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TITLE TRAC Analysis of Steam-Generator Overfill Transients

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TRAC ANALYSIS OF STEAM GENERATOR OVERFILL TRANSIENTS FOR TMI-1

by

Britt Bassett

ABSTRACT

A recent reactor safety issue concerning the overfilling of once-through steam generators leading to combined primary/secondary blowdown has been raised. A series of six calculations, performed with the LWR best-estimate code, TRAC-PD2, on a Babcock & Wilcox Plant (TMI-1), was carried out to investigate this safety issue. The base calculation assumed runaway main feedwater to one steam generator causing it to overfill, leading to a main-steam-line break. Four additional calculations build onto the base case with combinations of a pump-seal failure, a steam-generator tube rupture, and the pilot-operated relief valve not reseating. A sixth calculation involves only the rupture of a single steam-generator tube.

The results of this analysis indicate that for the transients investigated, the emergency cooling system provided an adequate make-up coolant flow to mitigate the accidents.

I. INTRODUCTION

The principal reactor safety issue relating to steam generators has been that they maintain a sufficient water level to remove the primary coolant energy generated by the reactor. There is now concern that an excessive water level may also affect the safety of the plant. The steam-generator overfill transient can be caused by the failure of the level-control system, which has no safety-grade equipment. This transient can affect the plant in several ways with such severe credible events as a simultaneous main-steam-line break and steam-generator tube rupture.

The concern raised by overfilling the steam generators is primarily based on the steam lines being flooded. Water in the steam lines could lead to increased dead weight, water-hammer effects, and valve failures from two-phase flows. If the level-control system fails open, rapid operator action would be necessary to prevent water spillage into the steam lines.[1]

This report gives details of calculations performed with a computer program to examine the steam-generator overfill problem. A best-estimate computer program for pressurized water reactor accident analysis was used. Secs. II and III contain more detail on the model and code. The specific plant modeled was Three Mile Island-Unit 1 (TMI-1).

Six calculations were performed to investigate various primary/secondary transients that are considered credible events. The first five of these calculations were all identical up to the time of the main-steam-line break. The sixth calculation was carried out for comparison and completeness.

Base Case: The MSLB (main-steam-line break) base case was initiated by a full-open failure of the main feedwater to one of the steam generators. This caused the steam generator to overfill, which resulted in the MSLB.

Case 1: This case had the same beginning as the MSLB base case. Shortly after the containment was isolated on an overpressure signal, pump-seal failures were assumed to occur in all four reactor coolant pumps.

Case 2: Case 2 was identical to Case 1 except that a SGTR (steam-generator tube rupture) occurred at the time of the MSLB.

Case 3: This case followed the MSLB base case except that the HPIS (high-pressure injection system) remained on throughout the transient. This caused the primary pressure to increase until the pressurizer-relief-valve setpoint was reached and the valve was assumed to fail open.

Case 4: Case 4 was identical to Case 3 except that a SGTR was assumed to occur at the time of the MSLB.

SGTR: The SGTR case had the rupture of a single tube as the only failure.

The results of these calculations are presented in Secs. IV through VII. The appendix includes additional information and comparisons for each of the six cases.

The primary objective of this analysis was to predict the thermal-hydraulic response of the system and to assess the potential for core uncovery in these transients. A second objective was to identify "accident signatures" that could be useful to operators in identifying and responding to such events. In addition, temperature histories of the reactor vessel wall were obtained for possible use in thermal-stress analysis.

II. THE CODE

These calculations were performed with an updated version of the TRAC-PD2 code (Transient Reactor Analysis Code, version PD2).[2] Most of these updates are for user convenience and are transparent to the actual calculations. Several of the changes that can affect results are discussed in this section. In particular, one modification was necessary to allow calculation of the overfill transients.

The initial part of five of these six calculations involves a SGOF (steam-generator overfill) caused by excessive feedwater flow. TRAC-PD2 has difficulty calculating the correct liquid droplet entrainment in the secondary of once-through steam generators. Normally, this problem has little influence on the overall calculation because the droplets are passed out of the steam generator, down the steam line, and out a boundary component with little effect on the heat transfer from primary to secondary. The higher steam-line mass flow is made up by giving the feedwater a higher value. However, in the SGOF case this entrainment will not allow filling of the steam generator while the reactor is operating at high power.

Figure 1 shows the vapor fractions for the five cells of the secondary side of the Loop-B steam generator during a test calculation. The test case was started from steady-state conditions with the Loop-B main feedwater system delivering 1200 kg/s, an unreasonably high value. The secondary water level rose slightly for the first 30 s, then the void fraction of the top cell dropped below 0.8 as more liquid was entrained. The increased entrainment allowed the steam line mass flow to match the feedwater mass flow. The flow match resulted in another steady state that was essentially unchanged from the

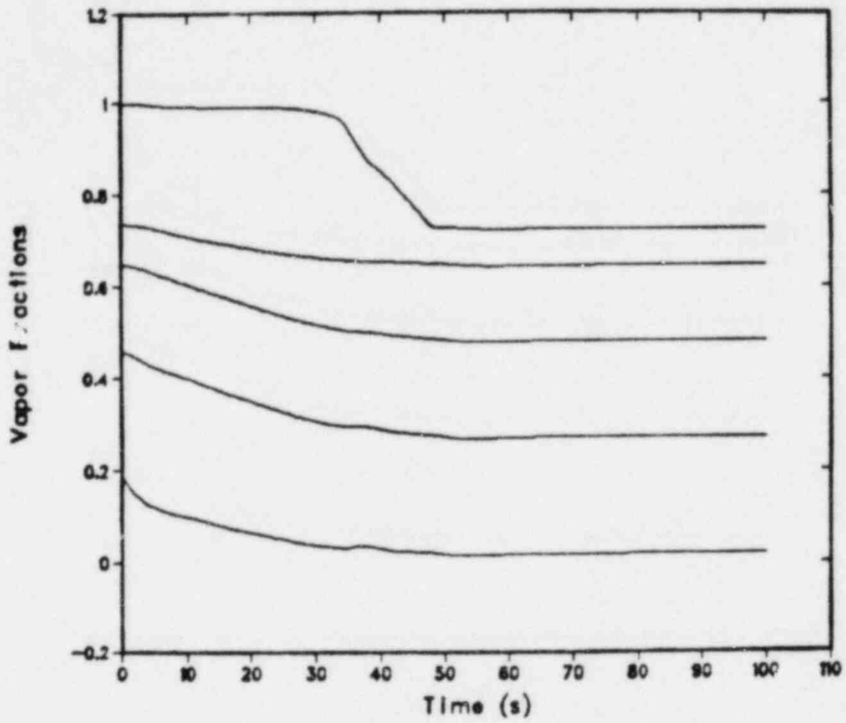

Fig. 1.
Steam generator secondary void fractions showing problem with entrainment.

initial one, with the primary showing little effect of the excessive feedwater flow.

The entrainment problem was overcome by modifying the code to promote a more sharply defined liquid-vapor interface for pool-type geometries. The results gave a more realistic calculation of the phase separation.[3] Figure 2 shows the vapor fractions in the steam generator with the code change and a main feedwater flow rate of 960 kg/s. As the water level rose, the cells filled until a significant amount of water started spilling over into the main steam line, and the MSLB was assumed to occur (at 240 s).

Other code modifications include: (1) a reactivity feedback model, (2) vent valves in the vessel, (3) auxiliary feedwater flow controlled by steam-generator water level, (4) a secondary tee added to the steam generator, and (5) the HPIS flow controlled by pressurizer water level.

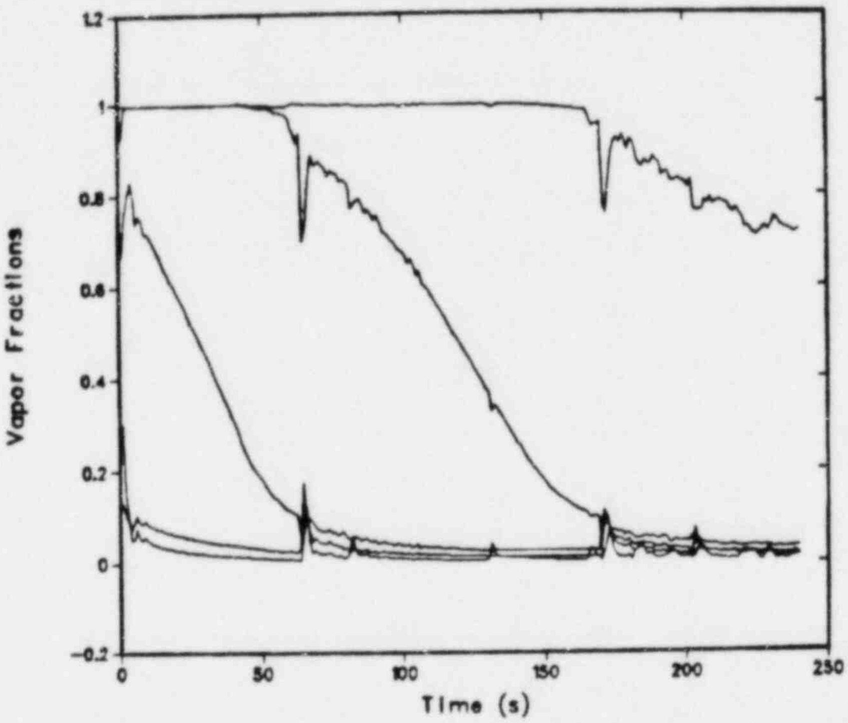

Fig. 2.
Steam generator secondary void fractions after the code change.

III. MODEL

The plant modeled for these calculations was the Three Mile Island-Unit 1 (TMI-1) nuclear power plant, a Babcock-and-Wilcox lowered-loop pressurized water reactor with two primary coolant loops. The model used for the computer code is shown schematically for each of the two loops in Figs. 3 and 4 with the reactor vessel repeated for clarity. Although the actual plant has two cold legs per loop, they have been combined for this model to increase computational efficiency. Most of the details for the model were derived from the plant FSAR (Final Safety Analysis Report).[4] Loop A of the model, as shown in Fig. 3, contains 27 components with 70 one-dimensional fluid cells and 28 three-dimensional vessel fluid cells. Loop B of the model contains 18 components with 55 one-dimensional fluid cells, excluding the vessel.

Loop A includes the pressurizer and its surge line. The exit at the top of the pressurizer provides for both the pilot-operated relief valve and the pressurizer safety valves. The back pressure for these valves is set close to atmospheric conditions. The pump-seal failure is modeled in the first computational cell below the pump of each loop and is adjusted to allow a constant

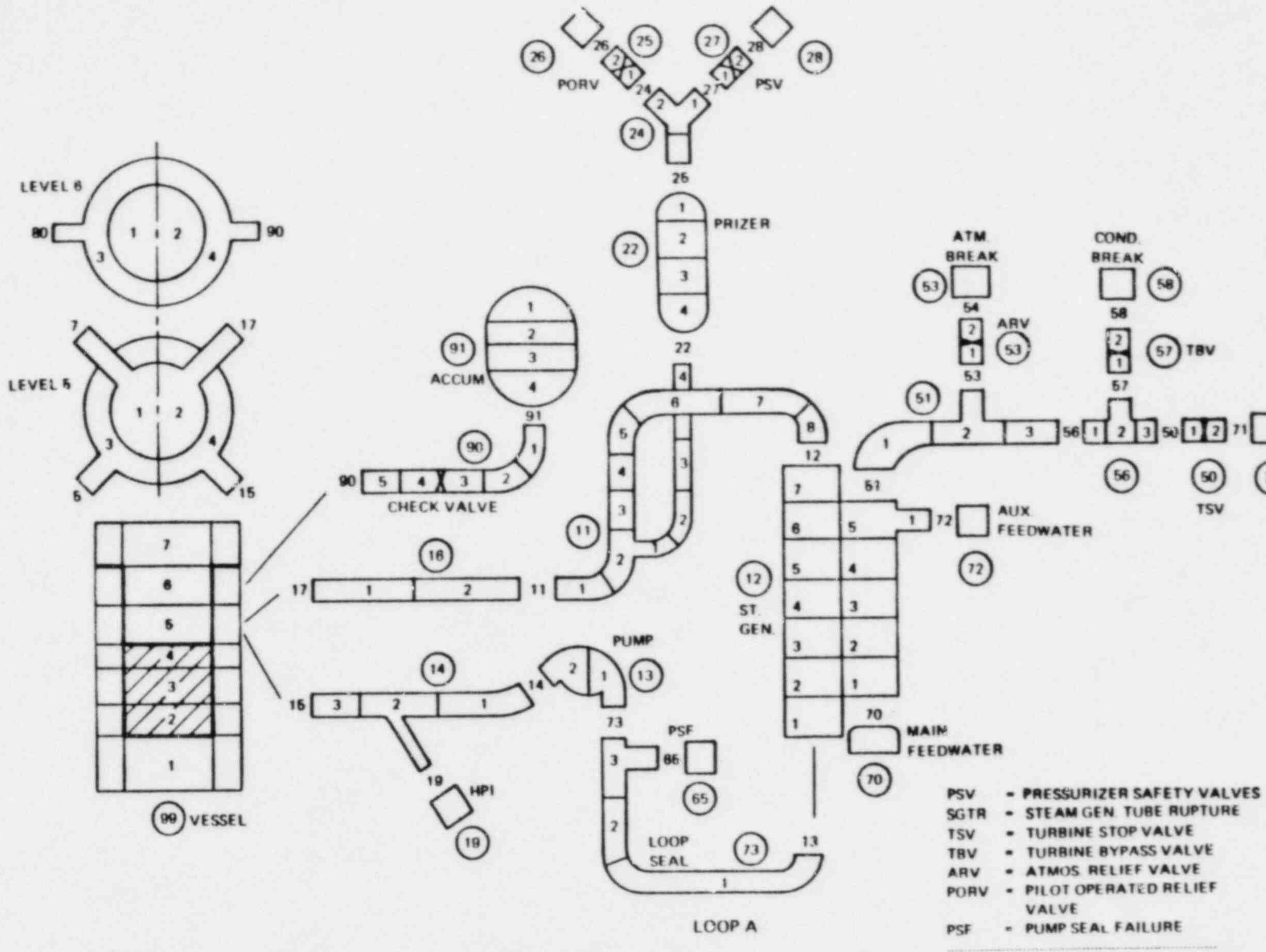

Fig. 3.
TMI-1 TRAC noding diagram, Loop A.

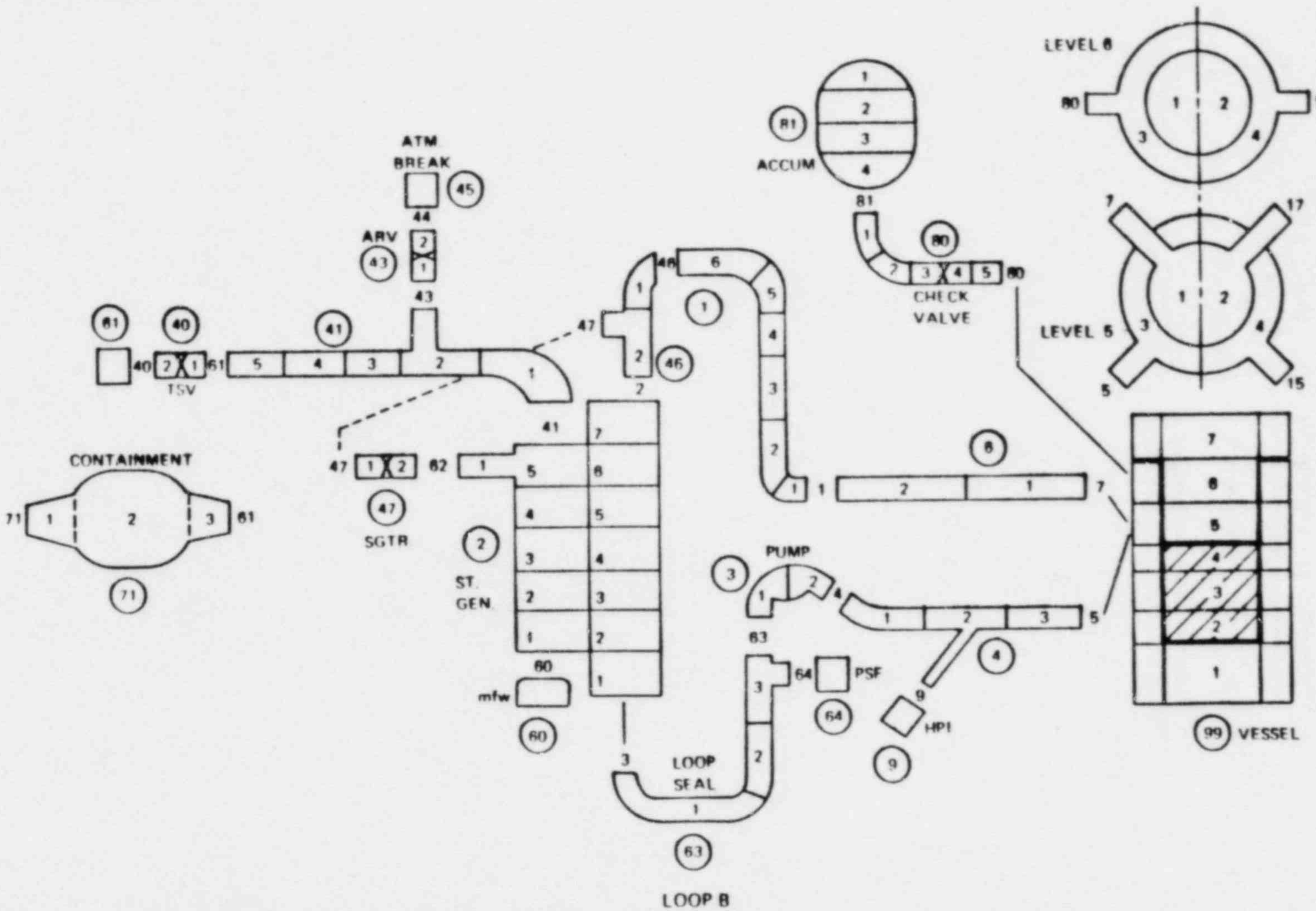

Fig. 4.
TMI-1 TRAC noding diagram, Loop B.

volumetric flow rate of 200 gpm. If actuated, at steady-state operating conditions the pump-seal failure will allow a flow of about 19 kg/s per loop.

The HPIS is modeled as a mass-flow-versus-pressure boundary condition with data derived from the pump curves included in the plant FSAR. The HPI pumps can maintain small flows up to 19 MPa, a pressure greater than the opening setpoints of either pressurizer relief valve type. At low pressures, the HPI for each loop is capable of a maximum flow of around 35 kg/s.

