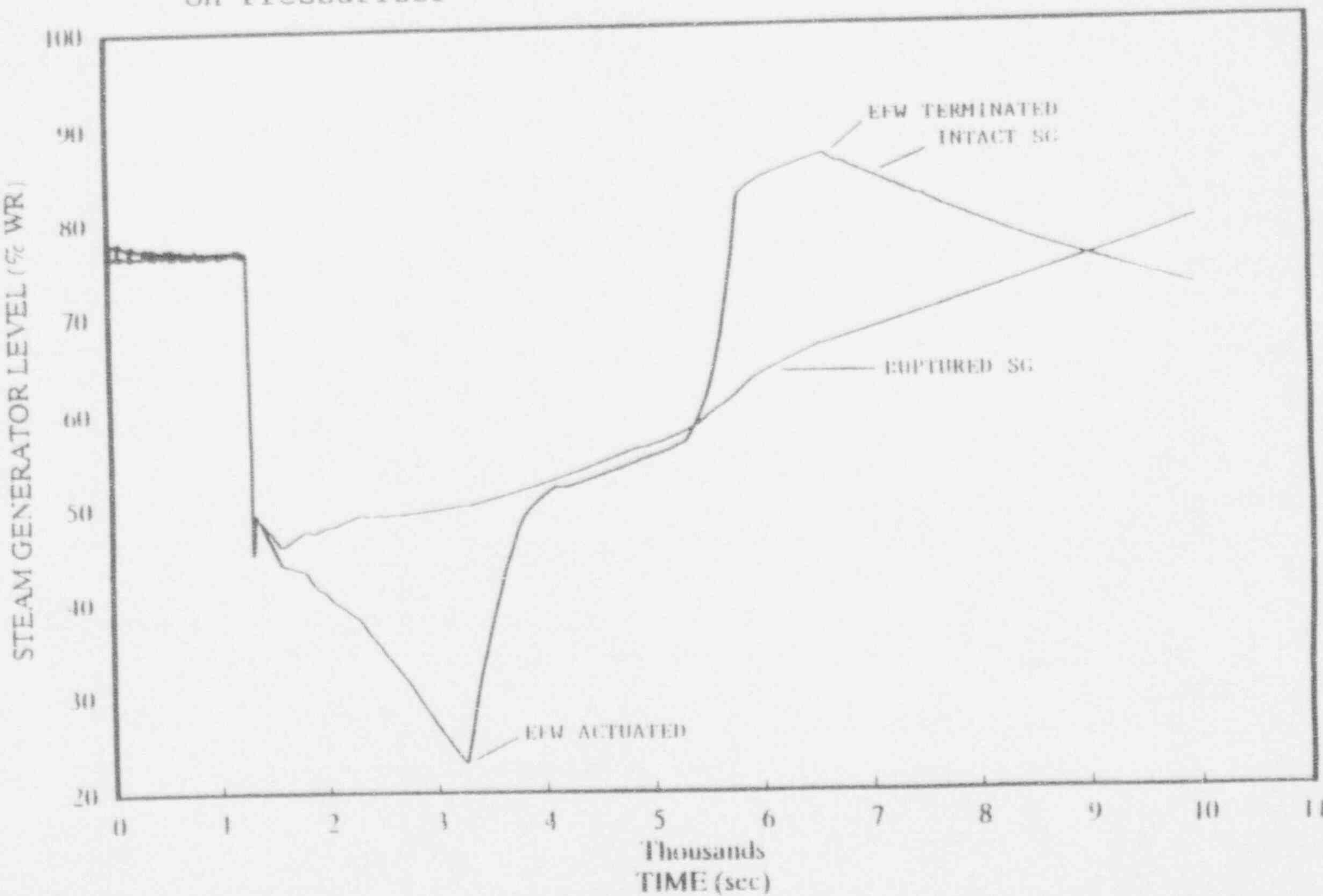


FIG. 4.3.4-4 Pressurizer Level vs. Time

Case 7 for 1 Tube Ruptured and Automatic Opening of RCGVS on Pressurizer

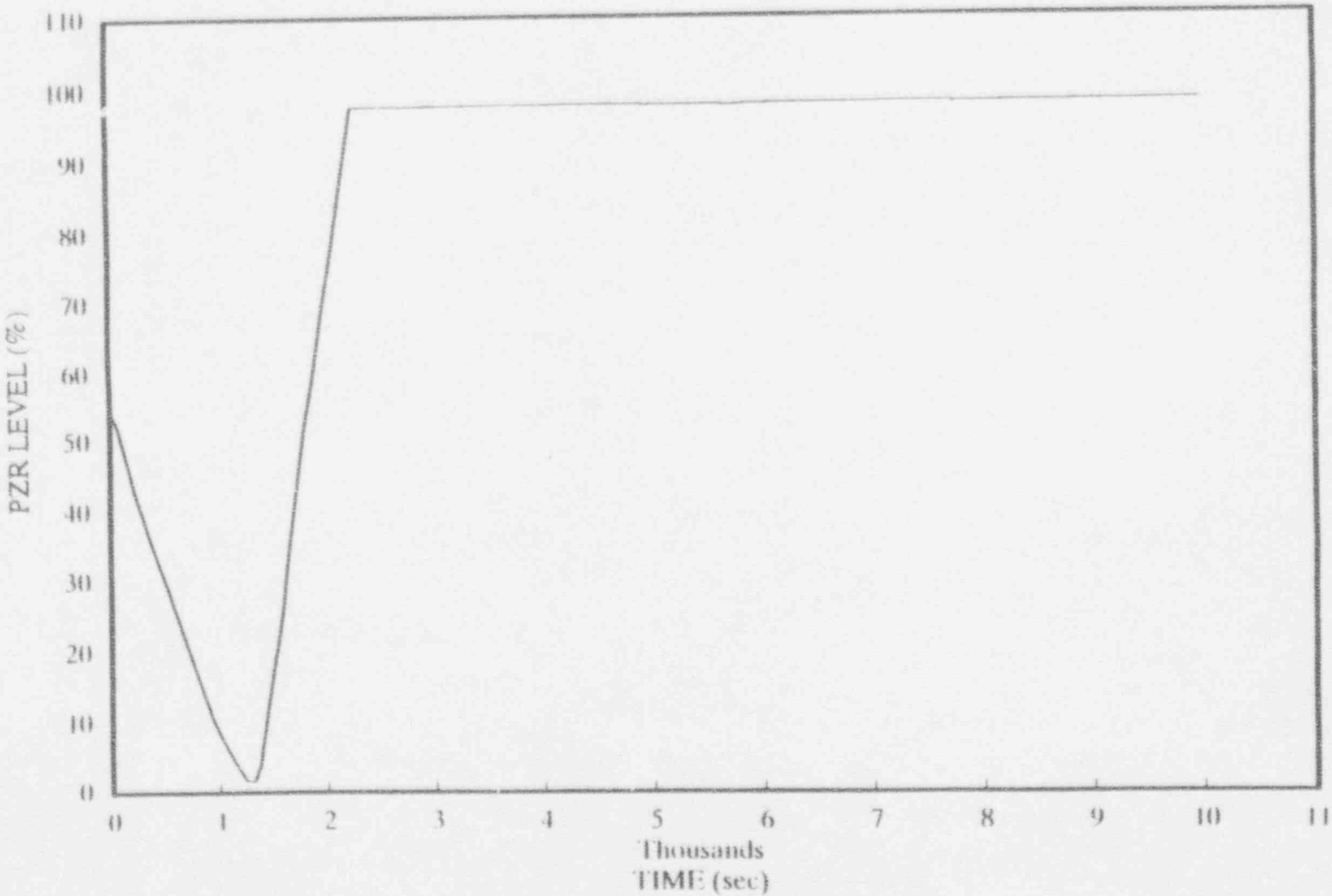


FIG. 4.3.4-5 Hot and Cold Leg Temperatures vs. Time
Case 7 for 1 Tube Ruptured and Automatic Opening of RCGVS on Pressurizer

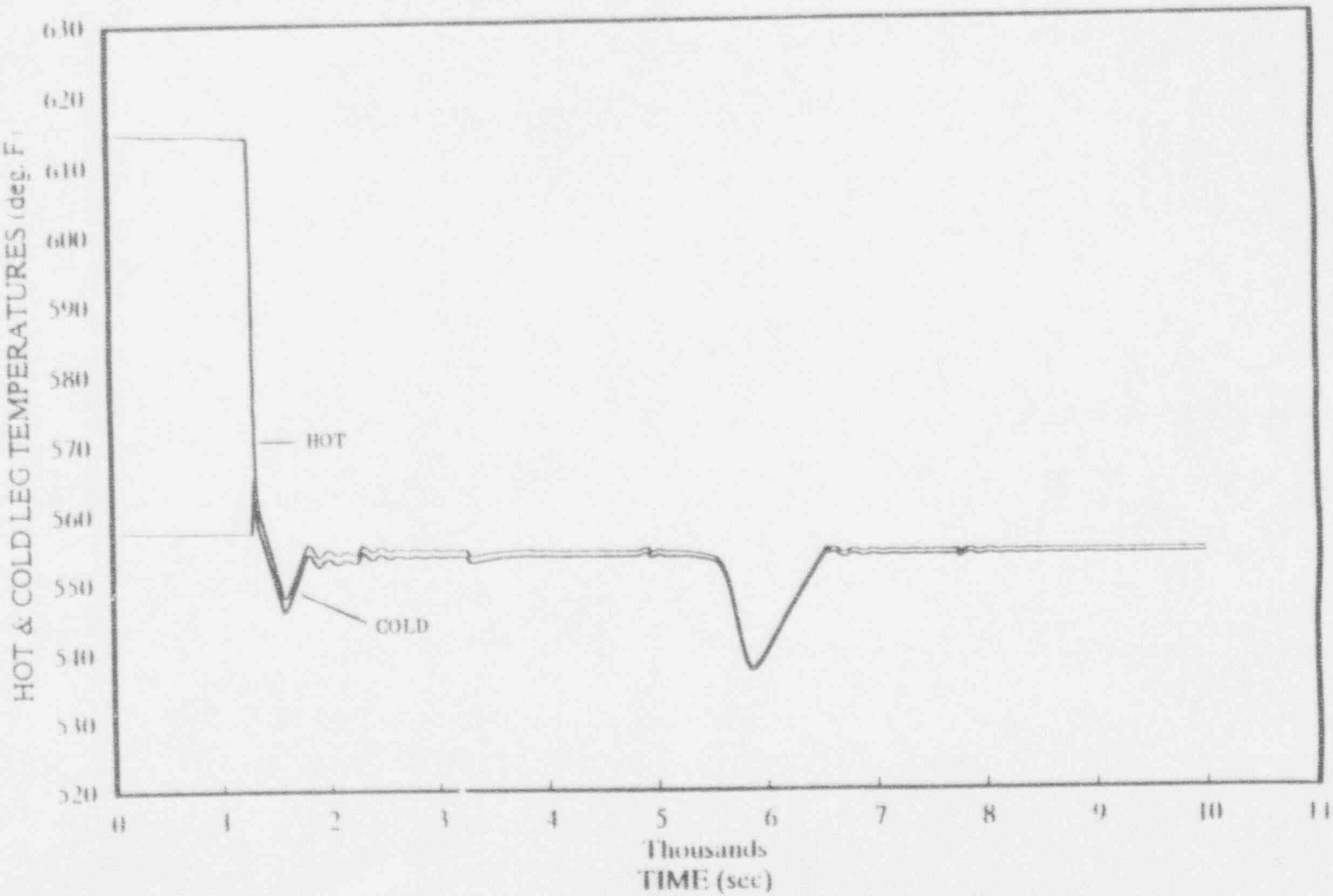


FIG. 4.3.4-6 RCS and SG Pressures vs. Time

Case 8 for 5 Tubes Ruptured and Automatic Opening of RCGVS on Pressurizer

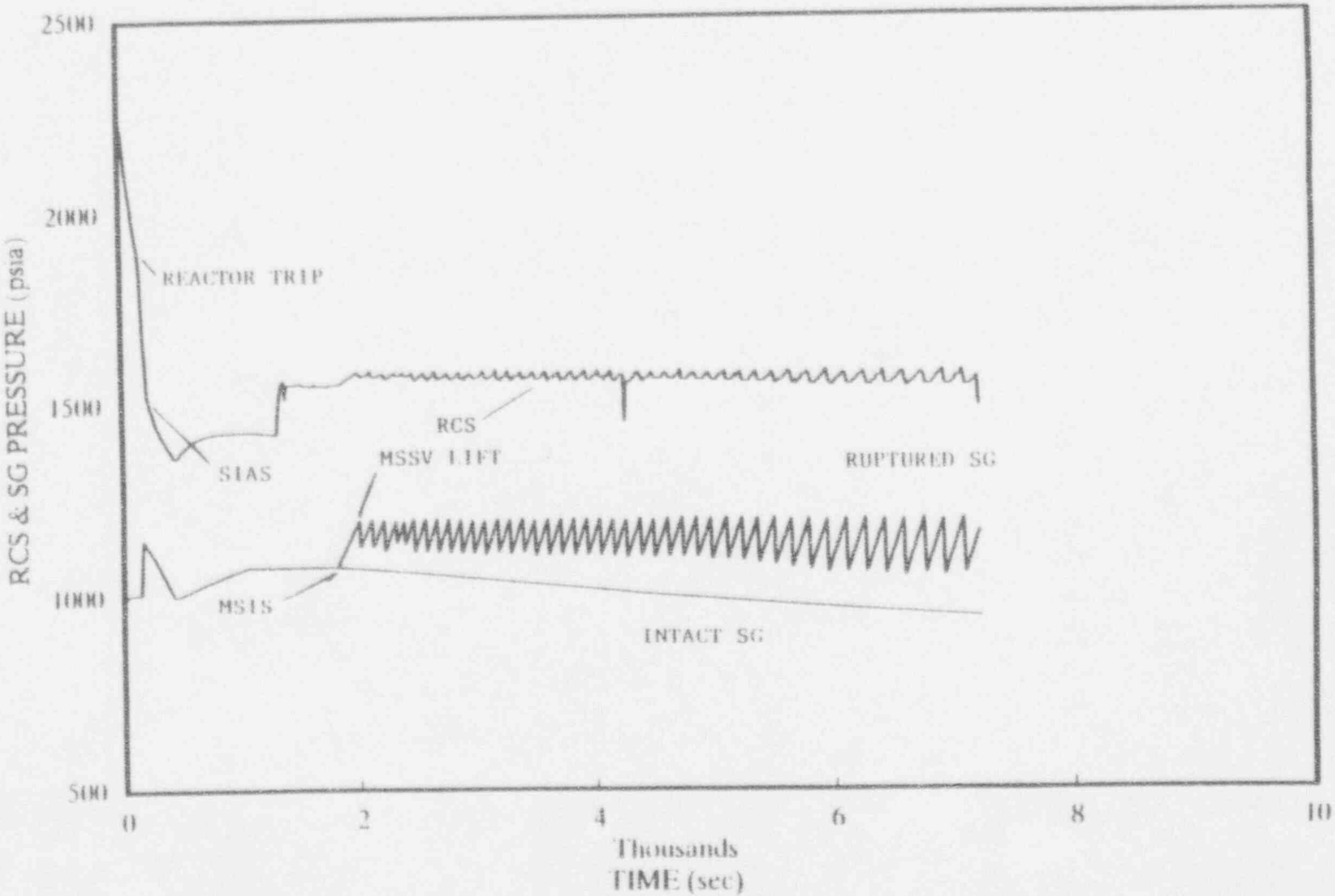


FIG. 4.3.4-7 Leak, HPSI and Bypass Flow Rates vs. Time

Case 8 for 5 Tubes Ruptured and Automatic Opening of RCGVS on Pressurizer

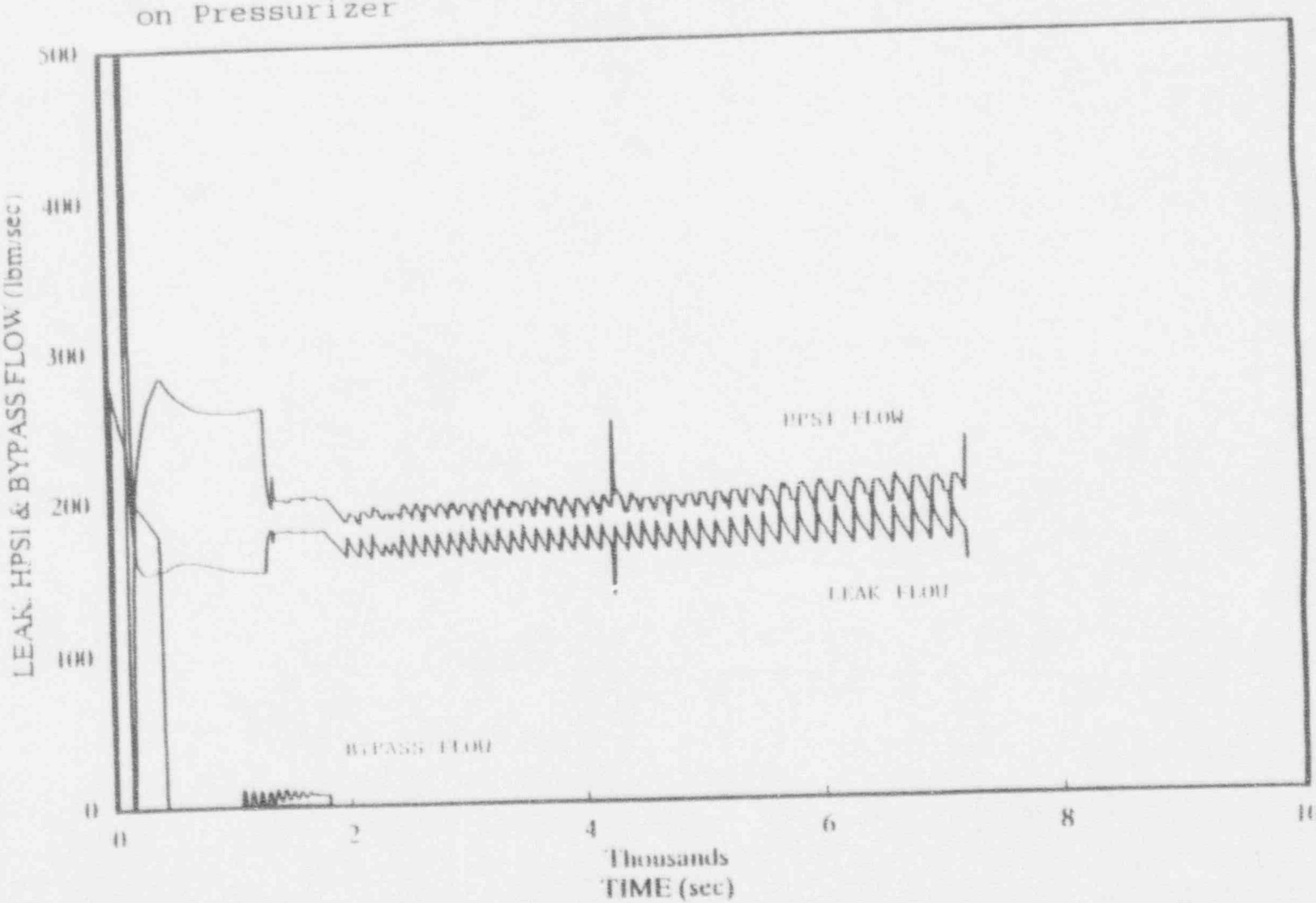


FIG. 4.3.4-8 Steam Generator Level vs. Time

Case 8 for 5 Tubes Ruptured and Automatic Opening of RCGVS on Pressurizer

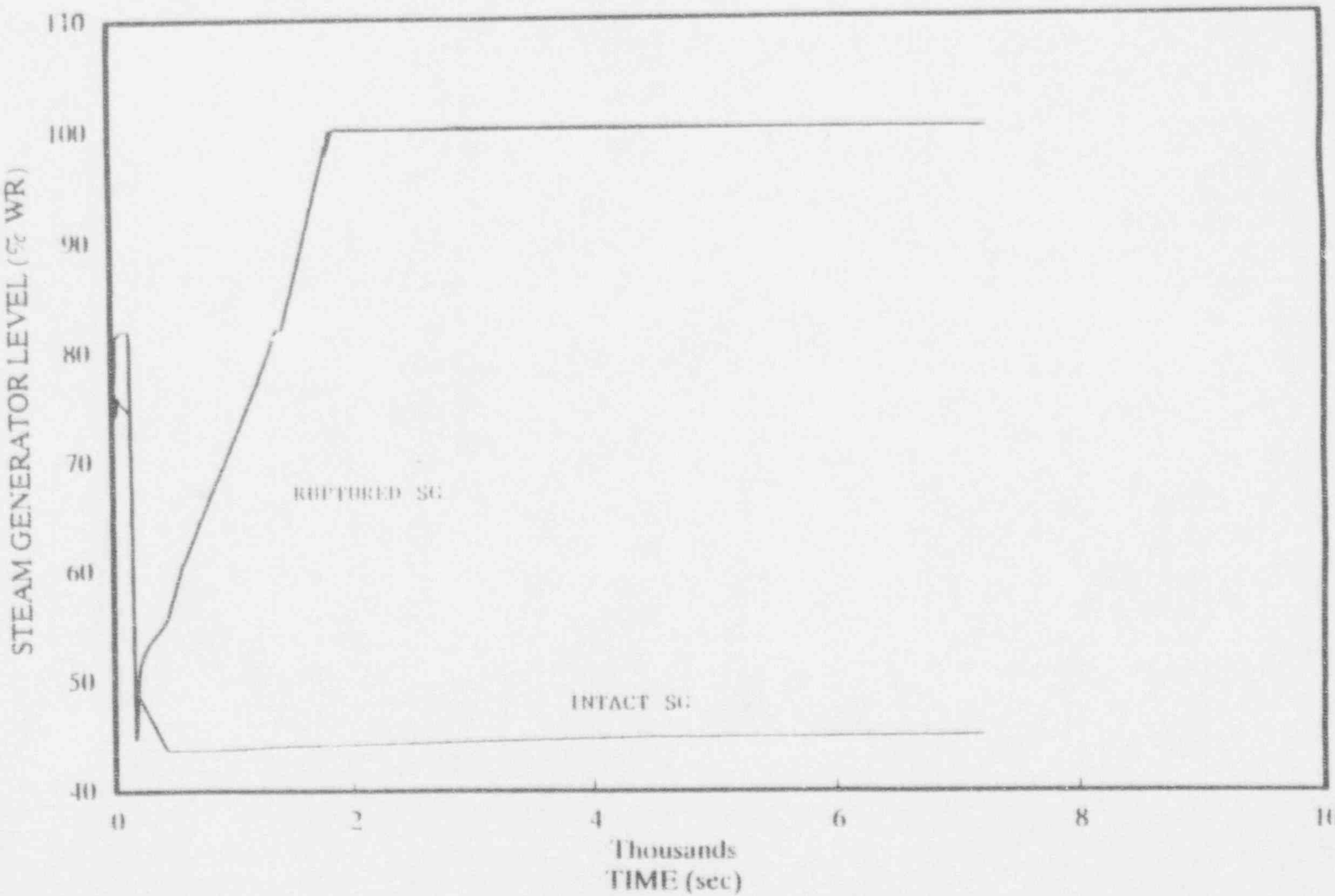


FIG. 4.3.4-9   Pressurizer Level vs. Time

Case 8 for 5 Tubes Ruptured and Automatic Opening of RCGVS on Pressurizer

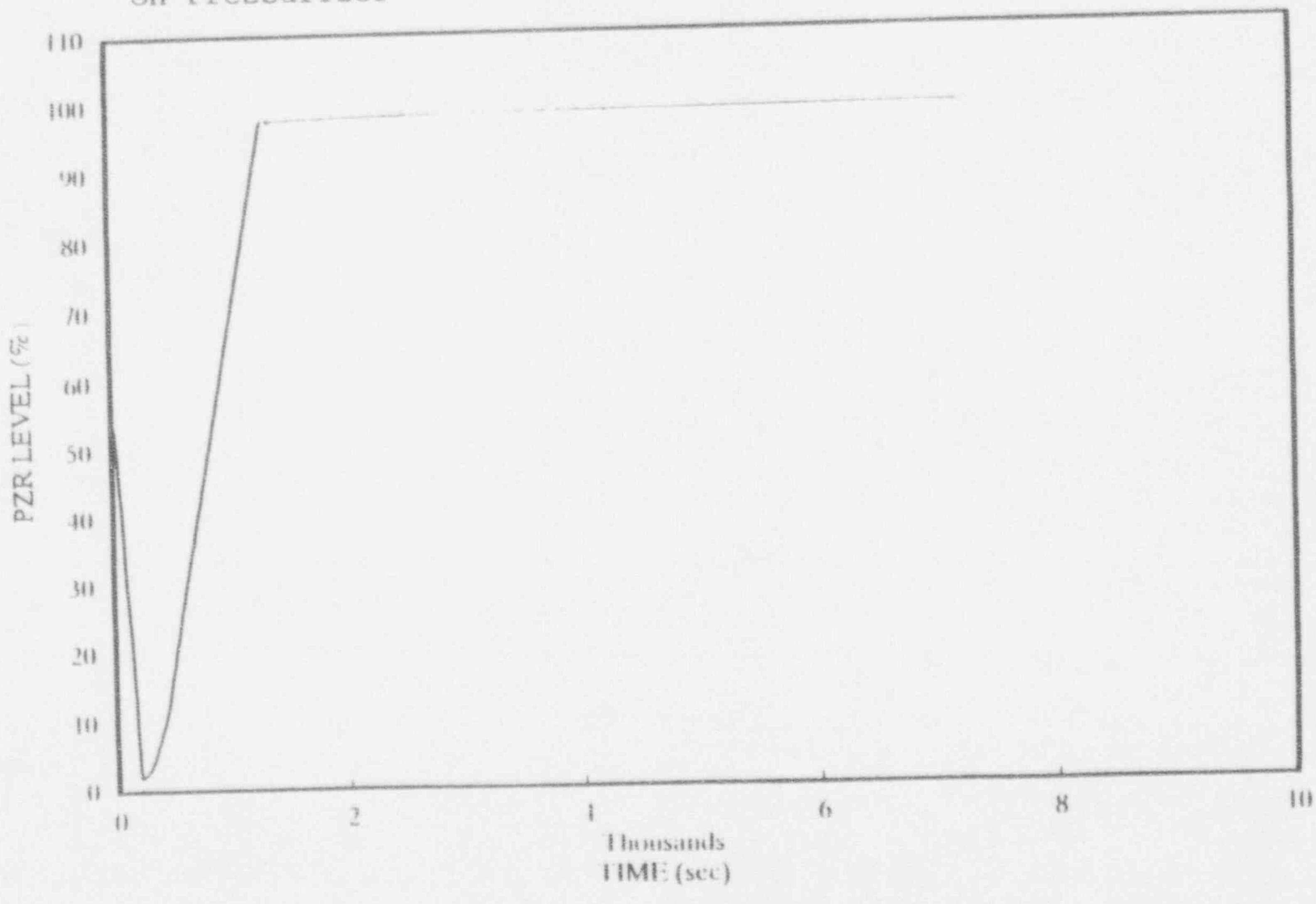
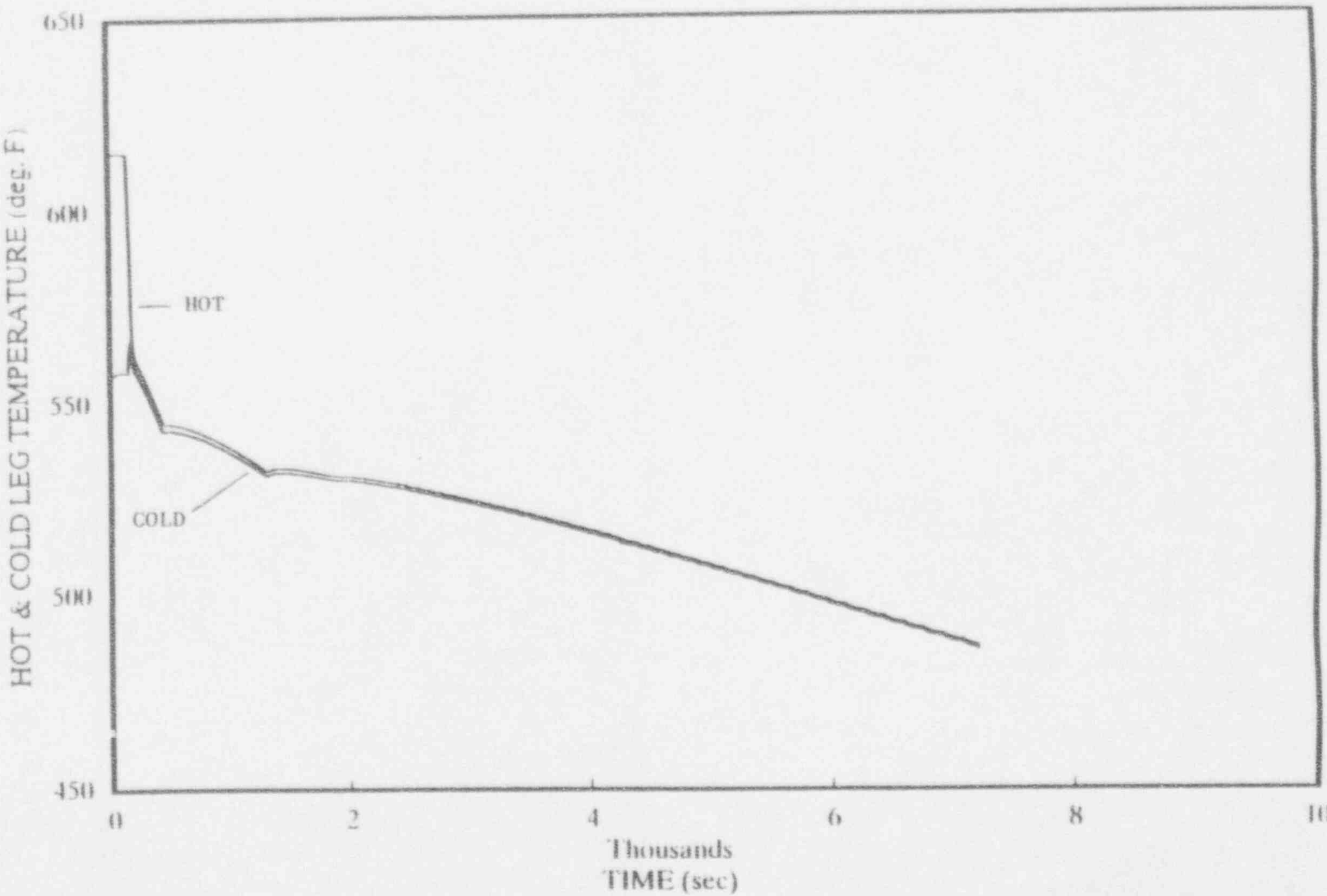


FIG. 4.3.4-10 Hot and Cold Leg Temperatures vs. Time
Case 8 for 5 Tubes Ruptured and Automatic Opening of RCGVS on Pressurizer



4.3.5 Automatic Blowdown of Steam Generator Liquid

This design change would automatically initiate the high capacity blowdown from the damaged steam generator to the condenser subsequent to a reactor trip and radiation indication in the SG that is a characteristic of a steam generator tube rupture. The maximum blowdown flow rate would be about 8% of full power steam flow rate. The blowdown would be initiated on a 2 out of 4 channel reactor trip signal and a 2 of 2 channel N-16 SG radiation detector signal. Case 9 represents this design change for one tube rupture case and case 10 denotes the design change for five tubes ruptured in one steam generator.

Figures 4.3.5-1 through 4.3.5-5 provide the transient results and Table 4.3.5-1 lists the sequence of major events for case 9. An examination of Figure 4.3.5-3 indicates that actuation of the high capacity blowdown immediately after reactor trip results in the dryout of the damaged steam generator. This is because subsequent to the reactor trip, the main feedwater is terminated and the break flow for one tube rupture (about 50 lbm/sec) is significantly smaller than the high capacity blowdown rate (about 195 lbm/sec). Subsequent to SG dryout the SG pressure (Figure 4.3.5-1) decreases resulting in an MSIS on low steam generator pressure at about 2868 seconds. Decay heat removal is accomplished by safety injection flow to the RCS and removal of RCS mass and energy through the break and into the condenser via the SG blowdown. In order to prevent these occurrences for the single tube rupture case, the blowdown flow would need to be controlled on SG level.

For case 10, the results are presented in Figures 4.3.5-6 through 4.3.5-10 and the sequence of major events is listed in Table 4.3.5-2. As can be seen from Figure 4.3.5-8 the actuation of the high capacity SG blowdown and quick opening of the steam bypass valves subsequent to turbine trip cause a drastic reduction in the damaged SG level. The bypass flow is terminated at about 415 seconds. Subsequently as the leak flow increases (due to the increase in RCS pressure) and essentially matches the blowdown flow, the damaged steam generator level reaches a quasi-steady state value of about 34 percent. The intact steam generator level decreases subsequent to reactor trip due to termination of main feedwater and actuation of the steam bypass flow. Eventually as the auxiliary feedwater flow is actuated on low level in the steam generator the level increases.

For both the one tube rupture case (case 9) and five tube ruptures (case 10), the high capacity blowdown results in a reduction in the damaged steam generator pressure and water level. Hence the MSSVs of the damaged steam generator remains unchallenged for more than 10,000 seconds (167 minutes) thereby preventing containment bypass due to the SGTR. However, the high capacity blowdown results in the dryout of the damaged steam generator for the one tube rupture case, which is not desirable from containment of the iodine species

in the SG water. To prevent this undesired occurrence for the single tube case, the high capacity blowdown system flowrate must be controlled on SG level signals.

TABLE 4.3.5-1

SEQUENCE OF EVENTS FOR CASE 9
STEAM GENERATOR TUBE RUPTURE (1 TUBE)
WITH SG BLOWDOWN (HIGH) ON N-16 INDICATION

TIME (Sec)	EVENT	SETPOINT
0.0	Tube Rupture Occurs	--
1100	Pressurizer Backup Heaters Actuated on Low Pressurizer Pressure, psia	2200
1289	Reactor Trips on Hot Leg Saturation Trip Signal	--
1290	Turbine Trips	--
1291	Steam Bypass System Actuated on High Steam Generator Pressure, psia	1078
1294	Pressurizer Pressure Reaches Safety Injection Actuation Signal (SIAS) Setpoint, psia	1835
1295	Main Feedwater Terminated on Low T_{avg}	--
1296	Damaged Steam Generator Blowdown (High) Actuated on Reactor Trip and N-16 Radiation Detector Signals	--
1850	Damaged Steam Generator Dries Out	--
2210	Auxiliary Feedwater Actuated to Intact Steam Generator on Low Level, ft. above tube sheet	20.09
2868	Main Steam Isolation Signal (MSIS) Generated on Low Pressure in the Damaged Steam Generator, psia	870
5843	Auxiliary Feedwater to Intact Steam Generator Terminated on High Level, ft. above tube sheet	40.46
*	Main Steam Safety Valves (MSSVs) on Damaged Steam Generator Actuated on High Steam Generator Pressure, psia	1200

* Event does not occur during the 10000 seconds of transient simulation.

TABLE 4.3.5-2
SEQUENCE OF EVENTS FOR CASE 10
STEAM GENERATOR TUBE RUPTURE (5 TUBES)
WITH SG BLOWDOWN (HIGH) ON N-16 INDICATION

TIME (Sec)	EVENT	SETPOINT
0.0	Tube Rupture Occurs	--
130	Pressurizer Backup Heaters Actuated on Low Pressurizer Pressure, psia	2200
149	Reactor Trips on Hot Leg Saturation Trip Signal	--
150	Turbine Trips	--
152	Steam Bypass System Actuated on High Steam Generator Pressure, psia	1078
165	Pressurizer Pressure Reaches Safety Injection Actuation Signal (SIAS) Setpoint, psia	1835
166	Main Feedwater Terminated on Low T_{avg}	--
167	Damaged Steam Generator Blowdown (High) Actuated on Reactor Trip and N-16 Radiation Detector Signals	--
415	Steam Bypass Valves closed on Low SG Pressure, psia	--
580	Auxiliary Feedwater to Intact Steam Generator Actuated on Low Level, ft above tube sheet	20.09
1380	Main Steam Isolation Signal (MSIS) Generated on Low Steam Generator Pressure, psia	870
4130	Auxiliary Feedwater to Intact Steam Generator Terminated on High Level, ft. above tube sheet	40.46
*	Main Steam Isolation Signal (MSIS) Generated on High Level in the Damaged Steam Generator, % wide range level	98
*	Main Steam Safety Valves (MSSVs) on Damaged Steam Generator Actuated on High Steam Generator Pressure, psia	1200

* Event does not occur during the 10000 seconds of transient simulation time.

FIG. 4.3.5-1 RCS and SG Pressures vs. Time

Case 9 for 1 Tube Ruptured and Automatic SG Liquid Blowdown To Condenser

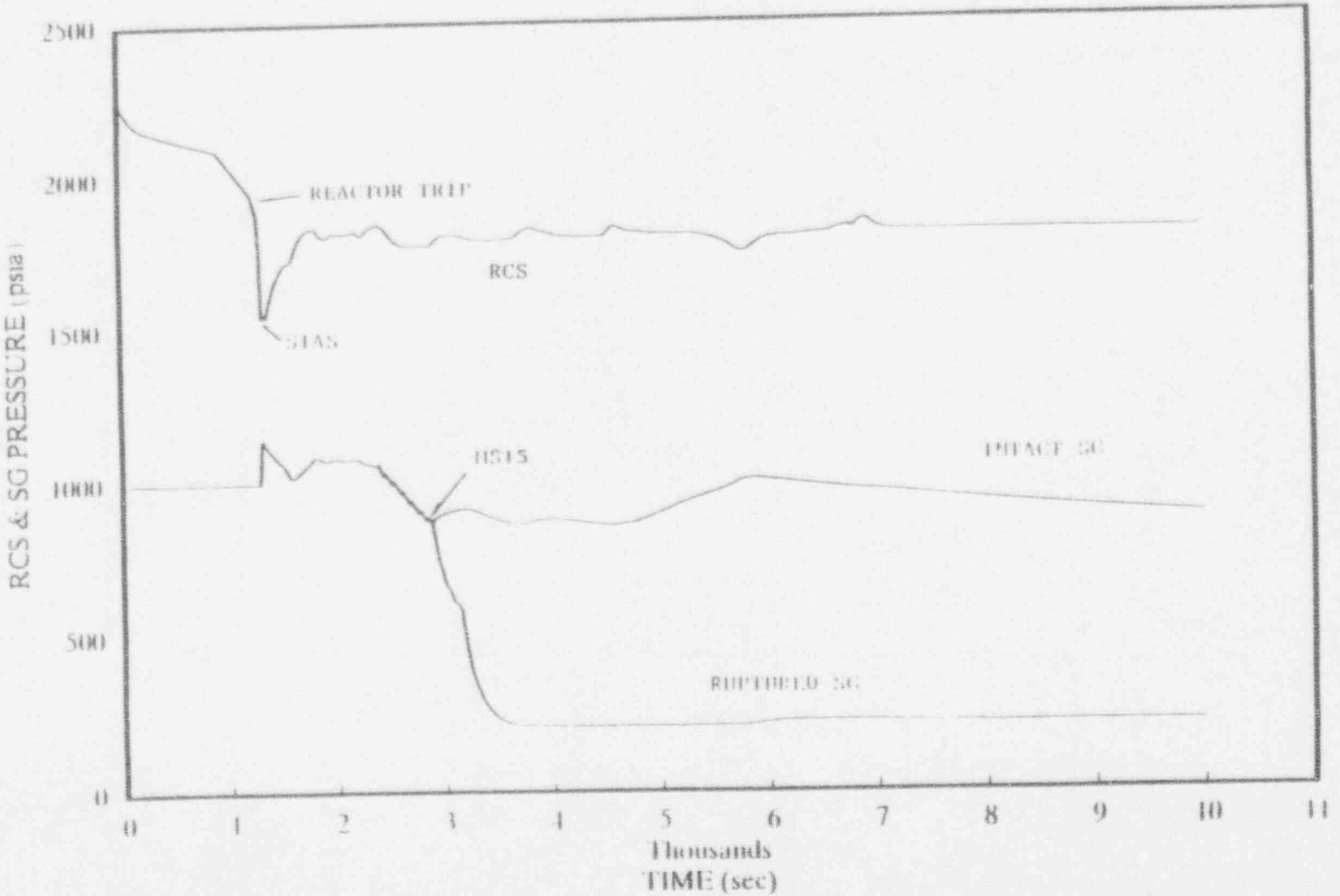


FIG. 4.3.5-2   Leak, HPSI and Bypass Flow Rates vs. Time

Case 9 for 1 Tube Ruptured and Automatic SG Liquid Blowdown To Condenser

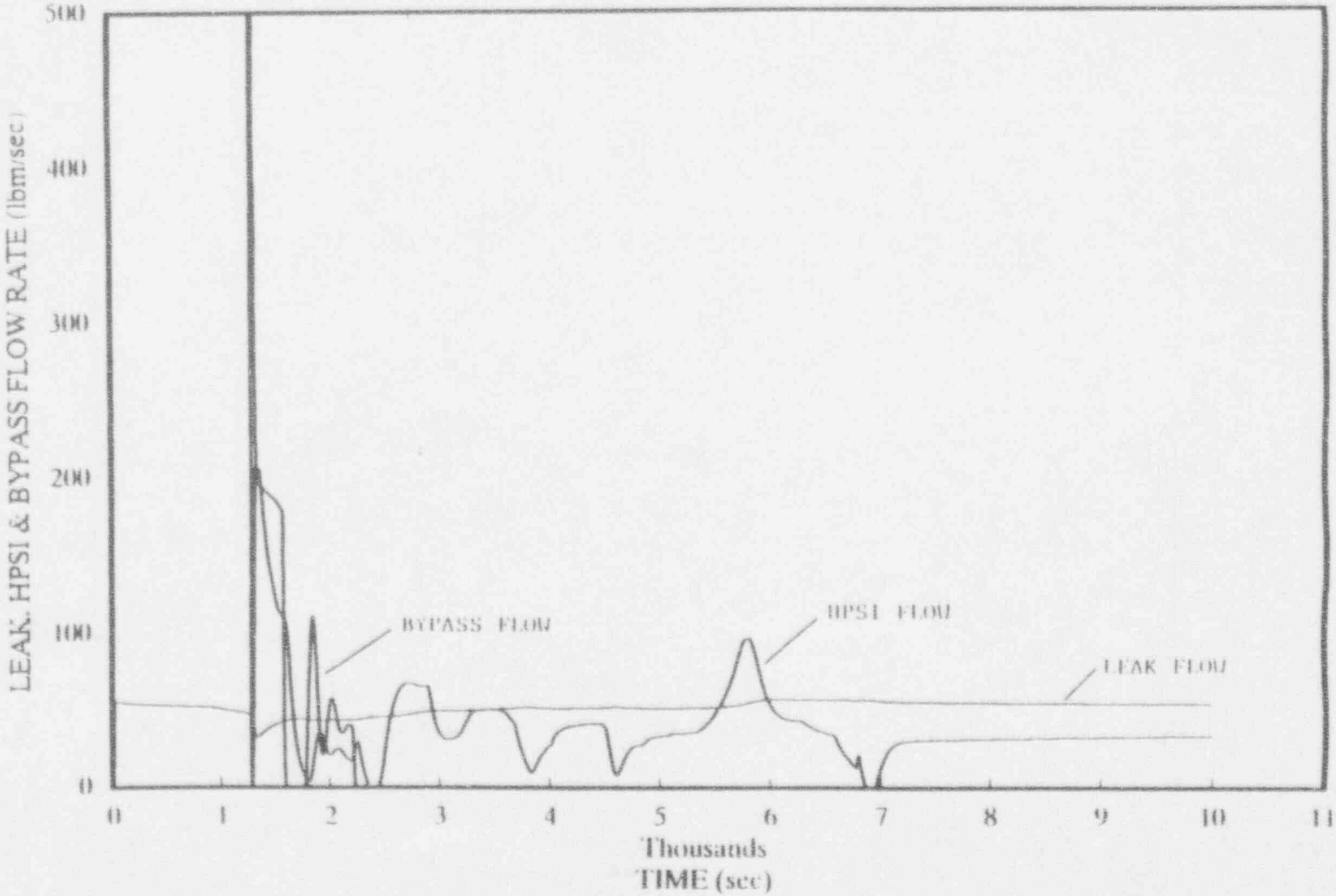


FIG. 4.3.5-3 Steam Generator Level vs. Time

Case 9 for 1 Tube Ruptured and Automatic SG Liquid Blowdown To Condenser

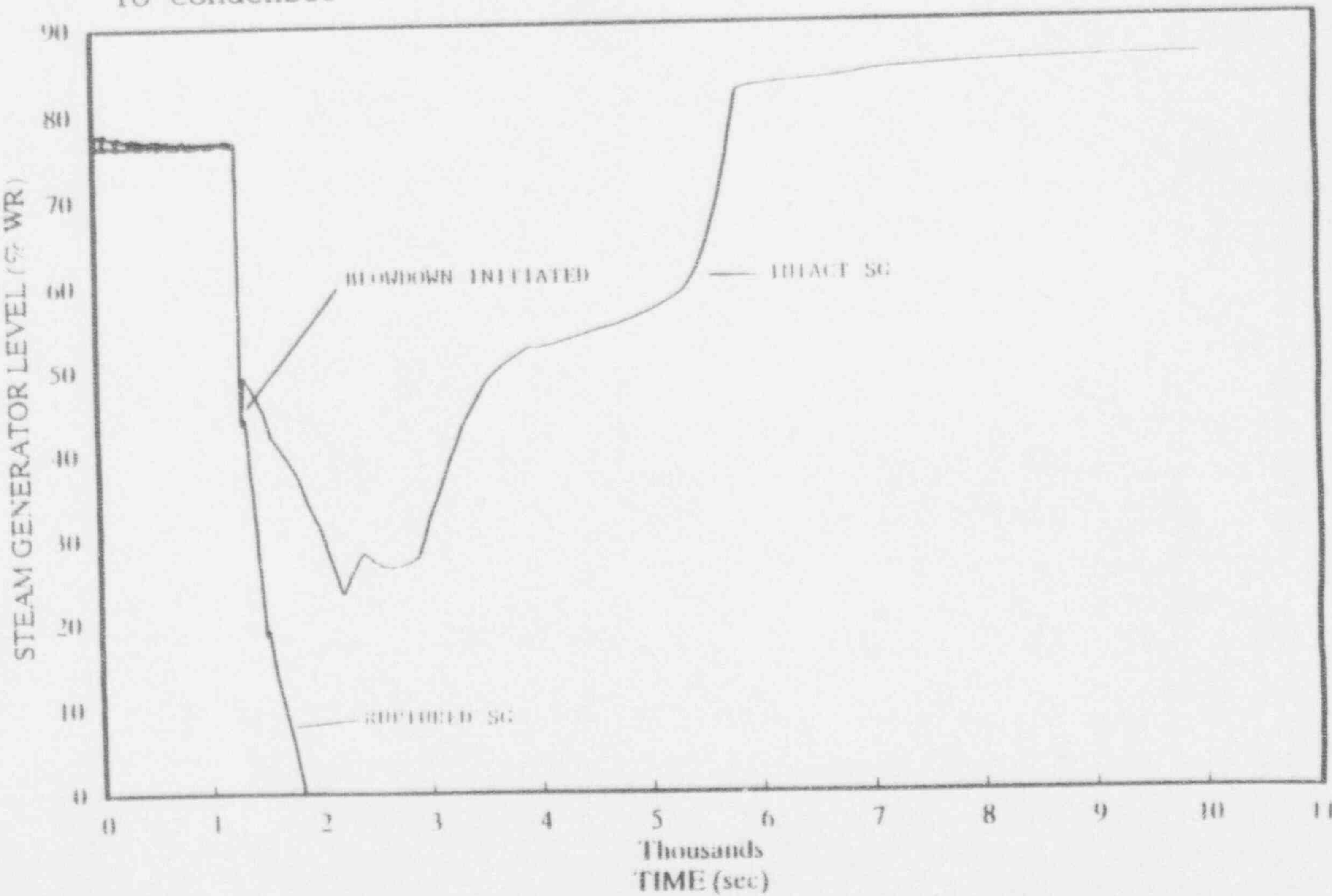


FIG. 4.3.5-4 Pressurizer Level vs. Time

Case 9 for 1 Tube Ruptured and Automatic SG Liquid Blowdown To Condenser

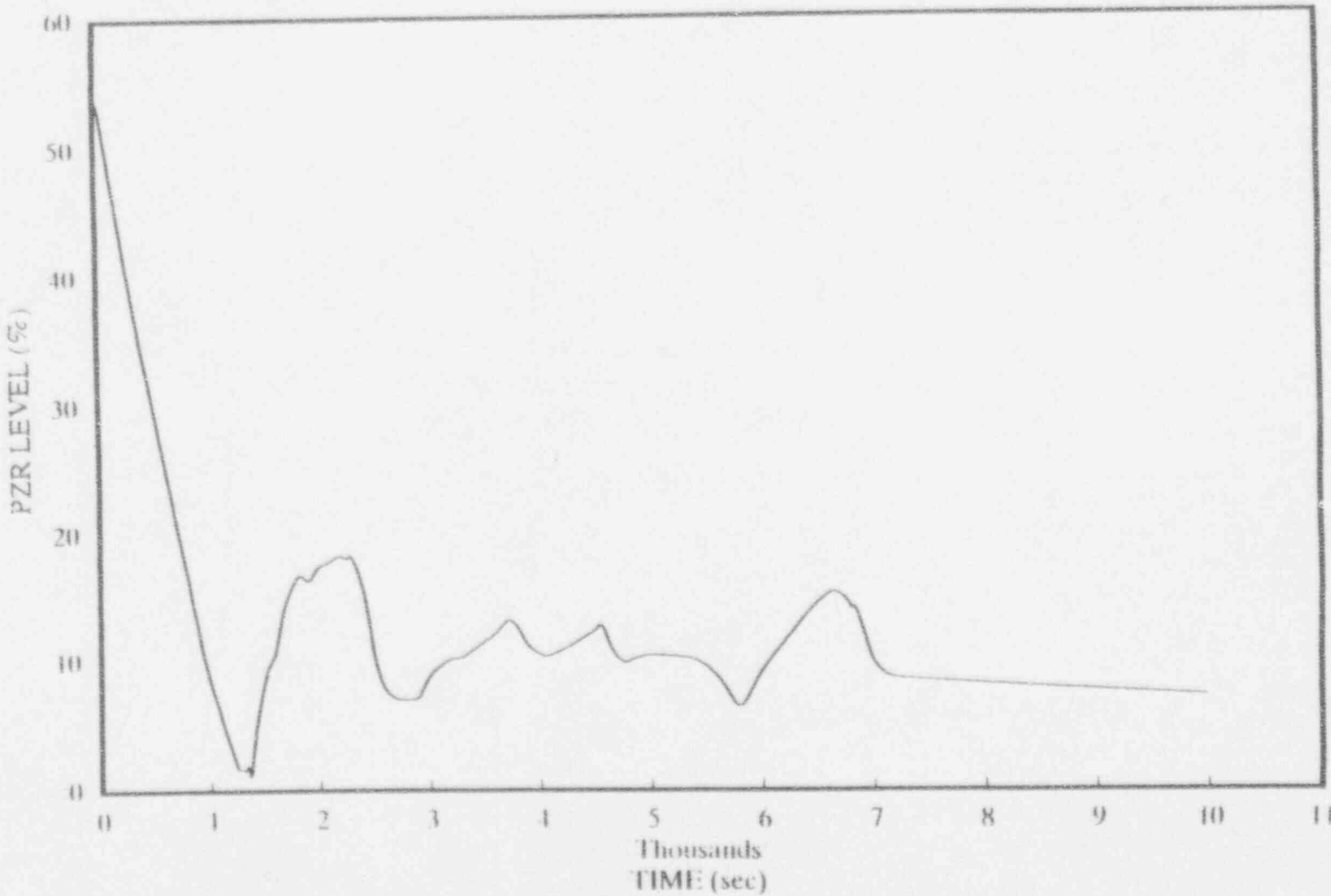


FIG. 4.3.5-5 Hot and Cold Leg Temperatures vs. Time
Case 9 for 1 Tube Ruptured and Automatic SG Liquid Blowdown To Condenser

