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ANL/LWR/NRC 83-7
July 1983

Decay Heat Removal During a Steam Generator Tube Rupture Event for a C-E System 80 Plant

M. F. Kennedy
H. Komoriya

Light Water Reactor Systems Analysis Section
Reactor Analysis & Safety Division
ARGONNE NATIONAL LABORATORY
9700 South Cass Avenue
Argonne, Illinois 60439

Prepared for:
Division of Systems Integration
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

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1. INTRODUCTION

This report documents the results of a series of calculations which were performed to investigate the relative effectiveness of the auxiliary pressurizer spray system when compared to the proposed addition of pilot operated relief valves (PORVs) on the pressurizer in mitigating the consequences of a steam generator tube rupture accident. The auxiliary pressurizer spray (APS) system is currently incorporated in the Combustion Engineering (C-E) pressurized water reactor nuclear steam supply system designs to allow for pressurizer spray flow in the event that the normal spray system is not available because the reactor coolant system pumps are not running. However, the current C-E System 80 plant designs do not have any PORVs on the primary reactor coolant system. The U.S. Nuclear Regulatory Commission (NRC) has asked C-E to provide justification as to why PORVs should not be required on the System 80 plants. Argonne National Laboratory, under contract to the Reactor Systems Branch of the NRC, performed the calculations discussed in this report to support the NRC evaluation of the C-E response. This report focuses on the steam generator tube rupture transient; a companion report [1] investigated the relative merits of the APS system versus the addition of PORVs in mitigating the potential consequences of a total loss of feedwater (both main and auxiliary) flow transient.

The initiating transient in this study is a single double ended guillotine rupture of a steam generator tube in either one (single SGTR event) or both (dual SGTR event) steam generators. The accident scenario for the initiating transient is the steam generator tube rupture accident discussed in Section 15.6.3 of the CESSAR Final Safety Analysis Report [2]. Unlike the FSAR case, the initial conditions for the calculations performed for this study were consistent with the 100% power nominal design conditions provided in the FSAR. Following a 10 minute delay after reactor trip, the operator was assumed to take control of the plant; the operator actions which were assumed are consistent with the steam generator tube rupture recovery guidelines presented in Reference [3].

The calculations were performed with RELAP5/MOD1.5 (ZELAP); the cycle 31 version was used for all of the calculations.

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A description of the plant model for the RELAP5 calculations is presented in Chapter 2. This chapter also includes a discussion of the resulting steady state solution which was obtained with RELAP5 for the 100% power nominal design conditions. The accident scenario assumptions and expected operator recovery actions are discussed in Chapter 3; this chapter also includes a discussion of the matrix of cases considered in this study. Chapter 4 contains the results of the transient calculations, and the overall conclusions for the study are presented in Chapter 5.

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2. PLANT INPUT MODEL

The RELAP5/MOD1 (cycle 18) input deck developed for the CESSAR feedwater line break audit calculation [4] was modified and reinitialized to run on RELAP5/MOD1.5 (cycle 31). The plant nodalization is shown in Fig. 1. A few changes from the feedwater line break audit calculation input model were made to increase the minimum Courant number and thereby increase the minimum time step which decreased the computing time for the transient calculations. Thermal hydraulic volumes which were not needed for the SGTR calculations were eliminated from the original feedwater line break accident calculation input model and some of the noding detail was reduced.

The computer code RELAP5/MOD1.5 was used in the analysis. One significant change between RELAP5/MOD1.5 (cy=31) and RELAP5/MOD1 (cy=18) which was used for the feedwater line break audit calculation is that the RELAP5/1.5 (cycle 31) has an option which can be utilized to adjust the junction void factor of the flow recirculated to the downcomer by the separator. By specifying the void limit of separator junction flow (0 to 1.0), the user can select the quality and flowrate of recirculation flow and tube sheet flow.

A steady-state initial solution was achieved with RELAP5 for nominal 100% rated power plant conditions. The major thermal-hydraulic plant parameters achieved from the steady-state calculation are compared to the plant nominal values in Table 1 (data taken from the CESSAR FSAR). A stable solution was established within 40 seconds after the initiation of the null transient calculation. All of the SGTR accident calculations were initiated following a 100 second null transient.

During some preliminary calculations, the RELAP5 results exhibited some significant mass error accumulation once the primary system reached saturation conditions. Initially the mass error was reduced by decreasing the maximum time step to 0.01 s when the hot legs begin to void. However, since the calculations were intended to be carried out for at least 1 hour of transient time, this time step would be very restrictive. The RELAP5 code developers provided some code updates which drastically reduced the mass error [5].

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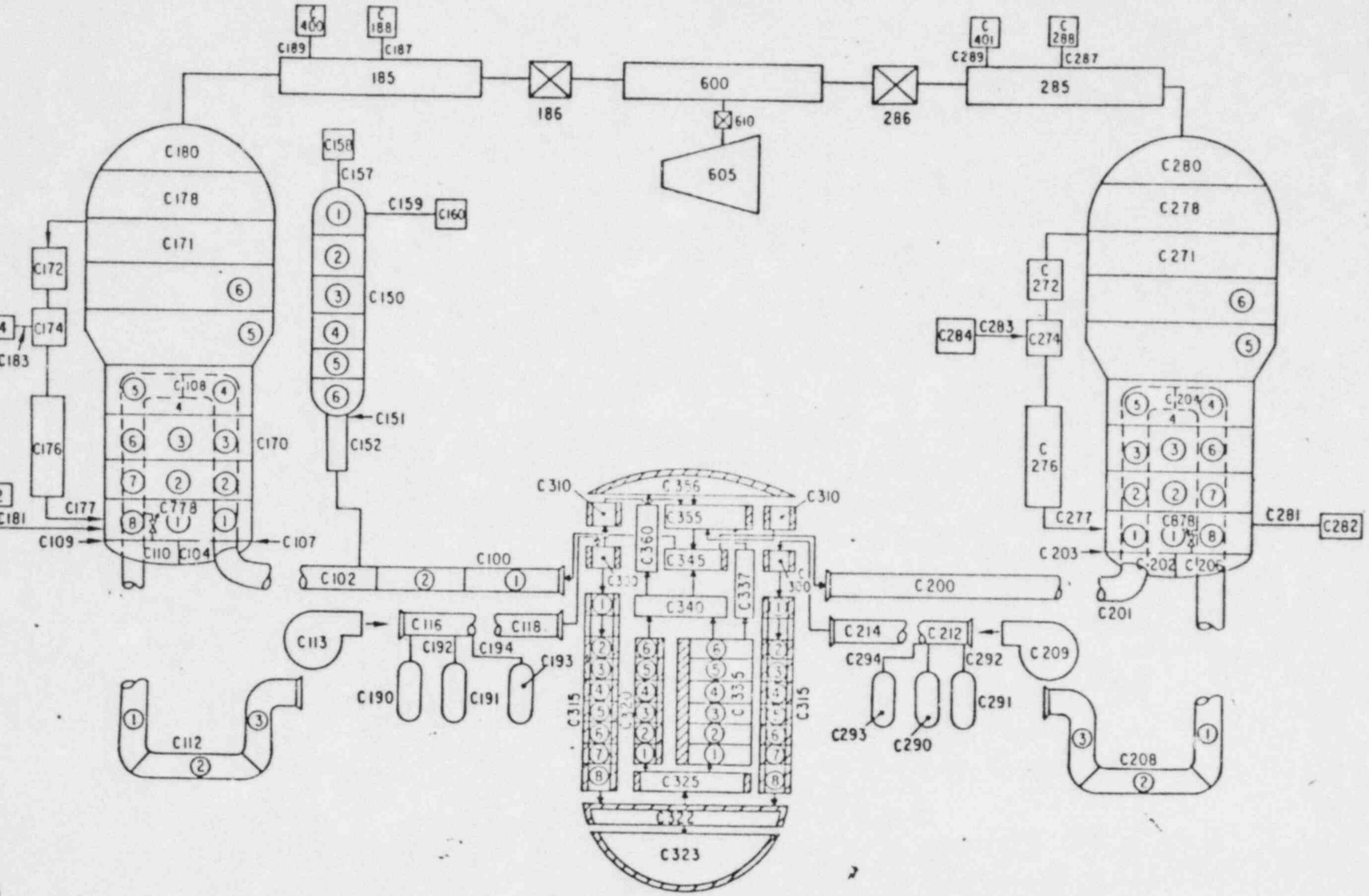

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FIG. 1.

Table 1. CESSAR NSSS Component Thermal and Hydraulic Parameters

Component	Plant Nominal Conditions	Steady State Initial Conditions
Reactor Vessel		
Rated core thermal power, MWt	3,800	3,800
Operating pressure, lb/in.^{2}a	2,250	2,250
Coolant outlet temperature, °F	621.2	621.8
Coolant inlet temperature, °F	564.5	565.9
Coolant outlet state	Subcooled	Subcooled
Total coolant flow, 10^6 lb/hr	164	164
Core average coolant enthalpy		
Inlet, Btu/lb	565	565
Outlet, Btu/lb	645	645
Average coolant density		
Inlet, lb/ft^3	45.9	45.8
Outlet, lb/ft^3	41.2	41.1
Upper head recirc. path flowrate, lb/s	319.4	315
Steam Generators		
Number of units	2	2
Primary Side (tube side)		
Inlet temperature, °F	621.2	621.8
Outlet temperature, °F	564.5	565.4
Secondary (shell side)		
Steam pressure/temperature, psia/°F	1070/552.8	1070/552.8
Steam flow per gen., lb/hr	8.59×10^6	8.59×10^6
Exit steam quality, %	99.75	99.43
Feedwater temperature, °F	450	450
Recirc. Ratio	3.25	3.28
Pressurizer		
Operating pressure, psia	2,250	2,250
Operating temperature, °F	653	653
Net internal fluid volume, ft^3	1,800	1,800
Installed heater capacity, kW	1,800	1,800

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Using these updates a maximum time step of 0.05 s was used when the primary system was voiding and the mass error did not exceed 0.2%. These updates were subsequently incorporated by the code developers into Cycle 31 of RELAP5/MOD1.5 which was used for all the final calculations performed for this study.

A number of plant features were incorporated into the RELAP5 plant model for this study. These plant features include plant component subsystems such as the auxiliary pressurizer spray, high pressure safety injection, charging, main feedwater and auxiliary feedwater systems. Also various primary and secondary side valves were modeled, including the proposed power operated relief valve on the pressurizer, the pressurizer and steam generator safety valves, main steam isolation valves, and the steam generator atmospheric dump valves. Plant trip functions to scram the reactor on low pressurizer pressure and to close the turbine stop valves were also modeled. All of these models are discussed in more detail in this succeeding paragraphs, including where necessary a discussion of how they were implemented in the RELAP5 plant model.

For the high pressure safety injection system (HPSI), only one delivery train was assumed to be available. The HPSI flow was obtained from Reference [6] and was implemented in the code as a flow versus pressure fill table. Injection of HPSI flow was actuated on a low pressurizer pressure signal at 1600 psia; there was a 30 s delay before safety injection flow was provided to the cold legs to account for the time delay to load the HPSI pumps onto the emergency diesel generators. This action occurs automatically; however, once the operator has taken control of the plant the HPSI flow can be throttled to control inventory and subcooling margin. In these calculations, the HPSI flow was assumed to be on (delivering flow as a function of downstream pressure) or off depending on the following criteria: off, if the subcooling is greater than 20°F in the hot legs and the pressurizer collapsed liquid level is greater than 100 inches and increasing; or, on otherwise.

The charging (makeup) system was assumed to deliver the full three charging pump capacity to the system which is 18.27 lb/s. In this study, the charging system was assumed to begin delivering full flow at the initiation of the break and continued until the calculations were terminated. The flow is

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split equally between the two loops. When the auxiliary pressurizer spray system is activated, the full charging system flowrate is diverted to the top of the pressurizer and is sprayed into the pressurizer steam space. The APS system is also turned off (and the flow diverted back to the cold legs) if the pressurizer collapsed liquid level exceeds 90% of the full range level. The charging system water was assumed to be at 120°F.

Both the main and auxiliary feedwater systems were modeled in the calculations as fill tables; the main feedwater was injected directly into the lower tube bundle region, and the auxiliary feedwater was injected into the upper region of the downcomer. The System 80 steam generators have integral economizers to pre-heat the feedwater but they were not modeled. Following turbine trip, the main feedwater flowrate was ramped to zero. The auxiliary feedwater system was activated when the collapsed liquid level in the steam generator downcomer decreased below 19.75 ft. The feedwater control system will try to maintain the downcomer level at or above this level. A delay time of 35 s was assumed the first time the system was activated to account for the loss of offsite power when the turbine is tripped. The auxiliary feedwater system delivers ~ 121 lb/s of 100°F water to each steam generator. When the operator isolates the ruptured steam generator, the auxiliary feedwater to that steam generator is terminated.

Main steam line safety valves and atmospheric dump valves were modeled for each steam generator. The main steam line safety valves were modeled as trip valves in RELAP5 with a flow versus pressure table. There are 3 banks of valves (2, 2, and 6 valves in each bank) on each loop. The banks of valves open sequentially at 1270, 1305 and 1333 psia with a total minimum relief capacity for the 20 valves of 19 x 10^6 lb/hr.

The atmospheric dump valves are used to relieve steam from the steam generators when the condenser is not available. These valves are used to reduce the primary system temperature following a reactor trip with a loss of offsite power and can be controlled by the operator to limit the cooldown rate to within prescribed limits. In the RELAP5 calculations, these valves were modeled as motor valves, and the valve area was sized to provide the design flow of 950,000 lb/hr at 1000 psia. The motor valves were controlled by a

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signal based on the rate of change of the average temperature on the primary system. When the average temperature was changing faster than 75°F/hr, the valves began to close. The valves were given a signal to open if the cooldown rate was less than 75°F/hr. One of the two atmospheric dump valves on each steam generator was modeled. When the operator isolates the ruptured steam generator, the atmospheric dump valves is closed.

Main steam isolation valves were modeled for each steam generator. These valves were closed either when the pressure in either of the steam generators decreased below 810 psia or if the steam generator was isolated by the operator at some point during the calculation.

Either the auxiliary pressurizer spray (APS) system or the PORV on the pressurizer is to be used to depressurizer the primary system during the transient. The APS system was modeled by diverting the charging system flow from the cold legs to the upper region of the pressurizer, if the activation criteria are met. The APS is used once the operator takes control of the plant and manually operates the plant systems. Auxiliary pressurizer spray flow is delivered to the pressurizer if the hot leg subcooling margin is greater than 25°F and continues until the subcooling decreases to below 20°F. When the APS system is not on, the charging system flow is delivered to the cold legs.

The PORV is used in some of the calculations instead of the APS system to depressurize the plant. In the RELAP5 calculation, the PORV is modeled as a trip valve which is either full open or closed depending on the same subcooling criteria as the APS system. The valve area was sized to discharge 119.7 lb/s (113 lb/hr/MWt) of steam at a pressure of 2500 psia. This is based on having two valves of the Calvert Cliffs (BG&E) type on the pressurizer.

A reactor trip on low pressurizer pressure was included in the model. The setpoint was 1785 psia which corresponds to the core protection calculator low pressure boundary trip setpoint. This signal caused the reactor scram rods to begin inserting negative reactivity into the core with a combined signal delay time of 0.89 s (0.55 s for signal delay and 0.34 s for coil release). The turbine stop valves and reactor coolant system pumps were

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tripped following a 0.5 s delay. The loss of offsite power was assumed to occur 0.5 s following the reactor trip signal.

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3. DESCRIPTION OF ACCIDENT SCENARIO

The accident scenario adopted in this analysis is comprised of two distinct phases: an initiating event and a transient recovery phase. For the initiating event phase, the accident scenario was taken from the sequence of events for the steam generator tube rupture (SGTR) analysis performed by C-E and reported in Chapter 15 of the CESSAR FSAR. This phase of the accident encompasses the period of time from the initiation of the break up until 600 s following the activation of the reactor trip signal. At 600 s after reactor trip, the operator is assumed to take control of the plant and implement the transient recovery guidelines; this period of time up until the break flow is terminated by the equilibrium of the pressures across the break opening is referred to in this report as the recovery phase of the accident. The operator guidelines for the SGTR accident which are discussed in CEN-152 [3] were implemented in this study. A more detailed discussion of both the initiation and recovery phases is provided in the remainder of this chapter.

The steam generator tube rupture accident is caused by the failure of one or more of the primary coolant tubes in the steam generators allowing a direct flow path between the primary and secondary coolant systems. Because of the large pressure difference between the primary and the secondary system, critical flow is developed initially at the leak opening. A significant amount of primary reactor coolant system (RCS) inventory can be transferred to the secondary system even for a small break area. This primary coolant provides a potential source of radioactive liquid which will mix with the secondary system liquid inventory and could eventually be transported to the environment through the condenser hotwell air ejectors or through the steam discharge valves on the secondary system. The loss of the RCS mass inventory through the break causes a drop in the pressurizer level and consequently in the pressurizer pressure. If the charging system is operating in the automatic mode, the system will respond upon sensing the deviation in pressurizer water level from the programmed normal pressurizer level. Without any operator intervention, the RCS pressure will continue to decrase and eventually cause a reactor trip on low pressurizer pressure.

Once the reactor trips, the turbine stop valves close and the safety valves on the steam lines will open automatically to mitigate the pressure buildup on the secondary system.

3.1 Initiating Phase

The general response of the plant to a postulated SGTR transient is discussed in the preceding paragraphs. This section focuses on the specific details of the initiating phase of the accident which were utilized in this study. The SGTR transient which was analyzed for Chapter 15 of the CESSAR FSAR was adopted for this phase of the analysis. The major assumptions which directly impact these calculations are outlined in the succeeding paragraphs. Although some of the calculations involved multiple tube ruptures (i.e, one tube ruptured in each steam generator), the assumptions regarding the plant response which were taken from the FSAR single SGTR analysis are applicable to both the single and multiple tube rupture transients.

the Reference break flows?

Because of differences in the break flow models between RELAP5 and the vendor's code, the critical discharge flowrate through the ruptured tube will be different. The transient is assumed to be initiated by the double-ended guillotine rupture of a single steam generator tube which results in a maximum break flow area of 0.00486 ft^2. However, the break flow area in the RELAP5 calculation was reduced to 0.00272 ft^2 so that the initial break flowrate computed by RELAP5 was equal to the initial break flowrate reported in the CESSAR FSAR. ×

As the pressurizer level decreased, the FSAR case assumed that the third charging pump was started and the letdown flow was throttled back to a minimum flow. In the ANL calculations, the letdown flow was assumed to be zero; also in order to simplify the control systems modeling, the charging system was assumed to deliver the full three charging system flowrate (18.27 lb/s) from the time the break was initiated. The FSAR calculation assumed the third charging pump came on and the letdown flow terminated at 30 s after initiation of the break. In both the FSAR calculation and the ANL calculation, the heaters in the pressurizer were de-energized when the pressure level decreased below 100 inches.

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The reactor protection system tripped the reactor when the pressurizer pressure decreased below the core protection calculator low pressure boundary trip setpoint of 1785 psia. Upon reactor trip, the turbine stop valves were closed and the system was assumed to experience a total loss of offsite power. Energy was removed from the steam generators by steam discharge through the safety valves on the main steam lines; no credit was taken for any action of the main steam dump and bypass valves. Because of the loss of offsite power and the closure of the turbine stop valves, the main reactor coolant pumps began to coastdown and the main feedwater flow was ramped to zero. The auxiliary feedwater system was assumed to be available if the downcomer level decreased below the low level setpoint value of 19.76 ft. A 45 s delay was assumed between the receipt of the signal and the delivery of feedwater to the steam generator to allow time for the auxiliary feedwater pumps to be loaded onto the emergency diesel generators. The auxiliary feedwater pumps could deliver up to 121 lb/s to each steam generator. Prior to reactor trip the main feedwater system was assumed to be in the automatic mode so that the feedwater flow to the ruptured steam generator would decrease as the level measuring system sensed the increasing level due to the leakage into the steam generator through the ruptured tube. In the ANL calculations, the main feedwater flowrate to the ruptured steam generator was decreased by the amount of leakage flow into the steam generator to simulate the feedwater control system.

When the pressurizer pressure decreased below 1600 psia, a safety injection actuation signal (SIAS) was generated and safety injection flow was assumed to be available for delivery to the primary system following a 50 s delay to allow for loading the safety injection pumps onto the emergency diesel generators.

The plant was assumed to respond only to automatically actuated safety systems until 10 minutes following reactor trip. After this 10 minute delay, the operator was assumed to take control of the plant and implement the SGTR recovery guidelines as discussed in Reference [3]. The important recovery guidelines are summarized in Section 3.2.

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3.2 SGTR Recovery Guidelines

The SGTR recovery guidelines were used as the source for information on what actions the operator would take during the transient recovery phase of the calculations. This phase was assumed to begin 10 minutes after reactor trip and end when the pressure drop across the break became zero or negative. The calculations were, in fact, beyond the first instance of negative break flow to insure that the primary to secondary leakage was capable of being terminated.

The overall SGTR recovery strategy is depicted in Fig. 2. The steps pertinent to the modeling required for the calculations discussed in this report are steps 1-4 and 6. Step 5 was not considered because the assumed loss of offsite power precluded the restarting of the main reactor coolant pumps.

The first recovery action which the operator was assumed to take was to reduce the reactor coolant system hot leg temperature to below 565°F to insure that the steam generator safety valves would not be lifted due to the primary system heat inventory. The temperature of 565°F is less than the saturation temperature corresonding to the pressure of the lowest opening setpoint of the steam generator safety valves. This is accomplished by feeding the steam generator with auxiliary feedwater and removing energy from the steam generators by discharging steam through the atmospheric dump valves (ADVs). Both steam generators are used to remove energy during this cooldown; one ADV on each steam generator was utilized to discharge steam. The ADV system was used because the condenser was not available. In order to control the rate of RCS cooldown, the ADVs were throttled; the cooldown rate was limited to less than 75°F/hr based on the average primary system temperature. For these calculations, the primary system average temperature was taken to be the average of the two hot legs and the two combined cold leg temperatures.

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When the temperature on the hot leg is less than 565°F, the ADV on the ruptured steam generator is closed and the auxiliary feedwater flow is terminated. Also, if the main steam isolation valve on the ruptured had not

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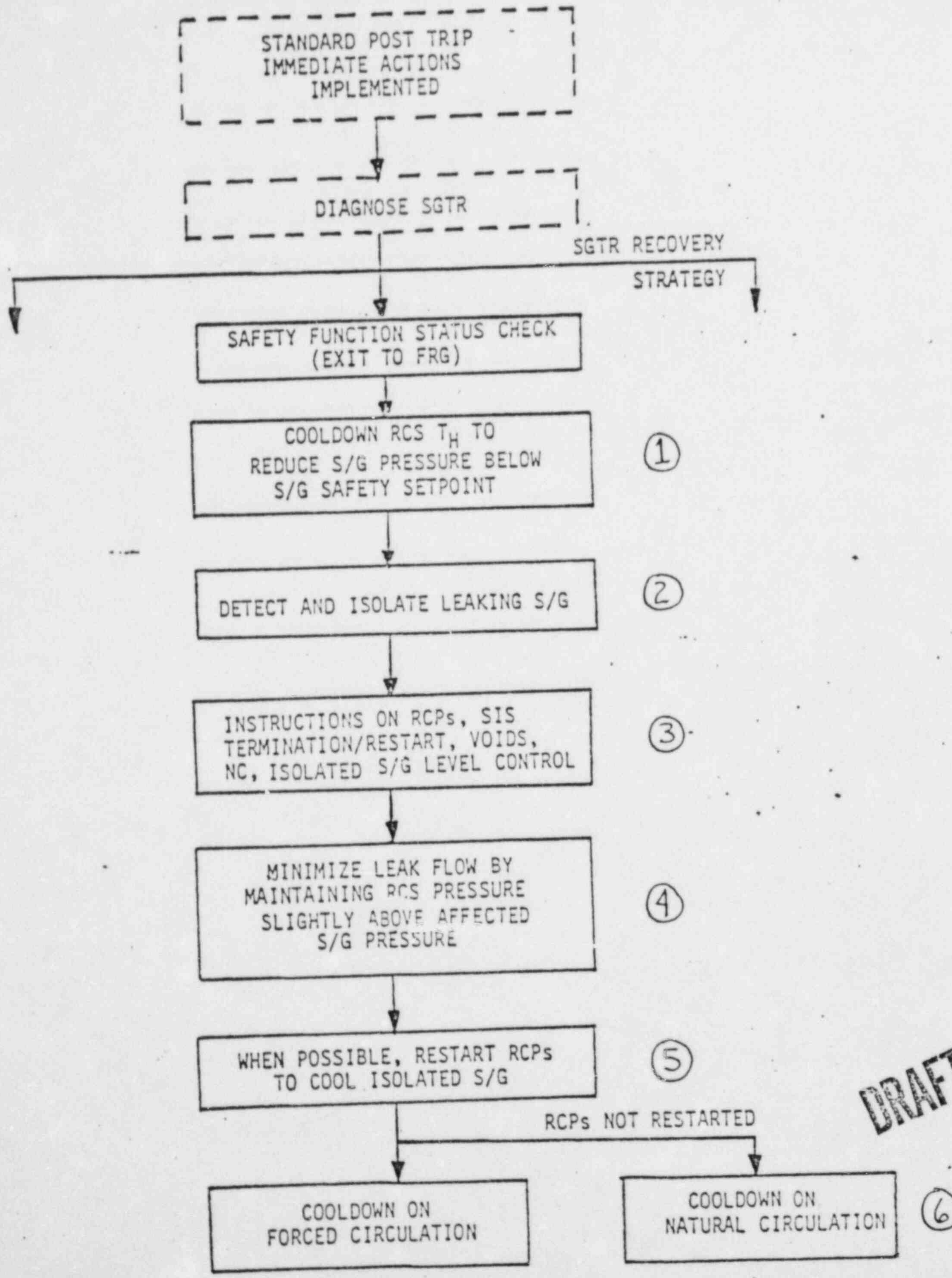
STEAM GENERATOR TUBE RUPTURE



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been closed by this time, the MSIV valve is closed. The ruptured steam generator is isolated with the only potential paths for steam release being the main steam line safety valves and the ADV, if the operator chooses to reopen it.

Once the ruptured steam generator is isolated, the operator continues to cool the primary system down with the ADV on the intact steam generator. Again the cooldown rate is limited to less than 75°F/hr by controlling the ADV flow depending on the deviation of the cooldown rate from the maximum allowed value of 75°F/hr. Make-up flow to the unaffected steam generator is provided by the auxiliary feedwater pumps which are programmed to maintain the downcomer water level at 19.76 ft.

The high pressure safety injection system (HPSI) which was automatically initiated when the pressurizer pressure decreased below 1600 psia will be placed in a manual mode once the operator takes control of the plant. The HPSI flow will be throttled by the operator depending on a set of criteria related to the hot leg subcooling margin and the pressurizer collapsed liquid level. In the RELAP5 calculations, the HPSI flow was assumed to be either on or off depending on the following criteria. The HPSI flow is terminated if the hot leg subcooling margin is greater than 20°F and the pressurizer level is greater than 100 inches and increasing. If any of these criteria are not met, the HPSI flow is re-established. Only one train of HPSI flow was assumed to be available in the calculations.

The only other operator action which was implemented in the RELAP5 calculations related to the actions taken by the operator to decrease the primary system pressure in an effort to equilibrate the pressures across the break and thus terminate the primary to secondary leakage. Although on the current C-E System 80 design only the pressurizer spray systems (either the normal or auxiliary pressurizer sprays) would be available for depressurizaing the primary system, a power operated relieve valve (PORV) on top of the pressurizer was modeled to provide an alternative means of depressurization so that the objective of this study which is to investigate the need for adding a PORV to the System 80 design could be achieved. Because the reactor coolant system pumps are unavailable, only the auxiliary pressurizer spray (APS)

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system is used to decrease the primary system pressure in these calculations. Whether or not the APS system or the PORV is being used, the same controlling logic was assumed for governing the operation of either system. The hot leg subcooling margin was used to determine the operator's activation of the depressurization system. The following criteria were utilized to govern the operator's actions. If the hot leg subcooling margin exceeded 25°F, the APS system was turned on; or the PORV was fully opened. If the subcooling decreased below 20°F, the APS system was turned off; or, the PORV was closed. The assumed 5°F of hysteresis in the control logic is to prevent the system from cycling too much.

The control criteria for the depressurization systems are not provided in the SGTR recovery guideline; the specific criteria used in this study were obtained from NRC [5].

3.3 Matix of Cases Analyzed

In order to make a determination on the need for a PORV on the System 80 plant, the matrix of cases outlined in Table 2 were analyzed. These calculations are intended to provide information on the relative usefulness of a PORV in mitigating the consequences of a SGTR accident. Cases 1-6 assume a single double ended guillotine rupture of one tube in only one steam generator; Cases 7-9 assume a single tube rupture in both steam generators.

The relative effectiveness of either system in allowing the operator to depressurize the primary system is investigated in cases 1, 2, 7 and 8. Cases 3 and 6 were included to investigate the impact on the operator's ability to terminate the primary to secondary leak if the ADV on the ruptured steam fails close when the operator attempts to isolate the ruptured steam generator. Case 3 assumed that the operator identified and corrected the stuck open valve after 20 minutes; in case 6, the ADV was left open until the end of the transient. In both Case 3 and 6, the ADV was assumed to stick open at the maximum area to which it had opened during the cooldown. This amounted to an effective flow area of ~30% of the full open area.

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Cases 4, 5 and 9 were included to address other issues than merely the relative depressurization capability of the two systems which may influence the decision to require a PORV on the primary system. If the operator

Table 2. Matrix of SGTR Cases Analyzed.

Case Number	Comment
1	Single with APS
2	Single with PORV
3	Single with APS stuck open ADV for 20 min.
4	Single with continuous APS
5	Single with continuous APS
6	Single with APS stuck open on ruptured SG for the duration of the calculations
7	Dual with APS
8	Dual with PORV
9	Dual with PORV -- feed and bleed

inadvertently fails to terminate the APS flow when the subcooling criterion is reached, the pressurizer could go solid. Cases 4 and 5 investigate the potential for recovering control of the plant and continuing to depressurize the plant if the APS system is unable to spray into the liquid solid pressurizer. The PORV could possibly be utilized at that point to remove liquid from the pressurizer to allow for some volume into which the operator could inject the APS flow. The pressurizer code safety valves would probably lift if the pressurizer went solid; however, the PORV would provide the operator with a controllable system for discharging mass from the primary and also on which could operate at pressure below the pressurizer safety valve pressure setpoint.

Finally Case 9 was analyzed to provide some information on whether the PORV would be useful in mitigating the consequences of tube rupture accidents in which at least one tube is broken in each steam generator. With the PORV, the operator could isolate both steam generators and then remove energy from the system by using a feed and bleed operation. The feed and bleed logic

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employed in Case 9 is the same as the logic employed in the total loss of feedwater flow analysis which is reported in Reference 1. The PORV is fully opened and the HPSI system delivers flow based on the downstream pressure conditions.

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4.0 CALCULATIONAL RESULTS

The calculations were subdivided into two categories. The first category contains all of the cases in which a single steam generator tube was ruptured in only one steam generator. The second category contains the cases in which there is a single ruptured tube in each steam generator. In each category, the cases are all identical until the operator actions are initiated. So, for each category, there is a base case calculation which includes the time period from the initiation of the break(s) until one of the steam generators is isolated and the long term cooldown of the plant begins. The individual cases discussed in this chapter were all restarted from either one of the base cases.

4.1 Doubled Ended Guillotine Rupture of a Single Tube in One Steam Generator

The base case for the single tube rupture cases was begun with a 100 s null transient to insure that steady state conditions had been achieved. The break was initiated at 100 s by opening the break valve junction 878 which is on the non-pressurizer loop. The break is at the tube sheet on the cold leg side of the U-tube region. The break location is the same as in the FSAR case. When the break was initiated, the charging system was assumed to begin injecting the full three pump flowrate into the cold legs. Also the main feedwater flowrate was decreased by an amount equivalent to the break flow to simulate the automatic operation of the feedwater level control system.

The results of the single tube rupture base case are discussed in Section 4.1.1 in conjunction with the results of the calculation in which the APS system was used to depressurize the primary system.

4.1.1 Auxiliary Pressurizer Spray Case

After the steam generator tube is ruptured, the primary reactor coolant system inventory continues to decrease because the charging system cannot replenish the liquid being lost through the break. As the inventory decreases, the pressurizer pressure and level decrease. The pres-

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surizer pressure transient is depicted in Fig. 3. When the level in the pressurizer falls below 100 inches, the pressurizer heaters are de-energized which causes the pressure to decrease faster. During this time period, the reactor power and primary system temperatures are holding relatively constant. Eventually, the pressurizer pressure decreases below the setpoint for the core protection calculator low pressure boundary trip (1785 psia). The turbine stop valves are closed instantaneously following the delay for the trip signal. Closing the turbine stop valves temporarily terminates the energy removal from the steam generators and reduces the primary to secondary heat transfer rate, causing a rapid increase in the pressurizer pressure. The pressurizer pressure then decreases rapidly as the control rods, which are inserted into the reactor core drastically reduce the energy input to the primary system. Following closure of the turbine stop valves, the secondary system pressure rises rapidly and the opening setpoints for the first two banks of safety valves are reached. Steam is discharged through the secondary safety valves decreasing the secondary system pressure and increasing the energy removal rate from the primary system. The primary system pressure begins to decrease slowly due to the energy removal through the steam generators when the safety valves are open. The safety valves eventually close when the atmospheric dump valves are opened to decrease the hot leg temperatures below 565°F. Opening of the ADVs marks the end of the initiation phase of the transient. The safety valves remain closed for the remainder of the transient. When the ADVs are opened, the pressurizer pressure decreases steadily. The ADVs are throttled to limit the primary system cooldown rate to $<$ 75°/hr. Both steam generators are being used during this initial cooldown period to insure that the loops respond symmetrically and the natural circulation flows in each loop remain stable. The ADVs were opened 10 minutes following reactor at ____ s (____ + 600 s = ____ s) when the operator was assumed to take control of the plant and remain open until the hot leg temperature decreases below 565°F. If the hot leg temperature decreases below 565°F, the ruptured steam generator is isolated by closing the main steam and feedwater isolation valves, and the ADV. This signals the end of the base case and occurs at ____ s. From this point on, the single tube rupture cases will differ depending on the assumed operator actions and/or assumed failures. All of the remaining calculations which assumed a single tube rupture in only one steam generator were initiated from this point. The remainder of this section

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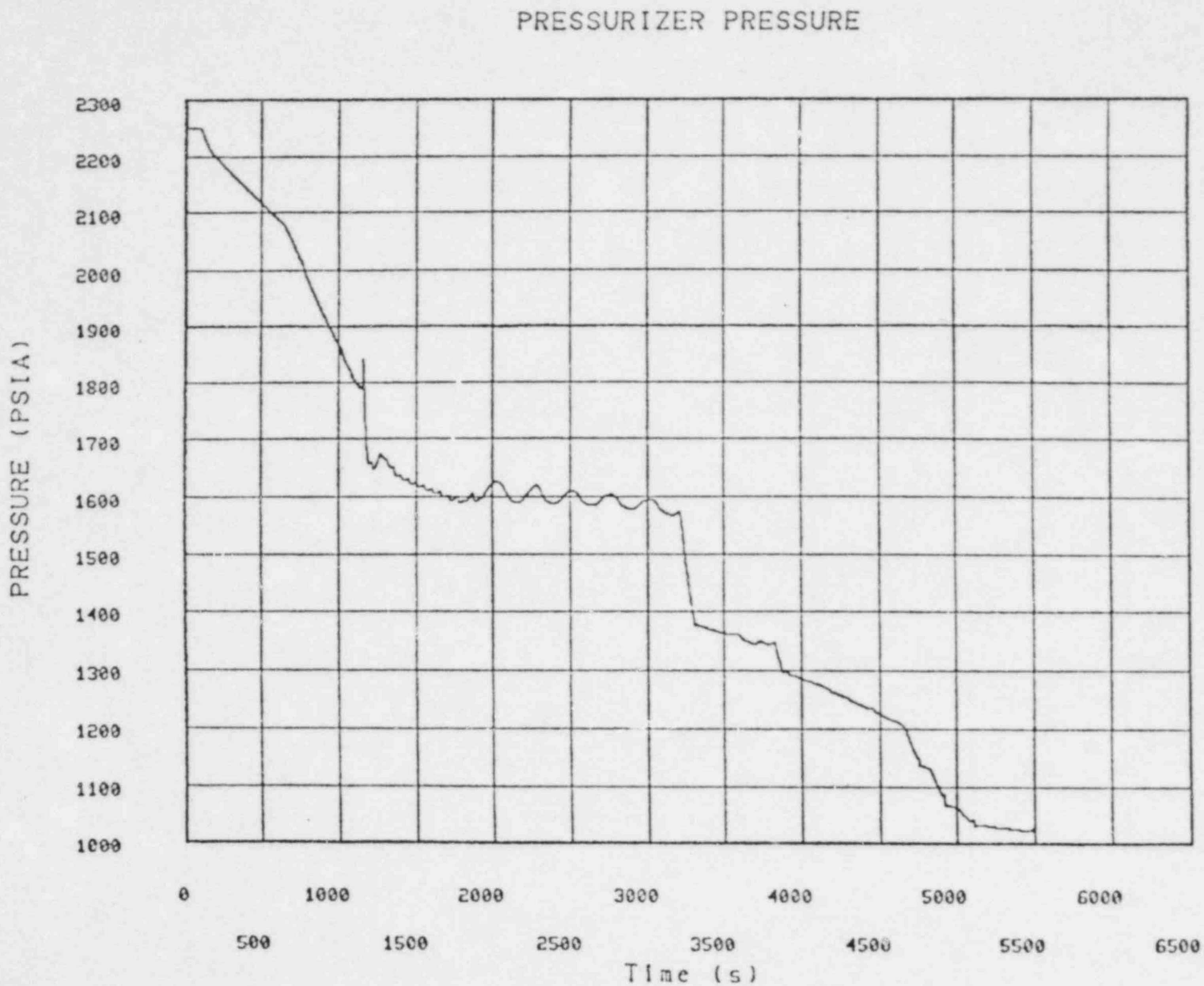

CASE 1 SINGLE SGTR APS

FIG. 3.

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will discuss the details of the APS case (Case 1) and where appropriate will discuss the response of various system parameters for both the base case (initiating phase) and the recovery phase. The remaining subsections in Section 4.1 will discuss only the recovery phase of each of the single tube rupture cases (i.e., Cases 2-6).

A table summarizing the major event sequences for all of the single tube rupture cases is provided in Tables 3 and 4.