The accumulators are included with a check valve that initially allows flow when the primary pressure falls below 4.24 MPa (615 psia). The accumulator flow is directed into the top of the vessel downcomer in the fluid cell above the cold-leg entrance.

Except for the SGTR case, all emergency feedwater flow is aligned to the intact loop of this model. Both the atmospheric relief valves and the turbine bypass valves are modeled. The turbine bypass valves are included because they pass steam to a condenser rather than directly to the atmosphere.

The turbine stop valves are set to start closing shortly after a reactor trip. During a MSLB, both steam generators initially blow down until the turbine stop valves close, isolating Loop A from the break.

Loop B, the side with the MSLB, differs from Loop A in only a few details. A SGTR at the top of the tube sheet is modeled using a valve component with a minimum flow area of 3.14×10^{-4} m^2. For this analysis, a single tube is assumed to rupture so that primary coolant will pass from the hot-leg entrance of the steam generator to the top computational cell of its secondary side. The turbine bypass valve is not included in Loop B because the steam line of this side is assumed to incur the break.

To initiate the MSLB, a pipe component is used to replace components 40 and 61 of Loop B, and component 71 of Loop A (see Fig. 3). The pipe component has a volume slightly larger than the actual containment volume and is used to give a rough prediction of when the containment overpressure signal will occur. This prediction is used to determine when the pump seals will fail.

The vessel is coarsely noded with only two radial rings and two azimuthal divisions for calculational efficiency. Levels 2 to 4 make up the core, level 5 has the penetrations for the hot and cold legs. and level 6 has the accumulator discharge piping. The vessel vent valves are modeled in level 6 and are programmed to allow no reverse leakage so that a steady-state solution may be more readily obtained.

The TRAC reactivity feedback model was used for these calculations. In addition, a model for the negative reactivity insertion from the boron in the HPI water was derived. The values for this insertion were calculated assuming the core was near its end-of-life. Without boron modeling, recriticality was calculated to result from the positive reactivity feedback of the cold HPIS water.

An internally consistent set of initial conditions for this TMI-1 model was obtained from a TRAC steady-state calculation. Table I lists some important parameters from this TRAC calculation along with values from the plant FSAR. Table II includes several important setpoints and flow areas included in the model.

TABLE I

STEADY-STATE INITIAL CONDITIONS

	TRAC	FSAR
Reactor power (MWt)	2568	2568
Coolant mass flow per pump (kg/s)	4025	4130
Primary Pressure (MPa)	15.1	15.1
Core inlet temperature (K)	563	563
Core outlet temperature (K)	591	591
Secondary pressure (MPa)	6.45	6.27
Steam-line temperature (K)	560	572
Steam flow (kg/s)	799[a]	706

[a]Including entrained liquid, see Sec. II.

TABLE II

INITIAL SETPOINTS

Low-pressure reactor trip		13.1 MPa
High-power reactor trip		2876 MWt
HPI initiation		11.13 MPa
Pilot-operated relief valve	open	15.75 MPa
	maximum flow area	2.19×10^{-4} m^2
Pressurizer safety valves	open	16.9 MPa
	maximum flow area	1.23×10^{-3} m^2
Accumulator check valves		4.24 MPa
Turbine bypass valves	open	7.1 MPa
	maximum flow area	1.14×10^{-2} m^2
Atmospheric relief valves	open	7.34 MPa
	maximum flow area	5.85×10^{-2} m^2
Containment overpressure		0.13 MPa

IV. THE MAIN-STEAM-LINE BREAK, BASE CASE

The MSLB transient was the base calculation used for Cases 1 to 4. This calculation is summarized by the event sequence in Table III, by the accompanying figures, and by the following list of assumptions and boundary conditions:

1. The maximum flow from the MFW (main feedwater) supply for Loop B was set to 961 kg/s. This is 20% higher than the TRAC steady-state flow and represents the fully rated capacity of the TMI-1 MFW supply. The MFW normally operates at 80% capacity during full-power operation.

2. The MSLB was assumed to occur about 5 s after the steam generator filled with a two-phase mixture. The break was a complete rupture of the 0.864 m (34 in.) ID steam line in Loop B and started the blowdown of both steam generators.

3. The MFW flow to both loops continued for 20 s after being tripped (at the time of the MSLB) to account for water in the pipes and valves leading to the steam generators. The feedwater flow to both loops then underwent a 14 s coastdown.

4. The reactor power tripped when it reached 2876 MWt, 112% of the steady-state value.

5. The Loop-A turbine stop valve started closing 4 s after the reactor trip signal and took 1 s to fully close. Closure of this valve terminated the blowdown of the Loop-A steam generator.

6. The auxiliary feedwater supply began delivering water to steam generator A after the MFW coasted down. The auxiliary feedwater supplied 331 K water at 57.4 kg/s and was cycled on and off as necessary to keep the secondary water level at about half of the steam generator height, or 7.5 m.

7. The heaters and sprays of the pressurizer were not activated for this analysis.

8. The HPIS was activated when the primary pressure fell below 11.13 MPa. It was then turned off as the pressurizer water level passed 6.5 m and turned on if the level fell below 6.3 m. There were two identical HPIs, one per loop.

9. The reactor coolant pumps were tripped 5 s after initiation of the HPIS.

10. Pressure relief from the steam lines was supplied in Loop A by the turbine bypass valve, which opened at 7.2 MPa. If more relief was needed, the atmospheric relief valves would have opened at 7.34 MPa. Loop B had the MSLB, so that modeling for secondary pressure relief in this loop was not necessary.

The initiating event for this transient was a fully open failure of the Loop-B MFW supply. This caused the secondary to start filling, slightly overcooling the primary through the Loop-B steam generator. The overcooling can be seen in Fig. 5, which shows an initial decrease in the primary pressure. The filling continued until slugs of water spilling into the steam line were assumed to cause the MSLB and loss of the MFW supply.

The initial blowdown of both steam generators caused a severe overcooling of the primary. Reactivity feedback from decreasing coolant temperature caused the core power to rise until the 112% overpower trip was reached. The turbine stop valves started closing after the reactor trip signal, isolating the Loop-A steam generator. All of these events took place within 12 s after the MSLB.

TABLE III

MSLB BASE CASE EVENT SEQUENCE

Event	Time (s)
Loop-B MFW fails full open	0
Steam-generator B overfills	235
MSLB occurs	241
MFW shutdown starts	241
Reactor overpower trip	246
Turbine stop valves close	252
Auxiliary feedwater starts	253
HPIS starts	265
Reactor coolant pumps turned off	270
HPIS off (pressurizer level control)	550
Auxiliary feedwater off (steam generator level control)	775
Secondary relief valves open	1600

Figure 5 shows the pressure drop caused by the MSLB. The Loop-A secondary pressure recovered after the turbine stop valves were closed. This pressure then decreased again as the auxiliary feedwater refilled and cooled the secondary. As the auxiliary feedwater was cycled off (~750 s), the secondary pressure increased until the setpoint of the turbine bypass valve was reached. For the remainder of the transient, the pressures and temperatures were controlled by the relieving capacity of the turbine bypass valve (Fig. 6) and the auxiliary feedwater delivering secondary coolant as needed (Fig. 7).

Figure 8 shows the secondary-side water level for both steam generators. The Loop-B level reflects the overfill and blowdown of the steam generator. The Loop-A level increased slightly until the MSLB because of the overcooling of Loop B and consequently reduced heat transfer to the Loop-A secondary with the same MFW flow rate. After the MSLB, the Loop-A steam generator emptied until the turbine stop valves closed. The level rose again because of the auxiliary feedwater flow until it reached the controlling setpoint at about 7.5 m.

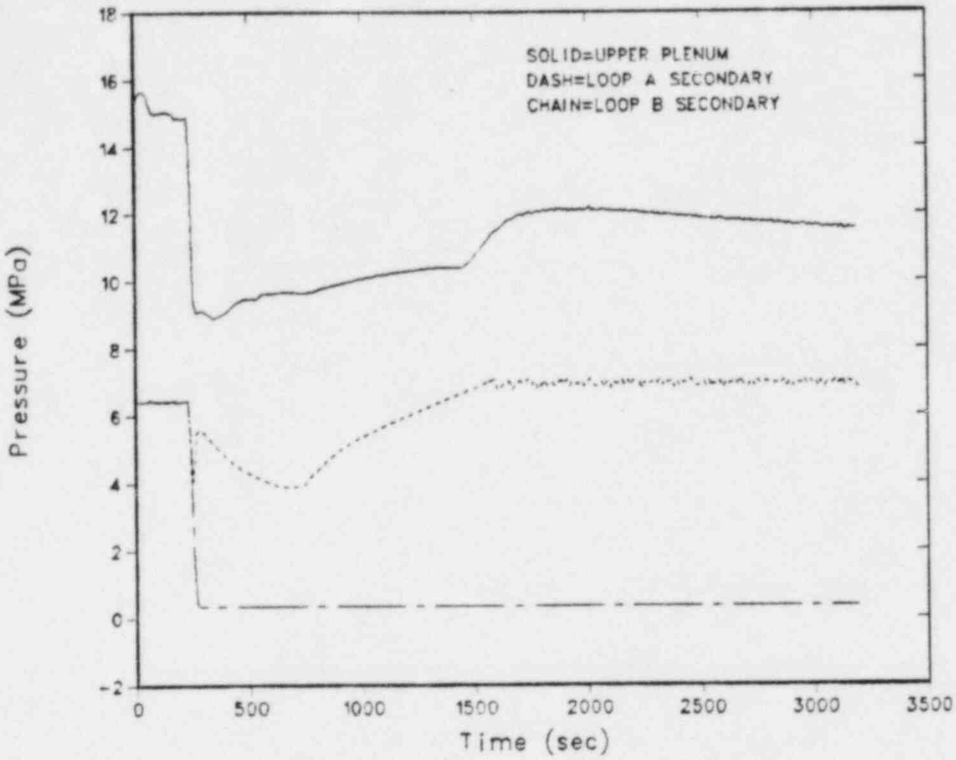

Fig. 5.
MSLB base case, average system pressures.

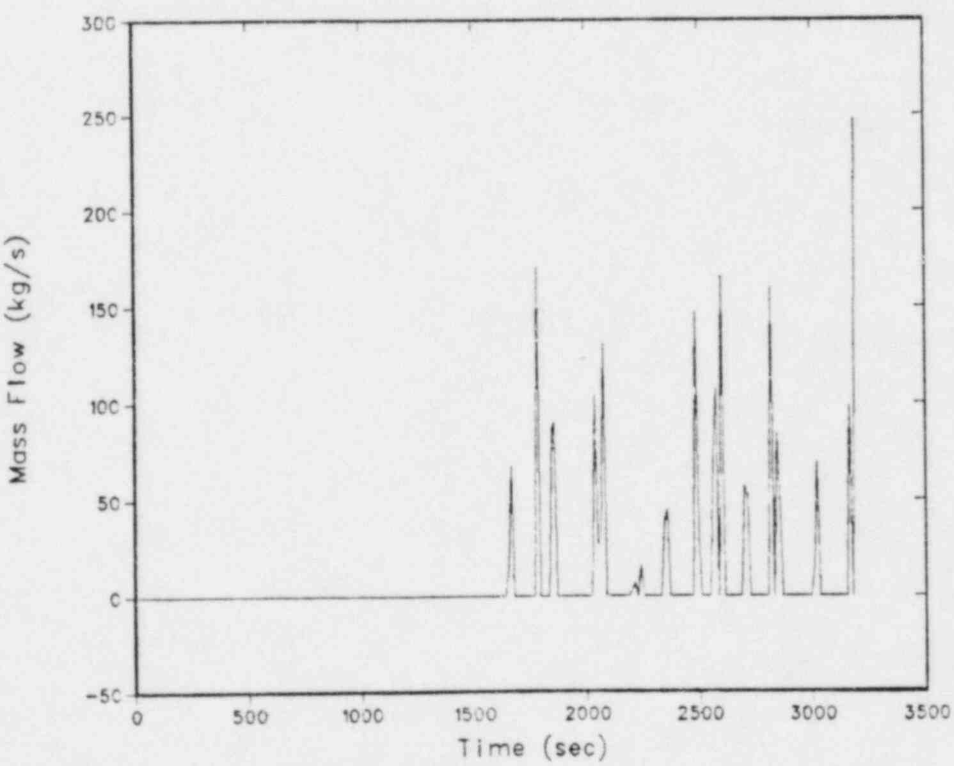

Fig. 6.
MSLB base case, turbine bypass valve mass flow.

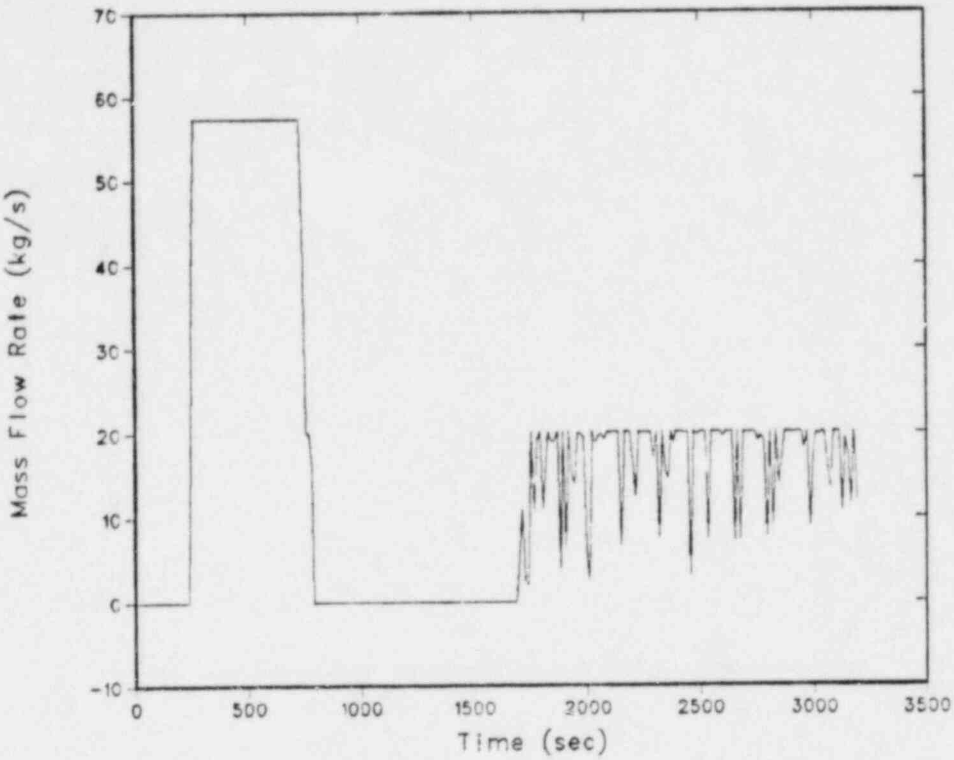

Fig. 7.
MSLB base case, auxiliary feedwater mass flow.

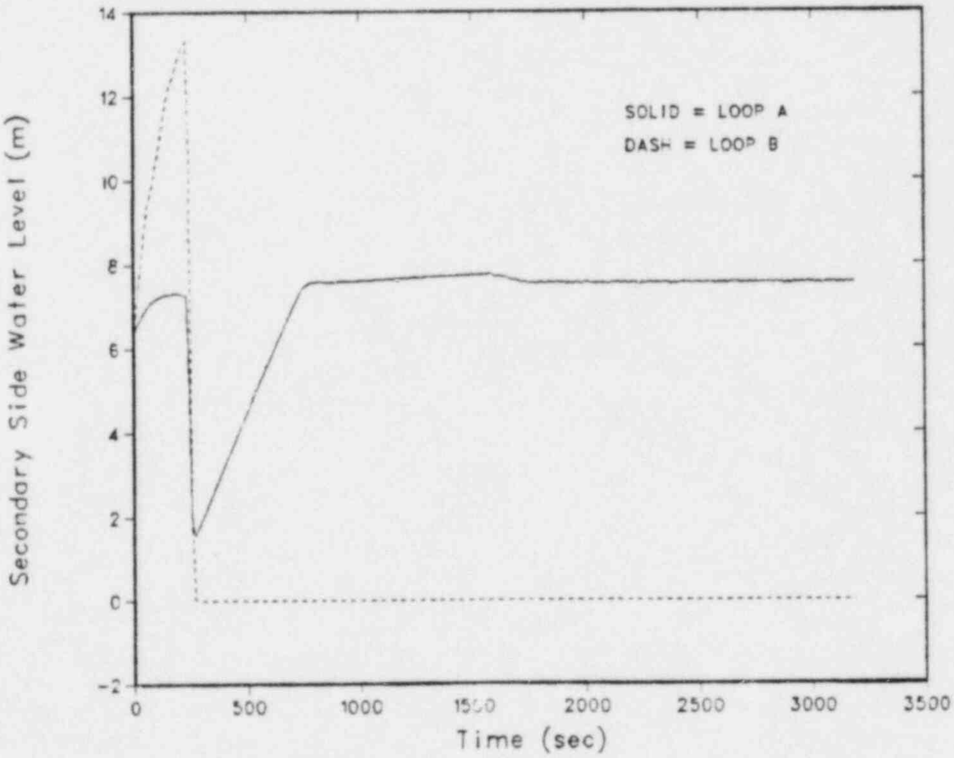

Fig. 8.
MSLB base case, Loops A and B steam-generator water level.

The vessel wall temperatures are presented in Fig. 9. These are average slab temperatures taken from four different locations in the vessel. The legend information corresponds to locations in the model diagram shown in Fig. 1. The initial cooling resulted from the MSLB and HPIS flow. After the HPIS was turned off, the wall temperature rose until steam relief from the Loop-A turbine bypass valves allowed cooling of the system.

