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THE B&W OWNERS GROUP

Analysis Committee

Best Estimate Steam Generator Single Double Ended Tube Rupture Analysis

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BEST-ESTIMATE STEAM GENERATOR
SINGLE DOUBLE-ENDED
TUBE RUPTURE ANALYSIS

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CONTENTS

List of Tables

List of Figures

Figures (Cont'd)

1. INTRODUCTION

This report is intended to supplement the information contained in the report, "Analytical Justification for the Treatment of RC Pumps Following Accident Conditions," B&W Document No. 77-1149091-00, February 1984. This report presents the analysis of a steam generator tube rupture for the 177 fuel assembly (FA) raised-loop design in compliance with the criteria presented in Nuclear Regulatory Commission (NRC) Generic Letter 83-10, dated February 8, 1983.

2. CONCLUSION

An adequate subcooling margin is maintained during steam generator tube rupture (SGTR) events for ruptures up to and including the double-ended rupture of a single tube. Thus forced circulation is ensured throughout the event if the operator follows procedures based on the Abnormal Transient Operating Guidelines (ATOG).

3. BEST-ESTIMATE ANALYSIS OF A SINGLE DOUBLE-ENDED STEAM GENERATOR TUBE RUPTURE

A single double-ended SGTR was simulated for the Davis-Besse raised-loop plant design. The analysis is intended to demonstrate that sufficient loss of subcooling margin will not occur resulting in a need to trip the reactor coolant (RC) pumps if an operator follows the ATOG for the event. The results of this analysis will support the bases for utilizing manual tripping of the RC pumps on the criterion of the loss of subcooling margin.

3.1. SGTR General Characteristics

An SGTR is a loss-of-coolant accident (LOCA) that allows reactor coolant to leak into the secondary side of the steam generator (SG) where it is released into the steam plant and can lead to significant offsite doses if this steam is released to the environment. For a complete severance of one SG tube, a leak rate of approximately 400 gpm at normal system pressure and temperature would be expected.

The leak from a failed tube cannot be isolated and reactor coolant will continue to be lost until the plant is completely cooled and depressurized and the primary loops have been drained.

Since a tube rupture can exhibit the same general characteristics as a small break LOCA, the general procedures for LOCA mitigation must be followed. A continuous cooldown and depressurization of the reactor coolant system (RCS) is essential to avoid the opening of the SG safety valves thus minimizing the risk of releasing radiation. Forced circulation by the RC pumps will provide a continuous uninterrupted cooldown and depressurization of the RCS.

The following best-estimate analysis of a single double-ended SGTR for the Davis-Besse raised-loop plant was performed to demonstrate that operator actions as per ATOG, to control RCS inventory, perform plant runback, and initiate low power reactor trip preclude the loss of subcooling margin and hence RCP trip, during a single double-ended SGTR event.

3.2. Method of Analysis (Best Estimate)

The analysis was performed with the REDBL5[1] computer code. A description of the REDBL5 model simulating the RCS and the SG secondary system is shown in Figures 3-1 and 3-2 and Table 3-2. The model has been developed to predict the system behavior during an SGTR event and simulate important operator actions as described in the ATOG. In addition, the model utilizes a non-equilibrium pressurizer model capable of predicting two-phase pressurizer inventory and mixture level.

Operator actions leading to a cold shutdown, system initial conditions, and other input assumptions are described in the following subsection.

3.2.1. General Operator Actions

The operator actions for the SGTR event are summarized in Figure 3-3. The SGTR event can be divided into four distinct categories. Each of the categories is addressed below.

Event Identification

The first stage for mitigation of an SGTR is prompt recognition of the event and determination of the affected steam generator. The occurrance of secondary radiation alarms (steam line monitor or condenser air ejector) almost simultaneous with decreasing RCS pressure and pressurizer level are unique indicators that an SGTR has occurred. This analysis assumed that the operator diagnoses the SGTR following the radiation alarm and pressurizer low level alarm and begins to take prescribed action.

Plant Control at Power

In the second stage of the event, the RCS pressure and pressurizer level must be stabilized so that the plant may be run back without tripping. A trip at high core power may result in venting radioactive steam to the environment through the secondary safety valves. Normally, the makeup (MU) system will automatically increase MU flow to stabilize pressurizer level. For a double-ended rupture (DER) of a single tube, the leak flow (~400 gpm) is greater than the MU flow. The operator is instructed to take action to increase MU flow and terminate letdown in order to stabilize the RCS. Once the RCS pressure and pressurizer level are stable, plant runback to 25% full power should begin.

This analysis assumes that the operator starts a second MU pump and isolates letdown in order to stabilize RCS pressure. Analysis[2] has shown that for a DER of a single tube, the operator has approximately 11 minutes to stabilize RCS pressure before the reactor trips automatically. Once the system is stabilized, the operator is assumed to run back the power.

Plant Runback to 25% Full Power

Operator action should be initiated to stabilize RCS pressure and pressurizer level while conducting a plant runback to low power without tripping. RCS inventory should be monitored during the plant runback. This analysis assumed integrated control system (ICS) action to reduce the main feedwater (MFW) demand to match a manual 20% per minute runback in core power level.

Upon reaching 25% full power, where the available turbine bypass (TB) capacity is sufficient to avoid lifting the steam safeties, the plant is tripped.

Cooldown and Depressurization

The initial objective of the cooldown is to bring the RCS hot leg temperature to a value (520F) that corresponds to a saturation pressure which is below the steam safety valve setpoint. This action will limit radiation releases to the atmosphere. Below 520F, the SG with the tube rupture can be isolated. The cooldown should be continued to cold shutdown conditions at a rate of 100F/h using both generators and the decay heat removal system (DHRS), while maintaining a subcooled RCS.

3.2.2. Assumptions and Initial Conditions

The following assumptions and initial conditions were used in this analysis.

- Core power is 2772 MWt.
- Offsite power is available throughout the transient.
- RC pumps operate throughout the transient.
- Initial pressurizer level is 195 inches (indicated).
- High pressure injection (HPI) and MU flow characteristics are as shown in Table 3-1.
- The primary-to-secondary leak flow is conservatively modeled as subcooled discharge, with a discharge coefficient of 1.0.
- Initial plant condition --

Power level	2772 MWt
Hot leg temperature	607.12F
Hot leg pressure	2169.0 psia
T_{avg}	583.14F
RC system flow rate	39746 lbm/s
Pressurizer level (as measured from the lower tap)	195 in.
Total steam flow rate	3264.5 lbm/s
Subcooling margin	40.28F

3.3. Results of Analysis

The primary-to-secondary leak flow rate which resulted from the DER was approximately 39 lbm/s (see Figure 3-4). Operator action was modeled to manually start a second MU pump and isolate letdown at 3 minutes and 3.5 minutes after rupture, respectively. The charging flow of two MU pumps was not sufficient to match the leak flow. Subsequently, pressurizer level continued to decrease (see Figure 3-8).

A runback in reactor power of 20% per minute was manually initiated immediately after letdown was isolated (see Figure 3-5). MFW was automatically ramped by the ICS to match core power (Figure 3-6), and maintain a constant T_{avg} (Figure 3-7).

When reactor power and steam load were within the turbine bypass capacity, 25%, the reactor and turbine were tripped. The turbine bypass system controlled secondary pressure while the loss of heat source on the primary side caused the RCS to contract. The RCS contraction caused a pressurizer outsurge and the pressurizer level decreased. Pressurizer sprays were initiated to reduce system pressure to ~1700 psia, at which time the pressurizer level began to increase due to MU and HPI (Figure 3-8).

The minimum indicated post-trip pressurizer level was 23 inches. Once pressurizer level began increasing, the analysis was terminated because it was assumed the operator would cooldown and depressurize the RCS while maintaining a minimum subcooled margin. The subcooled margin at the termination of the analysis was 52F. Figures 3-4 through 3-16 show the transient responses of pertinent parameters.

Plant Condition at Termination of Analysis -- Table 3-3 lists the sequence of events for this analysis.

Power level	82 MWt
Hot leg temperature	558.73F
Hot leg pressure	1674.0 psia
T_{avg}	558.5F
System flow rate	39,858 lbm/s
Pressurizer level (indicated)	30.8 in.
Bypass steam flow rate	113.26 lbm/s
Subcooling margin	52.28F

3.4. Conclusions

Operator action, in accordance with the ATOG, to stabilize RCS pressure and pressurizer level, run back the plant, and trip the reactor does preclude sufficient loss-of-subcooling margin to result in the indication for a need to trip the RC pumps.

Table 3-1. HPI and MU System Capacities

1. MU Flow Rate Vs Pressure

Flow Rate, gpm	Pressure, psig 1300	1525	1920	2090	2235	2370	2480	2640	2720
1 Pump (vwo)	307	282	232	207	182	157	132	82	32
2 Pumps (vwo)	454	416	346	309	274	237	194	127	50

2. HPI[a] Flow Rate Vs Pressure (two pumps)

Pressure, psig	185	395	745	1025	1375	1555	1755	1820
Flow Rate, gpm	1825	1715	1500	1310	1000	805	400	0.0

[a] Coupled with low pressure injection (LPI) in "piggyback" operation.

