ASSESSMENT OF TURBINE TRIP OF 6/16/83 FOR SATISFYING FSAR REQUIREMENTS

Summary

On June 16, 1983, SONGS 2 experienced a turbine trip from near full power. The Critical Functions Monitoring System (CFMS), a computer which monitors various plant parameters, was operating and recorded many plant parameters. The trip was initiated by a condenser pressure switch which had not reset following a period of elevated condenser pressure. The resulting turbine trip behaved as if it had been manually initiated. All parameters in the turbine trip procedure which had acceptance criteria had been recorded by the CFMS. Since the test met all acceptance criteria listed in the FSAR, namely being satisfactory from a commercial standpoint, the test was considered equivalent to the planned turbine trip test. Commercial rammifications such as saving an estimated three or four days of generation have led to the analysis and supporting material below. This material shows that operation of the plant was satisfactory. Sufficient data was gathered to show control systems operated satisfactorily. Operator actions were satisfactory, no anomalous problems were encountered (ie, no safety limits were violated), and the SBCS and feedwater control systems performed adequately.

The Trip

The trip consisted of four distinct but overlapping parts. In the first three seconds the turbine trip activated protective equipment including the reactor protective system and turbine and generator protective equipment. Second, from 3 to 60 seconds, control systems such as the steam bypass control system (SBCS), which bypasses steam to the main condenser, and pressurizer level and pressure control systems operated to limit pressures and levels. Third, a Safety Injection Actuation Signal (SIAS) was experienced at 36 seconds. SIAS was initiated on low pressurizer pressure of 1825 psia and caused safety-related equipment to start. A safety injection did not occur because reactor pressure was greater than the high pressure safety injection pumps shutoff head. The SIAS was not a safety limit so none was violated. By procedure the reactor operators were forced to deenergize all four reactor coolant pumps. Before deenergization the plant had been returned to near stability by the control systems; afterwards additional time (approximately five minutes) was required to again achieve stability. Two sets of stability were encountered, the second entirely at the hands of reactor operators. Thus the equipment and operators were able to demonstrate satisfactory performance far beyond the original scope of the turbine trip test procedure. Minor problems with the SBCS resulted in the SIAS; those problems have been identified and corrected.

The Assessment

The following assessment consists of five sections. First is a comparison of initial conditions and acceptance criteria which shows that all acceptance criteria from the turbine trip test procedure were met. A few initial conditions were slightly outside the test procedure's bounds, but a discussion of the differences shows they had little effect. The fact that all acceptance criteria were met shows the slight departures made little difference.

The second section is a Sequence of Events which lists equipment actuation times and effects. The Sequence shows that events occurred as expected.

The third section contains ten annotated graphs of selected parameters for the first two minutes of the trip. All of the single value acceptance criteria and applicable control systems are shown. Applicable control systems include those which affect the reactor coolant system, such as the chemical volume control system (charging and letdown), pressurizer pressure and level control, feedwater control, and SBCS. Detailed discussions of the graphs are included to demonstrate satisfactory operation despite minor problems with the SBCS and one feedwater pump turbine. A slow closing of the SBCS led to slight over-cooling of the primary coolant system and resulted in SIAS. One feedwater pump turbine speed control had been placed in manual, which caused the feed-water pumps to trip shortly after the turbine trip. From a commercial stand-point, however, the plant was shown to be controllable and stable.

The fourth section is a comparison of CESEC predictions and data for the turbine trip. CESEC is Combustion Engineering's predictive tool for system excursions such as trips. Departures from predictions are relatively small and due mostly to SBCS operation. The accuracy of the prediction shows an additional turbine trip is unnecessary, especially since the upcoming generator trip will be essentially identical.

Finally, a fifth section of four graphs has been devoted to the natural circul-ation which followed tripping the reactor coolant pumps. Entry, stabilization, and recovery from natural circulation was entirely controlled by the reactor operators. As mentioned above, the operators are required by their procedures to deenergize all reactor coolant pumps upon receipt of SIAS. A detailed discussion of the graphs is included.