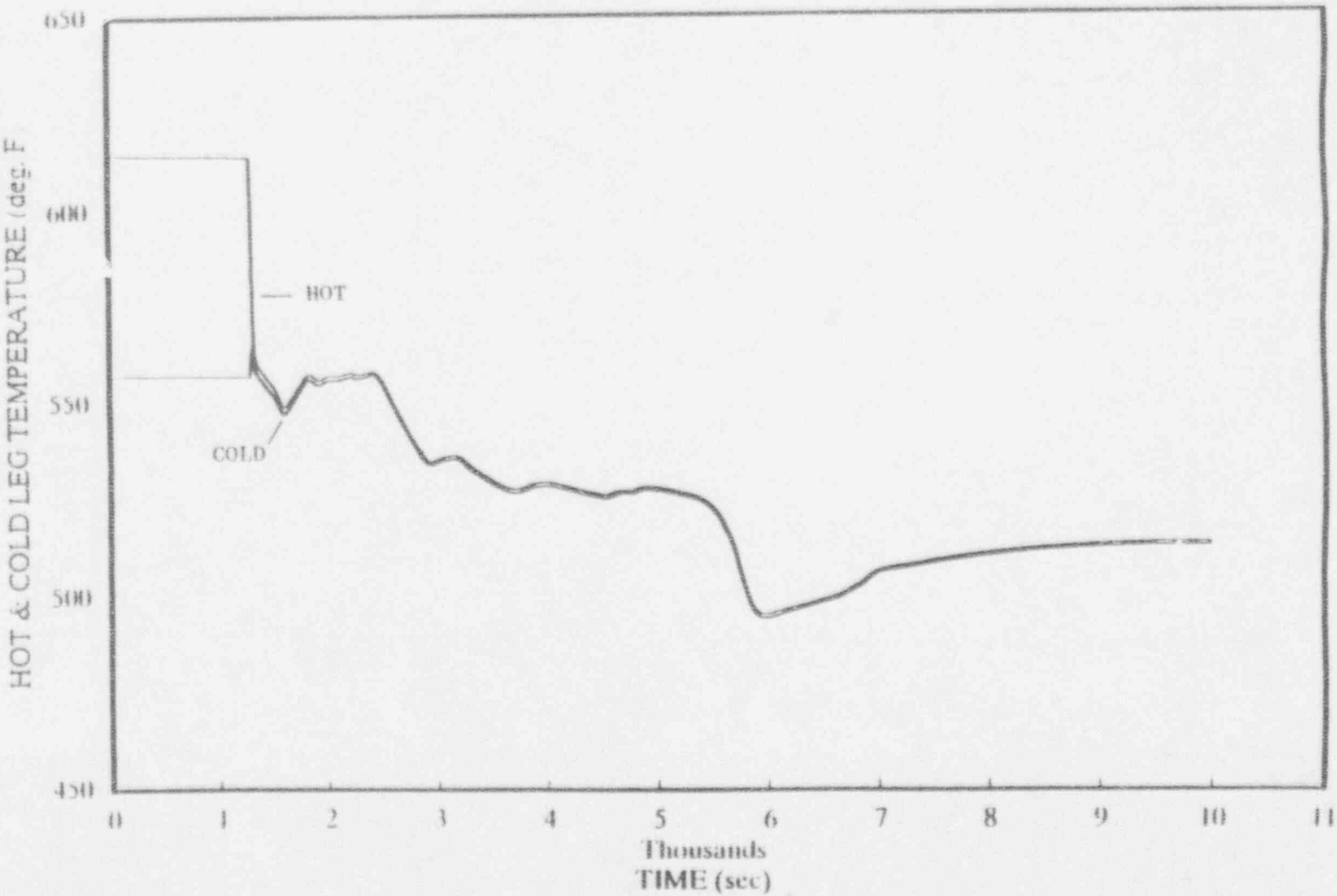


FIG. 4.3.5-6 RCS and SG Pressures vs. Time

Case 10 for 5 Tubes Ruptured and Automatic SG Liquid Blowdown To Condenser

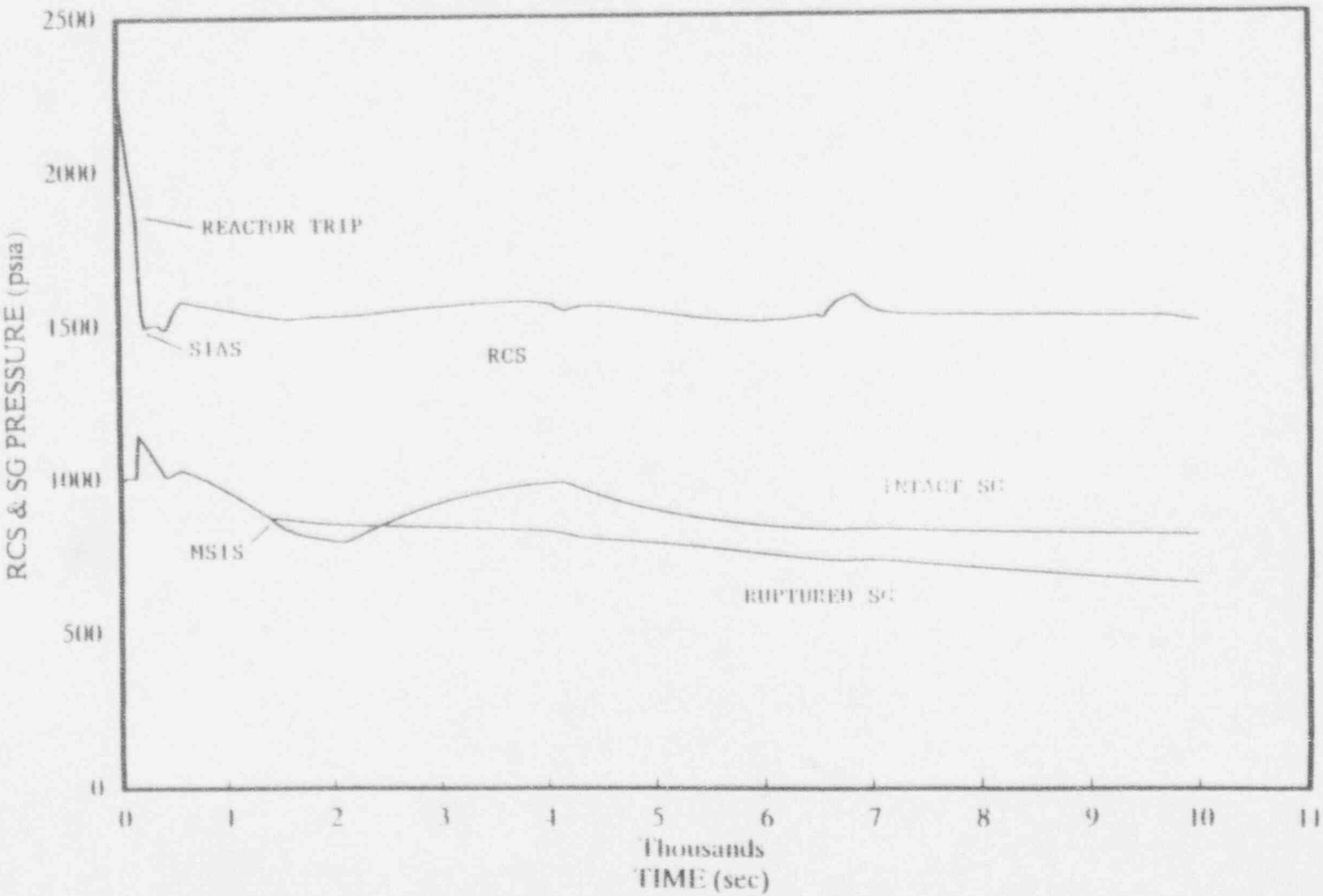


FIG. 4.3.5-7 Leak, HPSI and Bypass Flow Rates vs. Time Case 10 for 5 Tubes Ruptured and Automatic SG Liquid Blowdown To Condenser

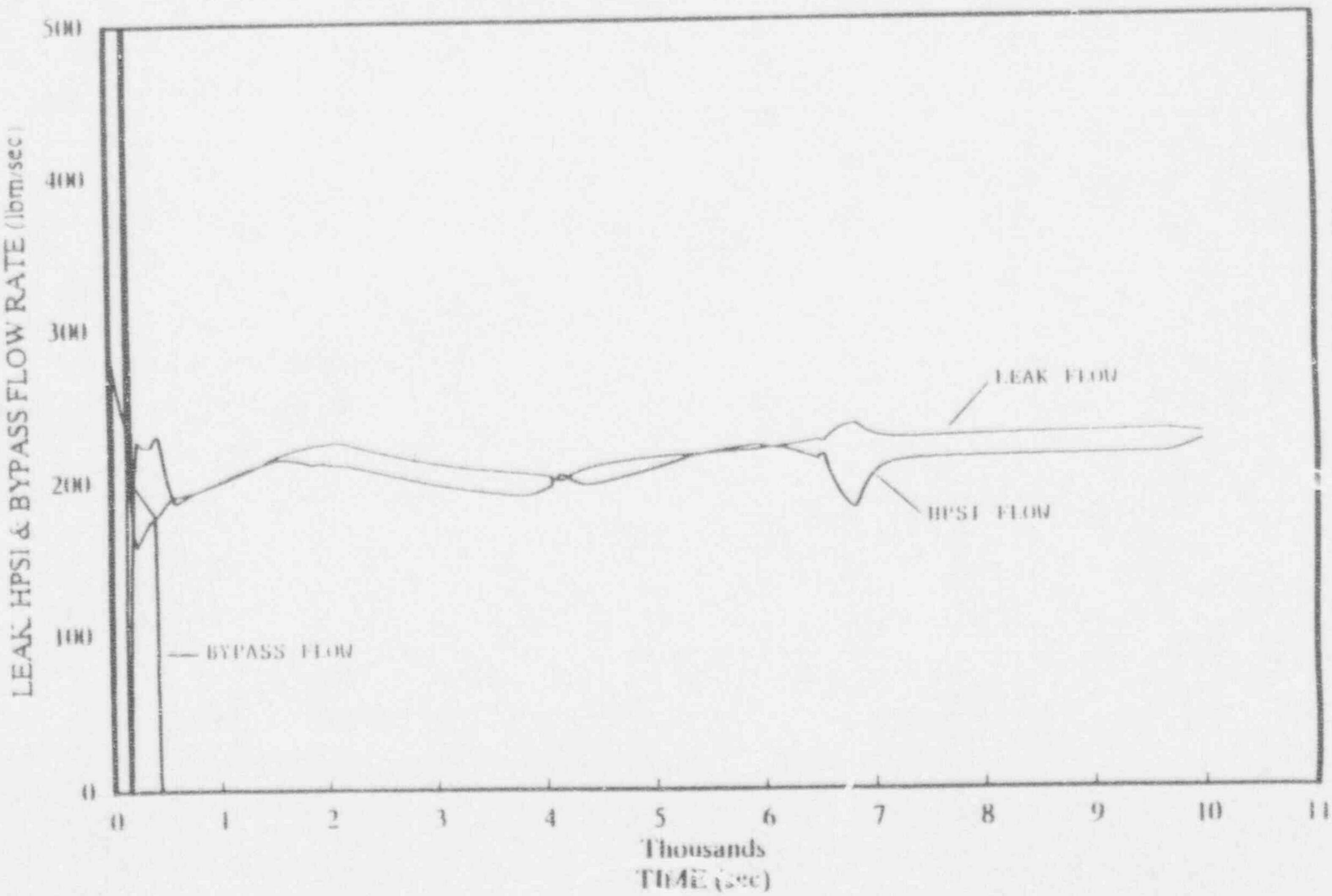


FIG. ?.3.5-8 Steam Generator Level vs. Time

Case 10 for 5 Tubes Ruptured and Automatic SG Liquid Blowdown To Condenser

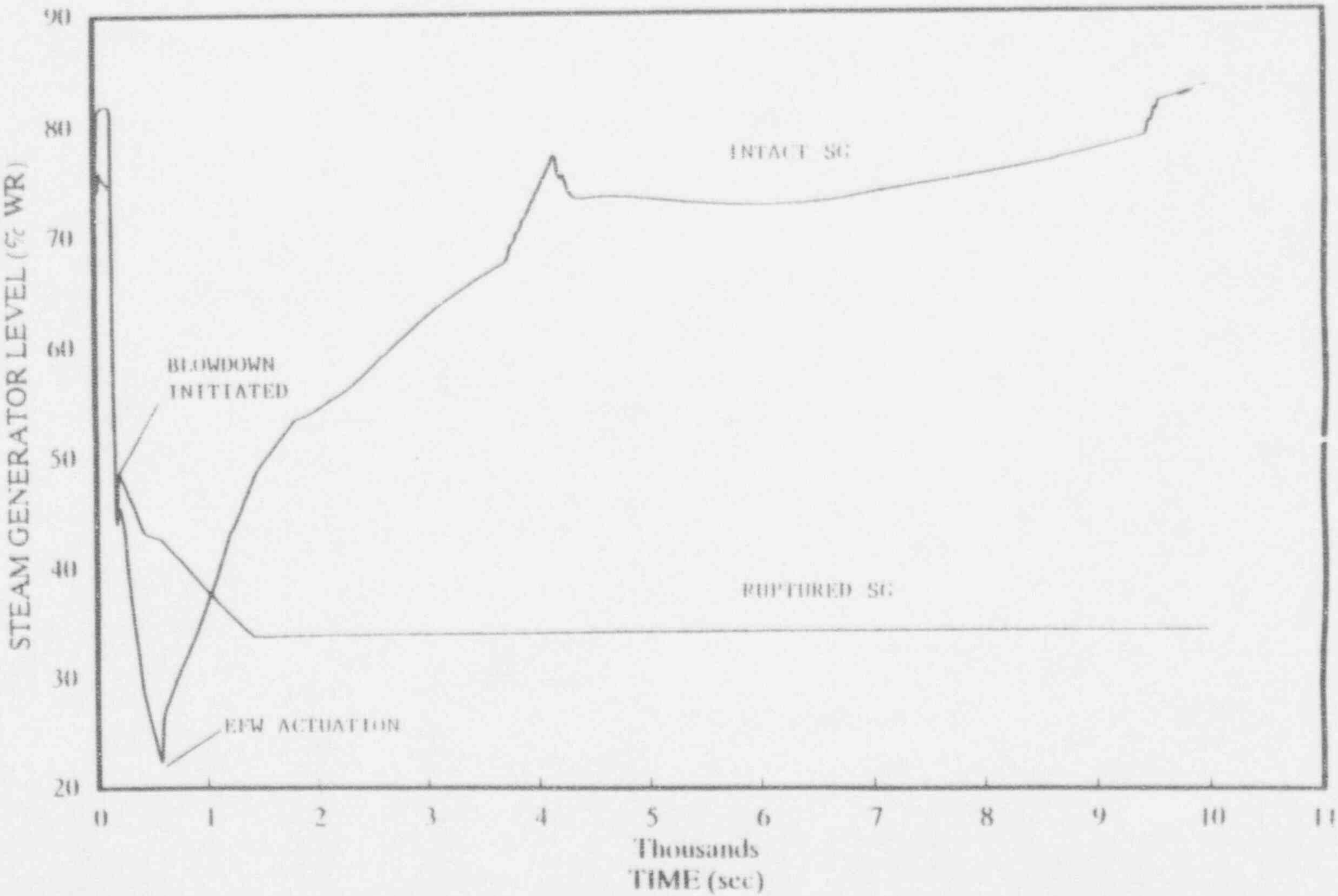


FIG. 4.3.5-9 Pressurizer Level vs. Time

Case 10 for 5 Tubes Ruptured and Automatic SG Liquid Blowdown To Condenser

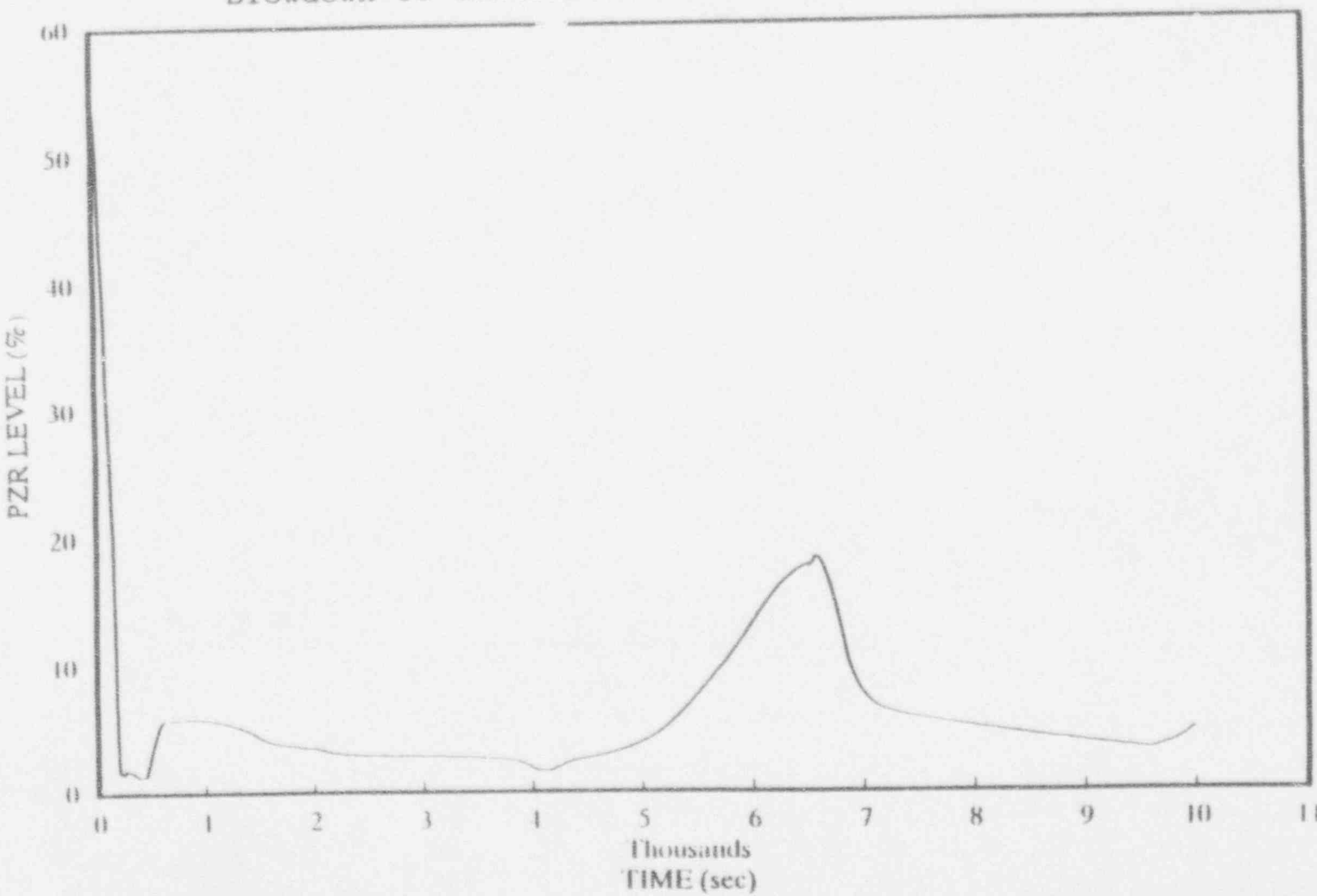
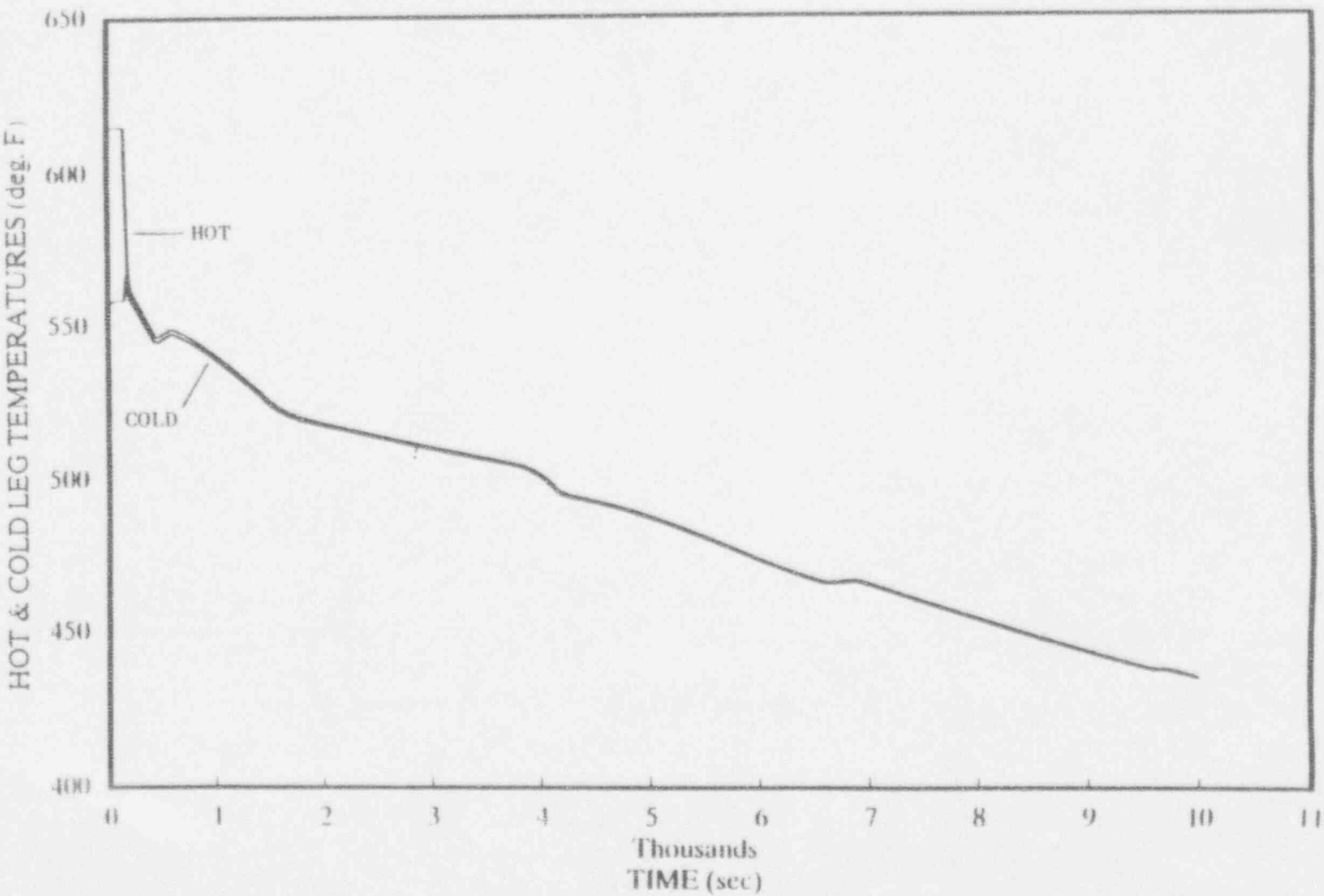


FIG. 4.3.5-10 Hot and Cold Leg Temperatures vs. Time

Case 10 for 5 Tubes Ruptured and Automatic SG Liquid Blowdown To Condenser



4.3.6 Automatic Reduction of Steam Bypass System Actuation Pressure

This design change focuses on automatic reduction of the steam bypass system actuation setpoint subsequent to the turbine trip (on reactor trip) and initial opening of the bypass valves at the normal setpoint (1078 psia). The automatic reduction of the setpoint result in a delayed closing of the bypass valves subsequent to the initial opening and in the reopening of the steam bypass system at 900 psia. This would allow relief of steam from the damaged steam generator (as well as from the intact steam generator) for a longer period allowing for the removal of some of the steam generator inventory.

Case 11 represents the one tube rupture case with the automatic resetting of the steam bypass system actuation setpoint down to 900 psia from 1078 psia. Figures 4.3.6-1 through 4.3.6-5 provide the results of this analysis and Table 4.3.6-1 lists the sequence of major events occurring during the transient. Figure 4.3.6-1 shows that after the initial opening of the bypass valves at a setpoint of 1078 psia, the steam generator pressures decrease below this value. However, the bypass valves do not close at this time due to the resetting of the setpoint to 900 psia. Thus the bypass closes only after the pressure reaches about 900 psia. A comparison of Figures 4.3.6-3 (for case 11) and 4.3.1-3 (for one tube rupture base case, case 1) shows that the damaged steam generator level increases at a faster rate for case 11. This is due to the increase in the break flow rate as a result of lowering the steam bypass actuation setpoint. The lowering of the damaged SG pressure results in the relatively higher break flow rate, since for both case 11 and case 1 the RCS pressure reach essentially the same quasi-steady state pressure in the long term (see Figures 4.3.6-1 and 4.3.1-1). In addition, the lowering of the bypass system setpoint result in a relatively smaller bypass flow rate in comparison to that for case 1 (see Figures 4.3.6-2 and 4.3.1-2). Note that for the case 1, the bypass system remains open beyond 10,000 seconds (167 minutes). Therefore, for the one tube rupture case, there is no relative benefit due to automatic resetting of the bypass actuation setpoint pressure. In fact, the resetting is expected to result in a slightly shorter time to damaged SG overfill and pressurization to MSSV lift.

Case 12 denotes the five tube ruptured case with the resetting of the bypass opening setpoint to 900 psia. Figures 4.3.6-6 through 4.3.6-10 provide the results of the analysis with the sequence of major occurrences listed in Table 4.3.6-2. As in the case of the one tube rupture case (case 11) the bypass valves opens up at 1078 psia and remains open till the SG pressure reaches 900 psia due to the resetting of the bypass opening setpoint (see Figure 4.3.6-6). The bypass valves open again as the steam generator pressure increases to 900 psia. For the five tube ruptured case, case 12,

the bypass flow is not enough to accommodate the large break flow rate and hence the damaged SG level (Figure 4.3.6-8) increases rapidly and reaches the MSIS setpoint at about 1700 seconds. Soon afterwards, at about 200 seconds later, the MSSV lift pressure of 1200 psia is reached and the MSSVs lift. In comparison to the base case for five tube ruptures (case 2), case 12 results in only marginal increase in the MSIS generation time (1590 seconds for case 1 and 1700 seconds for case 12) and MSSV lift time (1800 seconds for case 2 and 2000 seconds for case 12).

Thus, for the one tube rupture case there is no improved benefit due to the automatic lowering of the steam bypass opening setpoint. In fact, resetting of this setpoint hastens the fill up of the damaged SG in comparison to the results for the base case. For the five tubes ruptured case, there is only marginal benefit (about 200 seconds delay in MSSV lift time) due to resetting of the steam bypass opening pressure setpoint.

TABLE 4.3.6-1
SEQUENCE OF EVENTS FOR CASE 11
STEAM GENERATOR TUBE RUPTURE (1 TUBE)
WITH STEAM BYPASS SYSTEM SETPOINT RESET TO 900 PSIA

TIME (Sec)	EVENT	SETPOINT
0.0	Tube Rupture Occurs	--
1100	Pressurizer Backup Heaters Actuated on Low Pressurizer Pressure, psia	2200
1289	Reactor Trips on Hot Leg Saturation Trip Signal	--
1290	Turbine Trips	--
1291	Steam Bypass System Actuated on High Steam Generator Pressure, psia	1078
1293	Steam Bypass System Actuation Reset to Lower Setpoint on Reactor Trip and N-16 Radiation Detector Signals, psia	900
1294	Pressurizer Pressure Reaches Safety Injection Actuation Signal (SIAS) Setpoint, psia	1835
1295	Main Feedwater Terminated on Low T_{avg}	--
2185	Auxiliary Feedwater to Intact Steam Generator Actuated on Low Level, ft. above tube sheet	20.09
2390	Steam Bypass Valves close on Low Steam Generator Pressure	--
2720	Steam Bypass Valves reopen on High Steam Generator pressure, psia	900
5740	Auxiliary Feedwater to Intact Steam Generator Terminated on High Level, ft. above tube sheet	40.46
*	Main Steam Isolation Signal (MSIS) Generated on High Level in the Damaged Steam Generator, % wide range level	98
*	Main Steam Safety Valves (MSSVs) on Damaged Steam Generator Actuated on High Steam Generator Pressure, psia	1200

* Event does not occur within the 10000 seconds of transient simulation time.

TABLE 4.3.6-2

SEQUENCE OF EVENTS FOR CASE 12
STEAM GENERATOR TUBE RUPTURE (5 TUBES)
WITH STEAM BYPASS SYSTEM SETPOINT RESET TO 900 PSIA

TIME (Sec)	EVENT	SETPOINT
0.0	Tube Rupture Occurs	--
130	Pressurizer Backup Heaters Actuated on Low Pressurizer Pressure, psia	2200
149	Reactor Trips on Hot Leg Saturation Trip Signal	--
150	Turbine Trips	--
152	Steam Bypass System Actuated on High Steam Generator Pressure, psia	1078
155	Steam Bypass System Actuation Reset to Lower Setpoint on Reactor Trip and N-16 Radiation Detector Signals, psia	900
165	Pressurizer Pressure Reaches Safety Injection Actuation Signal (SIAS) Setpoint, psia	1835
166	Main Feedwater Terminated on Low T_{avg}	--
810	Steam Bypass Valves close on Low Steam Generator Pressure	--
1240	Steam Bypass Valves reopen on High Steam Generator Pressure, psia	900
1700	Main Steam Isolation Signal (MSIS) Generated on High Level in the Damaged Steam Generator, % wide range level	98
2000	Main Steam Safety Valves (MSSVs) on Damaged Steam Generator Actuated on High Steam Generator Pressure, psia	1200