Table 3-2. REDBL5 Volume and Junction Description

Component No.	
100,105,110-1 to 110-5 200,205,210-1 to 210-5	Hot leg
130,230	SG inlet plenum
140-1 to 140-10, 240-1 to 240-10	SG primary tube region
145,148,245,248	SG outlet plenum
150,180,250,280	Cold leg (pump suction)
161,181,261,281	RC pump
170,175,190,195 270,275,290,295	Cold leg (pump discharge)
301,305,310-1 to 310-3	RV downcomer
315,320	RV lower plenum
325	Core bypass
330-1,330-2,330-3	Core
345,350,355,360,365	RV upper plenum and head region
370,371	Vent valves (not used)
407	Pressurizer
408	Surge line
411	Spray valve
415,503	Pressurizer safety valves (not used)
501,502,651,751	Main steam safety valve and sink
551,552	Turbine
600,610,700,710	MFW piping
601,701	MFW isolation valve
615,620-1 to 620-4 715,720-1 to 720-4	SG downcomer

Table 3-2. (Cont'd)

Component	
625-1 to 625-5,630,635,640,645,648 725-1 to 725-5,730,735,740,745,748	SG secondary tube region
650,750	Steam risers
655,755	Steam piping
656,756	Main steam isolation valve
675,775	Steam chest
676,776	TSV
680	Main steam crossover
690,790,940,945	Auxiliary feedwater
800,801	Turbine bypass
802,803	Turbine bypass valves
904,911	MU system
905,906,907,908 915,920,925,930	HPI
909,910	Low pressure injection (not used)

Table 3-3. SGTR Sequence of Events

Event	Time after rupture, min:sec
SGTR at full power	0:00
MSL radiation monitors and/or condenser air ejector radiation monitors trip high secondary activity alarms	0:00
Low pressurizer level alarm	1:03
Operator starts second MU pump	3:00
Operator isolates letdown	3:30
Operator initiates reactor runback	4:00
Operator aligns HPI and LPI pumps in "piggyback" mode	4:00 to 7:45
Operator trips reactor and turbine	9:15
Minimum indicated pressurizer level of 23 inches	12:02
Analysis terminated	12:45

Figure 3-1. REDBL5 Volume and Junction Schematic

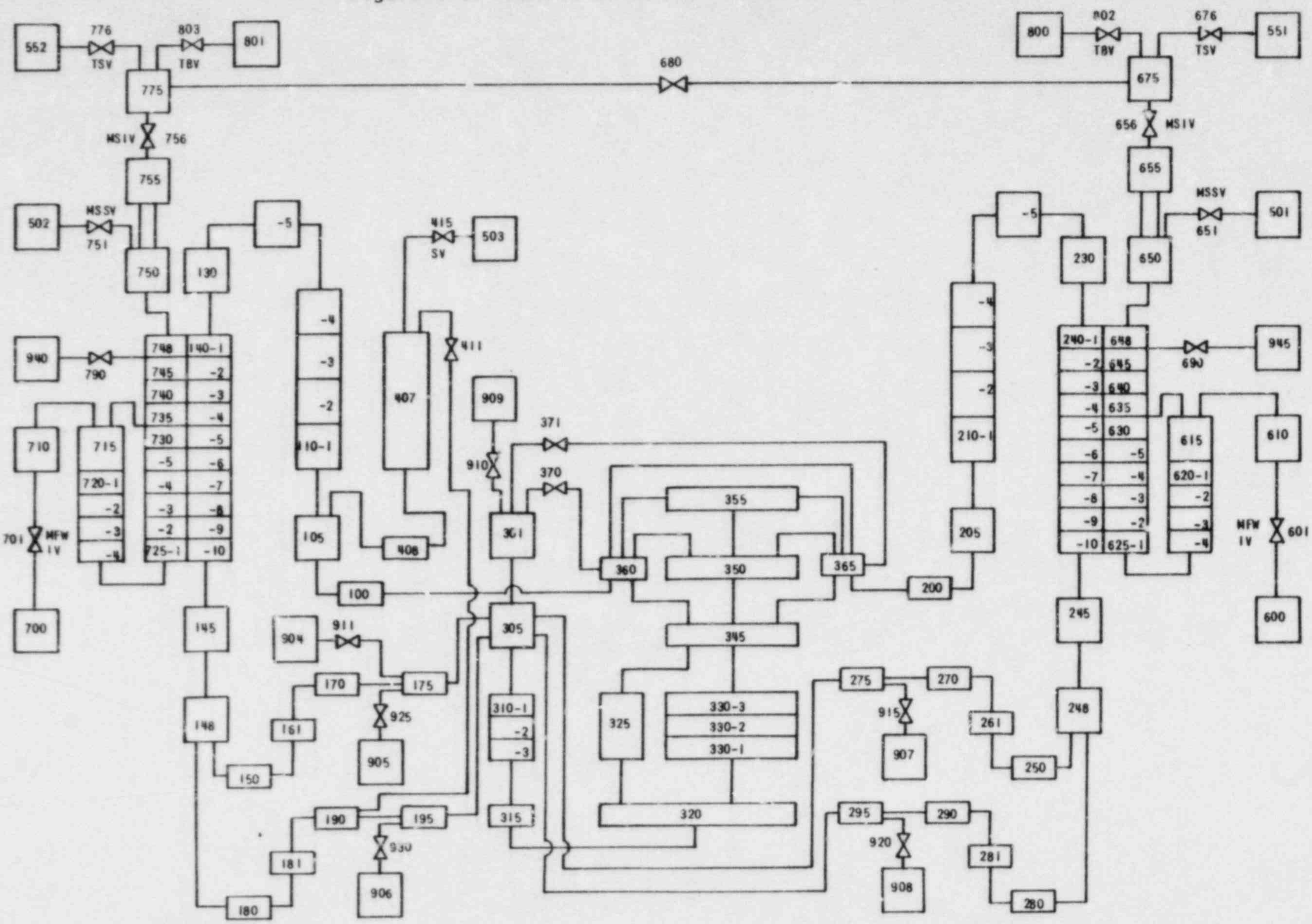
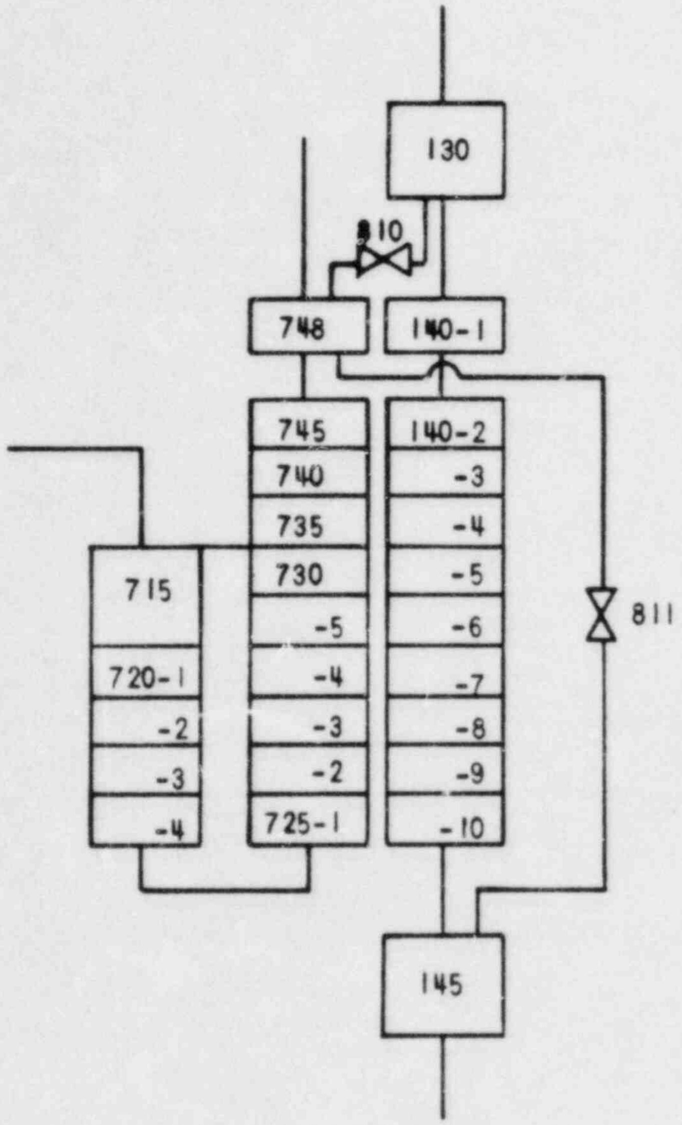


Figure 3-2. Detailed REDBL5 Component Diagram for SGTR Model



COMPONENT	DESCRIPTION
130	SG UPPER PLENUM
140-1 TO 140-10	SG PRIMARY TUBE REGION
145	SG LOWER PLENUM
715, 720-1 TO 720-4	SG DOWNCOMER
725-1 TO 725-5, 730, 735, 740, 745, 748	SG SECONDARY TUBE REGION
810	UPPER END OF RUPTURED OTSG TUBE
811	LOWER END OF RUPTURED OTSG TUBE