SECTION #1

DISCUSSION OF INITIAL CONDITIONS AND ACCEPTANCE CRITERIA

Table I compares initial conditoins which existed just before the trip and those specified by the test procedure and CESEC predictions. Table II compares the single value acceptance criteria with appropriate parameters during the trip. The two tables show that despite being slightly outside some of the initial conditions, all acceptance criteria were met.

Initial conditions are temperatures, pressures, and power levels which existed just before the trip and define starting conditions for the test and CESEC predictions. Marked departure has the potential for jeapordizing acceptance criteria although not for this trip.

Acceptance criteria are acceptable limits on water levels, steam pressures, temperatures, etc., which bound acceptable plant performance. Single value acceptance criteria bound only one upper and lower limit and a combination of single limits defines an acceptable envelope. Proper operation of control systems is vital to satisfying acceptance criteria, including single value acceptance criteria.

The plant performed acceptably from a commercial standpoint and meeting the FSAR's acceptance criteria. Failure to meet initial values did not significantly impact meeting the acceptance criteria; acceptance criteria were approached due to slow-closing SBCS valves. Rapid opening and closing of the SBCS valves, called "quick-open" and "quick-close" was experienced for the first time during the turbine trip and some adjustment can be expected any time a feature is first used. The turbine trip test procedure would also have activated the quick-opening feature so test results from the trip reflect what would have been expected from the test.

All initial values were within tolerance except cold leg temperature, pressurizer level, the number of operating charging pumps, steam generator blowdown flow, feedwater speed control, and test equipment. None of the departures significantly impacted the test, as discussed below.

First, coldleg temperature was high by 2°F. Up to a point the effect of control systems overshadows the small difference in temperature.

Second, two charging pumps rather than three were used since a dilution was in progress. Charging and letdown have the potential for changes in pressurizer level over the long term, not one or two minutes. Even if one charging pump had been operating before the trip, before six seconds all charging pumps would have been operating, just as with this trip. A single charging pump is important only for assessing pressurizer level control system performance; the fact that all three pumps were operating by six seconds shows the control system operated correctly.

Third, a small amount of steam generator blowdown, typical of normal operation, was flowing whereas the procedure called for none. Blowdown was isolated at fifteen seconds, early in the transient. Compared to main feedwater flow of 15,000 gpm, blowdown flow of 80 or 90 gpm has no short term effect on steam generator level or energy.

Fourth, one feedwater pump turbine was placed in manual speed control shortly before the trip. Turbine speed was maintained at its full power value even though feedwater flow was decreasing due to the control valves ramping shut on Reactor Trip Override (RTO). The purpose of RTO is to supply steam generators with a slight amount of warm feedwater, approximately that needed to balance decay heat, and restore levels with a minimum of operator action. Normal control functions are overridden because the low steam generator levels which always accompany a trip would call for increased flow. Increased flow could result in a rapid cooldown or feedwater pump trip on, for instance, low feedwater pump suction pressure. RTO decreases flow. As flow decreases, feedwater pump speed must also decrease accordingly or high discharge pressure will result and a protective pump trip will result as occured during the trip. Experience at other plants has shown frequent feedwater pump trips even with the pumps in automatic so even automatic control. Although manual speed control insured that a pump trip would occur, it is not clear that automatic would have avoided it.

Finally, special recording equipment was not operating. The recording equipment is used as a convenience in determining in a timely fashion if control systems are operating properly. Much of the same information can be painstakingly extracted from graphs of the transient such as are included in this report. The absence of recording equipment had little impact on the FSAR objectives of acceptable commercial operation; the plant operated satisfactorily from a commercial standpoint.

The transient will essentially be repeated during the load rejection (generator) trip.