FIG. 4.3.6-1 RCS and SG Pressures vs. Time

Case 11 for 1 Tube Ruptured and Automatic Reduction of SBCS Initiation Pressure

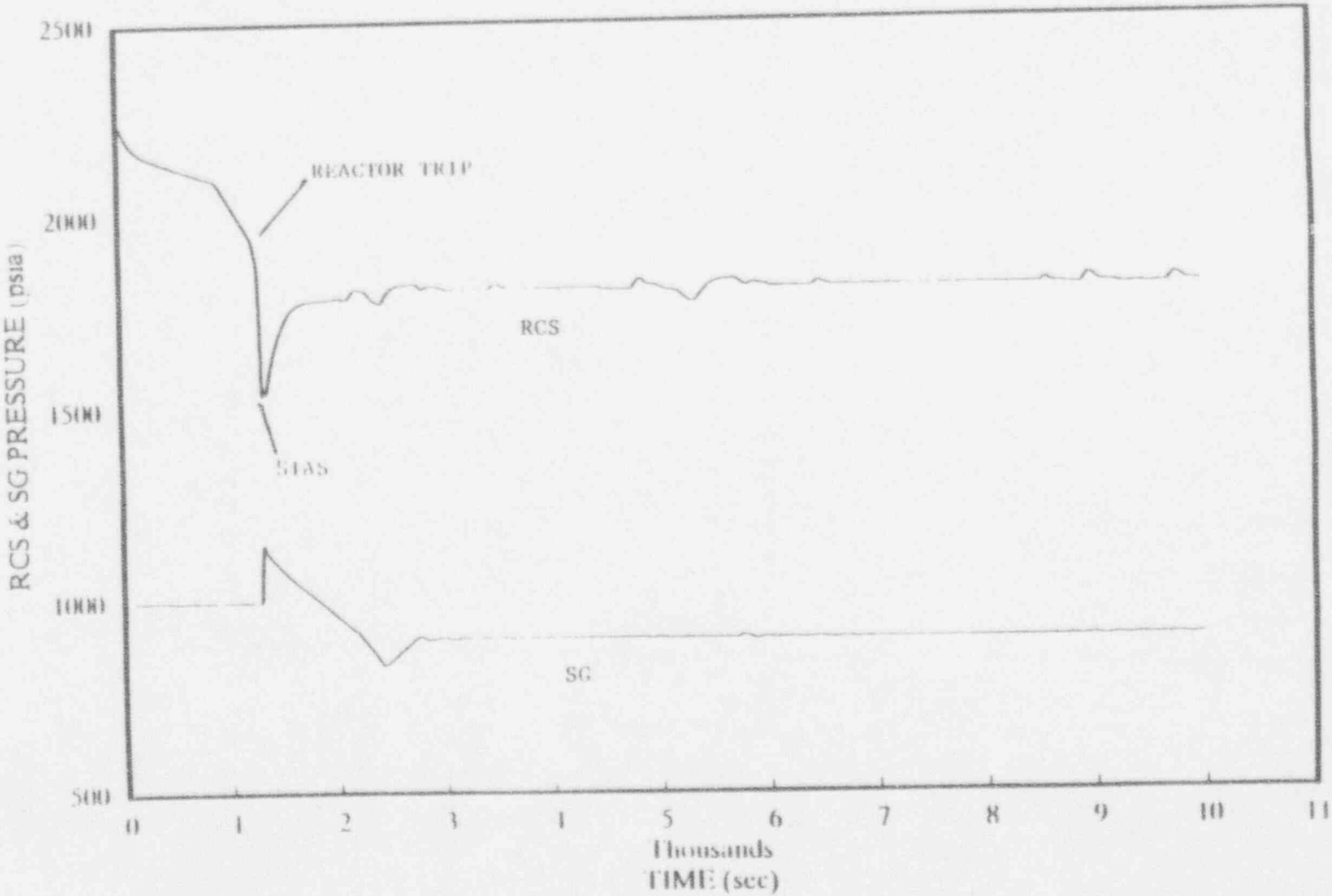


FIG. 4.3.6-2 Leak, HPSI and Bypass Flow Rates vs. Time

Case 11 for 1 Tube Ruptured and Automatic Reduction of SBCS Initiation Pressure

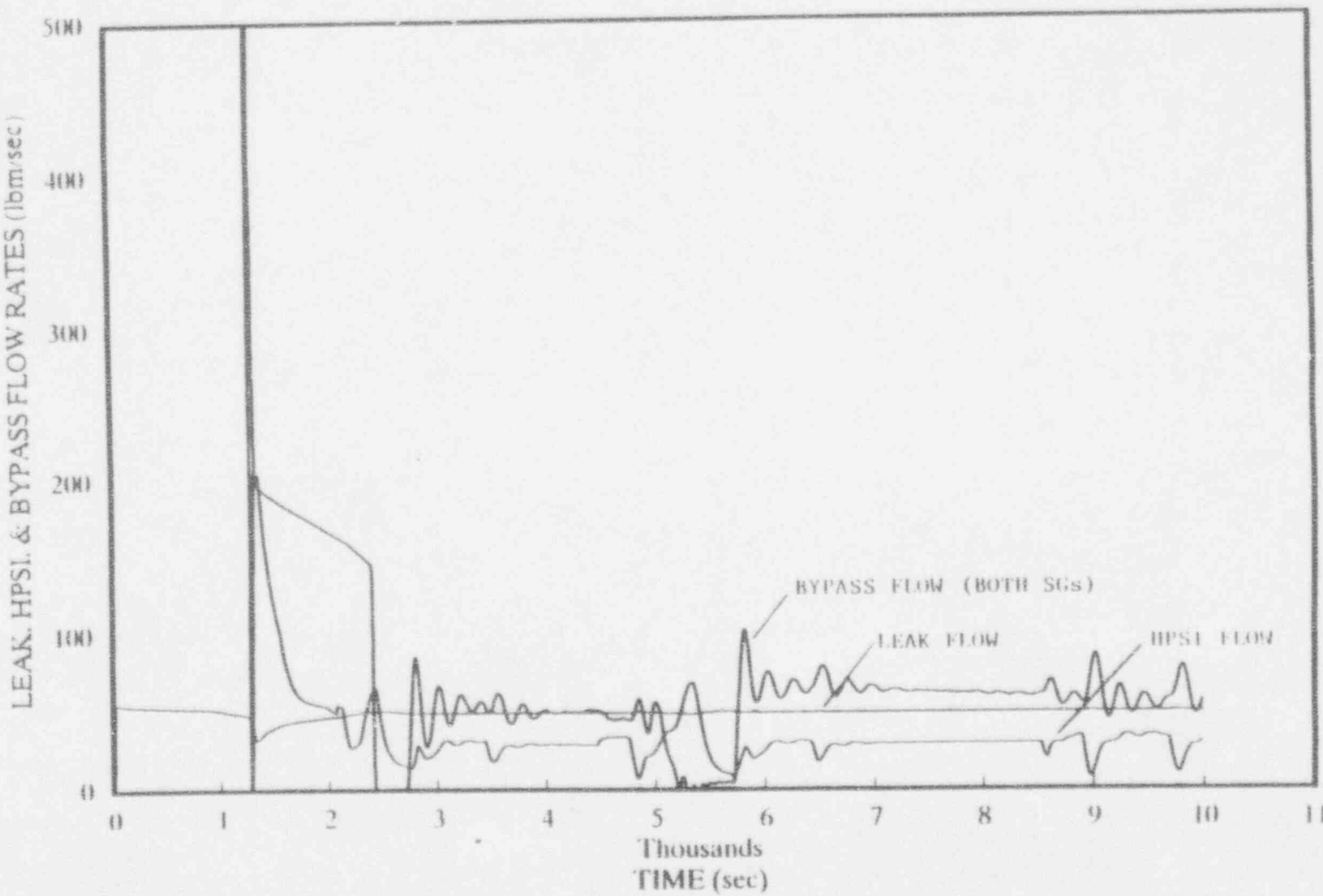


FIG. 4.3.6-3 Steam Generator Level vs. Time

Case 11 for 1 Tube Ruptured and Automatic Reduction of SBCS Initiation Pressure

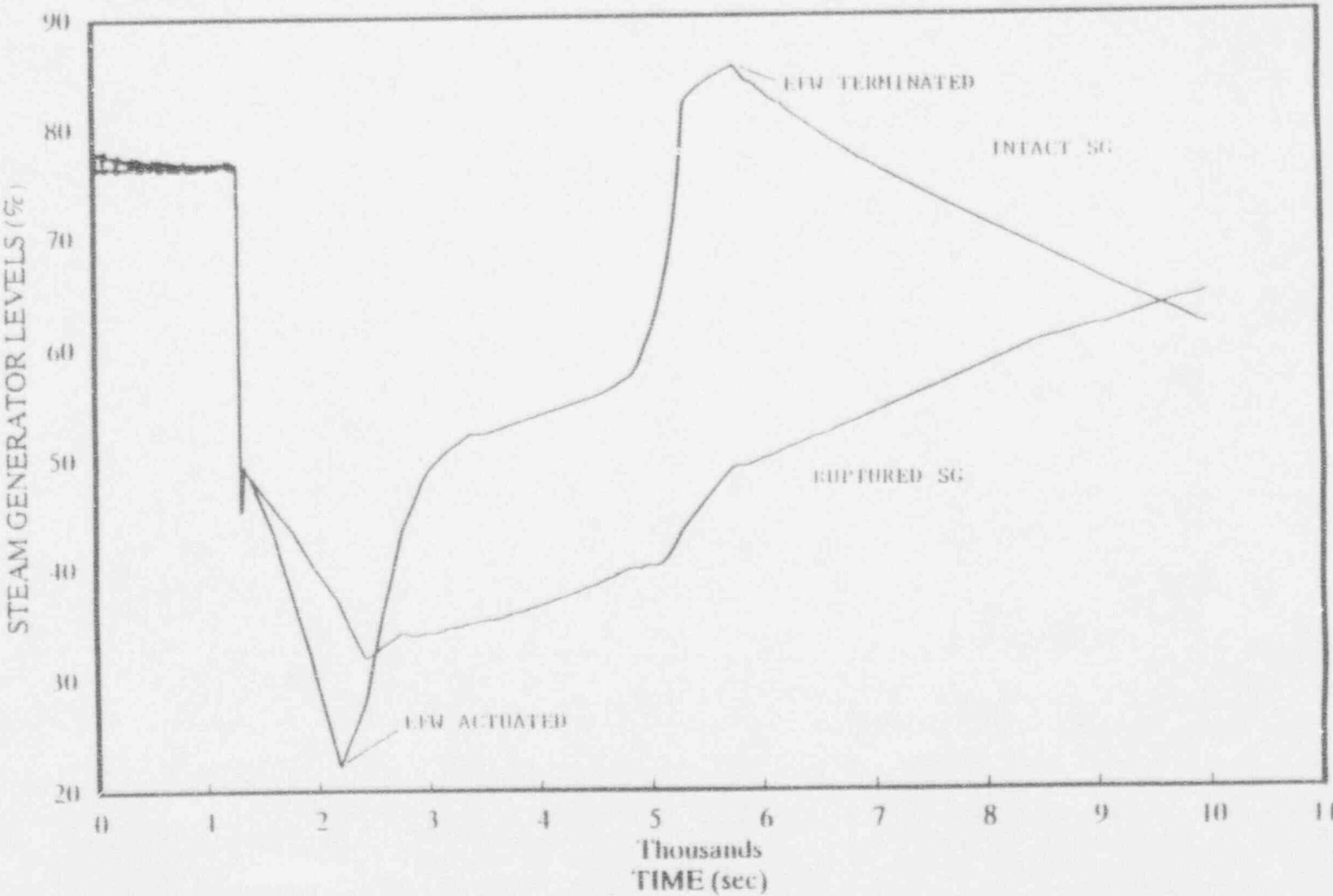


FIG. 4.3.6-4 Pressurizer Level vs. Time

Case 11 for 1 Tube Ruptured and Automatic Reduction of SBCS Initiation Pressure

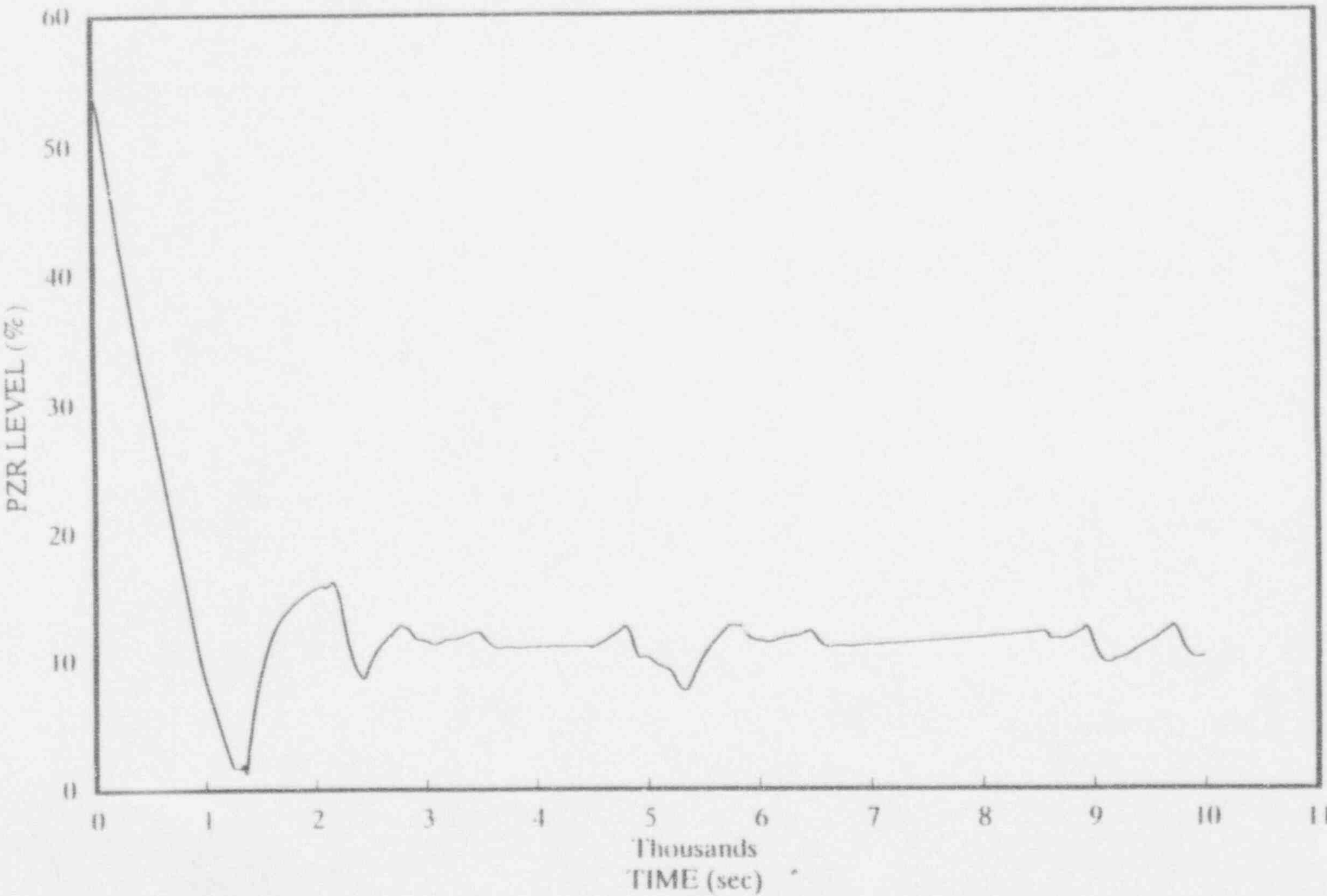


FIG. 4.3.6-5 Hot and Cold Leg Temperatures vs. Time

Case 11 for 1 Tube Ruptured and Automatic Reduction of SBCS Initiation Pressure

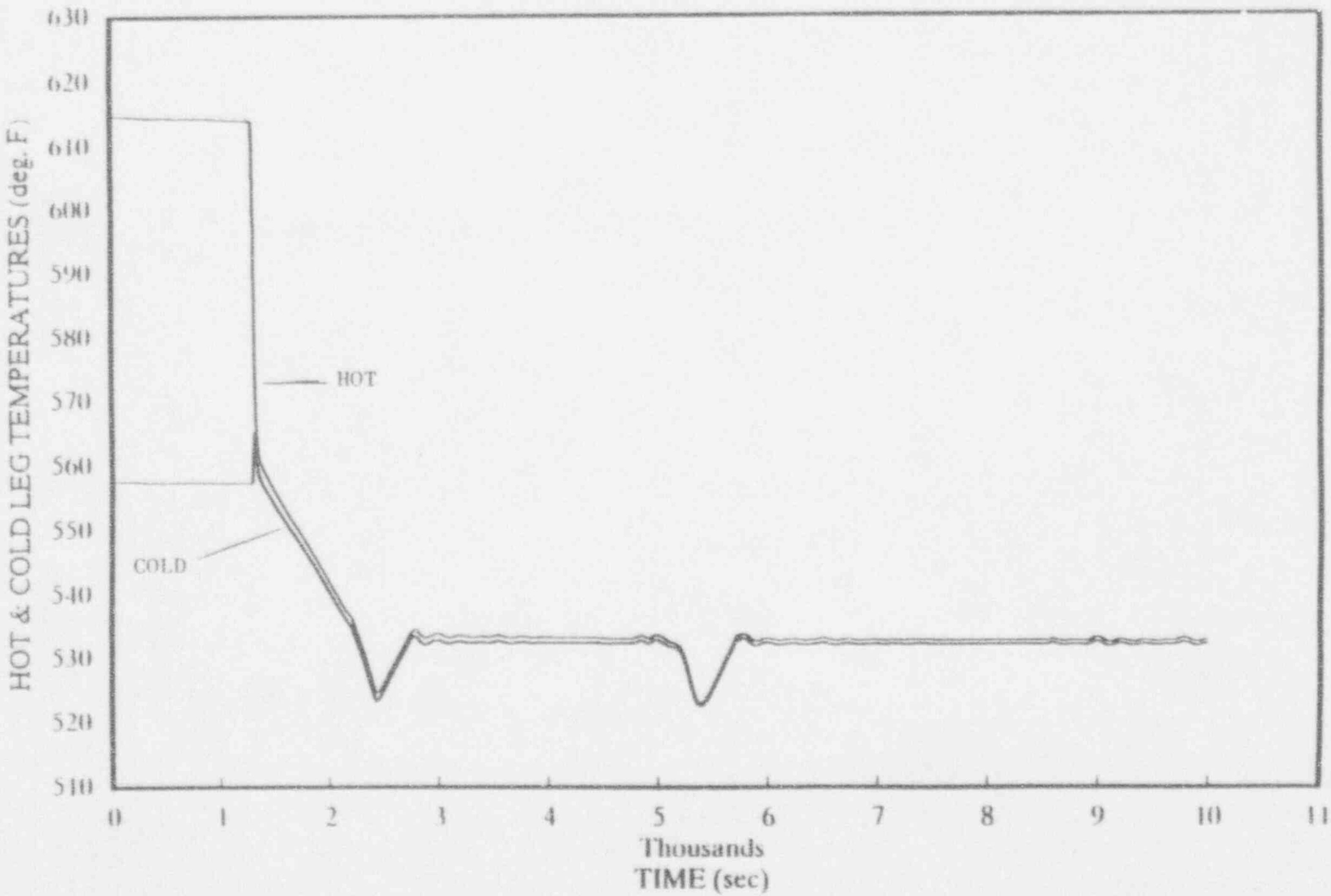


FIG. 4.3.6-6 RCS and SG Pressures vs. Time

Case 12 for 5 Tubes Ruptured and Automatic Reduction of SBCS Initiation Pressure

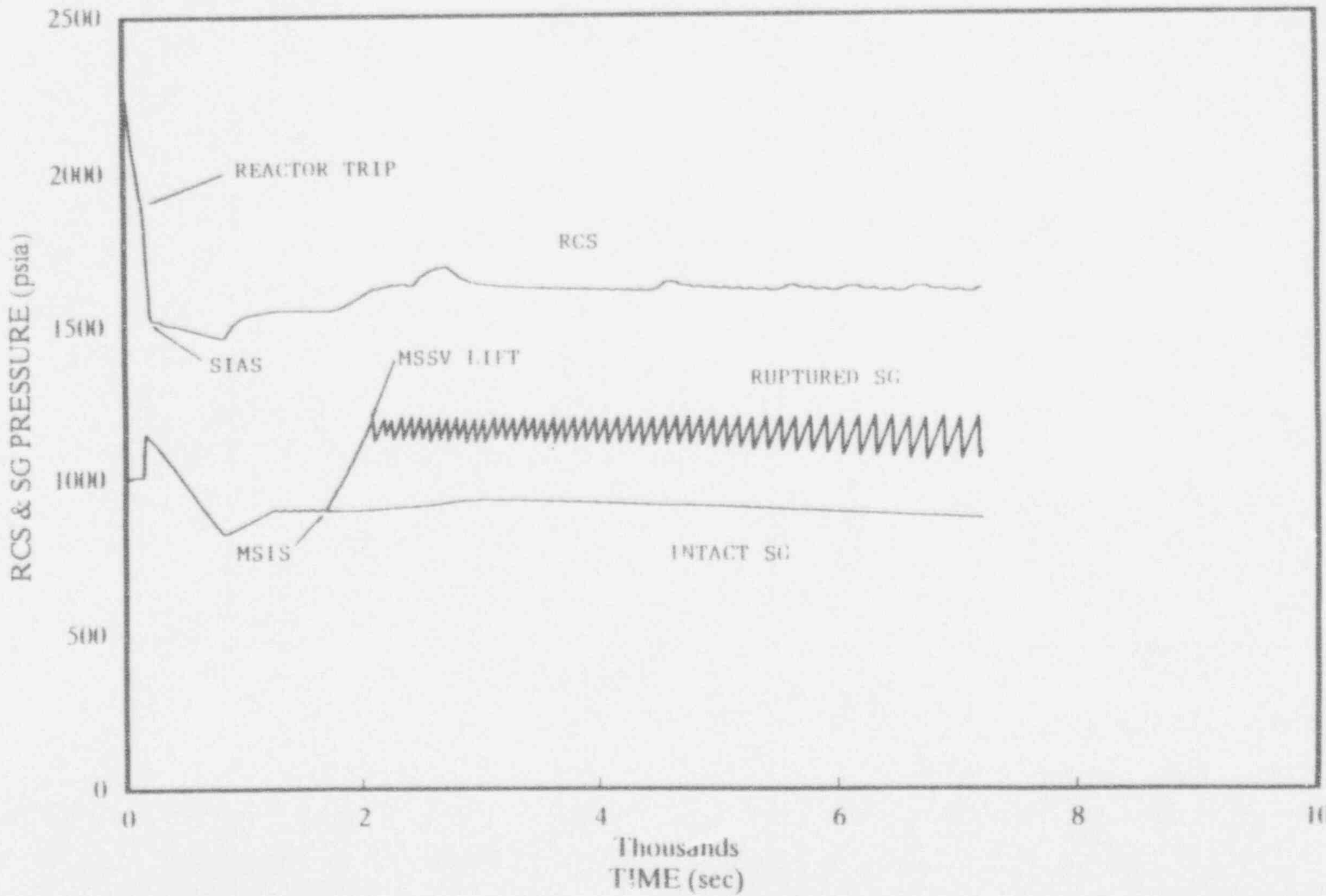


FIG. 4.3.6-7 Leak, HPSI and Bypass Flow Rates vs. Time

Case 12 for 5 Tubes Ruptured and Automatic Reduction of SBCS Initiation Pressure

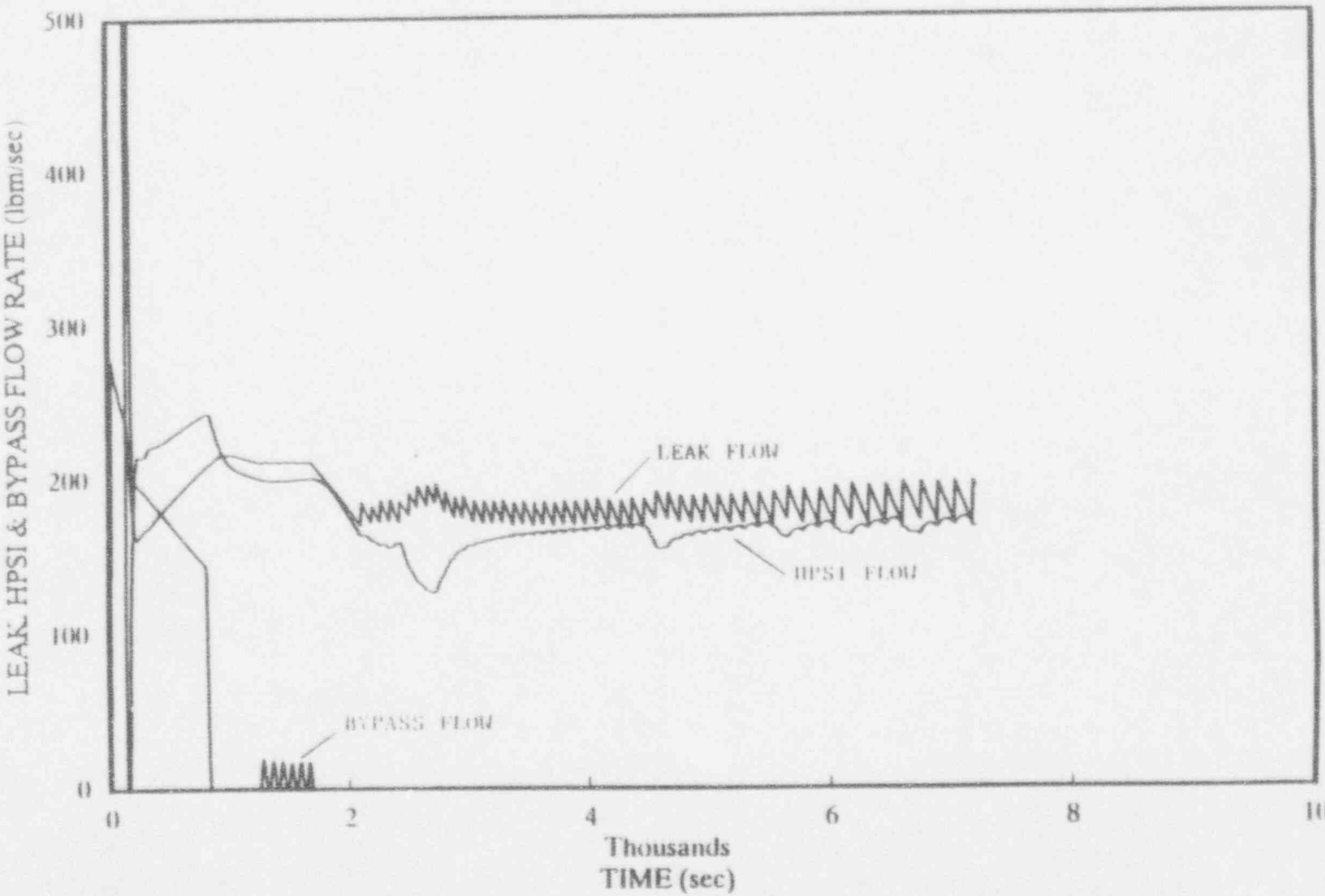


FIG. 4.3.6-8 Steam Generator Level vs. Time

Case 12 for 5 Tubes Ruptured and Automatic Reduction of SBCS Initiation Pressure

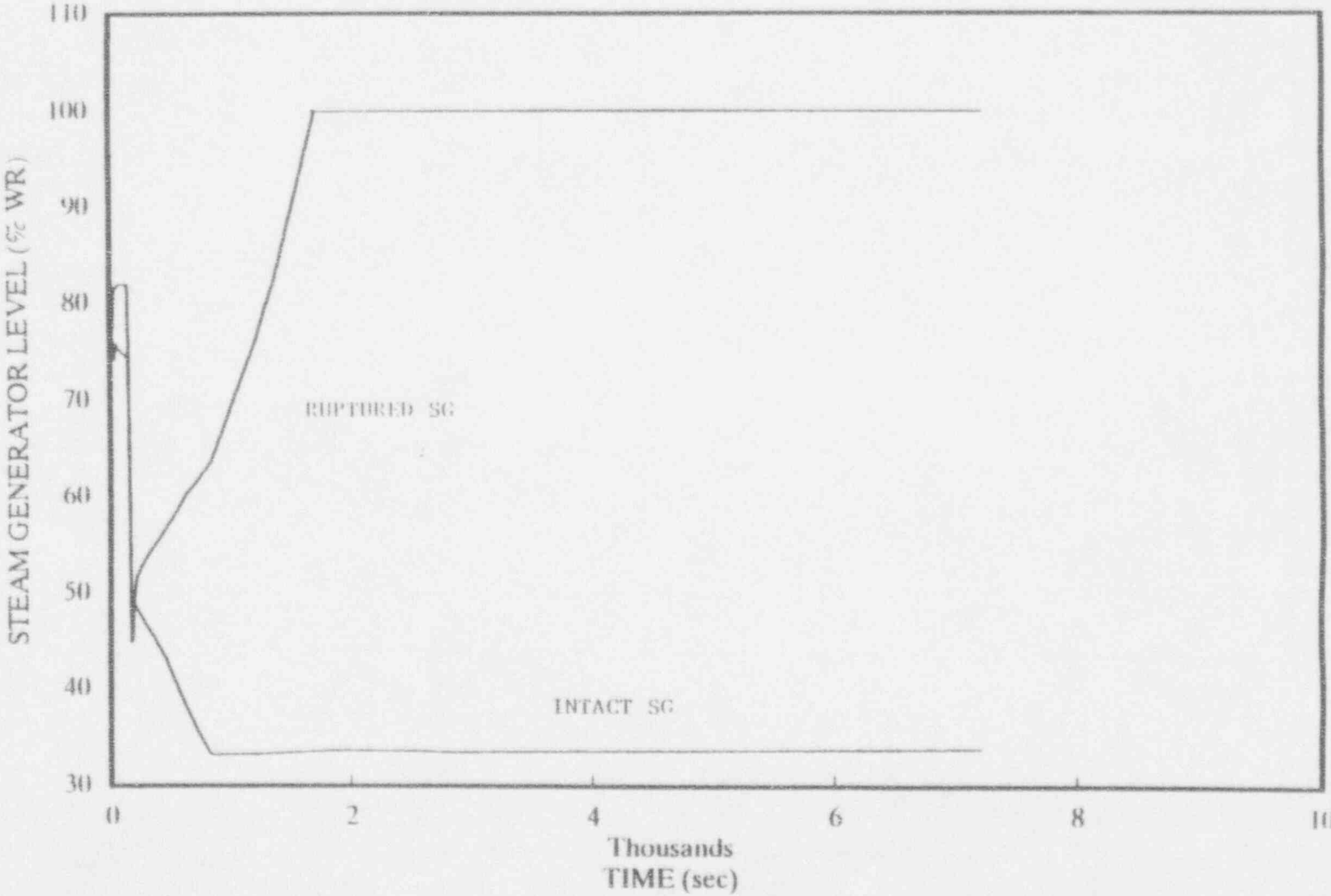


FIG. 4.3.6-9 Pressurizer Level vs. Time

Case 12 for 5 Tubes Ruptured and Automatic Reduction of SBCS Initiation Pressure

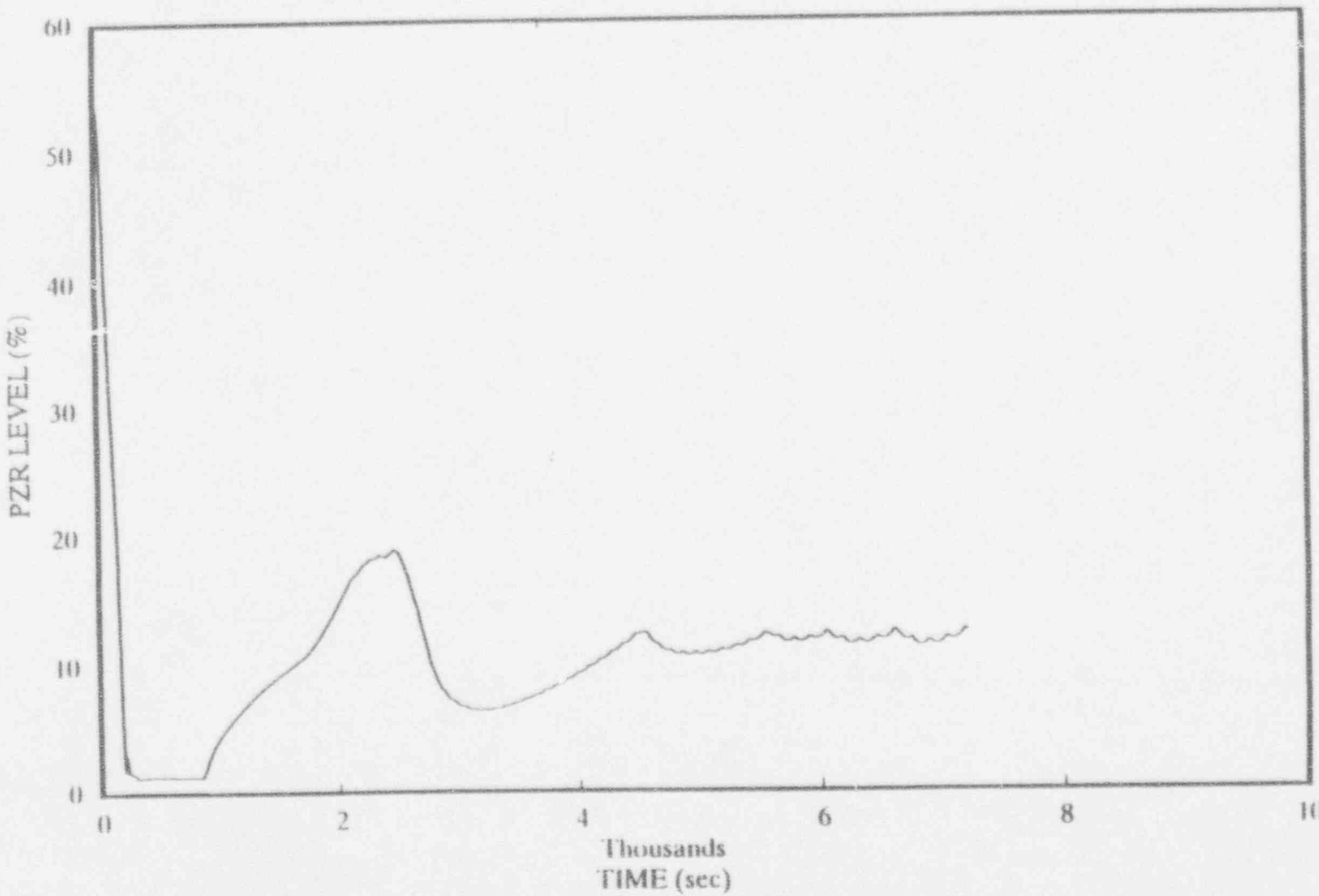
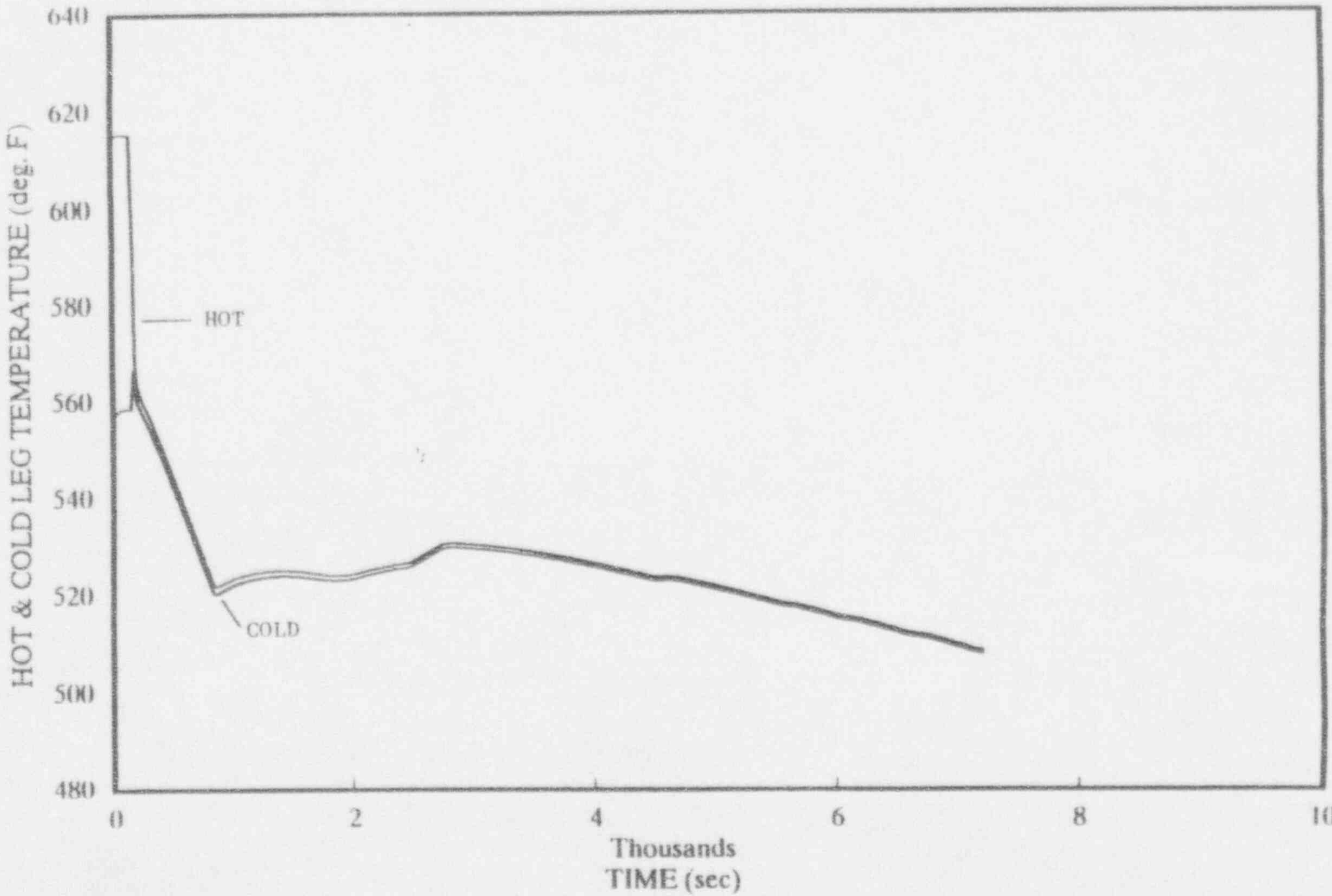


FIG. 4.3.6-10 Hot and Cold Leg Temperatures vs. Time

Case 12 for 5 Tubes Ruptured and Automatic Reduction of SBCS Initiation Pressure



4.3.7 Automatic Bypass of MSIS on Low Steam Generator Pressure

This design change pertains to opening of all of the steam bypass system as long as necessary to prevent the SG pressure and level from increasing rapidly and challenging the MSSVs. This change would necessitate bypassing of the MSIS on low SG pressure to keep the bypass system valves open. This bypassing would have to be based on a reactor trip signal coincident with an N-16 SG radiation detector signal. The N-16 detector signal is a control grade signal. Thus, the safety grade MSIS signal would have to be bypassed also using this control grade signal. This would be in violation of the NRC guidelines which require that control grade and safety grade instrumentation channels be kept totally isolated from one another. Since certain design basis events rely on the low pressure MSIS (e.g., Main Steam Line Break) such a change was rejected and no detailed analysis of this design change was carried out.

4.3.8 Automatic Opening of Rapid Depressurization System

The System 80+ design incorporates a Rapid Depressurization System (RDS) which provides a manual means of depressurizing the RCS when normal and emergency feedwater are unavailable for RCS heat removal. A design change to use this depressurization mechanism during a steam generator tube rupture event was considered. This change pertains to making the RDS actuate automatically upon an N-16 SG radiation detector signal coincident with a reactor trip signal and a high steam generator level signal. Both RDS valves are assumed to be open if the above conditions are reached.

For the one tube rupture case, it is expected that the RDS valves will not open for several hours (more than 15,000 seconds) since the damaged SG level builds up slowly and does not reach the MSIS setpoint on high SG level until after 15,000 seconds (extrapolation of Figure 4.3.1-3). It is expected that for the one tube rupture case this provides adequate time for the operator to take mitigating actions prior to actuation of the RDS valves.

For the five tubes ruptured case, case 13 denotes the analysis which assumes actuation of the RDS valves on a high level in the damaged SG. Figures 4.3.8-1 through 4.3.8-5 provides the results of this analysis and Table 4.3.8-1 lists the major sequence of events occurring during the transient. The actuation of the RDS valves causes a rapid depressurization of the RCS resulting in the primary to secondary break flow (figure 4.3.8-2) to decrease to zero. The initial rapid depressurization causes mementary loss of RCS subcooling. The core does not uncover, but two phase flow is present for approximately 300 seconds. As the RCS pressure (Figure 4.3.8-1) falls below the secondary pressure, the break flow reverses, subcooling is recovered, and the damaged SG inventory begins to drain into the RCS (see Figure 4.3.8-3). The break flow reverses since RDS valves have a combined effective flow area of 0.042 sq ft in contrast to the total break area for five tubes of 0.024 sq ft. Subsequent to the initial flow reversal, the break flow remains negative or at zero causing a reduction in the SG level and pressure. Hence the MSSVs are not challenged during the transient. The flow out through RDS valves causes an increase in the pressurizer level (Figure 4.3.8-4) as the safety injection flow increases with decreasing RCS pressure. The pressurizer fills soon afterwards and the RDS valves begins to discharge water.

The major benefit of this design option is that the damaged SG build-up and subsequent challenge to the MSSVs are eliminated. However, this design change has the potential for boron dilution within the RCS as well as the uncertain chemical effects caused by introducing secondary coolant into the RCS. The original inventory in the steam generator does not contain boron and mixing of this water with the RCS fluid through reverse break flow has the potential for significant dilution if the RDS is opened

automatically at an early time (prior to adequate boration of the ruptured SG secondary via the leak flow).

TABLE 4.3.8-1

SEQUENCE OF EVENTS FOR CASE 13
STEAM GENERATOR TUBE RUPTURE (5 TUBES) WITH AUTOMATIC
OPENING OF THE RDS ON N-16 INDICATION & HIGH SG LEVEL

TIME (Sec)	EVENT	SETPOINT
0.0	Tube Rupture Occurs	---
130	Pressurizer Backup Heaters Actuated on Low Pressurizer Pressure, psia	2200
149	Reactor Trips on Hot Leg Saturation Trip Signal	---
150	Turbine Trips	---
152	Steam Bypass System Actuated on High Steam Generator Pressure, psia	1078
165	Pressurizer Pressure Reaches Safety Injection Actuation Signal (SIAS) Setpoint, psia	1835
166	Main Feedwater Terminated on Low T_{avg}	---
1590	Main Steam Isolation Signal (MSIS) Generated on High Level in the Damaged Steam Generator, % wide range level	98
1600	Rapid Depressurization System is Actuated on N-16 Indication & High SG Level	---
1610	Break Flow reverses as RCS Pressure decrease below SG Pressure	---
1640	Pressurizer Fills to 100%	---

FIG. 4.3.8-1 RCS and SG Pressures vs. Time

Case 13 for 5 Tubes Ruptured and Automatic Rapid Depressurization System

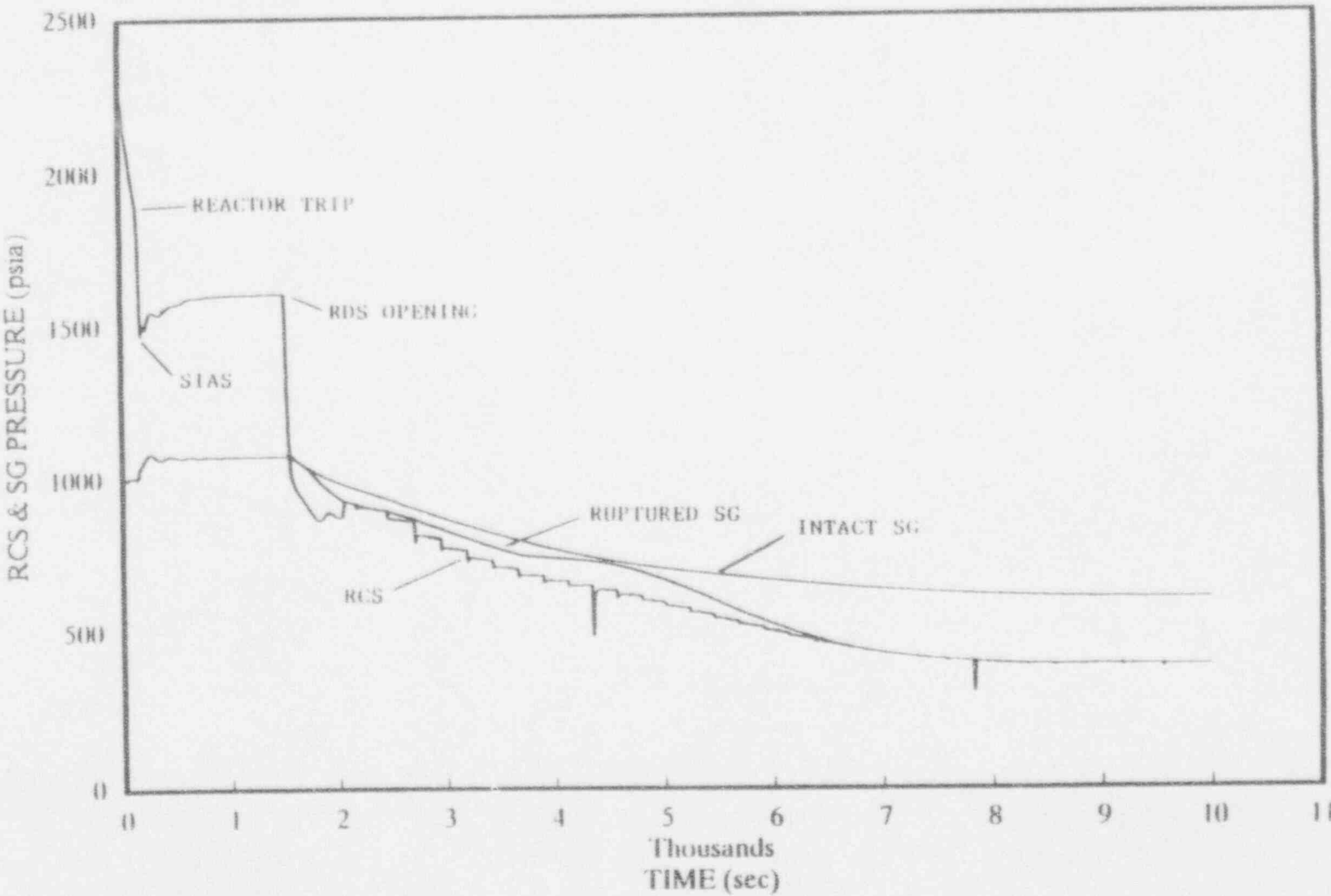


FIG. 4.3.8-2 Leak, HPSI and Bypass Flow Rates vs. Time

Case 13 for 5 Tubes Ruptured and Automatic Rapid Depressurization System

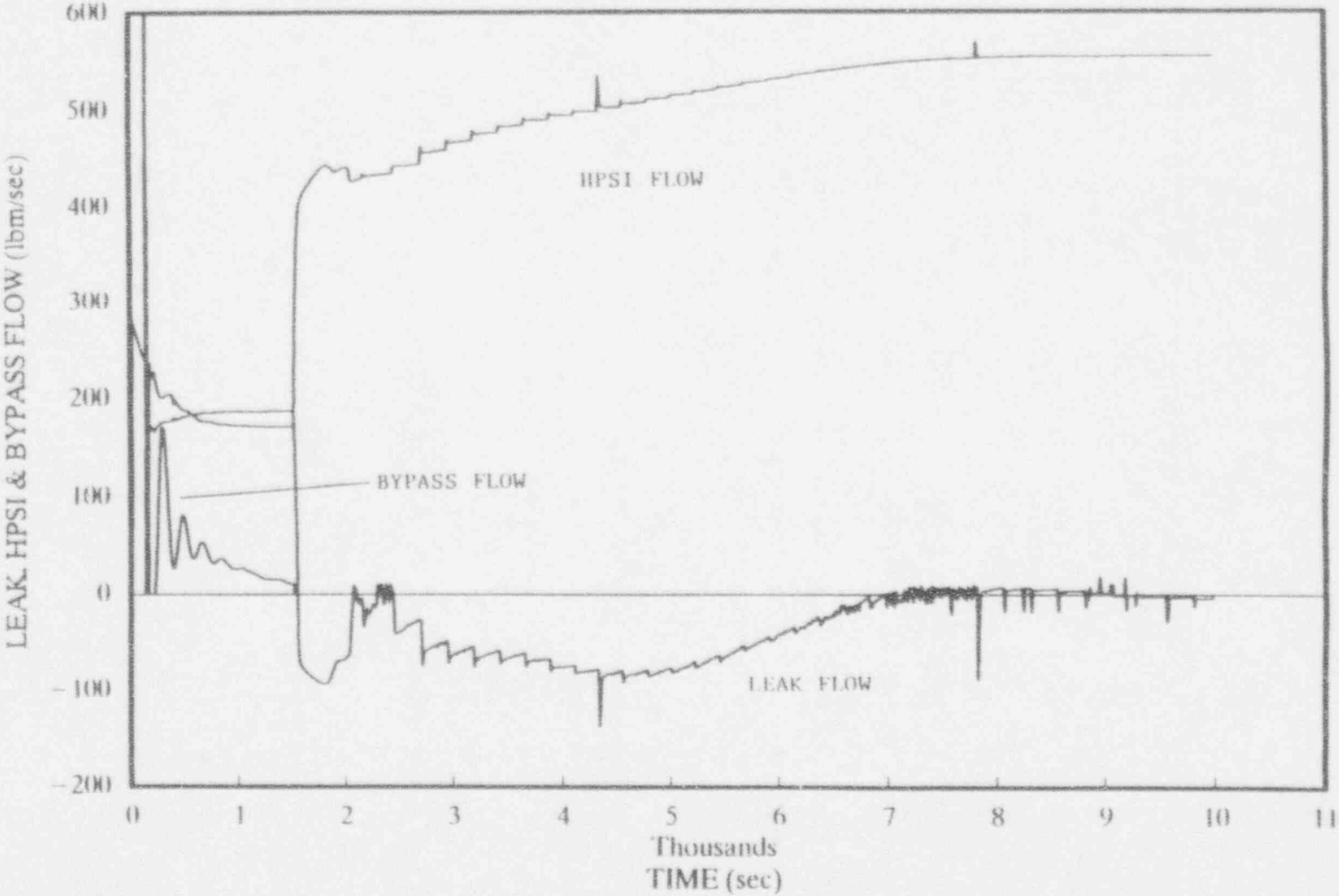


FIG. 4.3.8-3 Steam Generator Level vs. Time

Case 13 for 5 Tubes Ruptured and Automatic Rapid Depressurization System

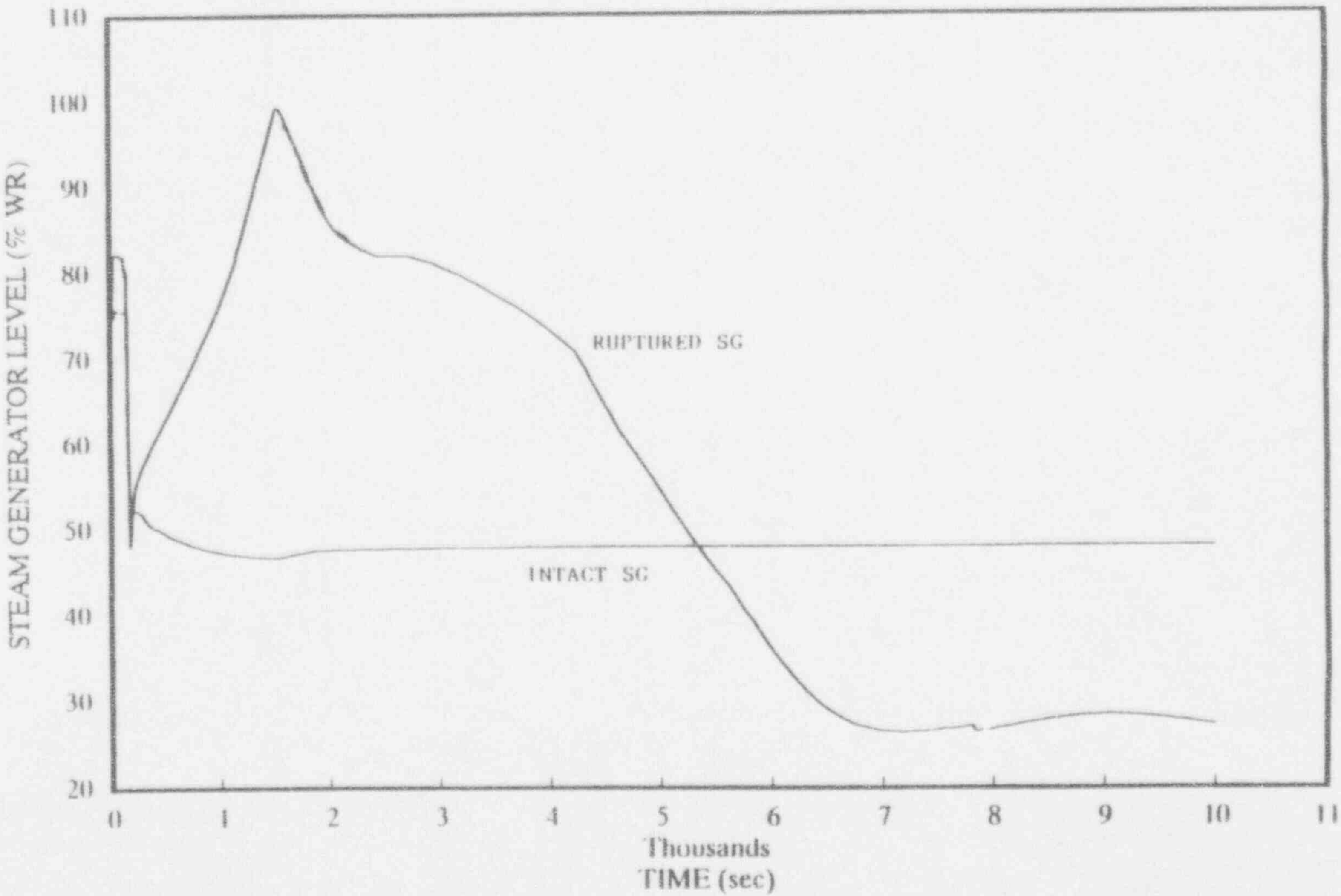


FIG. 4.3.8-4 Pressurizer Level vs. Time

Case 13 for 5 Tubes Ruptured and Automatic Rapid Depressurization System

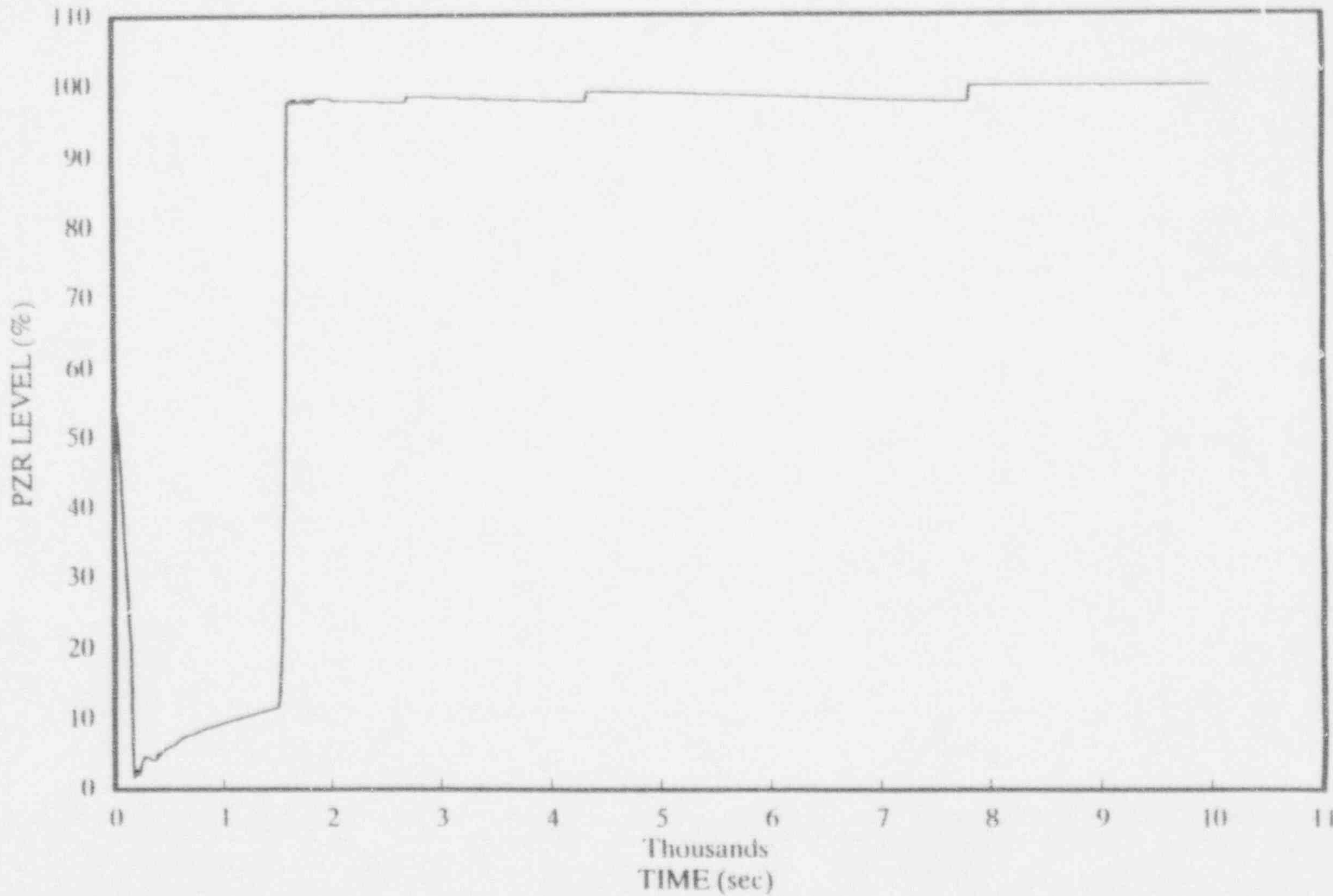
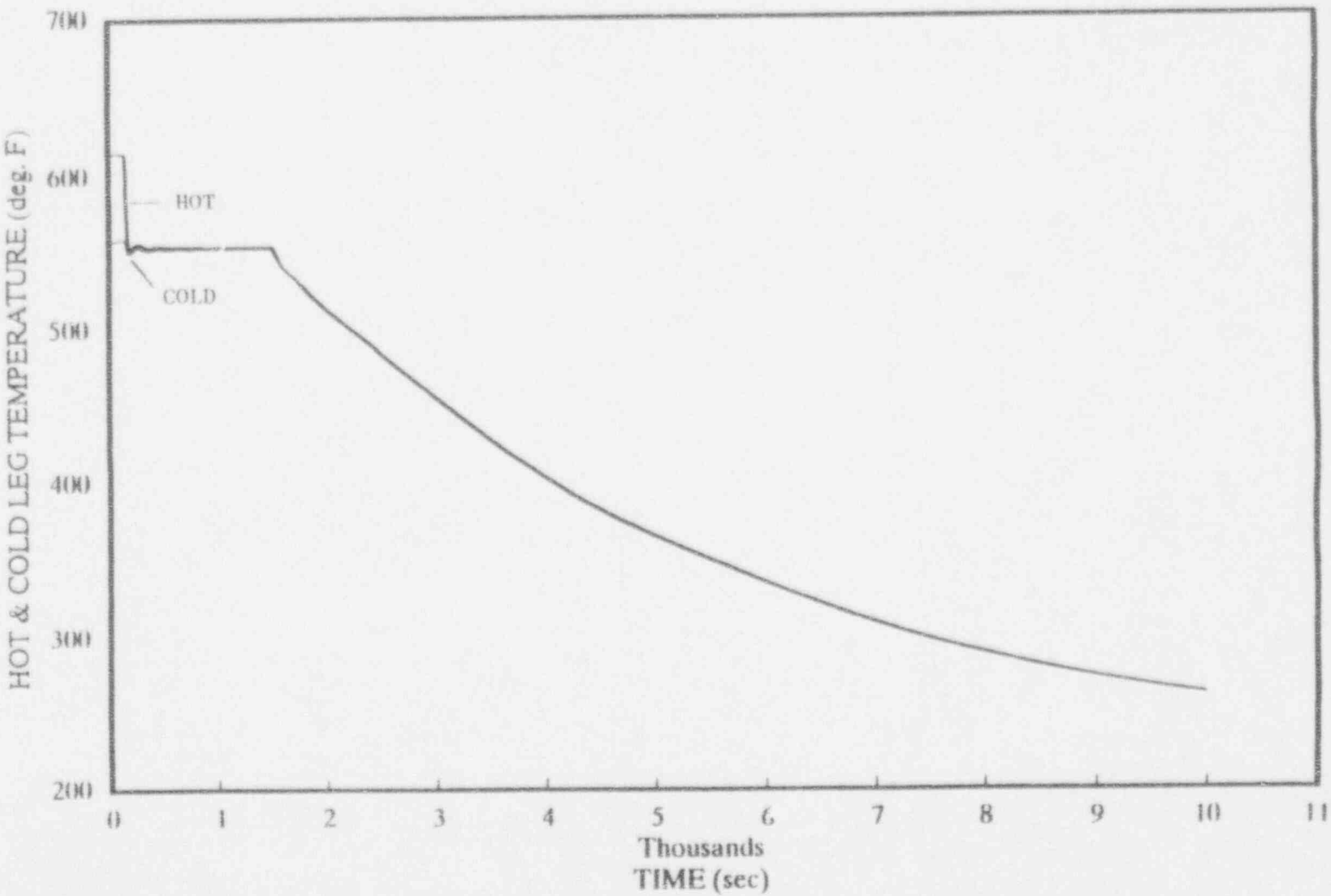


FIG. 4.3.8-5 Hot and Cold Leg Temperatures vs. Time

Case 13 for 5 Tubes Ruptured and Automatic Rapid Depressurization System



4.3.9 Increase Main Steam Safety Valve Lift Setpoint by 200 psi

This design change is aimed at delaying MSSV opening by increasing the opening setpoint pressure by 200 psi. Current System 80+ design has an MSSV opening setpoint pressure for the first valve bank of 1200 psia. Increasing this setpoint by 200 psi impacts primarily the five tube case in comparison to the one tube case, since the one tube case does not result in opening of the MSSVs for more than 15,000 seconds. For the five tube ruptured case it is estimated that the increased setpoint of 1400 psia would delay the MSSV opening by about 300 seconds (5 minutes).

