ENCLOSURE I

CEN-239, DEPRESSURIZATION AND DECAY HEAT REMOVAL RESPONSES TO NRC QUESTIONS

JUNE 1983

CEN-239

DEPRESSURIZATION AND DECAY HEAT REMOVAL

RESPONSE TO NRC QUESTIONS

Prepared for the C-E OWNERS GROUP

NUCLEAR POWER SYSTEMS DIVISION
JUNE, 1983

C-E POWER SYSTEMS
COMBUSTION ENGINEERING, INC.

LEGAL NOTICE

CEN-239

DEPRESSURIZATION
AND
DECAY HEAT REMOVAL

RESPONSE TO NRC QUESTIONS

PREPARED FOR THE COMBUSTION ENGINEERING OWNERS GROUP

Nuclear Power Systems Division
June, 1983

Combustion Engineering, Inc.

ABSTRACT

The NRC staff has requested information on the capability of the C-E 3410 and the C-E 3800 Class designs with respect to the rapid depressurization and decay heat removal capabilities without power operated relief valves (PORVs). In response to this request C-E has completed a program for the Combustion Engineering Owners Group to answer fourteen questions which, taken collectively, provide an assessment of the potential effect on plant safety of adding PORVs to the above plant classes.

The program to assess the potential impact on safety involved a probabilistic risk assessment and a performance evaluation of the 3410 and the 3800 plants, both with and without PORVs. A total loss of feedwater (TLOFW), a steam generator tube rupture (SGTR), and a loss of coolant accident (LOCA) due to the inadvertent opening of a PORV were explicitly evaluated for their contribution to the risk of core damage. Performance evaluations were conducted relative to plant response during a SGTR, certain multiple SGTR scenarios, a small break LOCA with no high pressure safety injection, and a TLOFW. In addition, a performance evaluation relative to pressurized thermal shock and anticipated transients without scram were performed.

The results of the probabilistic assessment indicated that the change in core damage frequency due to installation of PORVs was impacted only by the TLOFW and LOCA events, the impact of the SGTR being negligible. The results further showed that any change in the core damage frequency due to the addition of automatic or manually initiated PORVs would be very small and that overall the change due to adding PORVs could in fact be an increase in the core damage frequency for cases where auxiliary feedwater and other mitigating systems are highly reliable. Finally, the probabilistic assessment showed that the effect on core damage frequency, whether an increase or decrease, is very small when compared to the proposed NRC safety guideline of 10^{-4} core melts per year.

The results of the performance evaluation indicated that no significant benefits would be realized from the back fit of PORVs to the 3410 and the 3800

plants. Further, an evaluation of the effects of adding PORVs on plant availability was conducted which showed a negative impact, i.e., the addition of PORVs would increase the plant shutdown time per year.

In general the efforts conducted for the Combustion Engineering Owners Group in response to the NRC questions and the results obtained showed that the benefits realized from addition of PORVs are insufficient to warrent a recommendation that PORVs be installed on the 3410 and the 3800 plants.

EXECUTIVE SUMMARY

This report provides generic responses to a request from the NRC Staff for additional information regarding the rapid depressurization and decay heat removal capability of the C-E NSSS without PORVs. As such the information and data compiled in CEN-239 are applicable to the San Onofre Nuclear Generating Station Units 2 & 3 (3410 Class plants), the Waterford Steam Electric Station Unit 3 (3410 Class plant), the Palo Verde Nuclear Generating Station Units 1, 2, and 3 (3800 Class plants), and the Washington Public Supply System Nuclear Project Number 3 (3800 Class plant). CEN-239 contains the results of the performance evaluations and the four supplements to CEN-239 contain the results of the plant specific probabilistic risk assessments. The analyses presented in this document were performed at the request of NRC in order to address specific concerns which the NRC Staff had regarding the response of the C-E NSSS without PORVs to certain postulated events. In general, these postulated events are beyond the design bases of the plants. As such, the results of the analyses presented in this report represent best estimate plant response to the specific scenarios postulated by the NRC Staff and should not be construed as advance engineering design work or operating procedure information for any future system which may or may not be installed.

A brief summary of each question asked by the NRC Staff is listed below along with a brief summary of the response contained in ths main body of the report.

Question 1: Auxiliary Spray Capability

This question effectively asks that a full description of the auxiliary spray system be given along with a discussion of the capability of the system to effect RCS depressurization under a variety of conditions.

The auxiliary spray system has been included in every C-E designed NSSS and has been demonstrated to be an effective depressurization system under conditions where RCPs are not operating and therefore main spray is not available. This system, which is an integral part of the CVCS, consists of two redundant safety-grade auxiliary spray valves and associated piping. The auxiliary spray valves in conjunction with the loop charging valves direct charging flow at the outlet of the regenerative heat exchanger through the pressurizer spray nozzle and into the pressurizer steam space. Auxiliary spray provides the safety-related method for relatively rapid and controlled depressurizstion of the RCS to cold shutdown conditions. As such the system has a degree of performance consistent with the NRC Branch Technical Position RSB 5-1.

The approximate depressurization rates achievable using the auxiliary spray system are presented in Table I (p. vii) for the 3410 plant and the 3800 plant. As suggested by the data in Table I, the rate of depressurization is controlled by varying the number of operating charging pumps. These rates are sufficiently rapid to provide for successful mitigation of events that require a reduction in system pressure when main spray is not available. Specifically plant pressure during the SGTR event, which is one of the most challenging design basis events for an operator from the standpoint of RCS depressurization, is shown in the report to be satisfactorily accomplished using auxiliary spray. During this event system depressurization is found to be limited by the procedural requirement to maintain proper RCS subcooling and not by the specific depressurization method. Therefore auxiliary spray provides a performance level comparable to PORVs for mitigation of the tube rupture event and minimizing the primary-to-secondary leak rate. Figure I (p. viii) contains the results of the SGTR analysis showing a comparison of the leak rates in a C-E NSSS using auxiliary spray versus PORVs to accomplish system depressurization. Note, as indicated above, that the response of the system is virtually identical, i.e., auxiliary spray provides a performance level comparable to PORVs as far as minimizing primary-to-secondary leak rate. Further, the use of auxiliary spray would be perferable to the use of a PORV since the rate of depressurization that results when a relief is opened can be very rapid, is difficult for an operator to readily control, and can quickly lead to a loss of loop subcooling.

When the auxiliary spray system is in operation, the temperature difference between the spray flow and the pressurizer steam space can vary from approximately 100°F to several hundred degrees and more depending upon system pressure, loop temperatures, and letdown flow. As a result, a means must be

Table I

AUXILIARY SPRAY PERFORMANCE STUDY[1]

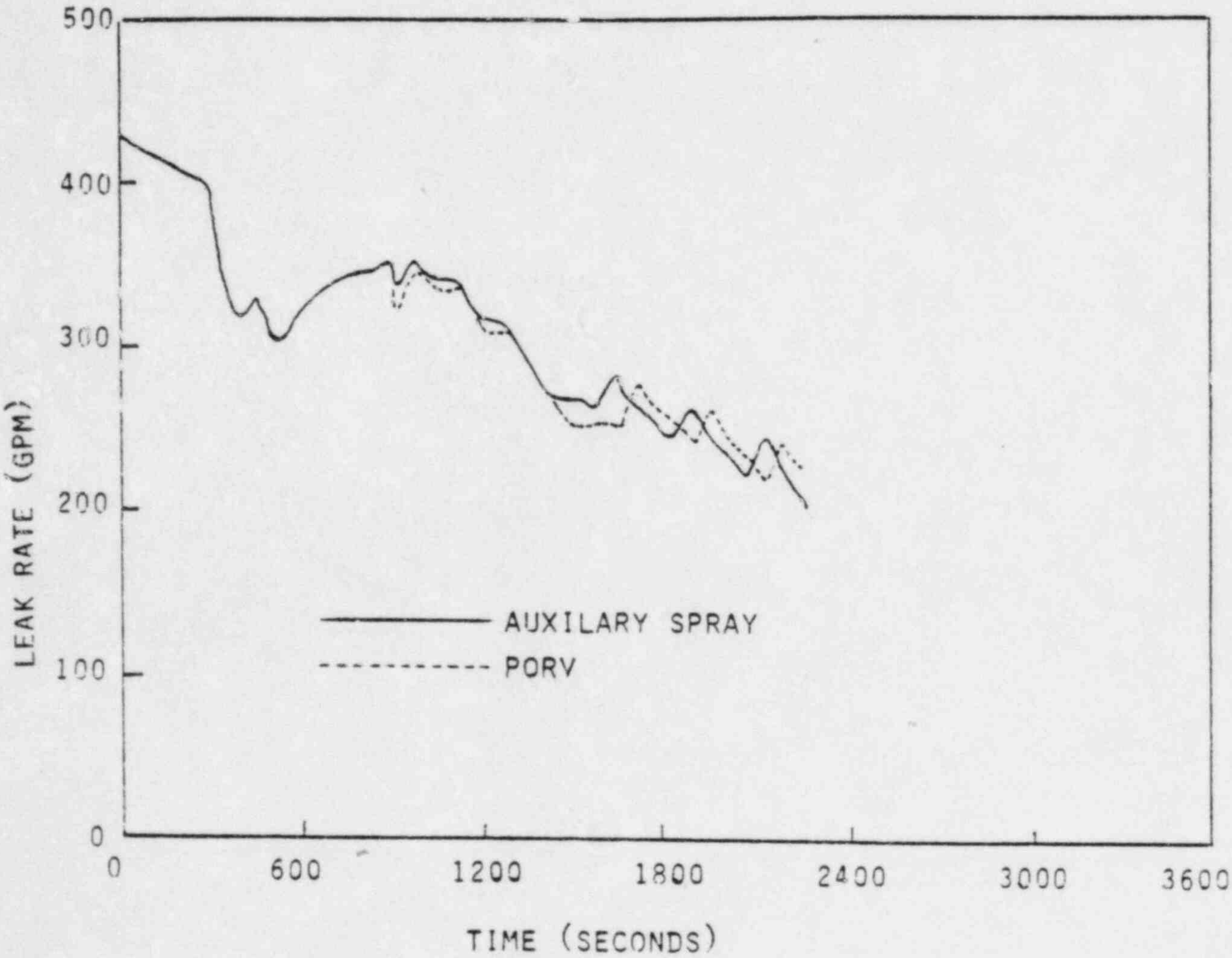
Plant Class	Number of Charging Pumps	Depressurization Rates (psi/second) with letdown	without letdown[2]
3410	1	0.50	0.85
3410	2	1.10	1.65
3410	3	1.80	2.45
3800	1	0.45	0.70
3800	2	1.05	1.45
3800	3	1.65	2.10

(1) For comparison with these rates, the depressurization rates that would be achieved via various size PORVs are as follows: 0.9 psi/seconds with a vent area of 0.0021 ft^2, 4.5 psi/second with a vent area of 0.0095 ft^2, and 13.7 psi/second with a vent area of 0.0341 ft^2.

(2) Note that the rate of depressurization without letdown is higher than with letdown due to the absence of preheating in the regenerative heat exchanger, i.e., the temperature of the spray fluid is low.

FIGURE I

SGTR ANALYSIS
COMPARISON OF LEAKRATES IN A C-E NSSS
USING AUXILIARY SPRAY VS PORVs TO EFFECT
SYSTEM DEPRESSURIZATION



available to determine the effects of thermal stress on various portions of the spray system and account for these effects over the life of the plant. A methodology has been developed which accounts for these stresses by determining a quantity called the cumulative usage factor. Table II (p. x) shows a typical procedure used to calculate the pressurizer spray nozzle cumulative usage factor. This usage factor is established based upon analysis which accounts for such items as anticipated spray flowrate, spray temperature, duration of spray, availability of main spray bypass flow, fluid medium, i.e., steam or water, and pressurizer temperature. Typically, the calculated usage factor is expected to be less than about 0.65 and no further action is required. If, however, the calculated usage factor should exceed 0.65 at any time during plant life, subsequent spray operations will be restricted such that the differential temperature between the pressurizer and spray fluid is less than or equal to 200°F. This restriction will remain in effect until an engineering evaluation of the spray nozzle can be completed to demonstrate that the continued use of the spray system outside the restriction is acceptable.

The procedures for keeping track of thermal stresses over the life of the plant in the spray system are currently being refined and further developed. When implemented a table similar to Table II may be included in the plant Technical Specifications.

Table II

TYPICAL PROCEDURE USED TO CALCULATE THE PRESSURIZER SPRAY NOZZLE CUMULATIVE USAGE FACTOR

MAIN SPRAY				AUXILIARY SPRAY			
ΔT_M	N_A	N	N/N_A	ΔT_A	N_A	N	N/N_A
201-250	7900			201-250	5000		
251-300	4500			251-300	2200		
301-350	2900			301-350	1300		
351-400	1900			351-400	850		
401-450	1200			401-450	550		
451-500	850			451-500	375		
501-550	555			501-550	225		
				551-600	150		
		$\Sigma N/N_A$=	______			$\Sigma N/N_A$=	______

Cumulative Usage Factor

$\Sigma N/N_A$ (Main Spray) ______________

$\Sigma N/N_A$ (Aux. Spray) ______________

Total ______________ = Cumulative Usage Factor

ΔT_M = The temperature difference between the pressurizer steam space and the main spray line fluid.

ΔT_A = The temperature difference between the pressurizer steam space and the auxiliary spray line fluid.

N_A = Allowable number of spray cycles for indicated ΔT range.

N = Actual number of cycles for indicated ΔT range.

Question 2: Use of PORVs to Minimize Challenges to the RPS

This question effectively asks for a discussion of the benefits to plant safety that might be derived from employing PORVs to reduce challenges to the reactor protective system.

The use of PORVs to minimize challenges to the RPS would require a continously aligned fast acting valve with a setpoint below the setpoint of the reactor trip on high system pressure. This configuration is essentially the configuration employed by TMI-2 prior to the accident of 28 March 1979. Following TMI-2 a reevaluation of the design features of the TMI reactor was conducted in order to improve plant safety. One of the findings of the reevaluation was that the reactor appeared to be unusually sensitive to certain transient conditions originating in the secondary system. Further, the actuation before reactor trip of a power operated relief valve could, if the valve sticks open, aggravate the transient. As a result, holders of operating licenses for similarly designed reactors were instructed by IE Bulletins to decrease the reactor high pressure trip setpoint and to increase the pressurizer PORV setpoint to reduce challenges to these valves.

In a C-E NSSS which employs PORVs in the basic design, these valves are actuated by the same bistable trip units which actuate a reactor trip on high RCS pressure. In contrast to some PWR designs which use the PORVs to preclude high pressure reactor trips subsequent to significant load reductions, the intended function of these valves in the C-E design was to reduce the number of challenges to the pressurizer code safety valves that could result from certain overpressure transients. In fact, C-E was requested by the NRC staff to investigate the possibility of further minimizing PORV openings by raising, for example, the relief setpoint above that of the overpressure trip. Although this and several other possibilities for minimizing PORV openings were investigated, the original design philosophy of the early C-E plants, i.e., activation of both the reactor trip and the power operated relief valves from same trip bistable, remained unchanged because it represented the optimum compromise with respect to minimizing challenges to the pressurizer code safety valves and minimizing challenges to the PORVs. As each of the early

Combustion Engineering plants became operational and data began to be compiled, the effectiveness of such systems as the pressurizer spray system, the SBCS, etc., to limit pressure transients was demonstrated. As a result, C-E was unable to substantiate any real advantages in opening PORVs during most overpressure transients in order to reduce challenges to the pressurizer code safety valves. In addition it was determined that code safety valve weepage occurred at pressures below normal operating pressure and not as a result of increases in system pressure approaching the safety valve setpoint. When this experience was considered along with the potential for spurious relief value operation and relief valve leakage problems, C-E decided to remove PORVs from its NSSS design beginning with 1970 Contracts (ANO-2) and including the 3410 and the 3800 Class plants.

Question 3: Effect of PORVs on ATWS

This question effectively asks for a discussion of the benefits that might be derived from the use of PORVs for mitigation of the peak RCS pressure attained during an ATWS.

Although the addition of PORVs to the 3410 and the 3800 Class plants could provide additional relief capacity for mitigation of the peak RCS pressure resulting from ATWS, it should be realized that use of a PORV for this purpose would require a continuously aligned fast acting capability. This configuration would increase the susceptibility to a relief valve initiated SBLOCA and may not be consistent with other PORV functions being evaluated. In addition, there are other alternatives currently being considered by the NRC Staff that will improve plant response to ATWS and therefore the benefit that might be gained from a PORV would depend on the incorporation of any of these alternatives.

To answer this particular question, an analysis was performed to determine the required increase in total relief area, beyond that provided by the pressurizer code safety valves, needed to limit peak RCS pressure below 3200 psia (ASME Boiler Pressure Vessel Code Stress Level C) during the worst case ATWS. Two cases were examined for each class of plant. The first case assumes current plant design and therefore does not credit a turbine trip; the second case assumes a safety-grade turbine trip upon receipt of a reactor trip signal in order to preserve secondary inventory. The results of this analysis are shown in Table III (p. xiv). As can be seen from these results, the relief area provided by the pressurizer code safety valves for the 3800 plant is sufficient to limit pressure below 3200 psia if a turbine trip is credited; if a turbine trip is not credited an additional 0.05 ft^2 of relief area is required. For the 3410 plant, an addition 0.10 ft^2 of relief area is required if a turbine trip is credited and an addition 0.15 ft^2 is required if the turbine trip is not credited. For comparison with existing PORVs, the increased relief area required for the current 3410 design (0.15 ft^2) is three times larger than the total area of the two PORVs in the C-E designed St. Lucie 2 plant and eight times larger than the total area of the two PORVs typically installed in operating C-E plants.

Table III

ATWS ANALYSIS RESULTS

Plant Class	Peak RCS Pressure (psia)# No Turbine Trip	Peak RCS Pressure (psia)# With Turbine Trip	Additional Relief Area (ft^2)* No Turbine Trip	Additional Relief Area (ft^2)* With Turbine Trip
3410	4290	3943	∿ 0.15	∿ 0.10
3800	3800	2918	∿ 0.05	0

Peak pressure during ATWS analysis with no PORVs.

* Additional relief area required to limit peak RCS pressure to less than 3200 psia.

Although PORVs could provide additional relief capacity for mitigation of peak pressure during ATWS, such a configuration would be susceptible to the leakage problems historically associated with these valves and would increase the susceptibility to a relief valve initiated SBLOCA. Further, alternate solutions (such as a safety-grade turbine trip upon receipt of a reactor trip signal, improvements to the reactor shutdown system reliability, etc.) are currently being considered by the NRC Staff which may provide adequate mitigation to ATWS without the need for the additional pressure relief capacity afforded by a PORV.

Question 4: Effect of PORVs on PTS

This question effectively asks for a discussion of the benefits that might be derived from use of PORVs for mitigation of the pressure transient in the PTS scenario.

The cooldown transient due to a full steam line break represents the most challenging cooldown transient for a C-E NSSS for a single event design basis accident. This event coupled with a subsequent repressurization to the code safety valve setpoint represents the highest possible pressure challenge to a plant without PORVs in the PTS scenario. An analysis was performed to evaluate two very severe postulated overcooling events without the use of PORVs with the reactor coolant system assumed to repressurize to the primary system safety valve setpoint pressure of 2500 psia. The two PTS events considered were a steam line break with a break flow area of 0.5 ft^2 and a steam line break with a break flow area of 1.29 ft^2. Note that earlier studies have indicated that this size range is more challenging for PTS than larger break sizes. Initial plant conditions were conservatively chosen to maximize the cooldown magnitude. Operator actions to avoid repressurization were not credited, even though conditions and signals for throttling HPSI flow and charging flow would be indicated in sufficient time for operator action. Stress analysis and fracture mechanics analysis were performed using methods previously submitted to the NRC. The specified material properties for the controlling region in both the 3410 and 3800 vessels are as follows:

Copper	=	0.10%
Phosphorous	=	0.008%
Initial RT_{NDT}	=	40°F

The anticipated end of life peak fluence is 3.2×10^{19} neutrons/cm^2 with an energy greater than 1.0 MeV. Using the above material properties and the end of life fluence, no crack extension would be predicted. In order to permit the demonstration of a substantial safety margin on crack extension, more severe assumptions were made, i.e., the initial RT_{NDT} and the end of life fluence were increased arbitrarily to more than twice the design life valves for both classes of plant as follows:

Initial RT_{NDT} = 100°F

EOL Fluence = 6×10^{19} neutrons/cm^2

The results of the analysis indicate that no crack initiation would occur for the two steam line break PTS transients analyzed for more than twice the design life of the plant. It can therefore be concluded that the 3410 and the 3800 pressure vessels exhibit large margins of capability to withstand the most severe postulated cooldown transients with full repressurization to the code safety valve setpoint and that there does not appear to be any need to provide PORV mitigation of PTS.

Question 5: Multiple Failures Scenarios

This question effectively asks that two specific multiple failure scenarios be reviewed to determine that they are satisfactorily handled without the use of PORVs. The two specific scenarios that were evaluated were multiple tube ruptures in both steam generators and a SBLOCA concurrent with a failure of HPSI. Detailed analysis demonstrated that these multiple failure scenarios could be satisfactorily handled without the use of PORVs.

The SGTR aspect of this question asks whether PORVs might be helpful to limit offsite radioactive releases and ensure core coolability for certain multiple tube failure scenarios. The concerns center around whether adequate pressure control is available without PORVs, whether unacceptable releases would occur for ruptures in both steam generator without PORVs, and whether adequate ECCS delivery and capacity will be available without PORVs. To address these concerns, a tube rupture scenario involving one double-ended rupture in both steam generators and a tube rupture scenario involving three double-ended ruptures in both steam generators were analyzed. The two hour dose results at the exclusion area boundary for these scenarios are shown in Table IV (p. xix). Note that in each case the limit is less than the 300 REM limit specified in 10 CFR 100. Also note that the two hour dose releases for the three tubes per steam generator case is smaller than the one tube per steam generator case. This behavior results from the fact that in the three tubes per steam generator case the leak rate exceeds the ADV steaming rate during the cooldown, and hence secondary level increases. This increase in level means that mass and energy are being transferred from the primary and stored in the steam generators. In addition, the greater flow area produced by the three tube case means a lower RCS pressure and hence a greater safety injection flowrate. This increase in safety injection tends to cool the plant and hence less steaming through the ADVs is required prior to placing the plant on shutdown cooling. The analyses results for multiple tube ruptures in both steam generators for the 3410 and 3800 Class plants demonstrated that as many as three tubes can be simultaneously ruptured in each steam generator and the plants can be aggressively cooled to shutdown cooling entry conditions using ADVs without exceeding offsite dose limits or exhausting RWT water supplies.

Table IV

SUMMARY OF TWO HOUR DOSE RESULTS FOR MULTIPLE STEAM GENERATOR TUBE RUPTURES AT THE EXCLUSION AREA BOUNDARY[1]

Parameter	3410 Class 1 Tube/SG	3410 Class 3 Tubes/SG	3800 Class 1 Tube/SG	3800 Class 3 Tubes/SG
GIS[2]	55 REM	45 REM	105 REM	95 REM
PIS[3]	95 REM	80 REM	230 REM	220 REM

(1) In calculating dose results, the site dispersion factor for Waterford was used for the 3410 case and the site dispersion factor for Washington was used for the 3800 case.

(2) GIS - Event generated iodine spike.

(3) PIS - Pre-existing iodine spike.

In addition to the multiple SGTR scenarios, this question asks how small break LOCAs with no high pressure injection are satisfactorily handled without PORVs. The basic premise behind this question is that PORVs may be useful in depressurizing the RCS to the point where LPSI and SITs can function to cool the reactor core. To answer this question, an analysis was performed in which the small break LOCA with no HPSI transient was simulated both with and without the use of PORVs. For the case in which PORVs were not used, RCS depressurization was accomplished by means of aggressive steam generator cool-down using the ADVs. Three cases, identified below, were simulated in the analysis.

Case 1: No operator action (base case).
Case 2: Steam generator cooldown via ADVs.
Case 3: RCS depressurization via PORVs.

The basic results of the analysis for the SBLOCA with no HPSI are shown in Figure II (p. xxi) and in Figure III (p. xxii). Figure II shows RCS pressure vs time and indicates, as expected, that the overall depressurization rate using PORVs is greater than the rate using aggressive steam generator cooldown via ADVs. As shown in Figure III, however, core uncovery did not occur when the plant was depressurized via steam generator cooldown and, in contrast, core uncovery did occur when the plant was depressurized via PORVs. The basic explanation for this behavior is that depressurization via PORVs increases the rate of RCS mass loss which in turn results in core uncovery. It therefore appears that the optimum response to this casualty is to depressurize via aggressive steam generator cooldown to the point where SITs and eventually LPSI pumps can begin to operate.

FIGURE II

SBLOCA WITH NO HPSI
RCS PRESSURE

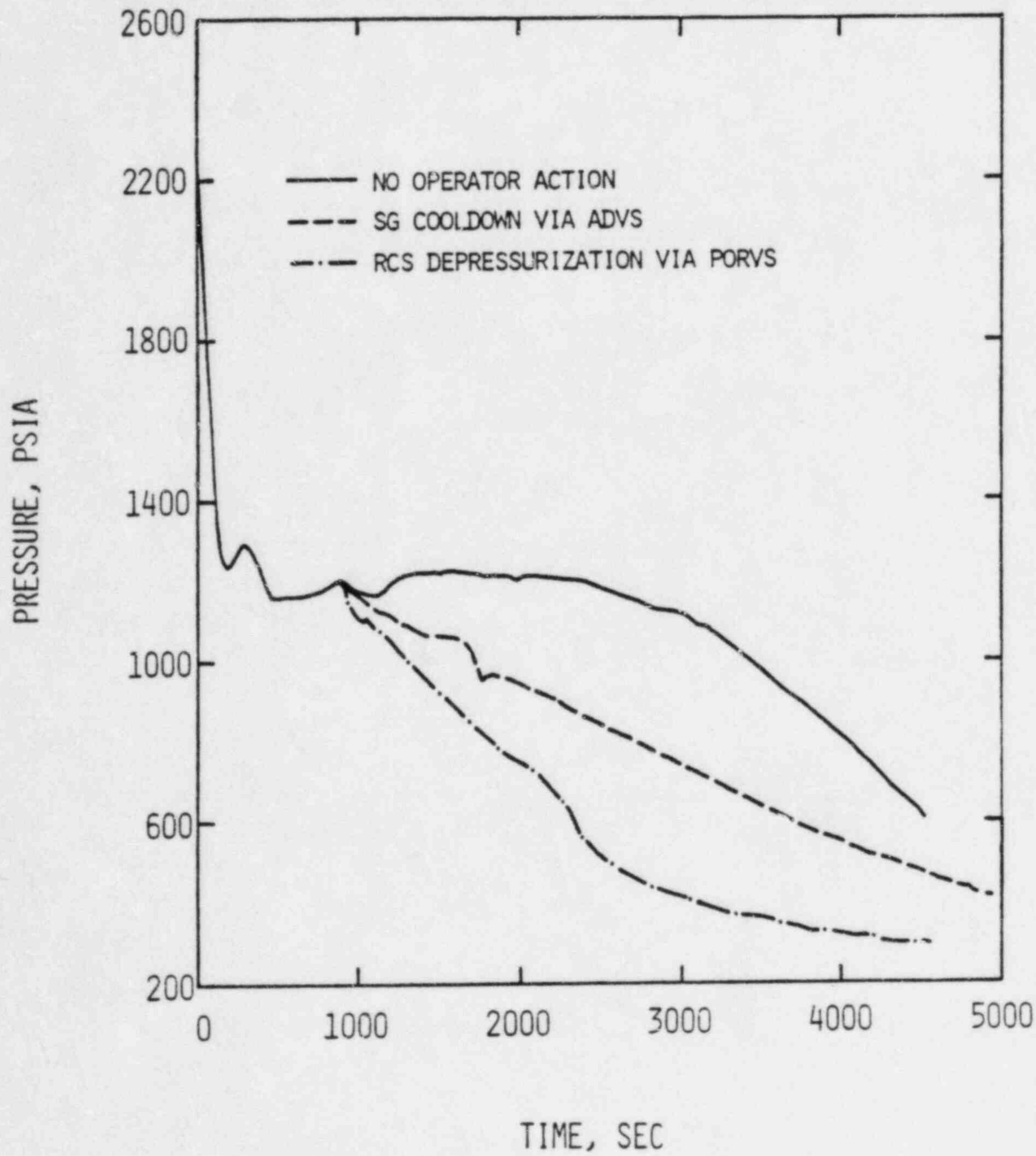
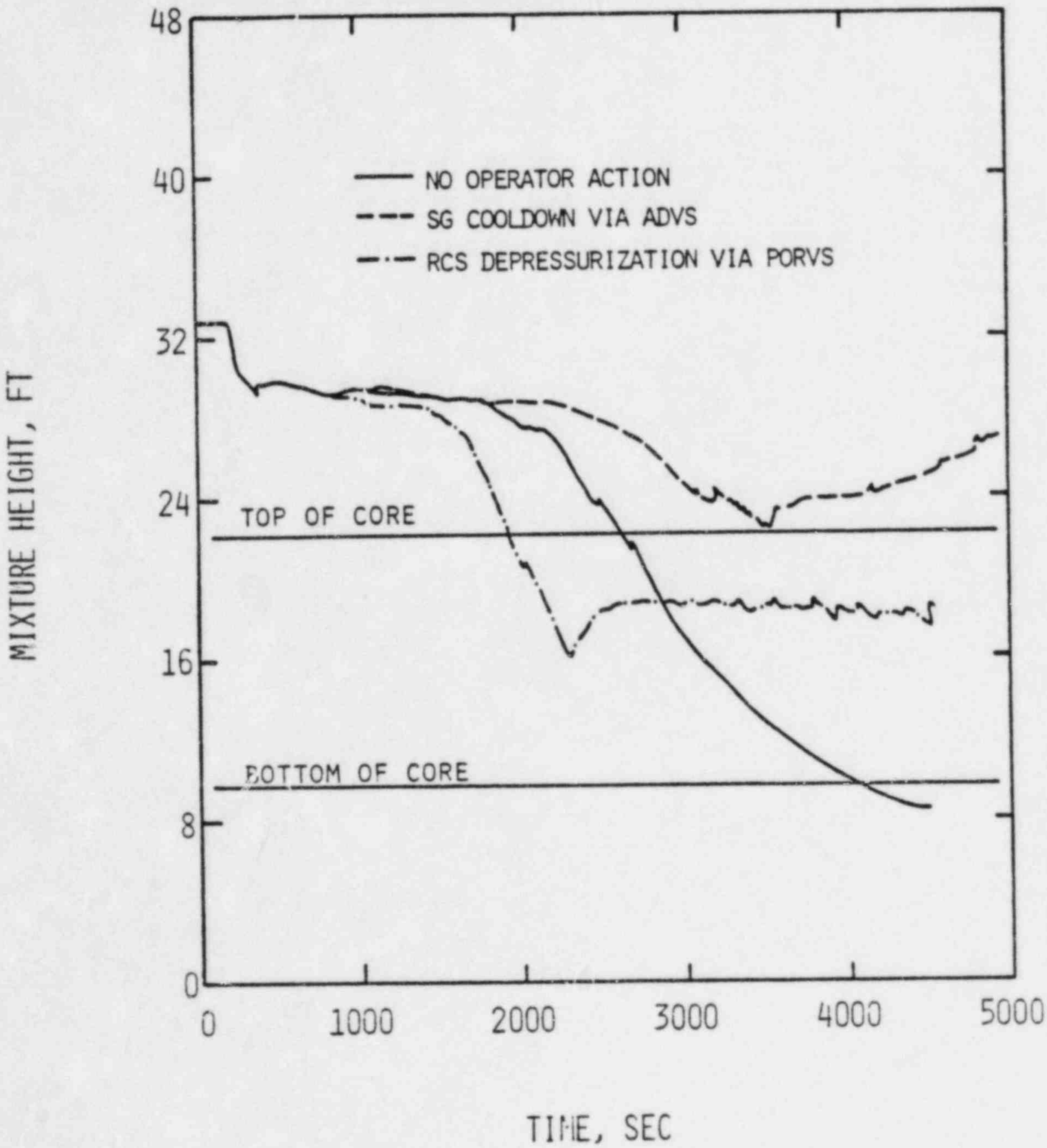


Figure III

SBLOCA WITH NO HPSI
REACTOR INNER VESSEL TWO-PHASE MIXTURE LEVEL



Question 6: Use of Low Pressure Pumps for Feeding SGs

This question effectively asks for an analysis to demonstrate that steam generator depressurization followed by feeding using a low head pump is a viable technique for mitigation of a TLOFW event without adverse core cooling consequences.

The use of existing low pressure pumps such as condensate pumps may provide plant operators with a useful capability to supply feedwater to the steam generators during certain low probability scenarios which are beyond the design bases of the plant. For example, a scenario that started with a loss of main feedwater due to a relatively minor failure in the MFW system or FWCS could result in a total loss of feedwater if the first failure were followed by multiple failures in the auxiliary feedwater system which prevented this system from functioning. In such a situation where now the AFWS is no longer usable, an operator would have only about ten to fifteen minutes to find and correct the problem in the MFW system prior to inventory depletion in the steam generators to the point where the turbine driven MFW pumps could not be restarted. At this point with main and auxiliary feedwater unavailable and with insufficient inventory in the steam generators to restart a turbine driven main feedwater pump, one or both steam generators could be depressurized via ADVs to the point where a surrogate pump such as a condensate pump could be used to supply feedwater for decay heat removal and, if desired, a recovery of the MFW system could be performed.

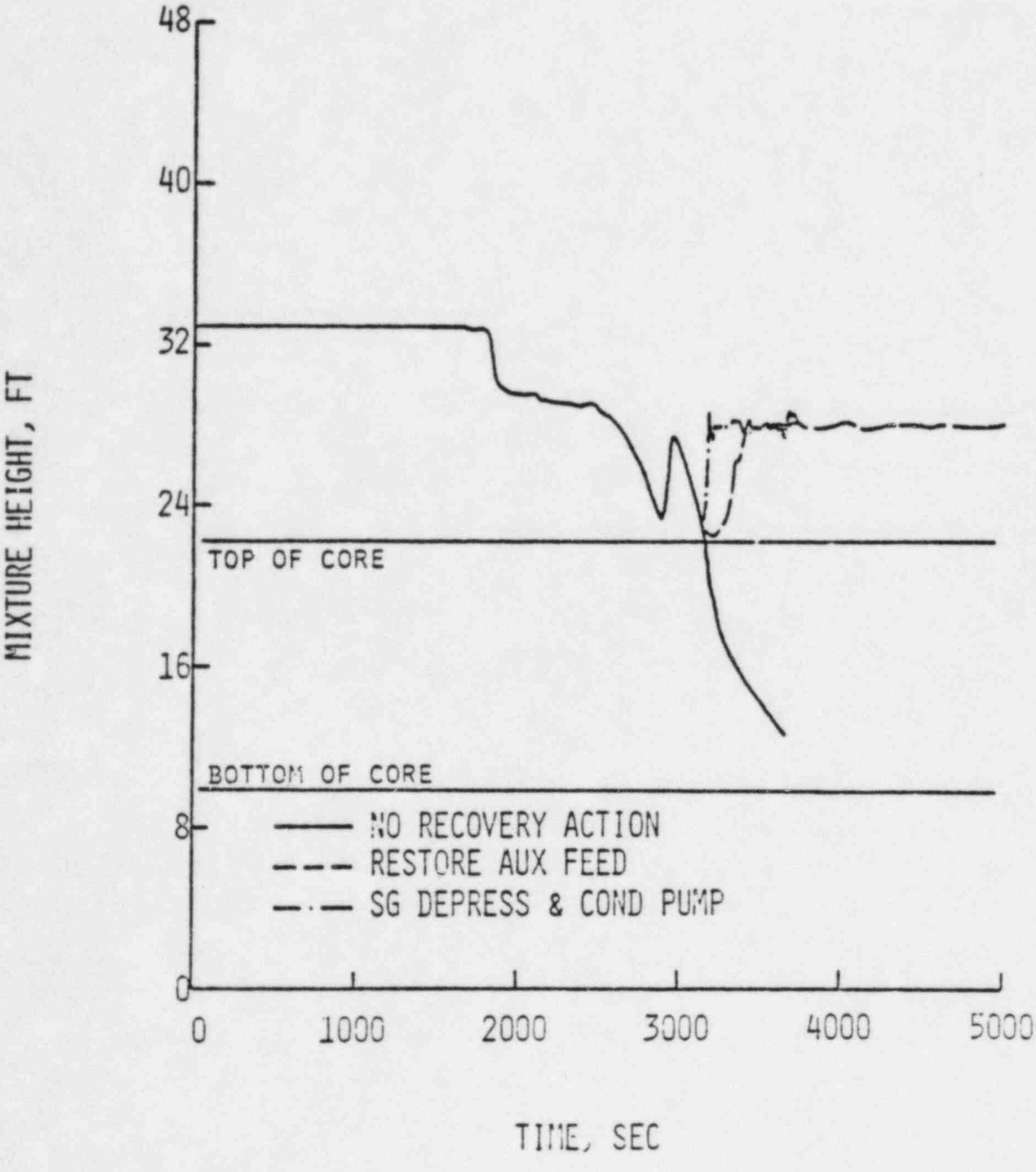
The actual equipment and interface requirements for this type of application are plant specific and as such will be supplied by individual utilities. Generic analyses, however, were performed evaluating this method of operation showing that it is a viable method for which specific procedures and training could be developed. Specifically, the results from both a steady-state analysis and a transient analysis are presented. The steady-state analysis demonstrated that the capacity of the ADVs currently installed in the 3410 plants and the 3800 plants is sufficiently large to allow for decay heat removal plus steam generator depressurization to the point where a surrogate low pressure pump can be used to supply feedwater. The transient analysis demonstrated the dynamic behavior of the RCS to a TLOFW followed by steam generator depressurization and injection of feedwater from a low head pump. As shown in Figure IV (p. xxv) steam generator depressurization followed by use of a condensate pump is equivalent to restoration of the auxiliary feedwater system as far as preventing core uncovery and providing adequate core cooling. The analysis also demonstrated that primary coolant contraction did not result in core uncovery and that a return to power was unlikely due to boration. Finally, it was demonstrated that adequate cooling could be maintained even though the potential exists for the pressure in the steam generator to increase above the shutoff head of the surrogate pump and therefore terminate feedwater flow. In such a situation cyclical steam generator pressure oscillations would be established with cyclical delivery of feedwater as pressure decreased below pump shutoff head.

Initial review indicates that the best suited pump for use as a surrogate feedwater pump is probably a condensate pump. This pump appears to be well suited for this application since system lineup for feedwater delivery can be readily accomplished, pump flow characteristics are usually such that only modest steam generator depressurization need be accomplished prior to delivery, and the supply of available feedwater is of high quality. A second possible candidate for use as a surrogate feedwater pump would be an emergency firewater pump. The advantage of using this pump would be the availability of an emergency power supply; however, the system lineup necessary to initiate feed is somewhat more difficult than with the condensate pump and the water would be of a lesser quality.

With regard to the structural effect of such operations on the steam generators, the report points out that early designs which relied upon manually initiated auxiliary feedwater were specified to include a limited number of feedwater initiations to a hot, dry steam generator. Although this specification was deleted with the inclusion of automatically initiated AFW,

FIGURE IV

REACTOR INNER VESSEL TWO-PHASE MIXTURE LEVEL
FOR A TLOFW WITH RESTORATION OF
SECONDARY HEAT SINK



calculations have indicated that the 3410 and the 3800 plants are capable of accepting a limited number of initiations of 70°F feedwater to a hot and dry steam generator via the feedwater ring and downcomer. Further, initiation of feedwater in such an in extremis situation would represent a last resort effort to provide for core cooling and prevent core damage. In this situation, the structual integrity of the steam generators would be evaluated on a plant specific basis as necessary once the RCS was safely cooled down prior to resuming operation.

Question 7: Chemistry Considerations

This question effectively asks for a discussion of the effects of adding water to a steam generator that deviates from the recommended C-E water cheimstry program on structural integrity and heat transfer capability.

The use of existing low pressure pumps or backup water supplies could provide a useful capability to an operator to supply feedwater to the steam generators during certain low probability scenarios which result in a loss of normal water sources. Feeding a steam generator under the conditions may, in the long tern, impact structural integrity and heat transfer capabilities if the quality of the water used deviates significantly from the recommended C-E water chemistry program. The use of a steam generator in this so called "off-design performance" mode represents, however, an in extremis situation where short-term action must be taken to provide adequate core cooling and prevent possible core damage. In such a case, an operator would employ the best quality water supply available. This water supply may involve the use of one of the backup water supplies for the AFWS as required by the post-TMI Action Plan or such potential sources as the following:

1. Reactor-grade makeup water system.
2. Service-grade water from fire protection system.
3. Potable water from domestic water systems.
4. On-site bulk cooling water storage reservoirs or basin.

Over the short time frame during which relatively poor quality water might be used to feed a steam generator, i.e., the time it takes to cool down, depressurize, and place the plant safely on the shutdown cooling system, damage to structural integrity and heat transfer capability to the extent that would prevent a steam generator from providing adequate heat removal is highly unlikely. Further, once the plant was safely placed on shutdown cooling and prior to resuming normal operations, secondary side cleanup along with inspections to ensure structural integrity would be performed as necessary.

Initial review indicates that the best pump for use as a surrogate low pressure feedwater pump is probably a condensate pump. This pump appears to be ideally suited for a number of reasons including the availability of high quality water. As an alternative, an emergency firewater pump might be employed. This second pump has the advantage over a condensate pump of an available emergency power supply although the water would be of lesser quality. Dispite the use of lesser quality feedwater, the potential for extensive corrosion and U-tube fouling during a plant cooldown are low such that the heat transfer function of the steam generators would not be significantly impacted prior to safely placing the plant on shutdown cooling.

Question 8 - Extended Loss of Feedwater

This question is effectively a request for a probabilistic determination of the frequency of core melt due to a loss of feedwater. In addition, information is requested regarding the time to initiate core melt following a TLOFW.

A review of operating experience and a fault tree analysis was performed to determine the frequency of loss of MFW events. The analysis has been performed on a plant specific bases and is contained in separate supplements to this report for each participating utility. The results of the analysis are quantified by a statistical distribution which represents the frequency of loss of MFW. For the representative plant, the initiating event frequency can be expressed in terms of a median value of 1.23 event per year with an associated error factor of 3. The median value represents the estimate, considering uncertainty, that would be expected to be higher than the true value with 50% confidence. The associated error factor is defined as the ratio of the 95th to 50th percentile. This factor, when multiplied by the median value, yields the upper bound estimate which would be expected to be higher than the true value with 95% confidence.

These results were further incorporated into an extensive evaluation of the core damage frequency due to loss of the secondary heat sink. The analysis included an investigation of the potential for recovering feedwater. The core damage frequency contribution resulting from a loss of the secondary heat sink was evaluated for the current plant design which includes low pressure pumps for secondary heat removal following steam generator depressurization but has no PORVs, and for an assumed plant design which includes PORV depressurization and decay heat removal (feed-and-bleed) but does not credit low pressure pumps for feeding the generators. The resulting core damage frequencies for the representative plant are 2.6×10^{-6} per year with an associated error factor of 30 without PORVs and 1.0×10^{-6} per year with an associated error factor of 21 with PORVs. In order to determine the reduction in total core damage frequency associated with utilizing alternate secondary heat removal capability, the loss of secondary heat sink core damage frequency which included alternate secondary heat removal capability was statistically subtracted from the loss of secondary heat sink core damage frequency with no alternate secondary heat removal capability and no PORVs. The result indicates a net decrease in core damage frequency due to alternate secondary heat removal capability of 2.0×10^{-6} per year (median value) with an associated error factor of 17. The complete analysis and a characterization of the consequences for each participating plant are presented in the respective supplements to this report.

An analysis was performed to determine the time to initiate core melt following a TLOFW when no operator actions are taken to recover from the event. For the purpose of the analysis, the time to initiate core melt was defined as the time the best estimate cladding temperature of the hottest fuel rod was calculated to reach 2200°F. In addition, an analysis was performed to determined the time available to the operator following a TLOFW to successfully take corrective action. Preventing core uncovery was selected as the basis for determing this time. In particular the study investigated three corrective actions:

1. Restoration of auxiliary feedwater.
2. Initiation of feed-and-bleed.
3. Steam generator depressurization and initiation of feedwater from a low head pump.

The results of the TLOFW analysis as listed in Table V (p. xxxi) and shown in Figure V (p. xxxii) and Figure VI (p. xxxiii) are presented in the main report. The following conclusions are made based on the this analysis:

1. Based upon a criteria of 2200°F peak clad temperature, the onset of core melt for the 3410 plants is approximately 60 minutes following a TLOFW and the onset of core melt for the 3800 plants is approximately 70 minutes following a TLOFW.

2. The operator has significantly more time to regain the steam generators as heat sinks, either by restoring auxiliary feedwater or by initiating steam generator depressurization, than by initiating feed-and-bleed in order to prevent core

Table V

SUMMARY OF RESULTS FOR TLOFW TRANSIENT ANALYSIS

	3410 Plant	3800 Plant
Minimum time hottest fuel rod clad temperature reaches 2200°F for unmitigated TLOFW transient.	60 min.	70 min.
Time to restore auxiliary feedwater to prevent core uncovery.	50 min.	59 min.
Time to initiate feed-and-bleed to prevent core uncovery.	20 min.	25 min.
Time to initiate SG depressurization and feed via a low head pump to prevent core uncovery.	50 min.	59 min.

FIGURE V

3410 CLASS PLANT
TLOFW ANALYSIS RESULTS

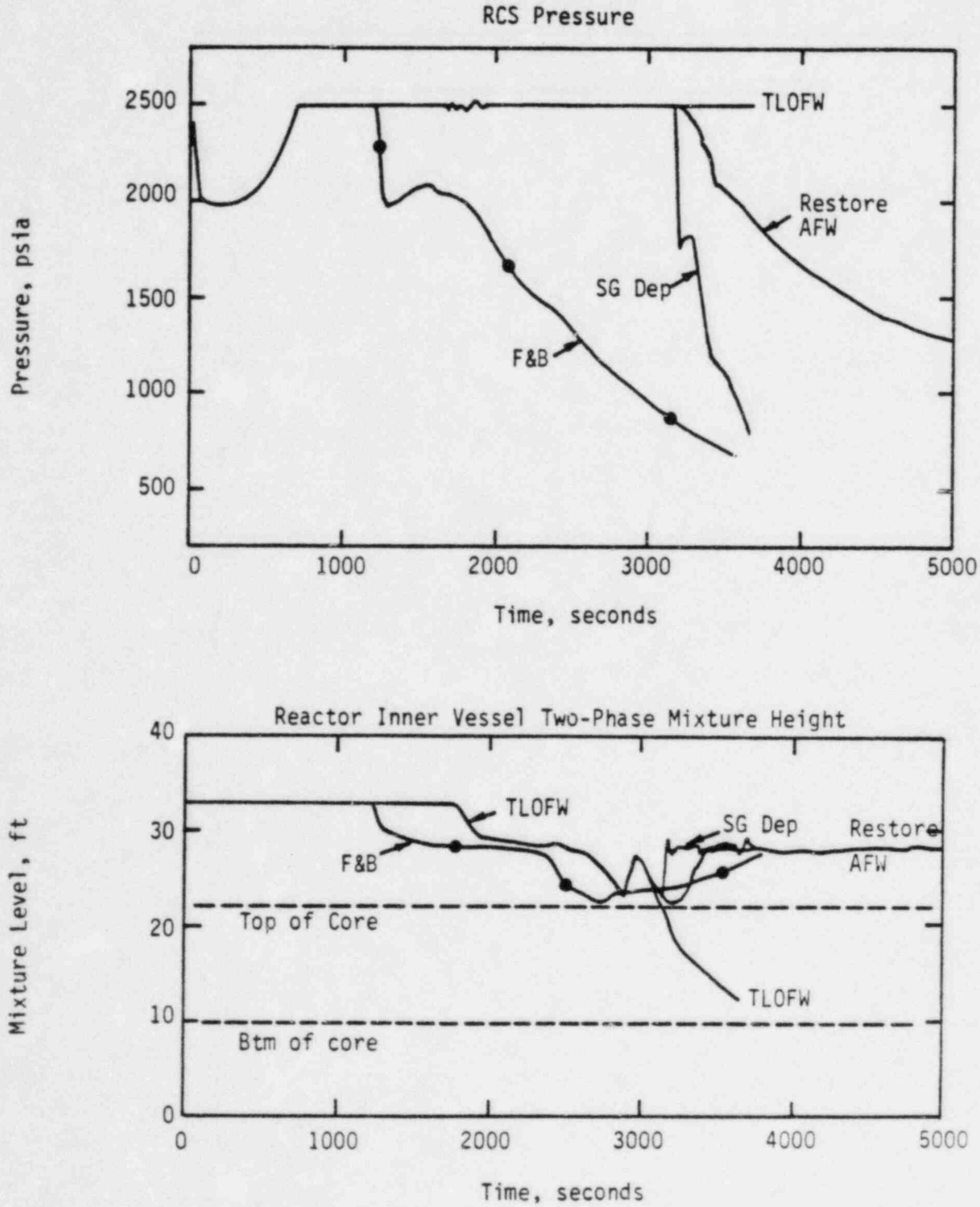
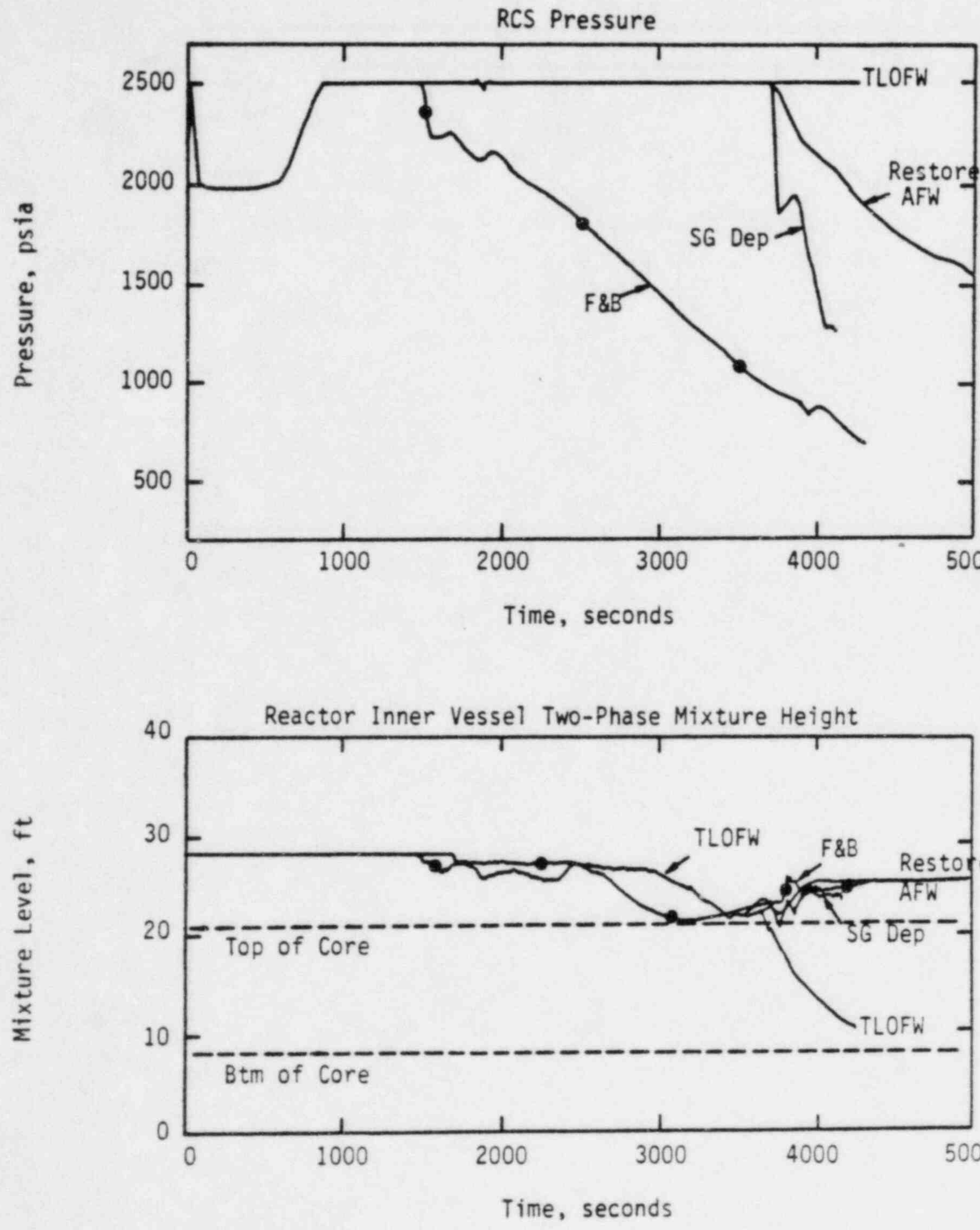


FIGURE VI

3800 CLASS PLANT
TLOFW ANALYSIS RESULTS



uncovery. The reason for this is that regaining the steam generators as heat sinks accomplishes RCS heat removal by condensing steam within the steam generators (and thereby depressurizing the RCS). Opening PORVs, on the other hand, accomplishes RCS heat removal by removing inventory. As a result, feed-and-bleed must be initiated relatively early in the event to preclude losing inventory out the PSVs to the extent that core uncovery occurs.

3. Depressurizing the steam generators results in a slightly better inner vessel level response than restoring auxiliary feedwater even though the latter case regains the generators as heat sinks sooner. The reason for this is that the steam generator temperatures (saturation temperature) is lower at the lower pressure obtained during secondary depressurization which increases the primary-to-secondary temperature differential.

4. Initiating auxiliary spray during a TLOFW instead of charging to the loops will decrease the time to core uncovery, i.e., sooner, since inventory added to the RCS is retained in the pressurizer and not available in the core for boil off.

Question 9: Risk due to SGTR

This question effectively asks for an assessment of the risk to plant safety following steam generator tube failure.

The frequency of the SGTR accident sequences which could potentially lead to core damage were statistically combined into two categories: 1) Scenarios resulting from SGTR in one or two steam generators assuming offsite power was available, and 2) Scenarios resulting from SGTR in one or two steam generators with a coincident loss of offsite power. The core damage frequency contribution due to SGTR in one or two steam generators for the representative plant can be expressed in terms of a median value of 1.5×10^{-5} per year with an associated error factor of 5. The median value represents the estimate, considering uncertainty, that would be expected to be higher than the true value with 50% confidence. The associated error factor is defined as the ratio of the 95th to 50th percentile. This factor, when multipled by the median value, yields the upper bound estimate which would be expected to be higher than the true value with 95% confidence. The core damage frequency contribution due to SGTR in one or two steam generators with coincident loss of offsite power is estimated to be 1.5×10^{-6} with an associated error factor of 11. The decrease in core damage frequency due to the added depressurization capabilities of a PORV was determined to be negligible compared to the core damage frequency contribution from all other SGTR accident sequences for the first of the four plants to be analyzed.

The likelihood of steam lines filling with subcooled water during a SGTR was also investigated. The total frequency of sequences that could possibly lead to steam generator overfill conditions was determined for the representative plant to be approximately 6.6×10^{-4} per year (median value) with an associated error factor of 6. The complete analysis and a characterization of the consequences for each plant participating in this study are presented in the respective supplements to this report.

Question 10: Risk due to PORV Initiated LOCA

This question effectively asks for an assessment of the core melt frequency from PORV initiated LOCA.

The core damage frequency due to PORV initiated LOCA was evaluated based upon a plant design which would be assumed to provide increased RCS decay heat removal and depressurization capability. In this design the PORVs are manually opened and the plant is assumed to operate with the PORV block valves normally closed which tends to minimize the risk associated with PORV initiated LOCA. The results of the analysis are quantified by a statistical distribution representing the core damage frequency of PORV LOCA. The core damage frequency contribution due to PORV LOCA for the representative plant can be expressed in terms of a median value of 1.2×10^{-7} per year with an associated error factor of 15. The median value represents the estimate, considering uncertainty, that would be expected to be higher than the true value with 50% confidence. The associated error factor is defined as the ratio of the 95th to 50th percentile. This factor, when multipled by the median value, yields the upper bound estimate which would be expected to be higher than the true value with 95% confidence. If automatic actuation of the PORVs were to be assumed and if the plant were to operate with the block valves normally open, the core damage frequency contribution due to PORV LOCA would become 1.4×10^{-6} per year with an associated error factor of 13. The detailed analysis and a characterization of the consequences are provided in the plant specific supplements to the report.

Question 11: Effect on Safety and Additional Benefits

This question effectively asks for the net change in plant safety if PORVs were installed considering such items as the potential for primary feed-and-bleed, the risk from steam generator tube failures, and the core melt frequency from PORV initiated LOCA. The question also asks for any additional benefits that might be realized from the addition of such valves.

The overall change in core damage frequency (net gain or loss in safety) due to the installation of PORVs was determined by examining only those events which were considered to significantly contribute to an increase or decrease in the total core damage frequency. The core damage frequency contribution due to LOHS events and PORV initiated LOCA is impacted by the presence of PORVs while the change in SGTR core damage frequencies does not contribute to a net gain or loss in safety. Results indicate a net change in total core damage frequency for the representative plant due to the installation of manually or automatically actuated PORVs that is substantially less than the proposed NRC safety guideline of 10^{-4} core melts per year. The complete risk assessment analysis for each of the plants participating in this study is contained in the plant specific supplements to this report.

The question of the additional benefits that might be realized from the addition of PORVs is a much broader subject than the estimation of core damage probabilities and would be dependent upon the actual PORV system configuration. In general, the analyscs completed for this study indicate that no significant performance benefits would be realized from the backfit of PORVs to the 3410 and the 3800 plants. Specifically with respect to the SGTR, this event is within the capabilities of the current design of the 3410 and the 3800 plants to successfully mitigate. In addition, analyses presented in the body of the report indicate that auxiliary spray has essentially the same ability as PORVs in reducing system pressure during a tube rupture, and that auxiliary spray has the added benefit of a higher degree of pressure and inventory control. With respect to the possibility of using PORVs to minimize challenges to the RPS, such a configuration would require a PORV setpoint below that of the reactor trip on high pressure. C-E's philosophy in plants that employ PORVs in their design is to activiate them from the same bistable trip that activates a reactor trip on high pressure in order to prevent challenges to the pressure code safety valves. To deviate from this philosophy could increase the probability of core damage in certain events by delaying a reactor trip and could increase the probability of a PORV initiated LOCA.

An evaluation of the benefits that might be realized from the addition of PORVs in order to mitigate ATWS revealed that the additional relief capacity afforted by such valves could decrease the peak RCS pressure resulting from the ATWS transient. As indicated in the body of the report, however, the size of the relief valve necessary to reduce this peak pressure is very much larger than the largest PORV currently installed in C-E operating plants; this size might make such a solution to the ATWS problem impractical. In addition, other solutions to ATWS are currently being considered by the NRC such as increasing the reliability of the reactor shutdown system and the incorporation of a safety-grade turbine trip which appear to be viable solutions. With respect to pressurized thermal shock, detailed evaluation show that no additional benefits would be realized with PORVs in the 3410 and the 3800 plants since both the 3410 and the 3800 pressure vessels exhibit large margins (assuming twice the predicted end of life fluence) of capability to withstand the most severe postulated cooldown transients with full repressurization to the code safety valve setpoint.

An evaluation of various multiple failure scenarios was also performed in order to assess the potential benefits of PORVs. Specifically, it was shown that up to three tube ruptures in both steam generators for the 3410 and the 3800 plants were successfully mitigated with the current design and that the two hour dose releases were within the criteria of 10 CFR 100. Also, from the evaluation of the SBLOCA with no HPSI transient, RCS depressurization via steam generator cooldown is preferable to system depressurization via PORVs in lowering pressure to the point where LPSI pumps and SITs could function since additional RCS inventory was not lost and core uncovery did not occur. In addition, it was demonstrated that steam generator depressurization via ADVs followed by use of a surrogate low pressure pump to feed steam generators in the event of a TLOFW was a viable method of providing for core cooling.

A function of the PORVs on operating plants that should also be considered is the use of PORVs for the purpose of providing low temperature overpressure protection. For the 3410 and the 3800 plants this function is provided by the shutdown cooling system relief valves and meets all of the design criteria placed upon any LTOP system. Therefore no added safety benefits could be realized from PORVs in this respect since the LTOP function is already adequately provided for. PORVs would, however, allow for a slightly higher LTOP set point pressure since the SCS design pressure would no longer be limiting.

Finally in order to further assess the desirability of adding PORVs to plant designs which do not include them a study was conducted to determine the potential impact of power operated relief valves on plant availability. For this study two basic modes of operation were considered. First, a manual mode was evaluated in which it was assumed that both PORVs and the blocking valves would be normally closed during power operations and manually opened as needed. Second, an automatic mode was considered in which it was assumed that the blocking valves would be normally open during power operations and that the setpoint of the PORVs would coincide with the setpoint of the reactor trip on high pressure. The results of this study are compiled in Table VI (p. xL). From this study it appears that the addition of PORVs to the 3410 and the 3800 plants would have a negative impact on plant availability.

Table VI

POWER OPERATED RELIEF VALVE IMPACT
ON PLANT AVAILABILITY[(a)]

Configuration	Maintenance Outages Caused	Cleanup Following Actuation	Net Impact
Manual	2.2 hours	(b)	2.2 hours
Automatic	3.6 hours	21 hours	24.6 hours

(a) Additional critical path shutdown hours per plant year.

(b) For this study it was assumed that PORVs would be actuated manually to perform a primary feed-and-bleed operation only. As a result it was further assumed that any cleanup time associated with such operation would be non-critical path.

Question 12: Cost of PORV Addition

The cost of adding PORVs could vary widely between plants and cannot be addressed generically in this report. This question will be responded to on a plant specific basis by each of the utilities participating in this study.

Question 13: SG Tube Plugging Criteria

This question effectively asks for an assessment of the accuracy of eddy current testing and for an evaluation of the probability that inservice inspections will fail to detect a degraded steam geneator U-tube.

The purpose of eddy current testing of steam generator tubing is to establish the general condition of the primay boundary and to identify any forms of degradation which may be occuring. This general assessment is qualitative in nature and provides information for plant operations and corrective actions planning. When tube degradation is observed, quantitative ECT results are used to determine the need for preventive action such as the plugging or sleeving of degraded tubes, support plate rim cut, sludge lancing, or coolant chemistry changes.

Examples of the forms of tube degradation in the 3410 and the 3800 steam generators are pitting, wastage, mechanical wear or fretting, and intergranular corrosion. Comparisons of the ECT measured flaw sizes with actual flaw sizes indicated that eddy current testing is highly accurate at measuring degradation except in the case of intergranular corrosion where the tendency is to slightly underpredict this type of attack. Improved ECT methods are presently under development to address this problem. Further, the probability of incorrectly classifying the extent of tube degradation due to ECT error is low as indicated in Table VII (p. xLiii).

Table VII

PROBABILITY OF INCORRECT TUBE CLASSIFICATION DUE TO ECT ERROR

Defect Depth	Wear/Fretting	Wastage	Pitting
60%	3%	10%	1.3%
70%	0.7%	6%	0.2%
80%	0.1%	4%	< 0.1%
90%	< 0.1%	3%	< 0.1%
95%	< 0.1%	2%	< 0.1%

Question 14: System 80 SG Vibration Analysis

This question is applicable only to those plants using the System 80 design (Palo Verde Nuclear Generating Station and Washington Public Power Supply System). These utilities will provide a separate response to the question.

LIST OF ACRONYMS AND ABBREVIATIONS

ACRS	Advisory Committee on Reactor Safeguards
ANO-2	Arkansas Nuclear One - Unit 2
ASME	American Society of Mechanical Engineers
ADV	Atmospheric dump valve
AFW	Auxiliary feedwater
AFWS	Auxiliary feedwater system
ATWS	Anticipated transient without scram
BOP	Balance of plant
Btu	British thermal unit
C-E	Combustion Engineering
CEOG	Combustion Engineering Owners Group
CFR	Code of Federal Regulations
CST	Condensate storage tank
CVCS	Chemical and volume control system
ECCS	Emergency core cooling system
ECT	Eddy current testing
EFW	Emergency feedwater
EFWS	Emergency feedwater system
EOL	End of life
ESFAS	Engineering safety features actuation signal
FSAR	Final Safety Analysis Report
FWCS	Feedwater control system
GIS	Generated iodine spike
HPSI	High pressure safety injection
IE	Inspection and Enforcement
ISI	Inservice inspection
LOCA	Loss of coolant accident
LOFW	Loss of feedwater
LOFC	Loss of forced circulation
LOHS	Loss of heat sink
LPSI	Low pressure safety injection
LWR	Light water reactor
MFIV	Main feedwater isolation valve

MFW	Main feedwater
MSIV	Main steam isolation valve
MSIS	Main steam isolation signal
MSLB	Main steam line break
MSSV	Main steam safety valve
Mw	Megawatt
NPSH	Net position suction head
NRC	Nuclear Regulatory Commission
NSSS	Nuclear steam supply system
PIS	Pre-existing iodine spike
PLCS	Pressurizer level control system
PORV	Power operated relief valve
PPCS	Pressurizer pressure control system
PRA	Probabilistic risk assessment
PTS	Pressurized thermal shock
PWR	Pressurized water reactor
PZR	Pressurizer
RCP	Reactor coolant pump
RCS	Reactor coolant system
REM	Roentgen equivalent man
RPS	Reactor protective system
RRS	Reactor regulating system
RSB	Reactor Systems Branch
RTD	Resistance temperature detectors
RTP	Rated thermal power
RVUH	Reactor vessel upper head
RWT	Refueling water tank
SBCS	Steam bypass control system
SBLOCA	Small break loss of coolant accident
SCS	Shutdown cooling system
SG	Steam generator
SGTR	Steam generator tube rupture
SIAS	Safety injection actuation signal
SIS	Safety injection system
SIT	Safety injection tank

SLB	Steam line break
SONGS	San Onofre Nuclear Generating Station
TLOFW	Total loss of feedwater
TMI-2	Three Mile Island Unit 2
WPPSS	Washington Public Power Supply System

TABLE OF CONTENTS

1.0 INTRODUCTION

1.1 Purpose

This report provides generic responses to a request from the NRC Staff for additional information regarding the rapid depressurization and decay heat removal capability of the C-E NSSS without power operated relief valves. The responses are based upon efforts completed on behalf of the C-E Owners Group to address specific concerns which the NRC Staff had regarding the response of the C-E NSSS without PORVs to certain postulated events. In general, these postulated events are beyond the design bases of the plants. As such, the results of the analyses presented in this report represent best estimate plant response to the specific scenarios postulated by the NRC Staff and should not be construed as advance engineering design work or operating procedure information for any future system which may or may not be installed

1.2 Scope

This report is applicable to the C-E plants listed in Table 1.0-1 (p. 2). Throughout the report, the various plants have been referenced according to their plant class, i.e., San Onofre and Waterford are referred to as 3410 Class plants; Palo Verde and Washington Nuclear Project are referred to as 3800 or System 80 Class plants. Table 1.0-1 also identifies two basic differences between the classes of plants important to depressurization and decay heat removal. Other significant plant differences will be identified as appropriate in Section 2.0 below.

1.3 Background

Early C-E NSSS designs used power operated relief valves as non-safety-grade equipment to limit overpressure transients to pressures below the ASME Code safety valve setpoint. This function was intended to reduce challenges to the safety valves and thus minimize

Table 1.0-1

CEOG TASK PARTICIPANTS AND PLANT CHARACTERISTICS

PLANT (Utility)	RATED THERMAL POWER (Mw)	PZR SIZE (ft^3)	REACTOR VESSEL UPPER HEAD VOLUME (ft^3)
San Onofre Nuclear Generating Station, Units 2 and 3 (Southern California Edison Co.)	3410	1500	900
Waterford Steam Electric Station, Unit 3 (Louisiana Power & Light Co.)	3410	1500	900
Palo Verde Nuclear Generating Station, Units 1, 2 and 3 (Arizona Public Service Co.)	3800	1800	2000
Washington Nuclear Project, Unit 3 (Washington Public Power Steam System)	3800	1800	2000

valve weepage and avoid potential leakage following actuation. These PORVs were not intended to provide a safely-related mitigating function and were therefore not credited in plant safety analyses. PORVs were intended, however, to be used in conjunction with this trip on high pressurizer pressure in order to mitigate pressure transients and thus reduce safety valve actuation.

As each of the early plants became operational, the effectiveness of the high pressure reactor trip and the pressurizer spray system to limit pressure transients was demonstrated. Consequently, C-E was unable to identify any advantages to opening PORVs during such transients in order to reduce challenges to the safety valves and thus reduces the potential for leakage. PORVs were also considered to be counterproductive since significant leakage problems of their own had been experienced. Furthermore, best estimate transient analysis had demonstrated that the pressure overshoot above the high pressure reactor trip setpoint during most transients was minimal and that primary safety valves were not challenged when PORV operation was not credited. PORVs were therefore considered unnecessary during power operations and were eliminated from later C-E designs.

Recently, a contingency method of core cooling employing a once through flow scheme in the RCS has been advanced by the NRC as an alternate means of removing decay heat. This scheme would use PORVs in conjunction with high pressure safety injection pumps and has been referred to as a feed-and-bleed method of core cooling. In this regard, the Advisory Committee on Reactor Safeguards, following its review of the C-E System 80 design, stated the following: (See Reference 1.)

> In recent years, the availability of reliable shutdown heat removal capability for a wide range of transients has been recognized to be of great importance to safety. The System 80 design does not include the capability for rapid, direct depressurization of the primary system or

for any method of heat removal immediately after shutdown which does not require use of the steam generator. [Note that the C-E 3410 Class plants are similar to System 80 in this respect.] In the present design, the steam generators must be operated for heat removal after shutdown when the primary system is at high pressure and temperature. This places extra importance on the reliability of the auxiliary feedwater system used in connection with System 80 steam generators and extra requirements on the integrity of the steam generators. The ACRS believes that special attention should be given to these matters in connection with any plant employing the System 80 design. The Committee also believes that it may be useful to give consideration to the potential for adding valves of a size to facilitate rapid depressurization of the System 80 primary coolant system to allow more direct methods of decay heat removal. The Committee wishes to review this matter further with the cooperation of Combustion Engineering and the NRC Staff.

In subsequent meetings with the ACRS and the NRC Staff, C-E presented its position and the bases for plant designs which do not employ PORVs as follows:

1. The NSSS is coupled with a highly reliable, safety-grade auxiliary feedwater system.

2. Cold shutdown conditions can be achieved using only safety-grade systems during a loss of offsite power and with an additional single failure.

3. The steam generator design includes many features which will enhance tube integrity. In addition, careful attention to the plant water chemistry program will ensure that the magnitude of any impurity ingress into the steam generators is maintained at a low level, during normal operations.

4. In the event of a loss of auxiliary feedwater, the potential exists for a contingency scheme using low head pumps to supply water. In this scheme, steam generators would be depressurized below the shutoff head of the contingency or surrogate feedwater pumps prior to their use.

5. A review of probabilistic analyses appeared to show no justification for the adding of PORVs strictly for decay heat removal purposes.

The NRC Staff then concluded that the current licensing requirements relative to the AFWS reliability could be met without the need for a feed-and-bleed mode of cooling. The ACRS position, as stated in Reference 1, and the recent steam generator tube rupture event at the Ginna plant, however, led the Staff to re-examine the reliability and integrity of the steam generators for decay heat removal over the life of the plant. Specifically, the NRC expressed concerns for the need for a rapid depressurization capability in the event of tube failures in both steam generators. In addition, the staff wanted to examine the potential benefits of providing this capability to afford the operator greater flexibility in responding to certain other events such as ATWS and PTS. The staff therefore made the request of the various utilities involved in this project to provide additional information in the form of answers to the fourteen questions addressed in Section 2.0 below.

1.4 Organization of Report

Information in Section 2.0 below is presented in a question and answer type format in which the specific question asked by the NRC Staff is given followed by a generic response applicable to the 3410 and the 3800 plants. Note the certain of the questions are plant specific in nature and as such responses will be provided by the individual utilities. Specifically, each utility participating in this study will provide plant specific responses to Parts a and b of

Question 6, Question 12, and Parts a, c, and d of Question 13. In addition, System 80 plants will provide their response to Question 14.

Finally, four separate supplement to in this report will be prepared in order to address the probabilistic risk assessment portions of the NRC questions detailed in Section 2.0. Supplement No. 1 to CEN-239 will present the plant specific PRA evaluation for SONGS Units 2 and 3, Supplement No. 2 will present the PRA evaluation for Waterford, Supplement No. 3 will present the PRA evaluation for Palo Verde Units 1, 2, and 3, and Supplement No. 4 will present the PRA evaluation for WPPSS.

2.0 RESPONSES TO NRC REQUEST FOR ADDITIONAL INFORMATION

2.1 Question 1: Auxiliary Spray Capability

C-E has not demonstrated that the auxiliary spray system can satisfactorily depressurize the reactor coolant system during events where depressurization must be accomplished and the normal spray is unavailable. In addition, for some scenarios containment isolation results in a loss of preheating to the auxiliary spray, which can result in a thermal transient to the spray nozzle piping and pressurizer spray. Please address the capability of the spray system to accommodate such thermal transients.

Please address the following aspects of auxiliary spray system:

a. A full description of the system.
b. The means to control the depressurization rate.
c. The maximum depressurization rate available.
d. The consequences of a failed open spray valve.
e. An evaluation of the ability to depressurize using the technique in the event of void formation in the vessel upper head. In such an eventuality, continued auxiliary spray operation could collapse the pressurizer steam bubble and result in a rapid insurge producing a water solid pressurizer. It is not readily apparent that the auxiliary spray would be effective in such a situation.
f. The sources of reactor coolant grade borated water for auxiliary spray.
g. The time available for manual loading of the charging pump onto the emergency diesel generator.
h. The stresses induced in the pressurizer and nozzle must be shown to be acceptable, considering the worst combination of flows, temperatures, and pressures.

2.1.1 Response to Question 1

The auxiliary spray system has been included in all C-E designed NSSSs and has been demonstrated to be an effective depressurization system under conditions where RCPs are not operating and therefore main spray is not available. For the plants participating in this study, the auxiliary spray system has been upgraded from earlier designs and provides a degree of performance consistent with the criteria of Branch Technical Position RSB 5-1. The rate of depressurization and the magnitude of the total pressure reduction achievable with auxiliary spray are sufficient to provide successful mitigation of design base events such as the SGTR without the use of PORVs. In addition, thermal stresses on the pressurizer spray nozzle as a result of auxiliary spray operation do not place undue limitations on its use. The following sections provide a detailed review of the auxiliary spray system in the areas requested.

2.1.2 Description of the Auxiliary Spray System

During normal plant operations for a C-E supplied NSSS, spray flow is provided to the pressurizer via the main spray valves. The configuration of this system for a typical C-E plant is shown in Figure 2.1-1. (All figures for Section 2.1 of this report are contained together at the end of the section (p. 47).) The differential pressure across an operating RCP is used to provide the motive force for main spray flow with the main spray valves operating to control flowrate. The main spray valves operate as proportional or throttling valves when in automatic to control flowrate between a system pressure of 2275 psia and a system pressure of 2300 psia, i.e., the main spray valves will begin to open if system pressure increases above 2275 psia and are fully open when pressure reaches 2300 psia. The minimum flowrate produced by this system is approximately 375 gpm and the corresponding depressurization rate at normal operating tempertures is about 7.0 psi/second. Because the differential temperature between main spray and the pressurizer steam space can vary from approximately 100°F under normal operating conditions to several hundred degrees and more depending upon system pressure and loop temperatures, each spray valve is provided with a bypass line as shown in Figure 2.1-1. These bypass lines are capable of passing about 1.5 gpm to the pressurizer whenever RCPs are operating in order to keep the spray nozzle relatively cool and thus prevent thermal shock when main spray is initiated.

For situations in which the reactor coolant pumps are not available, e.g., loss of offsite power, pump failure, manual action of operators in response to plant conditions, etc., main spray cannot be used to control system pressure. All C-E plants, however, are provided with an auxiliary spray system to provide a means to reduce pressure should main spray not be available. Although slight differences exist from plant to plant, the basic design, purpose, and function of this system is the same for all C-E NSSSs. (A description of the auxiliary spray system for each of the utilities participating in this study is presented below.) For each of these plants, the auxiliary spray system has been included in the basic design (and is therefore an integral part) of the CVCS. Auxiliary spray is initiated by diverting the flow from positive displacement charging pumps at the outlet to the regenerative heat exchanger away from the loop charging nozzles and through the auxiliary spray line. Flow then proceeds down the auxiliary spray line to the point where the line connects with the main spray piping (up stream of the main spray valves as shown in Figure 2.1-1) and into the pressurizer. Flowrate and hence depressurization rate are controlled, as shown in Section 2.1.3, by varying the number of operating charging pumps.

Figure 2.1-2 contains a simplified schematic of the SONGS CVCS showing the valves and piping associated with the auxiliary spray portion of that system along with the various sources of reactor coolant grade borated water. (Section 9.3.4 of Reference 2 contains a complete description of the SONGS chemical and volume control system along with the system design bases and a discussion of the various operational modes.) Spray flow is normally initiated from the control room by opening the auxiliary spray valve (2HV-9201), ensuring the two main spray valves are closed, and closing the two loop charging valves (2HV-9202 and 2HV-9203). Although not shown in Figure 2.1-2, the height difference between the top of the pressurizer and the RCS loops is about thirty feet; therefore, both loops charging valves must be closed in order to initiate auxiliary spray. This action will divert charging flow from the positive displacement charging pumps at the outlet of the regenerative heat exchanger away from the loop charging nozzles and through the auxiliary spray line to the pressurizer spray nozzle. In the event that either the auxiliary spray valve (2HV-9201) fails to open or one of the loop charging valve fails to close, a manual bypass line has been provided as shown in Figure 2.1-2. Auxiliary spray can be manually initiated from outside containment if Valve 2HV-9201 fails to open by first opening Valve 130-C-334 and then securing loop charging by closing 2HV-9202 and 2HV-9203. If one of the loop charging valves fails to close, spray can still be initiated by opening Valve 130-C-334 and then closing 2HV-9201 or 2HV-9200. Again, as stated above, both main spray valves must be closed in order to prevent flow through the main spray lines into the RCS loops. In addition, boron concentration in the pressurizer can be increased as necessary by lining up the suction of the charging pumps to any of the various borated water sources shown in Figure 2.1-2 with the CVCS operating in an automatic or manual mixing mode as described in Section 9.3.4 of Reference 2.

Figure 2.1-3 contains a simplified schematic of the Waterford Unit 3 CVCS showing the valves and piping associated with the auxiliary spray portion of that system along with the various sources of reactor coolant grade borated water. (Section 9.3.4 of Reference 3 contains a complete description of the Waterford Unit 3 chemical and volume control system along with the system design bases and a discussion of the various operational modes.) Spray flow is normally initiated from the control room by opening one of two auxiliary spray valves (CH-517 or ICH-E2505B) and closing the two loop charging valves (CH-518 and CH-519). This action will divert charging flow from the positive displacement charging pumps at the outlet of the regenerative heat exchanger away from the loop charging nozzles and through the auxiliary spray line to the pressurizer spray nozzle. A check valve in the main spray piping prevents bypassing of the pressurizer by eliminating flow of charging fluid back through the main spray valves into the RCS. Should one auxiliary spray valve fail to open, redundancy is provided by two Class 1E solenoid operated valves (CH-517 and ICH-E2505B) in parallel as shown in Figure 2.1-3. Although not shown in Figure 2.1-3, the height difference between the top of the pressurizer and the RCS loops is about thirty feet; therefore, both loop charging valves must be closed in order to initiate auxiliary spray. The two loop charging valves which must be closed in order to prevent flow into the RCS loops during auxiliary spray operations are Class 1E solenoid valves which are designed to fail in the closed position upon loss of power. Finally, boron concentration in the pressurizer can be increased as necessary by lining up the suction of the charging pumps to any of the various borated water sources shown in Figure 2.1-3 with the CVCS operating in an automatic or manual mixing mode as described in Section 9.3.4 of Reference 3.

Figure 2.1-4 and Figure 2.1-5 contain simplified schematics of the Palo Verde CVCS and the Washington Nuclear Project CVCS, respectively. Each of these figures shows the valves and piping associated with the auxiliary spray portion along with the various sources of reactor coolant grade borated water. (Section 9.3.4 of Reference 4 and Section 9.3.4 of Reference 5 contain a complete description of the Palo Verde chemical and volume control system and the WPPSS chemical and volume control system, respectively, along with the system design bases and a discussion of the various operational modes.) Spray flow is normally initiated from the control room by opening one of two auxiliary spray valves (CH-203 or CH-205) and closing the loop charging valve (CH-240). This action will divert charging flow from the positive displacement charging pumps at the outlet of the regenerative heat exchanger away from the loop charging nozzles and through the auxiliary spray line to the pressurizer spray nozzle. A check valve in the main spray piping prevents bypassing of the pressurizer by eliminating flow of charging fluid back through the main spray valves into the RCS. Should one auxiliary spray valve fail to open, redundancy is provided by two Class 1E solenoid operated valves (CH-203 and CH-205) in parallel as shown in Figure 2.1-4 and in Figure 2.1-5. Although not shown in Figure 2.1-4 or Figure 2.1-5, the height difference between the top of the pressurizer and the RCS loops is about thirty feet; therefore, both loop charging valves must be closed in order to initiate auxiliary spray. The loop charging valve, CH-240, which must be fully closed in order to get full auxiliary spray flow is air operated with a Class 1E solenoid. The valve is designed to fail closed on loss of air and loss of power to the solenoid. Finally, boron concentration in the pressurizer can be increased as necessary by lining up the suction of the charging pumps to any of the various borated water sources shown in Figure 2.1-4 or Figure 2.1-5 with the CVCS operating in an automatic or manual mixing mode as described in Section 9.3.4 of References 4 or Section 9.3.4 of Reference 5.

2.1.3 Depressurization Rate Study

A detailed parametric study was performed for both 3410 and 3800 plants in order to assess the performance of the auxiliary spray system under a variety of conditions. For this study a special computer code was used in order to model the essential characteristics of the pressurizer and the auxiliary spray system. This code uses a simplified model of the pressurizer and a simplified model of the reactor coolant system in order to calculate best estimate depressurization rates based upon spray flow into the pressurizer steam space at a fixed flowrate and a fixed temperature. The results produced by this code have been successfully benchmarked against actual plant data and the C-E full scope best estimate computer simulation code.

The results of the auxiliary spray performance study for the 3410 Class plant are contained in Figure 2.1-6 and Figure 2.1-7. Figure 2.1-8 shows the values of various pertinent parameters for the 3410 pressurizer. The results of the auxiliary spray performance study for the 3800 Class plant are contained in Figure 2.1-9 and Figure 2.1-10. Figure 2.1-11 shows the values of various pertinent parameters for the 3800 pressurizer. For each class of plant, depressurization studies were performed as follows:

A. Pressure versus time with one, two, and three charging pumps running and letdown in operation (Figure 2.1-6 and Figure 2.1-9).

B. Pressure versus time with one, two, and three charging pumps running and letdown secured (Figure 2.1-7 and Figure 2.1-10).

Table 2.1-1 (p. 14) contains a summary of the auxiliary spray performance study for both the 3410 and 3800 Class plants. Note that the depressurization rates in this table were obtained by measuring the initial depressurization rate from the curves in Figures 2.1-6, 2.1-7, 2.1-9 and 2.1-11. Also note that system pressure was assumed to remained above saturation pressure in the reactor vessel upper head at all times during the study to prevent steam bubble formation in that region. Section 2.1.4.1, however, contains a discussion of the process of maintaining a steam bubble in the pressurizer. In addition, Section 2.1.4.2 contains a discussion of depressurization process during a SGTR event in which the effects of steam bubble formation in the RVUH on event mitigation are presented.

During a plant depressurization using the auxiliary spray system, direct control over the depressurization rate is maintained by varying the number of operating charging pumps. As shown in Table 2.1-1, this depressurization rate is almost directly proportional to the spray flowrate, i.e., the depressurization rate using three charging pumps is approximately equal to three times the rate using

Table 2.1-1

AUXILIARY SPRAY PERFORMANCE STUDY[1]

Plant Class	Number of Charging Pumps	Depressurization Rates (psi/second) with letdown	without letdown[2]
3410	1	0.50	0.85
3410	2	1.10	1.65
3410	3	1.80	2.45
3800	1	0.45	0.70
3800	2	1.05	1.45
3800	3	1.65	2.10

---

(1) For comparison with these rates, the depressurization rates that would be achieved via various size PORVs are as follows: 0.9 psi/seconds with a vent area of 0.0021 ft^2, 4.5 psi/second with a vent area of 0.0095 ft^2, and 13.7 psi/second with a vent area of 0.0341 ft^2.

(2) Note that the rate of depressurization without letdown is higher than with letdown due to the absence of preheating in the regenerative heat exchanger, i.e., the temperature of the spray fluid is low.

one charging pump, and the depressurization rate using two charging pumps is approximately equal to twice the rate using one charging pump. The maximum depressurization rate is obtained by operating all three charging pumps which maximizes spray flow. In the event that an auxiliary spray valve should fail in the open position, direct control over depressurization can still be maintained by controlling the normal loop charging valve. Referring to Figure 2.1-4, for example, if CH-205 were to fail open all charging flow could be diverted from the pressurizer to the RCS loop by opening CH-240. This change in flow direction results from the height difference between the pressurizer and the loop charging nozzle, i.e., the top of the pressurizer is approximately thirty feet above the loop charging nozzle, and the fact that charging will flow to the loop as the path of least resistance if CH-205 and CH-240 are both open. Therefore, if an auxiliary spray valve should fail in the open position, spray flow can be initiated and secured as required by opening and closing the loop charging valve. As a final note, in the event of a loss of offsite power, charging flow can be regained by the operators without having to leave the control room as soon as the emergency diesel generators have started and the 1E buses are reenergized. The sequence of events necessary to start the emergency diesels and reenergize the 1E buses is accomplished automatically upon loss of offsite power normally within about two minutes.

2.1.4 Control of Depressurization

The depressurization rates achievable using auxiliary spray were presented in Section 2.1.3. These depressurization rates alone, however, do not allow for a complete assessment of the effectiveness of auxiliary spray as a depressurization method; the ability to control depressurization under a variety of conditions must also be considered. Two aspects of pressure control using auxiliary spray will therefore be addressed below. First, the ability to maintain a pressurizer steam bubble so as to assure the effectiveness of the spray will be considered. Second, pressure control during a steam generator tube rupture will be discussed.

2.1.4.1 Maintaining a Pressurizer Steam Bubble

Auxiliary spray is only effective as long as a steam bubble is maintained in the pressurizer. During a plant depressurization, several mechanisms exist by which the pressurizer might become filled with water and thus collapse the steam space. Three such mechanisms are as follows:

1. Coolant addition from the use of the auxiliary spray in the absense of letdown.

2. Coolant addition from the initiation of safety injection.

3. Coolant addition from fluid displaced out of the RVUH following upper head steam bubble formation.

Examining the first of these mechanisms, it is apparent that the effect of coolant addition to the pressurizer via the use of auxiliary spray is the absence of letdown is gradual and therefore does not present a problem with respect to depressurization control. The gradual effect referred to is the slow filling of the pressurizer as coolant is added through the spray nozzle. Neglecting for the moment the small effect on volume due to the compressibility of water, a spray flowrate of 88 gpm into the pressurizer will produce a reduction in the steam space volume of approximately 17 ft^3/minute. If we assume an initial steam volume of 700 ft^3 for the 3410 pressurizer and 900 ft^3 for the 3800 pressurizer, see Figure 2.1-8 and Figure 2.1-11, and now take into account an appropriate insurge due to the compressibility of water, calculations show that it will take approximately 40 minutes to fill the 3410 pressurizer solid and approximately 50 minutes to fill the 3800 pressurizer solid under these conditions. Referring again to Figure 2.1-7 and Figure 2.1-10 which show plant depressurizations in the absence of letdown, a total pressure decrease of approximately 550 psi was obtained for both the 3410 and the 3800 plant using two charging pumps after only seven minutes of spray operation. Therefore, sufficient volume exists in the pressurizer to allow for substantial pressure reductions using auxiliary spray under conditions where the pressurizer level will be increasing during depressurization due to the absence of letdown.

The second mechanism which will result in coolant addition to the pressurizer with subsequent collapse of the steam space is the initiation of safety injection. In a controlled plant cooldown and depressurization, the SIAS will be bypassed to allow for system depressurization without actuation of the SIS. During a depressurization transient, however, that results in the actuation of this system, RCS pressure will effectively stabilize at or just below the shutoff head of the HPSI pumps depending upon plant conditions. If further depressurization is required, safety injection must first be secured or throttled. Current emergency procedure guidelines, Reference 6, provide operators with the necessary and adequate guidance in such an event. As an example, if an SIAS has been initiated and the SIS is operating, it must continue to operate at full capacity until the SIS termination criteria are met. Early termination may be desirable when the criteria are met to preclude PTS situations or HPSI pump damage, e.g., damage to shaft seals. Termination of safety injection should be sequenced by stopping one pump at a time while observing the termination criteria. Throttling of HPSI flow is permissible. The SIS termination criteria are as follows:

1. Proper RCS subcooling established. The establishment of RCS subcooling ensures the fluid in the core is subcooled and provides sufficient margin for establishing flow should subcooling deteriorate when safety injection flow is secured. Voids may exist in some parts of the RCS, e.g., reactor vessel upper head, but these are permissible as long as core heat removal is maintained.

2. Pressurizer level is regained and is constant or increasing. A pressurizer level constant or increasing in conjunction with Criterion 1 above is an indication that RCS inventory control has been established.

3. At least on steam generator is available for removing heat from the RCS. Steam generator availability requires feed flow and steam flow which are indications that primary-to-secondary heat removal is possible.

If these criteria are met, the operator may either terminate or throttle the SIS. The operator may decide to throttle rather than terminate if the SIS is to be used to control pressurizer level or plant pressure. A general assessment of the SIS performance can be made from the control room. The operator should confirm that at least one train and preferably both trains of the SIS are operating and that the system delivery rate is consistent with RCS pressure. Injection flowrates to each cold leg should be approximately equal; departures from this would indicate a closed flow path or some system leakage.

The third mechanism mentioned above which will result in coolant addition to the pressurizer with subsequent collapse of the pressurizer steam space is the formation of a steam bubble in the reactor vessel upper head. Under natural circulation conditions, the RVUH is relatively stagnant and thus the temperature in that region will lag behind the temperatures in the remainder of the RCS during a plant cooldown. During the subsequent depressurization using auxiliary spray, saturation conditions will eventually be reached in the upper head and the coolant there will begin to boil and flash to steam. Continued use of auxiliary spray under these circumstances will have a reduced effect on pressure and will cause the RVUH steam bubble to expand displacing more coolant into the pressurizer. In such a situation a number of solutions or paths are avilable to an operator which will permit continued depressurization of the RCS. For example, if a relatively rapid pressure reduction in the RCS is not required, depressurization can simply be delayed to allow the RVUH to cool via heat conduction to the cooler portions of the RCS. If conditions required that a more expeditions depressurization be accomplished, however, two possible paths exist for a more aggressive cooling of the RVUH. The first path involves the use of the reactor vessel head vent system. Once a steam bubble has been formed in the upper head, the head vent could be opened resulting in the release of mass and energy from this region. In this manner, a continued pressure decrease of approximately five to ten psi/minute can be achieved. The second path for a more aggressive cooldown of the RVUH involves a drain-and-fill process similar to that performed by Florida Power and Light on Unit 1 of their St. Lucie plant. (See Reference 7.) Specifically, a steam bubble would be allowed to form and expand in the RVUH. The warm water flushed from the upper head during this process would mix and be cooled by the fluid in the rest of the RCS. Action would then be taken by the operator to collapse or shrink this steam bubble thereby forcing relatively cool loop water back into the upper head and further lowering temperatures in that region. The action to collapse the RVUH steam bubble would take the form of a system pressure increase via the operation of pressurizer heaters or the use of loop charging or both. Several cycles of this drain-and-fill process would be required to completely cool the upper head and allow for system depressurization to condition that permit use of the SCS.

A conceptual description of a general procedure that might be used for the drain-and-fill process are as follows:

1. Following cooldown and prior to RCS depressurization, establish pressurizer level between 35% to 50%.

2. Commence RCS depressurization by manually operating the auxiliary spray system. Maintain pressurizer cooldown rate within technical specifications requirement.

3. Maintain at least 20°F + (inaccuracies) subcooled margin in the RCS based on hot leg RTDs or core exit thermocouples.

4. Reset or bypass the ESFAS and reduce safety injection tank pressures as required due to the decreasing primary pressure.

5. During the RCS depressurization, monitor for condensible steam bubble formation. Symptoms are pressurizer level increases significantly greater than expected while operating auxiliary spray, letdown flow unexpectedly greater than charging flow if the PLCS is in automatic, and the reactor vessel level monitor (if installed) indicates a steam bubble or saturation conditions in the RVUH.

6. Once steam bubble formation in the RVUH is indicated, perform the following:

   a. Continue using auxiliary spray allowing the steam bubble in the RVUH to expand.

   b. Stop spraying when pressurizer level has increased to approximately 90% or the reactor vessel level monitor indicates a level approximately three feet above the upper guide structure.

c. Collapse the steam bubble by energizing all available pressurizer heaters or commencing charging flow to the RCS loops or both. The reactor vessel head vent may be opened to aid in steam bubble collapse.

d. Stop the charging flow and deenergize tne pressurizer heaters when the steam bubble has collapsed.

e. Allow RVUH temperature to decrease following collapse of the steam bubble prior continuing depressurization.

f. Repeat Steps a through e for several drain and fill cycles until SCS entry pressures are attained.

As mentioned above, drain-and-fill process very similar to that described above was performed at Florida Power and Light's St. Lucie Unit 1 during their cooldown event of 11 June 1980. (See Reference 7 for a complete discussion of the cooldown.) Figure 2.1-12 shows pressurizer level and RCS pressure behavior during the event. Cooldown on natural circulation by feeding the steam generators and dumping steam to the condenser began at about 3:00 in the morning. Natural circulation had been well established by the time the cooldown started. The cooldown progressed at an average rate of 60°F per hour until about 6:00. Shortly after that, an attempt was made to cool the pressurizer and reduce pressure through the use of auxiliary spray from the charging pumps. Between 6:15 and 7:15 the water level in the pressurizer rose unexpectedly, much more than could be explained by the volume of water being charged into the reactor coolant system. The pressure at 6:15, when the steam bubble apparently first started to form under the head of the reactor vessel, was somewhere between 1140 and 690 psig, the pressure log entries at 6:00 and 6:30 respectively. Saturation temperature at

6:15 corresponding to the mean pressure between 6:00 and 6:30 was 535°F, likely very nearly the temperature of the reactor vessel head and its contents at the beginning of bubble formation. The cold leg temperature was 320°F at this time, so a temperature differential of about 200°F existed in the reactor vessel between the top of the flange and the coolant nozzles.

By 7:15, continued use of the auxiliary spray system had caused pressurizer level to increase to 100%. Pressurizer cooldown was stopped and charging was initiated to the RCS loops. This action caused pressurizer level to decrease rapidly indicating that loop charging had at least partially collapsed the RVUH steam bubble. Over the next several hours the RVUH continued to be cooled by drain-and-fill as charging flow was alternated between the RCS loops and the auxiliary spray system. The following important conclusions, see Reference 7, should be noted as a result of this event:

1. Natural circulation decay heat removal and subsequent cooldown of the reactor coolant system were adequate.

2. At the time the steam bubble first started to form under the reactor vessel head, there existed in the reactor vessel a temperature difference of about 200°F between the top of the vessel flange and the coolant nozzles.

3. When the RVUH steam bubble had first formed and pressurizer level had increased to 100%, system pressure had already decreased to approximately 450 psia indicating substantial cooling of the upper head.

4. Substantial collapsing of the upper head steam bubble was effected by the use of loop charging alone.

5. Following the initial steam bubble formation, system pressure was reduced by approximately 300 psi using drain-and-fill to cool the RVUH over a three hour period prior to initiation of shutdown cooling.

6. When the SCS was initiated, a steam bubble still existed in the RVUH. No abnormal effects on decay heat removal were noted.

2.1.4.2 Depressurization During a SGTR

2.1.4.2.1 Introduction to the SGTR Event

The SGTR is one of the most challenging design basis events for an operator from the standpoint of plant depressurization. For the majority of design basis events, depressurization is required prior to placing the plant on shutdown cooling. Pressure reduction in such instances is a slow deliberate process accomplished over a period of several hours and is therefore not very limiting with respect to plant design depressurization capabilities. The SGTR event, however, benefits by an early relatively rapid RCS depressurization to minimize the primary-to-secondary leakage and thereby minimizing any radiological releases. It has been suggested that the depressurization capability afforded by a PORV could be valuable in accomplishing this early depressurization in a more rapid manner than with the use of the auxiliary spray system. The analysis results of this section show that although a rapid pressure reduction is desirable, factors other than the specific method of depressurization, i.e., auxiliary spray vs PORVs, are limiting. Therefore, auxiliary spray provides essentially the same capability as a PORV during a SGTR without the additional complication of coolant discharge to the containment.

Before presenting analytical results, the basic strategy for mitigation of a SGTR and the factors affecting pressure control will be reviewed. For the SGTR event, the general goals related to controlling both RCS inventory and activity releases are met by minimizing leakage between the primary system and the secondary system and, following isolation of the affected steam generator, by avoiding opening of the MSSVs of that unit. Primary-to-secondary leakage is minimized by reducing the pressure differential between the reactor coolant system and the secondary side of the steam generators. The potential for activity release is minimized by reducing challenges to the MSSVs on the affected steam generator. This second action is necessary since an operator has no direct control over the closing of the secondary safety valves once they open other than reducing secondary pressure; further, the possibility is always present that a MSSV could stick in the open position.

Two mechanisms exist which could cause a secondary safety valve to lift once the steam generator has been isolated. The first mechanism is through the addition of heat from the RCS. Current emergency procedure guidelines, Reference 6, require that a plant cooldown using both steam generators be conducted to lower hot leg temperatures to less than 535°F (minus instrument error) for the 3410 Class plant and less than 554°F (minus instrument error) for the 3800 Class plant prior to isolation of the affected unit. This action will ensure that the temperature in the isolated unit will be below the saturation pressure corresponding to the safety valve setpoint. Should pressure increase due to heat input from the RCS and begin to approach this setpoint, appropriate operator action will be taken. This action includes increased steaming of the unaffected steam generator to lower system temperatures, the use of the SBCS on the affected unit, or if necessary, the use of the ADVs on the affected unit.

The second mechanism which will cause a secondary safety valve to lift once the steam generator is isolated is the addition of coolant through the rupture with RCS pressure relatively high. This second process has an inherent time delay, however, in that the pressure drop across the rupture will keep the generator from seeing full RCS pressure until the generator is almost solid.

The optimum response to control RCS inventory and to control activity release during the SGTR event is to lower RCS pressure below the MSSV setpoint and then to essentially equalize as soon as possible RCS pressure with the secondary pressure in the ruptured steam generator. Specifically, Reference 6 calls for maintaining primary system pressure below the secondary safety valve setpoint and slightly above the pressure in the generator with the rupture. This is accomplished by reducing RCS pressure using main spray if RCPs are available, using auxiliary spray if RCPs are not available, or throttling HPSI pumps if the SIS is operating. Maintaining RCS pressure slightly above secondary side pressure will minimize the loss of primary fluid while eliminating the possibility of reactor coolant dilution. In addition, heat input to the isolated steam generator is controlled by controlling RCS temperatures. In executing this optimum response strategy the following three factors must be considered:

1. Loop subcooling

   In order to ensure adequate core cooling and to provide proper NPSH for the reactor coolant pumps, at least 20°F of subcooling must be maintained in the reactor coolant system. The need to maintain 20°F of subcooling and thus ensure adequate core cooling and proper NPSH is more important and therefore takes precedent over the goal of reducing primary system pressure to a point slightly above secondary pressure in the isolated unit. As a result, pressure reduction in the RCS to minimize the pressure drop across the rupture may be delayed by the operator by an amount necessary to achieve this subcooling until loop temperatures can be reduced. Note that during this cooldown, the isolated steam generator may cool faster in the lower regions due to temperature stratification and poor mixing. This situation is illustrated in Figure 2.1-13. The steam space in the isolated steam generator will lag in the cooldown process and cause the fluid in the lower regions to be subcooled. This situation is actually desirable because it will tend to maintain the pressure in that steam generator relatively high and therefore allow the differential pressure across the rupture to be minimized while ensuring adequate subcooling. As thermal equilibrium conditions are gradually approached, i.e., a condition of complete temperature mixing in the steam generator in Figure 2.1-13, pressure in that unit will decrease making it necessary to further reduce RCS pressure to again minimize leakage. As noted above, the need to maintain subcooling in the primary system to ensure adequate core cooling and proper NPSH for pump operation takes precedent over the goal of minimizing the differential pressure across the break.

2. HPSI flow

Following the tube rupture, the initial loss of primary system inventory will produce a decrease in pressurizer level with a resultant decrease in RCS pressure. As pressure continues to fall an SIAS will result and the HPSI pumps will start. If conditions permit these pumps can eventually refill and repressurize the primary system at or just below their shutoff head and, as a result, increase primary-to-secondary leakage. If further depressurization is required, safety injection must first be throttled or secured. As stated in Section 2.1.4.1 above, current emergency procedure guidelines provide the operator with the necessary and adequate guidance in such an event. If an SIAS has been initiated and the SIS in operating during a SGTR, it must continue to operate at full capacity until the SIS termination criteria are met. These termination criteria are as follows:

1. Proper RCS subcooling established.
2. Pressure level is regained and is constant or increasing.
3. At least one steam generator is available for removing heat from the RCS.

3. Natural circulation

The relationship between primary temperatures and pressures and secondary temperatures and pressures under natural circulation conditions is shown graphically in Figure 2.1-14 for the 3800 Class plant. (Although the specific numbers would be slightly different for the 3410 plant, the situation and conclusions of this example are the same due to the similarities in plant design.) Note that the exact situation represented in Figure 2.1-14 is the following: symmetric cooldown to lower hot leg temperatures to 554°F per Reference 6 complete, affected steam generator is ready for isolation, affected steam generator is still a heat sink. During natural circulation, the RCS cold leg temperature is approximately equal to the steam generator tube bundle temperature and approximately equal to the secondary saturation temperature. If we assume a 20°F differential temperature across the core, this is a good assumption based upon the decay heat levels that will most likely exist, RCS cold leg temperature will be 534°F (554°F-20°F). This corresponds to a secondary pressure under natural circulation conditions of 916 psia. In order to maintain 20°F of subcooling in the RCS, pressurizer pressure must be 1266 psia, saturation pressure for 574°F. Therefore at the point where the operator is ready to isolate the affected unit, RCS pressure is 350 psi greater than SG pressure. This corresponds to a leakrate of less than 200 gpm which in turn is roughly half of the initial leakrate (initial RCS pressure equal to 2250 psia, initial SG pressure equal to 1170 psia).