Once the ruptured steam generator has been isolated the HPSI flow and APS flow are controlled by the criteria outlined in Section 3.2. The charging system fluid will be spraying into the pressurizer (through the APS system, if the hot leg subcooling is > 25°F and injecting into the cold legs if the subcooling is < 20°F. The HPSI flow will be terminated only if the hot leg subcooling is > 20°F and the pressurizer collapsed liquid levels exceeds 100" and is rising; otherwise the HPSI flow is delivered to the cold legs, assuming the safety injection actuation signal had been received.

The transient response of the steam generator pressures is plotted in Fig. 4. Initially, the steam generator pressure is not affected by the influx of primary fluid through the ruptured tube; the pressure rise at ~ 1100 s is due to closure of the turbine stop valves. The secondary safety valves mitigate the pressure rise and the secondary pressure oscillates as the safety valves are cycled. Eventually the ADVs are opened and the pressure in both steam generators declines steadily. There is some oscillating in the secondary pressure response which is due to the cyclic throttling of the ADVs to limit the cooldown rate. At _____ s, the ruptured steam generator (on loop 2) is isolated and the pressure rises in response to the closure of the ADV to isolate the ruptured steam generator. The pressure in the steam generator on loop 1 continues to decrease as the ADV on this loop is used to continue to cooldown the plant until the leak can be terminated or the residual heat removal system can be initiated. (The initiation criteria for the residual heat removal system for System 80 are 400 psia and 350°F.)

The resulting pressure drop across the break (see Fig. 5) responds to the changes in the primary and secondary system pressures. The

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(TO BE PROVIDED)

Table 3. Event Sequences for Single SGTR Cases 1-3 (Time in sec.).

Events	Aux. Spray (Case 1)	PORV (Case 2)	Stuck Open ADV (Case 3)
Tube rupture begins	100.0		
PORV pressurizer heater turned off (Pzr water level < 100")	634.6		
RCS starts to boil	853.0		
Reactor trip (Pzr pressure < 1785 psia)	1073.5		
Turbine stop valve close	1074.0		
RCP trip	1074.0		
Steam generator safety valves open	1079.0		
HPSI flow signal (SIAS)	1524.7		
ADV flow actuated	1673.5		
Aux. feed to intact SG	1681.3		
Aux. feed to affected SG	1766.8		
Hot leg temp. < 565°F	1925.5		
---------- All single SGTR cases are the same up to here ----------			
Manual cooldown begins	1925.5	1925.5	1925.5
ADV stuck open	---	---	1925.5
Isolate broken SG	1925.5	1925.5	---
Aux. spray initiated	1925.5	---	1925.5
PORV operated	---	1925.5	---
Close stuck open ADV (20 min. after SG isolation)			3125.5
Negative break flow	3510.4	3391.5	5976.8

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(TO BE PROVIDED)

Table 4. Event Sequences for Single SGTR Cases 4-6 (Time in sec.).

Events	Aux. Spray (Case 3)	PORV (Case 4)	Stuck Open ADV (Case 5)
Tube rupture begins	100.0		
PORV pressurizer heater turned off (Pzr water level < 100")	634.6		
RCS starts to boil	853.0		
Reactor trip (Pzr pressure < 1785 psia)	1073.5		
Turbine stop valve close	1074.0		
RCP trip	1074.0		
Steam generator safety valves open	1079.0		
HPSI flow signal (SIAS)	1524.7		
ADV flow actuated	1673.5		
Aux. feed to intact SG	1681.3		
Aux. feed to affected SG	1766.8		
Hot leg temp. < 565°F	1925.5		
---------- All single SGTR cases are the same up to here ----------			
Manual cooldown begins	1925.5	1925.5	1925.5
ADV stuck open	---	---	1925.5
Isolate broken SG	1925.5	1925.5	---
Aux. spray initiated	1925.5	---	1925.5
PORV operated	---	1925.5	---
Close stuck open ADV (20 min. after SG isolation)			3125.5
Negative break flow	3518.4	3391.5	5976.8

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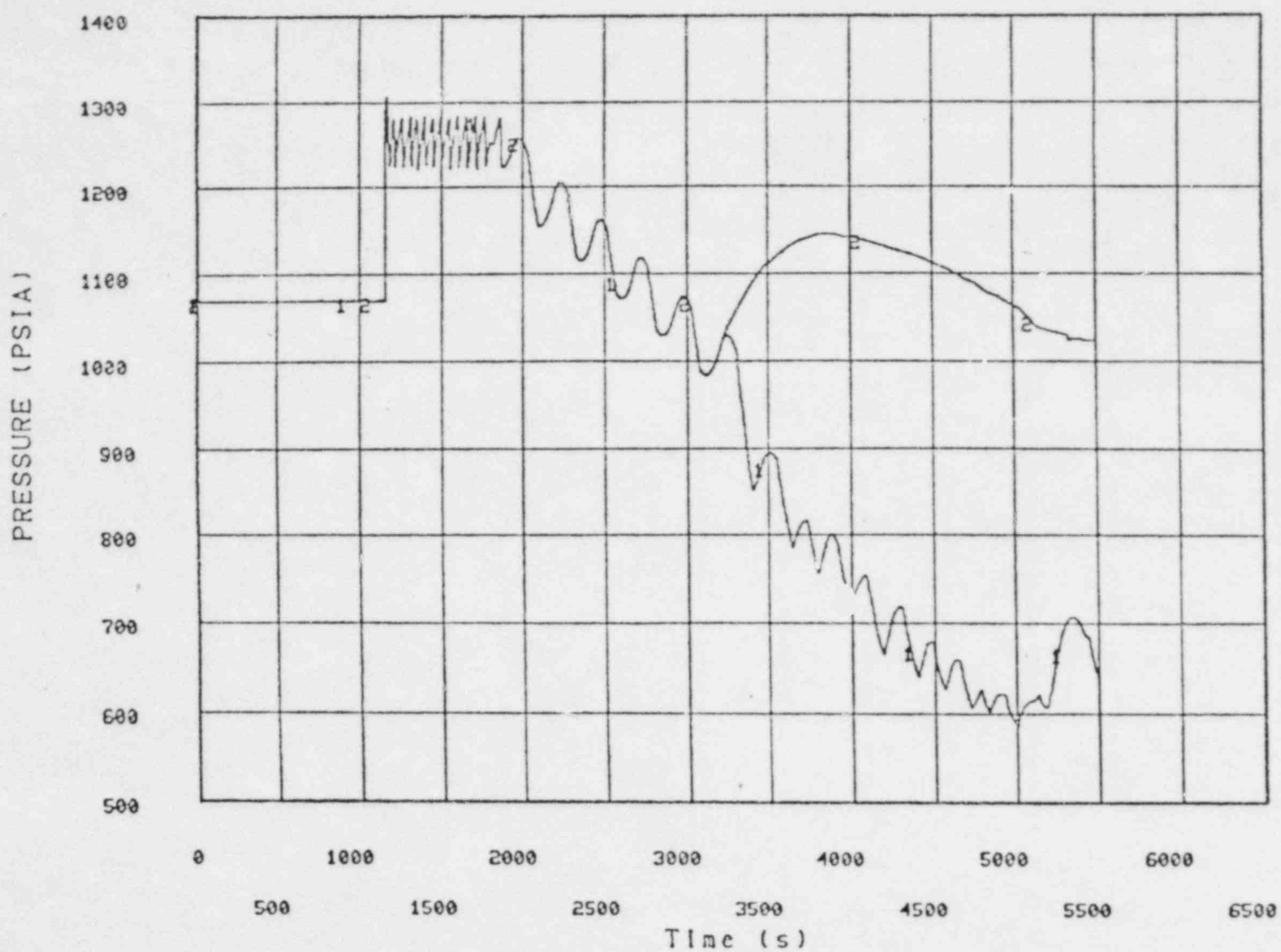
SG DØME PRESSURE: SG1,SG2



CASE 1 SINGLE SGTR APS

FIG. 4.

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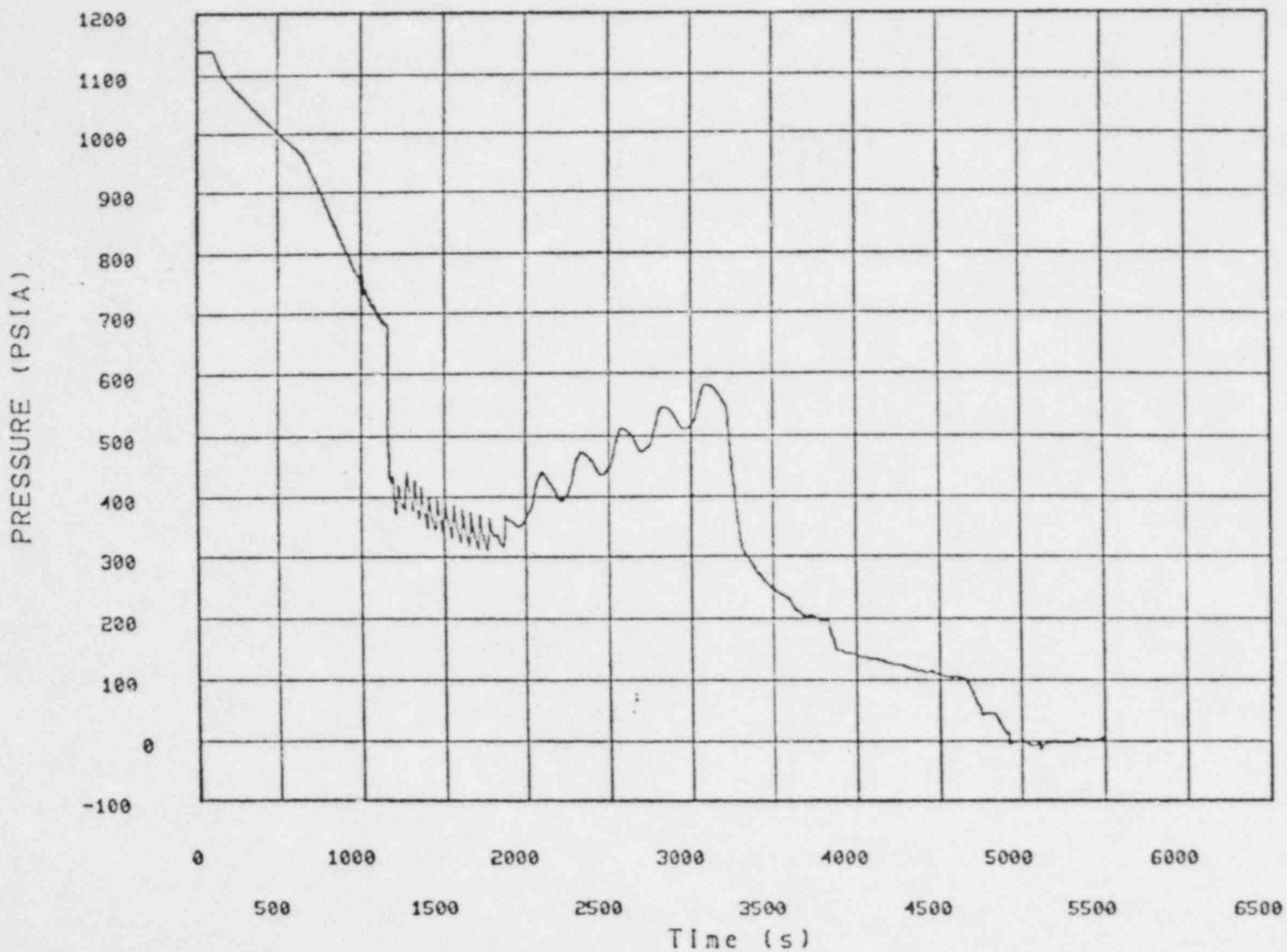
DELTA-P ACRØSS BRK JUN 878



CASE 1 SINGLE SGTR APS

FIG. 5

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pressure drop (ΔP) initially (up until the time of reactor trip) responds entirely to the decreasing primary system pressure. The first large decrease in the ΔP is due to the large increase in secondary pressure when the turbine stop valves are closed. The ΔP again continues to decrease because the safety valves are discharging steam and maintaining a somewhat constant average pressure in time in the steam generators whereas the primary system pressure continues to decrease due to the energy removal through the safety valves, the loss of mass through the break and the decreased energy input from the reactor core. While the ADVs are open from about 1850 s until about 3600 s, the ΔP remains relatively constant as the primary and secondary system pressures decrease at the same rate. The second large decrease in the ΔP is due to the isolation of the ruptured steam generator which causes the pressure in the loop 2 steam generator to decrease. The ΔP decreases some more due to the increasing secondary pressure, then decreases as the primary system pressure is decreased by the operator of the APS system which began at just before 4500 s. the ruptured steam generator pressure continues to decrease due to reverse heat transfer into the primary system. Eventually the pressure drop across the break decreases to zero (at time it actually goes slightly negative) and the leak is terminated.

The break flowrate versus time is displayed in Fig. 6. Initially the break flow is choked but eventually the flow becomes unchoked and can be related to the square root of the ΔP across the break junction.

The hot and cold leg temperatures on the pressurizer loop and on the other loop are shown on Figs. 7 and 8, respectively. Both sets of plots are nearly identical until ~ 4600 s which is when the natural circulation flow in the ideal loop is disrupted. Initially the temperatures show some slight changes due to the leak; the reactor trip and closure of the turbine stop valves cause the hot leg temperatures to decrease and the cold leg temperatures to increase, respectively. The cold leg temperatures then decrease due to the opening of the secondary side safety valves; the hot leg temperatures increase after the initial rapid drop because there is a power-cooling mismatch in the reactor core after the reactor coolant pumps were tripped. Natural circulation flow is then established in both loops and the temperatures begin to decrease as the ADVs are used to cooldown the primary

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CASE 1 SINGLE SGTR APS

FIG. 6.

CASE 1 SINGLE SGTR APS

FIG. 7

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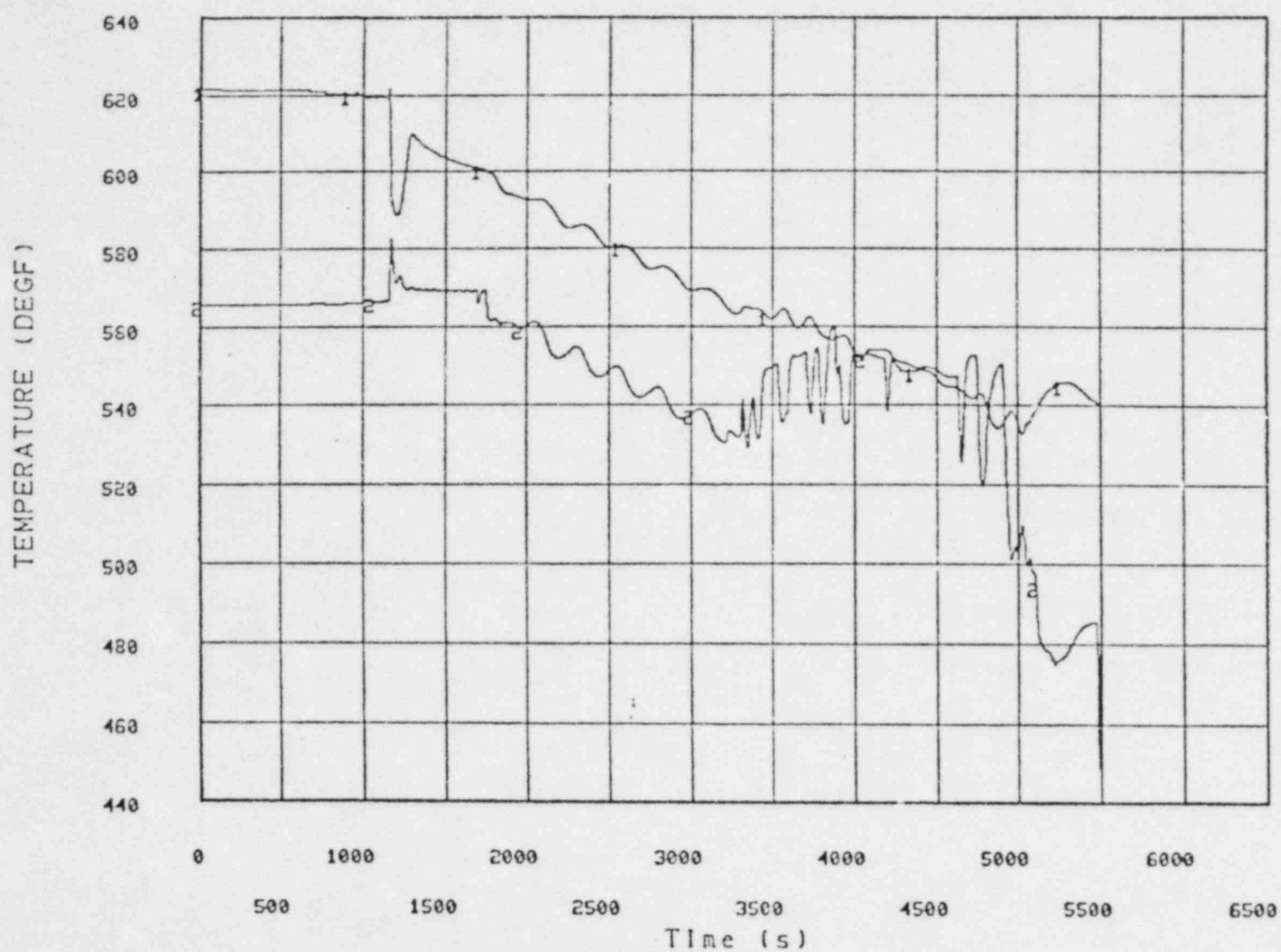
HØT AND CØLD LEG TEMPS: NØN PZR LP



CASE I SINGLE SGTR APS

FIG. 8

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system. The cooldown continues on loop 1 (with the pressurizer) because this loop is not isolated and is used to cool the system down once the ruptured steam generator is isolated. The temperature response on loop 2 behaves similarly except after 4600 s, the hot and cold leg temperature peaks are no longer synchronized after the natural circulation flow pattern on the isolated loop is disrupted because there is no more thermal driving force to support the flow once the ruptured steam generator is isolated. The flows through the pumps on loop 1 and 2 are displayed in Figs. 9 and 10, respectively.

The APS flowrate is shown in Fig. 11 and responds to the hot leg subcooling criteria discussed previously. The hot leg subcooling margin is displayed in Fig. 12.

The HPSI flows being injected into the cold legs of loop 1 and 2 are depicted in Figs. 13 and 14, respectively. Initially, before the recovery phase of the transient, the HPSI system responds automatically once the safety injection actuation signal is activated at when the pressure drops below 1600 psia. After the recovery phase is initiated the HPSI flow is governed by the criteria discussed in Section 3.2.

The ADV flowrates for both steam generators are depicted in Figs. 15 and 16. As per the discussion in Section 3.2, the ADVs are being throttled to limt the cooldown rate. If the cooldown rate based on a primary average temperature is increasing too fast, the valves begin to close. Then, if the cooldown rate is too slow, the valves begin to open. Eventually the ADV on the ruptured steam generator is completely closed when the hot leg temprature decreases below 565°F at ____ s.

A summary of the important integrated flows into and out of the primary and secondary systems is presented at the end of Section 4.1 in Table 5.

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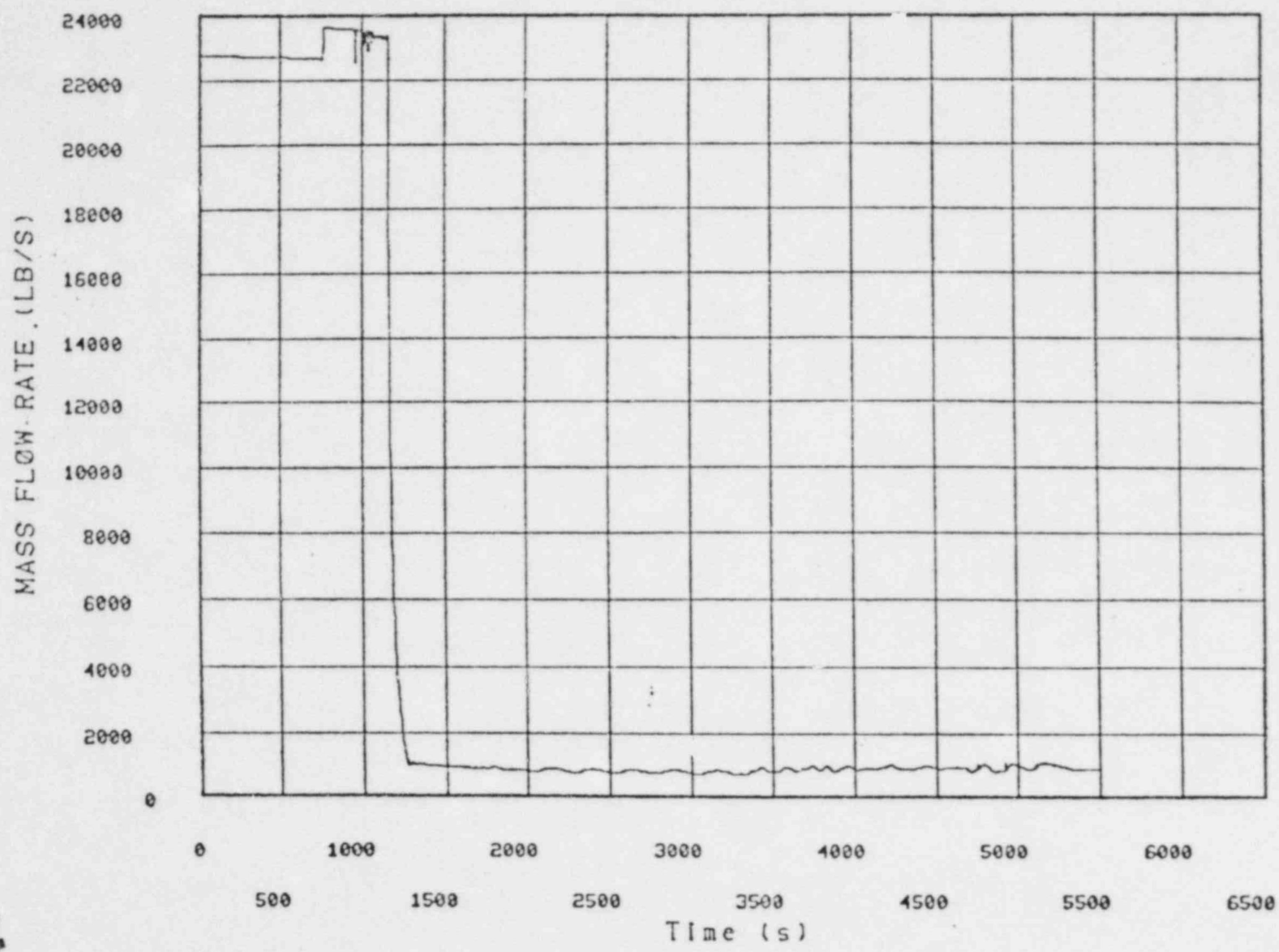
FLØW THRØUGH RCPS ØN LØØP1



CASE 1 SINGLE SGTR APS

FIG. 9

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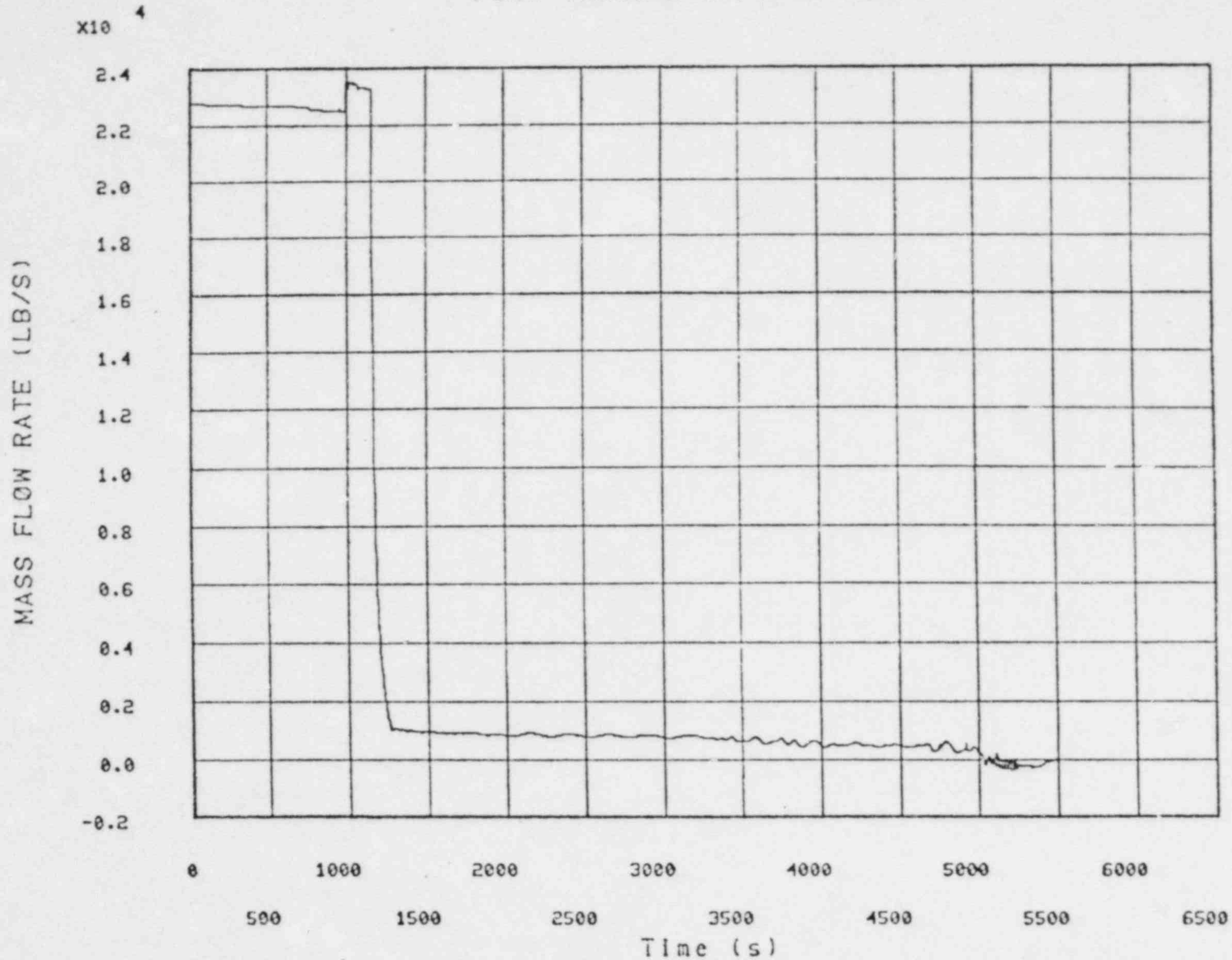
FLØW THRØUGH RCPS ØN LØØP2



CASE 1 SINGLE SGTR APS

FIG. 10

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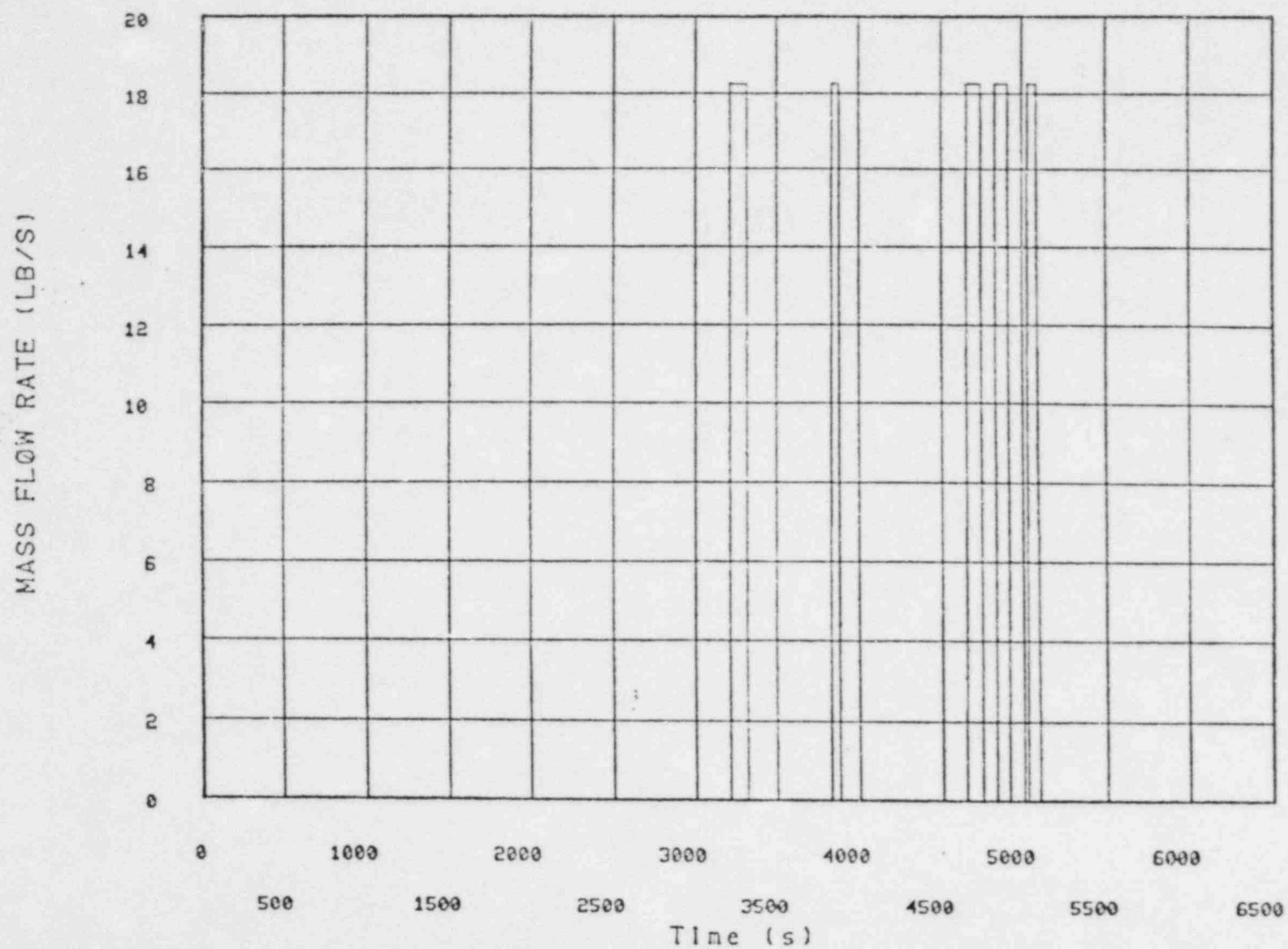
AUX. PZR SPRAY FLØW



CASE 1 SINGLE SGTR APS

FiG. 11

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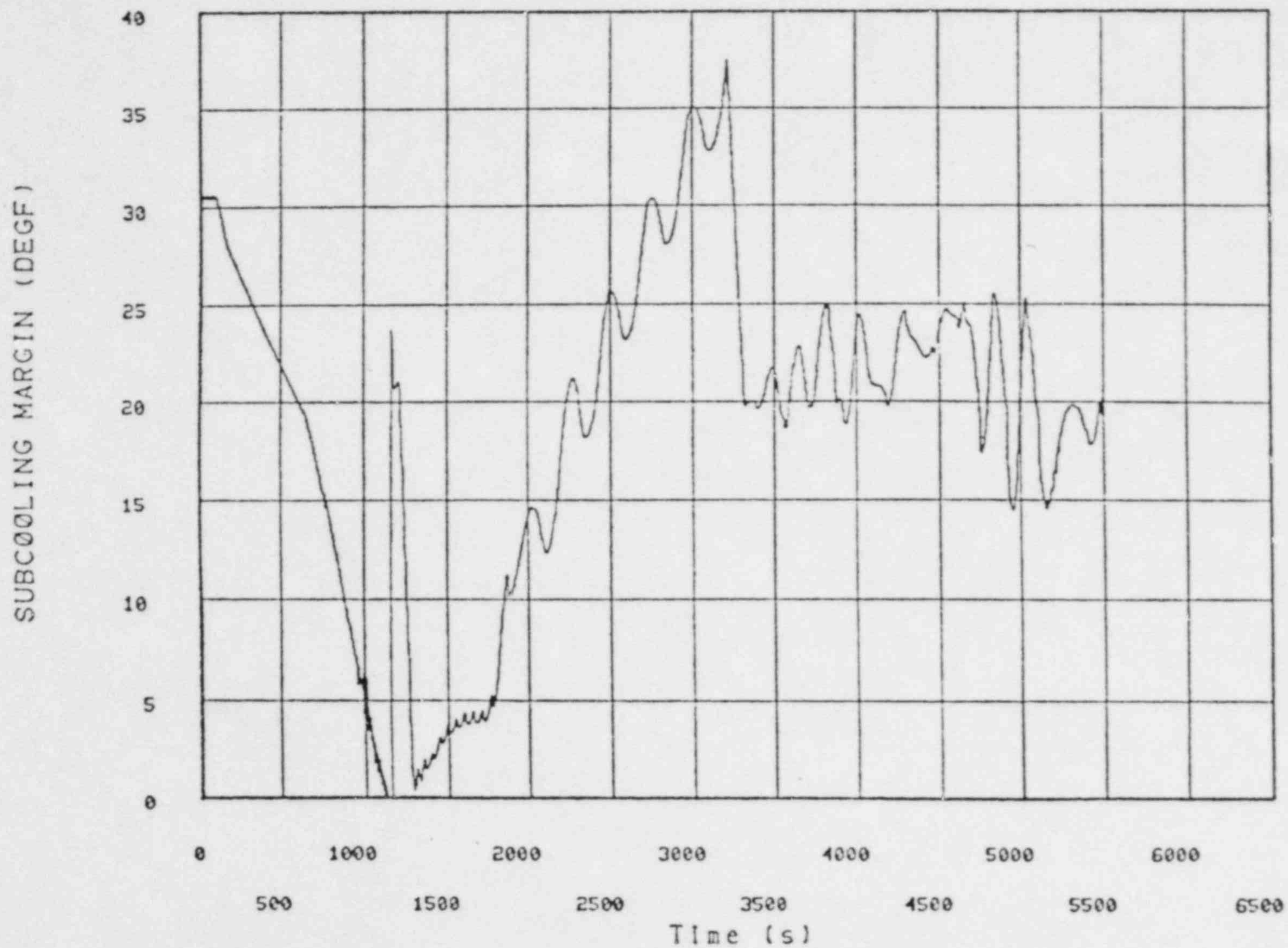
SUBCØØLING MARGIN IN VØL. 10002



CASE I SINGLE SGTR APS

FIG. 12

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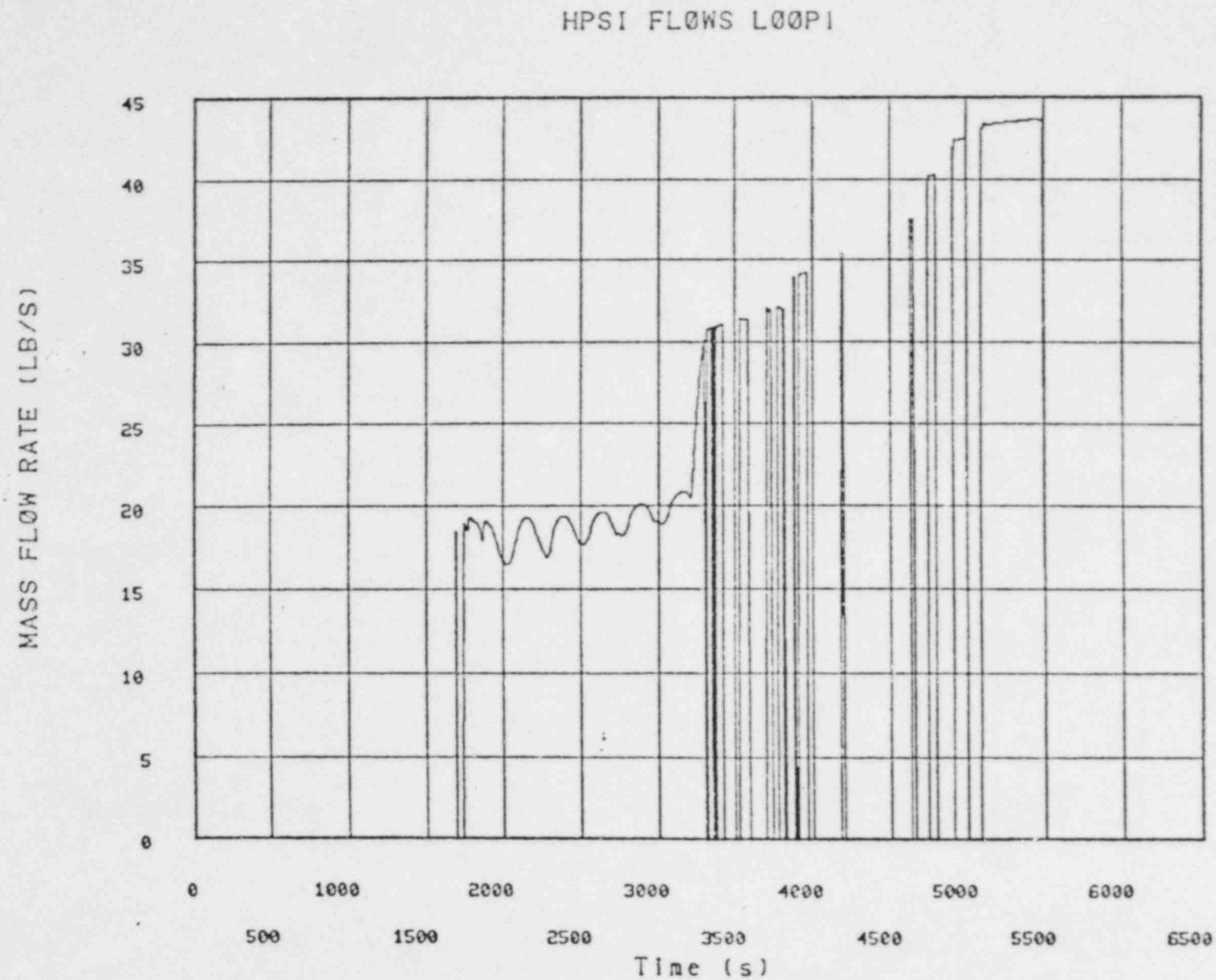