The raising of the MSSV lift setpoint has an adverse impact on certain Chapter 15 design basis events. In particular, for a small break LOCA for which the RCS pressure reaches a plateau around the MSSV setpoint the increase in setpoint would cause a reduction in the safety injection flow. This reduction results in increased clad temperatures for the small break LOCA. Analyses were performed to quantify this adverse effect. A parametric study was conducted for the Small break LOCA event using the licensing evaluation model. It used the CEFLASH-4AS and the PARCH computer codes to determine the impact of raising the MSSV setpoint from 1200 psia to 1500 psia. Two different small break LOCAs were analyzed, namely, 0.1 sq ft and 0.05 sq ft DVI line breaks. The reduction in integrated safety injection flow is shown in Figure 4.3.9-2 and the peak cladding temperature increase is shown in Figure 4.3.9-1 as a function of MSSV setpoint. It is seen that for the 0.1 sq ft break the reduction in the integrated HPSI flow is about 15 percent for an increase of 200 psi in the MSSV setpoint (from 1200 psia to 1400 psia). The increase in peak cladding temperature is about 700 deg F for the 0.1 sq ft break and about 1240 deg F for the 0.05 sq ft case. This increase is significantly large to cause (1) the peak cladding temperature for small break LOCA to exceed the peak cladding temperature for large break LOCAs, and (2) peak cladding temperature for small break LOCAs to exceed the Appendix K acceptance criterion of 2200 deg F.

Thus, raising the MSSV setpoint by 200 psi is considered not desirable, since its benefit for a five tube rupture case is minimal and its impact on a small break LOCA would be unacceptably high peak cladding temperature.

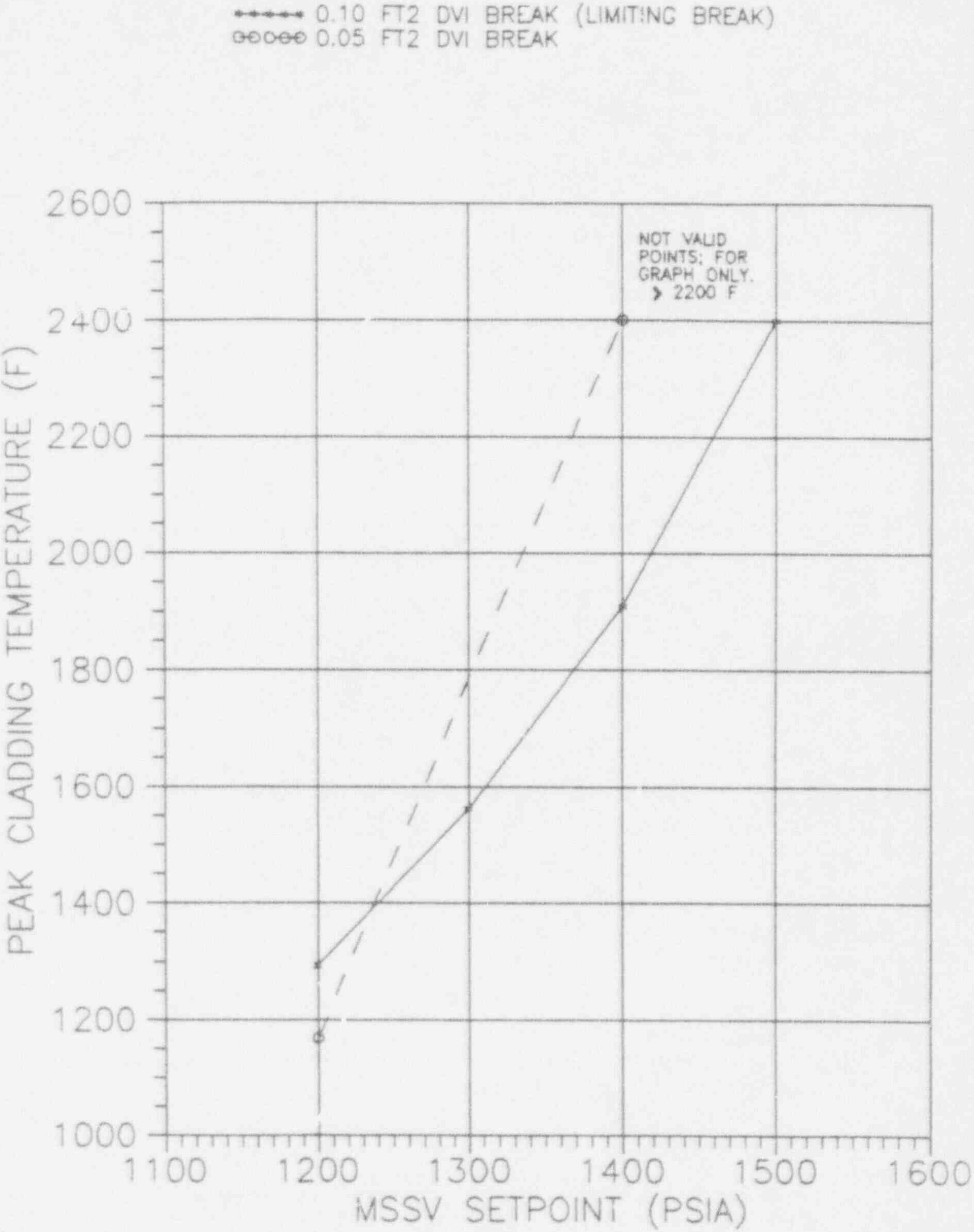


FIG. 4.3.9-1 Peak Cladding Temperature vs. MSSV Setpoint

Small Break LOCA

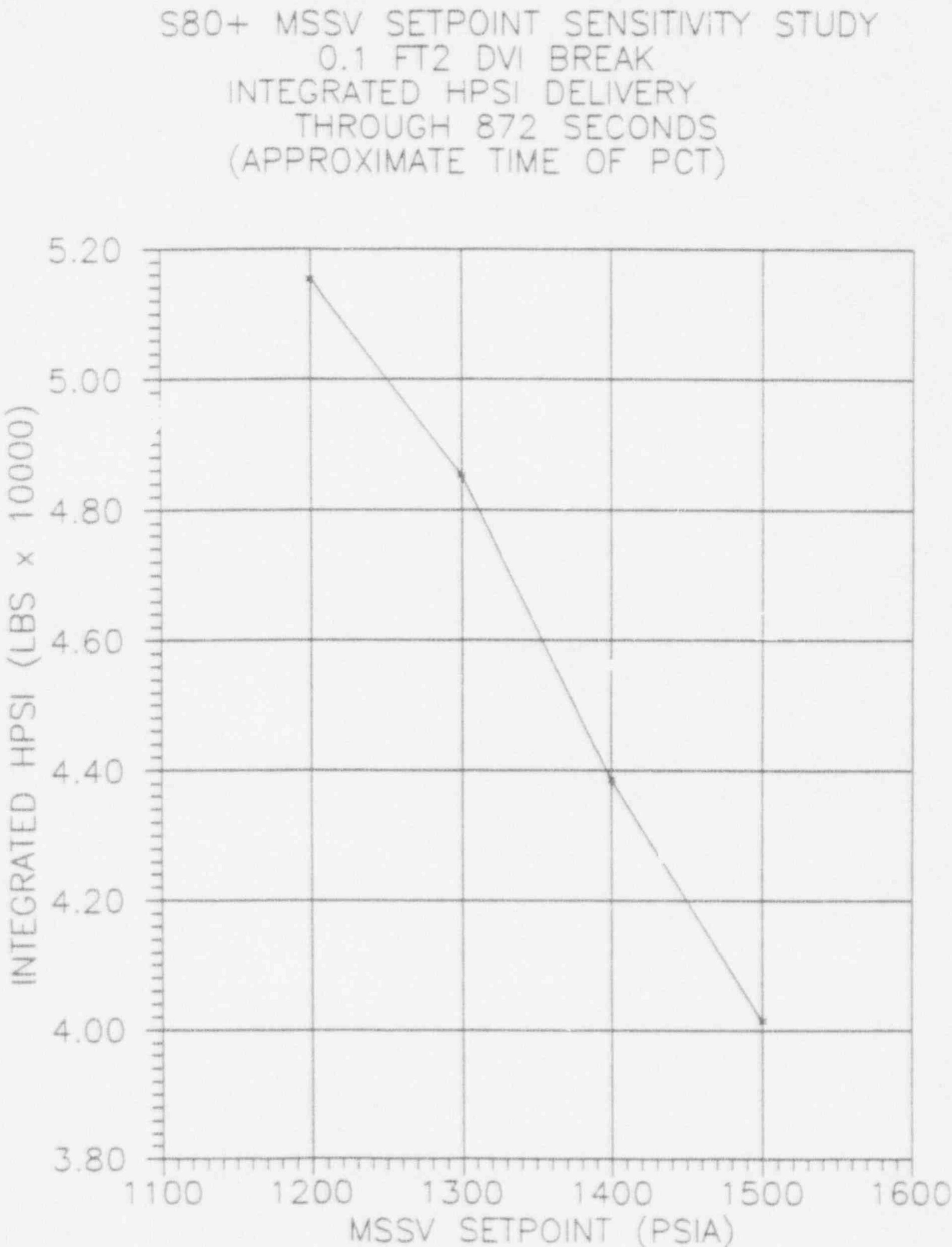


FIG. 4.3.9-2 Integrated HPSI Flow vs. MSSV Setpoint
0.1 sq. ft. LOCA

4.3.10 Automatic Blowdown of Steam Generator Liquid to IRWST

This design change is similar to the high capacity SG blowdown to the condenser discussed in Section 4.3.5. It considers automatic blowdown of the damaged SG liquid to the IRWST upon a reactor trip signal, N-16 SG radiation detector signal, and high water level in the SG. The IRWST would receive and cool the blowdown fluid by thermal mixing.

For the one tube rupture case, this option would not result in actuation of the SG blowdown for more than 15,000 seconds since the damaged SG water level does not reach a high value during this time (see Figure 4.3.1-3).

For the five tubes ruptured case with this design change, case 14, the analysis results are provided in Figures 4.3.10-1 through 4.3.10-5. The sequence of major events occurring during the transient is listed in Table 4.3.10-1. The analysis considers a blowdown rate of about 7% full power steam flow rate. In comparison to the base case, case 2, the transient results are the same for case 14 up to the time of actuation of the blowdown system. Blowdown is initiated subsequent to the reactor trip and upon reaching a high level in the damaged steam generator (blowdown actuation is assumed to occur when the level recovers to the initial value). This occurs at about 1120 seconds. Subsequently the damaged steam generator level (Figure 4.3.10-3) decreases and then gradually increases. The level remains below 100 percent for up to 10000 seconds. Following actuation of the blowdown the RCS pressure as well as the steam generator pressure (Figure 4.3.10-1) decrease and the bypass system closes.

As the SG liquid is discharged into the IRWST, it is expected that the IRWST fluid will get heated up since the blowdown liquid is at a significantly higher enthalpy than the IRWST fluid. Consequently, in the analysis the temperature of the IRWST fluid, which is used as the source for safety injection flow, is assumed to be at a higher temperature (about 55 deg F increase) than the initial temperature. Despite this increase in temperature, it is seen that the RCS fluid is cooled by safety injection flow as seen in Figure 4.3.10-5.

Thus, controlled automatic SG blowdown into the IRWST delays the MSIS generation for more than two hours consequently delaying MSSV lift for the five tubes ruptured case. In addition, by draining the damaged SG liquid into the IRWST the radioactive fluid is stored within the containment, thus eliminating any containment bypass concern.

On the negative side, the continued SG blowdown would result in a heat-up of the IRWST, resulting in boiling of a portion of the IRWST liquid and eventual pressurization of the containment. It is

expected that for up to two hours the boiling of IRWST fluid should be minimal and that the containment pressurization may not be that large (and containment sprays would not be actuated). Another negative impact of draining the SG fluid into the IRWST is the potential for boron dilution of the IRWST fluid. This potential exists since the original inventory in the SG is unborated. Since the IRWST fluid is source for safety injection, this potential needs to be considered from a shutdown margin requirement concern. It is expected that with about 4 million lbm of IRWST inventory and an initial SG inventory of about 200,000 lbm, this dilution may not be that significant to impact the shutdown margin requirement for the RCS as long as it can be assured that main and emergency feedwater flow can be reliably terminated to the ruptured SG.

TABLE 4.3.10-1

SEQUENCE OF EVENTS FOR CASE 14
STEAM GENERATOR TUBE RUPTURE (5 TUBES) WITH
SG BLOWDOWN TO IRWST ON HIGH SG WATER LEVEL

TIME (Sec)	EVENT	SETPOINT
0.0	Tube Rupture Occurs	---
130	Pressurizer Backup Heaters Actuated on Low Pressurizer Pressure, psia	2200
149	Reactor Trips on Hot Leg Saturation Trip Signal	---
150	Turbine Trips	---
152	Steam Bypass System Actuated on High Steam Generator Pressure, psia	1078
165	Pressurizer Pressure Reaches Safety Injection Actuation (SIAS) Setpoint, psia	1835
166	Main Feedwater Terminated on Low T_{avg}	---
1110	Damaged Steam Generator Water Level Reaches Normal Water Level, ft above tube sheet	40.46
1111	Damaged Steam Generator Blowdown to IRWST actuated on Reactor Trip and N-16 Radiation Detector Signals and on High Water Level	---
1350	Steam Bypass Valves closes on Low Steam Generator Pressure	---
9680	Main Steam Isolation Signal (MSIS) Generated on High Level in the Damaged Steam Generator, % wide range level	98
*	Main Steam Safety Valves (MSSVs) on Damaged Steam Generator Actuated on High Steam Generator Pressure, psia	1200

*Event does not occur during the 10000 seconds of transient simulation.

FIG. 4.3.10-1 RCS and SG Pressures vs. Time

Case 14 for 5 Tubes Ruptured and Automatic SG Liquid Blowdown to IRWST

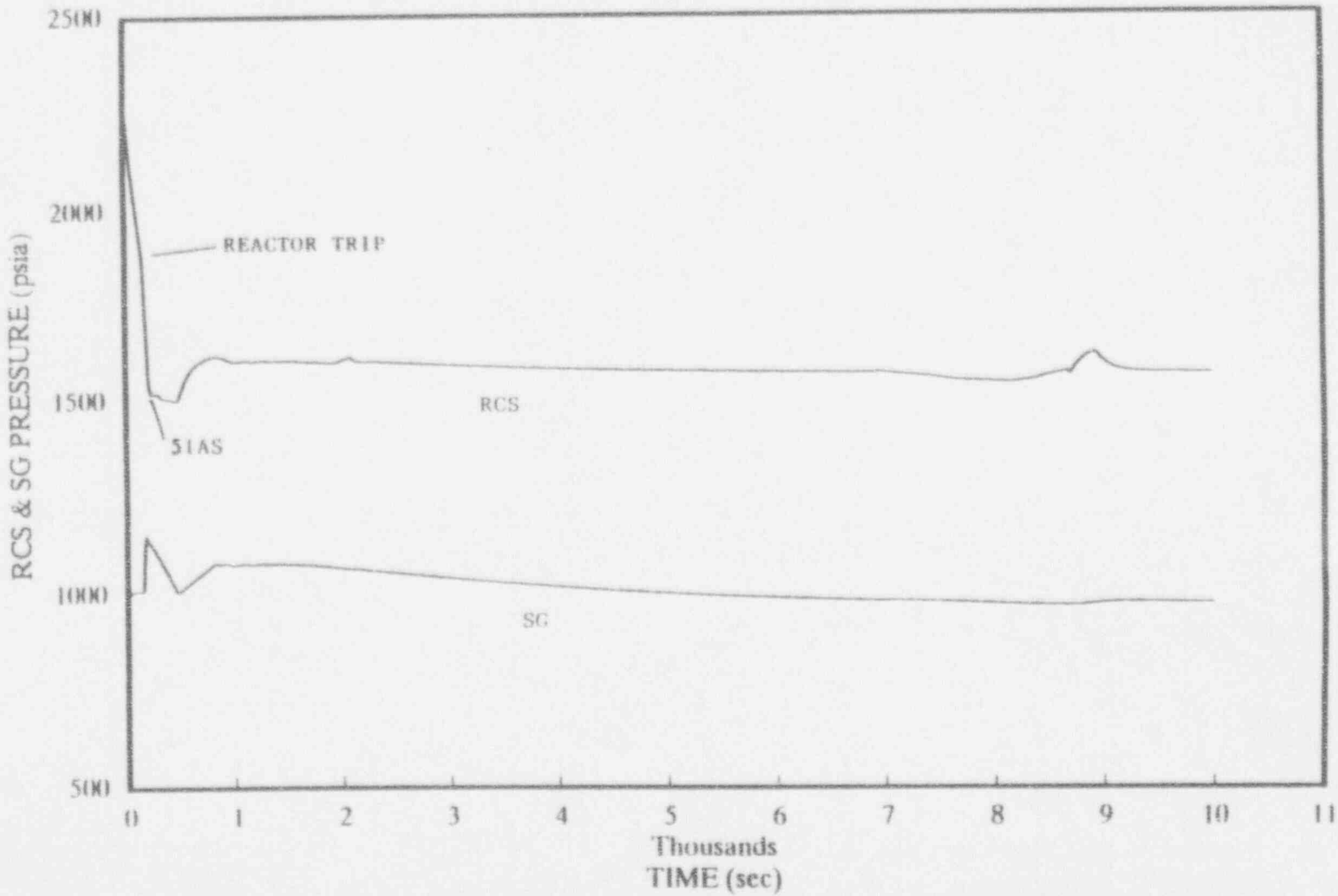


FIG. 4.3.10-2 Leak, HPSI and Bypass Flow Rates vs. Time

Case 14 for 5 Tubes Ruptured and Automatic SG Liquid Blowdown to IRWST

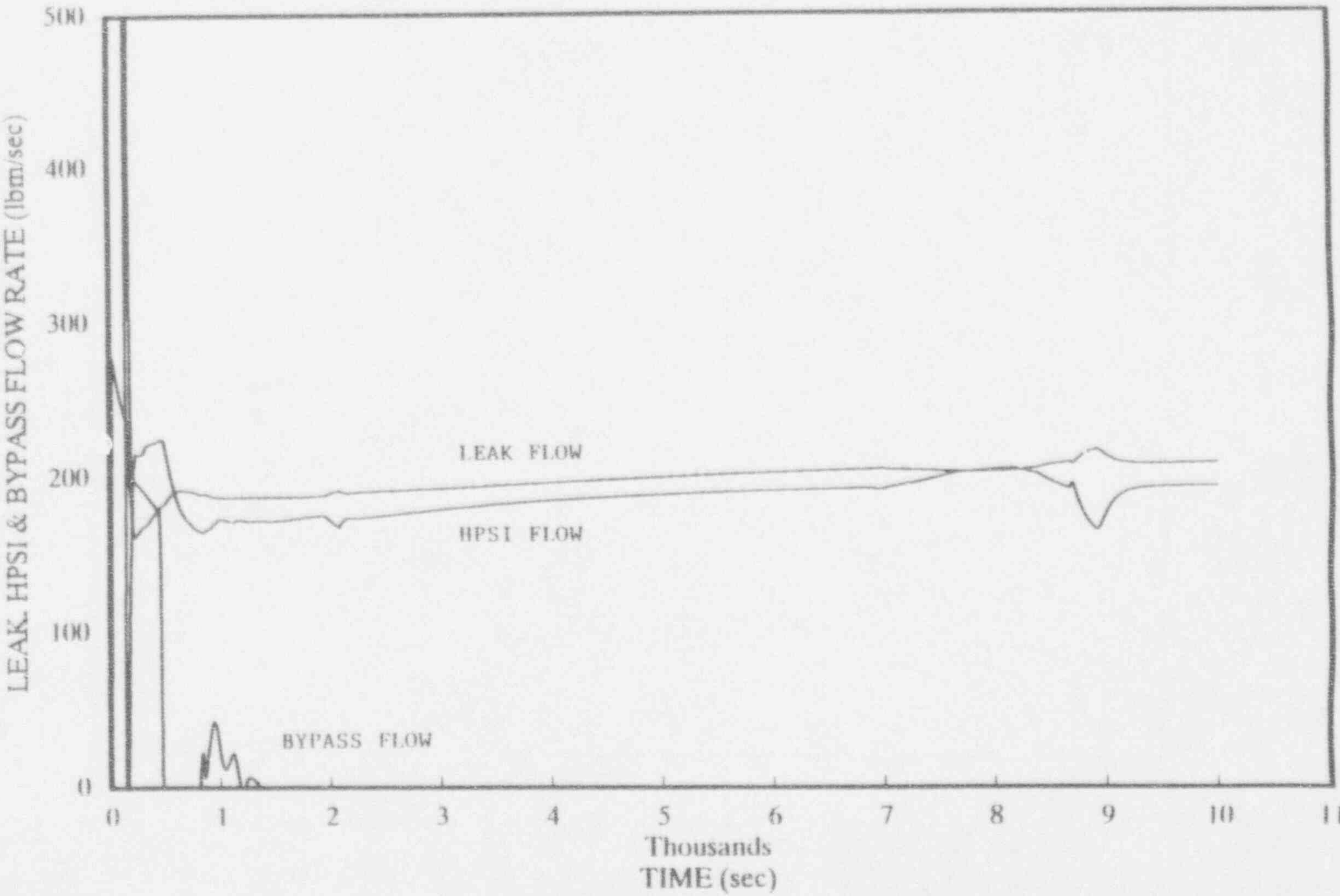


FIG. 4.3.10-3 Steam Generator Level vs. Time

Case 14 for 5 Tubes Ruptured and Automatic SG Liquid Blowdown to IRWST

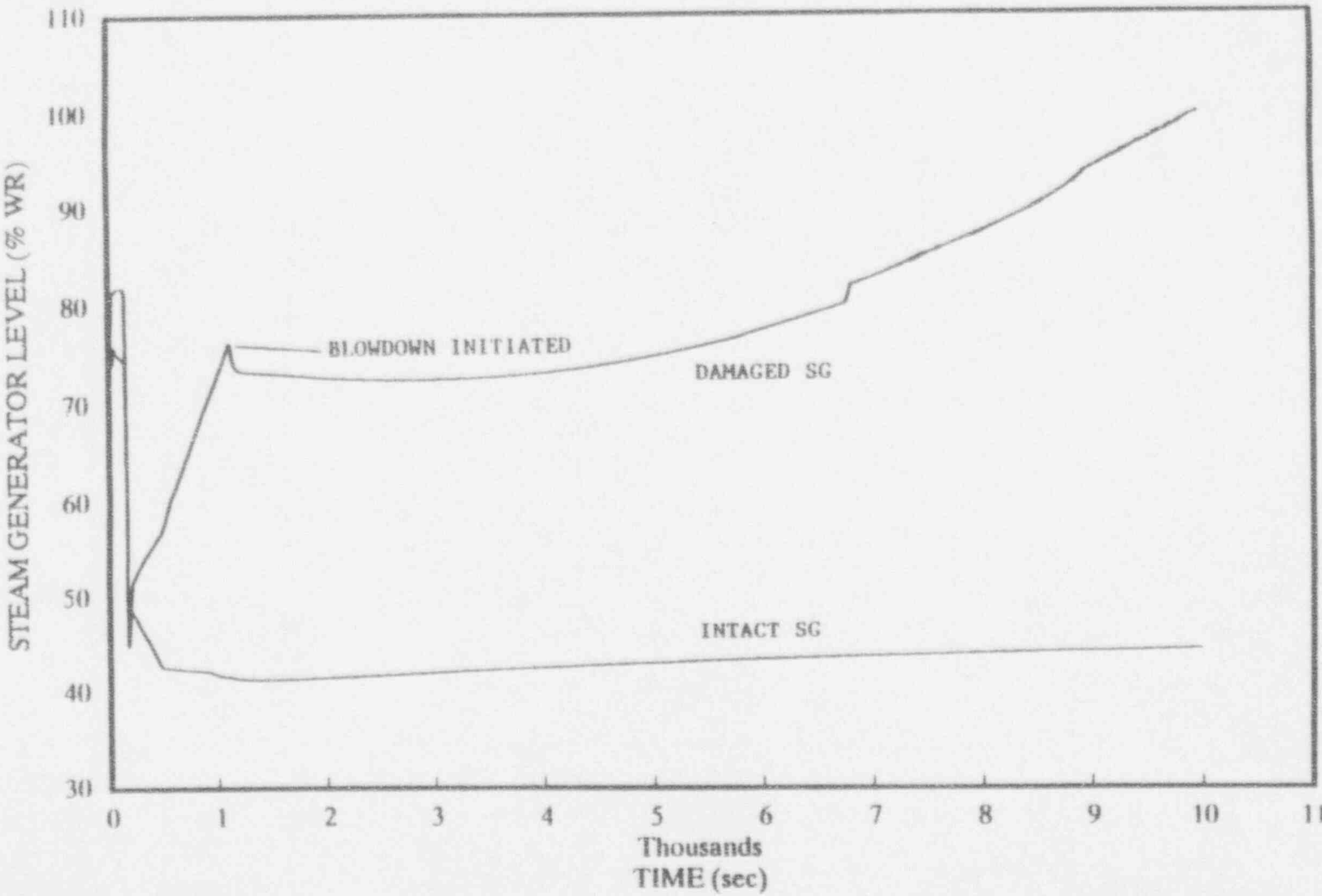


FIG. 4.3.10-4 Pressurizer Level vs. Time

Case 14 for 5 Tubes Ruptured and Automatic SG Liquid Blowdown to IRWST

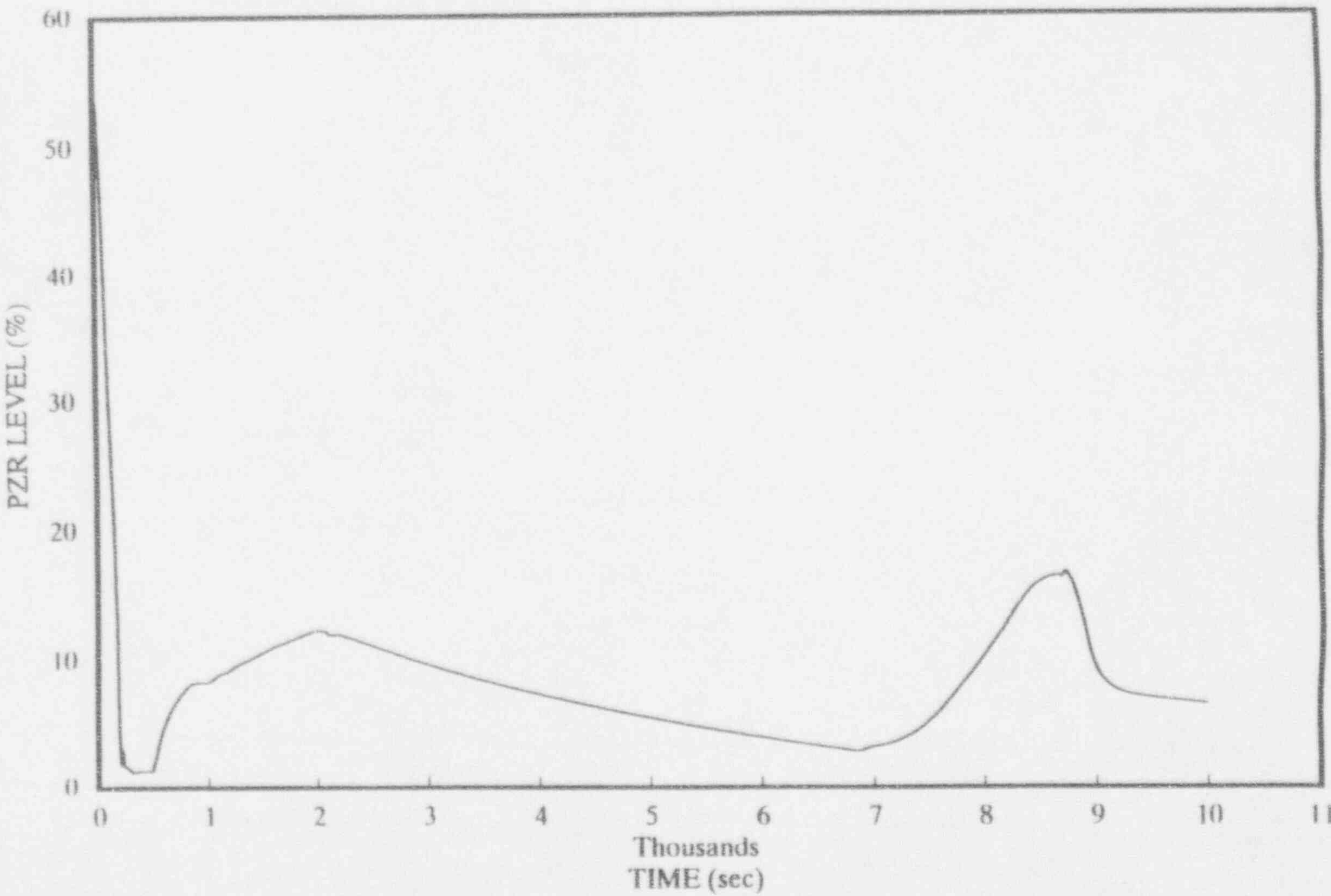
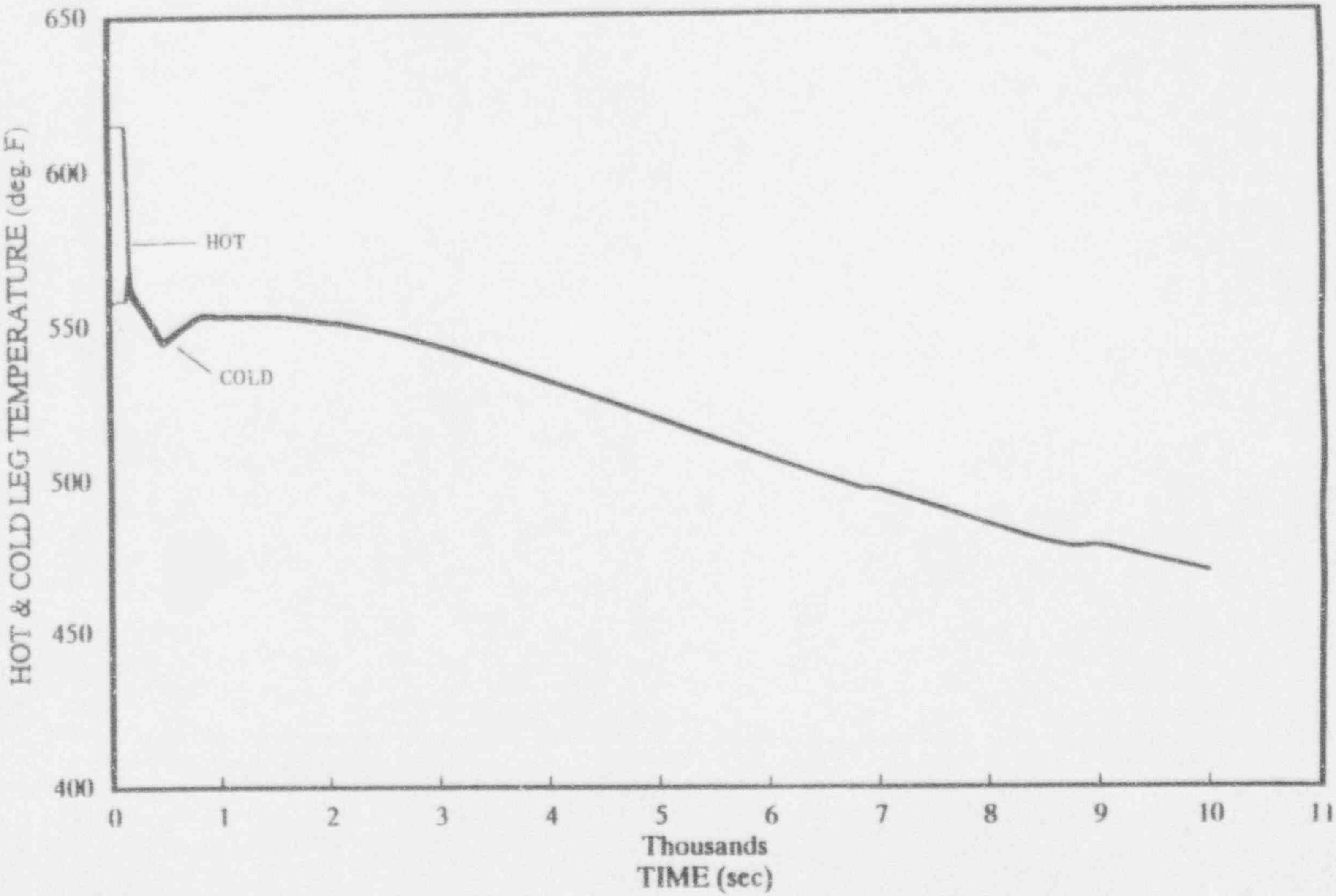


FIG. 4.3.10-5 Hot and Cold Leg Temperatures vs. Time
Case 14 for 5 Tubes Ruptured and Automatic SG Liquid Blowdown to IRWST



4.3.11 Automatic Initiation of the Atmospheric Dump Valves

For this design change, the atmospheric dump valves (ADVs) are assumed to be actuated on a high steam generator pressure setpoint. This setpoint value is chosen such that the ADVs open prior to challenges to the MSSV and later than the steam bypass valve actuation. The assumed benefit is that the ADVs open and relieve mass and energy to control the SG pressure and level thereby preventing the opening of the MSSVs. Although the ADVs relieve steam to the atmosphere, such a release is preferred over MSSV releases since the ADVs can be isolated by means of the associated block valves.

Analyses were performed to determine the RCS and secondary side performance with automatic actuation of the ADVs. The ADV opening setpoint was fixed at 1160 psia. This value is higher than the steam bypass valve setpoint of 1078 psia and lower than the opening setpoint of the first bank of the MSSVs of 1200 psia. For the one tube rupture case the ADVs are not expected to be actuated since the SG pressure remains below the ADV opening setpoint for longer than 10000 seconds. This is due to the actuation of the steam bypass valves which maintains the SG pressure at or below 1078 psia.

For the five tubes rupture base case (case 2), the steam bypass actuation maintains the SG pressure at or below 1078 psia. However, the bypass flow cannot keep up with the large break flow and the damaged SG level builds up. As seen in Figure 4.3.1-8, this level build-up initiates an MSIS. Subsequently the SG pressure builds-up to the opening setpoint of the ADVs. The five tube rupture case with automatic opening of the ADVs at 1160 psia is designated case 15. The results of the analysis of this case are shown in Figures 4.3.11-1 through 4.3.11-5. The sequence of major events occurring during the transient are listed in Table 4.3.11-1.

As seen from Figure 4.3.11-3, the damaged steam generator level increases very rapidly and an MSIS on high SG level is obtained at about 1590 seconds. The ADVs are not actuated till a later time since the SG pressure has to increase to about 1160 psia for this to occur. The steam generator continues to fill-up even after the ADVs open since the break flow is significantly greater than the ADV flow that is required to maintain the SG pressure at or below 1160 psia. In fact, the break flow is slightly higher than that for case 2 (base case) since the opening of the ADV causes a reduction in the SG pressure.

The main benefit from automatic actuation of the ADVs is that unisolable releases from a stuck open MSSV can be prevented. As seen from Figure 4.3.11-1, subsequent to initial actuation of the ADVs, the ADVs close, and then as the SG pressure builds up in the

absence of the steam bypass, the ADVs open again. This behavior will repeat in time as the ADVs cycle open and close to remove SG fluid and control SG pressure.

In the unlikely event an ADV sticks open, the ADV can be manually isolated by using the associated block valve.

One of the major limitations of this case is the potential for two phase and water release through the ADVs for the five tube rupture case. Prior to ADV actuation the damaged steam generator level builds up to the main steam isolation signal setpoint resulting in the closure of the steam bypass. Subsequently the steam generator pressure builds up and the ADVs are opened. Thus at the time of ADV opening, the damaged SG level is beyond the high steam generator level setpoint for the generation of an MSIS. The ADV opening is controlled by the steam generator pressure. Since the ADV opens only to control this pressure, with a five tube rupture the steam generator level can build up rapidly. This could result in build up of the level to the steam generator nozzles, and eventaully flooding of the steam lines with two phase and liquid potentially discharging a two phase mixture to the atmosphere. The ADVs are not currently qualified to pass two phase or liquid, and hence this must be addressed. In addition, release of two phase or water could result in significantly more adverse radiological consequences.