In the situation illustrated in Figure 2.1-14, if an operator wanted to reduce the leakrate without cooling down further, two possible paths are available to him. The first path involves decreasing RCS pressure. This action, however, will reduce the subcooled margin below 20°F and is not allowed since, as previously stated, the need to maintain proper subcooling takes precedent over the need to minimize leakage. The second path involves a restart of reactor coolant pumps, if available. The situation where the RCPs have been restarted and the affected unit is acting as a heat sink is shown in Figure 2.1-15. Cold leg temperature will remain at approximately 534°F but the differential temperature across the core will drop to approximately 3°F due to the increase in mass flow. RCS pressure can now be reduced to 1107 psia and still maintain 20°F of subcooling at the new hot leg temperature of 537°F. Under these conditions, the differential pressure across the rupture will be 191 psi (1107 psia - 916 psia) which results in a leakrate of about 84 gpm. To reiterate the pertinent point of this last discussion, by restarting RCPs the core differential temperature was reduced from 20°F to approximately 3°F which in turn allowed primary system pressure to be reduced from 1266 psia to 1107 psia while still maintaining 20°F subcooling. This reduction in RCS pressure reduced the differential pressure across the rupture which in turn reduced the leakrate from approximately 200 gpm to approximately 84 gpm. Also note that restart of the reactor coolant pumps has the additional benefit of forced cooling of the RVUH and thus preventing steam bubble formation in that region which could slow the depressurization process.

The final situation to be considered during natural circulation is the one in which the affected steam generator has been isolated, a plant cooldown on the unaffected steam generator is in progress, and the isolated steam generator is now a heat source. If the ruptured steam generator is isolated at the point shown in Figure 2.1-14, i.e., hot leg temperature equal to 554°F, cold leg temperature in the operating loop will remain constant at 534°F, cold leg temperature in the loop with the isolated steam generator will increase and eventually approach hot leg temperature, and hot leg temperature in both loops will increase by approximately 10°F. This situation is shown in Figure 2.1-16. Since hot leg temperature has increased by 10°F, RCS pressure will have to be increased to 1368 psia (saturation pressure for 584°F) in order to maintain proper loop subcooling. Note that the increase in loop differential temperature in the loop with the unaffected SG is the result of a decrease in primary mass flowrate due to the transition from a symmetric two loop flow situation to an asymmetric one loop flow situation. When the isolated steam generator eventually fills, its pressure will increase since RCS pressure is 1368 psia and the MSSV (lift setpoint equal to 1270 psia) will open. As previously stated, however, there is a built in time delay in this process since the pressure drop across the break will keep the steam generator from seeing full RCS pressure until the steam generator is almost completely solid. This time delay will allow the operator to take appropriate action to lower RCS temperatures which in turn will allow him to lower RCS pressure below the MSSV setpoint while maintaining proper loop subcooling.

Figure 2.1-17 shows the relationship between RCS pressures and temperatures and SG pressures and temperatures following isolation of the affected generator and an additional cooldown of 12°F on the unaffected unit. The cold leg temperature in the unaffected loop will be 522°F with a hot leg temperature of 552°F. Note again that the increase in core differential temperature from 20°F to 30°F in the loop with the unaffected SG is the result of a decrease in the primary mass flowrate due to the transition from a symmetric two loop to an asymmetric one loop flow situation. Hot leg temperatures in both loops will be equal, but since the ruptured steam generator is now a heat source, cold leg temperature in that loop will exceed hot leg temperature by approximately 2°F. Subcooling is determined based upon the highest loop temperature, in this case cold leg temperature in the affected loop, so that RCS pressure must be 1266 psia (saturation pressure for 554°F + 20°F = 574°F). Pressure in the ruptured steam generator will be anywhere from 1080 psia (saturation pressure at 554°F) to 1170 psia (saturation pressure at 564°F) depending on the extent of temperature stratification shown in Figure 2.1-13 with the corresponding pressure drop across the tube rupture anywhere from 96 psid to 186 psid. Therefore, following the cooldown of just 12°F, RCS pressure could be lowered to less than the MSSV lift setpoint of 1270 psia. Note that the above analysis does not include an allowance for instrument error. Also note that as the cooldown on the unaffected steam generator is continued allowing RCS pressure to be lowered, steam generator pressure could exceed primary pressure depending upon the extent of the temperature stratification effect shown in Figure 2.1-13. In this situation, operator action would be required to maintain RCS pressure greater than SG pressure (which would require maintaining a loop subcooled margin of greater than 20°F) in order to prevent possible dilution of the primary system.

As previously stated, the optimum response to control RCS inventory and to control activity release during the SGTR event is to lower RCS pressure below the MSSV setpoint and then to essentially equalize as soon as possible RCS pressure with the secondary pressure in the ruptured steam generator. Under natural circulation conditions the reactor vessel upper head is no longer forced cooled and the possibility exists that a steam bubble could form in this region and slow depressurization. In the detailed analysis that follows, depressurization using auxiliary spray and depressurization using PORVs during a SGTR will be compared. In addition, it will be demonstrated that the SGTR event is successfully mitigated using auxiliary spray, and further that depressurization with auxiliary spray is preferable to the very rapid relatively uncontrolled depressurization caused by opening a PORV.

2.1.4.2.2 SGTR Cases Analyzed

Five different tube rupture scenarios were analyzed to assess the effect of various depressurization methods on the SGTR event. The results demonstrate the basic elements of a tube rupture and show that the depressurization process is limited by procedure rather than by equipment, i.e., the system depressurization needed to mitigate the event subject to the 20°F loop subcooling limit is well within the capability of the auxiliary spray system. Further, the results show that auxiliary spray depressurization is preferable to depressurization using a PORV since the pressure decrease using a power operated relief valve is rapid and relatively uncontrolled and the possibility exists that subcooling in the RCS loops could quickly be lost.

Each of the five SGTR scenarios analyzed began with a single double-ended tube rupture in one steam generator with subsequent operator action to manually trip the reactor and then isolate the affected unit following a symmetric cooldown of the reactor coolant system to lower hot leg temperature below 565°F. A hot leg of 565°F is approximately ten degrees higher than that specified in Reference 6 and was chosen as conservative with respect to the analysis since it presented a greater challenge to the MSSVs. The five cases evaluated are shown in Table 2.1-2 (p. 32) and were analyzed using a best estimate full scope computer simulation code. This computer code uses a node and full path type network to model the reactor coolant system and accounts for steam bubble formation in the reactor vessel upper head. The 3800 Class plant was used as the reference plant for the study. Although the results presented below would be slightly different for the 3410 plants, the basic conclusion presented in Section 2.1.4.2.4 are the same for both 3410 and 3800 plants because of the similarities in system design. Table 2.1-3 (p. 33) lists the basic plant parameters used in the study and Table 2.1-4 (p. 34) lists the important assumptions.

Case 1 of the SGTR study, see Table 2.1-2, is the baseline case and examines a single tube rupture event when no system depressurization via auxiliary spray or an assumed PORV is attempted. Case 2 examines the single SGTR event when operator action is taken to lower system pressure using auxiliary spray subject to a subcooling limit of 30°F in the RCS loops. Note that the 30°F subcooling limit used in the

Table 2.1-2

SUMMARY OF SGTR CASES ANALYZED

Case	SG Isolation* (Seconds)	Assumed PORV	Auxiliary Spray	MSSV
1	1664	No	No	-
2	1335	No	88 gpm at 900 seconds subject to 30°F subcooling limit.	
3	1324	0.0341 ft^2 total effective area at 900 seconds subject to 30°F subcooling limit.	No	Not challenged
4	1335	No	88 gpm at 900 seconds subject to 30°F subcooling limit. After 2540 seconds, 88 gpm until RVUH void formation.	Not challenged
5	1335	0.0341 ft^2 total effective area after 2540 seconds until RVUH void formation.	88 gpm from 900 to 2540 seconds subject to 30°F subcooling limit.	Not challenged

* Hot Leg temoperature below 565°F.

Table 2.1-3

PLANT PARAMETERS AND CHARACTERISTICS USED FOR SGTR ANALYSES

Parameter	Valve
Initial power (Mw)	3800
Initial RCS pressure (psia)	2250
Pressurizer volume (ft^3)	1800
Initial pressurizer liquid level (ft^3)	1115
RVUH volume (ft^3)	2000
Initial core outlet temperature (°F)	621
Initial core inlet temperature (°F)	565
Initial SG pressure (psia)	1070
Initial SG inventory (lbm)	190,700
MSSV setpoint (psia)	1270
SBCS setpoint (psia)	1170
SIAS setpoint (psia)	1740
HPSI shutoff head (psia)	1800

Table 2.1-4

ASSUMPTIONS USED IN SGTR ANALYSES

1. Except as noted, Reference 6 guidelines followed.

2. Single double-ended tube rupture in one SG as event initiator at time zero.

3. SBCS available initially.

4. Manual reactor trip at 300 seconds.

5. RCPs tripped following SIAS plus an assumed delay. RCPs not restarted.

6. Affected SG isolated at T_h = 565°F. Blowdown and all steaming secured on affected SG following isolation.

7. Symmetric system cooldown via ADVs at 75°F/hr until affected unit isolated. Following isolation, cooldown continued on unaffected SG via ADVs on that unit.

8. Both ECCS trains available.

analysis is ten degrees higher than the limit specified in Reference 6 and is therefore conservative with respect to flow through the break into the affected steam generator. Case 3 looks at the single tube rupture event when operator action is taken to lower system pressure using assumed PORVs with a total effective flow area of 0.0341 ft^2. This flow area, 0.0341 ft^2, is approximately equal to the total effective flow area of the largest power operated relief valves currently installed on a C-E plant. As was done in Case 2, pressure was lowered subject to a subcooling limit of 30°F in the RCS loops. Two additional cases were considered in order to show the effect on system depressurization of steam bubble formation in the RVUH. In Case 4, which is identical to Case 2 for the first 2540 seconds of the event, see Table 2.1-2, auxiliary spray is initiated at 2540 seconds and system pressure is lowered allowing a steam bubble for form in the upper head. In Case 5, which is also identical to Case 2 for the first 2540 seconds of the event, assumed PORVs with a total effective flow area of 0.0341 ft^2 are opened at 2540 seconds and system pressure is lowered allowing a steam bubble to form in the upper head.

2.1.4.2.3 Results of SGTR Analysis

A chronology of important events for Case 1, the baseline case, is shown in Table 2.1-5 (p. 36). Pertinent results for Case 1 are shown in Figures 2.1-18 through Figure 2.1-25. Note that the simulation was performed for the first 2250 second only following the tube rupture in order to provide a base case for comparison with Case 2 and Case 3. The event was initiated at time zero with a single tube rupture in Steam Generator B. Pressurizer level and hence pressurizer pressure decrease initially due to mass loss through the rupture into SG B, see Figures 2.1-18 and 2.1-19. The reactor is manually tripped at 300 seconds. The resultant coolant contraction causes pressurizer level and hence pressure to decrease rapidly until an SIAS is obtained at about 400 seconds, see Figure 2.1-20. Reactor coolant pumps are manually tripped at about 550 seconds and the plant is taken into natural circulation. At 900

Table 2.1-5

CHRONOLOGY OF EVENTS - CASE 1

Time (Seconds)	Event
0	1 tube SGTR
300	Manual reactor trip
400	SIAS
550	RCPs off
900	75°F/hr cooldown initiated via ADVs
1664	Affected SG isolated
1664	Cooldown continued on unaffected SG
2250	Simulation terminated

seconds a symmetric cooldown per Reference 6 using ADVs is initiated at 75°F/hr in order to lower hot leg temperatures prior to isolation of the affected steam generator. Figure 2.1-21 shows RCS loop temperatures, Figure 2.1-22 shows loop subcooling, and Figure 2.1-23 shows steam generator pressures. Note in Figure 2.1-23 that the SBCS functions to maintain secondary pressure until the cooldown via ADVs is initiated at 900 seconds. The affected steam generator is isolated at about 1664 seconds and cooldown on the unaffected unit is continued. Figure 2.1-24 shows steam generator levels and Figure 2.1-25 shows leak flowrate.

A chronology of important events for Case 2, depressurization via auxiliary spray, is shown in Table 2.1-6 (p. 38). Pertinent results for Case 2 are shown in Figures 2.1-26 through 2.1-34. Note that the simulation was performed for the first 2250 seconds only following the tube rupture in order to easily compare the results with the base case, Case 1. The event was initiated at time zero with a single tube rupture in Steam Generator B. Pressurizer level and hence pressure decreased initially due to mass loss through the rupture into SG B, see Figures 2.1-26 and 2.1-27. The reactor is manually tripped at 300 seconds. The resultant coolant contraction causes pressurizer level and hence pressure to decrease rapidly until an SIAS is obtained at about 400 seconds, see Figure 2.1-28. Reactor coolant pumps are manually tripped at about 550 seconds and the plant is taken into natural circulation. At 900 seconds a symmetric cooldown per Reference 6 using ADVs is initiated at 75°F/hr in order to lower hot leg temperatures prior to isolation of the affected steam generator. In addition, at 900 seconds RCS depressurization using auxiliary spray, see Figure 2.1-29, is initiated subject to a 30°F subcooling limit. Figure 2.1-30 shows RCS loop temperatures, Figure 2.1-31 shows loop subcooling, and Figure 2.1-32 shows steam generator pressures. Note in Figure 2.1-32 that the SBCS functions to maintain secondary pressure until the cooldown via ADVs is initiated at 900 seconds. In comparison with the base case, a greater SIS flow is realized due to the lower system pressure and pressurizer level recovery begins at approximately 1200 seconds, see

Table 2.1-6

CHRONOLOGY OF EVENTS - CASE 2

Time (Seconds)	Event
0	1 tube SGTR
300	Manual reactor trip
400	SIAS
550	RCPs off
900	75°F/hr cooldown initiated via ADVs
900	RCS depressurization using auxiliary spray subject to 30°F subcooling limit
1335	Affected SG isolated
1335	Cooldown continued on unaffected SG
2250	Simulation terminated

Figure 2.1-27. The affected steam generator is isolated at about 1335 seconds and cooldown on the unaffected unit is continued. Note that the affected steam generator can be isolated approximtely 300 seconds sooner in Case 2 than in the base case, Case 1 since the increased SIS flow added to the overall system cooldown. Once proper pressurizer level has been regained, the HPSI pumps are cycled on and off as shown in Figure 2.1-28 in order to maintain level and maintain proper loop subcooling. Figure 2.1-33 shows steam generator levels and Figure 2.1-34 shows leak flowrate.

A chronology of important events for Case 3, depressurization via assumed PORVs, is shown in Table 2.1-7 (p. 40). Pertinent results for Case 3 are shown in Figures 2.1-35 through 2.1-43. Note that the simulation was performed for the first 2250 seconds only following the tube rupture in order to easily compare the results with the base case, Case 1. The event was initiated time zero with a single tube rupture in Steam Generator B. Pressurizer level and hence pressure decrease initially due to mass loss through the rupture into SG B, see Figures 2.1-35 and 2.1-36. The reactor is manually tripped at 300 seconds. The resultant coolant contraction causes pressurizer level and hence pressurizer pressure to decrease rapidly until an SIAS is obtained at about 400 seconds, see Figure 2.1-37. Reactor coolant pumps are tripped at about 550 seconds and the plant is taken into natural circulation. At 900 seconds a symmetric cooldown per Reference 6 using ADVs is initiated at 75°F/hr in order to lower hot leg temperatures prior to isolation of the affected steam generator. In addition, at 900 seconds RCS depressurization using assumed PORVs, see Figure 2.1-38, is initiated subject to a 30°F subcooling limit. Figure 2.1-39 shows RCS loop temperatures, Figure 2.1-40 shows loop subcooling, and Figure 2.1-41 shows steam generator pressures. Note in Figure 2.1-41 that the SBCS functions to maintain secondary pressure until the cooldown via ADVs is initiated at 900 seconds. As in Case 2, a greater SIS flow is realized due to the lower system pressure and pressurizer level recovery beg s at approximately 1200 seconds, Figure 2.1-36. Note that the affected steam generator can be isolated approximately 300

Table 2.1-7

CHRONOLOGY OF EVENTS - CASE 3

Time (Seconds)	Event
0	1 tube SGTR
300	Manual reactor trip
400	SIAS
550	RCPs off
900	75°F/hr cooldown initiated via ADVs
900	RCS depressurization using PORVs subject to 30°F subcooling limits
1324	Affected SG isolated
1324	Cooldown continued on unaffected SG
2250	Simulation terminated

seconds sooner in Case 3 than in the base case, Case 1, since the increased SIS flow added to the overall system cooldown. Once proper pressurizer level has been regained, the HPSI pumps are cycled on and off as shown in Figure 2.1-37 in order to maintain level and maintain proper loop subcooling. Figure 2.1-42 shows steam generator levels and Figure 2.1-43 shows leak flowrate.

Case 4 and Case 5 were performed in order to examine the effect of steam bubble formation on system depressurization. Case 4 is initially identical to Case 2 except that the simulation was not terminated at 2250 seconds. Instead, cooldown was continued on the unaffected steam generator and auxiliary spray flow was initiated at 2450 seconds and a steam bubble was formed in the RVUH. Figure 2.1-44 shows pressurizer pressure and Figure 2.1-45 shows pressurizer level for this case. Note that the simulation was terminated when pressurizer level reached approximately 80%. Figure 2.1-46 shows steam generator pressures and Figure 2.1-47 shows the RVUH water volume. Figure 2.1-48 shows the leak flowrate. Note that as a result of the system depressurization to the point of steam bubble formation in the upper head, RCS pressure become less than steam generator pressure and the leak flow reversed, see Figure 2.1-48. Figure 2.1-49 shows loop subcooling for Case 4. Note that sufficient subcooling was maintained to prevent steam bubble formation in the RCS loops.

Case 5 is also initially identical to Case 2 except the the simulation was not terminated at 2250 seconds. Instead, cooldown was continued on the unaffected steam generator and the assumed PORVs were opened at 2540 seconds and a steam bubble was formed in the RVUH. Figure 2.1-50 shows pressurizer pressure and Figure 2.1-51 show pressurizer level for Case 5. Note that the simulation was terminated shortly after the pressurizer completely filled and the PORVs began to pass saturated water. Also note that the rate at which pressurizer level increased following RVUH steam bubble formation was extremely rapid, Figure 2.1-51, in comparison to relatively controlled rate of level increase obtained in Case 4, Figure 2.1-45.

Figure 2.1-52 shows steam generator pressures and Figure 2.1-53 shows RVUH water volume. Figure 2.1-54 shows the leak flowrate. As was noted in Case 4, RCS pressure became less than steam generator pressure and the leak flow reversed. Finally, Figure 2.1-55 shows loop subcooling for Case 5. Note that very shorty after pressurizer level increased to 100%, loop subcooling rapidly dropped to zero. With such an uncontrolled drop in system pressure the possibility exists that steam bubbles could form in the RCS loops which could inhibit natural circulation.

2.1.4.2.4 Conclusions from the SGTR Analyses

The various plant Final Safety Analysis Reports contain detailed evaluations of the SGTR which demonstrate that the event can be successfully mitigated using auxiliary spray. The basic purpose of the study performed in this section of the report was to compare mitigation of a tube rupture using auxiliary spray with mitigation using PORVs and to examine the effects of RVUH steam bubble formation. The following conclusions can be made based upon the results in Section 2.1.4.2.3:

1. The use of auxiliary spray and the use of PORVs for plant depressurization provided the same performance as far as minimizing the primary-to-secondary leak rate, Figure 2.1-56.

2. Depressurization using auxiliary spray is perferable to depressurization using PORVs since the rate is more controllable and the event is not complicated by opening another hole in the RCS. (See Conclusion 6 below.)

3. The extent to which the plant can be depressurized and thus minimize primary-to-secondary leakage is limited by procedure and not limitations on plant equipment, i.e., the requirement to maintain proper subcooling in the RCS will dictate system pressure.

4. Early depressurization using auxiliary spray has the benefit of increasing ECCS delivery which can add to the overall RCS cooldown.

5. Continued depressurization via either auxiliary spray or PORVs with subsequent RVUH steam bubble formation were equivalent in their ability to further lower RCS pressure and minimize leakage, see Figure 2.1-57.

6. Use of PORVs to continue pressure reduction in the presence of a RVUH steam bubble has the disadvantage that the rate of depressurization can be very fast and therefore relatively uncontrollable. In addition the possibility exists that loop subcooling can be quickly lost, see Figure 2.1-58.

2.1.5 Thermal Stress Analysis

As stated in Section 2.1.2 above, spray flow during normal operations is provided to the pressurizer via the main spray system. The differential pressure across an operating RCP is used to provide the motive force for main spray flow with the main spray valves operating to control flowrate. For situations in which the reactor coolant pumps are not available, e.g., loss of offsite power, pump failure, manual action of operators in response to plant conditions, etc., the auxiliary spray system can be used to provide spray flow. Figure 2.1-1 shows the configuration of the main spray system for a typical C-E NSSS along with the auxiliary spray line connection. Since the temperature difference between the pressurizer steam space and the spray flow produced by the main spray system or the auxiliary spray system can vary from approximately 100°F under normal operating conditions to several hundred degrees and more depending upon system pressure and loop temperatures, a means must be available to determine the effects of thermal stress on various portions of the spray system and account for these effects over the life of the plant.

One such area of the spray system where proper accounting of thermal stresses must be made over the life of the plant is the pressurizer spray nozzle. Figure 2.1-59 shows a typical spray nozzle along with the thermal sleeve, which has been installed to protect the thicker metal portions, and the region subject to the highest thermal stress during spray operations. To account for the effects of stress in this region, a methodology has been developed which, when implemented, will determine a quantity termed the pressurizer spray nozzle cumulative usage factor. The cumulative usage factor is established based upon analysis which accounts for such factors as anticipated spray flowrate, spray temperature, duration of spray, availability of main spray bypass flow, fluid medium, i.e., steam or water, and pressurizer temperature. Based upon this analysis the number of allowable spray cycles is determined for various spray and pressurizer temperature combinations. (One spray cycle is defined as the opening and subsequent closing of either the main spray valve(s) or the auxiliary spray valve(s).) If the differential temperature between the pressurizer and the spray flow is less than 200°F, an unlimited number of cycles of either main spray or auxiliary spray are permitted during the life of the plant. If the differential temperature between the pressurizer and the spray flow is greater than 200°F, the spray cycle is recorded and the cumulative usage factor is determined as shown in Table 2.1-8 (p. 46).

Typically if the caluclated usage factor is less than about 0.65 no further action is required. If, however, the calculated usage factor exceeds 0.65 at any time during plant life, all subsequent spray operations will be restricted such that the differential temperature between the pressurizer and spray fluid is less than or equal to 200°F. This restriction will remain in effect until an engineering evaluation of the spray nozzle can be completed to demonstrate that continued use of the spray system outside this restriction acceptable.

The procedures for keeping track of thermal stresses over the life of the plant in the spray system are currently being refined and further developed. When implemented, a table similar to Table 2.1-8 will be included in the plant Technical Specifications.

Table 2.1-8

TYPICAL PROCEDURE USED TO CALCULATE THE
PRESSURIZER SPRAY NOZZLE CUMULATIVE USAGE FACTOR

MAIN SPRAY				AUXILIARY SPRAY			
ΔT_M	N_A	N	N/N_A	ΔT_A	N_A	N	N/N_A
201-250	7900			201-250	5000		
251-300	4500			251-300	2200		
301-350	2900			301-350	1300		
351-400	1900			351-400	850		
401-450	1200			401-450	550		
451-500	850			451-500	375		
501-550	555			501-550	225		
				551-600	150		
		$\Sigma N/N_A$=	______			$\Sigma N/N_A$=	______

Cumulative Usage Factor
$\Sigma N/N_A$ (Main Spray) ____________
$\Sigma N/N_A$ (Aux. Spray) ____________
Total ____________ = Cumulative Usage Factor

ΔT_M = The temperature difference between the pressurizer steam space and the main spray line fluid.

ΔT_A = The temperature difference between the pressurizer steam space and the auxiliary spray line fluid.

N_A = Allowable number of spray cycles for indicated ΔT range.

N = Actual number of cycles for indicated ΔT range.

Figures for Section 2.1

FIGURE 2.1-1

TYPICAL C-E NSSS SHOWING MAIN SPRAY SYSTEM AND AUXILIARY SPRAY CONNECTION

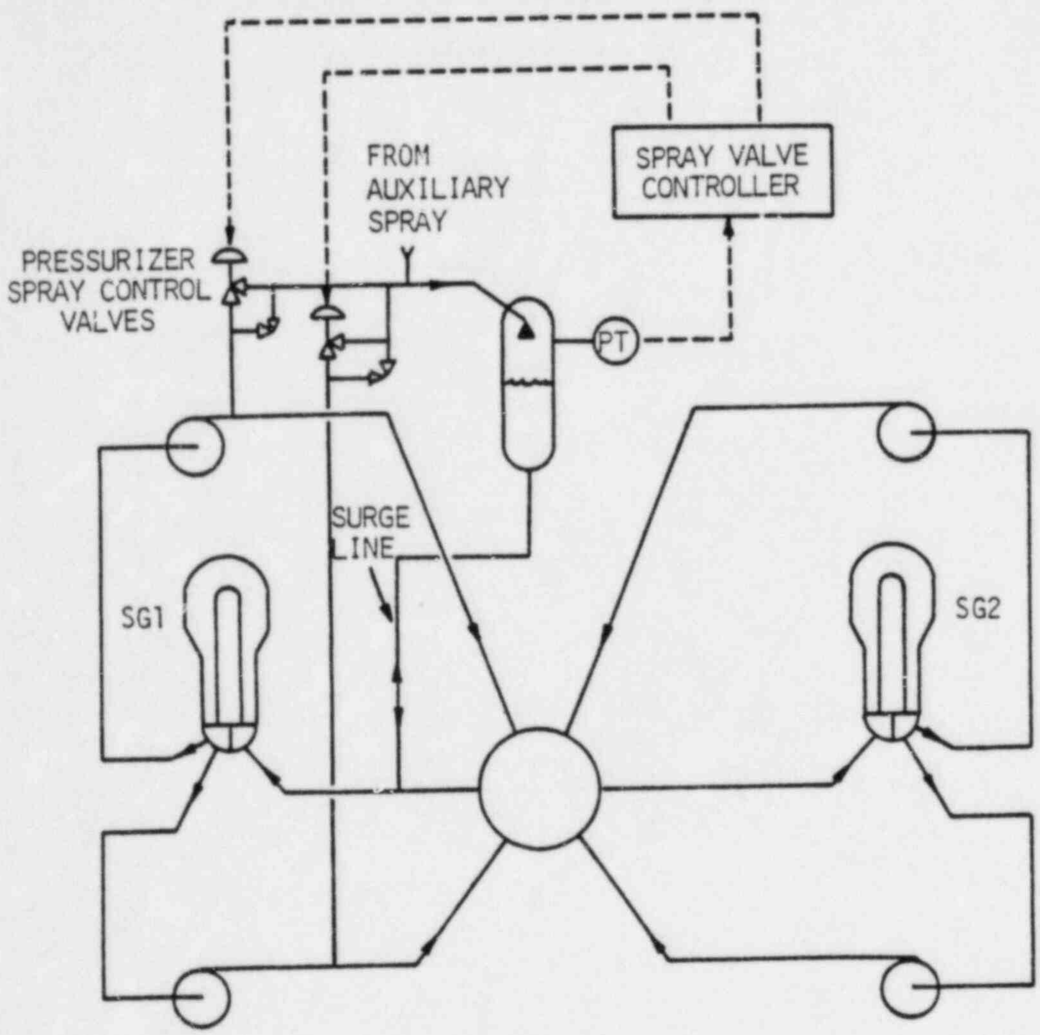


FIGURE 2.1-2

SIMPLIFIED SCHEMATIC OF <u>SONGS</u> CVCS SHOWING AUXILIARY SPRAY PORTION AND SOURCES OF BORATED WATER

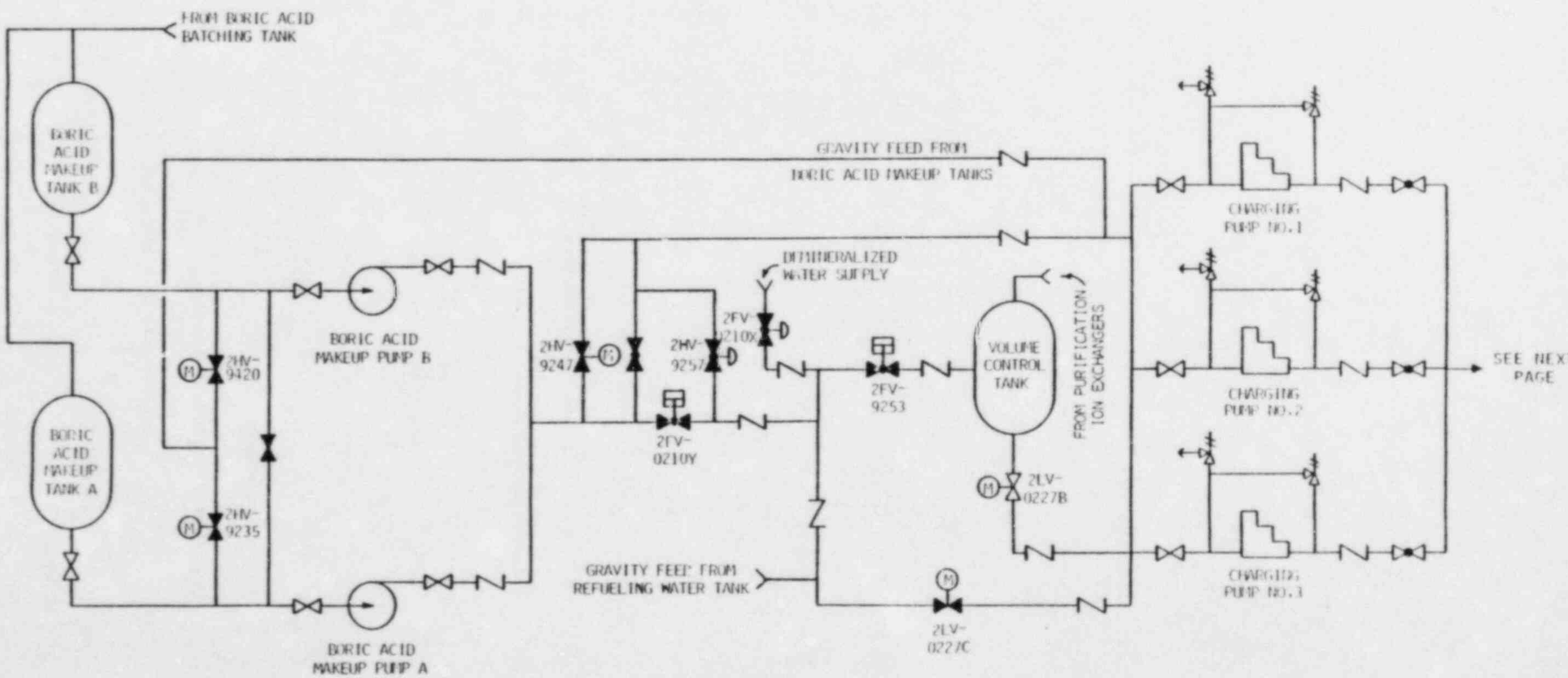


FIGURE 2.1-2 (CONT.)

SIMPLIFIED SCHEMATIC OF SONGS CVCS SHOWING AUXILIARY SPRAY PORTION AND SOURCES OF BORATED WATER

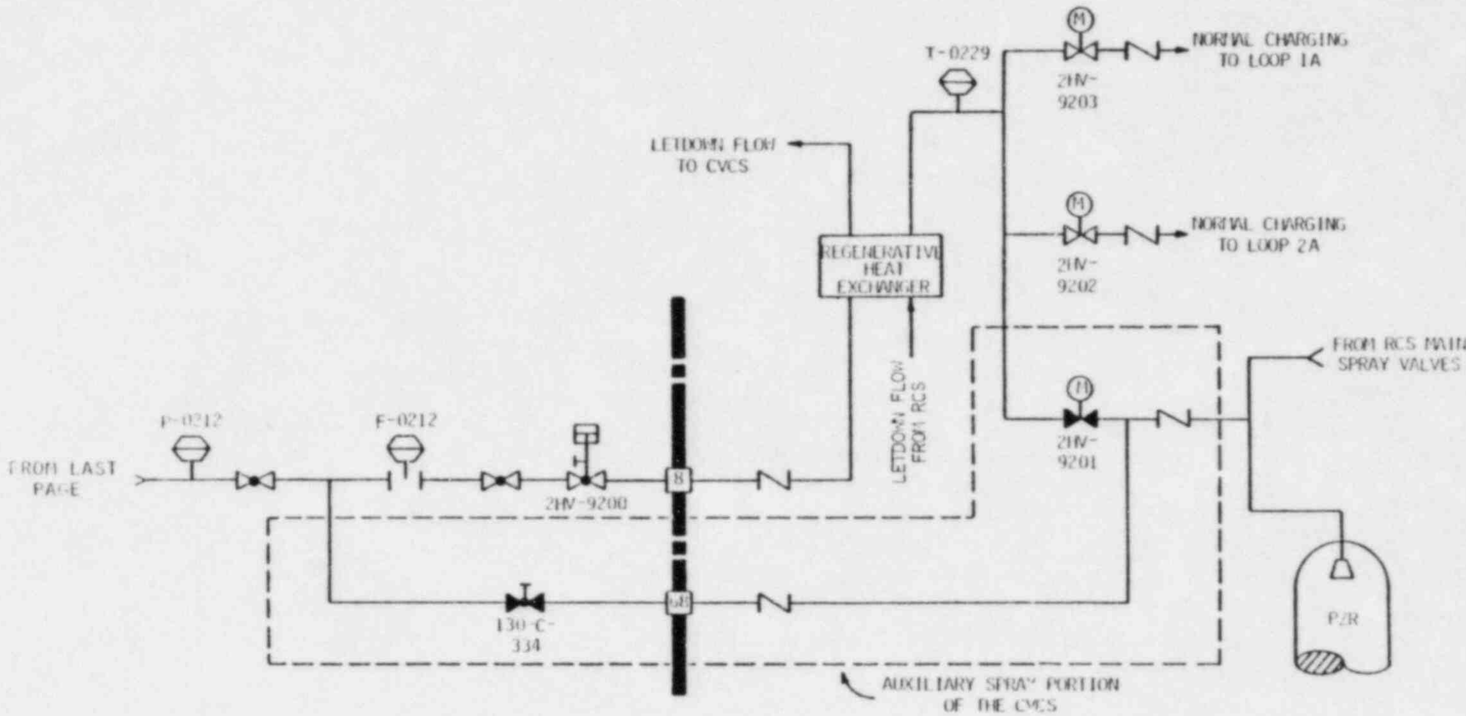


FIGURE 2.1-3

SIMPLIFIED SCHEMATIC OF WATERFORD CVCS SHOWING AUXILIARY SPRAY PORTION AND SOURCES OF BORATED WATER

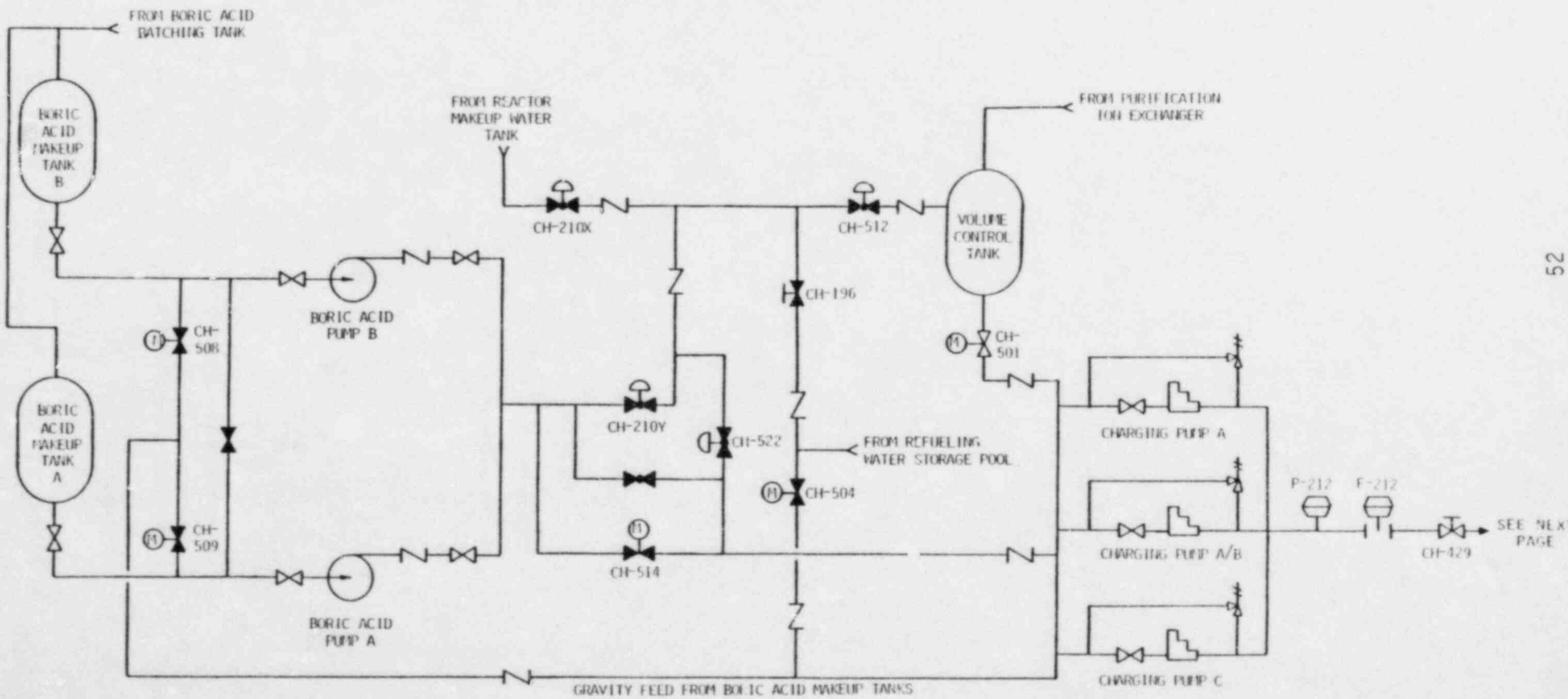


FIGURE 2.1-3 (CONT.)

SIMPLIFIED SCHEMATIC OF WATERFORD CVCS SHOWING AUXILIARY SPRAY PORTION AND SOURCES OF BORATED WATER

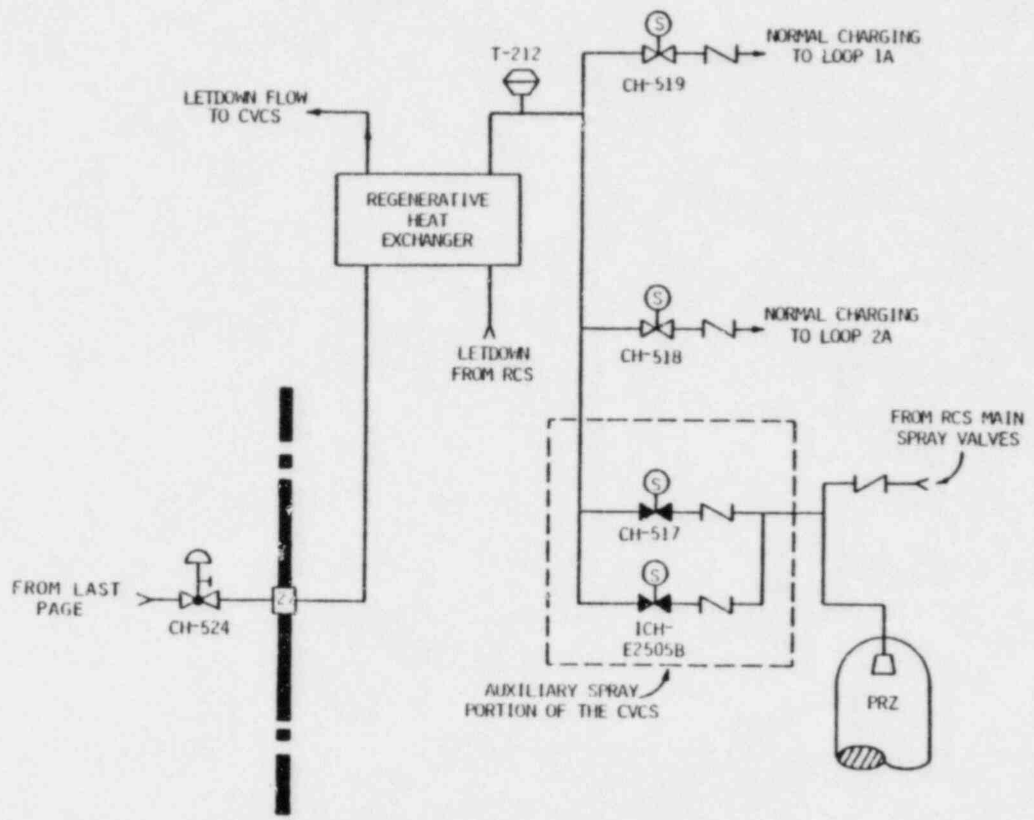


FIGURE 2.1-4

SIMPLIFIED SCHEMATIC OF PALO VERDE CVCS SHOWING AUXILIARY SPRAY PORTION AND SOURCES OF BORATED WATER

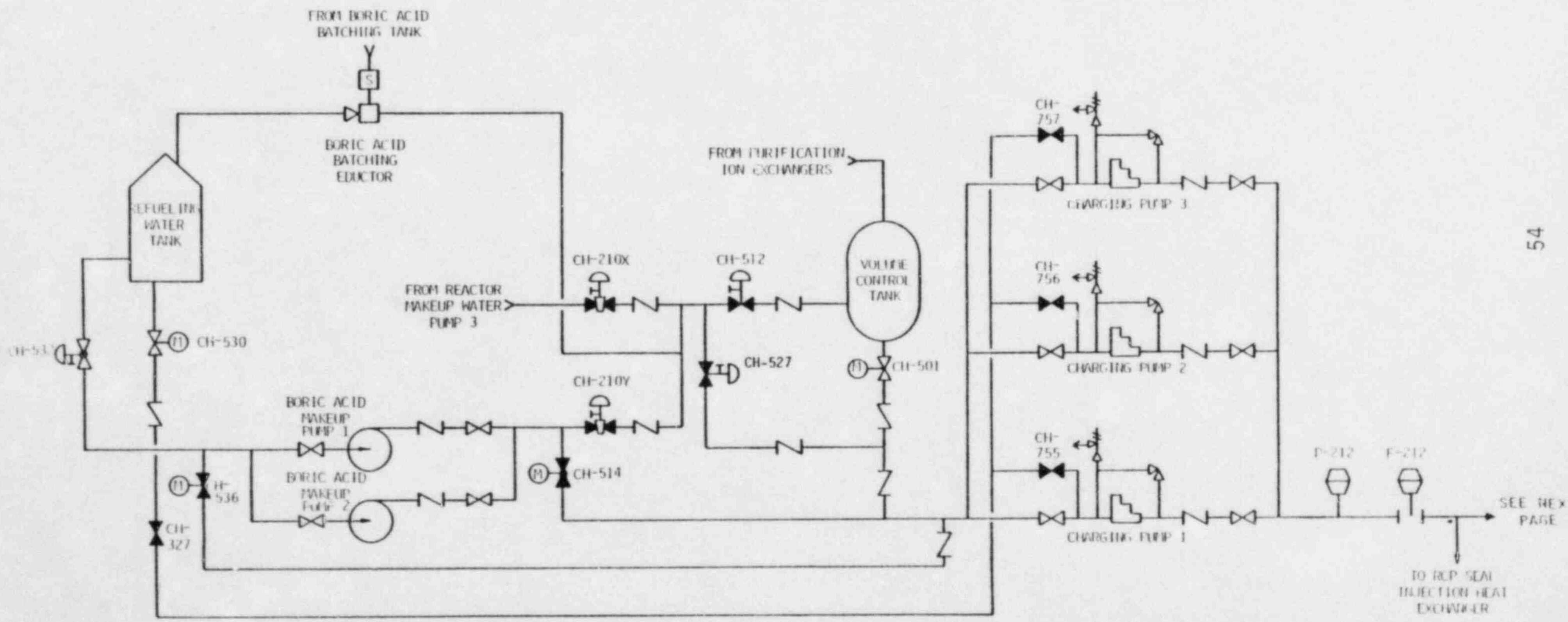


FIGURE 2.1-4 (CONT.)

SIMPLIFIED SCHEMATIC OF PALO VERDE CVCS SHOWING AUXILIARY PORTION AND SOURCES OF BORATED WATER

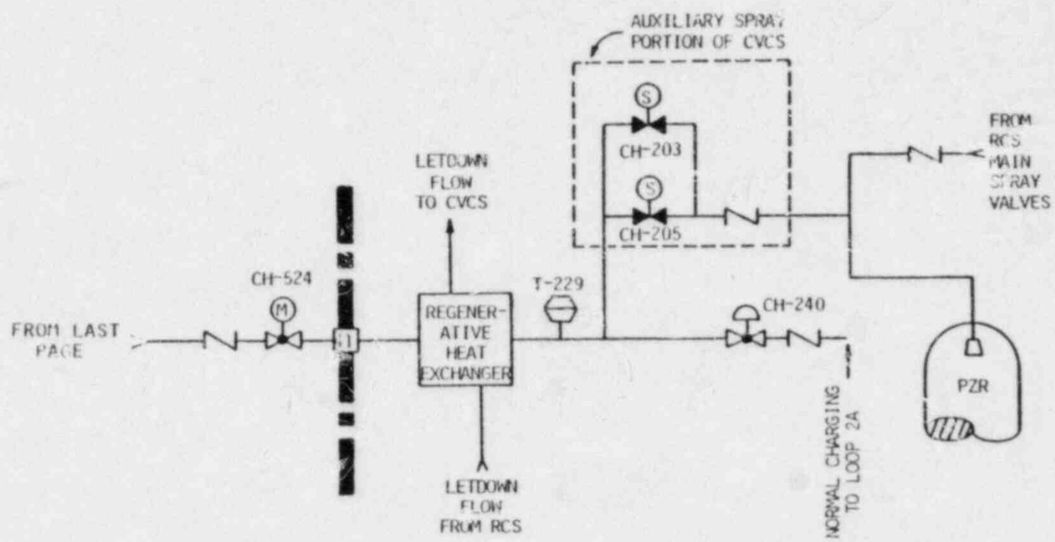


FIGURE 2.1-5

SIMPLIFIED SCHEMATIC OF WPPSS CVCS SHOWING AUXILIARY SPRAY PORTION AND SOURCES OF BORATED WATER

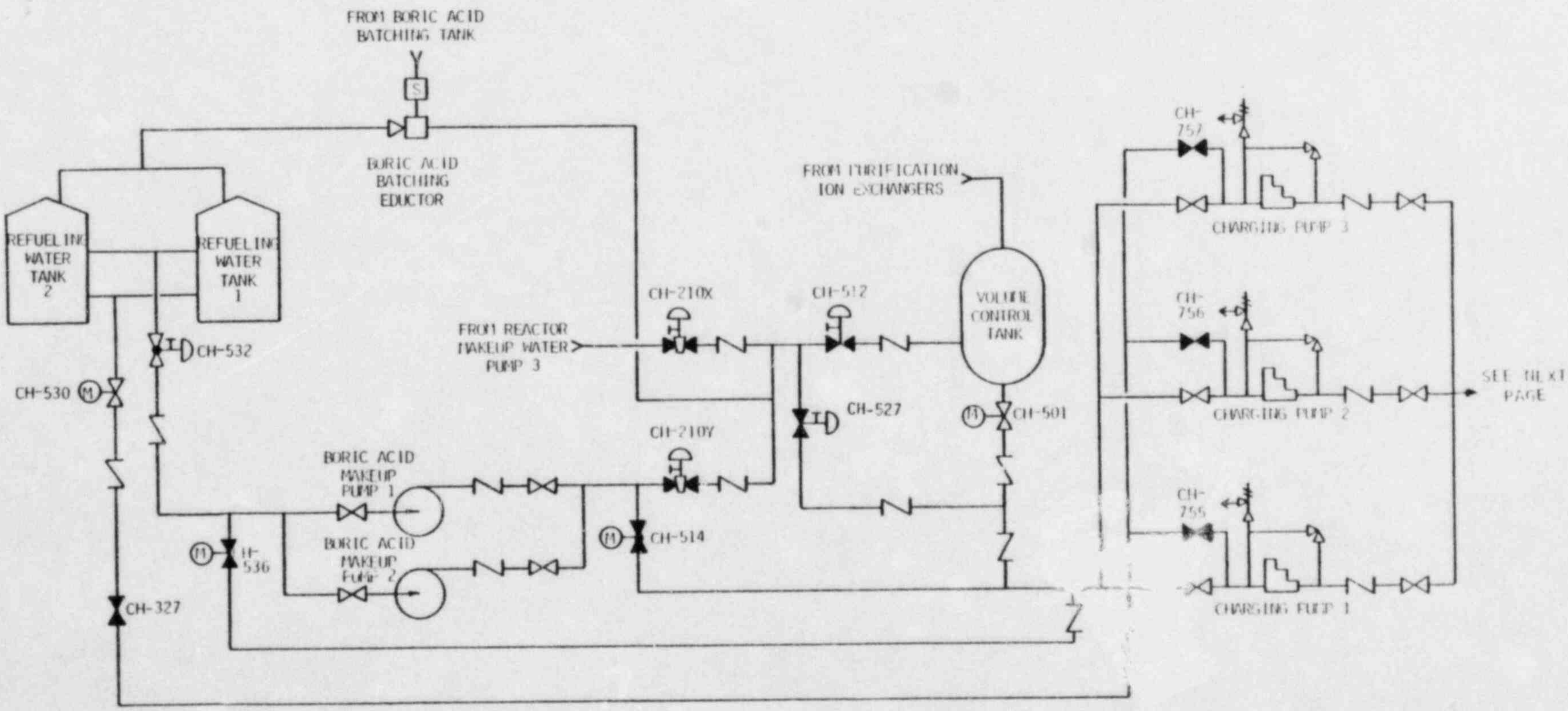


FIGURE 2.1-5 (CONT.)

SIMPLIFIED SCHEMATIC OF WPPSS CVCS SHOWING AUXILIARY SPRAY PORTION AND SOURCES OF BORATED WATER

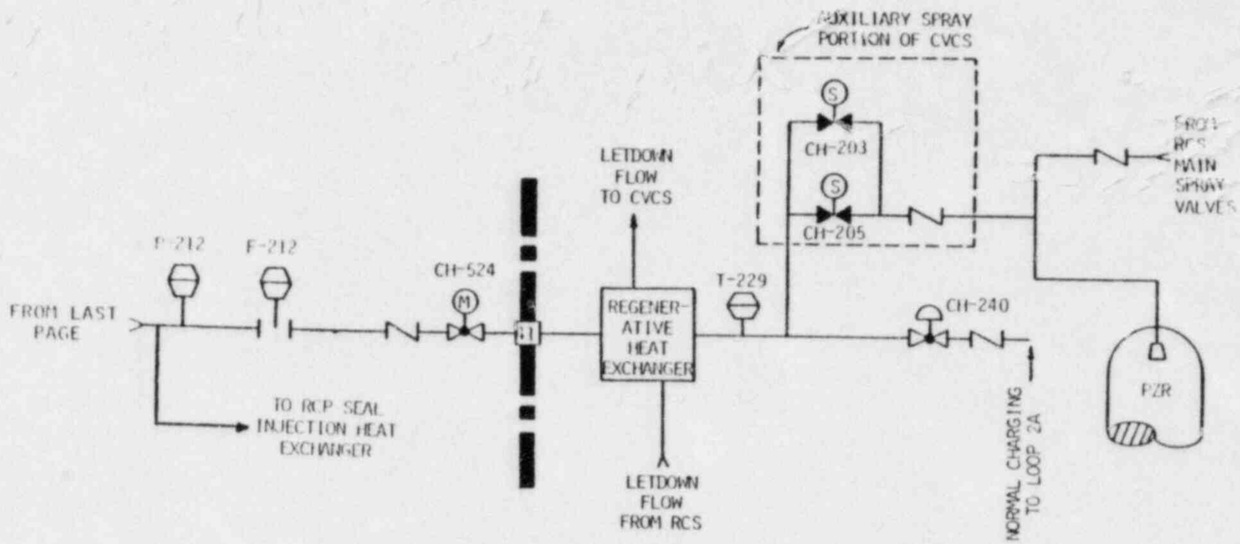


FIGURE 2.1-6

3410 CLASS PLANT
DEPRESSURIZATION VS NUMBER OF CHARGING PUMPS
WITH LETDOWN FLOW

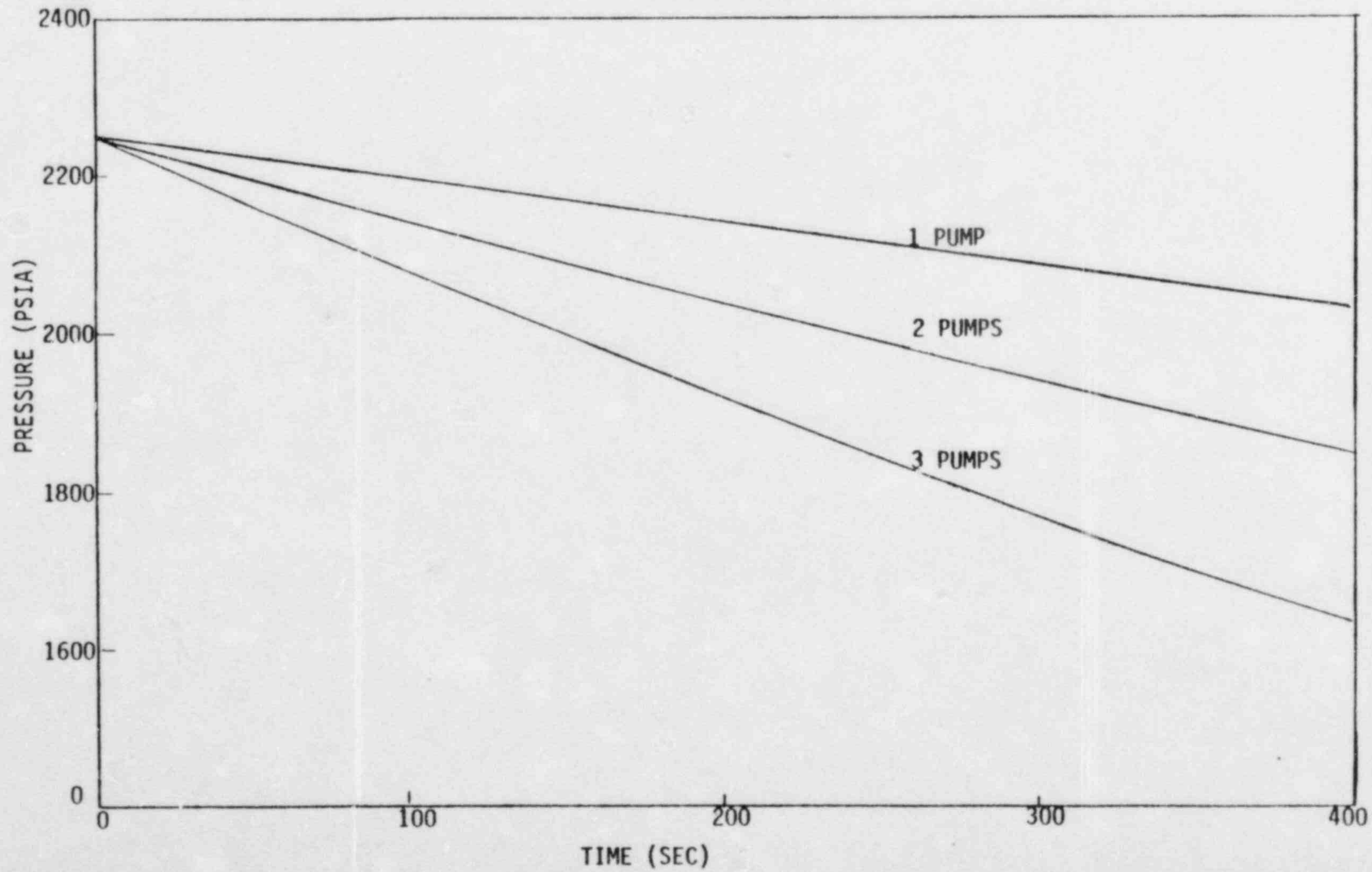


Figure 2.1-7

3410 CLASS PLANT
DEPRESSURIZATION VS NUMBER OF CHARGING PUMPS
WITH NO LETDOWN FLOW

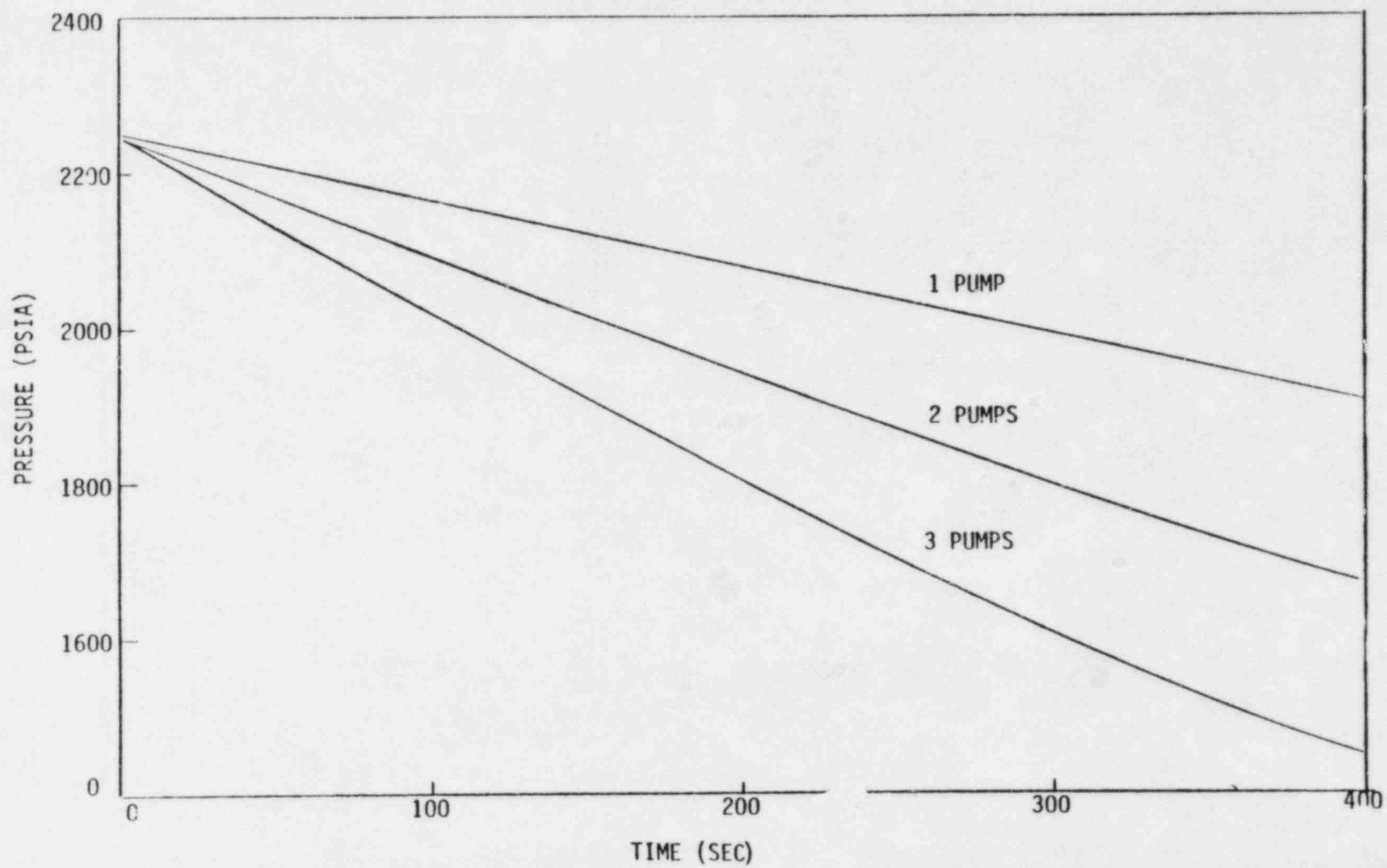
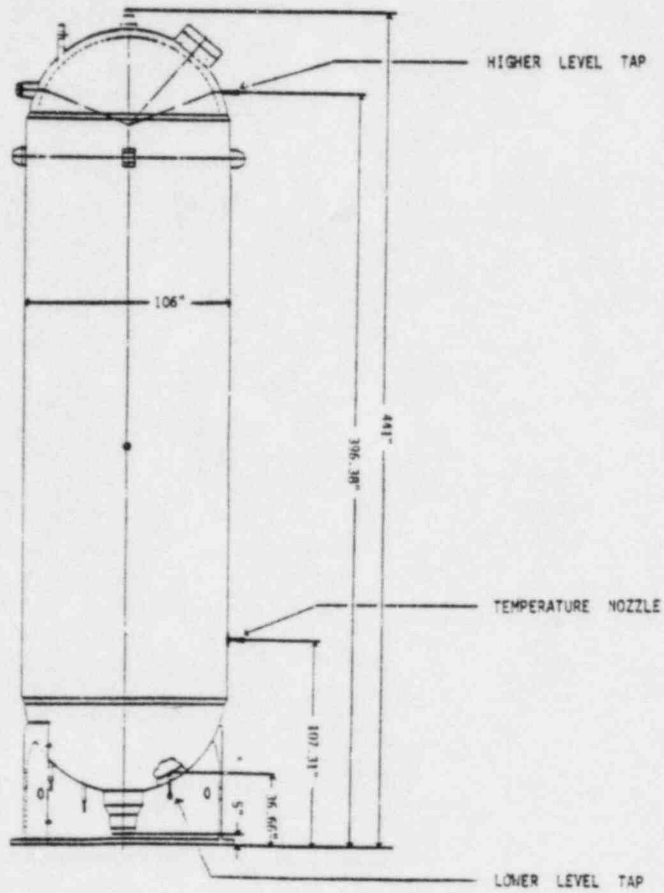


FIGURE 2.1-8

3410 PRESSURIZER PARAMETERS



PARAMETER	VALUE
NORMAL OPERATING PRESSURE (PSIA)	2250
NORMAL OPERATING TEMPERATURE (°F)	653
INTERNAL FREE VOLUME (FT^3)	1500
NORMAL (FULL POWER) OPERATING WATER VOLUME (FT^3)	800
NORMAL (FULL POWER) STEAM VOLUME (FT^3)	700

FIGURE 2.1-9

3800 CLASS PLANT
DEPRESSURIZATION VS NUMBER OF CHARGING PUMPS
WITH LETDOWN FLOW

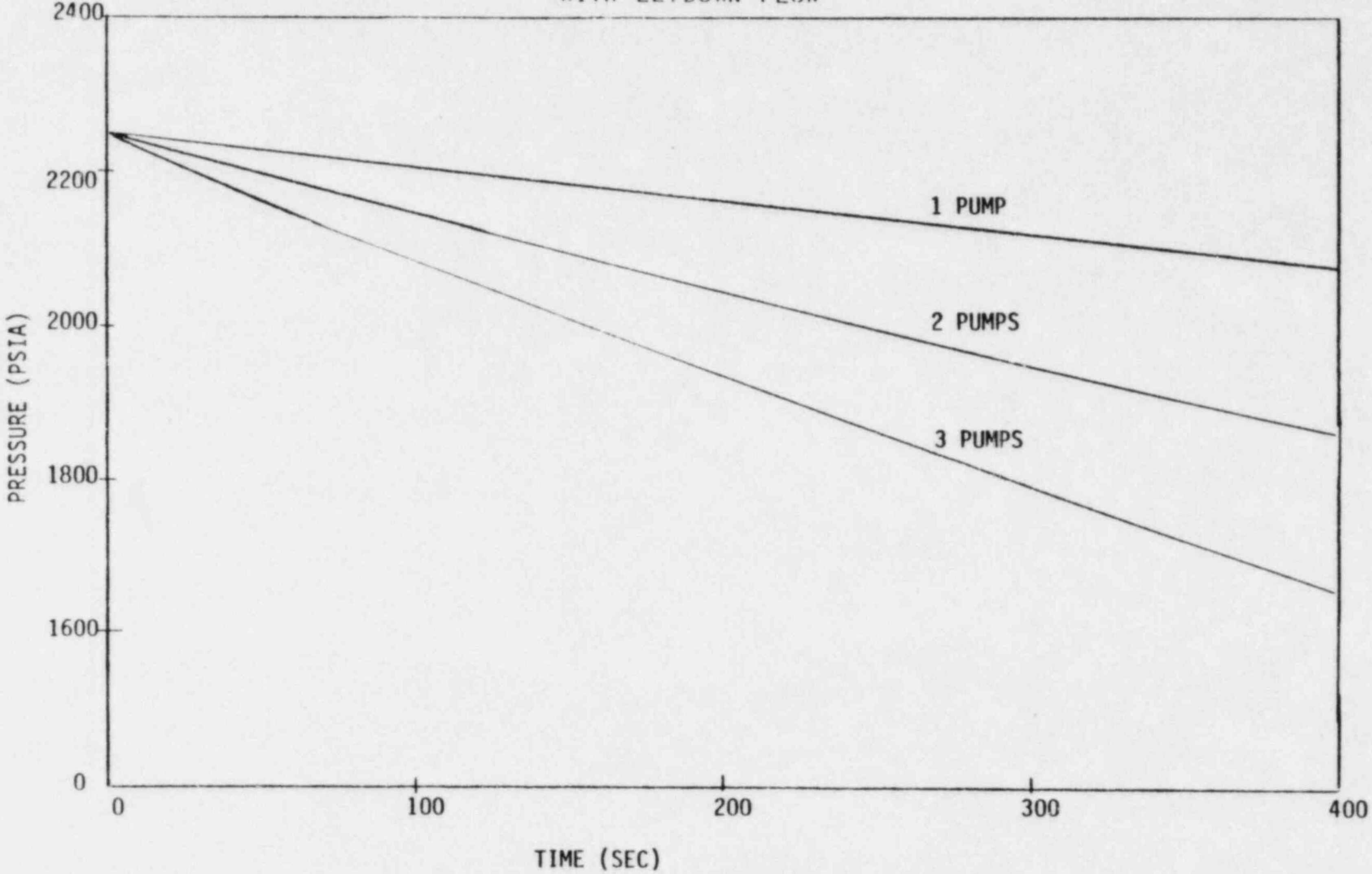


Figure 2.1-10

3800 CLASS PLANT
DEPRESSURIZATION VS NUMBER OF CHARGING PUMPS
WITH NO LETDOWN FLOW

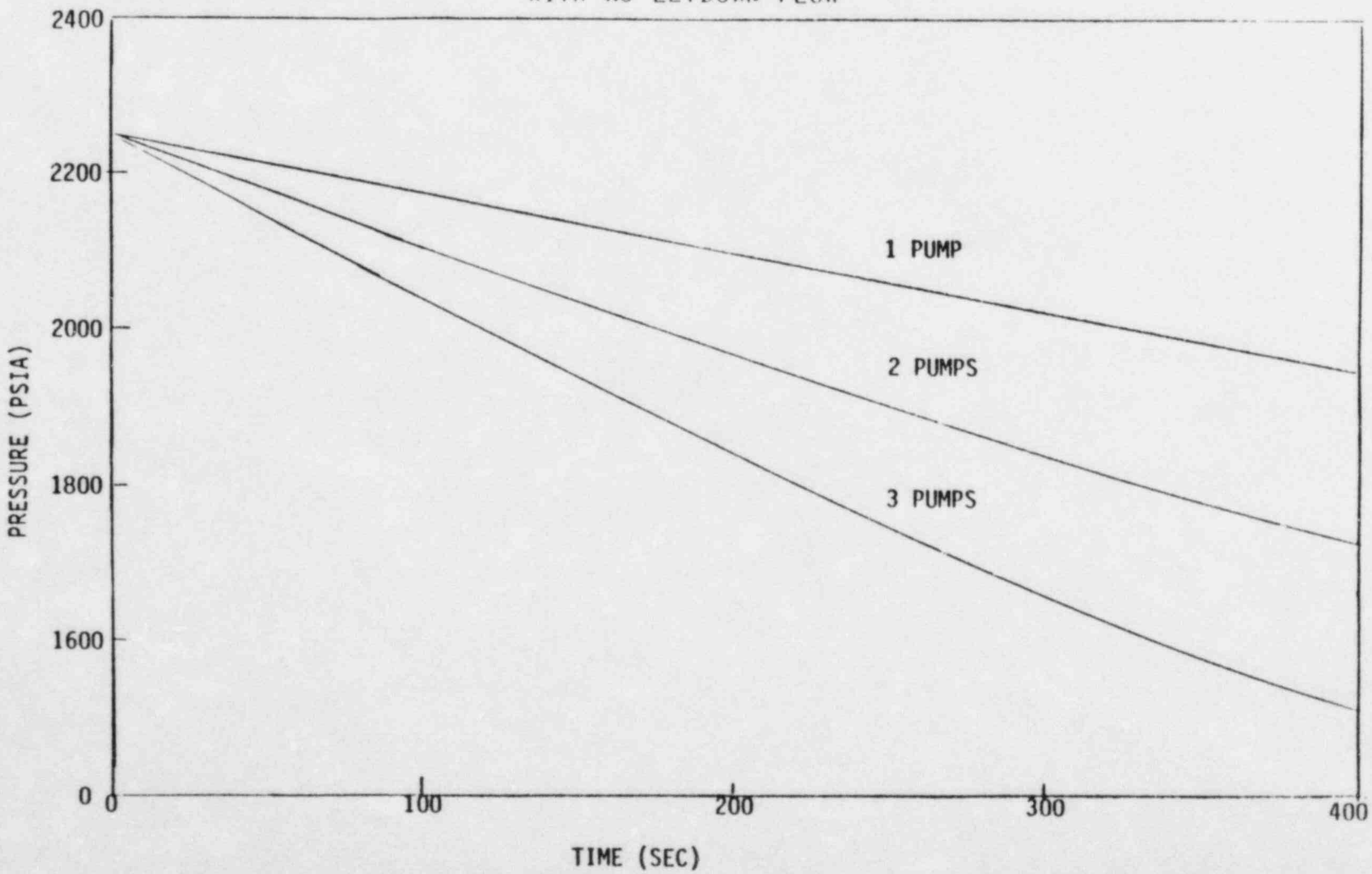
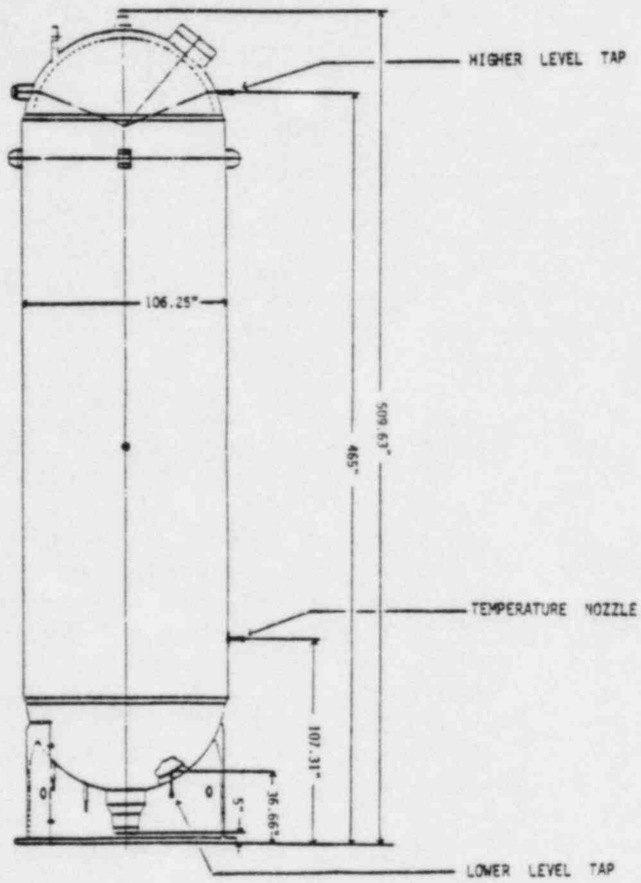


Figure 2.1-11

3800 PRESSURIZER PARAMETERS



Parameter	Value
Normal operating pressure (psia)	2250
Normal operating temperature (°F)	653
Internal free volume (ft^3)	1800
Normal (full power) operating water volume (ft^3)	900
Normal (full power) steam volume (ft^3)	900

FIGURE 2.1-12

PRESSURIZER LEVEL AND RCS PRESSURE DURING THE ST. LUCIE UNIT 1 COOLDOWN EVENT OF 11 JUNE 1980

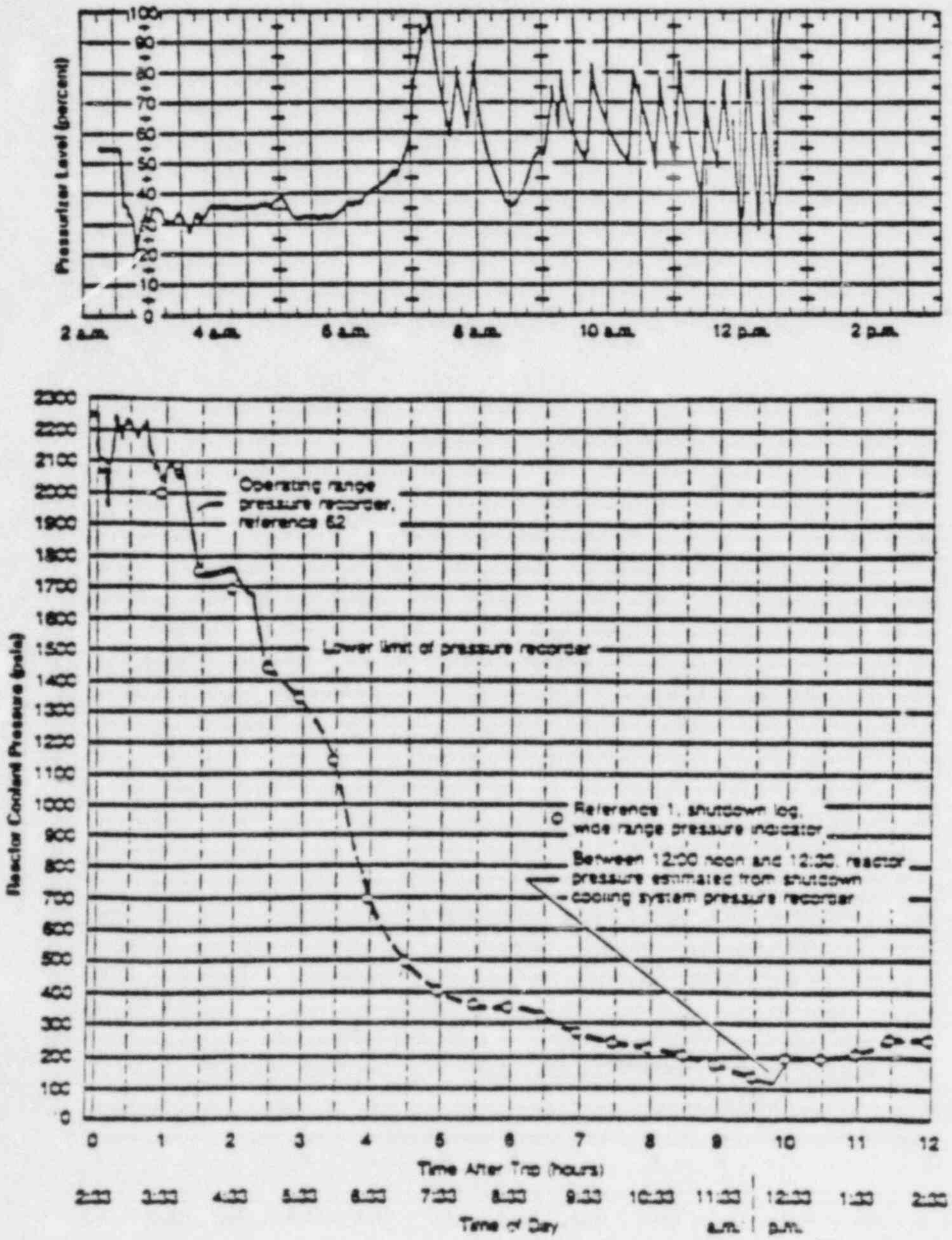
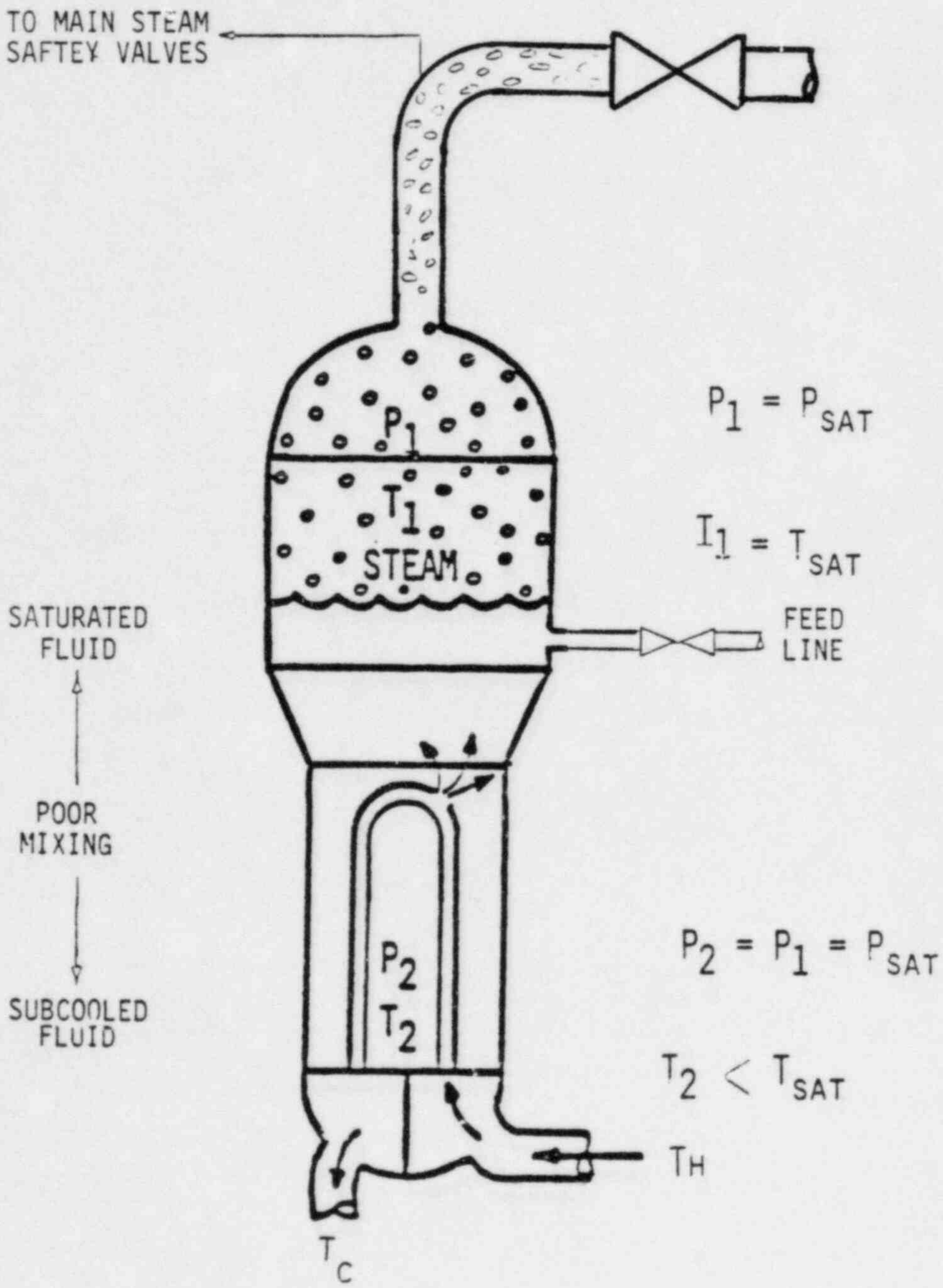


FIGURE 2.1-13

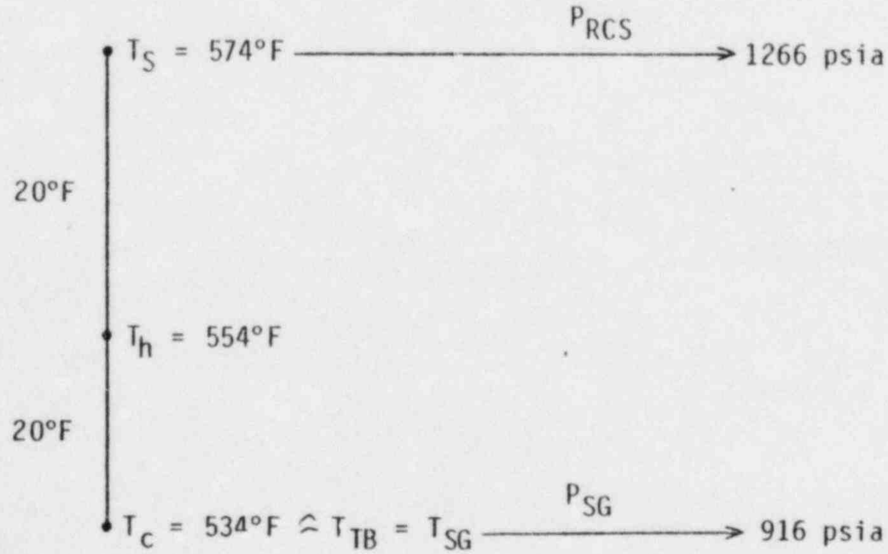
TEMPERATURE STRATIFICATION IN AN ISOLATED STEAM GENERATOR WITH A TUBE RUPTURE



$T_H < T_C$

Figure 2.1-14

TEMPERATURE AND PRESSURE RELATIONSHIP BETWEEN RCS AND SGs FOR NATURAL CIRCULATION WHEN AFFECTED SG IS A HEAT SINK



T_{TB} = tube bundle temperature

T_c = cold leg temperature

T_h = hot leg temperature

T_S = hot leg temperature + 20°F subcooling

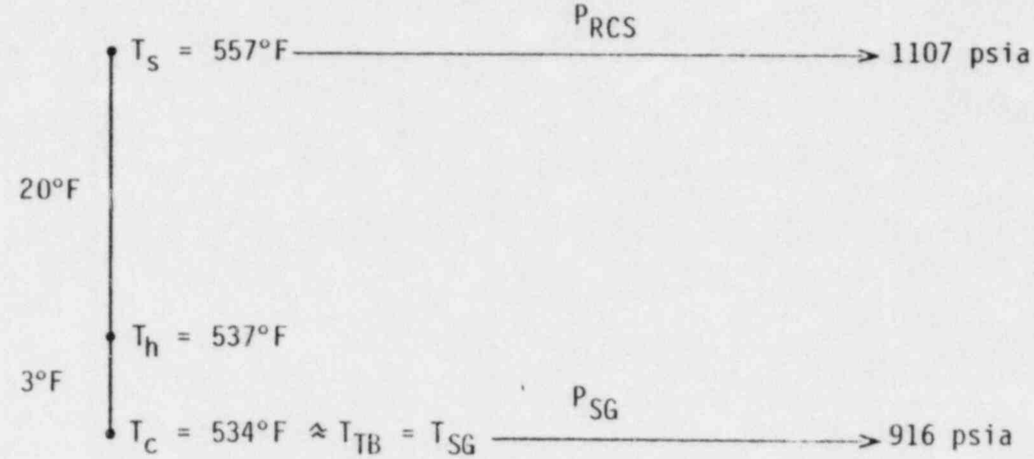
T_{SG} = secondary saturation temperature

P_{SG} = secondary saturation temperature

P_{RCS} = RCS pressure corresponding to 20°F subcooling

Figure 2.1-15

TEMPERATURE AND PRESSURE RELATIONSHIP BETWEEN RCS AND SGs
FOR FORCED CIRCULATION WHEN AFFECTED SG IS A HEAT SINK



T_{TB} = tube bundle temperature
T_c = cold leg temperature
T_h = hot leg temperature
T_s = hot leg temperature + 20°F
T_{SG} = secondary saturation temperature
P_{SG} = secondary saturation pressure
P_{RCS} = RCS pressure corresponding to 20°F subcooling

FIGURE 2.1-16

LOOP TEMPERATURE BEHAVIOR FOLLOWING ISOLATION OF THE AFFECTED SG

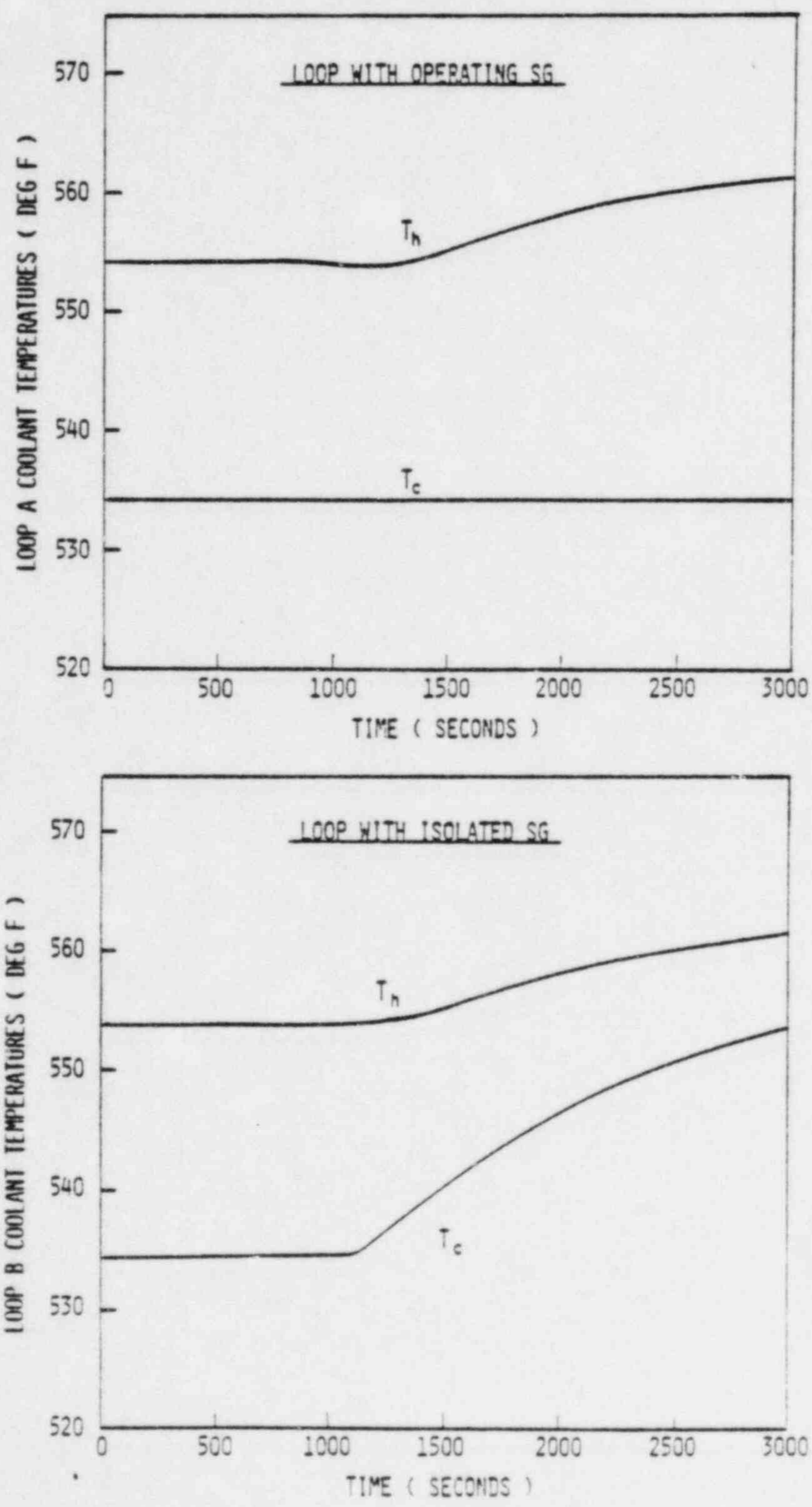
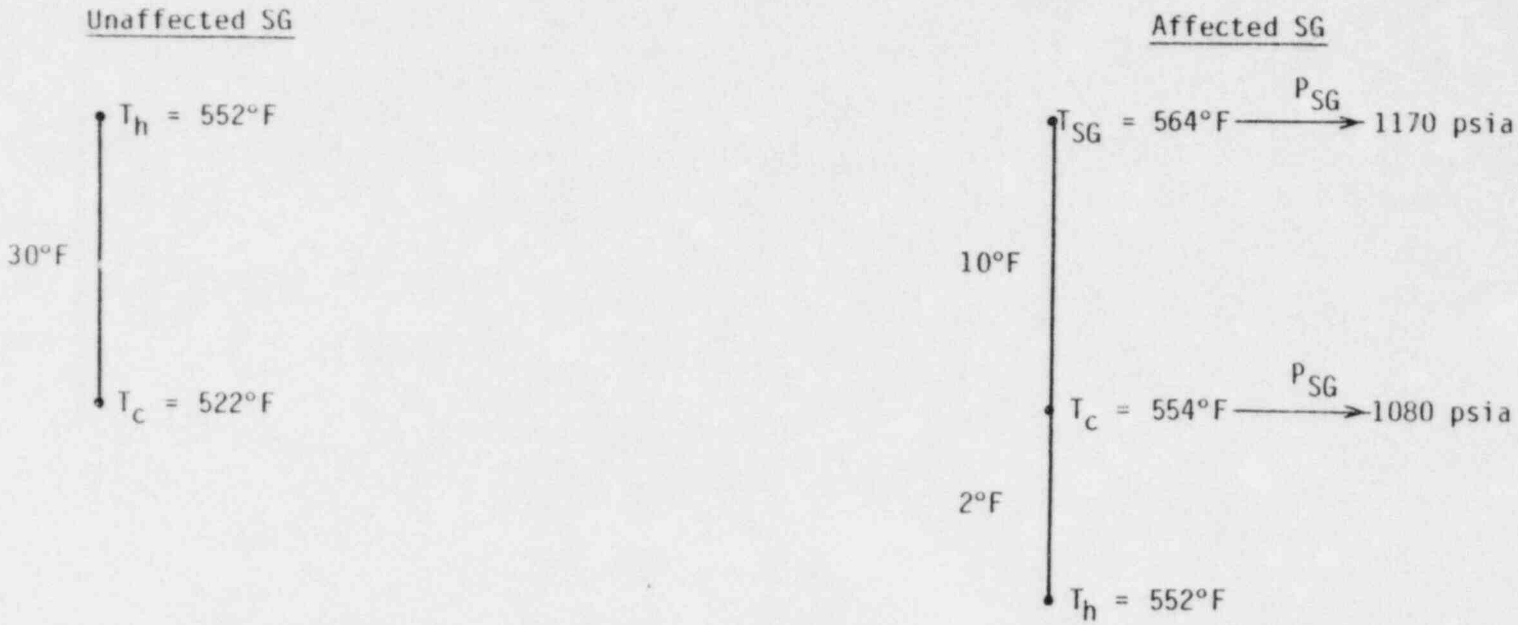


Figure 2.1-17

TEMPERATURE AND PRESSURE RELATIONSHIPS BETWEEN RCS AND SGs
FOR NATURAL CIRCULATION WHEN AFFECTED SG IS A HEAT SOURCE



T_c = cold leg temperature

T_h = hot leg temperature

T_{SG} = secondary saturation temperature

P_{SG} = secondary saturation pressure

Figure 2.1-18

SGTR CASE 1
PZR WIDE RANGE PRESSURE

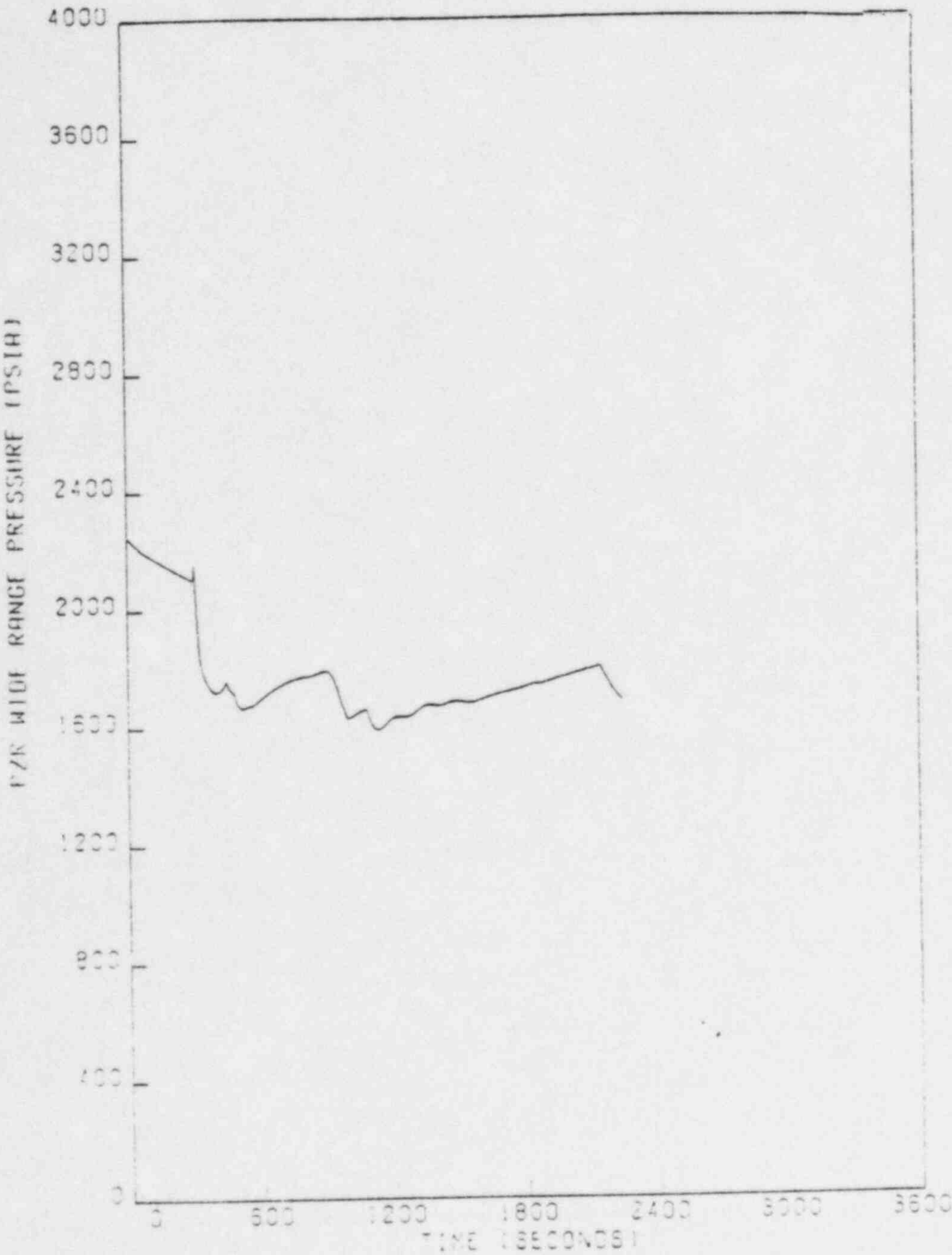


FIGURE 2.1-19

SGTR CASE 1
PZR LEVEL

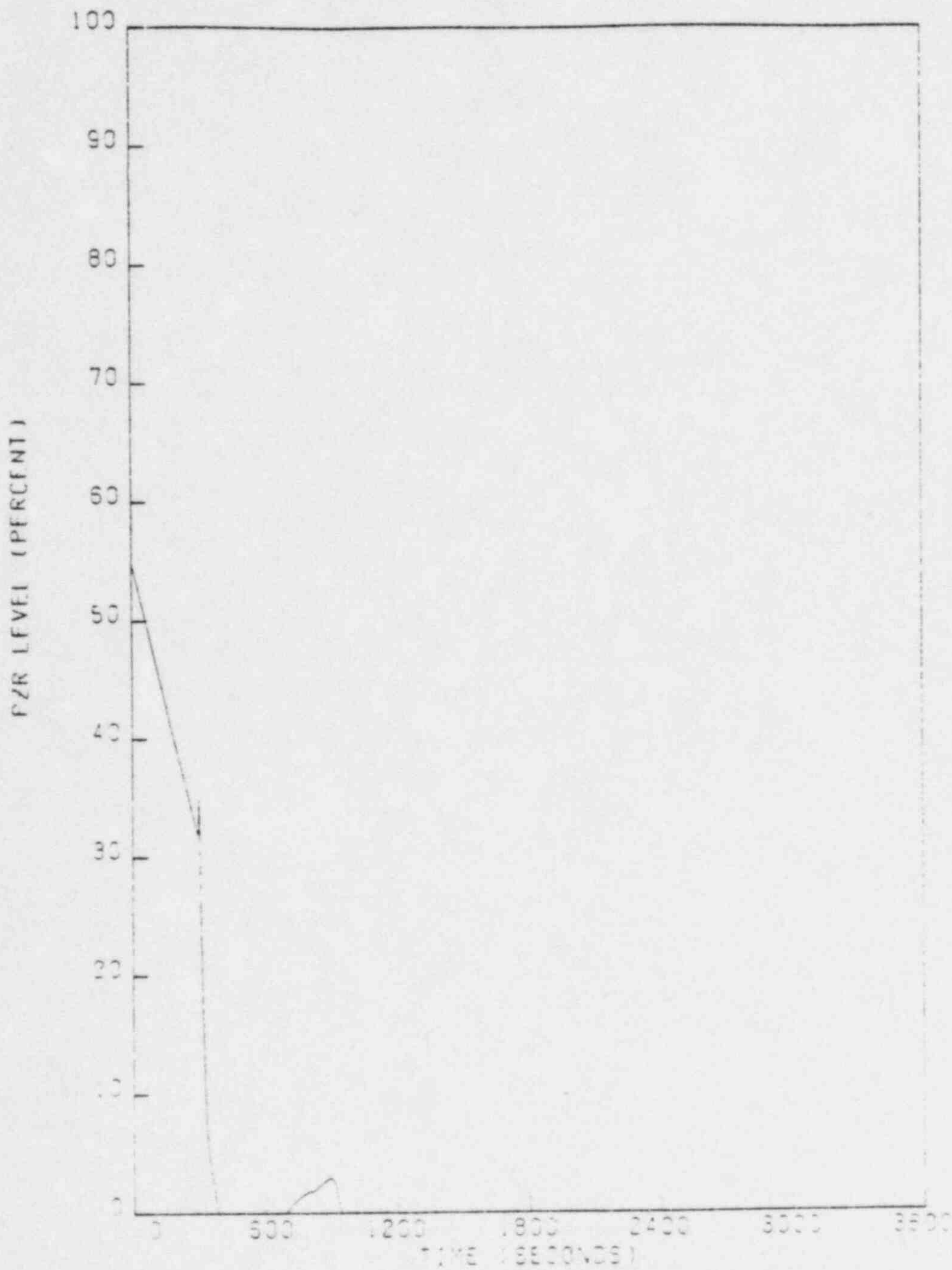


FIGURE 2.1-20

SGTR CASE 1
SIS FLOW

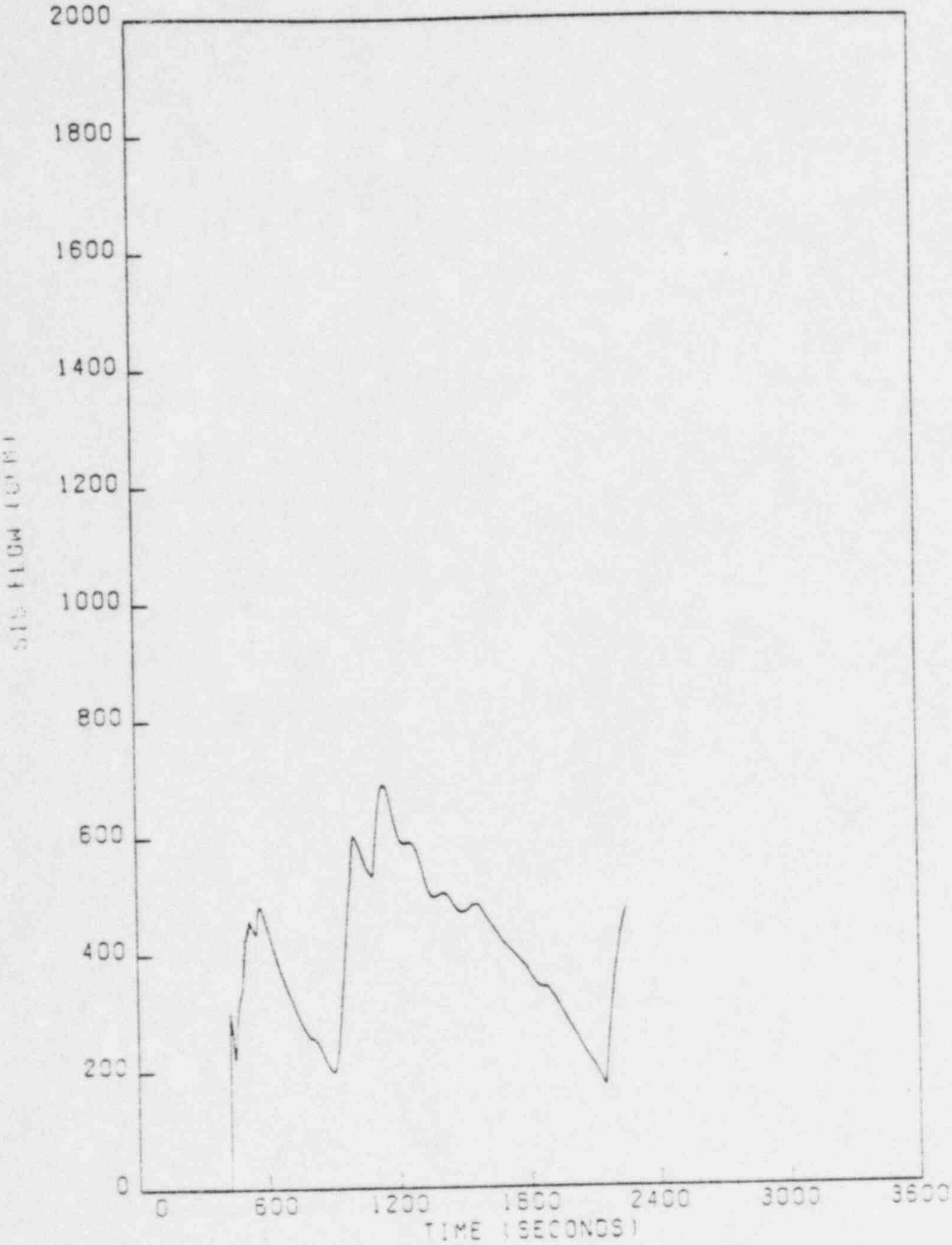


FIGURE 2.1-21

SGTR CASE 1
RCS LOOP TEMPERATURES

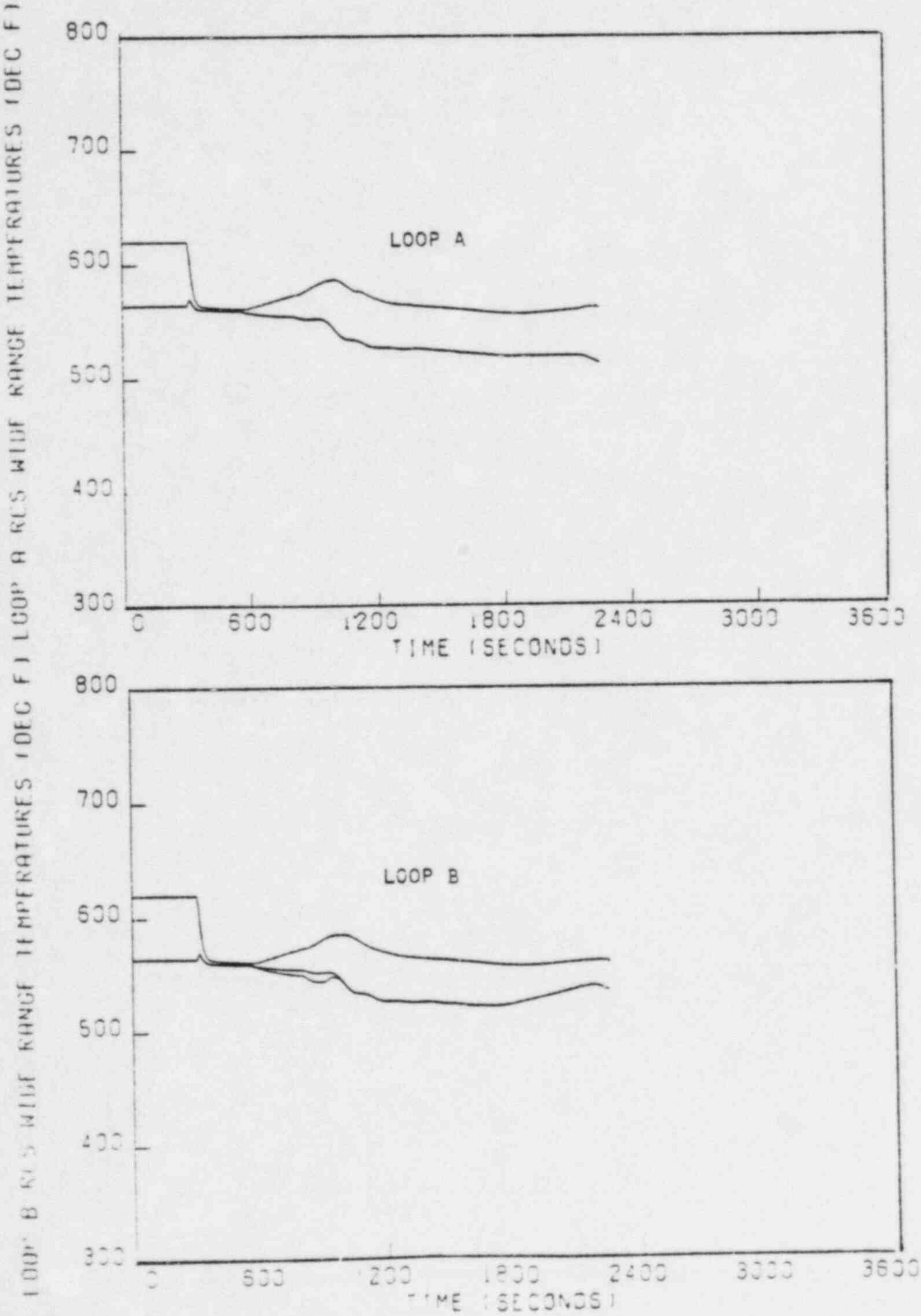


FIGURE 2.1-22

SGTR CASE 1
LOOP SUBCOOLING

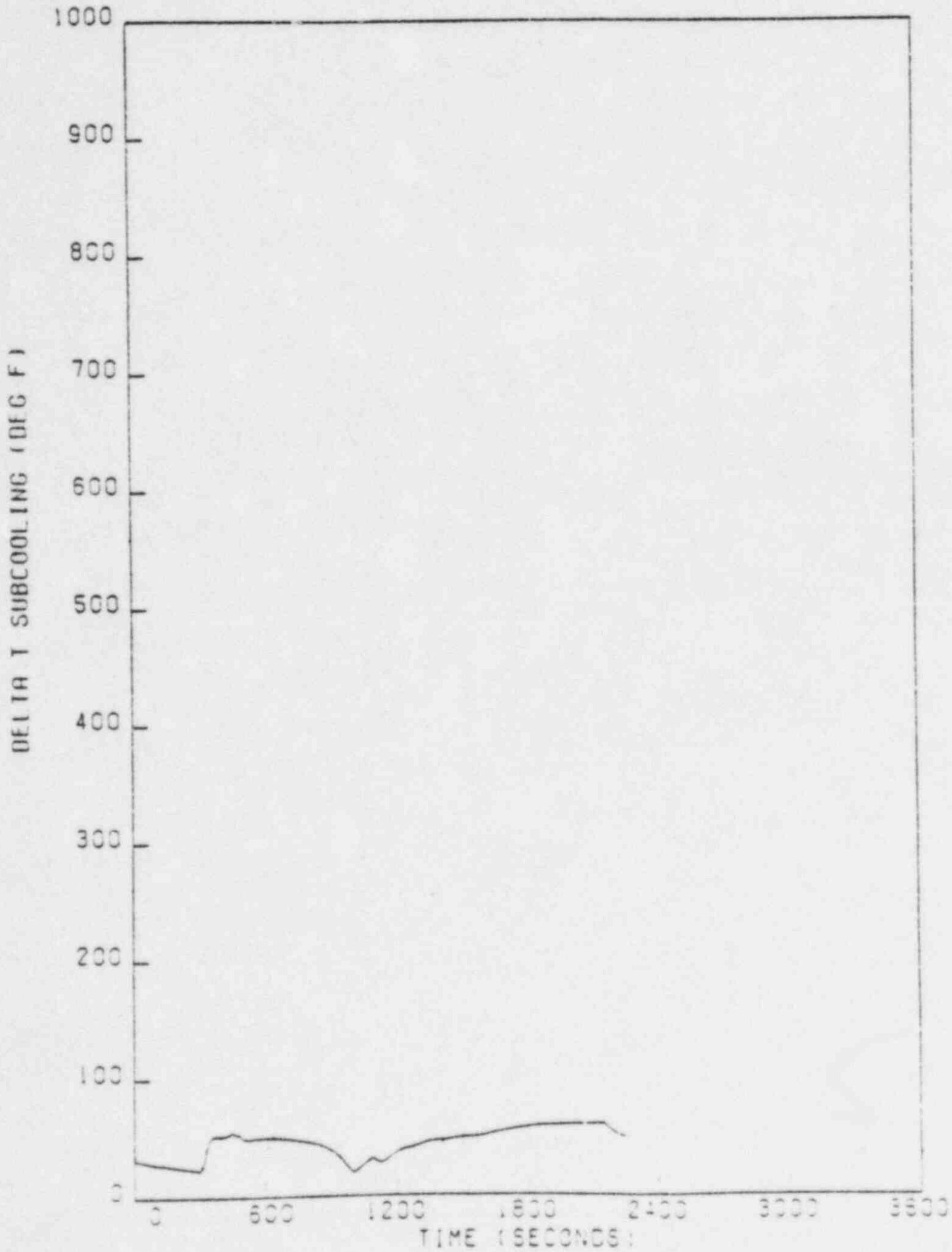
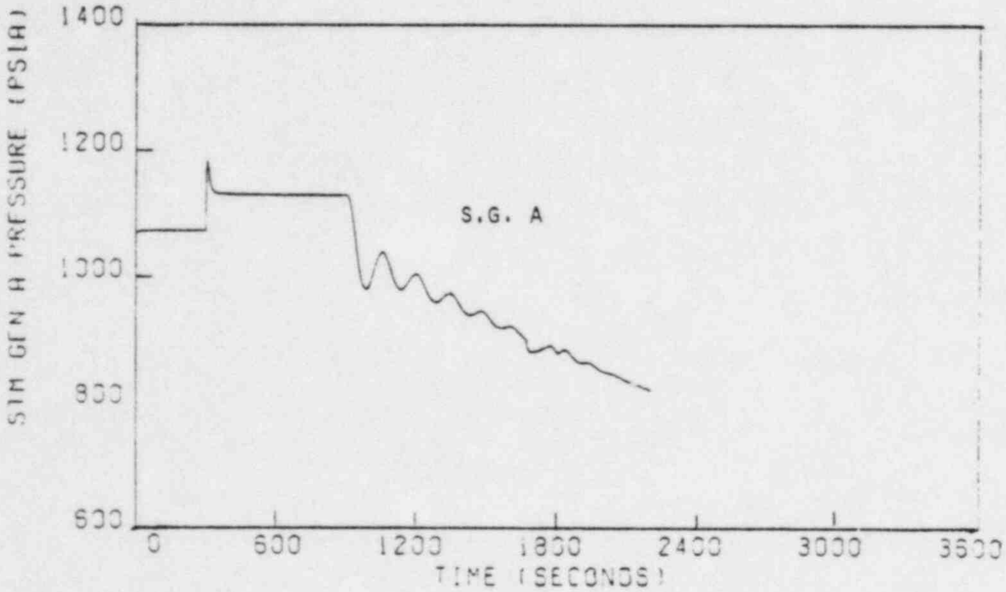