CASE 1 SINGLE SGTR APS

FIG. 13

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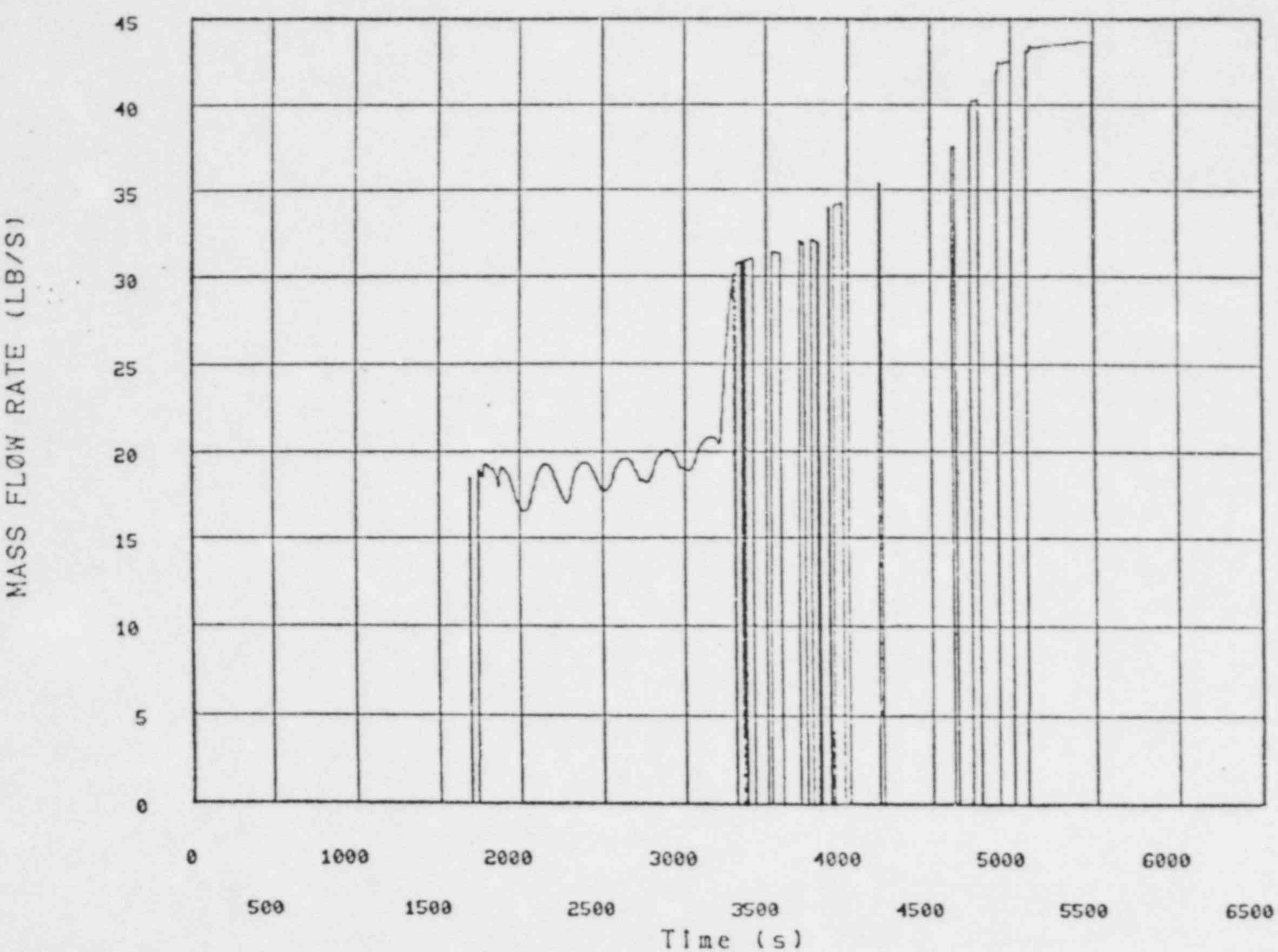
HPSI FLØWS LØØP2



CASE I SINGLE SGTR APS

FIG. 14

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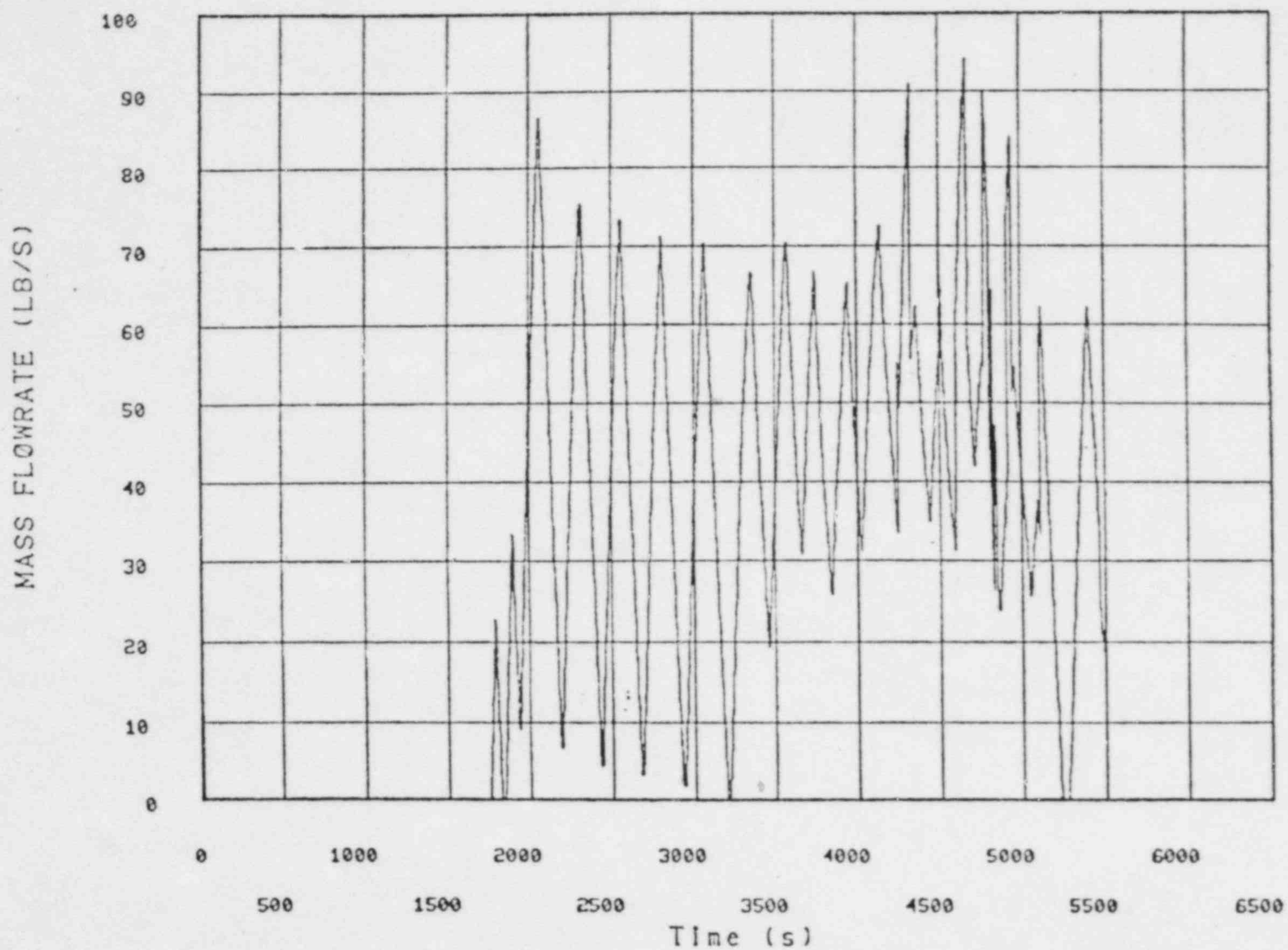
ADV FLØW SG1



CASE 1 SINGLE SGTR APS

FIG. 15

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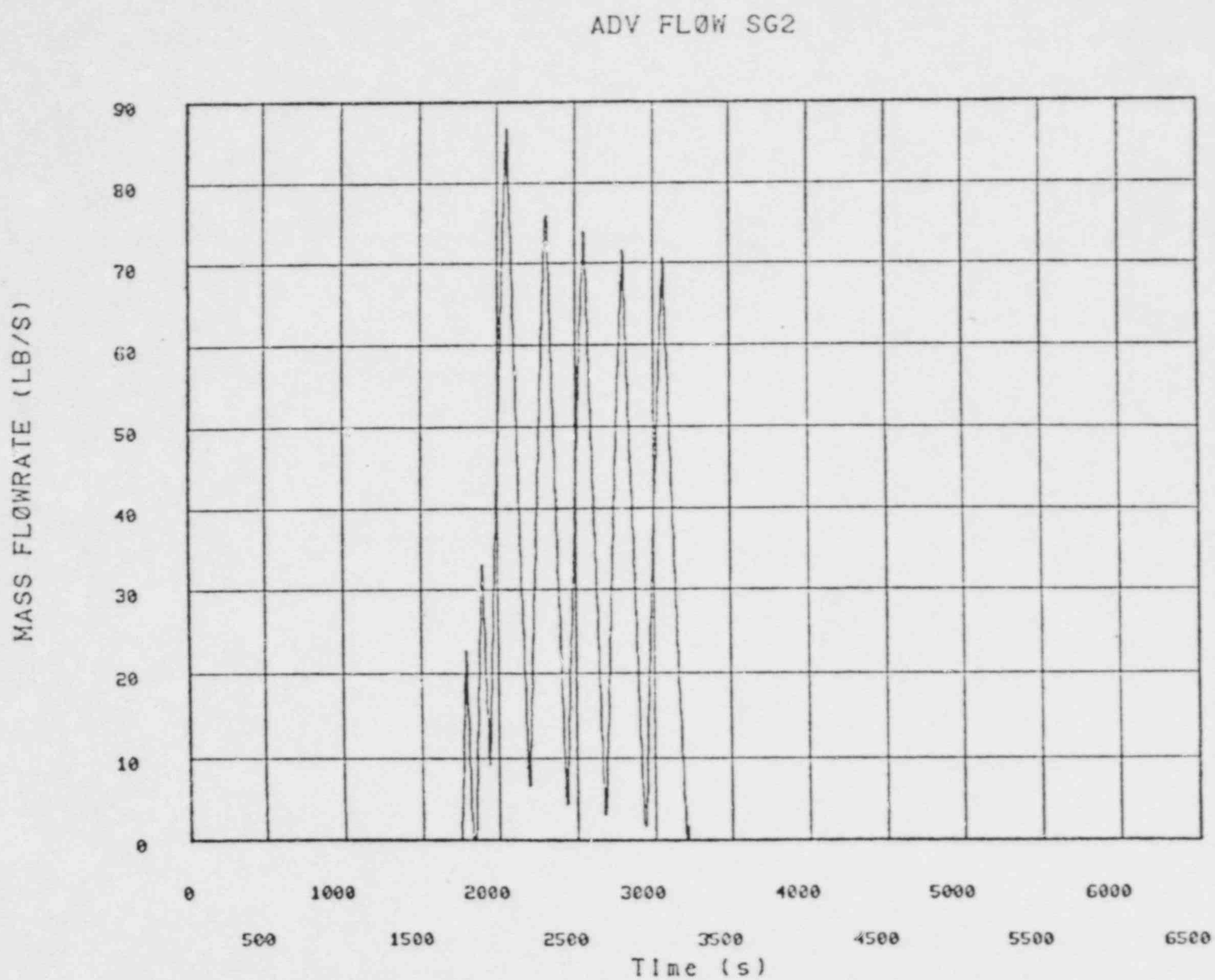

CASE 1 SINGLE SGTR APS

FIG. 16.

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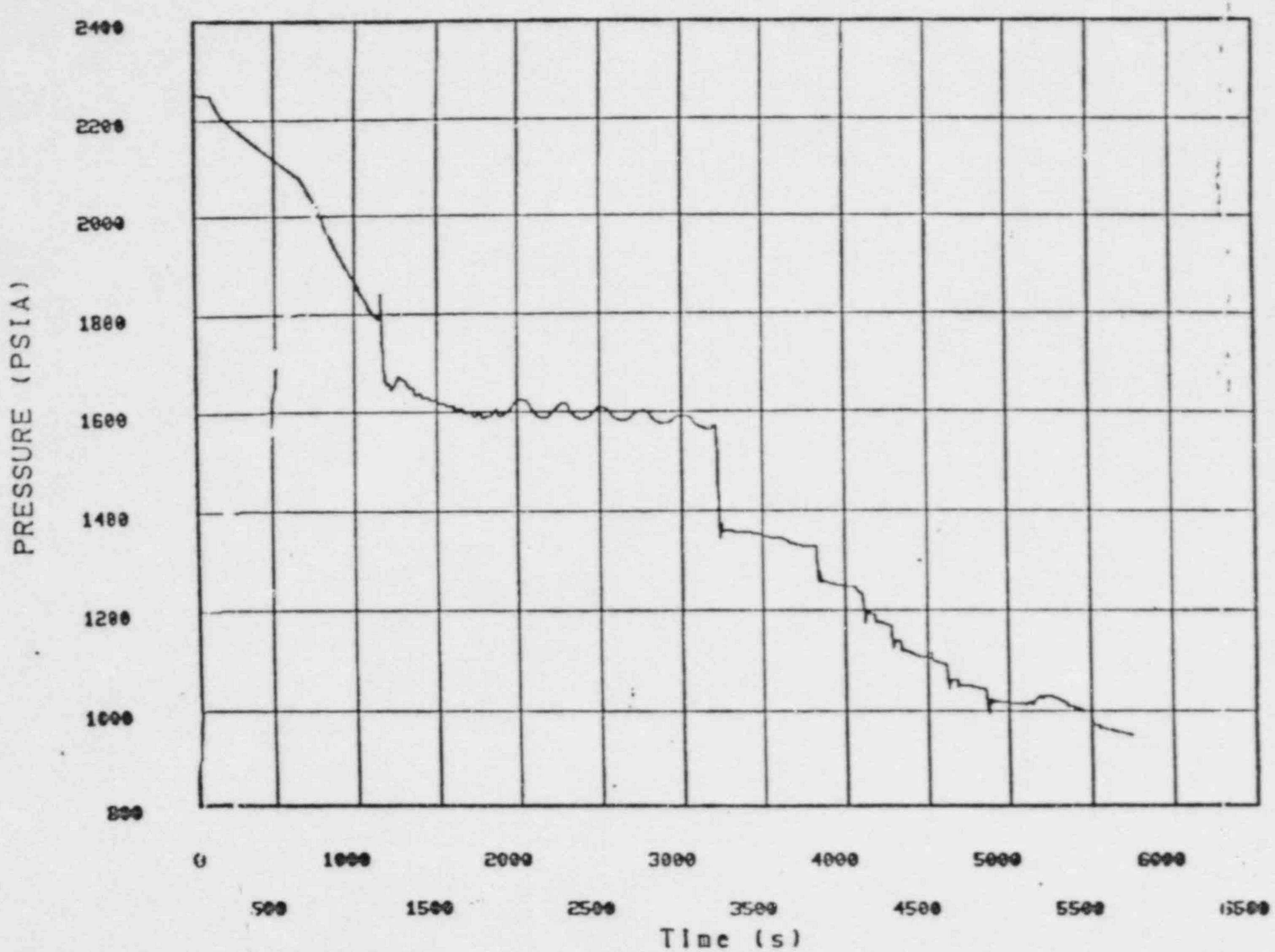
PRESSURIZER PRESSURE



CASE 2 SINGLE SGTR PØRV

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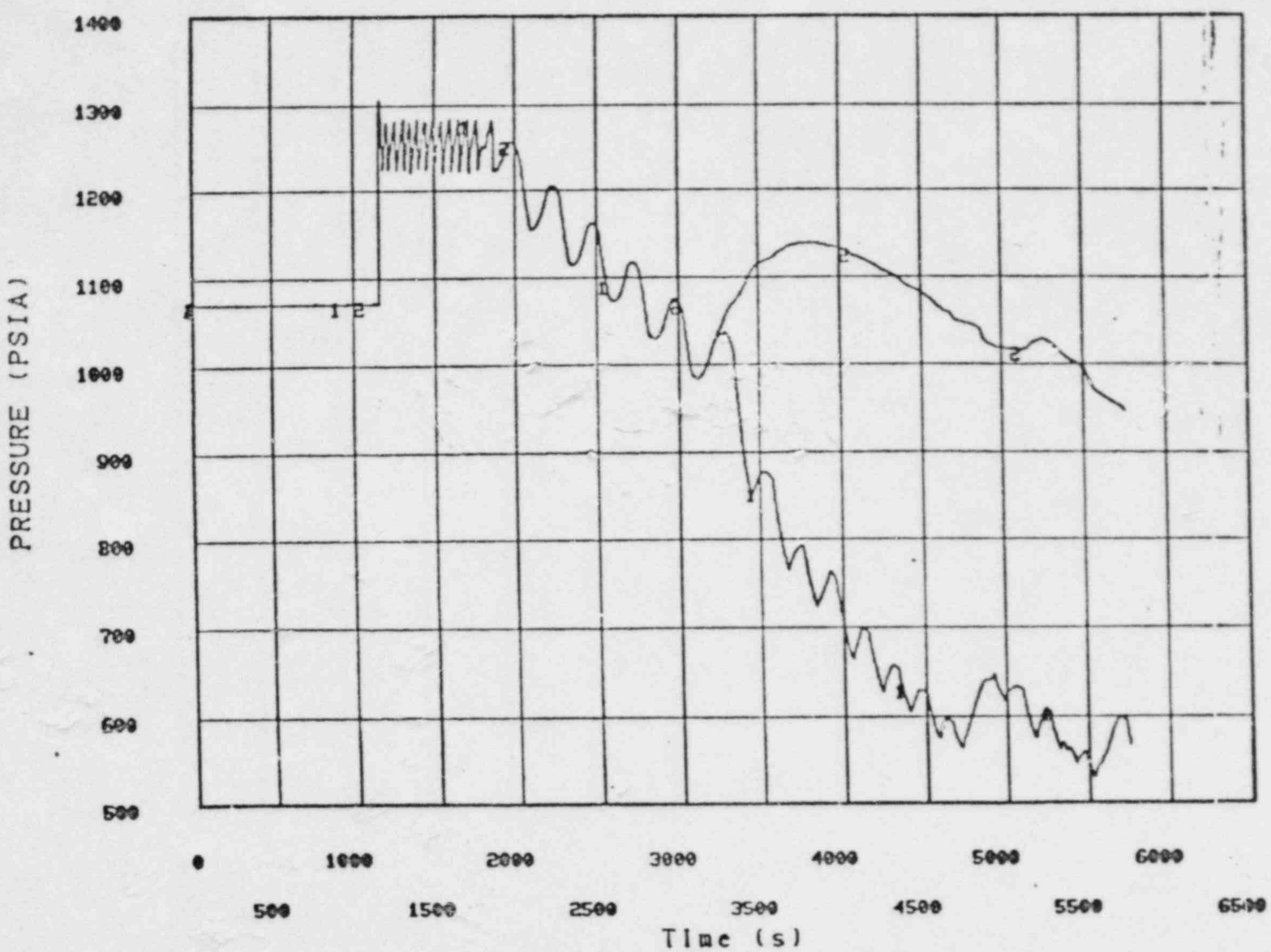
SG DØME PRESSURE: SG1,SG2



CASE 2 SINGLE SGTR PØRV

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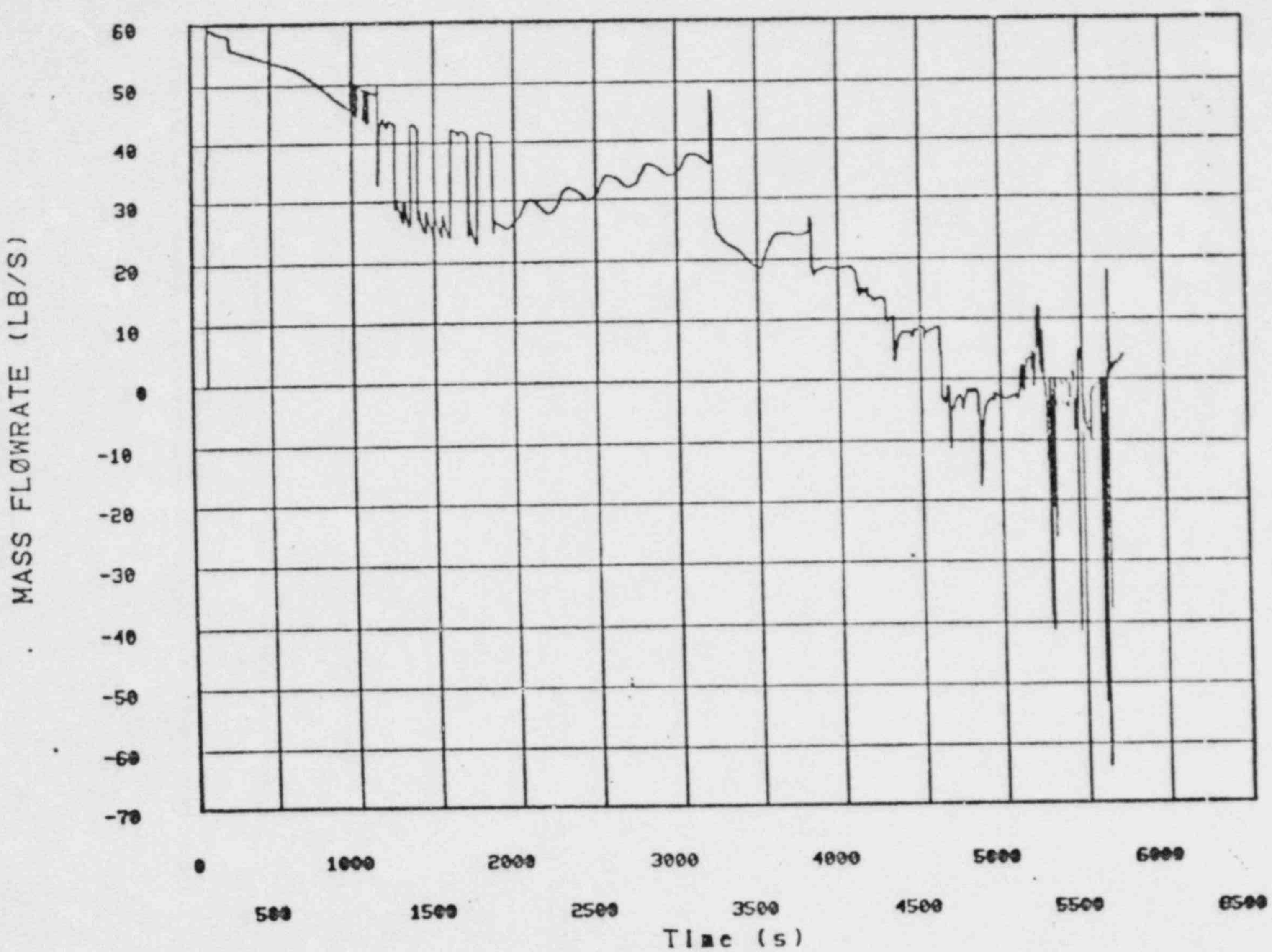
BREAK JUNCTIØN 878 FLØW



CASE 2 SINGLE SGTR PØRV

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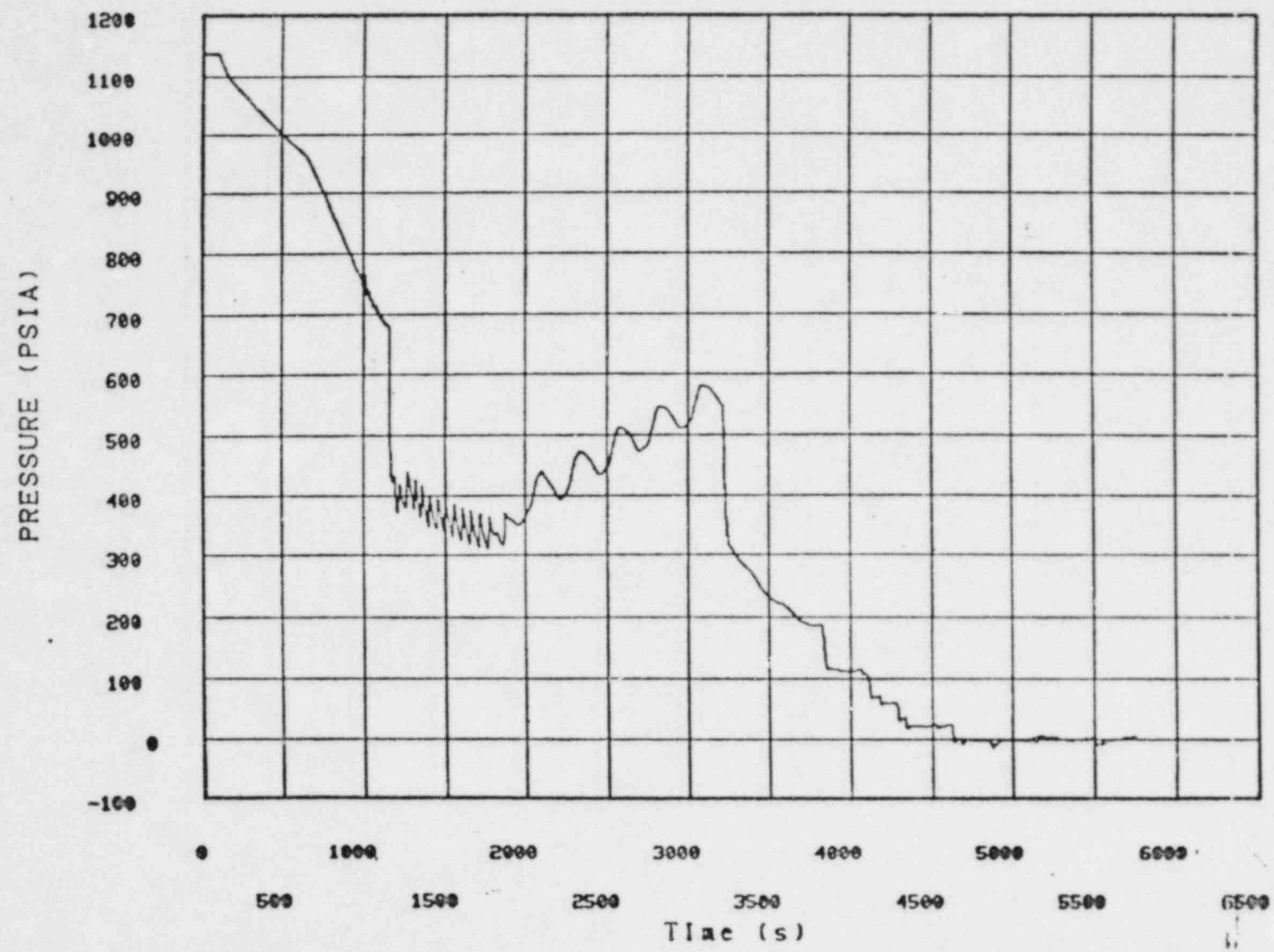
DELTA-P ACRØSS BRK JUN 878



CASE 2 SINGLE SGTR PØRV

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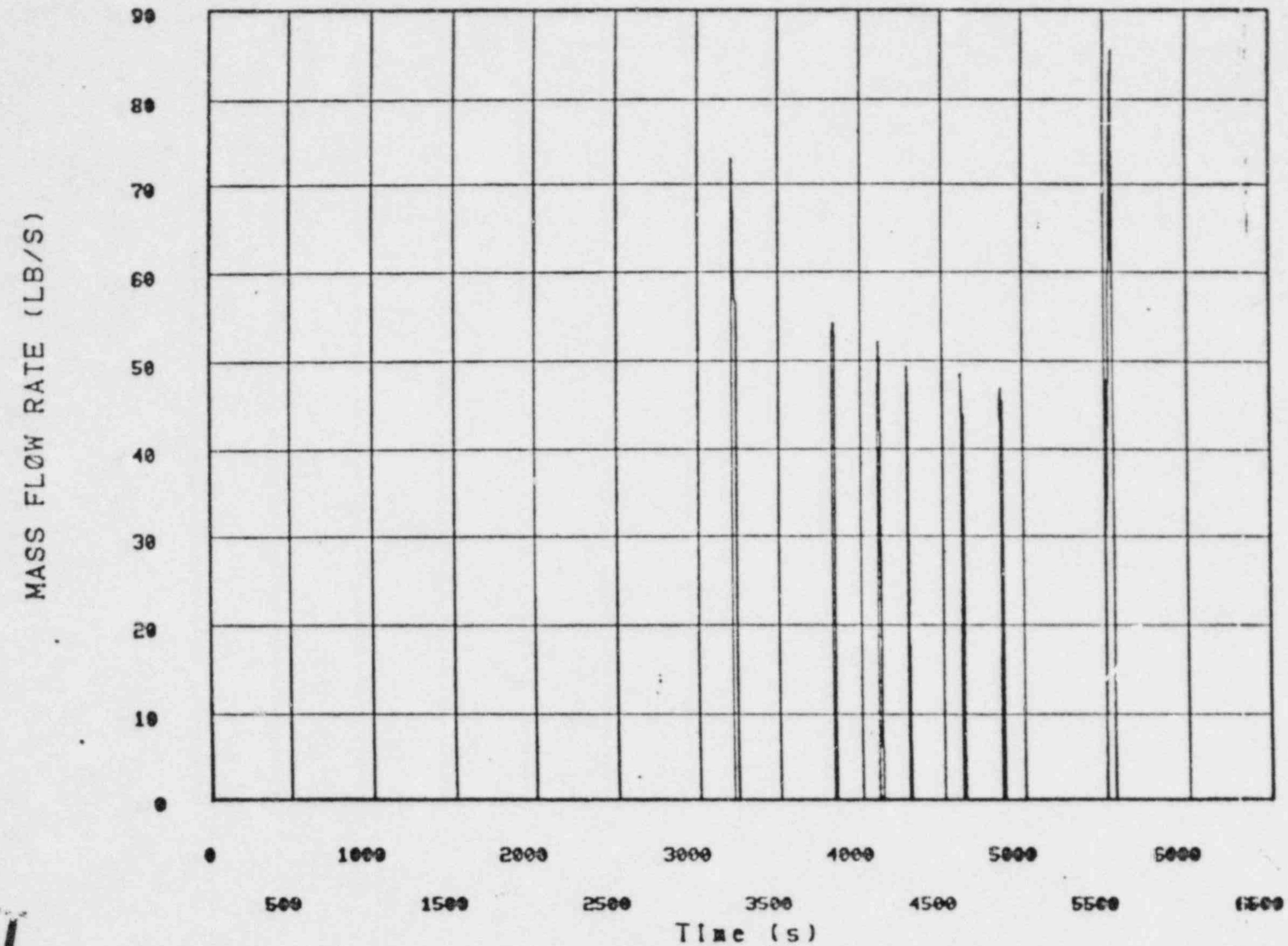
PØRV FLØW



CASE 2 SINGLE SGTR PØRV

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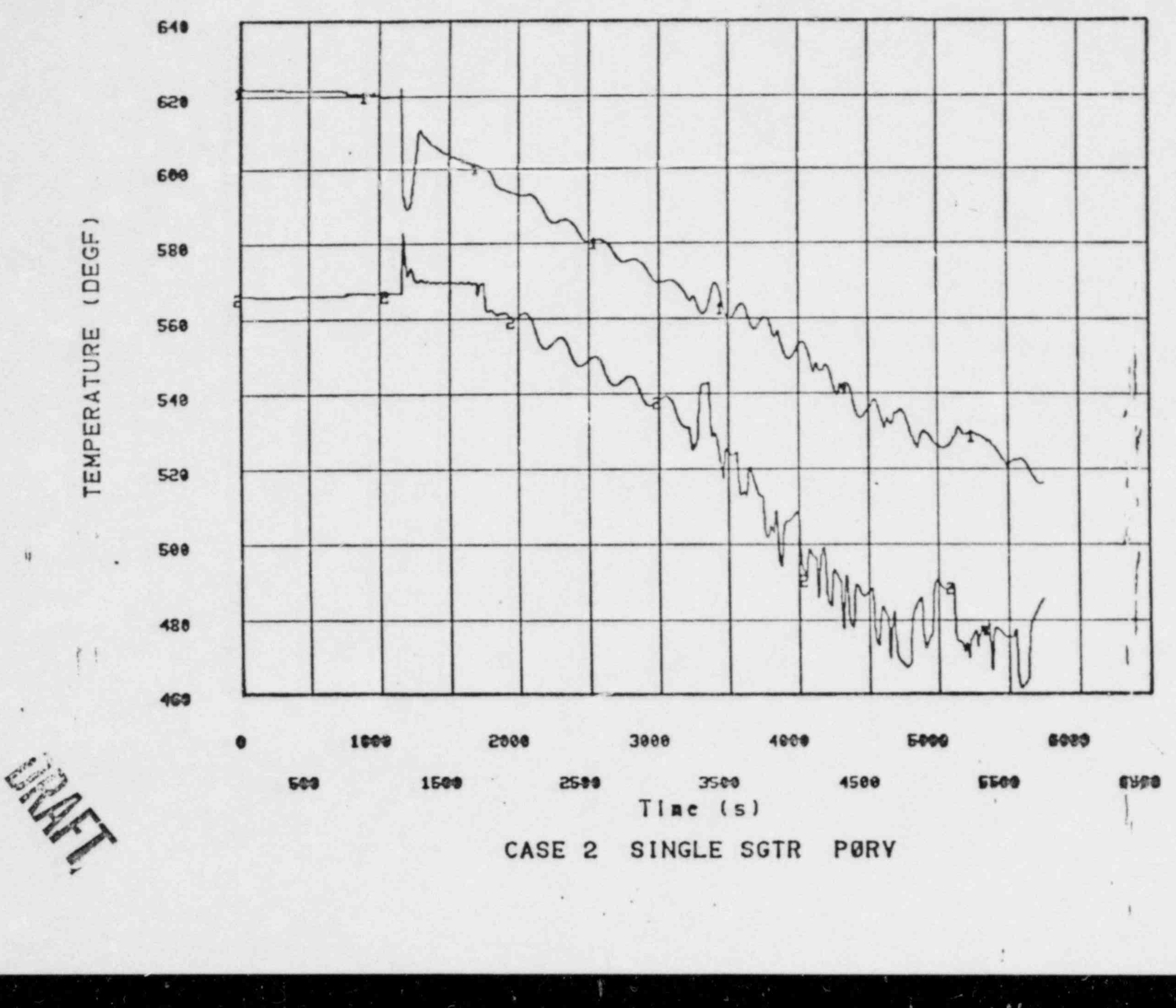
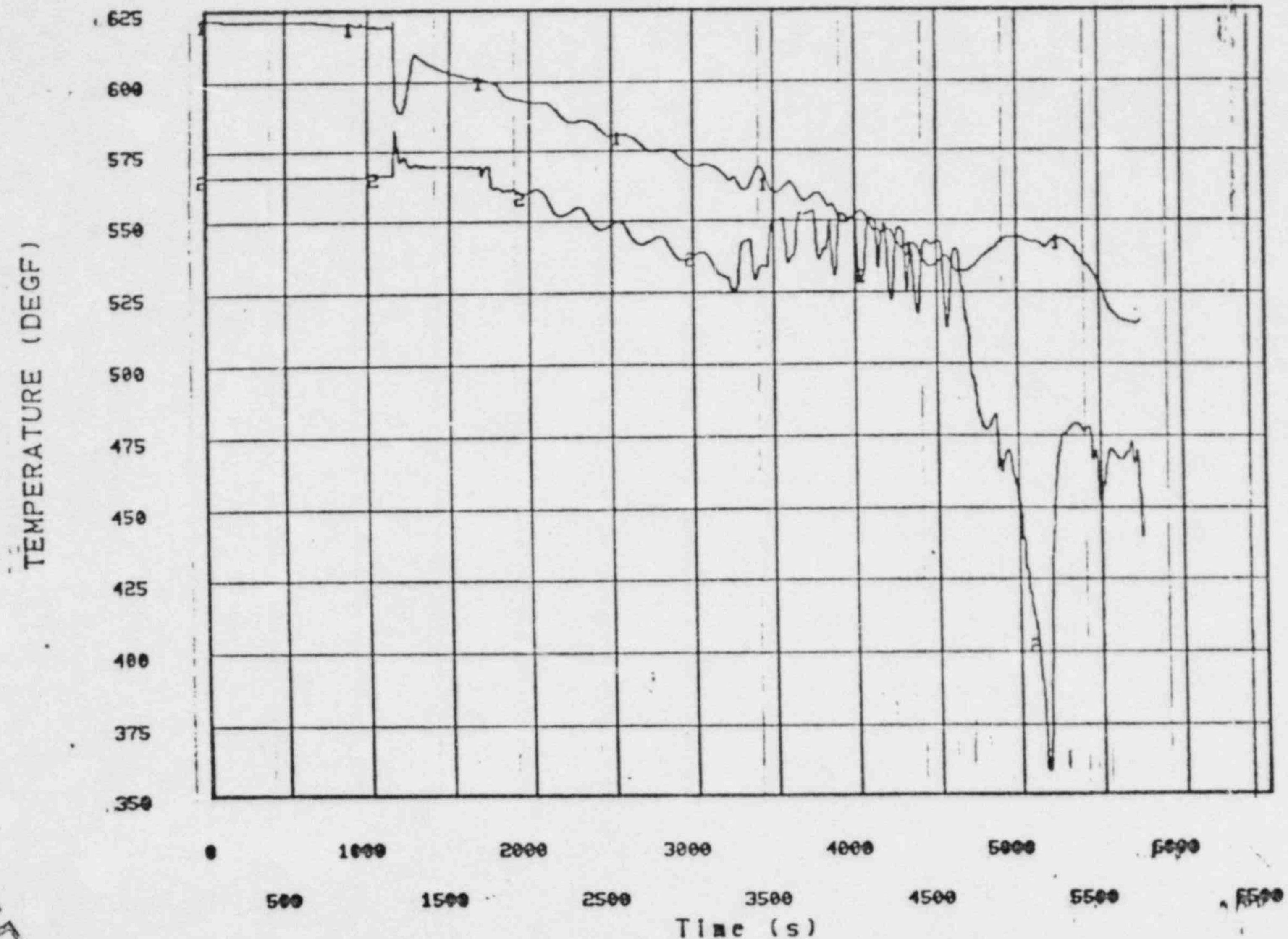
HØT AND CØLD LEG TEMPS ØN PZR LP