TABLE I

COMPARISON OF INITIAL CONDITIONS: CESEC PREDICTIONS, TEST PROCEDURE, AND 6/16/83 TURBINE TRIP

PARAMETER	INITIAL VALUES: CESEC	INITIAL VALUES: PROCEDURE	INITIAL VALUES: ACTUAL CONDITIONS	COMMENTS
- Core Power	100.6 % (3410 Mwt)	100+0, -2%	100%	Inferred from Thot-Tcold
- Tcold	552.0 °F	551 to 554 °F	556 °F	
- Thot	607 °F	n/a	607 °F	
Pressurizer				
- Presssure	2250 psia	2250 ± 15 psia	2264 psia	
- Level	53.9%	53.8 to 55.4%	57.0%	
- Steam Generator Pressure	922 psia	899 to 937 psia	936 psia	
- Charging Pumps Operating	One	One	Two	Letdown matching charging.
- Control Systems	In Automatic except CEDMCS, which was OFF, and Feedwater Pump K005 whose speed control was in Manual.			Feedwater pump was only deviation.
- Steam Generator Blowdown Flow	Secured	Secured	Small flow (80 gpm from #2, 90 gpm #1)	Isolated on EFAS, 15 seconds after trip.
- Test Equipment And Startup Computer	n/a	In service to observe control systems and other plant data.	Not operating.	CFMS and control room recorder charts provided data.

TABLE II

COMPARISON OF SINGLE VALUE ACCEPTANCE CRITERIA (PROCEDURE) VERSUS 6/16/83 TURBINE TRIP

PARAMETER	VALUES		COMMENTS
	SINGLE VALUE ACCEPTANCE	ACTUAL RESULTS AND TIME	
- Pressurizer Pressure	$\leq$ 2388 psia	2265 psia @ Trip	Highest was initial condition.
- Pressurizer Level	$\geq$ 11.0 % Indicated	15.0 % @ 45 seconds.	
- RCS Hot Leg 1 Minimum	$\geq$ 543.0 °F	543.0 °F @ 50 seconds.	
- RCS Hot Leg 2 Minimum	$\geq$ 543.0 °F	543.0 °F @ 50 seconds.	
- Steam Generator #1 Pressure	$\leq$ 1087.0 psia	1041 psia @ 6 seconds.	
- Steam Generator #2 Pressure	$\leq$ 1087.0 psia	1045 psia @ 6 seconds.	

NOTES:

1. Single value acceptance criteria are stated in Steps 8.3.1.1 through 8.3.1.6 of the test procedure 2PA-344-04, Revision 1, and are for FIRST 60 SECONDS OF TRIP ONLY.
2. Actual values were obtained from graphs of the parameters.
3. All parameters met their acceptance criteria.

SECTION #2

SEQUENCE OF EVENTS

Table III is a sequence of events which outlines automatic control and manual operator actions during the first thirty five minutes post trip. Although the table is not specifically separated, it can be divided into four distinct but overlapping parts. First, from 0 to 3 seconds, was when the protective circuitry actuated to trip the turbine, generator, and reactor. It did so without operator assistance.

Second, from 3 to 60 seconds, automatic operation of control systems such as the turbine bypass control valves (SBCS) limited pressure excursions and brought the plant to quite stable conditions. Third, automatic initiation and plant response to a Safety Injection Actuation Signal (SIAS) occurred from 36 to 47 seconds. Finally, manual response to the trip and SIAS, including deenergizing all four reactor coolant pumps, occurred from approximately one minute to 40 minutes.

The plant was in normal high power operation and the operators were not expecting the trip. The unexpected trip had the added benefit of showing typical, nominal plant operation since no special effort or equipment configuration was undertaken.

TABLE III

Turbine Trip from 100% Reactor Power
Sequence or Events from the Plant Computer
and the Critical Functions Monitoring System
June 16, 1983