FIGURE 2.1-23

SGTR CASE 1
SG PRESSURES



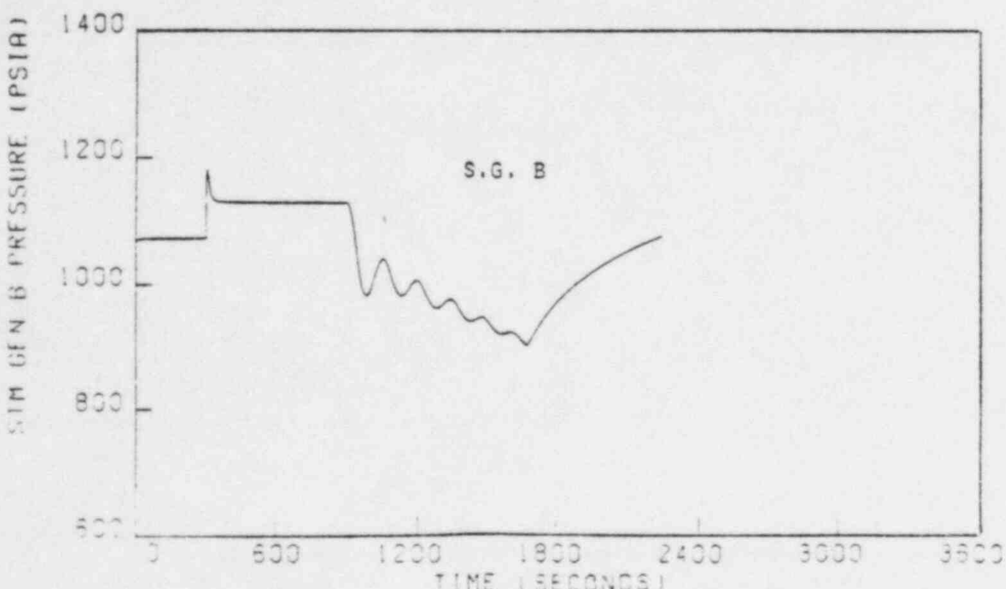
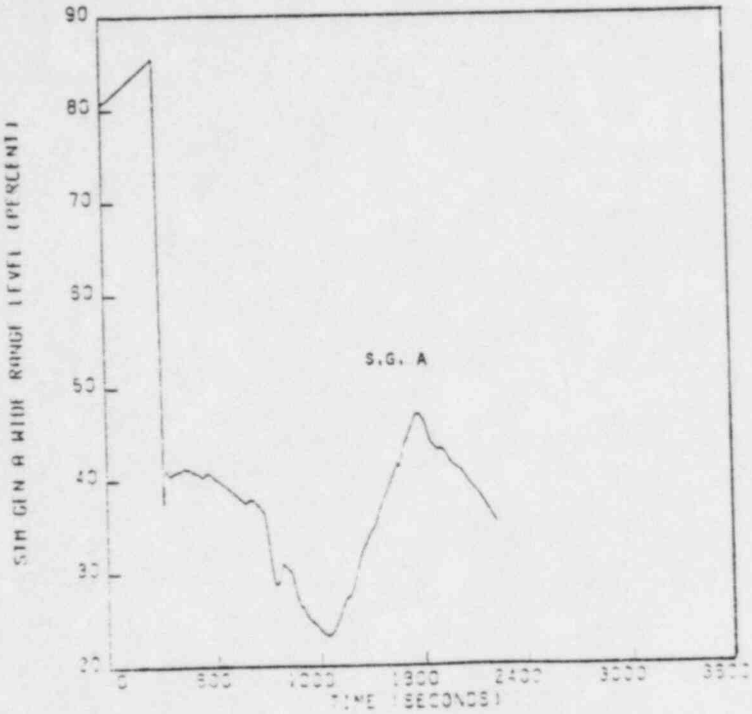


FIGURE 2.1-24

SGTR CASE 1
SG LEVELS



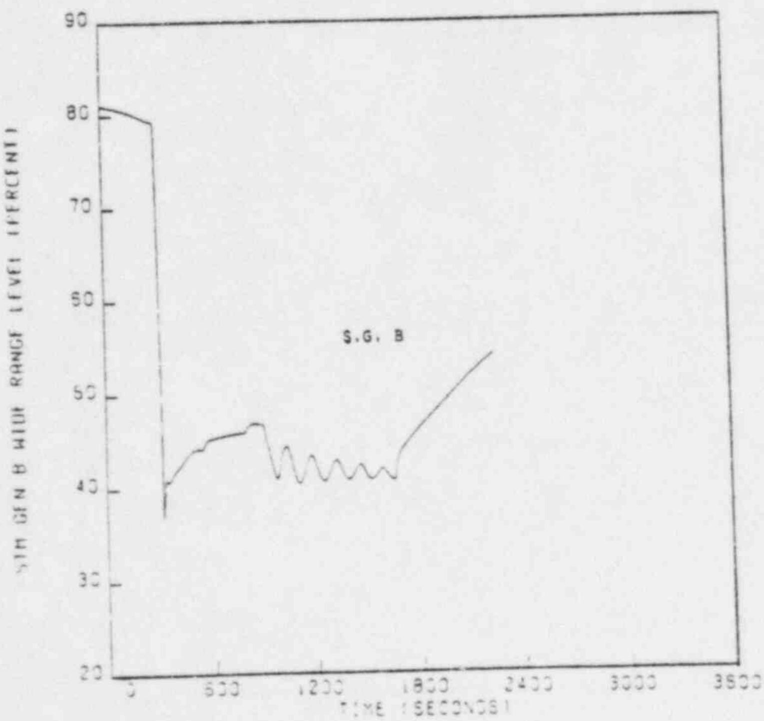


Figure 2.1-25

SGTR CASE 1
LEAK FLOWRATE

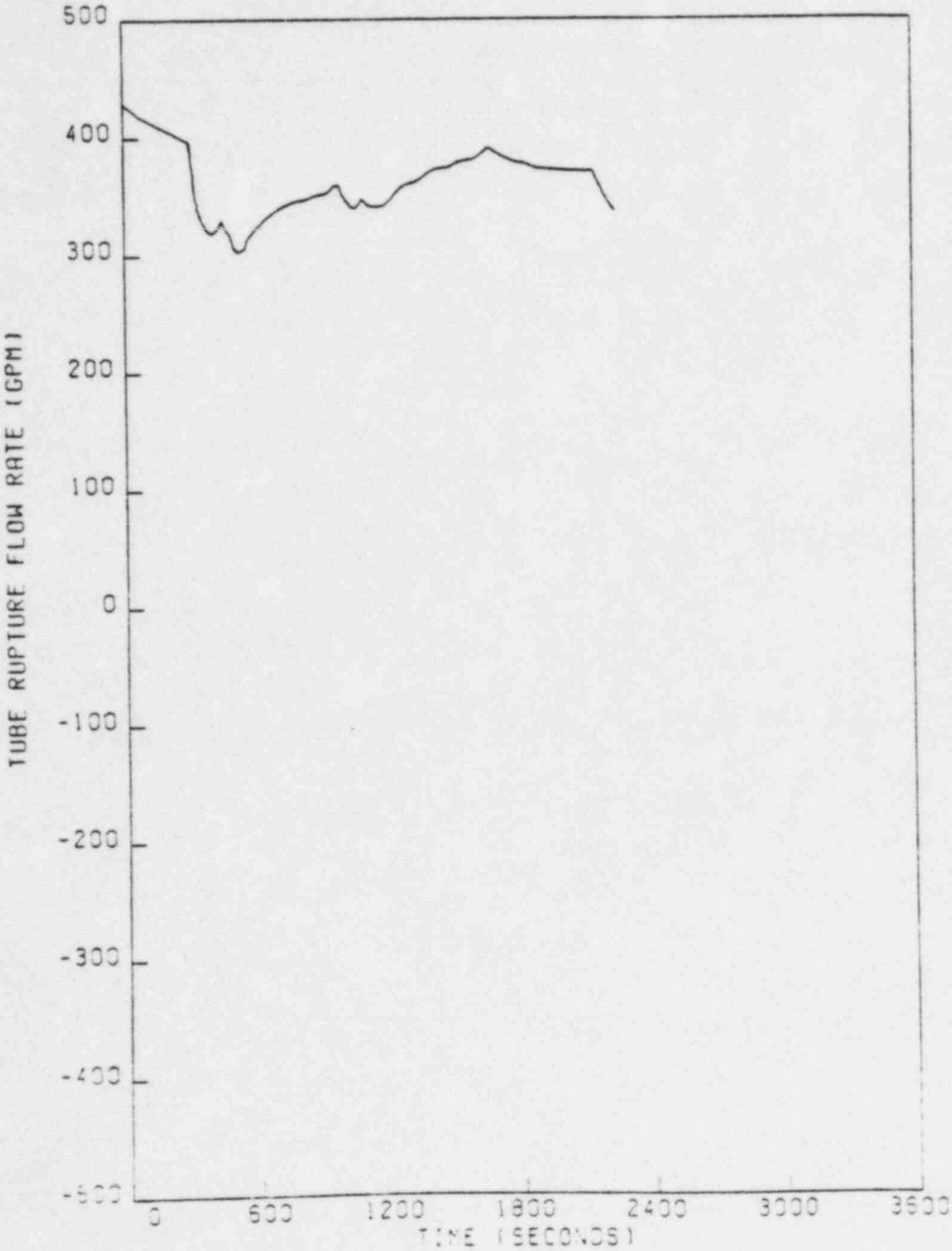


FIGURE 2.1-26

SGTR CASE 2
PZR PRESSURE

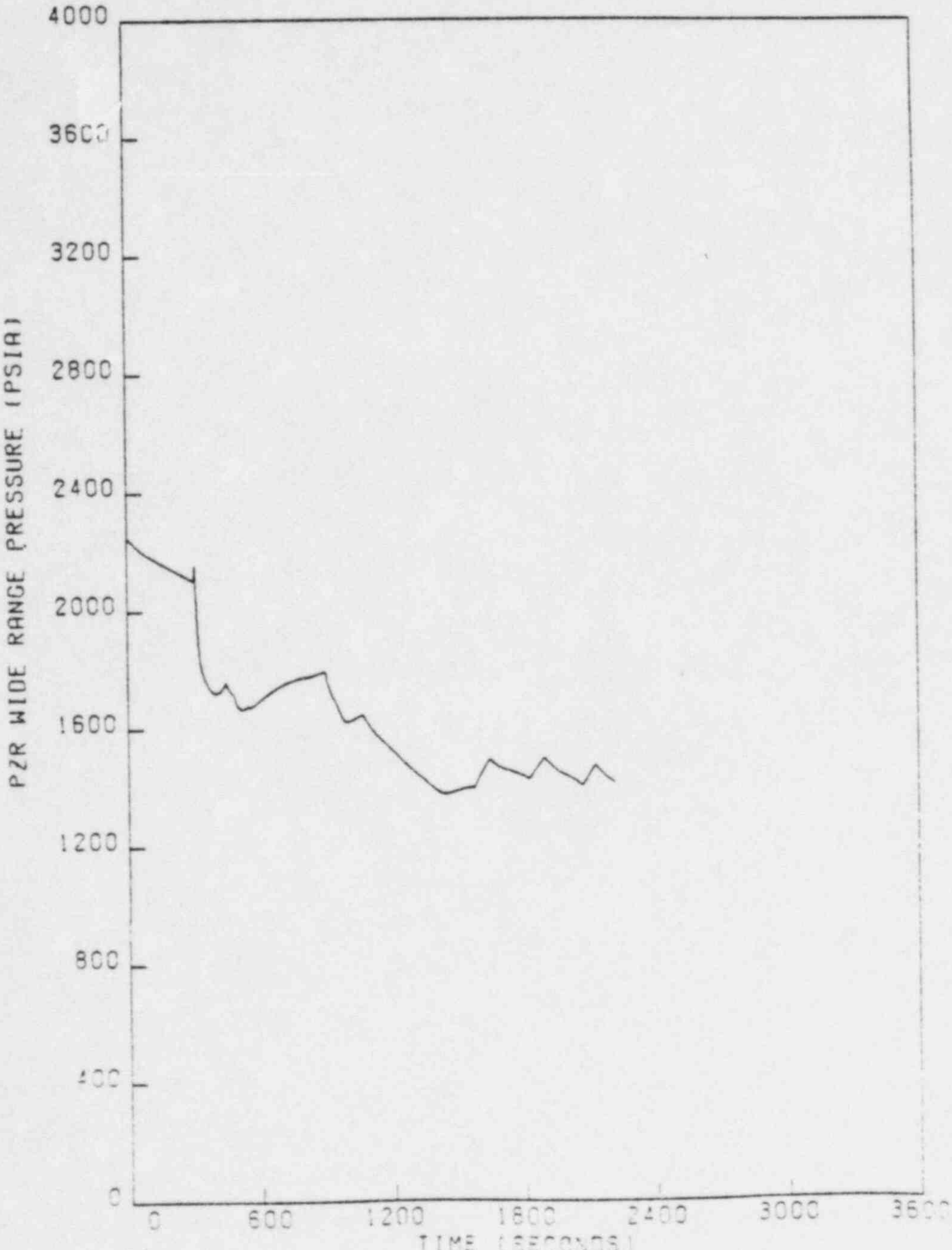


FIGURE 2.1-27

SGTR CASE 2
PZR LEVEL

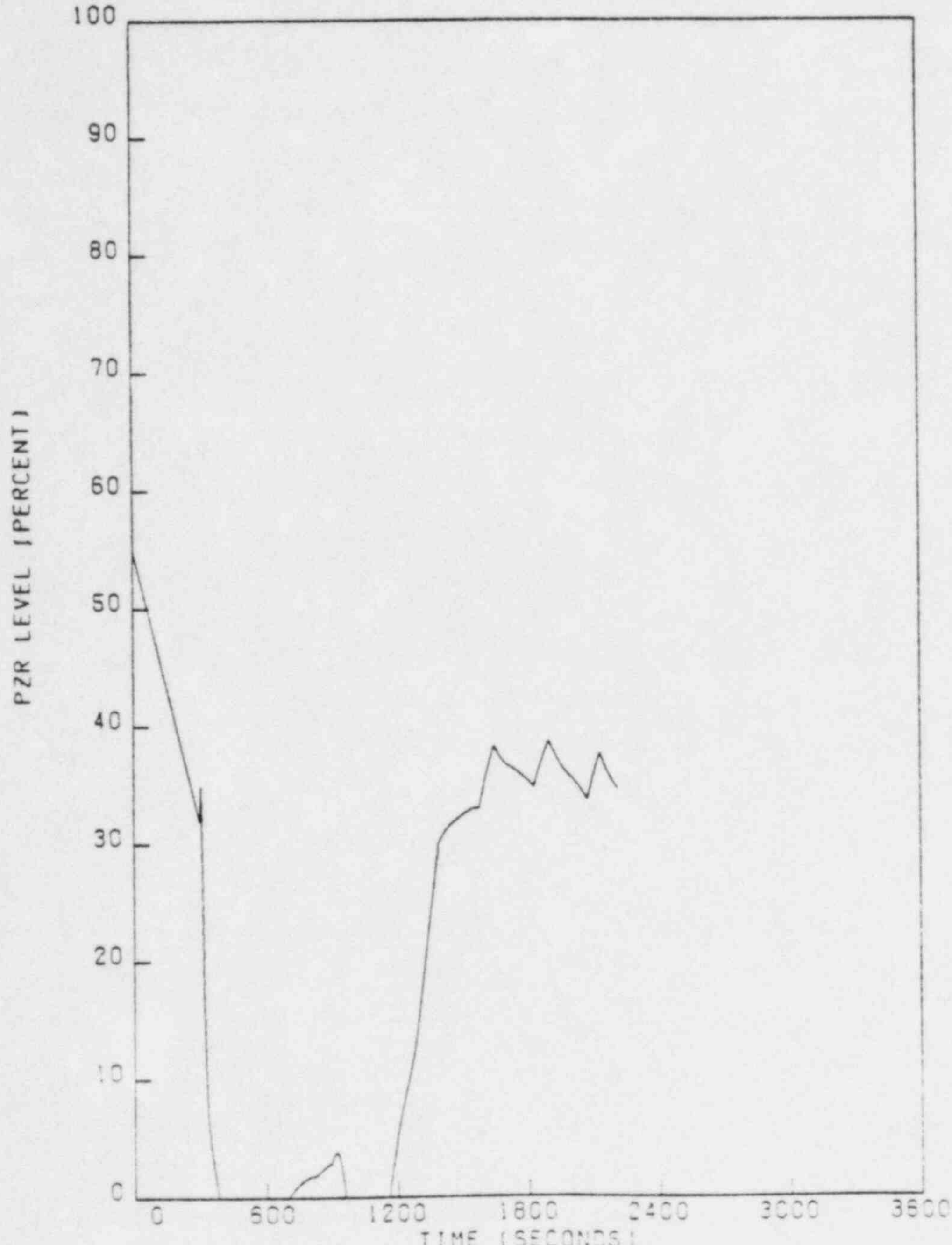


FIGURE 2.1-28

SGTR CASE 2
SIS FLOW

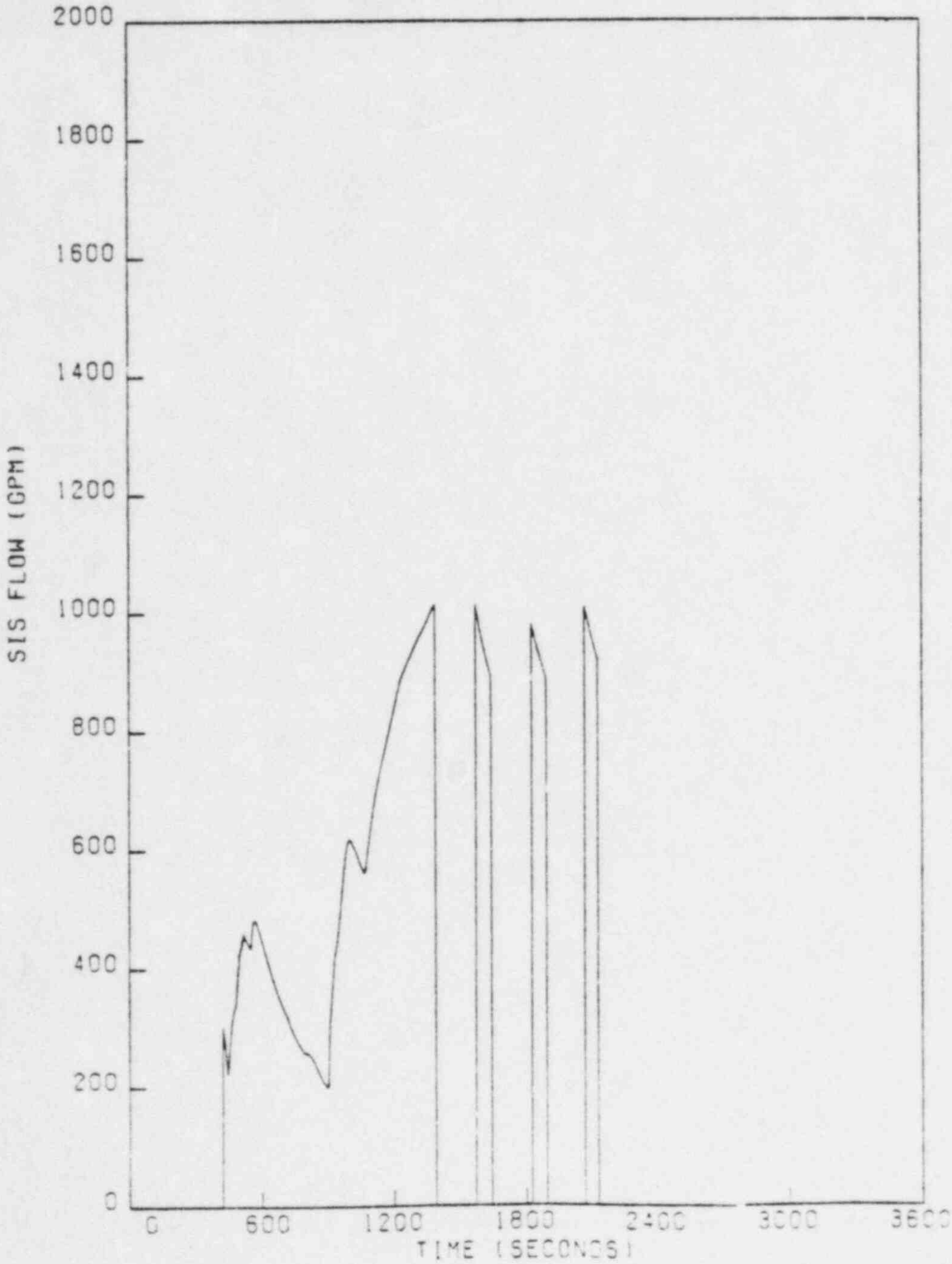


Figure 2.1-29

SGTR CASE 2
AUXILIARY SPRAY FLOW

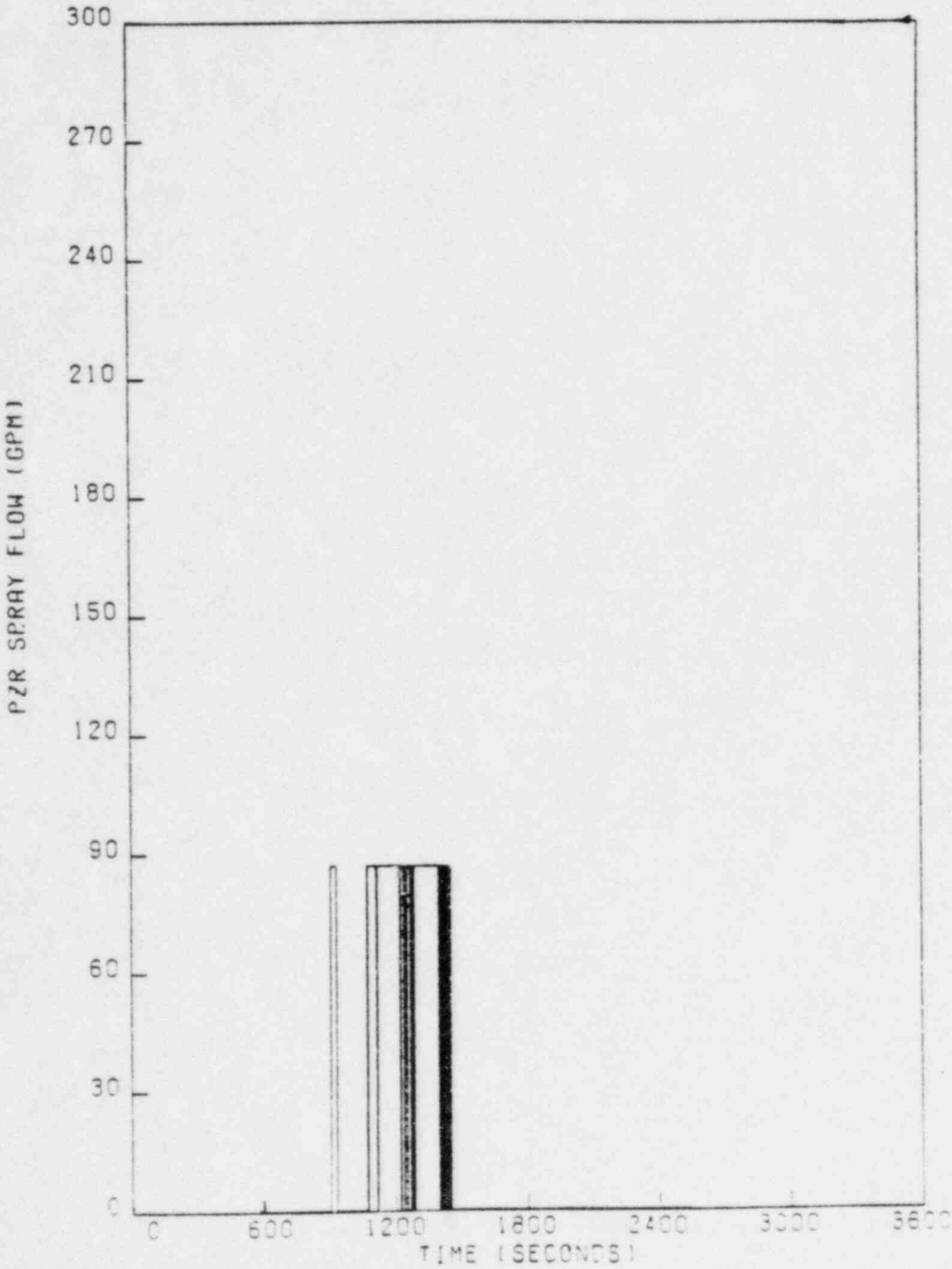


FIGURE 2.1-30

SGTR CASE 2
RCS LOOP TEMPERATURES

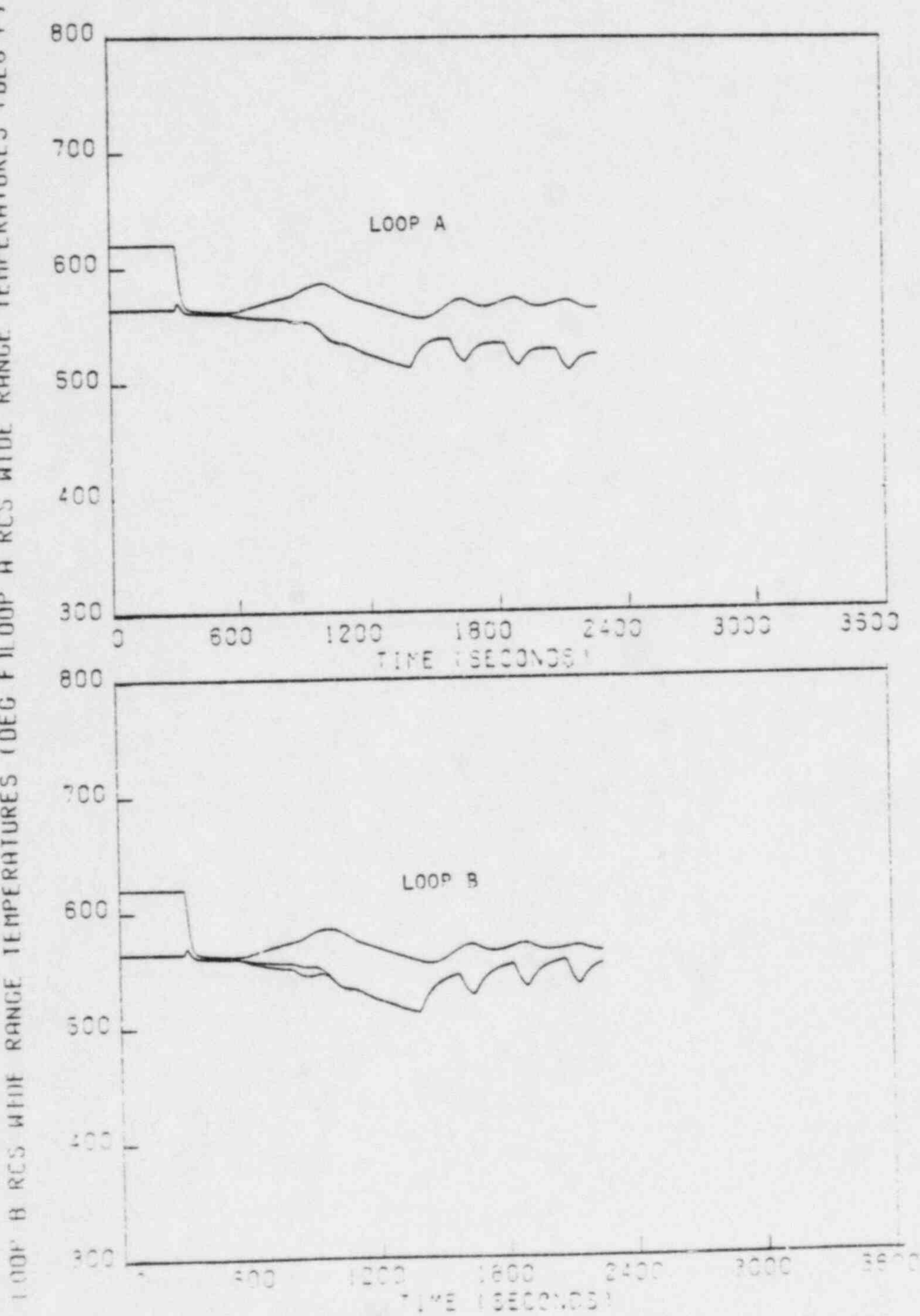


Figure 2.1-31

SGTR CASE 2
LOOP SUBCOOLING

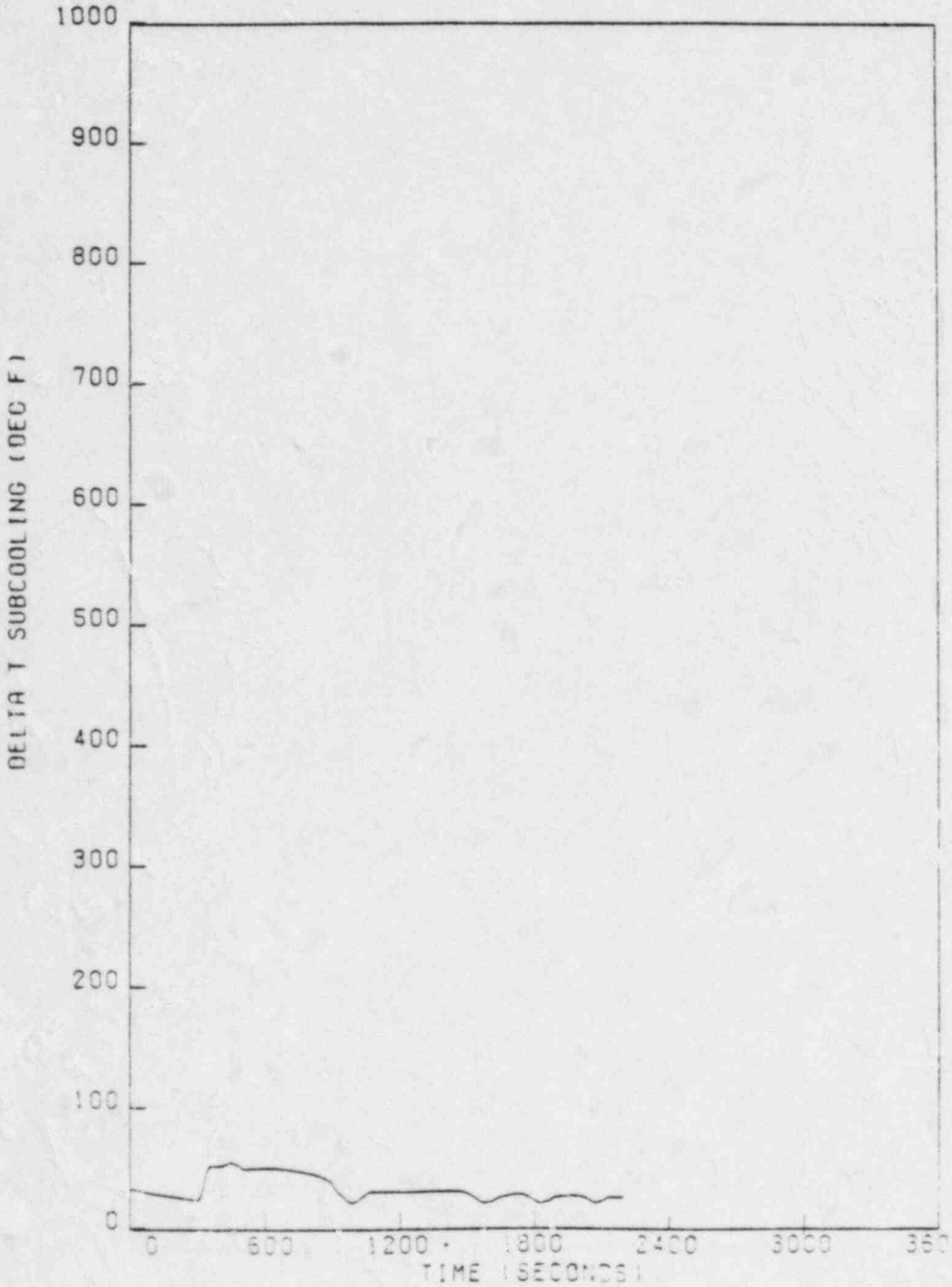


FIGURE 2.1-32

SGTR CASE 2
SG PRESSURES

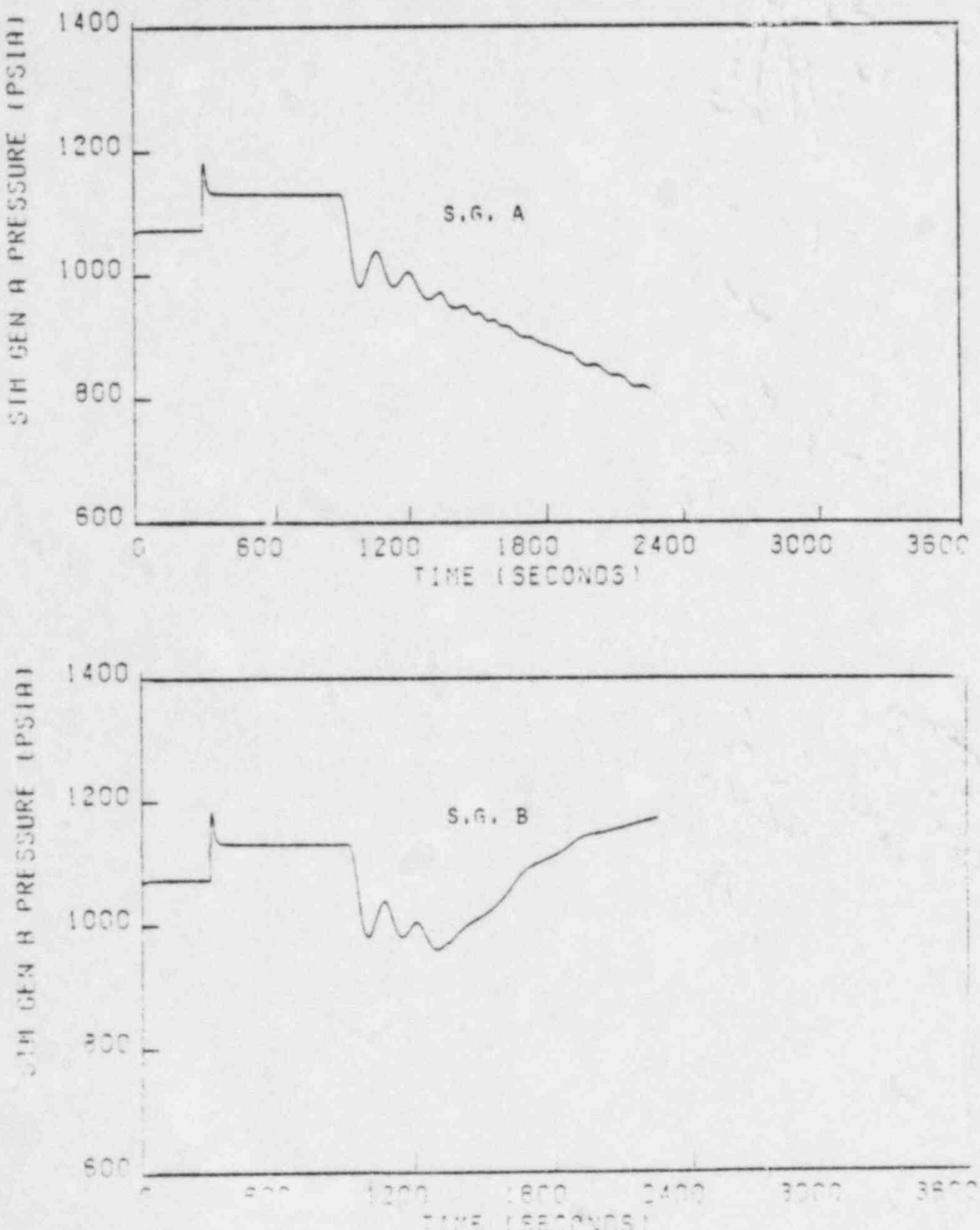


FIGURE 2.1-33

SGTR CASE 2
SG LEVELS

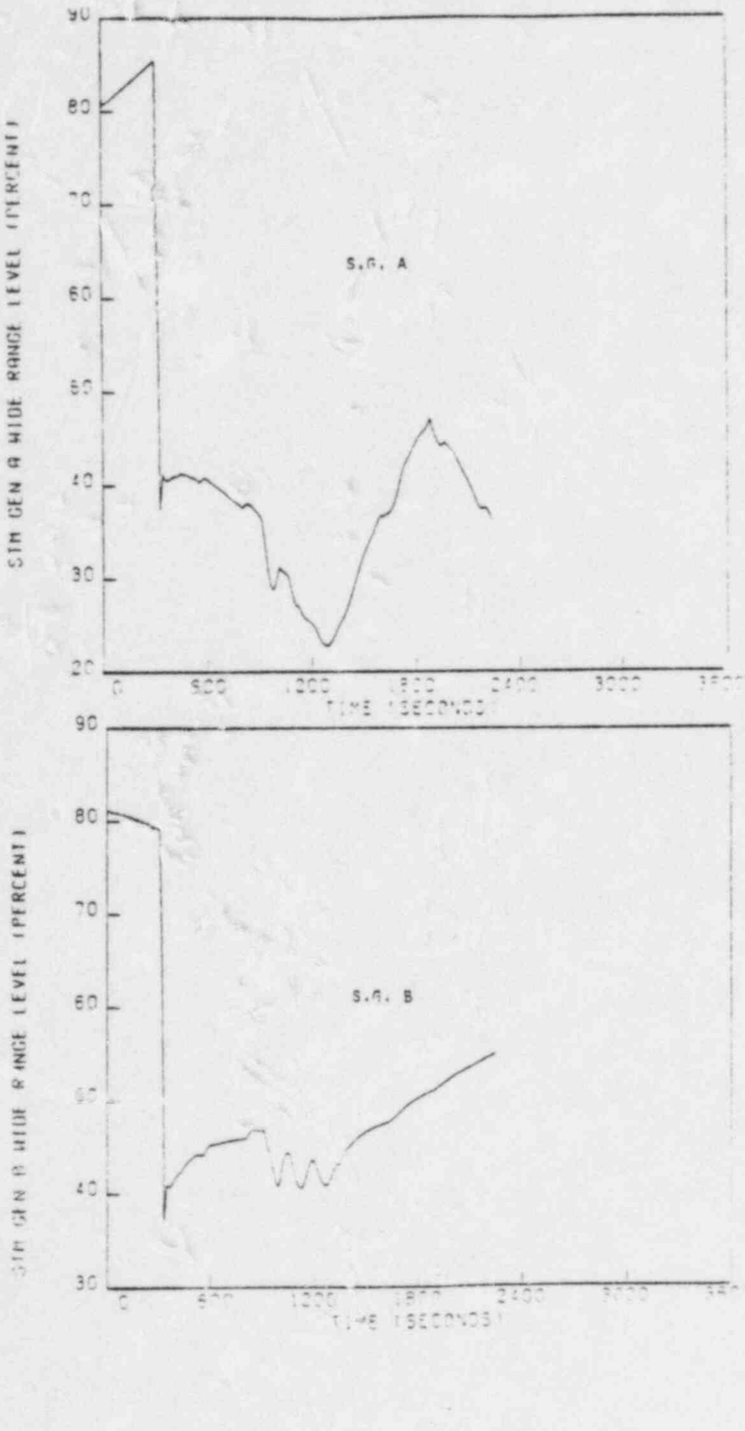


FIGURE 2.1-34

SGTR CASE 2
LEAK FLOWRATE

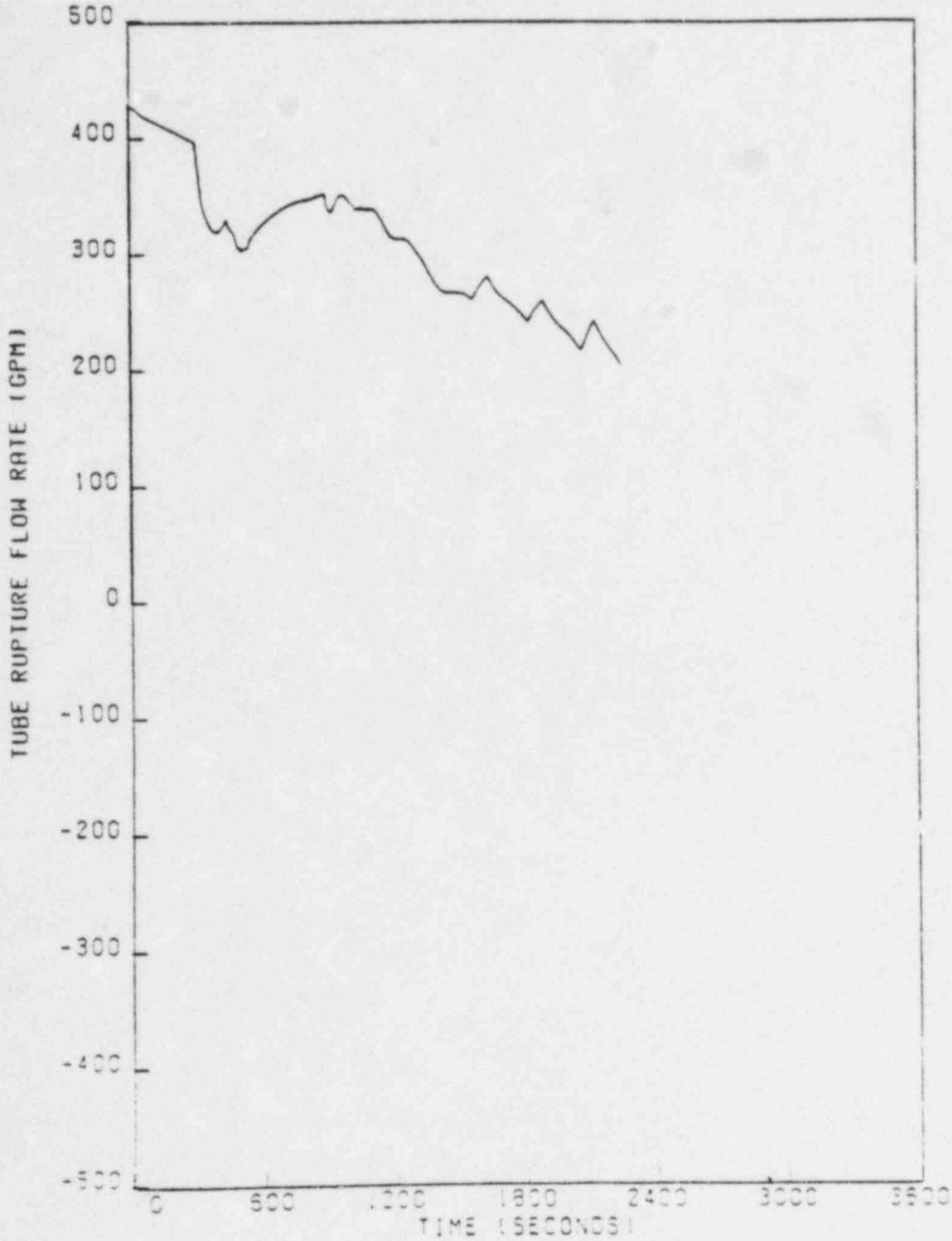


FIGURE 2.1-35

SGTR CASE 3
PZR PRESSURE

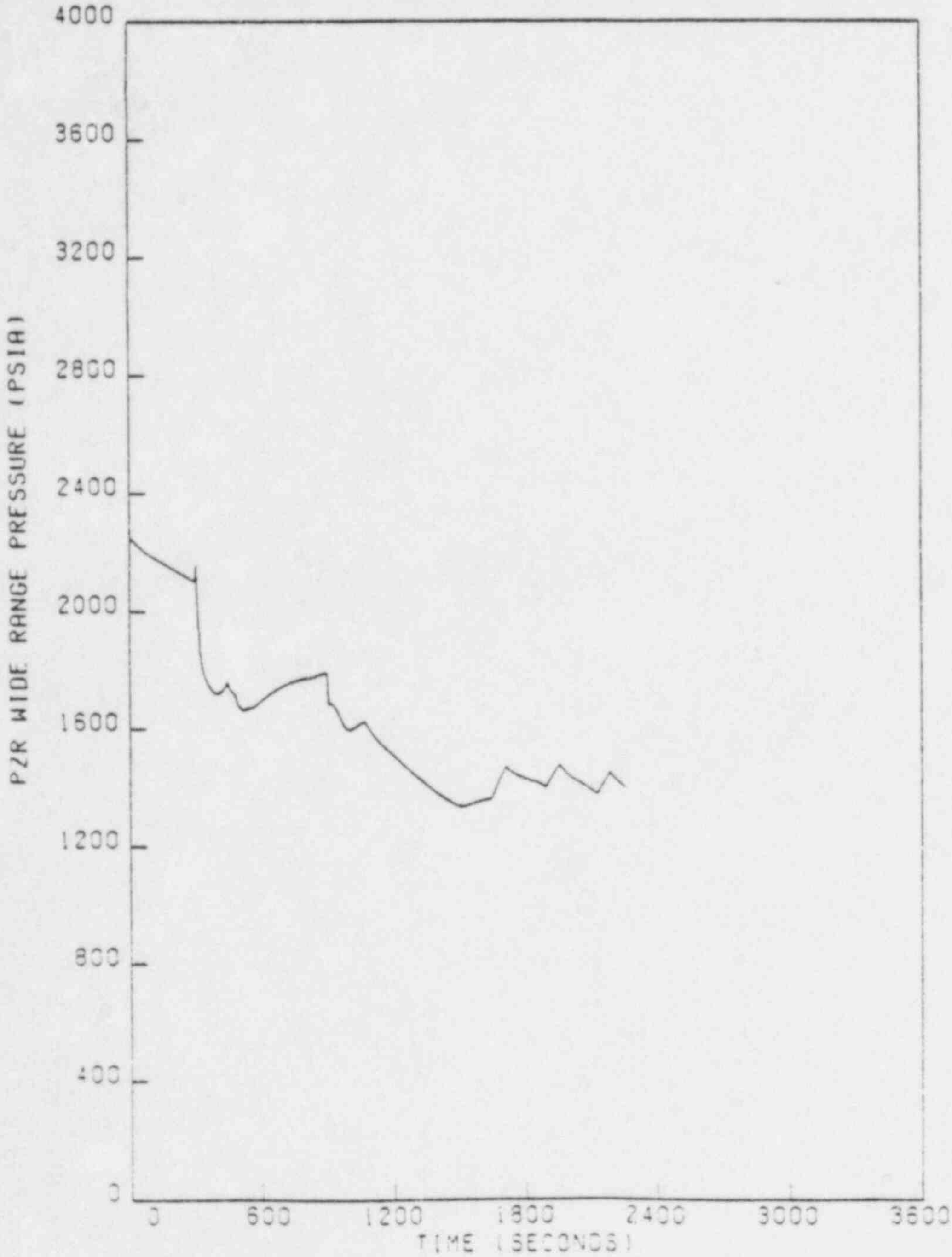


FIGURE 2.1-36

SGTR CASE 3
PZR LEVEL

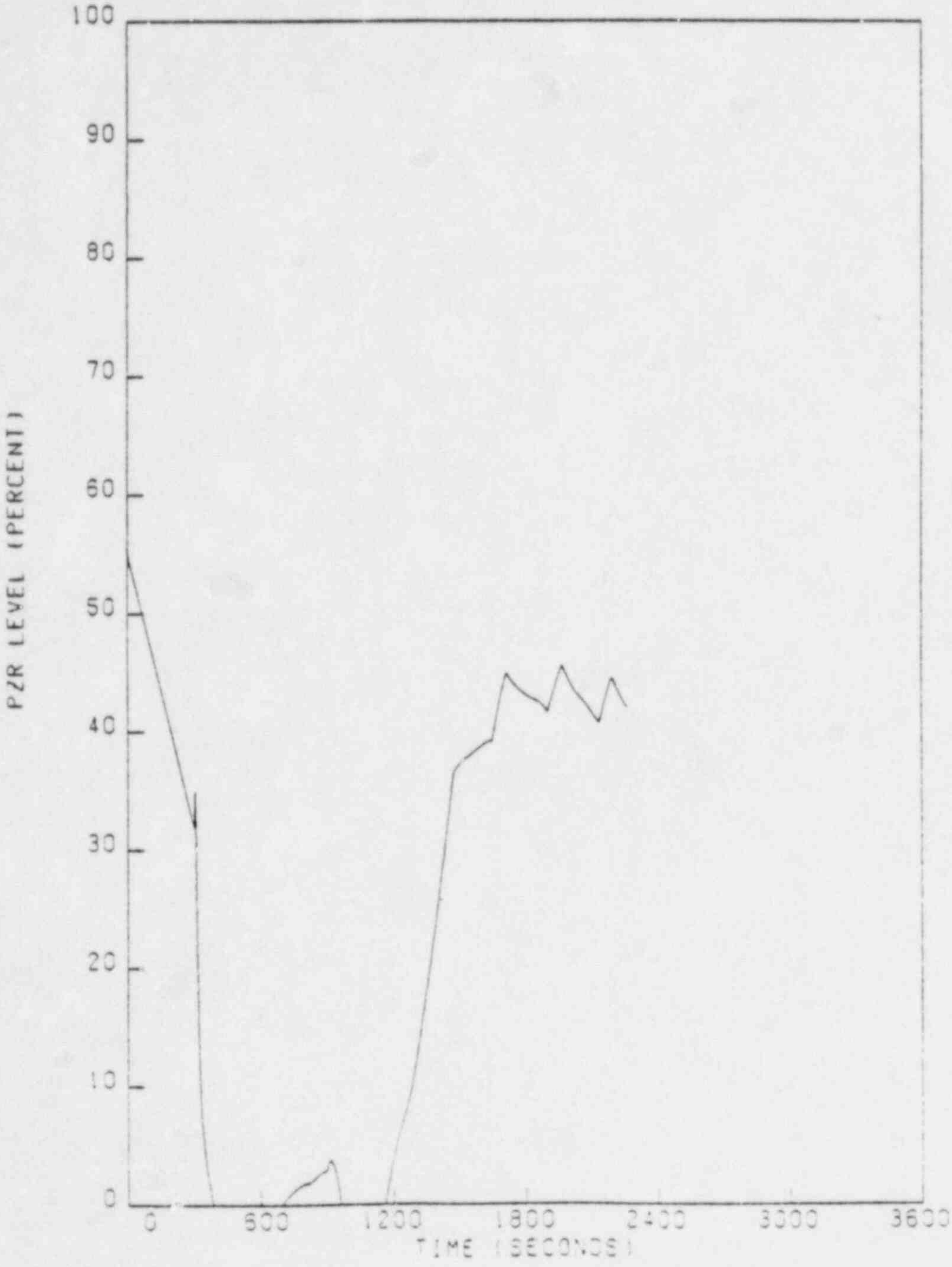


FIGURE 2.1-37

SGTR CASE 3
SIS FLOW

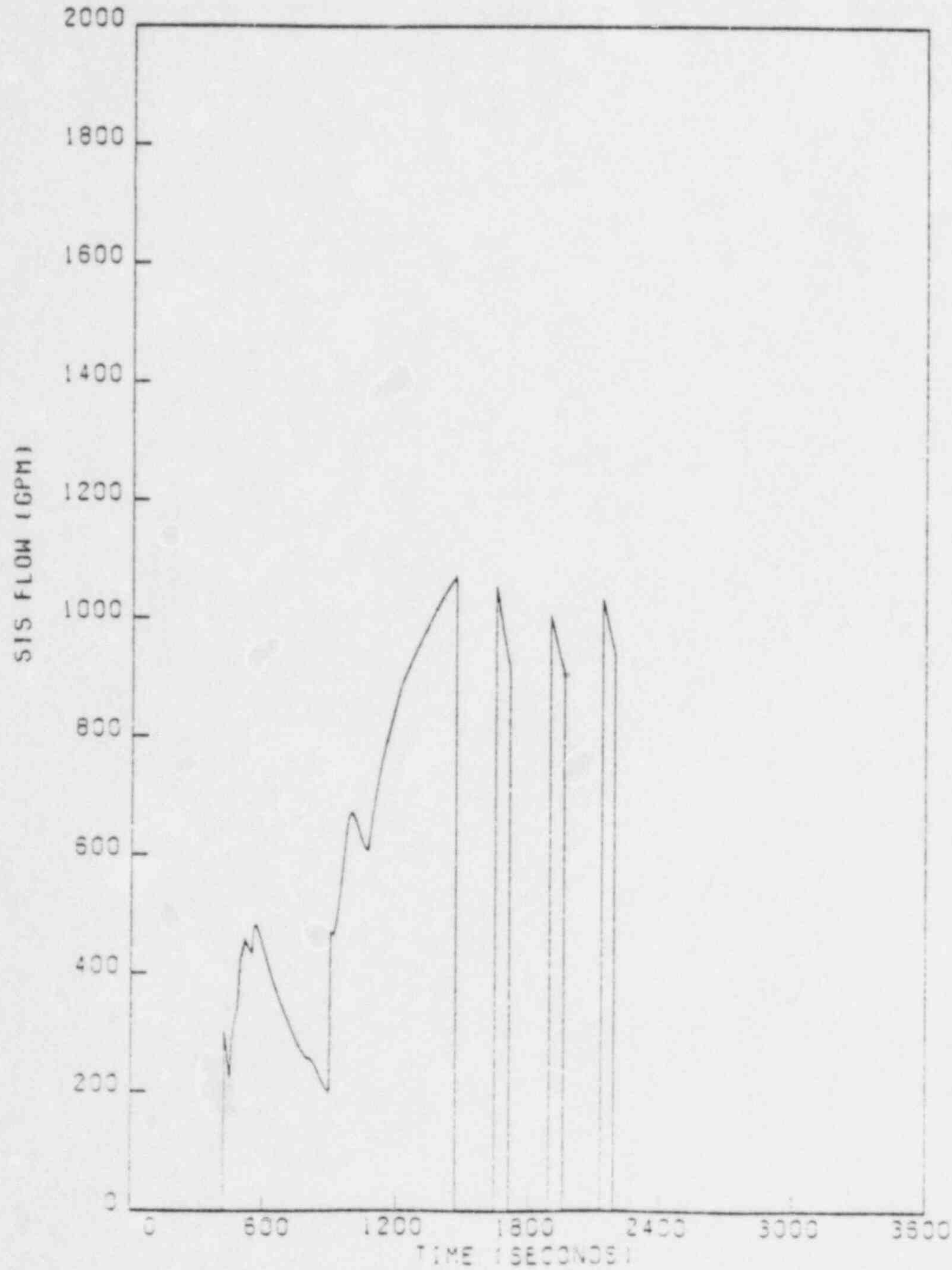


FIGURE 2.1-38

SGTR CASE 3
PORV FLOW

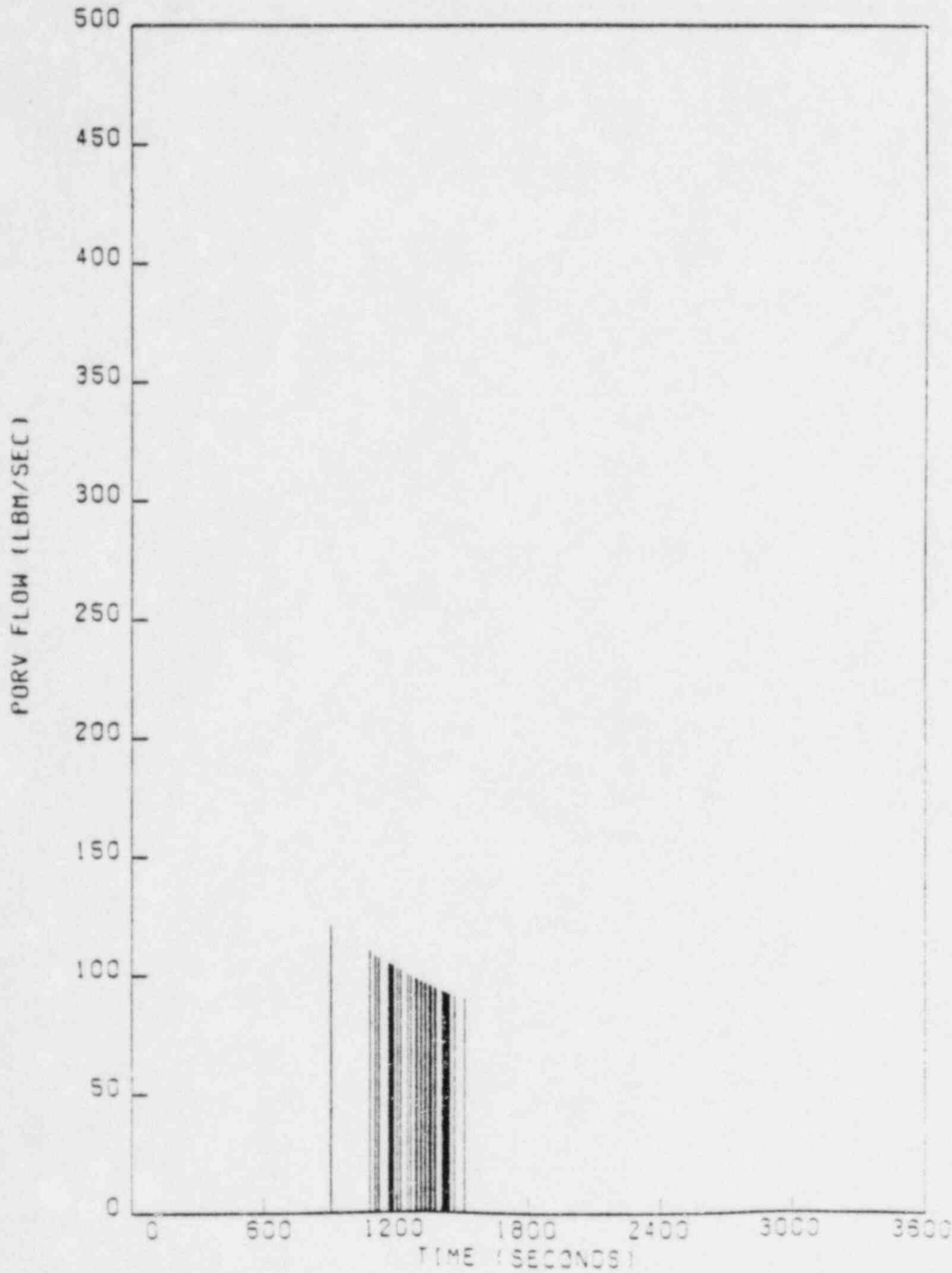


FIGURE 2.1-39

SGTR CASE 3
RCS LOOP TEMPERATURES

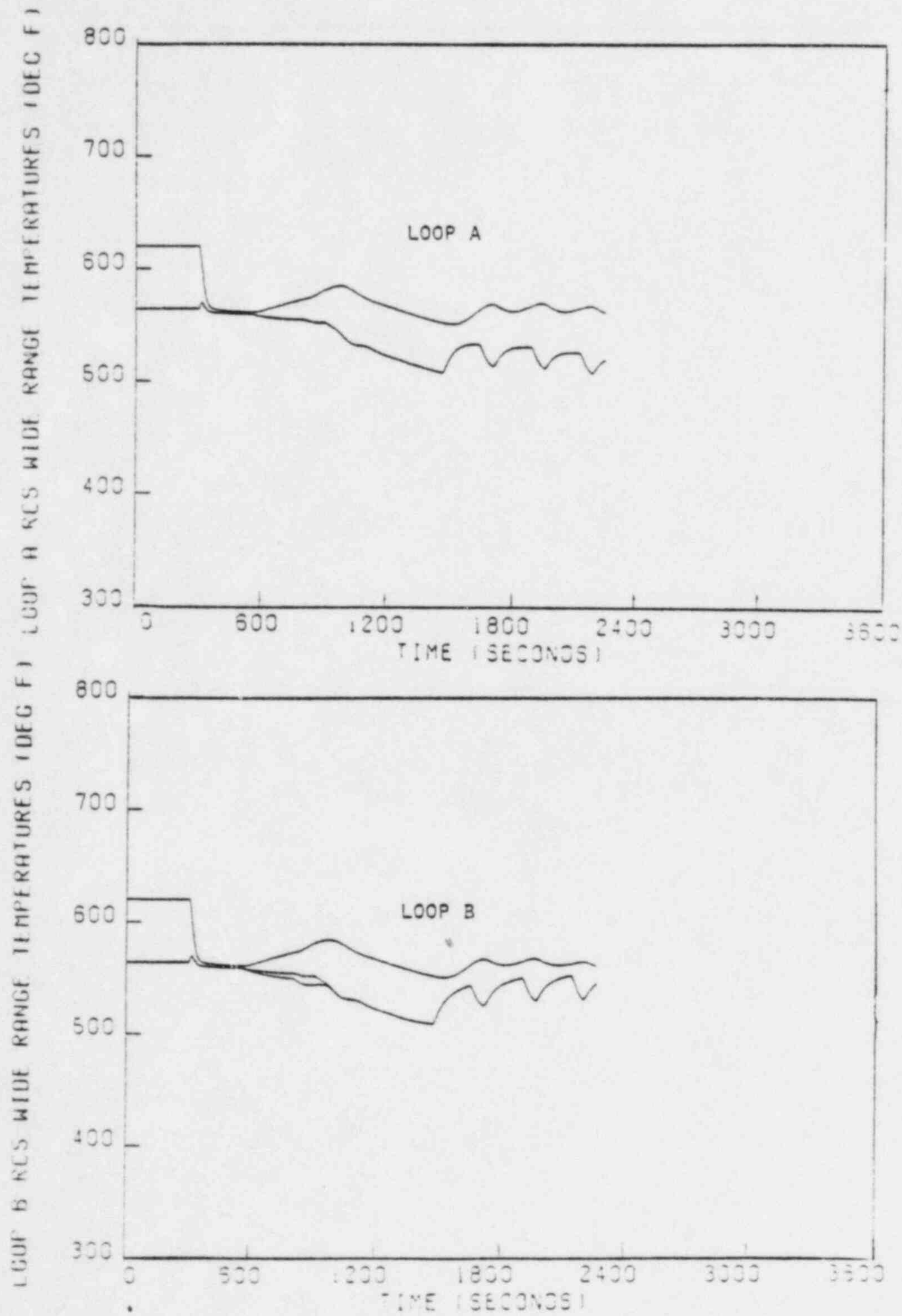


Figure 2.1-40

SGTR CASE 3
LOOP SUBCOOLING

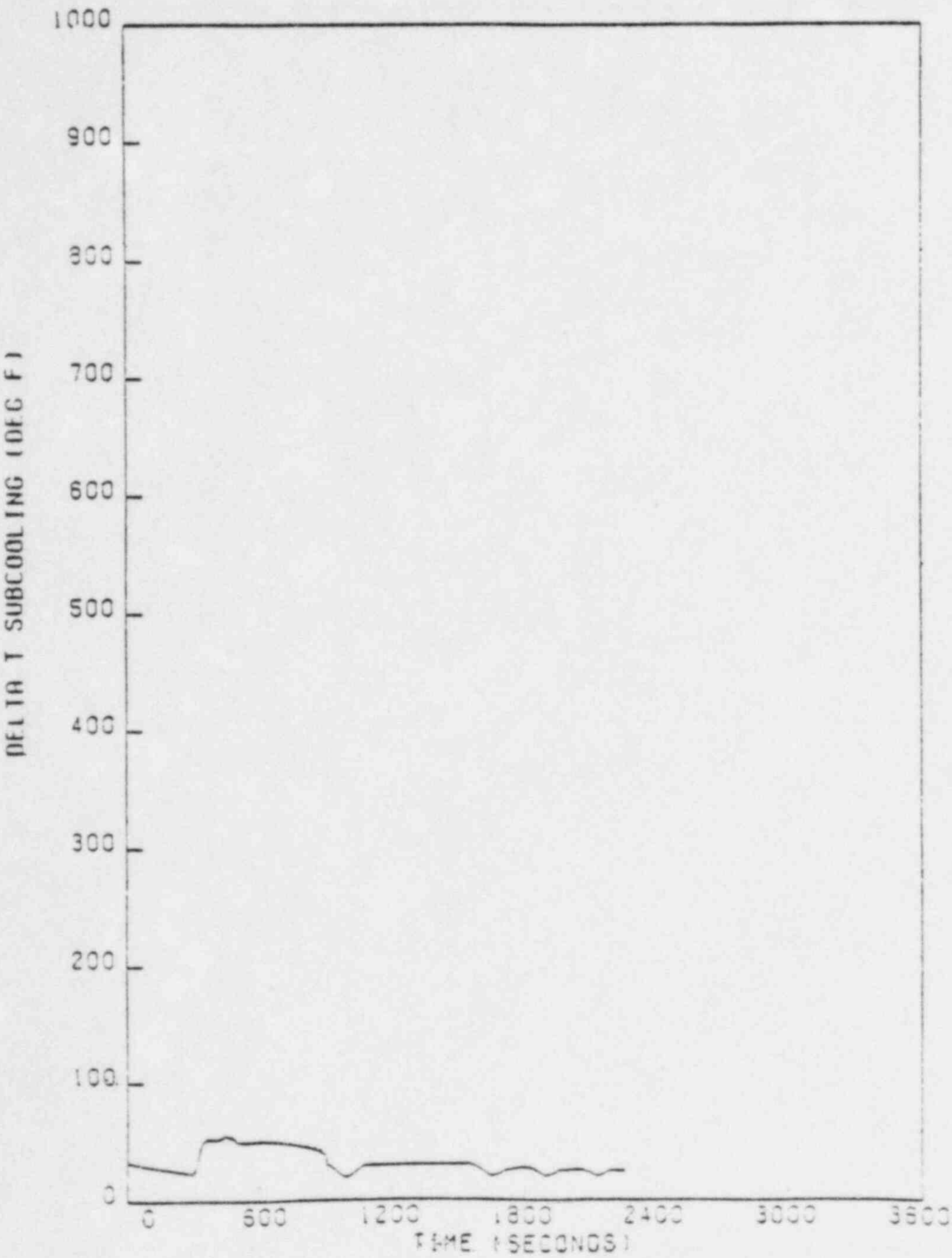
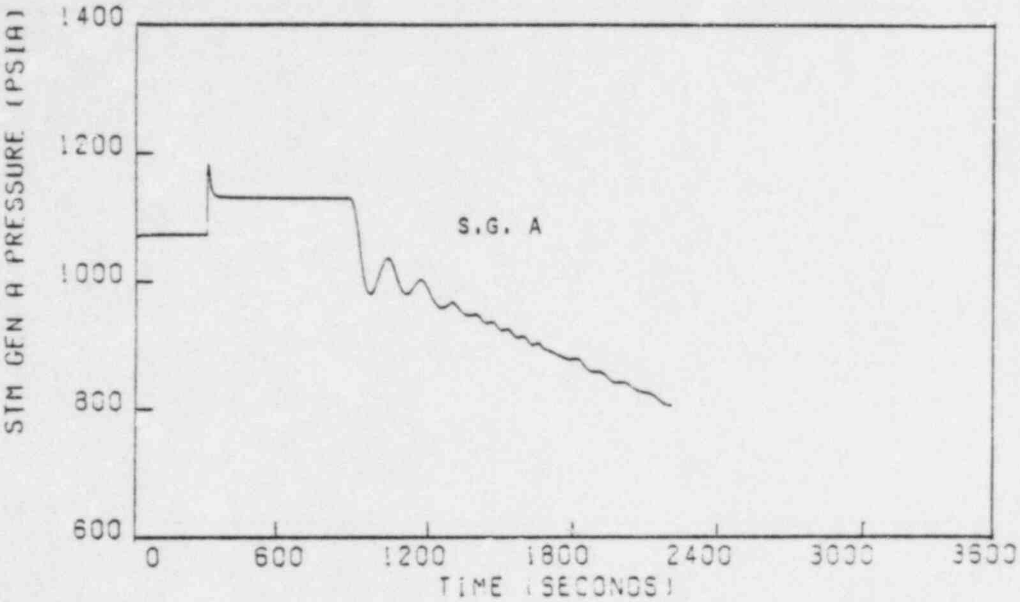