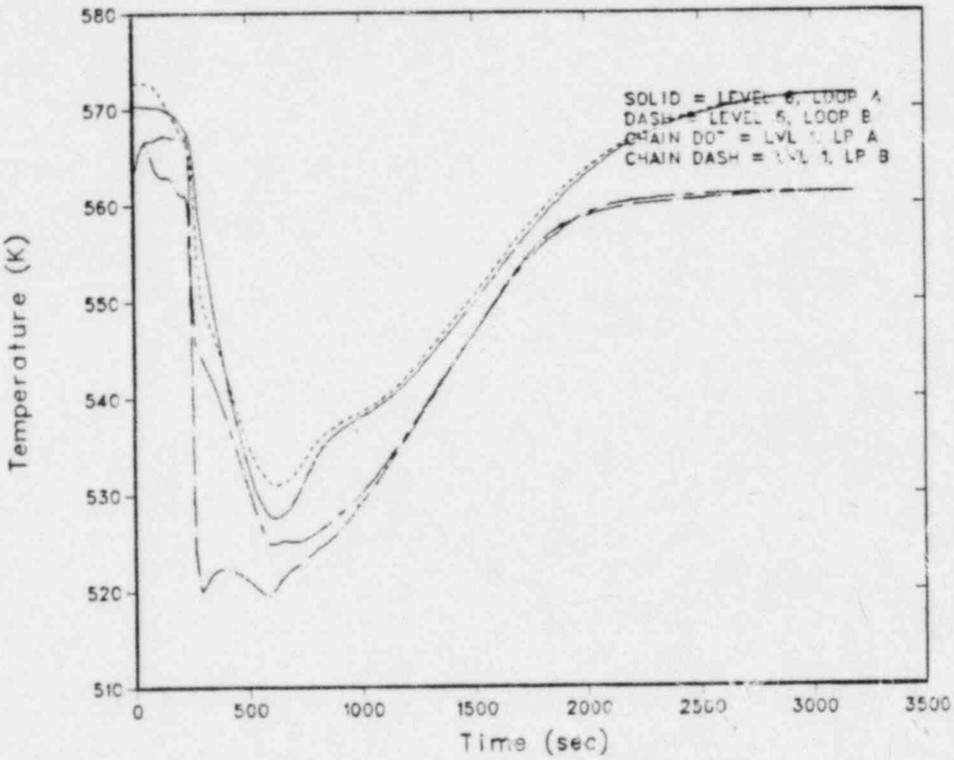

Fig. 9.
MSLB base case, vessel wall temperature.

V. PUMP-SEAL FAILURE AND STEAM-GENERATOR TUBE RUPTURE, CASES 1 AND 2

Cases 1 and 2 are very similar and will be discussed together. Both of these transients started from the MSLB. The assumptions and boundary conditions for them were identical to the MSLB base case except as noted below.

1. The PSF (pump-seal failures) were assumed to occur when the shaft cooling water flow ceased after containment isolation.

2. The main reactor coolant pumps were assumed to fail 10 s after the PSF occurred.

3. The HPIS was left on throughout the transient.

4. For Case 2, the complete rupture of a single steam-generator tube was assumed to occur at the time of the MSLB.

Table IV gives the event sequence for these two cases; and as can be seen, there is little difference between them.

The primary pressure for these two calculations, along with that for the MSLB base case, is presented in Fig. 10. The scalloping effect noticeable in the Case 1 (MSLB and PSF) curve corresponded with the filling of the four cells of the pressurizer. The differing pressure slopes on the Case 1 curve result from the competing effects of the rising liquid level compacting the remaining vapor, and the condensation of that vapor calculated by TRAC-PD2. Each of the cusps on this curve occurred at the same time that the void fraction of a pressurizer cell reached 0.1. Therefore, the appearance of this effect is due to

TABLE IV

CASES 1 AND 2 EVENT SEQUENCE

Event	Time (s)	
	Case 1	Case 2
MFW fails full open	0	0
Steam-generator B overfills	235	235
MSLB occurs	241	241
MFW shutdown starts	241	241
SGTR occurs	-	241
Reactor overpower trip	246	246
Pump-seal failures occur	248	248
Turbine stop valves close	252	252
Auxiliary feedwater starts	253	253
Reactor coolant pumps fail	258	258
HPIS starts	265	265
Auxiliary feedwater off (steam generator level control)	775	775
Pressurizer full	2600	-

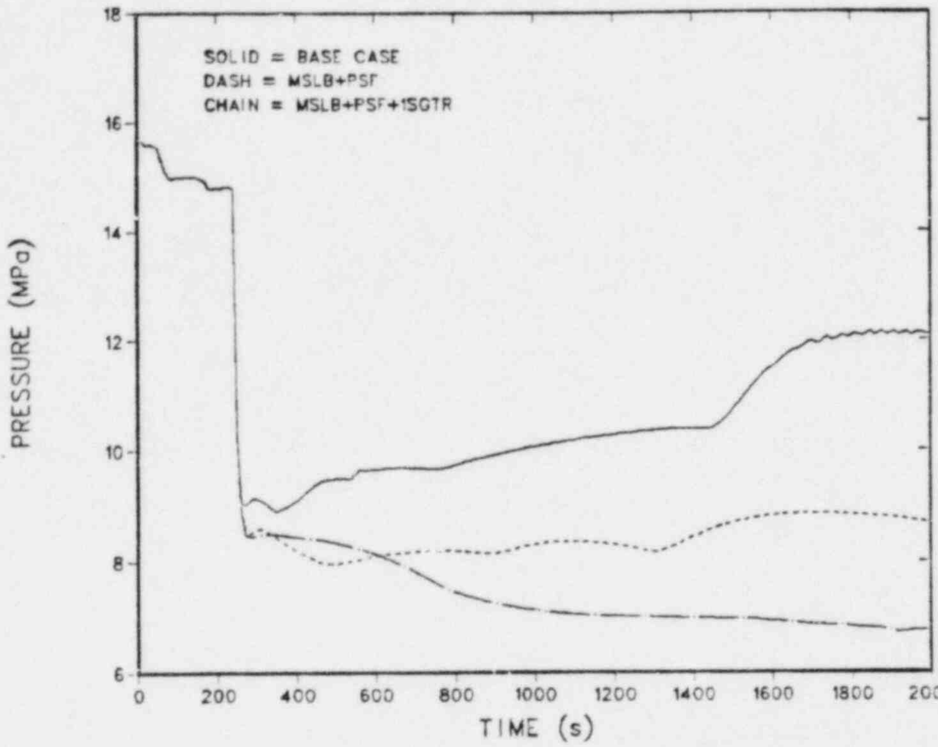

Fig. 10.
Cases 1 and 2 primary pressure.

coding in the condensation model that reduces the condensation rate as a cell fills so that very rapid bubble collapses would be eliminated.

Figure 11 shows the pressurizer water level. For Case 1, at about 2550 s, the pressurizer filled with liquid resulting in a rapidly increasing system pressure. The HPIS flow was pressure dependent so that it decreased enough during this pressure rise to just offset the PSF leakage. Therefore, by 2600 s an equilibrium was reached in this case.

Case 2 (MSLB, SGTR, and PSF) showed a continual decline in primary pressure as shown in Fig. 10. With the addition of the SGTR, the HPIS could not make up for the pressure decrease that was due to the sum of the primary leakages. Figure 11 also depicts this with the pressurizer water level. Figure 12 presents the upper plenum void fraction for the three cases and shows that for Case 2, the upper plenum voids did not disappear in a few hundred seconds after the MSLB as was observed in the other cases.

The primary system mass is shown in Fig. 13. The primary mass for Cases 1 and 2 dropped initially until the HPIS flow started. The Case 1 mass then increased until the HPIS flow was offset by the PSF leakage rate. The primary

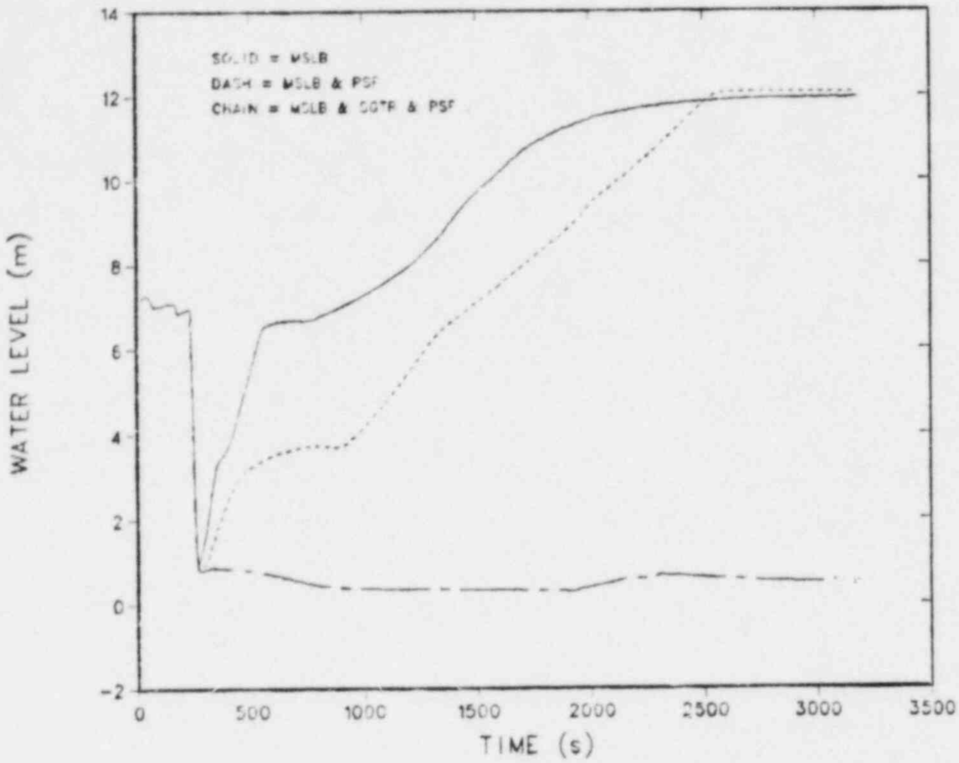

Fig. 11.
Cases 1 and 2 pressurizer water level.

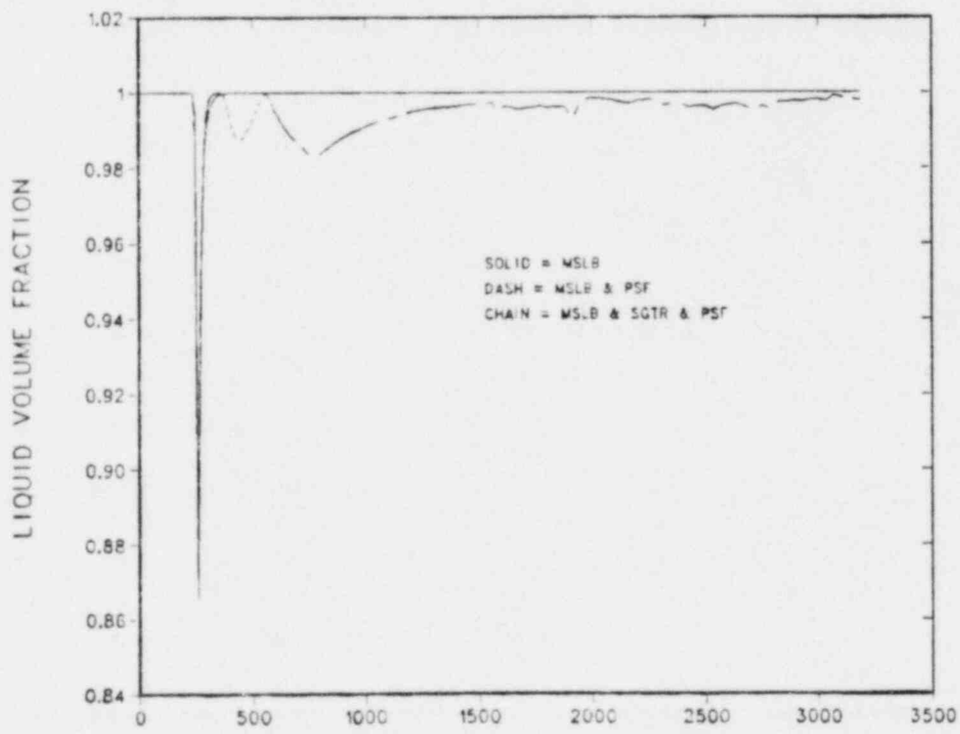

Fig. 12.
Cases 1 and 2 upper plenum liquid volume fraction.

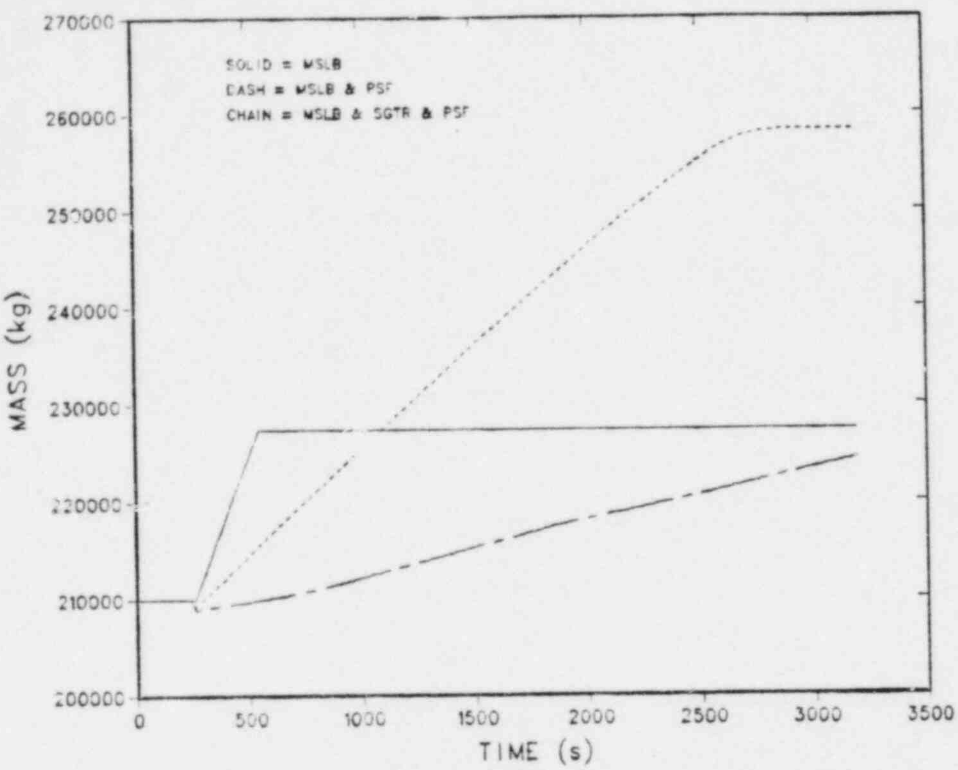

Fig. 13.
Cases 1 and 2 primary system mass.

mass for Case 2 also rose, but more slowly, with the HPI supplying somewhat more coolant than was being lost. The primary pressure (Fig. 10) and the pressurizer water level (Fig. 11) did not rise for Case 2 even though the system mass increased, because the primary coolant contracted as it was cooled by the HPIS flow. (For the MSLB base case the system mass rose when the HPIS came on, then remained constant as the HPIS flow was throttled. For the MSLB base case only, the HPIS was turned off as the pressurizer water level reached its steady-state value. Figure 11 shows that the water level for the MSLB base case started rising again because of primary coolant heating and expansion into the pressurizer.)

The intact-loop secondary pressure for these two calculations and for the MSLB base case is given in Fig. 14. The MSLB base case secondary pressure eventually held at the turbine bypass valve opening setpoint. The other cases behaved similarly to the base case except that less heat was transferred to the secondary with continuous HPIS flow in the primary. The primary started cooling the secondary in Cases 1 and 2 at about 1200 s. The rapid pressure

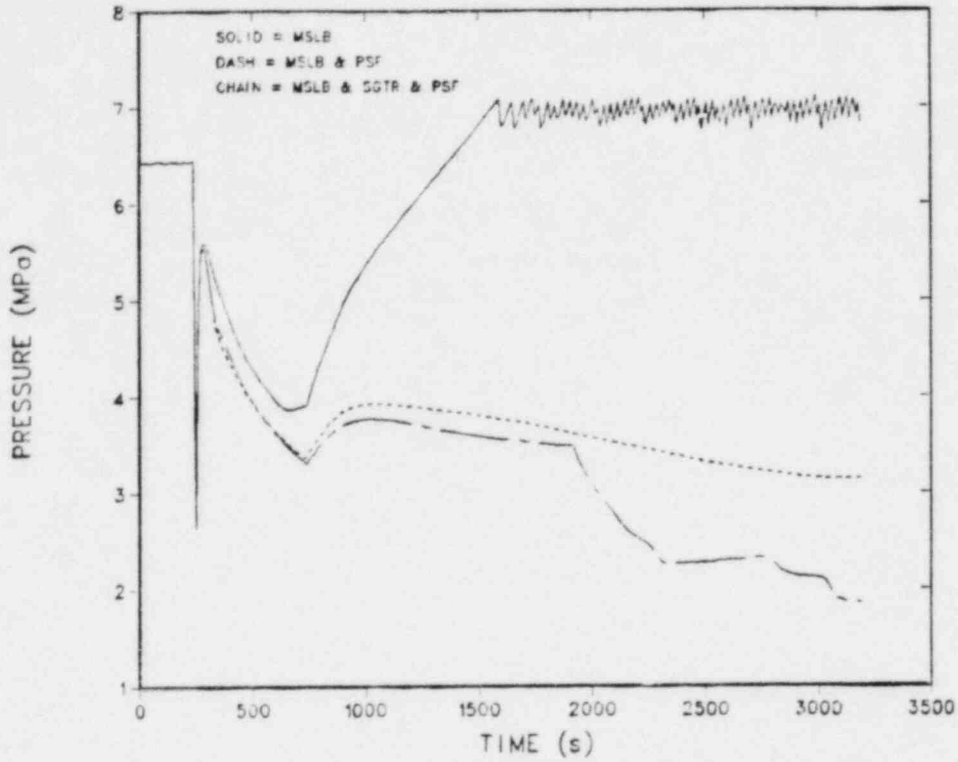

Fig. 14.
Cases 1 and 2 intact-loop secondary pressure.

drop in the Case 2 secondary (at 2000 s) shown in Fig. 14 was the result of an interesting phenomenon, discussed below, that the Case 2 calculation predicted.

Figure 15 presents the primary-loop mass flow for Case 2. The mass flow dropped substantially after the reactor coolant pumps failed. Loop B maintained a small mass flow of about 400 kg/s because of the leakage through the ruptured steam-generator tube. The Loop-A mass flow was much smaller and included several flow reversals. Figure 16 presents the same data as Fig. 15 but excludes the initial 400 s so that greater detail can be seen.

The Loop-A flow reversals were caused by a buildup of cold, dense HPIS water in the cold leg during low-flow periods. As sufficient cold water collected to surmount the slight elevation gain to the pump, it would fall into the loop seal. This cold leg is about 9 m higher, and previous to a flow reversal contained much denser liquid than the loop seal. With this elevation difference plus a density difference of as much as 80 kg/m^3, a significant natural circulation head was created.