Time from Trip (sec)	Event	Comments
0.000	Turbine Trip on low vacuum switch.	The initiating event.
0.022	Turbine Trip Relay Tripped.	The actual turbine trip.
0.033-0.175	Turbine Loss of Load Reactor Trip.	All four Channels tripped.
0.201-0.217	Reactor Trip Breakers open.	All eight breakers open.
0.260-0.319	CEDM Main Power Bus Under Voltage Relays open.	All four relays open.
1.126-1.687	All four CPC's trip on both low DNBR and Local Power Density.	Response to CEAs entering core.
2.0	Steam Bypass Valves quick open.	2HV-8423,-8424,-8425,-8426 open within 1 second.
2.0	Low Pressure Turbine Exhaust Hood Spray actuates.	This is automatic on a Turbine trip.
3.0	Turbine Loss of Load Reset.	Normal as power decreases.
3-4	CEA bottom contacts sensed as CEAs reach bottom of core.	All 91 rods reached the bottom.
5	Unit Auxiliary Transformer Low Current.	Completed Bus Transfer.
5	All Pressurizer Backup Heaters Energized by pressurizer controls.	Low Pressure Actuation Setpoint was reached.
4.6	Both Feedwater Pump Turbines tripped.	The turbines trip on high pump discharge pressure.
6	Highest Steam Generator #1 pressure.	(1041 psia)
6	Highest Steam Generator #2 pressure.	(1045 psia)
6	Charging Pump #3 started.	Response to low Pressurizer level.
9	Highest Charging flow.	(134 gpm)
11	Highest Cold Leg Temperature.	(560°F)

Time from Trip (sec)	Event	Comments
15	Low Level Steam Generator 2 ,PPS Channels 1 and 4 (25% on the Narrow Range level instruments).	This is the start of the Emergency Feed Actuation Signal (EFAS).
16	Low Level Steam Generator 1. Low Level Steam Generator 2.	PPS Channel 3 PPS Channel 2
17	Low Level Steam Generator 1.	PPS Channel 4
18	Low Level Steam Generator 1.	PPS Channels 1 and 2
18	Auxiliary Feedwater Pumps P140 and P141 Discharge to Steam Generator 1.	Auxillary Feedwater Flow enters Steam Generator 1.
19	Low Level Steam Generator 2.	PPS Channel 3
20	Auxiliary Feedwater Pump P140 Discharge to Steam Generator 2.	Auxillary Feedwater flow enters Steam Generator 2.
24	All Pressurizer Heaters Tripped, pressurizer level still decreasing.	Low Water Level Cutoff of 27% was reached.
34	Lowest Steam Generator 2 pressure.	(922 psia)
34	Highest Auxiliary Feedwater Flow to Steam Generator 2.	(800 gpm)
35	Highest Auxiliary Feedwater Flow to Steam Generator 1.	(922 gpm)
36	Low Pressurizer Pressure (1825),PPS Channels 2 and 3.	This is the start of the Safety Injection Actuation Signal (SIAS)
36	High Pressure Safety Injection (HPSI) Pumps P018 and P019 started.	Response to SIAS
36	Boric Acid Make-up Pumps started.	Response to SIAS
37	Low Pressurizer Pressure Channels 1 and 4.	
37	Completed isolation of Letdown.	This is part of the Containment Isolation Actuation Signal (CIAS) which happens on a SIAS.
40	Steam Bypass Control Valve 2HV-8426 closed.	
41	High Safety Injection Tank loop pressure.	HPSI pumps are up to speed.
41	Low Pressure Safety Injection (LPSI) Pump P016 running.	Response to SIAS

Time from Trip (sec)	Event	Comments
42	LPSI Pump P015 running.	Response to SIAS
44	Lowest Pressurizer Level.	(15%)
44	Lowest Pressurizer Pressure.	(1805 psia)
45	Diesel Generator G002 ready to Load.	Response to SIAS
45	Low Component Cooling Water flow to the Reactor Coolant Pumps (RCP's).	
45	Diesel Generator G003 ready to Load.	Response to SIAS
46	Containment Spray Pump 1 started.	Response to SIAS
46	Lowest Cold Leg Temperature.	(540°F)
47	Containment Spray Pump 2 started.	Response to SIAS
49	Lowest Hot Leg Temperature.	(543°F)
53	Steam Bypass Control Valve 2HV-8423 closed.	
54	Steam Bypass Control Valve 2HV-8424 closed.	
55	Component Cooling Water restored to the RCP's.	
69	Low Pressure Turbine Hood Spray secured automatically.	Normal response.
167	Low Pressurizer Pressure reset.	Channel 1, pressure increased.
169	Low Pressurizer Pressure reset.	Channels 3 and 4
171	Low Pressurizer Pressure reset.	Channel 2
172 (~3 min.)	Reactor Coolant Pumps manually tripped by reactor operators, natural circulation.	The trip is required in response to a SIAS.
~10 min.	Stable natural circulation achieved.	Differential temperature across reactor vessel stablized.
35 Min. 4 Sec.	One reactor coolant pump (RCP 1A) restarted.	End of natural circulation Returned to normal hot standby operation.