CASE 2 SINGLE SGTR PØRY

HØT AND CØLD LEG TEMPS: NØN PZR LP



CASE 2 SINGLE SGTR PØRV

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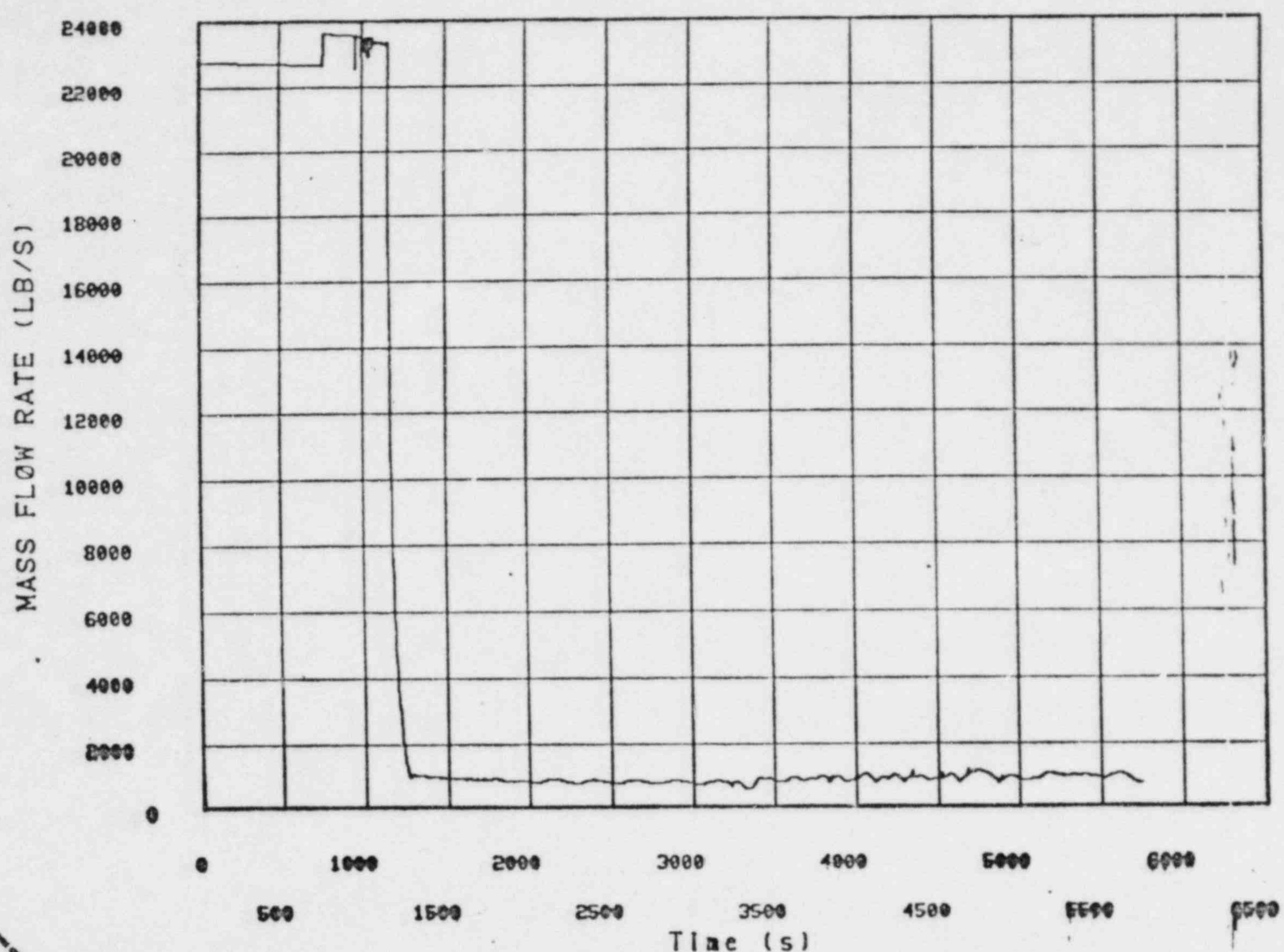
FLØW THRØUGH RCPS ØN LØØP1



CASE 2 SINGLE SGTR PØRV

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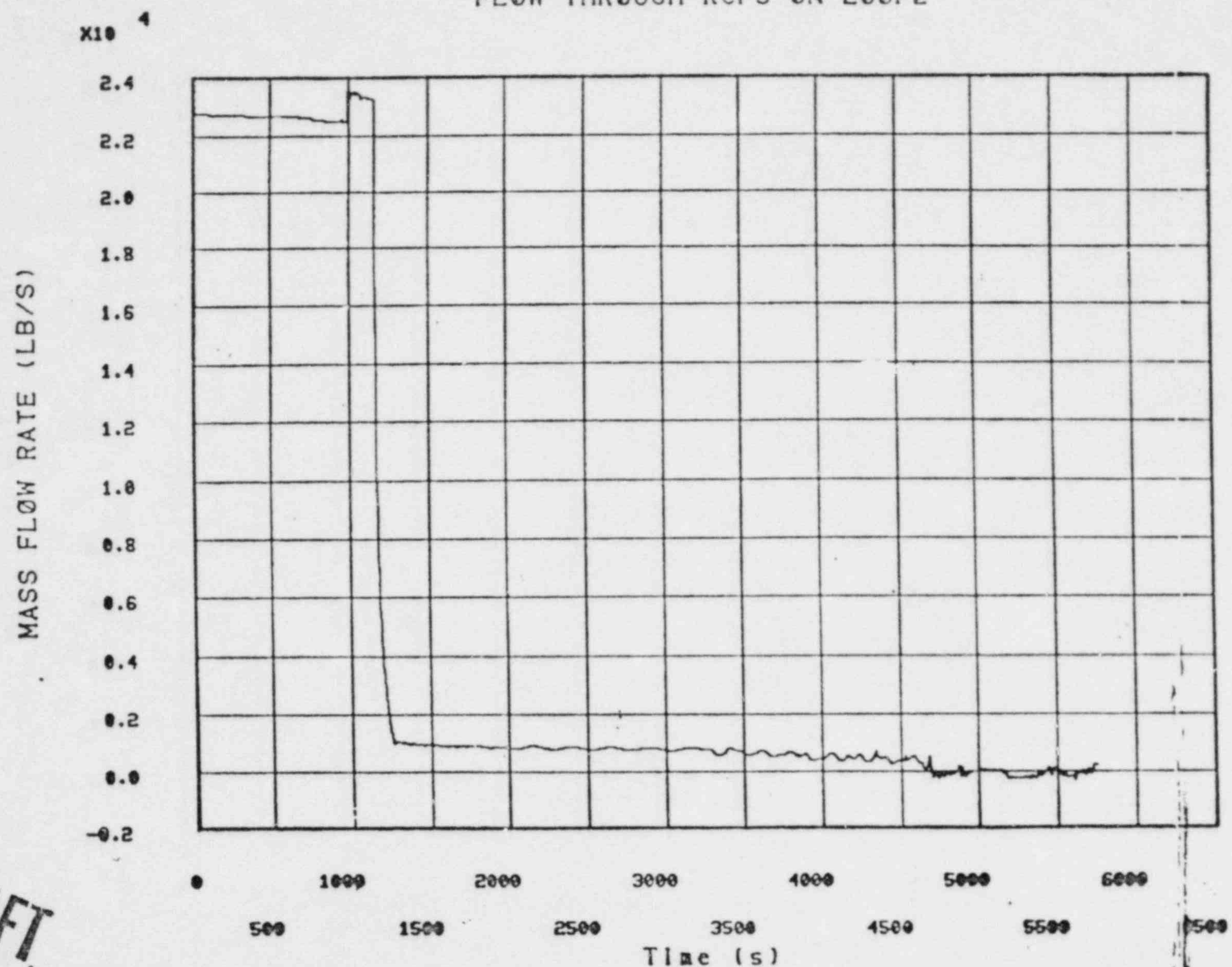

CASE 2 SINGLE SGTR PØRV

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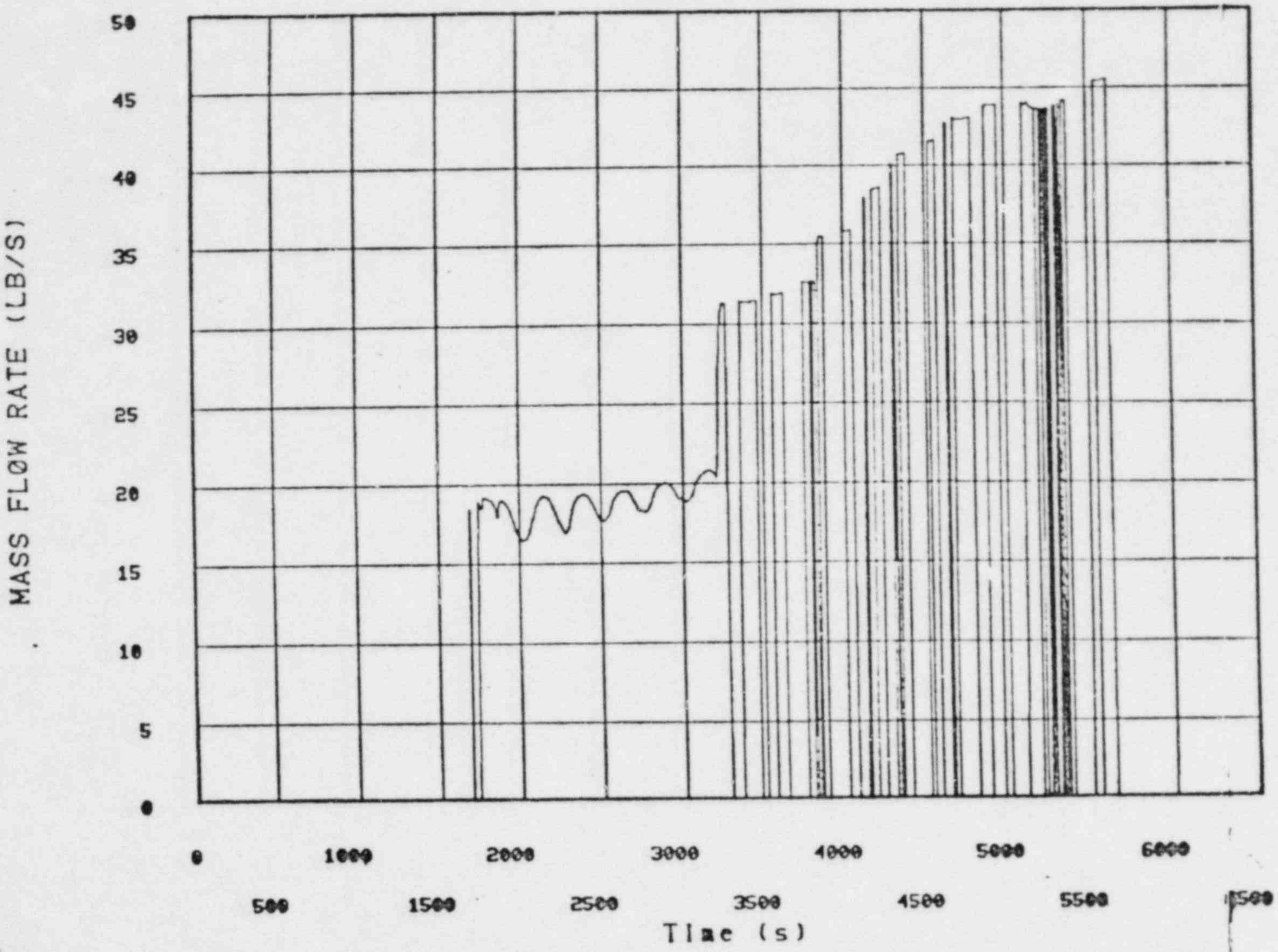
HPSI FLØWS LØØP1



CASE 2 SINGLE SGTR PØRV

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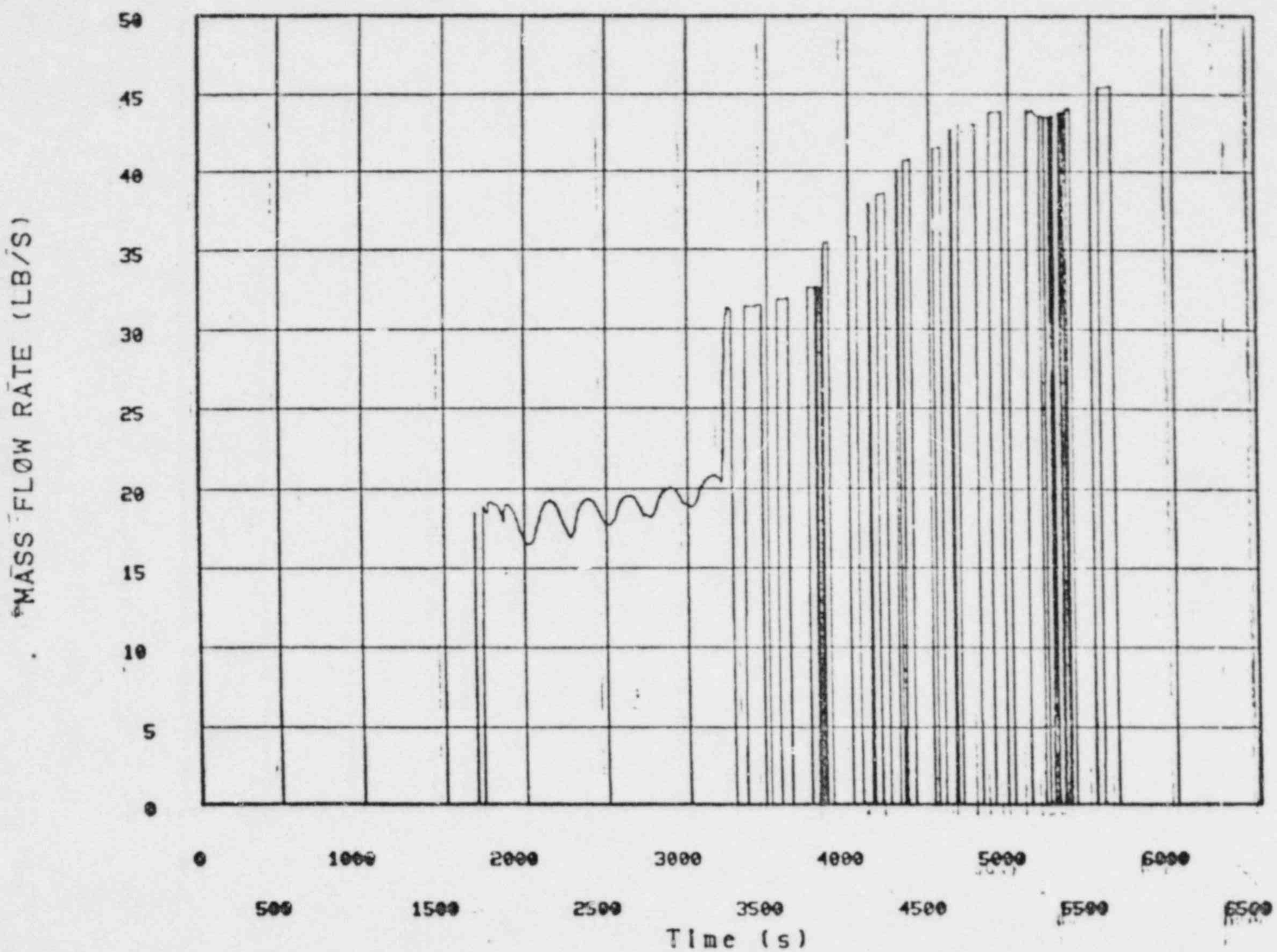
HPSI FLØWS LØØP2



CASE 2 SINGLE SGTR PØRV

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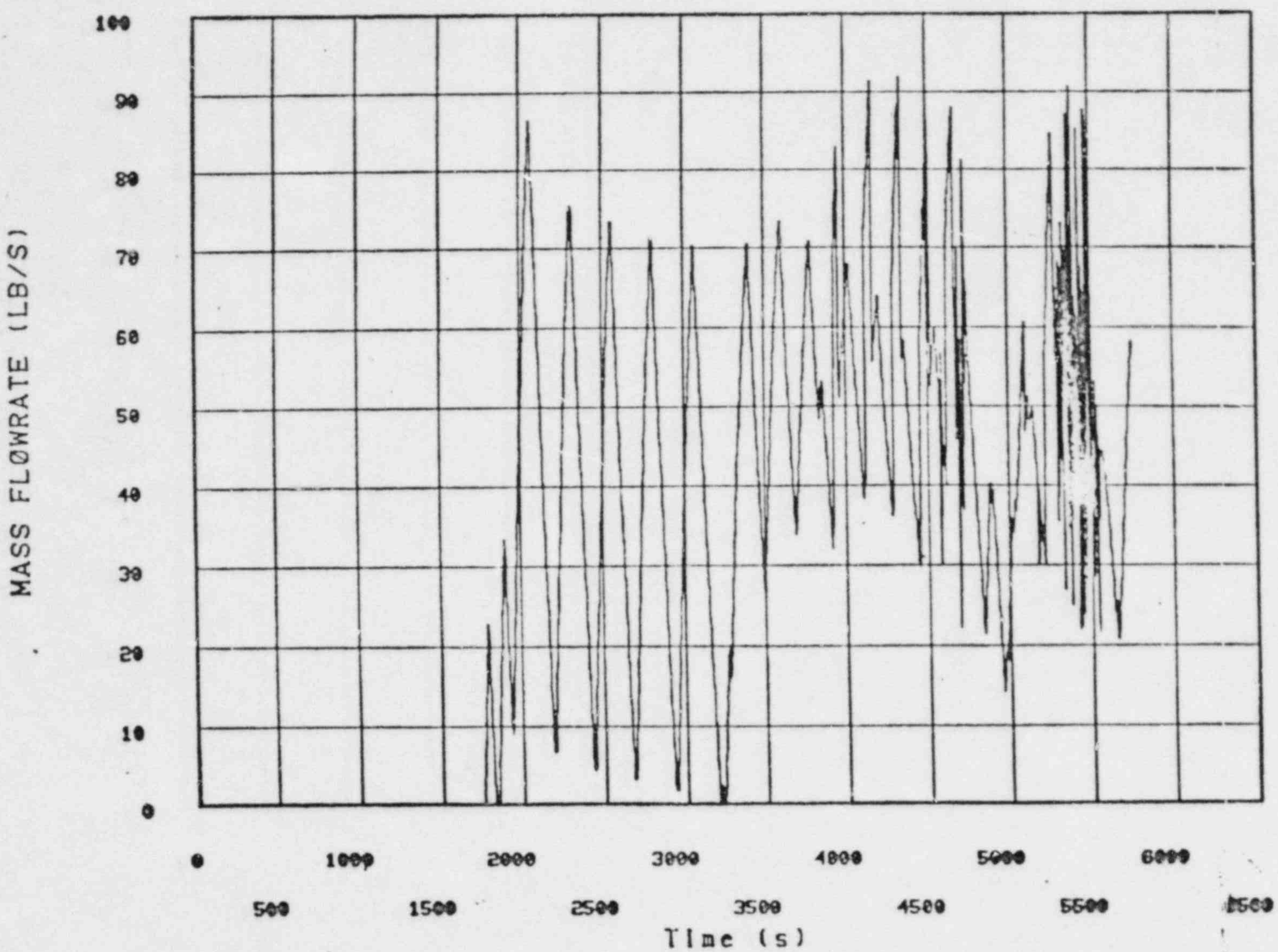
ADV FLØW SG1



CASE 2 SINGLE SGTR PØRV

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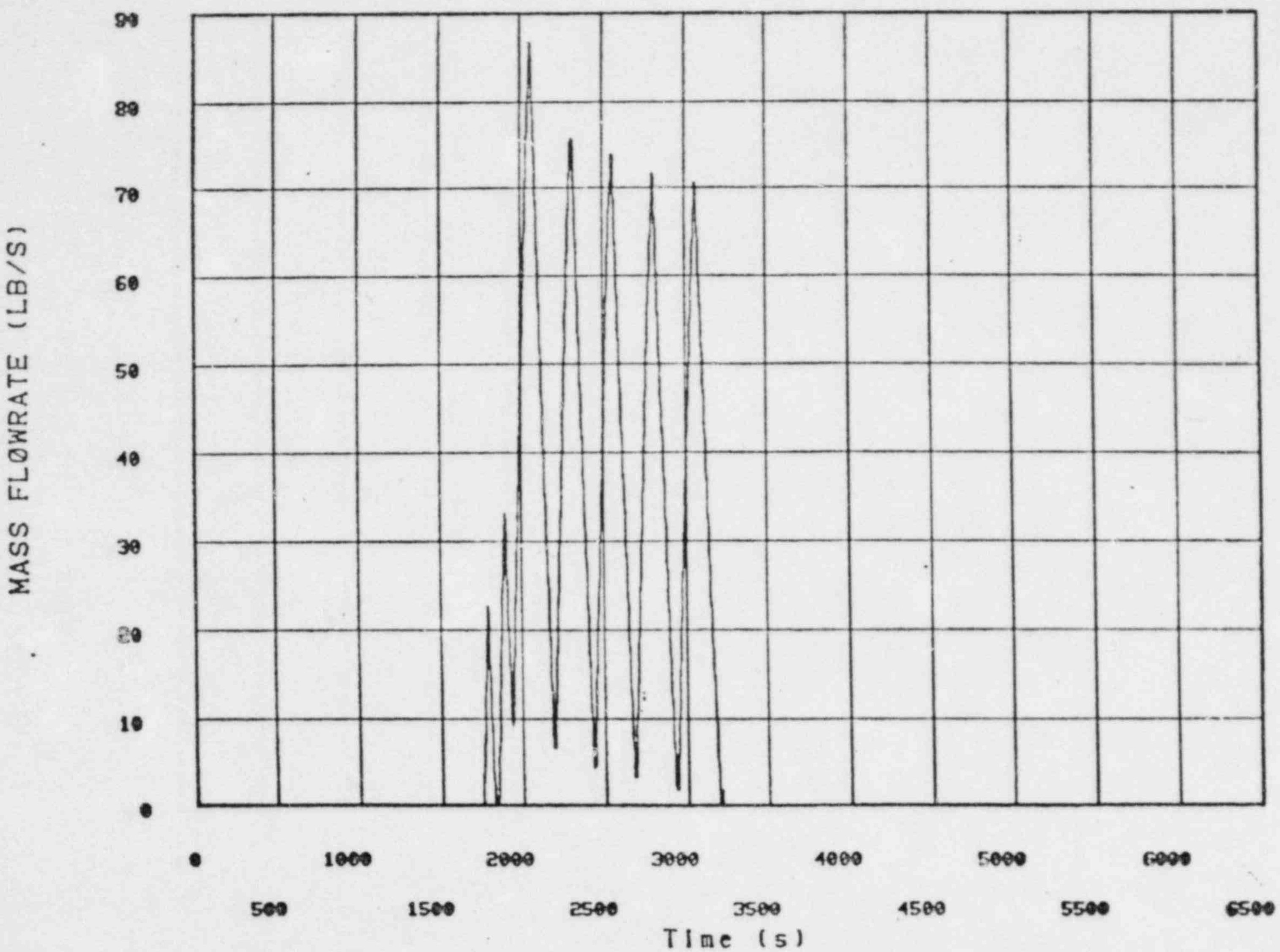
ADV FLØW SG2



CASE 2 SINGLE SGTR PØRV

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PRESSURIZER PRESSURE

CASE 3 SINGLE SGTR STUCK ADV-30

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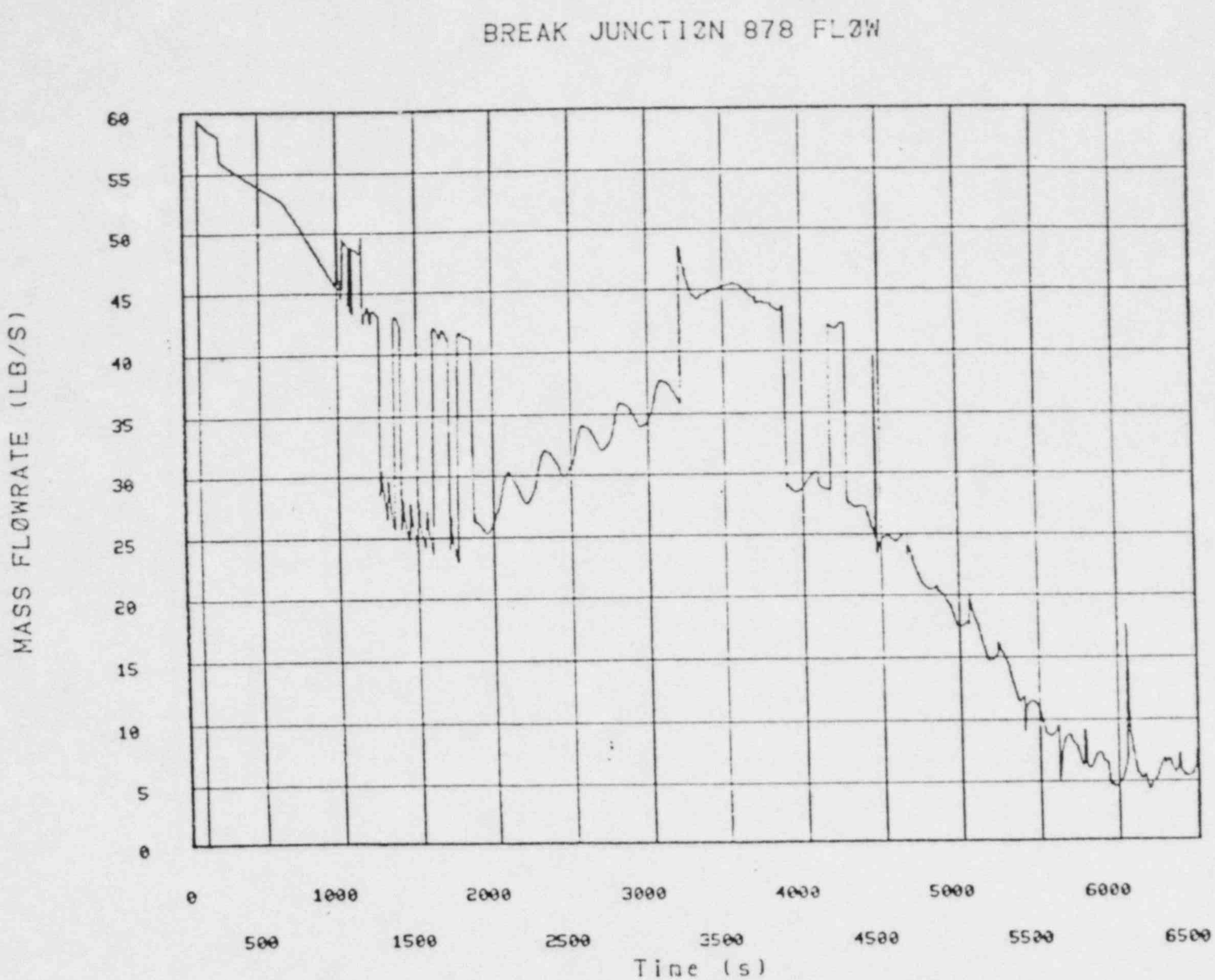

CASE 3 SINGLE SGTR STUCK ADV-30

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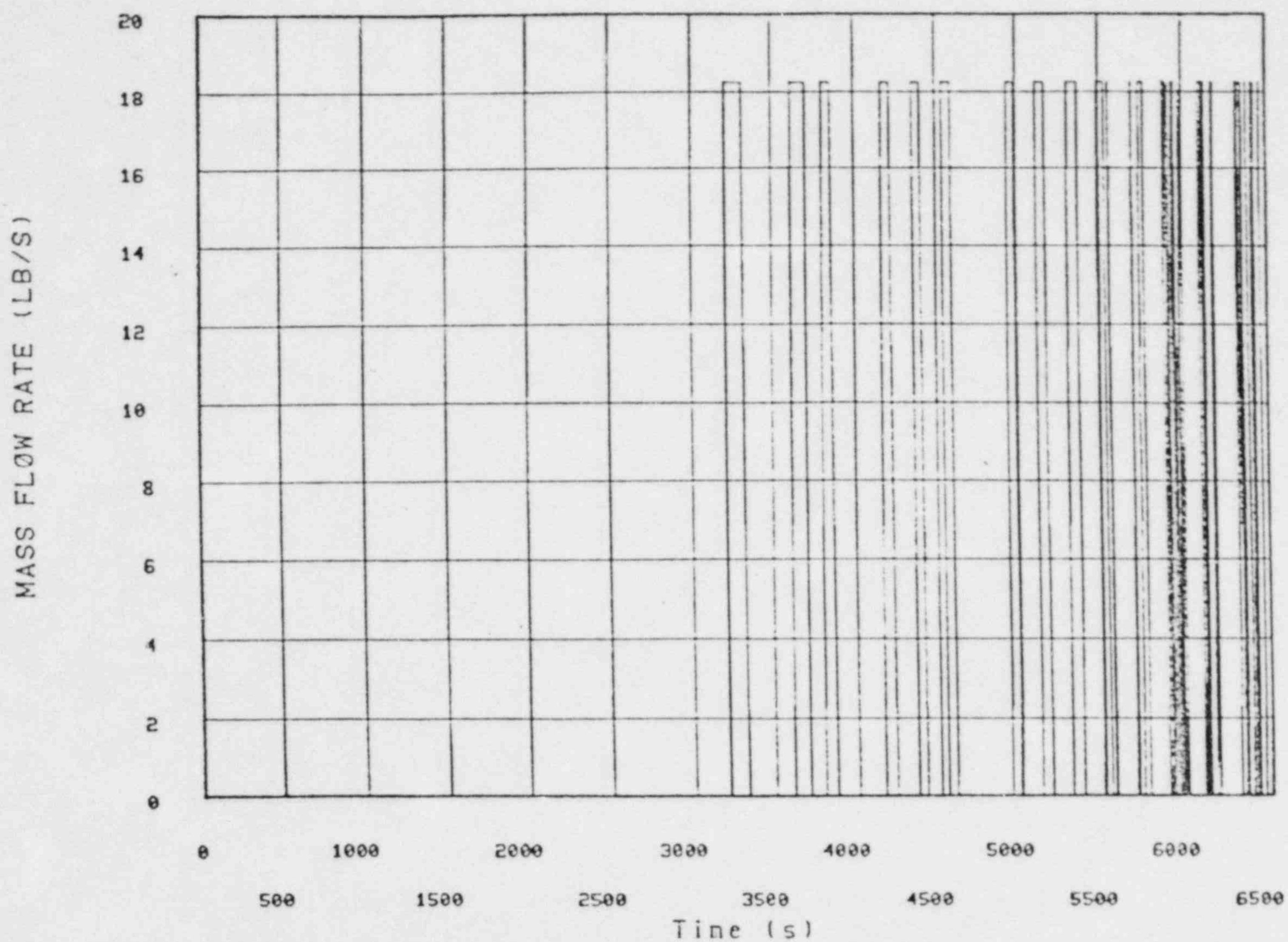
AUX. PZR SPRAY FLØW



CASE 3 SINGLE SGTR STUCK ADV-30

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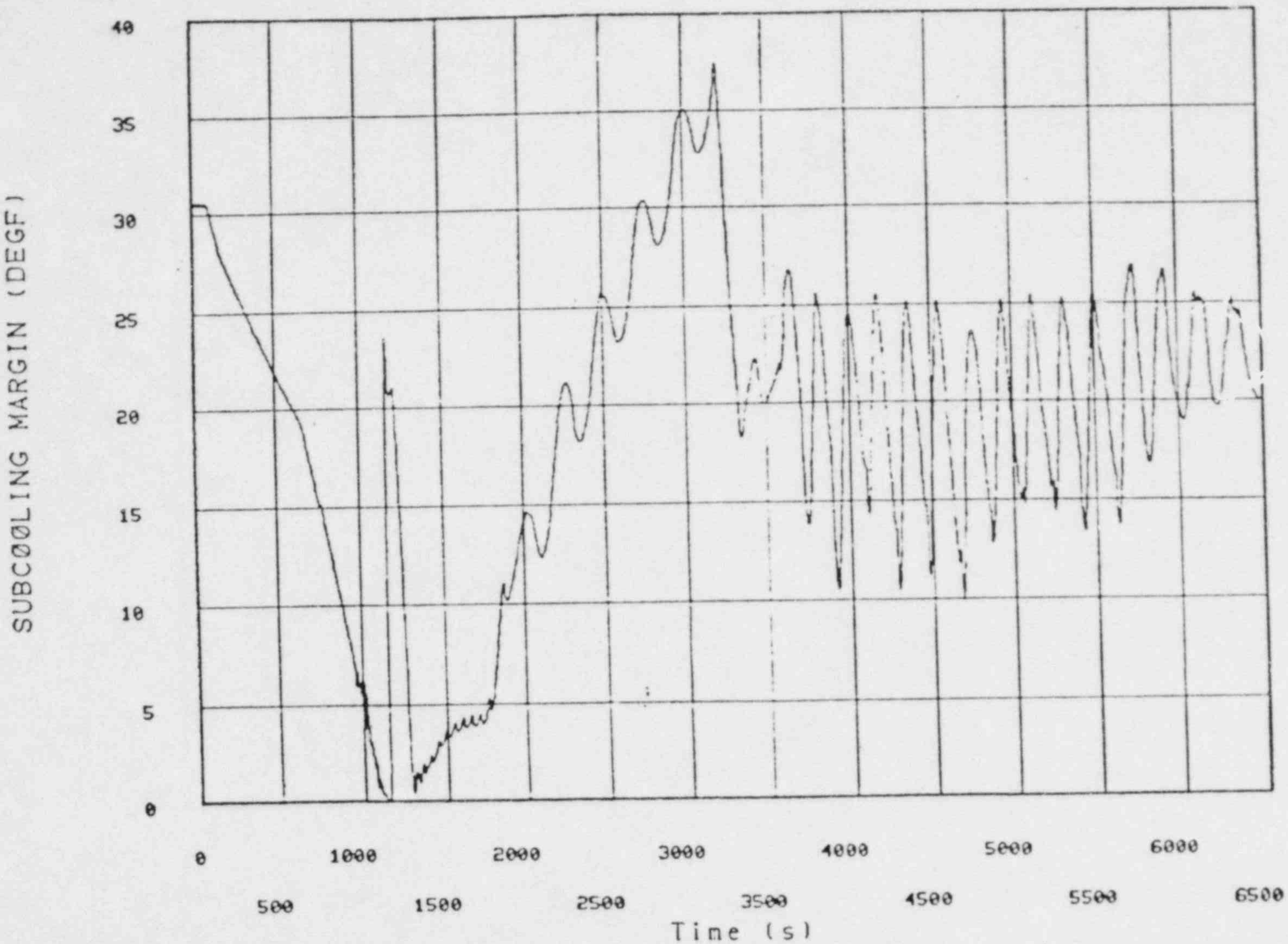
SUBCØØLING MARGIN IN VØL. 10C02



CASE 3 SINGLE SGTR STUCK ADV-30

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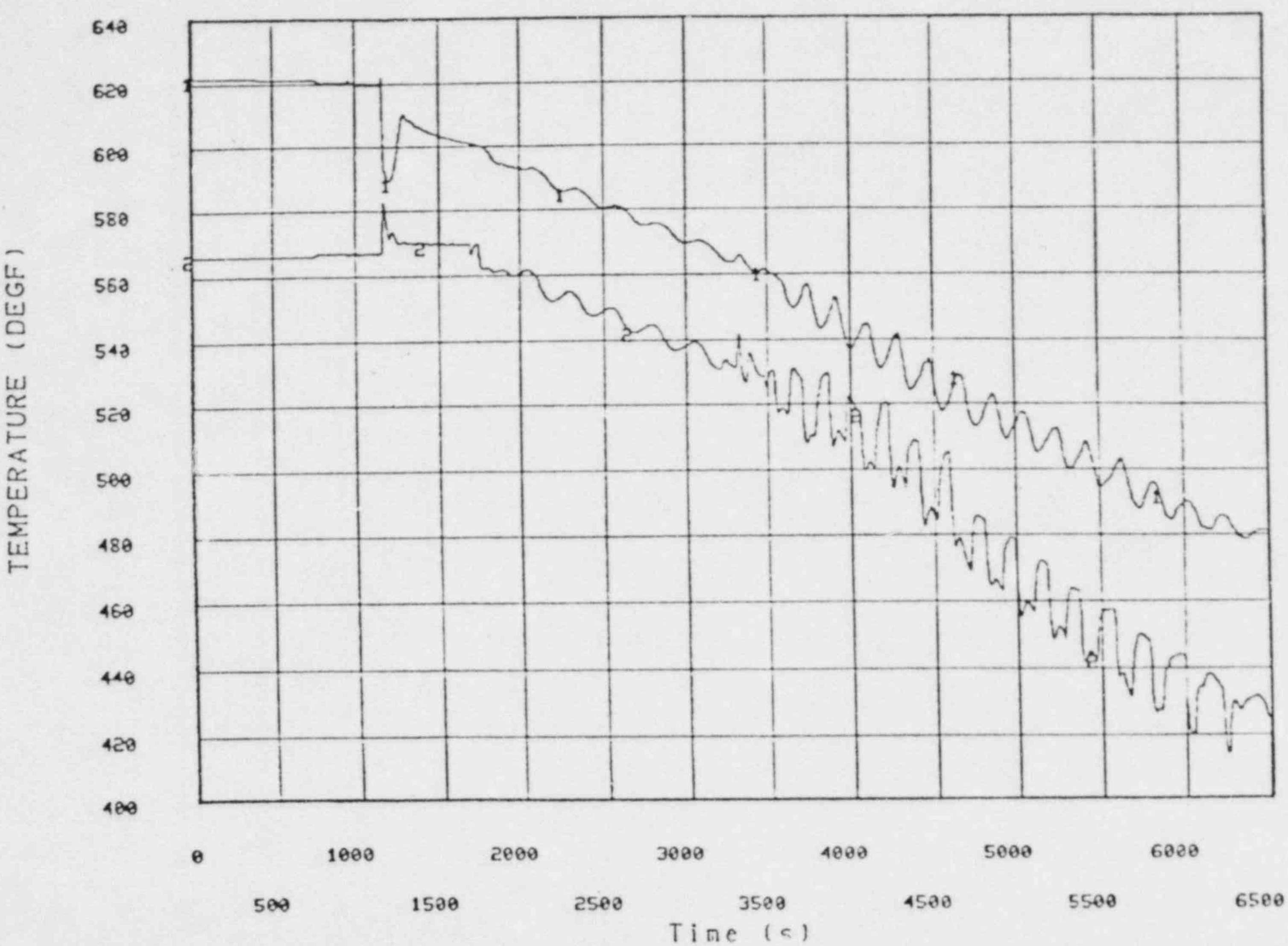
HØT AND CØLD LEG TEMPS ØN PZR LP