TABLE 4.3.11-1

SEQUENCE OF EVENTS FOR CASE 15
STEAM GENERATOR TUBE RUPTURE (FIVE TUBES) WITH AUTOMATIC ADV OPENING AT HIGH SG PRESSURE

TIME (Sec)	EVENT	SETPOINT
0.0	Tube Rupture Occurs	---
130	Pressurizer Backup Heaters Actuated on Low Pressurizer Pressure, psia	2200
149	Reactor Trips on Hot Leg Saturation Trip Signal	---
150	Turbine Trips	---
152	Steam Bypass System Actuated on High Steam Generator Pressure, psia	1078
165	Pressurizer Pressure Reaches Safety Injection Actuation Signal (SIAS) Setpoint, psia	1835
166	Main Feedwater Terminated on Low T_{avg}	---
1590	Main Steam Isolation Signal (MSIS) Generated on High Level in the Damaged Steam Generator, % wide range level	98
1700	Automatic Atmospheric Dump Valves (ADVs) on Damaged Steam Generator Actuated on High Steam Generator Pressure, psia	1160

FIG. 4.3.11-1 RCS and SG Pressures vs. Time
Case 15 for 5 Tubes Ruptured and Automatic ADVs

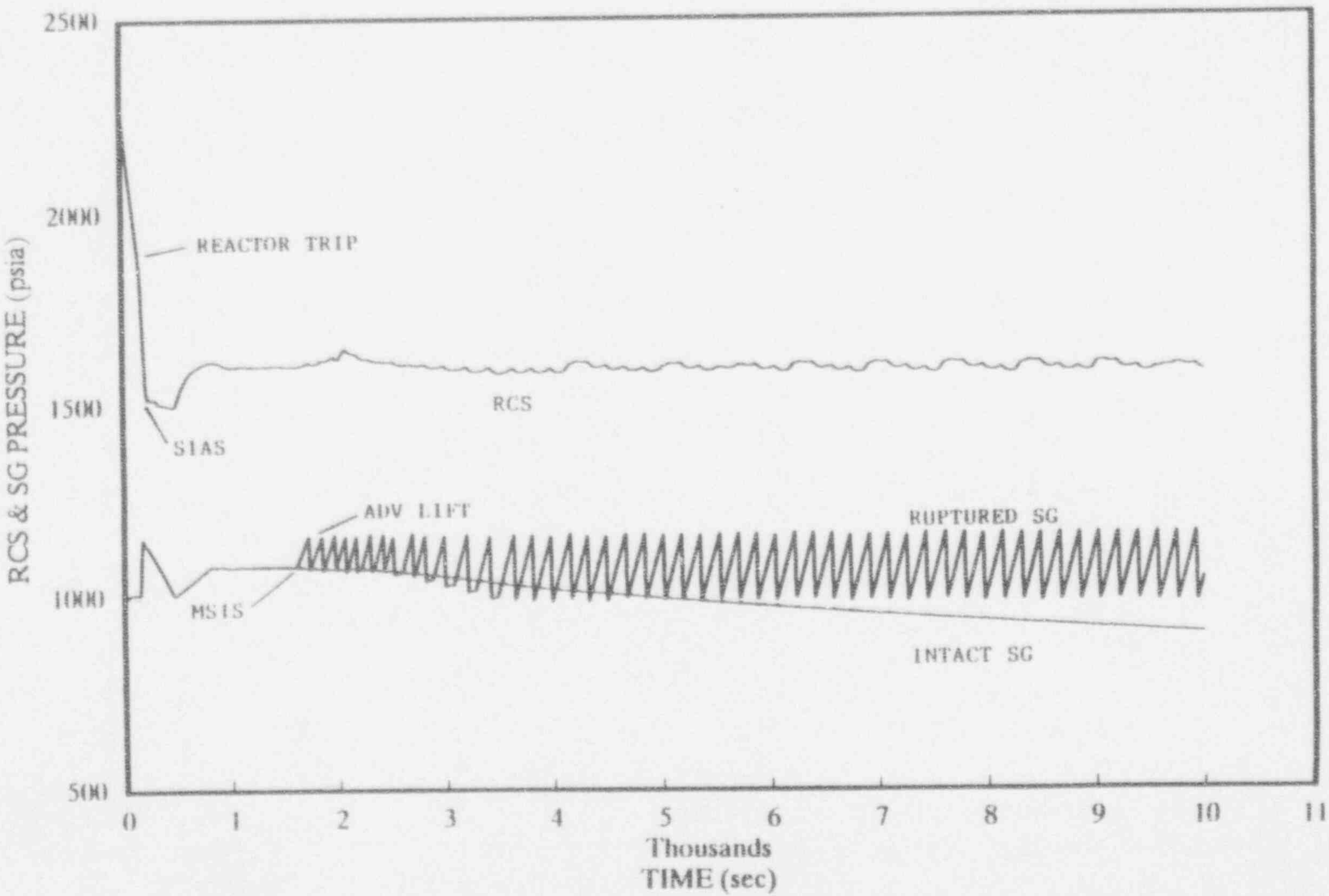


FIG. 4.3.11-2 Leak, HPSI and Bypass Flow Rates vs. Time
Case 15 for 5 Tubes Ruptured and Automatic ADVs

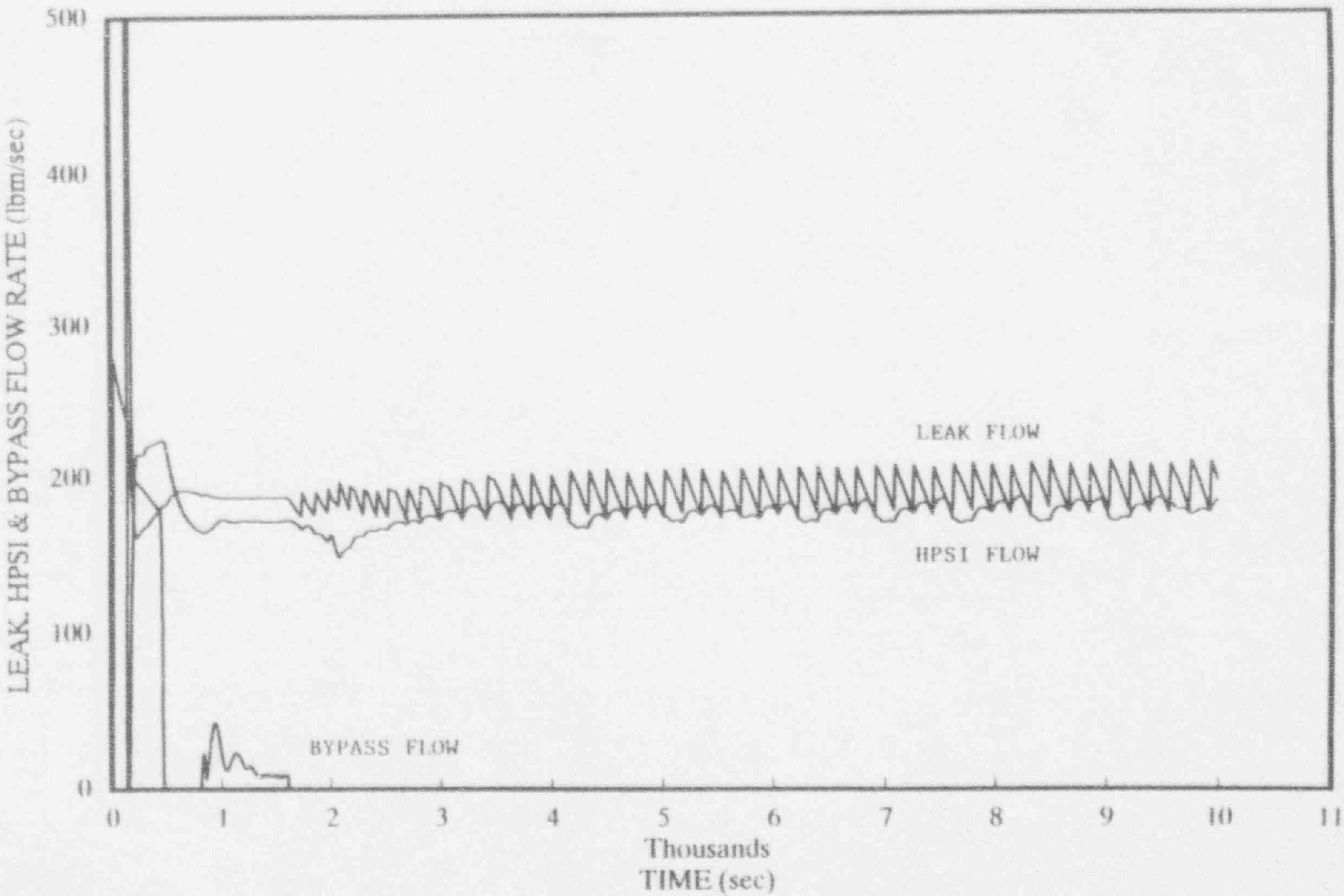


FIG. 4.3.11-3 Steam Generator Level vs. Time
Case 15 for 5 Tubes Ruptured and Automatic ADVs

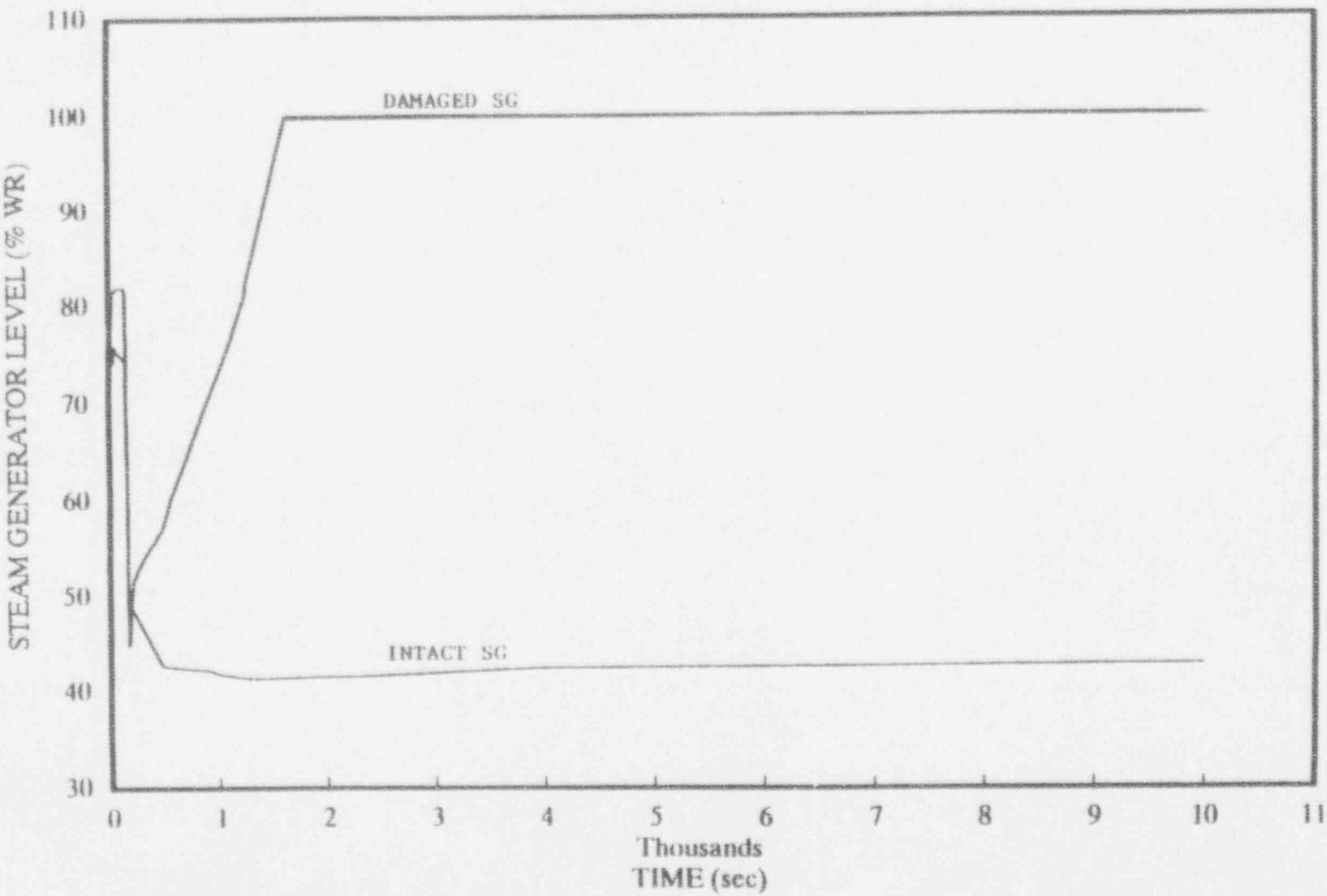


FIG. 4.3.11-4 Pressurizer Level vs. Time

Case 15 for 5 Tubes Ruptured and Automatic ADVs

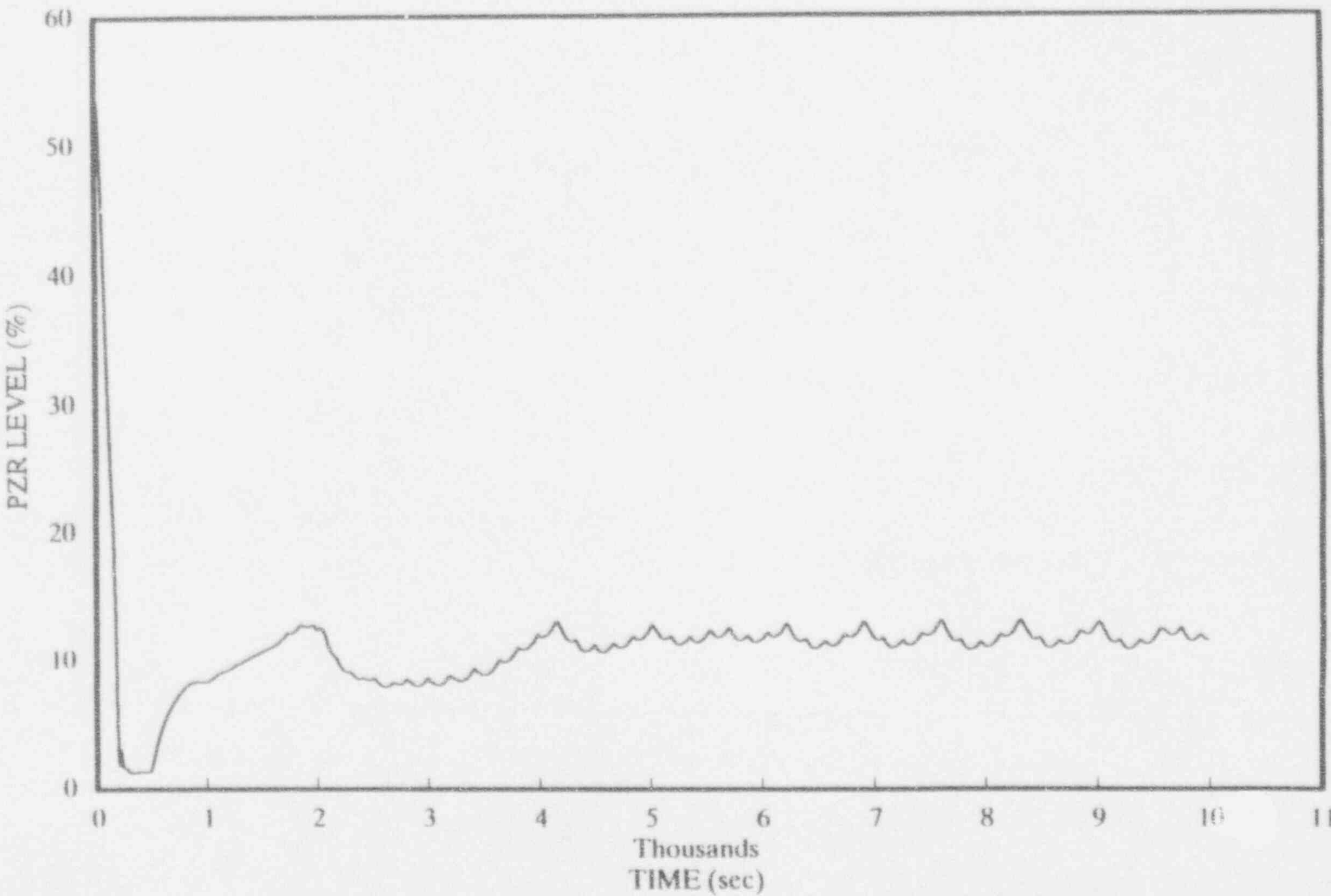
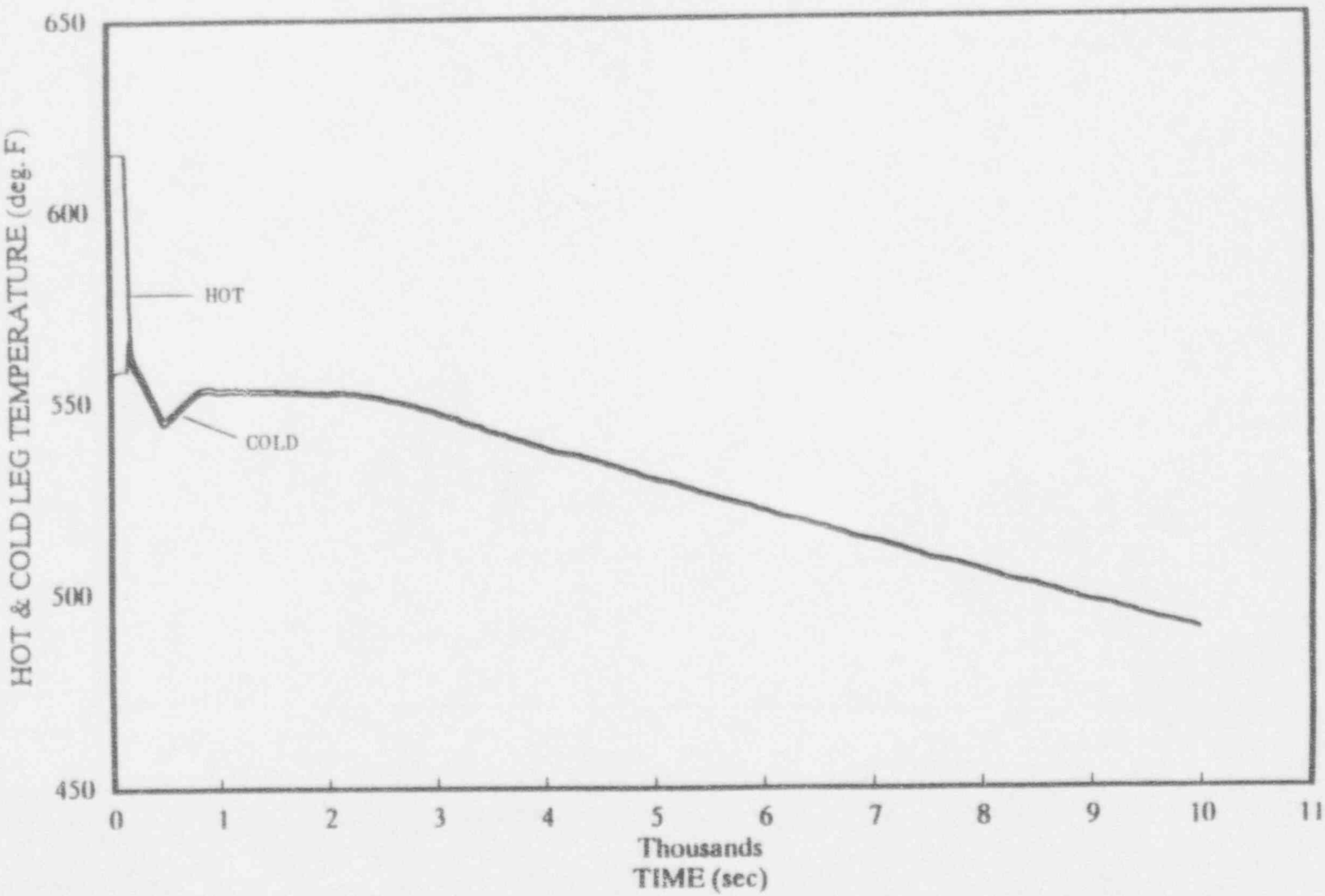


FIG. 4.3.11-5 Hot and Cold Leg Temperatures vs. Time

Case 15 for 5 Tubes Ruptured and Automatic ADVs



4.3.12 Natural Convection Cooling System for Steam Generator Secondary

A qualitative evaluation was performed to assess the benefit of this design change relative to the base cases, cases 1 and 2. The major difference between this design change and the base cases is that, in addition to steam relief throught he steam bypass valves, steam is also removed from the damaged steam generator via the natural convection pathway into the suppression pool. Although this would remove some of the secondary system energy via the suppression pool, the resulting reduction in the steam pressure could close the steam bypass valves (or close the valves sooner) thereby preventing the removal of some of the break flow from the steam generator. Since the steam released from the damaged steam generator (SG) via the suppression pool is condensed and returned to the SG the closure of the bypass valves hastens the damaged steam generator level buildup. This could result in an earlier SG overfill and the generation of an MSIS. Therefore, even with the cooling through the suppression pool the SG pressure will buildup and result in the opening of the MSSVs and subsequent flooding of the steam lines with two phase and/or water.

Thus, for the one tube rupture event with this design change, the damaged steam generator level is expected to build up more rapidly than that for the base case (case 1) and challenge the MSSVs sooner. For the five tubes ruptured case, this design change would hasten the MSSV lift in comparison to the base case (case 2), since the bypass system may be closed sooner causing an earlier MSIS generation. Therefore, the proposed design change does not result in any benefit in terms of containment bypass prevention during an SGTR event.

5.0 SYSTEM 80+ SYSTEM DESCRIPTIONS

5.1 Steam Generators

5.1.1 Description

The two System 80+ steam generators provide the heat removal function of the RCS. The primary side of each steam generator consists of approximately 12,600 3/4 " tubes which provide a large surface area for heat to transfer from the primary reactor coolant to the secondary feedwater. The steam produced by the primary side heat is transferred from the steam generators via the main steam system to the turbine generator which drives the electrical generator to produce electricity. When the reactor is operating at 100% power, the total steam flow produced by both steam generators is approximately 17.6×10^6 lbm/hr. Figure 5-1 presents a schematic of the steam generator including the nozzle penetrations. The primary side of the steam generator is designed to be safety class 1 and the secondary side is designed to be safety class 2. The total secondary volume of each steam generator is approximately 11280 ft^3. The secondary side of each steam generator is protected from overpressurization by 10 main steam safety valves (MSSVs). Each steam generator is equipped with 2 atmospheric dump valves (ADVs) which vent directly to atmosphere. A blowdown system is provided to help control secondary water chemistry and remove sludge buildup on the steam generator tube sheet. A sampling system is also provided to allow the capability of remotely monitoring secondary water chemistry.

5.1.2 Operation

A steam generator tube rupture incident is a penetration of the barrier between the reactor coolant system and the main steam system. The integrity of this barrier is significant from the standpoint of radiological safety in that a leaking steam generator tube allows the transfer of reactor coolant into the main steam system. Radioactivity contained in the reactor coolant would mix with the water in the shell side of the affected steam generator. This radioactivity will be transported by the steam through the turbine and then to the condenser, to atmosphere via the Main Steam Safety Valves/Atmospheric Dump Valves, or directly to the condenser via the Turbine Bypass System.

5.1.3 Steam Generator Instrumentation

Level instrumentation is provided on each steam generator to indicate the secondary water level. See Figure 5-2 for approximate locations of level instrument taps. Signal from the narrow range

level instruments are sent to the feedwater control system, which in turn controls the feedwater flow to the steam generators. In addition to controlling water level, the narrow range level signals are used for initiation of a Main Steam Isolation Signal (MSIS) which isolates the steam, feedwater, blowdown and sampling systems. Wide range level instruments are used as safety signals to actuate the emergency feedwater system in the event of a low water level and isolate potential leak path out of the steam generators. Pressure instrumentation performs a safety function, initiating a MSIS upon a low steam generator pressure.

5.2 Feedwater System

5.2.1 Description

The main feedwater system (MFWS) provides the secondary water to the steam generators which removes heat from the primary side. The MFW system consists of: three motor driven feedwater pumps which take feedwater from the condensate system and supply it to the steam generators; a feedwater control system (FWCS), which regulates the feedwater flow to the steam generators based on level inputs from the steam generator, receives flow inputs from the feedwater flow instrumentation, the steam flow instrumentation, and reactor power; the economizer and downcomer control valves which are modulated by the FWCS to adjust feedwater flow to the steam generators; and containment isolation valves which isolate the MFWS when a MSIS occurs on low steam generator pressure (≤ 850 psia) or high steam generator level (≥ 95%NR).

5.2.2 Operation

The feedwater system supplies feedwater to each steam generator through a downcomer nozzle and 2 economizer nozzles located on the steam generator (see Figure 5-3). During startup and shutdown, a motor driven startup pump is capable of providing 0-5% of full power feedwater flow to both steam generators through the downcomer nozzle. Startup and shutdown require manual operation for control of the feedwater. During operation between 5% and 20% power, the FWCS controls all the flow through the downcomer line keeping the economizer valves shut. For this range of power, the FWCS uses only the narrow range level instrumentation to control the feedwater flow. During operation between 20% and 100% power, the FWCS automatically controls flow to the steam generators by modulating the downcomer and economizer valves based on inputs from the steam generator level instrumentation, and the steam and feed flow instrumentation. In the event of a reactor trip, the FWCS will close the economizer flow control valve and regulate flow based on the average reactor coolant temperature and a preset 0% load feedwater setpoint using the downcomer feedwater control valve. If T_{avg} of the RCS is greater than the T_{avg} setpoint (approximately 557°F), the FWCS will send a signal to open the downcomer control valves to allow more flow to the steam generators. If T_{avg} is below the T_{avg} setpoint, the feedwater control valves will be closed which terminates main feedwater to that steam generator.

5.2.3 Instrumentation

Flow meters are provide on the economizer and downcomer feedwater lines to measure feedwater flow rate. The economizer flow meter

signal is directly input into the FWCS to control feedwater flow. Temperature indication is also provided on the feedwater lines These instruments perform no safety function.

5.3 Main Steam System

5.3.1 Description

The main steam system (MSS), which is shown schematically in Figure 5-4, consists of 28" ID piping which carries the steam from the steam generators to the turbine generator. Four safety grade Atmospheric Dump Valves (two per generator) are located off of the main steam lines and are vented to atmosphere. Isolation valves are provided upstream of the ADVs in the event of an inadvertent opening. These valves are used by the operator to dump steam during plant startup, cooldown or during transients. Ten Main Steam Safety Valves per generator are connected to the main steam lines upstream of the Main Steam Isolation Valves and are vented directly to atmosphere. These valves provide overpressure protection for the steam generators and the main steam piping. Four Main Steam Isolation valves (one per steam line) are provide which isolate the steam generator upon receipt of a MSIS (see figure for a general schematic). Also included in the MSS are Main Steam Isolation Bypass Valves. These valves are manually operated during heat up of the plant to warm the secondary system. They are closed during normal operation. (See Table 5-1.)

5.3.2 Operation

During normal operation the MSS carries the steam produced by the steam generators to the turbine generator to produce electricity. In the event of high steam generator level or low steam generator pressure an MSIS is generated which closes the main steam isolation valves. The operator is then required to use the ADVs to relieve steam to atmosphere or the MSSVs set point will be reached on high pressure and the MSSVs will actuate.

5.3.3 Instrumentation

Flow meters are provided at the outlet of the steam generators to measure steam flow rate. The meter signals are directly input into the FWCS to control feedwater flow. These instruments perform no safety function. The main steam header pressure is also monitored and used as input to the Steam Bypass Control System. The pressure indication is also non-safety grade.

5.4 Blowdown System

5.4.1 Description

Each steam generator is equipped with its own blowdown line with the capability of blowing down liquid from the hot leg or the economizer regions of the steam generator shell side. The blowdown piping is attached to two six inch blowdown nozzles in the tube sheet region of each SG and is routed outside containment to a blowdown processing system (see Figure 5-5). Containment isolation valves are provided in the blowdown lines which isolate upon receiving a Containment Isolation Signal (CIAS), an Emergency Feedwater Actuation Signal (EFAS), an Alternate Feedwater Actuation Signal (AFAS), or a MSIS. Three manual blowdown control valves located outside containment allow the operator to adjust the liquid blowdown rate. The blowdown piping is vented directly to a flash tank or the condenser.

5.4.2 Operation

During normal full power operation there is a continuous blowdown of either 0.2 or 1% of the main steam rate (MSR) per generator depending on water chemistry. The system is also designed for a high capacity blowdown (approximately 10% MSR) to remove crud buildup on the steam generator tube sheet.. High capacity blowdown can be operated for a short period of time (2 minutes) when the effluent is directed to the blowdown flash tank and for an indefinite period of time to the condenser. The blowdown system is isolated by a MSIS, a CIAS, a SIAS, and an EFAS to prevent loss of steam generator inventory in the event a transient occurs. This system provides no safety function except to isolate upon receipt of a safety signal.

5.4.3 Instrumentation

Sampling lines off of the blowdown nozzles continuously sample steam generator blowdown for radioactivity which would be indicative of a steam generator tube leak. Samples from each of the steam generator are monitored individually by a detector mounted in a shielded liquid sampler.

5.5 Turbine Bypass System

5.5.1 Description

The non safety grade Turbine Bypass System (TBS), schematically shown in Figure 5-4, consists primarily of eight turbine bypass valves and the Steam Bypass Control System (SBCS). The TBS is provided to accommodate load rejection in conjunction with the Reactor Power Cutback System without tripping the reactor or lifting the primary safety valves or the MSSVs. All eight turbine bypass valves are located in two lines branching off of the main steam header downstream of the MSIVs and are routed to the condenser. The turbine bypass valves are air operated valves with a combined capacity of 55% of the total full power steam flow at normal full power operation. These valves are normally controlled by the SBCS, but can be remote manually controlled. These valves are also designed to fail closed. The SBCS used reactor power, steam header pressure and steam flow to actuate the valves to dump steam to the condenser.

5.5.2 Operation

The turbine bypass system takes steam from the main steam header upstream of the turbine stop valves and discharges it directly to the main condenser, bypassing the turbine generator. During normal operation, the valves are under the control of the steam bypass control system. In the event of a reactor trip or a turbine trip, the SBCS provides either an open signal or a modulation signal to the TBS valve controllers, based on steam flow, pressurizer pressure and main steam header pressure. During cooldown or hot shutdown, the turbine bypass valves may be actuated individually from the main control room to regulate steam generator pressure and RCS temperature change.

5.5.3 Instrumentation

Pressurizer level, steam flow and steam pressure instrumentation are all inputs used in the SBCS to regulate the turbine bypass system. The turbine bypass system does not include any instrumentation for monitoring flow, pressure, temperature, or radiation.

5.6 **Radiation Monitoring**

5.6.1 Description of Current Radiation Detection Monitors

The System 80+ design is equipped with a Radiation Monitoring System (RMS) to assist plant operators in evaluating and controlling the radiological consequences of a potential equipment failure. The RMS consists of process and airborne radiation monitors. The process and effluent monitors typically consist of components such as a microprocessor, one or more detectors, a shielded detection chamber, sample pump flow instrumentation, and associated tubing and cabling. The area radiation monitors consist of a microprocessors and Geiger-Mueller tubes or ionization chambers for gamma radiation detection. Each process and effluent, and airborne monitor is located in an easily accessible area. Radiation level signals, high level alarms, and operation status alarms are generated by each microprocessor for local alarm capability and for transmittal to the Data Processing System (DPS) and the Discrete Indication and Alarm System (DIAS). Via the DPS and the DIAS, control room operators can obtain detailed information on monitor readings, alarm setpoints, and operating status.

Both types of radiation monitors are used in the secondary systems. The main steam lines are continuously monitored using area radiation monitors placed near the steam piping upstream of the MSSVs. These monitors alarm in the control room and are provided with non 1-E power. An off-line monitor samples the steam generator blowdown liquid. Sample lines upstream of the blowdown isolation valves carry effluent to the sampling room where it is continuously monitored for radiation. These monitors are provided with local alarms in the sampling room and also alarm in the control room via the DPS and DIAS. The blowdown radiation monitors are provided with non-1E power. This monitor uses a gamma scintillation detection system. The main condenser evacuation system is provided with an on-line monitor which continuously analyzes the gaseous effluent from the condenser vacuum pump discharge. A sample tap is also provided to allow the collection of periodic grab samples. This monitor is alarmed in the control room and is non-1E. This monitor uses a beta scintillation detection system.

5.6.2 Description of Added N-16 Radiation Monitors

Nitrogen-16 is formed in the primary reactor coolant when the fluid passes through the core region of the reactor vessel by a neutron, proton interaction with Oxygen-16. It has a half life of approximately 7 seconds. N-16 is essentially non-existent outside of nuclear reactors, which means the N-16 background levels outside the RCS are very low. Therefore, detection of the high energy N-16

gamma radiation in the secondary side of a PWR steam generator is a definite indicator of a primary to secondary leak. Unfortunately, because of the 7 second half life, large amounts of N-16 must be produced in the core in order to be detected in the secondary system. Current monitoring devices will only detect N-16 when the reactor power level is ≥ 25%. Currently N-16 monitors planned for the System 80+ design are powered with non-1E electrical power.

At power levels below 25%, the current monitors are used. They include steam line area, condenser vacuum exhaust and blowdown. Latching of these signals will be considered along with the N-16 latched signal described below.

The N-16 radiation monitors to be incorporated into the System 80+ design are scintillation detectors with microprocessor based signal conditioning. A detector would be installed outside of containment on one steam line leaving each steam generator. In the event of a tube rupture, the alarm will initiate and then may clear as reactor power decays due to the reactor trip. Therefore, when a N-16 radiation monitor detects the high gamma radiation condition, the alarm will be latched. Acknowledging the alarm does not reset the latch, the alarm latch must be reset separately by the operator. This logic is presented by Figure 5-6. In addition to alarming, the signal generated by the N-16 monitor would be utilized in coincidence with another signal to initiate some automatic function(s) to mitigate the consequences of a tube rupture event.

5.7 **Reactor Coolant Gas Vent System**

5.7.1 Description

The System 80+ design includes a safety grade reactor coolant gas vent system used to vent non-condensible gases and steam from the reactor vessel upper head and the pressurizer steam space. The system is comprised to two independent piping trains, one from the reactor vessel and one from the pressurizer each with parallel valve paths in each train allowing for single failure operation. The parallel path from the pressurizer and the reactor vessel upper head contains two isolation valves in series. The pipe trains are routed to the IRWST and the RDT. The valves are remote manually controlled.

5.7.2 Operation

The RCGVS is designed to be operable during all design basis events. In the event a void forms in either the reactor vessel upper head, the RCGBS may be used to depressurize the RCS and remove the void in the upper head In the pressurizer, if pressurizer spray is not available, the operator manually opens the RCGVS valves to vent steam and depressurize the reactor coolant system.

5.7.3 Instrumentation

Pressure indication is provided between the isolation valves in each RCGVS train which alarms and provides the operator with indication that a valve did not reseat or the valve leaks. Temperature indication is provided downstream of RCGVS isolation valves to monitor leakage from the reactor coolant pressure boundary.

5.8 RAPID DEPRESSURIZATION SYSTEM

5.8.1 Description

The rapid depressurization system (RDS) is provided in the system 80+ design to mitigate the consequences of the beyond design basis event of a total loss of feedwater. Two independent pipe trains off of the pressurizer steam space provide a means to rapidly depressurize the RCS. Each train has an isolation valve and a control valve to provide single failure proof operation. Both RDS trains are routed to the IRWST.

5.8.2 Operation

The RDS is designed as a safety grade system to be employed in the event of a total loss of feedwater. Once the operator diagnoses the event, he manually opens the RDS isolation and control valves to depressurize the RCS and initiate safety injection flow to the RCS (feed flow). The RDS removes energy from the RCS and the feed flow prevents core uncovery. With the RDS valves open, the RCS will depressurize until the safety injection actuation pressure is reached. At this point safety injection flow will be provided to the RCS to make up for the inventory being removed by the RDS.

5.8.3 Instrumentation

Pressure indication is provided between the isolation valves in each RDS train which alarms and provides the operator with indication that a valve did not reseat or that the valve leaks. Temperature indication is provided downstream of RDS isolation valves to monitor leakage from the reactor coolant pressure boundary.

5.9 PRESSURIZER AUXILIARY SPRAY SYSTEM

5.9.1 Description

The Auxiliary Pressurizer Spray (APS) system is a non safety grade system which is employed to depressurize the RCS in the event that main pressurizer spray is unavailable. Auxiliary spray is part of the chemical volume and control system for the System 80+ design. The charging pumps provide makeup water to the auxiliary spray system. The APS design consists of a pipe train teeing off of the charging line with a manual isolation valve which is normally closed.

5.9.2 Operation

In the event that main pressurizer spray is unavailable and the RCS requires depressurization, the operator manually opens the APS isolation valve to allow makeup water from the CVCS to depressurize the RCS. The operator has the capability to modulate the isolation valve to control the APS flow entering the pressurizer.

5.9.3 Instrumentation

The operator uses the pressurizer pressure and level indications along with APS valve position indication, pump performance and charging line flow indication.

TABLE 5-1

SYSTEM 80+ SECONDARY SYSTEM VALVES

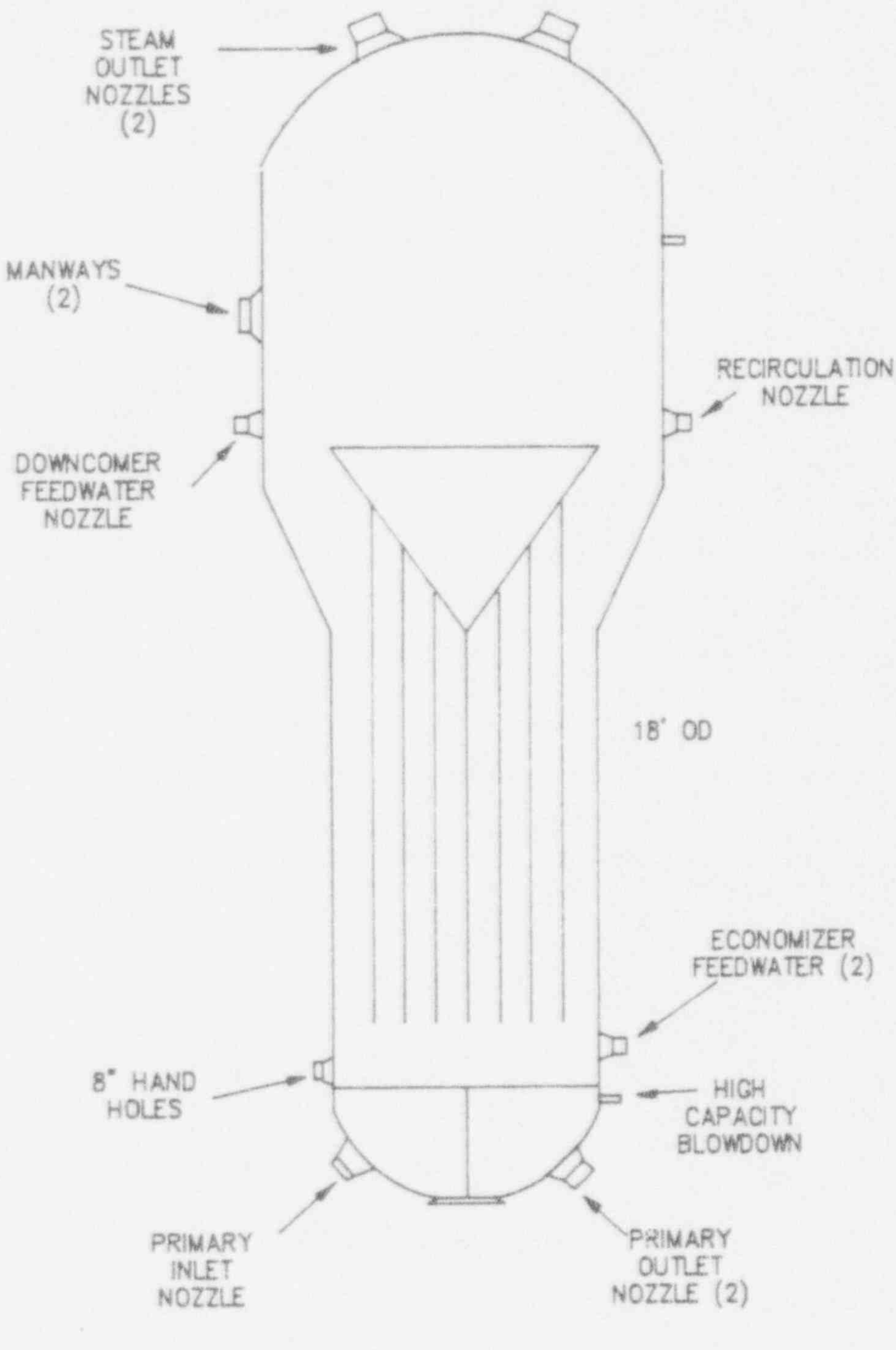
TITLE	NO VALVES PER SG	VALVE TYPE	OPERATOR TYPE	SAFETY CLASS	VALVE SAFETY FUNCTION	AUTOMATIC ACTUATION ON	MANUAL CONTROL
Main Steam [1] Isolation Valves	2	Globe	Pneumatic	2	To close	MSIS	Open/ Close
Main Steam Isol.[1] Bypass Valves	2	Gate	Pneumatic	2	To close	MSIS	Open/ Close
Main Steam Safety Valves	10	Safety	Self Actuated	2	To open	High SG Pressure	None
Atmospheric Dump Valves	2	Globe	Solenoid	2	To open	None	Throttle
Steam Bypass Control Valves	8 [2]	Globe	Pneumatic	4	None	High SG Pressure	Throttle
Blowdown & [1] Recirc. Valves	2	Gate	Motor	2	To close	EFAS, CIAS MSIS, AFAS	Open/ Close
Main Feedwater [1] Isolation Valves	4	Gate	Pneumatic	2	To close	MSIS	Open/ Close
Emergency Feed. Isolation Valves	4	Gate	Motor	2	To open on AFAS, EFAS To close on MSIS	EFAS, AFAS MSIS	Open/ Close
Emergency Feed. Steam Supply	1	Gate	Pneumatic	2	To open	EFAS, AFAS	Open/ Close
Sampling Sys.[1] Valves	4	Globe	Solenoid	2	To Close	EFAS, CIAS MSIS, AFAS	Open/ Close
Recirculation [1] Wet Layup Valves	1	Gate	Solenoid	2	Remain closed	None	Open/ Close
Nitrogen Sys. Valves	2	Globe	Manual	2	Remain closed	None	Open/ Close

1 designates containment isolation valves
2 8 valves total located on Main Steam Header

CIAS - Contaiment Isolation Actuation Signal (high containment pressure or low pressurizer pressure)
MSIS - Main Steam Isolation Signal (low steam generator pressure, or high steam generator level or high containment pressure)
AFAS - Alternate Emergency Feedwater Actuation Signal (low steam generator level)
EFAS - Emergency Feedwater Actuation Signal (low steam generator level)
Instrument Root Valves are not included