SECTION #3

GRAPHS OF SELECTED PARAMETERS

(First Two Minutes)

The following are graphs of selected parameters, including those for which there are acceptance criteria. A brief description of control systems and their influence on plant response is included. Only the first two minutes of the trip will be considered in this section since the procedure's acceptance criteria covered only that time. The graphs in this section are more detailed and have greater explanation than those in Section #4 which are comparisons with CESEC predictions.

Graph Number	Parameters and Systems	Comments
I	Steam Generator Pressures and SBCS Valve Actuation	Peak pressure met predictions and acceptance criteria; SBCS valves did not quick close and caused greater depressurization than expected of the primary and secondary. Performance did meet acceptance criteria.
II	Reactor Coolant System Temperatures	Response was typical of high-power trip and met acceptance criteria.
III	Pressurizer Level	Response was typical of any high-power trip and met acceptance criteria.
IV	Pressurizer Pressure	Response was typical of any high-power trip in that pressure decreased considerably. The high pressure acceptance criteria was met; there was no acceptance criteria for minimum pressure. A safety injection isolation signal (SIAS) was generated from low pressurizer pressure but repair and adjustment of SBCS circuitry will minimize chances of further SIAS.
V	Chemical Volume And Control System	The third charging pump started and letdown decreased to minimum per design and as expected. Letdown was isolated by SIAS and rapidly decreased to zero per design shortly thereafter. CVCS had no explicit acceptance criteria although satisfactory operation was shown.