Figure 3-3. Operator Actions Following SGTR

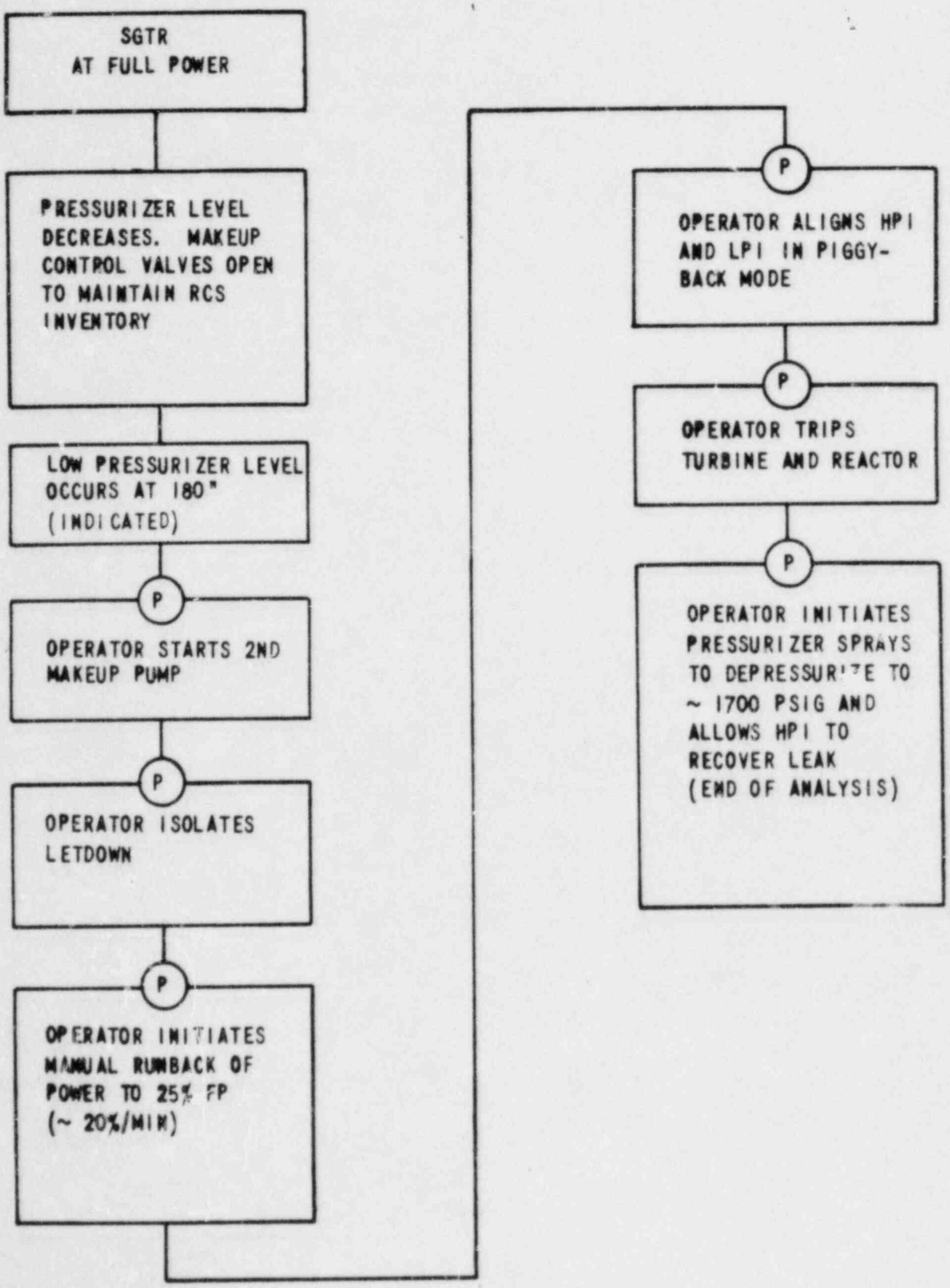


Figure 3-4. Total Leak Flow Rate Vs Time After Rupture

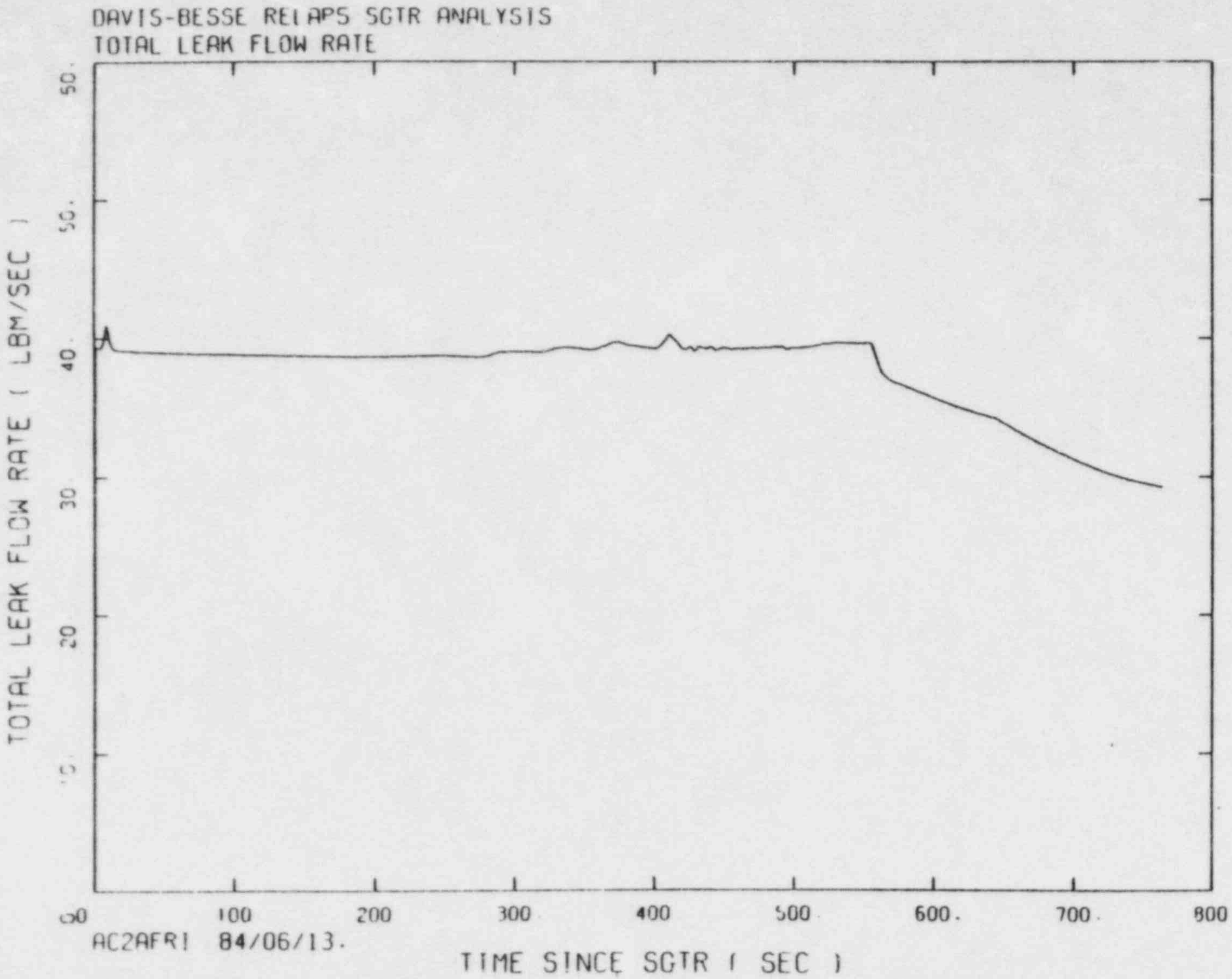


Figure 3-5. Total Reactor Power Vs Time After Rupture of a Single Double-Ended SG Tube