CASE 3 SINGLE SGTR STUCK ADV-30

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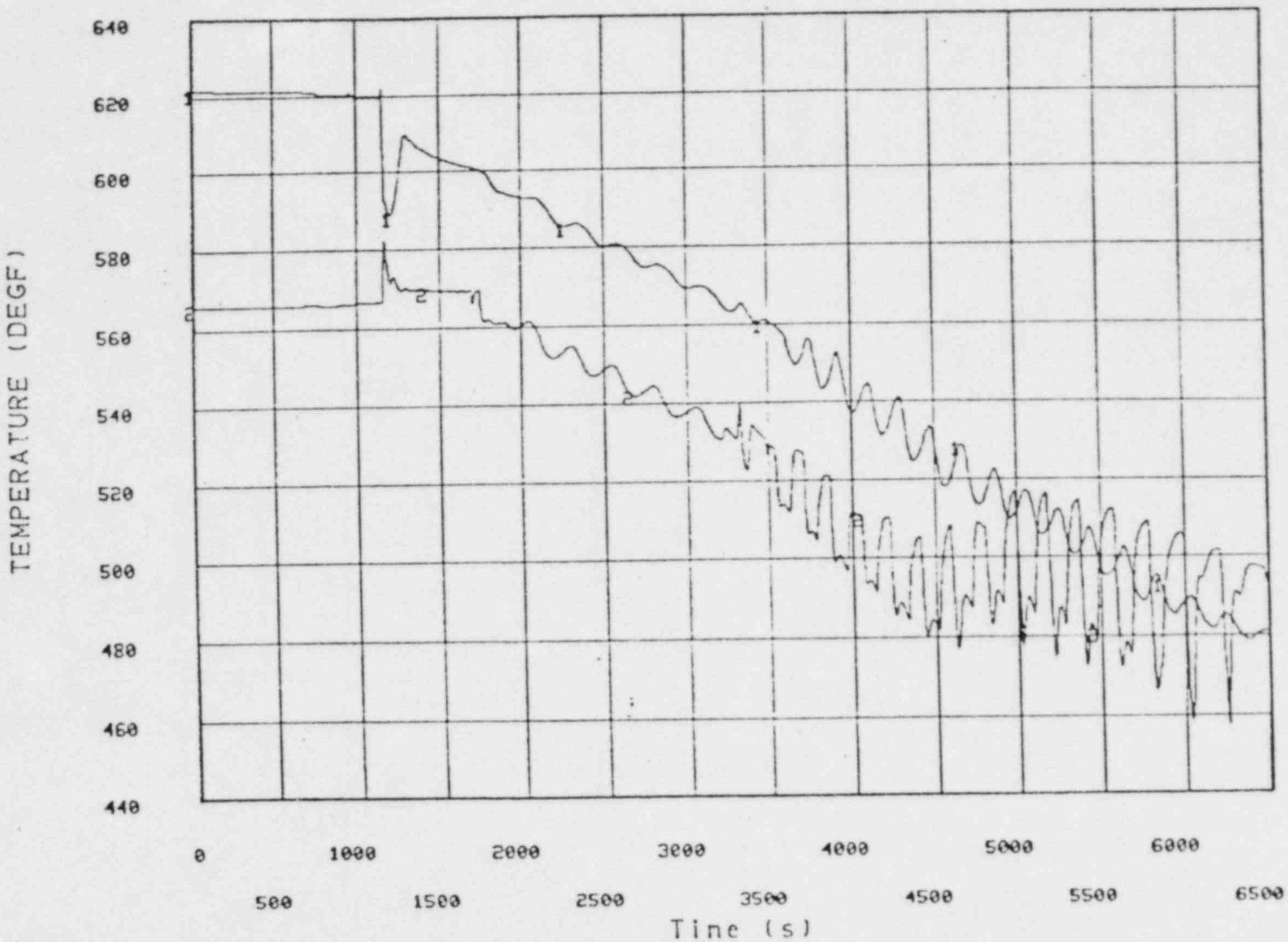
HØT AND CØLD LEG TEMPS: NØN PZR LP



CASE 3 SINGLE SGTR STUCK ADV-30

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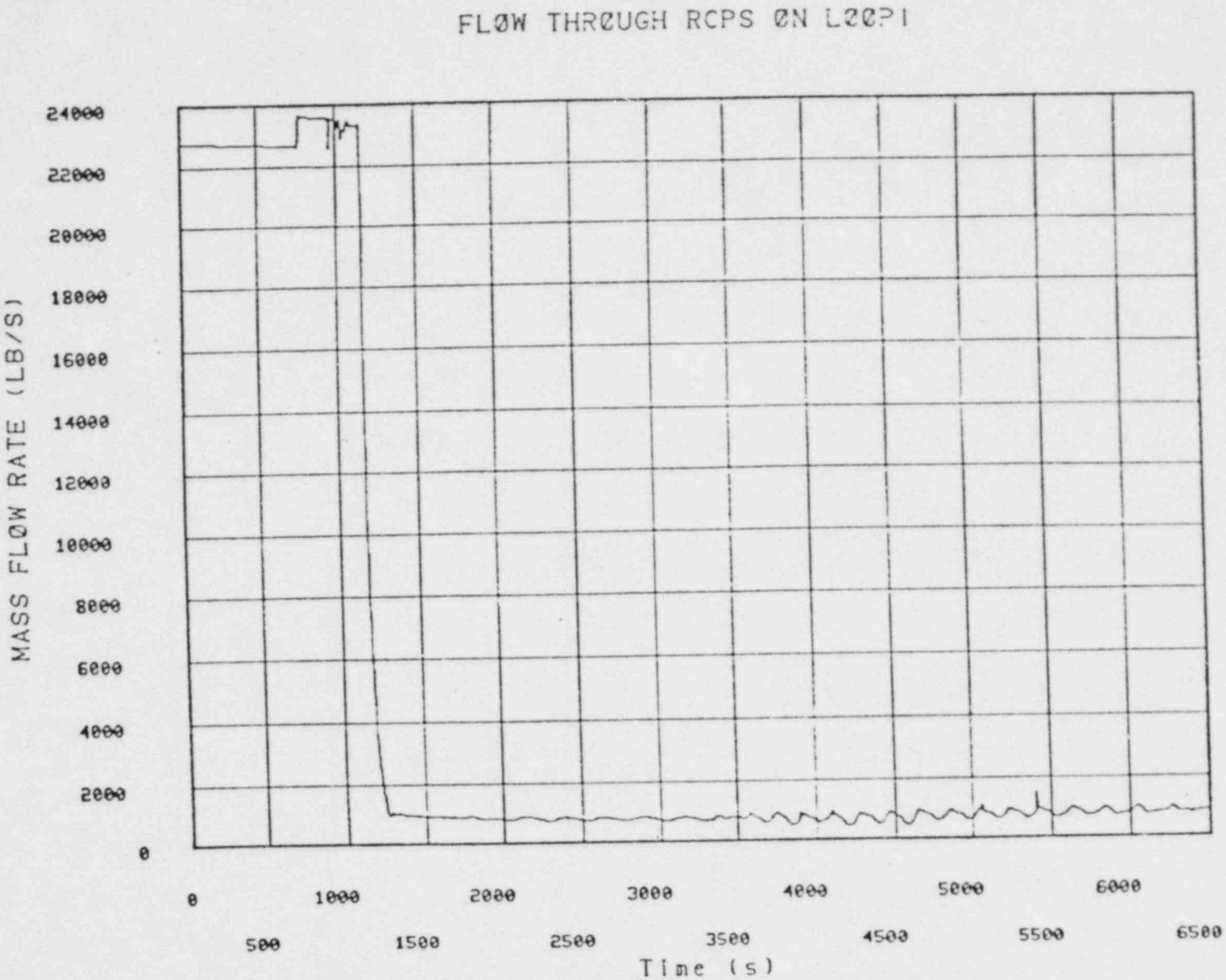

CASE 3 SINGLE SGTR STUCK ADV-30

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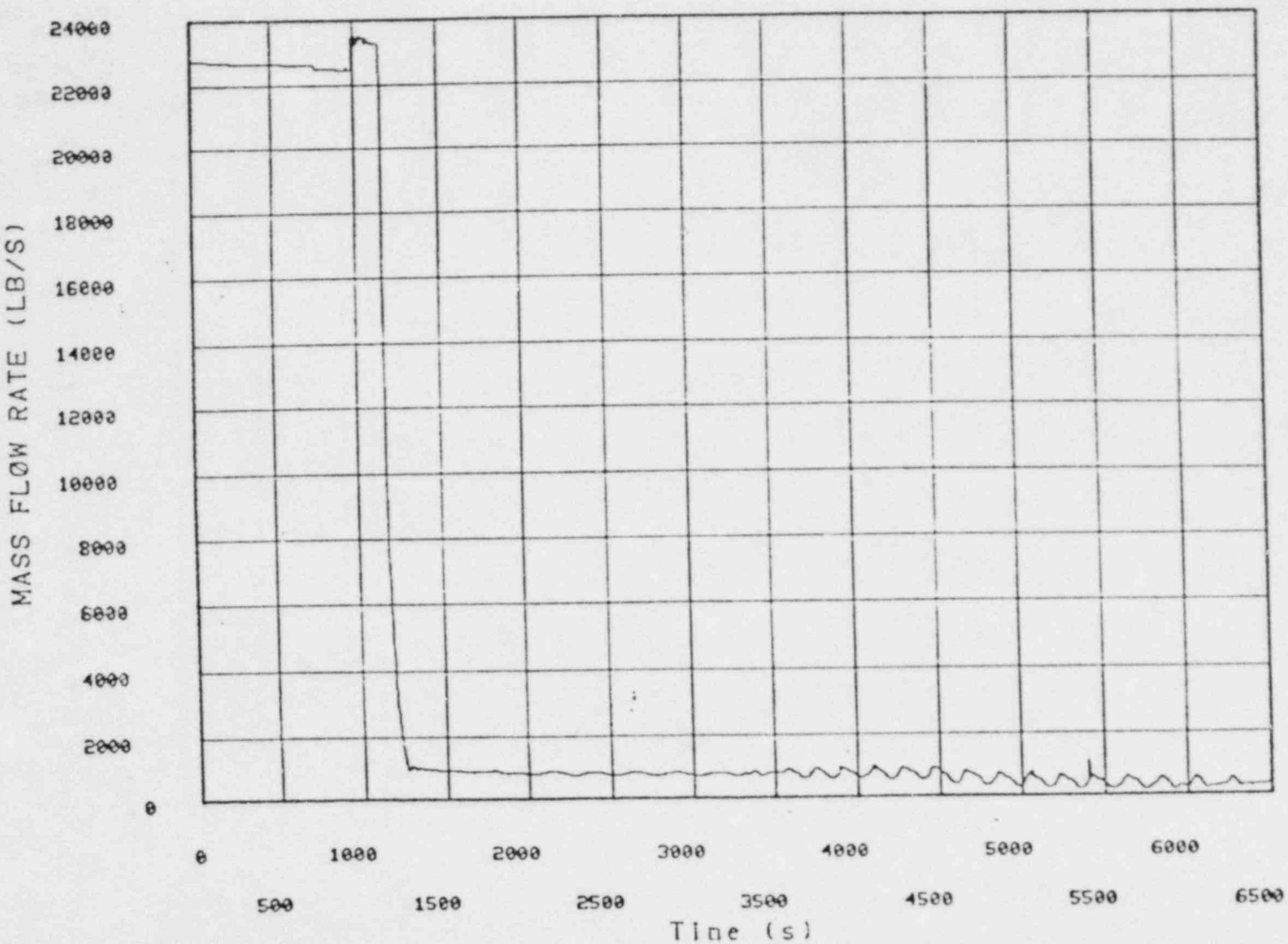
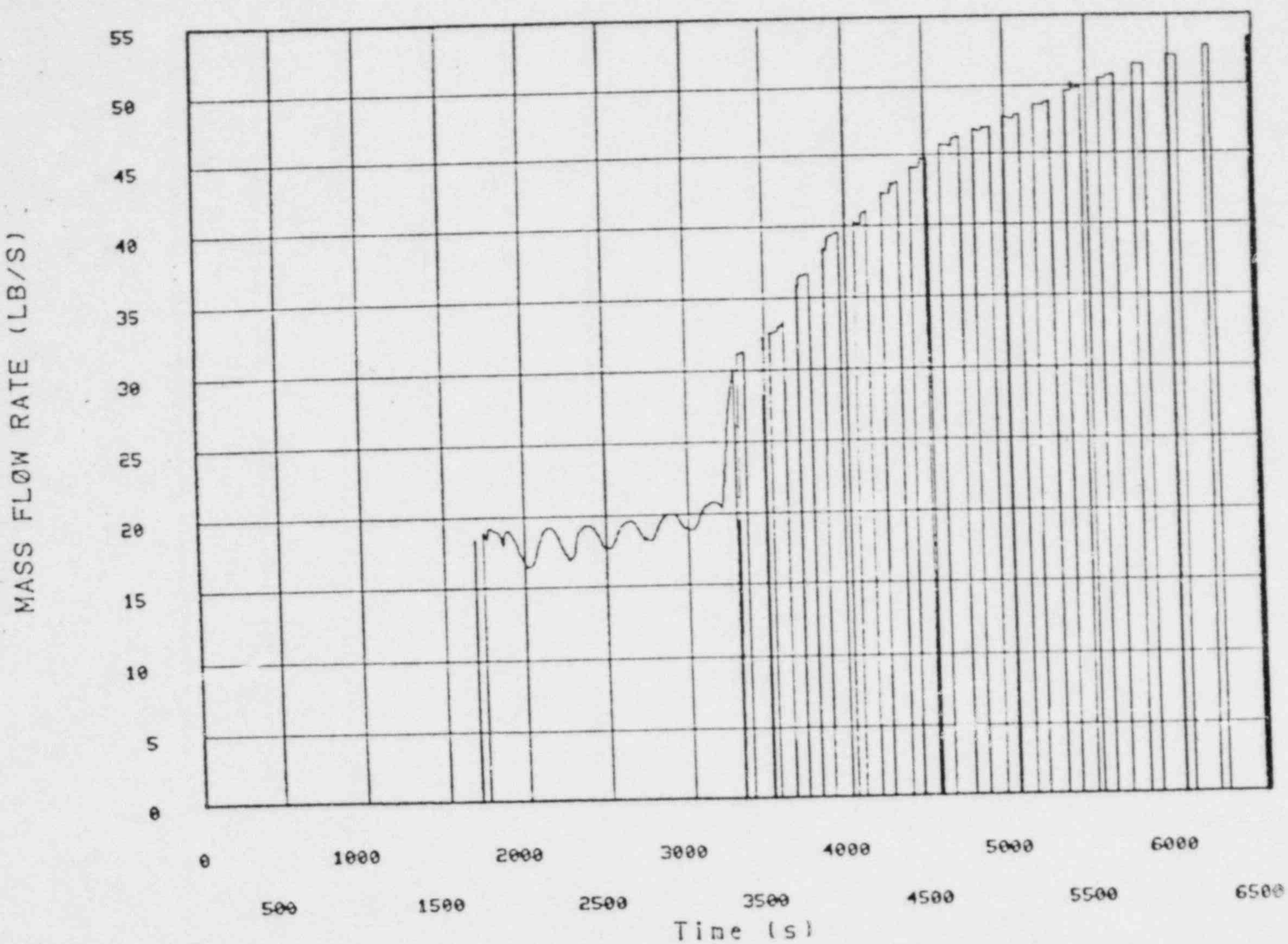
FLØW THRØUGH RCPS ØN LØØP2



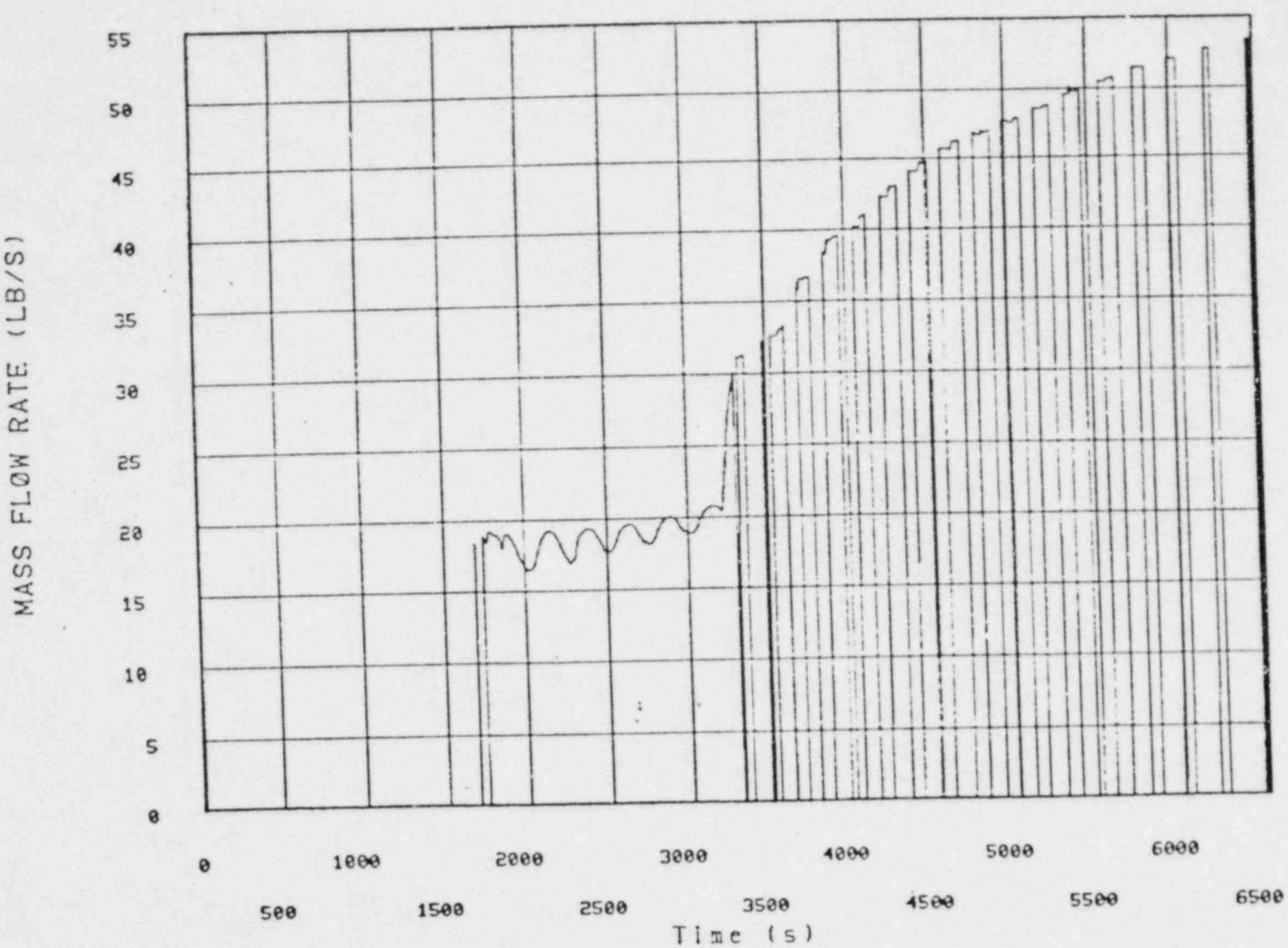
CASE 3 SINGLE SGTR STUCK ADV-30

HPSI FLØWS LØØP1



CASE 3 SINGLE SGTR STUCK ADV-30

HPSI FLØWS LØØP2



CASE 3 SINGLE SGTR STUCK ADV-30

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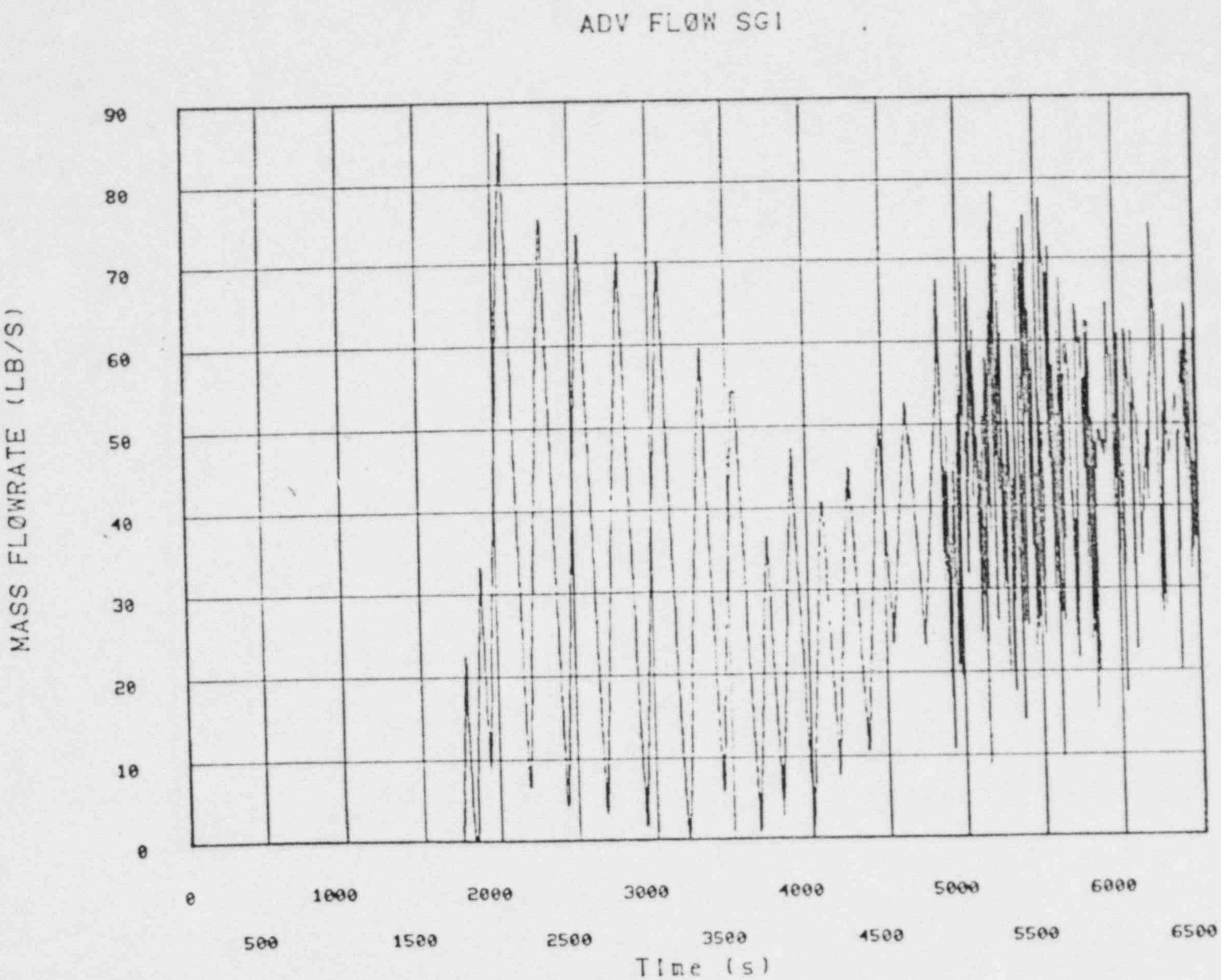

CASE 3 SINGLE SGTR STUCK ADV-30

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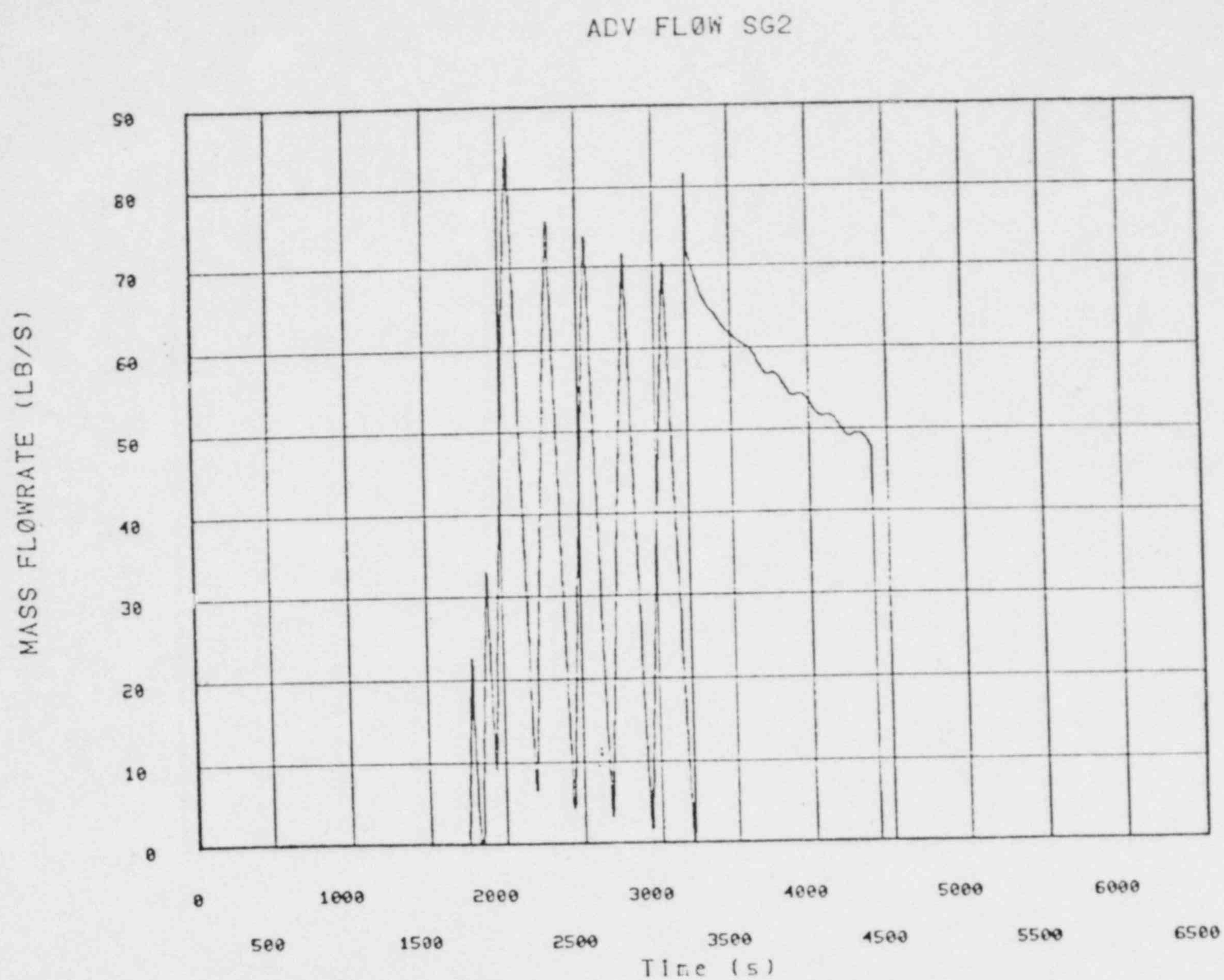

CASE 3 SINGLE SGTR STUCK ADV-30

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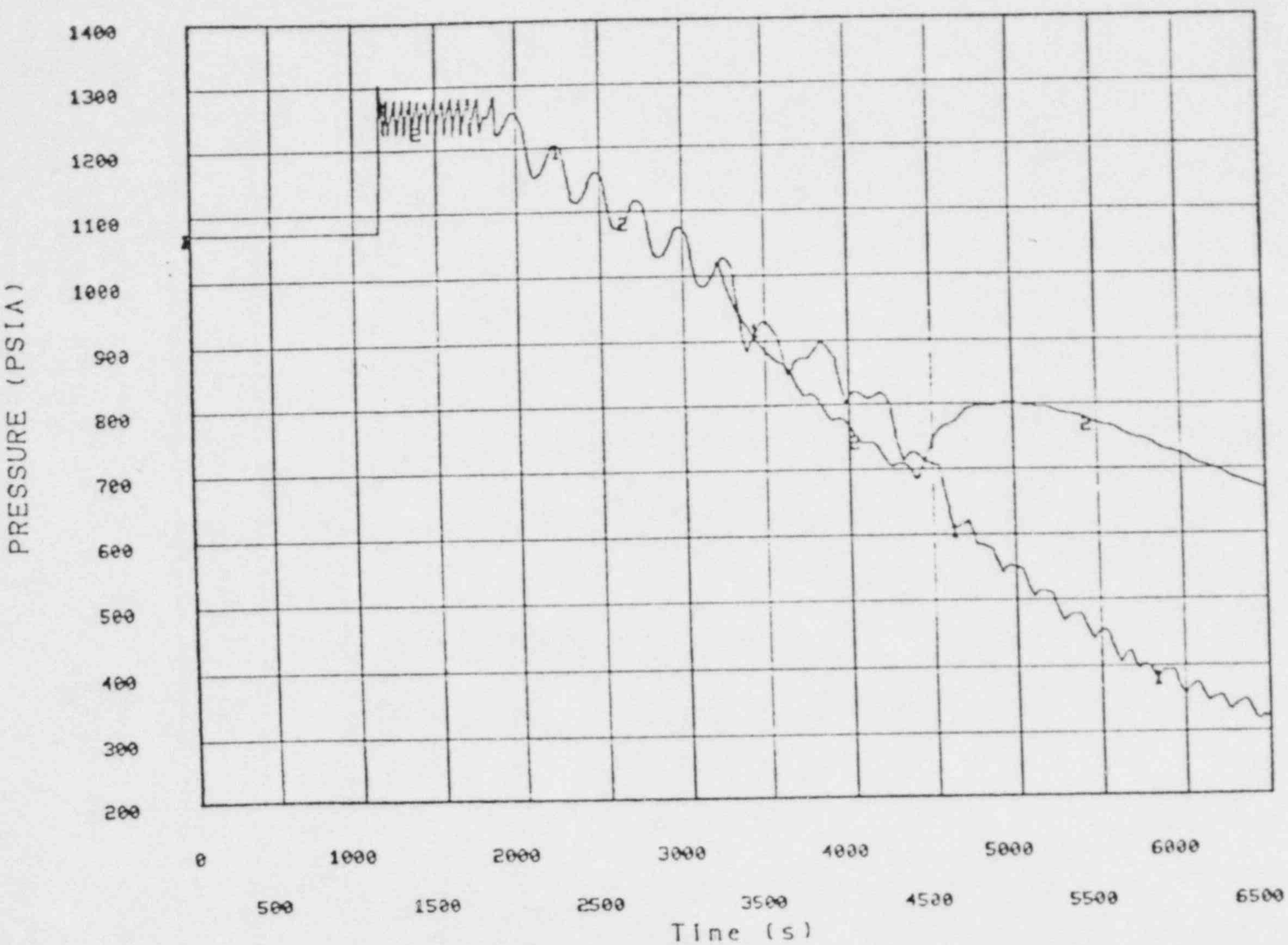
SG DØME PRESSURE: SG1,SG2



CASE 3 SINGLE SGTR STUCK ADV-30

DELTA-P ACRØSS BRK JUN 878

CASE 3 SINGLE SGTR STUCK ADV-30

DRAFT

(TO BE PROVIDED)

Table 5. Summary of Integrated System Flowrates for the Single Tube Rupture Cases.

Parameter/Case	1	2	3	4	5	6
Break						
APS						
PORV						
ADV SG1						
ADV SG2						
Safety Valves SG1						
Safety Valves SG2						
HPSI Loop 1						
HPSI Loop 2						
Pressurizer safety valve						

4.1.2 PORV Case (Case 2)

(To be written.) [FIGURES INCLUDED]

4.1.3 APS Case with Stuck Open ADV on the Ruptured Steam Generator (Case 3)

(To be written.) [FIGURES INCLUDED]

4.1.4 Continuous APS Due to Operator Error (Case 4)

(To be written.)

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4.1.5 Continuous APS with PORV (Case 5)

(To be written.)

4.1.6 APS Case with Stuck Open ADV Valve Until End of Transient (Case 6)

(To be written.)

4.2 Double Ended Guillotine Rupture of a Single Tube in Both Steam Generators

As in the single tube rupture cases discussed in Section 4.1, the cases with a single SGTR in both steam generators were all continuations from a base case calculation which ended when the ADV was closed on one of the steam generatoars. The base case was initiated, following a 100 s null transient, by opening the leak flow paths from the primary to secondary systems in both steam generators. The discussion of the base case is included in the discussion of the results of Case 7 in which the APS system is used to depressurize the primary system. For the remainder of the dual SGTR calculations, only the recovery phase of the transient will be discussed.

4.2.1 Auxiliary Pressurizer Spray Case (Case 7)

The overall plant response for the dual SGTR base case is very similar to the base case for the single SGTR cases. However, the timescale for the dual SGTR cases is more compressed than for the single SGTR cases because the increased break flow causes the primary system inventory and consequently the pressurizer pressure to decrease much faster. Because the primary system depressurization (Fig. 21) was so rapid, a reactor trip was generated very early at ___ s when the pressurizer pressure decreased below the core protection calculator low pressure boundary trip setpoint of 1785 psia. Again the post-trip response of the pressurizer pressure is qualitatively similar to the single SGTR base case. The depressurization of the primary system continues for another 600 s as primary system liquid inventory is discharged through the break and energy is removed from the steam generators through the steam generator safety valves. At 600 s following the reactor trip,, the ADVs are opened to reduce the hot leg temperatures to below 565°F. When the hot leg temperature decreases below 565°F, the ADV on loop 2 (the non-pressurizer loop) is closed and the steam generator on this loop is isolated by closing the main steam and feedwater isolation valves. This marks the termination of the base case and begins the recovery phase of the accident.

(REMAINDER OF TEXT TO BE WRITTEN)
[FIGURES INCLUDED]

4.2.2 PORV Case (Case 8)

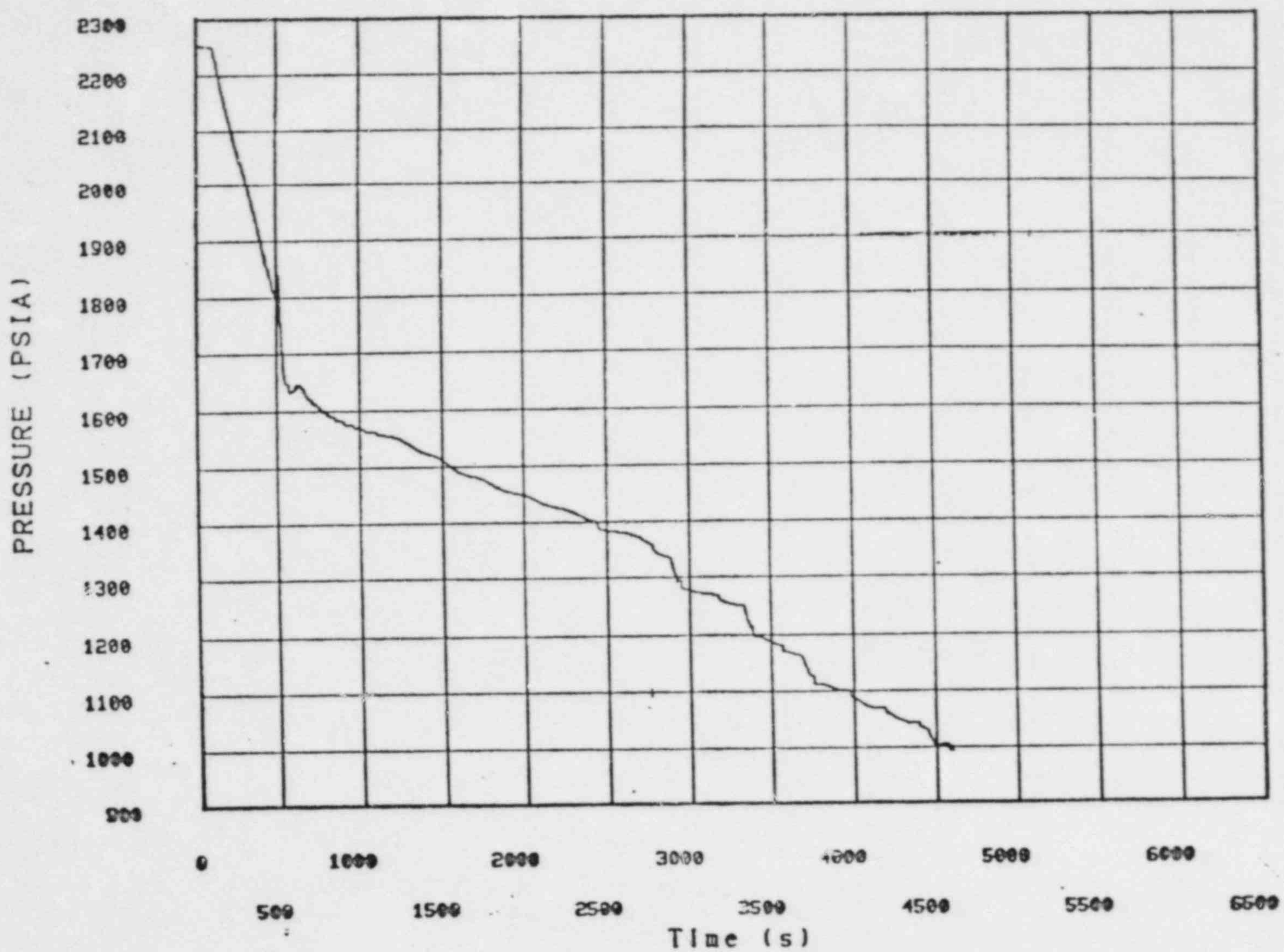
(To be written.) [FIGURES INCLUDED]

4.2.3 PORV Feed and Bleed Case (Case 9)

(To be written.)