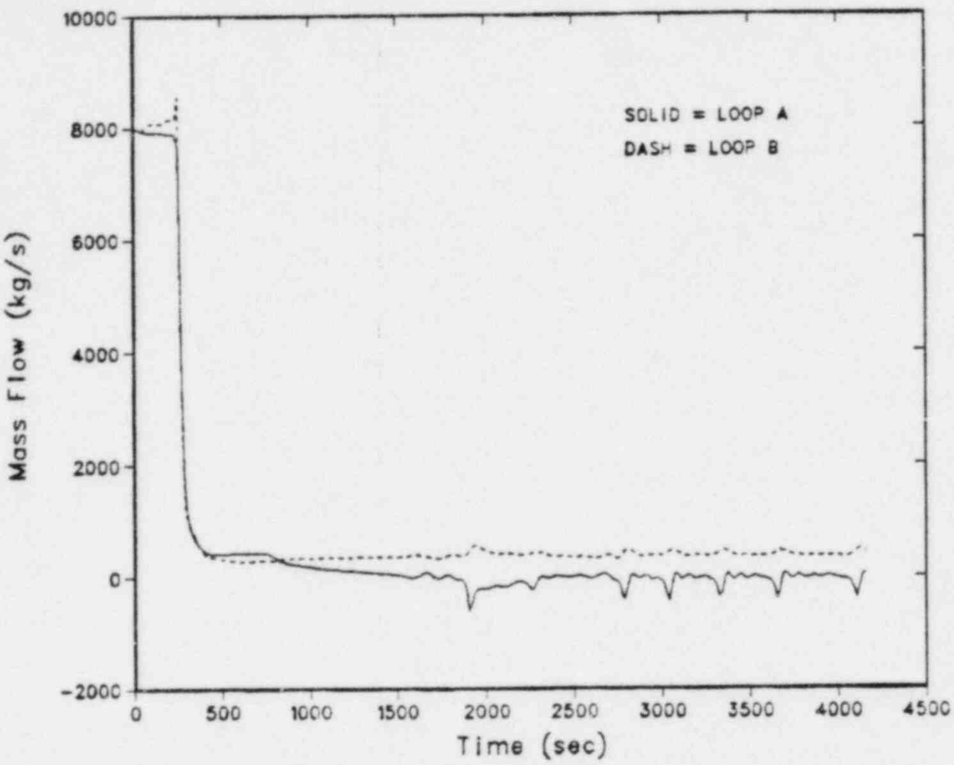

Fig. 15.
Case 2 loop mass flows

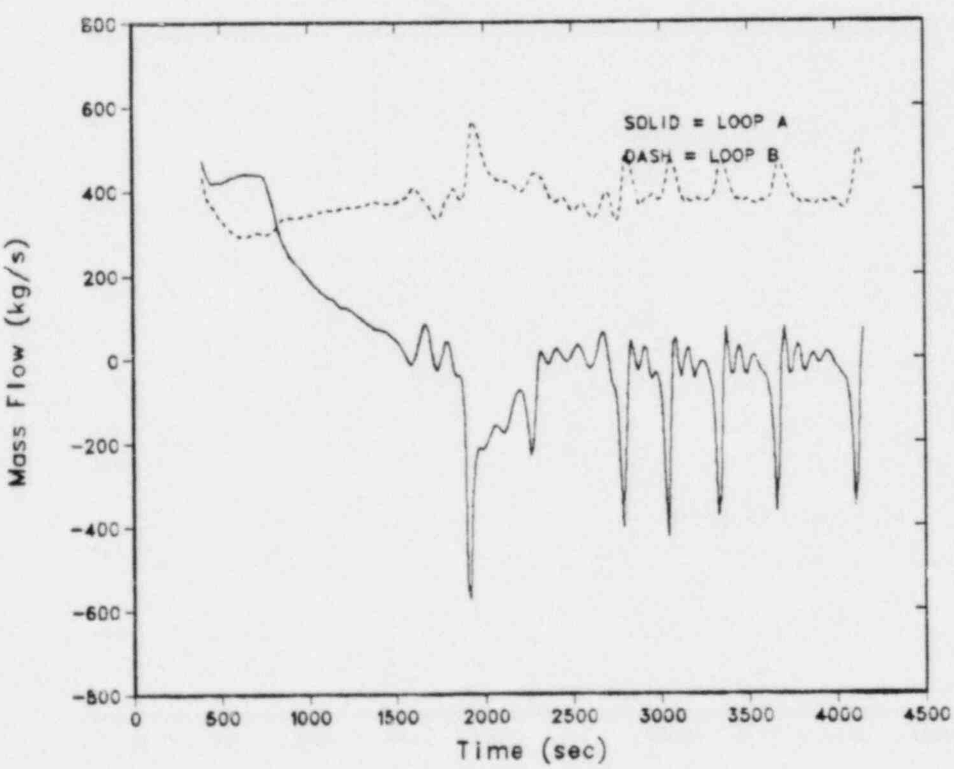

Fig. 16.
Case 2 loop mass flows (detail).

Figure 17 presents the coolant temperature in each pump and clearly shows the effect of the flow reversals. The cool, dense coolant from the HPIS buildup passed through the loop seal and into the steam generator where it heated and was mixed with warmer liquid. Figure 18 shows the less severe temperature transients in the steam generator and shows the secondary being cooled by the primary. This cooling caused the secondary to contract so that the auxiliary feedwater came on to restore the steam-generator coolant level (Fig. 19). Addition of cooler secondary water from the auxiliary feedwater system resulted in the secondary pressure drop seen in Fig. 14. The flow-reversal phenomena continue because the slug of cold water was diffused and warmer water from the vessel was drawn into the loop. The phenomena would not continue indefinitely because each reverse spike brings the loop temperature 8 to 10 K closer to the HPIS temperature.

The vessel wall temperature for Case 1 is presented in Fig. 20, and for Case 2 in Fig. 21. In both cases, the wall temperature dropped quickly after

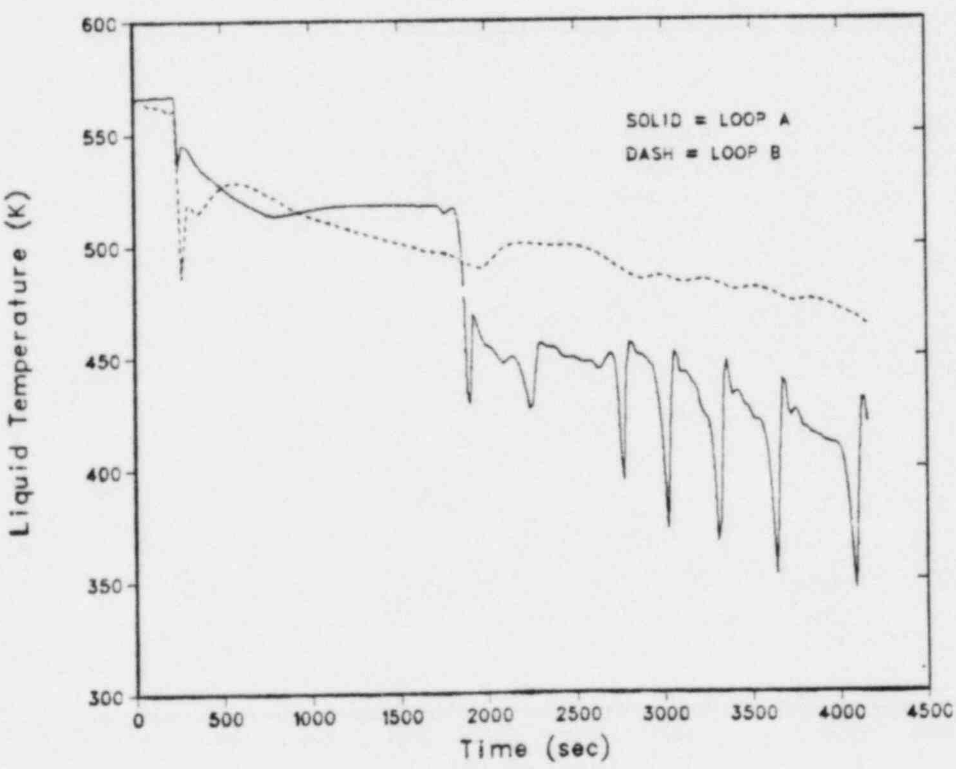

Fig. 17.
Case 2 pump liquid temperatures.

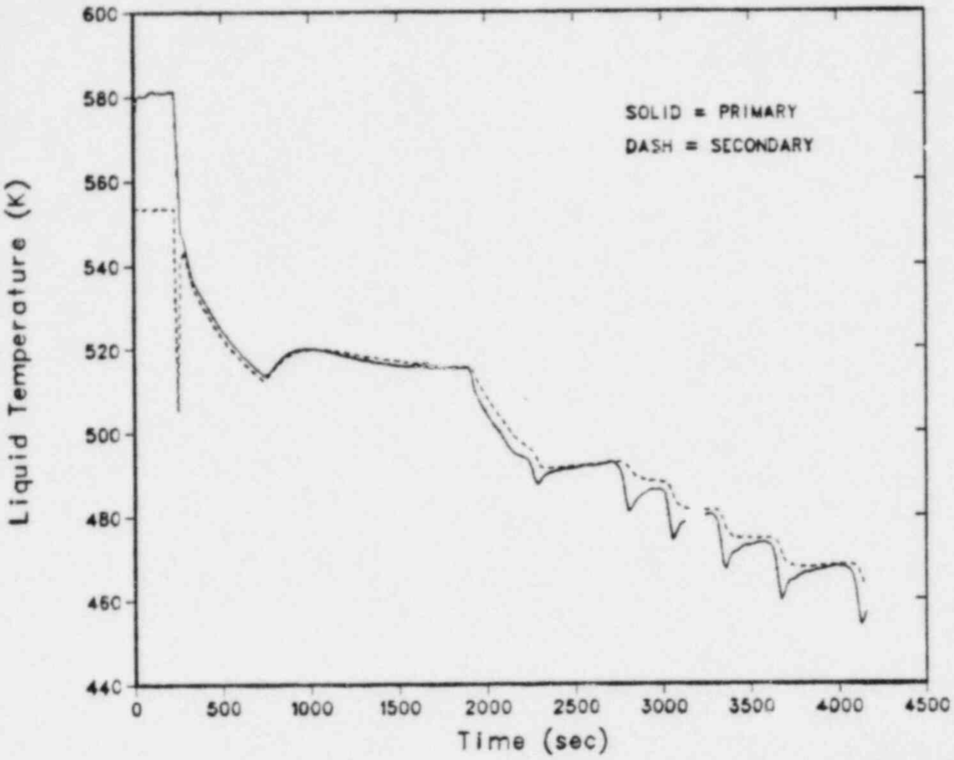

Fig. 18.
Case 2 primary and secondary temperatures in intact loop.

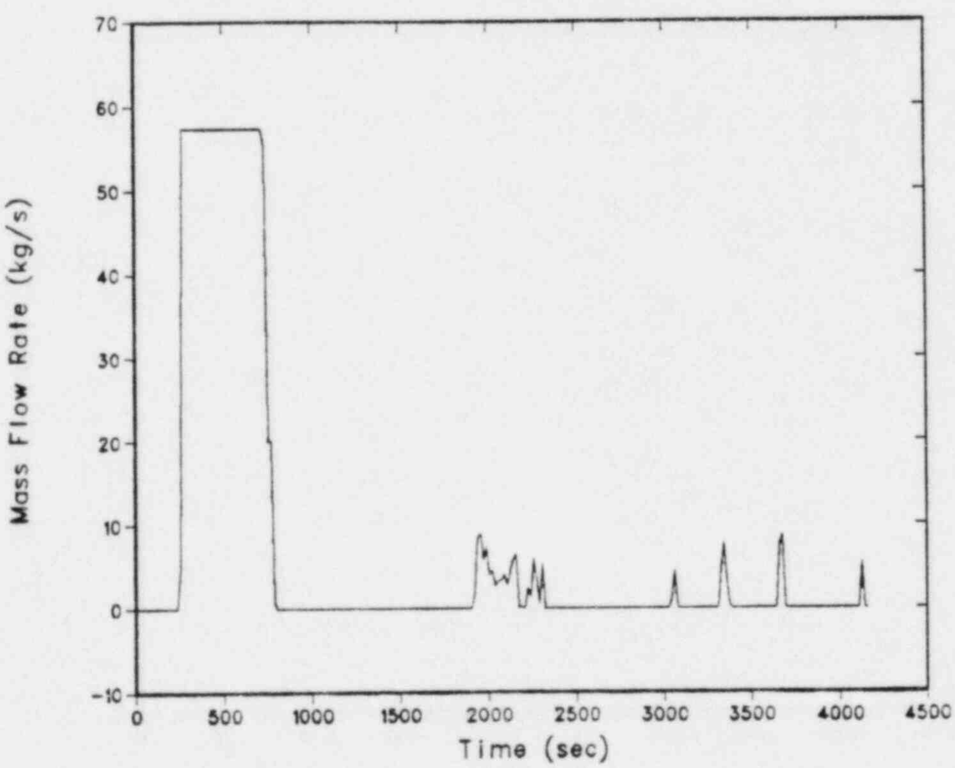

Fig. 19.
Case 2 auxiliary feedwater flow to intact loop.

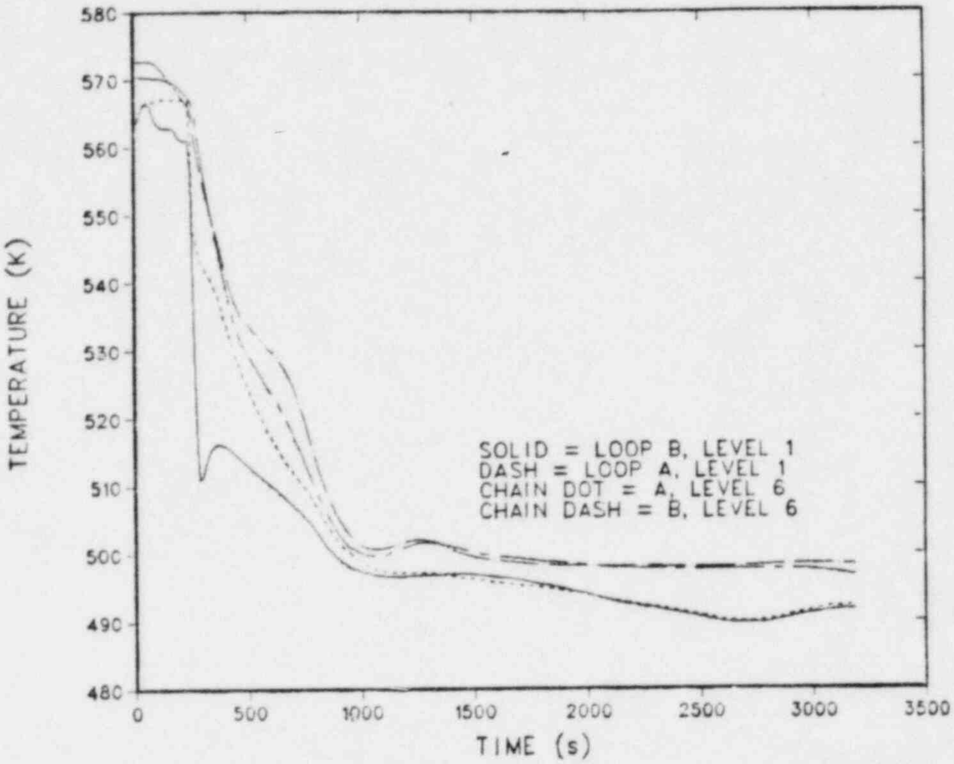

Fig. 20.
Case 1 vessel wall temperatures.

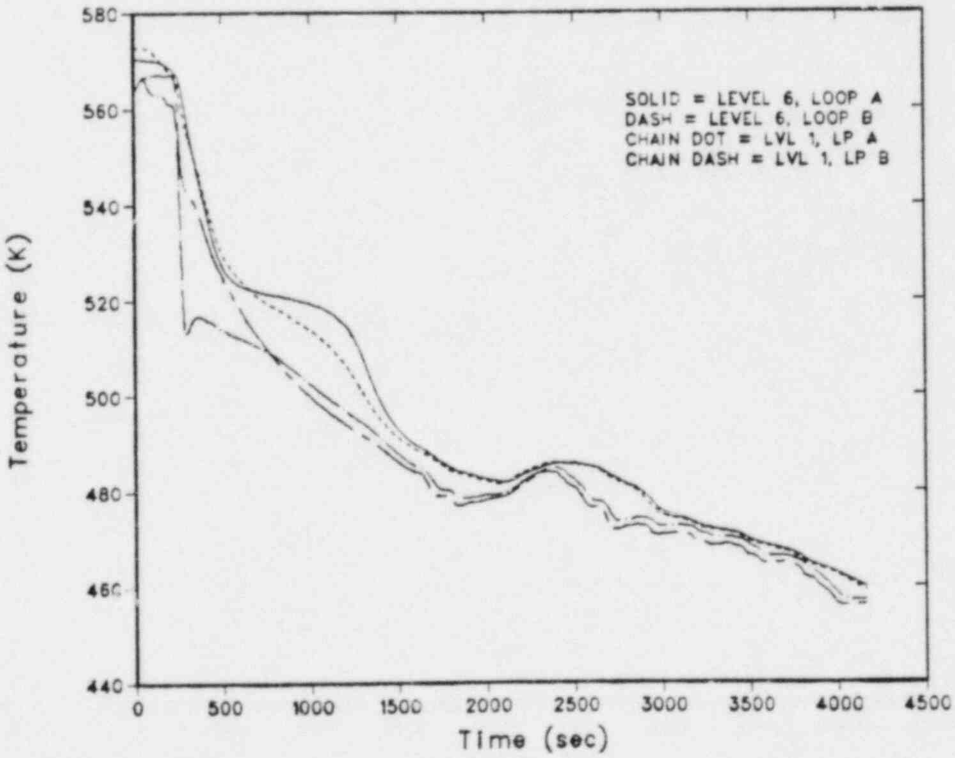

Fig. 21.
Case 2 vessel wall temperatures.

the MSLB and continued decreasing because of the primary cooling from the sustained HPIS flow.

VI. PORV FAILURE AND STEAM-GENERATOR TUBE RUPTURE, CASES 3 AND 4

Cases 3 and 4 will be discussed together because they are quite similar. Case 3 has an identical beginning to that of the MSLB base case and follows that calculation for the initial 550 s. The boundary conditions and assumptions given for the MSLB base case apply to these calculations except for the following modifications:

1. After initiation, the HPI system remained on throughout the transient;
2. The PORV (pilot-operated relief valve) was modeled so that it did not close after lifting and could relieve about 15 kg/s of steam or 37 kg/s of liquid; and
3. For Case 4, the complete rupture of a single steam-generator tube was assumed to occur simultaneously with the MSLB.