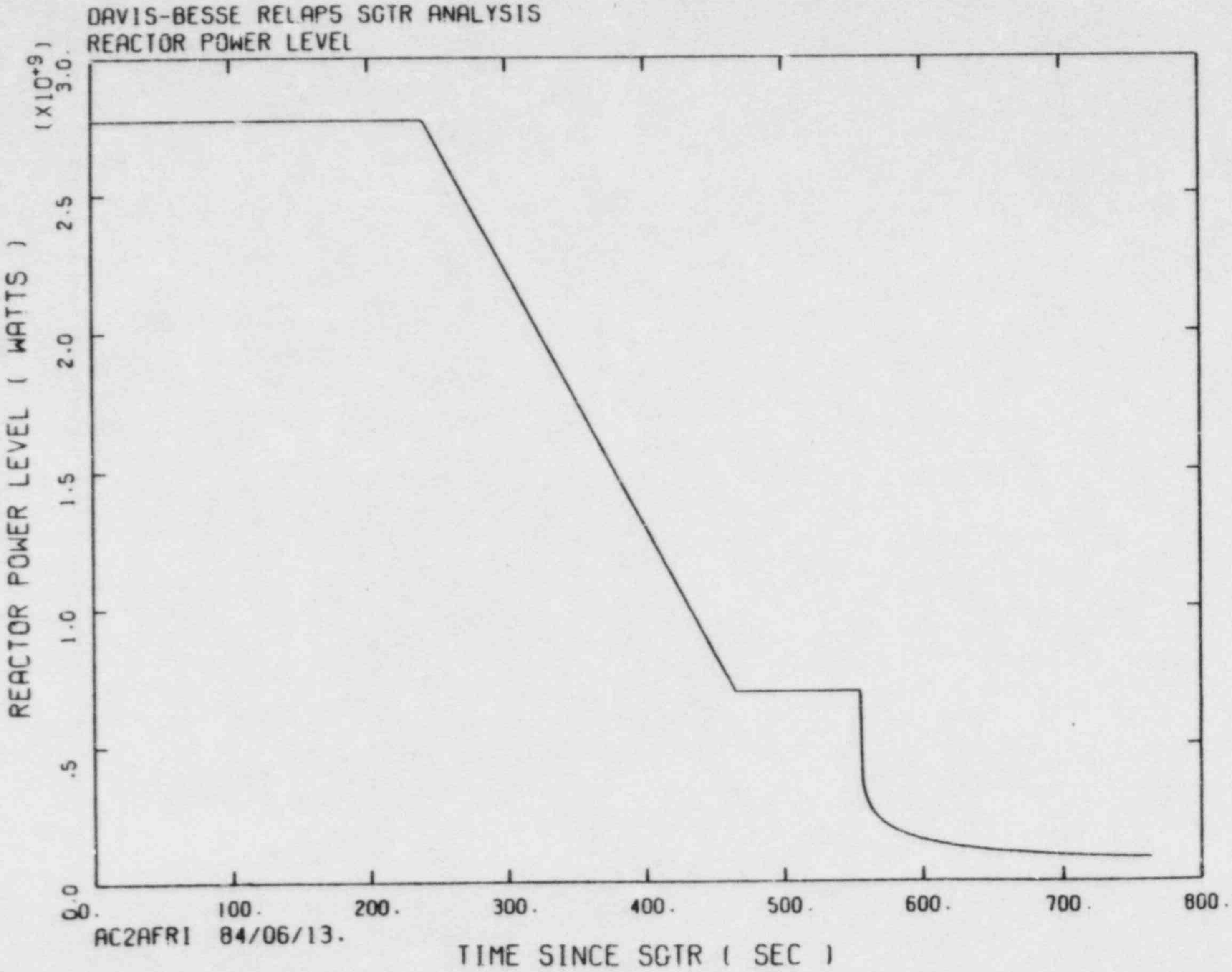


Figure 3-6. MFW Flow Rate Vs Time After Rupture

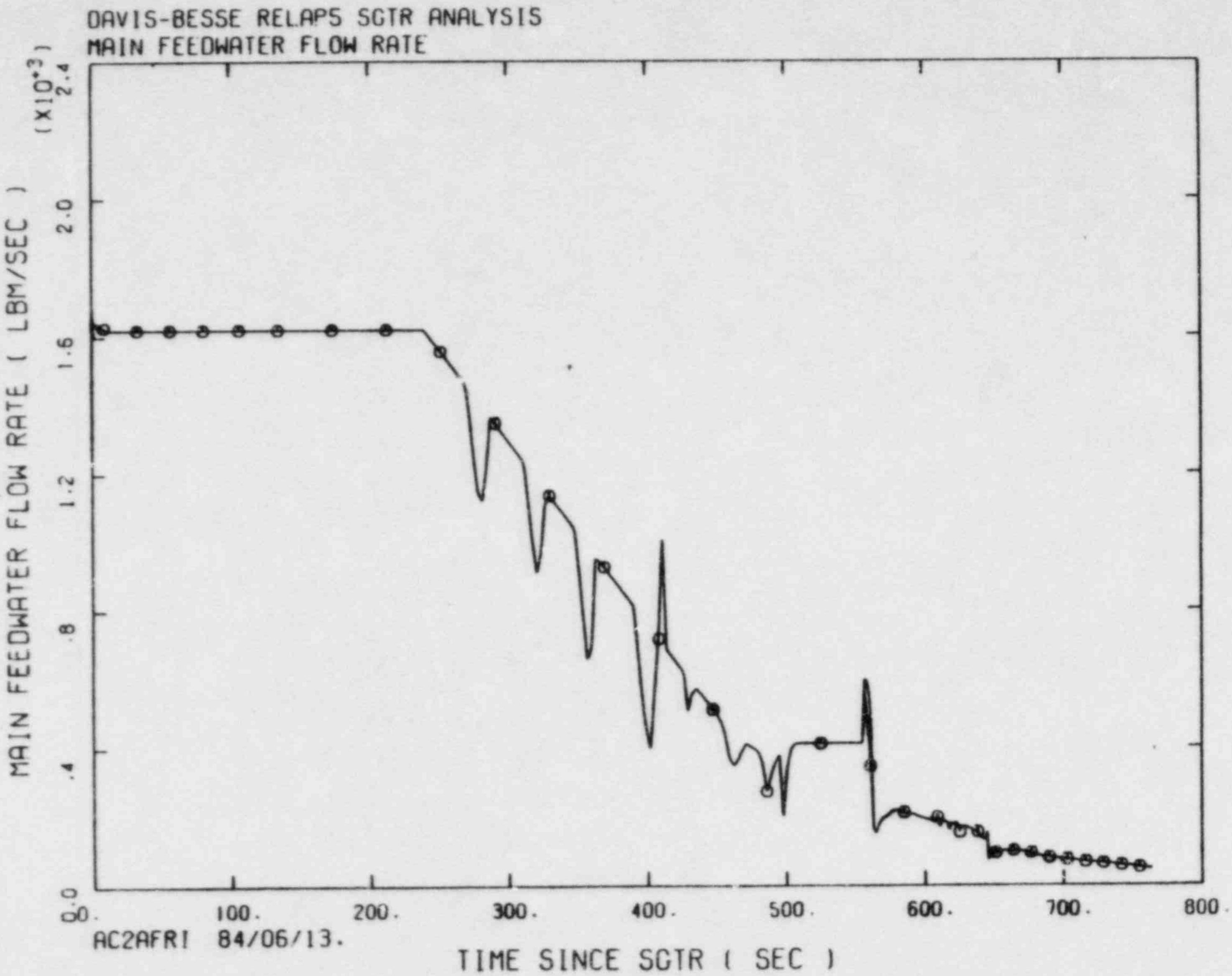


Figure 3-7. RCS Average Temperature

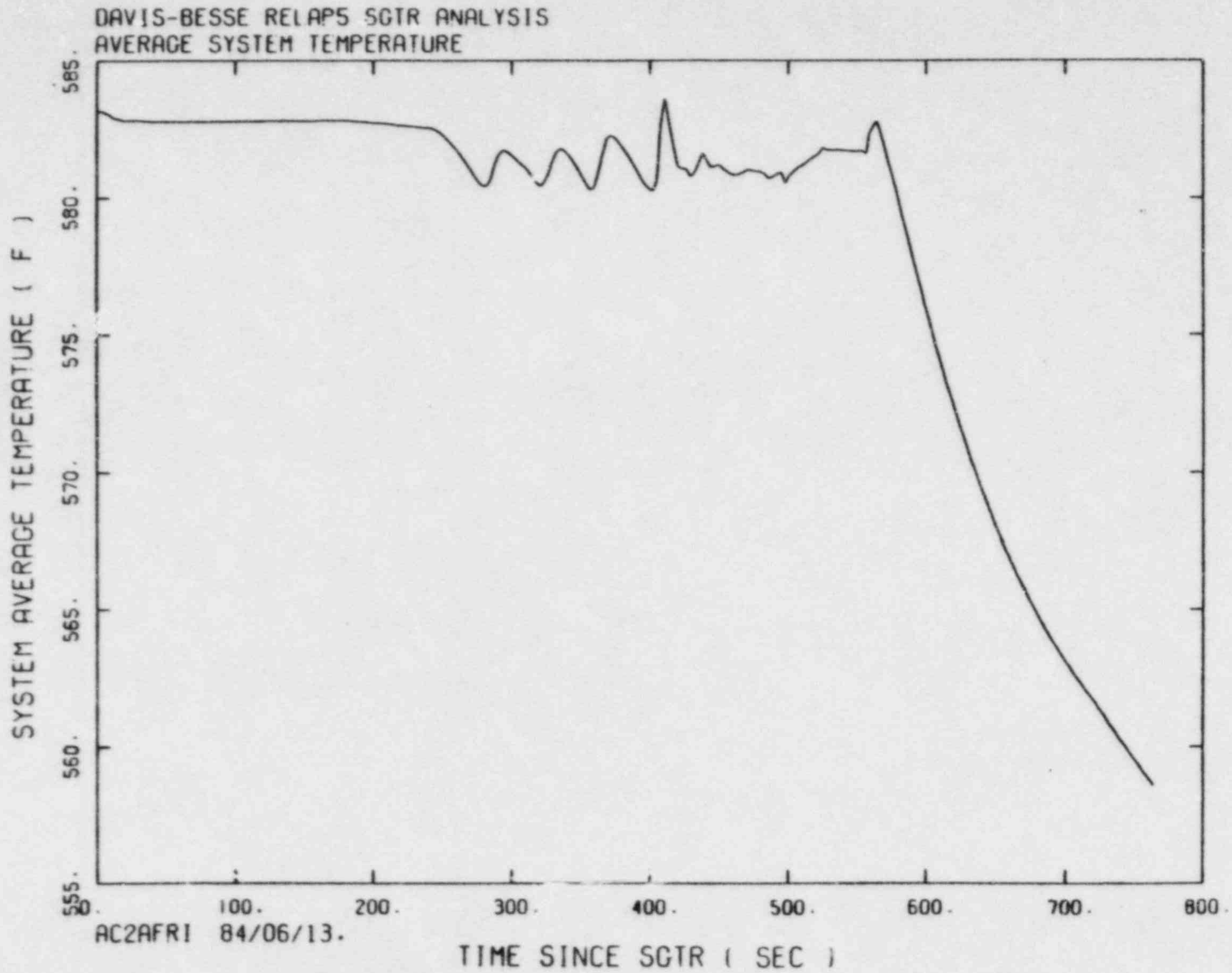


Figure 3-8. Pressurizer Collapsed Liquid Level Vs Time After Rupture

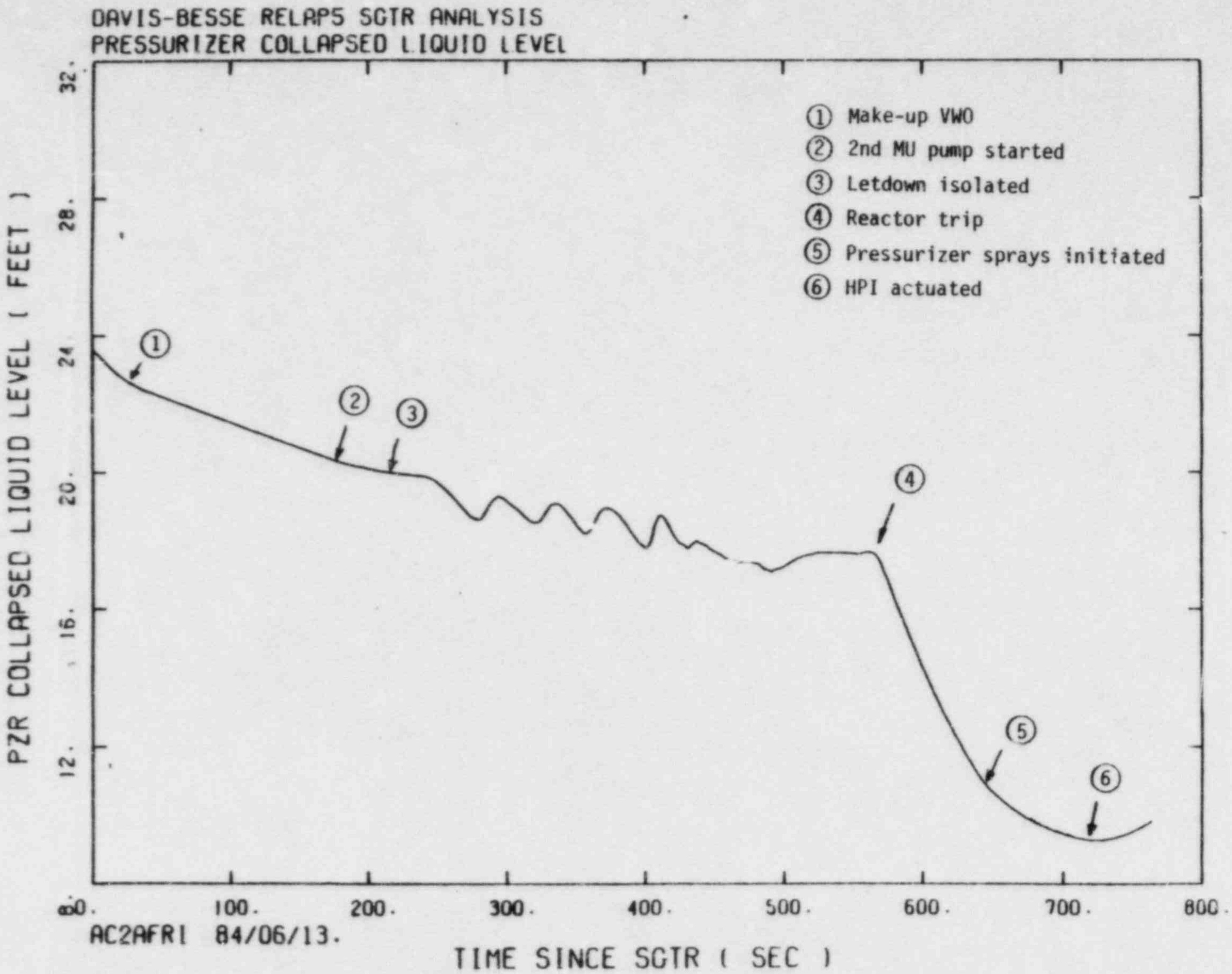