FIGURE 5-1

STEAM GENERATOR SCHEMATIC



NOTE: TOTAL SECONDARY VOLUME 11278 CU FT

FIGURE 5-2

STEAM GENERATOR
INSTRUMENT LOCATIONS

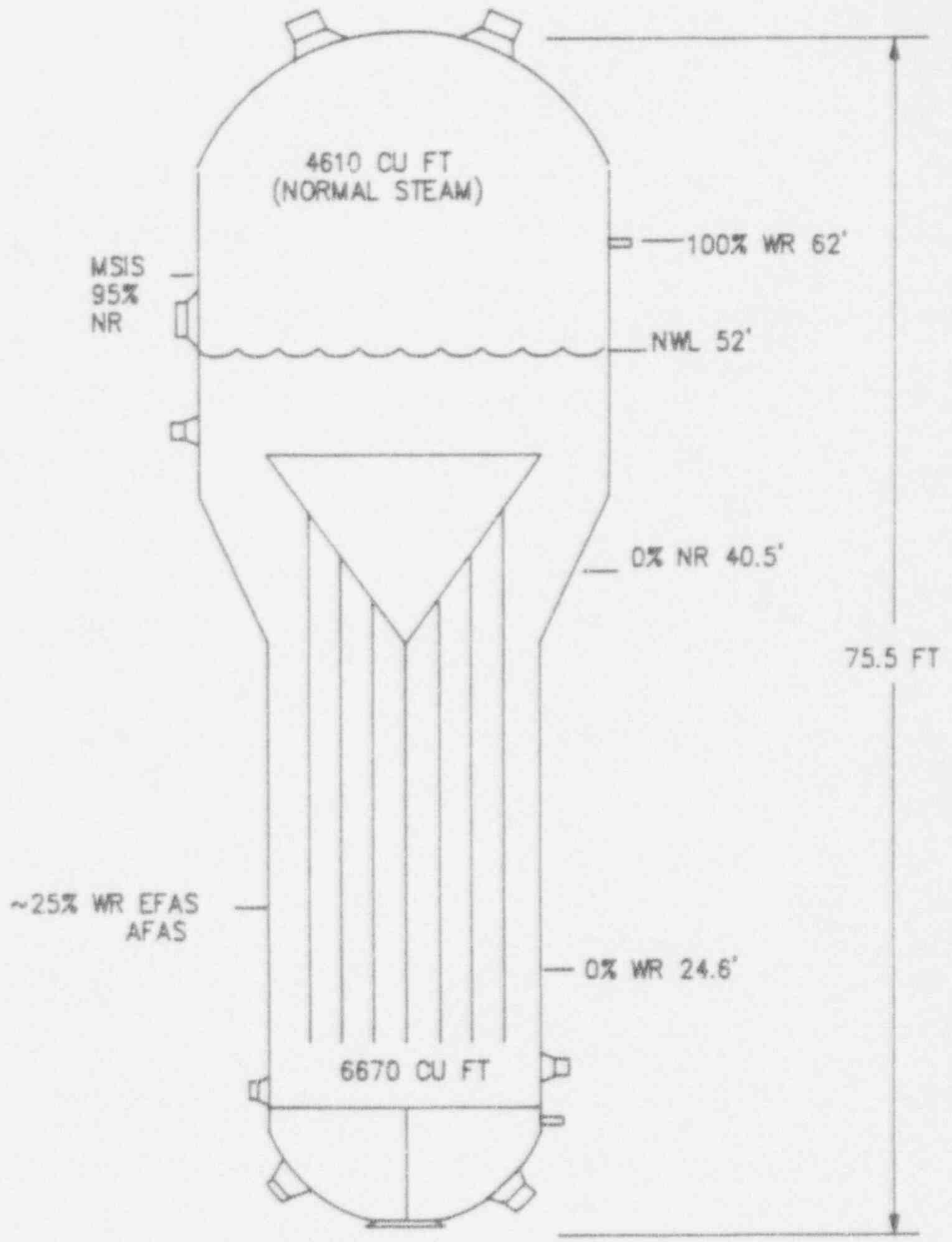


FIGURE 5-3

FEEDWATER SYSTEM SCHEMATIC

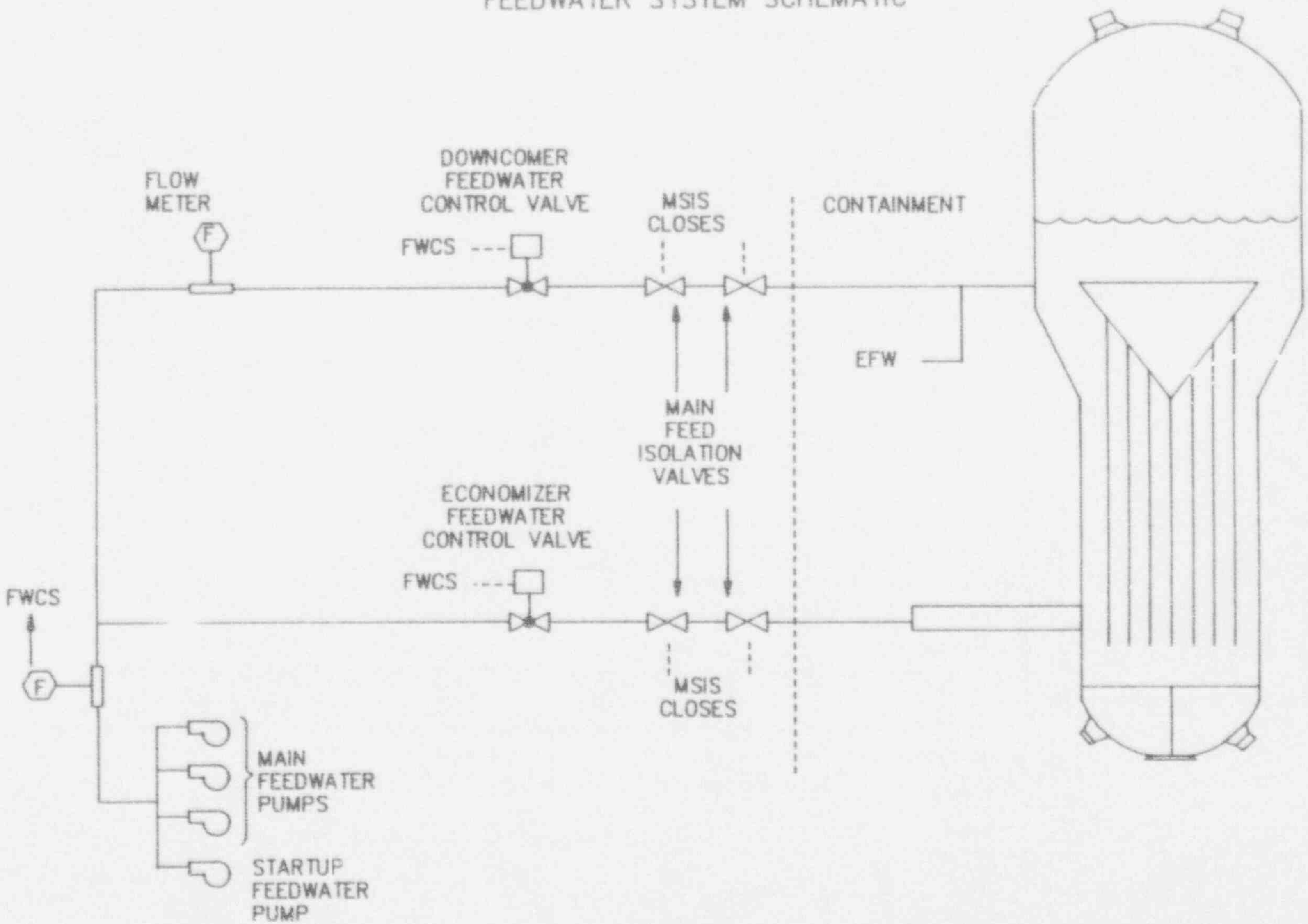


FIGURE 5-4

MAIN STEAM AND TURBINE BYPASS SYSTEMS

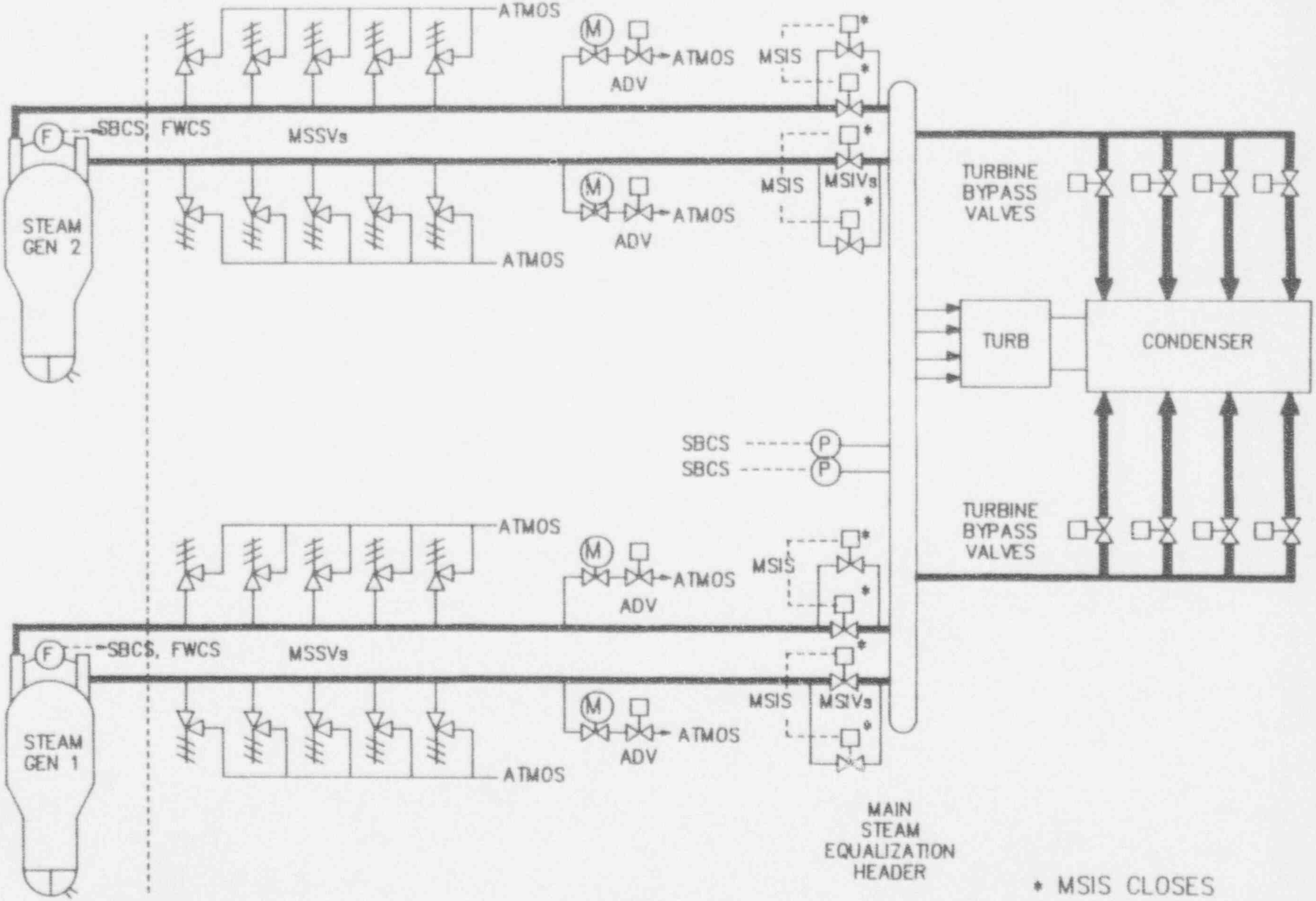


FIGURE 5-5

STEAM GENERATOR BLOWDOWN SYSTEM

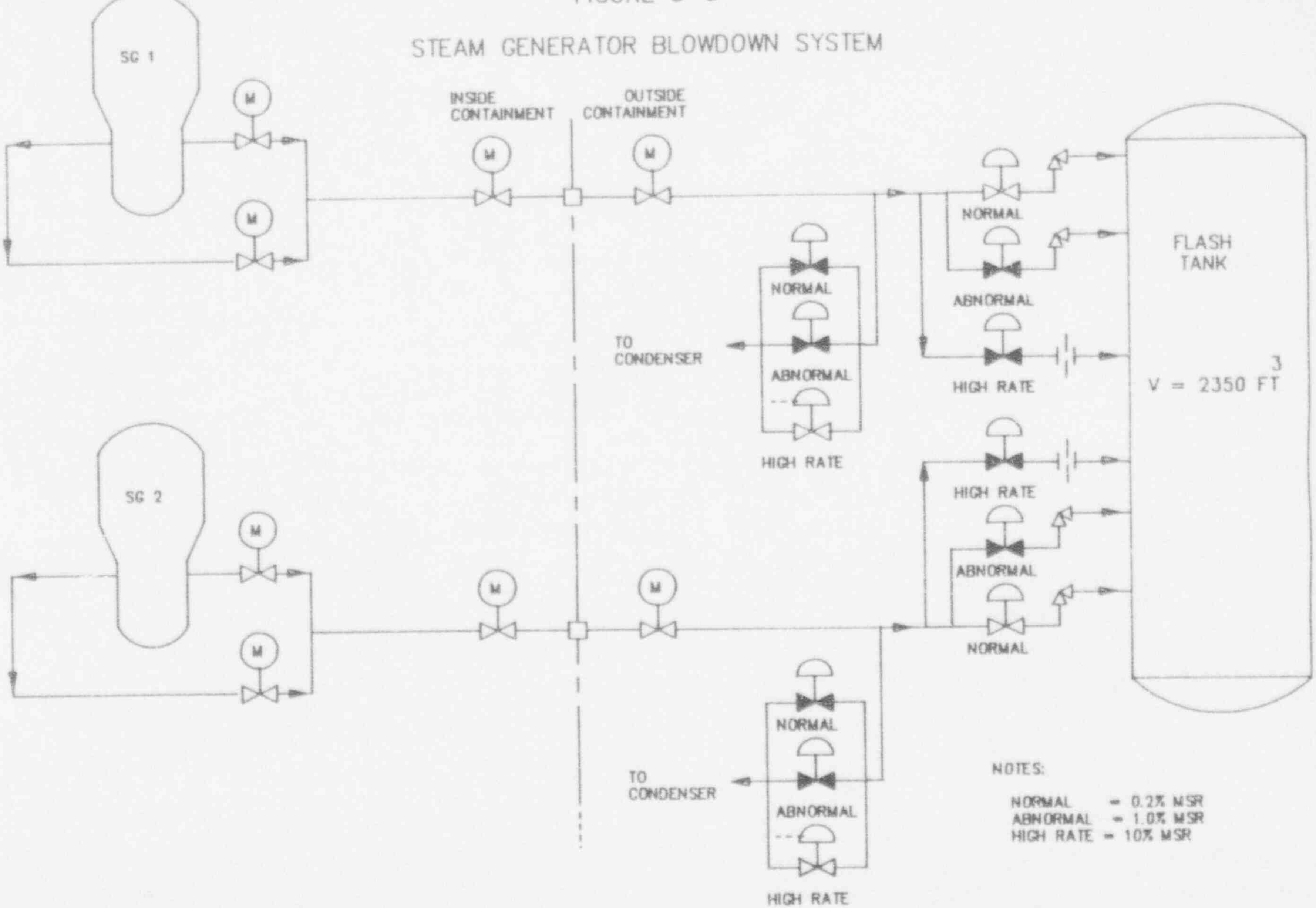
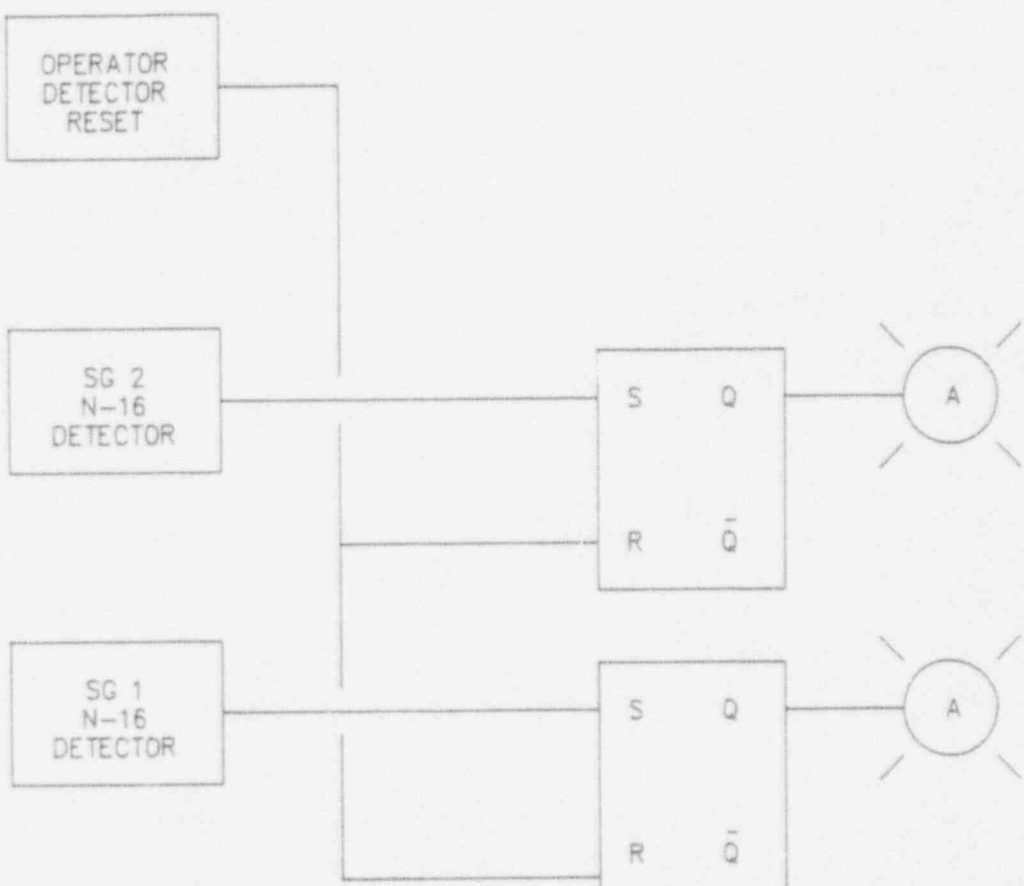


FIGURE 5-6

N-16 RADIATION MONITOR, DETECTION AND ALARM LOGIC



6.0 REFERENCES

6-1 Letter, D. M. Crutchfield (NRC) to R. A. Matzie (ABB), "CE System 80+ Protection Against Containment Bypass During A Steam Generator Tube Rupture (SGTR)," dated August 12, 1993.

6-2 Meetings between ABB and NRC on August 5, 1993, August 16, 1993, September 3, 1993 and September 16, 1993 concerning SGTR with containment bypass on the System 80+ design.

6-3 M. X. Franovich (NRC), "Public Meeting of September 16, 1993, To Discuss CE System 80+ Protection Against Containment Bypass During a Steam Generator Tube Rupture (SGTR)", minutes of meeting, dated September 23, 1993.

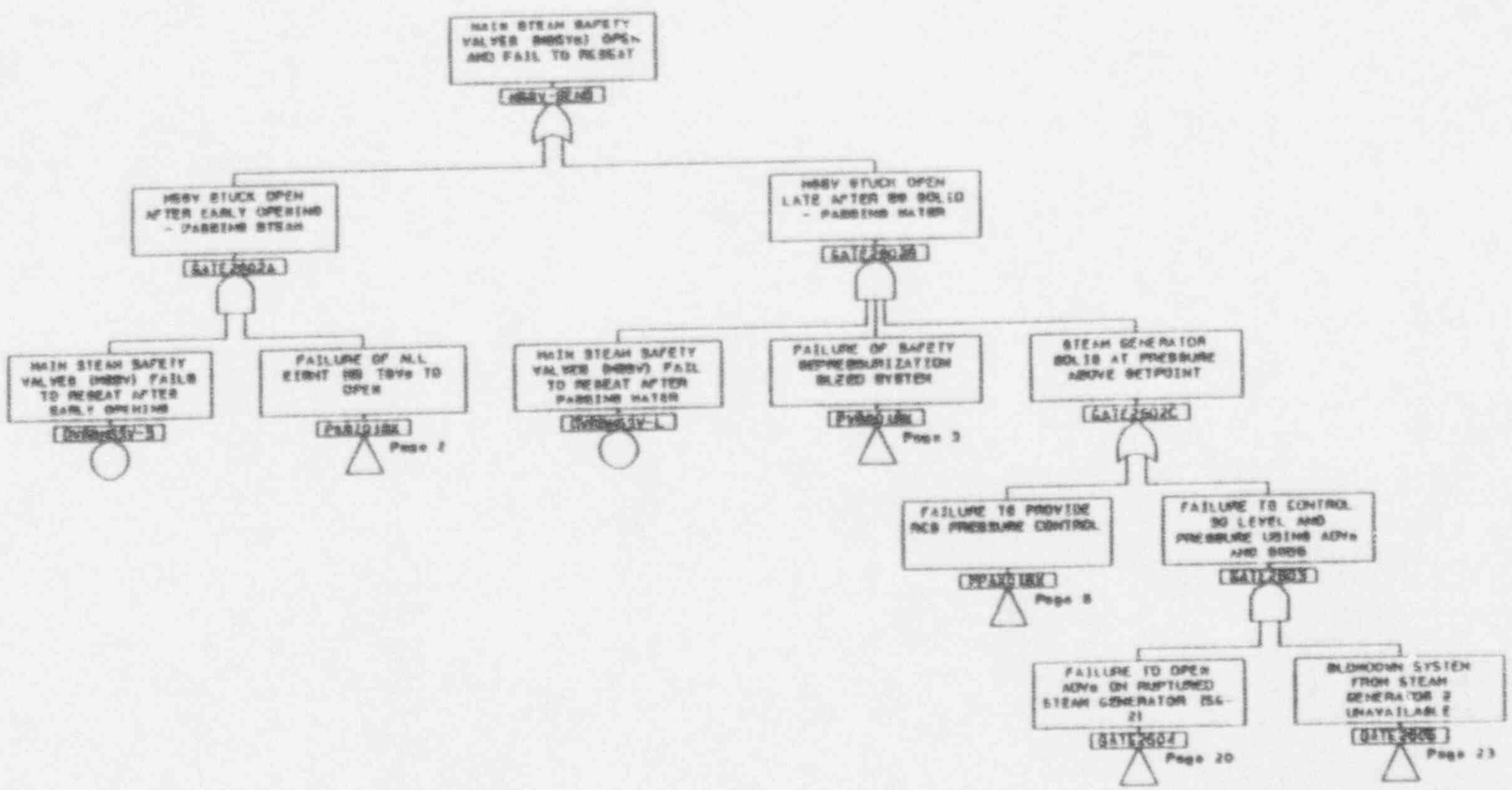
6-4 Letter, S. L. Magruder (NRC) to C. B. Brinkman (ABB), dated July 15, 1993, with attached report, "A Review of the Steam Generator Tube Rupture Procedure at the Borssele Nuclear Power Station," by G. Mayssier and L. Winters.

APPENDIX A

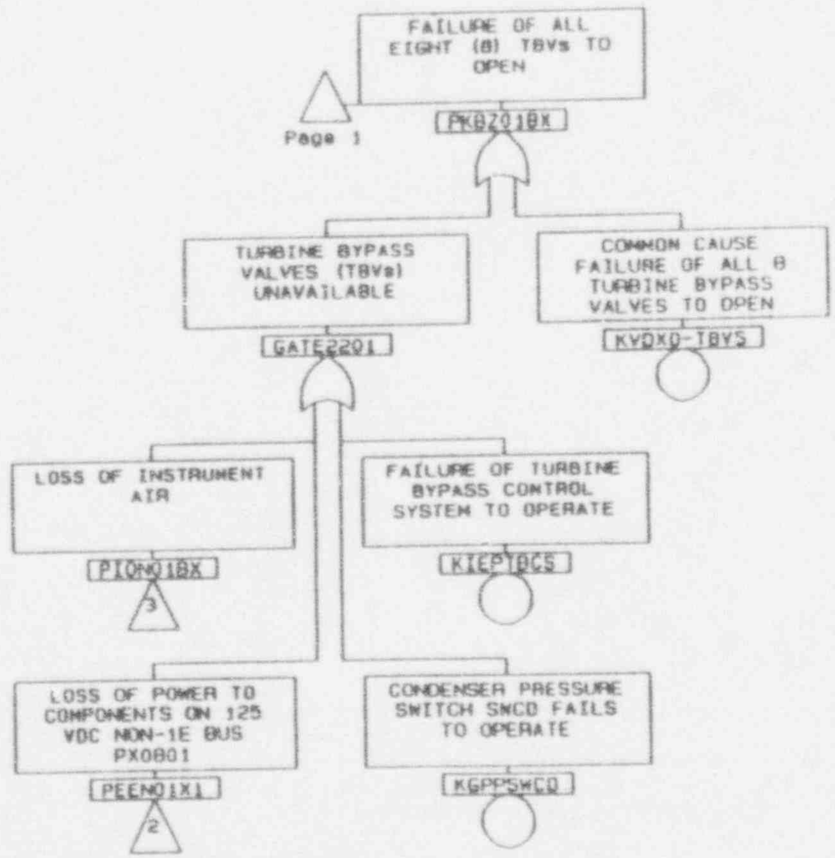
PRA METHODS AND RESULTS

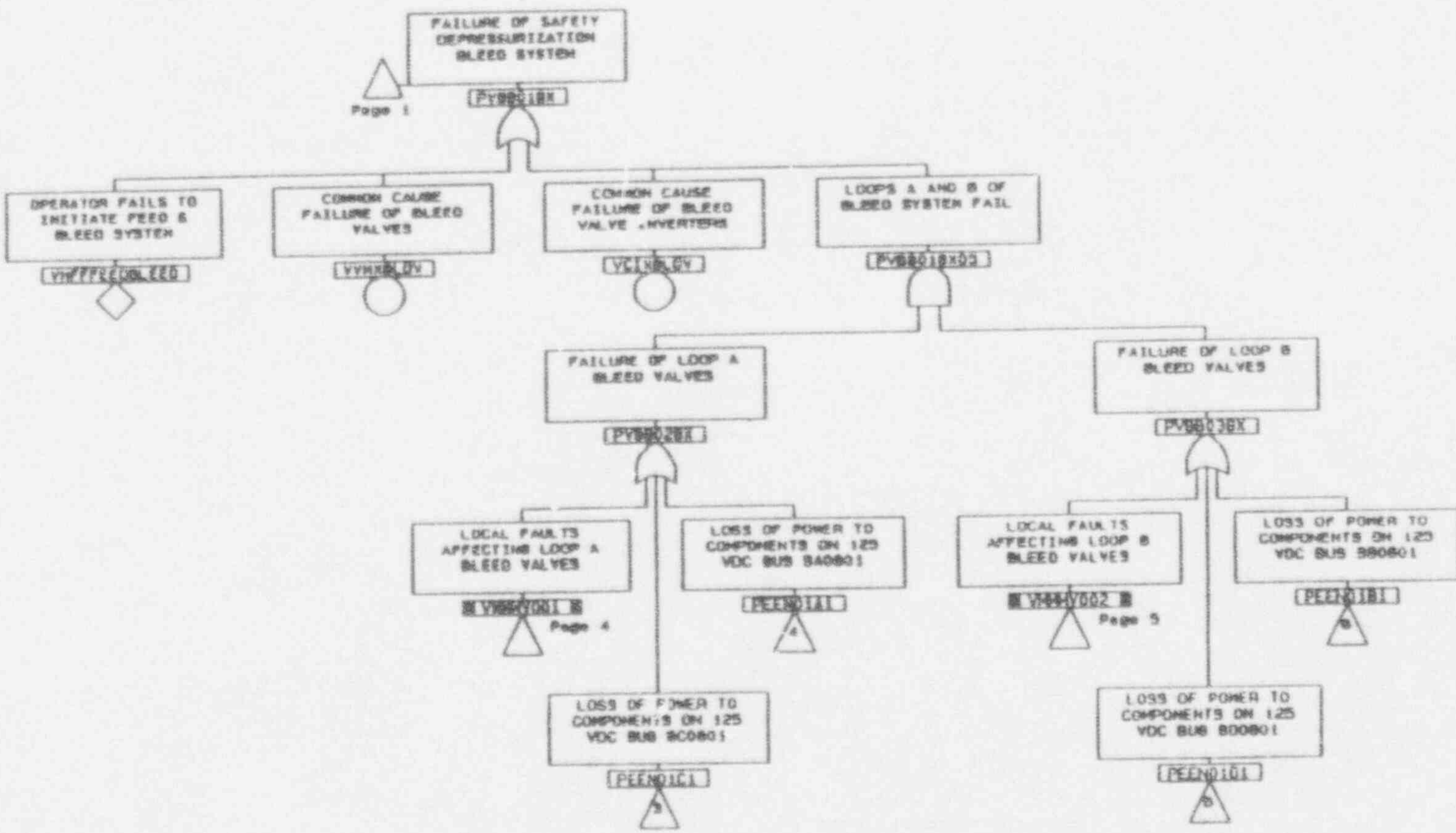
Fault Trees and Cutsets

These results provide the separate and cumulative conditional probabilities for a stuck open MSSV in the System 80+ design with various features that influence the SGTR event.



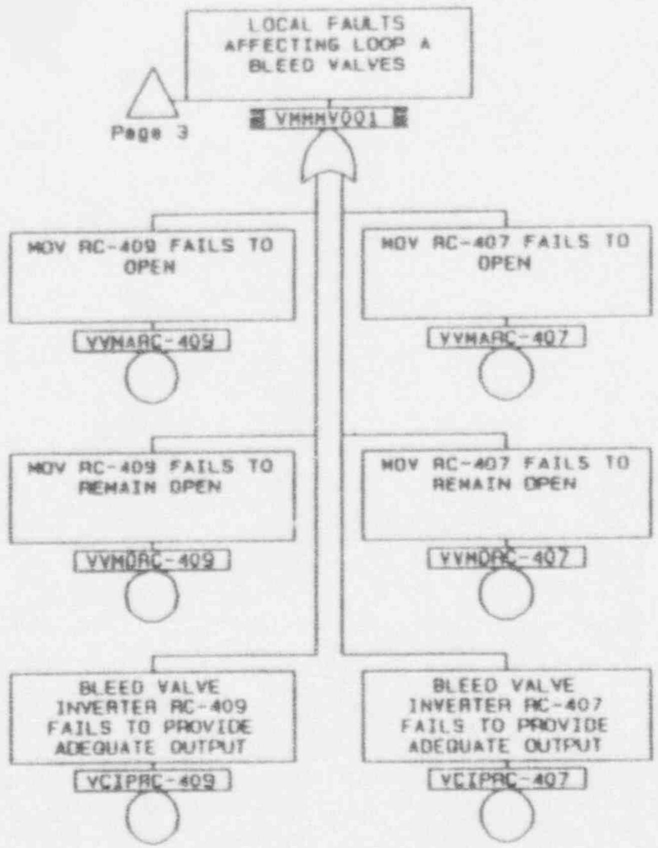
MSSV SENSITIVITY STUDY FOR RUPTURED SG	MSSV_SEN.CAF	Page 1

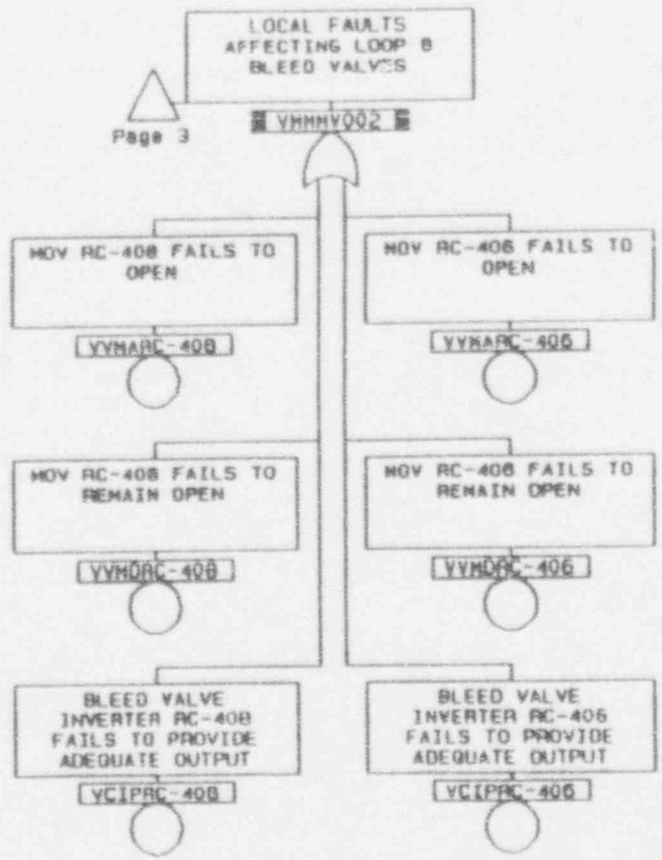

FAILURE OF ALL EIGHT (8) TBVs TO OPEN
Page 1
PKBZ01BX
TURBINE BYPASS VALVES (TBVs) UNAVAILABLE
GATE2201
COMMON CAUSE FAILURE OF ALL 8 TURBINE BYPASS VALVES TO OPEN
KVDXO-TBVS
LOSS OF INSTRUMENT AIR
PIQN01BX
3
FAILURE OF TURBINE BYPASS CONTROL SYSTEM TO OPERATE
KIEPTBCS
LOSS OF POWER TO COMPONENTS ON 125 VDC NON-1E BUS PX0801
PEEN01X1
2
CONDENSER PRESSURE SWITCH SWCD FAILS TO OPERATE
KGPPSWCD
1
2

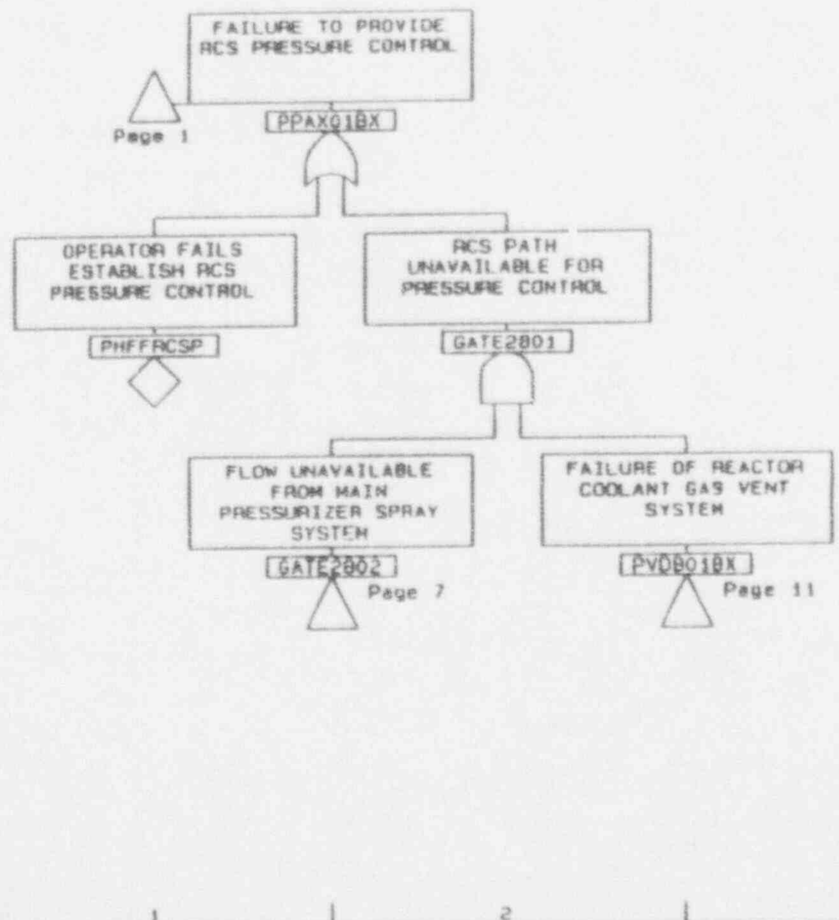


1 2 3 4 5

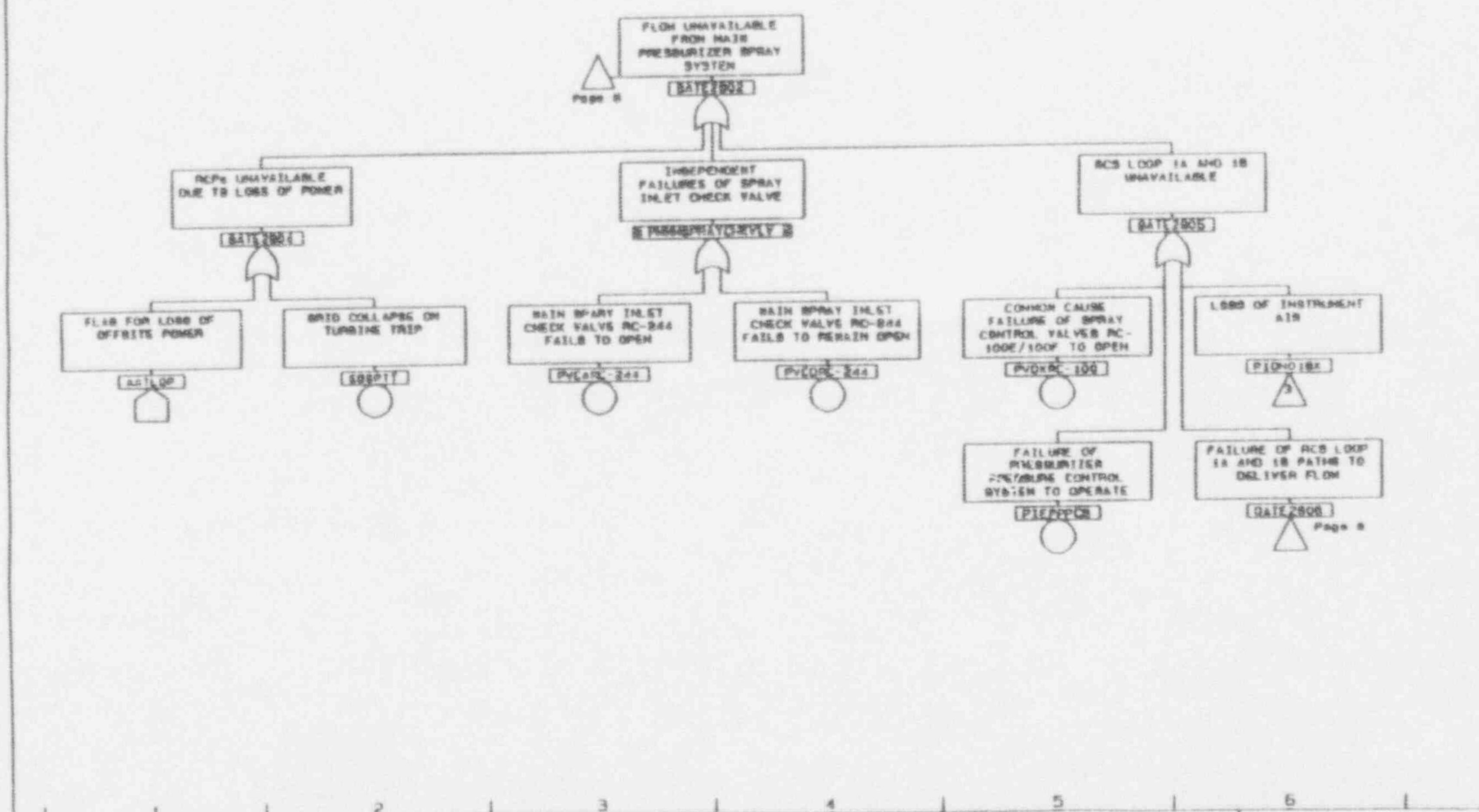
MSSV SENSITIVITY STUDY FOR RUPTURED SG | MSSV_SEN.CAF | Page 3


LOCAL FAULTS AFFECTING LOOP A BLEED VALVES
VMMMV001
Page 3
MOV RC-409 FAILS TO OPEN
VVMARC-409
MOV RC-407 FAILS TO OPEN
VVMARC-407
MOV RC-409 FAILS TO REMAIN OPEN
VVMDRC-409
MOV RC-407 FAILS TO REMAIN OPEN
VVMDRC-407
BLEED VALVE INVERTER RC-409 FAILS TO PROVIDE ADEQUATE OUTPUT
VCIPRC-409
BLEED VALVE INVERTER RC-407 FAILS TO PROVIDE ADEQUATE OUTPUT
VCIPRC-407
1
2

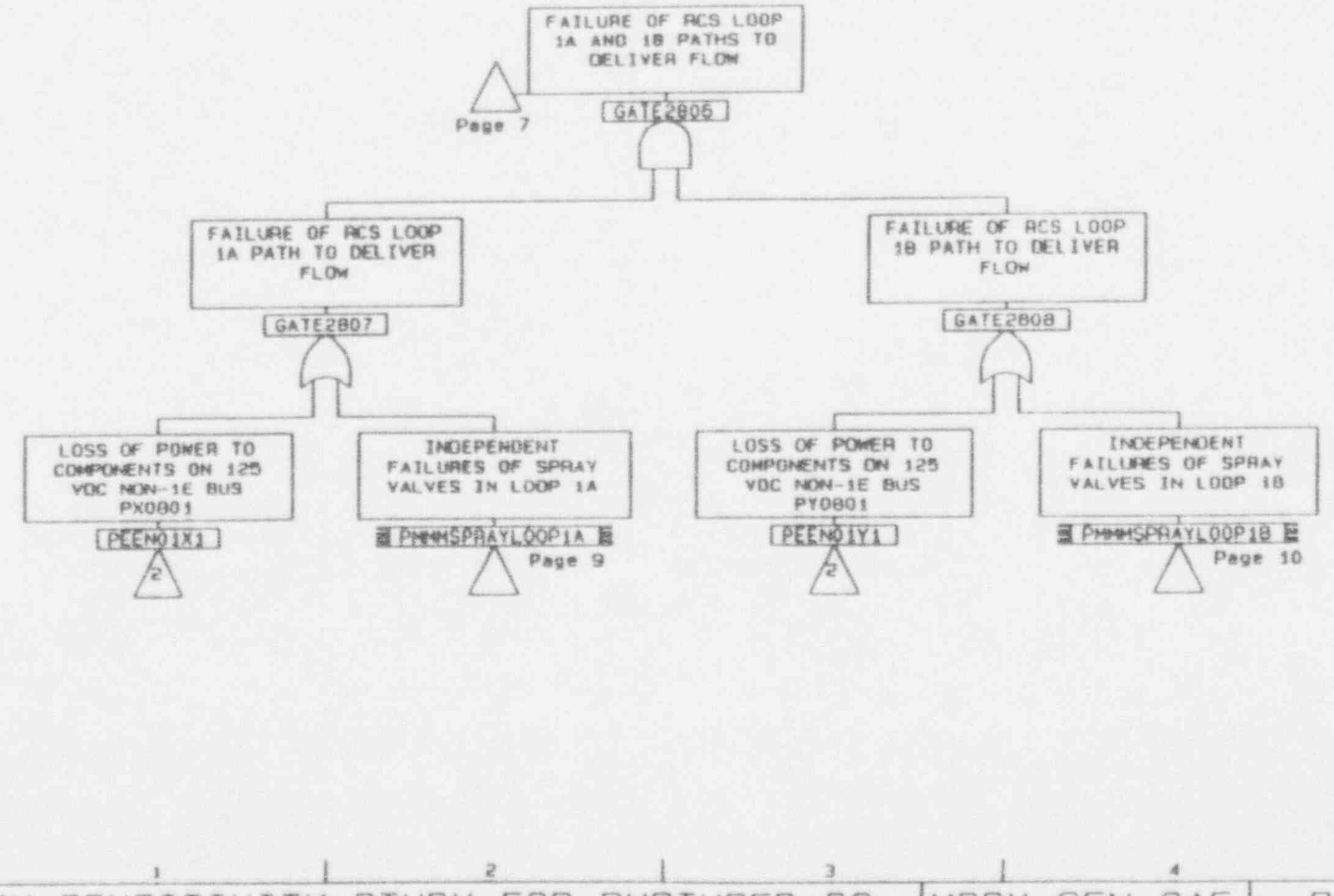

LOCAL FAULTS AFFECTING LOOP B BLEED VALVES
VMMMV002
Page 3
MOV RC-408 FAILS TO OPEN
VVMARC-408
MOV RC-406 FAILS TO OPEN
VVMARC-406
MOV RC-408 FAILS TO REMAIN OPEN
VVMDRC-408
MOV RC-406 FAILS TO REMAIN OPEN
VVMDRC-406
BLEED VALVE INVERTER RC-408 FAILS TO PROVIDE ADEQUATE OUTPUT
VCIPRC-408
BLEED VALVE INVERTER RC-406 FAILS TO PROVIDE ADEQUATE OUTPUT
VCIPRC-406
1
2

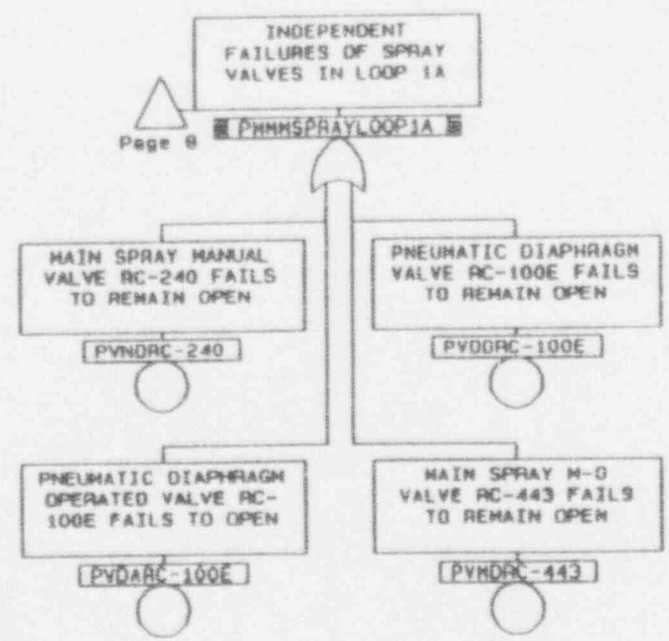


FAILURE TO PROVIDE RCS PRESSURE CONTROL
PPAX01BX
Page 1
OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL
PHFFRCSP
RCS PATH UNAVAILABLE FOR PRESSURE CONTROL
GATE2801
FLOW UNAVAILABLE FROM MAIN PRESSURIZER SPRAY SYSTEM
GATE2802
Page 7
FAILURE OF REACTOR COOLANT GAS VENT SYSTEM
PVDB01BX
Page 11
1
2

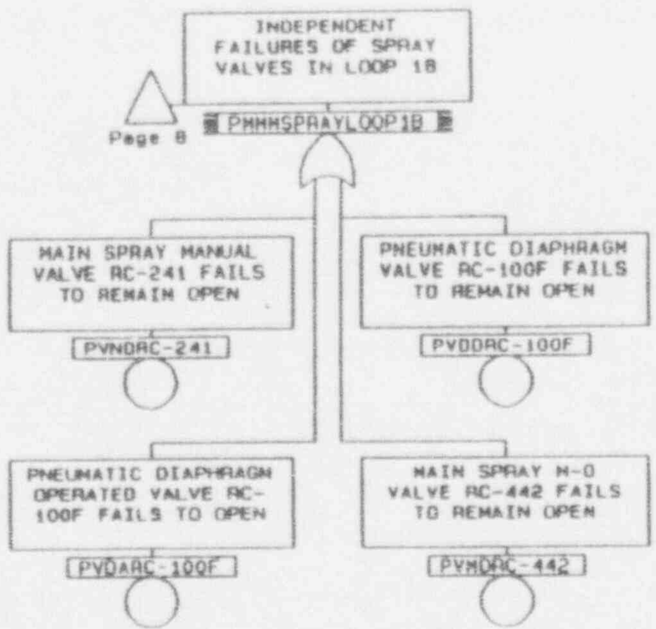


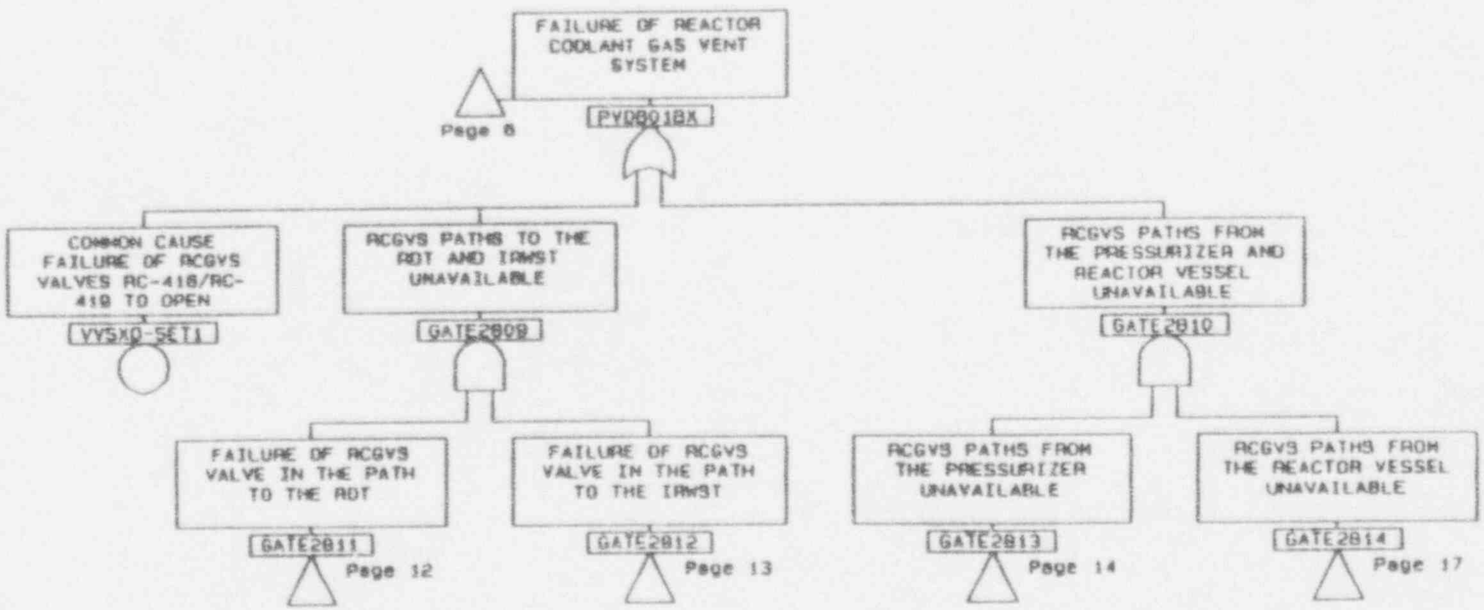
MSSV SENSITIVITY STUDY FOR RUPTURED SG	MSSV_SEN.CAF	Page 7

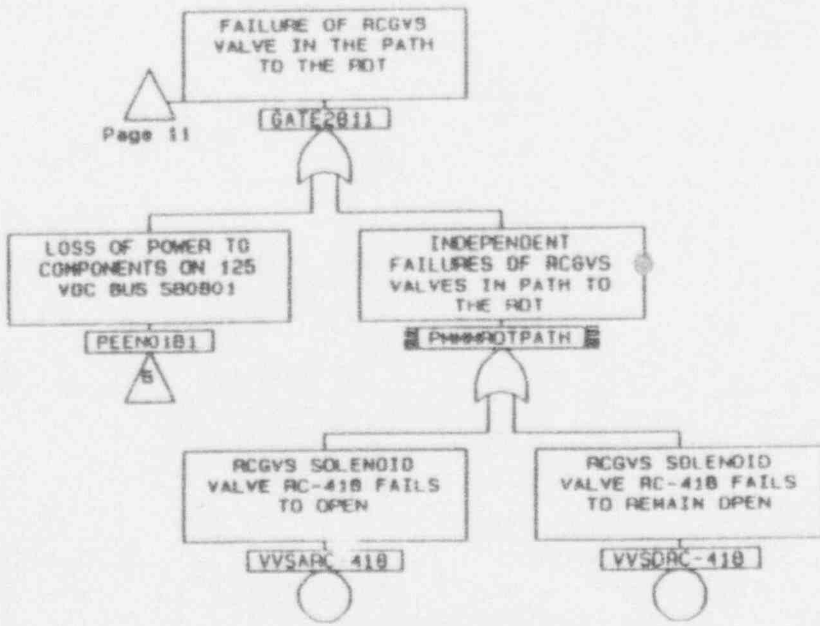

FAILURE OF RCS LOOP 1A AND 1B PATHS TO DELIVER FLOW
GATE2806
Page 7
FAILURE OF RCS LOOP 1A PATH TO DELIVER FLOW
GATE2807
FAILURE OF RCS LOOP 1B PATH TO DELIVER FLOW
GATE2808
LOSS OF POWER TO COMPONENTS ON 125 VDC NON-1E BUS PX0801
PEEN01X1
2
INDEPENDENT FAILURES OF SPRAY VALVES IN LOOP 1A
PMMMSPRAYLOOP1A
Page 9
LOSS OF POWER TO COMPONENTS ON 125 VDC NON-1E BUS PY0801
PEEN01Y1
2
INDEPENDENT FAILURES OF SPRAY VALVES IN LOOP 1B
PMMMSPRAYLOOP1B
Page 10
1
2
3
4

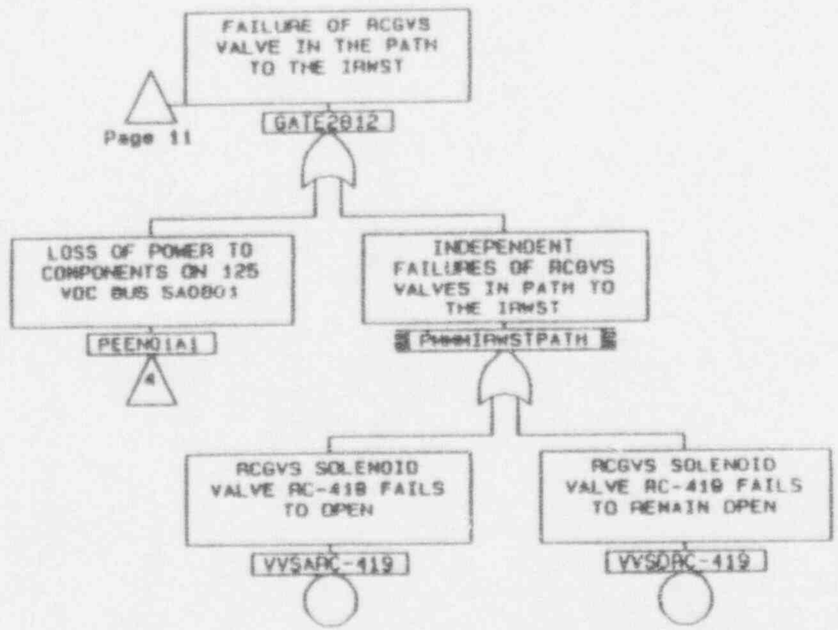


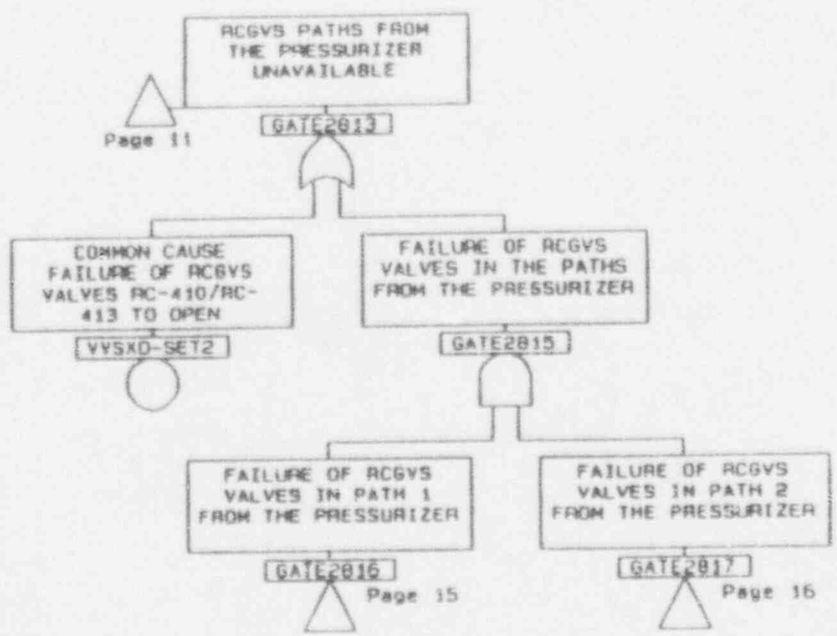
MSSV SENSITIVITY STUDY FOR RUPTURED SG	MSSV_SEN.CAF	Page 9