The event sequence for the two cases is quite similar and is presented in Table V.

Figure 22 presents the primary system pressure for these two calculations, along with the MSLB base case for comparison. The primary pressure in both Cases 3 and 4 increased slowly, allowing the condensation problem in the pressurizer to appear. This problem, evident in Fig. 22, is discussed in Sec. V.

Because there was no leakage from the primary in the initial stages of Case 3, the HPIS drove the primary pressure up to the PORV setpoint in 975 s. Figure 23 shows the PORV mass flow for Cases 3 and 4. Immediately after the PORV opened, the pressurizer became "water solid," so that the mass flow through this valve remained high. At the PORV opening pressure, the mass flow from the HPIS was higher than the PORV capacity so that the primary pressure continued to rise. The increased primary pressure reduced the HPIS flow so that a quasi-equilibrium condition was reached at approximately 1400 s, where the primary coolant system gains and losses have equilibrated.

Figure 24 presents the loop mass flows for Case 3 with the first 400 s of data excluded. The flow in the loop with the steam-line break was much smaller than the Loop-A flow where there was still primary-to-secondary heat transfer in the steam generators. Therefore, the coolant temperature for Loop B

TABLE V

CASES 3 AND 4 EVENT SEQUENCE

Event	Time (s) Case 3	Time (s) Case 4
MFW fails full open	0	0
Steam-generator B overfills	235	235
MSLB occurs	241	241
MFW shutdown starts	241	241
SGTR occurs	-	241
Reactor overpower trip	246	246
Turbine stop valves close	252	252
Auxiliary feedwater comes on	253	253
HPIS starts	265	265
Reactor coolant pumps turned off	270	270
Auxiliary feedwater off (steam generator level control)	775	775
Pressurizer fills	950	1400
PORV opens	975	1500
System equilibrium reached	1400	2000

continued to rise, whereas for Loop A it decreased as shown in Fig. 25. At ~775 s, the Loop-A steam-generator water level had reached its steady-state level so that the auxiliary feedwater was turned off. This is reflected in Figs. 24 and 25 by a drop in mass flow accompanied by the Loop-A coolant temperature increase.

The primary pressure in Case 4 rose more slowly because of the SGTR leakage. Figure 26 shows that the pressurizer filled at 1400 s, some 500 s slower than in Case 3. With the pressurizer filled, the system pressure rose much faster so that by 1500 s, the PORV opened. With the additional relieving capacity of the PORV, Case 4 also reached an equilibrium. Figure 27 gives a representation of this equilibrium by showing a summation of primary gains minus losses. Data for Case 3 and the MSLB base case are also included. The gain-minus-loss rate for Case 4 remains positive because of the continual

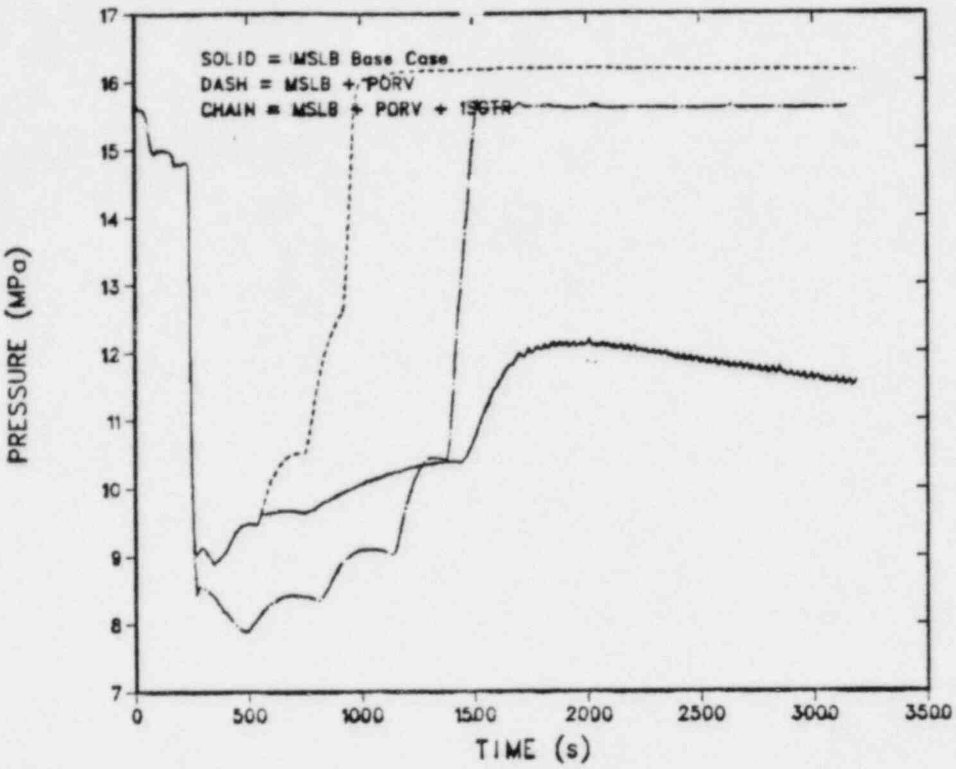

Fig. 22.
Cases 3 and 4, primary system pressure.

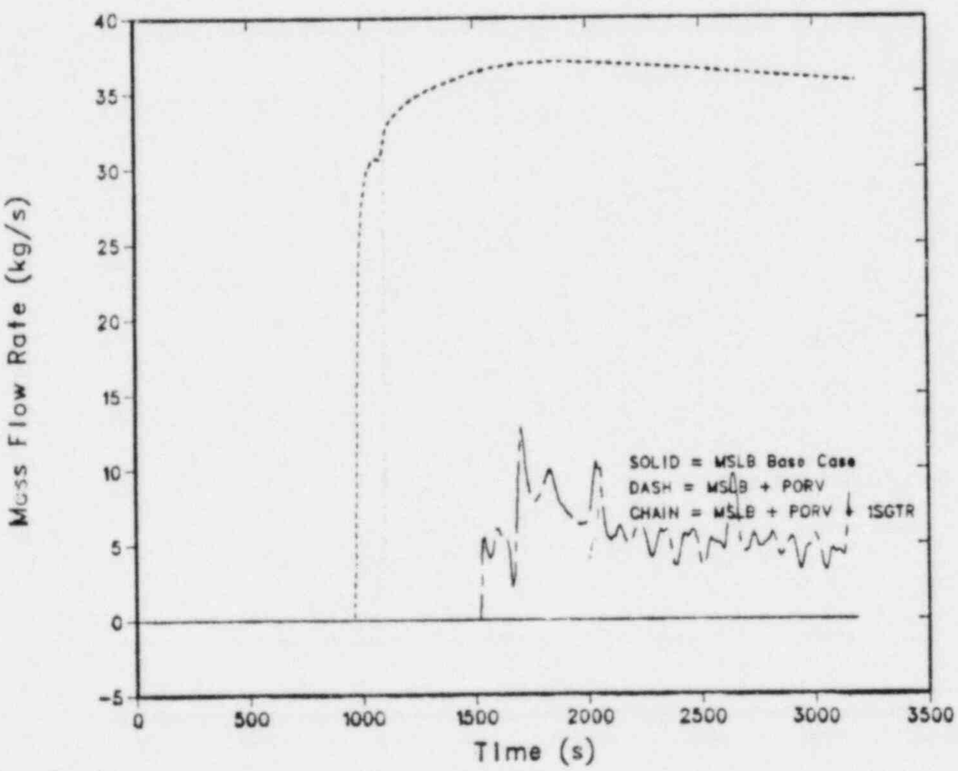

Fig. 23.
Cases 3 and 4, PORV mass flow.

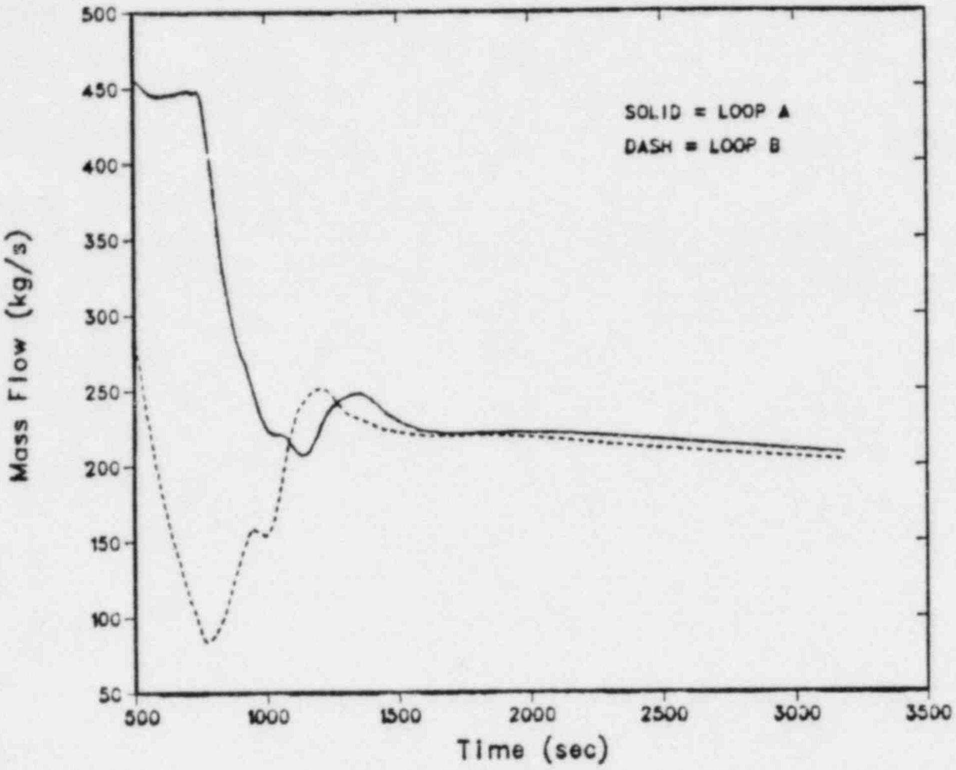

Fig. 24.
Case 3, Loops A and B mass flow (detail).

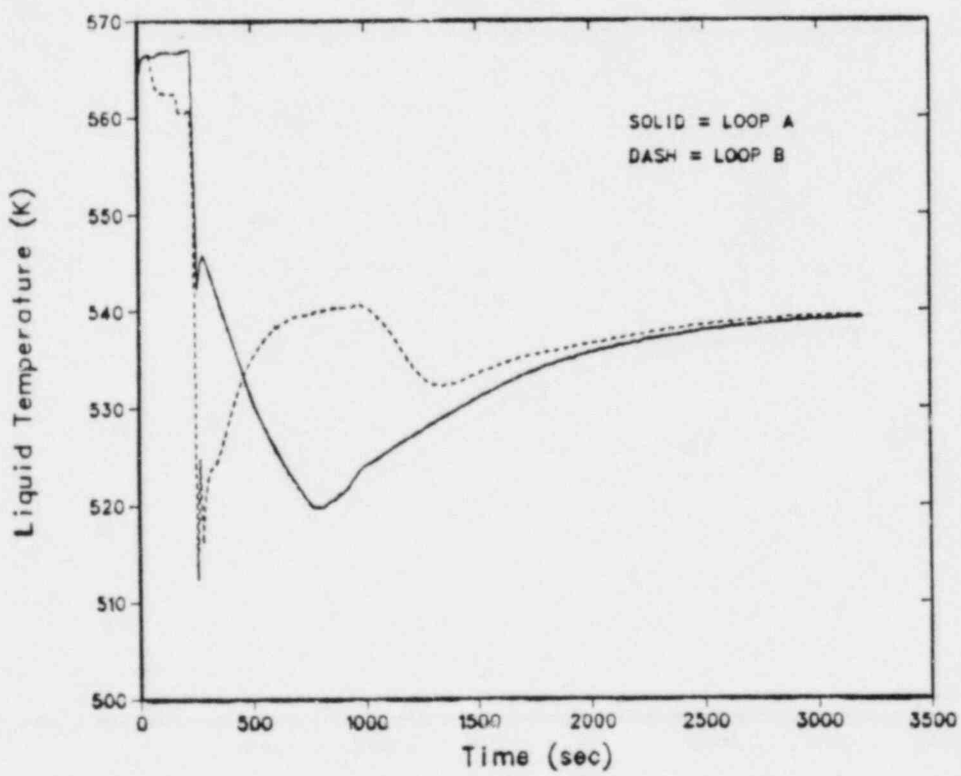

Fig. 25.
Case 3, Loops A and B cold-leg temperature.

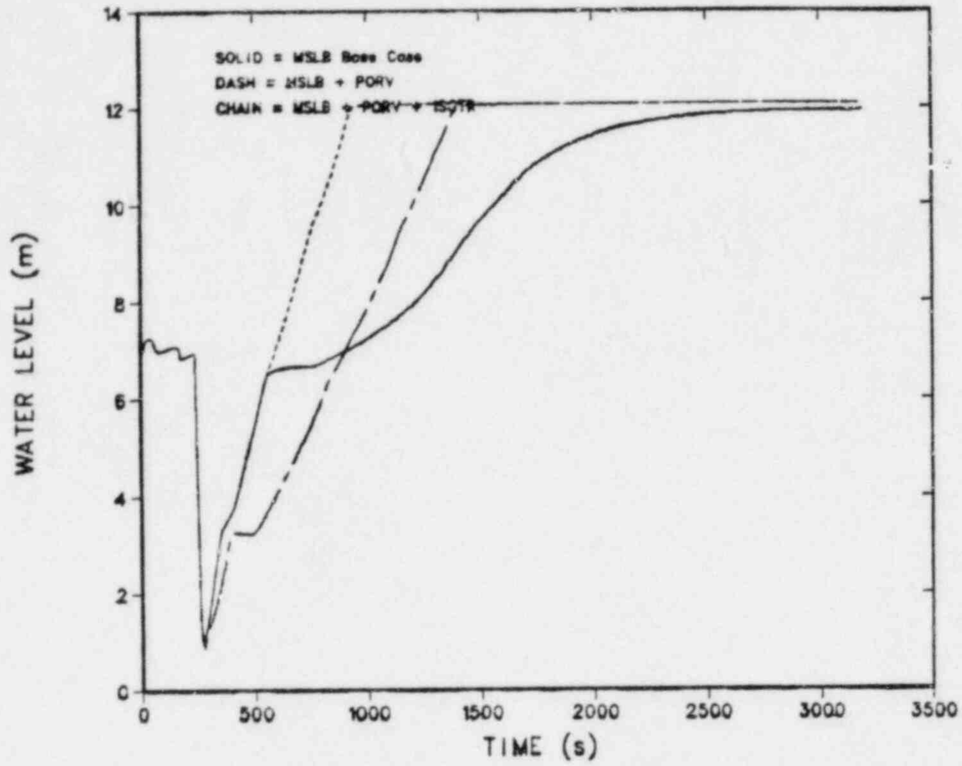

Fig. 26.
Cases 3 and 4 pressurizer water level.

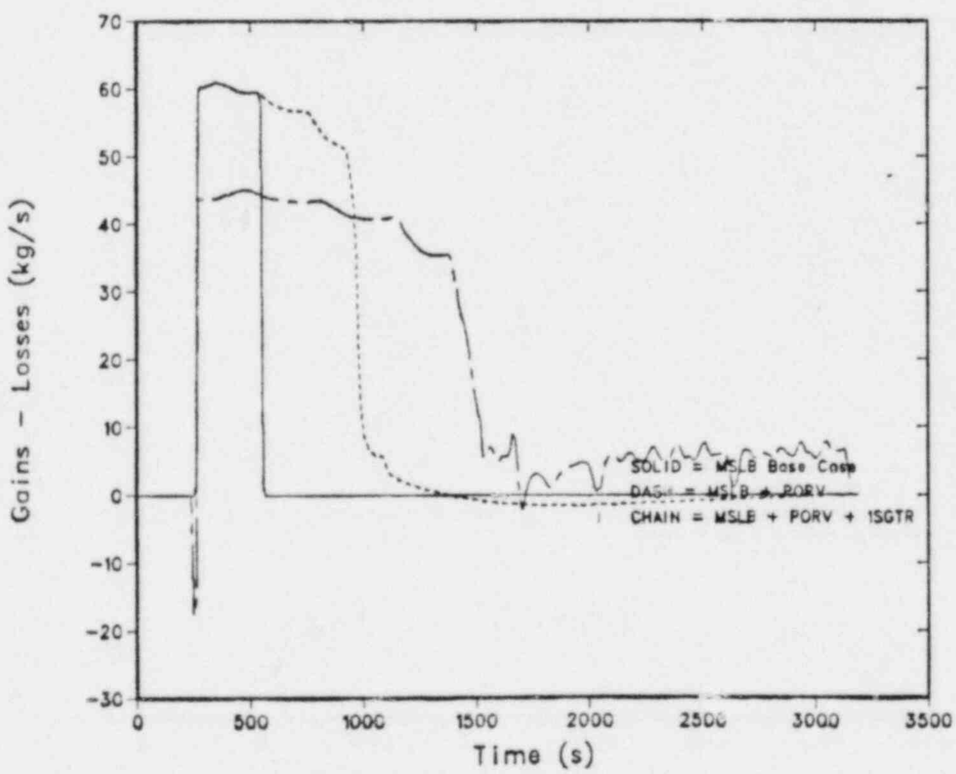

Fig. 27.
Cases 3 and 4, summation of primary gains minus losses.

cooling and contraction of the primary. The condensation problem discussed in Sec. V causes the wavering lines, seen in Fig. 27 between 300 and 1500 s, because the HPI flow was pressure dependent.

The flow reversals in the intact loop were also evident in Case 4 and are discussed in Sec. V. The loop mass flows in Case 4 were very similar to those in Case 2, which were presented in Fig. 16. Figure 28 gives a detailed view of the sum of the loop flows for Case 4. The initial 500 s is omitted from the plot to illustrate the flow reversals more clearly.

The vessel wall temperatures for Cases 3 and 4 are presented in Figs. 29 and 30. The reheating of the wall in Case 3 was due to the inability of the reduced HPIS flow to cool the primary. At about 1000 s, the HPIS flow was only 30 kg/s because of the high primary pressure.