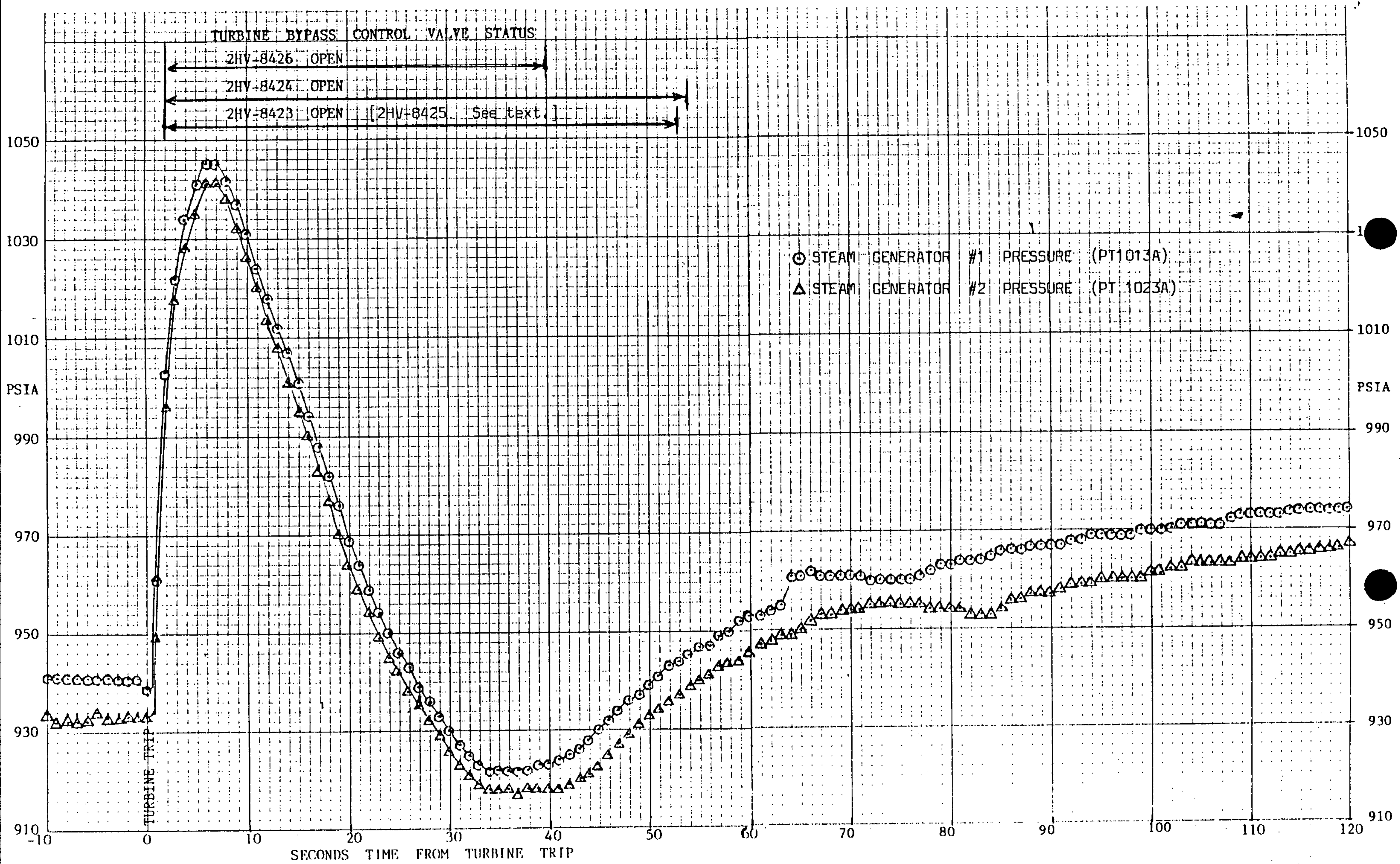
Graphs of Selected Parameters, Continued

Graph Number	Parameters and Systems	Comemnts
VI	Steam Generator Water Levels (Wide Range)	There was no acceptance criteria for water level, but it behaved acceptably thanks to early operation of the main feedwater system and later operation of the auxiliary feedwater system.
VII	Main Steam Flow	There was no acceptance criteria for main steam flow, but it behaved acceptably. Prolonged operation of the SBCS valves caused lengthy flow after the trip. Steam flow decreased as the valves modulated closed.
VIII	Main Feedwater Flow	There was no acceptance criteria for main feedwater flow. Feedwater flow started to ramp from 100% to 5% flow as designed but the main feedwater pumps tripped on high discharge pressure. One of the two pumps was in manual rather than automatic speed control and a high discharge pressure trip is expected with manual control from full flow.

GRAPH I

STEAM GENERATOR PRESSURES AND SBCS VALVE ACTUATION

(See following page for discussion.)



DISCUSSION OF GRAPH I: STEAM GENERATOR PRESSURES AND SBCS VALVE ACTUATION

Peak steam generator pressures met their single value acceptance criteria and behaved acceptably. Pressure increased rapidly after the turbine stop valves closed in 0.22 seconds (a design value). The SBCS valves quick-opened for the first time in the test program and opened rapidly enough to satisfy its design function of preventing secondary safety valve actuation. The lowest set-point safety valve is 1100 psia, well above peak pressure of 1045 psia.

The SBCS valves did not receive a quick close signal which would have limited minimum steam pressure. A faulty quick close control module was later discovered and it has been replaced. Adjustments will also be made which will cause the valves to close quickly.

After the SBCS valves closed pressure started to recover to a normal hot stand-by value of 1000 psia.

Open/closed position indication for three of the four SBCS valves was available. The fourth valve, 2HV-8425, receives its command signal with 2HV-8423, and its closing time must be quite close to 2HV-8423 as shown in Graph I. A recorder which measured actuator pressures, control signals, and inlet and discharge pressures indicated that the valve stroked similarly to the other three.