Figure 3-9. Hot Leg Temperature Vs Time After Rupture

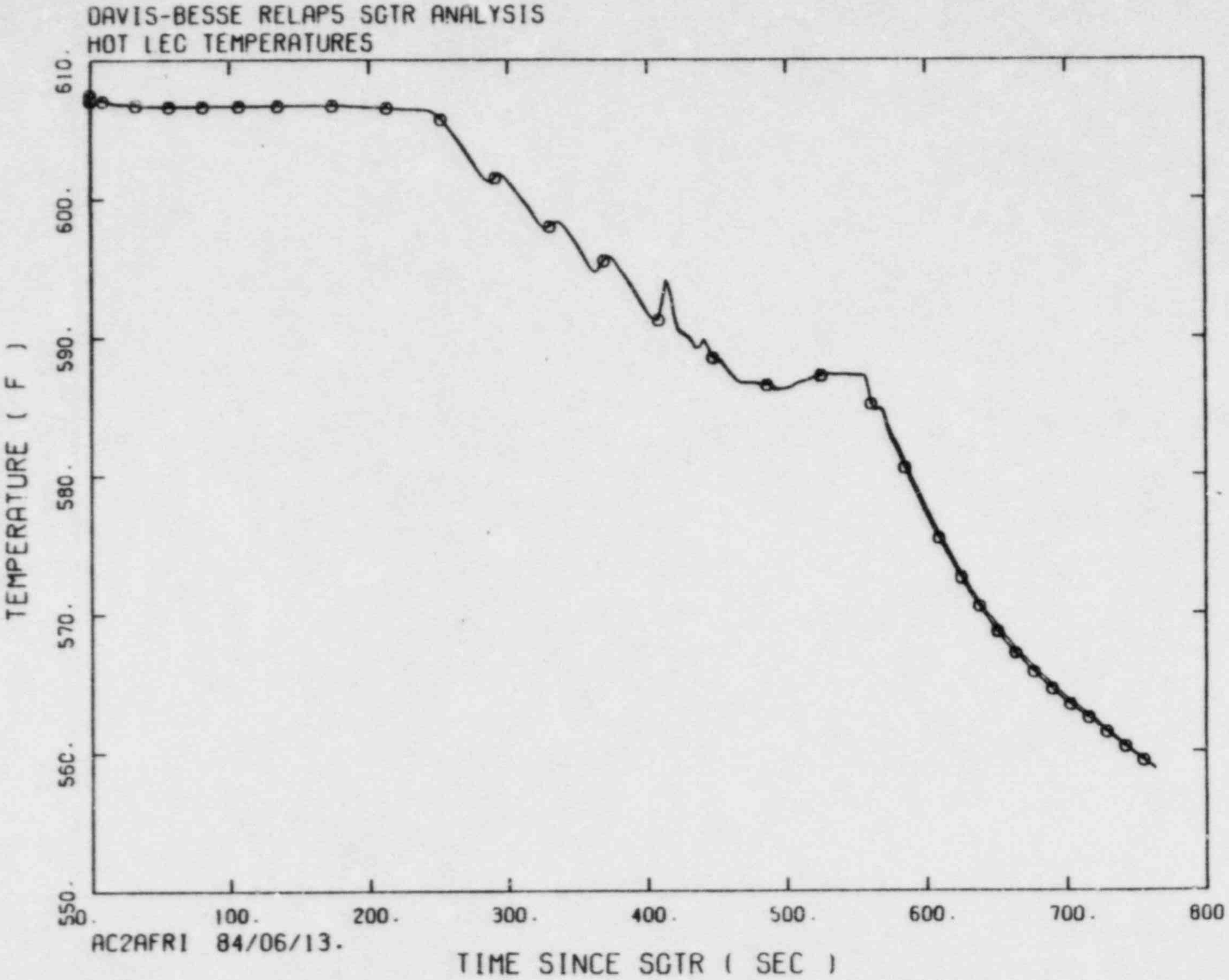


Figure 3-10. Cold Leg Temperature (Affected Loop) Vs Time After Rupture

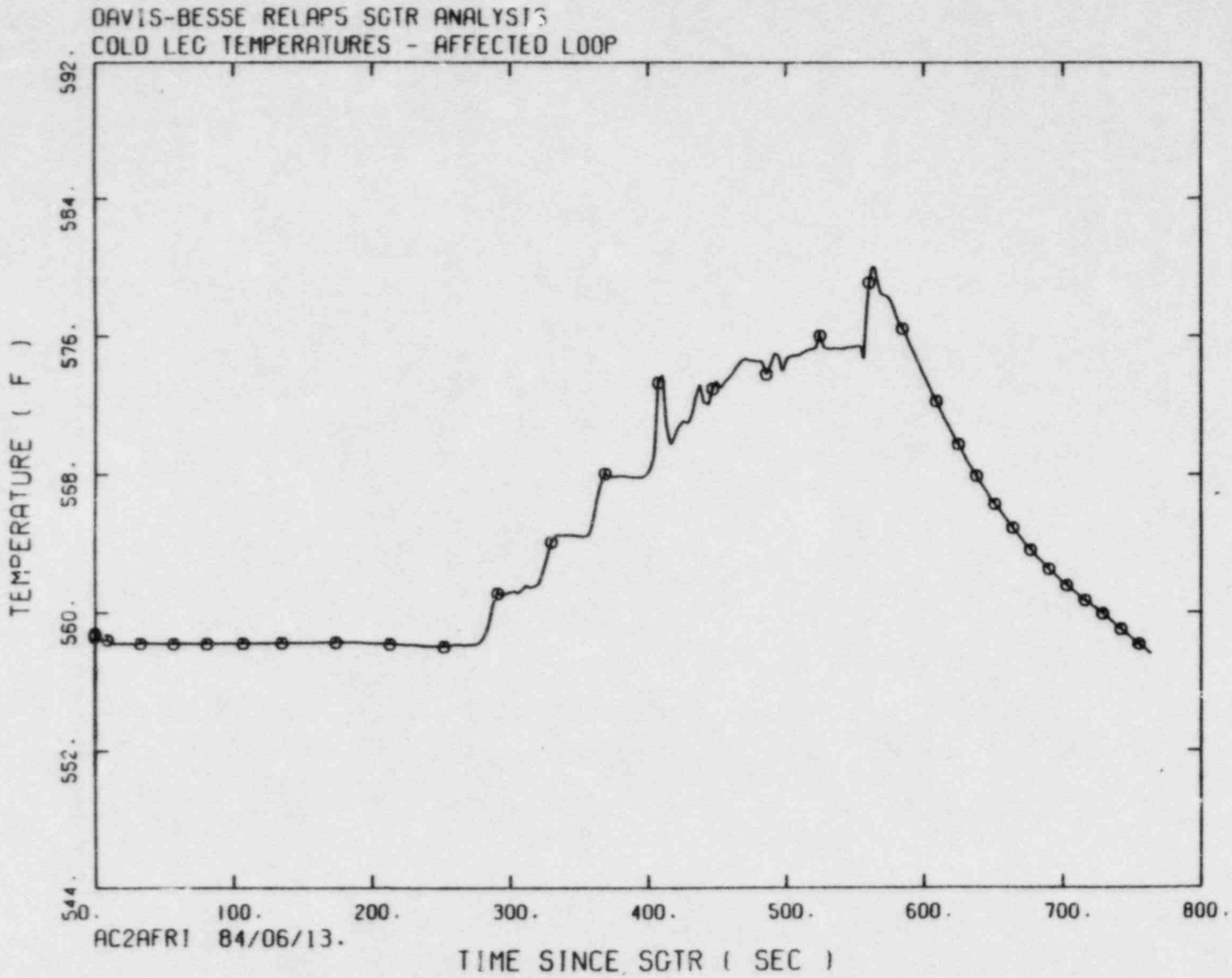


Figure 3-11. Cold Leg Temperature (Unaffected Loop) Vs Time After Rupture

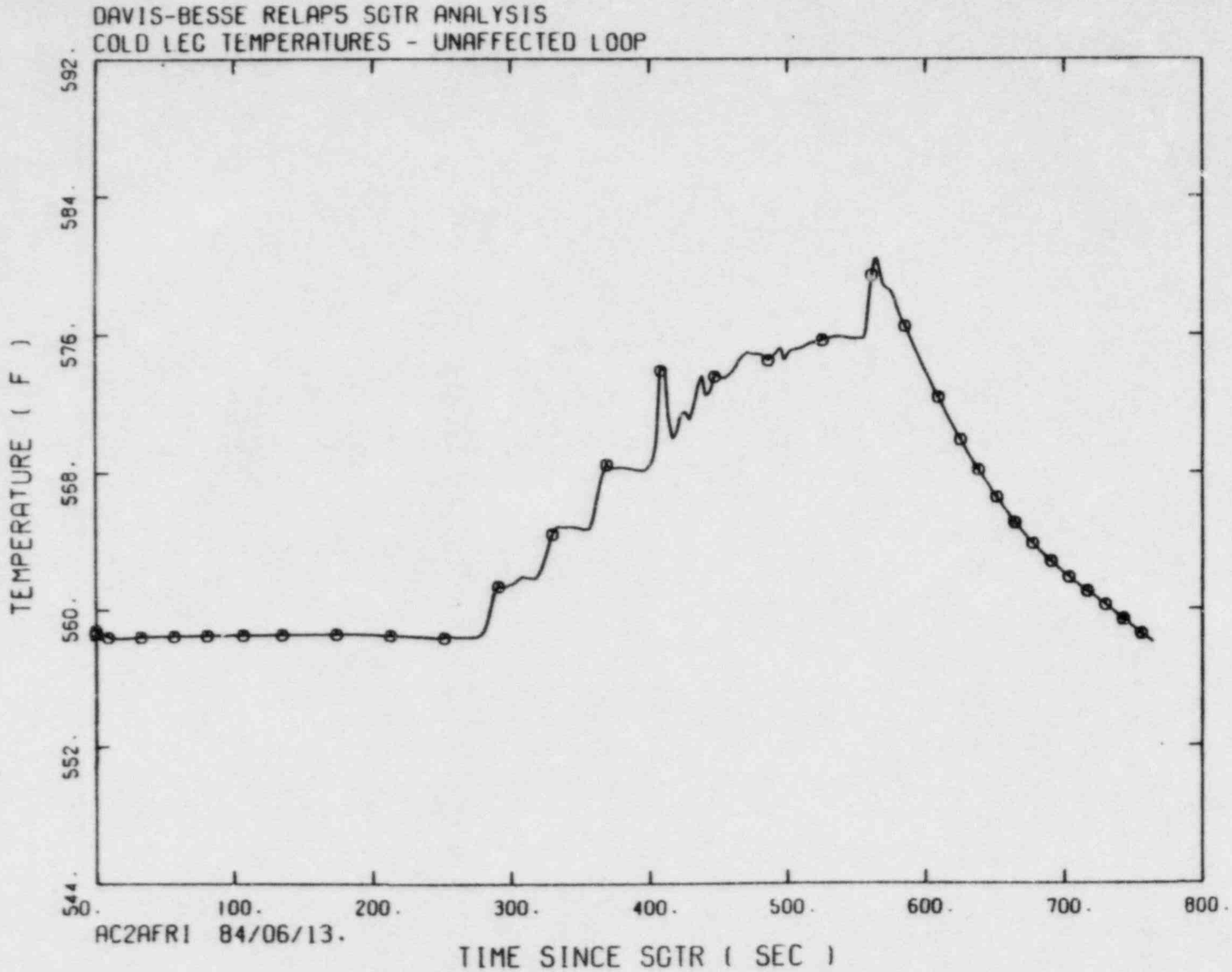