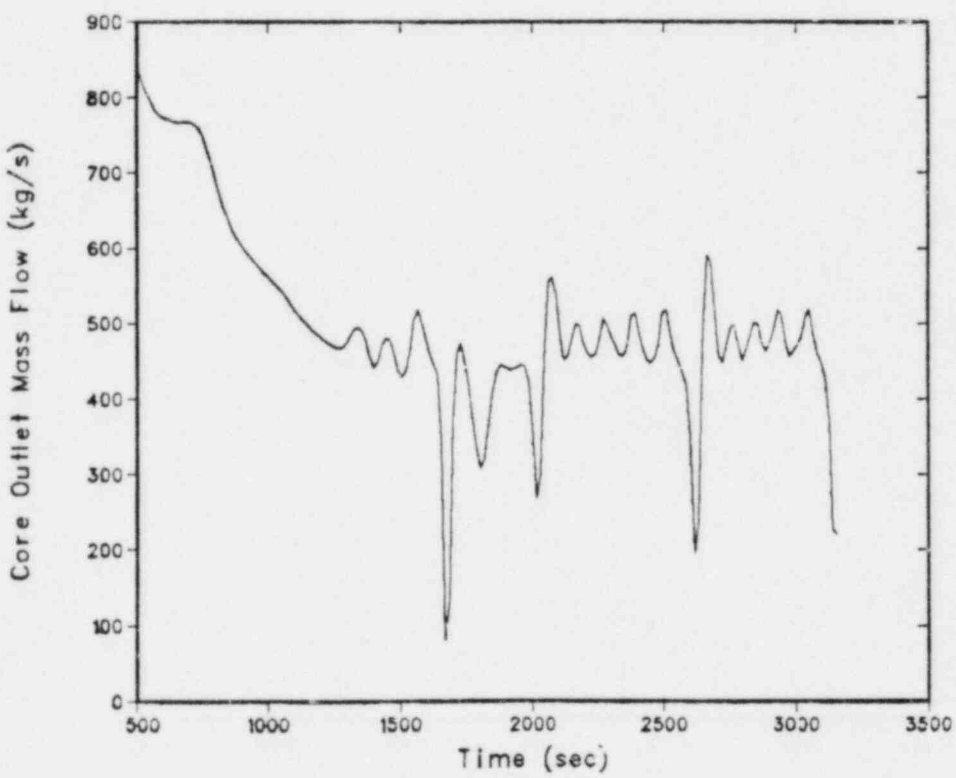

Fig. 28.
Case 4, core exit mass flow (detail).

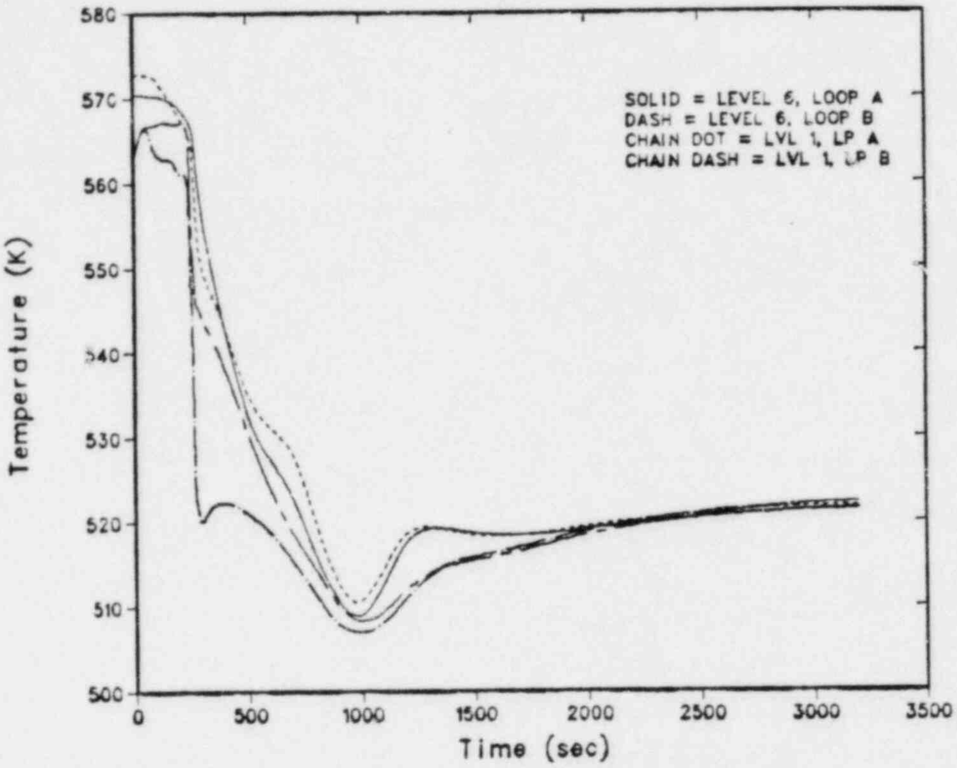

Fig. 29.
Case 3, vessel wall temperatures.

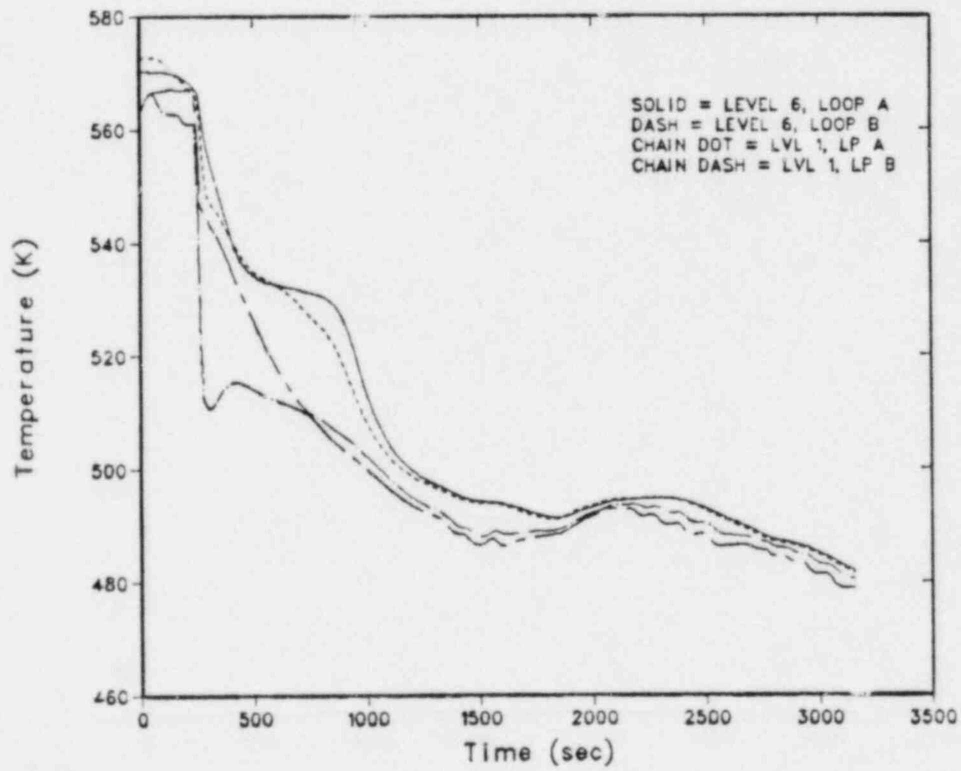

Fig. 30.
Case 4, vessel wall temperatures.

VII. THE STEAM-GENERATOR TUBE RUPTURE CASE

The SGTR case was the only calculation in this analysis that did not start from the SGOF and MSLB. The event sequence for the SGTR case is presented in Table VI, and the following list gives the controlling assumptions and boundary conditions used.

1. The complete rupture of a single steam-generator tube occurred 20 s into the transient. As in Cases 2 and 4, the rupture was assumed to occur at the top of the tube bundle.
2. The reactor was tripped on a low-primary-pressure signal (<13.1 MPa).
3. The turbine stop valves on both loops started closing 4 s after the reactor trip signal, and took 1 s to fully close.
4. The MFW (main feedwater) supply to both steam generators was shut off 20 s after the reactor trip. The MFW then took 14 s to coastdown as in the MSLB base case.
5. The auxiliary feedwater supply started as the MFW reached zero flow. The auxiliary feedwater was divided between the two steam generators with each receiving a maximum flow of 25 kg/s. The two auxiliary feedwater supplies were controlled on the steam generator secondary level so that they operated only if the secondary water level fell below the steady-state level.
6. The HPIS and reactor coolant pumps operated as in the MSLB base case.
7. The Loop-A secondary pressure relief was through the turbine bypass valve that opened at 7.2 MPa. For Loop B, the turbine bypass valve was not included in the model so that the atmospheric relief valve opened at 7.34 MPa to provide the pressure relief.

The system pressures for this calculation are presented in Fig. 31. The decreasing primary pressure was due to the SGTR leakage, and by ~450 s had reached the low-pressure-trip setpoint of the reactor. After the reactor tripped, the pressure fell more quickly as the primary cooled. The primary pressure started to recover when it reached the HPI setpoint (~490 s) and continued to rise until the HPIS was turned off. The pressure then fell because of the SGTR leakage until the HPIS started to cycle on and off as it maintained a constant pressurizer water level.

The secondary pressures (Fig. 31) rose as the turbine stop valves were closed until they reached the relief valve setpoints. Loop-A relief was from the turbine bypass valves and Loop B from the atmospheric relief valves. The

TABLE VI

SGTR EVENT SEQUENCE

Event	Time (s)
SGTR occurs	20
Reactor low-pressure trip	452
Turbine stop valves close	456
Turbine bypass valve first opens	460
Atmospheric relief valves open	470
MFW shutdown begins	472
Auxiliary feedwater starts	486
HPIS comes on	492
Reactor coolant pumps turned off	497
HPIS off, pressurizer level control	875

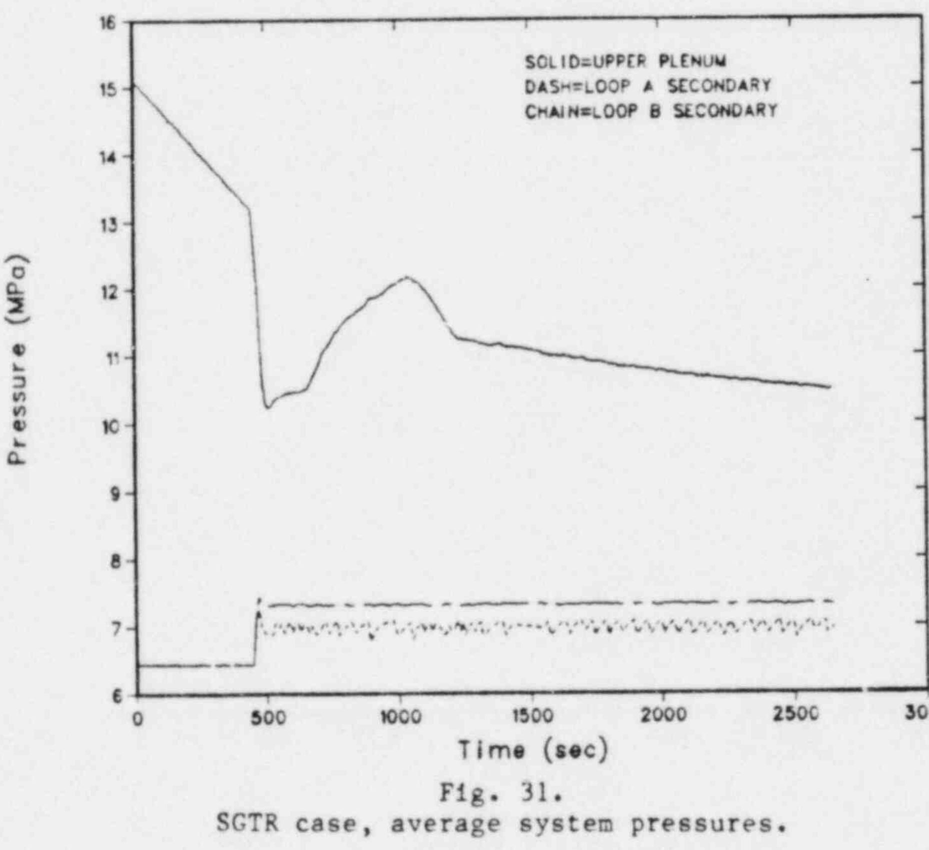

Fig. 31.
SGTR case, average system pressures.

atmospheric relief valves had a higher setpoint than the turbine bypass valves as can be seen in Fig. 31.

The vessel wall temperatures are shown in Fig. 32. The lower-plenum wall temperatures were strongly affected by the HPIS flow.

Figure 33 presents a plot of the primary and secondary temperatures in adjacent cells of the steam generator (primary cell 4, and secondary cell 3, see Fig. 3), depicting how the primary energy was transferred to the secondary. Figure 34 presents the same information for the Loop-B side. The Loop-B temperature plot is much smoother because the atmospheric relief valves have a higher relieving capacity than the turbine bypass valves of Loop A, therefore requiring fewer openings. Because of the lower setpoint of the turbine bypass valves, the Loop-A heat exchange occurred at a slightly lower temperature than in Loop B. This resulted in the loop flows shown in Fig. 35. (The first 600 s of data are omitted to gain more detail.)

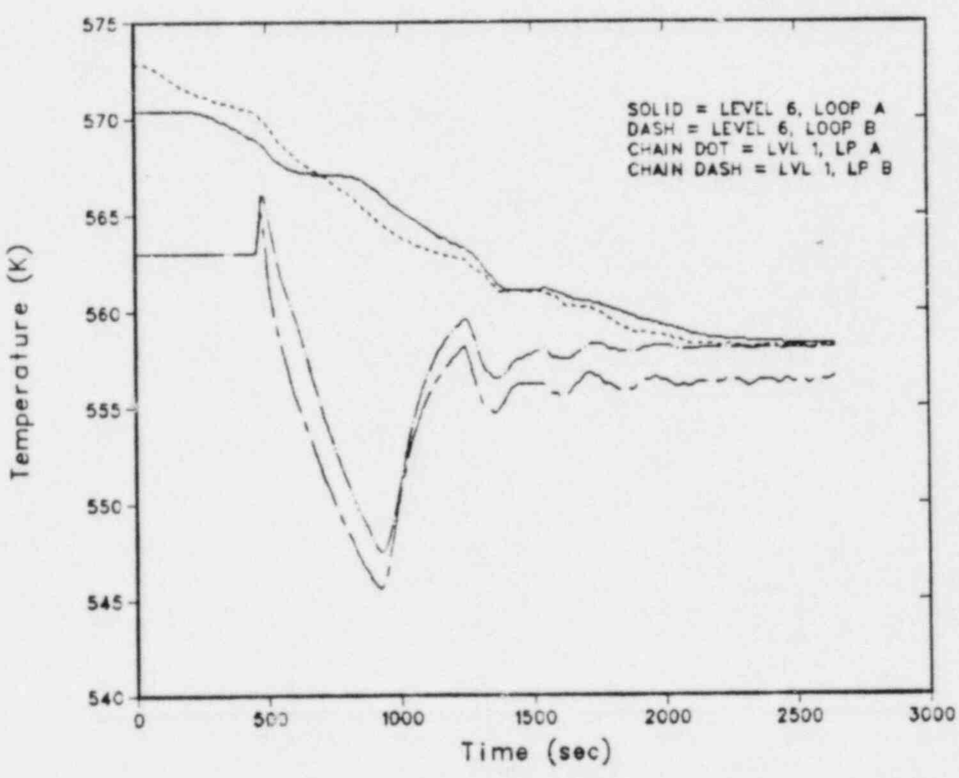

Fig. 32.
SGTR case, vessel wall temperatures.

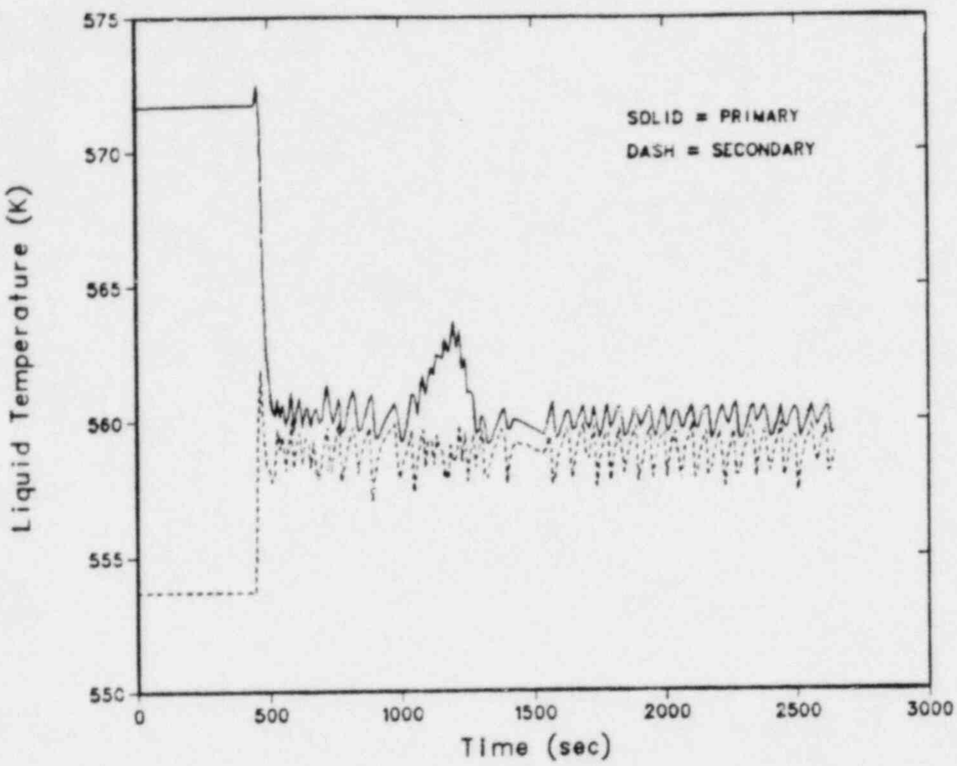

Fig. 33.
SGTR case, Loop-A steam generator temperatures.