FIGURE 2.1-41

SGTR CASE 3
SG PRESSURE



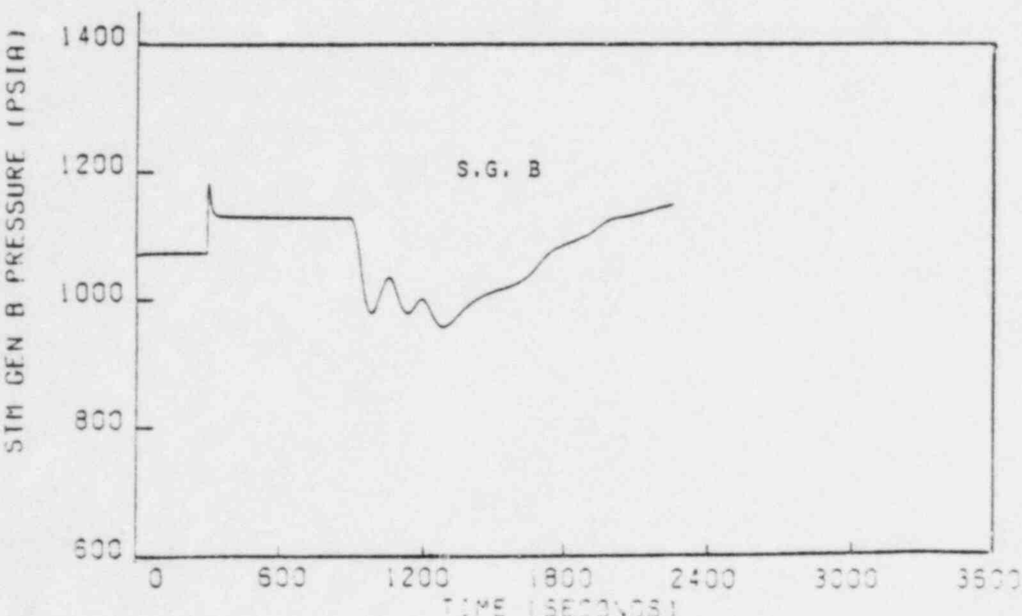


FIGURE 2.1-42

SGTR CASE 3
SG LEVELS

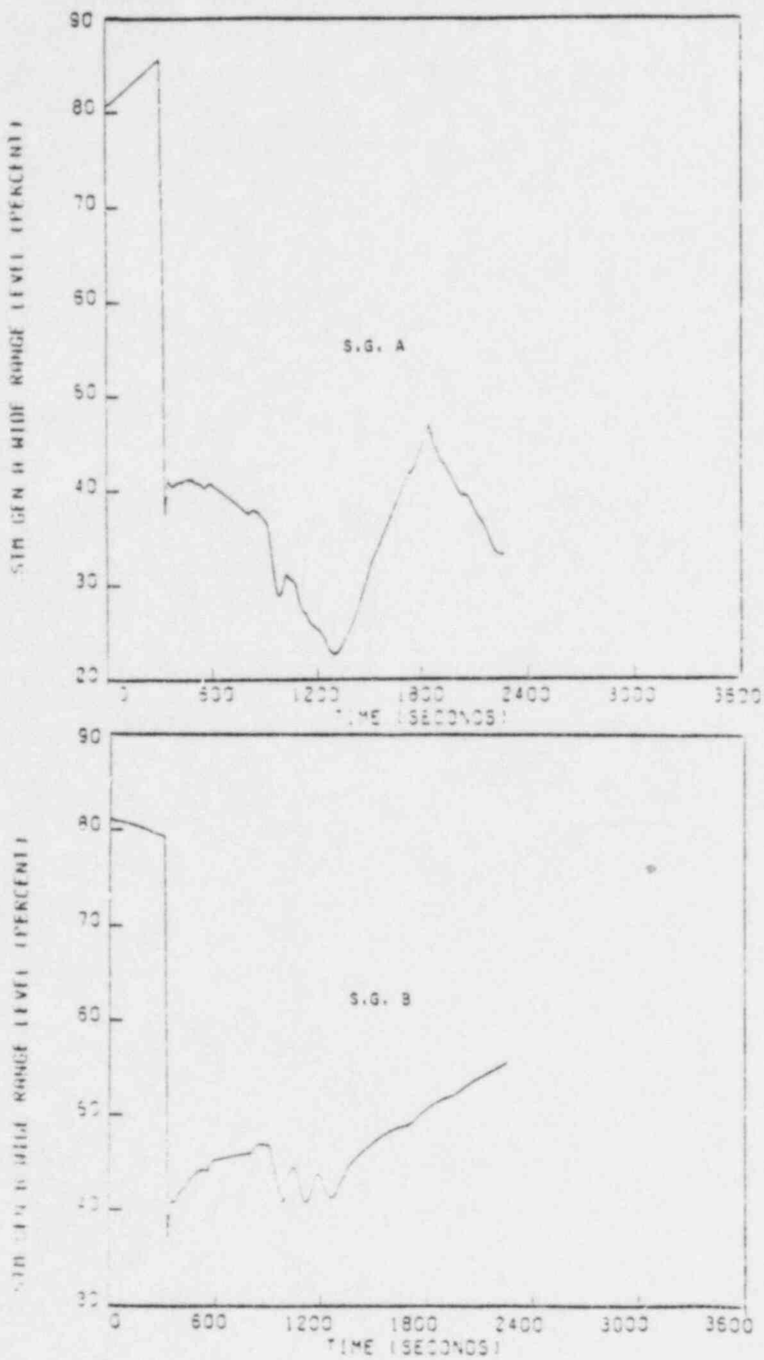


FIGURE 2.1-43

SGTR CASE 3
LEAK FLOWRATE

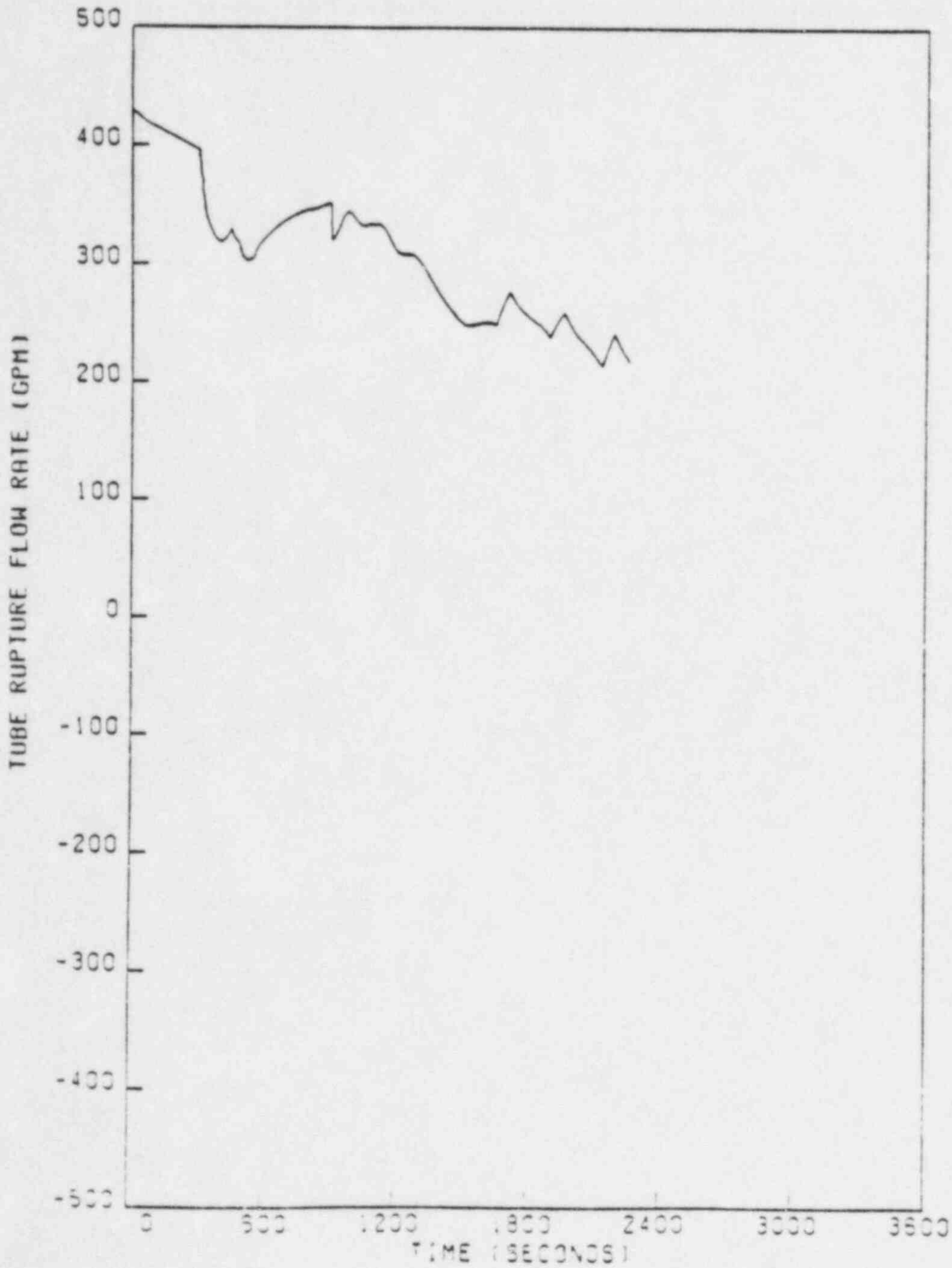


FIGURE 2.1-44

SGTR CASE 4
PZR PRESSURE

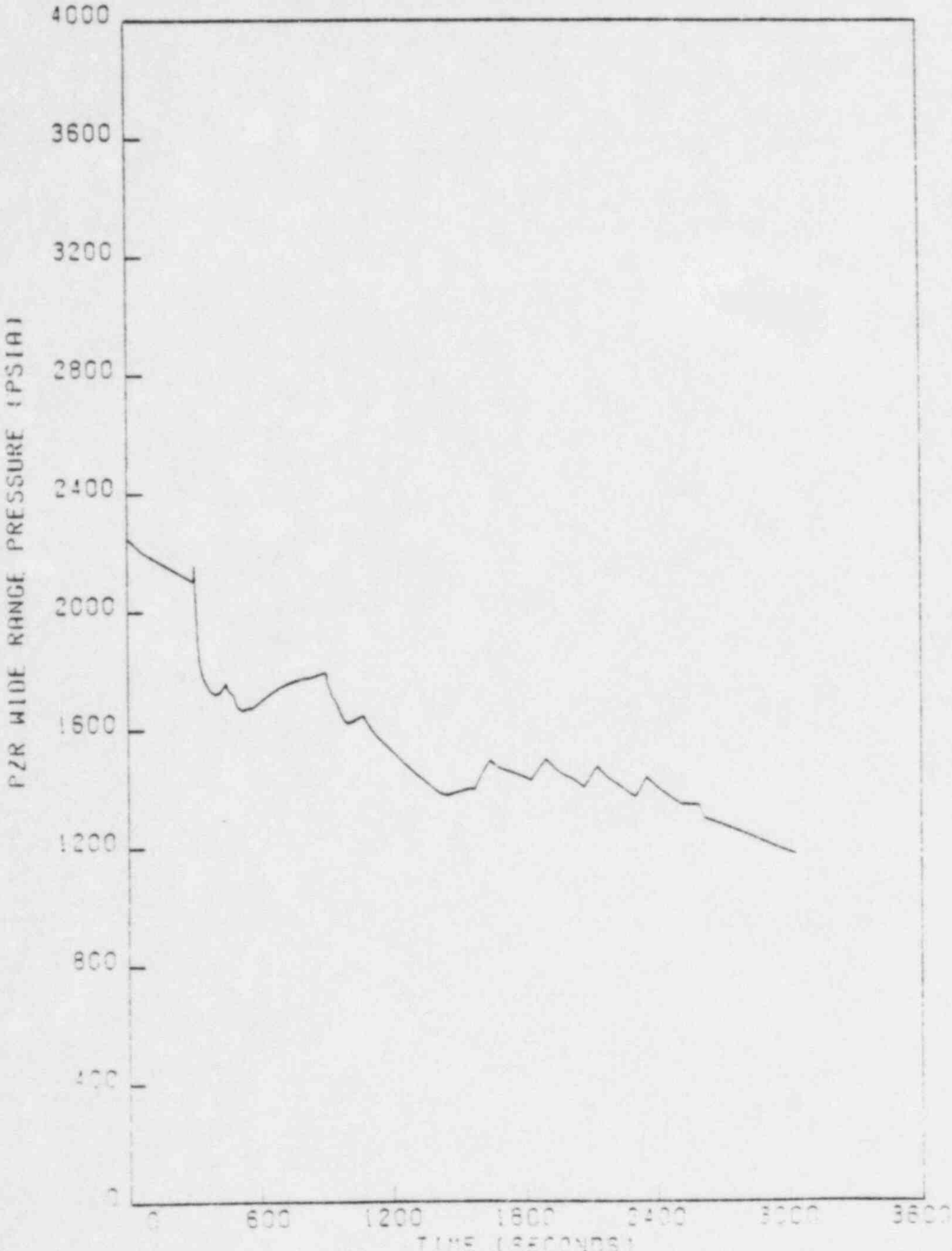


FIGURE 2.1-45

SGTR CASE 4
PZR LEVEL

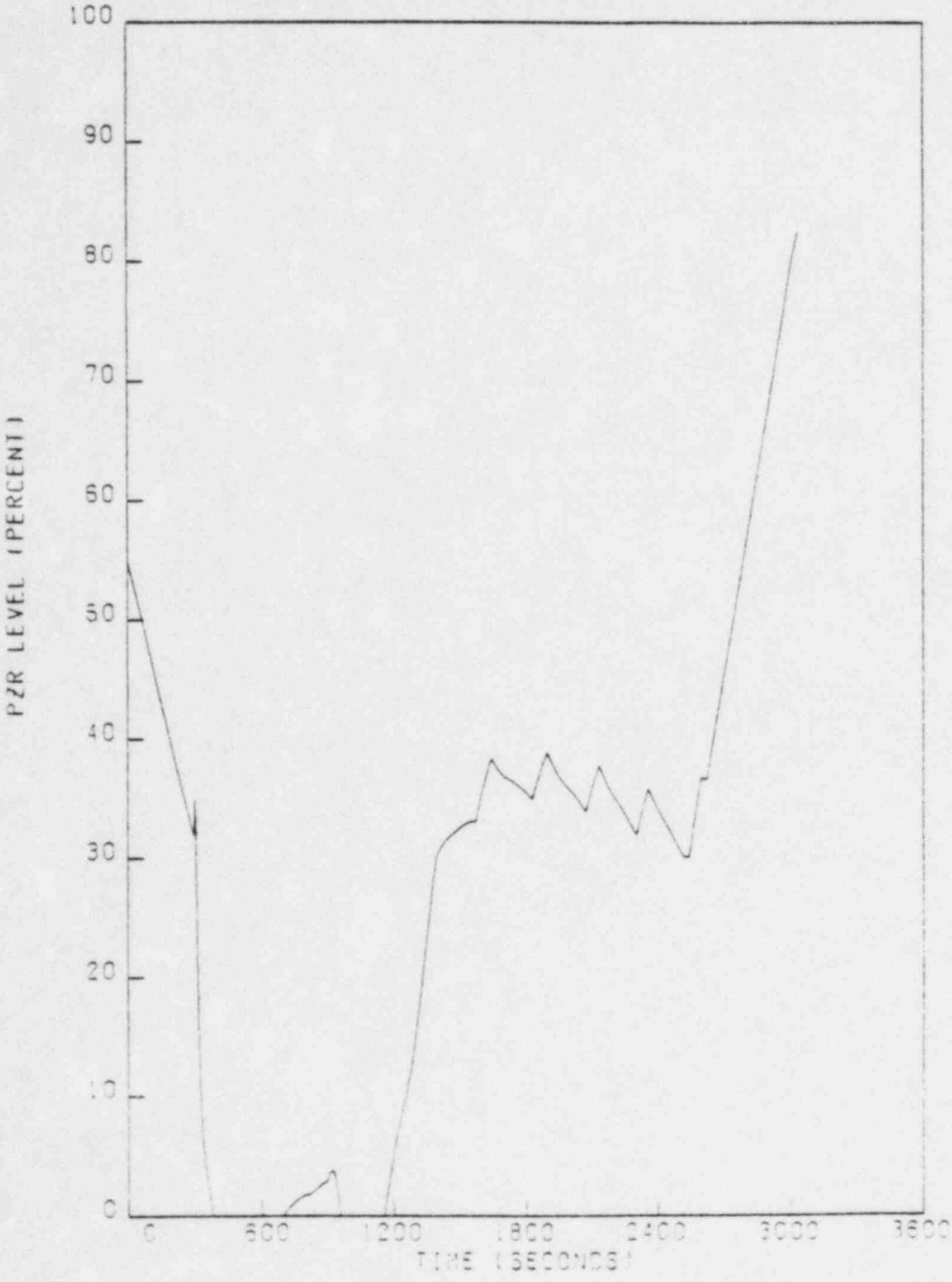


FIGURE 2.1-46

SGTR CASE 4
SG PRESSURES

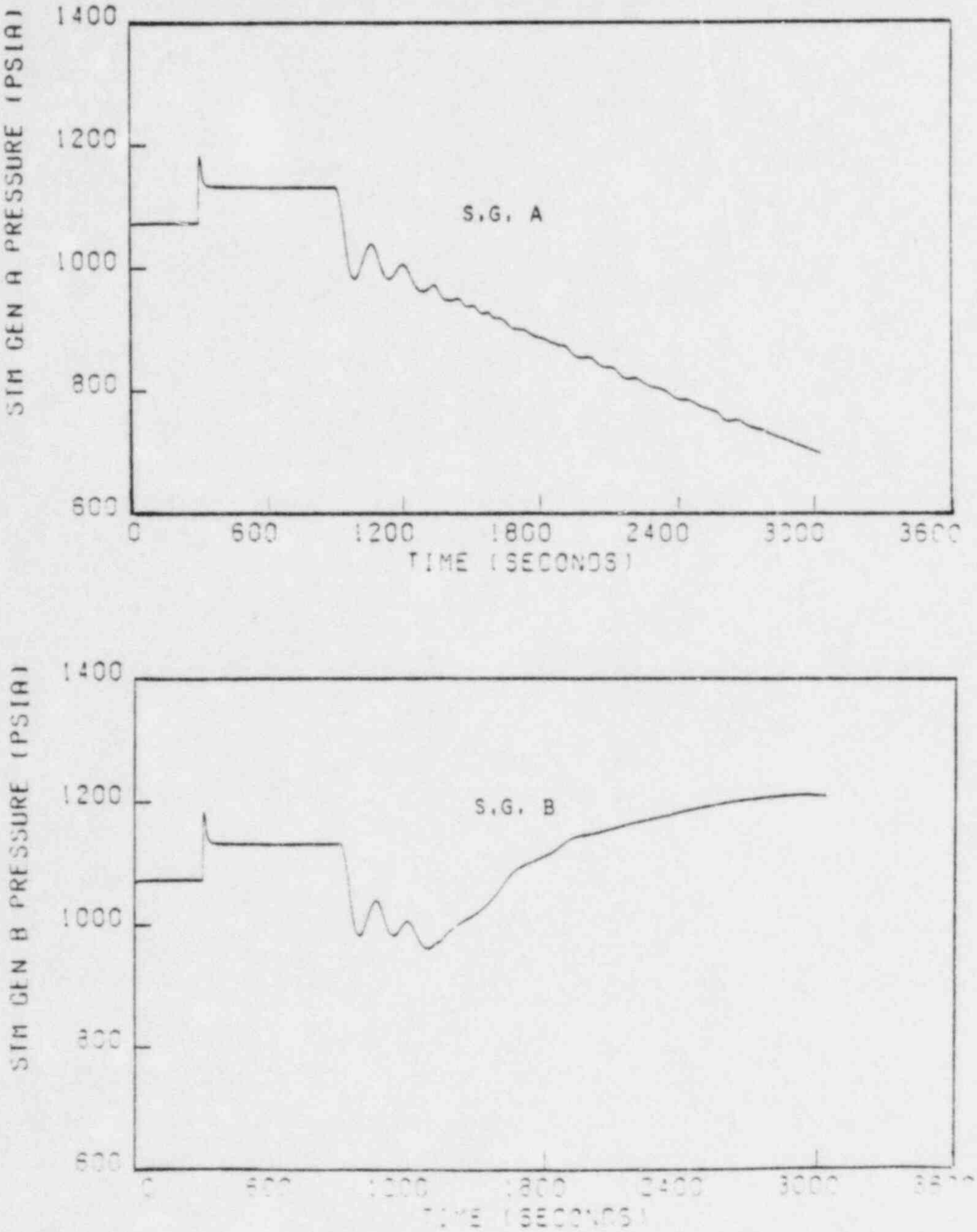


Figure 2.1-47

SGTR CASE 4
RVUH WATER VOLUME

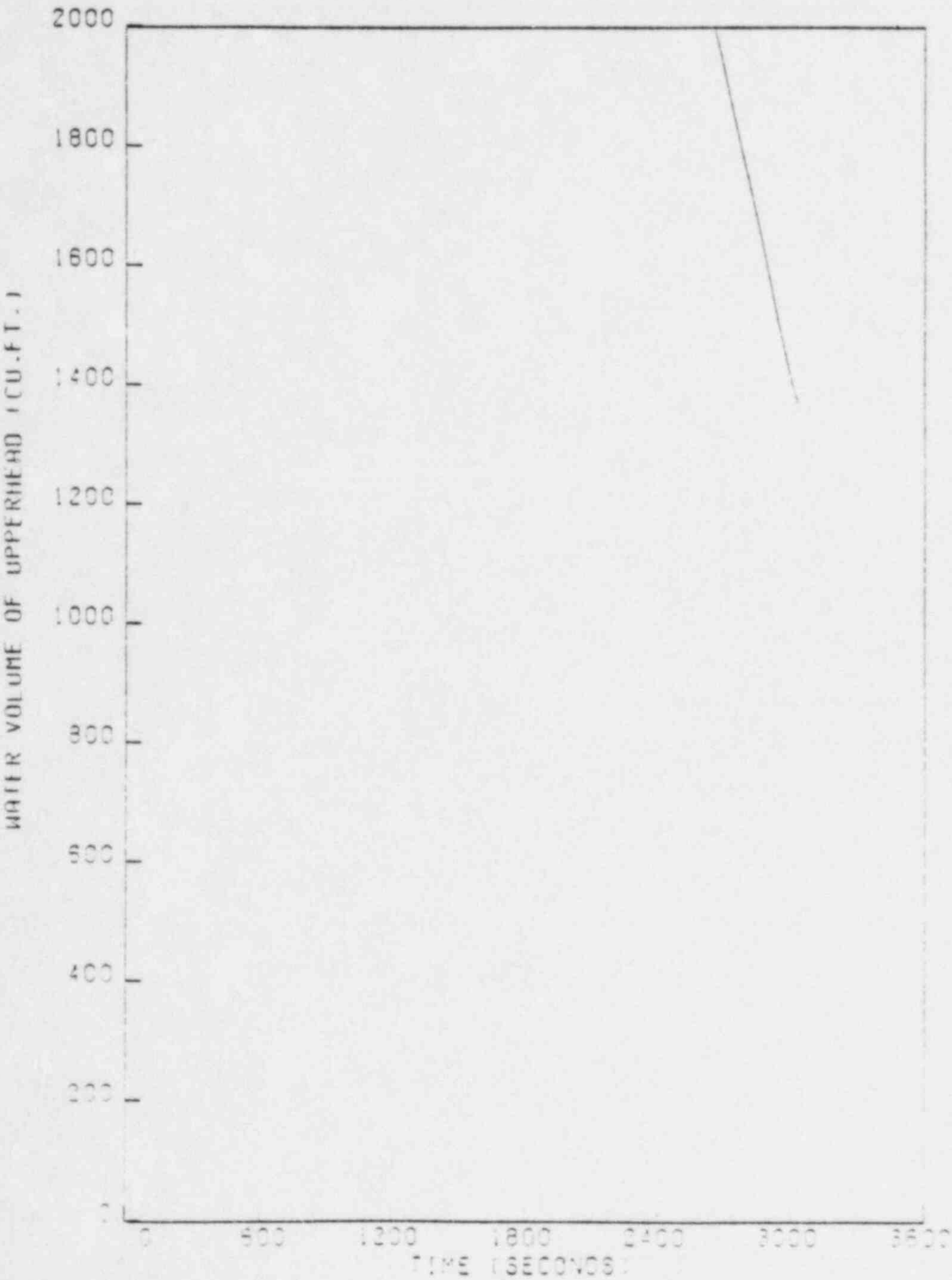


FIGURE 2.1-48

SGTR CASE 4
LEAK FLOWRATE

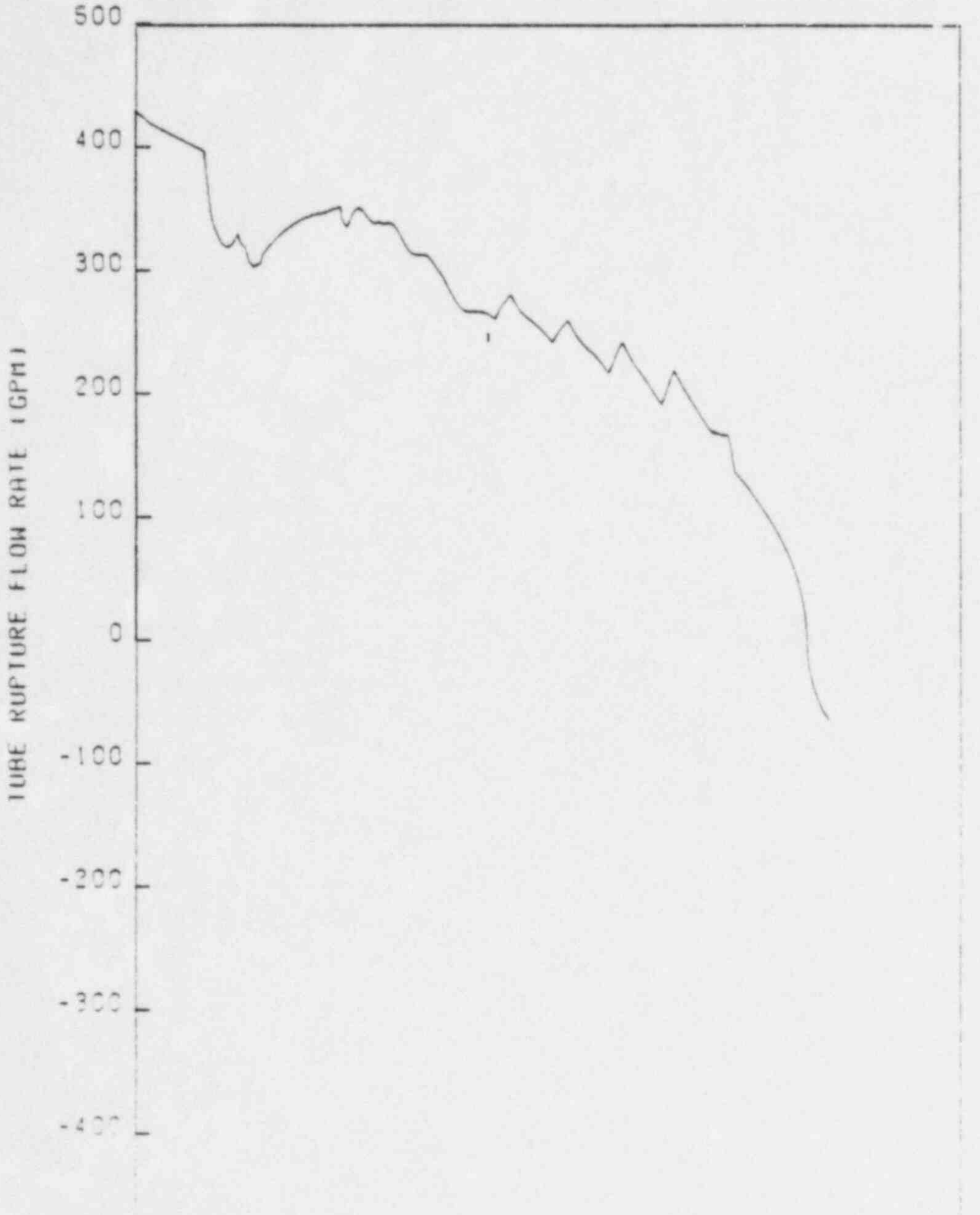


FIGURE 2.1-49

SGTR CASE 4
LOOP SUBCOOLING

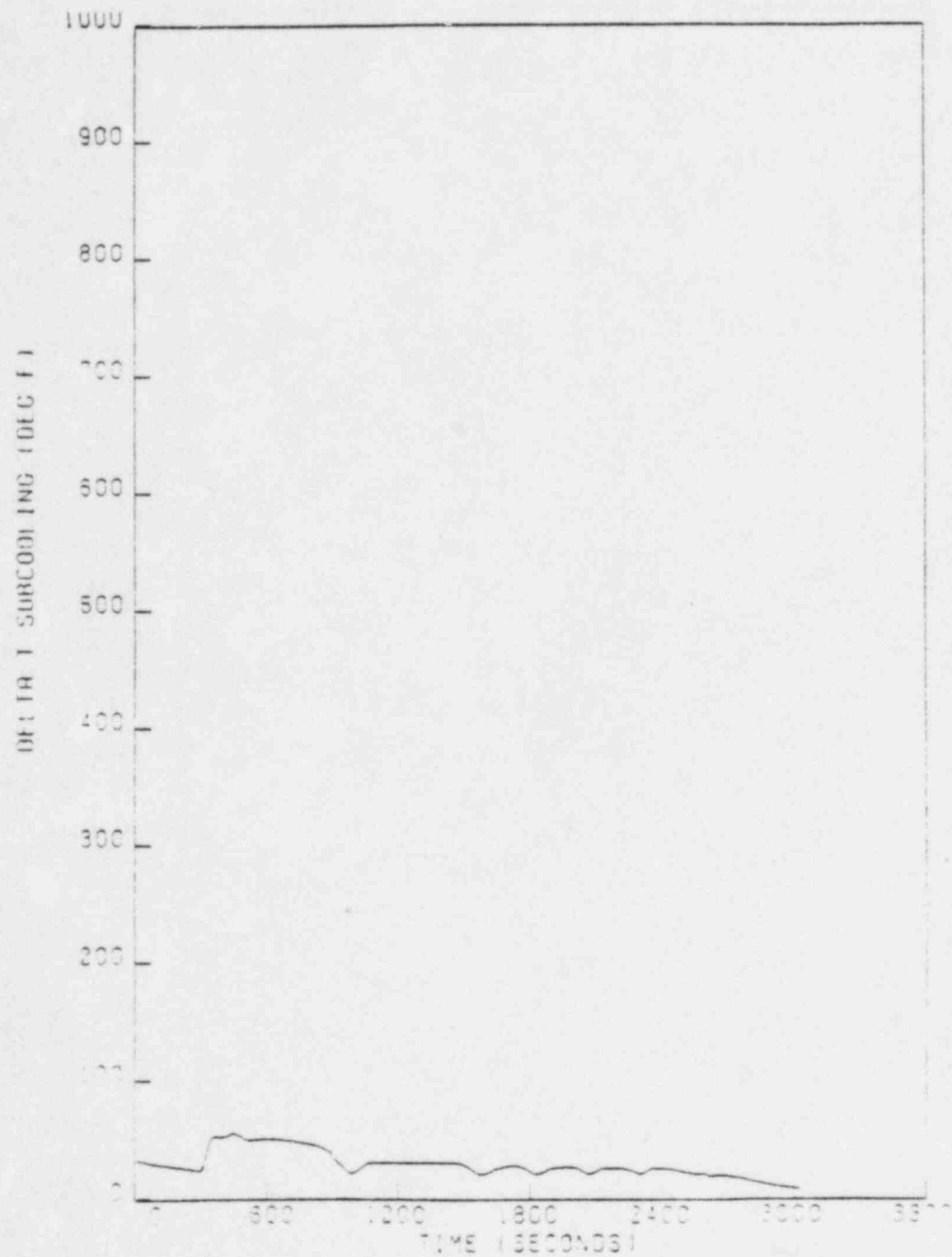


FIGURE 2.1-50

SGTR CASE 5
PZR PRESSURE

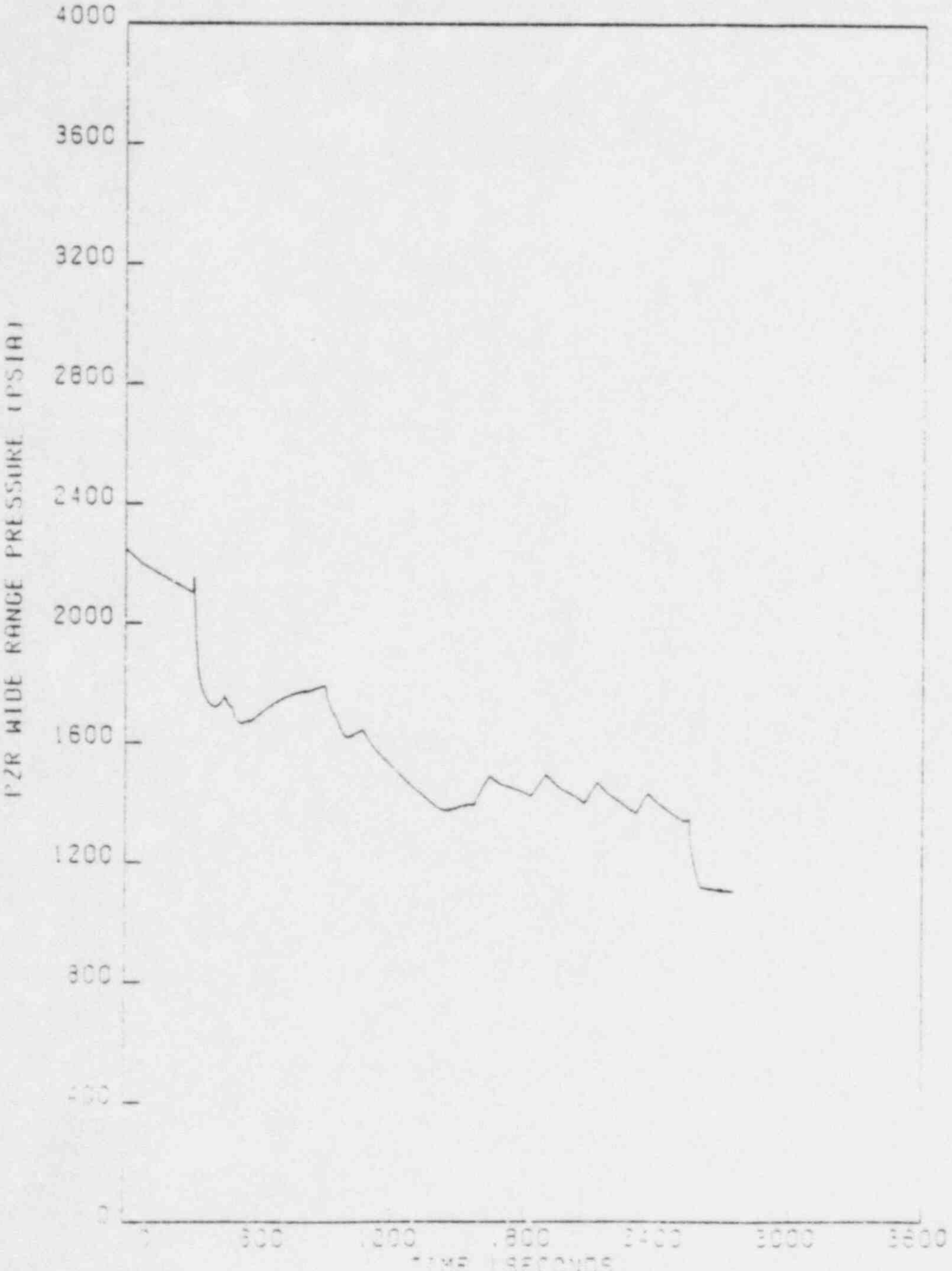


FIGURE 2.1-51

SGTR CASE 5
PZR LEVEL

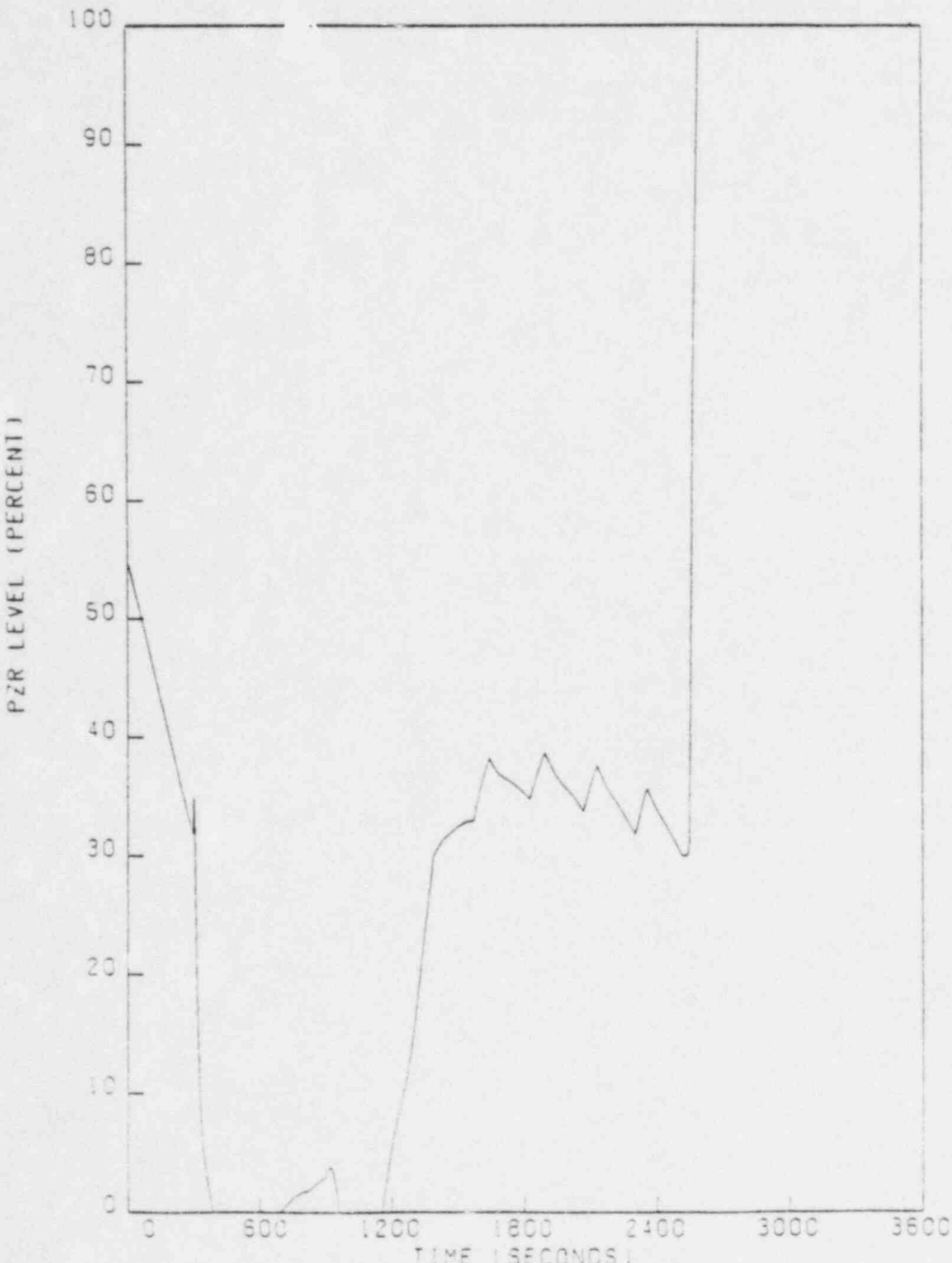


Figure 2.1-52

SGTR CASE 5
SG PRESSURES

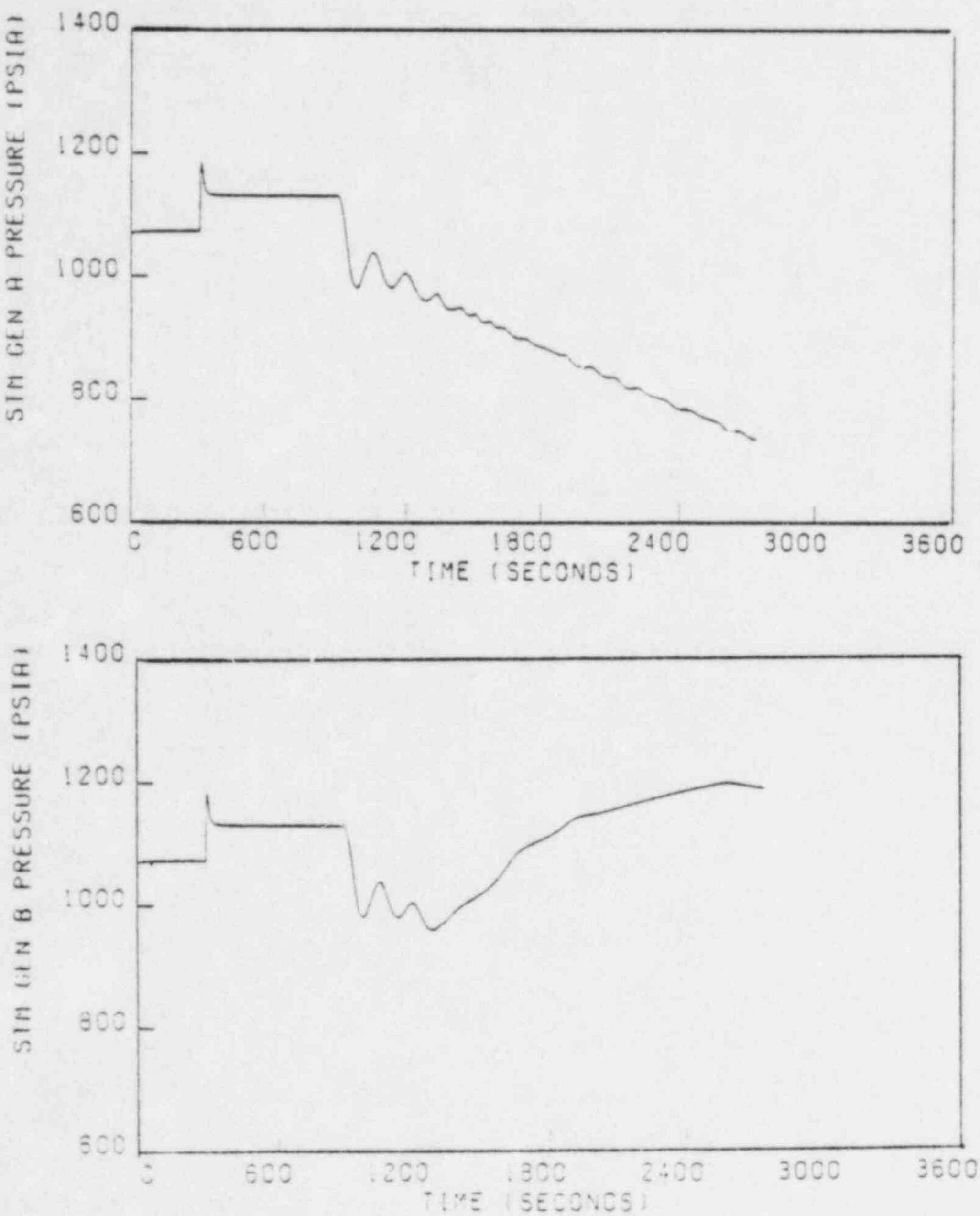


FIGURE 2.1-53

SGTR CASE 5
RVUH WATER VOLUME

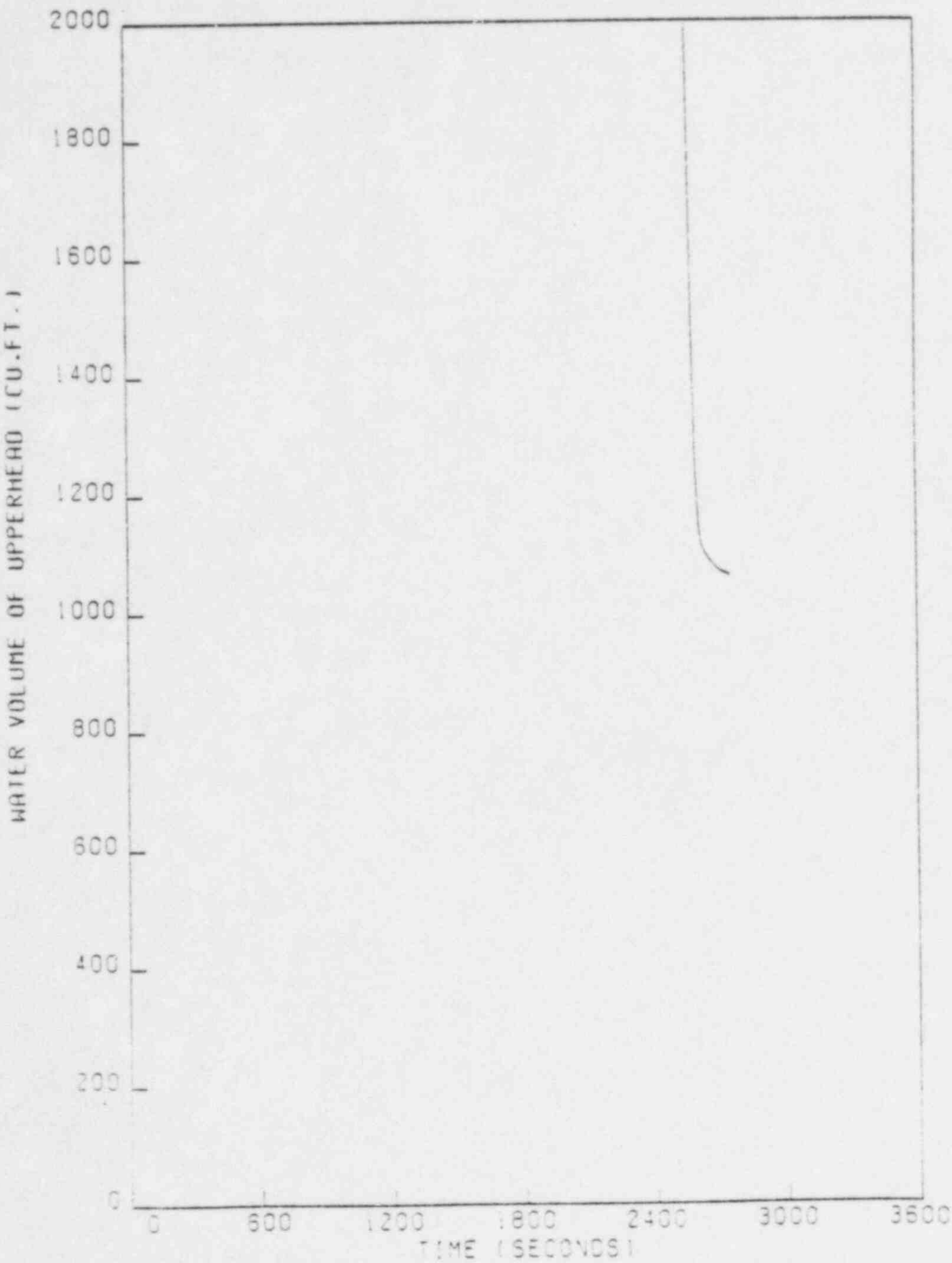


FIGURE 2.1-54

SGTR CASE 5
LEAK FLOWRATE

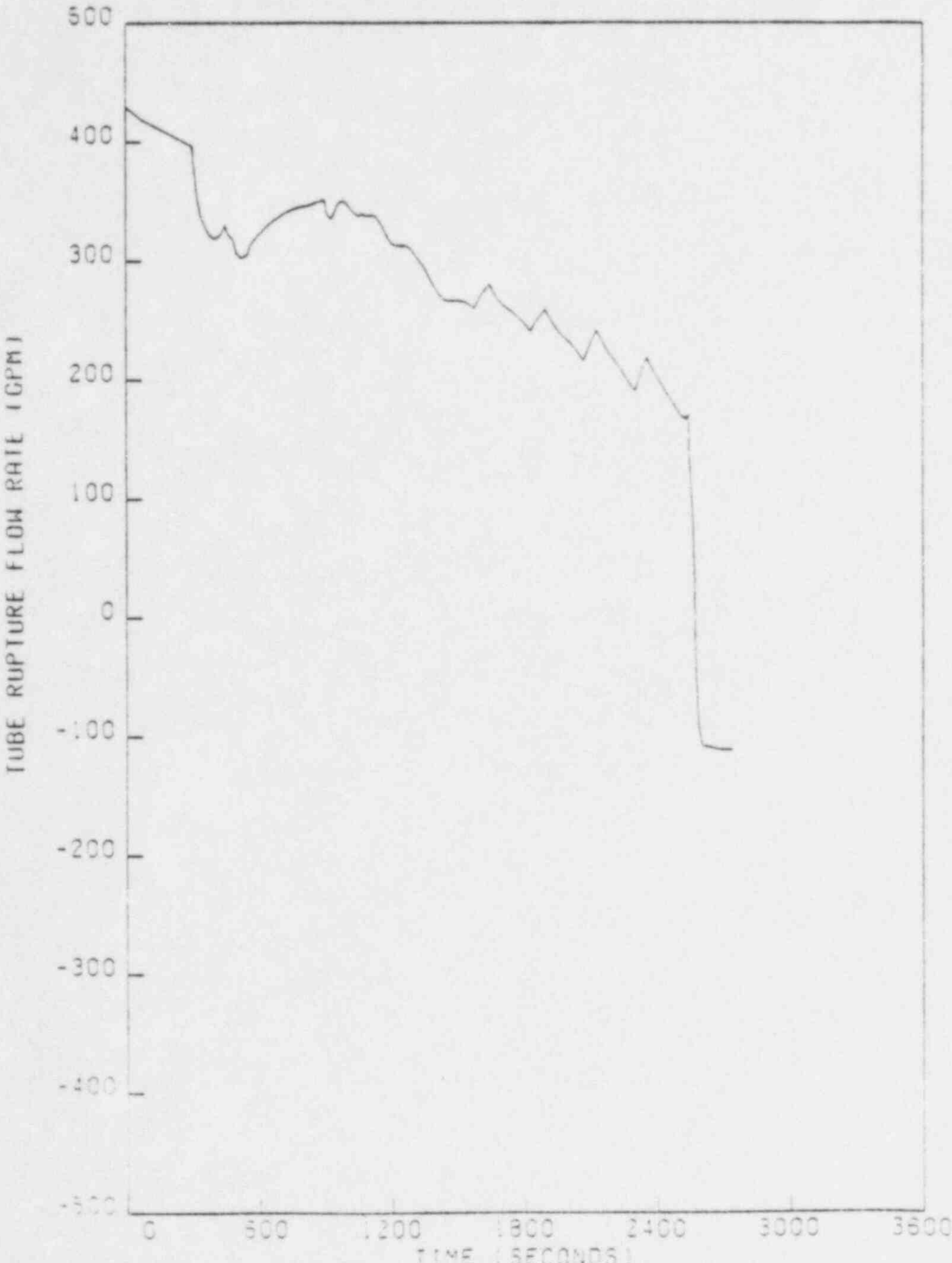


FIGURE 2.1-55

SGTR CASE 5
LOOP SUBCOOLING

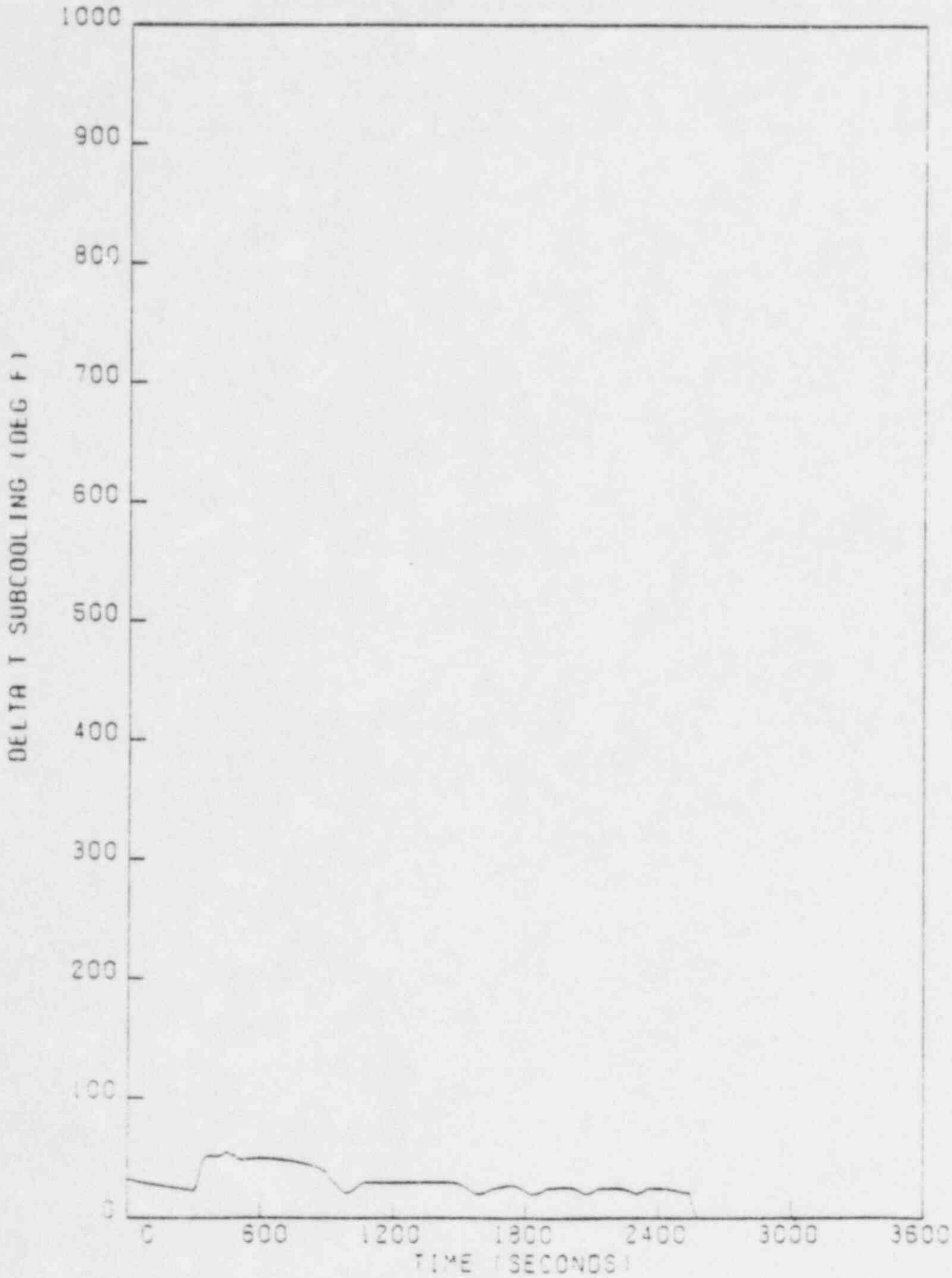


FIGURE 2.1-56

SGTR ANALYSIS
COMPARISON OF LEAK FLOWRATES
PRIOR TO RVUH STEAM BUBBLE FORMATION

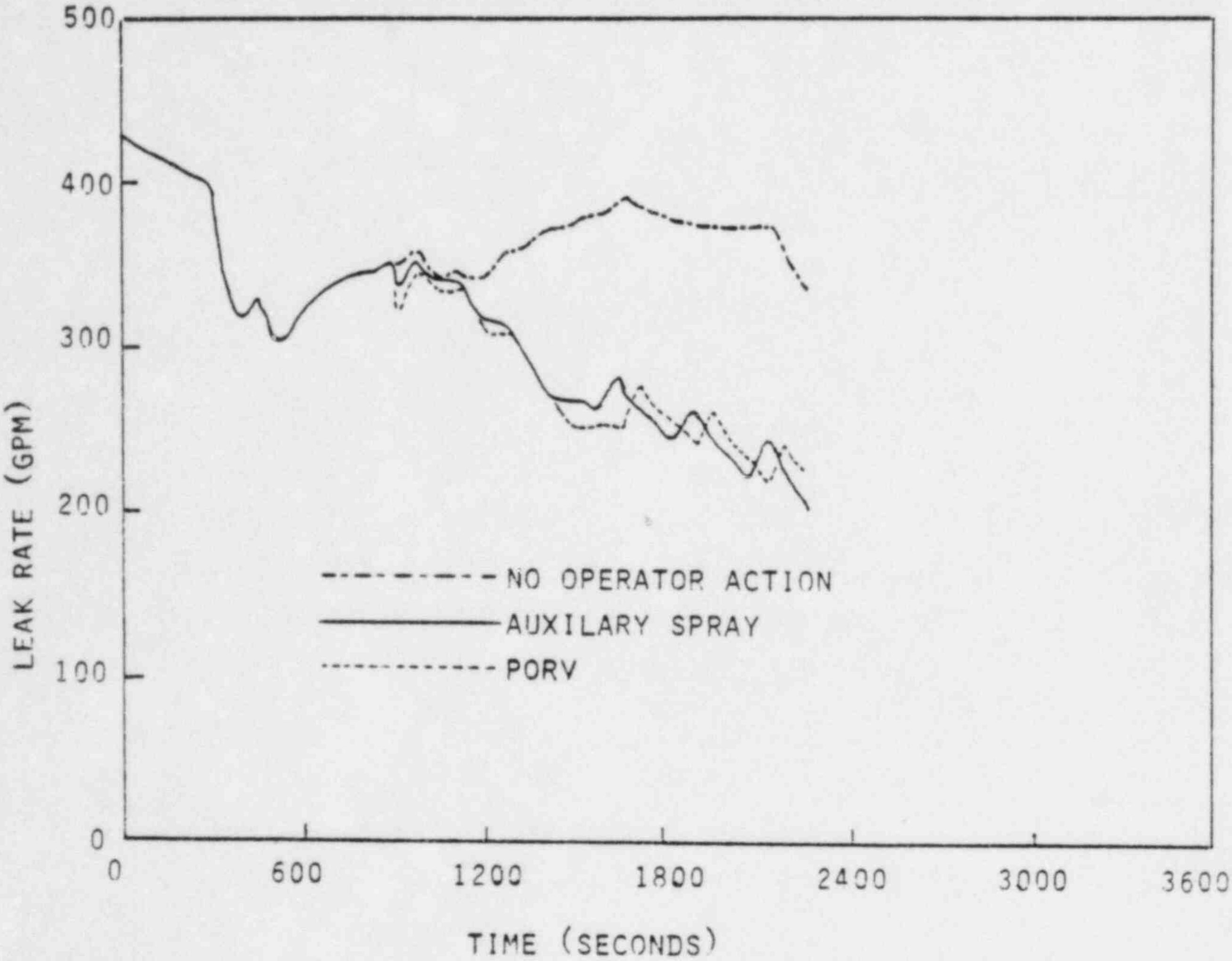


FIGURE 2.1-57

SGTR ANALYSIS
COMPARISON OF LEAK FLOWRATES
FOLLOWING RVUH STEAM BUBBLE FORMATION

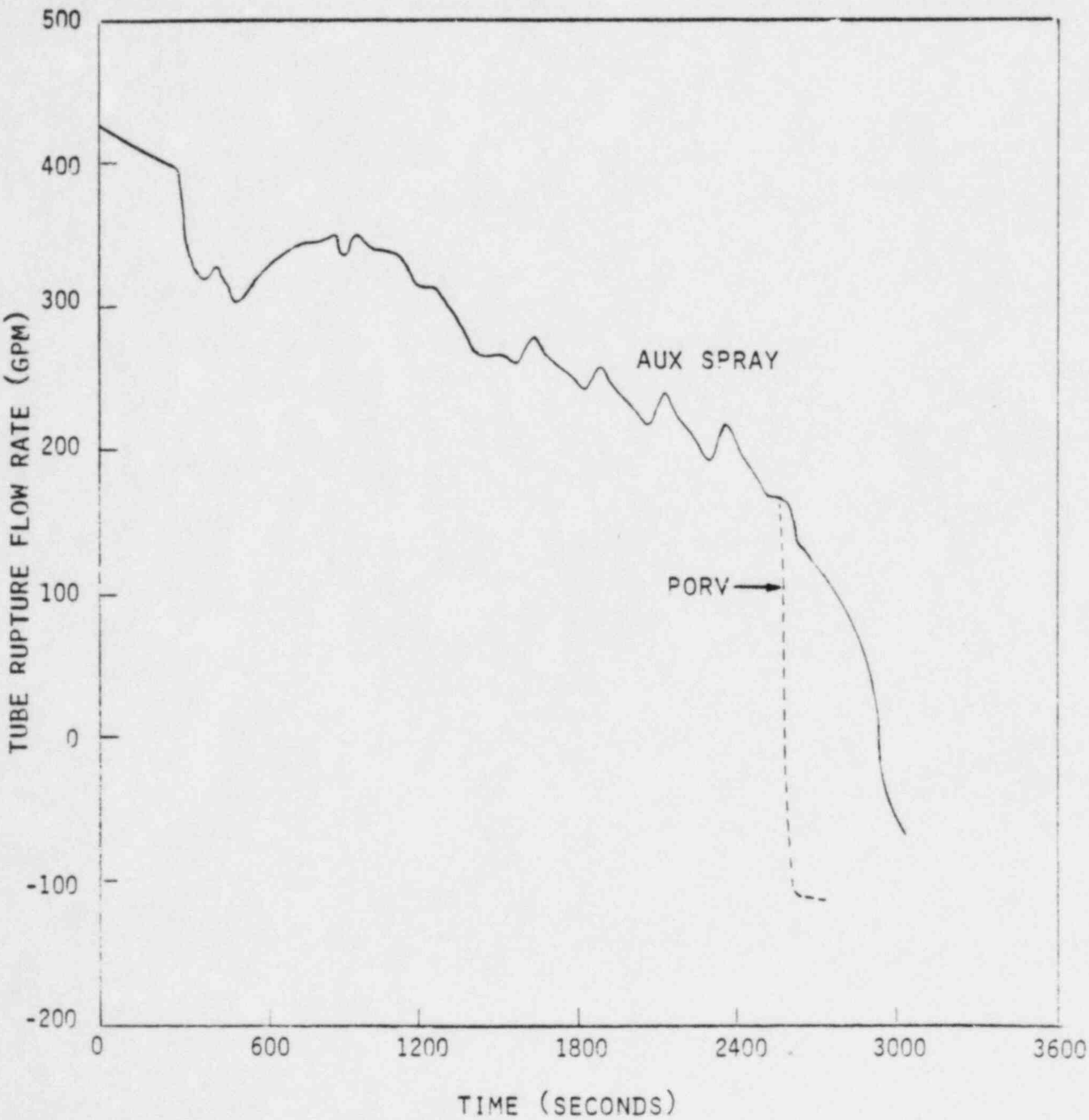


FIGURE 2.1-58

SGTR ANALYSIS
COMPARISON OF LOOP SUBCOOLING
WITH RVUH STEAM BUBBLE FORMATION

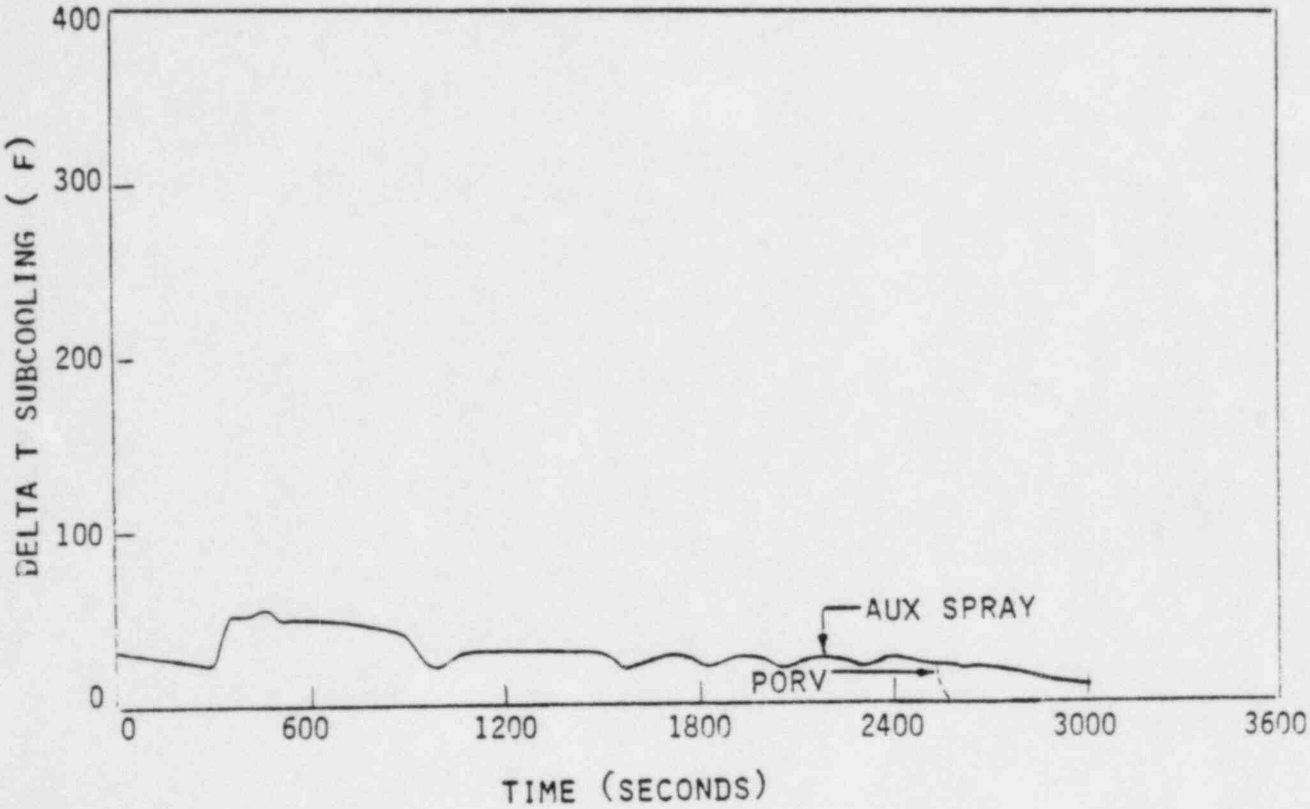
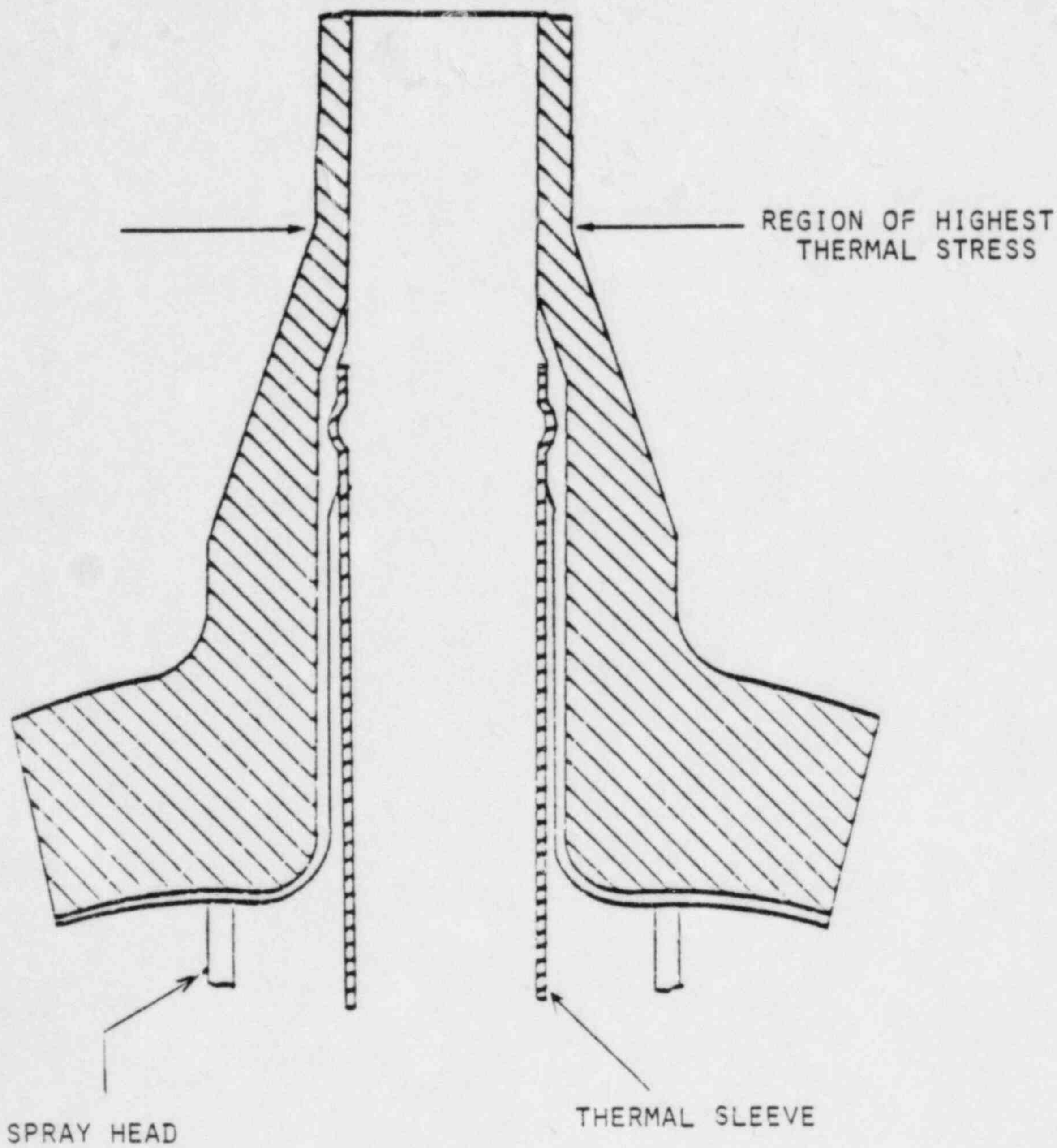


Figure 2.1-59

PRESSURIZER SPRAY NOZZLE SHOWING THERMAL SLEEVE AND REGION OF HIGHEST THERMAL STRESS



2.2 Question 2: Use of PORVs to Minimize Challenges to the RPS

In general, it is desirable to limit the number of challenges to the reactor protection system to minimize the probability of ATWS. Moreover, it is desirable to minimize the number of reactor trips during the lifetime of the plant for the following reasons: First, a ramp down in the reactor power will reduce the likelihood of a turbine trip. A turbine trip has the potential to cause a loss of condenser system and lift the secondary safety valves, increasing releases to the environment. Second, a controlled power reduction will increase the availability of the reactor coolant pumps. Third, a crud burst is less likely during a controlled reactor shutdown reducing the possibility of increasing coolant activity levels. Based on these considerations, as well as the lessons learned from the TMI-2 accident, how is the overall plant safety effected by the absence of PORVs?

2.2.1 Response to Question 2

The use of PORVs to minimize challenges to the RPS would require a continuously aligned fast acting valve with a setpoint below the setpoint of the reactor trip on high system pressure. This configuration is essentially the configuration employed at TMI-2 prior to the accident on 28 March 1979. In contrast to other PWR designs which use the PORVs to preclude high pressure reactor trips subsequent to significant load reductions, the principal function of these valves in the C-E design is to reduce the number of challenges to the pressurizer code safety valves that could result from certain overpressure transients. To change this philosphy and employ PORVs to minimize the number of reactor trips during the lifetime of the plant is undesirable since it could increase the probability of a relief valve initiated SBLOCA. In the sections that follow, background information will be presented along with data on C-E operating experience with PORVs. In addition, the reasons for deleting these valves from the 3410 and the 3800 Class designs will be detailed.

2.2.2 Background

Soon after the TMI-2 accident a reevaluation of the design features of that plant was conducted to determine what corrections or improvements were necessary in the basic design and in the operational philosophy in order to improve plant safety. The recommendations and requirements for improvements were then disseminated for use by the entire industry. One of the findings of the reevaluation was that the TMI-2 reactor appeared to be unusually sensitive to certain transient conditions originating in the secondary system. Further, certain features of this plant contributed to this sensitivity including actuation before reactor trip of a power operated relief valve on the primary system pressurizer which, if the valve sticks open, could aggravate the transient. As a result, holders of operating licenses for similarly designed reactors were instructed by IE Bulletins to decrease the reactor high pressure trip setpoint and to increase the pressurizer PORV setpoint to reduce challenges to these valves.

Table 2.2-1 (p. 115) lists operating pressures and various setpoint pressures for the TMI-2 reactor prior to the accident of March 1979, the TMI-2 reactor after the accident of March 1979, and C-E plants which incorporate PORVs in their design. Note that the relief valve setpoint for TMI-2 after the accident was increased to a pressure greater that of the reactor overpressure trip setpoint to reduce challenges to these valves. Also note that in the Combustion Engineering design the setpoint of the overpressure trip and the setpoint of the relief valves are identical. In fact, C-E PORVs are actuated by the same bistable trip units which actuate a reactor trip on high RCS pressure. In contrast to other PWR designs which use the PORVs to preclude high pressure reactor trips subsequent to significant load reductions, the principal function of these valves in the C-E design is to reduce the number of challenges to the pressurizer code safety valves that could result from certain overpressure transients. In order to deviate from this philosophy and employ the PORV function to reduce challenges to the RPS, as suggested by Question 2, a redesign of the PORV system would be

Table 2.2-1

CPERATING PRESSURE AND TYPICAL SETPOINTS FOR RELIEF VALVES, SAFETY VALVES, AND OVERPRESSURE TRIP

Parameter	Pre-TMI	Post-TMI*	C-E
Operating pressure (psia)	2155	2155	2250
Relief valve setpoint (psia)	2255	2450	2400
Overpressure trip (psia)	2355	2300	2400
Safety valve setpoint (psia)	2500	2500	2500

* Note that as a result of the TMI-2 accident the power operated relief valve setpoint was increased to a valve above that of the reactor trip on overpressure.

required with a subsequent change in the relief valve setpoint or the overpressure trip setpoint or both. If, for example, the relief valve setpoint remained unchanged at the value shown in Table 2.2-1 of 2400 psia, but the reactor trip setpoint on overpressure was raised to a value greater than 2400 psia but less than 2500 psia, a reduction in the number of reactor trips could be realized. This action would be undesirable, however, since it would require extensive reevaluation of the safety analysis in Chapter 15 of the FSAR, could delay the initiation of a reactor trip and therefore increase the probability of core damage for certain accidents, and would increase challenges to the code safety valves. As a second alternative, if the reactor trip setpoint on overpressure remained the same at the valve shown in Table 2.2-1 of 2400 psia, but the relief valve setpoint was lowered to a value less than 2400 psia, it would be possible to reduce the number of reactor trips. This action would also be undesirable, however, since it would increase the number of challenges to the PORVs and would be contrary to the general direction of the industry taken after TMI-2 which was to reduce, where possible, relief valve challenges. Note that C-E was in fact requested by the NRC Staff, see Reference 8, to investigate the possibility of minimizing PORV openings by raising, for example, the relief setpoint above that of the overpressure trip. Although this and several other possibilities for minimizing PORV openings were investigated, C-E's original design philosophy, i.e., activation of reactor trip and the power operated relief valves from same trip bistable, remained unchanged because it represented the optimum compromize with respect to minimizing challenges to the pressurizer code safety valves and minimizing challenges to the PORVs. (Reference 9 contains a complete summary of the various methods, other than changing of the relief valve and overpressure trip setpoint, used to reduce PORV failures on C-E plants).

2.2.3 C-E Operating Experience with PORVs

The early C-E NSSS design used PORVs as non-safety grade equipment to limit overpressure transients to below the pressurizer code safety valve setpoint. This function was intended to reduce challenges to the safety valves thereby minimizing weepage and minimizing the potential for leakage following safety valve actuation. PORVs were not intended to prevent a reactor trip on overpressure and were not credited in the plant safety analyses. PORVs were, however, intended to be used in conjunction with the overpressure trip to mitigate certain pressure transient. FSAR analysis for C-E operating plants indicate that relief valves would only be challenged during the course of a relative few of the analyzed transients. For transient that actually occur in operating plants, conditions are less severe than those postulated in the FSAR since initial conditions are generally less limiting, system failures are not as extensive, heat transfer coefficients are not as biased, etc. Of all the transients analyzed in the FSAR, only the loss-of-load events, the uncontrolled rod withdrawal event, and the loss of all non-emergency ac power event would actually result in lifting of a PORV.

Table 2.2-2 (p. 118) summaries the operating experience of PORVs in C-E plants based upon information supplied by the various plant operators and reported in Reference 9. The PORV actuations noted in Table 2.2-2 do not necessarily represents the total number which had occurred when the data was collected since PORV actuations were not reportable events and were therefore not routinely recorded. Table 2.2-3 (p. 119) summarizes the events resulting in an overpressure trip for which specific record of PORV actuation was not made. The information was complied from a review of published data obtained mainly from the NRC as stated in Reference 9. Since, by design, an overpressure trip should be accompained by PORV actuation, it can be inferred that actuation did in fact occur (except as noted) as a result of the trips in Table 2.2-3 although not specifically reported. Of the twenty-three incidents listed in Table 2.2-2 and in 2.2-3, fifteen resulted from a loss-of-load transient; of these fifteen, eleven were the result of a turbine runback condition. (Note that loss-of-load was the only transient which resulted in the opening of PORVs.) As stated in Reference 9, one of the actions taken to reduces challenges to the relief valves was to eliminate the turbine runback feature from all operating C-E plants.

Table 2.2-2

SUMMARY OF EVENTS INVOLVING PORV OPERATION

Plant	Date	Plant Conditions	Initiating Event	Comments
Consumers Power* Palisades	9-8-71	Mode 3	Technician deenergized RPS for maintenance.	PORV opened when RPS de-energized.
Baltimore Gas & Elec. Calvert Cliffs-1	7-6-79	Mode 5	Test of PORV.	During operational test of PORV valve failed to fully close. Adjusted pilot valve stroke.
Calvert Cliffs-2	8-20-80	Mode 1	MSIV closure.	PORVs cycled on high pressure.
Florida Power & Light St. Lucie-1	2-21-77	Mode 1	100% load rejection.	PORV cycled during test when reactor tripped on high pressure.
Omaha Public Power Dist. Fort Calhoun	5-28-78	Mode 1	Turbine control valve closed.	PORVs cycled when plant tripped on high pressure.
	12-20-78	Mode 5	Troubleshooting pressure recorder.	PORVs opened when technician pulled recorder fuses.
Northeast Utilities Millstone-2	8-10-79	Mode 5	Troubleshooting.	PORV opened on loss of ac to emergency bus.
Maine Yankee Atomic Power Company				
Maine Yankee	No PORV operation events.			

*Palisades has operated since 1972 with both PORV block valves shut.

Table 2.2-3

SUMMARY OF EVENTS RESULTING IN OVERPRESSURE TRIPS FOR WHICH NO SPECIFIC RECORD OF PORV ACTUATION WAS NOT MADE

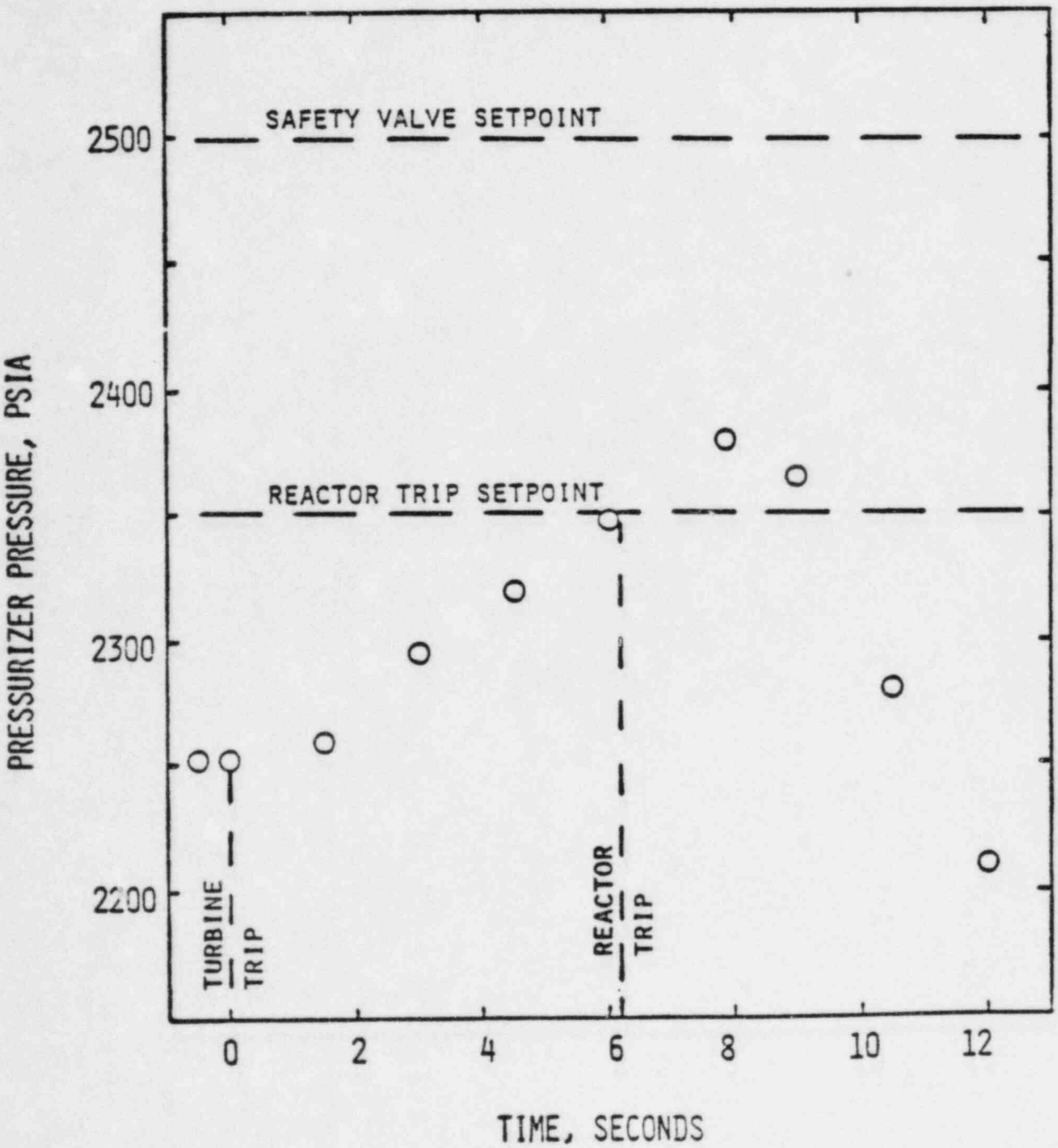
Plant	Date	Initial Power	Initiating Event	Comments
Consumers Power* Palisades	3-19-73	85%	Circuit noise.	Spurious high pressure trip.
	8-31-76	100%	MSIV shutting.	High pressure trip due to MSIV shutting.
	11-26-79	15%	Generator synchronizaing.	Spurious high pressure trip while bringing generator on line.
	5-22-78	100%	Closure of both MSIVs.	High pressure trip.
Baltimore Gas & Elec. Calvert Cliffs-1	7-08-75	100%	Turbine runback.	High pressure trip via turbine runback. Unable to verify PORV operation due to loss of plant computer.
	1-26-75	20%	Power reduction with manual pressurizer spray control.	High pressure trip.
Northeast Utilities Millstone-2	4-13-76	80%	Turbine runback.	High pressure trip.
	4-23-76	100%	Turbine runback.	High pressure trip.
	5-10-76	100%	Turbine runback.	High pressure trip.
	5-24-76	100%	Turbine runback.	High pressure trip.
	5-25-76	100%	Turbine runback.	High pressure trip.
	6-08-76	100%	Turbine runback.	High pressure trip.
	6-10-76	100%	Turbine runback.	High pressure trip.
	6-19-76	100%	Turbine runback.	High pressure trip.
	6-21-76	100%	Turbine runback.	High pressure trip.
	8-13-76	100%	Turbine runback.	High pressure trip.

* Palisades has operated since 1972 with both PORV blocking valves shut, therefore PORV actuation did not result in discharge.

As each of the early Combustion Engineering plants became operational and data began to be compiled, the effectiveness of such systems as the pressurizer spray system, the SBCS, etc., to limit pressure transients was demonstrated. As a result, C-E was unable to substantiate any real advantages in opening PORVs during most overpressure transients in order to reduce challenges to the pressurizer code safety valves. In addition it was determined that code safety valve weepage occurred at pressures below normal operating pressure and not as a result of increases in system pressure approaching the safety valve setpoint. When this experience was considered along with the potential for spurious relief value operation and relief valve leakage problems, C-E decided to remove PORVs from its NSSS design beginning with Arkansas (ANO-2) and including the 3410 and the 3800 Class plants. As a demonstration of the ability to mitigate the pressure transient following a loss-of-load without PORVs, a turbine trip from 100% power was performed on ANO-2 in January of 1980. Figure 2.2-1 (p. 121) shows pressurizer pressure response during the first twelve seconds of the test. A brief outline of the initial sequence of events is as follows: main turbine tripped at time zero, steam bypass control valves open and main spray initiated at two seconds, automatic reactor trip occurs at six seconds, and peak pressure is reached at approximately eight seconds. Note that the combination of main spray and the SBCS alone, i.e., no PORVs, in conjunction with the reactor trip was sufficient to limit peak pressure to less than 2400 psia.

Figure 2.2-1

RCS PRESSURE DURING ANO-2 TURBINE TRIP TEST



2.3 Question 3: Effect of PORV on ATWS

Even though the Commission has not approved a final ATWS rule, the ability to limit RCS pressure rise in an ATWS event is being contemplated for most LWR designs. Address the advantages and disadvantages of PORVs from the ATWS standpoint.

2.3.1 Response to Question 3

Although the addition of PORVs to the 3410 and the 3800 Class plants could provide additional relief capacity to mitigate peak RCS pressure resulting from an ATWS, it should be realized that use of a PORV for this purpose would require a continuously aligned fast acting capability. Such a configuration would increase the susceptibility to a relief valve initiated SBLOCA and may not be consistent with other PORV functions being evaluated. For example if these valves were added in order to provide a primary feed-and-bleed capability for decay heat removal, the line-up that would be specified during power operations would be one that required both relief valves and blocking valves to be closed in order to prevent inadvertent initiation. In addition, other possibly more viable solutions are being considered by the NRC Staff to the ATWS problem including improvements in the reactor shutdown system reliability and redesign of the turbine generator trip function.

In order to determine the exact size of relief valve that would be required to properly mitigate ATWS for the 3410 and the 3800 Class plants and to provide a comparison to existing relief valve design, a detailed parametric analysis was performed. For this analysis, the total relief area currently provided by the pressurizer code safety valve for each class of plant was increased parametrically in order to determine the additional relief area needed to limit peak RCS pressure to 3200 psia (ASME Boiler and Pressure Vessel Code Stress Level C) during the transient. Two cases were examined for each class of plant. The first case assumes current plant design and the second case assumes a safety-grade turbine trip upon receipt of a reactor trip signal. As stated below for the current plant design, an additional 0.05 ft^2 of relief area beyond that provided by the pressurizer code safety valves was required for the 3800 Class plant, and an additional 0.15 ft^2 of relief area was required for the 3410 Class plant. For the case which assumed a safety-grade turbine trip, no additional relief area was required for the 3800 Class plant and an additional 0.10 ft^2 was required for the 3410 plants. For comparison, the relief area of a typical PORV currently installed in C-E operating plants is 0.0095 ft^2 for a total PORV area (two valves per plant) of 0.019 ft^2. (Note that St. Lucie Unit 2 is the only exception in that they have two relatively large PORVs with a total area of 0.048 ft^2.)

2.3.2 ATWS Background

ATWS is a postulated event characterized by two features: 1) An anticipated transient, i.e., one which is expected to occur one or more times in the life of the reactor, and 2) No automatic or manual shutdown of the reactor by normal reactor protection system insertion of control rods. Anticipated transients may occur with a frequency as high as once or more per reactor year. Their consequence are normally mitigated by a combination of automatic reactor shutdown and various thermal-hydraulic functions performed by plant safety equipment. The principal mechanism which has been hypothesized to produce the failure to insert control rods is a common mode malfunction of identical components in all channels of the RPS.

In 1976 C-E performed an analysis to identify the postulated transient which produced the most adverse conditions for ATWS events relative to the limiting criteria proposed in Reference 10. The analysis documented in Reference 11, determined that the loss-of-feedwater ATWS produced the greatest challenge to the NSSS in terms of peak RCS pressure. In response to an NRC request for further information, the ATWS analysis documented in Reference 12 was performed. Since peak RCS pressure and associated system stresses are the primary concerns during an ATWS, only the LOFW ATWS was analyzed. The results presented in Reference 12 used modified and improved methods for analysis. One of the primary differences between the results in Reference 11 and the results in Reference 12 is that reactor vessel O-ring seal leakage was credited in the later analysis.

In response to a proposed rulemaking for ATWS events, the C-E Owners Group commented on the proposed rules in April of 1982 (Reference 13) by submitting a reanalysis of the LOFW ATWS using improved modelling of the steam generator primary-to-secondary heat transfer process and crediting a turbine trip at the start of the event. The purpose of the reanalysis was to inform the NRC Staff that the risks from the ATWS for C-E plants are less than had been previously thought. The combination of the turbine trip, if credited, and the improved heat transfer model led to a reduction in peak pressure and a significant reduction in the amount of primary coolant which leaked at the vessel head closure.

2.3.3 ATWS Analysis Assumptions

This analysis will determine the PORV size required to satisfy the ASME Boiler and Pressure Vessel Code Level C stress limit during an ATWS event for the 3410 Class plant and the 3800 Class plant. To do this, the total relief area was increased from the current area provided by the pressurizer code safety valves until the peak RCS pressure during the ATWS fell below the Level C limit. For this analysis, Level C was defined as 3200 psia as was done in the Reference 12. The major assumptions and methods used for this analysis are as follows:

1. A modified version of the best estimate ATWS code was employed using an improved primary-to-secondary heat transfer model. The code models the steam generator secondary as a single control volume for mass and energy conservation. The improved heat transfer model maintains this basic model, but for the purposes of heat transfer, segments the tube bundle region. Within each segment the local heat transfer coefficient is based on the local quality. A boiling curve has been generated for the saturated boiling, transition boiling, and film boiling heat transfer regimes. Heat transfer to steam is assumed to be zero. In order to calculate the local quality, a drift flux phase separation treatment is employed. The model calculates the axial distribution of steam based on the linear bubble production rate (boiling) within a segment and a steady-state bubble balance. This version of the best estimate code is the same version which was used in the CEOG comments on the proposed ATWS rulemaking in Reference 13.

2. The loss of feedwater ATWS was used for this analysis since previous analyses indicated that this event yielded the highest peak RCS pressure.

3. The initial conditions, control system status, and manual actions are consistent with those used in Reference 12 and are listed in Table 2.3-1 (p. 127).

4. For Case 1, a turbine trip was not assumed as was done in Reference 13 since this feature cannot be credited with the current design. For Case 2, a turbine trip upon receipt of a reactor trip signal was credited for comparison with Case 1.

Table 2.3-1

PERTINENT PLANT PARAMETERS USED FOR ATWS ANALYSIS

Parameter	3800 Plant	3410 Plant
Core		
Initial power (Mw)	3817	3410
Moderator temperature coefficient, (10^{-4} $\Delta\rho$/°F)	-0.68	-0.63
Reactor Coolant System		
Reactor coolant mass (lbm)	550,070	509,740
System volume, including pressurizer and surge line (ft^3)	13,897	11,800
Initial inlet temperature (°F)	565.0	553.0
Average temperature (°F)	594.5	584.4
Reactor vessel flow (gpm)	458,960	396,025
Maximum CVCS charging pump flow (gpm)	128	128
Initial pressure (psia)	2250	2250
Pressurizer		
Total volume (ft^3)	1850	1500

Table 2.3-1 (cont'd.)

Parameter	3800 Plant	3410 Plant
Initial water volume (ft^3)	900	800
Pressurizer area (ft^2)	50	50
Number of pressurizer code safety valves	4	2
Safety valve setpoint (psia)	2525	2525
Safety valve rated flow (lbm/hr/valve)	504,874	462,542
Opening pressure of proportional spray valve (psia)	2275	2275
Maximum proportional spray flow (gpm)	375	375
Full open pressure of proportional spray valve (psia)	2300	2300
Secondary System		
Initial steam generator pressure (psia)	1070	900
No load steam generator pressure (psia)	1170	1000
Steam generator full load liquid inventory (lbm)	163,700	164,000
Steam generator full load steam inventory (lbm)	15,500	13,000

Table 2.3-1 (cont'd.)

Parameter	3800 Plant	3410 Plant
Full power steam flowrate (lbm/hr)	1.7×10^7	1.5×10^7
Auxiliary feedwater flow capability (gpm/SG)	875	700
Auxiliary feedwater enthalpy (Btu/lbm)	80	80

2.3.4 ATWS Analysis Results

A typical sequence of events for the LOFW ATWS for a plant without PORVs is provided in Table 2.3-2 (p. 131). Note that this sequence does not include a safety-grade turbine trip. The times listed in this table are approximate in that slight differences in design such as safety valve capacity, various setpoints, auxiliary feedwater actuation, etc., will affect the transient. The loss of main feedwater produces a small initial increase in steam generator pressure and temperature. As inventory is depleted the secondary system can no longer remove all of the heat generated in the reactor core and RCS temperatures begin to increase at a moderate rate. The increase in temperature results in an insurge of expanding reactor coolant into the pressurizer which in turn results in an increase in system pressure. As the steam generator inventory is further depleted, a reactor trip on low steam generator level is actuated and pressurizer water level and hence pressure increase further. Pressure will continue to increase, a reactor trip on high pressurizer pressure will be generated, and the code safety valves will open. (Note that in the ATWS scenario, the trips generated by the RPS do not result in a scram.) Further expansion of reactor coolant results in filling of the pressurizer and a sharp increase in RCS pressure as the volumetric discharge capacity of the safety valves is exceeded. The sharp increase in pressure is postualed to produce leakage through the reactor vessel flange O-ring seal and within a few seconds of O-ring leakage, peak RCS pressure is reached. Pressure will now fall as heat generation in the core decreases due to moderator reactivity feedback and the reactor vessel flange will reseat. Eventually the code safety valves reseat and boration is manually initiated to shut the reactor down.

In order to perform the analysis for Case 1 (no turbine trip), PORVs of an assumed area were opened at approximately 25 seconds, see Table 2.3-2, upon receipt of the high pressure trip signal. The assumed area was varied parametrically and the peak RCS pressure determined. The results are shown in Figure 2.3-1 (p. 132) and Figure 2.3-2 (p. 133) and are summarized below.

Table 2.3-2

TYPICAL SEQUENCE OF EVENTS DURING LOFW ATWS

Time (Seconds)	Event
0	Loss of all main feedwater flow
16-19	High pressurizer pressure and level alarms
22	Low steam generator level reactor trip signal
25	High pressurizer pressure reactor trip signal
32	Auxiliary feedwater flow begins
52	Steam generator tubes begin to uncover
56	Pressurizer safety valves open
65	Low steam generator pressure reactor trip signal, MSIS
73	Pressurizer fills
78	Vessel flange O-Ring seal leakage begins
80	Minimum steam generator secondary liquid inventory
82	Maximum RCS pressure
90	Vessel head reseats on vessel flange
103	Maximum RCS average temperature
214	Pressurizer steam bubble reforms
218	Pressurizer safety valves close
600	Operator manually initiates soluble poison injection

FIGURE 2.3-1

3800 CLASS PLANT
RELIEF AREA VS PRESSURE FOR LOFW ATWS

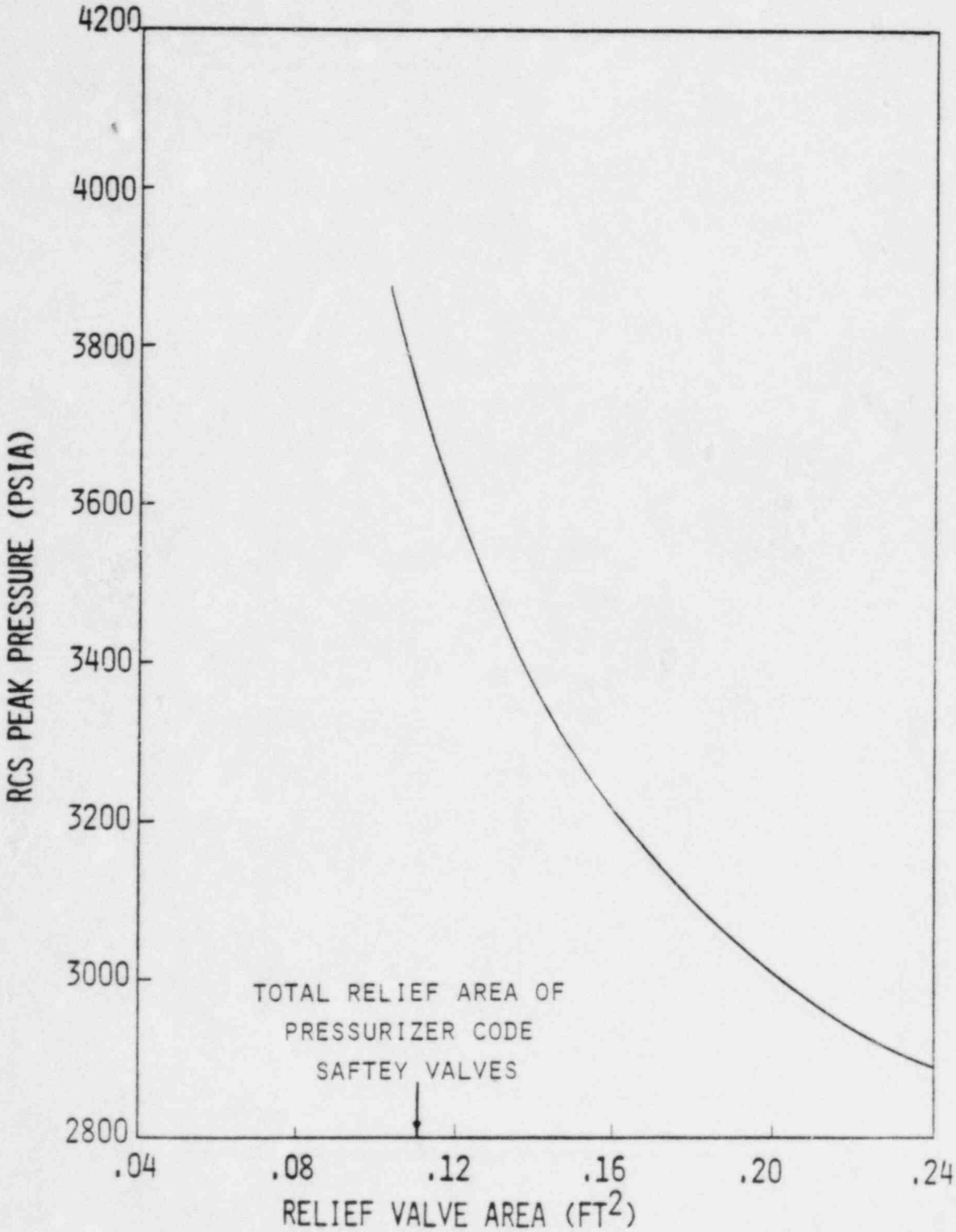
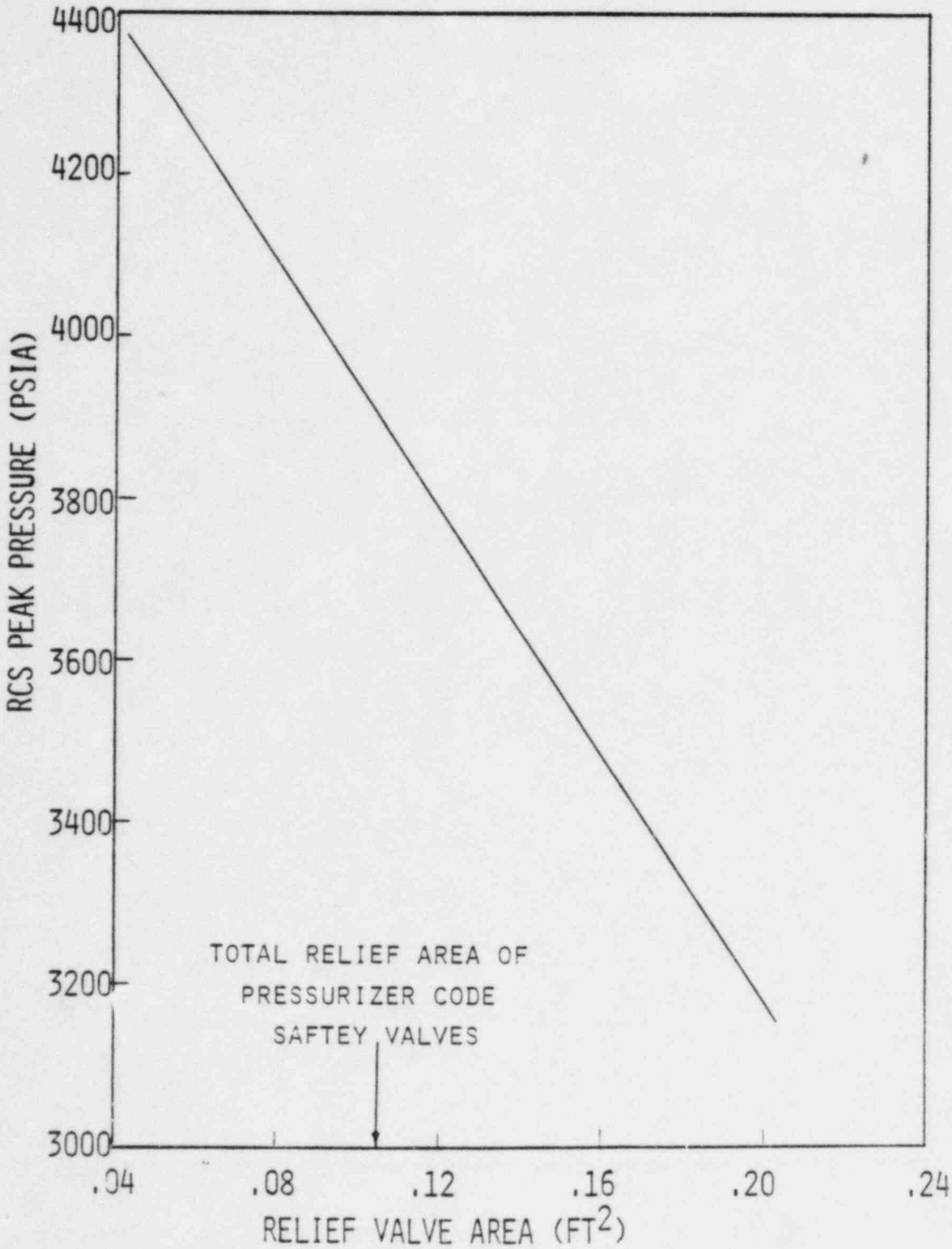


FIGURE 2.3-2

3410 CLASS PLANT
RELIEF AREA VS PRESSURE FOR LOFW ATWS



1. 3800 Class Plant - No Turbine Trip

Reference 12 used a primary safety valve rated flow of 20.2×10^5 lbm/hr for the 3800 class plant (total area of $\sim$0.11 ft^2). The results of this study indicate that 50% additional relief capacity ($\sim$0.05 ft^2) is required to limit the peak pressure during a LOFW ATWS to 3200 psia. This corresponds to a total relief area of $\sim$0.16 ft^2.

2. 3410 Class Plant - No Turbine Trip

The primary safety valve rated flow for the 3410 class plant, see Reference 12, is 9.25×10^5 lbm/hr (total area of $\sim$0.05 ft^2). The results of this analysis indicates that slightly less than four times this amount is required to limit the peak pressure to 3200 psia. This corresponds to an increase of 0.15 ft^2 for a total relief area of 0.20 ft^2.

The analysis for Case 2 (safety-grade turbine trip credited) was performed in a similar manner as the analysis for Case 1 in that PORVs of an assumed area were opened upon receipt of the high pressure trip signal. The assumed area was then varied parametrically and the peak RCS pressure determined. The results are summarized below.

1. 3800 Class Plant - Turbine Trip Credited

The results of this study indicate that no additional relief capacity is required to limit peak pressure during a LOFW ATWS to 3200 psia.

2. 3410 Class Plant - Turbine Trip Credited

The results indicate that an additional 0.10 ft^2 of relief area is required to limit peak pressure to 3200 psia.

2.3.5 ATWS Analysis Conclusions

The results of the analysis to determine the increased relief capacity required to limit peak RCS pressure to 3200 psia during ATWS are summarized in Table 2.3-3 (p. 136). The addition of PORVs to the 3410 and the 3800 Class plants could provide additional relief capacity to mitigate peak RCS pressure resulting from ATWS; however, this solution may not be viable because of the size of the valve that would be required and the system alignment. Considering current plant design, i.e., no turbine trip, the increased relief area noted in Table 2.3-3 for the 3410 plants is three times greater than the total area of the two PORVs installed in the C-E designed St. Lucie 2 plant and eight times larger than total area of the two PORVs typically installed in operating C-E plants. In addition, use of a PORV for ATWS mitigation would require a continuously aligned fast acting capability. Such a configuration would increase the susceptability to a relief valve initiated SBLOCA and may not be consistent with other relief valve functions being evaluated.

Table 2.3-3

ATWS ANALYSIS RESULTS

Plant Class	Peak RCS Pressure (psia)# No Turbine Trip	Peak RCS Pressure (psia)# With Turbine Trip	Additional Relief Area (ft^2)* No Turbine Trip	Additional Relief Area (ft^2)* With Turbine Trip
3410	4290	3943	∿ 0.15	∿ 0.10
3800	3800	2918	∿ 0.05	0

\# Peak pressure during ATWS analysis with no PORVs.

* Additional relief area required to limit peak RCS pressure to less than 3200 psia.

2.4 Question 4: Effect of PORVs on PTS

A PORV or other direct depressurization methods may be a viable technique for mitigating pressurized thermal shock (PTS). Address the exclusion of the PORV from the CESSAR-80 design considering PTS.

2.4.1 Response to Question 4

The cooldown transient due to a full steam line break represents the most challenging cooldown transient for a C-E NSSS for a single event design basis accident. This event coupled with a subsequent repressurization to the code safety valve setpoint represents the highest possible pressure challenge to a plant without PORVs in the PTS scenario. An analysis was performed to evaluate two very severe postulated overcooling events without the use of PORVs with the system assumed to repressurize to the primary system safety valve setpoint pressure of 2500 psia. The two PTS events considered were an intermediate size main steam line break and a small main steam line break since earlier studies have shown that this size range is more challenging for PTS than larger size breaks. For the intermediate size MSLB event a break flow area of 1.29 ft^2 was chosen for the analysis. This area corresponds to the System 80 (3800 Class plant) steam line flow restrictor area. A break flow area of 0.5 ft^2 was selected for the small MSLB event. The analyses were performed for the 3800 Class plant, and the results are applicable to the 3410 Class. Based upon linear elastic fracture mechanics analyses, the effects of the MSLB with subsequent repressurization have been evaluated to determine that vessel materials in the 3410 and the 3800 Class plants have considerable margin beyond the total accumulated fluence predicted at end-of-life to withstand this PTS event without the need for further mitigation by PORVs.

2.4.2 Thermal-Hydraulic Evaluation

This section presents the results of a thermal-hydraulic evaluation of the main steam line break accident for input to the pressurized thermal shock stress analyses. Both an intermediate size and a small SLB are evaluated in order to show the sensitivity of the results to break area.

In order to illustrate how the PTS concern arises, a qualitative discussion follows of a representative SLB transient in a C-E NSSS. It is assumed that a break occurs in the main steam piping upstream of the main steam isolation valve associated with one steam generator, to be referred to as the "affected" steam generator. The break increases steam flow from both steam generators, steam generator pressures and temperatures decrease, and heat removal from the reactor coolant system increases. Low steam generator pressure causes both a reactor trip signal and a main steam isolation signal. Reactor trip terminates fission power generation; MSIS terminates blowdown of the unaffected steam generator by closing the MSIVs and terminates main feedwater flow to both steam generators by closing MFIVs. A low steam generator water level signal in the affected steam generator will not start the auxiliary feedwater flow due to the inclusion of automatic AFW control logic based on steam generator pressure difference for all C-E non-PORV plants. The affected steam generator will dry out and RCS cooldown will terminate. If a low water level is present in the intact steam generator, the AFW control logic will initiate feed flow to the intact steam generator.

During the RCS cooldown transient, pressurizer pressure decreases to the safety injection actuation signal setpoint. An SIAS starts two high pressure safety injection pumps and three charging pumps. In addition, following SIAS on low pressurizer pressure the operator will trip all four reactor coolant pumps. The HPSI pumps will rapidly repressurize the RCS to the HPSI pump shutoff head, and the charging pumps will further pressurize the RCS, but at a lower rate.

Conditions identified in the emergency procedures for termination of emergency core cooling flow will be reached and charging and HPSI pump flow will be reduced in order to terminate RCS repressurization. The PTS concern arises due to the rapid decrease of reactor coolant temperature in the reactor vessel downcomer. PTS effects are increased by subsequent repressurization of the RCS by the charging and HPSI pumps.

In order to bound the PTS effects of an SLB, the evaluation was performed for an SLB occurring during hot zero power operation. This mode of operation maximizes RCS cooldown because steam generator water inventory is large and core decay heat is low. To further bound PTS effects, the breaks were evaluated with the assumption of no moisture carryover during the blowdown transient. This assumption maximizes total energy removal from the affected steam generator and, therefore, maximizes integral RCS heat removal.

A complete list of assumptions and plant parameters used for the SLB thermal-hydraulic evaluation for the two SLB cases is provided in Table 2.4-1 (p. 140). While not all of these assumptions and parameters have been chosen to maximize PTS effects, results are expected to provide an upper bound on the magnitude of RCS cooldown which can occur during an SLB. This is primarily due to the following combination of assumptions: 1) Hot zero power operating mode, 2) No moisture carryover, and 3) Zero decay heat. The results of the thermal-hydraulic evaluation of the intermediate size SLB (Case 1) are provided in Figures 2.4-1 and 2.4-2. (All figures for Section 2.4 of this report are contained together at the end of the section (p. 145).) Figure 2.4-1 shows the water temperature versus time in the reactor vessel downcomer. The downcomer water temperature was obtained assuming complete mixing of the cold leg flow with HPSI and charging pump flow. Figure 2.4-2 shows the downcomer pressure versus time. A rapid repressurization to the HPSI pump shutoff head can be seen with subsequent repressurization at a lower rate by the charging pumps. Operator action to terminate charging pump flow prior to reaching the pressurizer safety valve setpoint was not credited. These pumps are assumed to be manually shut off, however, at thirty minutes.

Table 2.4-1

ASSUMPTIONS AND PLANT PARAMETERS USED FOR SLB THERMAL-HYDRAULIC EVALUATION

Parameter	VALUE Case 1 (Intermediate Size SLB)	 Case 2 (Small SLB)
Steam flow area (ft^2)	1.29	0.05
Blowdown quality	1.0	1.0
Initial power level	0.0	0.0
Decay heat level	0.0	0.0
MSIS setpoint (psia)	820	820
SIAS setpoint (psia)	1600	1600
HPSI Pump shutoff pressure (psia)	1975	1975
AFW flow	0.0	0.0
Operator actions:		
a. Trip RCPs after SIAS on low pressurizer pressure (seconds)	30	30
b. Terminate charging flow (seconds)	1800	1800

Figures 2.4-3 and 2.4-4 show downcomer temperatures and downcomer pressures, respectively, for the small SLB (Case 2). The results for Case 2 are based upon an analysis performed for a 2600 Mw plant with the downcomer pressure scaled up to correspond to the higher shutoff head of the System 80 HPSI pumps.

2.4.3 Fracture Mechanics Analysis

2.4.3.1 Results of Fracture Mechanics Analysis for Case 1.

The stress analysis and fracture mechanics analysis were performed using the methods outlined in Reference 14. The specified material properties for the controlling region in both the 3410 and the 3800 vessels are as follows:

Copper	=	0.10%
Phosphorus	=	0.008%
Initial RT_{NDT}	=	40°F

The anticipated end of life peak fluence is 3.2×10^{19} neutrons/cm^2 with an energy greater than 1.0 MeV. Using the above material properties and the end of life fluence, no crack extension would be predicted. In order to permit the demonstration of a substantial safety margin on crack extension, more severe assumptions were made, i.e., the initial RT_{NDT} and the end of life fluence were increased arbitrarily to the following: (This combination of initial RT_{NDT} and total fluence represents more than twice the design life of the plant.)

Initial RT_{NDT}	=	100°F
EOL Fluence	=	6×10^{19} neutrons/cm^2

The plot of stress intensity vs time for the more severe case is shown in Figure 2.4-5 for various assumed crack depths. These stress intensities result from the pressure and temperature transients given in Figures 2.4-1 and 2.4-2. The applied stress intensity values were used in determining the critical crack depth diagram shown in Figure 2.4-6. From this figure it is apparent that the initiation toughness level is not exceeded during this transient. These results indicate that no crack initiation would occur for the intermediate size steam line break transient for more than twice the design life of the plant.

2.4.3.2 Results of Fracture Mechanics Analysis for Case 2.

The plot of stress intensity vs time for this case is shown in Figure 2.4-7 for various assumed crack depths. These stress intensities result from the pressure and temperature transients given in Figures 2.4-3 and 2.4-4. Figure 2.4-8 shows the critical crack depth diagram assuming an initial RT_{NDT} of 100°F and an EOL fluence of 6 x 10^{19} neutrons/cm^2. No initiation regions are shown in this figure which indicates that the initiation toughness level is not exceeded under these conditions. These results indicate that no crack initiation would occur for the small size steam line break transient for more than twice the design life of the plant.

2.4.4 Conclusions from PTS Analysis

Two MSLB cases, an intermediate size and a small size SLB, were analyzed to show the sensitivity of results to break size for the 3410 and the 3800 C-E NSSS plants. Initial plant conditions were conservatively chosen to maximize the cooldown magnitude. Operator actions to avoid repressurization were not credited, even though conditions and signals for throttling HPSI and reducing charging flow would be indicated in sufficient time for operator action. Fracture mechanics evaluations of the two transients were performed assuming maximum specified copper impurities and initial RT_{NDT}, and twice the FSAR value of fluence at end of plant life. It was found that no crack initiation would occur for any assumed preexisting flaws of infinite length.

It is therefore concluded that the 3410 and the 3800 pressure vessels exhibit large margins of capability to withstand the most severe postulated cooldown transients with full repressurization to the code safety valve setpoint pressure and, therefore, the lack of PORVs as a possible means for depressurization or for limiting repressurizations is not a concern from a PTS point of view.

Figures for Section 2.4

Figure 2.4-1

DOWNCOMER WATER TEMPERATURE DURING INTERMEDIATE SIZE SLB (CASE 1)

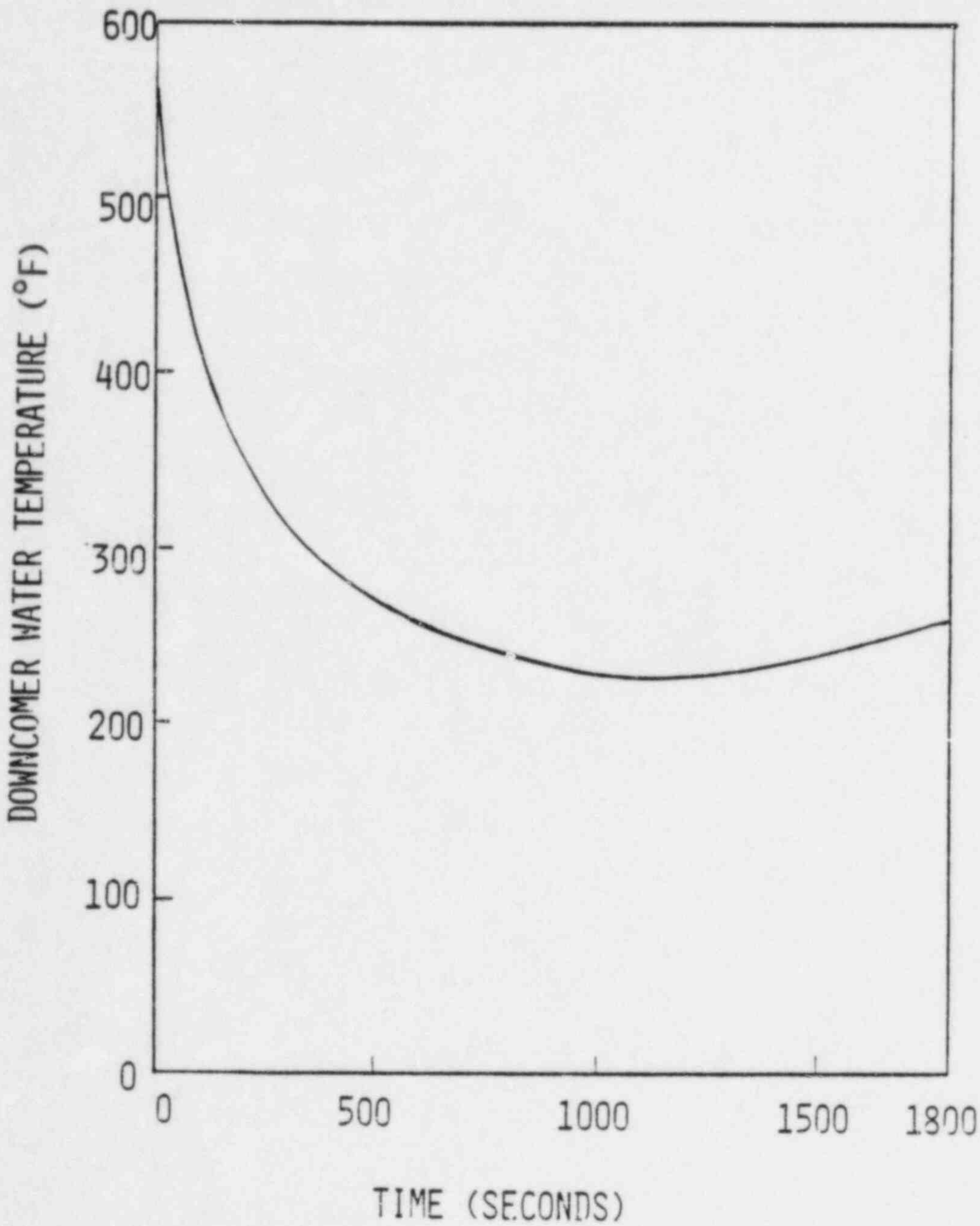


FIGURE 2.4-2

DOWNCOMER PRESSURE DURING
INTERMEDIATE SIZE SLB (CASE 1)

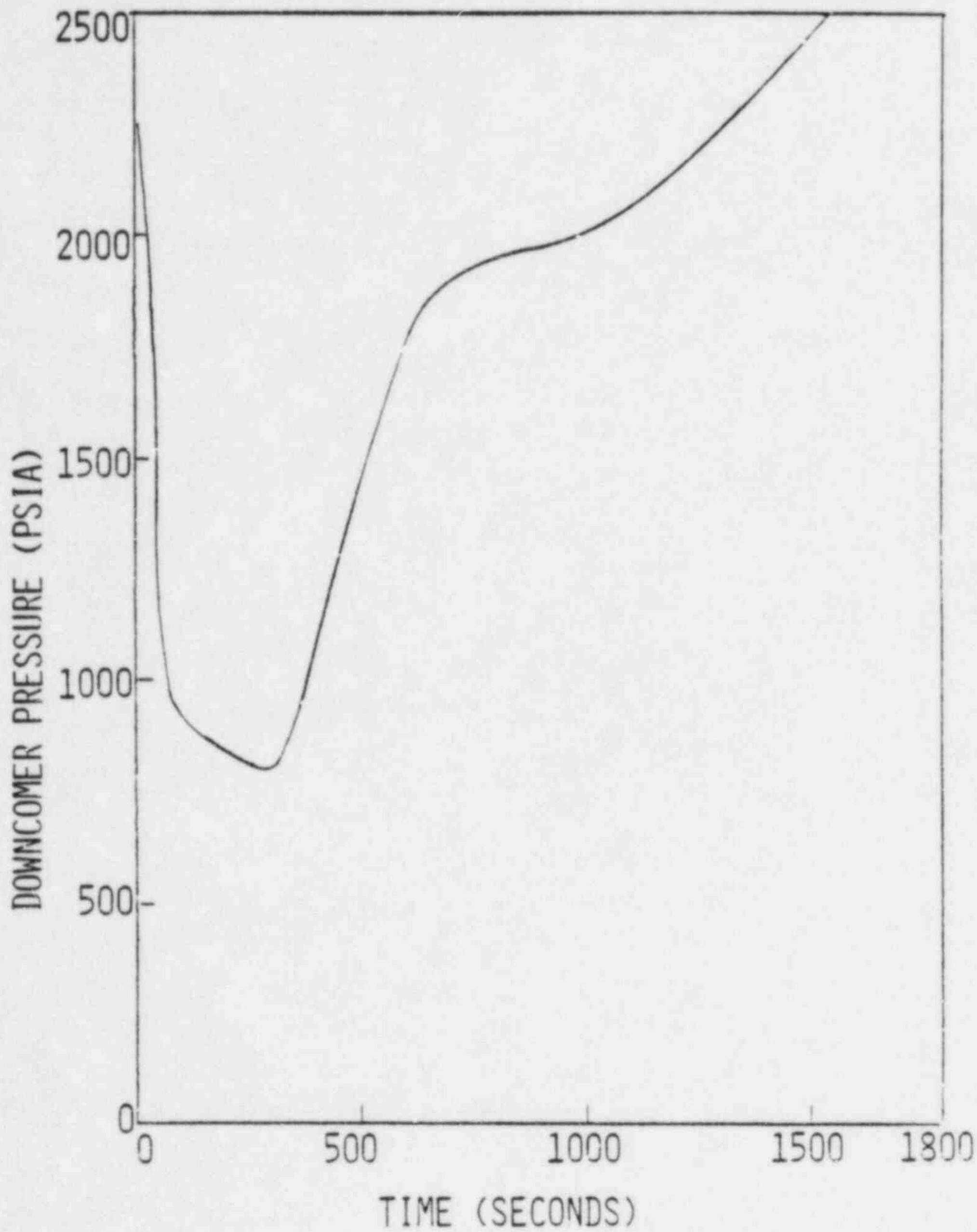


FIGURE 2.4-3

DOWNCOMER WATER TEMPERATURE DURING SMALL SIZE SLB (CASE 2)

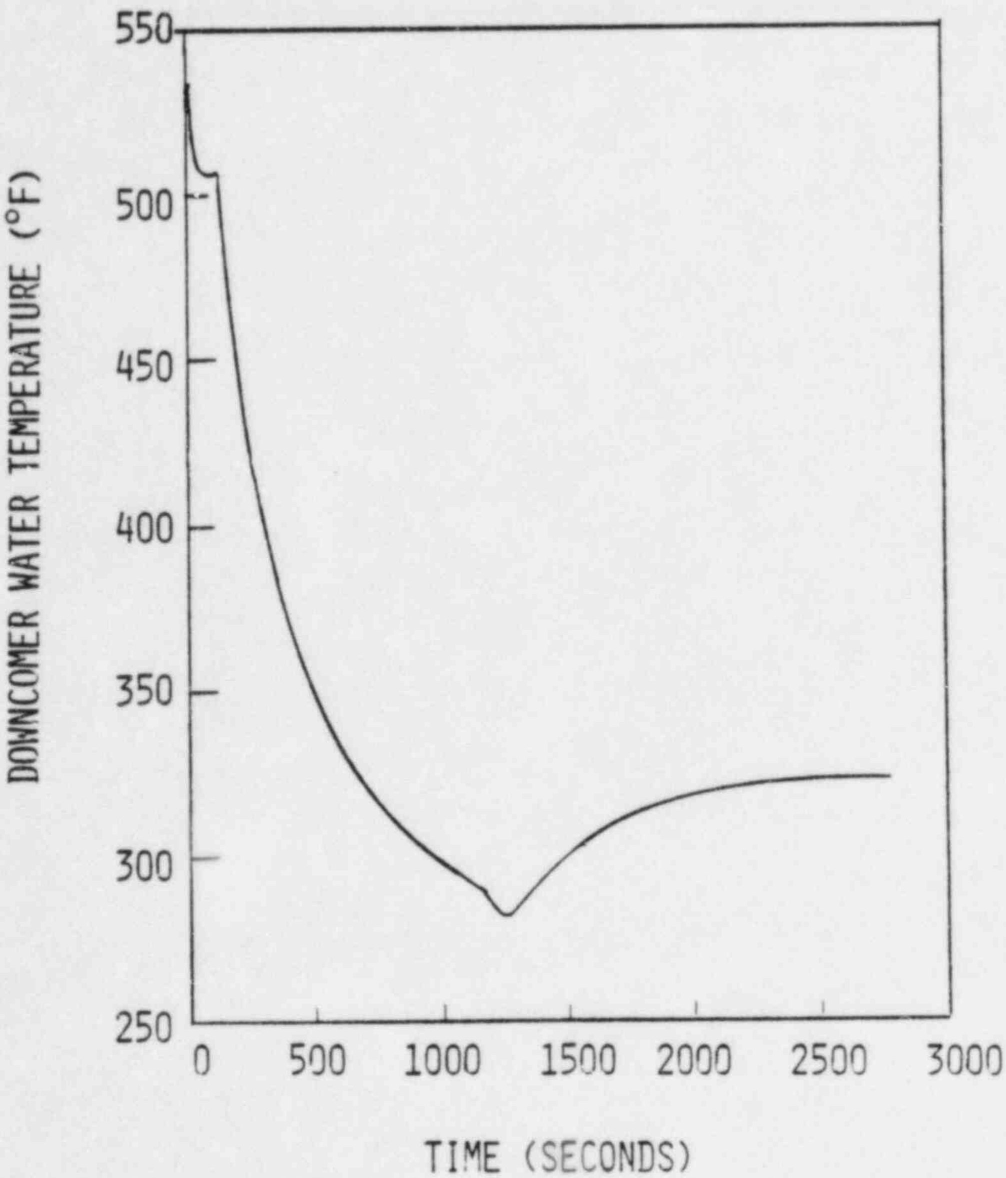


FIGURE 2.4-4

DOWNCOMER PRESSURE DURING SMALL SIZE SLB (CASE 2)

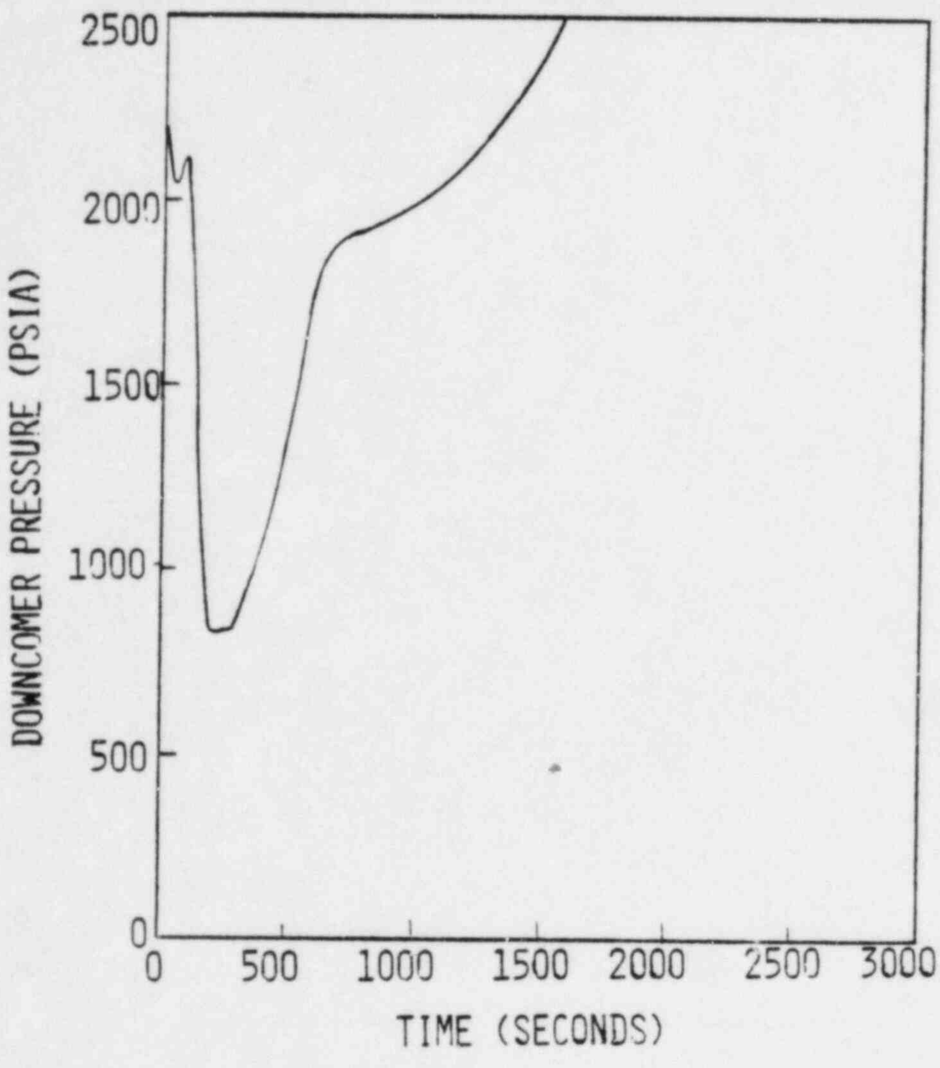


FIGURE 2.4-5

STRESS INTENSITY FOR VARIOUS ASSUMED CRACK DEPTHS
DURING INTERMEDIATE SIZE SLB (CASE 1)

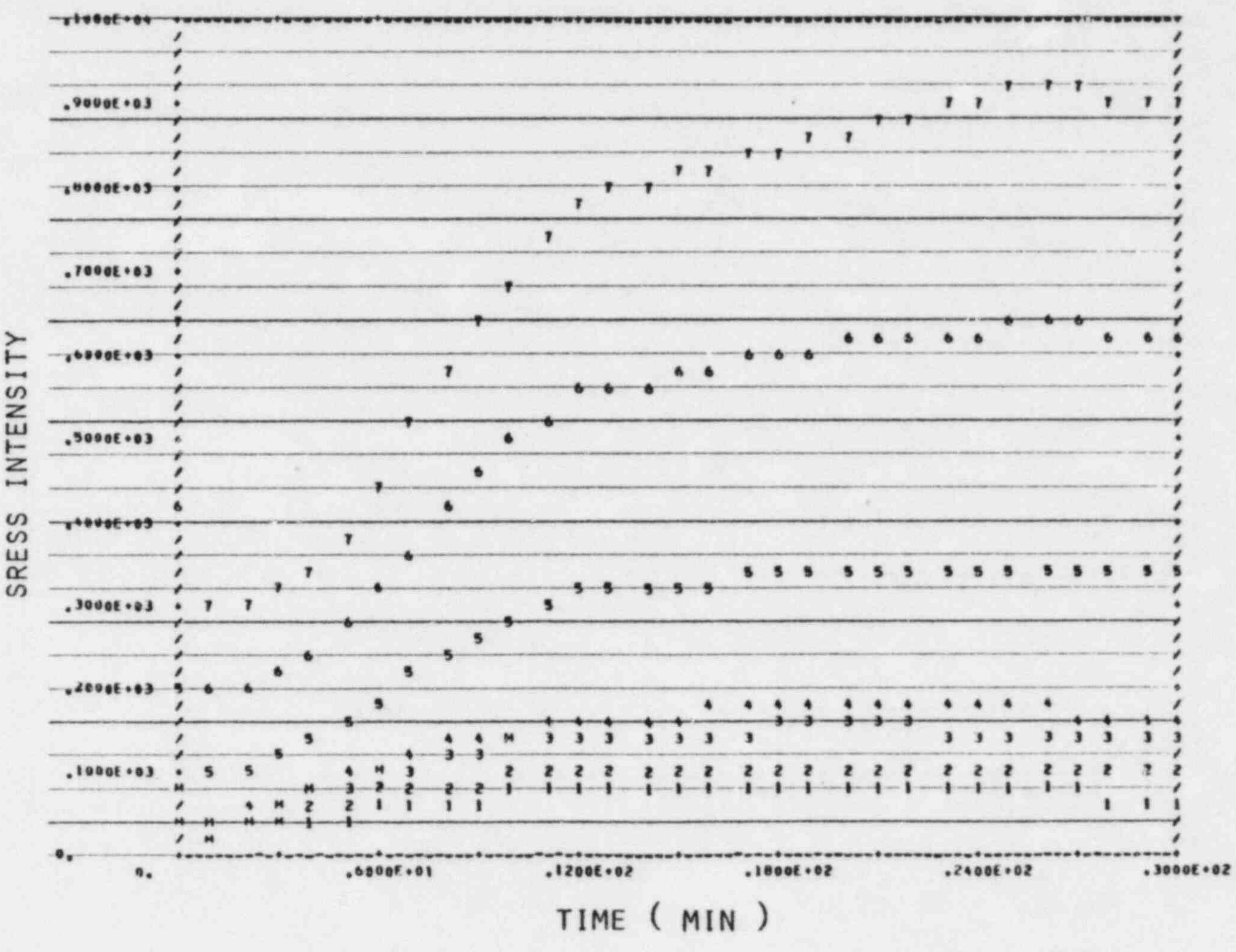


Figure 2.4-6

CRITICAL CRACK DEPTH DIAGRAM FOR
INTERMEDIATE SIZE SLB (CASE 1)

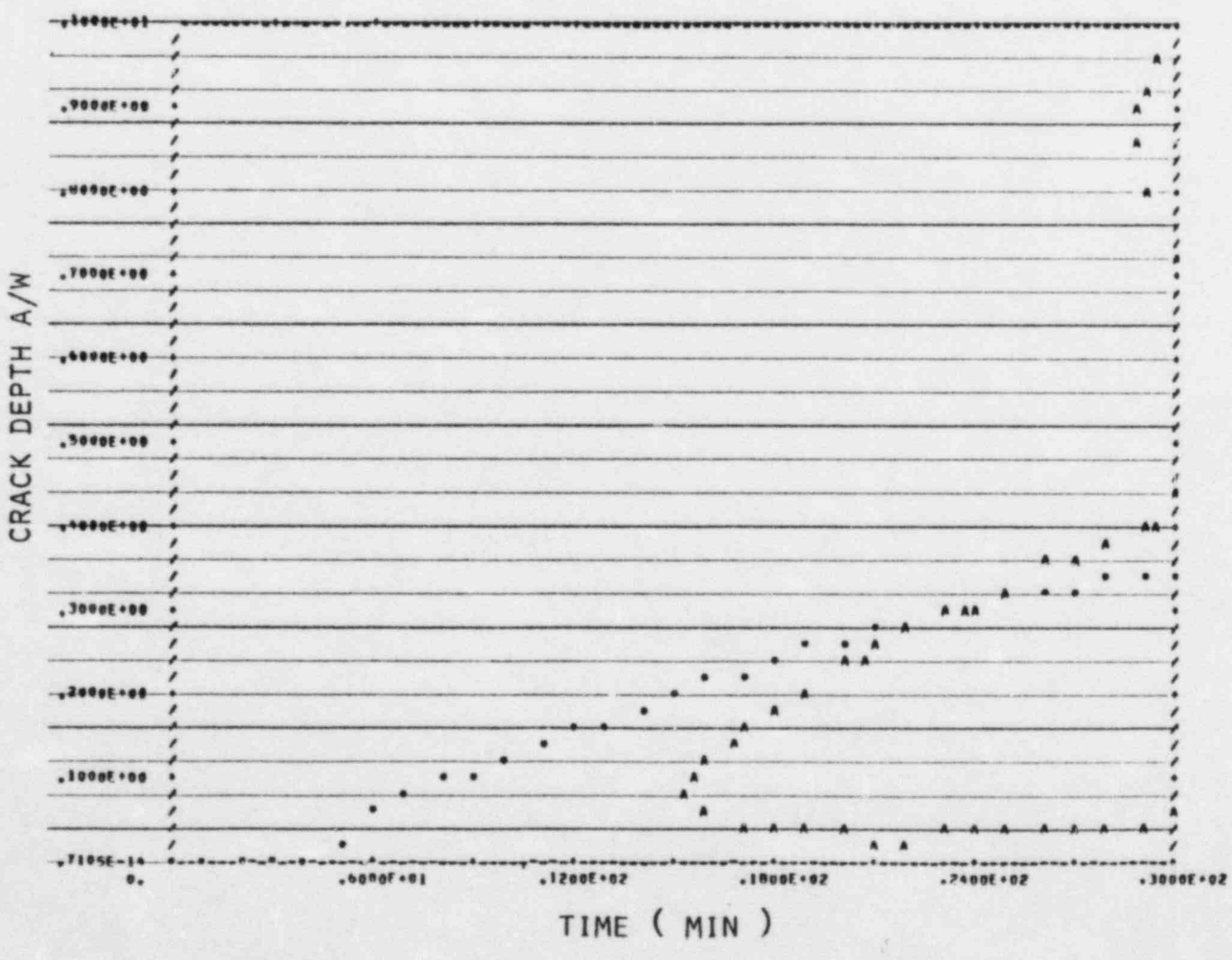


FIGURE 2.4-7

STRESS INTENSITY FOR VARIOUS ASSUMED CRACK DEPTHS
DURING SMALL SIZE SLB (CASE 2)

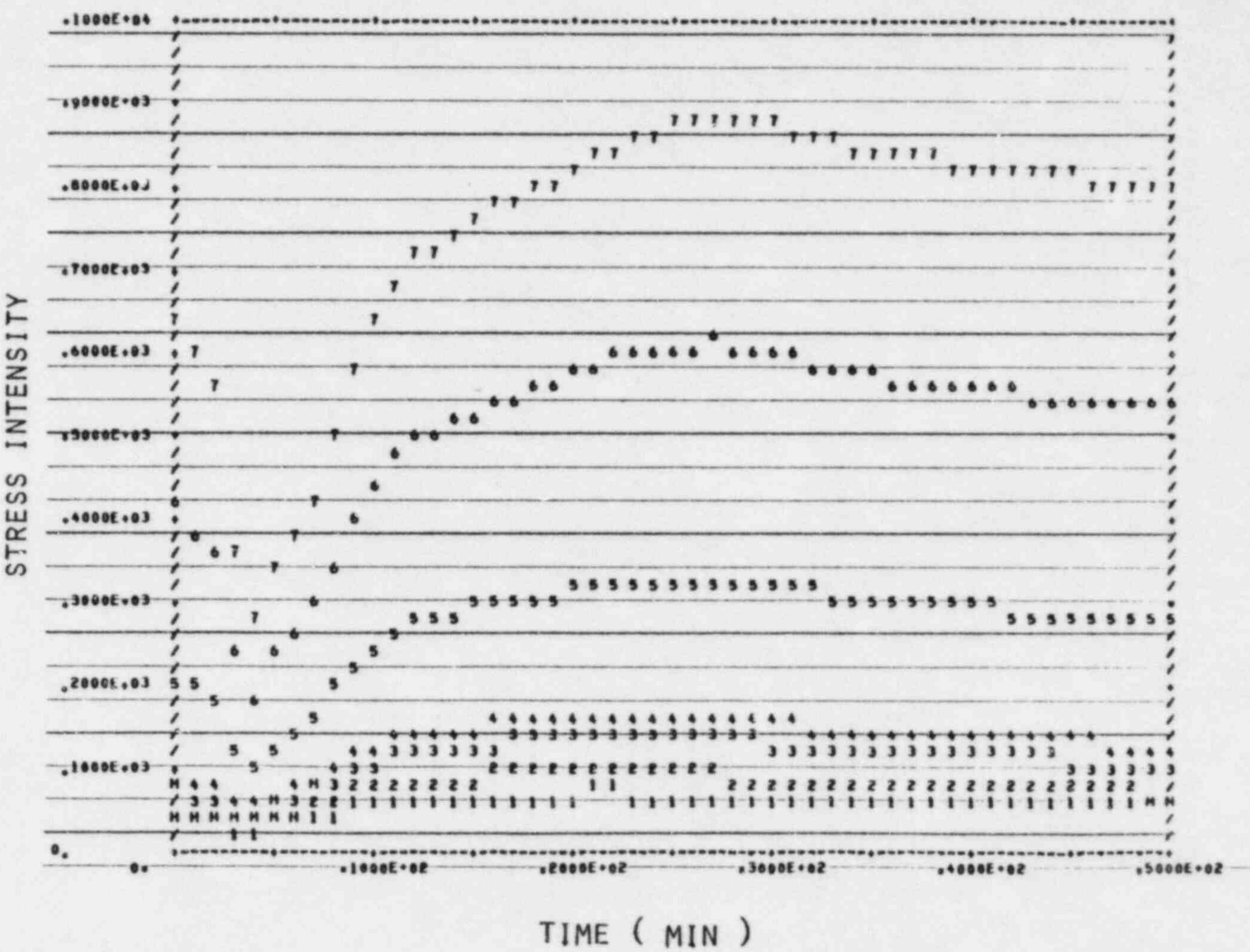
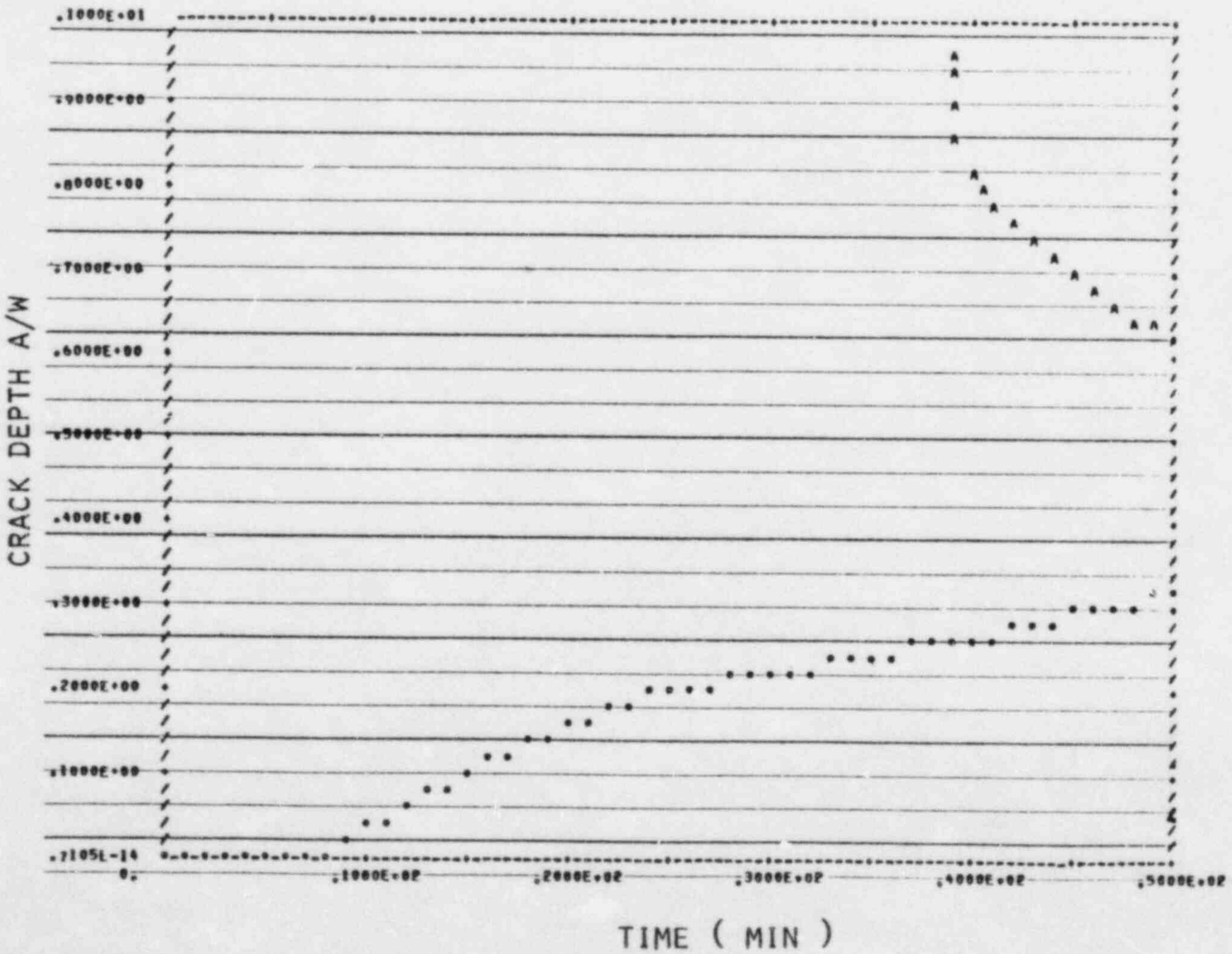


FIGURE 2.4-8

CRITICAL CRACK DEPTH DIAGRAM FOR SMALL SIZE SLB (CASE 2)



2.5 Question 5: Multiple Failure Scenarios

While the PORV may not be required based on classical safety analyses, there are a number of relatively low probability scenarios in which the ability to directly depressurize the RCS or to initiate primary feed-and-bleed may be essential for plant safety. For example, should tube ruptures occur in both steam generators to the extent that offsite releases would be excessive if the secondary systems were used, a PORV may be the only means of removing core decay heat without excessive offsite releases or running out of ECCS water. Small break LOCAs could be dealt with by depressurizing the RCS down to the pressure where low head safety injection pumps replenish fluid volume. Show how a variety of multiple failure events, including the above, are satisfactorily handled without the PORV.