DRAFT

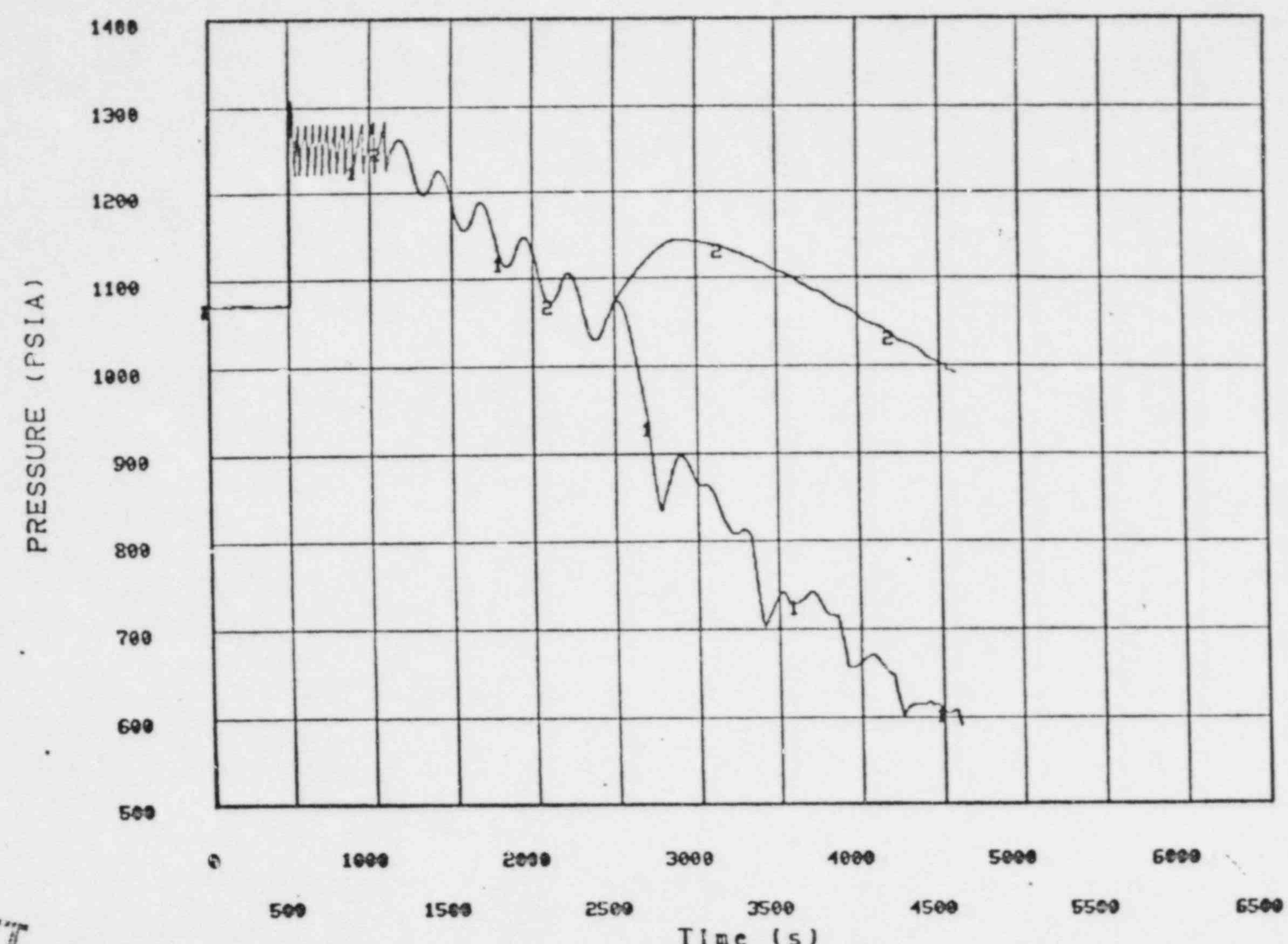
PRESSURIZER PRESSURE



CASE 7 DUAL SGTR APS

DRAFT

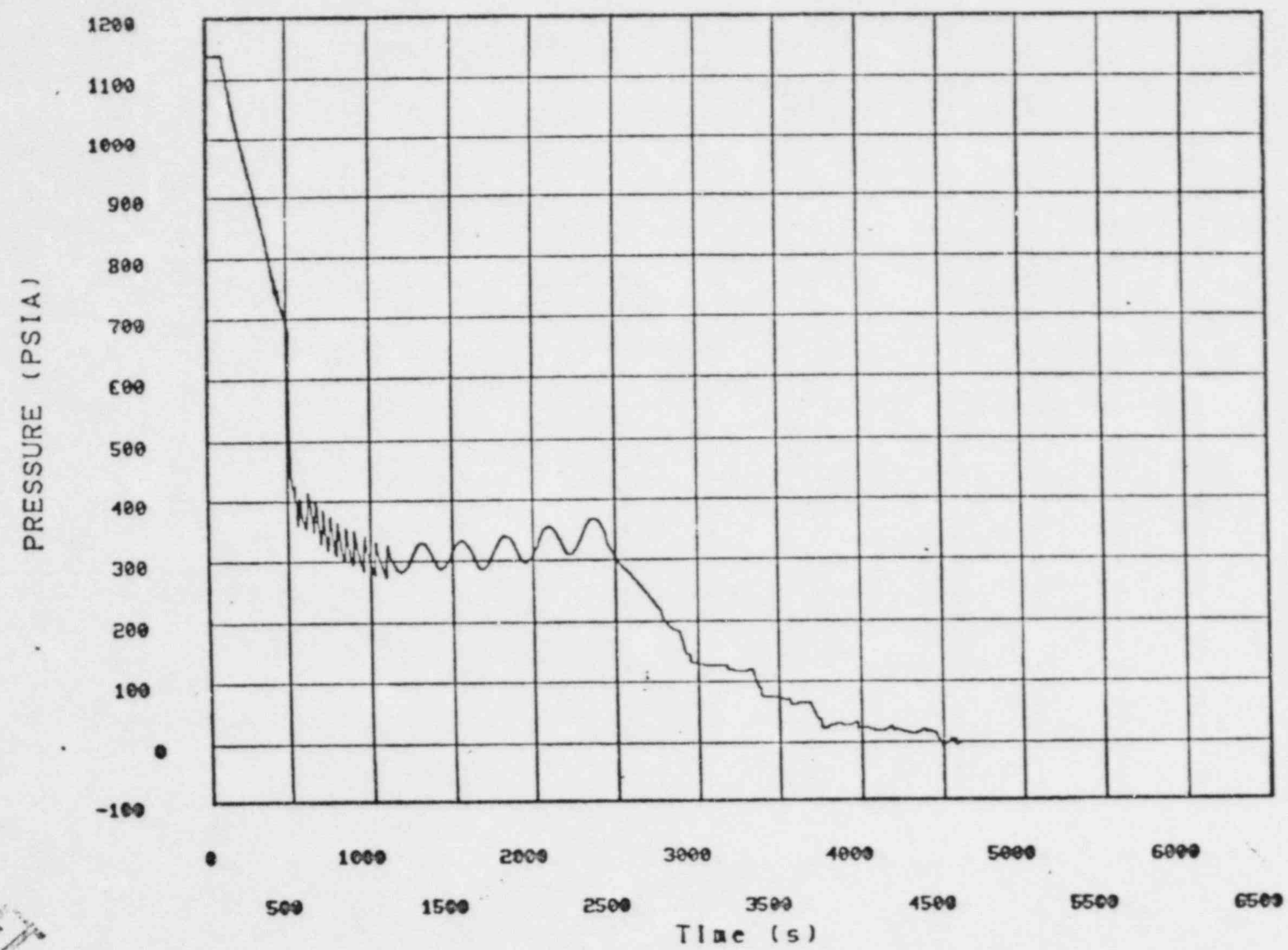
SG DØME PRESSURE: SG1,SG2



CASE 7 DUAL SGTR APS

DRAFT

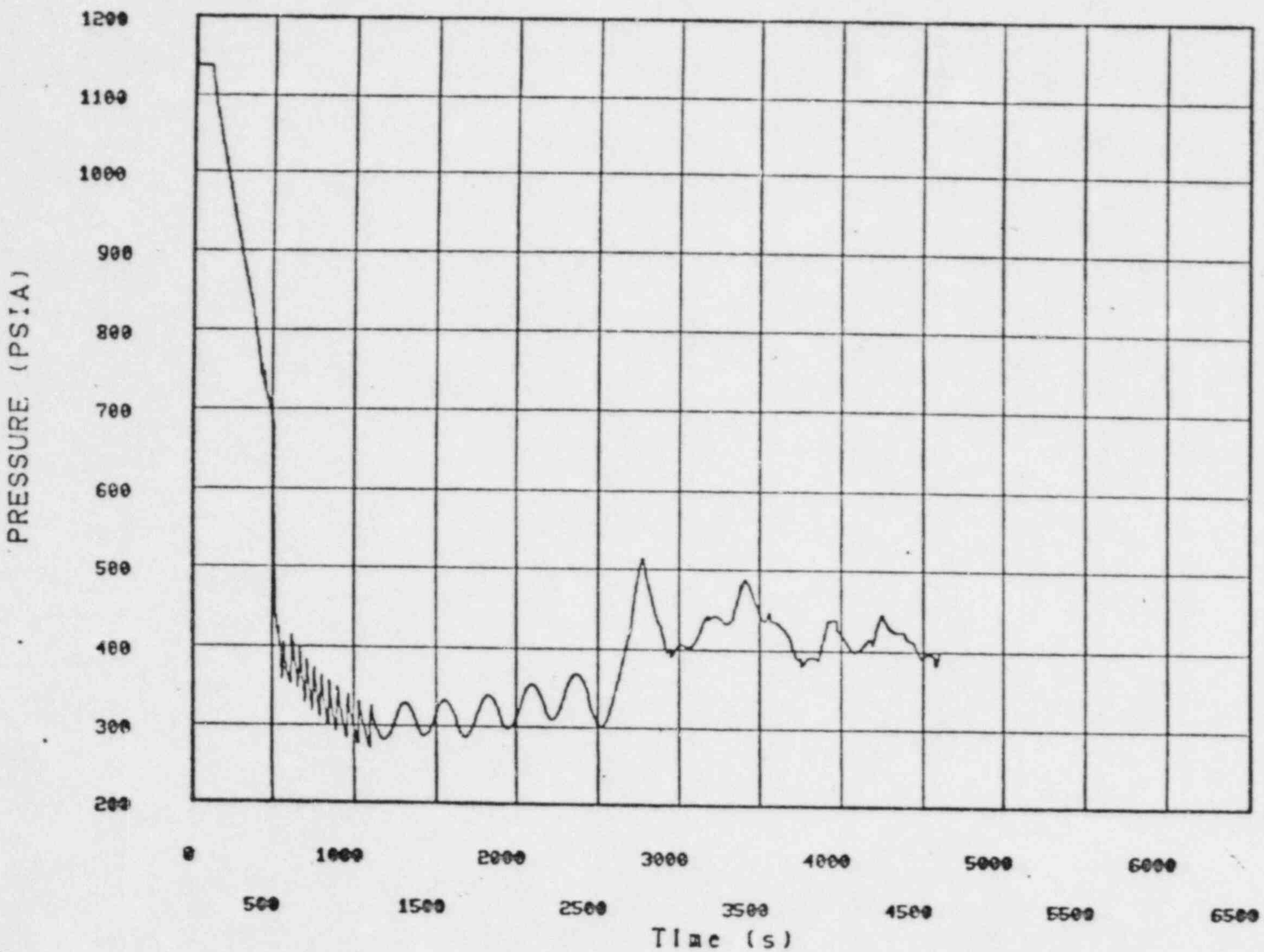
DELTA-P ACRØSS BRK JUN 878



CASE 7 DUAL SGTR APS

DRAFT

DELTA-P ACRØSS BR JUN 778



CASE 7 DUAL SGTR APS

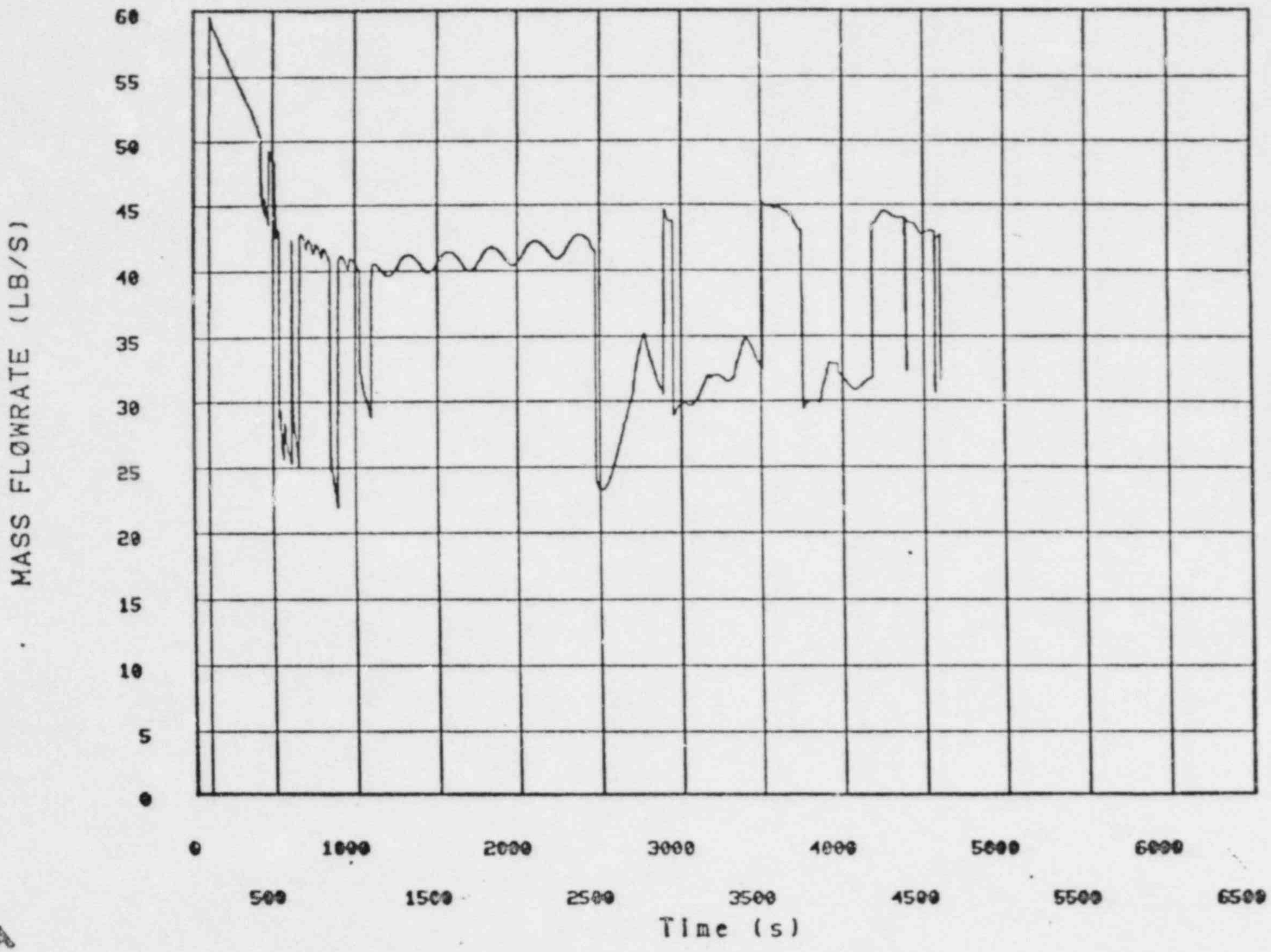
DRAFT

BREAK JUNCTIØN 878 FLØW

CASE 7 DUAL SGTR APS

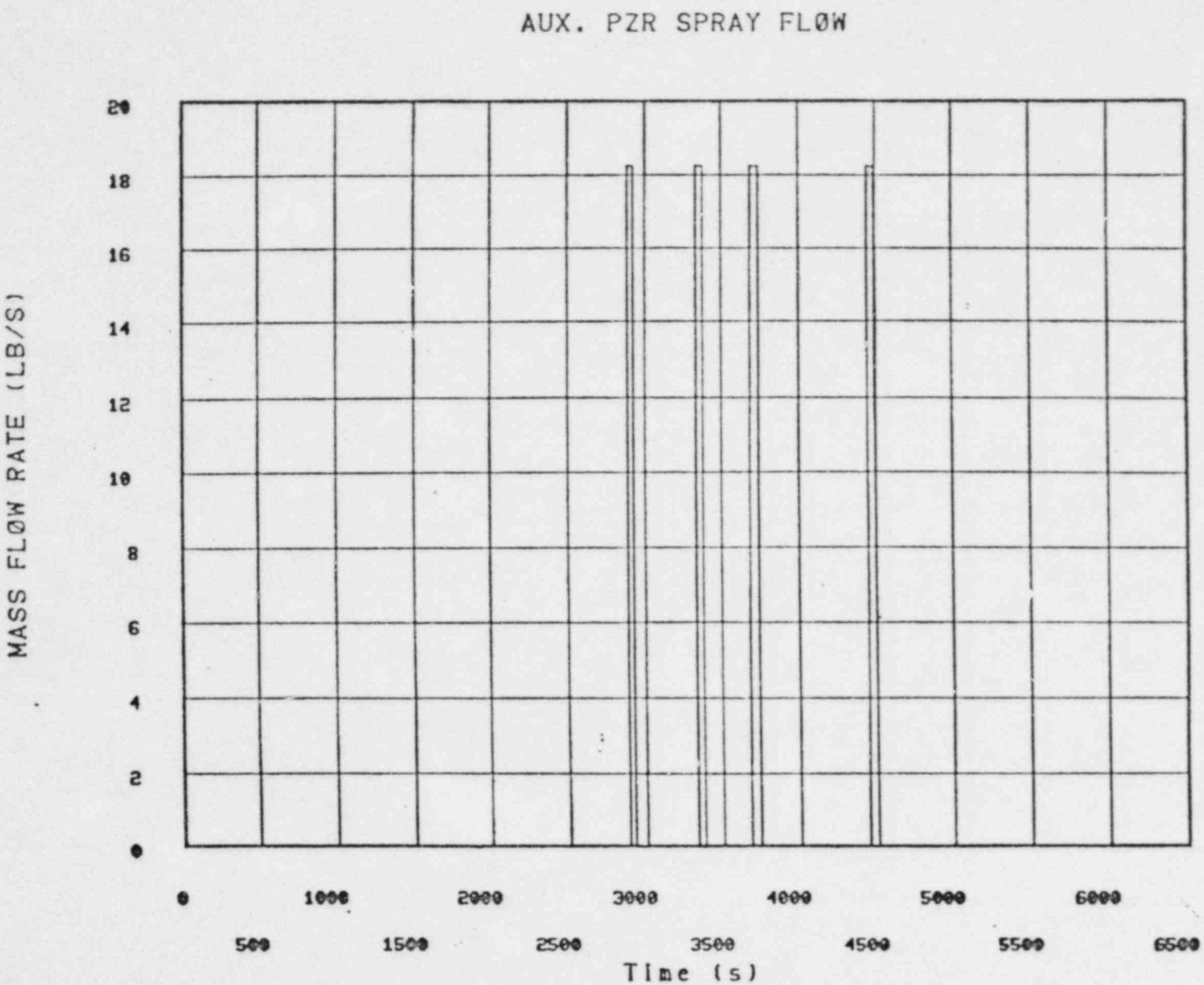
DRAFT

BREAK JUNCTIØN 778 FLØW



CASE 7 DUAL SGTR APS

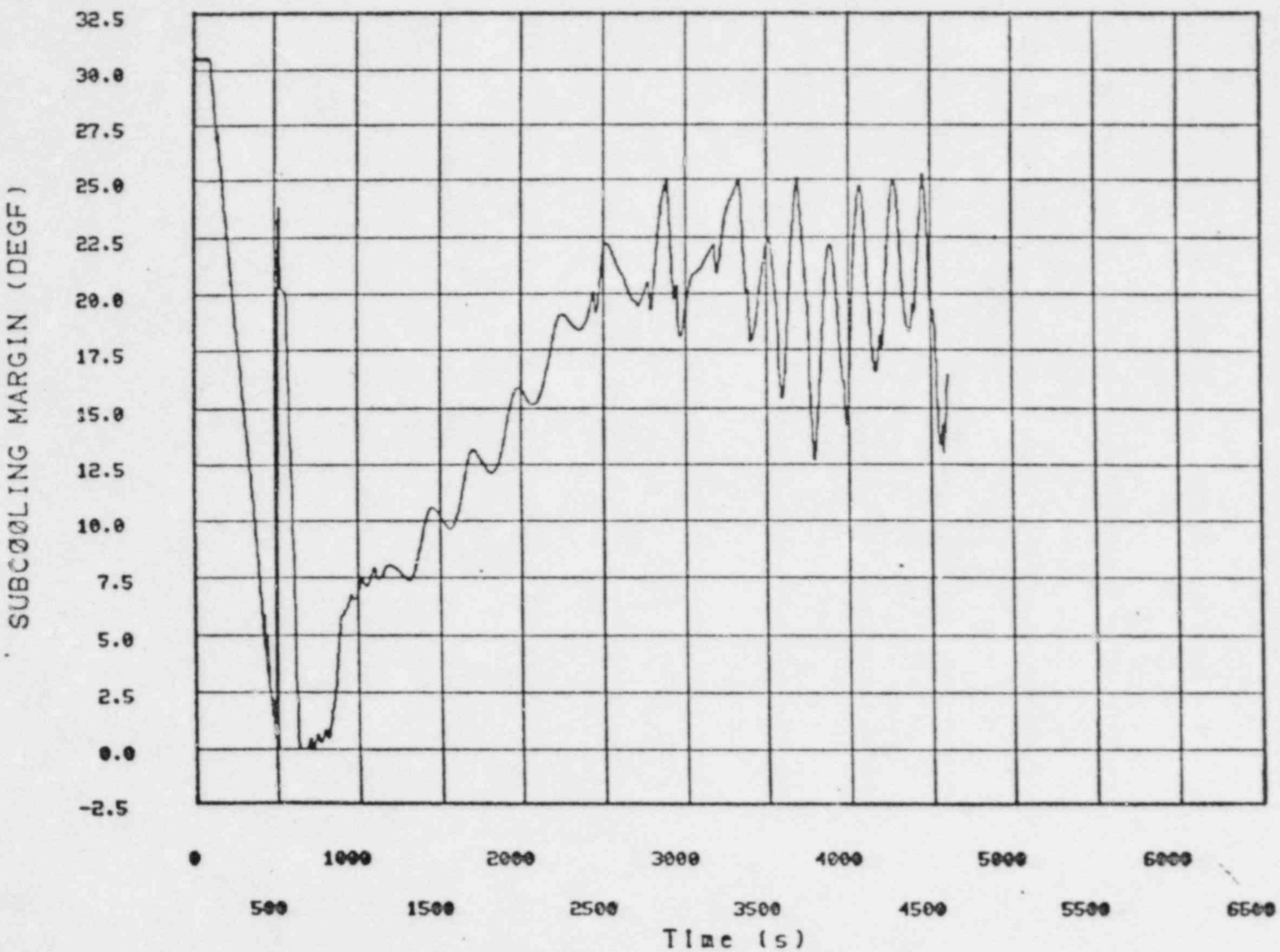
DRAFT.