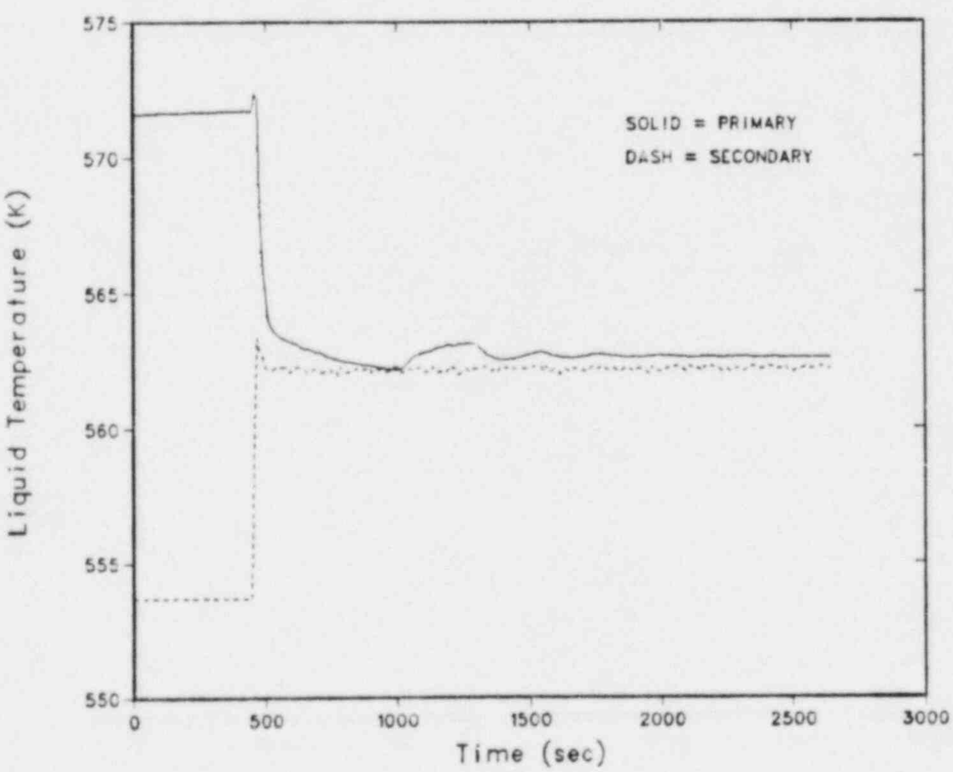

Fig. 34.
SGTR case, Loop-B steam generator temperatures.

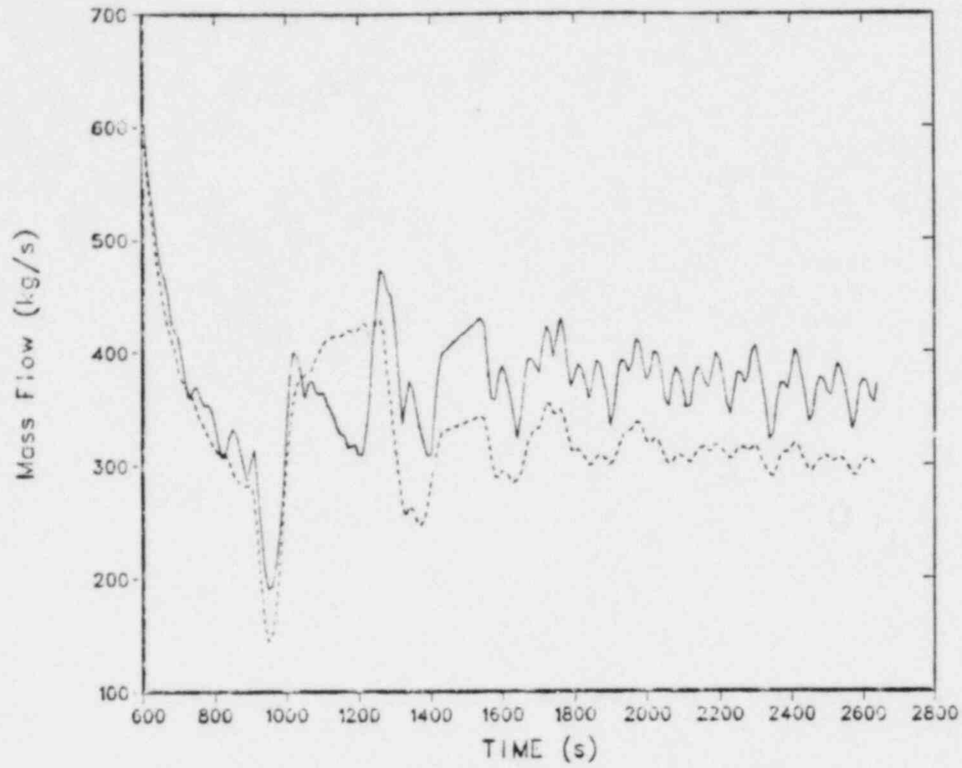

Fig. 35.
SGTR case, Loops A and B mass flows (detail).

Figure 36 gives the secondary water levels for the two steam generators. The Loop-B side initially dropped because of an increased secondary liquid entrainment that the code calculated with the addition of the SGTR leakage. After the reactor tripped, the secondaries started to fill because of the brief continuation of the MFW pumps and their coastdown. The SGTR leakage into the Loop-B secondary caused its level to remain high even though there was steam relief from the atmospheric relief valves. Therefore, the Loop-B auxiliary feedwater never came on. The Loop-A level dropped as steam relief occurred until the auxiliary feedwater came on at ~1200 s and maintained the level thereafter.

The sum of the HPIS flow minus the SGTR leakage is presented in Fig. 37. The dashed line at zero is added for convenience. There was a net leakage from the system until the HPIS came on, restoring the lost coolant. Then the HPIS was cycled on and off to maintain the pressurizer water level so that the net primary outflow remained near zero.

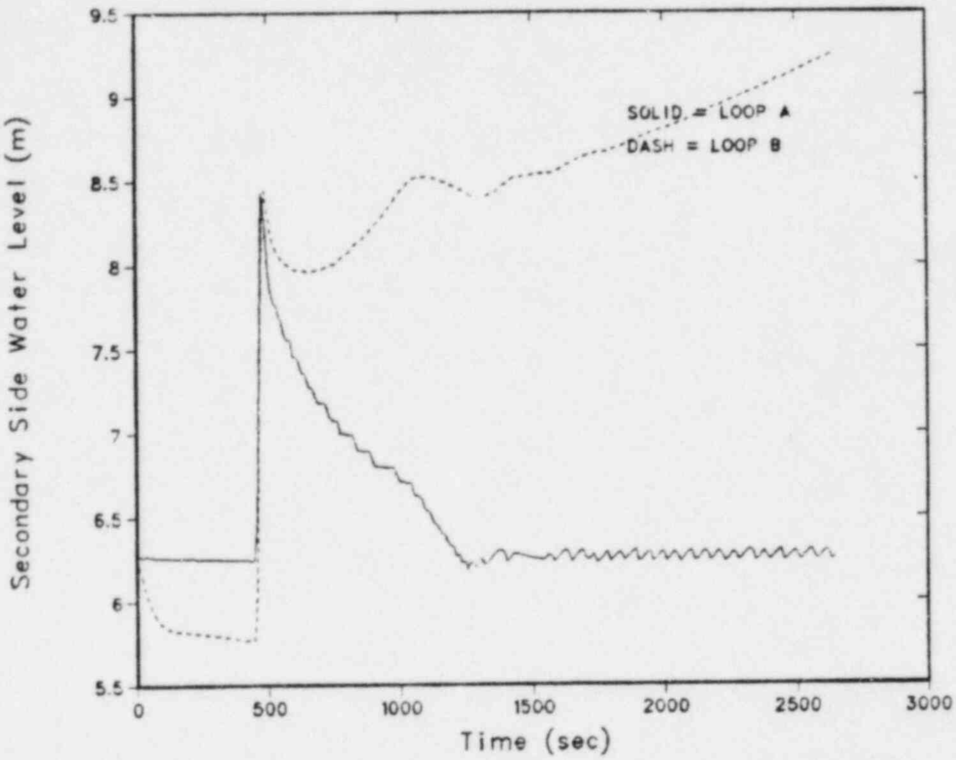

Fig. 36.
SGTR case, Loops A and B steam-generator water level.

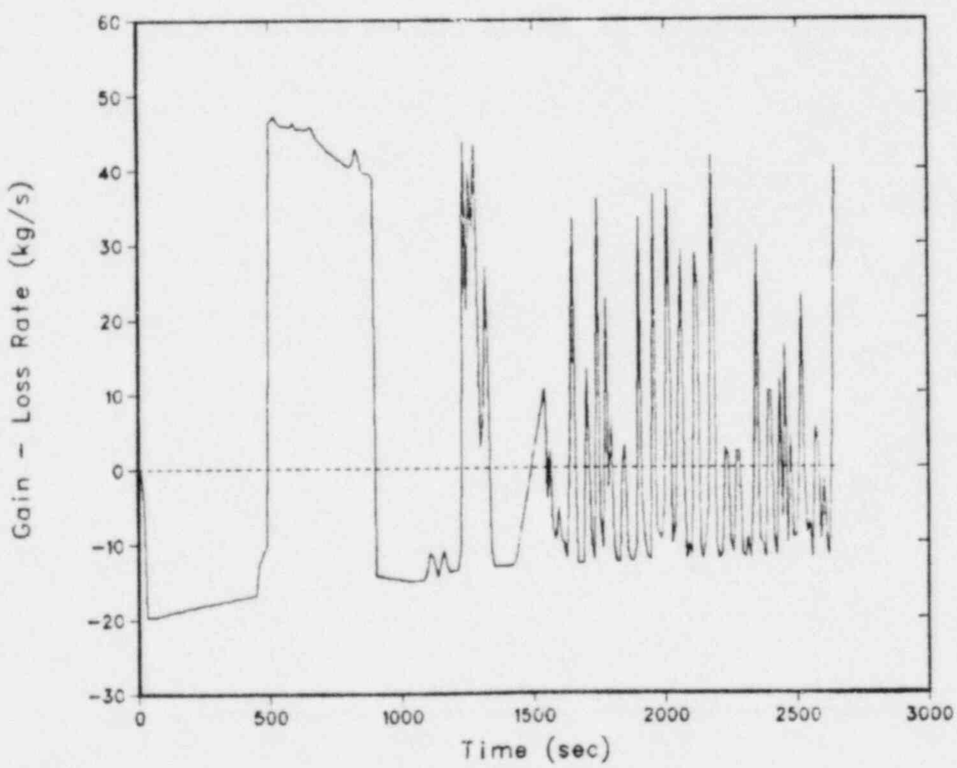

Fig. 37.
SGTR case, summation of primary gains minus losses.

VIII. CONCLUSIONS

The HPIS provided adequate make-up coolant flow in all of these calculations. The core was not uncovered and the primary pressure did not decrease enough for accumulator injection in any of the cases. The upper plenum voided slightly following the MSLB, but recovered within ~100 s for all transients except Case 2. Small voids remained in the upper plenum for Case 2 because of the larger primary leakages in this transient.

The condensation problem described in Sec. V gives some uncertainty in the calculations as to the timing of repressurization. Because the HPIS flow was pressure dependent, the changing repressurization rate with changing condensation rate in the pressurizer allows a feedback to occur so that the pressurizer water level could be affected. The final filling of the pressurizer is an important event in the pressure history of the primary in transients of this kind. These problems may have changed the timing of the transients, but the qualitative results should not be affected.

If calculations are to be performed that require accurate response of the secondary system, and in particular the primary/secondary coupling, a better steam generator model must be used. As shown in Section II, the primary is not nearly sensitive enough to changes in the secondary while still at high power.

The determination of the nature of a power plant transient from the control-room instrumentation can be a difficult task. The "accident signature" of the MSLB can clearly be seen by the rapid system pressure drops of both the primary and secondary. These pressure drops, coupled with steam generator dry-out, as indicated by the secondary water level, will identify the MSLB.

Because of the severity of the MSLB, other failures during the same transient will not be easy to distinguish. If a primary leakage of some kind has occurred, it will require the HPIS to remain on more than for a MSLB alone, and the primary pressure will not recover as quickly. The additional HPIS injection will cool the primary so that heat transfer to the intact secondary will be reduced. No clear signature of a PSF may be apparent, although heatup and failure of the reactor coolant pumps would indicate possible primary leakage through these seals. The SGTR will also be masked by the MSLB. An indication that it has occurred will be in the small but continuing mass flow of the broken loop, and in a continual loss of primary coolant.

The transient with only a SGTR will be easier to see. A slowly declining primary pressure, followed by a rising steam-generator water level, is characteristic of the SGTR.

The parameter histories of a calculation, such as those presented in this analysis, could be used to investigate an operator's ability to determine system failures from control room information.

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2. Safety Code Development Group, "TRAC-PD2, An Advanced Best-Estimate Computer Program for Pressurized Water Reactor Loss-of-Coolant Accident Analysis", Los Alamos National Laboratory report LA-8709-MS (May 1981).

3. J. C. Lee, et al., "Transient Modeling of Steam Generator Units in Nuclear Power Plants: Computer Code, TRANSG-01", EPRI NP-1368, Electric Power Research Institute (March 1980).

4. "Three Mile Island Final Safety Analysis Report", Metropolitan Edison Co. (March 1970).

APPENDIX

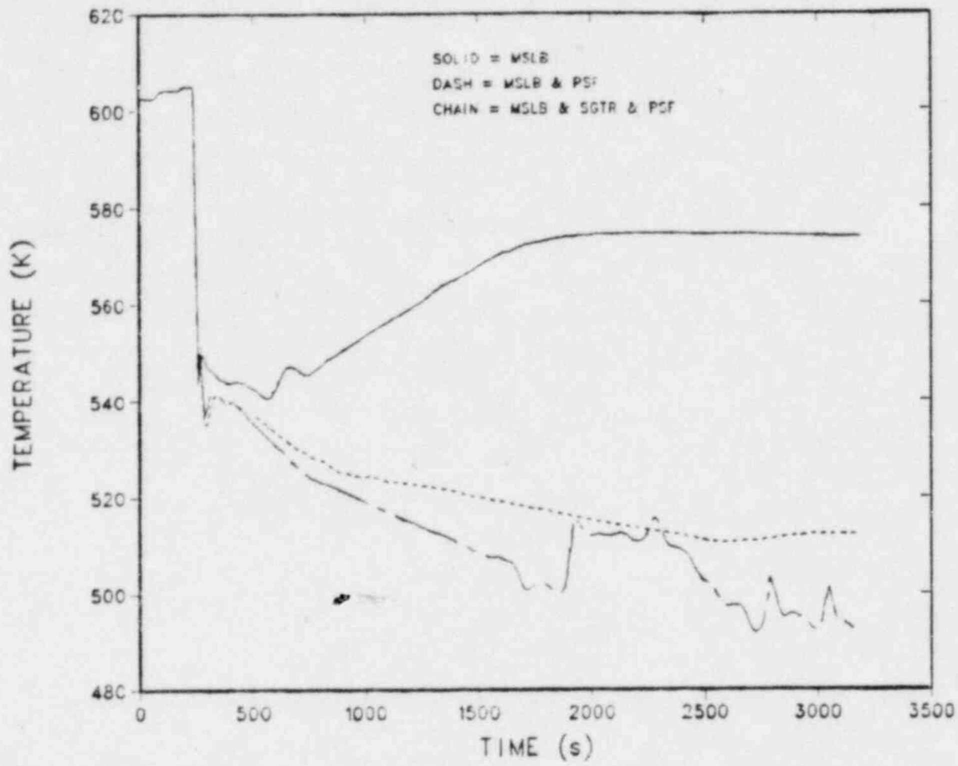

Fig. A1.
MSLB, Cases 1 and 2 average rod temperature.

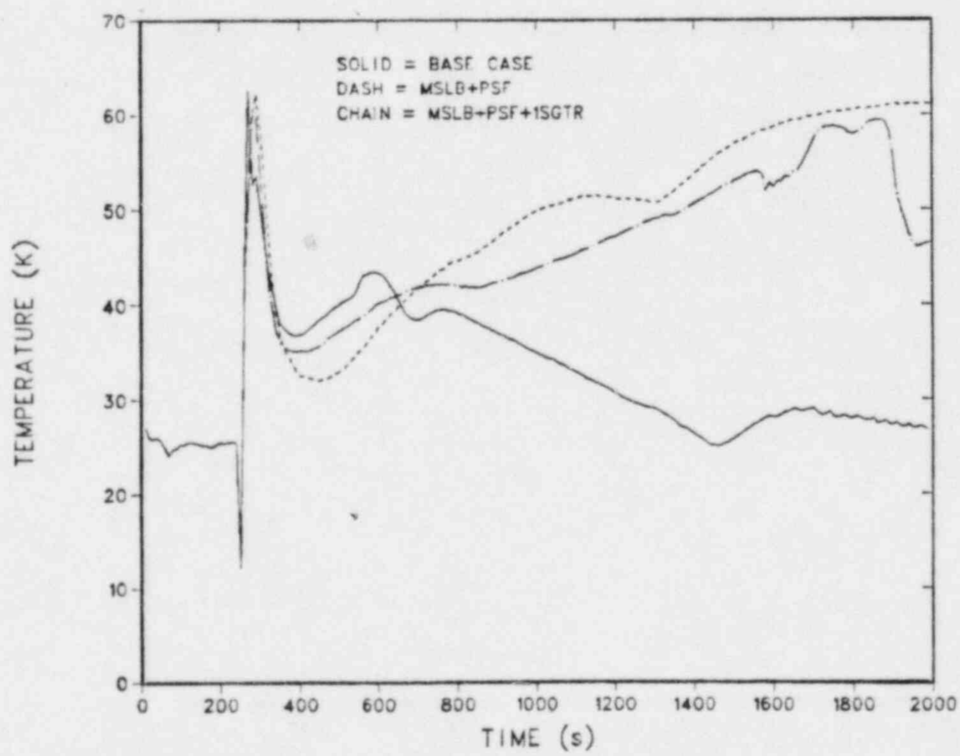

Fig. A2.
MSLB, Cases 1 and 2 hot-leg subcooling margin.