2.5.1 Response to Question 5

This question effectively asks that two specific multiple failure scenarios be reviewed to determine that they are satisfactorily handled without the use of PORVs. First, in Section 2.5.2 below a multiple SGTR analysis will be presented which shows successful mitigation without the use of power operated relief valves. Specifically, multiple tube ruptures in both steam generators will be considered. Second, in Section 2.5.3 a SBLOCA with failure of HPSI will be analyzed to show successful mitigation without PORVs.

2.5.2 Multiple Tube Ruptures in Both Steam Generators

To address the question of successful mitigation of multiple tube ruptures in both steam generators without PORVs, an evaluation of the plant thermal-hydraulic response and radiological releases was performed for various multiple tube rupture events. Specifically, two sets of best-estimate SGTR analyses for the 3410 and the 3800 Class plants were performed. The two sets included an analysis of one tube ruptured in each steam generator and an analysis of three tubes ruptured in each steam generator. (Note that the probability of more than three tube ruptures occurring in both steam generators is very low as discussed in Section 2.9.1.) The analyses were carried from event initiation through cooldown to shutdown cooling initiation conditions where both steam generators can be isolated. Oper- ator actions during the cooldown phase were selected according to Reference 6.

The purpose of the evaluation is to determine radiological doses that occur and ECCS water supply required during multiple SGTR events. From an offsite dose standpoint, the limiting number of tube ruptures in both steam generators is determined. The limit is then compared with the probability of occurrence for multiple tube rupture events, which is discussed in Section 2.9.1 of this report. From an ECCS water supply standpoint, the integrated ECCS flow required in each case is compared with available supplies to ensure adequate safety injection water supply.

2.5.2.1 Description of Analytical Methods

The 3410 plant and the 3800 plant thermal-hydraulic responses and offsite releases for multiple tube ruptures were calculated by use of a full plant computer code simulation. The code uses a node and flow path network to model the reactor coolant system. It accounts for potential steam bubble formation in the reactor vessel upper head region during the tube rupture events. The analytical methods also include a dynamic model of primary system and secondary system activities for use in the dose calculations. The activity concentrations are calculated to vary in time according to the generation rate of iodine, releases to the atmosphere, and dilution by ECCS water and auxiliary feedwater.

Key thermal-hydraulic assumptions and initial conditions for the multiple tube rupture analyses are provided in Tables 2.5-1 (p. 157) and 2.5-2 (p. 158). As shown in Table 2.5-1, best estimate ECCS

Table 2.5-1

MULTIPLE SGTR ANALYSIS THERMAL-HYDRAULIC ASSUMPTIONS

1. Best estimate two train HPSI - 70°F water temperature.

2. Offsite power lost on turbine trip.

3. 1.0 1971-ANS decay heat.

4. Best estimate break flow.

5. Break located on hot leg side of SG (Conservative location from dose standpoint).

6. No charging pumps after the loss of offsite power.

Table 2.5-2

MULTIPLE SGTR ANALYSIS INITIAL CONDITIONS

Parameter	Plant Class 3410	3800
RCS pressure (psia)	2250	2250
Core power (% of RTP)	100	100
Core inlet temperature (°F)	553	565
Core mass flow rate (%)	100	100
Pressurizer water volume (ft^3)	786	1115
Steam generator water inventory (ft^3)	176,950	190,700
Steam generator pressure (psia)	900	1070

injection flow models for two HPSI trains are specified, which are the same as that used in the TLOFW analysis reported in Section 2.8 of the report. The safety injection flow is taken from the refueling water tank, which is assumed to be at a temperature of 70°F. A mechanistic loss-of-offsite power is assumed. Therefore, the main pressurizer spray, main steam generator feedwater, and reactor coolant pumps are unavailable. Additionally, the 1971 ANS decay heat curve is specified for core power with a best estimate multiplier of 1.0.

The tube break flow is calculated by use of the Henry-Fauske (Reference 15) critical flow correlation. A best estimate break flow multiplier of 0.8 is applied to the correlation. This flow multiplier was determined by an evaluation of both the Ginna and Prairie Island tube rupture events and adjusts the tube break flow to correspond to values that are calculated for these events where ruptures have actually occurred.

Initial conditions for the multiple tube rupture analyses are provided in Table 2.5-2. Thermal-hydraulic best estimate conditions include an initial primary pressure of 2250 psia, and a core power and mass flowrate of 100% rated conditions. Best-estimate inlet core temperatures, initial pressurizer water volumes, and initial steam generator masses for the 3410 and the 3800 plant classes are assumed.

Key assumptions and initial conditions used in calculating offsite doses for the multiple tube rupture analyses are provided in Table 2.5-3 (p. 160). Offsite doses at the exclusion area boundary and low population zone are calculated according to conditions specified in the Standard Review Plan. For conditions of an event generated iodine spike initial primary and secondary activity levels are specified at the technical specification limits of 1.0 μCi/gm and 0.1 μCi/gm, respectively. A spiking factor of 500 is applied to the iodine generation rate in GIS calculations. For conditions of a pre-existing iodine spike, the primary activity is assumed to

Table 2.5-3

MULTIPLE SGTR ANALYSIS DOSE RELEASE
ASSUMPTIONS AND INITIAL CONDITIONS

1. Event generated iodine spike:

   Spiking factor - 500

   Initial primary activity - 1.0 μCi/gm

2. Initial secondary activity - 0.1 μCi/gm

3. Pre-existing iodine spike:

   Initial primary activity - 60 μCi/gm

4. Iodine partition coefficient between SG water and SG steam - 1/100

5. Site dispersion factors (second/m^3)

Site dispersion factors (second/m^3)	<u>2 Hours</u>	<u>8 Hours</u>
3410	6.3×10^{-4}	7.1×10^{-5}
3800	1.08×10^{-3}	1.1×10^{-4}

initially be 60 μCi/gm. Both calculations assume an iodine partition coefficient of 1/100 between the steam generator steam and steam generator water phases. Finally, site specific dispersion factors are assumed. The largest (most conservative) site dispersion factors for the 3410 and the 3800 plants are used in calculating the radiological releases.

The tube rupture is assumed to be located on the hot leg side of the steam generator just above the tubesheet for the dose calculation. In this location, the fluid from the primary side is at the hot leg temperature. A portion of the hot fluid flashes as it enters the cooler secondary fluid due to the change in pressure. The activity in this flashed portion of fluid is assumed to pass through the ADVs with a conservative iodine partition coefficient of 1.0. Therefore, the most conservative break location, from a dose standpoint, is on the hot side of the steam generator where the flashing of primary fluid is at a maximum.

Operator actions to cool the RCS to shutdown cooling entry conditions are illustrated in Figure 2.5-1. (All figures pertaining to Section 2.5 of this report are contained together at the end of the section (p. 185).) No operator action is assumed prior to thirty minutes. At thirty minutes, the operators follow the guidelines of Reference 6. Auxiliary spray is initiated and the pressurizer level increases above the heaters as system pressure decreases and hence HPSI flow increases. The steam generator ADVs are also partially opened to cool the RCS and prevent further MSSV opening. The cooldown phase is then initiated where the operator uses the ADVs, the pressurizer heaters and auxiliary spray, and HPSI throttling to control the plant cooldown while maintaining primary subcooling and pressurizer level. In this evaluation, the RCS is cooled at a rate of 100°F/hr. This rate is conservative from a dose standpoint since the cooldown is nearly completed within two hours and the doses must be calculated with the more stringent two hour site dispersion factors. A minimum RCS subcooling of approximately 20°F is maintained throughout the cooldown with the pressurizer half full.

A symmetric cooldown of the RCS is assumed by use of both steam generators in the multiple tube rupture analysis where both generators are affected. The symmetric cooldown is selected so that the RCS can be cooled at the aggressive rate of 100°F/hr during natural circulation. The symmetric cooldown also maximizes the radiological release. The control of the steam generator auxiliary feedwater is assumed to be automatic rather than manual to maximize the releases. In the automatic mode, auxiliary feedwater is initiated on a low steam generator level before the tubes uncover. The level is then allowed to increase until the reset high level is established at which point feedwater is terminated. The secondary level then oscillates between the low level and reset level. In comparison, the operator could control the feedwater flow to maintain a relatively constant secondary liquid level. The most conservative dose, however, will result by assuming the automatic feedwater control. In this mode the total integrated feedwater to the steam generator is less than with operator control since the inventory oscillates between a low level and reset level value rather than being maintained at a high constant level. Therefore, the ADV's are required to a greater extent and the releases are larger with automatic control.

2.5.2.2 Results - One Tube Ruptured in Each Steam Generator

The primary RCS and secondary steam generator pressures, RCS fluid temperatures, and RCS subcooling are provided in Figure 2.5-2 for the 3410 Class plant with one tube ruptured in each steam generator. The upper head and pressurizer levels and offsite doses at the exclusion area boundary are provided for this event in Figure 2.5-3. Similar thermal-hydraulic response and dose results are provided in Figures 2.5-4 and 2.5-5 for the 3800 Class plant with one tube ruptured in each steam generator. Initially in both plants, the RCS is operating at full power conditions with a pressure of 2250 psia. A tube rupture in each steam generator occurs at time zero and the RCS depressurize at a rate of 1.1 psi/second and 0.8 psi/second for the 3410 and 3800 Class plants, respectively.

The pressurizer level as shown in Figures 2.5-3 and 2.5-5 decreases and the pressurizer empties within ten minutes in both cases as primary water passes through the tube ruptures to the secondary side of the steam generators. The reactor in both cases is tripped on a low pressurizer pressure signal. The time of this trip occurs first in the 3410 plants in slightly more than seven minutes compared to ten minutes for the 3800 plants. Within three seconds of trip, the turbine trips and a mechanistic loss-of-offsite power is assumed. The steam generator secondary pressures then rapidly increase after isolation and main steam safety valves open until thirty minutes. During this time, the reactor vessel upper head regions of both plant classes are partially voided.

After thirty minutes, auxiliary spray is initiated for both plants to lower system pressure. This action will result in an increase in HPSI flow and thus rapidly increase pressurizer level above the pressurizer heaters. The operator then proceeds to aggressively cool both the 3410 and the 3800 plants to shutdown cooling initiation conditions. Both steam generator ADVs are opened to begin the RCS cooldown and to prevent further MSSV openings. By forty-five minutes into the event, the operator has established a 100°F/hr cooldown rate. Between about forty-five minutes and 2.3 hours, both plant classes are cooled at a rate of 100°F/hr by use of the ADVs, while the operator controls the RCS subcooling to about 20°F and maintains the pressurizer half full. Offsite accident doses shown in Figures 2.5-3 and 2.5-5 significantly increase during the rapid cooldown and reach a maximum of 95 REM for the 3410 plant and 230 REM for the 3800 plant at the exclusion area boundary by two hours for the PIS assumptions.

The reactor vessel upper head of both plant classes will completely void during the aggressive cooldown as shown in Figures 2.5-3 and 2.5-5. By about one hour for the 3800 plants (0.8 hours for the 3410 plant), the upper head liquid level has decreased to the bottom of the upper guide tube structure and steam is vented from the upper head to the subcooled liquid in the upper plenum. The venting of the upper head steam cools the upper head region and allows the depressurization to continue. Since the upper plenum and hot legs remain subcooled, the operator can take the plant to shutdown cooling entry conditions with the voided upper head.

Key thermal-hydraulic results and offsite doses are summarized in Tables 2.5-4 (p. 165) and 2.5-5 (p. 166) for the multiple tube rupture events that were analyzed. Results included on these tables are the RCS pressures and temperatures, the integrated primary-to-secondary leak, HPSI flow, steam generator auxiliary flow, and ADV and MSSV flows. Additionally, offsite doses are included in Table 2.5-8 that were calculated for GIS and PIS assumptions. These tables provide results for both the one and the three tube rupture cases in each steam generator. A complete discussion of the three tube ruptures in each steam generator analysis will be presented in 2.5.2.3 below.

Table 2.5-4 provides results for the 3410 and 3800 Class plants at thirty minutes, the time of first operator actions. During the first thirty minutes, the RCS response is calculated with normal functioning of safety equipment but with loss-of-offsite power conditions. By thirty minutes, the RCS pressures and temperatures are 1270 psia and 537°F for the 3410 plant and 1476 psia and 558°F for the 3800 plant. The total integrated primary-to-secondary leak is about 100,000 lbm for both plants with a single tube ruptured in each steam generator. The integrated HPSI flow basically matches this leak flow, therefore, the total RCS mass is relatively constant. For the 3410 plants, auxiliary steam generator feedwater is initiated on a low steam generator level. In comparison, auxiliary feedwater in the 3800 plants is not initiated by thirty minutes because the level for feedwater actuation is slightly lower than for the 3410 plants, and the feedwater actuation setpoint was not reached within this time. Energy is removed from the system by the opening of MSSVs with a total integrated flow of slightly more than 100,000 lbm for both plants.

Table 2.5-4

SUMMARY OF RESULTS MULTIPLE STEAM GENERATOR
TUBE RUPTURES AT THIRTY MINUTES

Parameter	3410 Class 1 Tube/SG	3410 Class 3 Tubes/SG	3800 Class 1 Tube/SG	3800 Class 3 Tubes/SG
Reactor trip (sec.)	442	117	602	166
RCS pressure (psia)	1270	1153	1476	1467
RCS temperature (°F)	537	535	558	552
Integrated primary-to-secondary leak (lbm)	98,900	159,800	100,000	224,100
Integrated HPSI (lbm)	87,200	171,800	102,800	190,500
Integrated auxiliary feed-water to both SGs (lbm)	134,000	0	0	0
Integrated MSSV flow from both SGs (lbm)	101,300	111,300	112,200	97,700
Integrated ADV flow from both SGs (lbm)	0	0	0	0

Table 2.5-5

SUMMARY OF RESULTS FOR MULTIPLE STEAM GENERATOR TUBE RUPTURES AT TWO HOURS

Parameter	3410 Class 1 Tube/SG	3410 Class 3 Tubes/SG	3800 Class 1 Tube/SG	3800 Class 3 Tubes/SG
RCS pressure (psia)	232	326	314	350
RCS temperature (°F)	370	390	388	398
Integrated primary-to-secondary leak (lbm)	313,400	717,100	360,400	860,128
Integrated HPSI (lbm)	384,800	806,530	434,100	897,600
Integrated auxiliary feed-water to both SGs (lbm)	292,900	0	275,000	0
Integrated MSSV flow from both SGs (lbm)	101,300	111,300	112,200	97,700
Integrated ADV Flow-from both SGs (lbm)	487,400	401,000	570,000	513,900
Dose - 2 Hours (REM) (1)				
GIS	55	45	105	95
PIS	95	80	230	220

(1) In calculating the dose results the site dispersion factor for Waterford was used for the 3410 case and the site dispersion factor for Washington was used for the 3800 case.

Table 2.5-5 provides results for the 3410 and 3800 Class plants at two hours for exclusion area boundary dose calculations. By two hours the RCS pressure and temperatures are 232 psia and 370°F for the 3410 plant and 314 psia and 388°F for the 3800 plant. In both single tube rupture cases, a total integrated ADV flow of more than 480,000 lbm is required to cool the RCS at a rate of 100°F/hr. These flows exceed the primary-to-secondary leak flow, therefore, an auxiliary feedwater flow of more than 275,000 lbm to both steam generators is required for both plants. During the cooldown, the steam generator secondary level is maintained above the steam generator tubes and below the steam generator separators. Additionally, the total integrated ECCS injection is less than 500,000 lbm in both plant classes, which is well within the RWT capacity of about four million lbm.

The maximum offsite releases shown in Table 2.5-5 for the multiple tube rupture analyses occur in two hours at the exclusion area boundary. The values range from 55 REM to 230 REM for the single tube rupture cases, which are less than the 300 REM limit specified by 10 CFR 100. Additionally, the maximum releases are calculated in all cases for the PIS conditions. In comparison to GIS assumptions, the primary activity concentration is at a maximum for PIS conditions early in the cooldown when the tube leakage is at a maximum. Therefore, the releases calculated with PIS assumptions exceed those calculated with GIS conditions.

2.5.2.3 Results - Three Tubes Ruptures in Each Steam Generator

The thermal-hydraulic response and dose release results for the 3410 Class plant with three tubes ruptured in each steam generator are provided in Figures 2.5-6 and 2.5-7. Similar results for the 3800 Class plant with three tubes ruptured in each steam generator are provided in Figures 2.5-8 and 2.5-9. Both plant classes are initially operating at 100% of rated full power, best estimate conditions. A three tube rupture in each steam generator occurs at time zero and the RCS initially depressurizes at a rate of 3.2

psi/second for the 3410 plant and 2.8 psi/second for the 3800 plant. Compared to the single tube rupture cases, the pressurizer levels decrease at a relatively rapid rate and empties within five minutes in both cases as primary fluid leaks at a high rate to the steam generator secondary side. A reactor trip occurs first for the 3410 plants at about two minute compared with a three minute trip for 3800 plants. Within three seconds of trip, the turbine trips and offsite power is terminated. The steam generator secondary pressures rapidly increase after isolation and safety valves open until operator action is taken at thirty minutes. With three tubes ruptured in each generator, the total primary-to-secondary flow exceeds the MSSV flow and the generators gradually fill. Therefore, auxiliary feedwater is not initiated for either plant class.

After thirty minutes, auxiliary spray is initiated for both plants to lower system pressure. This action will result in an increase in HPSI flow and thus rapidly increase pressurizer level above the pressurizer heaters. The operator then proceeds to aggressively cool both the 3410 and the 3800 plants to shutdown cooling initiation conditions. Both steam generator ADVs are opened to begin the RCS cooldown and to prevent further MSSV openings. By forty minutes into the event, the operator has established a 100°F/hr cooldown rate. Between forty minutes and 2.4 hours, both plant classes are aggressively cooled by the use of the ADVs while the operator controls the RCS subcooling at about 20°F and maintains the pressurizer half full. Offsite doses shown in Figures 2.5-7 and 2.5-9 reach the maximum of 80 REM for the 3410 plant and 220 REM for the 3800 plant at the exclusion area boundary by two hours.

The reactor vessel upper head of both plant classes will void during the cooldown as shown in Figures 2.5-7 and 2.5-9. Similar to the single tube rupture cases, the upper head level has decreased to the bottom of the upper guide structure by one hour for the 3410 plant and 0.8 hours for the 3800 plant. The greater number of tube ruptures does not appear to present additional requirements to the operator for control of the upper head void compared with the single tube rupture cases.

As discussed in the single tube rupture cases, key thermal-hydraulic results and offsite releases at thirty minutes and two hours are provided in Table 2.5-4 and Table 2.5-5. The results in Table 2.5-4 are provided at the time at which operator action is first taken. The RCS response is determined assuming normal functioning of safety equipment, but with a loss of offsite power. At thirty minutes, the RCS pressures and temperatures are 1153 psia and 535°F for the 3410 plant and 1467 psia and 552°F for the 3800 plant. The integrated primary-to-secondary leak is more than 159,000 lbm by thirty minutes for both plants with three tubes ruptured in each steam generator. The integrated HPSI flow basically matches the leak; therefore, the total RCS mass is relatively constant. Energy is removed from the system by the opening of MSSVs with an integrated flow of more than 97,000 lbm for both plants. Since the primary-to-secondary leak flow exceeds the MSSV flow, the steam generators gradually fill and auxiliary feedwater is not initiated for either class of plant.

Table 2.5-5 summarizes results for the cases with three tubes ruptured in each steam generator at two hours. A total integrated ADV flow of 401,000 lbm for the 3410 plant and 513,900 lbm for the 3800 plant is required to cool the RCS at a rate of 100°F/hr. These flows do not exceed the primary-to-secondary leak flows, so the steam generators continue to fill and auxiliary feedwater is not required. In fact, the steam generator secondary level gradually increases during the cooldown, but remains below the steam separators for both classes. The total HPSI flow for both cases is less than 900,000 lbm, which is within the RWT storage capacities.

The maximum offsite releases shown in Table 2.5-5 for the three tube rupture analyses occur in two hours at the exclusion area boundary. These values range from 45 REM to 220 REM for the three tubes rupture cases, which are less than the 300 REM limit specified by 10 CFR 100. Note that the total releases for the three tube events are less than that for the single tube ruptures. This is a result of the larger break area of the three ruptured tube cases, which removes a significant portion of the primary energy compared to the cases with one ruptured tube in each steam generator. This energy is stored on the secondary side of the steam generator as the liquid level increases. Therefore, the total ADV flow with three tubes ruptured in each steam generator is less than that required to cool the plant with one ruptured tube in each steam generator and the releases are therefore slightly lower.

The analyses of each multiple tube rupture event is carried to shutdown cooling initiation conditions. In all cases, the primary RCS temperature is cooled to 350°F and the pressure is reduced below 350 psia in slightly more than two hours. After two hours, offsite releases are calculated for the low population zone according to the Standard Review Plan. The site disperson factor is significantly lower for these calculations; therefore, the total release are significantly lower than the two hour exclusion area boundary doses. In fact, the maximum releases at the low population zone is 22 REM, which is calculated for the 3800 plants class at the time when shutdown cooling entry conditions are reached and the steam generators can be isolated. Therefore, the maximum releases occur at two hours and are calculated at the exclusion area boundary.

2.5.2.4 Conclusions - Multiple Tube Ruptures in Both steam Generator

The analyses results for multiple tube ruptures in both steam generators for the 3410 and 3800 Class plants have demonstrated that as many as three tubes can be simultaneously ruptured in each steam generator and the plants can be aggressively cooled to shutdown cooling entry conditions without exceeding offsite dose limits or exhausting RWT water supplies. For comparison, Section 2.9.1 provides analytical results that determine the probability of simulataneous tube ruptures in both steam generators. It is demonstrated that the probability of more than one tube simultaneously rupturing in each steam generator is extremely unlikely.

2.5.3 SBLOCA with no HPSI

In addition to the multiple SGTR scenarios, Question 5 asks how small break LOCAs with no high pressure injection are satisfactorily handled without PORVs. To answer this question, an analysis was performed in which the small break LOCA with no HPSI transient was simulated both with and without the use of PORVs. For the case in which PORVs were not used, RCS depressurization was accomplished by means of aggressive steam generator cooldown with the ADVs. For the case in which PORVs were used, no steam generator cooldown was assumed. Three cases, identified below, were simulated in the analysis.

Case 1: No operator action.
Case 2: Steam generator cooldown via ADVs.
Case 3: RCS depressurization via PORVs.

The following sections describe the method of analysis, the results of the transient simulations, and the conclusions.

2.5.3.1 Method of Analysis

The transient simulations for this section of the report were performed using the 3410 Class plant as the reference plant. The conclusions of the analysis, however, also apply to the 3800 Class plants since the overall NSSS design and layout of the 3410 plant and 3800 plant are similar, both plant classes have similar SIT and LPSI pump designs, and the 3800 Class plants have more ADV relieving capacity per megawatt than the 3410 Class plants. In addition as will be seen in the next section, the physical phenomenon which control the two mitigation procedures are such that the conclusions of the analysis apply to both plant classes.

Table 2.5-6 (p. 173) lists the values for the important system parameters used in the transient simulations. In general, best estimate information was used in characterizing the plant systems and initial conditions. Important assumptions used in the analysis are listed in Table 2.5-7 (p. 174). The transient simulations were performed using an improved version of the CEFLASH-4AS computer code described in Section 3.2 of Reference 16. Improvements were made in two areas to more realistically describe the thermal-hydraulic processes that occur in the surge line and the pressurizer when PORVs and safety valves are open. First, an entrainment model was used to model the entrainment of liquid into the surge line from the hot leg and into the PORVs and safety valves from the pressurizer. Second, the finite difference wall heat model was upgraded to include a detailed calculation of surface heat transfer coefficients. This upgraded model was applied in the pressurizer and the reactor vessel upper head.

The analysis was performed for a 0.02 ft^2 break in the RCP discharge leg. This break size was selected as a representative break size in the range of small break sizes expected to be most limiting for this type transient. A smaller break size would result in a lower rate of RCS mass loss and thereby give the operator more time to depressurize the RCS. A larger break size would result in a more rapid depressurization (without any operator action) to the pressure at which the SIT would begin to operate. Thus, even though the break flowrate would be greater for a larger break size, the SIT flow would re-cover the core before there would be sufficient time for significant heatup.

2.5.3.2 Results for Case 1: No Operator Action

This section describes the results of the transient simulation of the small break LOCA with no HPSI transient when no action is taken by the operator to depressurize the RCS. The sequence of events and

Table 2.5-6

IMPORTANT INITIAL CONDITIONS AND SYSTEM PARAMETERS USED IN THE SMALL BREAK LOCA WITH NO HPSI ANALYSIS

Parameter	Value
Current Plant Design:	
Initial core power (Mw)	3410
Initial RCS pressure (psia)	2250
Initial RCS flow rate (lbm/hr)	148×10^6
Initial cold leg temperature (°F)	553
Initial hot leg temperature (°F)	612
Initial steam generator pressure (psia)	895
Low pressure reactor trip setpoint (psia)	1763
SIAS setpoint (psia)	1600
Manual RCP trip (psia)	1300
Safety injection tank pressure (psia)	615
LPSI pump shutoff head (psia)	210
MSSV setpoint (psia)	1100
ADV Capacity (Steam at 900 psia), per valve (lbm/hr)	703,000
ADV effective flow area, per valve (ft^2)	0.108
Number of ADVs per SG	1
Additional Parameters Assumed for Case 3:	
PORV capacity (Steam at 2400 psia), per valve (lbm/hr)	432,000
PORV effective flow area, per valve (ft^2)	0.0228
Number of PORVs	2

Table 2.5-7

ASSUMPTIONS USED IN THE SMALL BREAK LOCA WITH NO HPSI ANALYSIS

1. 0.02 ft^2 break in a RCP discharge leg.

2. HPSI pumps fail to start both automatically on SIAS and manually.

3. All three charging pumps off the entire transient.

4. Reactor/turbine trip occurs on low pressurizer pressure.

5. The RCPs are tripped manually at 1300 psia.

6. No SBCS. MSSV regulate steam generator pressure after reactor trip.

7. Manual operator action at fifteen minutes to either begin steam generator cooldown using ADVs (Case 2) or open PORVs (Case 3).

8. Operator maintains a 100°F/hr cooldown rate (Case 2).

9. Auxiliary pressurizer spray is not available.

10. 1.0 1971 ANS decay heat.

11. Homogeneous equilibrium critical flow model used to calculate break flow, PORV flow, and ADV flow.

the physical phenomenon which occur during the transient are similar to those of a small break LOCA with HPSI except that the RCS inventory transient response is negatively impacted by the absence of HPSI. Because of this similarity a detailed discussion of the transient is not presented. The transient description given below begins at the time of core uncovery. The reader is referred to Sections 3.1 and 3.8 of Reference 17 for qualitative and quantitative descriptions of the small break LOCA transient.

The sequence of important events for Case 1 is listed in Table 2.5-8 (p. 176). Figures 2.5-10 through 2.5-14 present the important system parameters, plotted as a function of time, which are discussed below.

The core begins to uncover at approximately 2600 seconds, Figure 2.5-10. At that time, RCS heat removal is being accomplished by reflux boiling and by the flow out the break. Steam produced by boiling in the core is condensed in the steam generators and flows back to the reactor vessel. Two phase fluid is flowing out the break, Figures 2.5-11 and 2.5-12. RCS pressure, Figure 2.5-13, is being controlled by the steam generators at a pressure greater than the pressure of the steam generators in order that the RCS steam can be condensed. RCS inventory is not being controlled. Inventory is leaving the RCS through the break and there is no injection into the RCS since the RCS pressure is above the SIT pressure at 2600 seconds.

As the amount of core uncovery increases after 2600 seconds the steam produced in the core begins to superheat. The steam generators then remove RCS heat by de-superheating the steam. This allows the RCS to depressurize below the steam generator pressure since it is no longer necessary for the RCS saturation temperature to be greater than the steam generator saturation temperature in order for the steam generators to remove RCS heat. This, in conjunction with the decreasing steam production in the core, as uncovery increases, and the increasing break flow quality, Figure 2.5-12, causes the RCS to depressurize.

Table 2.5-8

SEQUENCE OF EVENTS FOR CASE 1

0.02 ft^2 BREAK WITH NO HPSI AND NO OPERATOR ACTION

Event	Time (seconds)
Break	0
Reactor/turbine trip on low pressure	68
MSSVs open	73
RCPs trip (manual at 1300 psia)	129
Core uncovery begins	2622
Hotest fuel rod clad temperature reaches 2200°F	3640
SIT injection begins	4485
End of simulation	4500

At approximately 3600 seconds the cladding temperature of the hotest fuel rod reaches 2200°F, Figure 2.5-14. At approximately 4100 seconds the reactor inner vessel two-phase mixture level decreases below the bottom of the core. At about 4500 seconds, the RCS pressure reaches 600 psia and the SITs begin to inject at which time the transient simulation was terminated.

2.5.3.3 Results for Case 2: Steam Generator Cooldown via ADVs

This section describes the results of Case 2, the small break LOCA with no HPSI transient simulation in which the operator begins a rapid steam generator cooldown in response to the accident. The purpose of the rapid steam generator cooldown is to depressurize the RCS below the pressure of the SITs in order that they reflood the core.

The sequence of important events for the transient is listed in Table 2.5-9 (p. 178). The system parameters discussed below are shown as a function of time in Figures 2.5-15 through 2.5-18.

In the transient simulation, it was assumed that the operator begins the steam generator cooldown at fifteen minutes by opening both ADVs. It was further assumed that he maintains a 100°F/hr cooldown rate and that auxiliary feedwater is available to maintain steam generator inventory.

Prior to fifteen minutes the transient is identical to the no operator action transient (Case 1) just described. At fifteen minutes, the operator opens both ADVs and establishes a cooldown rate of 100°F/hr in each steam generator. The steam generator pressure, Figure 2.5-15, responds by decreasing in order to maintain saturation pressure at the steam generator temperature.

The steam generator cooldown causes the RCS to begin to cooldown and to depressurize, Figure 2.5-15. The decrease in RCS pressure relative to the unmitigated transient results in a decrease in the break flowrate, Figure 2.5-16, and consequently, an increase in the

Table 2.5-9

SEQUENCE OF EVENTS FOR CASE 2
0.02 ft^2 BREAK WITH NO HPSI AND WITH RAPID SG COOLDOWN

Event	Time (seconds)
Break	0
Reactor/turbine trip on low pressure	68
MSSVs open	73
RCPs trip (manual at 1300 psia)	129
Operator begins SG cooldown	900
SIT injection begins	3535
Core uncovery	(1)
End of simulation	5000

(1) Core uncovery is not predicted to occur.

RCS inventory, Figure 2.5-17. At approximately 3500 seconds the RCS depressurizes to 600 psia at which time the SITs begin to inject into the RCS. The SIT flowrate, Figure 2.5-18, exceeds the leak rate so the RCS inventory begins to increase.

At this point in the transient, the operator has regained control of RCS inventory. By continuing the steam generator cooldown, and therefore the RCS depressurization, the resultant SIT flow will keep the core covered. At 200 psia the LPSI pumps will begin to inject and maintain RCS inventory after the SITs empty at an RCS pressure of approximately 100 psia.

2.5.3.4 Results for Case 3: RCS Depressurization via PORVs

This subsection describes the transient results for Case 3, the small break LOCA with no HPSI transient mitigated by the opening of PORVs. The purpose of opening the PORVs is to rapidly depressurize the RCS below the pressure of the SITs in order that they can reflood the core.

The sequence of important events for the transient is listed in Table 2.5-10 (p. 180). The system parameters discussed below are shown as a function of time in Figure 2.5-19 through 2.5-24. In the simulation it was assumed that the operator opens two PORVs at fifteen minutes and keeps them full open for the remainder of the transient. It was further assumed that the operator does not cooldown the steam generators in parallel with opening the PORVs. The transient is identical to the no operator action transient described above, Case 1, until fifteen minutes at which time the operator opens two PORVs. The PORVs in conjunction with the break provide sufficient area to vent the steam produced in the RCS so the RCS begins to depressurize, Figure 2.5-19. Figures 2.5-20 and 2.5-21 show the leak flowrate and PORV flowrate, respectively. At approximately 1900 seconds the core begins to uncover, Figure 2.5-22, and at approximately 2300 seconds the SITs begin to inject, Figure 2.5-23.

Table 2.5-10

SEQUENCE OF EVENTS FOR CASE 3
0.02 ft^2 BREAK WITH NO HPSI AND WITH RCS DEPRESSURIZATION VIA PORVs

Event	Time (seconds)
Break	0
Reactor/turbine trip on low pressure	68
MSSVs open	73
RCPs trip (manual at 1300 psia)	129
Operator opens PORVs	900
Core uncovery begins	1931
SIT injection begins	2291
Minimum core uncovery occurs	2297
End of simulation	5000

The SITs do not provide sufficient flow to quickly refill the core. The inner vessel two-phase mixture level increases from a minimum level of sixteen feet at about 2300 seconds to approximately nineteen feet where it remains for the duration of the simulation, Figure 2.5-22. This occurs because the PORVs do not provide sufficient area, i.e., PORVs do not vent enough steam, to depressurize the RCS at a rate which will result in sufficient SIT flow to refill the core. The clad temperature as a function of time is shown in Figure 2.5-24.

2.5.3.5 Comparison of Results

The three scenarios simulated in this analysis were described in the previous sections. This section compares the important results of the three scenarios with respect to overall system performance. The transient RCS pressure, RCS inventory, and reactor inner vessel two-phase mixture level are compared in Figures 2.5-25 through 2.5-27 for the three cases.

As shown in Figure 2.5-25, opening the PORVs (Case 3) results in the fastest initial RCS depressurization. This depressurization, however, is accomplished by venting steam from the RCS rather than condensing steam in the steam generators as in Case 2. Therefore, even though Case 3 results in the fastest initial RCS depressurization and, hence, the lowest leak flowrate, the added mass loss via the PORVs results in an overall RCS mass loss rate greater than that for Case 1 or Case 2, Figure 2.5-26. Case 3 also results in the earliest time of core uncovery, Figure 2.5-27.

Because of the larger effective flow area of the ADVs (0.108 ft^2 per valve) versus that of the PORVs (0.0228 ft^2 per valve), RCS depressurization can be maintained at lower RCS pressures by means of steam generator cooldown than it can by use of PORVs. As shown in Figure 2.5-25, the rate of RCS depressurization begins to decrease at about 500 psia for Case 3, whereas for Case 2 the RCS depressurization rate remains fairly constant. As a result of the decrease in the rate of depressurization the SIT flowrate decreases for Case 3 and, as shown in Figure 2.5-27, level recovery stops at about 2700 seconds and the core remains partially uncovered.

2.5.3.6 Conclusions

Two general conclusions that are demonstrated by this analysis are as follows:

1. Either aggressive steam generator cooldown or opening PORVs can prevent the serious consequences of a small break LOCA with no high pressure safety injection if the actions are taken in a timely fashion.

2. Steam generator cooldown via ADVs is preferable to direct RCS depressurization via PORVs for mitigation of the SBLOCA transient with no HPSI for the following four reasons.

    a. Break sizes that are too small to result in rapid RCS depressurization to the SIT injection pressure also result in relatively small mass loss rates. Steam generator cooldown can depressurize the RCS at a sufficiently rapid rate to recovery from such break sizes, and therefore rapid direct depressurization of the RCS via PORVs is not required.

    b. Steam generator cooldown can maintain the rate of RCS depressurization at low pressures after the SITs begin to inject. This results in SIT flow in excess of the break flow.

c. The use of PORVs increases the rate of RCS mass loss and thus results in core uncovery. In contrast, rapid steam generator cooldown via ADVs maintained the core covered, Figure 2.5-27.

d. Much larger PORVs than those used in this analysis would be required to maintain an RCS depressurization rate that would results in sufficient SIT flow to recover the core.

Figures for Section 2.5

FIGURE 2.5-1

OPERATOR ACTION DURING MULTIPLE SGTR

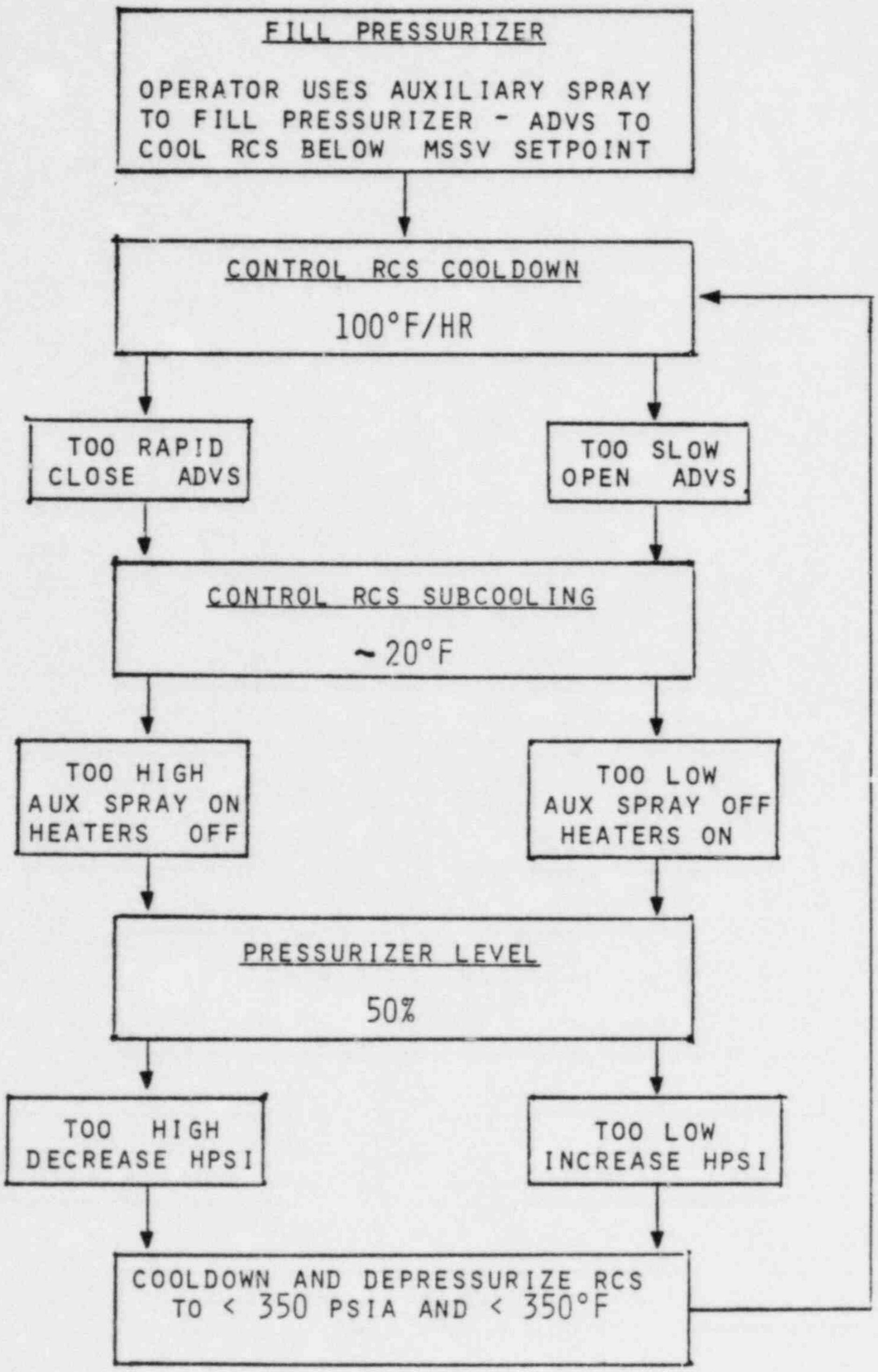
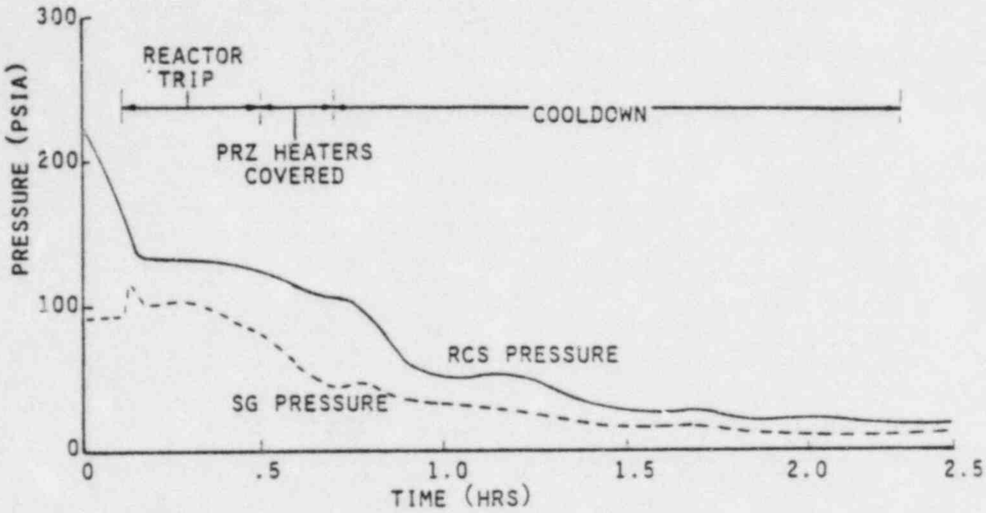


FIGURE 2.5-2

3410 CLASS PLANT
TEMPERATURES AND PRESSURES DURING MULTIPLE SGTR
ONE TUBE PER SG



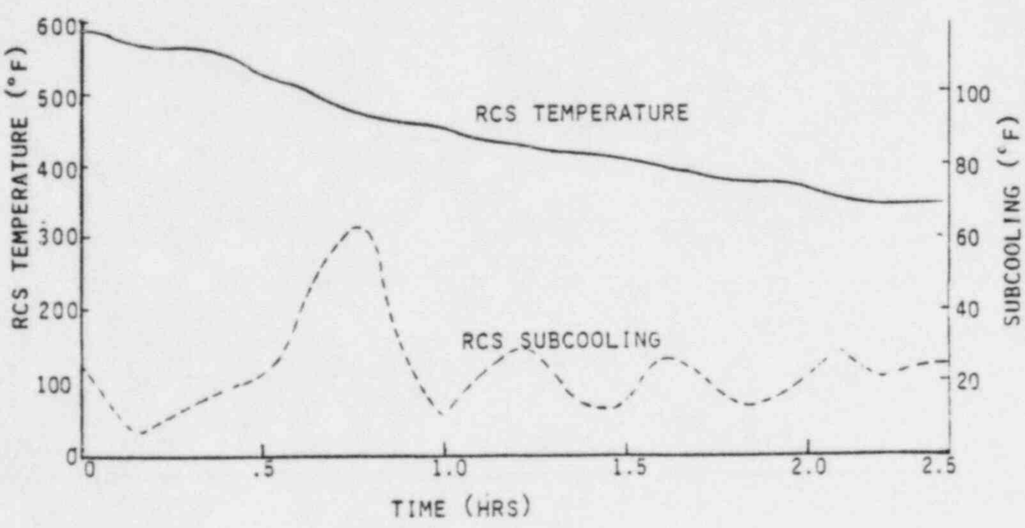
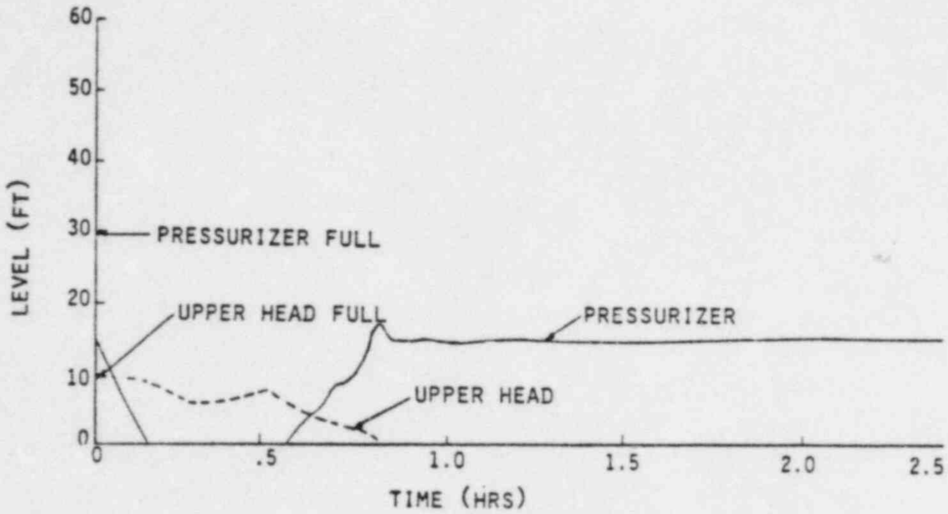


FIGURE 2.5-3

3410 CLASS PLANT
LEVELS AND DOSES DURING MULTIPLE SGTR
ONE TUBE PER SG



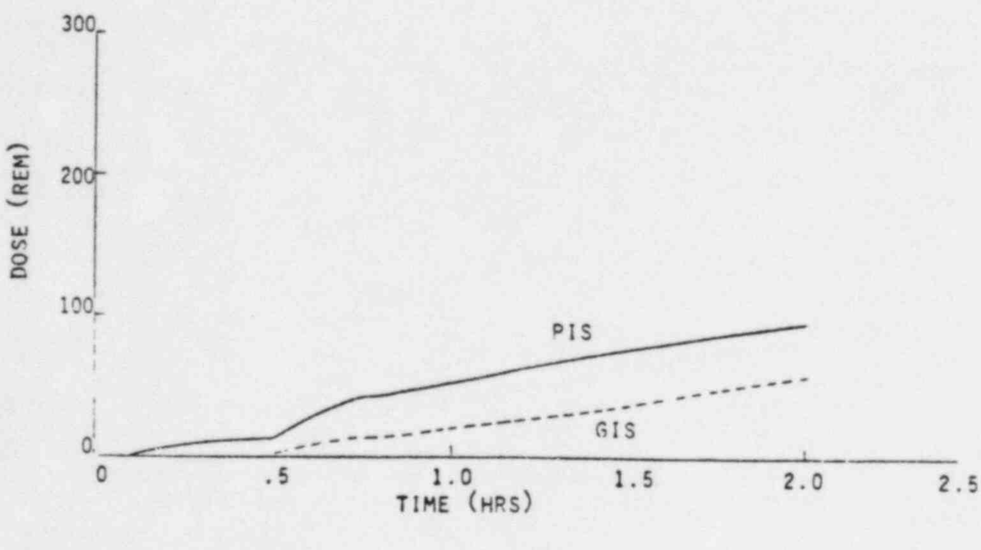
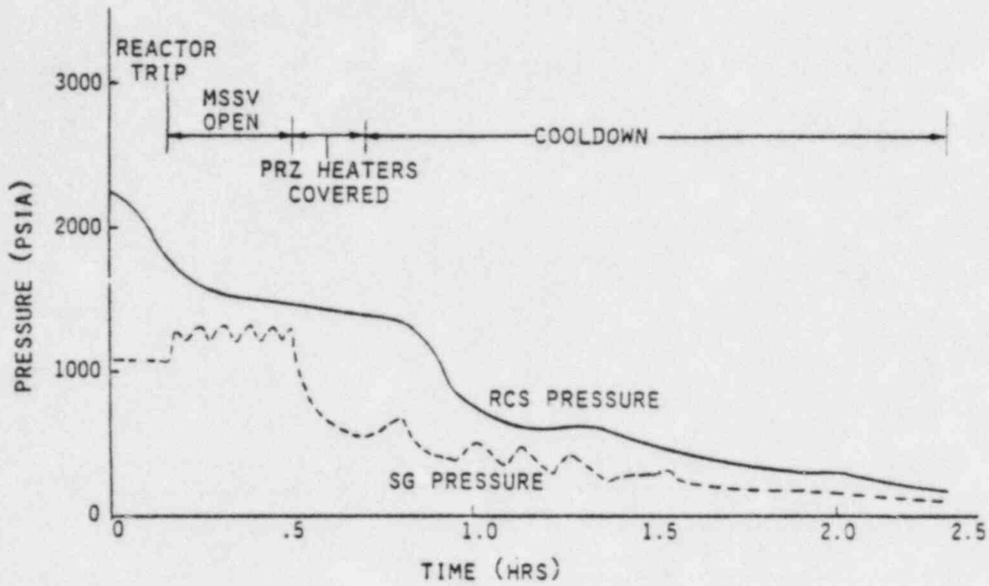


FIGURE 2.5-4

3800 CLASS PLANT
TEMPERATURES AND PRESSURES DURING MULTIPLE SGTR
ONE TUBE PER SG



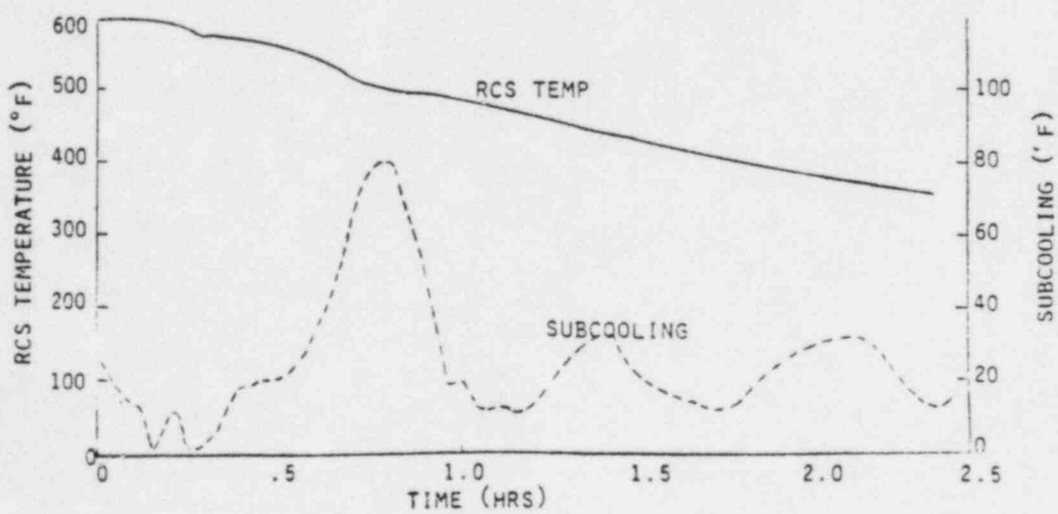
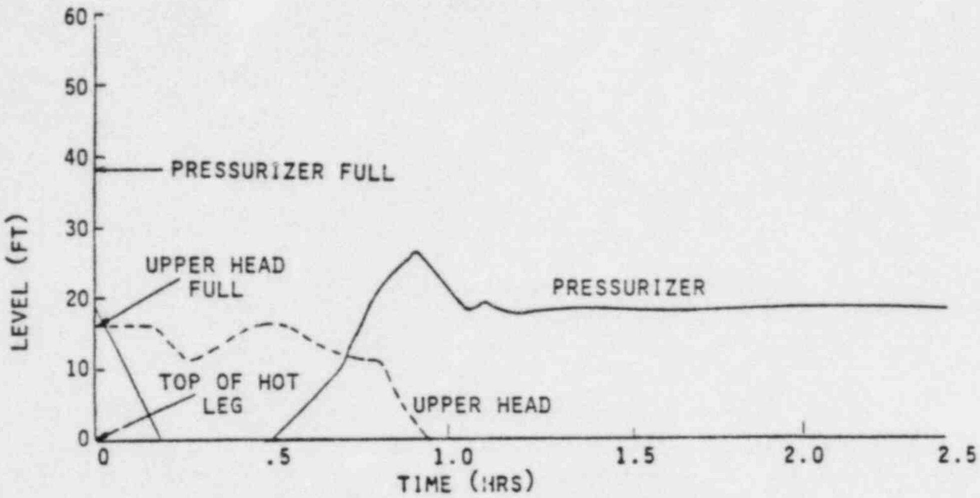


FIGURE 2.5-5

3800 CLASS PLANT
LEVELS AND DOSES DURING MULTIPLE SGTR
ONE TUBE PER SG



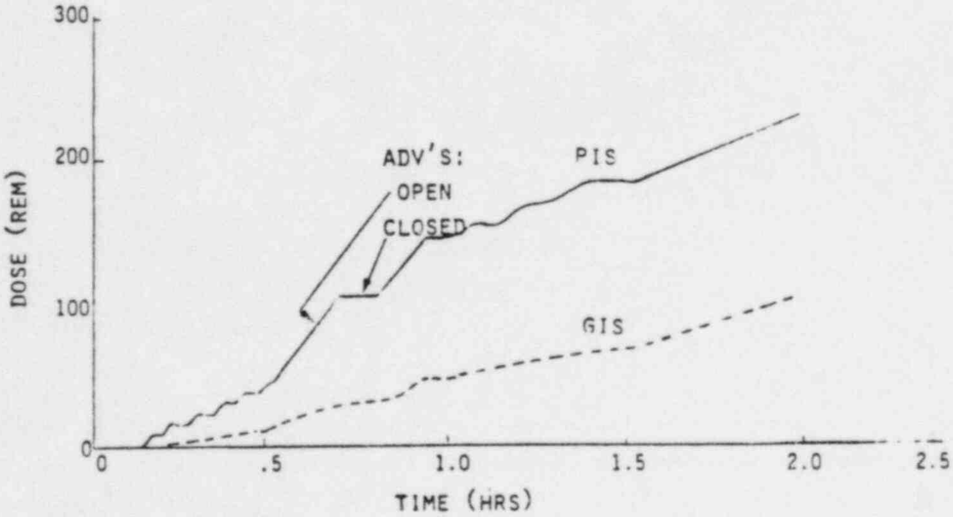
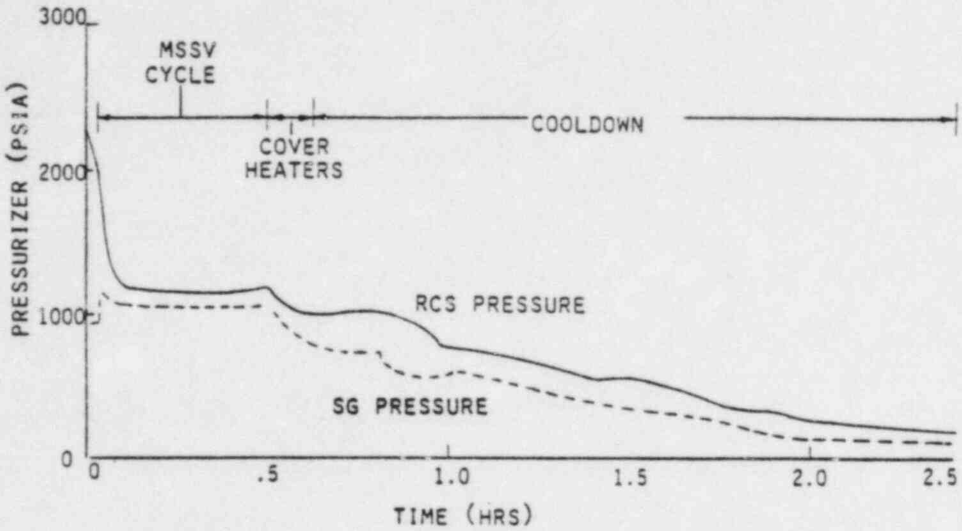


FIGURE 2.5-6

3410 CLASS PLANT
TEMPERATURES AND PRESSURES DURING MULTIPLE SGTR
THREE TUBES PER SG



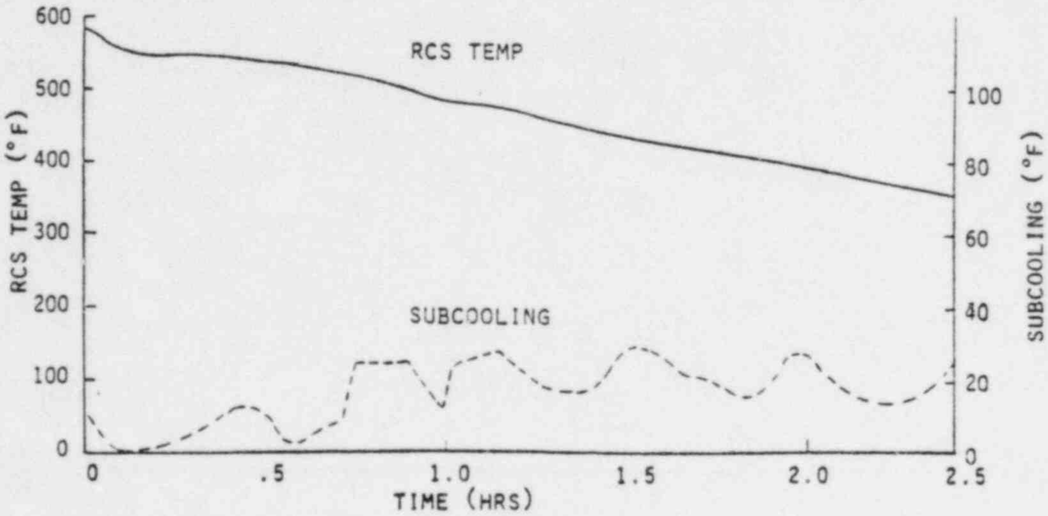
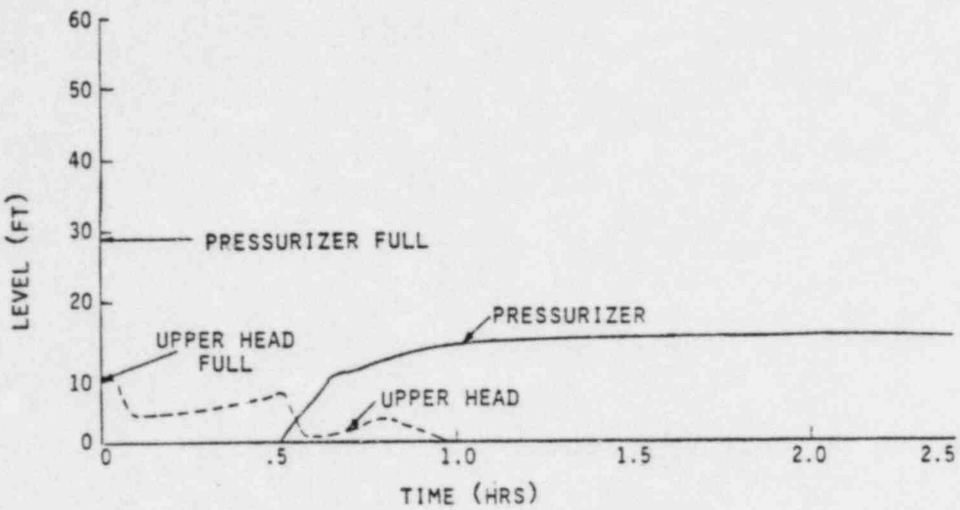


FIGURE 2.5-7

3410 CLASS PLANT
LEVELS AND DOSES DURING MULTIPLE SGTR
THREE TUBES PER SG



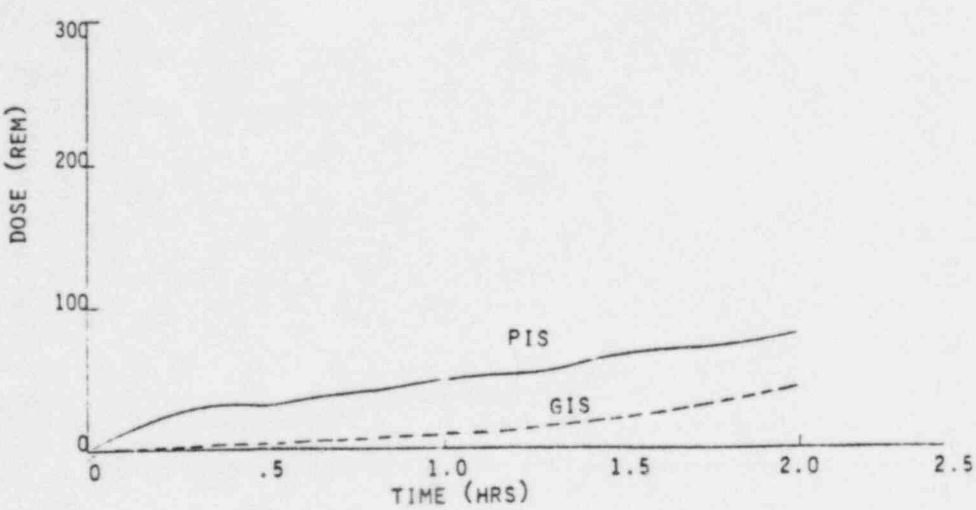
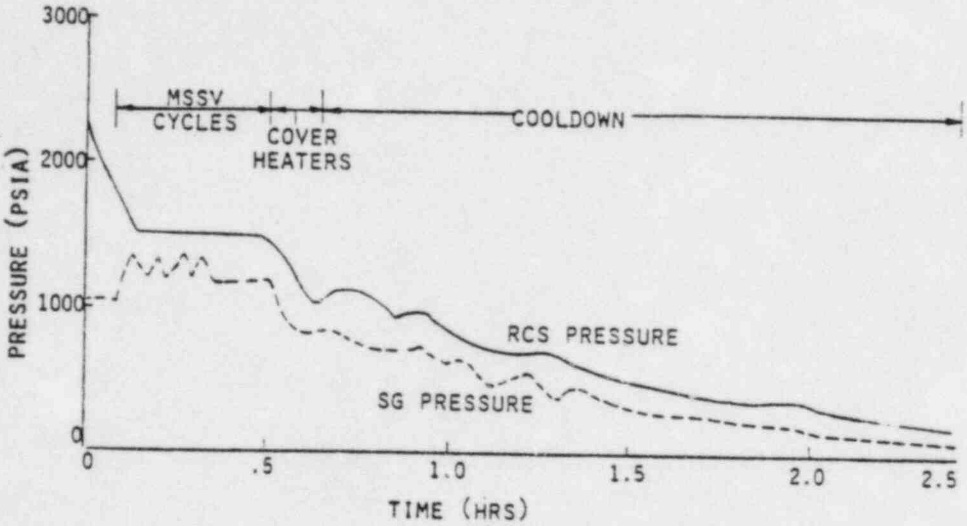


FIGURE 2.5-8

3800 CLASS PLANT
TEMPERATURES AND PRESSURES DURING MULTIPLE SGTR
THREE TUBES PER SG



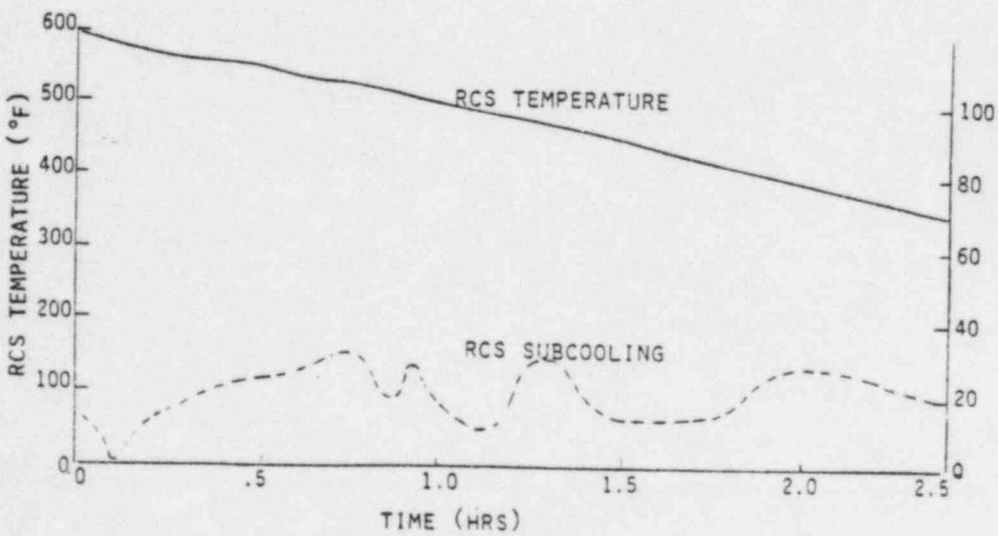
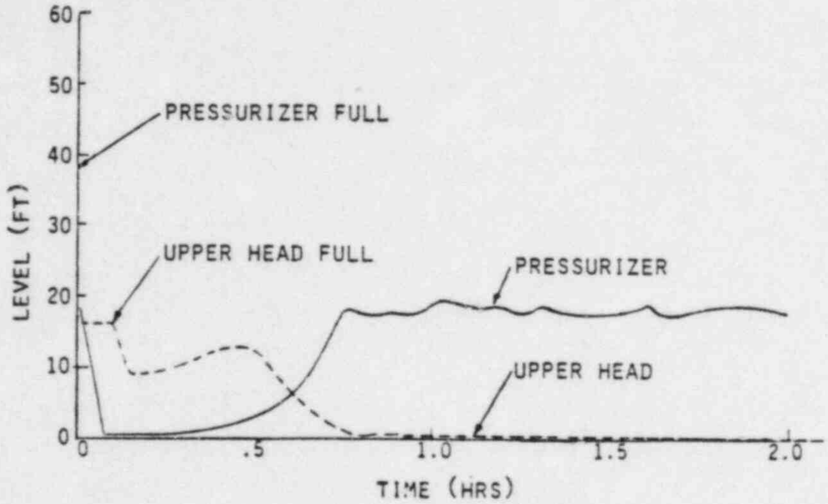