CASE 7 DUAL SGTR APS

DRAFT

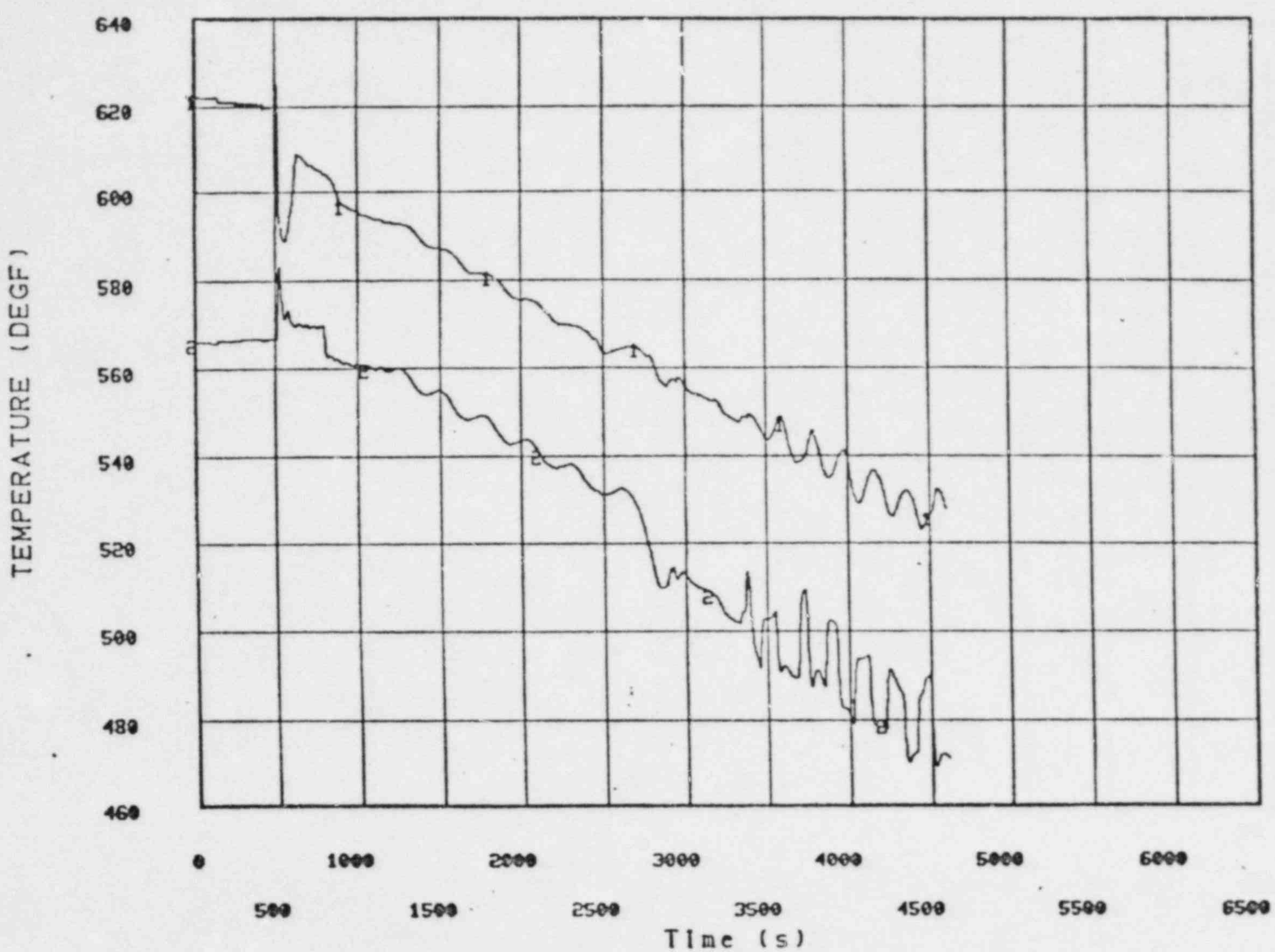
SUBCØØLING MARGIN IN VØL. 10002



CASE 7 DUAL SGTR APS

DRAFT

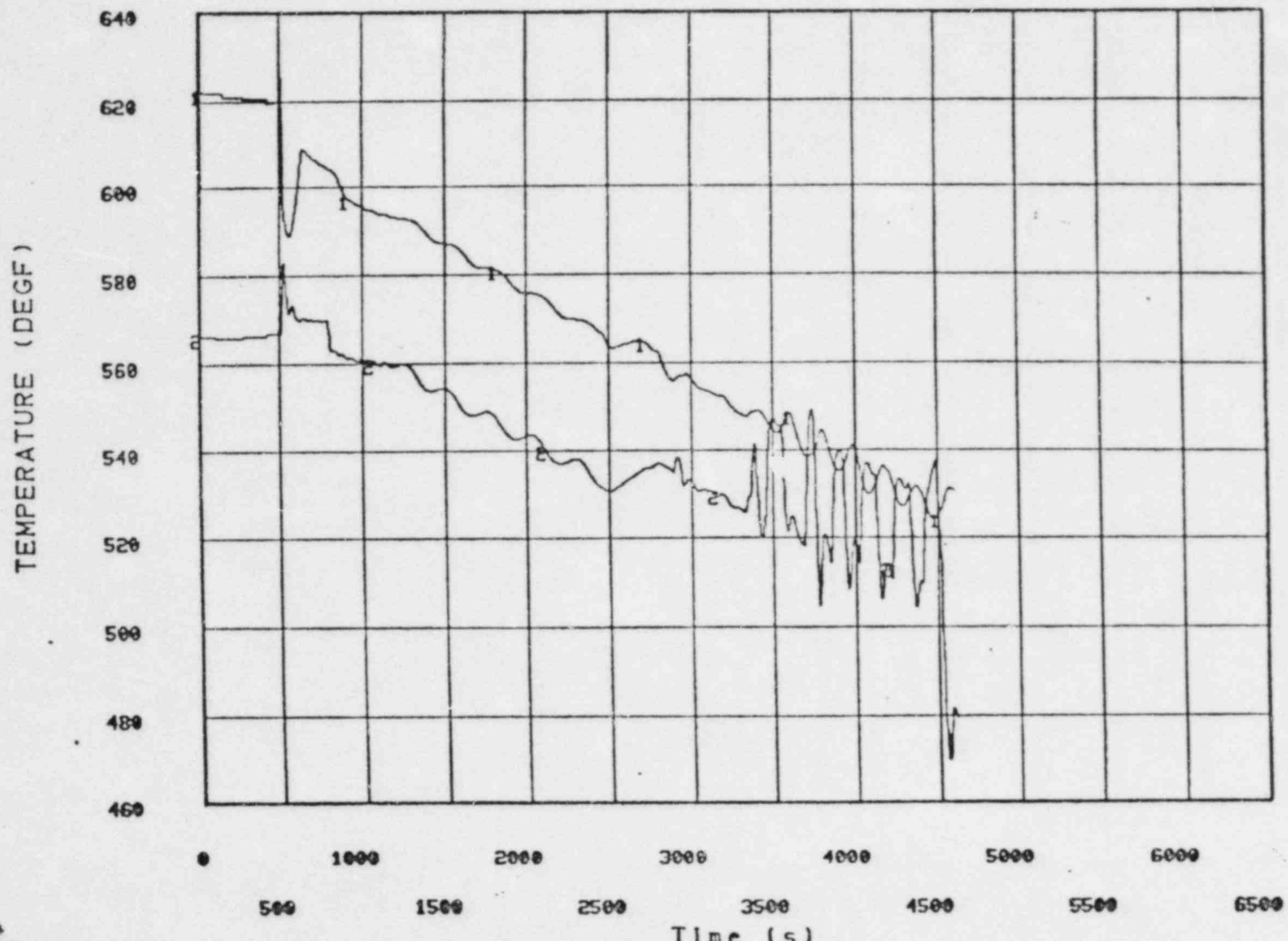
HØT AND CØLD LEG TEMPS ØN PZR LP



CASE 7 DUAL SGTR APS

DRAFT

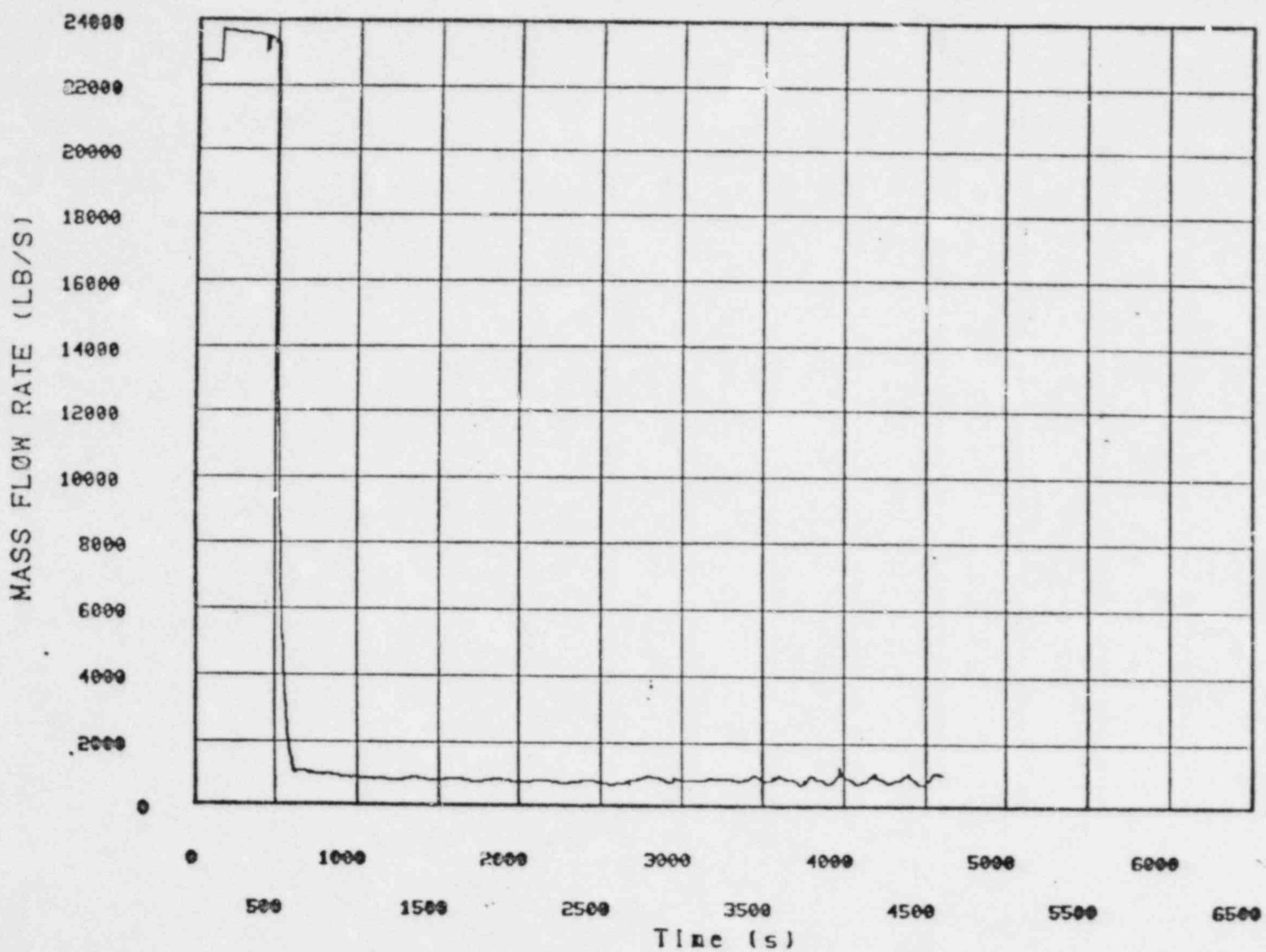
HØT AND CØLD LEG TEMPS: NØN PZR LP



CASE 7 DUAL SGTR APS

DRAFT

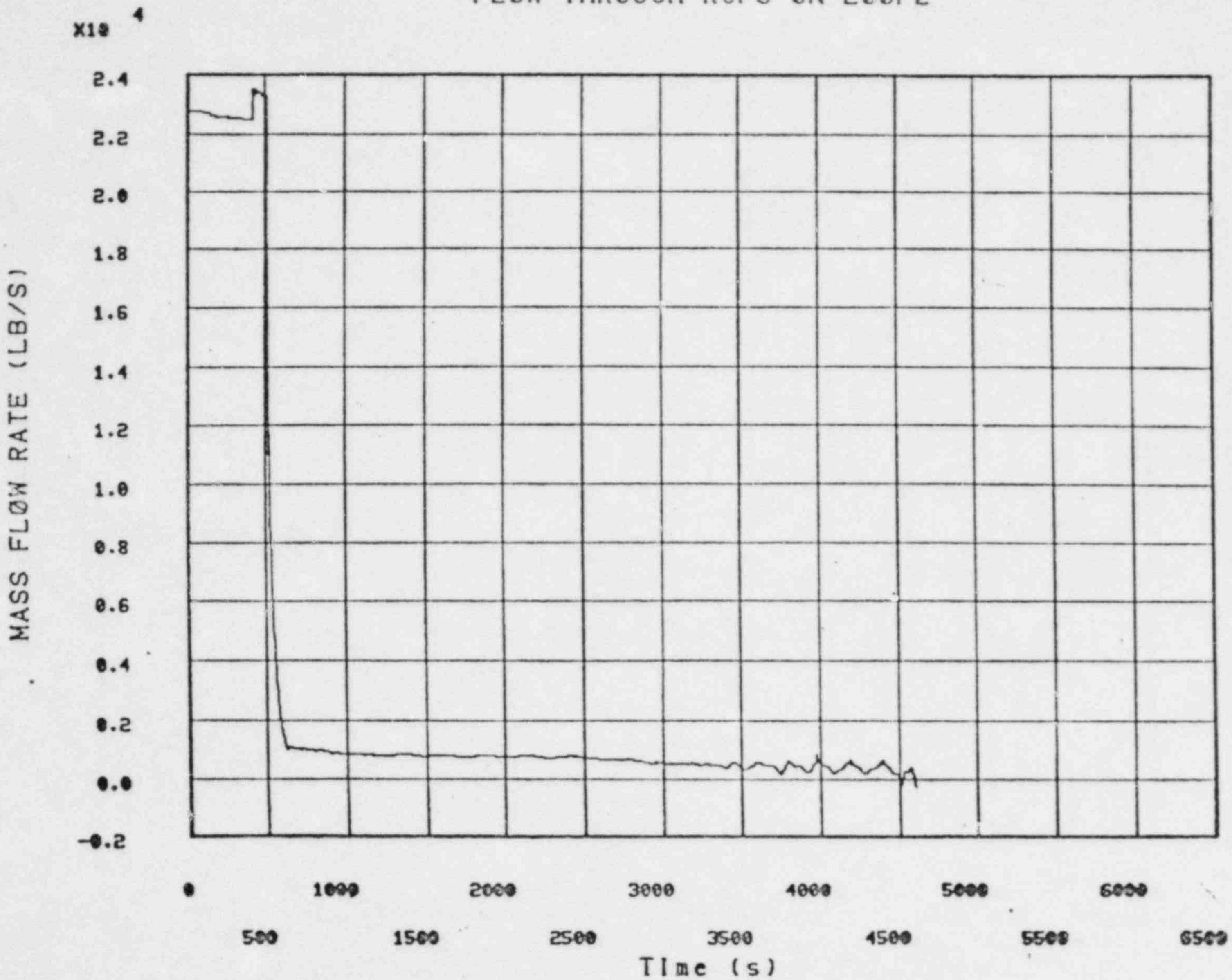
FLØW THRØUGH RCPS ØN LØØP1



CASE 7 DUAL SGTR APS

DRAFT

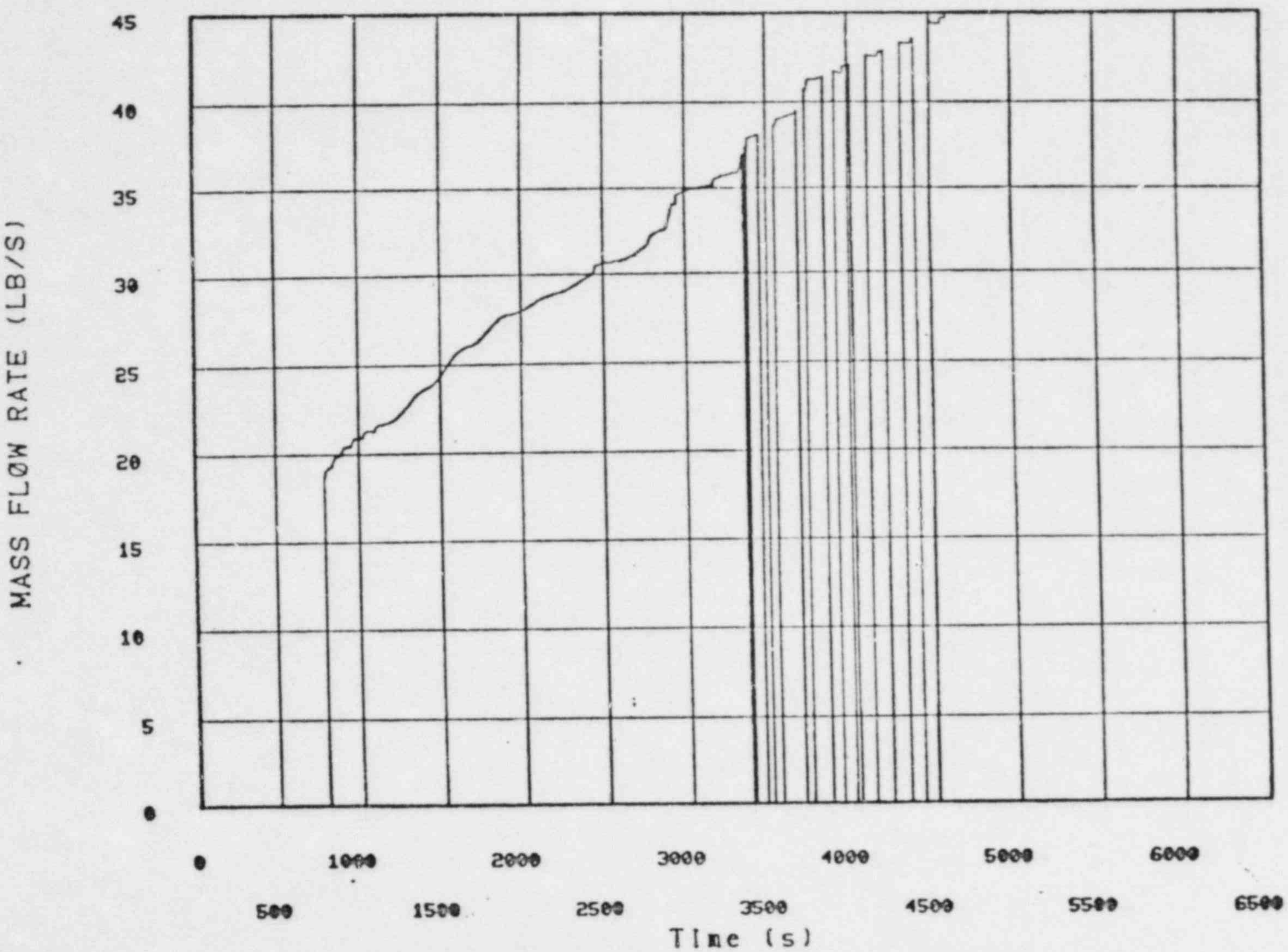
FLØW THRØUGH RCPS ØN LØØP2



CASE 7 DUAL SGTR APS

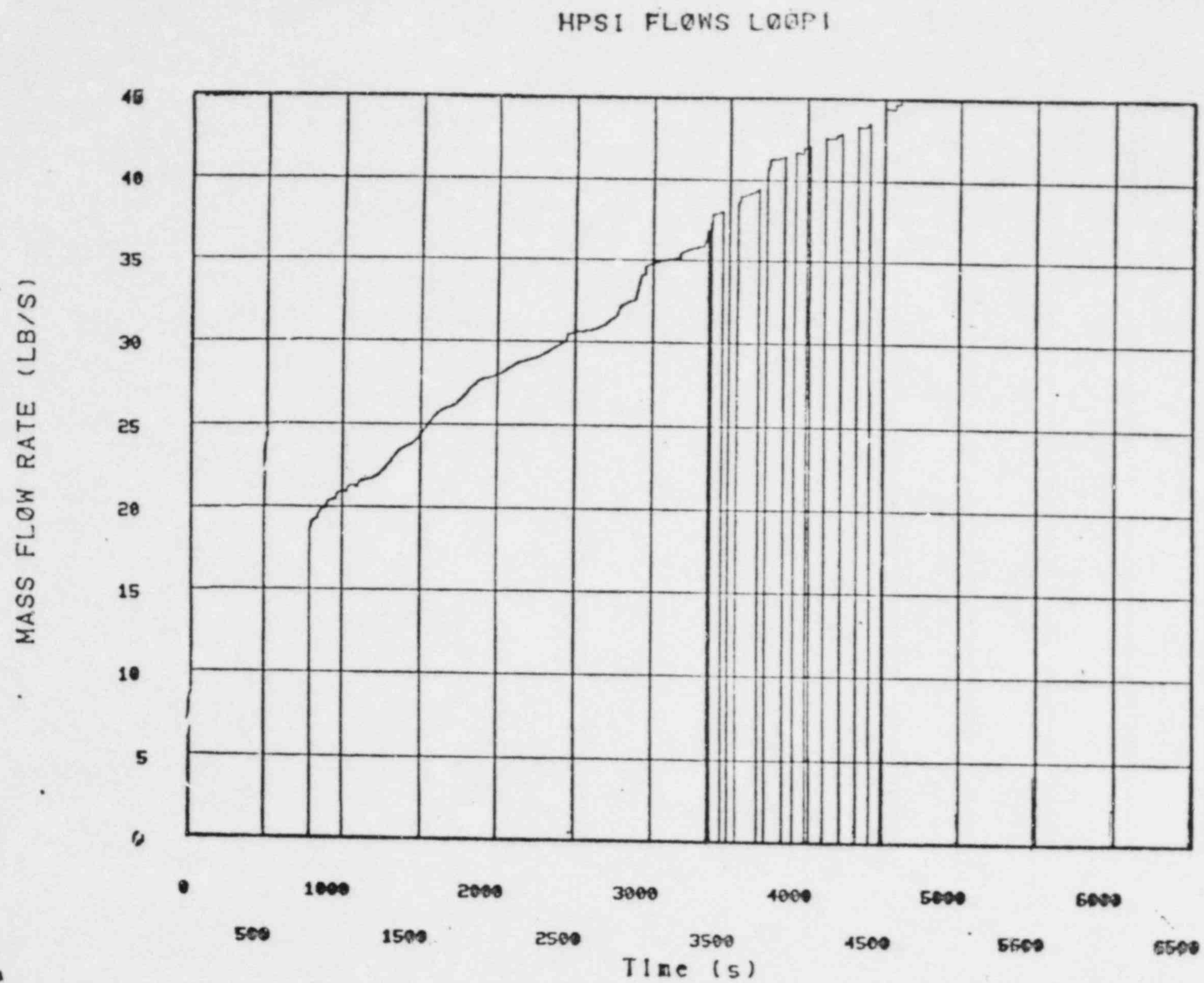
DRAFT

HPSI FLØWS LØØP2



CASE 7 DUAL SGTR APS

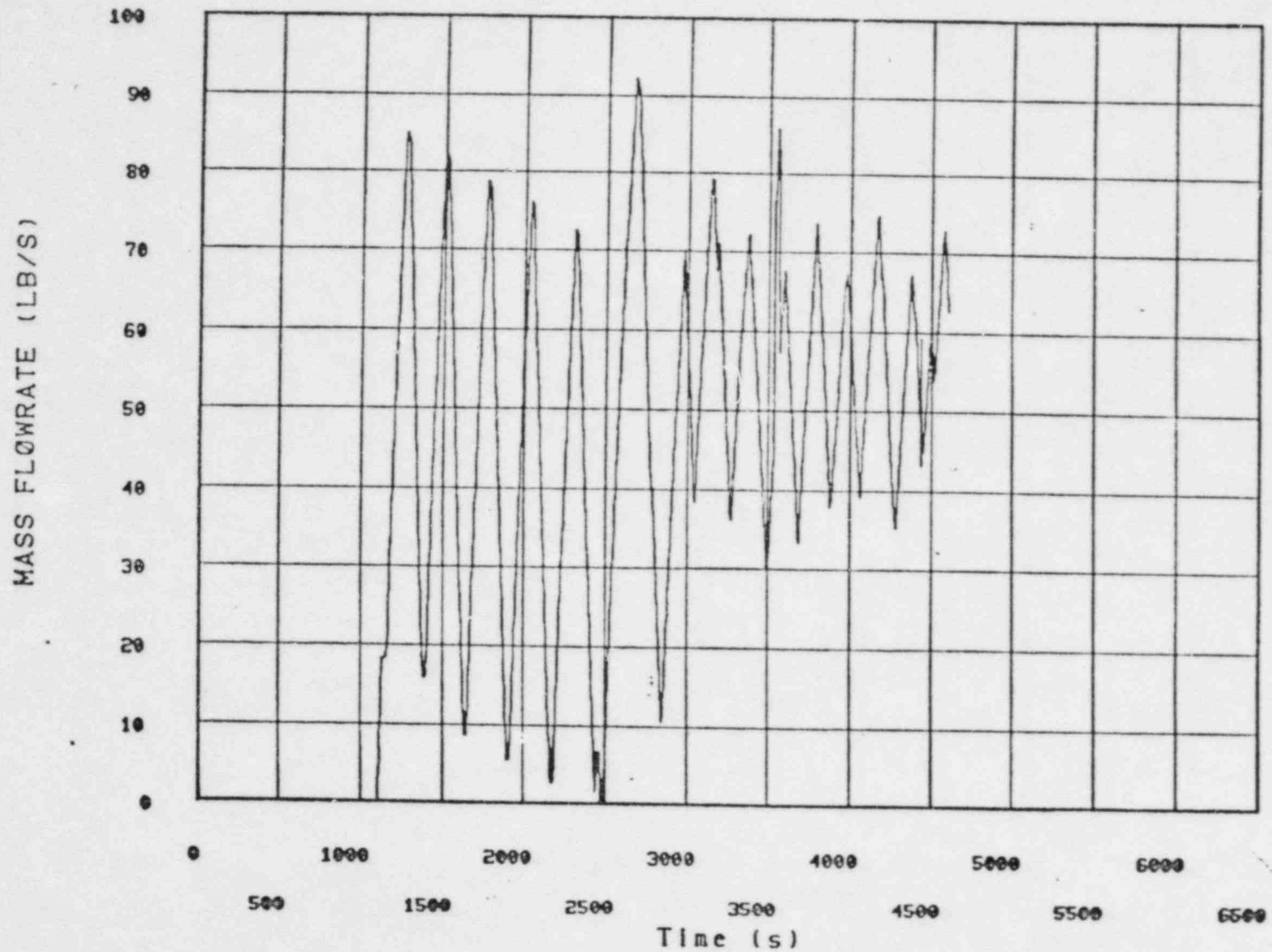
DRAFT



CASE 7 DUAL SGTR APS

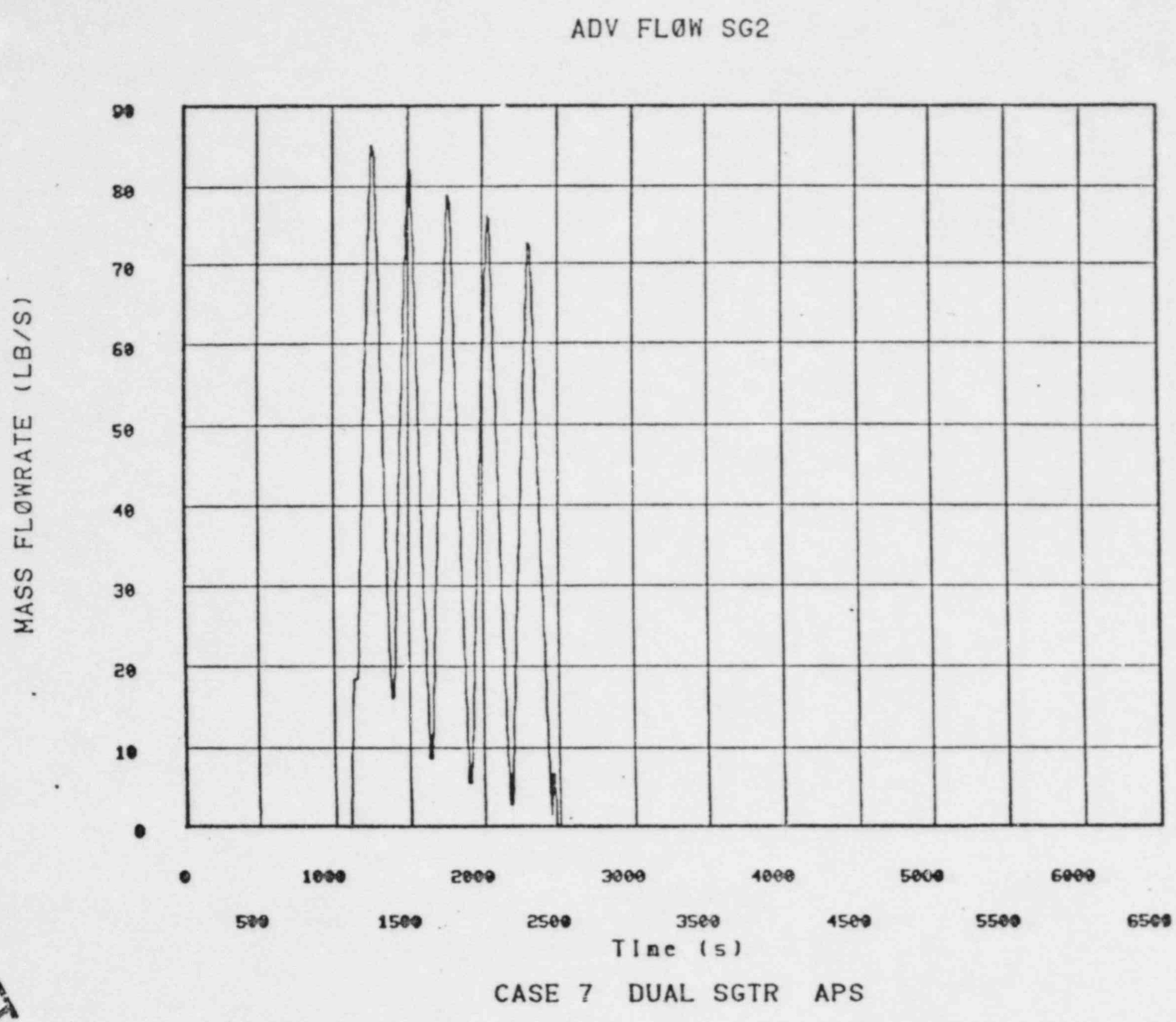
DRAFT

ADV FLØW SG1



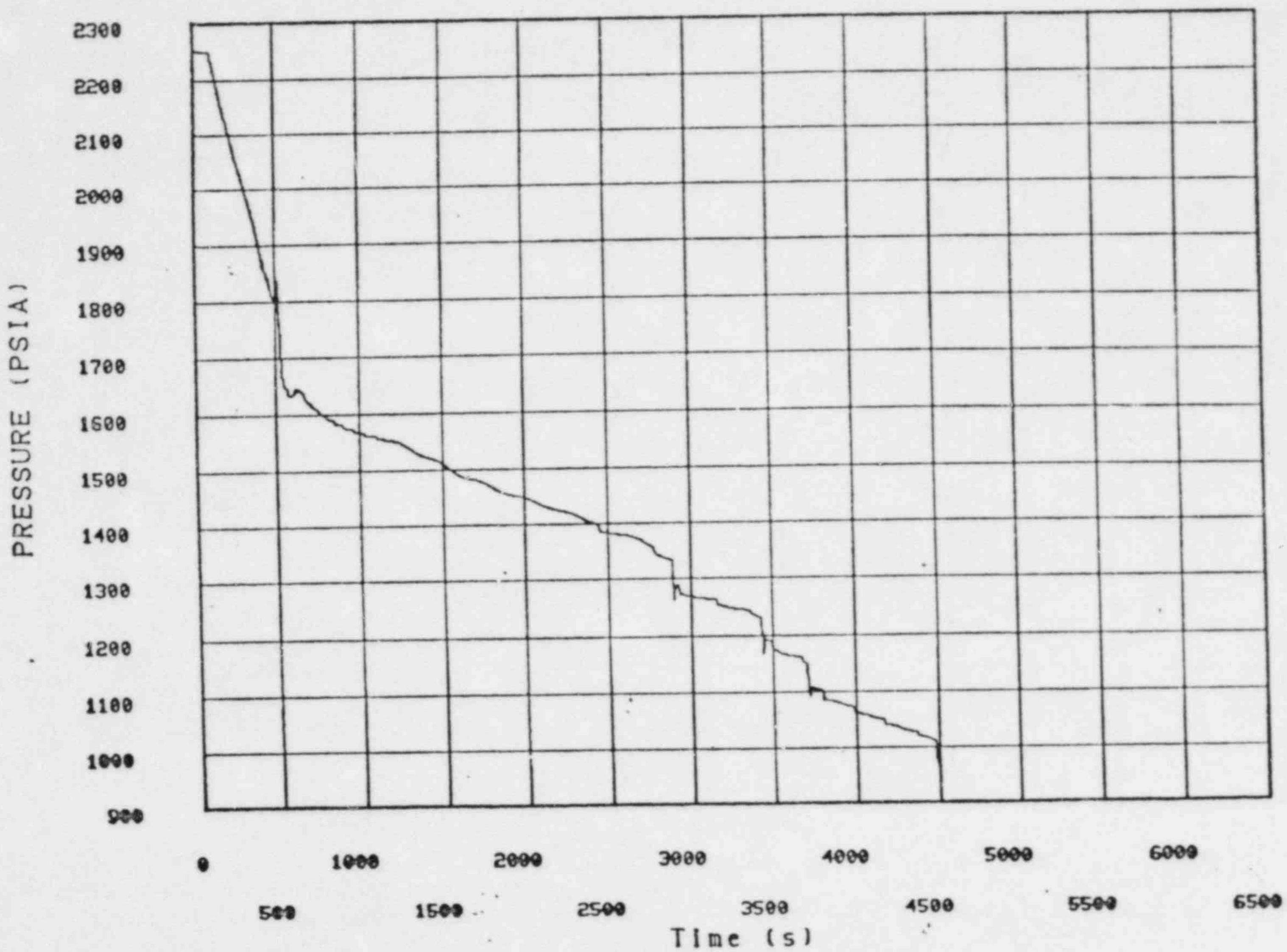
CASE 7 DUAL SGTR APS

DRAFT


ADV FLØW SG2
MASS FLØWRATE (LB/S)
0
10
20
30
40
50
60
70
80
90
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
5500
6000
6500
TIme (s)
CASE 7 DUAL SGTR APS

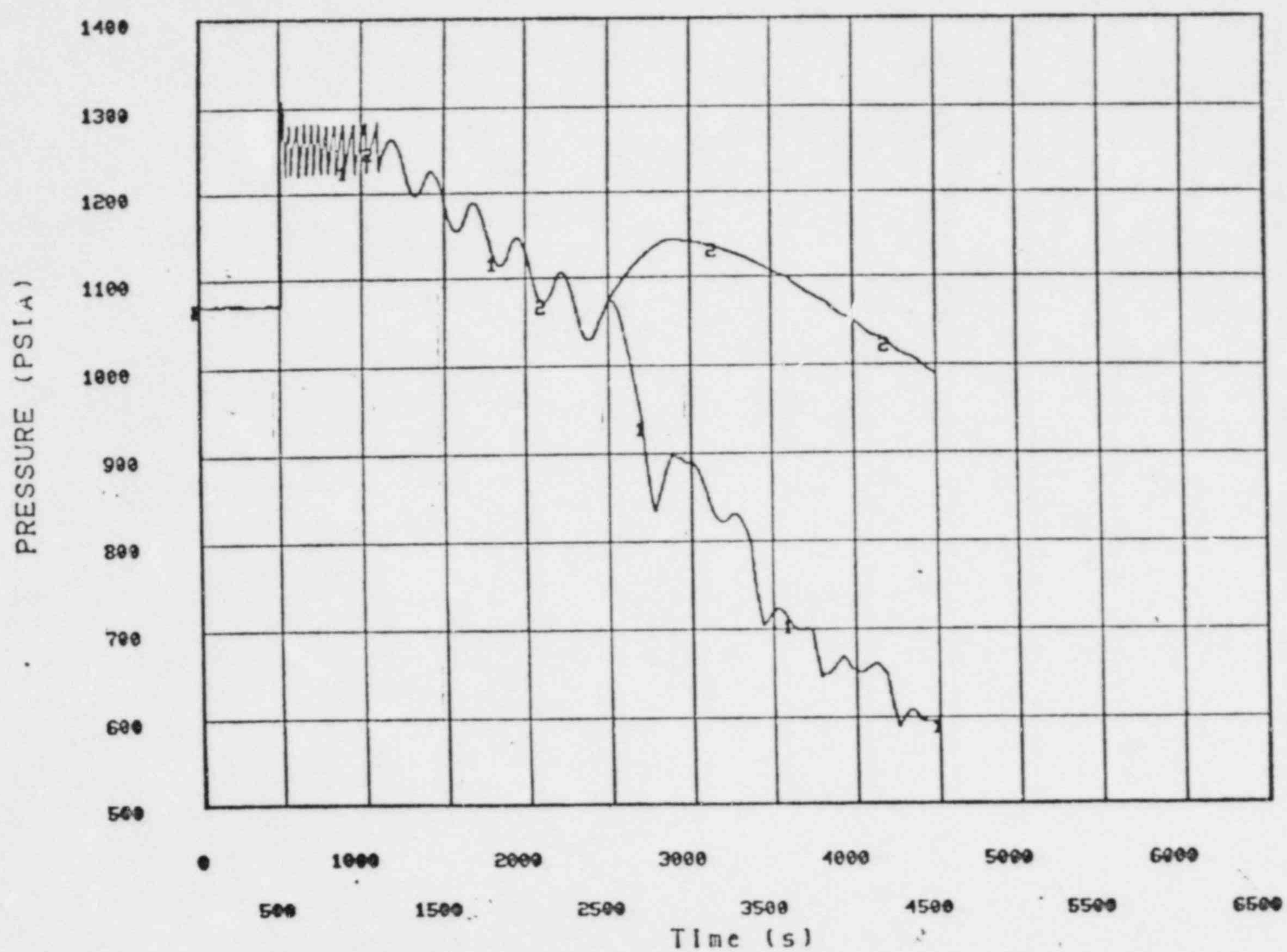
DRAFT

PRESSURIZER PRESSURE



CASE 8 DUAL SGTR PØRV

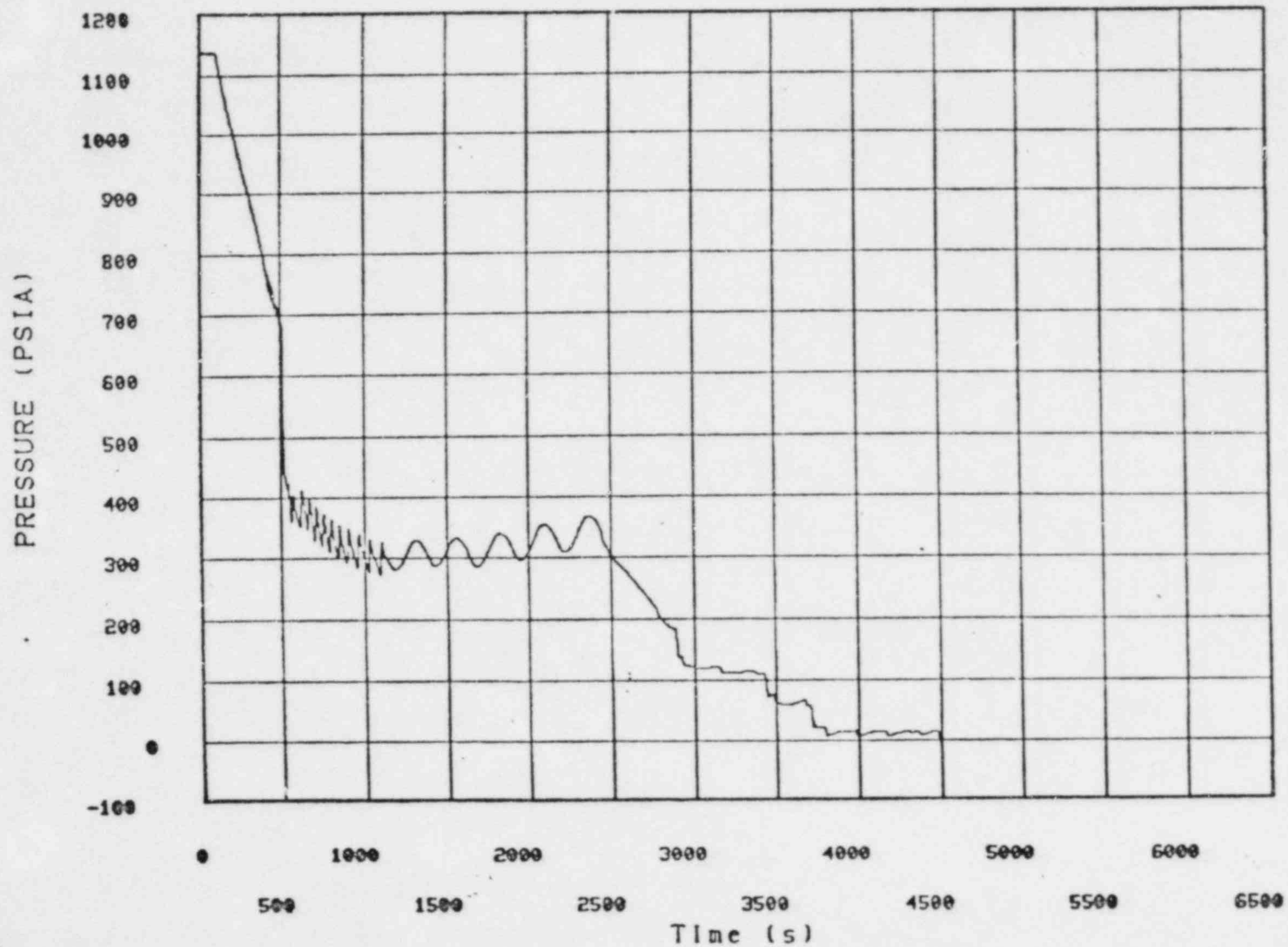
SG DØME PRESSURE: SG1,SG2



CASE 8 DUAL SGTR PØRV

DRAFT

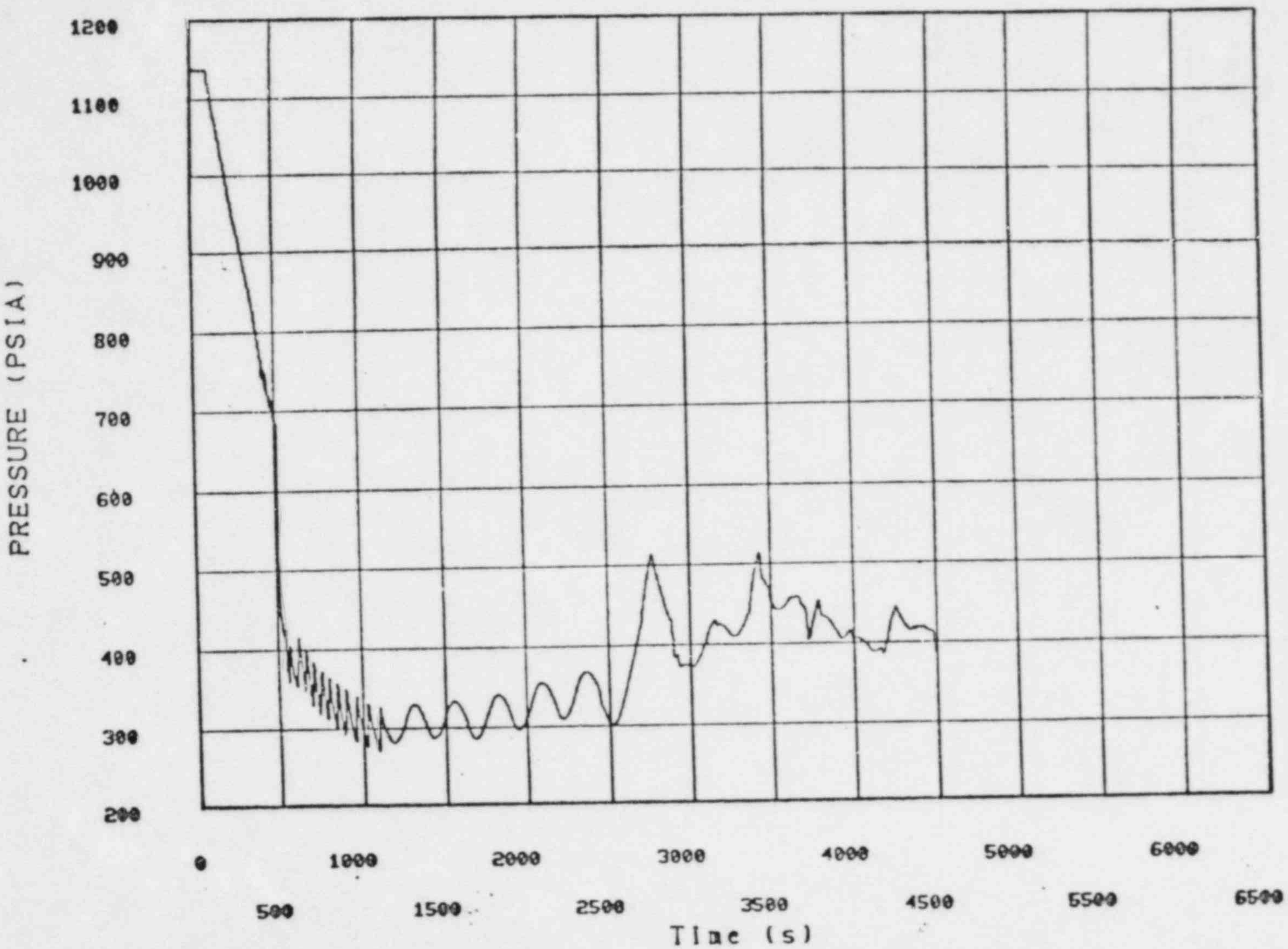
DELTA-P ACRØSS BRK JUN 878



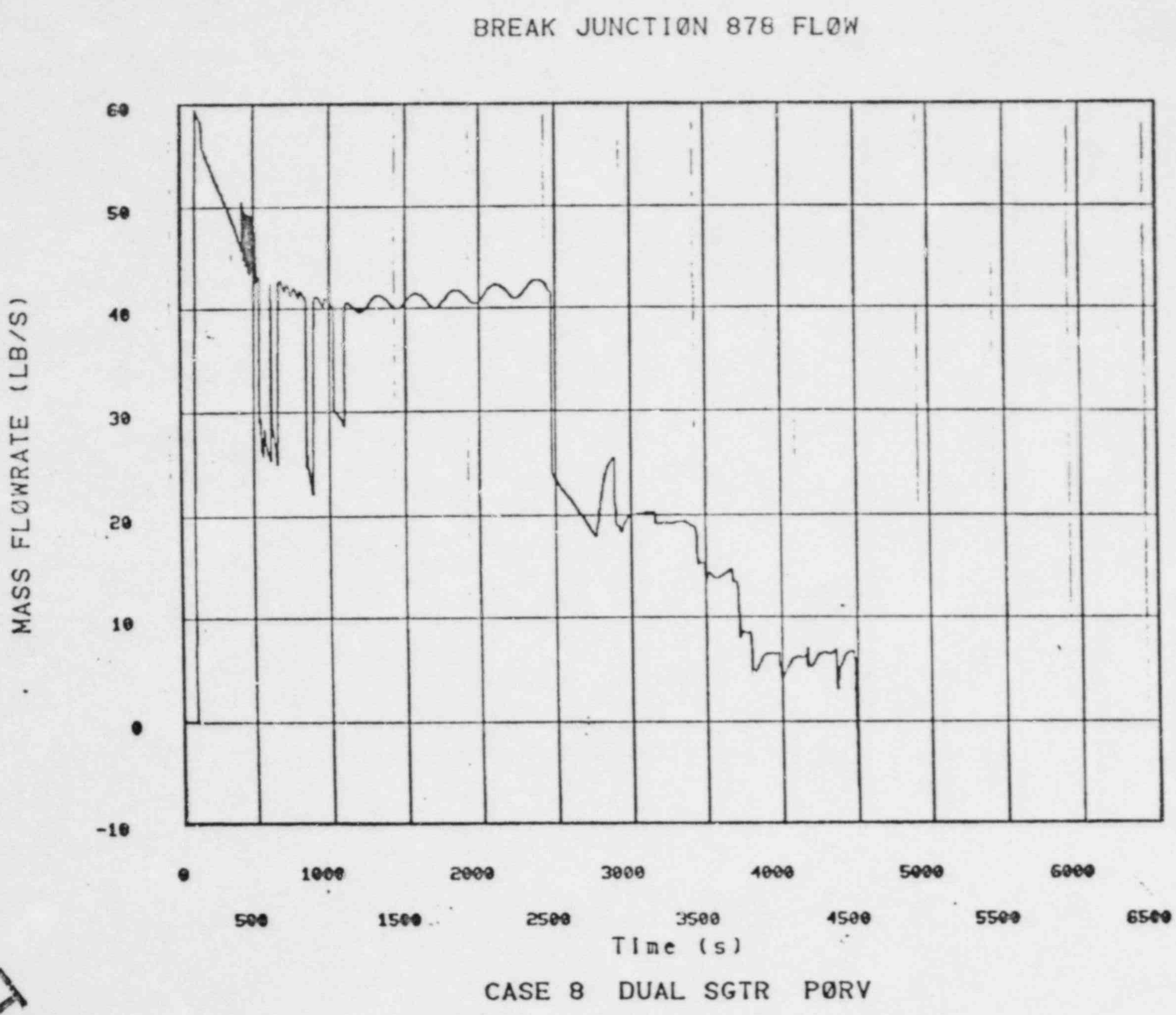
CASE 8 DUAL SGTR PØRV

DRAFT

DELTA-P ACRØSS BR JUN 778

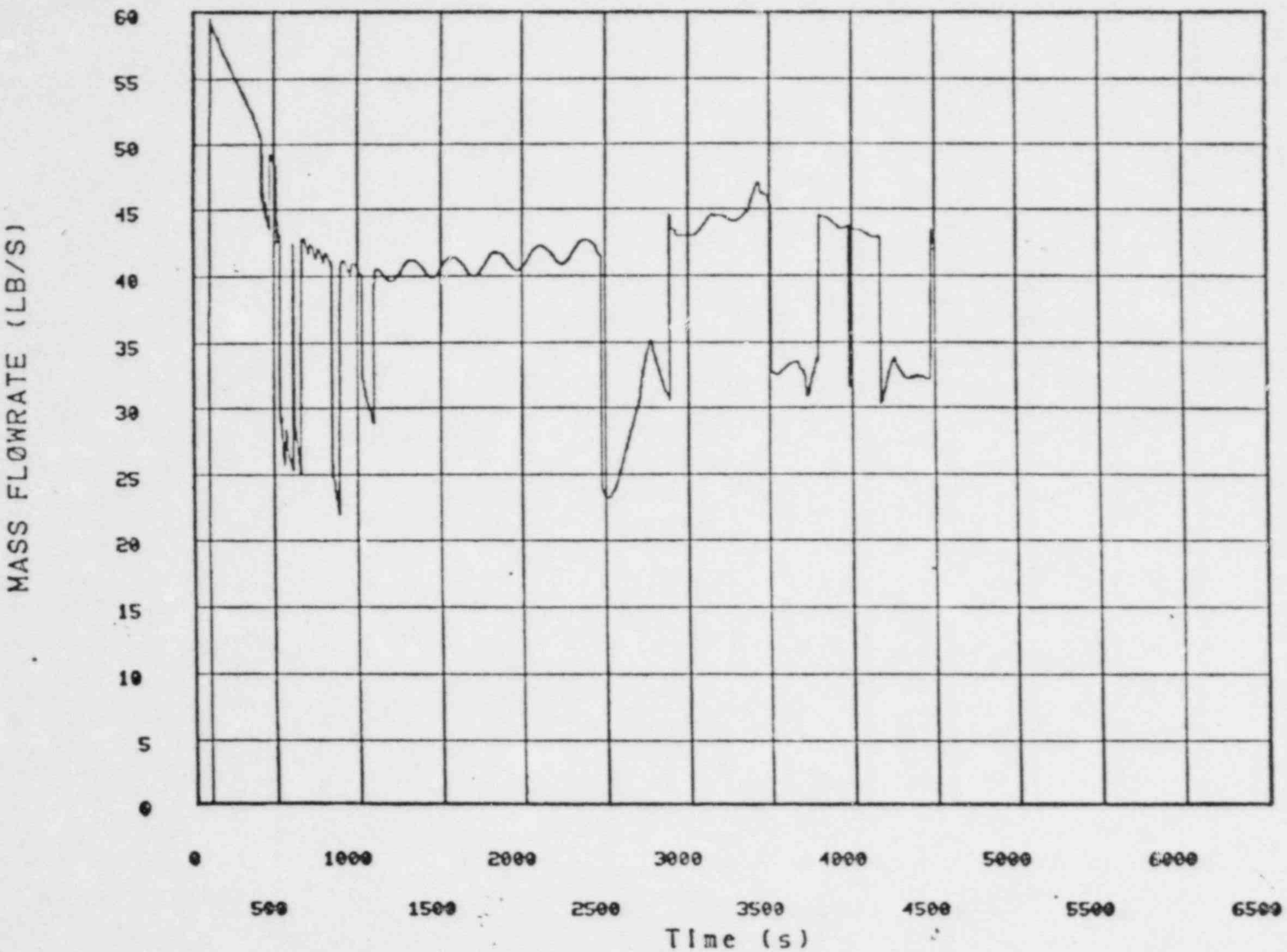


CASE 8 DUAL SGTR PØRV


BREAK JUNCTIØN 878 FLØW
MASS FLØWRATE (LB/S)
60
50
40
30
20
10
0
-10
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
5500
6000
6500
Time (s)
CASE 8 DUAL SGTR PØRV