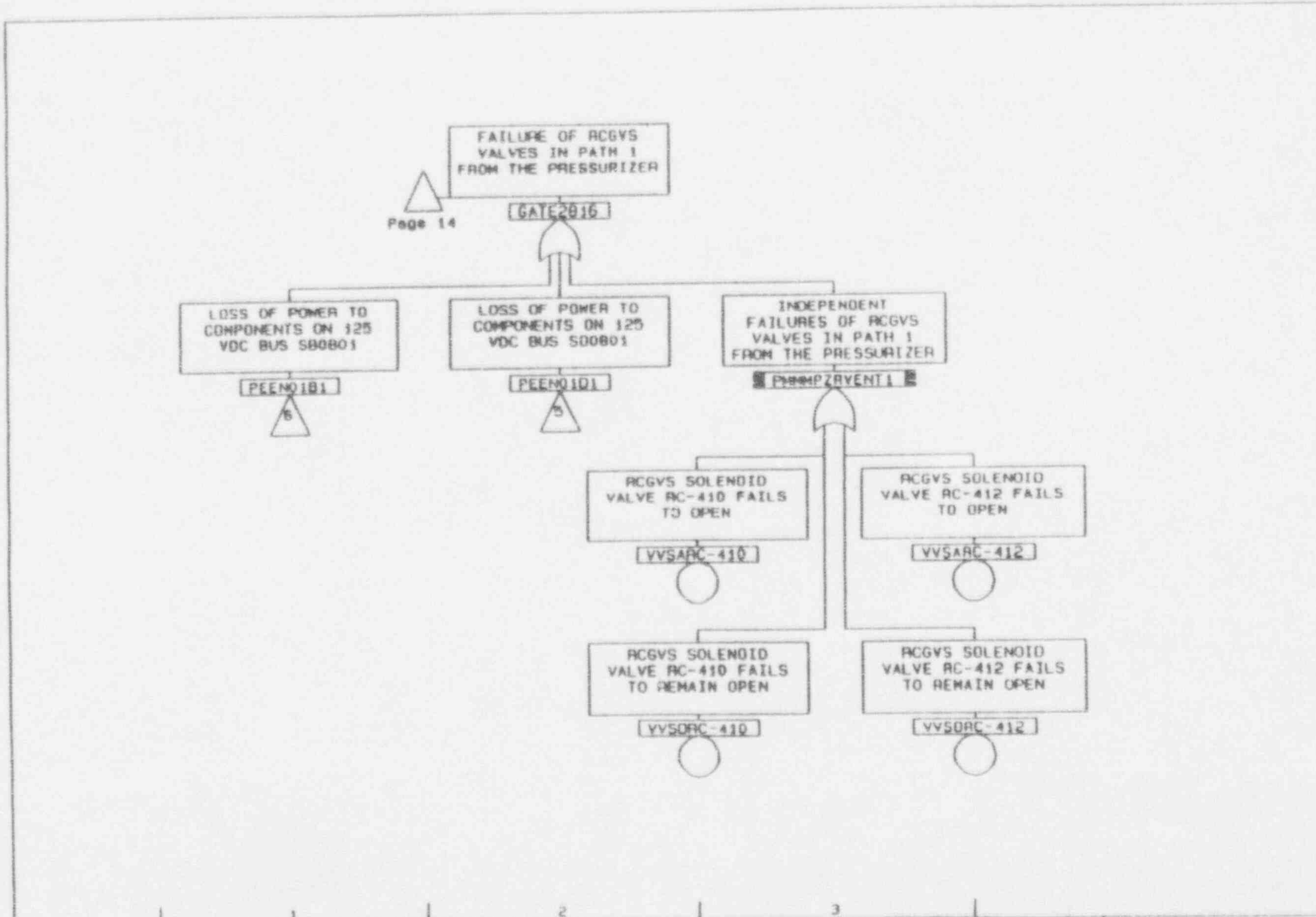

INDEPENDENT FAILURES OF SPRAY VALVES IN LOOP 1B
Page 8
PMMMSPRAYLOOP1B
MAIN SPRAY MANUAL VALVE RC-241 FAILS TO REMAIN OPEN
PVNDRC-241
PNEUMATIC DIAPHRAGM VALVE RC-100F FAILS TO REMAIN OPEN
PVDDRC-100F
PNEUMATIC DIAPHRAGM OPERATED VALVE RC-100F FAILS TO OPEN
PVDARC-100F
MAIN SPRAY M-O VALVE RC-442 FAILS TO REMAIN OPEN
PVMDRC-442

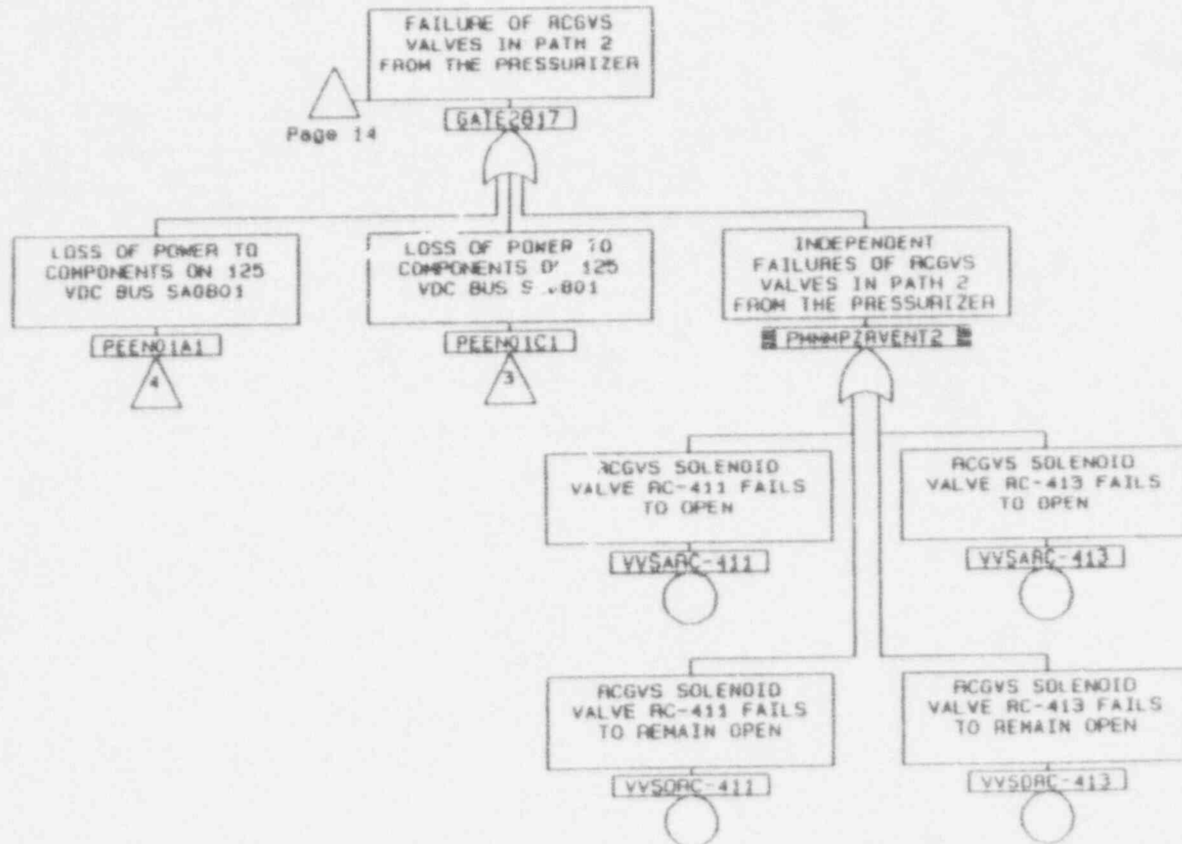

FAILURE OF REACTOR COOLANT GAS VENT SYSTEM
PYDB01BX
Page 8
COMMON CAUSE FAILURE OF RCGVS VALVES RC-418/RC-419 TO OPEN
VYSXO-SET1
RCGVS PATHS TO THE RDT AND IRWST UNAVAILABLE
GATE2809
RCGVS PATHS FROM THE PRESSURIZER AND REACTOR VESSEL UNAVAILABLE
GATE2810
FAILURE OF RCGVS VALVE IN THE PATH TO THE RDT
GATE2811
Page 12
FAILURE OF RCGVS VALVE IN THE PATH TO THE IRWST
GATE2812
Page 13
RCGVS PATHS FROM THE PRESSURIZER UNAVAILABLE
GATE2813
Page 14
RCGVS PATHS FROM THE REACTOR VESSEL UNAVAILABLE
GATE2814
Page 17
1
2
3
4

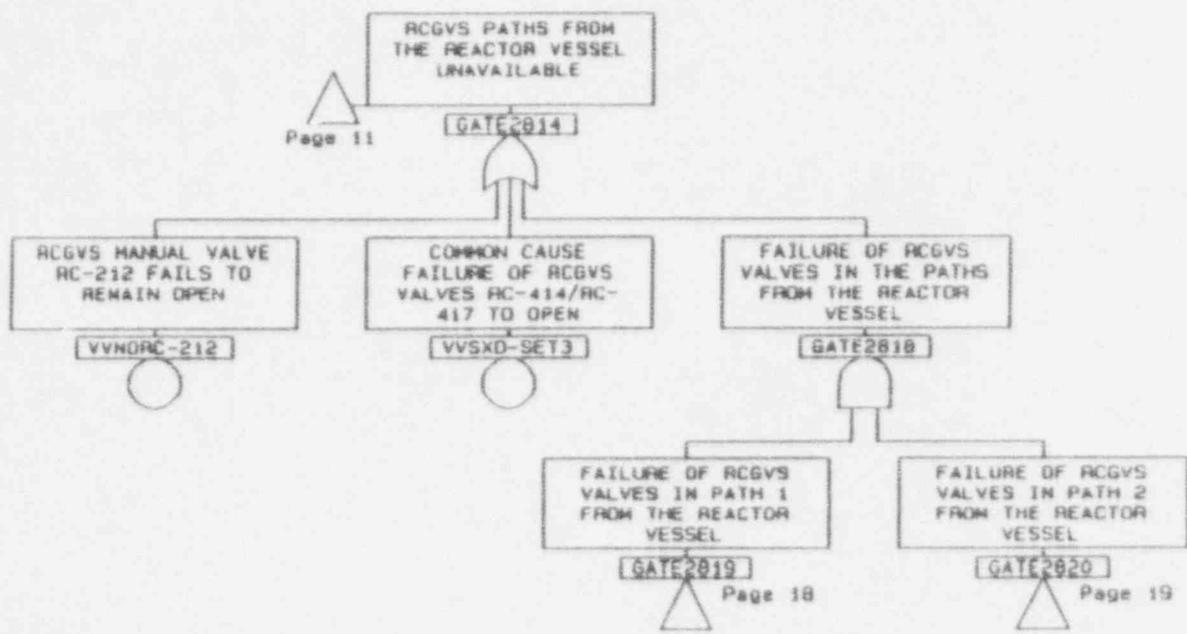

FAILURE OF RCGVS VALVE IN THE PATH TO THE RDT
Page 11
GATE2811
LOSS OF POWER TO COMPONENTS ON 125 VDC BUS S80B01
PEEN01B1
INDEPENDENT FAILURES OF RCGVS VALVES IN PATH TO THE RDT
PHMMRDTPATH
RCGVS SOLENOID VALVE RC-418 FAILS TO OPEN
VVSARC 418
RCGVS SOLENOID VALVE RC-418 FAILS TO REMAIN OPEN
VVSDRC-418
1
2


FAILURE OF RCGVS VALVE IN THE PATH TO THE IRWST
GATE2012
Page 11
LOSS OF POWER TO COMPONENTS ON 125 VDC BUS 5A0801
PEEN01A1
4
INDEPENDENT FAILURES OF RCGVS VALVES IN PATH TO THE IRWST
RCGVS SOLENOID VALVE RC-419 FAILS TO OPEN
VVSARC-419
RCGVS SOLENOID VALVE RC-419 FAILS TO REMAIN OPEN
VVSDRC-419
1
2

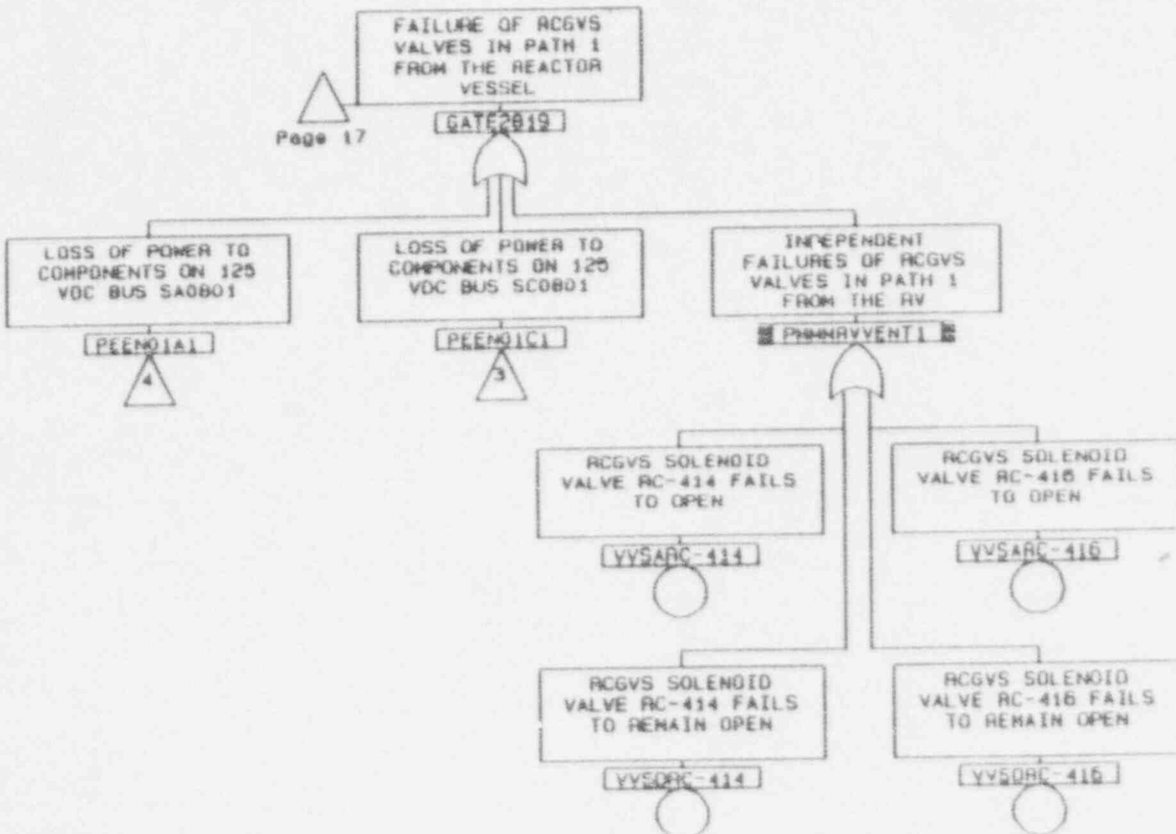

RCGVS PATHS FROM THE PRESSURIZER UNAVAILABLE
GATE2813
Page 11
COMMON CAUSE FAILURE OF RCGVS VALVES RC-410/RC-413 TO OPEN
VVSXO-SET2
FAILURE OF RCGVS VALVES IN THE PATHS FROM THE PRESSURIZER
GATE2815
FAILURE OF RCGVS VALVES IN PATH 1 FROM THE PRESSURIZER
GATE2816
Page 15
FAILURE OF RCGVS VALVES IN PATH 2 FROM THE PRESSURIZER
GATE2817
Page 16
1
2

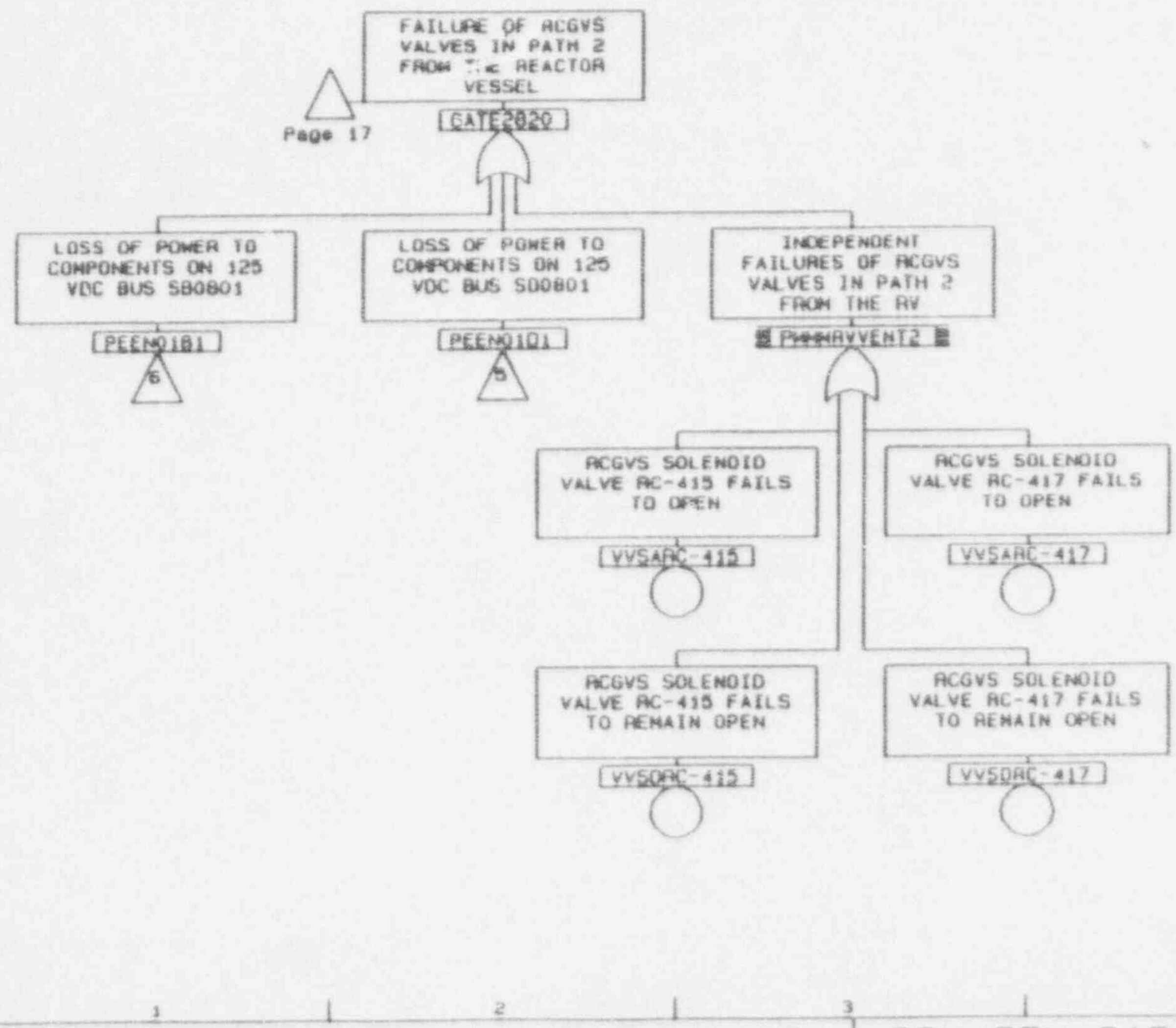

FAILURE OF RCGVS VALVES IN PATH 1 FROM THE PRESSURIZER
GATE2016
Page 14
LOSS OF POWER TO COMPONENTS ON 125 VDC BUS SB0B01
PEEN01B1
6
LOSS OF POWER TO COMPONENTS ON 125 VDC BUS SD0B01
PEEN01D1
5
INDEPENDENT FAILURES OF RCGVS VALVES IN PATH 1 FROM THE PRESSURIZER
PHMMPZRVENT1
RCGVS SOLENOID VALVE RC-410 FAILS TO OPEN
VVSARC-410
RCGVS SOLENOID VALVE RC-412 FAILS TO OPEN
VVSARC-412
RCGVS SOLENOID VALVE RC-410 FAILS TO REMAIN OPEN
VVSORC-410
RCGVS SOLENOID VALVE RC-412 FAILS TO REMAIN OPEN
VVSORC-412
1
2
3

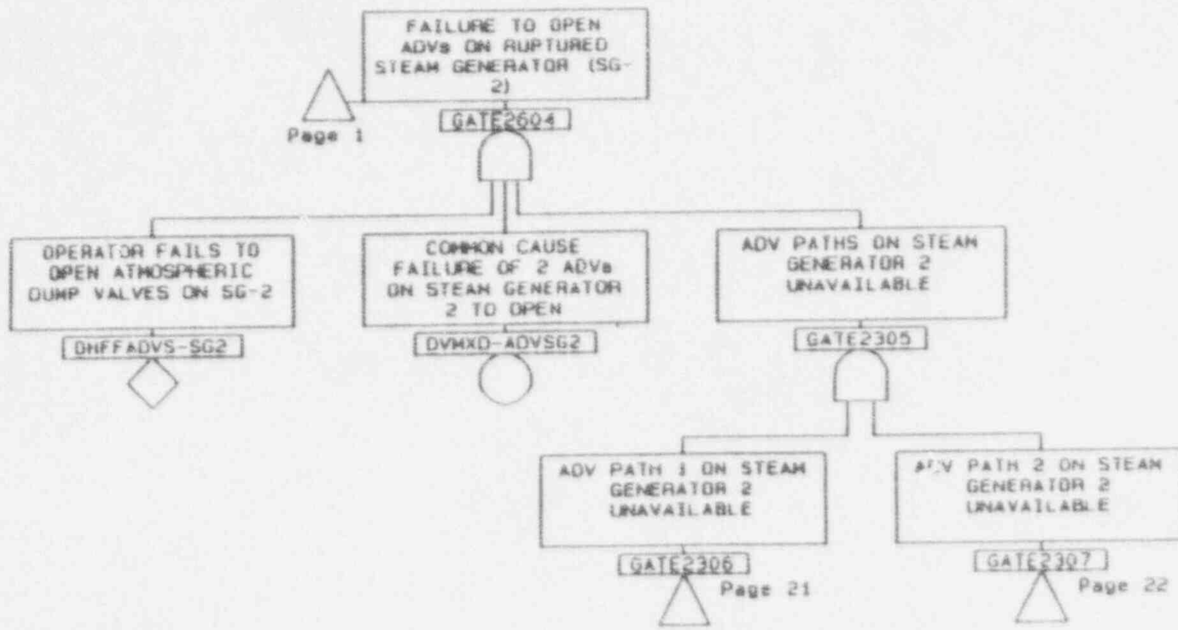

FAILURE OF RCGVS VALVES IN PATH 2 FROM THE PRESSURIZER
Page 14
GATE2017
LOSS OF POWER TO COMPONENTS ON 125 VDC BUS SA0801
PEEN01A1
4
LOSS OF POWER TO
PEEN01C1
3
INDEPENDENT FAILURES OF RCGVS VALVES IN PATH 2 FROM THE PRESSURIZER
PHMMPZRVENT2
RCGVS SOLENOID VALVE RC-411 FAILS TO OPEN
VVSARC-411
RCGVS SOLENOID VALVE RC-413 FAILS TO OPEN
VVSARC-413
RCGVS SOLENOID VALVE RC-411 FAILS TO REMAIN OPEN
VVSORC-411
RCGVS SOLENOID VALVE RC-413 FAILS TO REMAIN OPEN
VVSORC-413

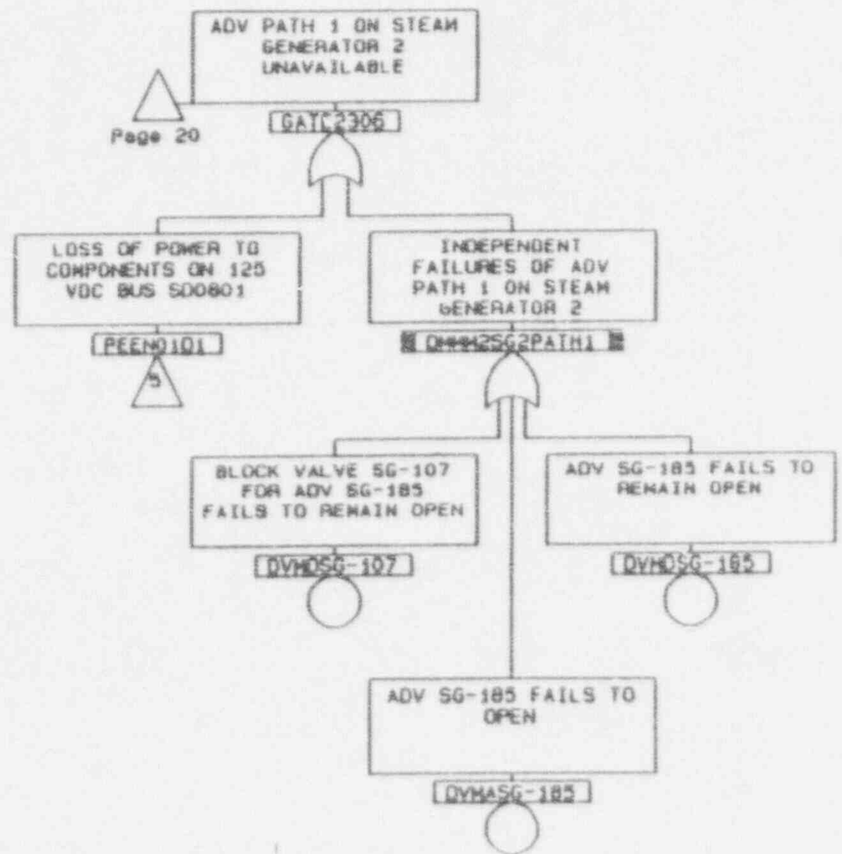


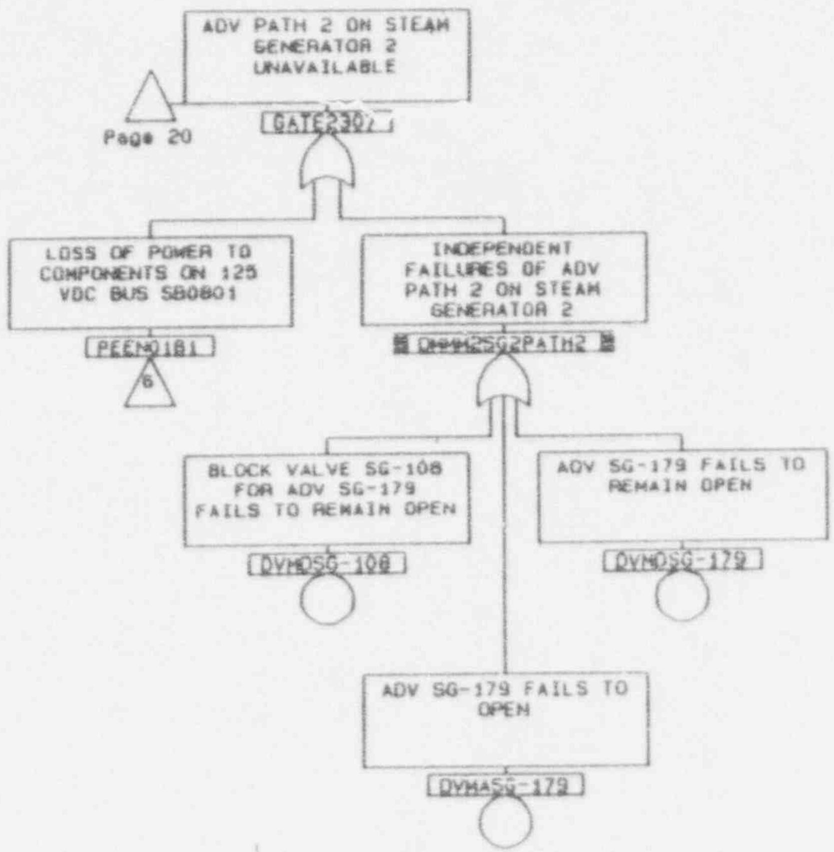
RCGVS PATHS FROM THE REACTOR VESSEL UNAVAILABLE
GATE2014
Page 11
RCGVS MANUAL VALVE RC-212 FAILS TO REMAIN OPEN
VVNORC-212
COMMON CAUSE FAILURE OF RCGVS VALVES RC-414/RC-417 TO OPEN
VVSXO-SET3
FAILURE OF RCGVS VALVES IN THE PATHS FROM THE REACTOR VESSEL
GATE2018
FAILURE OF RCGVS VALVES IN PATH 1 FROM THE REACTOR VESSEL
GATE2019
Page 18
FAILURE OF RCGVS VALVES IN PATH 2 FROM THE REACTOR VESSEL
GATE2020
Page 19


FAILURE OF RCGVS VALVES IN PATH 1 FROM THE REACTOR VESSEL
GATE2019
Page 17
LOSS OF POWER TO COMPONENTS ON 125 VDC BUS SA0801
PEEN01A1
4
LOSS OF POWER TO COMPONENTS ON 125 VDC BUS SC0801
PEEN01C1
3
INDEPENDENT FAILURES OF RCGVS VALVES IN PATH 1 FROM THE RV
PHWNRVVENT1
RCGVS SOLENOID VALVE RC-414 FAILS TO OPEN
VVSARC-414
RCGVS SOLENOID VALVE RC-416 FAILS TO OPEN
VVSARC-416
RCGVS SOLENOID VALVE RC-414 FAILS TO REMAIN OPEN
VVSORC-414
RCGVS SOLENOID VALVE RC-416 FAILS TO REMAIN OPEN
VVSORC-416

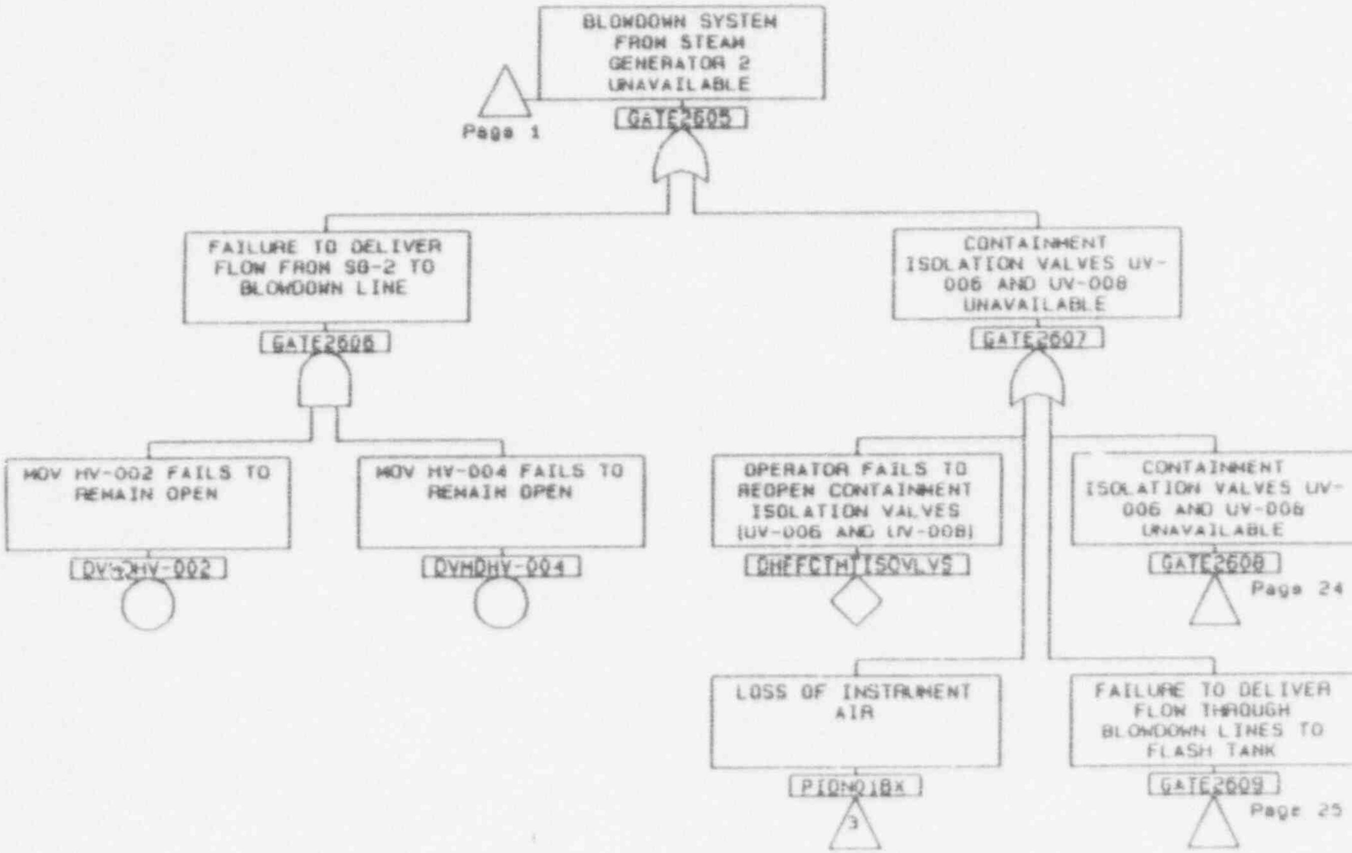

FAILURE OF RCGVS
VALVES IN PATH 2
FROM
REACTOR
VESSEL
GATE2020
Page 17
LOSS OF POWER TO
COMPONENTS ON 125
VDC BUS SB0801
PEEN01B1
6
LOSS OF POWER TO
COMPONENTS ON 125
VDC BUS SD0801
PEEN01D1
5
INDEPENDENT
FAILURES OF RCGVS
VALVES IN PATH 2
FROM THE RV
RCGVS SOLENOID
VALVE RC-415 FAILS
TO OPEN
VVSARC-415
RCGVS SOLENOID
VALVE RC-417 FAILS
TO OPEN
VVSARC-417
RCGVS SOLENOID
VALVE RC-415 FAILS
TO REMAIN OPEN
VVSDRC-415
RCGVS SOLENOID
VALVE RC-417 FAILS
TO REMAIN OPEN
VVSDRC-417
1
2
3


FAILURE TO OPEN ADVs ON RUPTURED STEAM GENERATOR (SG-2)
GATE2604
Page 1
OPERATOR FAILS TO OPEN ATMOSPHERIC DUMP VALVES ON SG-2
DHFFADVS-SG2
COMMON CAUSE FAILURE OF 2 ADVs ON STEAM GENERATOR 2 TO OPEN
DVMXD-ADVSG2
ADV PATHS ON STEAM GENERATOR 2 UNAVAILABLE
GATE2305
ADV PATH 1 ON STEAM GENERATOR 2 UNAVAILABLE
GATE2306
Page 21
ADV PATH 2 ON STEAM GENERATOR 2 UNAVAILABLE
GATE2307
Page 22

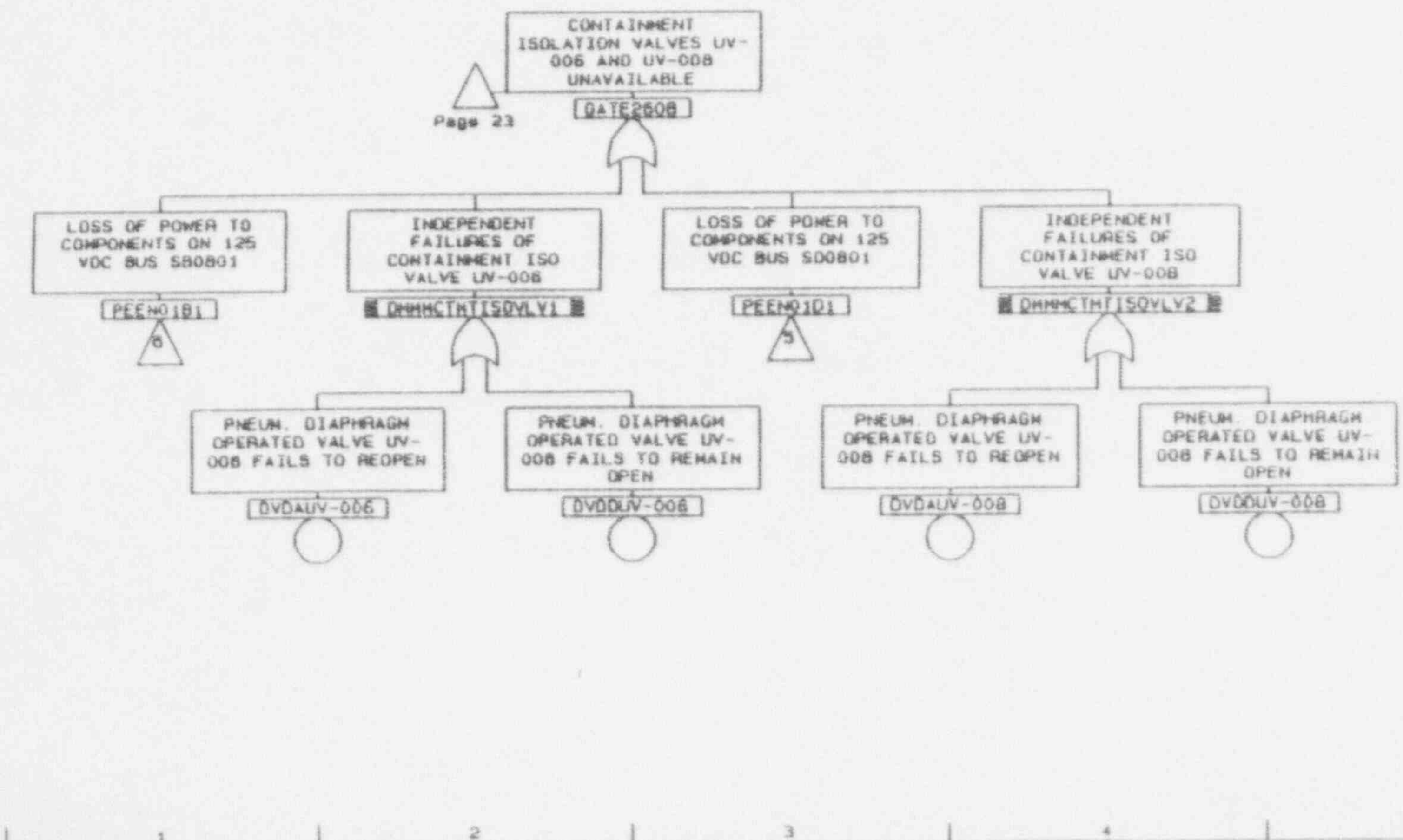

ADV PATH 1 ON STEAM GENERATOR 2 UNAVAILABLE
GATC2306
Page 20
LOSS OF POWER TO COMPONENTS ON 125 VDC BUS SD0801
PEEN0101
5
INDEPENDENT FAILURES OF ADV PATH 1 ON STEAM GENERATOR 2
BLOCK VALVE SG-107 FOR ADV SG-185 FAILS TO REMAIN OPEN
DVHOSG-107
ADV SG-185 FAILS TO REMAIN OPEN
DVHOSG-185
ADV SG-185 FAILS TO OPEN
DVMASG-185
1
2

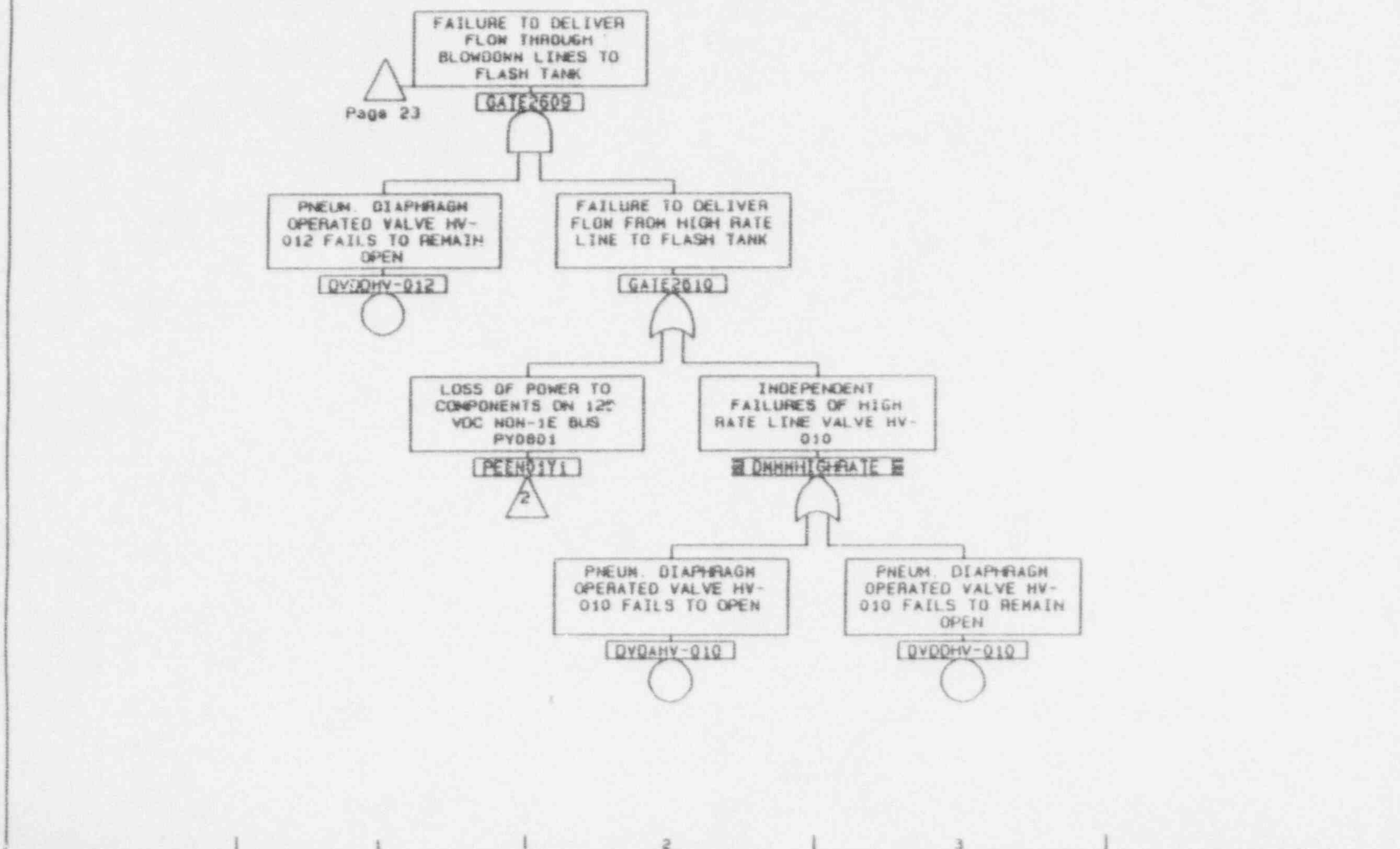

ADV PATH 2 ON STEAM GENERATOR 2 UNAVAILABLE
GATE2307
Page 20
LOSS OF POWER TO COMPONENTS ON 125 VDC BUS SB0801
PEEN0181
6
INDEPENDENT FAILURES OF ADV PATH 2 ON STEAM GENERATOR 2
BLOCK VALVE SG-108 FOR ADV SG-179 FAILS TO REMAIN OPEN
DVMDSG-108
ADV SG-179 FAILS TO REMAIN OPEN
DVMDSG-179
ADV SG-179 FAILS TO OPEN
DVMASG-179

1 2


BLOWDOWN SYSTEM FROM STEAM GENERATOR 2 UNAVAILABLE
GATE2605
Page 1
FAILURE TO DELIVER FLOW FROM SG-2 TO BLOWDOWN LINE
GATE2606
CONTAINMENT ISOLATION VALVES UV-006 AND UV-008 UNAVAILABLE
GATE2607
MOV HV-002 FAILS TO REMAIN OPEN
MOV HV-004 FAILS TO REMAIN OPEN
DVMDHV-004
OPERATOR FAILS TO REOPEN CONTAINMENT ISOLATION VALVES (UV-006 AND UV-008)
CONTAINMENT ISOLATION VALVES UV-006 AND UV-008 UNAVAILABLE
GATE2608
Page 24
LOSS OF INSTRUMENT AIR
PIDN018X
3
FAILURE TO DELIVER FLOW THROUGH BLOWDOWN LINES TO FLASH TANK
GATE2609
Page 25

1 2 3 4


CONTAINMENT ISOLATION VALVES UV-006 AND UV-008 UNAVAILABLE
GATE2608
Page 23
LOSS OF POWER TO COMPONENTS ON 125 VDC BUS SB0801
PEEN01B1
6
INDEPENDENT FAILURES OF CONTAINMENT ISO VALVE UV-006
DHMMCTMTISOVLV1
LOSS OF POWER TO COMPONENTS ON 125 VDC BUS SD0801
PEEN01D1
5
INDEPENDENT FAILURES OF CONTAINMENT ISO VALVE UV-008
DHMMCTMTISOVLV2
PNEUM. DIAPHRAGM OPERATED VALVE UV-006 FAILS TO REOPEN
DVDAUV-006
PNEUM. DIAPHRAGM OPERATED VALVE UV-006 FAILS TO REMAIN OPEN
DVDDUV-006
PNEUM. DIAPHRAGM OPERATED VALVE UV-008 FAILS TO REOPEN
DVDAUV-008
PNEUM. DIAPHRAGM OPERATED VALVE UV-008 FAILS TO REMAIN OPEN
DVDDUV-008
1
2
3
4


FAILURE TO DELIVER FLOW THROUGH BLOWDOWN LINES TO FLASH TANK
GATE2609
Page 23
PNEUM. DIAPHRAGM OPERATED VALVE HV-012 FAILS TO REMAIN OPEN
DVDDHV-012
FAILURE TO DELIVER FLOW FROM HIGH RATE LINE TO FLASH TANK
GATE2610
LOSS OF POWER TO COMPONENTS ON 125 VDC NON-1E BUS PY0801
PEEN01Y1
2
INDEPENDENT FAILURES OF HIGH RATE LINE VALVE HV-010
DHHHHIGHRATE
PNEUM. DIAPHRAGM OPERATED VALVE HV-010 FAILS TO OPEN
DVDAHV-010
PNEUM. DIAPHRAGM OPERATED VALVE HV-010 FAILS TO REMAIN OPEN
DVDDHV-010
1
2
3