FIGURE 2.5-9

3800 CLASS PLANT
LEVELS AND DOSES DURING MULTIPLE SGTR
THREE TUBES PER SG



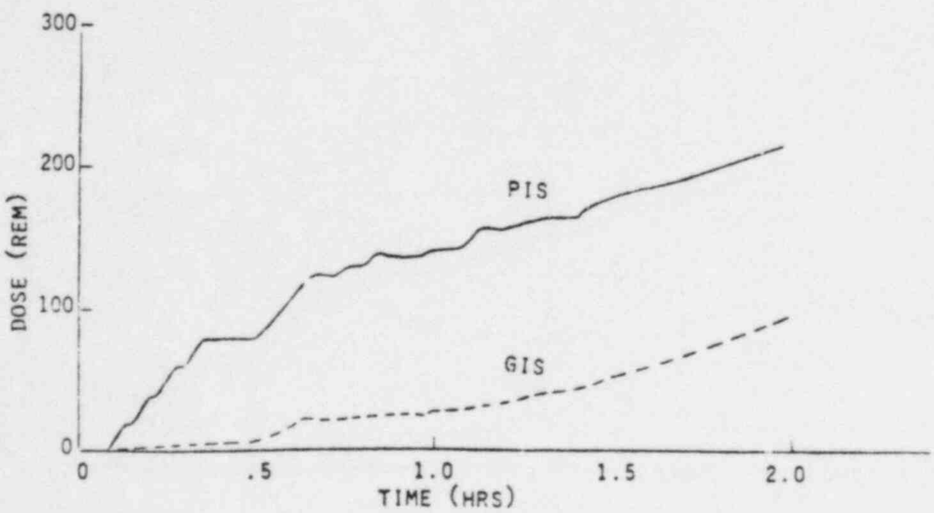


Figure 2.5-10

SBLOCA WITH NO HPSI
REACTOR INNER VESSEL TWO-PHASE MIXTURE LEVEL
CASE 1 - NO OPERATOR ACTION

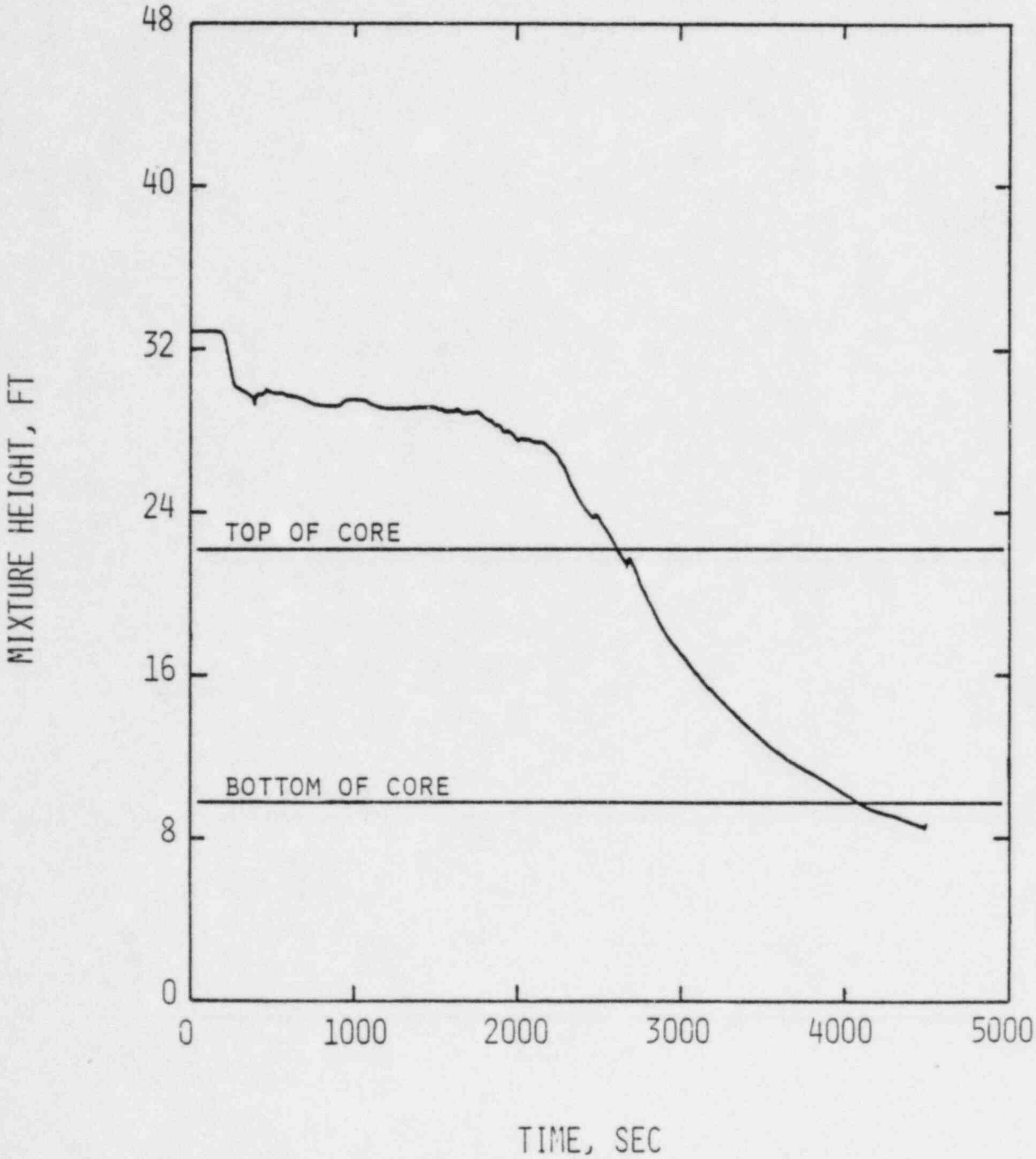


FIGURE 2.5-11

SBLOCA WITH NO HPSI
LEAK FLOWRATE
CASE 1 - NO OPERATOR ACTION

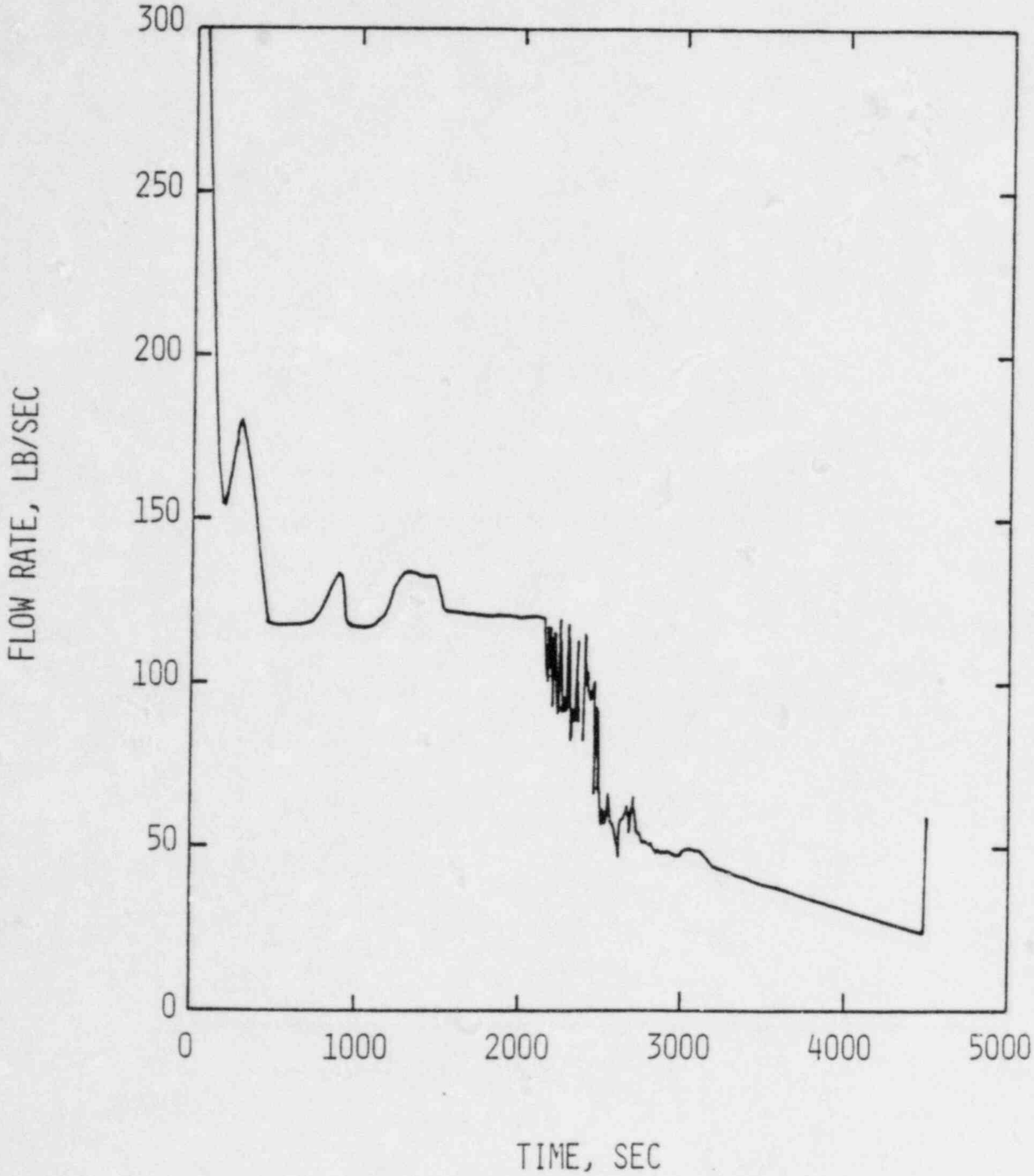


FIGURE 2.5-12

SBLOCA WITH NO HPSI
LEAK FLOW QUALITY
CASE 1 - NO OPERATOR ACTION

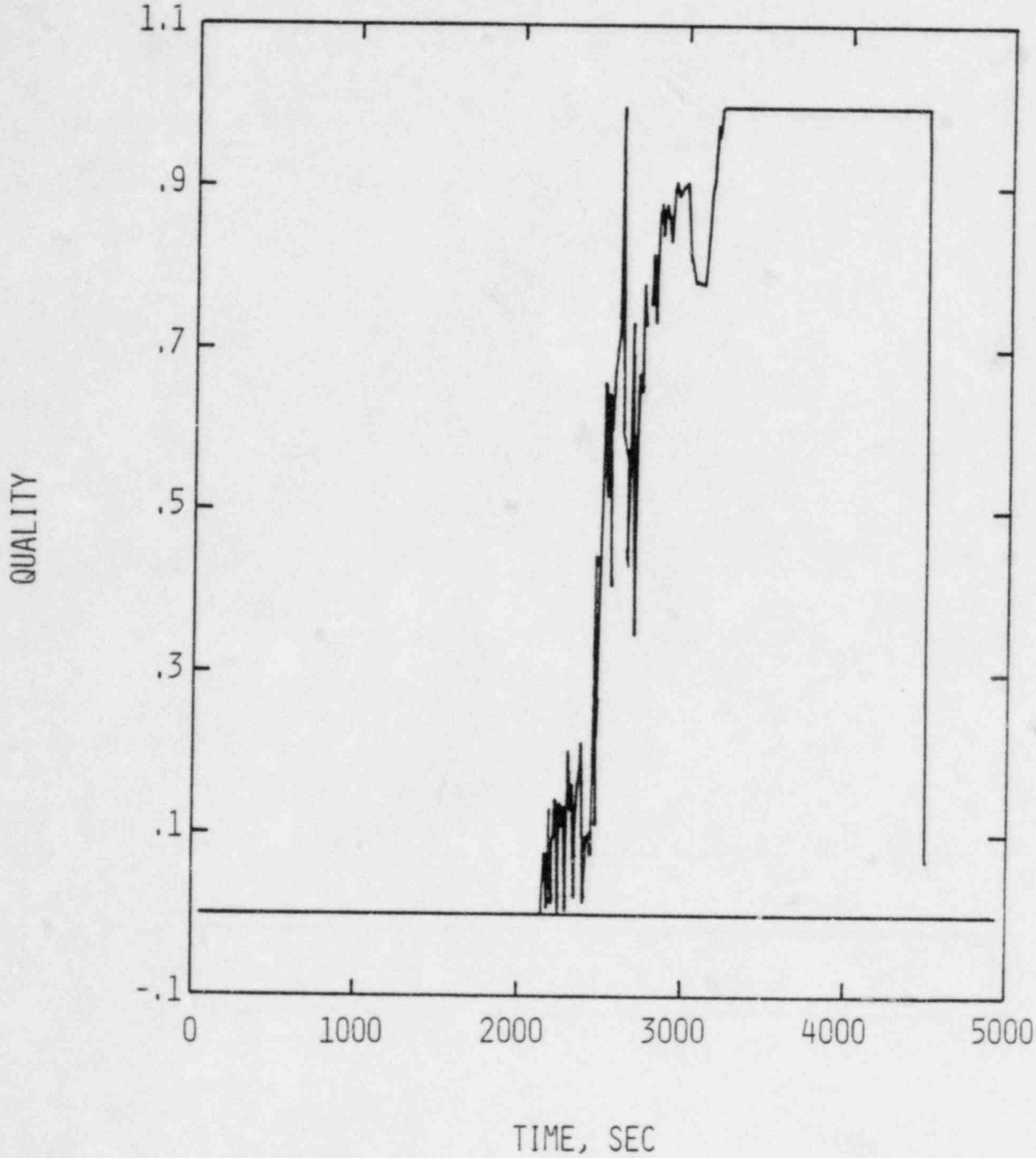


FIGURE 2.5-13

SBLOCA WITH NO HPSI
SG AND RCS PRESSURES
CASE 1 - NO OPERATOR ACTION

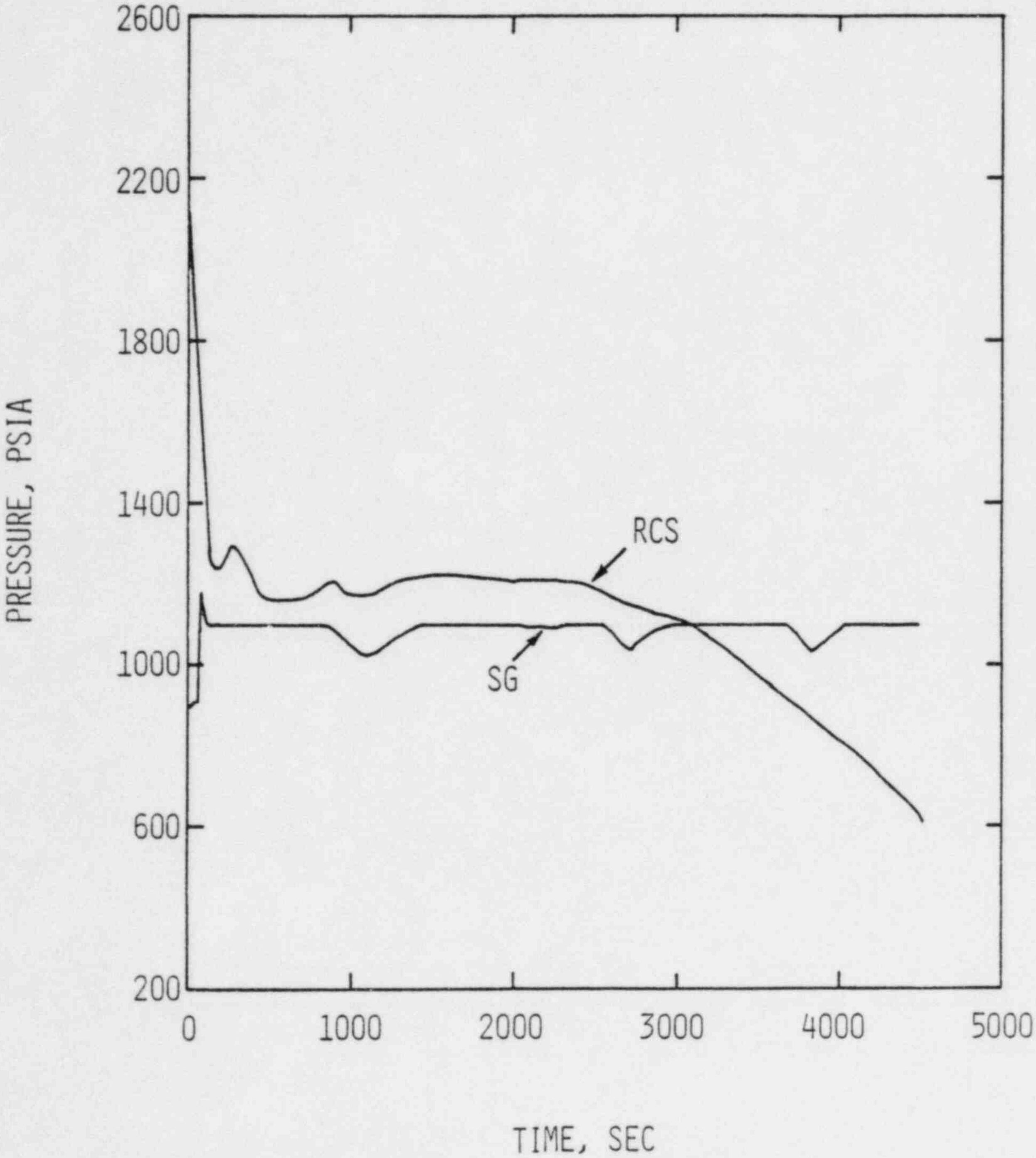


FIGURE 2.5-14

SBLOCA WITH NO HPSI
HOTTEST FUEL ROD CLADDING TEMPERATURE
CASE 1 - NO OPERATOR ACTION

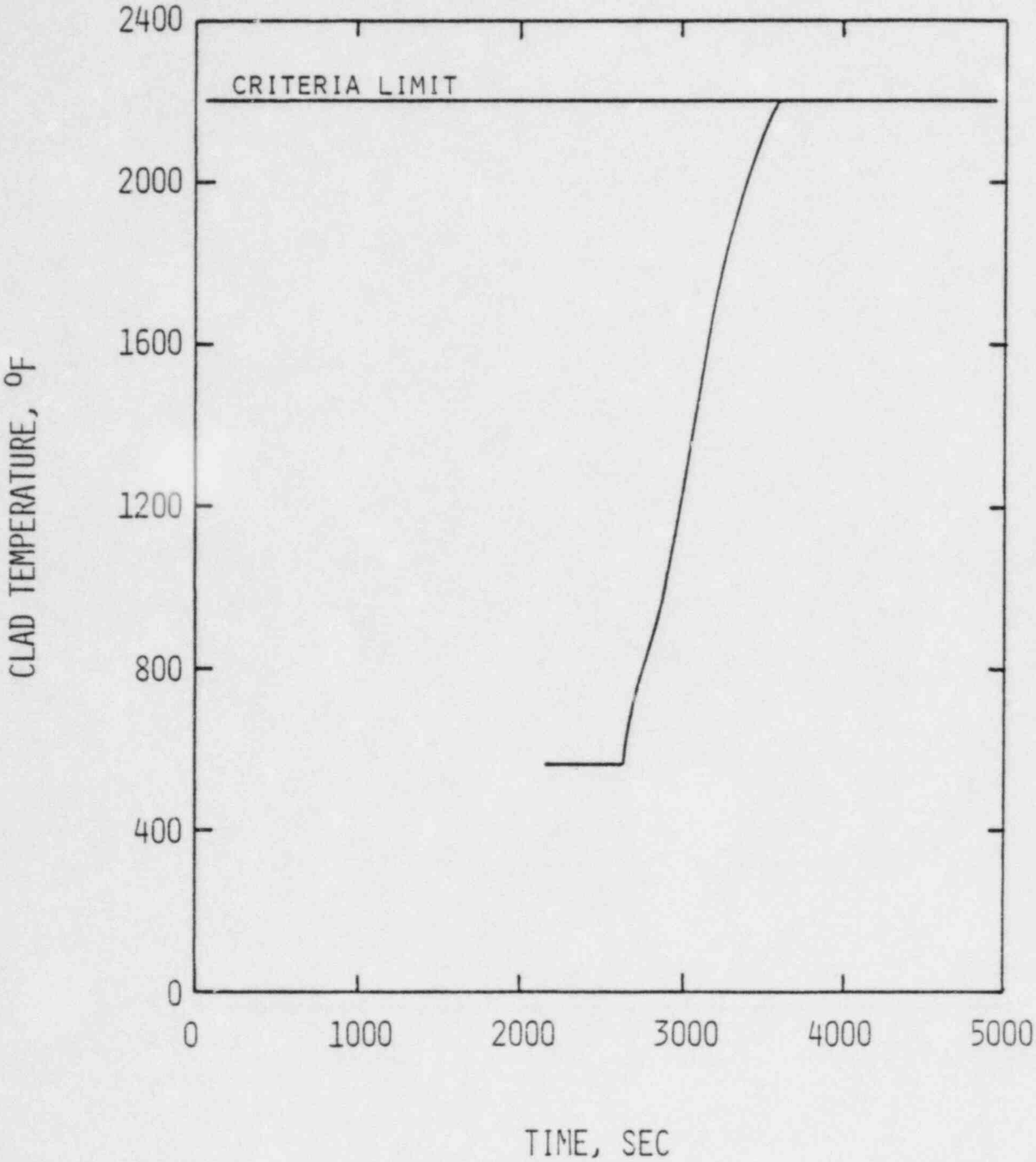


FIGURE 2.5-15

SBLOCA WITH NO HPSI
SG AND RCS PRESSURE
CASE 2 - SG COOLDOWN VIA ADVs

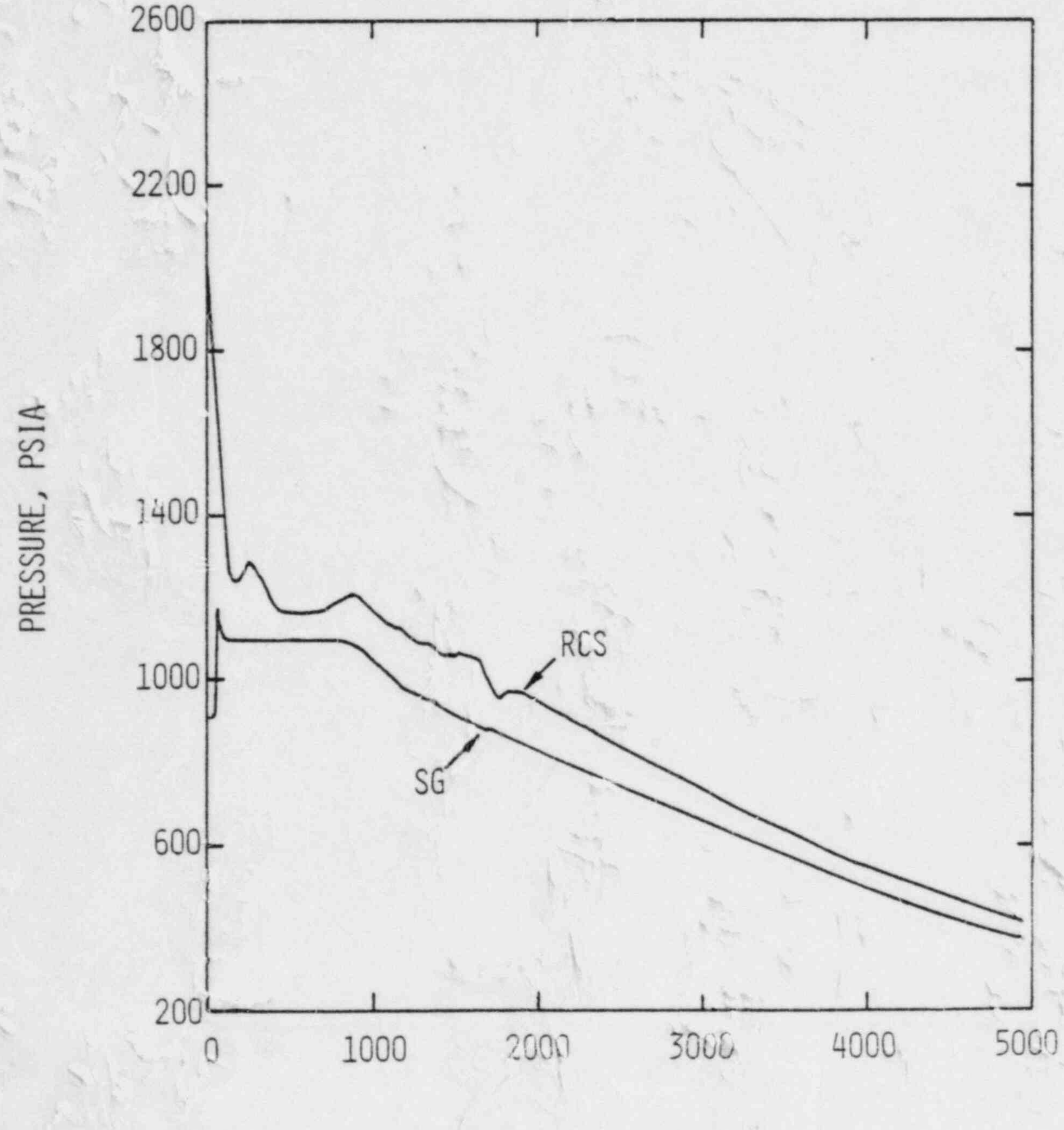


FIGURE 2.5-16

SBLOCA WITH NO HPSI
LEAK FLOWRATE
CASE 2 - SG COOLDOWN VIA ADVs

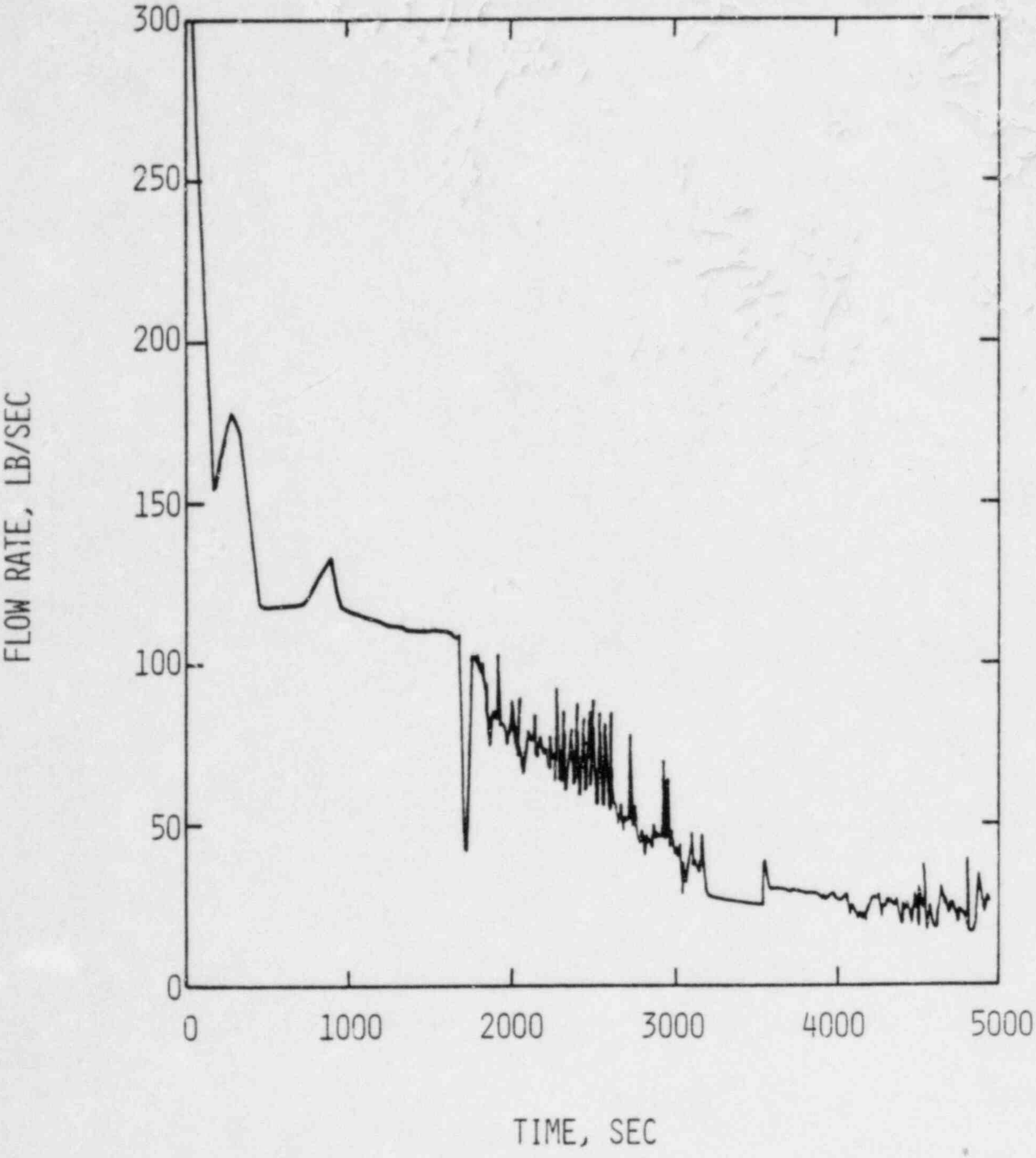


FIGURE 2.5-17

SBLOCA WITH NO HPSI
REACTOR INNER VESSEL TWO-PHASE MIXTURE LEVEL
CASE 2 - SG COOLDOWN VIA ADVs

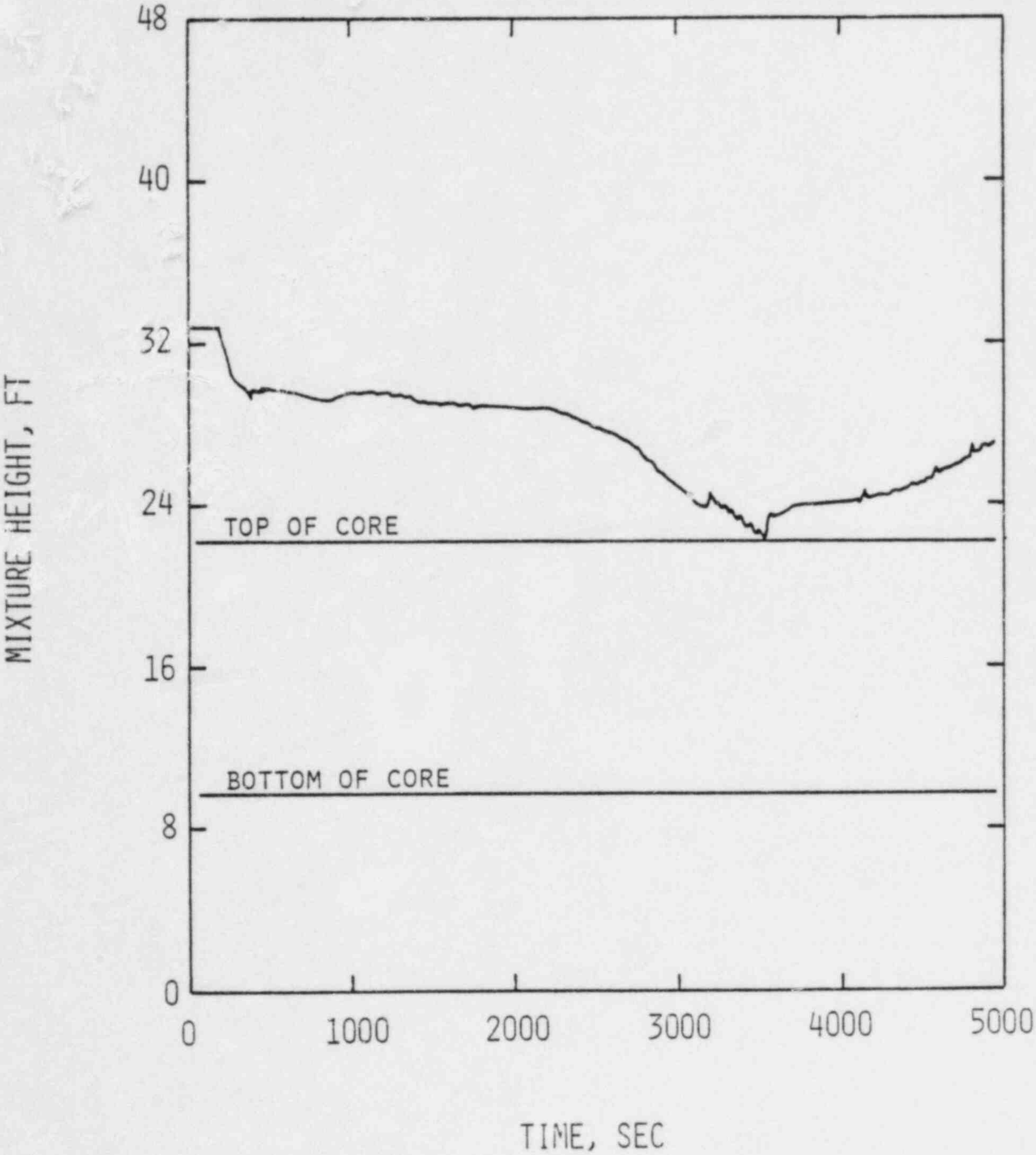


FIGURE 2.5-18

SBLOCA WITH NO HPSI
SIT FLOWRATE
CASE 2 - SG COOLDOWN VIA ADVs

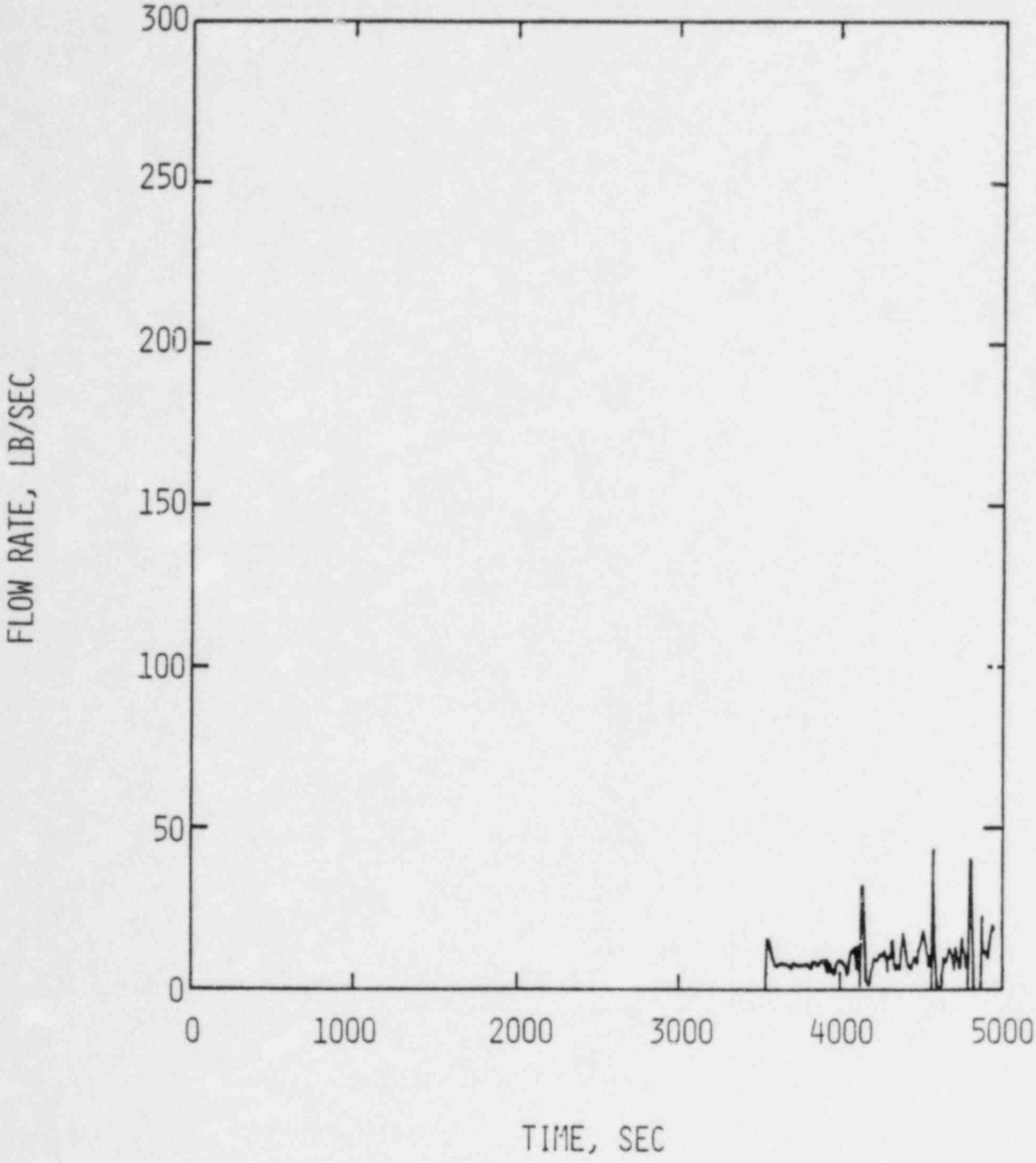


FIGURE 2.5-19

SBLOCA WITH NO HPSI
RCS PRESSURE
CASE 3 - DEPRESSURIZATION VIA PORVs

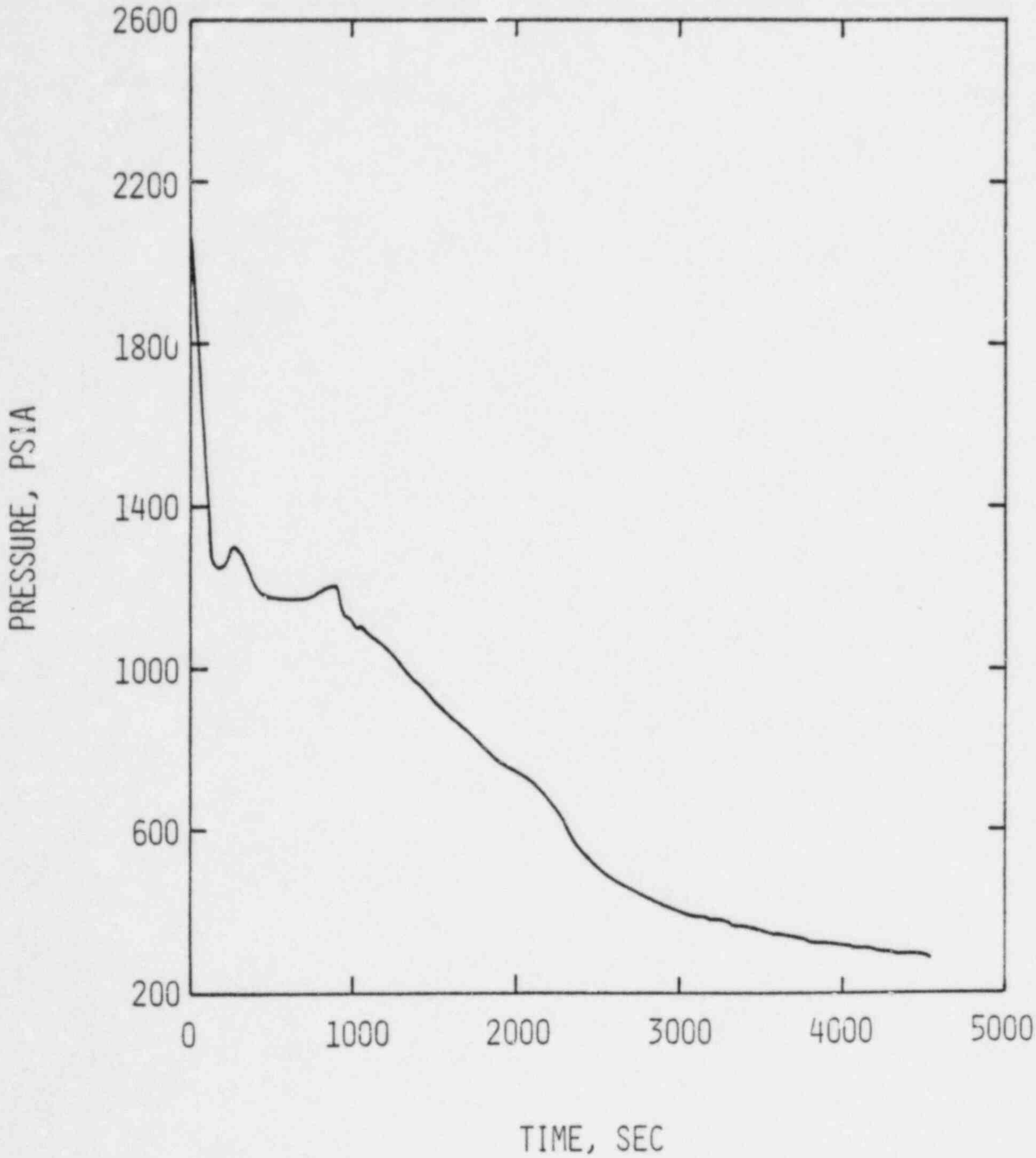


Figure 2.5-20

SBLOCA WITH NO HPSI
LEAK FLOWRATE
CASE 3 - DEPRESSURIZATION VIA PORVs

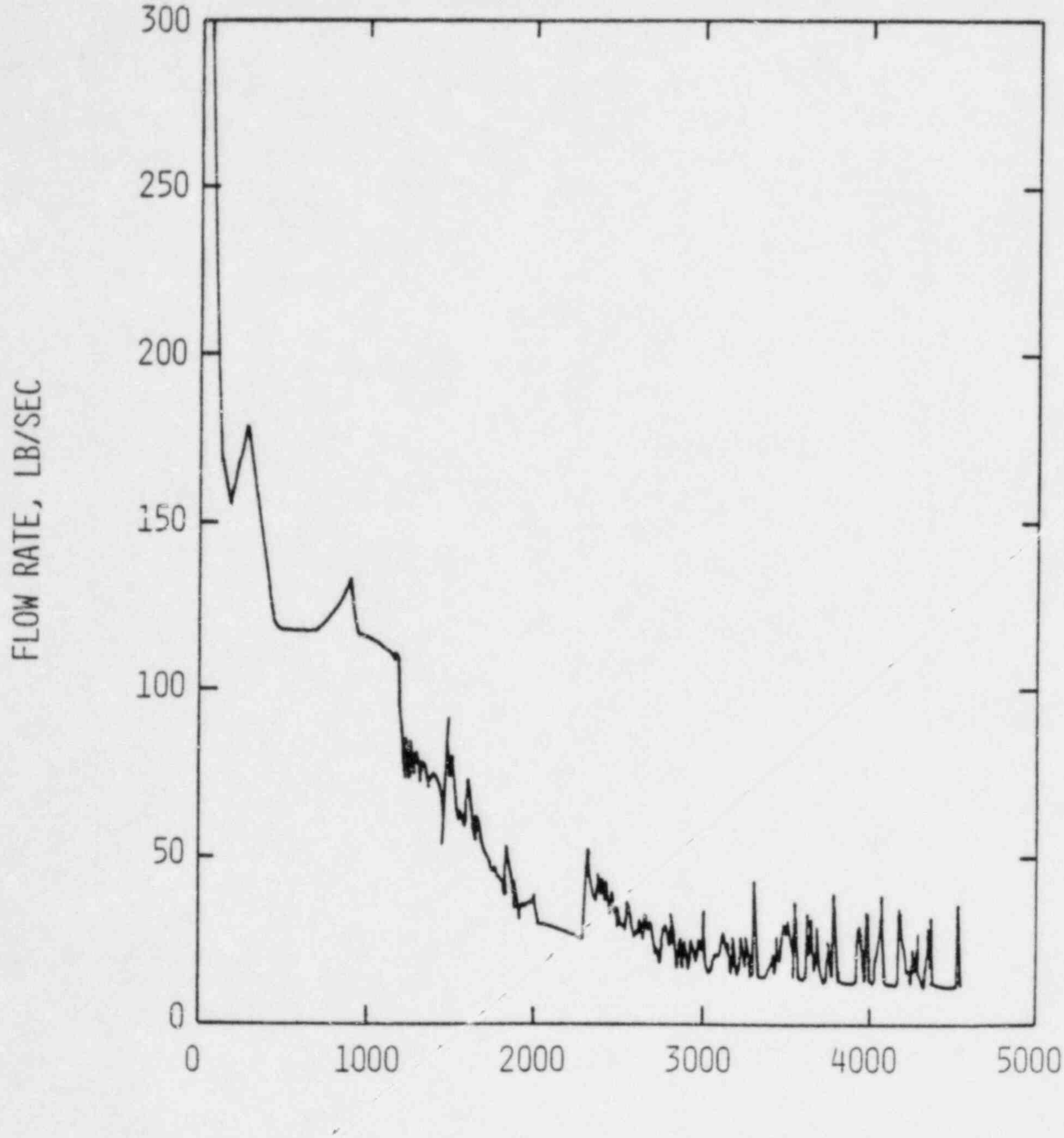


FIGURE 2.5-21

SBLOCA WITH NO HPSI
PORV FLOWRATE
CASE 3 - DEPRESSURIZATION VIA PORVs

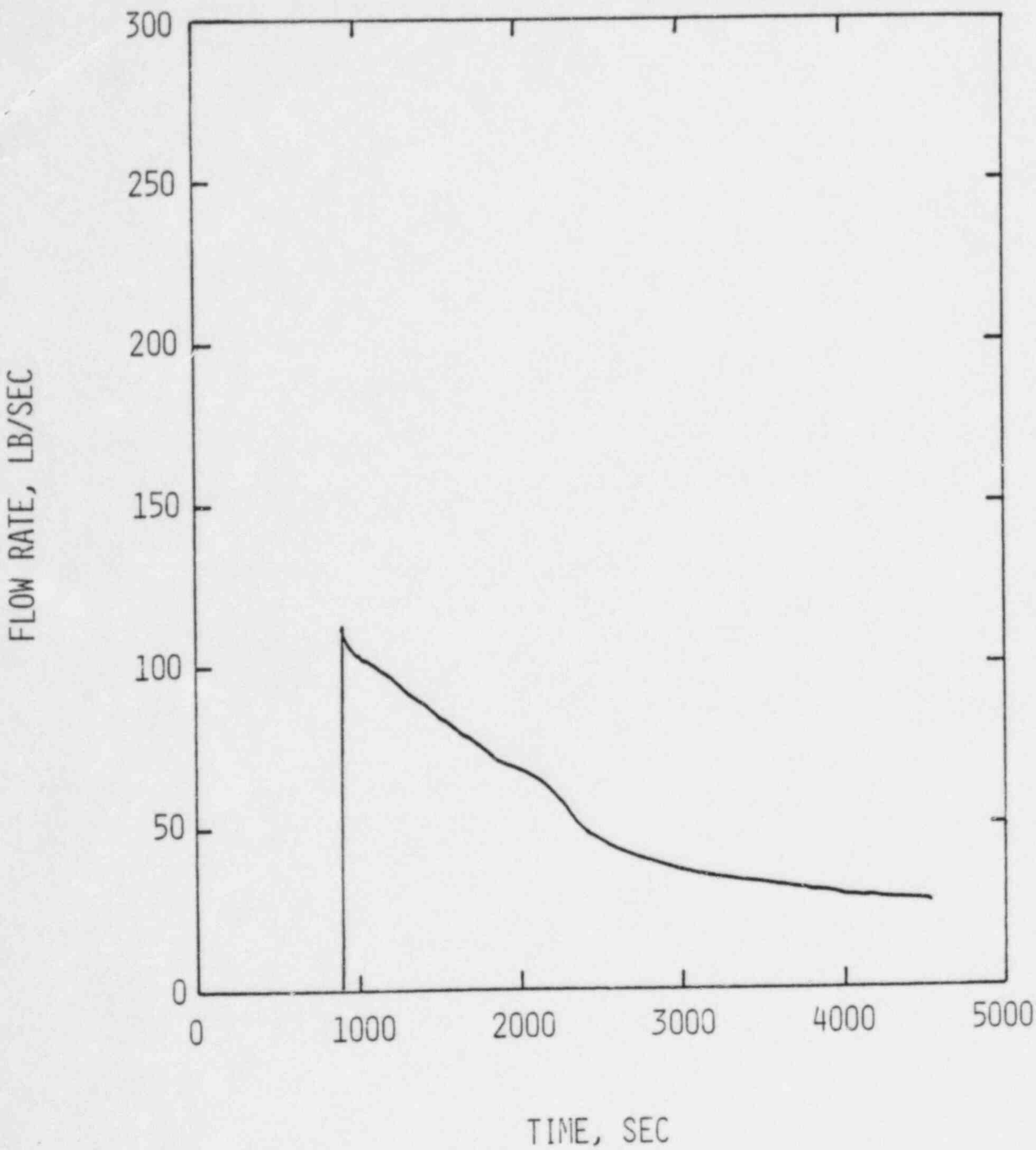


FIGURE 2.5-22

SBLOCA WITH NO HPSI
REACTOR INNER VESSEL TWO-PHASE MIXTURE LEVEL
CASE 3 - DEPRESSURIZATION VIA PORVs

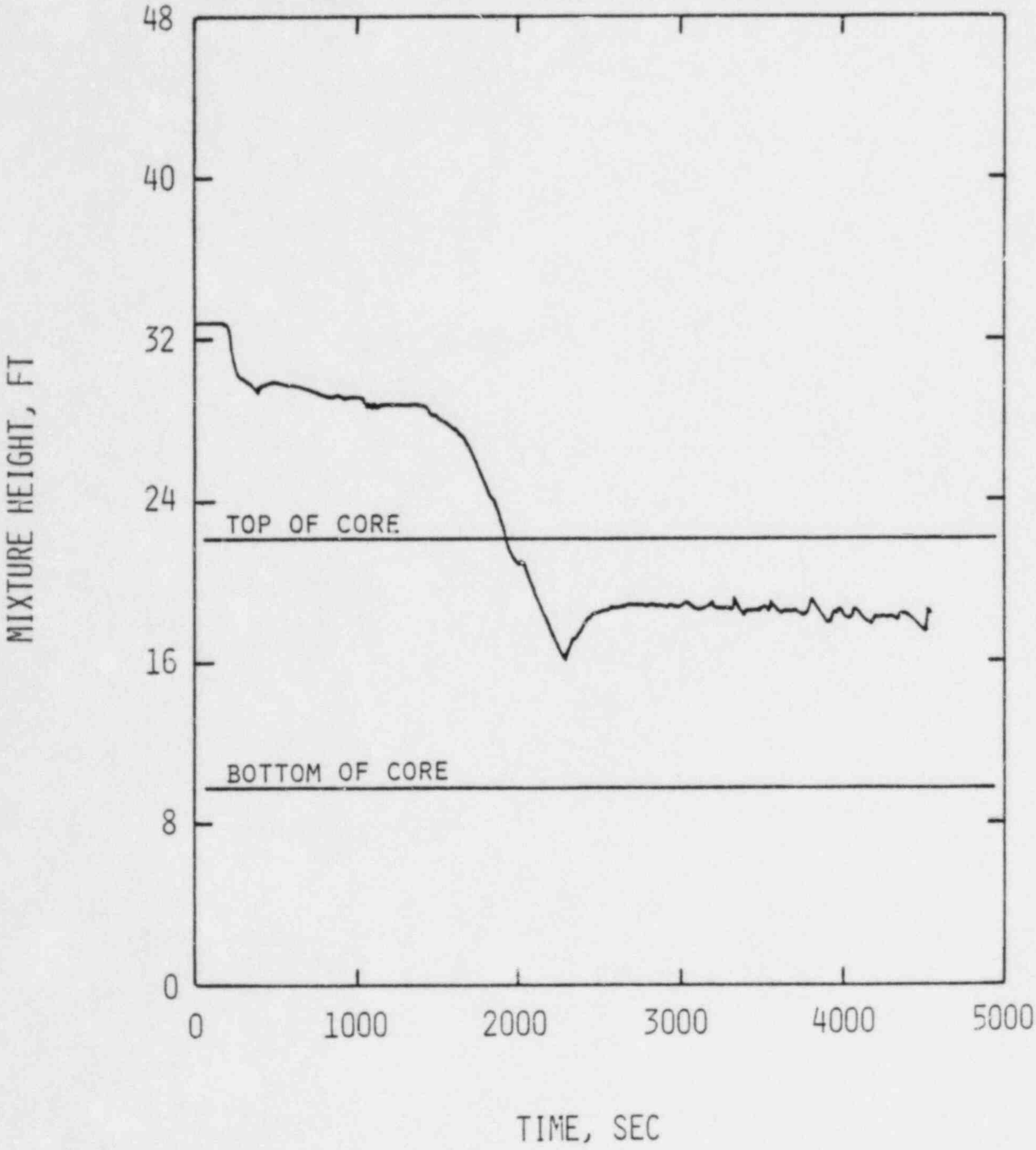


Figure 2.5-23

SBLOCA WITH NO HPSI
SIT FLOW
CASE 3 - DEPRESSURIZATION VIA PORVs

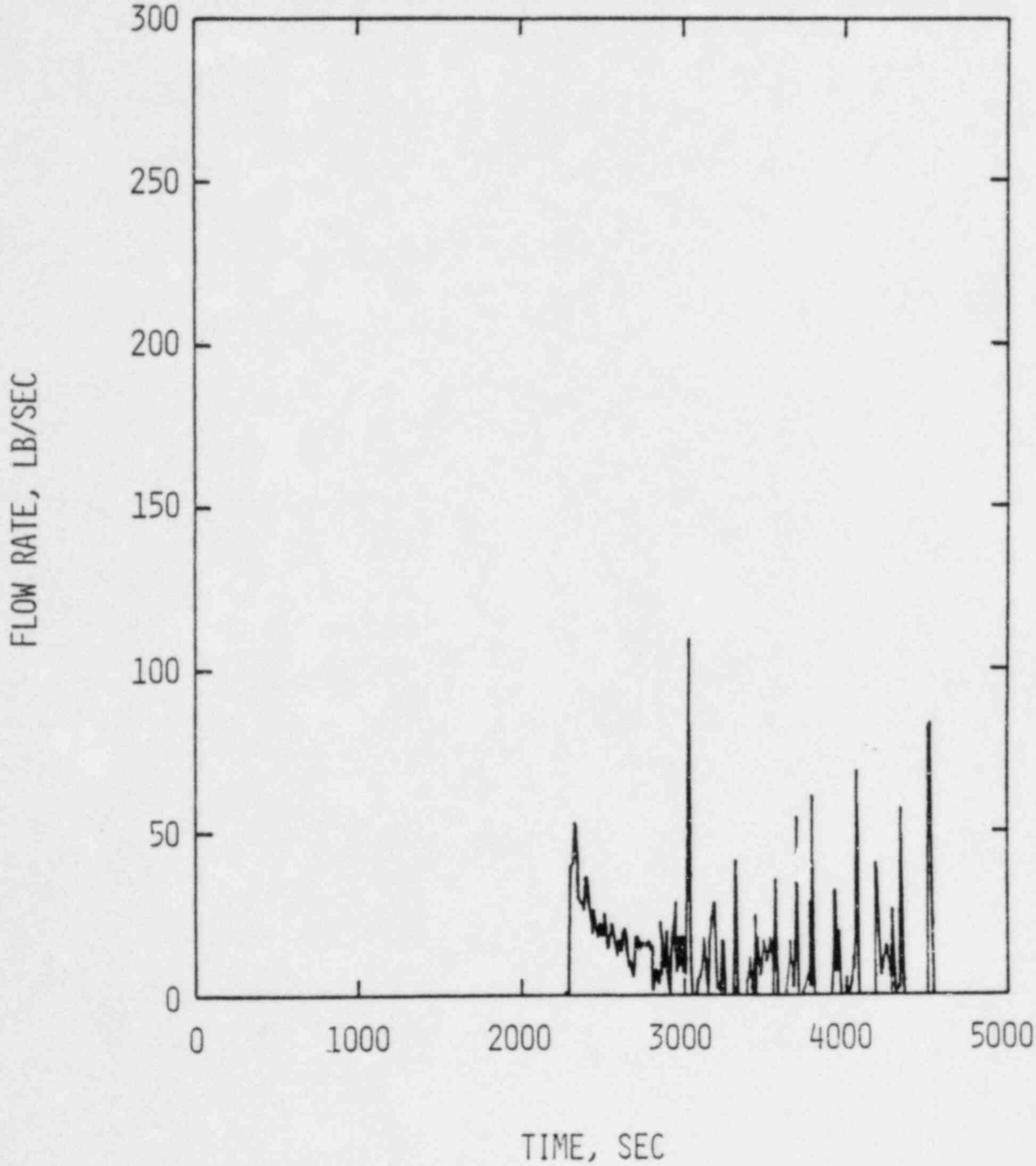


FIGURE 2.5-24

SBLOCA WITH NO HPSI
HOTTEST FUEL ROD CLADDING TEMPERATURE
CASE 3 - DEPRESSURIZATION VIA PORVs

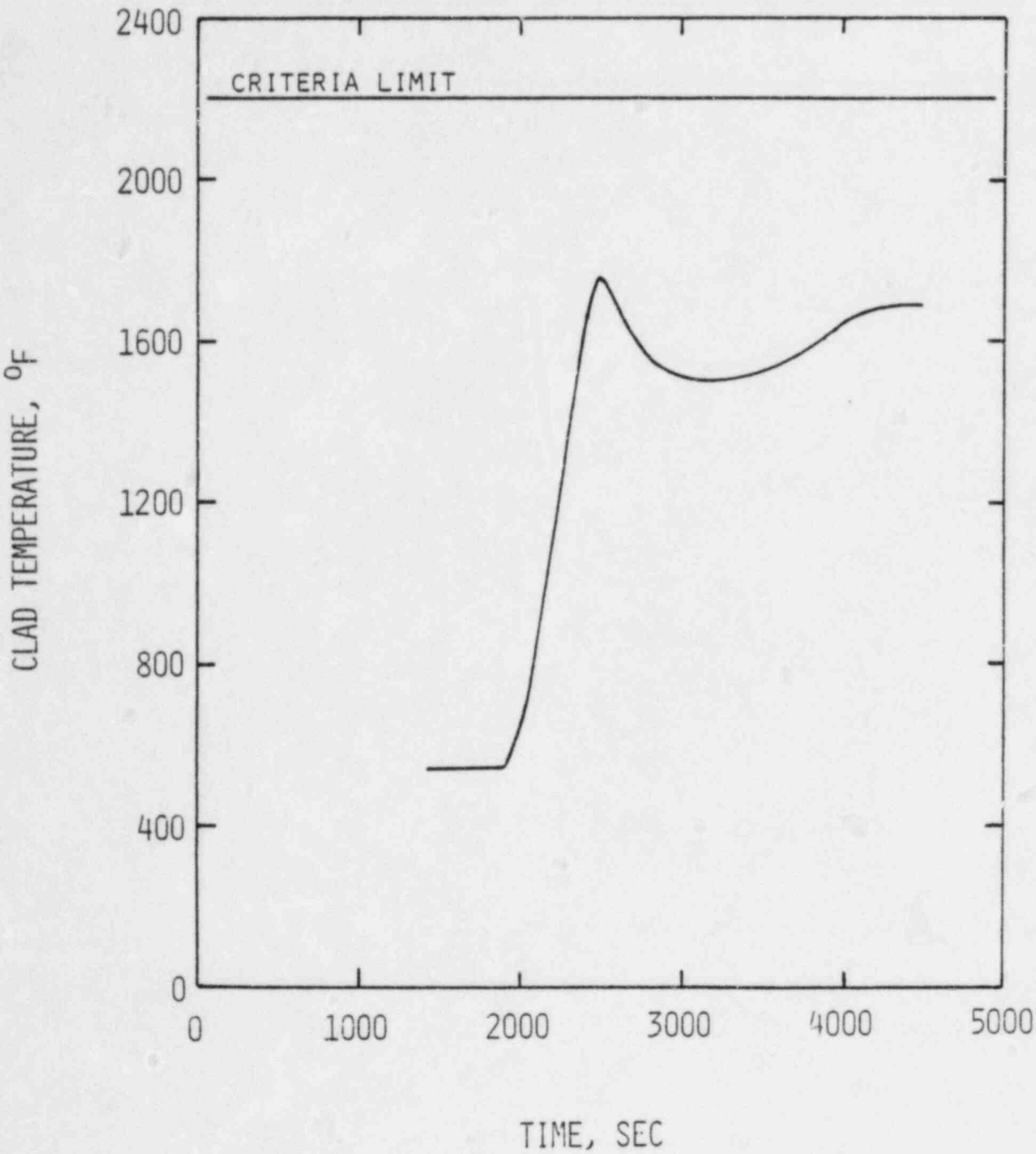


FIGURE 2.5-25

SBLOCA WITH NO HPSI
COMPARISON OF RCS PRESSURES

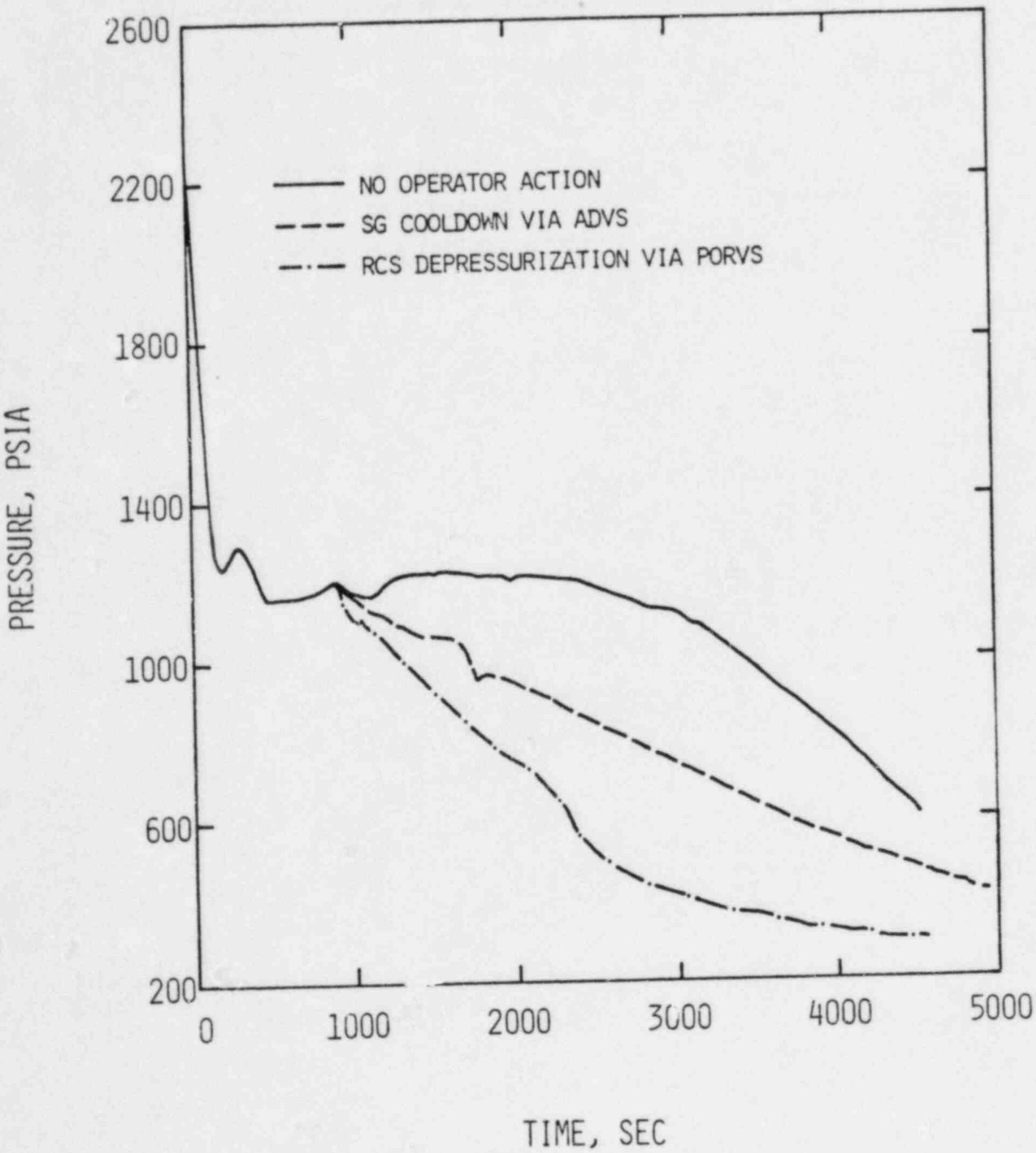


FIGURE 2.5-26

SBLOCA WITH NO HPSI
COMPARISON OF RCS INVENTORY

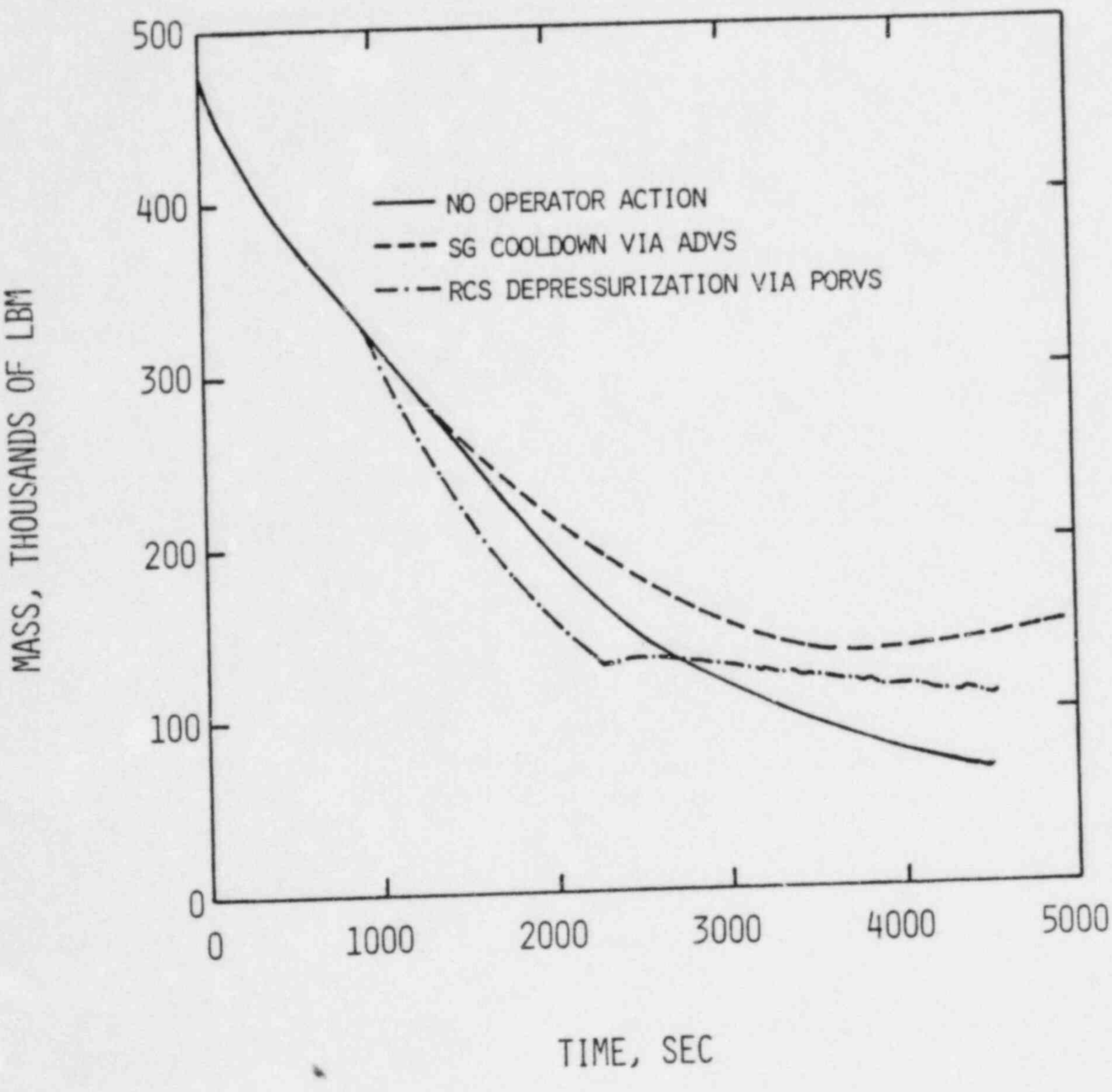
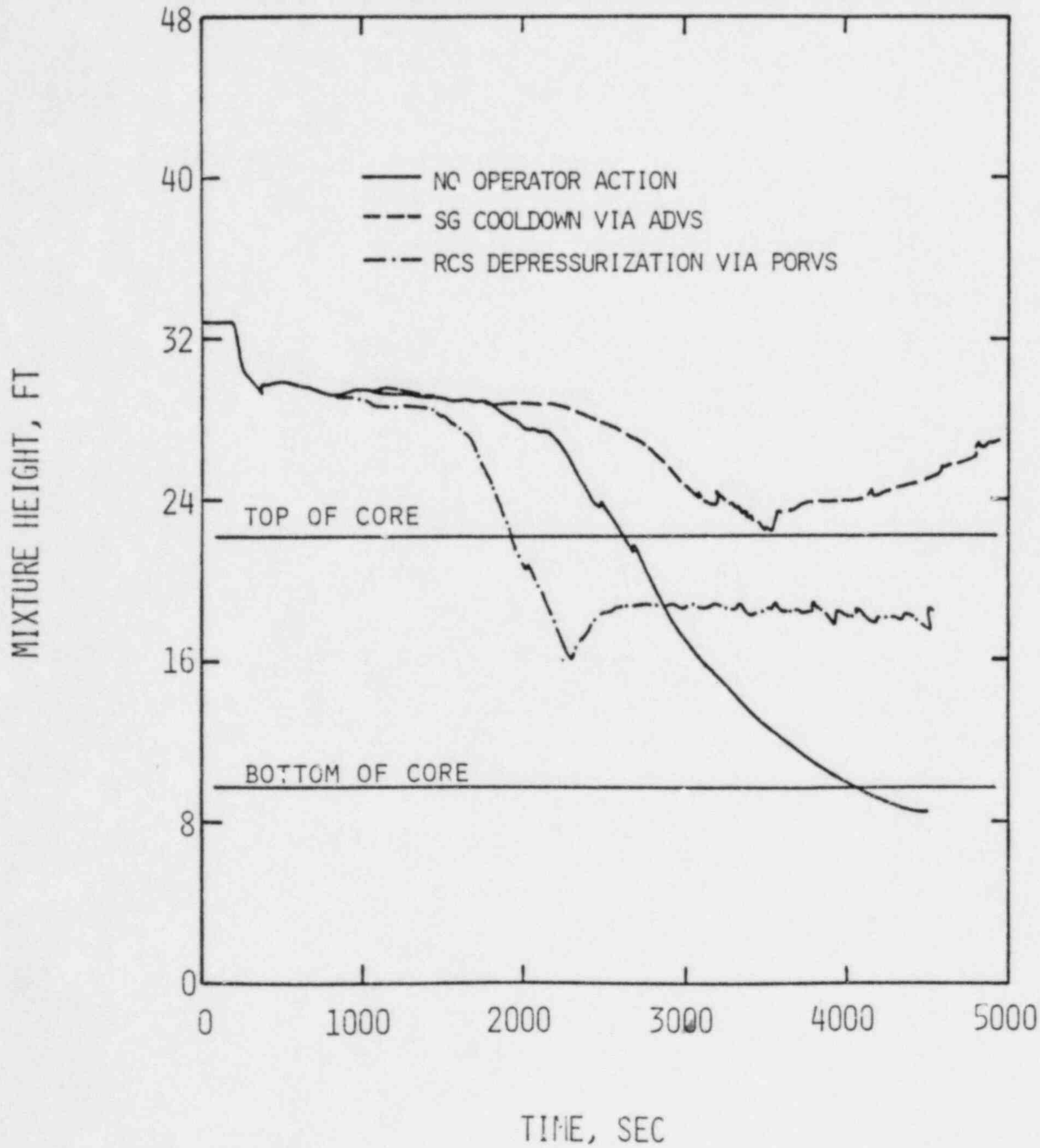


FIGURE 2.5-27

SBLOCA WITH NO HPSI
COMPARISON OF
REACTOR INNER VESSEL TWO-PHASE MIXTURE LEVEL



2.6 Question 6: Use of Low Pressure Pumps for Feeding SGs

C-E has proposed the use of a low pressure system to supplement the auxiliary feed system. The submittal did not specify which low pressure system, so an evaluation of its capabilities or uses could not be performed. Provide the following specific information:

a. Describe the system and its use, including water supplies (and their capacity), flow paths, pumps, power supplies to components, control equipment and procedures.

b. Describe the water chemistry interface requirements for the proposed low pressure system in order to assure its use will not cause unacceptable steam generator integrity degradation or heat transfer capability. (See Item 7.)

c. Show that blowdown of the steam generator is a viable technique without adverse core cooling consequences. Show that a concurrent rapid primary system cooldown and potential primary system contract does not result in inadequate core cooling or a return to power.

d. Show that there are no adverse consequences while feeding a dry steam generator with the low pressure system.

e. If steam generator pressure rises above the shutoff head of the low pressure pumps intended to be used, describe the method of regaining feed flow without compromising core cooling.

2.6.1 Response to Question 6:

The use of existing low pressure pumps such as condensate pumps may provide a useful capability to an operator to supply feedwater to the steam generators during certain low probability scenarios which are essentially beyond the design bases of the plant. For example, a scenario that started with a loss of main feedwater due to a relatively minor failure in the MFW system or FWCS could result in a total loss of feedwater if the first failure were followed by a multiple failure in the auxiliary feedwater system which prevented this sytem from functioning. In such a situation where now the AFWS is no longer usable, an operator would have only about ten to fifteen minutes to find and correct the problem in the MFW system and restore that system prior to inventory depletion in the steam generators to the point where the turbine driven MFW pumps could not be restarted, i.e., steam generator dryout. At this point with both main and auxiliary feedwater down and with insufficient inventory in the steam generators to restart a turbine driven main feedwater pump, one or both steam generators could be depressurized via ADVs to the point where a surrogate pump such as a condensate pump could be used to supply feedwater for decay heat removal and, if desired, a recovery of the MFW system could be performed.

The actual equipment and interface requirements for this application as requested in Parts a and b of the question are plant specific and as such will be supplied by individual utilities. Generic analyses, however, were performed evaluating this method of operation showing that it is a viable method for which specific procedures and training could be developed. In addition, initial review indicates that the best suited pump for use as a surrogate feedwater pump is probably a condensate pump. This pump appears to be ideally suited for this application since system lineup for feedwater delivery can be readily accomplished, pump flow characteristics are usually such that only modest steam generator depressurization need be accomplished prior to delivery, and the supply of available feedwater is of high quality. A second possible candidate for use as a surrogate feedwater pump would be an emergency firewater pump. The advantage of using this pump would be the availability of an emergency power supply; however, the system lineup necessary to initiate feed is somewhat more difficult than with the condensate pump and the water would be of a lesser quality.

In the sections that follow, the results of both a steady-state analysis and a transient analysis of a total loss of feedwater event will be presented. The steady-state analysis will demonstrate that the capacity of the ADVs currently installed in the 3410 and the 3800 plants is sufficiently large to allow for decay heat removal plus steam generator depressurization to a point where a surrogate low pressure pump can be used to supply feedwater, and the transient analysis will demonstrate the dynamic response of the RCS to a TLOFW followed by steam generator depressurization and injection of feedwater from a low head pump. In addition, the consequences of feeding a hot and dry steam generator will be discussed.

2.6.2 Steam Generator Depressurization Analysis

This section presents an analysis of the capability of the steam generators to remove decay heat under conditions where secondary makeup is supplied using plant pumps other than main or auxiliary feedwater pumps. Post reactor trip decay heat removal is normally accomplished in hot standby by dumping steam from the steam generators to the atmosphere or the condenser and supplying feedwater with either the main or auxiliary feedwater pumps. Without these pumps (generally the only available pumps with sufficient head) it is possible to remove decay heat using lower head pumps by first reducing steam generator pressure.

The specific steam generator depressurization scenario considered is as follows: Subsequent to reactor trip and loss of all feedwater, the plant would be brought to hot standby using either the secondary safety valves or the ADVs. With both main feedwater and auxiliary feedwater unavailable, the existing steam generator secondary side inventory would quickly be depleted preventing recovery of the turbine driven MFW pumps. The ADVs would be opened to depressurize the steam generators and a previously aligned low head pump would be used to deliver feed to one or both steam generators. Sufficient feedwater flow and steam flow would be available for either continuous decay heat removal or, if desired, a plant cooldown. Feeding of one or both steam generators would continue using the low head pump until the AFW system or the MFW system is restarted or the plant is placed on shutdown cooling.

The steady-state calculations that follow were performed at a conservative point after reactor trip in order to determine the required ADV area necessary to achieve and maintain steady-state heat removal using a depressurized steam generator. Thirty minutes following reactor trip was chosen at the point at which the steady-state analysis was performed since this point is conservative with respect to decay heat level, i.e., the actual decay heat level that will exist in the core by the time an operator commences steam generator depressurization will be less than the value at thirty minutes. The required ADV area necessary to achieve and maintain steady-state heat removal using a depressurized steam generator can then be compared to the existing ADV area, and if the existing ADV area is larger, the actual ability to maintain adequate core cooling in this mode will depend only upon the flow capabilities of the particular surrogate feedwater pump.

The transient analysis that follows was performed to show the dynamic response of the RCS to a TLOFW. The work provides a best estimate calculation of the NSSS response versus time for the particular ADV and surrogate pump combination investigated.

2.6.2.1 Steady-State Analysis

The ADV area required to remove both decay and reactor coolant pump heat assuming steady-state conditions can be found for any point in time after reactor as follows:

At any time (t) after reactor trip, from simple conservation of energy in the RCS,

$$q_D(t) + q_{RCP} = \dot{M}_p \; C_p \; (T_h - T_c) \tag{1}$$

where,

$q_D(t)$ = decay heat at time (t) (Btu/hr)
q_{RCP} = reactor coolant pump heat (Btu/hr)
$\dot{M}_p$ = primary system mass flowrate (lbm/hr)
C_p = primary system specific heat (Btu/lbm-°F)
T_h = hot leg temperature (°F)
T_c = cold leg temperature (°F).

From conservation of energy in the steam generators,

$$\dot{M}_p \; C_p \; (T_h - T_c) = m_g \; h_g - m_{FW} \; h_{FW} \tag{2}$$

where,

m_g = steaming rate (lbm/hr)
m_{FW} = feedwater rate (lbm/hr)
h_g = steam enthalpy (Btu/lbm)
h_{FW} = feedwater enthalpy (Btu/lbm).

Assuming that the feedwater rate equals the steaming rate (i.e., $m_g = m_{FW}$), Equations 1 and 2 can be rearranged to solve for m_g, or

$$m_g = \frac{q_D(t) + q_{RCP}}{h_g - h_{FW}} . \tag{3}$$

At a given feedwater temperature, the difference between h_g and h_{FW} is approximately constant over the range of pressures of interest (50 to 900 psia). Therefore, Equation 3 can be simplified as follows:

$$m_g = \frac{q_{D(t)} + q_{RCP}}{C} \tag{4}$$

where, C = 1106 Btu/lbm, which is $(h_g - h_{FW})$ at 50 psia and a feedwater temperature of 100°F.

Once the required steaming rate is determined from Equation 4, the required dump valve area can be calculated from the following equation for critical flow:

$$A = \frac{2.68 \times 10^{-4} \, (h_g - 185) \, m_g}{0.53 \, (P) \, 3600} \tag{5}$$

where,

A = dump valve area (ft^2)
P = steam pressure (psia).

Using Equation 5 one can generate a curve of the required ADV area as a function of steam generator pressure for any point in time after reactor shutdown. Figures 2.6-1 and 2.6-2 show these curves for the 3800 and the 3410 plants at thirty minutes after trip. (All figures for Section 2.6 of this report are contained together at the end of the section (p. 231).)

As an example of this analysis, it was determined from Equation 4 that 251 gpm of 100°F feedwater is required for the 3410 class plants to remove decay heat and pump heat thirty minutes after trip assuming steady-state conditions (steam flow = feed flow). From the head-flow characteristics of the particular surrogate feedwater pump used, one can determine the discharge pressure corresponding to 251 gpm. Then, referring to Figure 2.6-2, if the ADV area at the required pump discharge pressure is less than the existing ADV area adequate heat removal will result.

Table 2.6-1 (p. 222) provides a summary of the ADV capacities and corresponding flow area for the plants participating in this study. For each of these plants sufficient atmospheric steam dump capacity exists to maintain hot standby conditions and, as supported by previous calculations, to cool the primary system down to shutdown cooling system initiation conditions.

2.6.2.2 Transient Analysis - TLOFW

This section presents the results of an analysis performed to show the response of the C-E NSSS to a total loss of feedwater. The analysis consisted of a simulation of the recovery from a TLOFW by means of steam generator depressurization and injection of feedwater from a low head pump. The method, results, and conclusions of the analysis are presented below.

2.6.2.2.1 Method of Analysis for TLOFW

A simulation of a total loss of feedwater event followed by steam generator depressurization and delivery of feedwater from a low head pump was performed for both the 3410 and the 3800 plants in order to respond to Question 8 concerning the time to core melt. The complete transient results for the 3410 plant are presented here in order to show the dynamic response of the NSSS. Note that the results for the 3800 plant are very similar and therefore not repeated. The

Table 2.6-1

SUMMARY OF ADV CAPACITIES AND FLOW AREAS

Plant	Number of ADVs	Rated Capacity Per ADV (lbm/hr)	Area Per ADV (ft^2)	Total ADV Area (ft^2)
SONGS 2 & 3	2	703,000 @ 900 psia	0.103	0.206
Waterford 3	2	800,000 @ 900 psia	0.117	0.234
System 80	4	950,000 @ 1070 psia	0.125	0.500

simulations were performed using an improved version of the CEFLASH-4AS computer code described in Section 3.2 of Reference 16. Improvements were made in two areas to more realistically described the thermal-hydraulic processes that occur in the surge line and the pressurizer when the pressurizer code safety valves are open. First, an entrainment model was used to model the entrainment of liquid into the surge line from the hot leg and into the primary safety valves from the pressurizer. Second, the finite difference wall heat model was upgraded to include a detailed calculation of surface heat transfer coefficients. This upgrade model was applied in the pressurizer and the reactor vessel upper head. The important system parameters and analysis assumptions are contained in Table 2.6-2 (p. 224) and Table 2.6-3 (p. 225).

2.6.2.2.2 Results of TLOFW Analysis

This section describes the results of the transient simulation of the recovery from a TLOFW by means of steam generator depressurization and injection of feedwater from a low pressure pump. The sequence of events for the transient is listed in Table 2.6-4 (p. 226). Figures 2.6-3 through 2.6-11 present the major system parameters plotted as a function of time.

The initiating event is a TLOFW. As the transient progresses the steam generators dryout, the RCS heats up and pressure increases causing the PSV to open at 2500 psia. In the analysis it was assumed that the operator begins the steam generator depressurization at 50 minutes by opening (full open) one ADV in each steam generator. At 50 minutes when the operator begins steam generator depressurization, the steam generators are essentially dry and at a pressure of 1100 psia, the setpoint pressure of the MSSV. The pressure in the RCS is being regulated by the PSVs at 2500 psia. Core heat is being removed by boiling in the core and RCS heat is being removed by flow out the PSVs. RCS inventory is being depleted since the PSV flow exceeds the charging flow.

Table 2.6-2

SYSTEM PARAMETERS AND INITIAL CONDITIONS FOR THE TLOFW ANALYSIS

Parameter	Value
Initial core power (Mw)	3410
Initial RCS pressure (psia)	2250
Initial RCS flowrate (lbm/hr)	148×10^6
Initial cold leg temperature (°F)	553
Initial hot leg tempterature (°F)	612
Initial SG pressure (psia)	895
Low SG level reactor trip setpoint (%)	10
SIAS setpoint (psia)	1763
Charging pump flowrate, per pump (gpm)	44
HPSI pump shutoff head (psia)	1420
HPSI pump runout flow, per pump (gpm)	905
RWT temperature (°F)	70
SIT gas pressure (psia)	615
PSV setpoint (psia)	2500
PSV capacity at 2500 psia, per valve (lbm/hr)	463,000
PSV effective flow area, per valve (ft^2)	0.0232
Number of PSVs	2
MSSV setpoint (minimum) (psia)	1100
ADV capacity at 900 psia, per valve (lbm/hr)	703,000
ADV effective flow area, per valve (ft^2)	0.108
Condensate pump flowrate, per pump (gpm)	2300
Condensate pump shutoff head (psia)	350

Table 2.6-3

MAJOR ASSUMPTIONS USED IN THE TLOFW ANALYSIS

1. Main feedwater lost to both steam generators instantaneously.

2. Auxiliary feedwater fails to start both automatically and manually.

3. All reactor coolant pumps are tripped manually at 10 minutes.

4. One charging pump is started at 20 minutes.

5. One train of safety injection pumps is assumed to operate.

6. When initiating SG depressurization, one ADV per SG is opened (full open).

7. SBCS, PLCS, PPCS, and auxiliary spray do not operate.

9. 1.0 1971-ANS decay heat.

10. Homogeneous equilibrium critical flow model used to predict PSV and ADV flowrates.

Table 2.6-4

SEQUENCE OF EVENTS FOR THE TLOFW ANALYSIS

Event	Time
Total loss of feedwater	0 sec.
Reactor trip	20 sec.
MSSVa open	24 sec.
SG dryout	10 min.
RCP trip, manual	10 min.
PSVs open	12 min.
Charging pump on, manual	20 min.
RCS (hot side) reaches saturation	28 min.
ADV open, manual	50 min.
Condensate pumps inject to SG	52 min.
PSVs close	52 min.
HPSI pump on	56 min.
SITs inject	62 min.

When the ADVs are opened, the steam generators rapidly depressurize, see Figure 2.6-3. At 3130 seconds the steam generator pressure drops below the delivery pressure of the low pressure pumps and feedwater is restored to the steam generators, Figure 2.6-4. (In this analysis, a conservative representation of the condensate pump was assumed with a constant delivery of 2300 gpm at a steam generator pressure of less than 350 psia).

As the steam generator level is restored, Figure 2.6-5, RCS heat is removed by condensation in the steam generator tubes. This establishes a reflux boiling mode of heat and mass transfer in the RCS. The condensation of steam causes the RCS pressure to decrease beginning at 3140 seconds, see Figure 2.6-6. When the RCS pressure decreases below 2500 psia the PSVs close and the loss of RCS inventory stops. The reactor vessel mixture level begins to increase, Figure 2.5-7, due to the condensation of steam, the injection of charging flow, and the draining of the pressurizer, see Figure 2.6-8, into the reactor vessel. Note from Figure 2.6-7 that core uncovery does not occur.

As the steam generator level increases, the increasing heat transfer causes the steam generator level to swell. In turn, the steam release increases thereby increasing the steam generator pressure beginning at 3180 seconds. At 3190 seconds, the pressure increases above the maximum delivery pressure of the condensate pumps and the injection of feedwater stops, Figure 2.6-4. With the temporary cessation of feedwater at 3190 seconds, the steam generator level begins to decrease, Figure 2.6-5. The decreasing level causes a decrease in the heat transfer which in turn causes a decrease in the steam production and therefore a decrease in steam generator pressure. At 3300 seconds the pressure decreases to the point where feedwater flow is restored.

This cycling of steam generator pressure and level and feedwater flow repeats several times during the transient simulation. However, as shown in Figure 2.6-5, there is a gradual increase in the steam generator level during the cycling. The first time the feedwater cycles off, the decrease in steam generator heat transfer causes a temporary increase in the RCS pressure from 3200 to 3300 seconds, Figure 2.6-6. During the second cycling there is sufficient heat transfer so the RCS pressure does not increase but rather the rate of depressurization temporarily decreases, 3350 seconds to 3500 seconds in Figure 2.6-6. At 3390 seconds, the RCS pressure decreases below the HPSI pump shutoff head and the HPSI pump begins to augment the charging pump in refilling the RCS. By 3700 seconds, the SITs begin to inject and simulation was terminated.

2.6.2.2.3 Conclusions from TLOFW Analysis

The transient simulation demonstrates that steam generator depressurization and initiation of feedwater from a low pressure pump results in acceptable core cooling. When this action is taken prior to the initiation of core uncovery, the resultant RCS depressurization stops the loss of RCS inventory through the PSVs and reflux boiling then removes core and RCS heat. The results also demonstrate that the primary system contraction does not result in inadequate core cooling. To illustrate, consider the saturated depressurization from 2500 psia to 1400 psia, the shutoff head of the HPSI pumps. During such a depressurization the density of saturated water increases from about 35 lbm/ft^3 to about 43 lbm/ft^3 as temperatures in the RCS decrease. If the depressurization were to start when the RCS was drained to the top of the core, the contraction due to cooling via the steam generators would drop the core and annulus mixture levels by about four feet which is equivalent to about 370 ft^3. Several factors, however, combine to negate this contraction. First, after the PSVs close when the RCS pressure decreases below 2500 psia, the liquid retained in the pressurizer is free to drain back into the RCS. In the transient simulated for this analysis, there was approximately 1300 ft^3 of liquid in the pressurizer which drained back into the RCS. This is over three times the volume lost by contraction in the example given above. Second, since the depressurization is accomplished by steam condensation and not by steam removal from the RCS, the condensed liquid is available via reflux to replace the volume lost by the contraction. Continuing the above example, if the level was at the top of the core at the start of the depressurization, there would be approximately 5000 ft^3 of steam in the reactor vessel, hot legs and steam generators. In depressurizing from 2500 psia to 1400 psia, the density of saturated steam decreases from about 8 lbm/ft^3 to about 3 lbm/ft^3. This translates to about 22,000 lbm of condensed steam or about 500 ft^3 of liquid as compared to the 370 ft^3 lost by the contraction in the above example.

It was also concluded that the primary system cooldown does not result in a return to power. Several factors contribute to prevent this. First, prior to the start of the cooldown, the charging pumps are injecting borated water at 44 gpm per pump, and when the RCS depressurizes below the HPSI pump shutoff head, the HPSI pumps will also inject borated water. In addition, the core is in a partially voided condition as core heat is being removed by boiling both when the PSVs are open and when the steam generators are removing RCS heat by condensation. Finally, during the period of time when the PSVs are open and the RCS inventory is steaming out the PSVs, boric acid concentration is increasing in the core since boric acid is non-volatile.

The final conclusion concerns the increase of steam generator pressure above the shutoff head of the low pressure pumps. For the combination of ADV size and low pressure pump simulated in the analysis, this phenomenon does occur. However, as described in the previous section, the pressure increase is cyclic and the steam generator level and heat transfer increase over the course of the cycles.

2.6.3 Consequences of Feeding a Dry Steam Generator

Early C-E NSSS designs which relied upon manually initiated auxiliary feedwater were specified to include a limited number of feedwater initiations to a hot, dry steam generator. Although this specification was deleted with the inclusion of automatically initiated AFW, calculations have indicated that the 3410 and the 3800 plants are capable of accepting a limited number of initiations of 70°F feedwater to a hot and dry steam generator via the feedwater ring and downcomer. Initiation of the feedwater in such an *in extremis* situation would represent a last resort effort to provide for core cooling and prevent core damage. Following such an initiation, the structual integrity of the steam generators would be evaluated on a plant specific basis as necessary once the RCS was safely cooled down prior to resuming operation.

Figures for Section 2.6

FIGURE 2.6-1

3800 CLASS PLANT
REQUIRED ADV AREA PER STEAM GENERATOR
VS STEAM PRESSURE

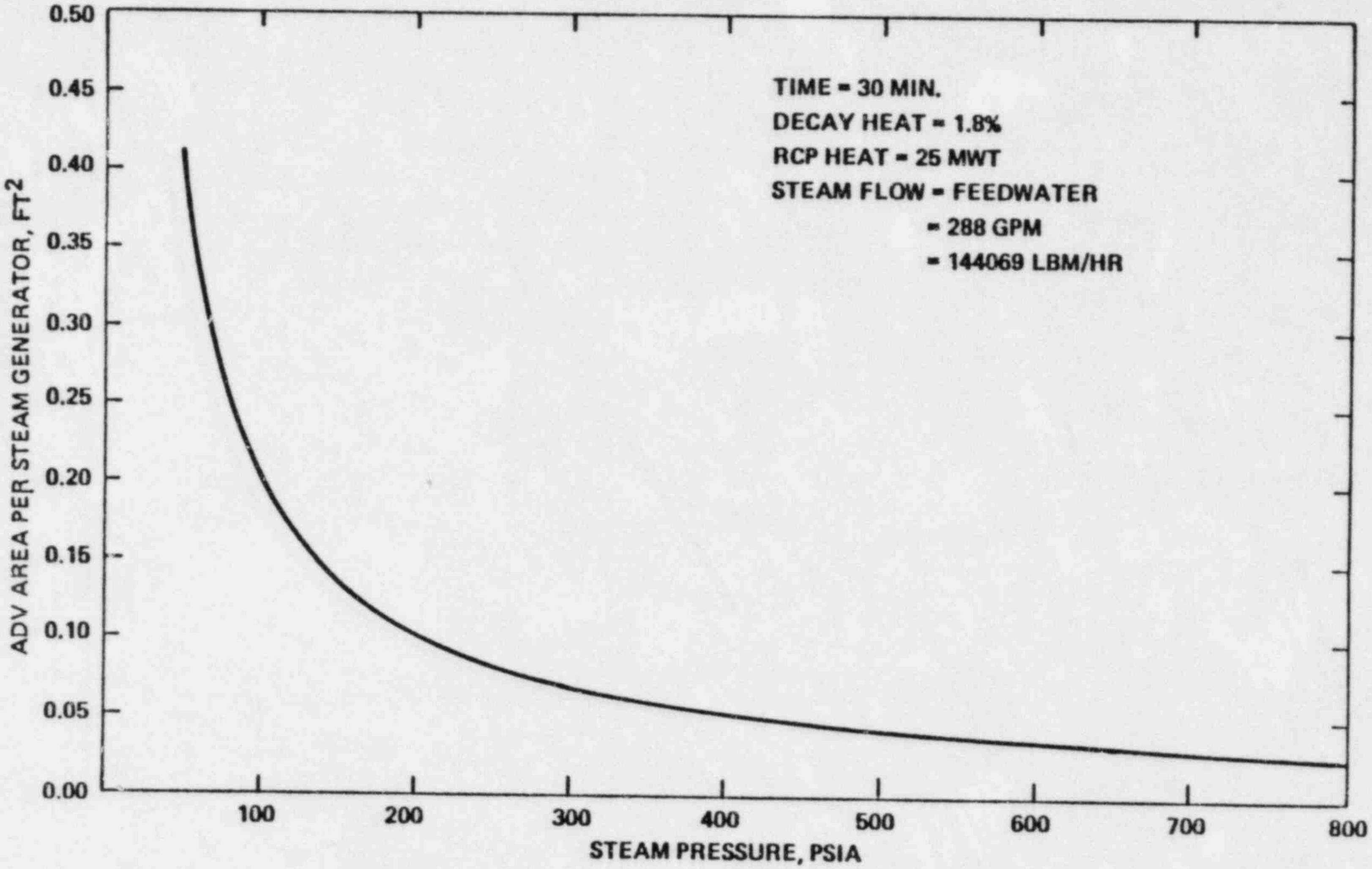


FIGURE 2.6-2

3410 CLASS PLANT
REQUIRED ADV AREA PER STEAM GENERATOR
VS STEAM PRESSURE

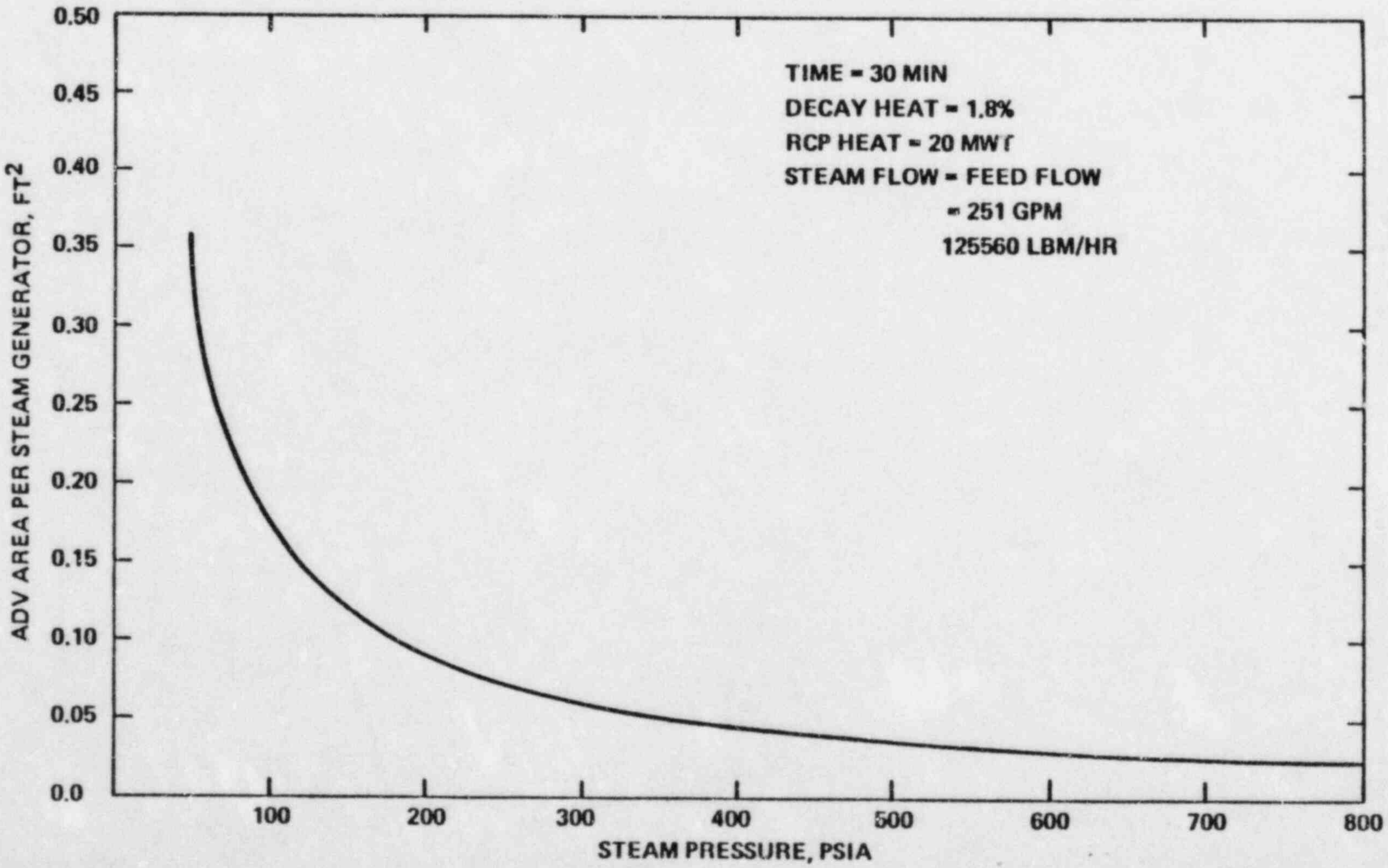


Figure 2.6-3

TLOFW TRANSIENT ANALYSIS
SG PRESSURE

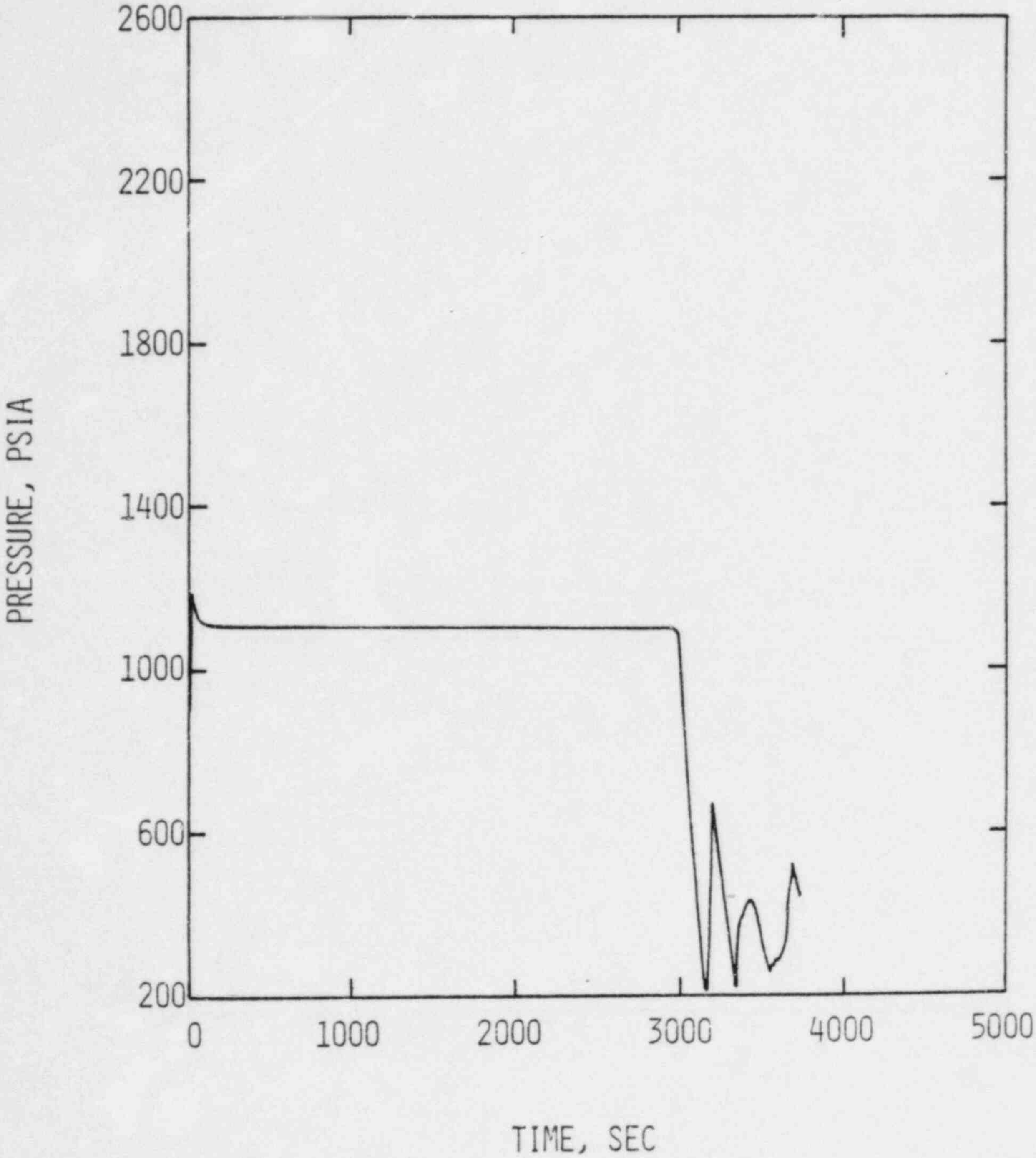


FIGURE 2.6-4

TLOFW TRANSIENT ANALYSIS
FEEDWATER FLOWRATE

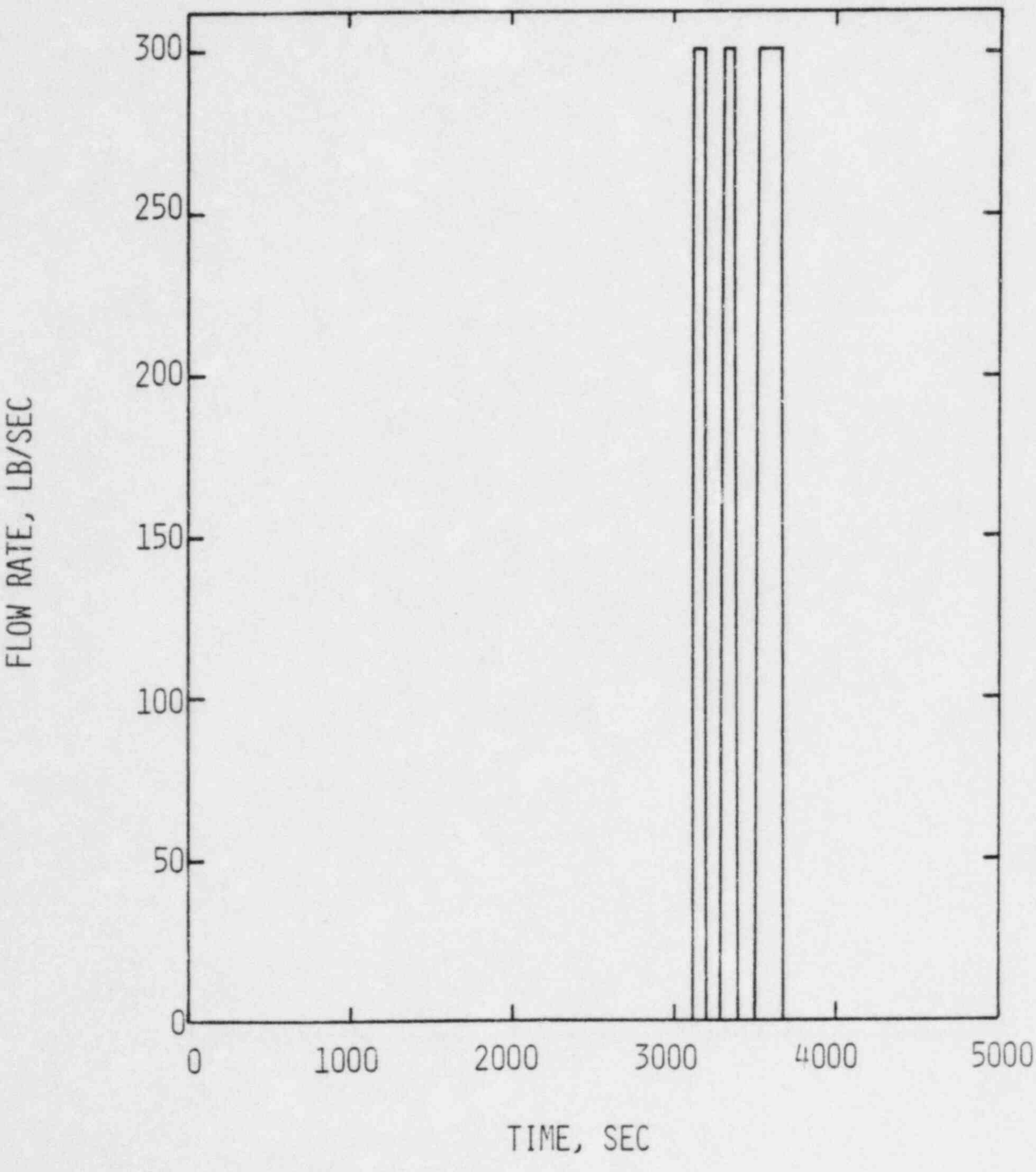


FIGURE 2.6-5

TLOFW TRANSIENT ANALYSIS
SG TWO-PHASE MIXTURE LEVEL

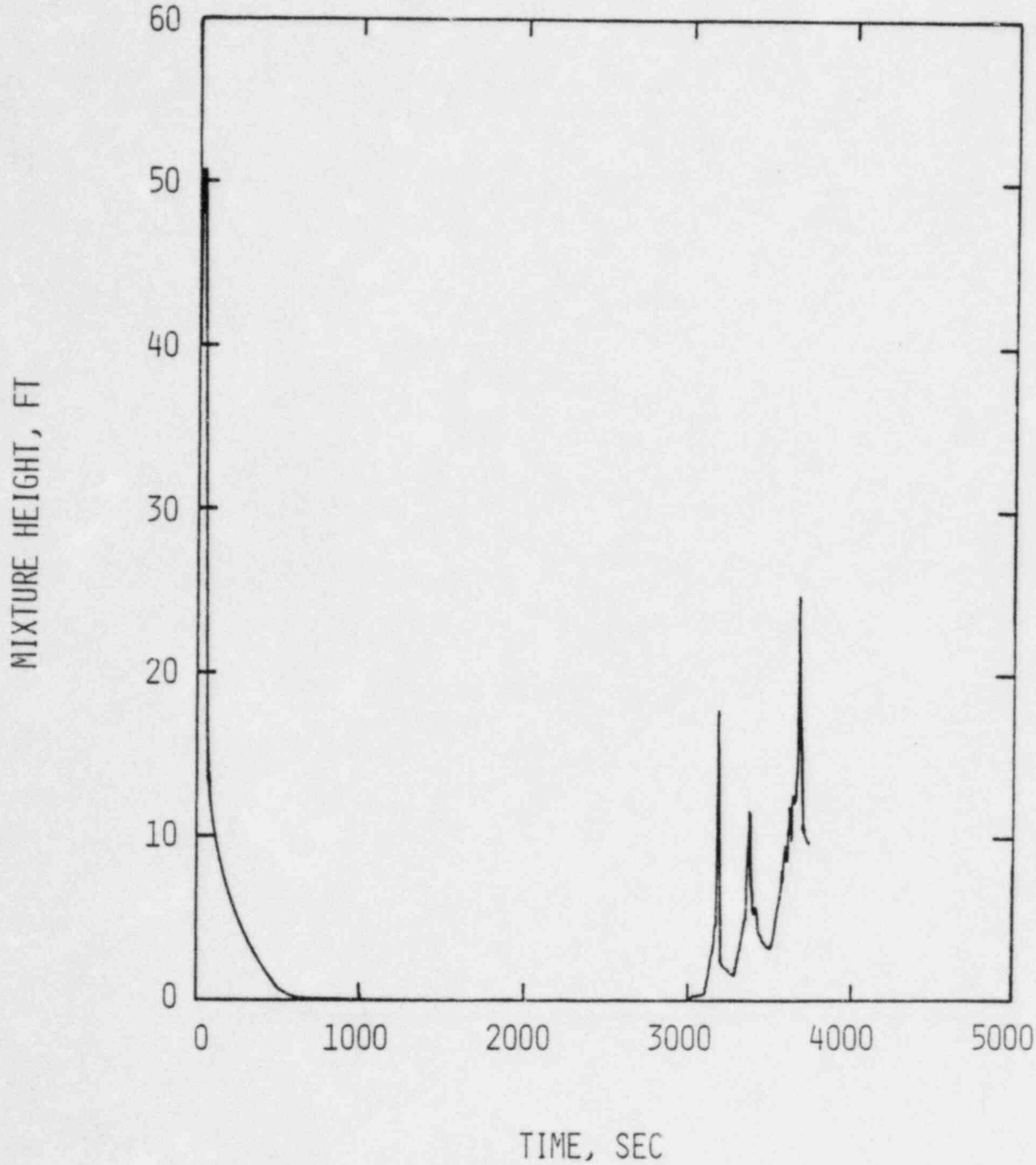


FIGURE 2.6-6

TLOFW TRANSIENT ANALYSIS
RCS PRESSURE

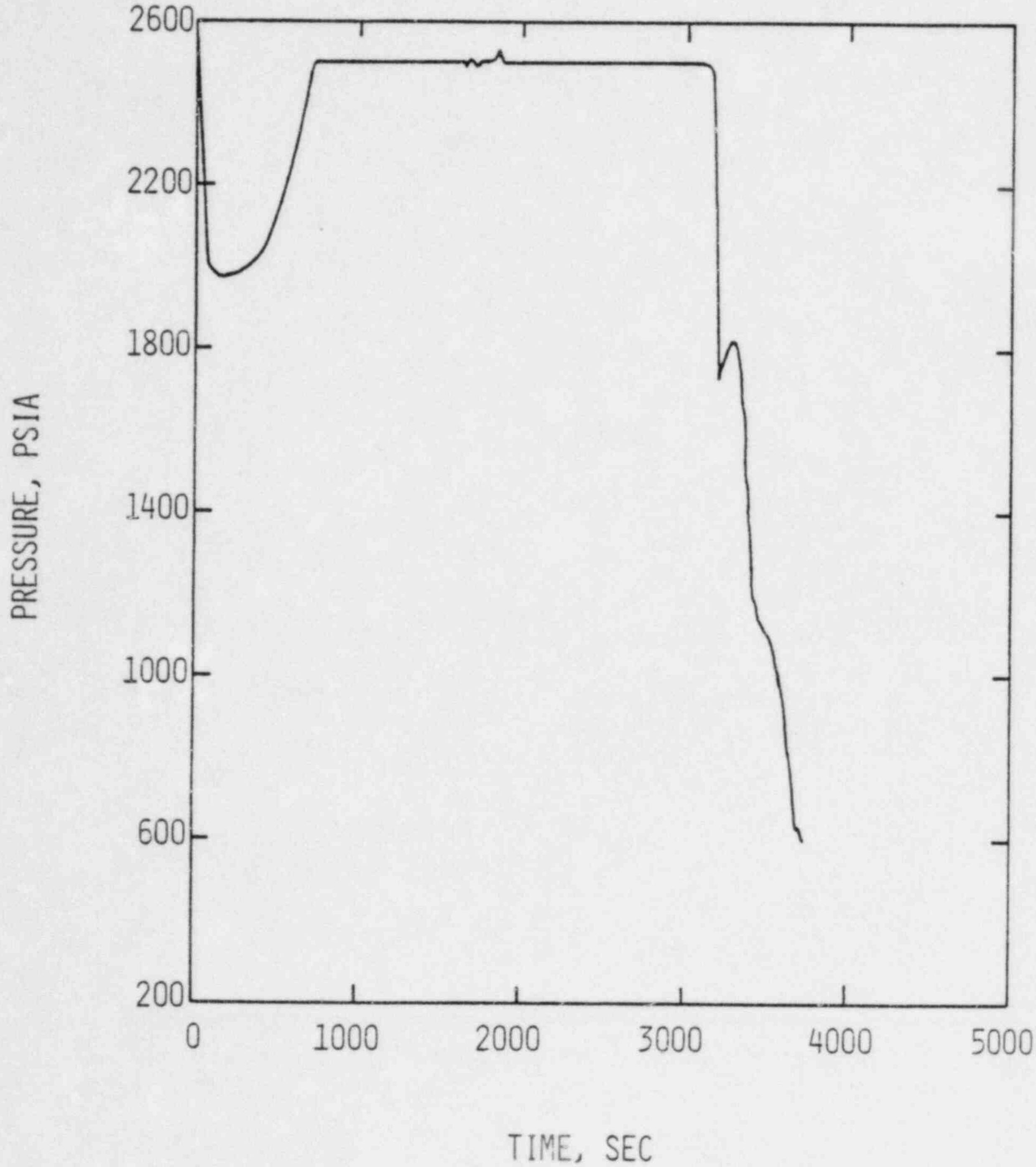


Figure 2.6-7

TLOFW TRANSIENT ANALYSIS
REACTOR INNER VESSEL TWO-PHASE
MIXTURE LEVEL

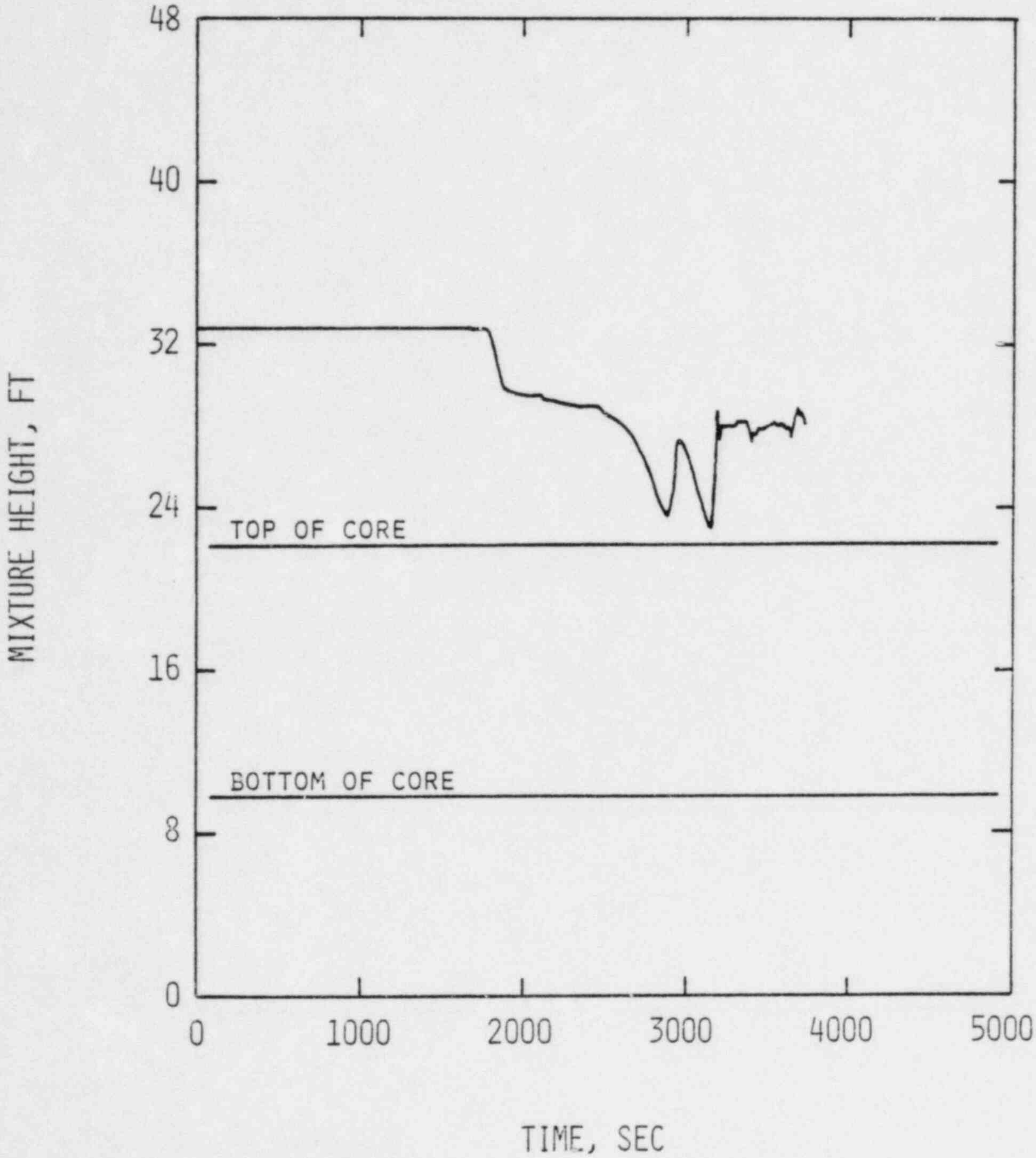


FIGURE 2.6-8

TLOFW TRANSIENT ANALYSIS
PZR TWO-PHASE MIXTURE LEVEL

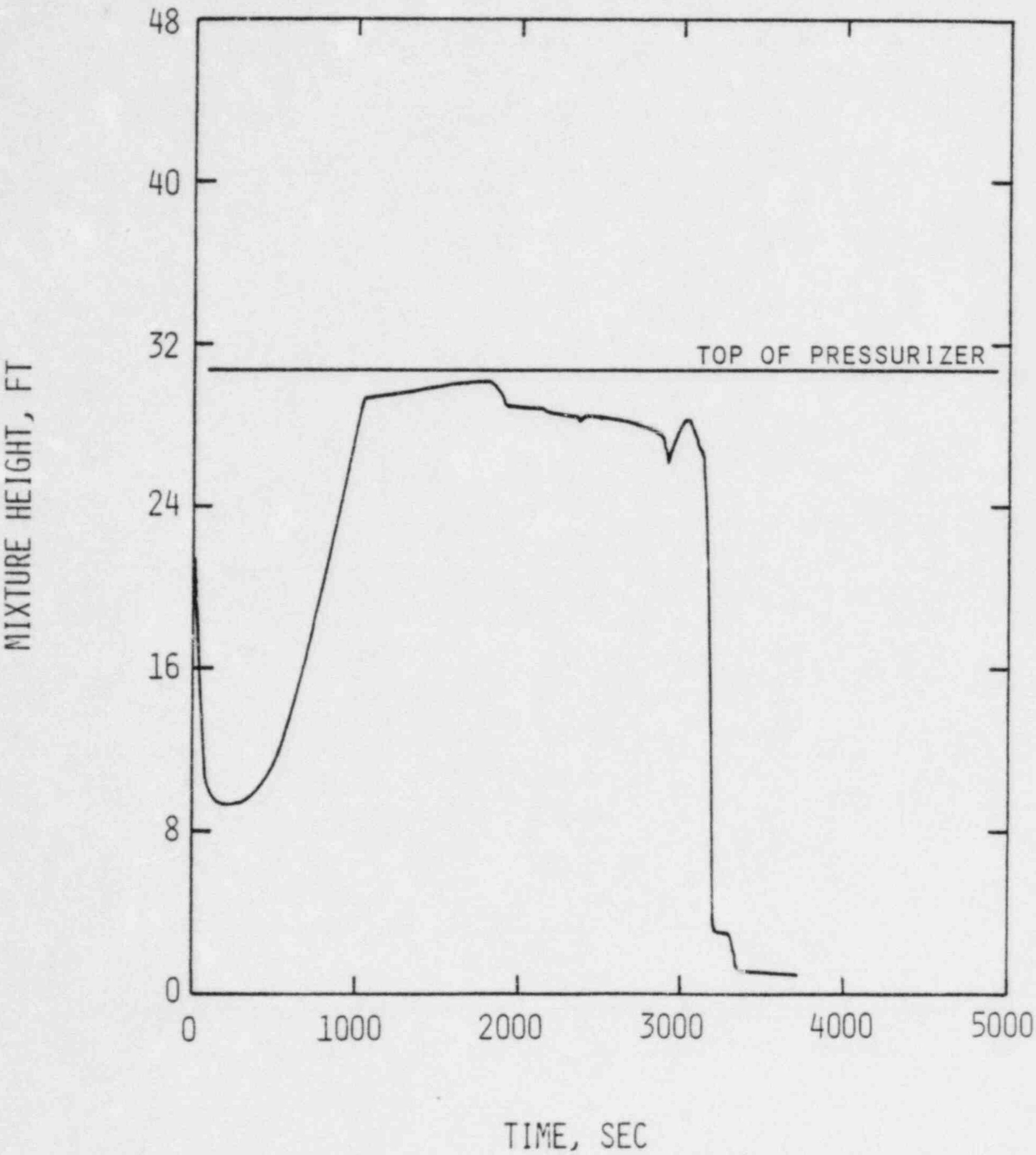


Figure 2.6-9

TLOFW TRANSIENT ANALYSIS
ADV FLOWRATE

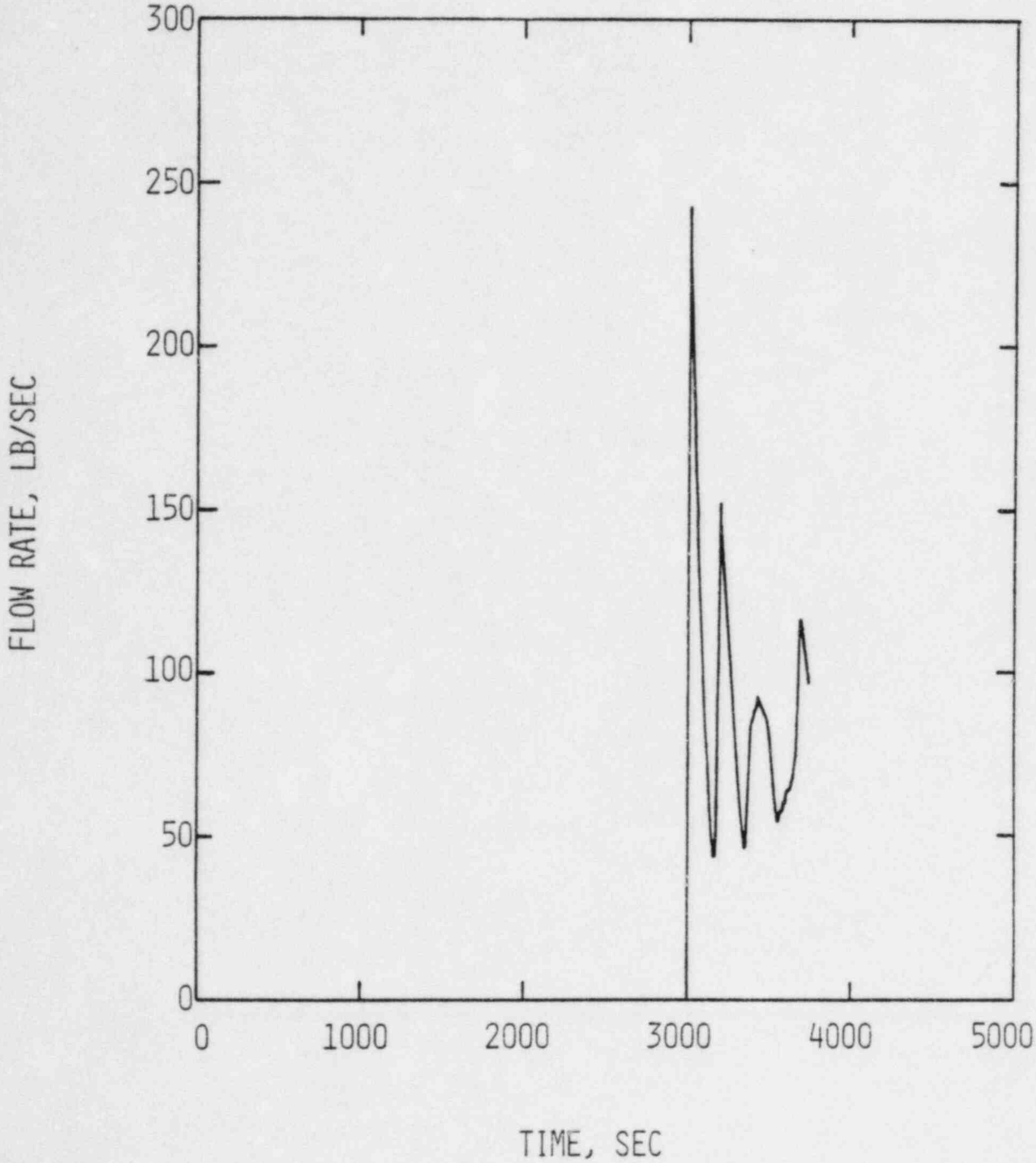


FIGURE 2.6-10

TLOFW TRANSIENT ANALYSIS
PZR CODE SAFETY VALVE
FLOWRATE

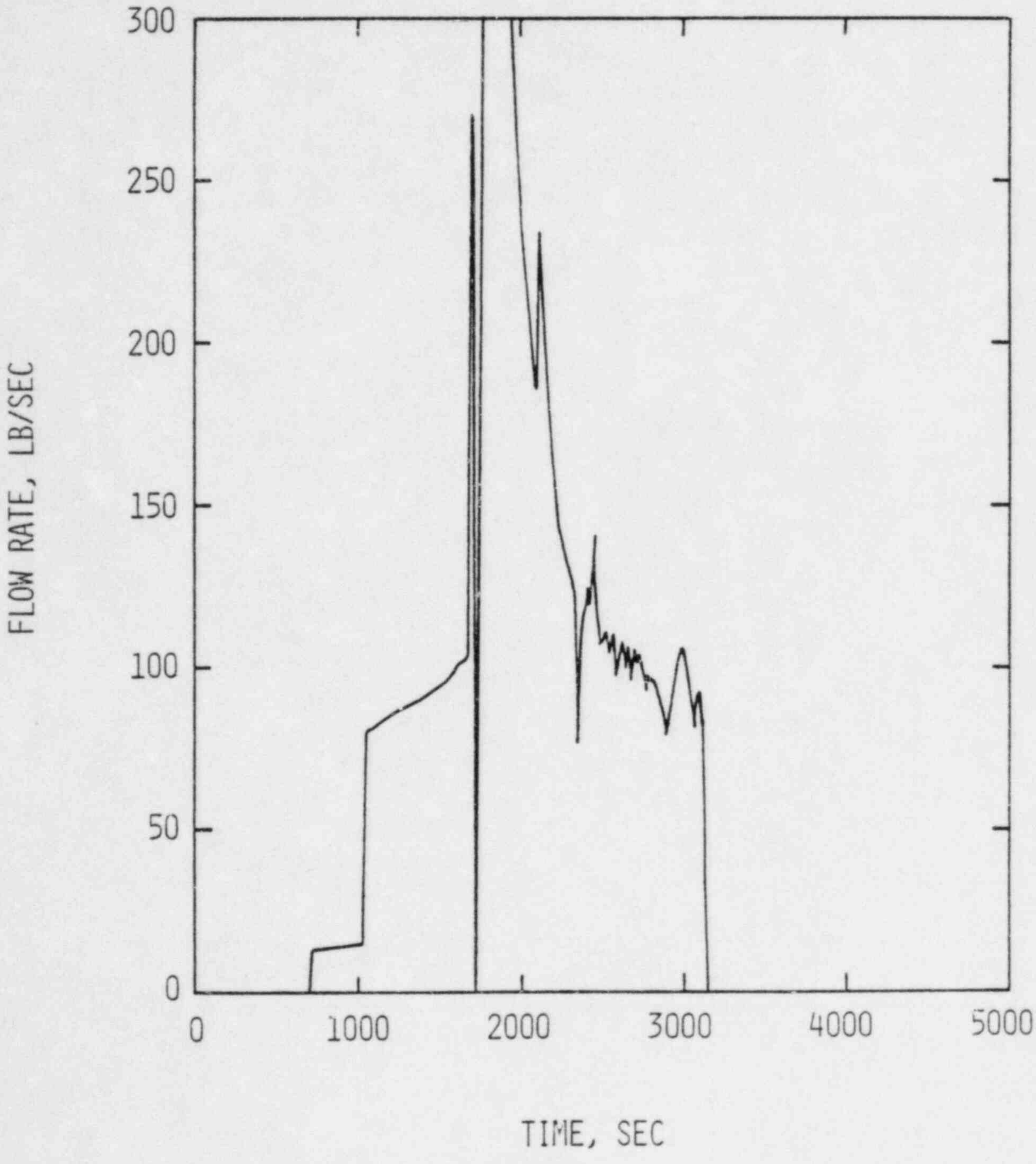
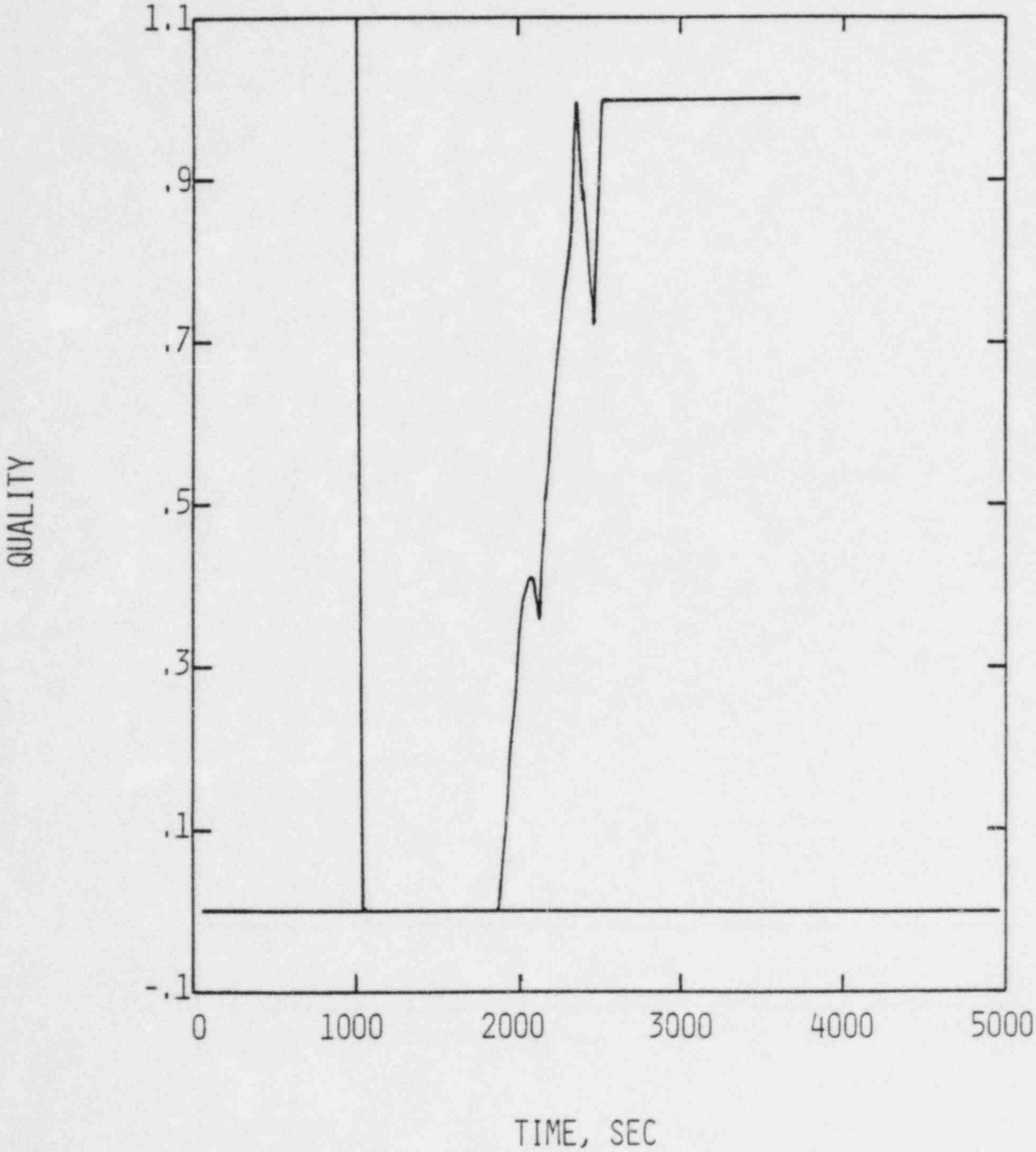


Figure 2.6-11

TLOFW TRANSIENT ANALYSIS
PZR CODE SAFETY VALVE
QUALITY



2.7 Question 7: Chemistry Considerations

Provide information and test data which will demonstrate the steam generator structural integrity and heat transfer capabilities will be maintained under secondary water chemistry conditions that deviate from the recommended C-E water chemistry program. Specifically, the following considerations should be addressed for the spectrum of CESSAR plant sites:

a. Provide data to demonstrate that excessive corrosion of the primary pressure boundary will not occur which could result in primary-to-secondary leakage complicating the accident conditions. (Data pertaining to synthetic cooling water is not considered appropriate, due to the inability to include all potentially corrosive species in their exact chemical conditions.)

b. Provide an assessment of the total corrosive damage anticipated in the steam generators as a consequence of main condenser cooling water injection. Relate the anticipated corrosion damage to the steps which will be necessary to ensure structural integrity prior to a restart.

c. For your proposed shutdown method, provide calculations and/or test data which will demonstrate that excessive heat transfer surface fouling will not occur and impede the ability of the steam generators to perform their cooldown function.

d. Describe the steam generator design features which will reduce their susceptibility to excessive corrosion during the proposed injection of main condenser cooling water.