Figure 3-12. Hot Leg Pressure Vs Time After Rupture

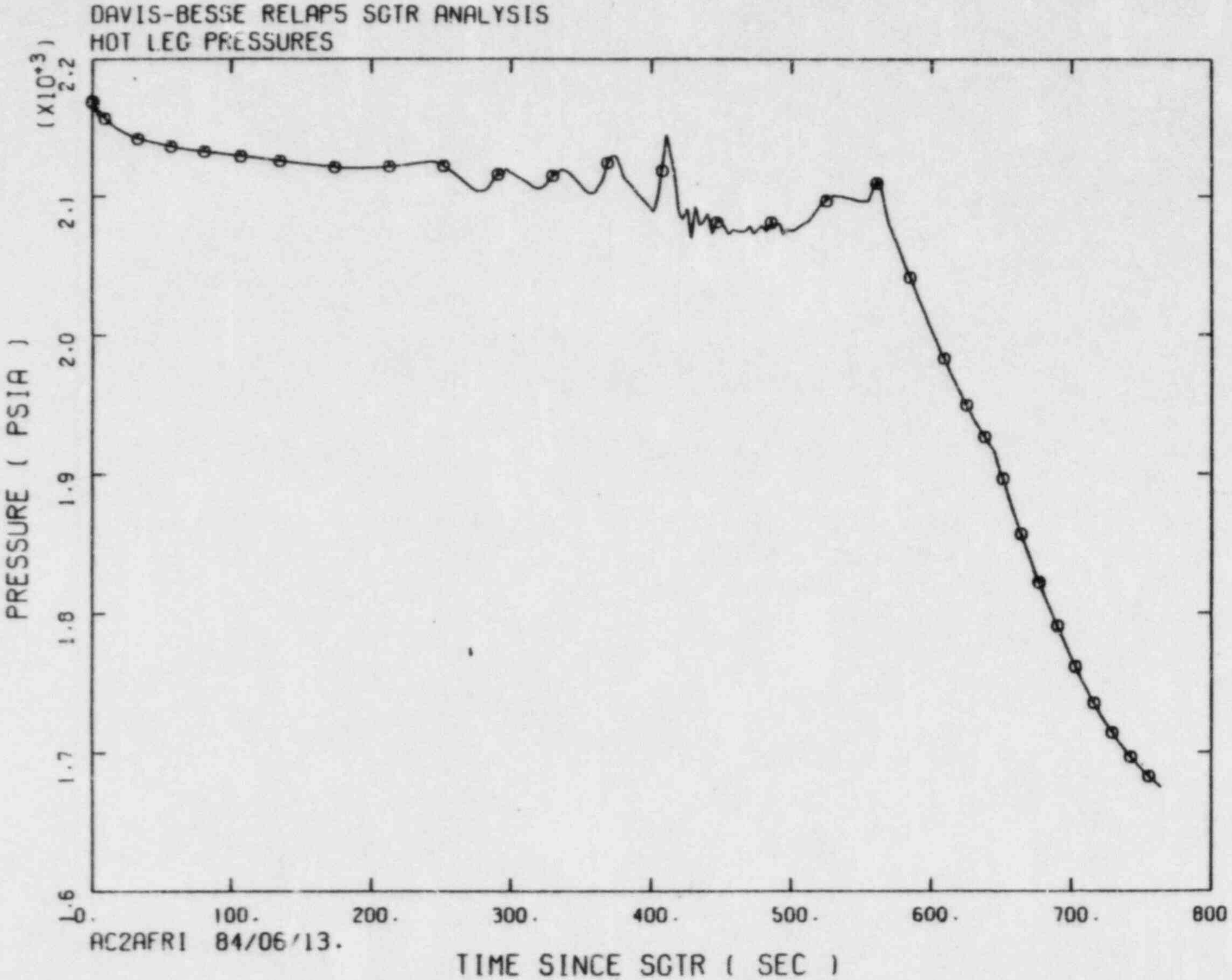


Figure 3-13. Surge Line Flow Vs Time After Rupture

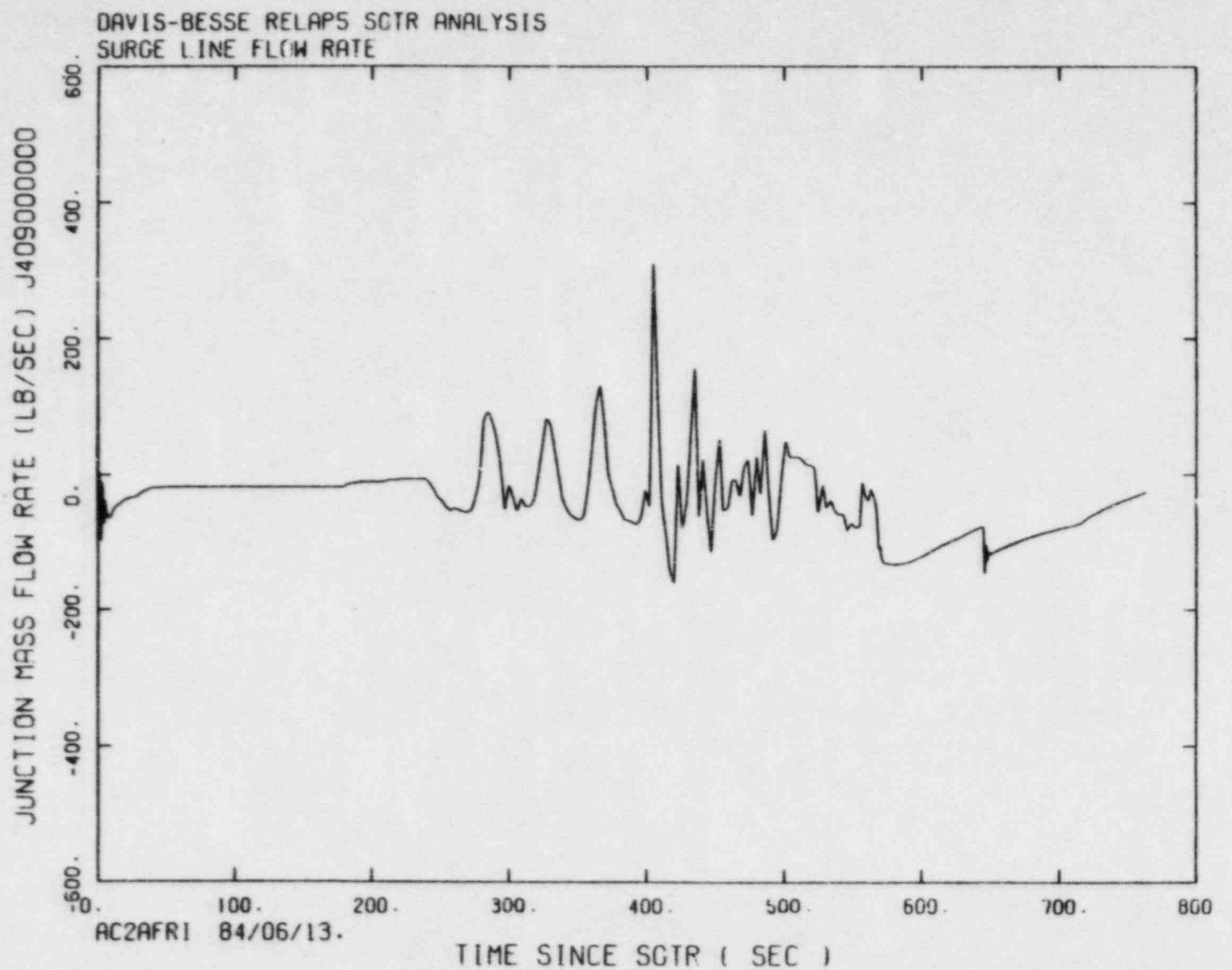


Figure 3-14. Net Injection Flow Rate Vs Time After Rupture

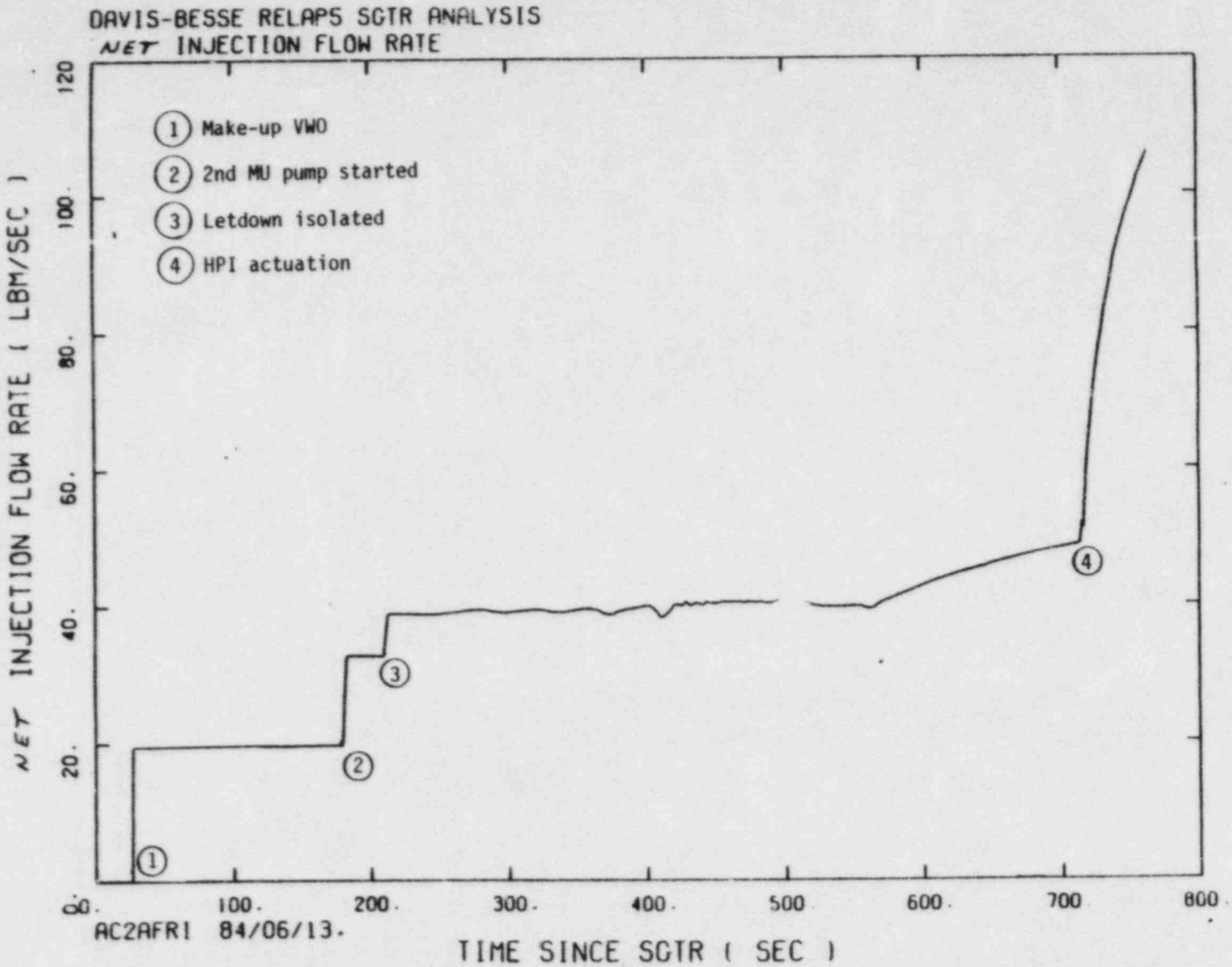


Figure 3-15. Top and Bottom SGTR Leak Flow Rate Vs Time After Rupture