DRAFT

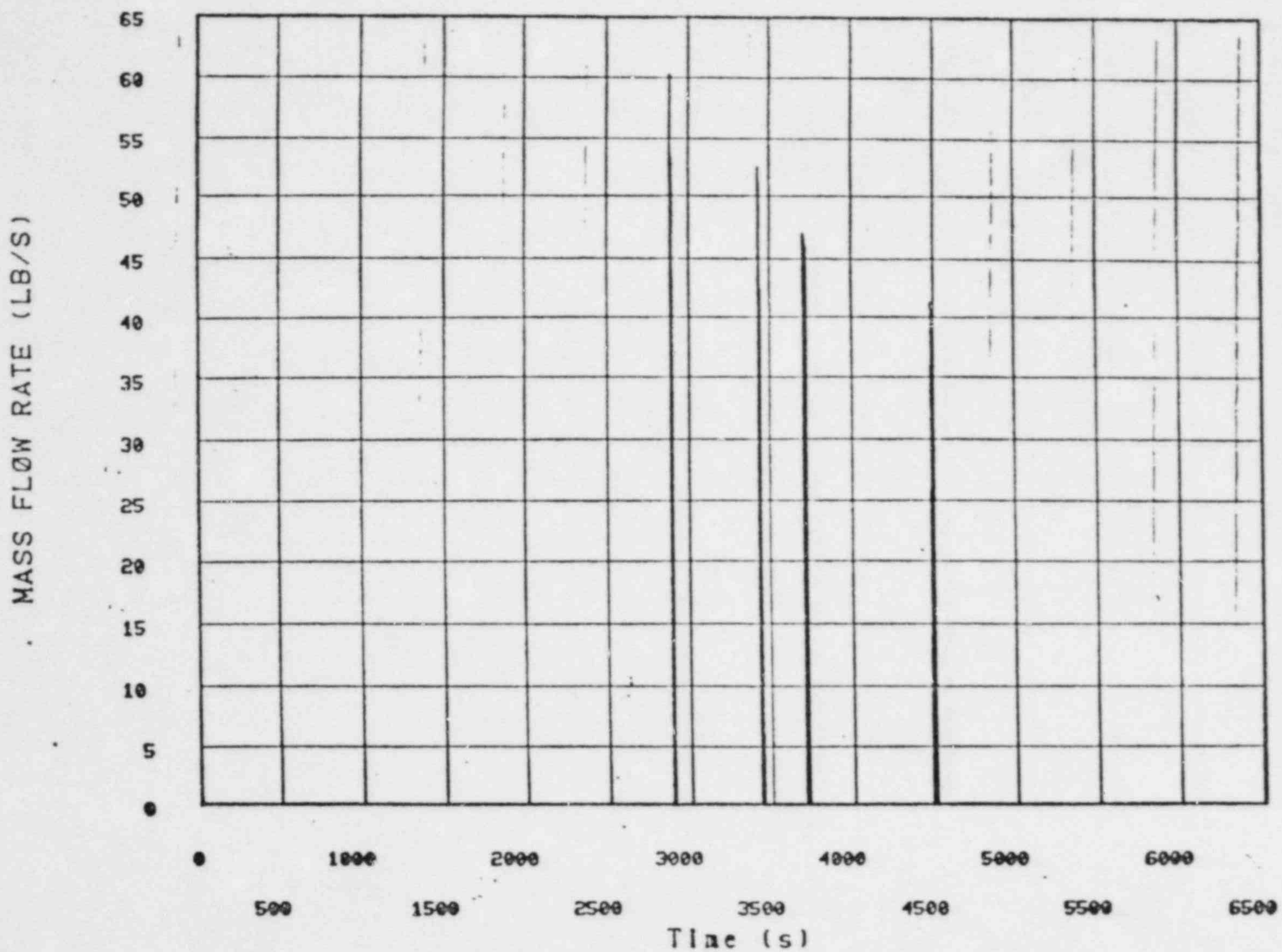
BREAK JUNCTIØN 778 FLØW



CASE 8 DUAL SGTR PØRV

DRAFT

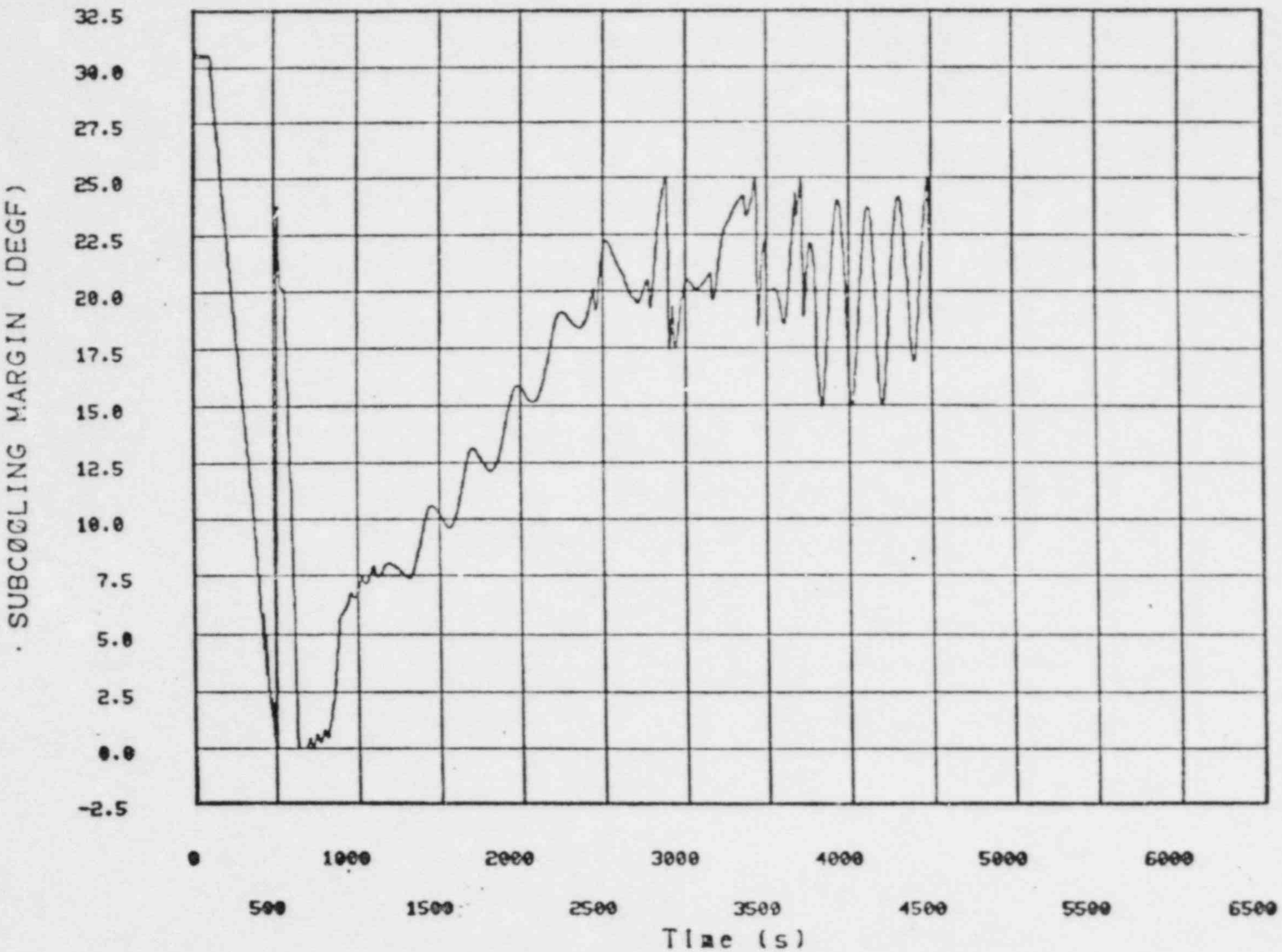
PØRV FLØW



CASE 8 DUAL SGTR PØRV

DRAFT

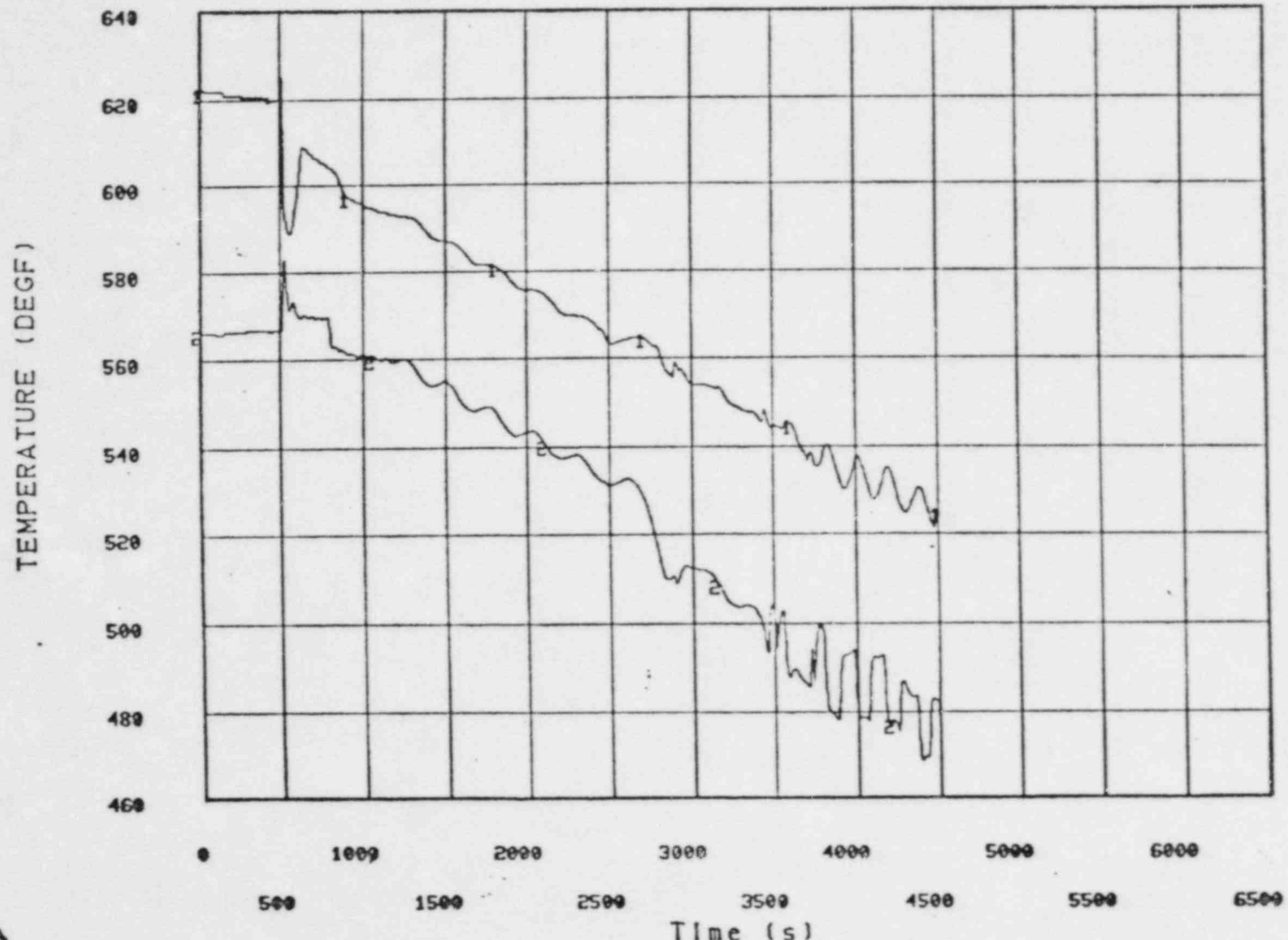
SUBCØØLING MARGIN IN VØL. 10002



CASE 8 DUAL SGTR PØRV

DRAFT

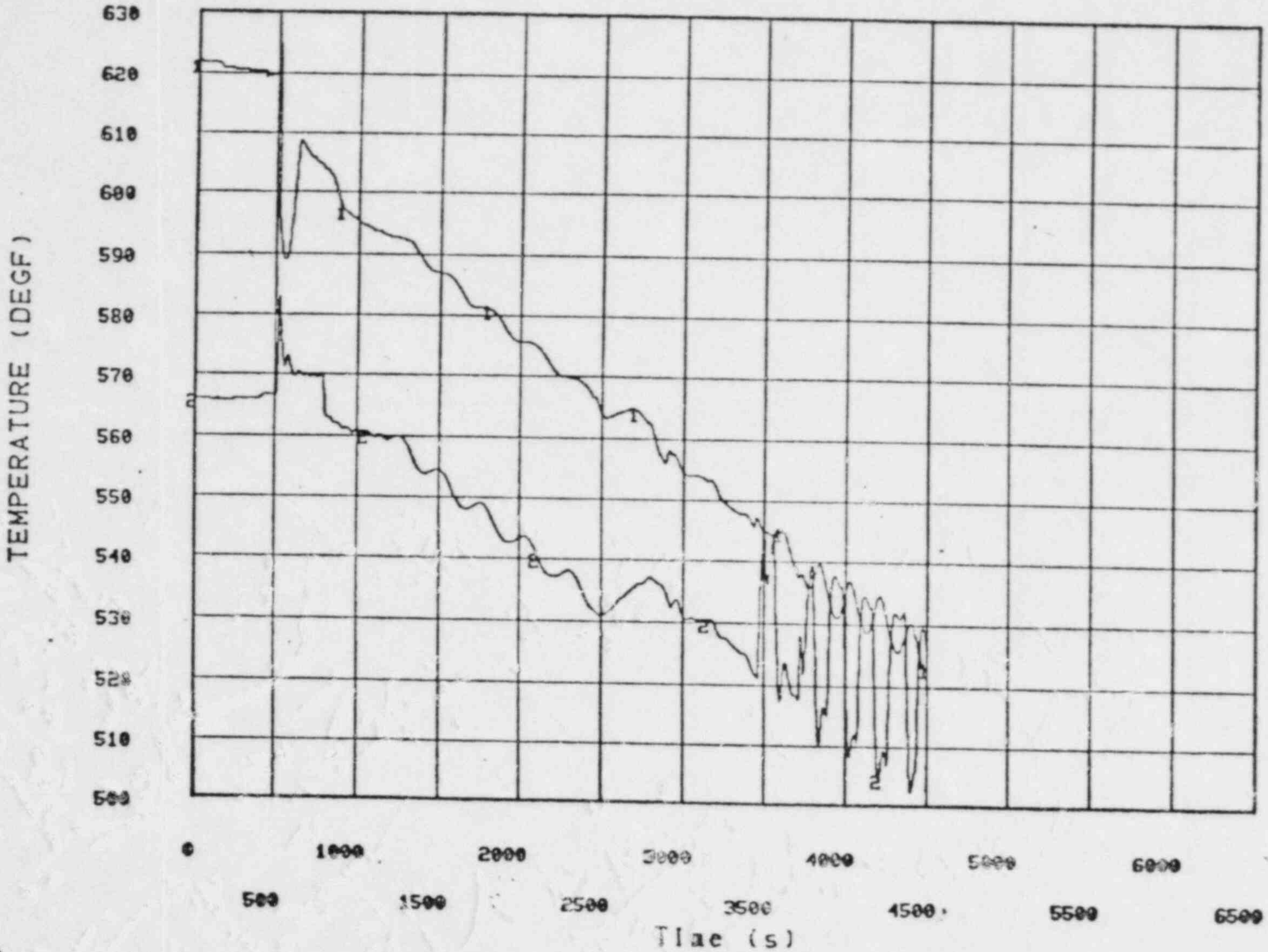
HØT AND CØLD LEG TEMPS ØN PZR LP



CASE 8 DUAL SGTR PØRV

DRAFT

HØT AND CØLD LEG TEMPS: NØN PZR LP



CASE 8 DUAL SGTR PØRV

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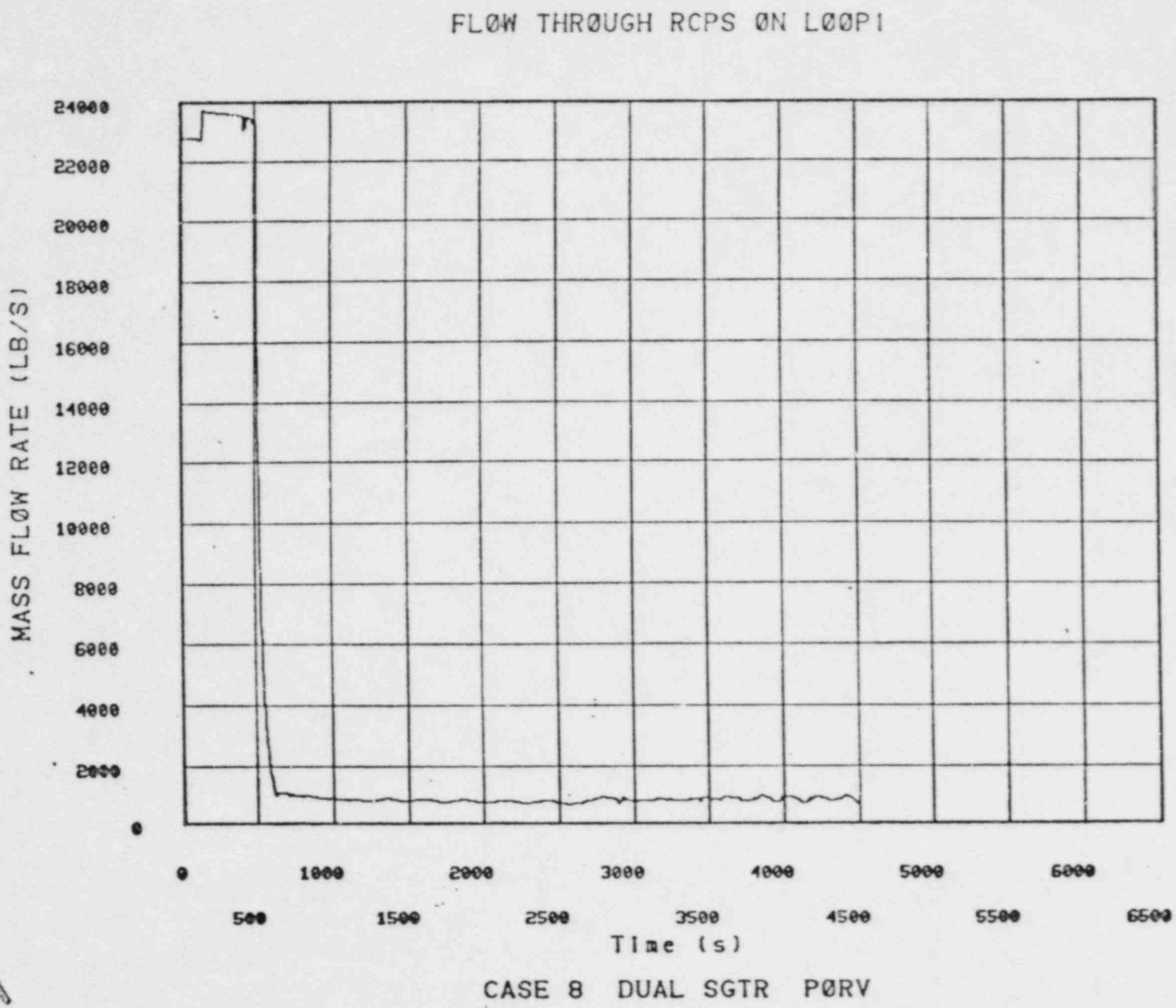
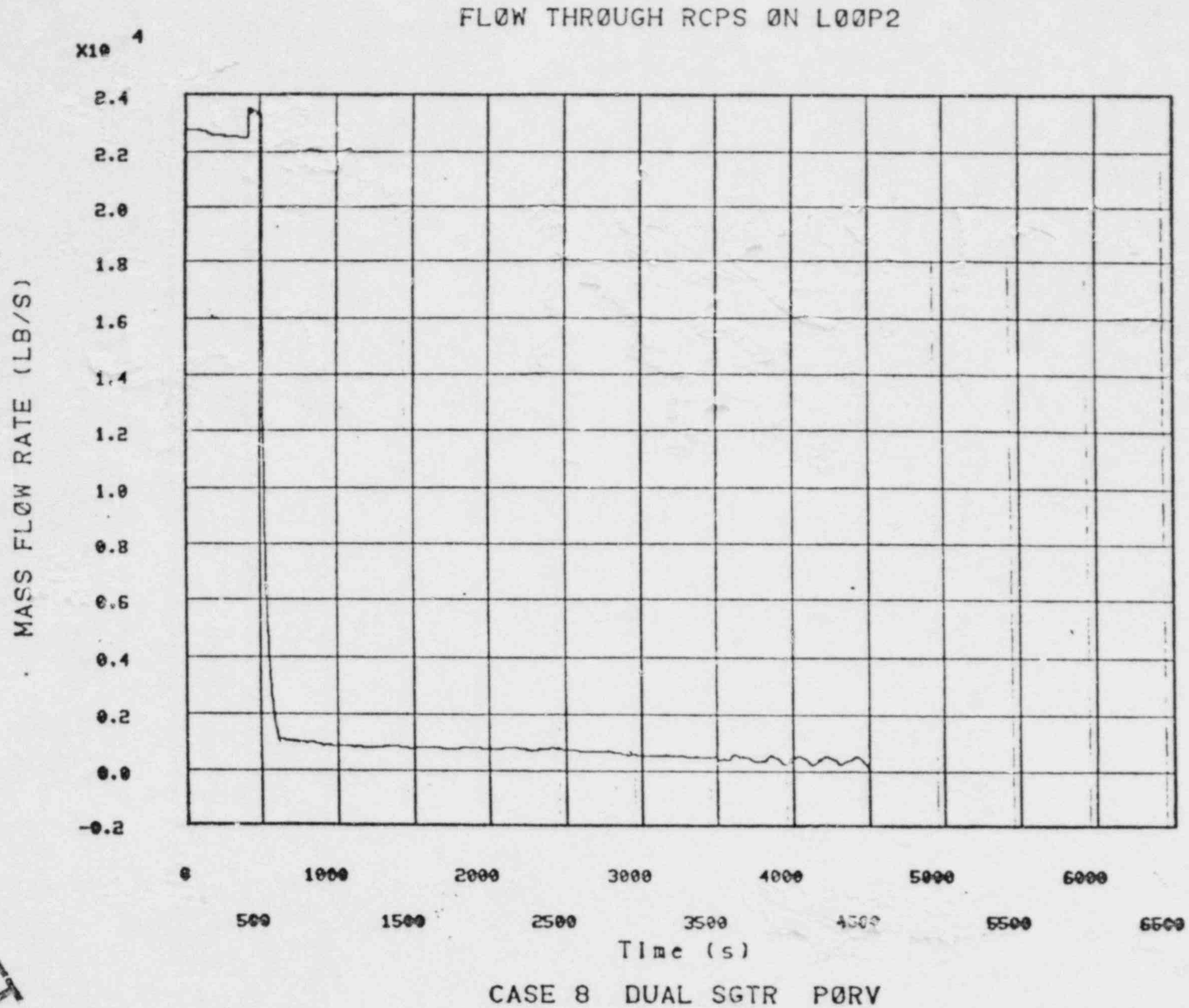

FLØW THRØUGH RCPS ØN LØØP1
MASS FLØW RATE (LB/S)
24000
22000
20000
18000
16000
14000
12000
10000
8000
6000
4000
2000
0
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
5500
6000
6500
Time (s)
CASE 8 DUAL SGTR PØRV

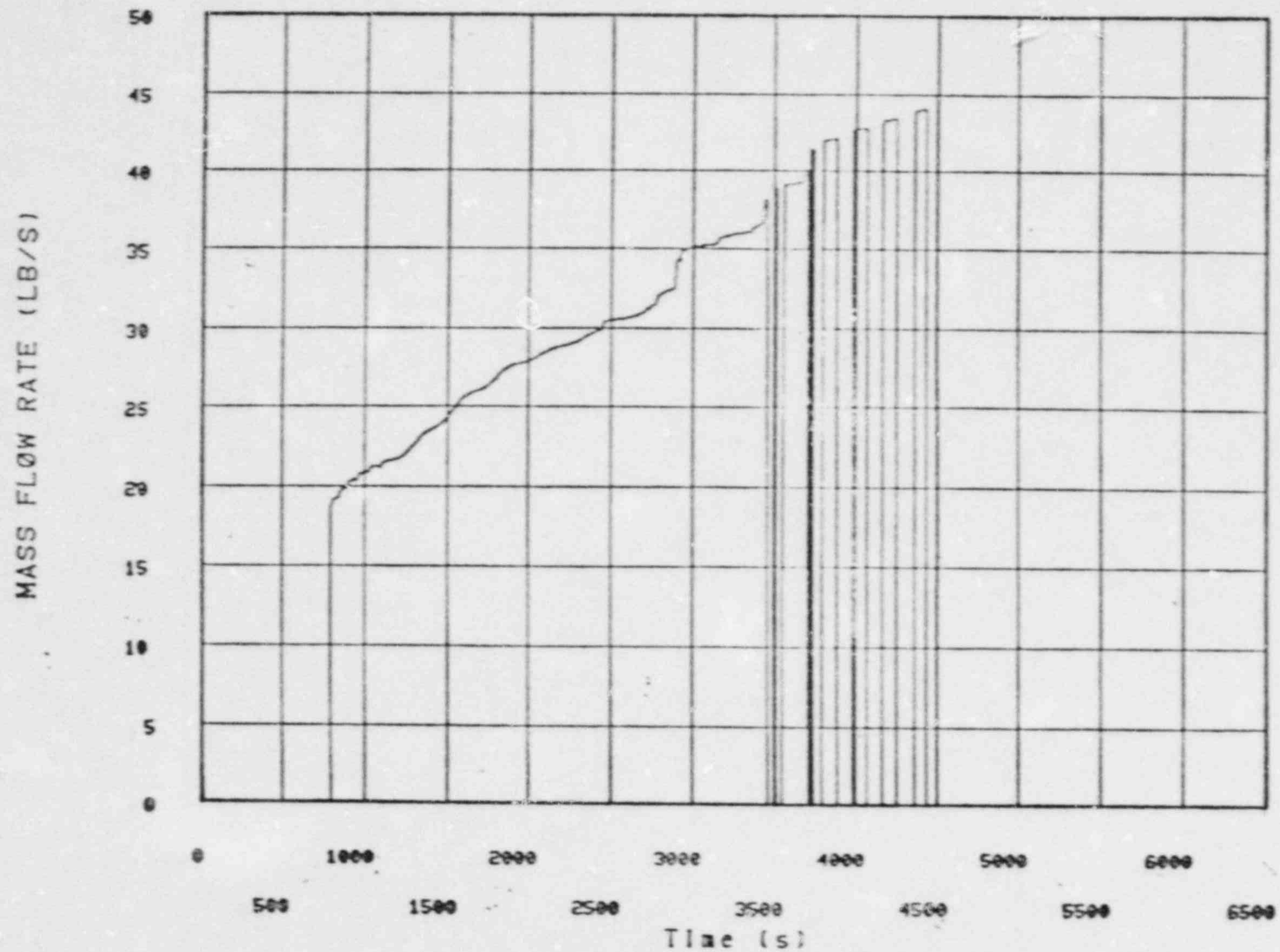
DRAFT



FLØW THRØUGH RCPS ØN LØØP2
X10 4
2.4
2.2
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
-0.2
MASS FLØW RATE (LB/S)
0
500
1000
1500
2000
2500
3000
3500
4000
5000
5500
6000
6500
Time (s)
CASE 8 DUAL SGTR PØRV

DRAFT

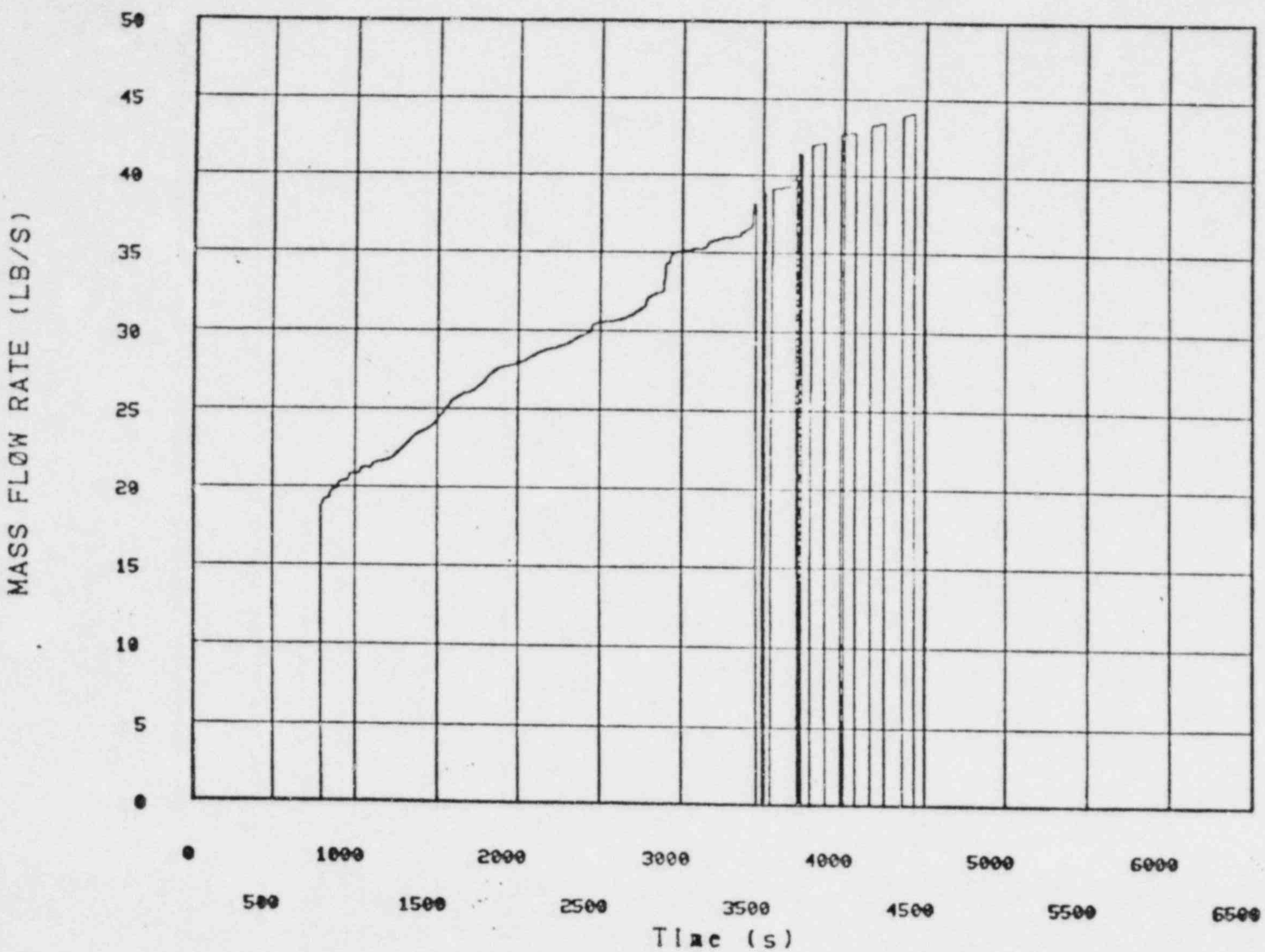
HPSI FLØWS LØØP1



CASE 8 DUAL SGTR PØRV

DRAFT

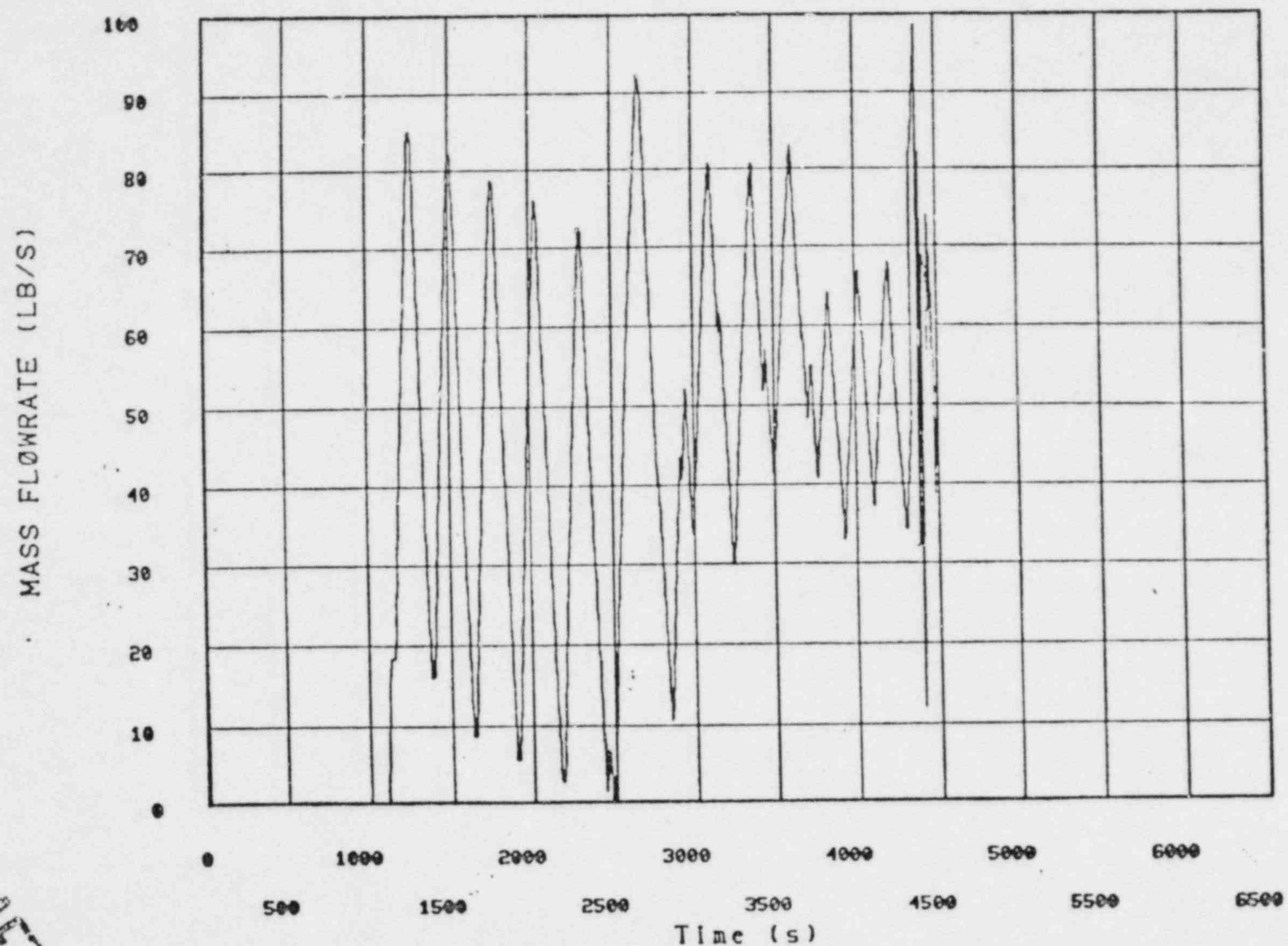
HPSI FLØWS LØØP2



CASE 8 DUAL SGTR PØRV

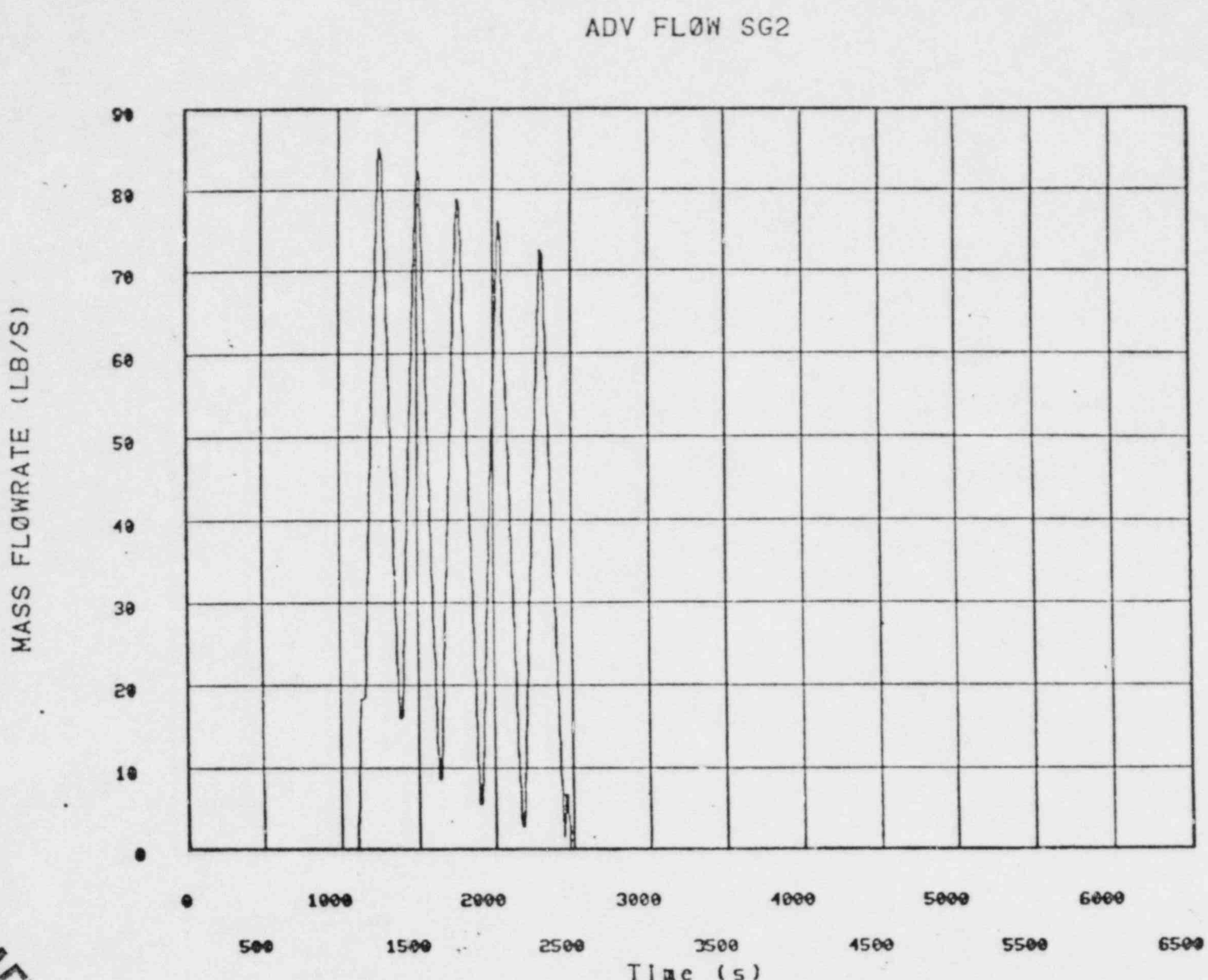
DRAFT

ADV FLØW SG1



CASE 8 DUAL SGTR PØRV

DRAFT



CASE 8 DUAL SGTR PØRV

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5.0 CONCLUSIONS

For the single tube rupture cases, the PORV was more effective in depressurizing the primary system and terminating the primary to secondary leakage. The PORV case (case 2) results indicated that the leak could be terminated about 5 minutes earlier than the APS case. This is out of a total transient time of approximately 75-80 minutes. The calculations would have displayed a much wider margin between the APS and PORV cases if the PORV would have been controlled using a less restrictive logic. The APS system cannot effectively depressurize the system once the subcooling margin is lost because it cannot remove energy from the system. However, the PORV is able to remove energy from the system, so it is capable of depressurizing the primary system even though the subcooling margin is lost. The addition of a PORV would provide the operator with an additional degree of flexibility to deal with potential accident scenarios. The effectiveness of the PORV to remove energy from the primary system will be demonstrated in Case 9 which is currently underway.

With the criteria for operating the PORV as implemented in this study, there is no advantage, as far as the SGTR event is concerned, in installing a large PORV (versus the smaller BG&E size valve used in this study), because the larger PORV will only result in an earlier closure of the valve once it is opened when the subcooling margine decreases below 20°F.

Once the results from Cases 4, 5, 6 and 9 are obtained, the conclusions will be expanded to reflect the new results.

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ACKNOWLEDGMENTS

This report was prepared by ANL staff in partial fulfillment of a project under the direction of the U.S. NRC Division of Systems Integration, R. J. Mattson, Director; B. Sheron, Branch Chief for Reactor Systems; N. Lauben, Section Leader; J. Guttmann, Project Manager. L. B. Marsh of the NRC Reactor Systems Branch provided direct technical guidance during the performance of this task.

ANL staff who provided input to this report, in addition to the authors, were P. B. Abramson who provided general technical assistance and guidance and K. S. Chung who developed the initial input deck and ran some of the preliminary calculations; K. Rank and J. Bracken, report preparation; and R. D. Wright, Jr., drafting services.

DRAFT

REFERENCES

1. H. K. report.

2. CESSAR SGTR

3. CEN-152

4. ANL/LWR/NRC 83-2

5. Private communication with Vic Ransom (   ), mass error updates.

6. Responses to Question 440.40 on CESSAR docket.

7. Telecon from Tad Marsh, NRC, Jan. 83.

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