2.7.1 Response to Question 7

The use of existing low pressure pumps or backup water supplies could provide a useful capability to an operator to supply feedwater to the steam generators during certain low probability scenarios which result in a loss of normal water sources. Feeding a steam generator under these conditions may, in the long term, impact structural integrity and heat transfer capabilities if the quality of the water used deviates significantly from the recommended C-E water chemistry program. The use of a steam generator in this so called "off-design performance" mode represents, however, an in extremis situation where short-term action must be taken to provide adequate core cooling and prevent possible core damage. In such a case, an operator would employ the best quality water supply available. This water supply may involve the use of one of the backup water suppplies for the AFWS as required by the post-TMI Action Plan or such potential sources as the following:

1. Reactor-grade makeup water system.
2. Service-grade water from fire protection system.
3. Potable water from domestic water systems.
4. On-site bulk cooling water storage reservoirs or basin.

Over the short time frame during which relatively poor quality water might be used to feed a steam generator, i.e., the time it takes to cooldown, depressurize, and place the plant safely on the shutdown cooling system, damage to structural integrity and heat transfer capability to the extent that would prevent a steam generator from providing adequate heat removal would not occur. Further, once the plant was safely placed on shutdown cooling and prior to resuming normal operations, secondary side cleanup along with inspections to ensure structural integrity would be performed as necessary.

Initial review indicates that the best pump for use as a surrogate low pressure feedwater pump is probably a condensate pump, see Section 2.6.1. This pump appears to be ideally suited for a number of reasons including the availability of high quality water. As an alternative, an emergency fire water pump might be employed. This second pump has the advantage over a condensate pump of an available emergency power supply although the water would be of lesser quality. In the sections that follows an assessment of the short-term potential for corrosion will be presented along with an assessment of the short- term effects on heat transfer capabilities from feeding a steam generator with relatively poor quality feedwater. In addition, the various design features of the 3410 and the 3800 steam generators that contribute to minimize corrosion will be discussed.

2.7.2 Chemistry Evaluation

Since the conditions under which the steam generators might be feed using a surrogate low pressure pump are off-design, i.e., feedwater that could deviate from the recommended C-E water chemistry program, test data does not exist which documents the performance of the steam generator U-tube material, Alloy-600, under these conditions. Dispite this general lack of applicable test data, it is not anticipated that usage of poor quality water during the relatively short time period necessary to conduct a plant cooldown and safely place the plant on shutdown cooling will significantly affect plant response. Proprietary faulted chemistry tests have been conducted by C-E using synthetic impurity additions and using actual cooling water additions at concentrations less than those which would be anticipated from usage of some of the alternate feedwater sources discussed above. Although these studies used relatively dilute impurity additions, concentrating devices are included in the models which result in impurity concentrations on the order of 10^6. Failures have been observed in these concentrated regions, but only after exposure times much longer than the relatively short time period necessary to conduct a plant cooldown.

2.7.2.1 Assessment of Potential for Steam Generator Corrosion

As discussed under Section 2.7.2 above, test data to support definition of the corrosion damage from the addition of poor quality feedwater to a steam generator does not exist. There will undoubtedly be some impact upon the Alloy 600 tubing, but the short exposure time and the relative immunity of Alloy 600 to corrosion attack should limit the damage. More significant problems may occur with the stainless and carbon steel components within the steam generator. Steel components may face general and stress corrosion cracking attack. Although immediate failure is not likely due to the short exposure time, corrosion damage may impact the long term integrity.

For these reasons, extensive steam generator inspections will be necessary prior to resuming normal plant operations following use of poor quality feedwater to provide for plant cooling in the event of a TLOFW. Eddy-current tubing inspections, secondary side visual inspections, and a steam generator flush program would be necessary as a minimum. Sludge lancing and a water washdown of internal surfaces may be necessary to remove containments from sludge piles and exposed surfaces. Critical components which cannot be visually inspected, e.g., egg crate tube supports, etc., may require simulation in a laboratory environment to the existing chemical conditions in order to assess their integrity.

2.7.2.2 Assessment of Effects on Heat Transfer Capabilities

The combined design heat transfer capability of the steam generators installed in a C-E NSSS is typically about 110% of rated thermal power. During a plant cooldown, the heat load that will be imposed upon the generators will be comprised of decay heat, reactor coolant pump heat, and sensible heat. The total heat load from these three inputs is less than 3% of rated thermal power. Therefore, a significant amount of fouling must occur before the heat transfer coefficient would decrease to the point of impairment of the cooldown function. It is unlikely that fouling to this extent would occur during a relatively short cooldown period.

2.7.3 Minimizing Steam Generator Corrosion Through Design

Various design features are included on all C-E steam generators to avoid potential chemical and material incompatability, sludge accumulation, and other chemistry related problems during normal operation. Each design consideration will reduce the steam generator susceptability to excessive corrosion during the relatively brief exposure to poor quality feedwater. Among the design features which minimize both corrosion and fouling are use of corrosion resistant materials, grid flow distribution, open support structure design, tube joint integrity, and the blowdown system.

2.7.3.1 Material Selection

Corrosion resistant materials, which include Alloy 600 tubing for the heat transfer surfaces, are used in all C-E steam generators. In addition, the tube support structures in contact with the generator U-tubes (primarily the egg-crates support structure) are made of ferritic stainless steel for 3800 plants and carbon steel for 3410 plants. Should poor quality feedwater be introduced into one of these steam generators, the use of these materials will minimize the corrosion impact.

2.7.3.2 Flow Distribution

Flow distributions and velocities on the secondary side of the steam generator during normal steaming operation are particularly important considerations in the steam generator design. Contaminant ingress from the condensate and feedwater systems are known to have caused tubing degradation in regions of reduced flow where concentration can occur. The degradation has taken the form of pitting, inter-granular cracking, general wastage, and tube denting (including side effects such as support plate cracking and primary side stress-induced intergranular corrosion cracking). To minimize the potential for these conditions, the secondary side hydraulics of the C-E steam generator have been carefully optimized to ensure that regions of localized dryout (which can concentrate boiler water solids) do not exist and that local velocities will permit particulate dropout only in the region of the crud removal system. In addition because of the economizer section of the 3800 Class steam generator, these units have been fitted with additional flow distribution baffles located immediately above the tubesheet. The exact location of these baffles is determined with the aid of computer models which simulate thermal hydraulic behavior in that region and therefore insure uniform flow distribution through the tube bundle and prevent dropout of boiler water particulates, see Figure 2.7-1. (All figures pertaining to Section 2.7 of this report are contained together at the end of the section (p. 253).)

It should be noted that the steaming rates and hence feed flowrates that will exist during an off-design mode of operation, i.e., steam generator depressurized with feed supplied via a low head pump, will be low and therefore the flow distribution and velocity mechanisms discussed above may not function as effectively to minimize corrosion as they do when operating at designed power. The short time exposure to high concentrations of impurities should, however, limit U-tube and component degradation.

2.7.3.3 Support Structures

The same thermal-hydraulic simulation used to position the flow distribution baffles for the 3800 steam generators is used to optimize the location of the tube bundle supports for both the 3410 and the 3800 plants. The resulting design insures that optimal tubing support is provided without inducing low flow regions. Figure 2.7-1 shows the distribution of the 3800 steam generator U-tube supports and Figure 2.7-2 shows the distribution for the 3410 unit. Figure 2.7-3 through Figure 2.7-5 show the details of the vertical egg-crate supports, the bend region supports, and the horizontal tube supports. Where appropriate large punchout holes are typically provided in the horizontal supports to enhance flow as detailed in Figure 2.7-4 and Figure 2.7-5. The design is superior to a drilled support plant design in that it provides large open flow areas and limits the accumulation of chemical deposits by reducing local flow eddies.

2.7.3.4 Tube Joint Integrity

The tube-to-tubesheet joint of some designs has provided a concentrating crevice which has resulted in tubing degradation. All C-E steam generators are assembled using an explosive expansion technique. This technique eliminates the crevices which can occur along the length of the tube in the tube sheet, thus eliminating this potential corrosion problem

2.7.3.5 Steam Generator Blowdown

The 3800 steam generator incorporates a high capacity blowdown system which permits the periodic on-line removal of solids which may accumulate on the tubesheet. A two-duct system is provided, Figure 2.7-6 which permits separate control and prevention of particulate buildup on the hot and cold side of the tube bundle. As discussed above, flow distribution baffles prevent the dropout of particulates within the tube bundle, but encourage dropout in the region between the inner row of U-tubes and the center of the tubesheet. When properly connected to external piping and tankage, this ducting provides the capability to increase the blowdown flow for short periods of time to flowrates approaching five percent of full steam flow while at full power or nine percent of full steam flow while at hot standby. Flowrates of this magnitude produce sudden local velocity increases adjacent to the tubesheet of sufficient magnitude to re-entrain particulates dropped from the recirculating flow. Periodic use of the blowdown system prevents the accumulation of corrosion products on the tubesheet which could cause flow disturbances leading to concentration of contaminants and tubing degradation. The 3410 steam generators also have design provisions for bottom blowdown to reduce total solids or to remove sludge accumulation from the tubesheet surface. The design capacity, however, is smaller than that provided in the 3800 units.

Since blowdown flowrates are a function of secondary side pressure, the ability to blowdown a depressurized steam generator during an off-design mode of operation will be reduced. Even at reduced flowrates, however, substantial removal of containments can still be effected to help limit concentration buildups.

Figures for Section 2.7

FIGURE 2.7-1

3800 CLASS PLANT
STEAM GENERATOR ASSEMBLY

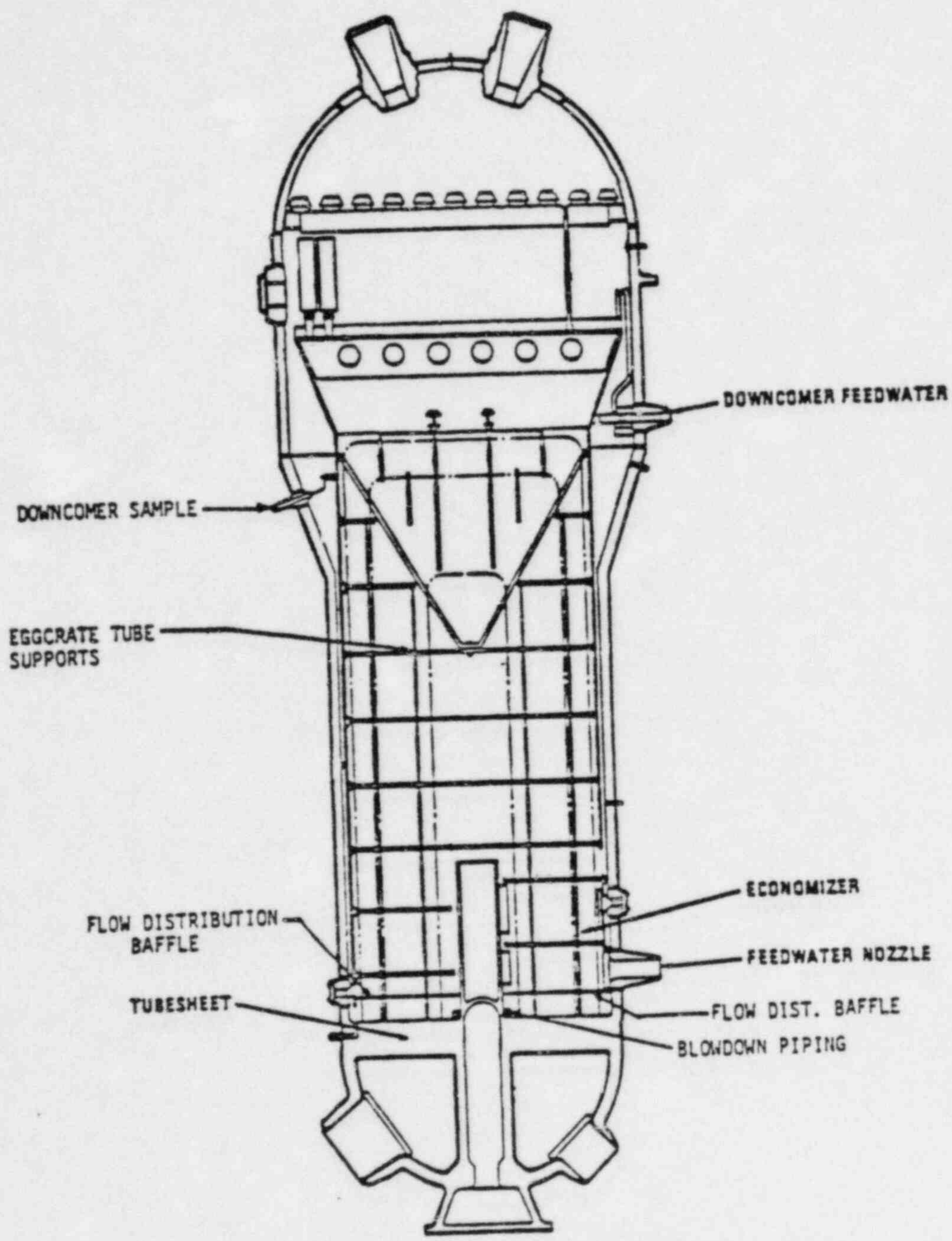


FIGURE 2.7-2

3410 CLASS PLANT
STEAM GENERATOR ASSEMBLY

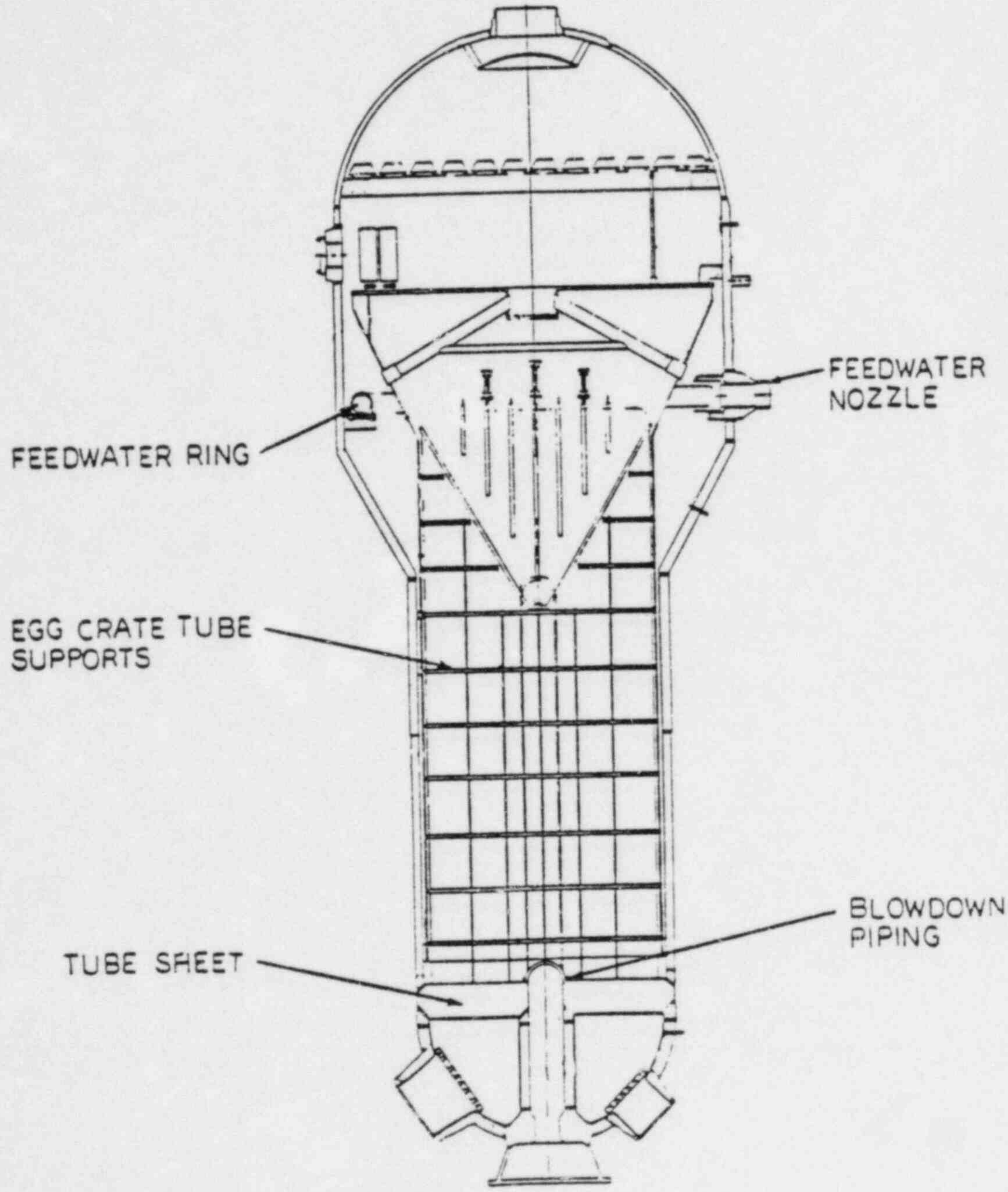


FIGURE 2.7-3

TYPICAL EGG-CRATE TUBE SUPPORT

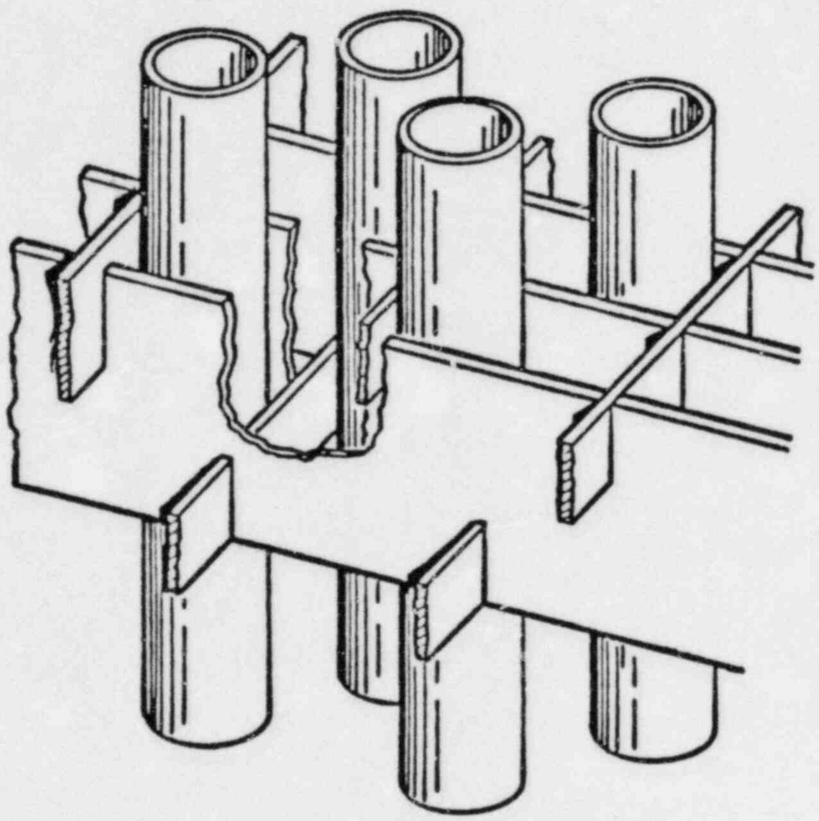


FIGURE 2.7-4

TYPICAL BEND REGION TUBE SUPPORT

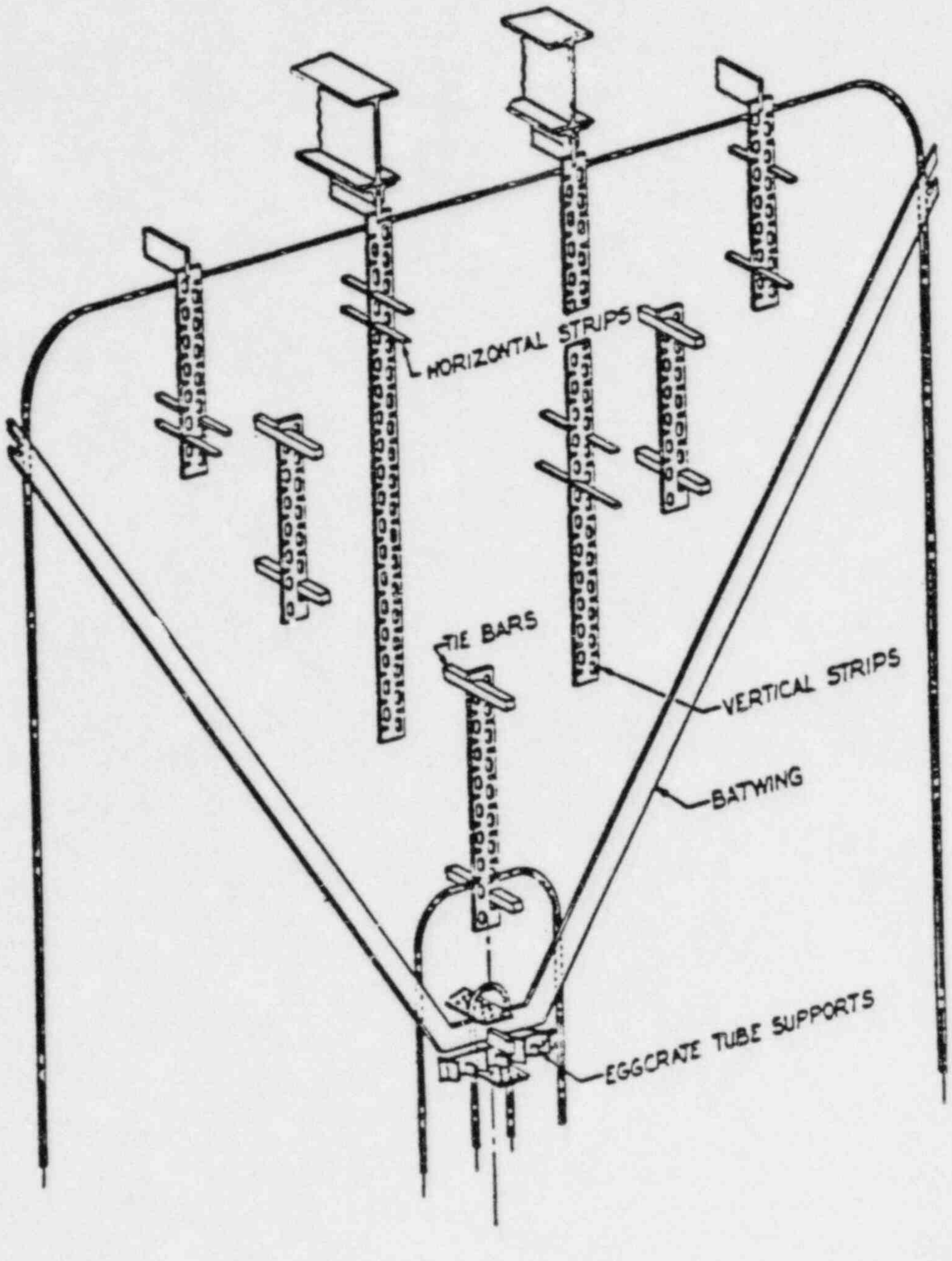


FIGURE 2.7-5

TYPICAL HORIZONTAL TUBE SUPPORT

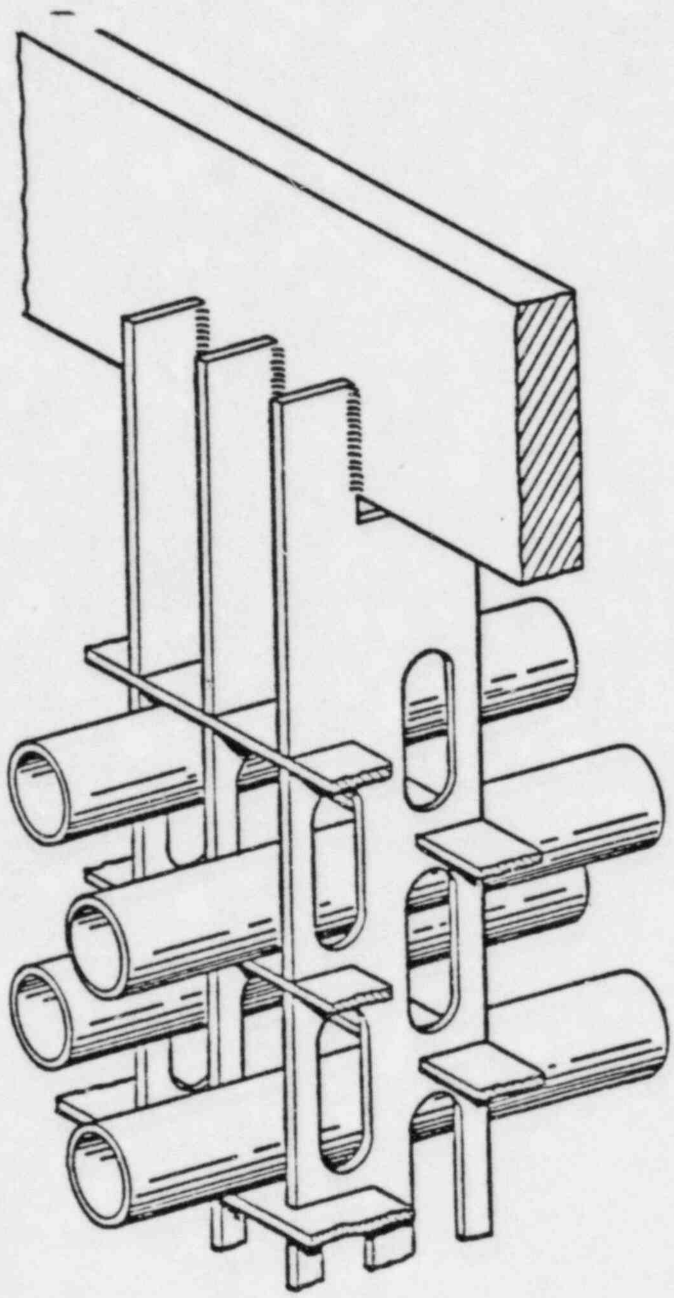
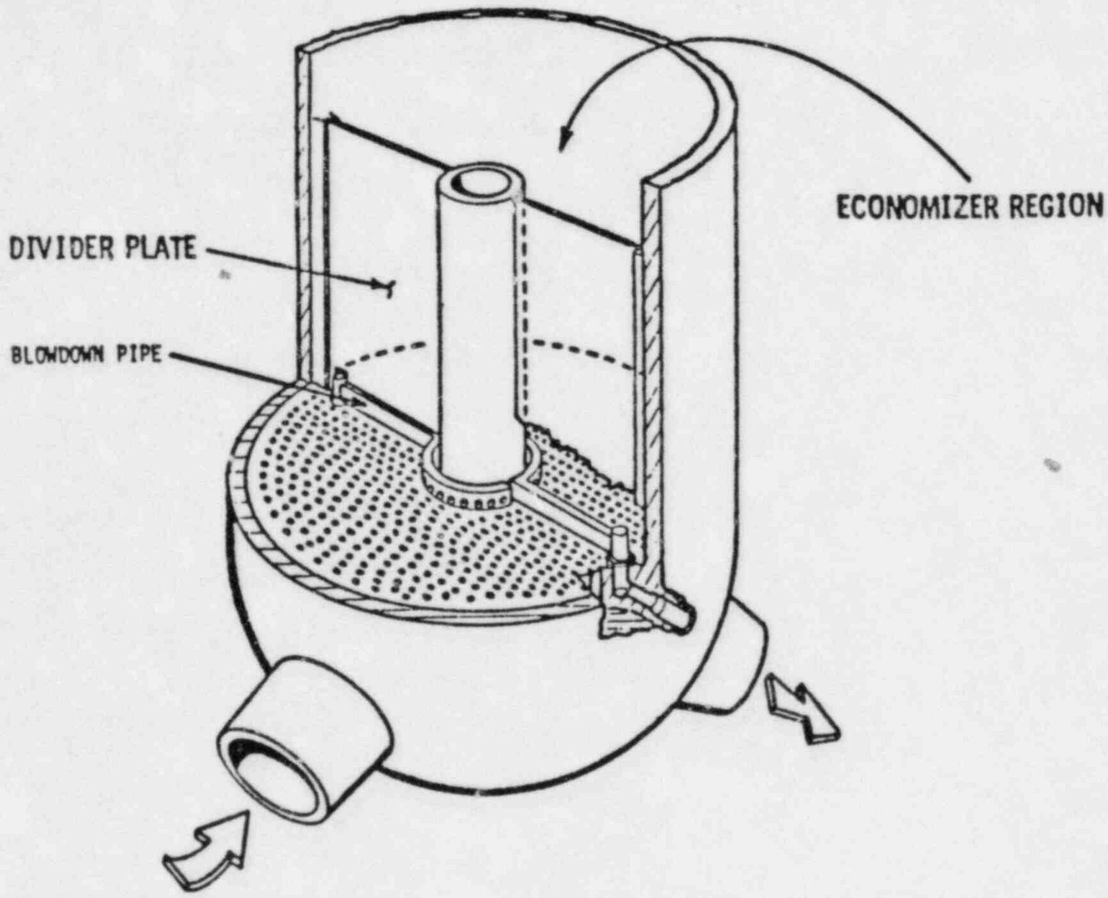


FIGURE 2.7-6

SYSTEM 80 SG BLOWDOWN PIPING



2.8 Question 8: Extended Loss of Feedwater

For extended loss of main and auxiliary feedwater case where feed/bleed would be a potential backup:

a. What is the frequency of loss of main feedwater events; break down initiators that affect more than MFW, e.g., DC power?

b. What is the probability of recovering main feedwater? Provide your bases such as availability of procedures and the human error rates?

c. What is the probability of losing all auxiliary feedwater (given Item a)? Include considerations of recovering auxiliary feedwater as well as common cause failures (including those which could affect main feedwater availability and support system dependencies) and failures that could be hidden from detection via tests?

d. What is the uncertainty in the estimates provided for a), b) and c)?

e. How long would it take for core melt to initiate?

f. Were core to melt under these conditions, what is the likelihood of steam generator tube rupture(s) due to steam pressure from slumping core?

g. Characterize the consequences from core melt events of e) and f).

2.8.1 Response to Question 8

A review of operating experience and a fault tree analysis was performed to determine the frequency of loss of MFW events. The analysis was completed on a plant specific bases and is contained in separate supplements to this report for each participating utility. The results of the analysis are quantified by a statistical distribution which represents the frequency of loss of MFW. For the representative plant, the initiating event frequency can be expressed in terms of a median value of 1.23 events per year with an associated error factor of 3. The median value represents the estimate, considering uncertainty, that would be expected to be higher than the true value with 50% confidence. The associated error factor is defined as the ratio of the 95th to 50th percentile. This factor, when multiplied by the median value, yields the upper bound estimate which would be expected to be higher than the true value with 95% confidence.

These results were further incorporated into an extensive evaluation of the core damage frequency due to loss of the secondary heat sink. The analysis included an investigation of the potential for recovering feedwater. The core damage frequency contribution resulting from a loss of the secondary heat sink was evaluated for the current plant design which includes low pressure pumps for secondary heat removal following steam generator depressurization but has no PORVs, and for an assumed plant design which includes PORV depressurization and decay heat removal (feed-and- bleed) but does not credit low pressure pumps for feeding the generators. The resulting core damage frequencies for the representative plant are 2.6×10^{-7} per year with an associated error factor of 30 without PORVs and 1.0×10^{-6} per year with an associated error factor of 21 with PORVs. In order to determine the reduction in total core damage frequency associated with utilizing alternate secondary heat removal capability, the loss of secondary heat sink core damage frequency which included alternate secondary heat removal capability was statistically subtracted from the loss of secondary heat sink core damage frequency with no alternate secondary heat removal capability and no PORVs. The result indicates a net decrease in core damage frequency due to alternate secondary heat removal capability of 2.0×10^{-6} per year (median value) with an associated error factor of 17. The complete analysis and a characterization of the consequences are presented in the plant specific supplements.

In order to respond to Part e of Question 8, an analysis of a TLOFW event was performed. The results are contained below and indicate that the hottest fuel rod cladding temperature reaches 2200°F for the worst case TLOFW transient at 60 minutes for the 3410 plants and 70 minutes for the 3800 plants. In addition, the analysis below indicates that initiation of steam generator depressurization and feed via a low head pump is perferable to initiation of RCS feed-and-bleed since inventory loss from the primary system is smaller and an operator has more time to initiate the recovery action.

2.8.2 TLOFW Analysis to Determine Time to Initiate Core Melt

An analysis was performed to determine time to initiate core melt following a extended loss of both main and auxiliary feedwater when no operator action is taken to recover from the event. In addition, an analysis was performed to determined the time available to the operator following a TLOFW in which successful corrective action can be taken in order to prevent core damage. In particular three corrective actions were assumed as follows:

1. Restoration of auxiliary feedwater.
2. Initiation of feed-and-bleed.
3. Steam generator depressurization and initiation of feedwater from a low head pump.

The following sections describe the method and assumptions used in the analysis, the results of the computer simulations of the TLOFW transient and the conclusions of the analysis.

2.8.2.1 Method and Assumptions of the Analysis

Eight separate transients, four for the 3410 plants and four for the 3800 plants, were simulated in order to perform this analysis. Each of the eight transients or cases are identified in Table 2.8-1 (p. 265). A base case, i.e., a TLOFW transient with no operator action to recover from the event, was perform for each class of plant in order to determine the time to initiate core melt. For the purpose of this analysis, the time to initiate core melt was defined as the time that the best estimate cladding temperature of the hottest fuel rod was calculate to reach 2200°F. The two base cases are Case 1 and Case 5 in Table 2.8-1.

The three corrective action scenarios listed above and in Table 2.8-1 were simulated to determine the time which the operator must act in order to prevent core uncovery. Preventing core uncovery was selected as the basis for determining the time for taking corrective action. Tables 2.8-2 (p. 266) and 2.8-3 (p. 267) list the values for the important system parameters used in the transient simulations. In general, best estimate information was used in characterizing plant systems and initial conditions. Important assumptions used in the analysis are listed in Table 2.8-4 (p. 268).

The transient simulations were performed using an improved version of the CEFLASH-4AS computer code described in Section 3.2 of Reference 16. Improvements were made in two areas to more realistically described the thermal-hydraulic processes that occur in the surge line and the pressurizer when PORVs and safety valves are open. First, an entrainment model was used to model the entrainment of liquid into the surge line from the hot leg and into the PORVs and safety valves from the pressurizer. Second, the finite difference wall heat model was upgraded to include a detailed calculation of surface heat transfer coefficients. This upgraded model was

Table 2.8-1

TOTAL LOSS OF FEEDWATER TRANSIENT SIMULATIONS

Case Number	Operator Action	NSSS
1	No recovery action	3410
2	Restoration of auxiliary feedwater	3410
3	Initiation of feed-and-bleed	3410
4	SG depressurization and initiation of feed from a low pressure pump	3410
5	No recovery action	3800
6	Restoration of auxiliary feedwater	3800
7	Initiation of feed-and-bleed	3800
8	SG depressurization and initiation of feed from a low pressure pump	3800

TABLE 2.8-2

SYSTEM PARAMETERS AND INITIAL CONDITIONS FOR THE 3410 PLANTS

Parameter	Value
Current Plant Design:	
Initial core power (Mw)	3410
Initial RCS pressure (psia)	2250
Initial RCS flowrate (lbm/hr)	148×10^6
Initial cold leg temperature (°F)	553
Initial hot leg tempterature (°F)	612
Initial SG pressure (psia)	895
Low SG level reactor trip setpoint (%)	10
SIAS setpoint (psia)	1763
Charging pump flow rate, per pump (gpm)	44
HPSI pump shutoff head (psia)	1420
HPSI pump runout flow, per pump (gpm)	905
RWT temperature (°F)	70
SIT gas pressure (psia)	615
PSV setpoint (psia)	2500
PSV capacity (steam at 2500 psia), per valve (lbm/hr)	463,000
PSV effective flow area, per valve (ft^2)	0.0232
Number of PSVs	2
MSSV setpoint (minimum) (psia)	1100
ADV capacity (steam at 900 psia), per valve (lbm/hr)	703,000
ADV effective flow area, per valve (ft^2)	0.108
AFW pump flow rate, per pump (gpm)	350
CST temperature (°F)	70
Condensate pump flow rate, per pump (gpm)	2300
Condensate pump shutoff head (psia)	350
Additional Parameters Assumed for Case 3:	
PORV setpoint (psia)	2400
PORV capacity (steam at 2400 psia), per valve (lbm/hr)	432,000
PORV effective flow area, per valve (ft^2)	0.0228
Number of PORVs	2

Table 2.8-3

SYSTEM PARAMETERS AND INITIAL CONDITIONS FOR THE 3800 PLANTS

Parameter	Value
Current Plant Design:	
Initial core power (Mw)	3878
Initial RCS pressure (psia)	2250
Initial RCS flowrate (lbm/hr)	164×10^6
Initial cold leg temperature (°F)	565
Initial hot leg tempterature (°F)	622
Initial SG pressure (psia)	1068
Low SG level reactor trip setpoint (%)	10
SIAS setpoint (psia)	1600
Charging pump flowrate, per pump (gpm)	44
HPSI pump shutoff head (psia)	1882
HPSI pump runout flow, per pump (gpm)	1126
RWT temperature (°F)	70
SIT gas pressure (psia)	608
PSV setpoint (psia)	2500
PSV capacity (steam at 2500 psia), per valve (lbm/hr)	504,900
PSV effective flow area, per valve (ft^2)	0.0253
Number of PSVs	4
MSSV setpoint (minimum) (psia)	1270
ADV capacity (steam at 1070 psia), per valve (lbm/hr)	959,000
ADV effective flow area, per valve (ft^2)	0.122
AFW pump flowrate, per pump (gpm)	875
CST temperature (°F)	70
Condensate pump flowrate, per pump (gpm)	3000
Condensate pump shutoff head (psia)	350
Additional Parameters Assumed for Case 7:	
PORV setpoint (psia)	2400
PORV capacity (steam at 2400 psia), per valve (lbm/hr)	432,000
PORV effective flow area, per valve (ft^2)	0.0228
Number of PORVs	2

Table 2.8-4

ASSUMPTIONS USED IN THE TLOFW TRANSIENT ANALYSIS

1. Main feedwater lost to both steam generators instantaneously.
2. Auxiliary feedwater fails to start both automatically and manually.
3. All reactor coolant pumps are manually tripped at 10 minutes.
4. One charging pump started at 20 minutes.
5. One train of safety injection pumps assumed to operate.
6. When auxiliary feedwater restored, one train assumed to operate.
7. When initiating feed and bleed, two PORVs are opened (full open).
8. When initiating SG depressurization, one ADV per SG is opened (full open).
9. SBCS, PLCS, PPCS, and auxiliary spray do not operate.
10. 1.0% of the 1971-ANS decay heat.
11. Homogeneous equilibrium critical flow model is used to predict PSV, PORV, and ADV flowrates.

applied in the pressurizer and the reactor vessel upper head. Best estimate fuel rod cladding temperatures were calculated using the PARCH computer code described in Reference 18.

2.8.2.2. Time to Core Melt for the TLOFW Transient with No Operator Action

The initiating event scenario that was selected for analysis was chosen so as to produce the minimum time to initiate core melt. Four basic assumptions lead to minimizing the time to core melt. First, the analysis assumed the instantaneous loss of all feedwater to both steam generators. Second, reactor trip was assumed to occur on low steam generator level thereby minimizing the steam generator inventory remaining after reactor trip. Third, reactor coolant pump operation was assumed for ten minutes following the TLOFW since maintenance of forced circulation hastens steam generator dryout. Fourth, operation of the turbine bypass system was not assumed, and therefore RCS heat is removed via the MSSV. Since the pressure maintained by the MSSV is higher than that of the turbine bypass system, the boiling of steam generator inventory will remove less RCS heat per pound than the boiling process at the set pressure of the turbine bypass system.

The sequence of important events for the TLOFW transient with no operator action for both the 3410 and the 3800 plants are given in Table 2.8-5 (p. 270). The important NSSS and steam generator parameters are plotted as a function of time in Figure 2.8-1 through 2.8-14. (All figures for Section 2.8 of this report are contained together at the end of the section (p. 281).) The reader is referred to Section 3.10 of Reference 17 for a general discussion of the TLOFW transient. As shown in Figure 2.8-7 and in Figure 2.8-14, the clad temperature of the hottest fuel rod exceeds 2200°F at 60 minutes for the 3410 plants and 70 minutes for the 3800 plants. Therefore, using the definition of the initiation of core melt assumed in this analysis i.e., 2200°F, core melt would begin at approximately one hour for the worst case scenario of an unmitigated TLOFW event.

Table 2.8-5

SEQUENCE OF EVENTS FOR THE TLOFW TRANSIENT WITH NO RECOVERY ACTION

Event	Time 3410 Plant	 3800 Plant
Total loss of feedwater	0 sec.	0 sec.
Reactor trip	20 sec.	29 sec.
MSSVs open	24 sec.	29 sec.
RCPs trip, manual	10 min.	10 min.
SG dryout	10 min.	12 min.
PSVs open	12 min.	14 min.
Charging pump on, manual	20 min.	20 min.
RCS (hot side) reaches saturation	28 min.	29 min.
Core uncovery begins	53 min.	63 min.
Hottest fuel rod temperature reaches 2200°F	60 min.	70 min.

For scenarios other than the worst case scenario described above, the time to initiate core melt will be greater than 60 minutes for the 3410 plants and greater than 70 minutes for the 3800 plants. There are two major factors which influence this time: 1) The amount of core and RCS heat which must be removed, and 2) The steam generator inventory available to remove this heat. Conditions which decrease the amount of heat to be removed or increase the amount of steam generator inventory will increase the time to core melt. Examples of three such scenarios are as follows:

1. TLOFW from less than 100% power. In this scenario not only is the amount of core decay heat decreased but the steam generator inventory is increased since steam generator inventory increases as power decreases.

2. TLOFW coincident with loss of offsite power or with a reactor/turbine trip. This scenario significantly increases the steam generator inventory available after reactor trip and therefore increases the time to steam generator dryout.

3. Non-instantaneous loss of main or auxiliary feedwater or both. Any scenario which maintains feed flow beyond the time assumed in the worst case scenario will increase steam generator inventory available after reactor trip and therefore will increase time to steam generator dryout.

The following three sections discuss the time available to the operator to take various corrective actions following the worst case scenario TLOFW in order to prevent the reactor core from uncovering. As noted in Section 2.8.2.1 above, core uncovery was arbitrarity selected as the common point in each scenario for determining the time to take corrective action.

2.8.2.3 Time to Restore Auxiliary Feedwater

Restoring one train of the auxiliary feedwater system by 50 minutes for the 3410 plants and 59 minutes for the 3800 plants prevents core uncovery for the worst case scenario TLOFW described in the preceding section.

Figure 2.8-15 through Figure 2.8-18 show the pressure and the reactor inner vessel two-phase mixture level as a function of time for this transient for both classes of plant. Table 2.8-6 (p. 273) lists the sequence of events. As shown in Figure 2.8-15 and Figure 2.8-17 and as indicated in Table 2.8-6, within a few minutes of restoring auxiliary feedwater RCS pressure falls below 2500 psia and the PSVs close. The reduction is system pressure results from regaining the secondary as a heat sink with subsequent condensation of steam on the primary side of the U-tubes. With the closing of the pressurizer code safety valves, RCS inventory loss stops and the liquid in the pressurizer drains back into the reactor vessel. Charging flow and high pressure safety injection flow (when RCS pressure drops sufficiently) then restore primary system inventory, see Figure 2.8-16 and Figure 2.8-18.

2.8.2.4 Time to Initiate a Feed-and-Bleed Method of Core Cooling

Initiating feed-and-bleed by 20 minutes for the 3410 Mwt plants and 25 minutes for the 3800 plants prevents core uncovery for the worst case scenario TLOFW described in Section 2.8.2.2. This assumes two relatively large PORVs and one train of HPSI as indicated in Section 2.8.2.1.

Figure 2.8-19 through Figure 2.8-22 show the pressure and the reactor inner vessel two-phase mixture level as a function of time for this transient for both classes of plant. Table 2.8-7 (p. 274) lists the sequence of events. When the PORVs are manually opened, the RCS begins to rapidly depressurize. This causes the PSVs to

Table 2.8-6

SEQUENCE OF EVENTS FOR THE TLOFW TRANSIENT
WITH RESTORATION OF AUXILIARY FEEDWATER

Event	Time	
	3410 Plant	3800 Plant
Total loss of feedwater	0 sec.	0 sec.
Reactor trip	20 sec.	29 sec.
MSSVs open	24 sec.	29 sec.
RCPs trip, manual	10 min.	10 min.
SG dryout	10 min.	12 min.
PSVs open	12 min.	14 min.
Charging pump on, manual	20 min.	20 min.
RCS (hot side) reaches saturation	28 min.	29 min.
Restore auxiliary feedwater	50 min.	59 min.
PSVs close	53 min.	62 min.
MSSVs open	55 min	65 min.
HPSI pumps on	75 min.	82 min.
Core uncovery begins	(a)	(a)

(a) Core uncovery is not predicted to occur.

Table 2.8-7

SEQUENCE OF EVENTS FOR THE TLOFW TRANSIENT
WITH INITIATION OF FEED-AND-BLEED

Event	Time 3410 Plant	Time 3800 Plant
Total loss of feedwater	0 sec.	0 sec.
Reactor trip	20 sec.	29 sec.
MSSVs open	24 sec.	29 sec.
RCPs trip, manual	10 min.	10 min.
SG dryout	10 min.	12 min.
PSVs open	12 min.	14 min.
Charging pump on, manual	20 min.	20 min.
RCS (hot side) reaches saturation	20.5 min.	20 min.
PORVs open, manual	20 min	25 min.
PSVs close	20 min.	25 min.
HPSI pumps on	41 min.	48 min.
Core uncovery begins	(a)	(a)

(a) Core uncovery is not predicted to occur.

close; however, RCS inventory continues to be lost. The PORVs are large enough so that after the RCS reaches saturation pressure these valves continue to vent the steam produced by boiling in the core and by flashing in the RCS. As a result, the RCS continues to depressurize. The HPSI pumps are actuated on an SIAS. As the RCS pressure continues to decrease, the PORV flowrate decreases and the HPSI flowrate increases. When the HPSI flow exceeds the PORV flow the RCS inventory begins to increase. At this point in the transient the operator has regained control of RCS inventory.

2.8.2.5 Time to Initiate SG Depressurization

In this simulation it was assumed that the operator initiates steam generator depressurization by opening (full open) one ADV per steam generator and that a condensate pump was used to supply feedwater. Tables 2.8-2 and 2.8-3 give the design characteristics of the ADVs and condensate pumps used in the analysis. The results of the analysis show that taking this corrective action by 50 minutes for the 3410 plants and 59 minutes for the 3800 plants prevents core uncovery following the worst case TLOFW scenario described in Section 2.8.2.2.

Figure 2.8-23 through Figure 2.8-26 show the pressure and reactor inner vessel two phase mixture level as a function of time for this transient for both classes of plant. Table 2.8-8 (p. 276) lists the sequence of events. As shown in Figure 2.8-23 and Figure 2.8-25 and as indicated in Table 2.8-8, within a few minutes of commencing steam generator depressurization RCS pressure falls below 2500 psia and the PSVs close. The reduction in system pressure results from regaining the secondary as a heat sink with subsequent condensation of steam on the primary side of the U-tubes. With the closing of the pressurizer code safety valves, RCS inventory loss stops and the liquid in the pressurizer drains back into the reactor vessel. Charging flow and high pressure safety injection flow (when RCS pressure drops sufficiently) then restore primary system inventory, see Figure 2.8-24 and Figure 2.8-26.

Table 2.8-8

SEQUENCE OF EVENTS FOR THE TLOFW TRANSIENT
WITH INITIATION OF FEEDWATER FROM CONDENSATE PUMP

Event	Time 3410 Plant	Time 3800 Plant
Total loss of feedwater	0 sec.	0 sec.
Reactor trip	20 sec.	29 sec.
MSSVs open	24 sec.	29 sec.
RCPs trip, manual	10 min.	10 min.
SG dryout	10 min.	12 min.
PSVs open	12 min.	14 min.
Charging pump on, manual	20 min.	20 min.
RCS (hot side) reaches saturation	28 min.	24 min.
ADV open, manual	50 min.	59 min.
Condensate pumps inject to SGs	52 min.	61 min.
PSVs close	52 min.	62 min.
HPSI pumps on	56 min.	67 min.
SITs on	62 min.	(a)
Core uncovery begins	(b)	(b)

(a) Simulation terminated before SITs on.

(b) Core uncovery is not predicted to occur.

2.8.2.6 Comparison of Charging vs Auxiliary Spray

In each of the eight TLOFW cases analyzed above, it was assumed that charging flow was initiated at twenty minutes to the RCS cold leg. If charging flow were to be initiated sooner, core uncovery would be delayed as one would expect due to the increase in inventory. If, for comparison, an operator were to initiate auxiliary spray instead of initiating charging, the RCS might be depressurized to the point where the HPSI pumps would operate. In order to determine the effect on core uncovery, two simulations were performed comparing the use of charging vs the use of auxiliary spray. The simulations were identical to Case 1 above, see Section 2.8.2.1, except with respect to the use of charging. In the first simulation auxiliary spray was initiated at 100 seconds using two charging pumps and in the second simulation cold leg injection was initiated at 100 seconds using two charging pumps. Figure 2.8-27 shows a comparison of RCS pressures for the two simulations and Figure 2.8-28 shows a comparison of the reactor inner vessel two-phase mixture levels. Note in Figure 2.8-27 that the use of auxiliary spray allowed the RCS to be slightly more depressurized, but that system pressure quickly increased once steam generator dryout began to occur. As a result, core uncovery occurred sooner than the case where charging was directed to the loops, see Figure 2.8-28, and in fact HPSI never occurred. The basic reason for the decrease in core uncovery time was that the inventory added to the RCS was retained in the pressurizer and therefore not available in the core for boil off.

2.8.2.7 Conclusions

Table 2.8-9 (p. 278) and Figures 2.8-29 and 2.8-30 summarize the results of the TLOFW transient analyses. The following conclusions are made based on the results of the analysis:

1. Based upon a criteria of 2200°F peak clad temperature, the onset of core melt for the 3410 plants is approximately 60 minutes following a TLOFW and the onset of core melt for the 3800 plants is approximately 70 minutes following a TLOFW.

Table 2.8-9

SUMMARY OF RESULTS FOR TLOFW TRANSIENT ANALYSIS

	3410 Plant	3800 Plant
Minimum time hottest fuel rod clad temperature reaches 2200°F for unmitigated TLOFW transient.	60 min.	70 min.
Time to restore auxiliary feedwater to prevent core uncovery.	50 min.	59 min.
Time to initiate feed-and-bleed to prevent core uncovery.	20 min.	25 min.
Time to initiate SG depressurization and feed via a low head pump to prevent core uncovery	50 min.	59 min.

2. The operator has significantly more time to regain the steam generators as heat sinks, either by restoring auxiliary feedwater or by initiating steam generator depressurization, than by initiating feed-and-bleed in order to present core uncovery. The reason for this is that regaining the steam generators as heat sinks accomplishes RCS heat removal by condensing steam within the steam generators (and thereby depressurizing the RCS). Opening PORVs on the other hand, accomplishes RCS heat removal by removing inventory. As a result, feed-and-bleed must be initiated relatively early in the event to preclude losing inventory out the PSVs to the extent that core uncovery occurs.

3. Depressurizing the steam generators results in a slightly better inner vessel level response than restoring auxiliary feedwater even though the latter case regains the generators as heat sinks sooner. The reason for this is that the heat sink temperature (saturation temperature) is lower at the lower pressure obtained during secondary depressurization which increase the primary-to-secondary temperature differential.

4. Initiating auxiliary spray during a TLOFW instead of charging to the loops will decrease the time to core uncovery, i.e., sooner, since inventory added to the RCS is retained in the pressurizer and not available in the core for boil off.