Gate/Event Name	Page	Zone	Gate/Event Name	Page	Zone	Gate/Event Name	Page	Zone	Gate/Event Name	Page	Zone
AATLOP	7	1	GATE2609	25	1	PEENO1C1	16	2	PVMDRC-443	9	2
DHFFADVS-SG2	20	1	GATE2610	25	2	PEENO1C1	18	2	PVNDRC-240	9	1
DHFFCTMTISOVLVS	23	3	GATE2801	6	2	PEENO1D1	3	5	PVNDRC-241	10	1
DMMM2SG2PATH1	21	2	GATE2802	6	1	PEENO1D1	15	2	VCIPRC-406	5	2
DMMM2SG2PATH2	22	2	GATE2802	7	3	PEENO1D1	19	2	VCIPRC-407	4	2
DMMMCTMTISOVLV1	24	2	GATE2804	7	2	PEENO1D1	21	1	VCIPRC-408	5	1
DMMMCTMTISOVLV2	24	4	GATE2805	7	5	PEENO1D1	24	3	VCIPRC-409	4	1
DMMMHIGHRATE	25	2	GATE2806	7	6	PEENO1X1	2	1	VCIXBLDV	3	3
DVDAHV-010	25	2	GATE2806	8	2	PEENO1X1	8	1	VHFFFEEDBLEED	3	1
DVDAUV-006	24	1	GATE2807	8	1	PEENO1Y1	8	3	VMMMV001	3	3
DVDAUV-008	24	4	GATE2808	8	3	PEENO1Y1	25	1	VMMMV001	4	1
DVDDHV-010	25	3	GATE2809	11	2	PHFFRCSP	6	1	VMMMV002	3	5
DVDDHV-012	25	1	GATE2810	11	4	PIEPPPCS	7	5	VMMMV002	5	1
DVDDUV-006	24	2	GATE2811	11	1	PIONO1BX	2	1	VVMARC-406	5	2
DVDDUV-008	24	5	GATE2811	12	1	PIONO1BX	7	6	VVMARC-407	4	2
DVMASG-179	22	2	GATE2812	11	2	PIONO1BX	23	3	VVMARC-408	5	1
DVMASG-185	21	2	GATE2812	13	1	PKBZO1BX	1	2	VVMARC-409	4	1
DVMDHV-002	23	1	GATE2813	11	4	PKBZO1BX	2	2	VVMDRC-406	5	2
DVMDHV-004	23	2	GATE2813	14	1	PMMMIRWSTPATH	13	2	VVMDRC-407	4	2
DVMDSG-107	21	1	GATE2814	11	5	PMMMPZRVENT1	15	3	VVMDRC-408	5	1
DVMDSG-108	22	1	GATE2814	17	2	PMMMPZRVENT2	16	3	VVMDRC-409	4	1
DVMDSG-179	22	2	GATE2815	14	2	PMMMRDTPATH	12	2	VVMXBLDV	3	2
DVMDSG-185	21	2	GATE2816	14	1	PMMMRVVENT1	18	3	VVNDRC-212	17	1
DVMXD-ADVSG2	20	2	GATE2816	15	2	PMMMRVVENT2	19	3	VVSARC-410	15	3
DVRBMSSV-L	1	3	GATE2817	14	2	PMMMSPRAYCHKVLV	7	4	VVSARC-411	16	3
DVRBMSSV-S	1	1	GATE2817	16	2	PMMMSPRAYLOOP1A	8	2	VVSARC-412	15	4
EBGPTT	7	2	GATE2818	17	3	PMMMSPRAYLOOP1A	9	1	VVSARC-413	16	4
GATE2201	2	1	GATE2819	17	3	PMMMSPRAYLOOP1B	8	4	VVSARC-414	18	3
GATE2305	20	3	GATE2819	18	2	PMMMSPRAYLOOP1B	10	1	VVSARC-415	19	3
GATE2306	20	3	GATE2820	17	4	PPAXO1BX	1	5	VVSARC-416	18	4
GATE2306	21	1	GATE2820	19	2	PPAXO1BX	6	1	VVSARC-417	19	4
GATE2307	20	4	KGPPSWCD	2	2	PVBBO1BX	1	4	VVSARC-418	12	1
GATE2307	22	1	KIEPTBCS	2	2	PVBBO1BX	3	2	VVSARC-419	13	1
GATE2602A	1	1	KVDXD-TBVS	2	2	PVBBO1BX05	3	4	VVSDRC-410	15	3
GATE2602B	1	4	MSSV-SENS	1	3	PVBBO2BX	3	3	VVSDRC-411	16	3
GATE2602C	1	5	PEENO1A1	3	4	PVBBO3BX	3	5	VVSDRC-412	15	4
GATE2603	1	6	PEENO1A1	13	1	PVCARC-244	7	3	VVSDRC-413	16	4
GATE2604	1	5	PEENO1A1	16	1	PVCDRC-244	7	4	VVSDRC-414	18	3
GATE2604	20	2	PEENO1A1	18	1	PVDARC-100E	9	1	VVSDRC-415	19	3
GATE2605	1	6	PEENO1B1	3	6	PVDARC-100F	10	1	VVSDRC-415	18	4
GATE2605	23	2	PEENO1B1	12	1	PVDBO1BX	6	2	VVSDRC-417	19	4
GATE2606	23	1	PEENO1B1	15	1	PVDBO1BX	11	2	VVSDRC-418	12	2
GATE2607	23	3	PEENO1B1	19	1	PVDDRC-100E	9	2	VVSDRC-419	13	2
GATE2608	23	4	PEENO1B1	22	1	PVDDRC-100F	10	2	VVSXD-SET1	11	1
GATE2608	24	2	PEENO1B1	24	1	PVDXRC-100	7	5	VVSXD-SET2	14	1
GATE2609	23	4	PEENO1C1	3	3	PVMDRC-442	10	2	VVSXD-SET3	17	2

Filter: 'ACTIVE'

MODULE/EVENT NAME	DESCRIPTION	RATE	EXPOSURE	B.E. PROB.	MOD./CS. PROB.
1) MSSVSENB					*2.28E-04
1) DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	8.96E-05
KVDXD-TBVS	COMMON CAUSE FAILURE OF ALL 8 TURBINE BYPASS VALVES TO OPEN		1.60E-03	1.60E-03	
2) DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	4.48E-05
EBGPTT	GRID COLLAPSE ON TURBINE TRIP		8.00E-04	8.00E-04	
3) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	4.29E-05
PHFFRCSP	OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL		4.69E-03	4.69E-03	
VHFFFEEDBLEED	OPERATOR FAILS TO INITIATE FEED & BLEED SYSTEM		9.15E-03	9.15E-03	
4) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	2.25E-05
PHFFRCSP	OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL		4.69E-03	4.69E-03	
VVMXBLDV	COMMON CAUSE FAILURE OF BLEED VALVES		4.80E-03	4.80E-03	
5) DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	1.11E-05
ISXRIAS	IA CONTROLS FAIL TO OPERATE PROPERLY		1.99E-04	1.99E-04	
6) DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	4.06E-06
KIEPTBCS	FAILURE OF TURBINE BYPASS CONTROL SYSTEM TO OPERATE		7.25E-05	7.25E-05	
7) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	2.70E-06
PHFFRCSP	OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL		4.69E-03	4.69E-03	
VVMARC-406	MOV RC-406 FAILS TO OPEN		2.40E-02	2.40E-02	
VVMARC-409	MOV RC-409 FAILS TO OPEN		2.40E-02	2.40E-02	
8) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	2.70E-06
PHFFRCSP	OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL		4.69E-03	4.69E-03	
VVMARC-407	MOV RC-407 FAILS TO OPEN		2.40E-02	2.40E-02	
VVMARC-408	MOV RC-408 FAILS TO OPEN		2.40E-02	2.40E-02	
9) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	2.70E-06
PHFFRCSP	OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL		4.69E-03	4.69E-03	
VVMARC-406	MOV RC-406 FAILS TO OPEN		2.40E-02	2.40E-02	
VVMARC-407	MOV RC-407 FAILS TO OPEN		2.40E-02	2.40E-02	
10) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	2.70E-06
PHFFRCSP	OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL		4.69E-03	4.69E-03	
VVMARC-408	MOV RC-408 FAILS TO OPEN		2.40E-02	2.40E-02	
VVMARC-409	MOV RC-409 FAILS TO OPEN		2.40E-02	2.40E-02	
11) DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	8.46E-07
KGPPSWCD	CONDENSER PRESSURE SWITCH SWCD FAILS TO OPERATE	6.30E-07	24	1.51E-05<	
12) DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	6.72E-07
EBBQPX0801S	125 VDC CIRCUIT BREAKER PX0801S OPENS SPURIOUSLY	5.00E-07	24	1.20E-05	
13) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	4.50E-07
PHFFRCSP	OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL		4.69E-03	4.69E-03	
VCIXBLDV	COMMON CAUSE FAILURE OF BLEED VALVE INVERTERS		9.60E-05	9.60E-05	
14) DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	2.69E-07

	ELCPPX0801	BUS FAULT ON 125 VDC BUS PX0801.	2.00E-07	24	4.80E-06	
15)	DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	1.78E-07
	IADXAIRDRYS	COMMON CAUSE FAILURE OF INSTRUMENT AIR DRYERS		3.18E-06	3.18E-06	
16)	DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	1.34E-07
	IWCKC-1A	AIR COMPRESSOR C-1A FAILS TO OPERATE (RUN)	1.00E-04	24	2.40E-03	
	IWCXDCOMP	COMMON CAUSE DEMAND FAILURE OF AIR COMPRESSORS		1.00E-03	1.00E-03	
17)	DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	1.08E-07
	ELCX125C1E	COMMON CAUSE FAILURE OF 125 VDC CLASS 1E BUS		1.08E-07	1.08E-07	

Filter: 'ACTIVE'

MODULE/EVENT NAME	DESCRIPTION	RATE	EXPOSURE	B.E. PROB.	MOD./CS. PROB.
1) MSSVSEN1					*6.96E-02
1) DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	5.60E-02
2) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	9.38E-03
PHFFRCSP	OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL		9.38E-03	9.38E-03	
3) DHFFADVS-SG2	OPERATOR FAILS TO OPEN ATMOSPHERIC DUMP VALVES ON SG-2		4.66E-03	4.66E-03	4.66E-03
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
4) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	2.00E-04
VVSXD-SET1	COMMON CAUSE FAILURE OF RCGVS VALVES RC-418/RC-419 TO OPEN		2.00E-04	2.00E-04	
5) DVMXD-ADVSG2	COMMON CAUSE FAILURE OF 2 ADVs ON STEAM GENERATOR 2 TO OPEN		2.00E-04	2.00E-04	2.00E-04
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
6) DVMASG-179	ADV SG-179 FAILS TO OPEN	4.00E-03	1	4.00E-03	1.60E-05
DVMASG-185	ADV SG-185 FAILS TO OPEN	4.00E-03	1	4.00E-03	
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
7) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	6.40E-07
VVSXD-SET2	COMMON CAUSE FAILURE OF RCGVS VALVES RC-410/RC-413 TO OPEN		8.00E-04	8.00E-04	
VVSXD-SET3	COMMON CAUSE FAILURE OF RCGVS VALVES RC-414/RC-417 TO OPEN		8.00E-04	8.00E-04	
8) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	1.08E-07
ELCX125C1E	COMMON CAUSE FAILURE OF 125 VDC CLASS 1E BUS		1.08E-07	1.08E-07	
9) DVMASG-185	ADV SG-185 FAILS TO OPEN	4.00E-03	1	4.00E-03	4.80E-08
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
EBBQSB0801S	125 VDC CIRCUIT BREAKER SB0801S OPENS SPURIOUSLY	5.00E-07	24	1.20E-05	
10) DVMASG-179	ADV SG-179 FAILS TO OPEN	4.00E-03	1	4.00E-03	4.80E-08
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
EBBQSD0801S	125 VDC CIRCUIT BREAKER SD0801S OPENS SPURIOUSLY	5.00E-07	24	1.20E-05	
11) DVMASG-179	ADV SG-179 FAILS TO OPEN	4.00E-03	1	4.00E-03	1.92E-08
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
ELCPSD0801	BUS FAULT ON 125 VDC BUS SD0801.	2.00E-07	24	4.80E-06	
12) DVMASG-185	ADV SG-185 FAILS TO OPEN	4.00E-03	1	4.00E-03	1.92E-08
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
ELCPSB0801	BUS FAULT ON 125 VDC BUS SB0801.	2.00E-07	24	4.80E-06	
13) DVMASG-179	ADV SG-179 FAILS TO OPEN	4.00E-03	1	4.00E-03	1.34E-08
DVMDSG-185	ADV SG-185 FAILS TO REMAIN OPEN	1.40E-07	24	3.36E-06	
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
14) DVMASG-185	ADV SG-185 FAILS TO OPEN	4.00E-03	1	4.00E-03	1.34E-08
DVMDSG-179	ADV SG-179 FAILS TO REMAIN OPEN	1.40E-07	24	3.36E-06	
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
15) DVMASG-179	ADV SG-179 FAILS TO OPEN	4.00E-03	1	4.00E-03	1.34E-08
DVMDSG-107	BLOCK VALVE SG-107 FOR ADV SG-185 FAILS TO REMAIN OPEN	1.40E-07	24	3.36E-06	
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	

16)	DVMASG-185	ADV SG-185 FAILS TO OPEN	4.00E-03	1	4.00E-03	1.34E-08
	DVMDSG-108	BLOCK VALVE SG-108 FOR ADV SG-179 FAILS TO REMAIN OPEN	1.40E-07	24	3.36E-06	
	DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	

Filter: 'ACTIVE'

MODULE/EVENT NAME	DESCRIPTION	RATE	EXPOSURE	B.E. PROB.	MOD./CS. PROB.
1) MSSVSEN2					*6.30E-02
1) DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	5.60E-02
2) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	4.69E-03
PHFFRCSP	OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL		4.69E-03	4.69E-03	
3) DHFFADVS-SG2	OPERATOR FAILS TO OPEN ATMOSPHERIC DUMP VALVES ON SG-2		2.33E-03	2.33E-03	2.33E-03
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
4) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	2.00E-04
VVSXD-SET1	COMMON CAUSE FAILURE OF RCGVS VALVES RC-418/RC-419 TO OPEN		2.00E-04	2.00E-04	
5) DVMXD-ADVSG2	COMMON CAUSE FAILURE OF 2 ADVs ON STEAM GENERATOR 2 TO OPEN		2.00E-04	2.00E-04	2.00E-04
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
6) DVMASG-179	ADV SG-179 FAILS TO OPEN	4.00E-03	1	4.00E-03	1.60E-05
DVMASG-185	ADV SG-185 FAILS TO OPEN	4.00E-03	1	4.00E-03	
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
7) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	6.40E-07
VVSXD-SET2	COMMON CAUSE FAILURE OF RCGVS VALVES RC-410/RC-413 TO OPEN		8.00E-04	8.00E-04	
VVSXD-SET3	COMMON CAUSE FAILURE OF RCGVS VALVES RC-414/RC-417 TO OPEN		8.00E-04	8.00E-04	
8) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	1.08E-07
ELCX125C1E	COMMON CAUSE FAILURE OF 125 VDC CLASS 1E BUS		1.08E-07	1.08E-07	
9) DVMASG-185	ADV SG-185 FAILS TO OPEN	4.00E-03	1	4.00E-03	4.80E-08
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
EBBQSB0801S	125 VDC CIRCUIT BREAKER SB0801S OPENS SPURIOUSLY	5.00E-07	24	1.20E-05	
10) DVMASG-179	ADV SG-179 FAILS TO OPEN	4.00E-03	1	4.00E-03	4.80E-08
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
EBBQSD0801S	125 VDC CIRCUIT BREAKER SD0801S OPENS SPURIOUSLY	5.00E-07	24	1.20E-05	
11) DVMASG-179	ADV SG-179 FAILS TO OPEN	4.00E-03	1	4.00E-03	1.92E-08
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
ELCPSD0801	BUS FAULT ON 125 VDC BUS SD0801.	2.00E-07	24	4.80E-06	
12) DVMASG-185	ADV SG-185 FAILS TO OPEN	4.00E-03	1	4.00E-03	1.92E-08
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
ELCPSB0801	BUS FAULT ON 125 VDC BUS SB0801.	2.00E-07	24	4.80E-06	
13) DVMASG-179	ADV SG-179 FAILS TO OPEN	4.00E-03	1	4.00E-03	1.34E-08
DVMDSG-185	ADV SG-185 FAILS TO REMAIN OPEN	1.40E-07	24	3.36E-06	
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
14) DVMASG-185	ADV SG-185 FAILS TO OPEN	4.00E-03	1	4.00E-03	1.34E-08
DVMDSG-179	ADV SG-179 FAILS TO REMAIN OPEN	1.40E-07	24	3.36E-06	
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
15) DVMASG-179	ADV SG-179 FAILS TO OPEN	4.00E-03	1	4.00E-03	1.34E-08
DVMDSG-107	BLOCK VALVE SG-107 FOR ADV SG-185 FAILS TO REMAIN OPEN	1.40E-07	24	3.36E-06	
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	

16)	DVMASG-185	ADV SG-185 FAILS TO OPEN	4.00E-03	1	4.00E-03	1.34E-08
	DVMDSG-108	BLOCK VALVE SG-108 FOR ADV SG-179 FAILS TO REMAIN OPEN	1.40E-07	24	3.36E-06	
	DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	

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MODULE/EVENT NAME	DESCRIPTION	RATE	EXPOSURE	B.E. PROB.	MOD./CS. PROB.
1) MSSVSEN3					*9.59E-03
1) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	9.38E-03
PHFFRCSP	OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL		9.38E-03	9.38E-03	
2) DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	8.96E-05
KVDXD-TBVS	COMMON CAUSE FAILURE OF ALL 8 TURBINE BYPASS VALVES TO OPEN		1.60E-03	1.60E-03	
3) DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	4.48E-05
EBGPTT	GRID COLLAPSE ON TURBINE TRIP		8.00E-04	8.00E-04	
4) DHFFADVS-SG2	OPERATOR FAILS TO OPEN ATMOSPHERIC DUMP VALVES ON SG-2		4.66E-03	4.66E-03	2.93E-05
DHFFCTMTISOVLVS	OPERATOR FAILS TO REOPEN CONTAINMENT ISOLATION VALVES (UV-006 AND		6.28E-03	6.28E-03	
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
5) DHFFADVS-SG2	OPERATOR FAILS TO OPEN ATMOSPHERIC DUMP VALVES ON SG-2		4.66E-03	4.66E-03	1.38E-05
DVDAUV-006	PNEUM. DIAPHRAGM OPERATED VALVE UV-006 FAILS TO REOPEN	2.96E-03	1	2.96E-03	
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
6) DHFFADVS-SG2	OPERATOR FAILS TO OPEN ATMOSPHERIC DUMP VALVES ON SG-2		4.66E-03	4.66E-03	1.38E-05
DVDAUV-008	PNEUM. DIAPHRAGM OPERATED VALVE UV-008 FAILS TO REOPEN	2.96E-03	1	2.96E-03	
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
7) DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	1.11E-05
ISXRIAS	IA CONTROLS FAIL TO OPERATE PROPERLY		1.99E-04	1.99E-04	
8) DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	4.06E-06
KIEPTBCS	FAILURE OF TURBINE BYPASS CONTROL SYSTEM TO OPERATE		7.25E-05	7.25E-05	
9) DHFFADVS-SG2	OPERATOR FAILS TO OPEN ATMOSPHERIC DUMP VALVES ON SG-2		4.66E-03	4.66E-03	3.73E-06
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
EBGPTT	GRID COLLAPSE ON TURBINE TRIP		8.00E-04	8.00E-04	
10) DHFFCTMTISOVLVS	OPERATOR FAILS TO REOPEN CONTAINMENT ISOLATION VALVES (UV-006 AND		6.28E-03	6.28E-03	1.26E-06
DVMXD-ADVSG2	COMMON CAUSE FAILURE OF 2 ADVs ON STEAM GENERATOR 2 TO OPEN		2.00E-04	2.00E-04	
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
11) DHFFADVS-SG2	OPERATOR FAILS TO OPEN ATMOSPHERIC DUMP VALVES ON SG-2		4.66E-03	4.66E-03	9.27E-07
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
ISXRIAS	IA CONTROLS FAIL TO OPERATE PROPERLY		1.99E-04	1.99E-04	
12) DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	8.46E-07
KGPPSWCD	CONDENSER PRESSURE SWITCH SWCD FAILS TO OPERATE	6.30E-07	24	1.51E-05<	
13) DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	6.72E-07
EBBOPX0801S	125 VDC CIRCUIT BREAKER PK0801S OPENS SPURIOUSLY	5.00E-07	24	1.20E-05	
14) DVDAUV-006	PNEUM. DIAPHRAGM OPERATED VALVE UV-006 FAILS TO REOPEN	2.96E-03	1	2.96E-03	5.92E-07
DVMXD-ADVSG2	COMMON CAUSE FAILURE OF 2 ADVs ON STEAM GENERATOR 2 TO OPEN		2.00E-04	2.00E-04	
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
15) DVDAUV-008	PNEUM. DIAPHRAGM OPERATED VALVE UV-008 FAILS TO REOPEN	2.96E-03	1	2.96E-03	5.92E-07
DVMXD-ADVSG2	COMMON CAUSE FAILURE OF 2 ADVs ON STEAM GENERATOR 2 TO OPEN		2.00E-04	2.00E-04	
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	

16)	DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	2.69E-07
	ELCPPX0801	BUS FAULT ON 125 VDC BUS PX0801.	2.00E-07	24	4.80E-06	
17)	DHFFADVS-SG2	OPERATOR FAILS TO OPEN ATMOSPHERIC DUMP VALVES ON SG-2		4.66E-03	4.66E-03	1.79E-07
	DVDOUV-008	PNEUM. DIAPHRAGM OPERATED VALVE UV-008 FAILS TO REMAIN OPEN	1.60E-06	24	3.84E-05	
	DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
18)	DHFFADVS-SG2	OPERATOR FAILS TO OPEN ATMOSPHERIC DUMP VALVES ON SG-2		4.66E-03	4.66E-03	1.79E-07
	DVDOUV-006	PNEUM. DIAPHRAGM OPERATED VALVE UV-006 FAILS TO REMAIN OPEN	1.60E-06	24	3.84E-05	
	DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
19)	DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	1.78E-07
	IADXAIRDRYS	COMMON CAUSE FAILURE OF INSTRUMENT AIR DRYERS		3.18E-06	3.18E-06	
20)	DVMXD-ADVSG2	COMMON CAUSE FAILURE OF 2 ADVs ON STEAM GENERATOR 2 TO OPEN		2.00E-04	2.00E-04	1.60E-07
	DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
	EBGPTT	GRID COLLAPSE ON TURBINE TRIP		8.00E-04	8.00E-04	
21)	DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	1.60E-07
	EBGPTT	GRID COLLAPSE ON TURBINE TRIP		8.00E-04	8.00E-04	
	VVSXD-SET1	COMMON CAUSE FAILURE OF RCGVS VALVES RC-418/RC-419 TO OPEN		2.00E-04	2.00E-04	
22)	DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	1.34E-07
	IWCKC-1A	AIR COMPRESSOR C-1A FAILS TO OPERATE (RUN)	1.00E-04	24	2.40E-03	
	IWCXDCOMP	COMMON CAUSE DEMAND FAILURE OF AIR COMPRESSORS		1.00E-03	1.00E-03	
23)	DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	1.08E-07
	ELCX125C1E	COMMON CAUSE FAILURE OF 125 VDC CLASS 1E BUS		1.08E-07	1.08E-07	
24)	DHFFCTMTISOVLVS	OPERATOR FAILS TO REOPEN CONTAINMENT ISOLATION VALVES (UV-006 AND		6.28E-03	6.28E-03	1.00E-07
	DVMASG-179	ADV SG-179 FAILS TO OPEN	4.00E-03	1	4.00E-03	
	DVMASG-185	ADV SG-185 FAILS TO OPEN	4.00E-03	1	4.00E-03	
	DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	

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MODULE/EVENT NAME	DESCRIPTION	RATE	EXPOSURE	B.E. PROB.	MOD./CS. PROB.
1) MSSVSEN4					*5.63E-02
1) DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	5.60E-02
2) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	1.72E-04
PHFFRCSP	OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL		9.38E-03	9.38E-03	
VHFFFEEDBLEED	OPERATOR FAILS TO INITIATE FEED & BLEED SYSTEM		1.83E-02	1.83E-02	
3) DHFFADVS-SG2	OPERATOR FAILS TO OPEN ATMOSPHERIC DUMP VALVES ON SG-2		4.66E-03	4.66E-03	8.53E-05
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
VHFFFEEDBLEED	OPERATOR FAILS TO INITIATE FEED & BLEED SYSTEM		1.83E-02	1.83E-02	
4) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	4.50E-05
PHFFRCSP	OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL		9.38E-03	9.38E-03	
VVMXBLDV	COMMON CAUSE FAILURE OF BLEED VALVES		4.80E-03	4.80E-03	
5) DHFFADVS-SG2	OPERATOR FAILS TO OPEN ATMOSPHERIC DUMP VALVES ON SG-2		4.66E-03	4.66E-03	2.24E-05
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
VVMXBLDV	COMMON CAUSE FAILURE OF BLEED VALVES		4.80E-03	4.80E-03	
6) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	5.40E-06
PHFFRCSP	OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL		9.38E-03	9.38E-03	
VVMARC-406	MOV RC-406 FAILS TO OPEN		2.40E-02	2.40E-02	
VVMARC-409	MOV RC-409 FAILS TO OPEN		2.40E-02	2.40E-02	
7) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	5.40E-06
PHFFRCSP	OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL		9.38E-03	9.38E-03	
VVMARC-408	MOV RC-408 FAILS TO OPEN		2.40E-02	2.40E-02	
VVMARC-409	MOV RC-409 FAILS TO OPEN		2.40E-02	2.40E-02	
8) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	5.40E-06
PHFFRCSP	OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL		9.38E-03	9.38E-03	
VVMARC-407	MOV RC-407 FAILS TO OPEN		2.40E-02	2.40E-02	
VVMARC-408	MOV RC-408 FAILS TO OPEN		2.40E-02	2.40E-02	
9) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	5.40E-06
PHFFRCSP	OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL		9.38E-03	9.38E-03	
VVMARC-406	MOV RC-406 FAILS TO OPEN		2.40E-02	2.40E-02	
VVMARC-407	MOV RC-407 FAILS TO OPEN		2.40E-02	2.40E-02	
10) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	3.66E-06
VHFFFEEDBLEED	OPERATOR FAILS TO INITIATE FEED & BLEED SYSTEM		1.83E-02	1.83E-02	
VVSXD-SET1	COMMON CAUSE FAILURE OF RCGVS VALVES RC-418/RC-419 TO OPEN		2.00E-04	2.00E-04	
11) DVMXD-ADVSG2	COMMON CAUSE FAILURE OF 2 ADVs ON STEAM GENERATOR 2 TO OPEN		2.00E-04	2.00E-04	3.66E-06
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
VHFFFEEDBLEED	OPERATOR FAILS TO INITIATE FEED & BLEED SYSTEM		1.83E-02	1.83E-02	
12) DHFFADVS-SG2	OPERATOR FAILS TO OPEN ATMOSPHERIC DUMP VALVES ON SG-2		4.66E-03	4.66E-03	2.68E-06
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
VVMARC-406	MOV RC-406 FAILS TO OPEN		2.40E-02	2.40E-02	

	VVMARC-409	MOV RC-409 FAILS TO OPEN	2.40E-02	2.40E-02	
13)	DHFFADVS-SG2	OPERATOR FAILS TO OPEN ATMOSPHERIC DUMP VALVES ON SG-2	4.66E-03	4.66E-03	2.68E-06
	DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER	1.00	1.00E+00	
	VVMARC-407	MOV RC-407 FAILS TO OPEN	2.40E-02	2.40E-02	
	VVMARC-408	MOV RC-408 FAILS TO OPEN	2.40E-02	2.40E-02	
14)	DHFFADVS-SG2	OPERATOR FAILS TO OPEN ATMOSPHERIC DUMP VALVES ON SG-2	4.66E-03	4.66E-03	2.68E-06
	DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER	1.00	1.00E+00	
	VVMARC-406	MOV RC-406 FAILS TO OPEN	2.40E-02	2.40E-02	
	VVMARC-407	MOV RC-407 FAILS TO OPEN	2.40E-02	2.40E-02	
15)	DHFFADVS-SG2	OPERATOR FAILS TO OPEN ATMOSPHERIC DUMP VALVES ON SG-2	4.66E-03	4.66E-03	2.68E-06
	DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER	1.00	1.00E+00	
	VVMARC-408	MOV RC-408 FAILS TO OPEN	2.40E-02	2.40E-02	
	VVMARC-409	MOV RC-409 FAILS TO OPEN	2.40E-02	2.40E-02	

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MODULE/EVENT NAME	DESCRIPTION	RATE	EXPOSURE	B.E. PROB.	MOD./CS. PROB.
1) MSSVSEN5					*4.87E-03
1) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	4.69E-03
PHFFRCSP	OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL		4.69E-03	4.69E-03	
2) DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	8.96E-05
KVDXD-TBVS	COMMON CAUSE FAILURE OF ALL 8 TURBINE BYPASS VALVES TO OPEN		1.60E-03	1.60E-03	
3) DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	4.48E-05
EBGPTT	GRID COLLAPSE ON TURBINE TRIP		8.00E-04	8.00E-04	
4) DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	1.11E-05
ISXRIAS	IA CONTROLS FAIL TO OPERATE PROPERLY		1.99E-04	1.99E-04	
5) DHFFADVS-SG2	OPERATOR FAILS TO OPEN ATMOSPHERIC DUMP VALVES ON SG-2		2.33E-03	2.33E-03	7.32E-06
DHFFCTMTISOVLVS	OPERATOR FAILS TO REOPEN CONTAINMENT ISOLATION VALVES (UV-006 AND		3.14E-03	3.14E-03	
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
6) DHFFADVS-SG2	OPERATOR FAILS TO OPEN ATMOSPHERIC DUMP VALVES ON SG-2		2.33E-03	2.33E-03	6.90E-06
DVDAUV-006	PNEUM. DIAPHRAGM OPERATED VALVE UV-006 FAILS TO REOPEN	2.96E-03	1	2.96E-03	
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
7) DHFFADVS-SG2	OPERATOR FAILS TO OPEN ATMOSPHERIC DUMP VALVES ON SG-2		2.33E-03	2.33E-03	6.90E-06
DVDAUV-008	PNEUM. DIAPHRAGM OPERATED VALVE UV-008 FAILS TO REOPEN	2.96E-03	1	2.96E-03	
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
8) DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	4.06E-06
KIEPTBCS	FAILURE OF TURBINE BYPASS CONTROL SYSTEM TO OPERATE		7.25E-05	7.25E-05	
9) DHFFADVS-SG2	OPERATOR FAILS TO OPEN ATMOSPHERIC DUMP VALVES ON SG-2		2.33E-03	2.33E-03	1.86E-06
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
EBGPTT	GRID COLLAPSE ON TURBINE TRIP		8.00E-04	8.00E-04	
10) DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	8.46E-07
KGPPSWCD	CONDENSER PRESSURE SWITCH SWCD FAILS TO OPERATE	6.30E-07	24	1.51E-05<	
11) DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	6.72E-07
EBBQPX0801S	125 VDC CIRCUIT BREAKER PX0801S OPENS SPURIOUSLY	5.00E-07	24	1.20E-05	
12) DHFFCTMTISOVLVS	OPERATOR FAILS TO REOPEN CONTAINMENT ISOLATION VALVES (UV-006 AND		3.14E-03	3.14E-03	6.28E-07
DVMXD-ADVSG2	COMMON CAUSE FAILURE OF 2 ADVs ON STEAM GENERATOR 2 TO OPEN		2.00E-04	2.00E-04	
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
13) DVDAUV-006	PNEUM. DIAPHRAGM OPERATED VALVE UV-006 FAILS TO REOPEN	2.96E-03	1	2.96E-03	5.92E-07
DVMXD-ADVSG2	COMMON CAUSE FAILURE OF 2 ADVs ON STEAM GENERATOR 2 TO OPEN		2.00E-04	2.00E-04	
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
14) DVDAUV-008	PNEUM. DIAPHRAGM OPERATED VALVE UV-008 FAILS TO REOPEN	2.96E-03	1	2.96E-03	5.92E-07
DVMXD-ADVSG2	COMMON CAUSE FAILURE OF 2 ADVs ON STEAM GENERATOR 2 TO OPEN		2.00E-04	2.00E-04	
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	

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MODULE/EVENT NAME	DESCRIPTION	RATE	EXPOSURE	B.E. PROB.	MOD./CS. PROB.
15) DNFFADVS-SG2	OPERATOR FAILS TO OPEN ATMOSPHERIC DUMP VALVES ON SG-2		2.33E-03	2.33E-03	4.64E-07
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
ISXRIAS	IA CONTROLS FAIL TO OPERATE PROPERLY		1.99E-04	1.99E-04	
16) DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	2.69E-07
ELCPPX0801	BUS FAULT ON 125 VDC BUS PX0801.	2.00E-07	24	4.80E-06	
17) DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	1.78E-07
IADXAIRDRYS	COMMON CAUSE FAILURE OF INSTRUMENT AIR DRYERS		3.18E-06	3.18E-06	
18) DVMXD-ADVSG2	COMMON CAUSE FAILURE OF 2 ADVs ON STEAM GENERATOR 2 TO OPEN		2.00E-04	2.00E-04	1.60E-07
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
EBGPTT	GRID COLLAPSE ON TURBINE TRIP		8.00E-04	8.00E-04	
19) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	1.60E-07
EBGPTT	GRID COLLAPSE ON TURBINE TRIP		8.00E-04	8.00E-04	
VVSXD-SET1	COMMON CAUSE FAILURE OF RCGVS VALVES RC-418/RC-419 TO OPEN		2.00E-04	2.00E-04	
20) DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	1.34E-07
1WCKC-1A	AIR COMPRESSOR C-1A FAILS TO OPERATE (RUN)	1.00E-04	24	2.40E-03	
1WCXDCOMP	COMMON CAUSE DEMAND FAILURE OF AIR COMPRESSORS		1.00E-03	1.00E-03	
21) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	1.08E-07
ELCX125C1E	COMMON CAUSE FAILURE OF 125 VDC CLASS 1E BUS		1.08E-07	1.08E-07	

Filter: 'ACTIVE'

MODULE/EVENT NAME	DESCRIPTION	RATE	EXPOSURE	B.E. PROB.	MOD./CS. PROB.
1) MSSVSEN6					*3.93E-04
1) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	1.72E-04
PHFFRCSP	OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL		9.38E-03	9.38E-03	
VHFFFEEDBLEED	OPERATOR FAILS TO INITIATE FEED & BLEED SYSTEM		1.83E-02	1.83E-02	
2) DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	8.96E-05
KVDXD-TBVS	COMMON CAUSE FAILURE OF ALL 8 TURBINE BYPASS VALVES TO OPEN		1.60E-03	1.60E-03	
3) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	4.50E-05
PHFFRCSP	OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL		9.38E-03	9.38E-03	
VVMXBLDV	COMMON CAUSE FAILURE OF BLEED VALVES		4.80E-03	4.80E-03	
4) DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	4.48E-05
EBGPTT	GRID COLLAPSE ON TURBINE TRIP		8.00E-04	8.00E-04	
5) DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	1.11E-05
ISXRIAS	IA CONTROLS FAIL TO OPERATE PROPERLY		1.99E-04	1.99E-04	
6) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	5.40E-06
PHFFRCSP	OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL		9.38E-03	9.38E-03	
VVMARC-406	MOV RC-406 FAILS TO OPEN		2.40E-02	2.40E-02	
VVMARC-409	MOV RC-409 FAILS TO OPEN		2.40E-02	2.40E-02	
7) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	5.40E-06
PHFFRCSP	OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL		9.38E-03	9.38E-03	
VVMARC-408	MOV RC-408 FAILS TO OPEN		2.40E-02	2.40E-02	
VVMARC-409	MOV RC-409 FAILS TO OPEN		2.40E-02	2.40E-02	
8) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	5.40E-06
PHFFRCSP	OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL		9.38E-03	9.38E-03	
VVMARC-406	MOV RC-406 FAILS TO OPEN		2.40E-02	2.40E-02	
VVMARC-407	MOV RC-407 FAILS TO OPEN		2.40E-02	2.40E-02	
9) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	5.40E-06
PHFFRCSP	OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL		9.38E-03	9.38E-03	
VVMARC-407	MOV RC-407 FAILS TO OPEN		2.40E-02	2.40E-02	
VVMARC-408	MOV RC-408 FAILS TO OPEN		2.40E-02	2.40E-02	
10) DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	4.06E-06
KIEPTBCS	FAILURE OF TURBINE BYPASS CONTROL SYSTEM TO OPERATE		7.25E-05	7.25E-05	
11) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	9.00E-07
PHFFRCSP	OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL		9.38E-03	9.38E-03	
VCIXBLDV	COMMON CAUSE FAILURE OF BLEED VALVE INVERTERS		9.60E-05	9.60E-05	
12) DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	8.46E-07
KGPPSWCD	CONDENSER PRESSURE SWITCH SWCD FAILS TO OPERATE	6.30E-07	24	1.51E-05<	
13) DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	6.72E-07
EBBQPX0801S	125 VDC CIRCUIT BREAKER PX0801S OPENS SPURIOUSLY	5.00E-07	24	1.20E-05	
14) DHFFADVS-SG2	OPERATOR FAILS TO OPEN ATMOSPHERIC DUMP VALVES ON SG-2		4.66E-03	4.66E-03	5.36E-07

DHFFCTMTISOVLVS	OPERATOR FAILS TO REOPEN CONTAINMENT ISOLATION VALVES (UV-006 AND		6.28E-03	6.28E-03	
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
VHFFFEEDBLEED	OPERATOR FAILS TO INITIATE FEED & BLEED SYSTEM		1.83E-02	1.83E-02	
15) DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	2.69E-07
ELCPPX0801	BUS FAULT ON 125 VDC BUS PX0801.	2.00E-07	24	4.80E-06	
16) DHFFADVS-SG2	OPERATOR FAILS TO OPEN ATMOSPHERIC DUMP VALVES ON SG-2		4.66E-03	4.66E-03	2.52E-07
DVDAUV-008	PNEUM. DIAPHRAGM OPERATED VALVE UV-008 FAILS TO REOPEN	2.96E-03	1	2.96E-03	
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
VHFFFEEDBLEED	OPERATOR FAILS TO INITIATE FEED & BLEED SYSTEM		1.83E-02	1.83E-02	
17) DHFFADVS-SG2	OPERATOR FAILS TO OPEN ATMOSPHERIC DUMP VALVES ON SG-2		4.66E-03	4.66E-03	2.52E-07
DVDAUV-006	PNEUM. DIAPHRAGM OPERATED VALVE UV-006 FAILS TO REOPEN	2.96E-03	1	2.96E-03	
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
VHFFFEEDBLEED	OPERATOR FAILS TO INITIATE FEED & BLEED SYSTEM		1.83E-02	1.83E-02	
18) DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	1.78E-07
IADXAIRDRYS	COMMON CAUSE FAILURE OF INSTRUMENT AIR DRYERS		3.18E-06	3.18E-06	
19) DHFFADVS-SG2	OPERATOR FAILS TO OPEN ATMOSPHERIC DUMP VALVES ON SG-2		4.66E-03	4.66E-03	1.40E-07
DHFFCTMTISOVLVS	OPERATOR FAILS TO REOPEN CONTAINMENT ISOLATION VALVES (UV-006 AND		6.28E-03	6.28E-03	
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
VVMXBLDV	COMMON CAUSE FAILURE OF BLEED VALVES		4.80E-03	4.80E-03	
20) DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	1.34E-07
IWCKC-1A	AIR COMPRESSOR C-1A FAILS TO OPERATE (RUN)	1.00E-04	24	2.40E-03	
IWCXDCOMP	COMMON CAUSE DEMAND FAILURE OF AIR COMPRESSORS		1.00E-03	1.00E-03	
21) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	1.08E-07
PHFFRCSP	OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL		9.38E-03	9.38E-03	
VCIPRC-409	BLEED VALVE INVERTER RC-409 FAILS TO PROVIDE ADEQUATE OUTPUT	2.00E-05	24	4.80E-04	
VVMARC-406	MOV RC-406 FAILS TO OPEN		2.40E-02	2.40E-02	
22) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	1.08E-07
PHFFRCSP	OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL		9.38E-03	9.38E-03	
VCIPRC-406	BLEED VALVE INVERTER RC-406 FAILS TO PROVIDE ADEQUATE OUTPUT	2.00E-05	24	4.80E-04	
VVMARC-409	MOV RC-409 FAILS TO OPEN		2.40E-02	2.40E-02	
23) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	1.08E-07
PHFFRCSP	OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL		9.38E-03	9.38E-03	
VCIPRC-408	BLEED VALVE INVERTER RC-408 FAILS TO PROVIDE ADEQUATE OUTPUT	2.00E-05	24	4.80E-04	
VVMARC-409	MOV RC-409 FAILS TO OPEN		2.40E-02	2.40E-02	
24) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	1.08E-07
PHFFRCSP	OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL		9.38E-03	9.38E-03	
VCIPRC-406	BLEED VALVE INVERTER RC-406 FAILS TO PROVIDE ADEQUATE OUTPUT	2.00E-05	24	4.80E-04	
VVMARC-407	MOV RC-407 FAILS TO OPEN		2.40E-02	2.40E-02	
25) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	1.08E-07
PHFFRCSP	OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL		9.38E-03	9.38E-03	
VCIPRC-408	BLEED VALVE INVERTER RC-408 FAILS TO PROVIDE ADEQUATE OUTPUT	2.00E-05	24	4.80E-04	
VVMARC-407	MOV RC-407 FAILS TO OPEN		2.40E-02	2.40E-02	
26) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	1.08E-07
PHFFRCSP	OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL		9.38E-03	9.38E-03	
VCIPRC-407	BLEED VALVE INVERTER RC-407 FAILS TO PROVIDE ADEQUATE OUTPUT	2.00E-05	24	4.80E-04	

	VVMARC-408	MOV RC-408 FAILS TO OPEN		2.40E-02	2.40E-02	
27)	DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	1.08E-07
	PHFFRCSP	OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL		9.38E-03	9.38E-03	
	VCIPRC-407	BLEED VALVE INVERTER RC-407 FAILS TO PROVIDE ADEQUATE OUTPUT	2.00E-05	24	4.80E-04	
	VVMARC-406	MOV RC-406 FAILS TO OPEN		2.40E-02	2.40E-02	
28)	DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	1.08E-07
	PHFFRCSP	OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL		9.38E-03	9.38E-03	
	VCIPRC-409	BLEED VALVE INVERTER RC-409 FAILS TO PROVIDE ADEQUATE OUTPUT	2.00E-05	24	4.80E-04	
	VVMARC-408	MOV RC-408 FAILS TO OPEN		2.40E-02	2.40E-02	
29)	DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	1.08E-07
	ELCX125C1E	COMMON CAUSE FAILURE OF 125 VDC CLASS 1E BUS		1.08E-07	1.08E-07	

Filter: 'ACTIVE'

MODULE/EVENT NAME	DESCRIPTION	RATE	EXPOSURE	B.E. PROB.	MOD./CS. PROB.
1) MSSVSEN7					*5.61E-02
1) DVRBMSSV-S	MAIN STEAM SAFETY VALVES (MSSV) FAILS TO RESEAT AFTER EARLY OPENIN		5.60E-02	5.60E-02	5.60E-02
2) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	4.29E-05
PHFFRCSP	OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL		4.69E-03	4.69E-03	
VHFFFEEDBLEED	OPERATOR FAILS TO INITIATE FEED & BLEED SYSTEM		9.15E-03	9.15E-03	
3) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	2.25E-05
PHFFRCSP	OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL		4.69E-03	4.69E-03	
VVMXBLDV	COMMON CAUSE FAILURE OF BLEED VALVES		4.80E-03	4.80E-03	
4) DHFFADVS-SG2	OPERATOR FAILS TO OPEN ATMOSPHERIC DUMP VALVES ON SG-2		2.33E-03	2.33E-03	2.13E-05
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
VHFFFEEDBLEED	OPERATOR FAILS TO INITIATE FEED & BLEED SYSTEM		9.15E-03	9.15E-03	
5) DHFFADVS-SG2	OPERATOR FAILS TO OPEN ATMOSPHERIC DUMP VALVES ON SG-2		2.33E-03	2.33E-03	1.12E-05
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
VVMXBLDV	COMMON CAUSE FAILURE OF BLEED VALVES		4.80E-03	4.80E-03	
6) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	2.70E-06
PHFFRCSP	OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL		4.69E-03	4.69E-03	
VVMARC-407	MOV RC-407 FAILS TO OPEN		2.40E-02	2.40E-02	
VVMARC-408	MOV RC-408 FAILS TO OPEN		2.40E-02	2.40E-02	
7) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	2.70E-06
PHFFRCSP	OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL		4.69E-03	4.69E-03	
VVMARC-406	MOV RC-406 FAILS TO OPEN		2.40E-02	2.40E-02	
VVMARC-407	MOV RC-407 FAILS TO OPEN		2.40E-02	2.40E-02	
8) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	2.70E-06
PHFFRCSP	OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL		4.69E-03	4.69E-03	
VVMARC-406	MOV RC-406 FAILS TO OPEN		2.40E-02	2.40E-02	
VVMARC-409	MOV RC-409 FAILS TO OPEN		2.40E-02	2.40E-02	
9) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	2.70E-06
PHFFRCSP	OPERATOR FAILS ESTABLISH RCS PRESSURE CONTROL		4.69E-03	4.69E-03	
VVMARC-408	MOV RC-408 FAILS TO OPEN		2.40E-02	2.40E-02	
VVMARC-409	MOV RC-409 FAILS TO OPEN		2.40E-02	2.40E-02	
10) DVMXD-ADVSG2	COMMON CAUSE FAILURE OF 2 ADVs ON STEAM GENERATOR 2 TO OPEN		2.00E-04	2.00E-04	1.83E-06
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
VHFFFEEDBLEED	OPERATOR FAILS TO INITIATE FEED & BLEED SYSTEM		9.15E-03	9.15E-03	
11) DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	1.83E-06
VHFFFEEDBLEED	OPERATOR FAILS TO INITIATE FEED & BLEED SYSTEM		9.15E-03	9.15E-03	
VVSXD-SET1	COMMON CAUSE FAILURE OF RCGVS VALVES RC-418/RC-419 TO OPEN		2.00E-04	2.00E-04	
12) DHFFADVS-SG2	OPERATOR FAILS TO OPEN ATMOSPHERIC DUMP VALVES ON SG-2		2.33E-03	2.33E-03	1.34E-06
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER		1.00	1.00E+00	
VVMARC-407	MOV RC-407 FAILS TO OPEN		2.40E-02	2.40E-02	

VVMARC-408	MOV RC-408 FAILS TO OPEN	2.40E-02	2.40E-02	
13) DHFFADVS-SG2	OPERATOR FAILS TO OPEN ATMOSPHERIC DUMP VALVES ON SG-2	2.33E-03	2.33E-03	1.34E-06
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER	1.00	1.00E+00	
VVMARC-406	MOV RC-406 FAILS TO OPEN	2.40E-02	2.40E-02	
VVMARC-409	MOV RC-409 FAILS TO OPEN	2.40E-02	2.40E-02	
14) DHFFADVS-SG2	OPERATOR FAILS TO OPEN ATMOSPHERIC DUMP VALVES ON SG-2	2.33E-03	2.33E-03	1.34E-06
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER	1.00	1.00E+00	
VVMARC-408	MOV RC-408 FAILS TO OPEN	2.40E-02	2.40E-02	
VVMARC-409	MOV RC-409 FAILS TO OPEN	2.40E-02	2.40E-02	
15) DHFFADVS-SG2	OPERATOR FAILS TO OPEN ATMOSPHERIC DUMP VALVES ON SG-2	2.33E-03	2.33E-03	1.34E-06
DVRBMSSV-L	MAIN STEAM SAFETY VALVES (MSSV) FAIL TO RESEAT AFTER PASSING WATER	1.00	1.00E+00	
VVMARC-406	MOV RC-406 FAILS TO OPEN	2.40E-02	2.40E-02	
VVMARC-407	MOV RC-407 FAILS TO OPEN	2.40E-02	2.40E-02	