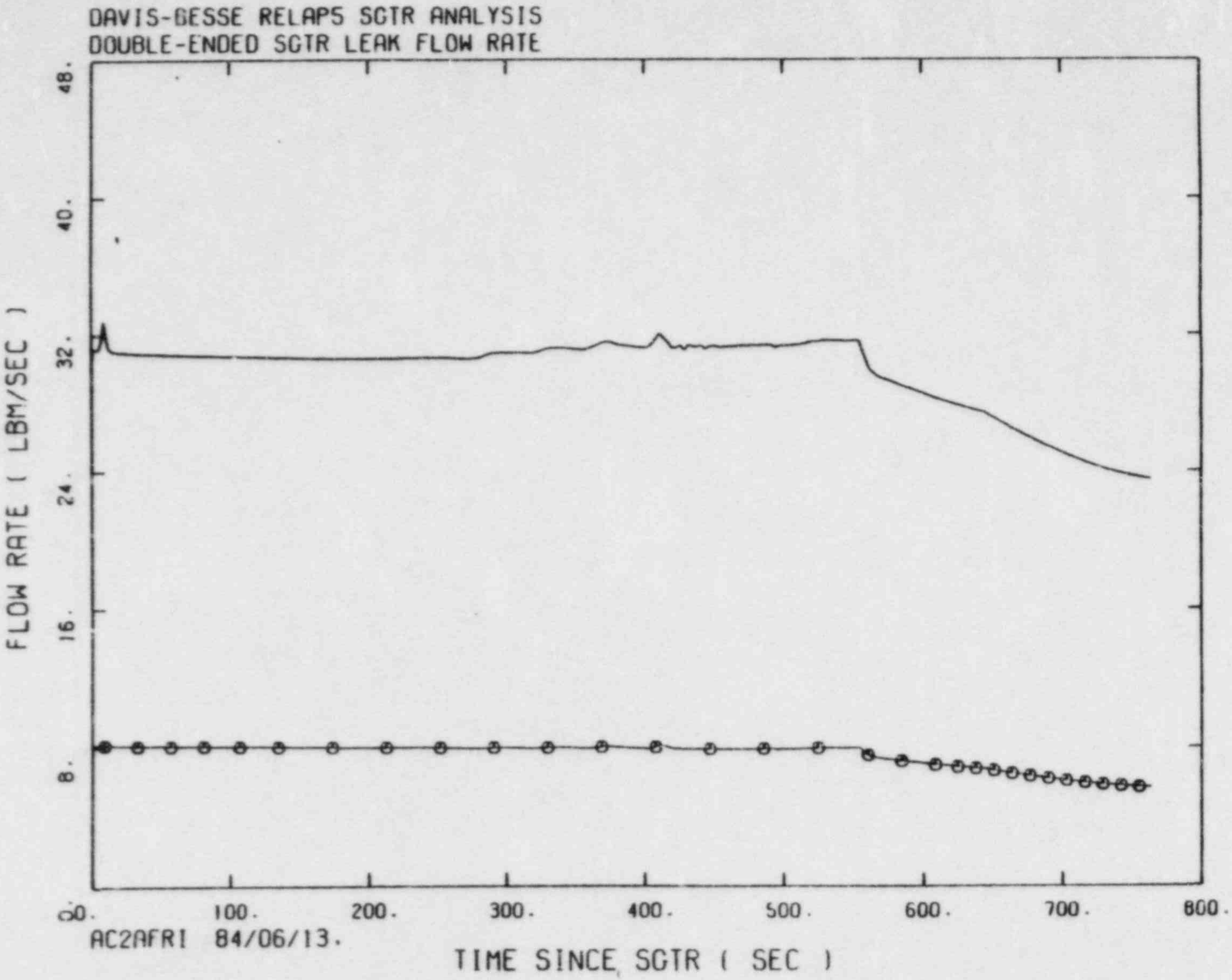


Figure 3-16. Subcooling Margin Vs Time After Rupture

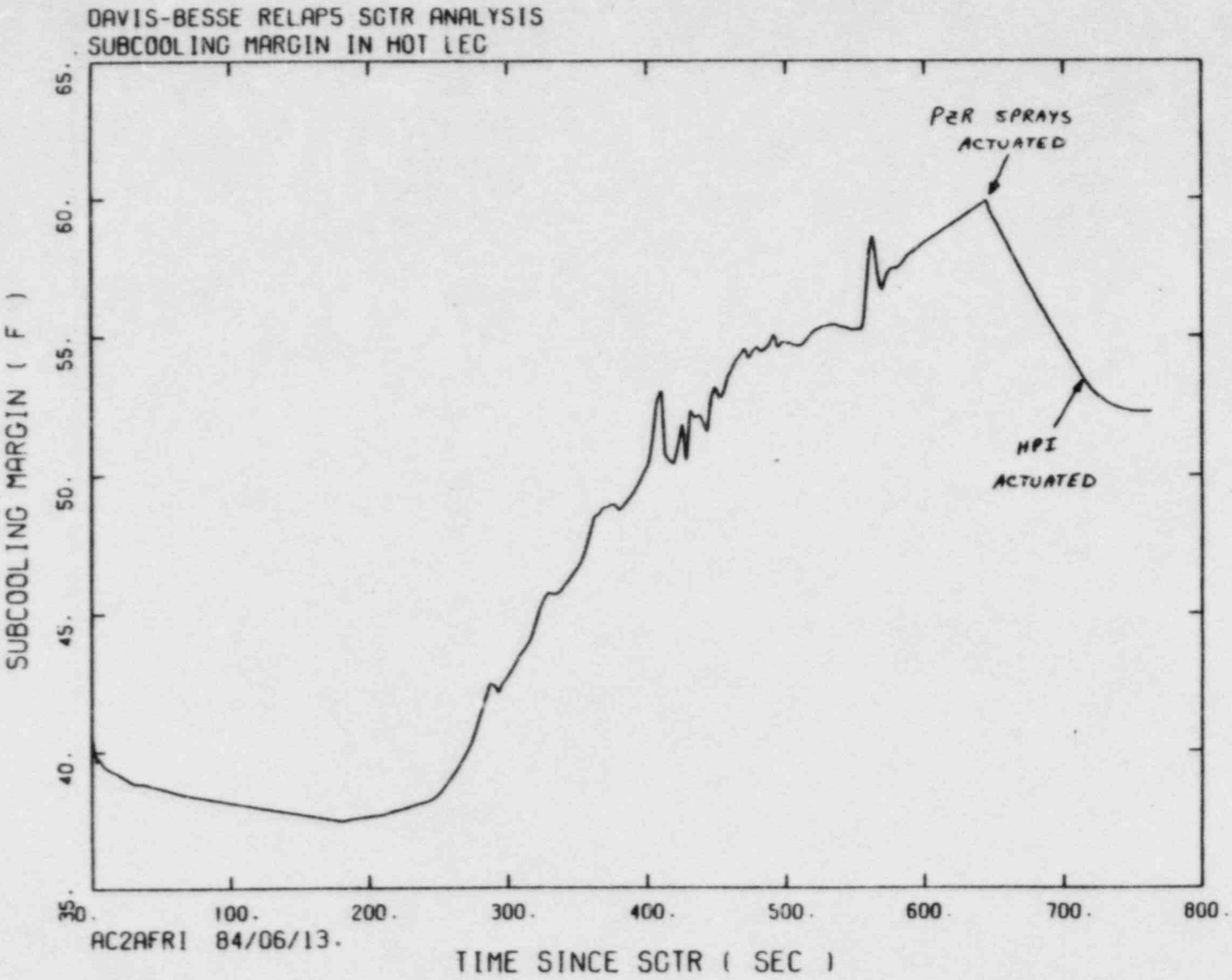


IMAGE EVALUATION TEST TARGET (MT-3)

150mm

6″

IMAGE EVALUATION
TEST TARGET (MT-3)

150mm

6"

4. REFERENCES

1. REDBL5 -- An Advanced Computer Program for Light-Water Reactor LOCA and Non-LOCA Transient Analysis -- Babcock & Wilcox Version of RELAP 5-, UPGD-TM-7, Rev E, Babcock & Wilcox, Lynchburg, Virginia, May 1984.
2. Arkansas Nuclear One -- Unit 1 Abnormal Transient Operating Guidelines, The SGTR Event, B&W Document 74-1122058-00, Babcock & Wilcox, Lynchburg, Virginia, August 20, 1982.