Figures for Section 2.8

FIGURE 2.8-1

3410 CLASS PLANT
TLOFW WITH NO OPERATOR ACTION
RCS AND SG PRESSURES

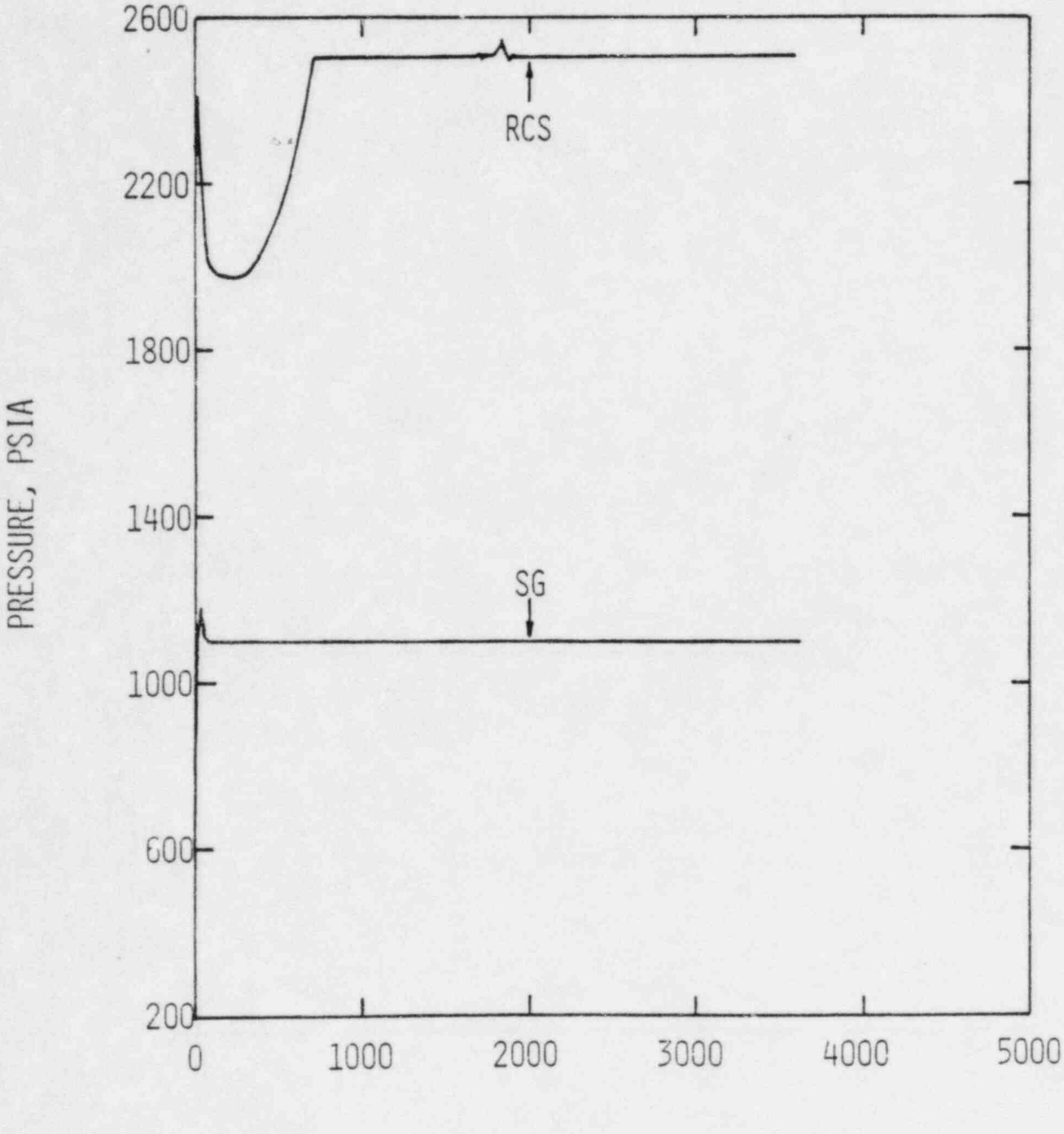


FIGURE 2.8-2

3410 CLASS PLANT
TLOFW WITH NO OPERATOR ACTION
REACTOR INNER VESSEL TWO-PHASE MIXTURE LEVEL

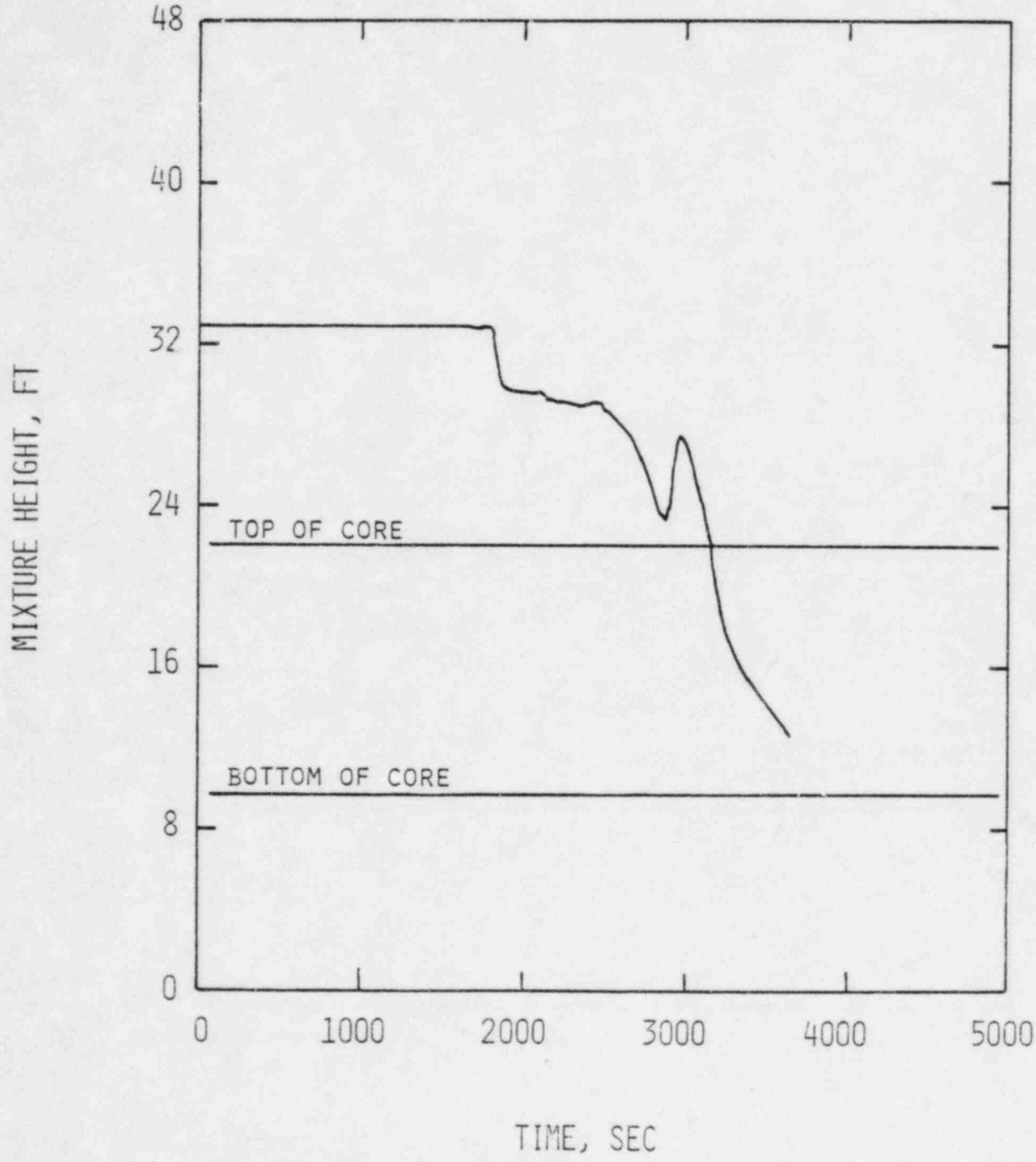


FIGURE 2.8-3

3410 CLASS PLANT
TLOFW WITH NO OPERATOR ACTION
PZR TWO-PHASE MIXTURE LEVEL

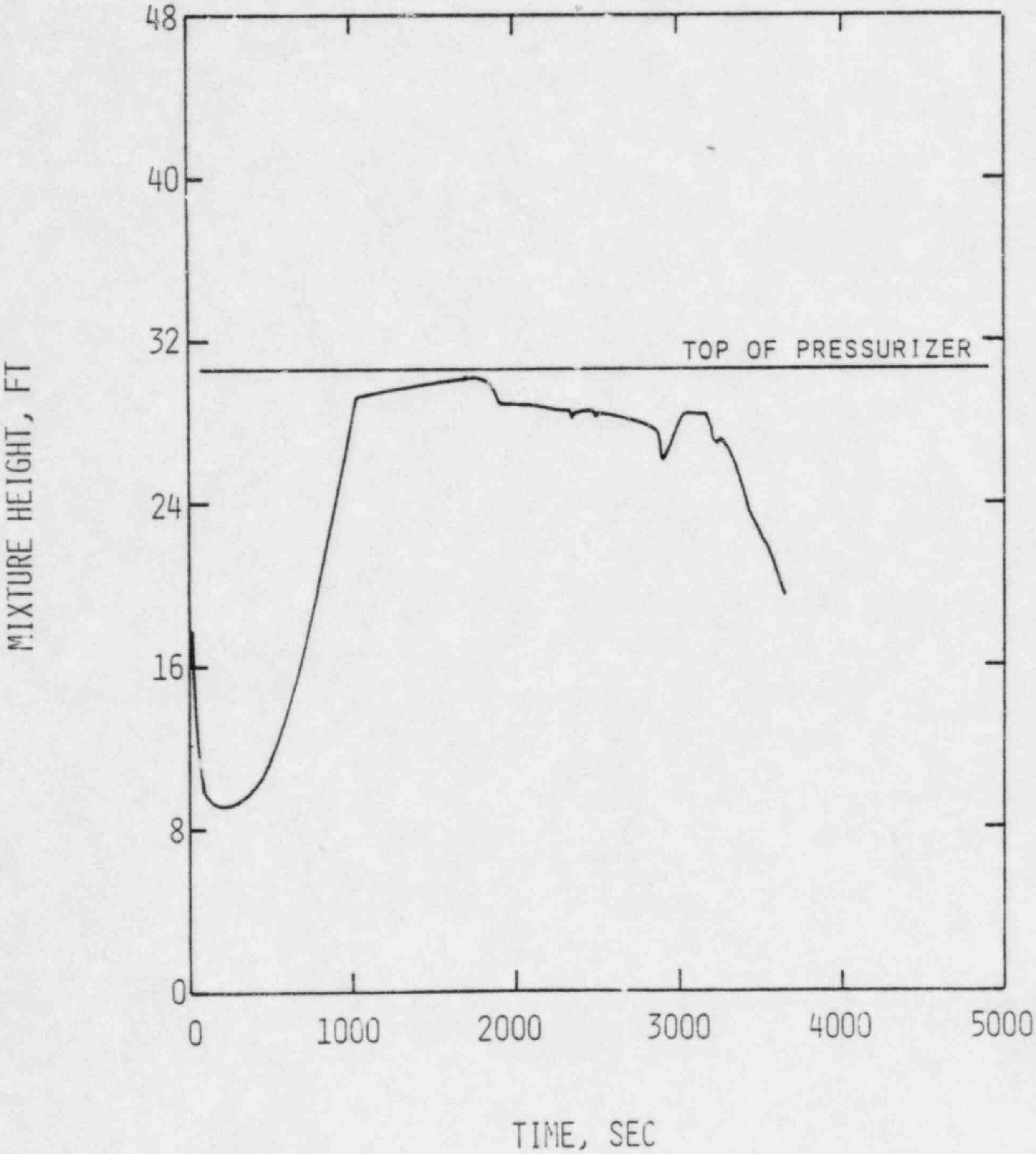


FIGURE 2.8-4

3410 CLASS PLANT
TLOFW WITH NO OPERATOR ACTION
SG TWO-PHASE MIXTURE LEVEL

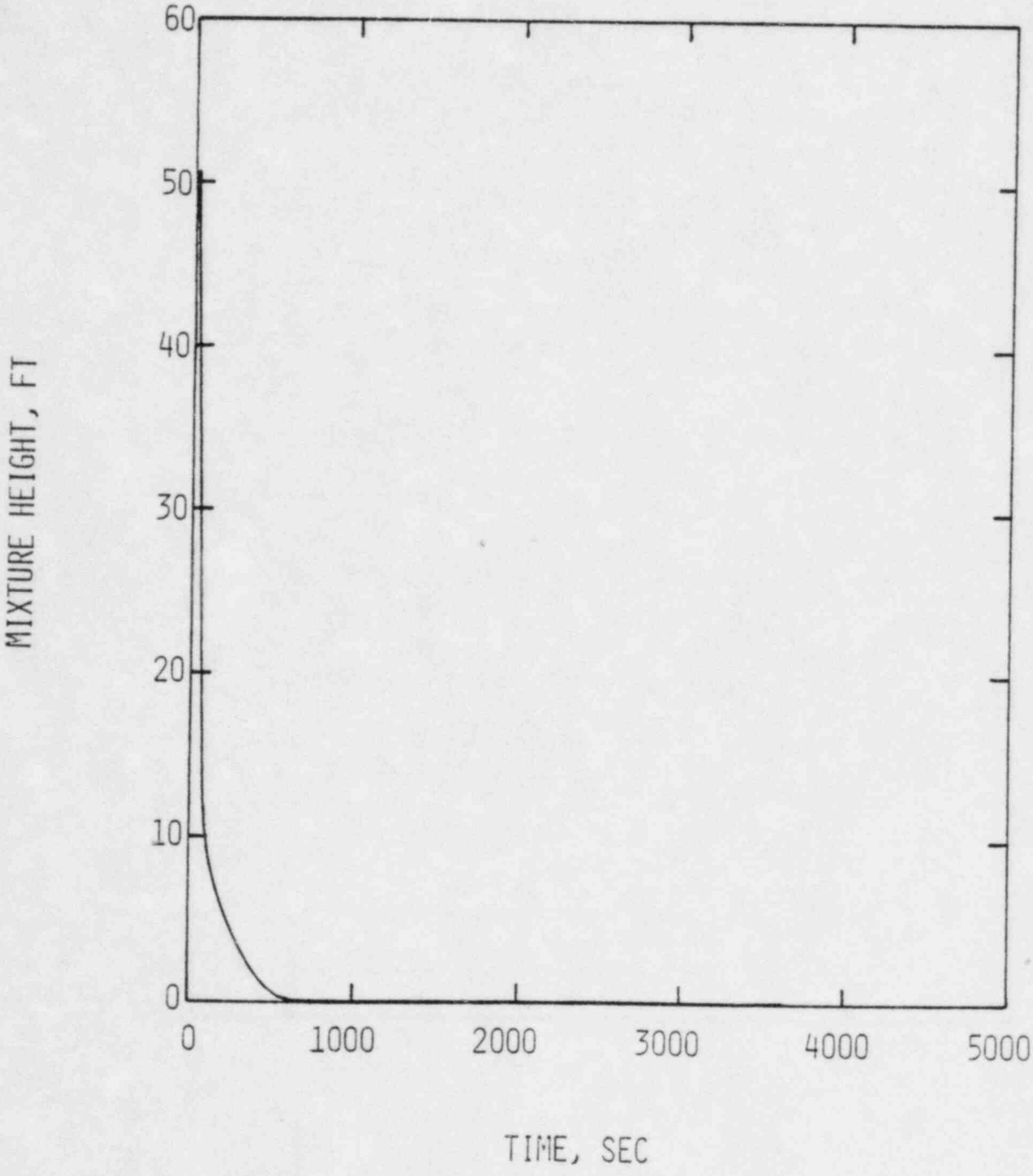


Figure 2.8-5

3410 CLASS PLANT
TLOFW WITH NO OPERATOR ACTION
PZR SAFETY VALVE FLOWRATE

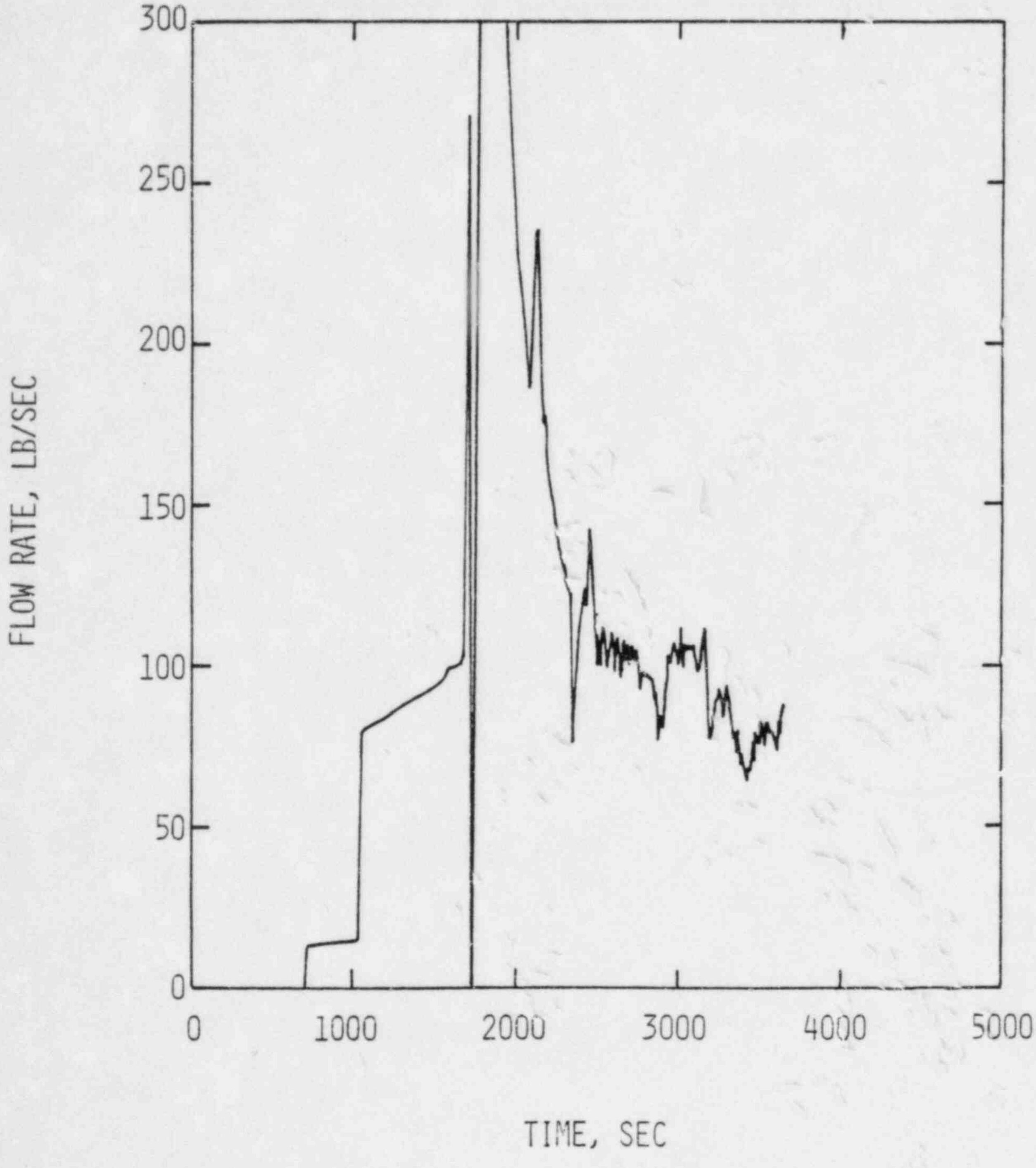


FIGURE 2.8-6

3410 CLASS PLANT
TLOFW WITH NO OPERATOR ACTION
PZR SAFETY VALVE QUALITY

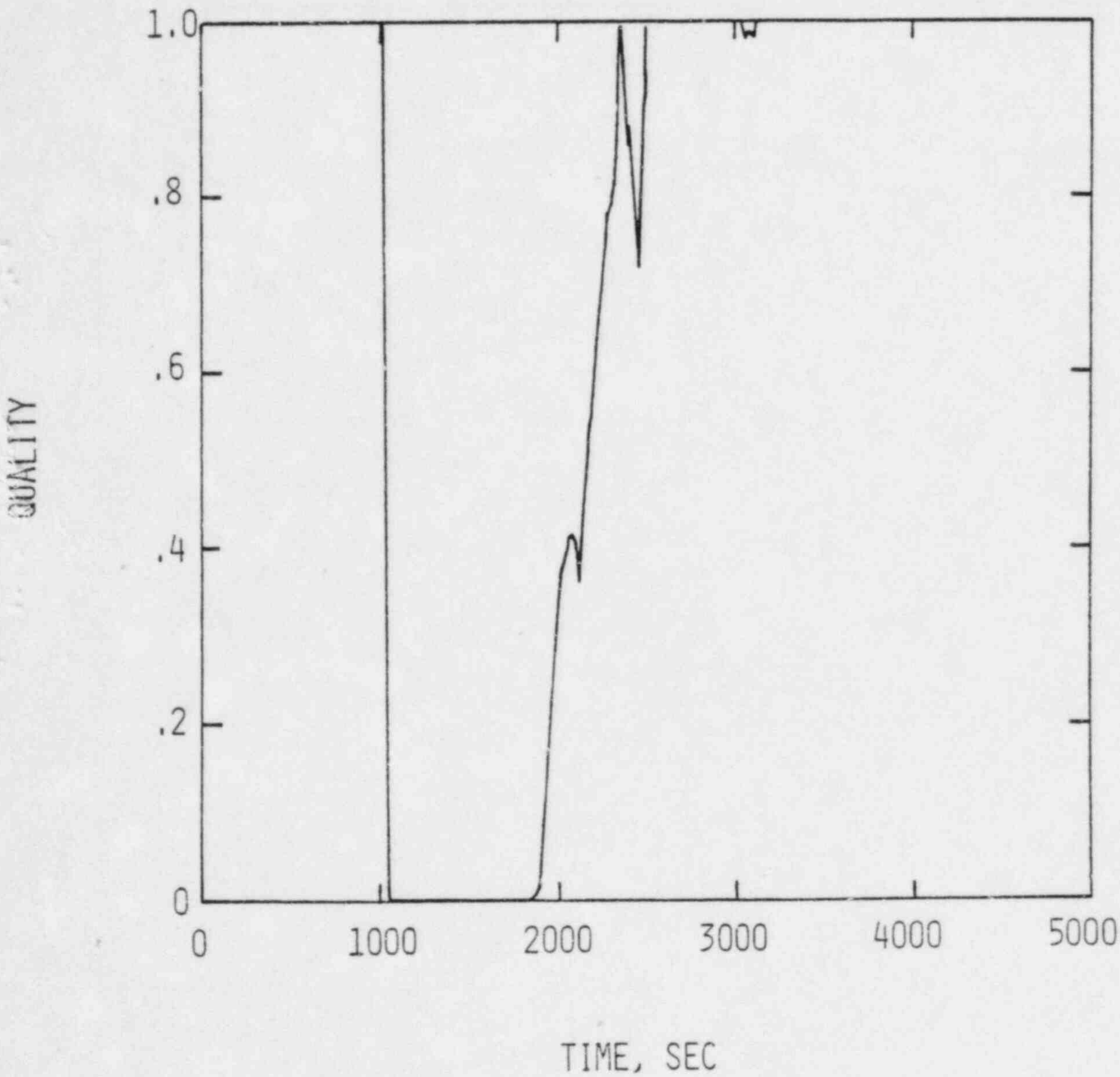


FIGURE 2.8-7

3410 CLASS PLANT
TLOFW WITH NO OPERATOR ACTION
HOTTEST FULL ROD CLADDING TEMPERATURE

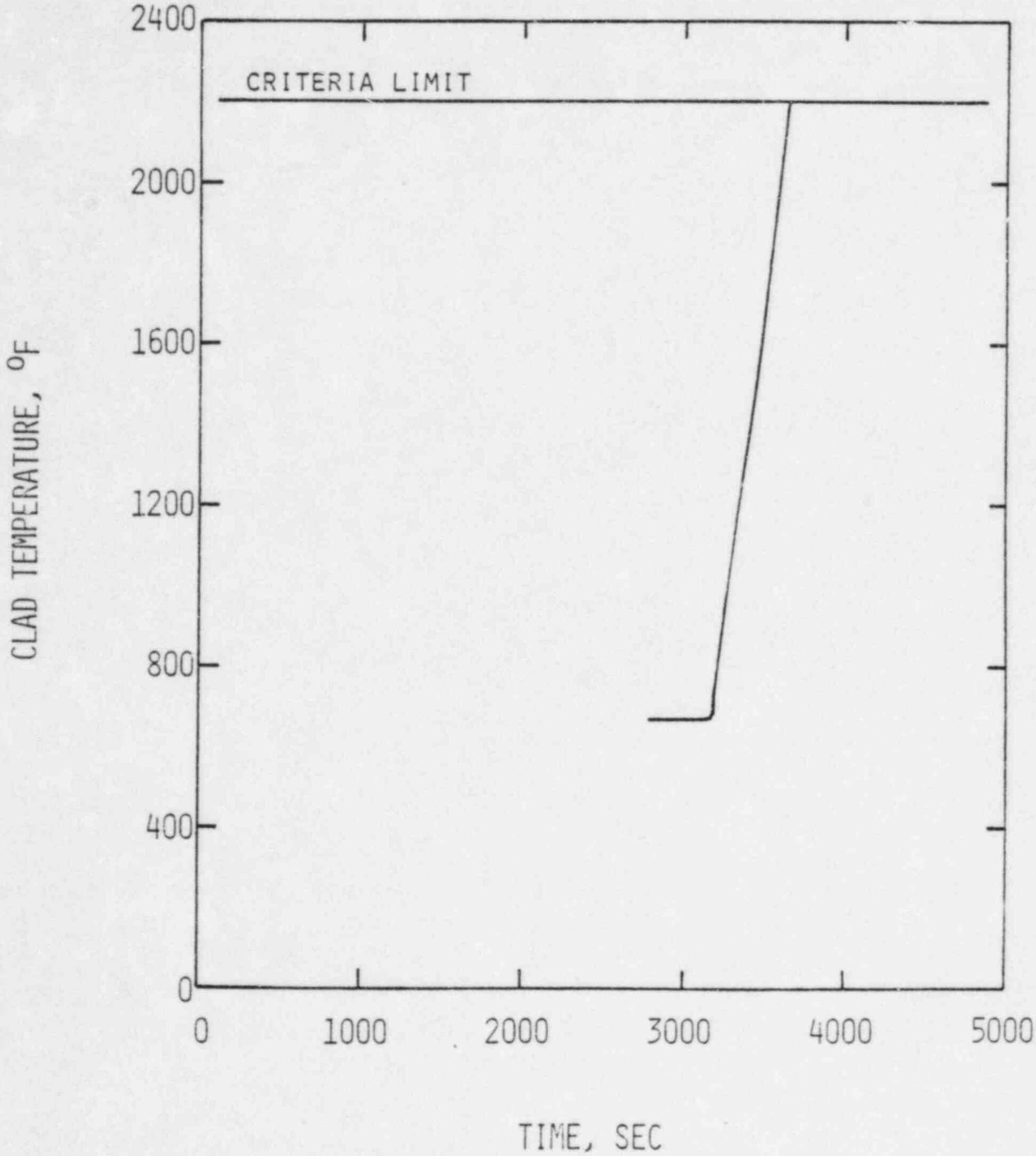


FIGURE 2.8-8

3800 CLASS PLANT
TLOFW WITH NO OPERATOR ACTION
RCS AND SG PRESSURE

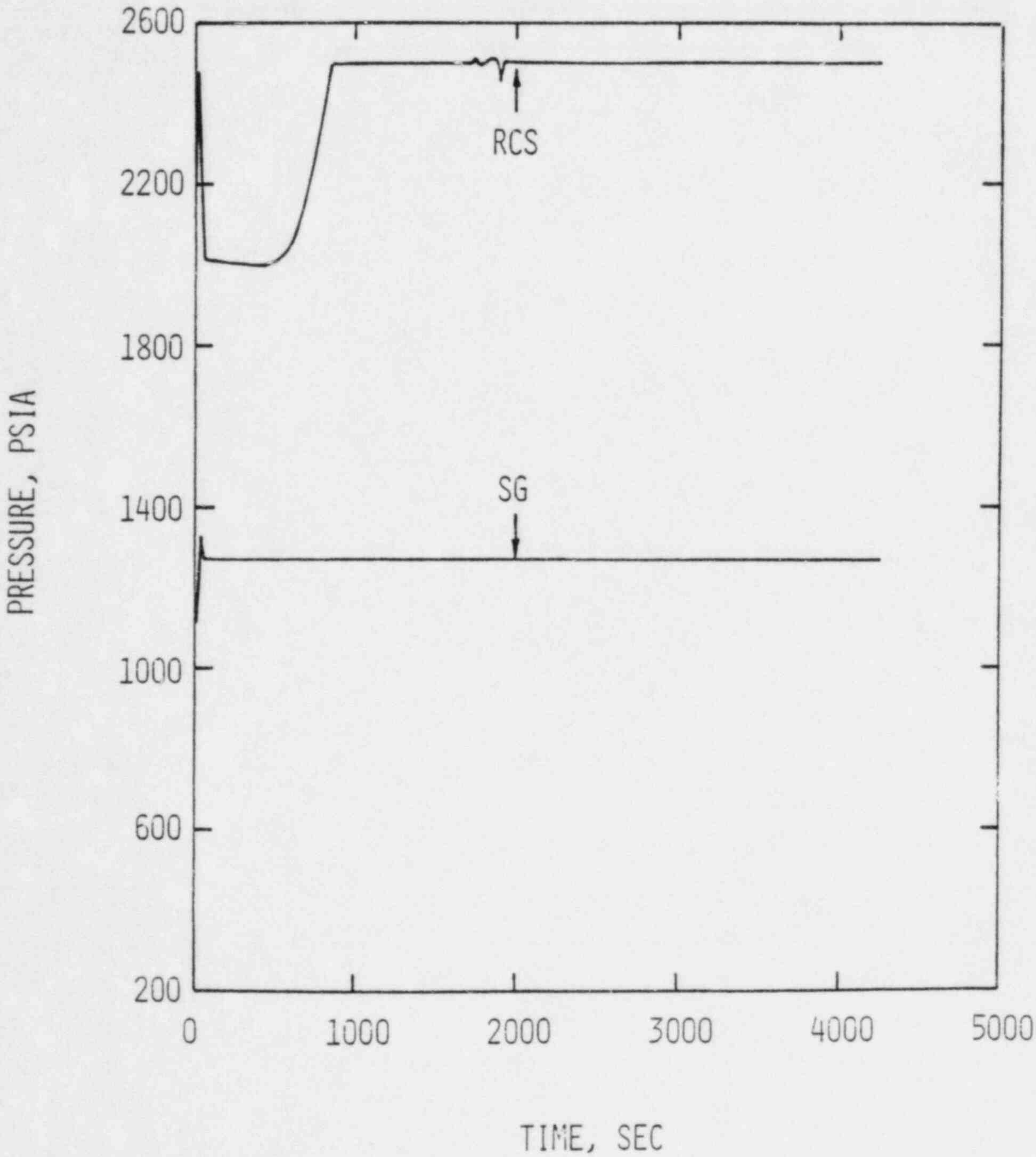


FIGURE 2.8-9

3800 CLASS PLANT
TLOFW WITH NO OPERATOR ACTION
REACTOR INNER VESSEL TWO-PHASE MIXTURE LEVEL

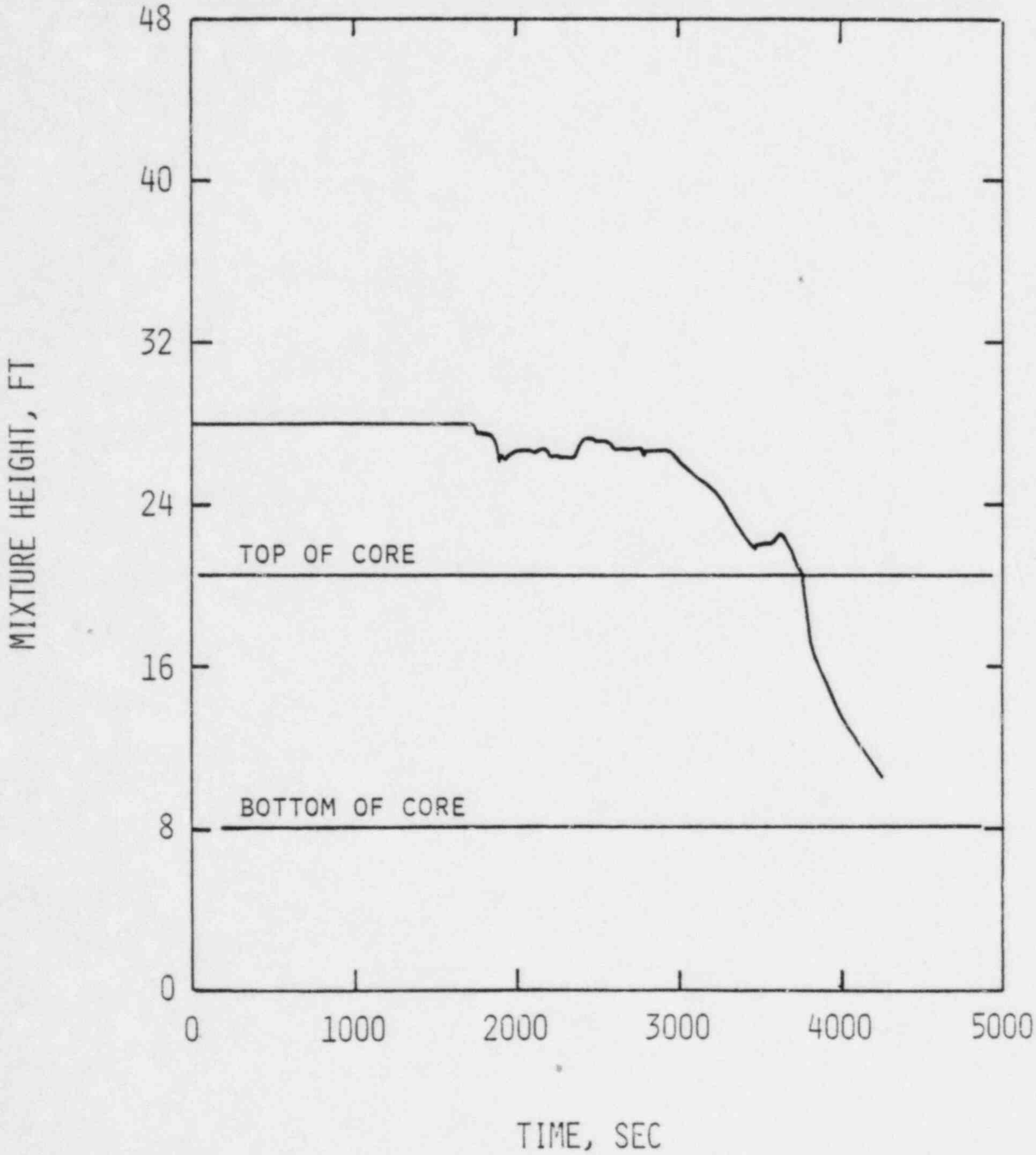


Figure 2.8-10

3800 CLASS PLANT
TLOFW WITH NO OPERATOR ACTION
PZR TWO-PHASE MIXTURE LEVEL

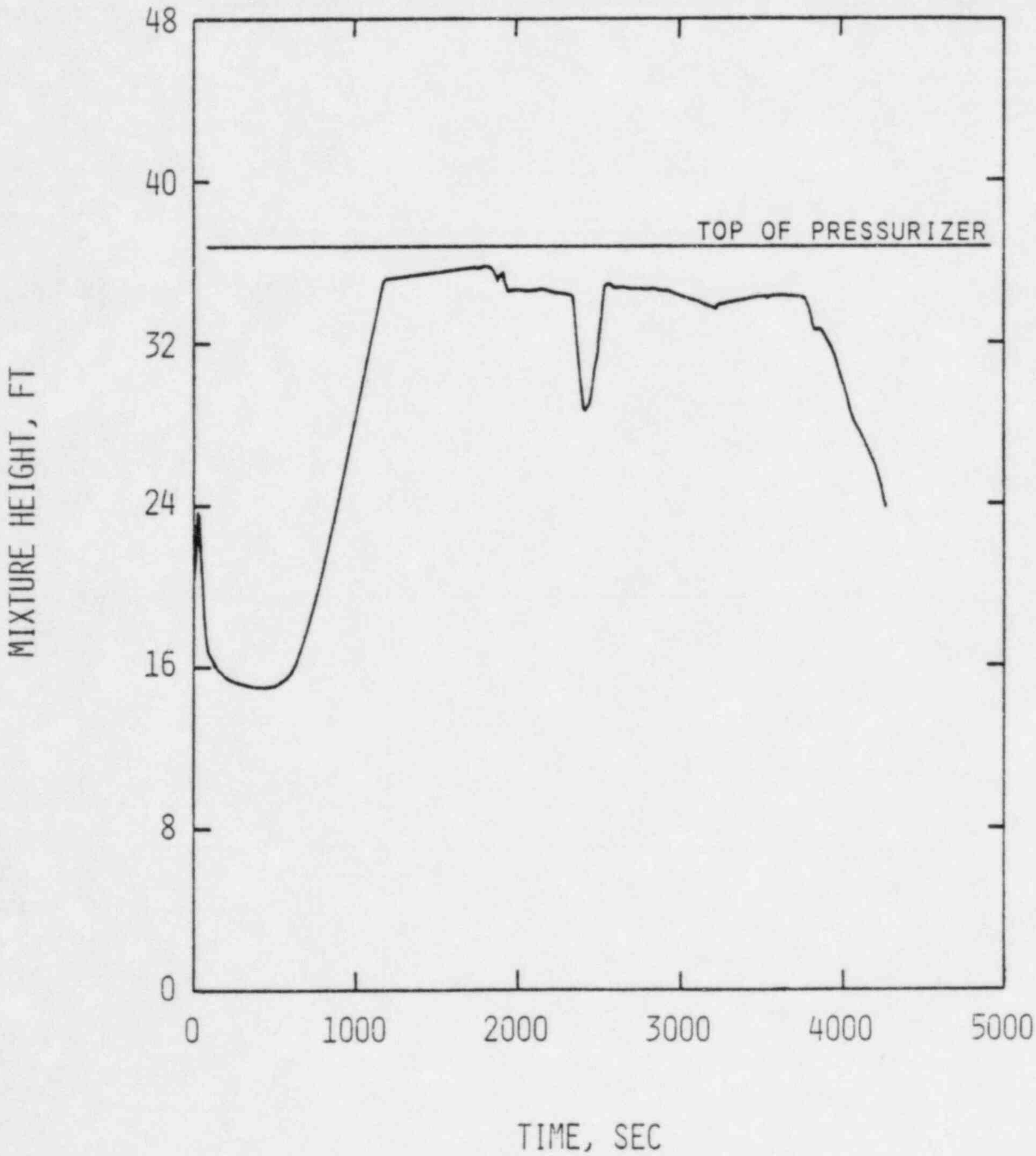


FIGURE 2.8-11

3800 CLASS PLANT
TLOFW WITH NO OPERATOR ACTION
SG TWO-PHASE MIXTURE LEVEL

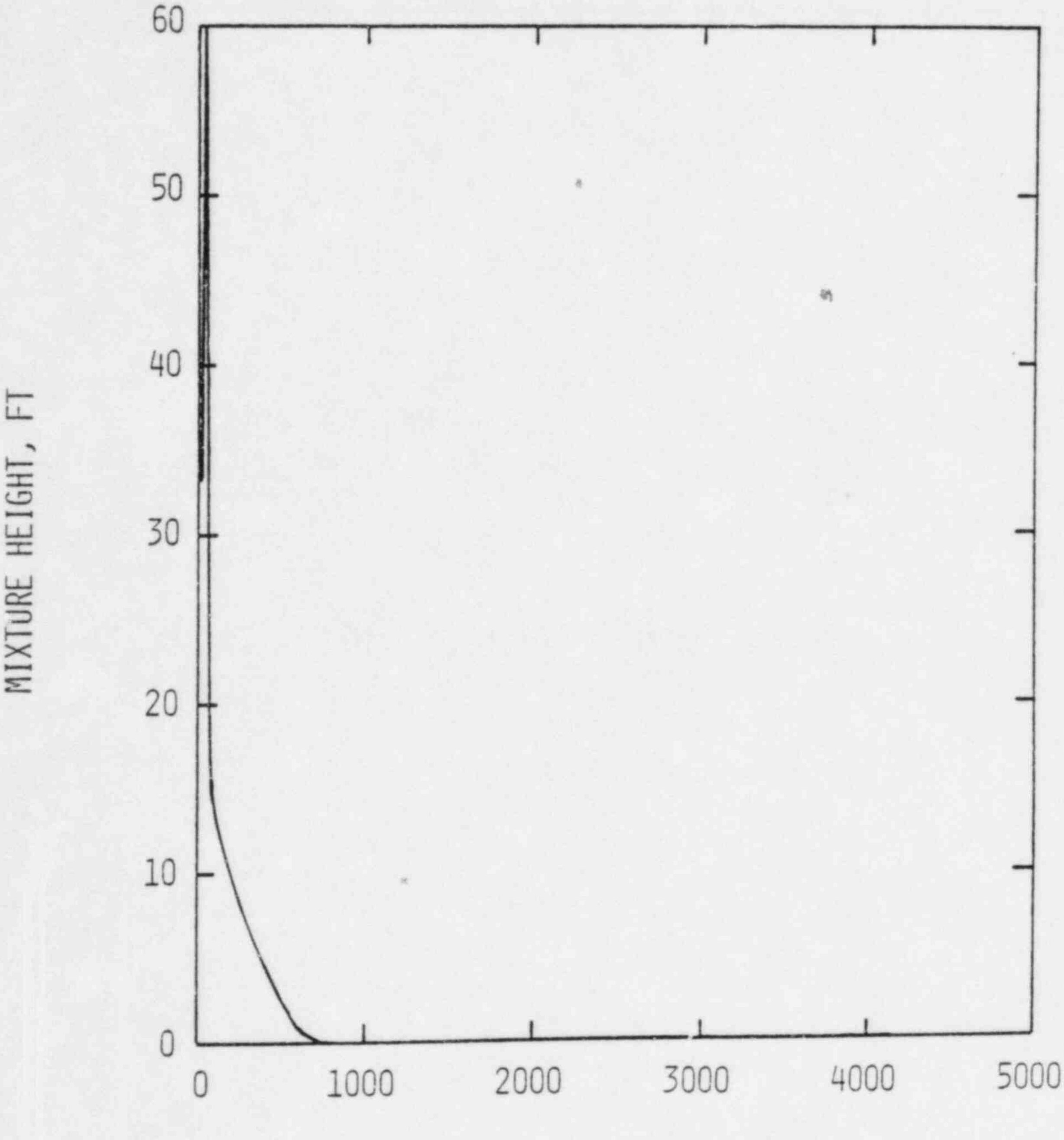


FIGURE 2.8-12

3800 CLASS PLANT
TLOFW WITH NO OPERATOR ACTION
PZR SAFETY VALVE FLOWRATE

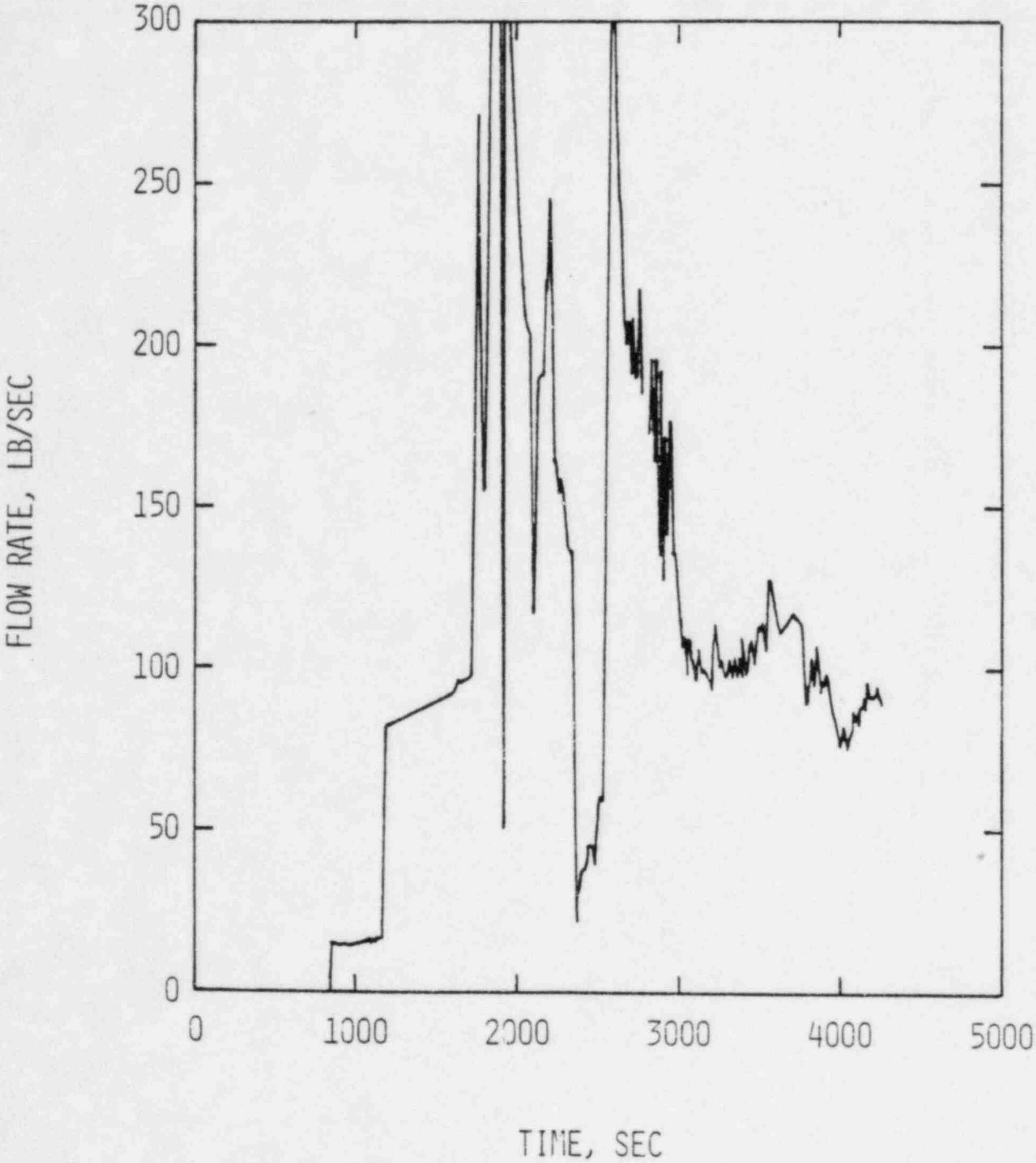


Figure 2.8-13

3800 CLASS PLANT
TLOFW WITH NO OPERATOR ACTION
PZR SAFETY VALVE QUALITY

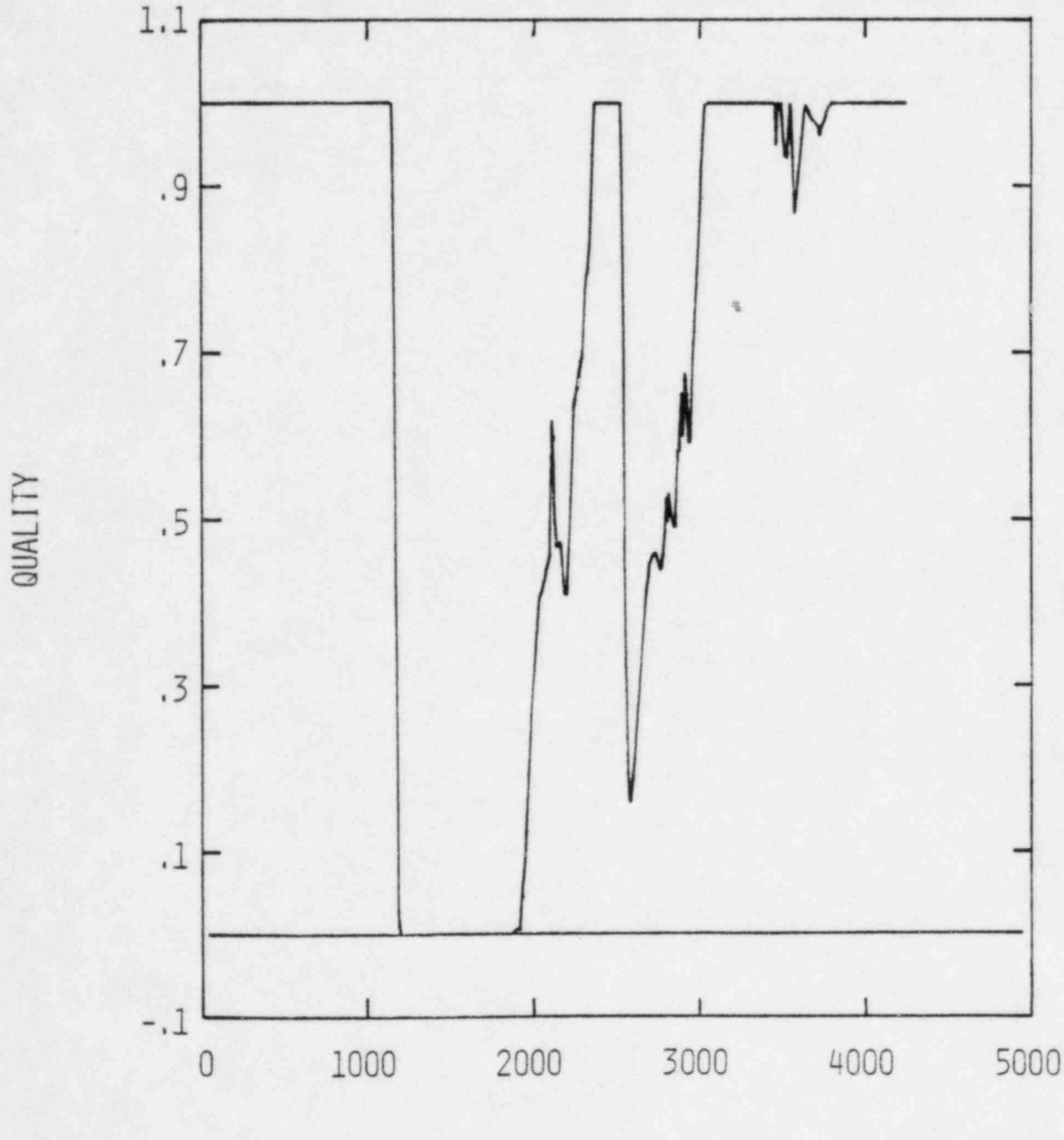


FIGURE 2.8-14

3800 CLASS PLANT
TLOFW WITH NO OPERATOR ACTION
HOTTEST FUEL ROD CLADDING TEMPERATURE

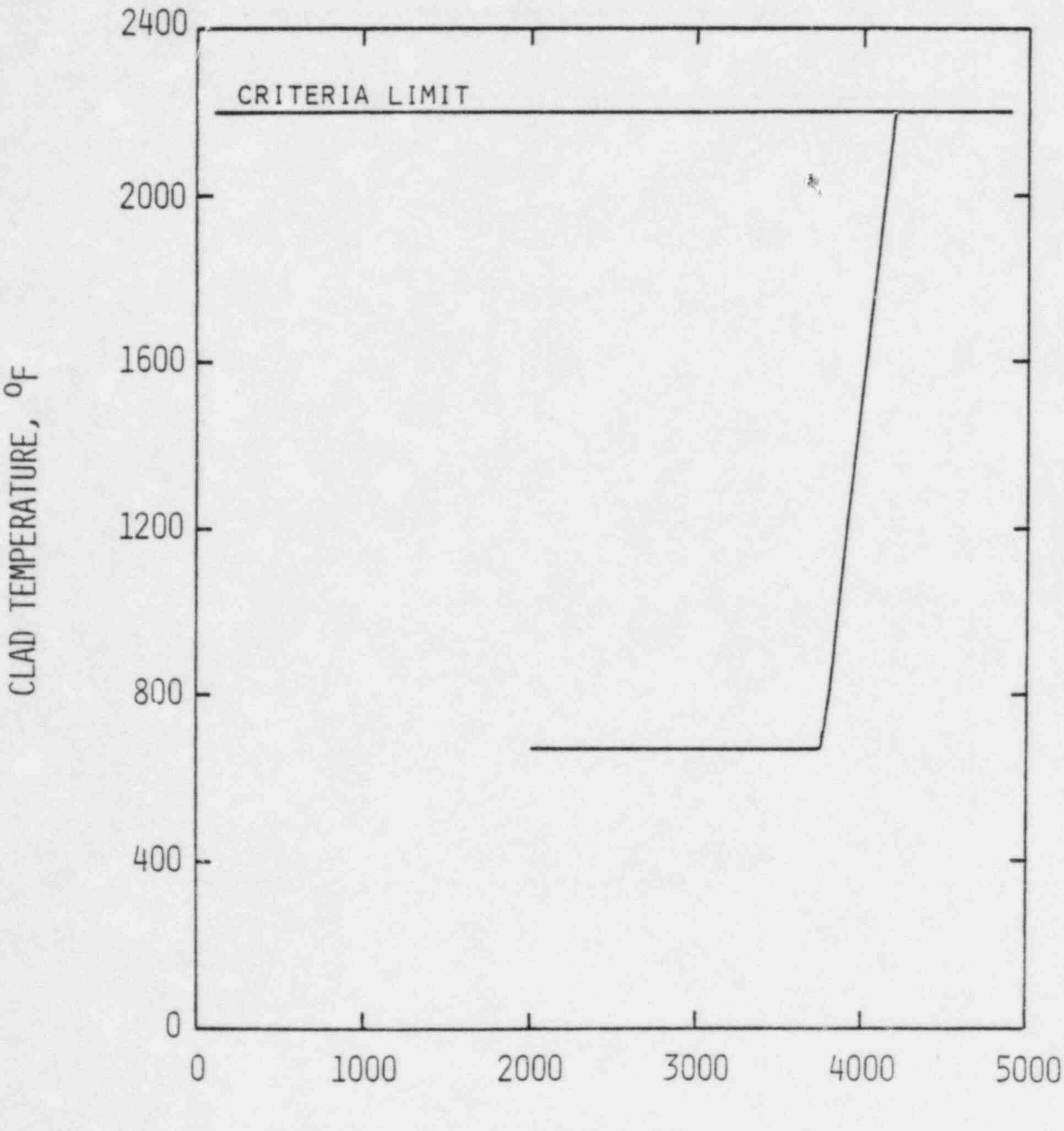


FIGURE 2.8-15

3410 CLASS PLANT
TLOFW WITH RESTORATION OF AUXILIARY FEEDWATER
RCS PRESSURE

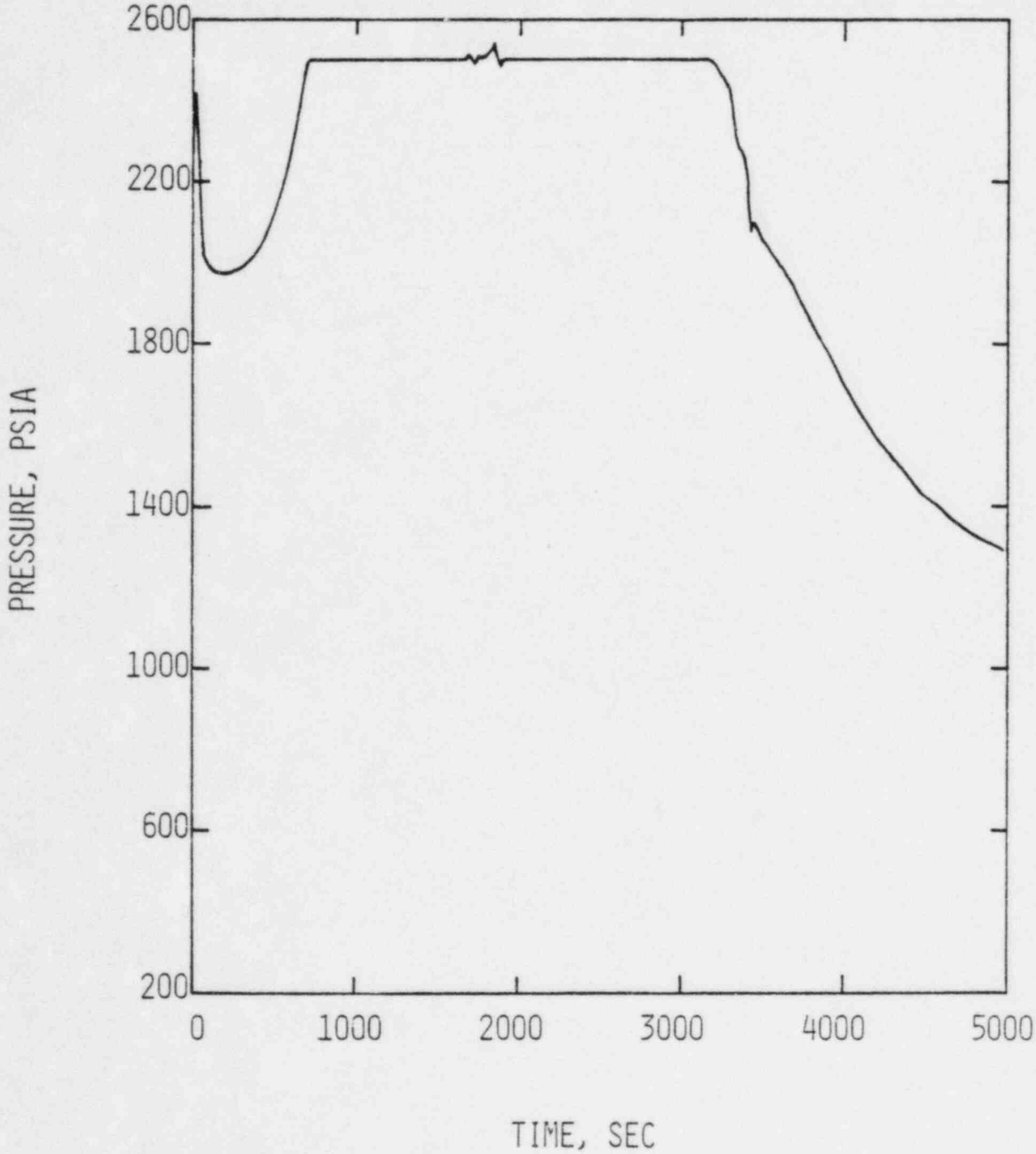


Figure 2.8-16

3410 CLASS PLANT
TLOFW WITH RESTORATION OF AUXILIARY FEEDWATER
REACTOR INNER VESSEL TWO-PHASE MIXTURE LEVEL

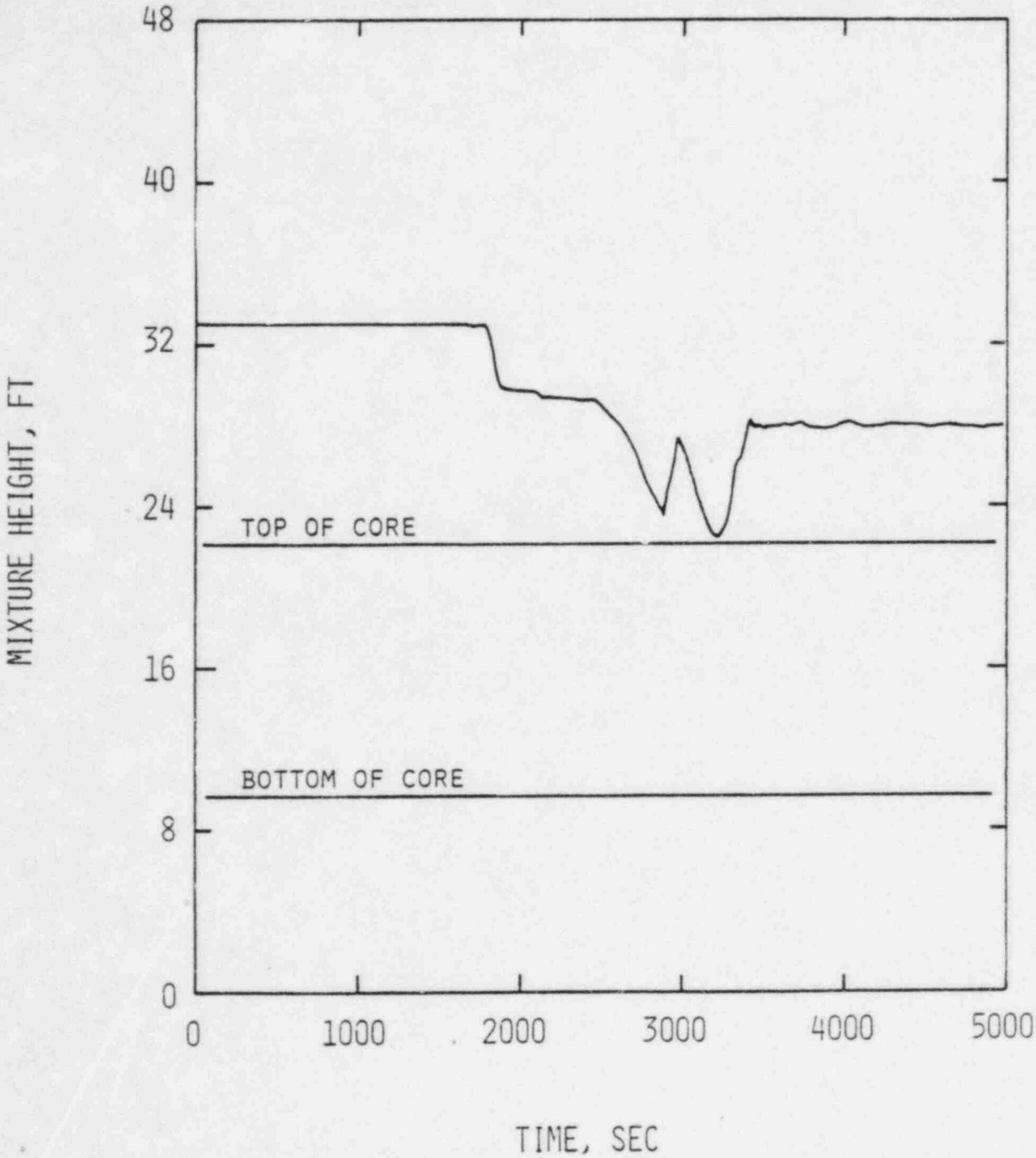


Figure 2.8-17

3800 CLASS PLANT
TLOFW WITH RESTORATION OF AUXILIARY FEEDWATER
RCS PRESSURE

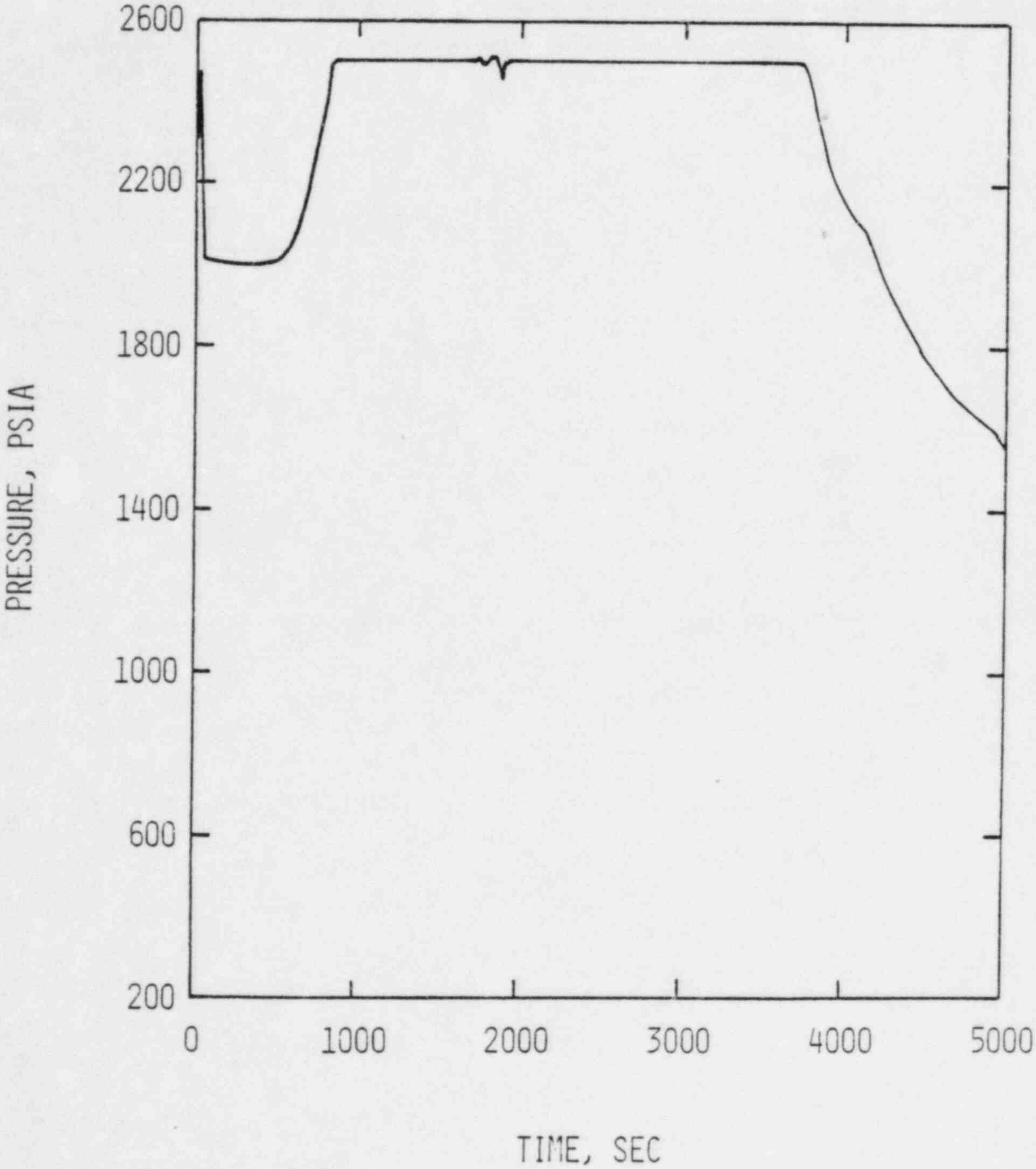


FIGURE 2.8-18

3800 CLASS PLANT
TLOFW WITH RESTORATION OF AUXILIARY FEEDWATER
REACTOR INNER VESSEL TWO-PHASE MIXTURE LEVEL

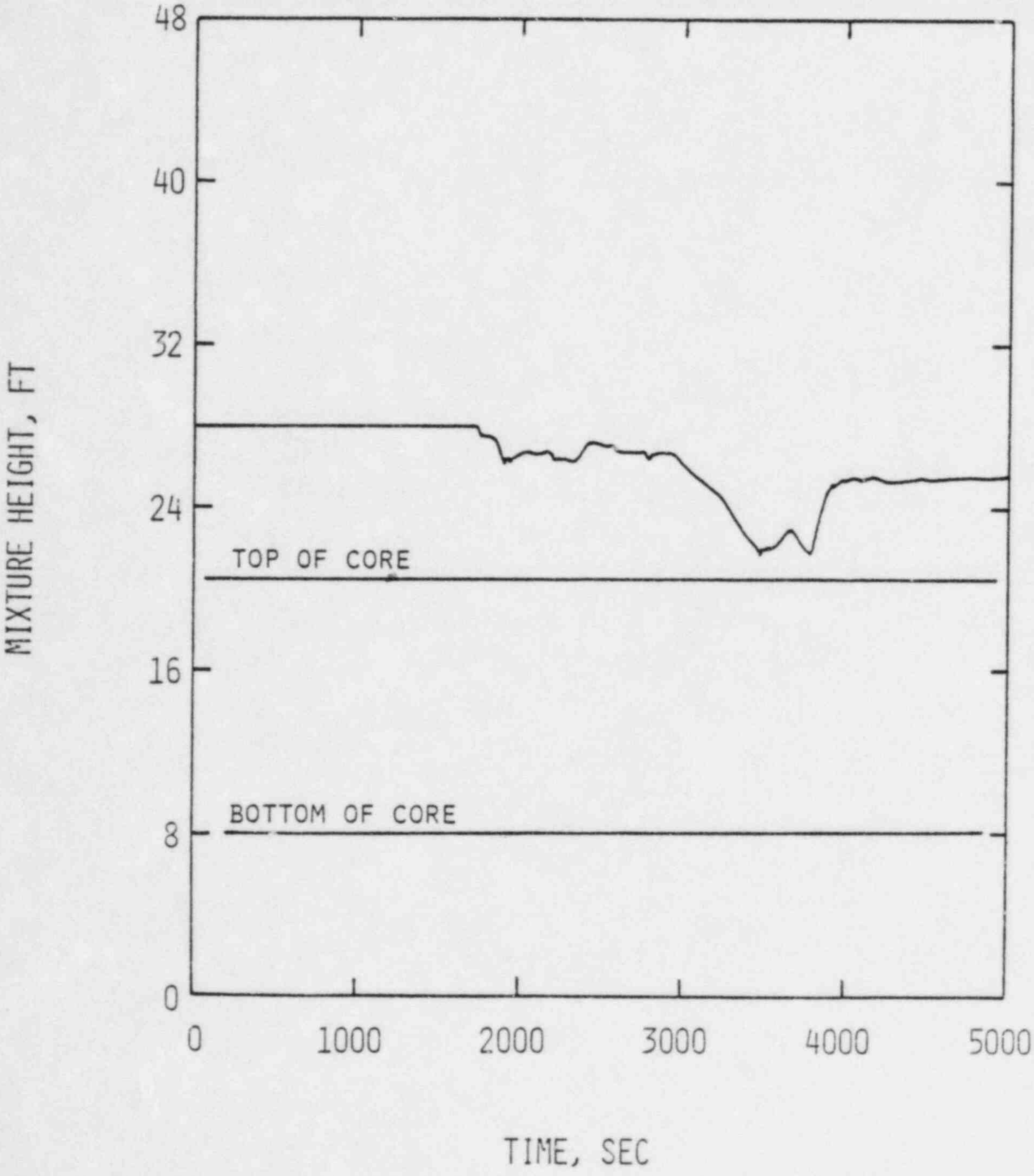


FIGURE 2.8-19

3410 CLASS PLANT
TLOFW WITH INITIATION OF FEED-AND-BLEED
RCS PRESSURE

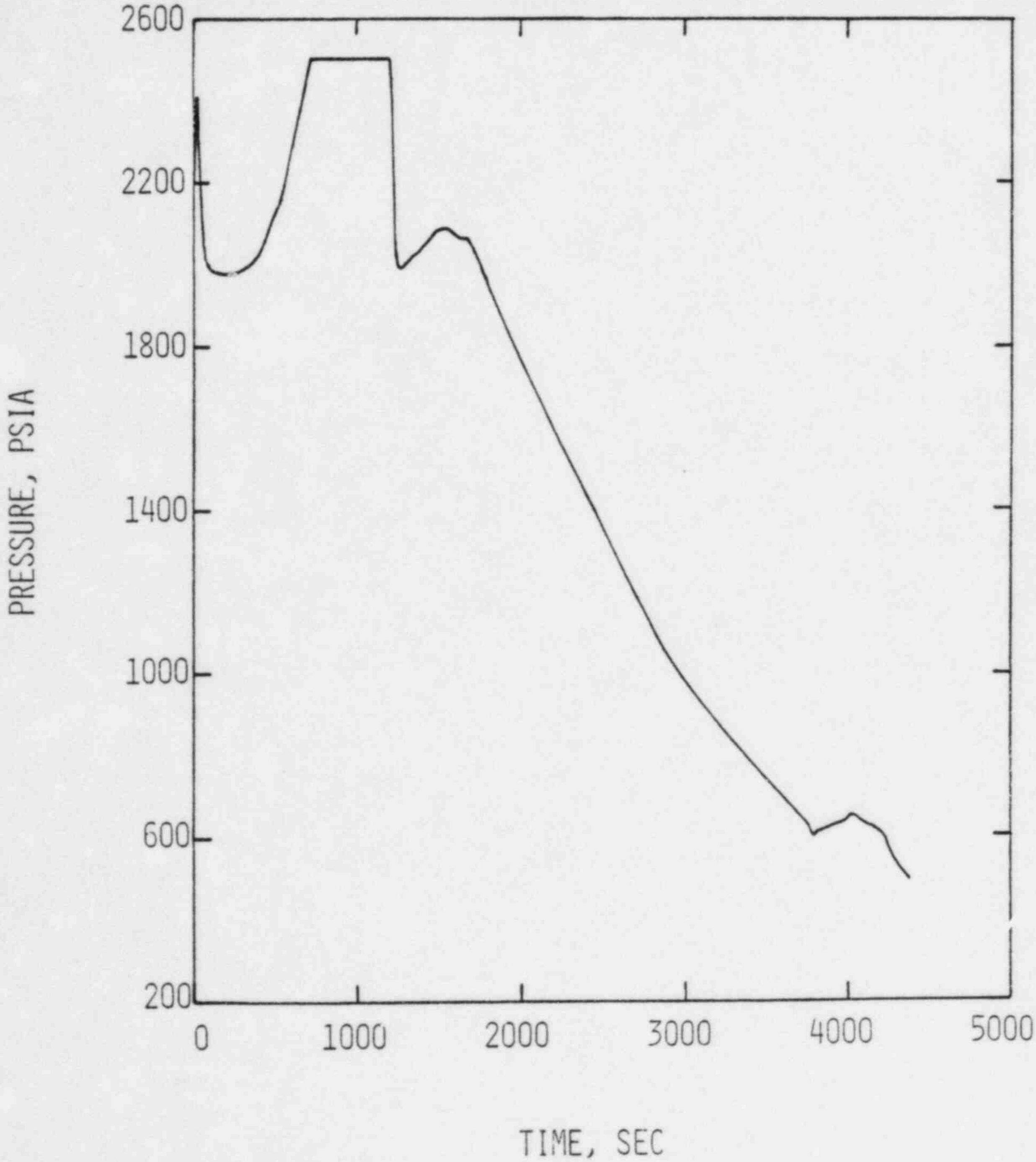


FIGURE 2.8-20

3410 CLASS PLANT
TLOFW WITH INITIATION OF FEED-AND-BLEED
REACTOR INNER VESSEL TWO-PHASE MIXTURE LEVEL

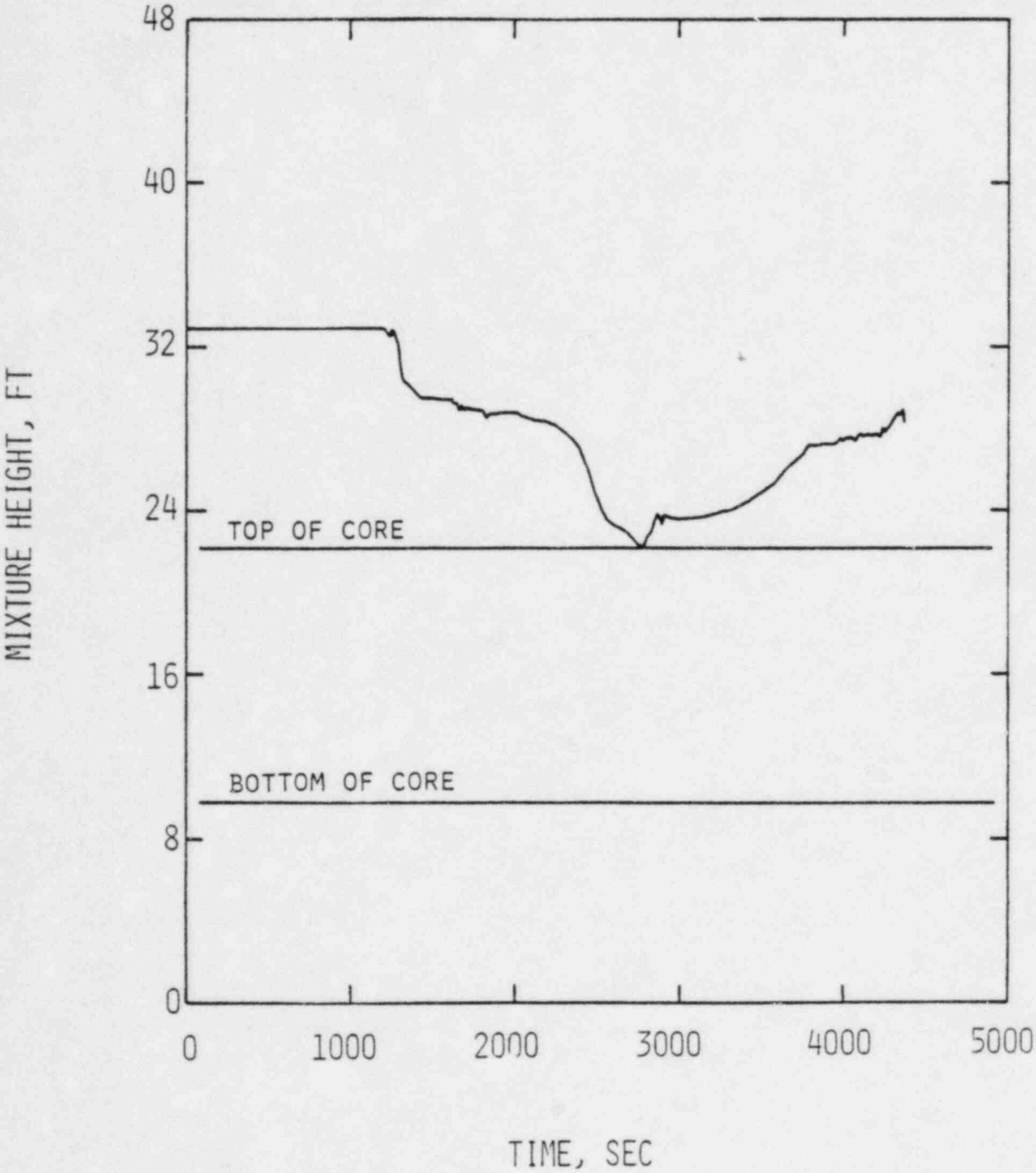


FIGURE 2.8-21

3800 CLASS PLANT
TLOFW WITH INITIATION OF FEED-AND-BLEED
RCS PRESSURE

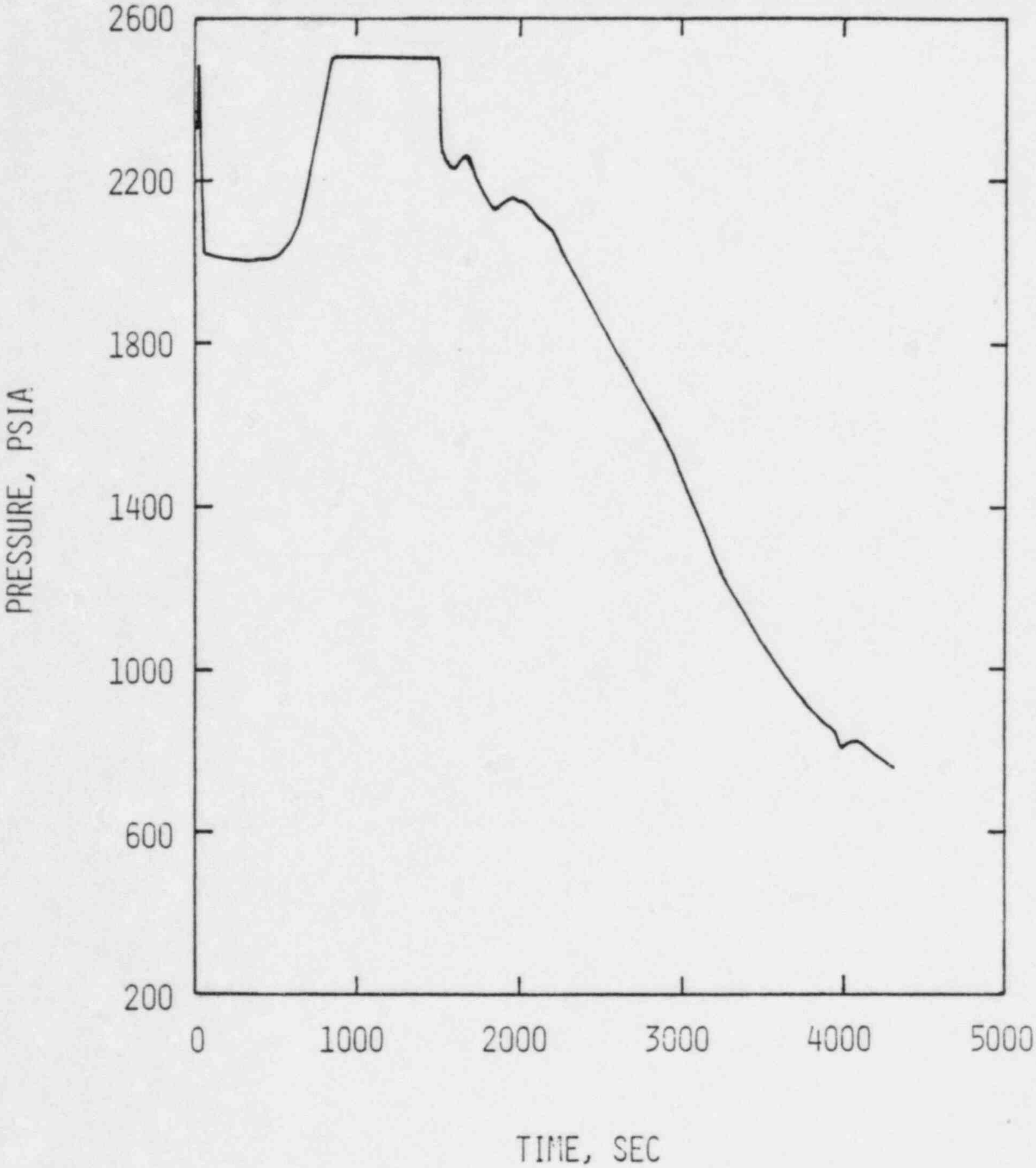


FIGURE 2.8-22

3800 CLASS PLANT
TLOFW WITH INITIATION OF FEED-AND-BLEED
REACTOR INNER VESSEL TWO-PHASE MIXTURE LEVEL

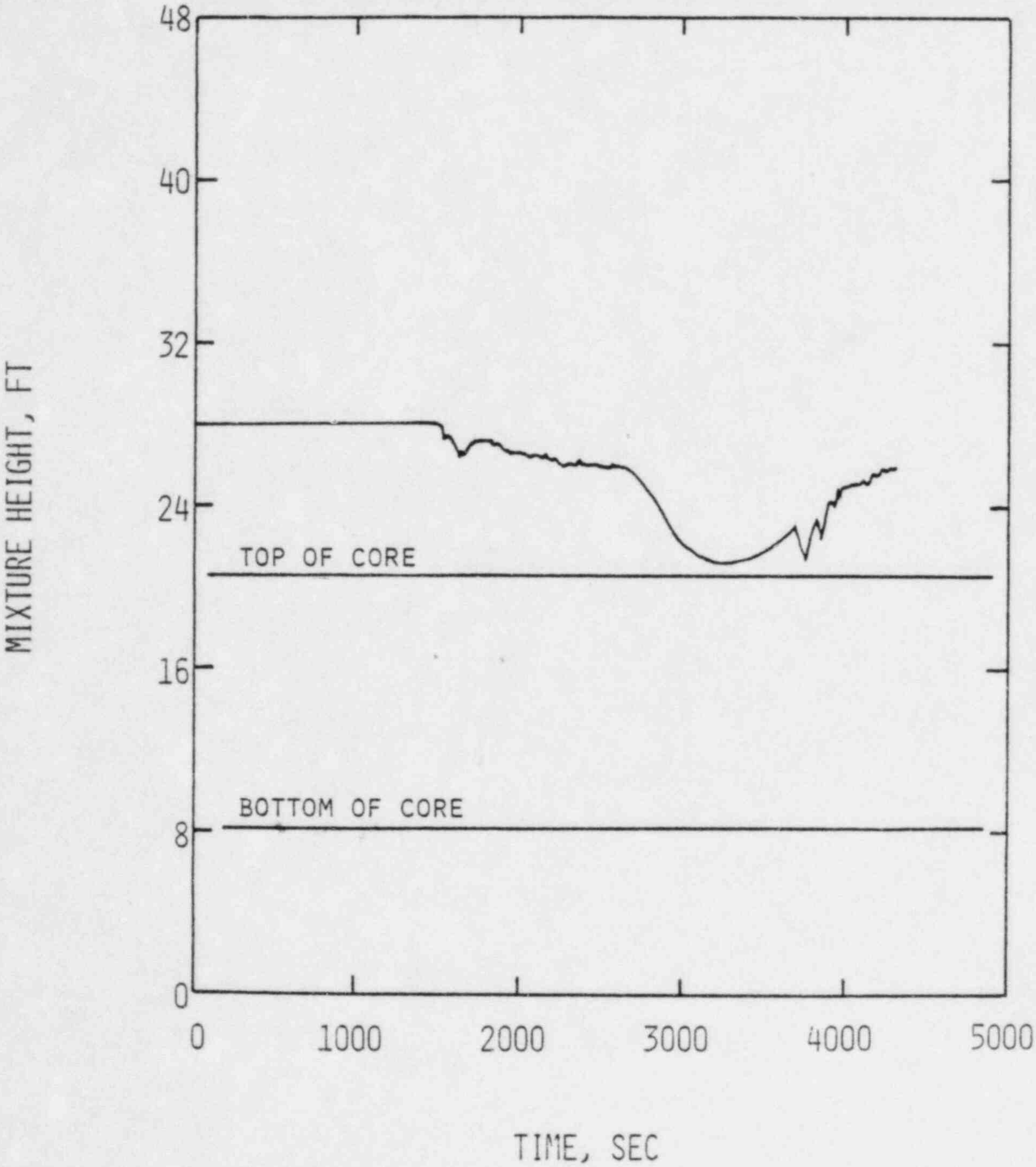


FIGURE 2.8-23

3410 CLASS PLANT
TLOFW WITH SG DEPRESSURIZATION
RCS PRESSURE

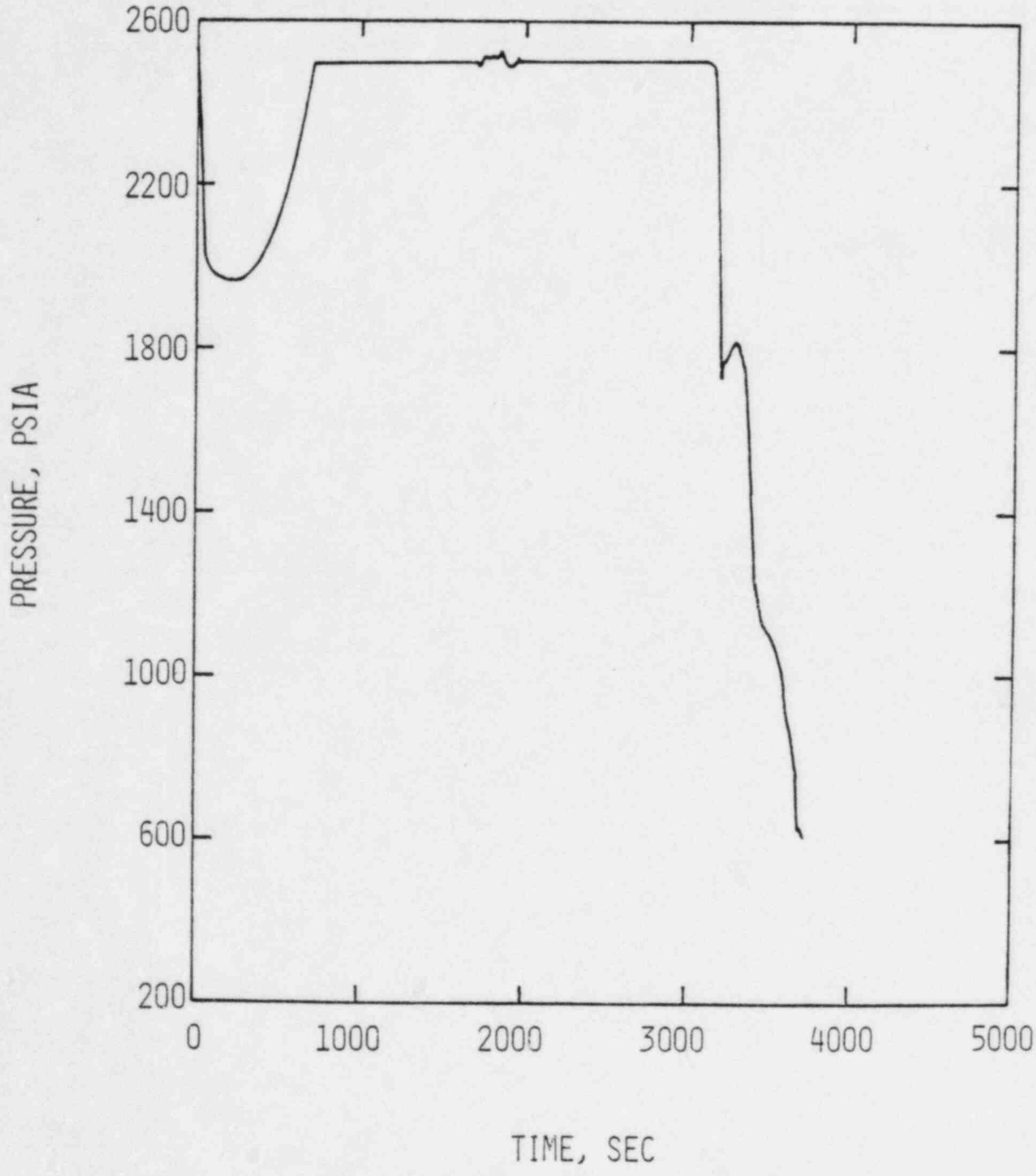


FIGURE 2.8-24

3410 CLASS PLANT
TLOFW WITH SG DEPRESSURIZATION
REACTOR INNER VESSEL TWO-PHASE MIXTURE LEVEL

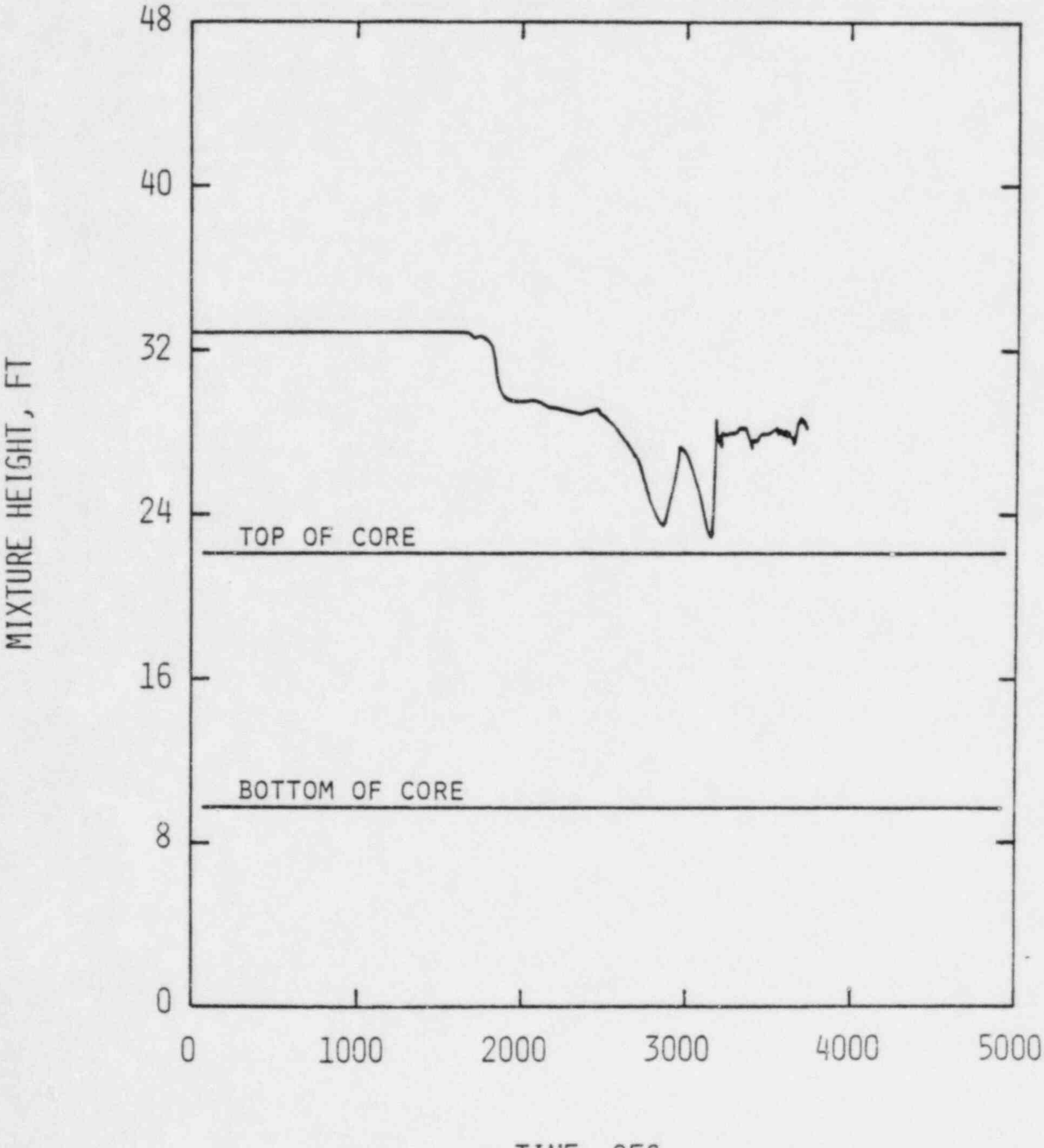


FIGURE 2.8-25

3800 CLASS PLANT
TLOFW WITH SG DEPRESSURIZATION
RCS PRESSURE

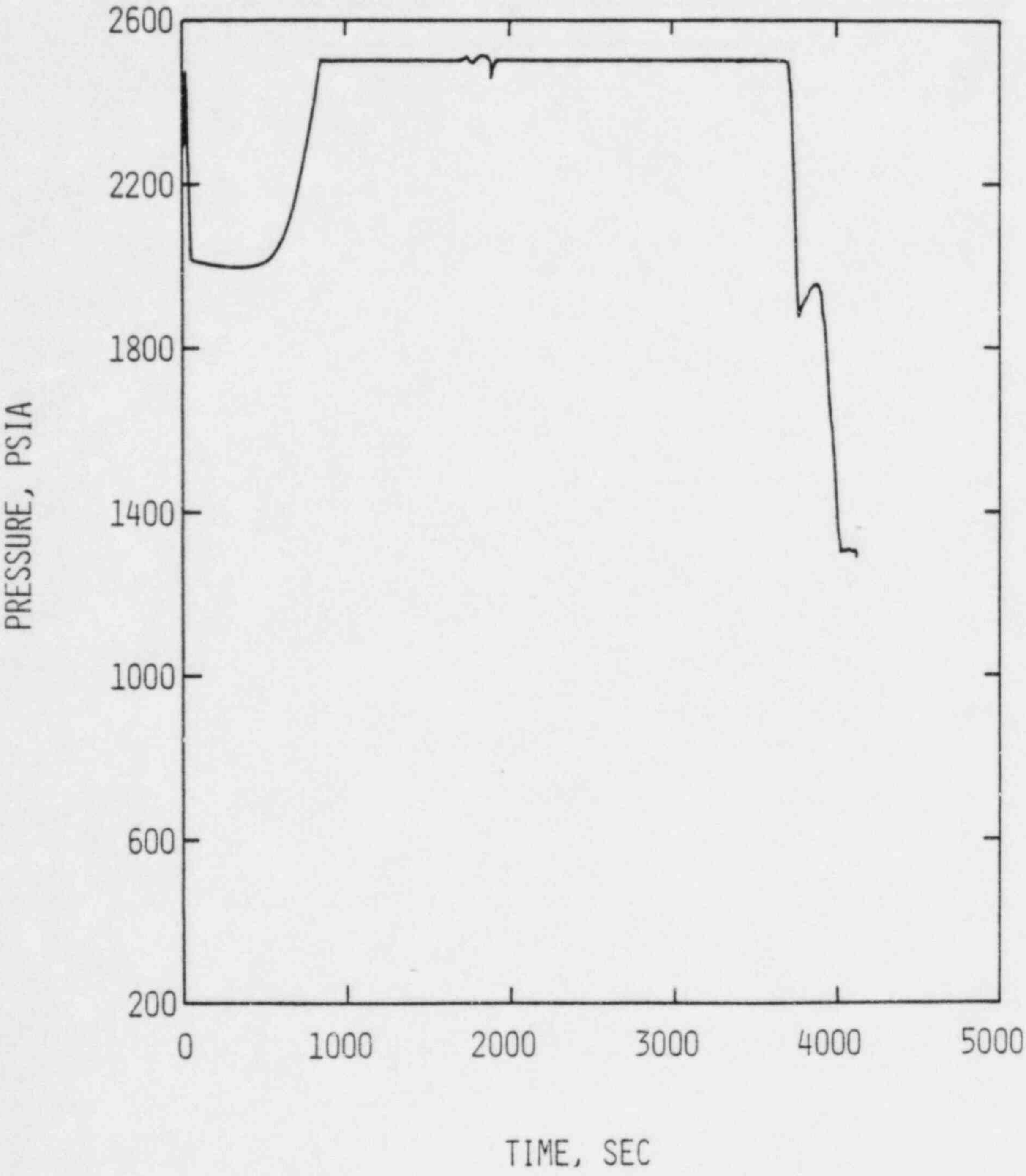


FIGURE 2.8-26

3800 CLASS PLANT
TLOFW WITH SG DEPRESSURIZATION
REACTOR INNER VESSEL TWO-PHASE MIXTURE LEVEL

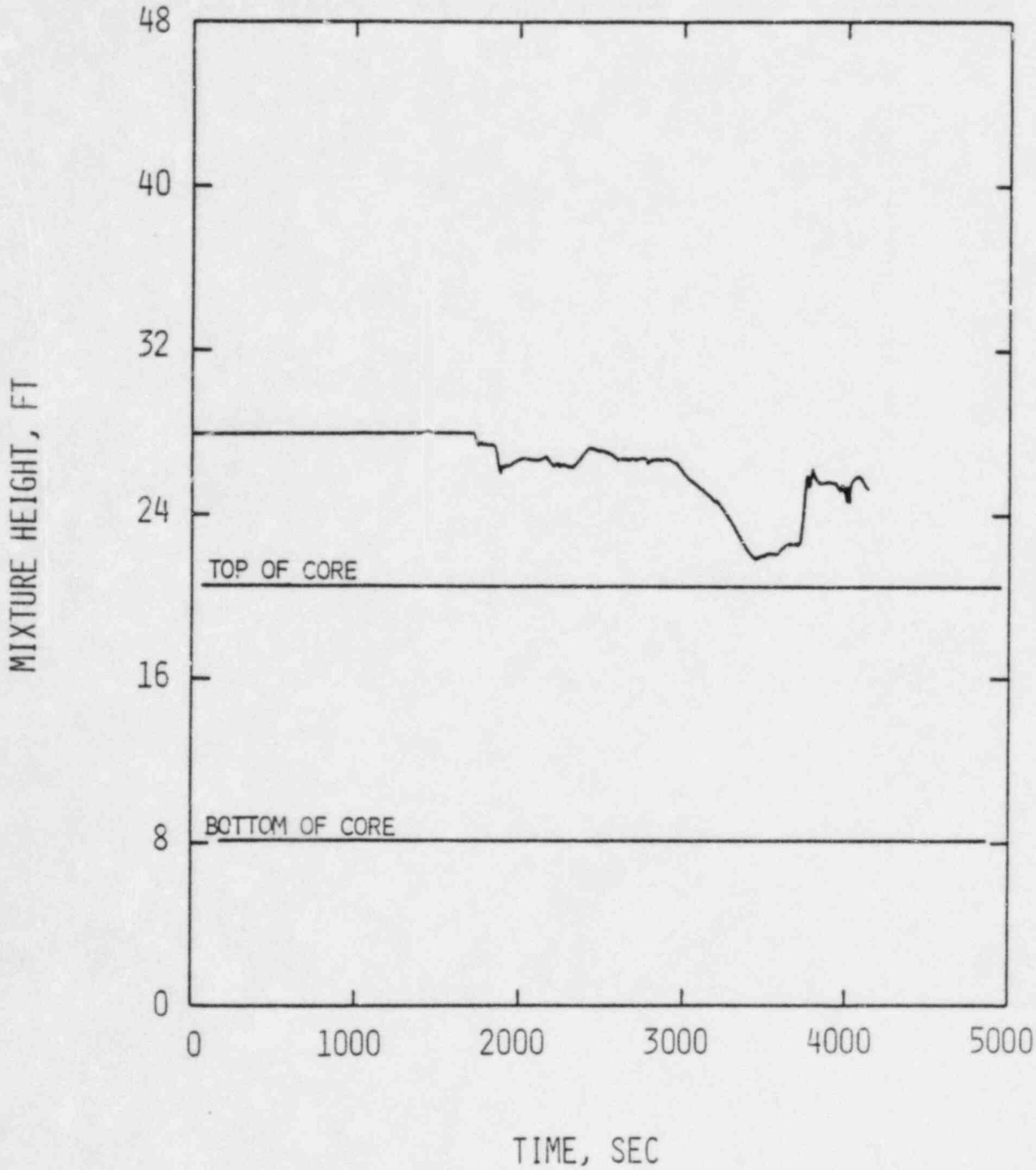


Figure 2.8-27

EFFECT OF AUXILIARY SPRAY VS CHARGING TO RCS LOOP
RCS PRESSURE

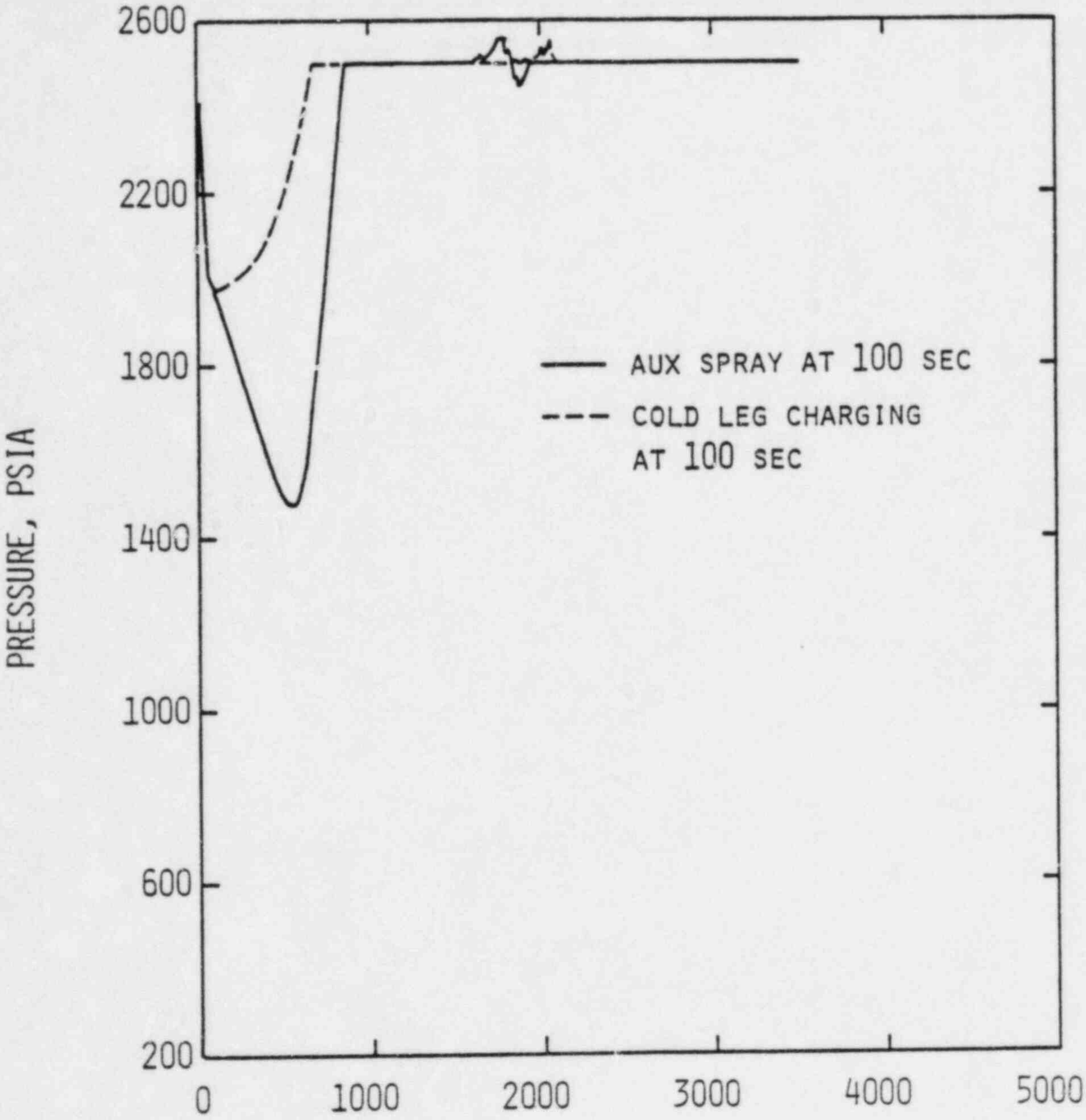


FIGURE 2.8-28

EFFECT OF AUXILIARY SPRAY VS CHARGING TO RCS LOOP
REACTOR INNER VESSEL TWO-PHASE MIXTURE

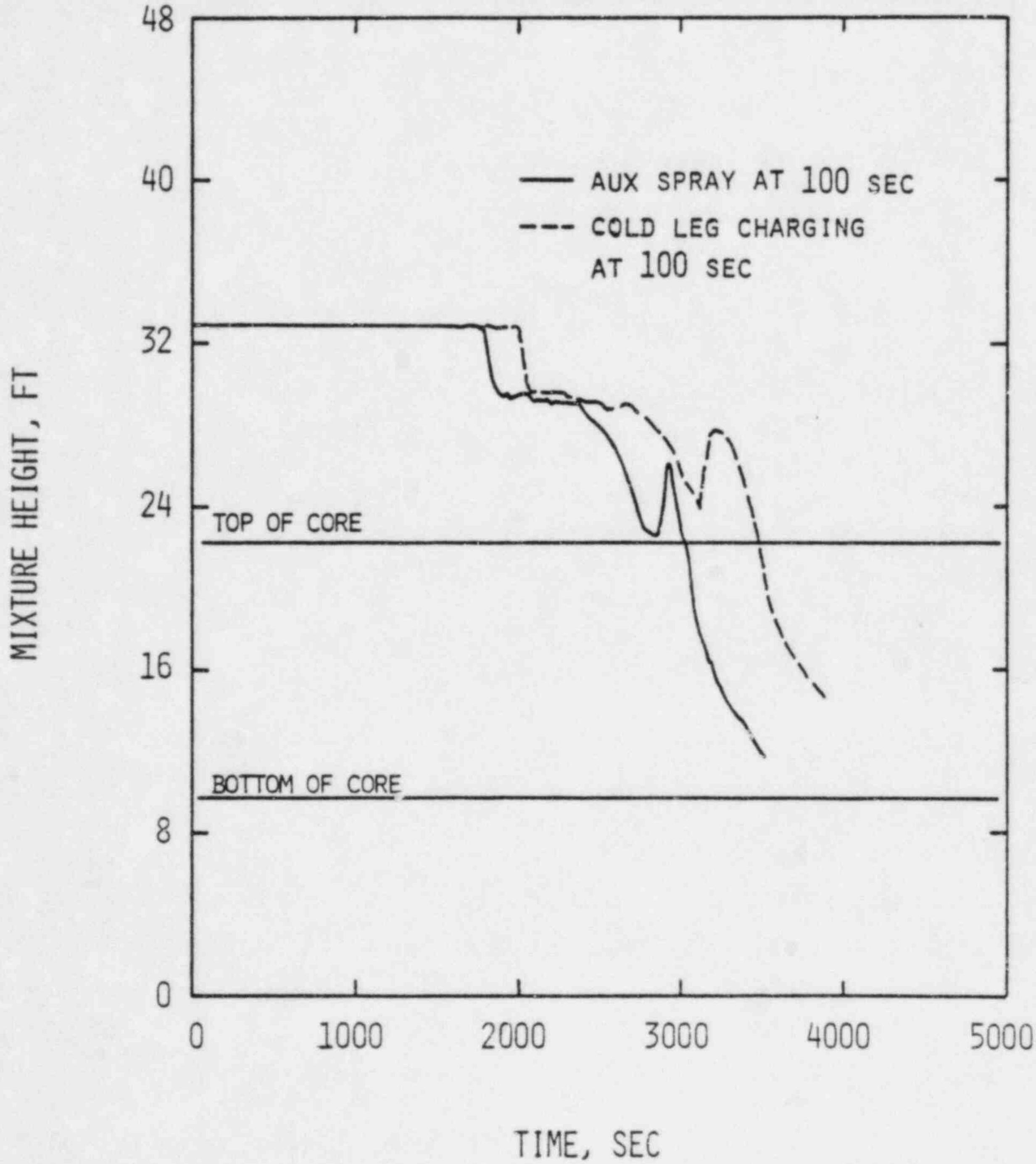


Figure 2.8-29

3410 CLASS PLANT
TLOFW ANALYSIS RESULTS

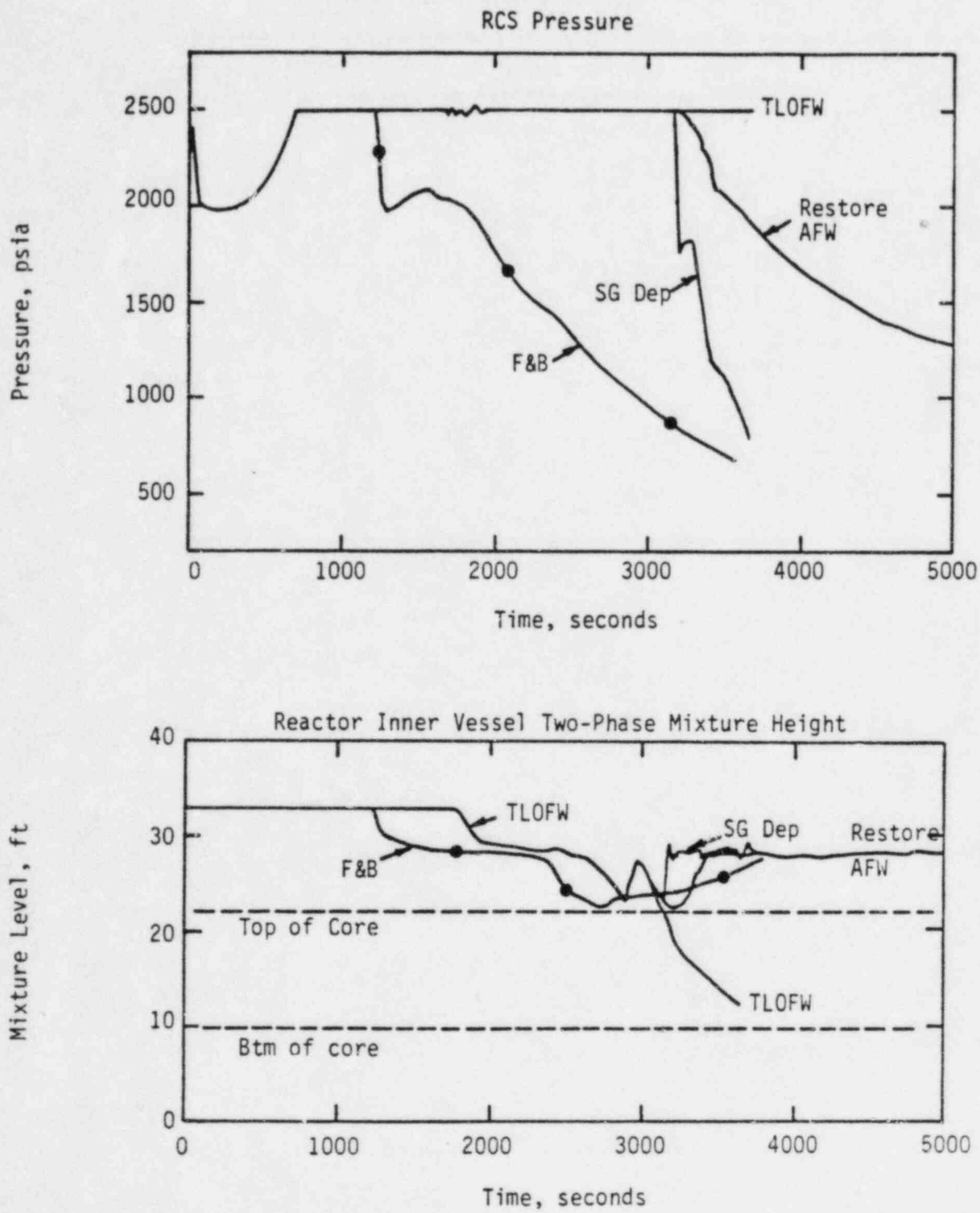
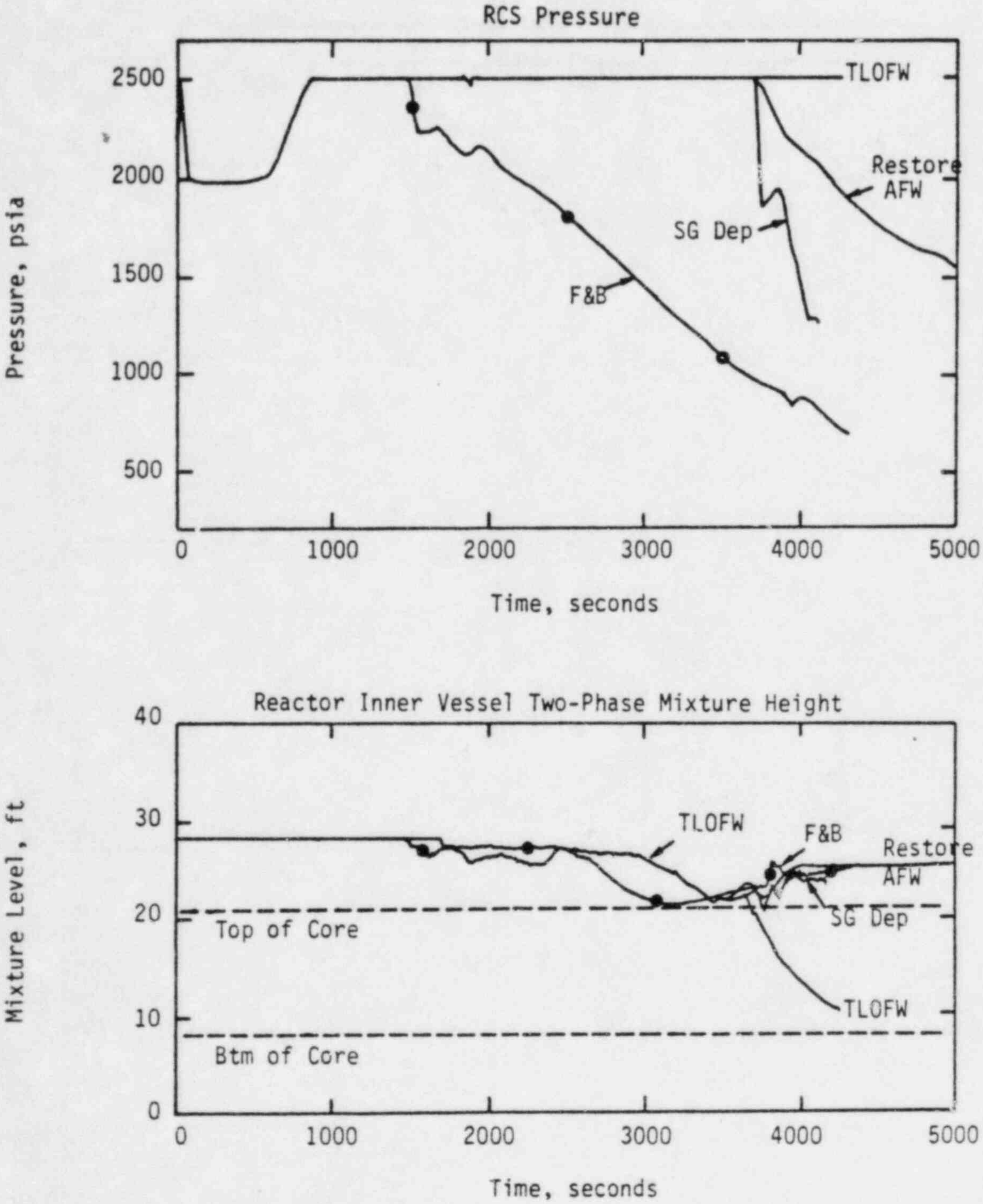


FIGURE 2.8-30

3800 CLASS PLANT
TLOFW ANALYSIS RESULTS



2.9 Question 9: SGTR Risk Analysis

What is the risk from steam generator(s) tube failures? As a minimum, consider the following:

a. Scenarios leading to core melt from one or more steam generator tubes failing in one steam generator. Include paths which consider failure of relief or safety valve in the faulted steam generator, capability of (or loss thereof) to depressurize the secondary side, the role of the ECCS including inventory and Saron availability.

b. What is the frequency of steam generator tube ruptures in two steam generators? This estimate should include consideration of common cause failures such as design errors, events resulting in extremely high ΔP across the tubes, aging, etc. If tubes were to fail in both steam generators, what is the probability of core melt and generally characterize the consequences.

c. For a) and b) above, discuss the likelihood of steamlines filling with subcooled water and any consequential failures.

d. For a) and b), discuss uncertainties including human error rates (carefully considering the clarity and unambiguity of procedures).

2.9.1 Response to Question 9

The frequency of the SGTR accident sequences which could potentially lead to core damage were statistically combined into two categories: 1) Scenarios resulting from SGTR in one or two steam generators, and

2) Scenarios resulting from SGTR in one or two steam generators with a coincident loss of offsite power. The core damage frequency contribution due to SGTR in one or two steam generators for the representative plant can be expressed in terms of a median value of $1.5x10^{-5}$ per year with an associated error factor of 5. The median value represents the estimate, considering uncertainty, that would be expected to be higher than the true value with 50% confidence. The associated error factor is defined as the ratio of the 95th to 50th percentile. This factor, when multiplied by the median value, yields the upper bound estimate which would be expected to be higher than the true value with 95% confidence. The core damage frequency contribution due to SGTR in one or two steam generators with coincident loss of offsite power is estimated to be $1.5x10^{-6}$ per year with an assoicated error factor of 11. The decrease in core damage frequency due to the added depressurization capabilities of a PORV was determined to be negligible compared to the core damage frequency contribution from all other SGTR accident sequences for the first of the four plants to be analyzed.

The likelihood of steam lines filling with subcooled water during a SGTR was also investigated. The total frequency of sequences that could possibly lead to steam generator overfill conditions was determined for the representative plant to be approximately $6.6x10^{-4}$ per year (median value) with an associated error factor of 6. The complete analysis and a characterization of the consequences of each plant participating in this study are presented in the respective supplements to this report.

2.10 Question 10: Risk due to PORV Initiated LOCA

What is the core melt frequency from PORV initiated LOCA? Characterize the consequences?

2.10.1 Response to Question 10

The core damage frequency due to PORV initiated LOCA was evaluated based upon a plant design which would be assumed to provide increased RCS decay heat removal and depressurization capability. In this design the PORVs are manually opened and the plant is assumed to operate with the PORV block valves normally closed which tends to minimize the risk associated with PORV initiated LOCA. The results of the analysis are quantified by a statistical distribution representing the core damage frequency of PORV LOCA. The core damage frequency contribution due to PORV LOCA for the representative plant can be expressed in terms of a median value of 1.2×10^{-7} per year with an associated error factor of 15. The median value represents the estimate, considering uncertainty, that would be expected to be higher than the true value with 50% confidence. The associated error factor, when multipled by the median value, yields the upper bound estimate which would be expected to be higher than the true value with 95% confidence. If automatic actuation of the PORVs were to be assumed and if the plant were to operate with the block valves normally open, the core damage frequency contribution due to PORV LOCA would become 1.4×10^{-6} per year with an associated error factor of 13. The detailed analysis and a characterization of the consequences are provided in the plant specific supplements to the report.

2.11 Question 11: Effect on Safety and Additional Benefits

What is the net gain (or loss) in safety considering 8, 9, and 10 above if PORVs were to be installed? Are there any additional benefits (or drawbacks) achieved by installing PORVs? Examples of potential benefits are mitigation of ATWS and pressurized thermal shock, and reduced risk associated with depressurized primary system during a core melt.

2.11.1 Response to Question 11

This question effectively asks for the net change in plant safety if PORVs were installed considering such items as the potential for primary feed-and-bleed, the risk from steam generator tube failures, and the core melt frequency from PORV initiated LOCA. The question also asks for any additional benefits that might be realized from the addition of such valves.

2.11.2 Change in Core Damage Frequency

The overall change in core damage frequency (net gain or loss in safety) due to the installation of PORVs was determined by examing only those events which were considered to significantly contribute to an increase or decrease in the total core damage frequency. The core damage frequency contribution due to LOHS events and PORV initiated LOCA is impacted by the presence of PORVs while the change in SGTR core damage frequencies does not contribute to a net gain or loss in safety. Results indicate a net change in total core damage frequency for the representative plant due to the installation of manually or automatically actuated PORVs to be substantially less than the proposed NRC safety guideline of 10^{-4} core melts per year. The complete risk assessment analysis for each plant participating in this study is contained in the plant specific supplements to this report.

2.11.3 Additional Benefits from PORVs

The question of the additional benefits that might be realized from the addition of PORVs is a much broader subject than the estimation of core damage probabilities and would be dependent upon the actual PORV system configuration. In general, the analyses completed for this study indicate that no significant benefits would be realized from the backfit of PORVs to the 3410 and the 3800 plants. Specifically with respect to the SGTR, this event is within the capabilities of the current design of the 3410 and the 3800 plants to successfully mitigate. In addition, analyses presented in the body of the report indicate that auxiliary spray has essentially the same ability as PORVs in reducing system pressure during a tube rupture, and that auxiliary spray has the added benefit of a higher degree of pressure and inventory control. With respect to the possibility of using PORVs to minimize challenges to the RPS, such a configuration would require a PORV setpoint below that of the reactor trip on high pressure. C-E's philosophy in plants that employ PORVs in their design is to activiate them from the same bistable trip that activates a reactor trip on high pressure in order to prevent challenges to the pressure code safety valves. To deviate from this philosophy could increase the probability of core damage in certain events by delaying a reactor trip and could increase the probability of a PORV initiated LOCA.

An evaluation of the benefits that might be realized from the addition of PORVs in order to mitigate ATWS revealed that the additional relief capacity afforted by such valves could decrease the peak RCS pressure resulting from the ATWS transient. As indicated in the body of the report, however, the size of the relief valve necessary to reduce this peak pressure is very much larger than the largest

PORV currently installed in C-E operating plants; this size might make such a solution to the ATWS problem impractical. In addition, other solutions to ATWS are currently being considered by the NRC such as increasing the reliability of the reactor shutdown system and the incorporation of a safety-grade turbine trip which appear to be viable solutions. With respect to pressurized thermal shock, detailed evaluation show that no additional benefits would be realized with PORVs in the 3410 and the 3800 plants since both the 3410 and the 3800 pressure vessels exhibit large margins (assuming twice the predicted end of life fluence) of capability to withstand the most severe postulated cooldown transients with full repressurization to the code safety valve setpoint.

An evaluation of various multiple failure scenarios was also performed in order to assess the potential benefits of PORVs. Specifically, it was shown that up to three tube ruptures in both steam generators for the 3410 and the 3800 plants were successfully mitigated with the current design and that the two hour dose releases were within the criteria of 10 CFR 100. Also, from the evaluation of the SBLOCA with no HPSI transient, RCS depressurization via steam generator cooldown is preferable to system depressurization via PORVs in lowering pressure to the point where LPSI pumps and SITs could function since additional RCS inventory was not lost and core uncovery did not occur. In addition, it was demonstrated that steam generator depressurization via ADVs followed by use of a surrogate low pressure pump to feed steam generators in the event of a TLOFW was a viable method of providing for core cooling.

Finally, a function of the PORVs on operating plants that must be considered is the use of PORVs for the purpose of providing low temperature overpressure protection. For the 3410 and the 3800 plants this function is provided by the shutdown cooling system relief valves and meets all of the design criteria placed upon any

LTOP system. Therefore no added safety benefits could be realized from PORVs in this respect since the LTOP function is already adequately provided for. PORVs would, however, allow for a slightly higher LTOP set point pressure since the SCS design pressure would no longer be limiting.

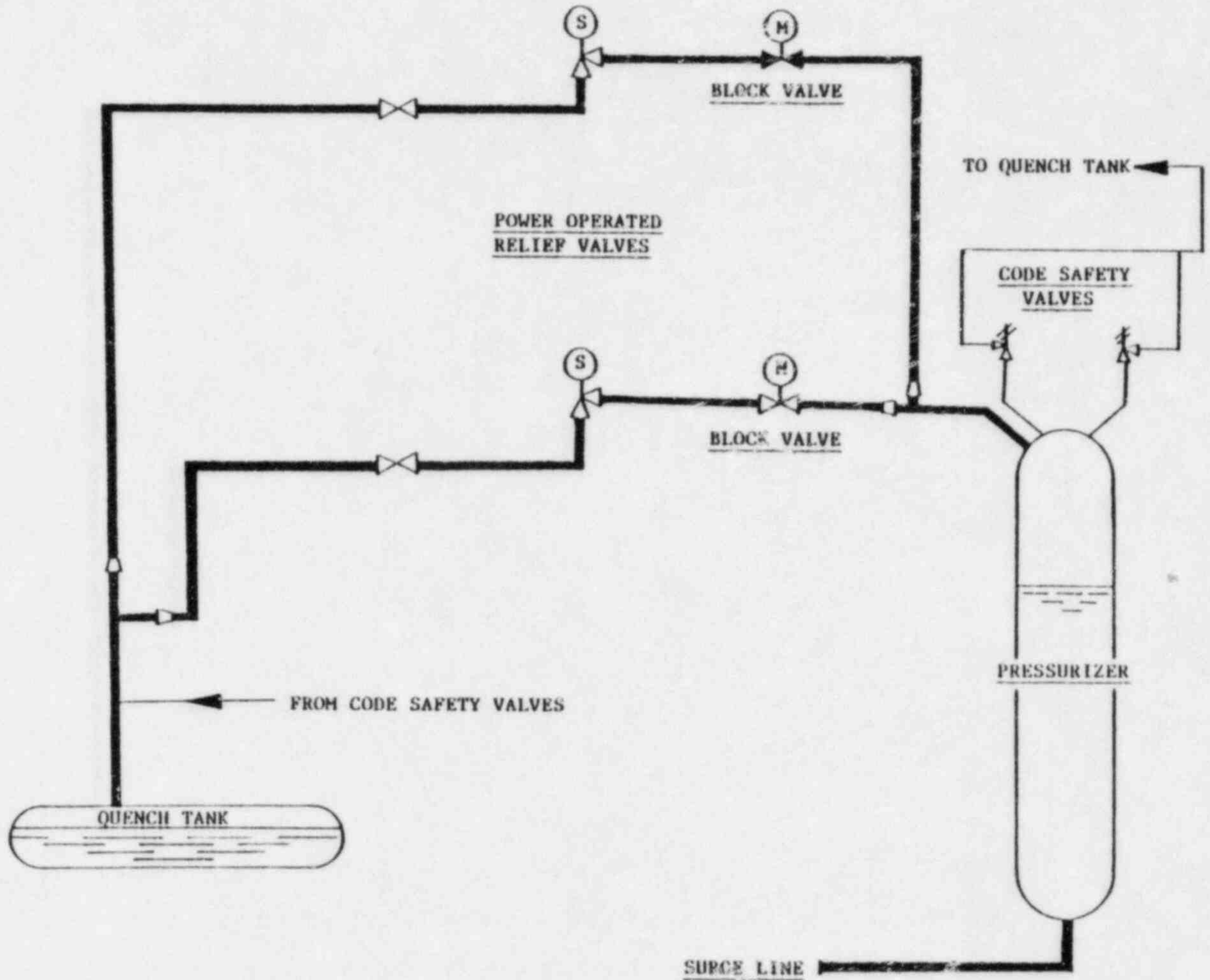
2.11.4 Availability Study

In order to further assess the desirability of adding PORVs to plant designs that do not now include them an availability study was conducted. The objective of this study was to determine the potential impact of the power operated relief valves on plant availability. PORVs would have a negative impact on plant availability if additional shutdowns were required for maintenance of the valves or if problems resulting from failure or misoperation of the valves during a transient extended an outage.

The basic configuration evaluated consists of two parallel sets of two valves in series, as shown in Figure 2.11-1 (p. 321). Two basic modes of operation were assumed for the study. First, a manual mode was considered in which it was assumed that both the PORVs and the blocking valves would be normally closed during power operations and manually opened as needed. This mode of operation would be intended for use only as a feed-and-bleed method of core cooling. Second, an automatic mode was considered in which it was assumed that the blocking valves would be normally open during power operations and that the setpoint of the PORVs would coincide with the setpoint of the reactor trip on high pressure. The automatic configuration is consistent with the configuration employed by operating C-E plants which incorporate PORVs in their design. Operating experience data in C-E's Reliability Data System and the Nuclear Power Experience books were reviewed to determine PORV problems and the impact of these problems on plant availability. (Note: TMI-2 was excluded). The PORV problems were then evaluated with respect to the specifics of the valve configuration to determine the potential availability impact.

Figure 2.11-1

TYPICAL PORV CONFIGURATION



For the basic power operated relief valve configuration of two parallel sets of two normally closed, manually actuated valves in series, the type of valve problems that could impact plant availability are excessive seat leakage to the quench tank, excessive stem or flange leakage, failure to open when required, and failure to close after opening. Historically, excessive PORV seat leakage has caused an average of two hours of downtime per plant year with a PORV seat leakage problem once every 73 plant years of operation, on the average. A configuration of two normally closed valves in series should be less susceptible to seat leakage of a magnitude that would require a maintenance shutdown. It is therefore assumed that the pressurizer relief valve seat leakage will cause an average of one hour of downtime per plant year. PORV stem and flange leakage problems have historically caused 1.2 hours of downtime per plant year. Therefore, it is assumed that pressurizer relief valve stem leakage problems will cause an average of 1.2 hours of downtime per plant year. The failure modes, fail to open when required and fail to close following an opening, presume the occurrence of an event that requires the use of these valves. Failure of a relief valve to open when needed would result in loss of the feed-and-bleed function. This would cause a significant impact on availability. However, as documented in the response to Question 10, the scenarios involving both an event requiring feed-and-bleed and the failure of feed and bleed is extremely rare. Failure of a relief valve to close following an opening would result in a small LOCA. Because the relief valve configuration includes two valves in series, closure of the second (blocking) valve would terminate the problem with minimal impact on plant availability. Based on the above discussion the manual power operated relief valve configuration is expected to have an average impact on plant availability of approximately 2.2 hours per plant year.

A PORV configuration consisting of two parallel sets of two valves in series with the downstream valve in each set normally closed and automatically actuated and the upstream valve normally open and manually actuated has been considered as an alternative. The automatically actuated valve will open when reactor coolant system pressure reaches the high pressurizer pressure setpoint. Because this configuration is similar to the current PORV configurations on operating C-E plants, it will be subject to the same maintenance related problems. Hence, this configuration is expected to cause an average of 3.6 hours of downtime per plant year due to stem and seat leakage problems. The impact of failure to open when required and failure to close when needed for feed-and-bleed operations would essentially be the same as discussed for the manual relief valve configuration. Due to the size of the PORVs and the size of the quench tank, operation of relief valves would break the quench tank rupture disk with resultant discharge to the containment. Operating experience indicates that cleanup and repair associated with this type of event contributes about 100 hours of downtime per event. C-E plants have had 12 transients which challenged the PORVs in 55 years of operating experience. This is a PORV challenge rate equal to 0.21 events per plant year. Hence, there would be an average of 0.21 events per year in which cleanup is required as a result of a relief valve challenge and failure of the quench tank rupture disk. These events will cause an average of 21 hours per plant year of additional downtime. Therefore, the automatic configuration can be expected to cause an average of 24.6 hours of downtime per plant year.

In summary the manual PORV configuration of two parallel sets of two manually actuated valves in series would have a potential impact on plant availability of an additional 2.2 hours of downtime per plant year due to stem and seat leakage problems. This configuration would not have any benefit in terms of improving plant availability. An automatic relief valve configuration, which includes an automatic actuation feature at the high pressure trip setpoint, would contribute an additional 24.6 hours of downtime per plant year due to stem and seat leakage problems and containment cleanup following failure of the quench tank rupture disc. Table 2.11-1 (p. 324) summarizes these results.

Table 2.11-1

POWER OPERATED RELIEF VALVE IMPACT ON PLANT AVAILABILITY[a]

Configuration	Maintenance Outages Caused	Cleanup Following Actuation	Net Impact
Manual	2.2 hours	(b)	2.2 hours
Automatic	3.6 hours	21 hours	24.6 hours

(a) Additional critical path shutdown hours per plant year.

(b) For this study it was assumed that PORVs would be actuated manually to perform a primary feed-and-bleed operation only. As a result it was further assumed that any cleanup time associated with such operation would be non-critical path.

2.12 Question 12: Cost of PORV Addition

If the results in 11 yield appreciable gain in safety, what could be the cost of installing PORVs?

2.12.1 Response to Question 12

The cost of adding PORVs could vary widely between plants and cannot be addressed generically in this report. This question will be responded to on a plant specific basis by each of the participating utilities.

2.13 Question 13: SG Inservice Inspection

One of the main reasons C-E has concluded that PORVs are not needed for emergency decay heat removal is that alternative water sources could be made available to the steam generators for decay heat removal purposes. An inherent assumption in this approach is that steam generator integrity will be maintained throughout the life of the plant. One method of assuring combined steam generator integrity is by inservice inspection and plugging of tubes excessively degraded. Please discuss the following:

a. What is the minimum allowable wall thinning that could exist in the steam generator tubes without plugging?

b. What is the probability that ISI will not detect a degraded tube? Provide the margin of error in eddy current measurements at various depths of degradation.

c. Given a steam generator with the maximum allowed tube thinning and degradation, confirm that those tubes will maintain their integrity by demonstrating they have been analyzed and shown to remain intact for all design basis loadings used for the steam generator design including seismic loads.

d. Describe the analytical and experimental justification for establishing a minimum acceptable steam generator tube wall thickness for the C-E System 80 steam generators in accordance with guidelines in Regulator Guide 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes." The justification should include the analyses to calculate the hydraulically induced loading on the steam generator and the thermal response of its tubes and shell to an assumed LOCA, MSLB and an FWLB.

2.13.1 Response to Question 13

Information necessary to respond to Item a, Item c, and Item d of Section 2.13 will be supplied by the individual utilities participating in this study. Information necessary to respond to Item b is presented below.

2.13.2 Introduction

The purpose of eddy current testing of steam generator tubing is to establish the general condition of the primary boundary and to identify any forms of degradation which may be occurring. This general assessment is qualitative in nature and provides information for plant operations and corrective actions planning. When tube degradation is observed, quantitative ECT results are used to determine the need for preventive action such as the plugging or sleeving of degraded tubes, support plate rim cut, sludge lancing, or coolant chemistry changes.

Different types of tube degradation can require different types of ECT equipment and procedures. In addition, interfering effects may be present in the field which can require modifications to equipment or procedures. The following lists certain types of flaws and interfering effects.

FLAW	INTERFERING EFFECTS
Wastage	Mechanical flaws due to manufacture
Erosion	Dents due to corrosion
Intergranular corrosion	Tube supports
Pitting	Sludge (magnetite and copper)
Mechanical wear/fretting	Pilgering (manufacture)
	Permeability effects
	Tube sheet/expansion area

Experienced ECT operators and data analysts will select the best combination of equipment and techniques to suit the conditions observed in the field. For this reason, the accuracy of ECT will be discussed for specific types of flaws.

2.13.3 ECT Accuracy

The 3400 and the 3800 plants have the latest designs of C-E steam generators which incorporate numerous features to minimize tube degradation. The types and extent of potential tube damage to these units can only be estimated. In addition, the state-of-the-art in ECT techniques is advancing rapidly. For these reasons, the ECT accuracies discussed here should not be considered to be representative of any particular plant or ECT vendor.

To establish the accuracy of ECT in measuring the depth of tube degradation, both laboratory tests and the limited amount of field data have been reviewed. The available laboratory data consists of ECT measurements of artificially defected tube samples. The field data consists of ECT measurements of tubes in operating steam generators. These tubes were then removed from the steam generators and subjected to metallographic examination to determine the actual defect depths. The following list provides a summary of the field data. The primary use of such field data is to confirm laboratory results.

ECT Comparisons with Pulled SG Tubes

Flaw Type	Number of Data Points	Number of Tubes
Intergranular Corrosion	24	24
Pitting	9	9
Wastage	2	1

Figure 2.13-1 (p. 331) shows the data plotted as a function of ECT indicated vs. actual defect depth for different types of defect.

To ensure steam generator integrity, the most important concern regarding ECT error is the possibility that ECT measurements will result in a severely degraded tube being incorrectly classified as within acceptable operating limits.

2.13.4 Probability of ECT Error

A typical limit on tube degradation is 60% of original wall thickness. This limit is established considering all accident and seismic loads as well as considerable safety factors. An operational tube plugging limit is then established to allow for possible additional degradation between inspections and error in ECT measurements. Typical plugging limits allow for degradation equal to 40% of original wall thickness.

For several defect types and depths of degradation, the probability was calculated that the ECT error will result in the incorrect classification of a tube. Table 2.13-1 (p. 332) gives the probabilities for each defect type and depth.

FIGURE 2.13-1

ETC ERROR DATA FOR VARIOUS DEFECT TYPES

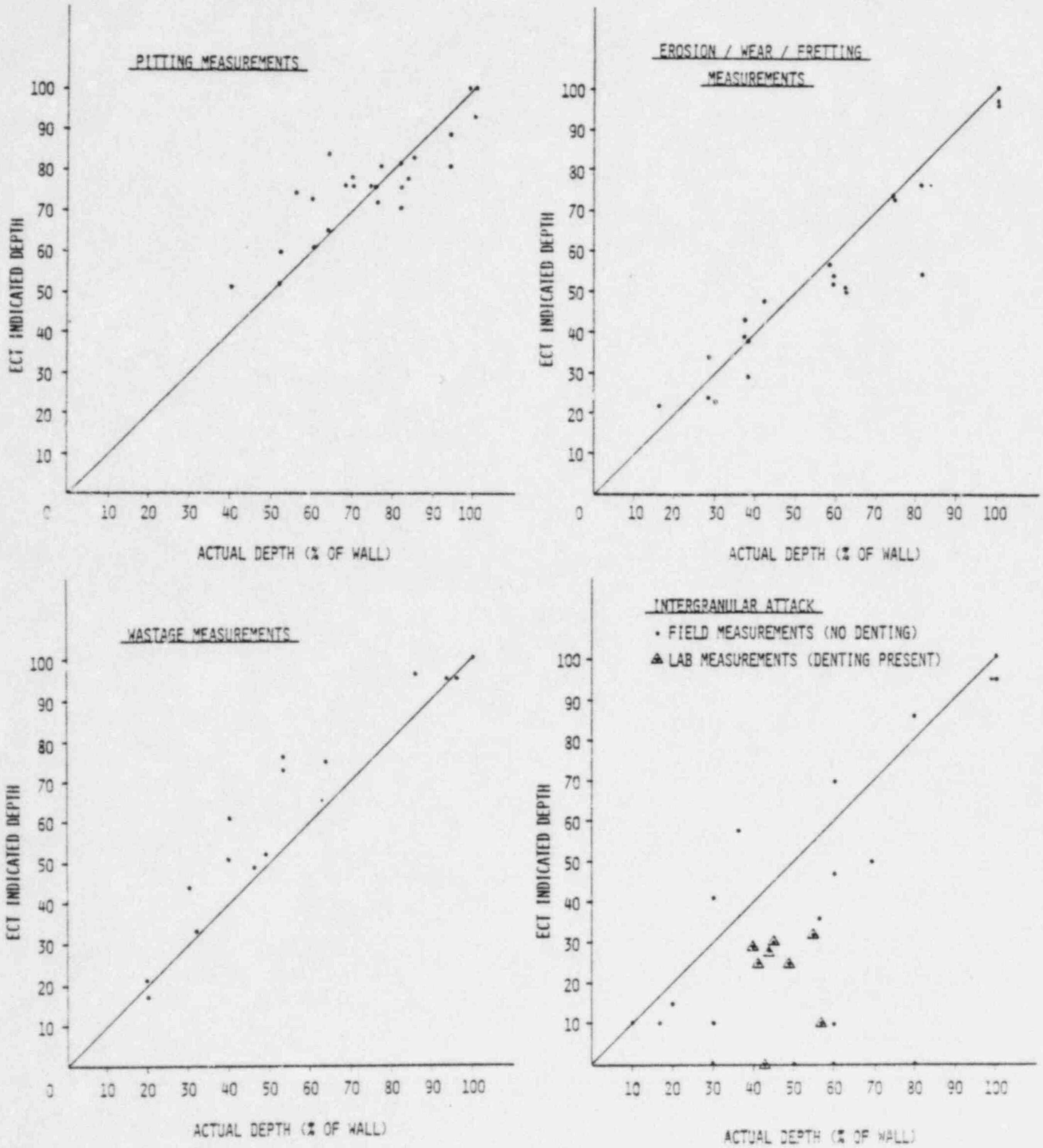


Table 2.13-1

PROBABILITY OF INCORRECT TUBE CLASSIFICATION DUE TO ECT ERROR

Actual Defect Depth	Probability Wear/Fretting	Wastage	Pitting
60%	3%	10%	1.3%
70%	0.7%	6%	0.2%
80%	0.1%	4%	< 0.1%
90%	< 0.1%	3%	< 0.1%
95%	< 0.1%	2%	< 0.1%

The probabilities given in Table 2.13-1 are calculated using the available laboratory and field data from References 19 through 23. The laboratory data was compared to the available field data for pitting, wastage, and intergranular corrosion. Where possible, laboratory and field data were pooled. In the case of intergranular corrosion, the field data, Reference 21, was obtained for non-dented tubes from the tubesheet crevice area in operating steam generators of other C-E flow design. The laboratory data, Reference 20, examined tubes subjected to intergranular corrosion in the presence of denting.

The error data for intergranular attack is too limited and scattered to permit calculation of meaningful probabilities. The data for wear/fretting and wastage was obtained from laboratory comparisons using single frequency ECT equipment. Newer multifrequency/multiparameter ECT equipment can be expected to provide greater accuracy on measurements of these types of defect. In each case, the observed error data was tested for normality and was shown to be reasonably normal in distribution.

2.13.5 Conclusions

Table 2.13-1 indicates that ECT has a low probability of incorrectly classifying severely defective tubes for most types of defects. In the case of intergranular corrosion, the data presented in Figure 2.13-1 indicates a tendency to currently underpredict intergranular attack. Improved ECT methods are presently under development to address this problem. Tubes in C-E designed steam generators have not experienced identifiable intergranular attack.

Present ECT equipment, properly employed, can adequately identify and characterize the type and the extent of tube degradation which might occur in the 3410 and the 3800.

2.14 Question 14: System 80 SG Vibration Analysis

Fretting wear type damage of steam generator tubes in the vicinity of the feedwater inlet has been observed in certain preheat type steam generators of design similar to the C-E System 80 steam generators. This damage is attributed to flow induced vibrations originating in the economizer of the steam generator. Provide a description of vibration analyses and model flow testing performed during the design of the C-E System 80 steam generators to assure that no damaging flow induced vibrations would occur in these steam generators.

2.14.1 Response to Question 14

This question is applicable only to those plants using the System 80 design (Palo Verde Nuclear Generating Station and Washington Public Power Supply System). These utilities will provide a separate response to the question.

3.0 REFERENCES

1. ACRS letter to N.J. Palladino dated December 15, 1981, Subject: ACRS Report on Palo Verde Nuclear Generating Station Units 1, 2, and 3.

2. "Final Safety Analysis Report for San Onofre Nuclear Generating Station, Units 2 & 3," Docket No. 5-361/362, Amendment 30, July, 1982.

3. "Final Safety Analysis Report for Waterford Steam Electric Station, Unit No. 3," Docket No. 50-382, Amendent 30, December, 1982.

4. "Final Safety Analysis Report for Palo Verde Nuclear Generating Station," Docket No. STN 50-528/529/520, Amendment 10, December, 1982.

5. "Final Safety Analysis Report for Washington Public Supply System, Nuclear Project No. 3," Docket No. 5-508, Amendment 2, November, 1982.

6. "Combustion Engineering Emergency Procedure Guidelines," CEN-152, Rev. 01, November, 1982.

7. "Analysis and Evaluation of St. Lucie Unit 1 Natural Circulation Cooldown," NSAC-16/INPO-2, December 1980.

8. "Generic Evaluation of Feedwater Transients and Small Break Loss-of-Coolant Accidents in Combustion Engineering Designed Operating Plants," NUREG-0635, January, 1980.

9. "PORV Failure Reduction Methods," CEN-145, December, 1980.

10. "Technical Report on Anticipated Transients without SCRAM for Water-Cooled Power Reactors," WASH-1270, September, 1973.

11. "ATWS Analyses, Analysis of Anticipated Transients without SCRAM in Combustion Engineering NSSSs," CENPD-158, Rev. 1, May, 1976.

12. "ATWS Early Verification, Response to NRC Letter of February 15, 1979, for Combustion Engineering NSSSs," CNPD-263-P, November, 1979.

13. Letter from K.P. Baskin to NRC dated 4/23/82, SE-82-312, Subject: C-E Owners Group Comments on Porposal Standards for the Reduction of Risks from Anticipated Transients without SCRAM (ATWS) Events for Light-Water-Cooled Nuclear Power Plants.

14. "Evaluation of Pressurized Thermal Shock Effects due to Small Break LOCAs with Loss of Feedwater for the Combustion Engineering NSSS," CEN-189, December, 1981.

15. "Contribution to the Theory of Two-Phase, Once Component Critical Flow," H.K. Fauske, Argonne National Laboratory Report, ANP-6633, 1962.

16. "Response to NRC Action Plan Item II.k.3.30, Justification of Small Break LOCA Methods," CEN-203-P, March, 1982.

17. "Review of Small Break Transients in Combustion Engineering Nuclear Steam Supply Systems," CEN-114-P, July, 1979.

18. "PARCH A FORTRAN-IV Digital Program to Evaluate Pool Boiling, Axial Rod and Coolant Heatup," CENPD-138-P, August 1974.

19. "Evaluation of the Eddy Current Method of Inspecting Steam Generator Tubing," BNL-NUREG-50512-R, J. H. Flora, S. D. Brown and J. R. Weeks, March 1976.

20. C-E Memorandum N-ISI-024, L. Edwards, Subject: NUSCO Steam Generator Settlement Programs, May 14, 1982.

21. "Eddy Current Optimization for the Detection/Characterization of Intergranular Attack in Steam Generator Tubing," EPRI-NP-2088-SR, S. D. Brown, January, 1982.

22. C-E Qualification Report, Eddy Current and Pit Measurements of Copper Oxide and Copper Coated PASNY Steam Generator Tubes, L. Edwards, J. Lareau, September, 1982.

23. C-E Memorandum, ISI-82-236, J. P. Lareau, Subject: PASNY Steam Generator Meeting with NRC, September 23, 1982.