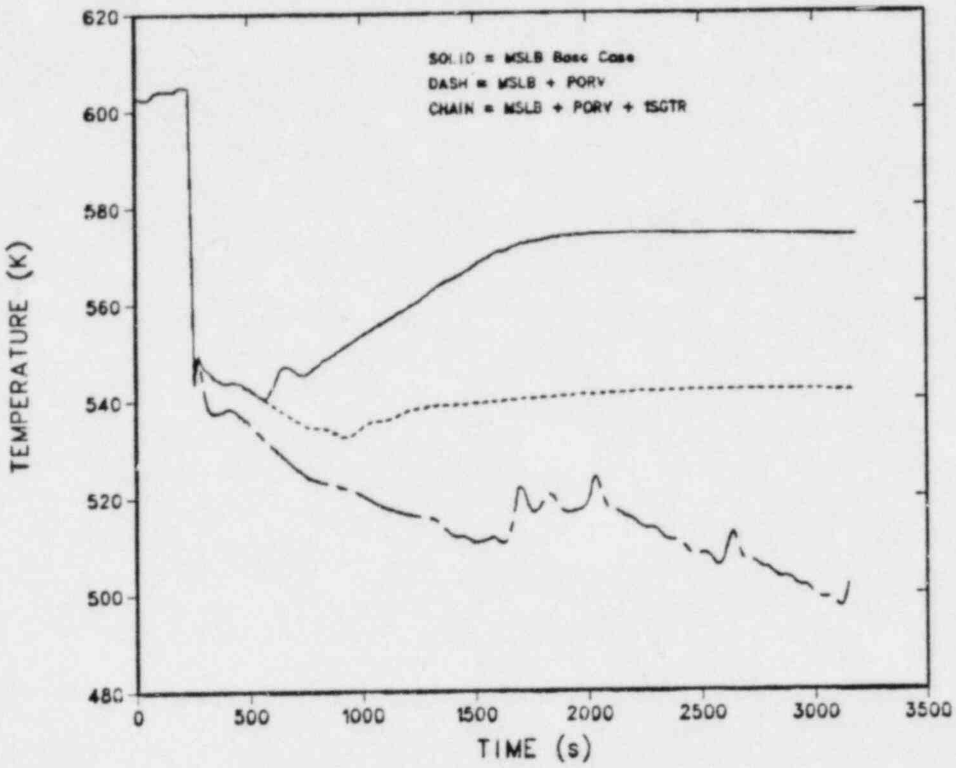

Fig. A3.
MSLB, Cases 3 and 4 average rod temperature.

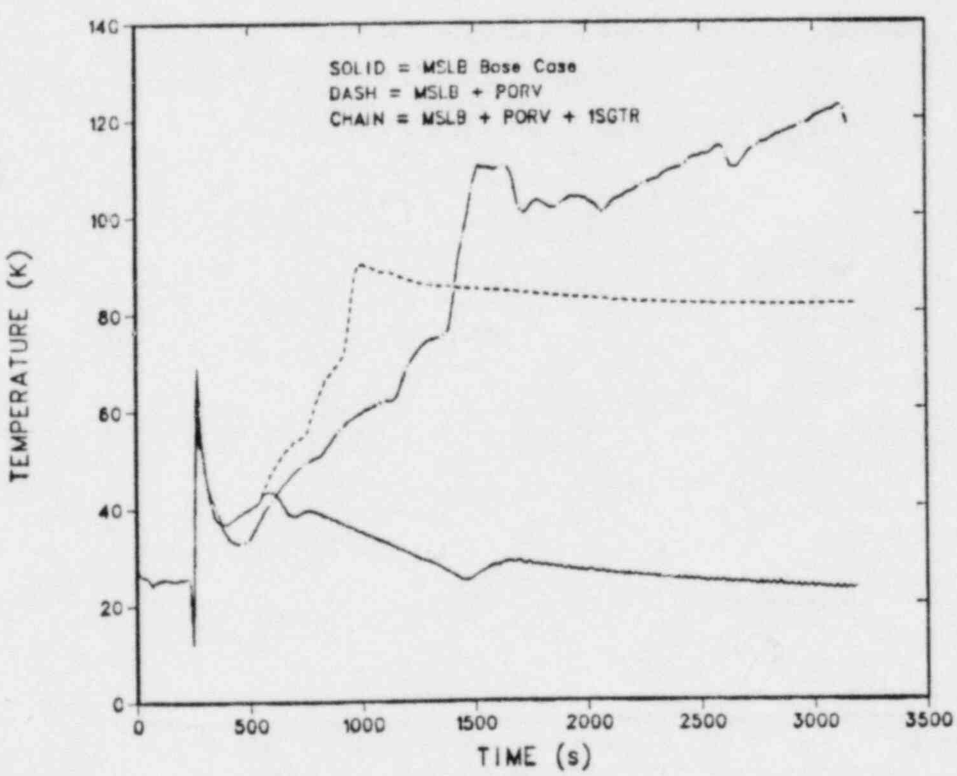

Fig. A4.
MSLB, Cases 3 and 4 hot-leg subcooling margin.

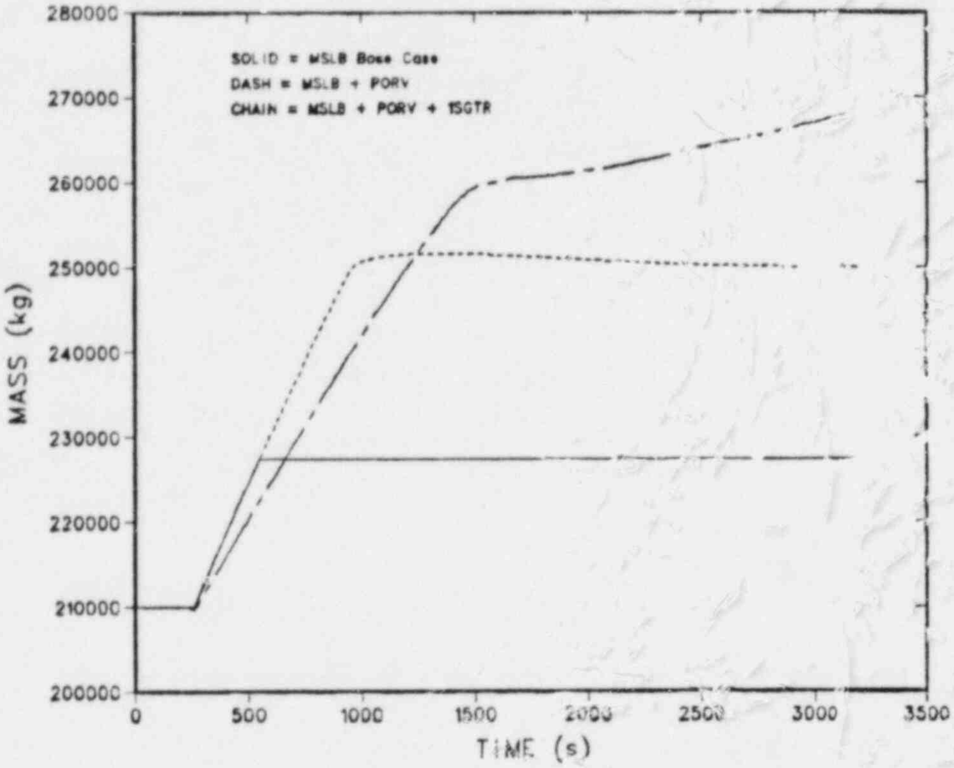

Fig. A5.
MSLB, Cases 3 and 4 primary system mass.

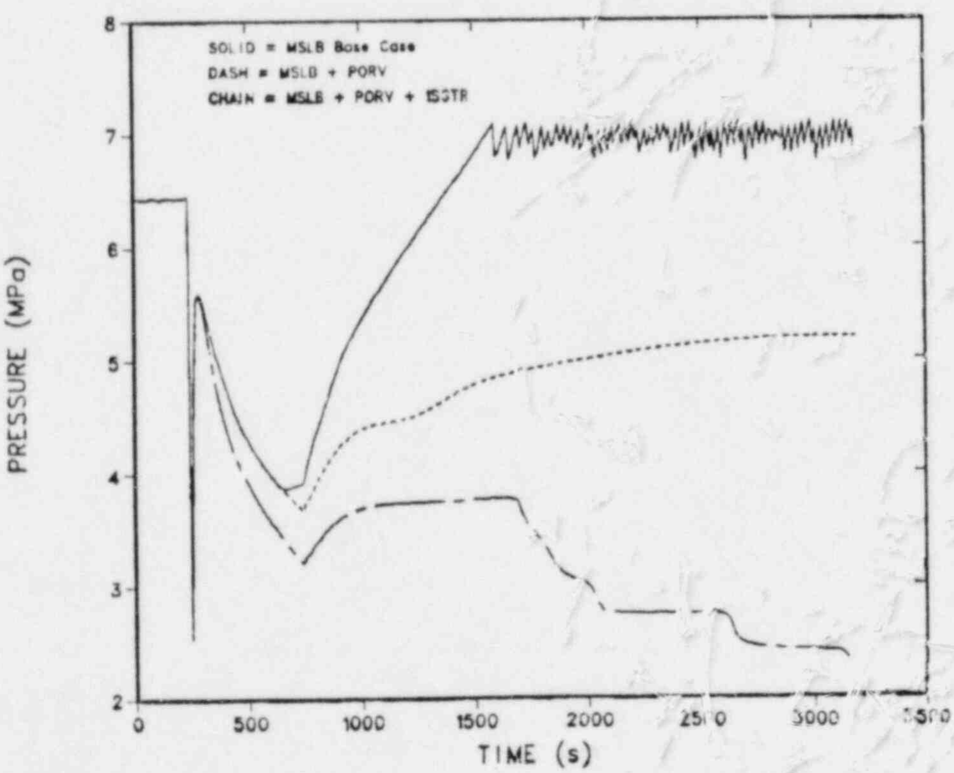

Fig. A6.
MSLB, Cases 3 and 4 intact secondary pressure.

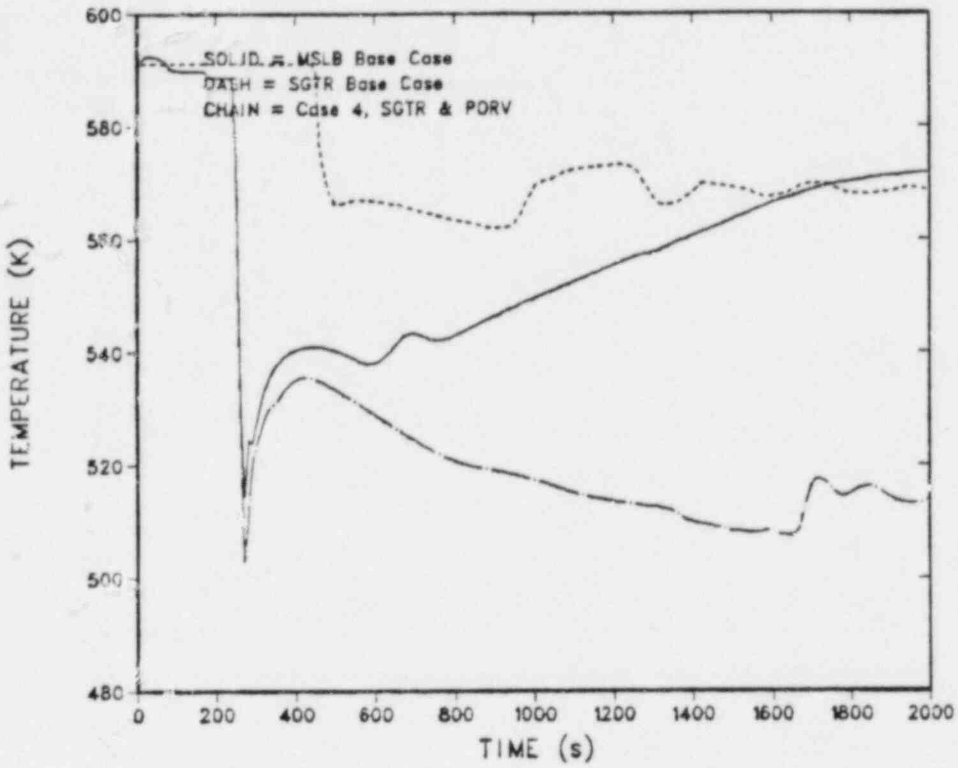

Fig. A7.
MSLB, SGTR, and Case 4 hot-leg temperature.

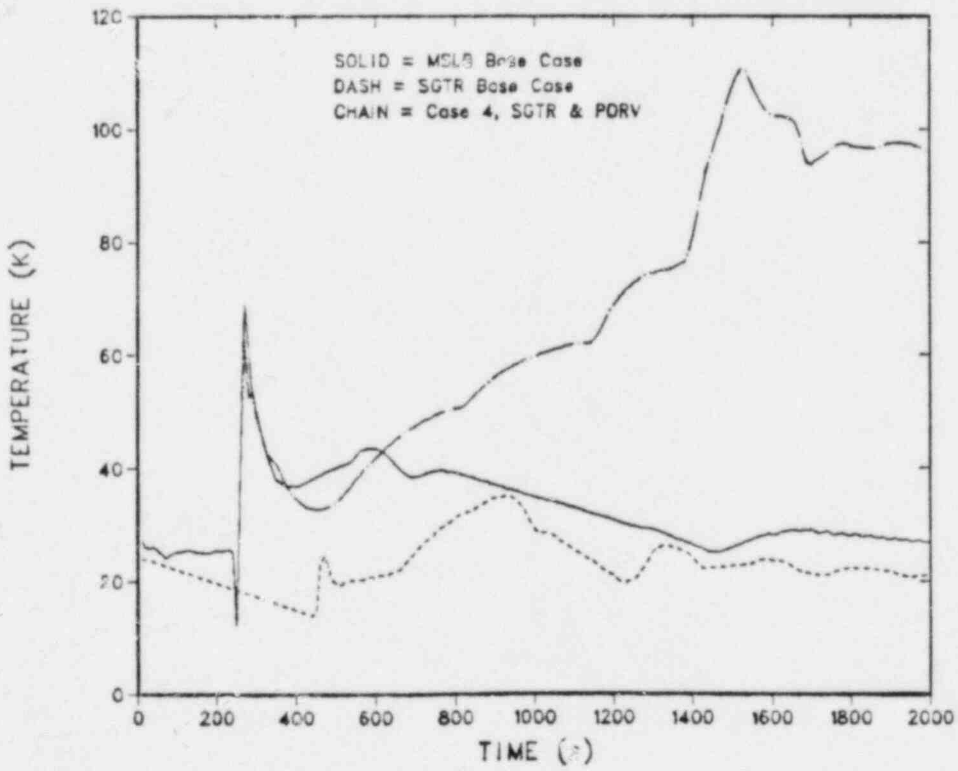

Fig. A8.
MSLB, SGTR, and Case 4 hot-leg subcooling margin.

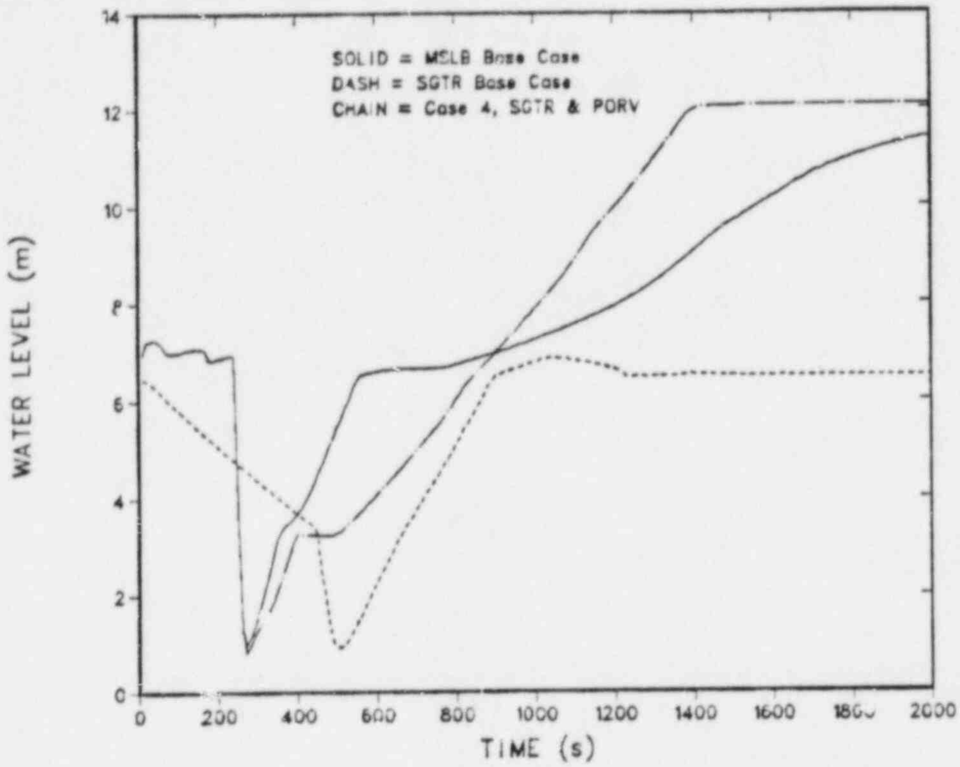

Fig. A9.
MSLB, SGTR, and Case 4 pressurizer water level.

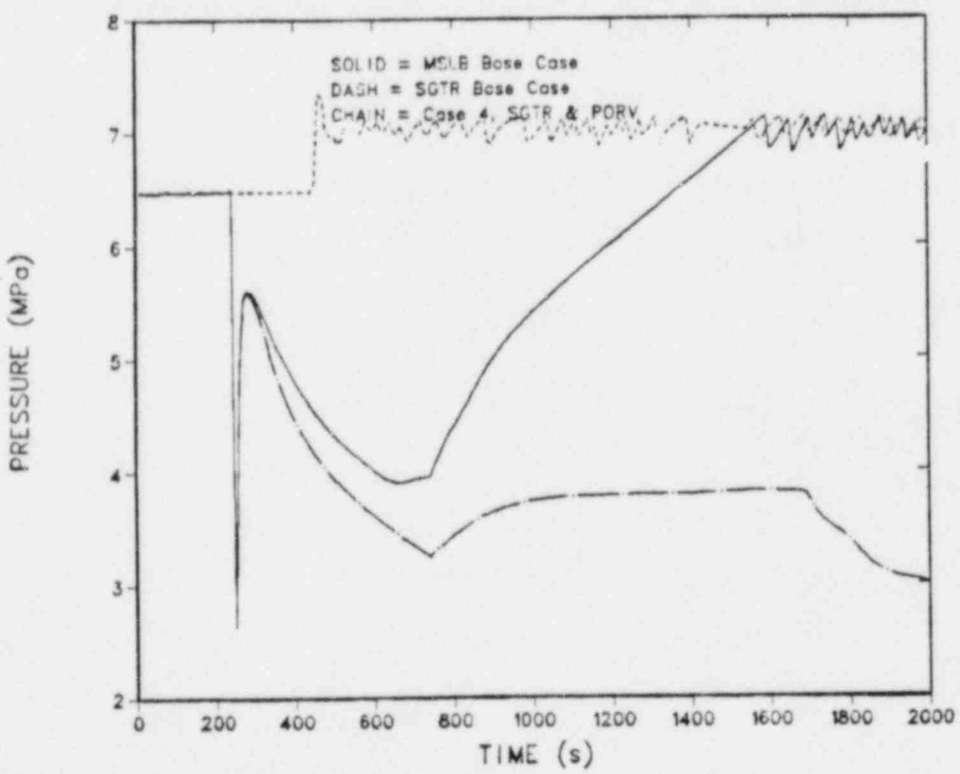

Fig. A10.
MSLB, SGTR, and Case 4 intact secondary pressure.