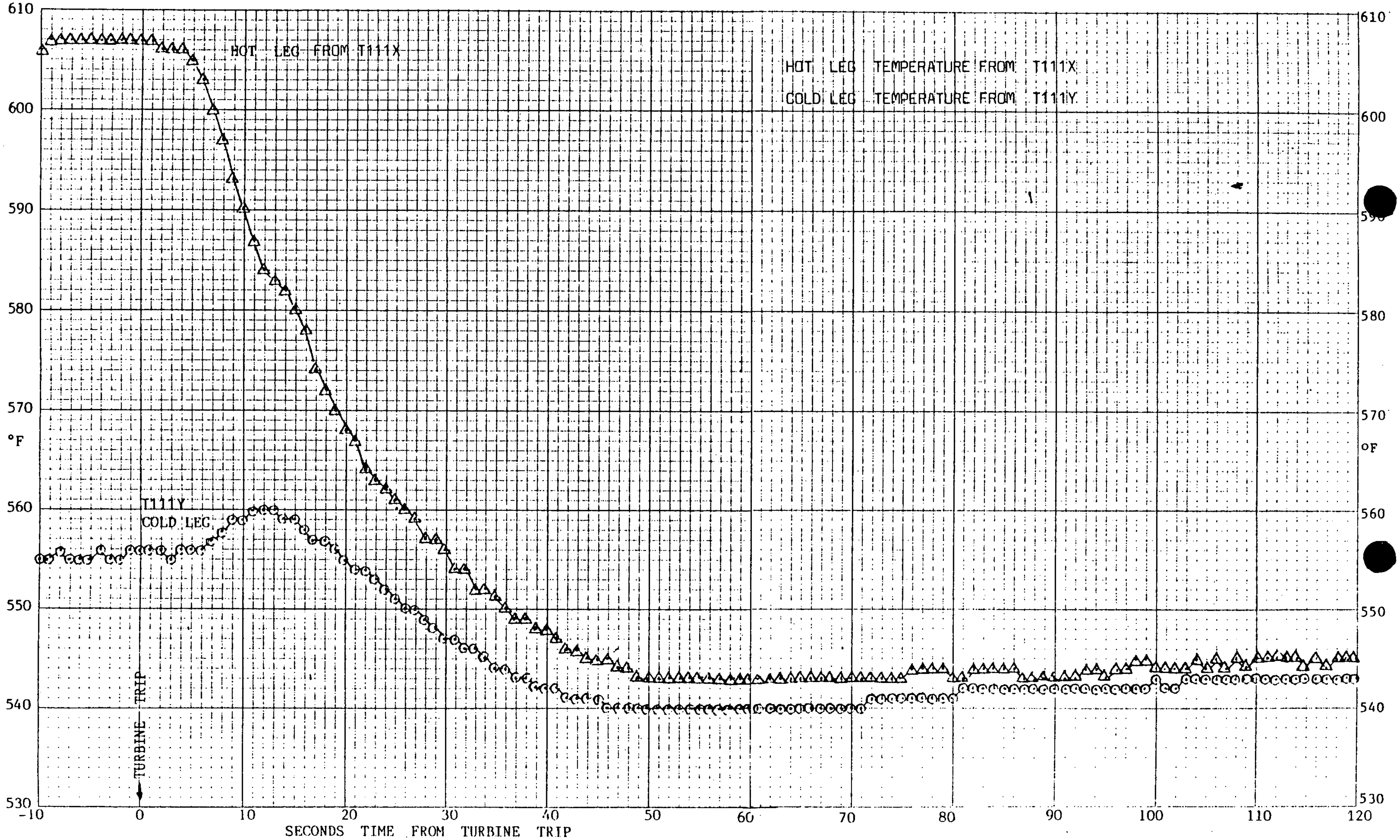
SBCS operation has a profound effect on the rest of the plant. Overcooling, as occurred during this trip, will result in lower than expected pressurizer water level and pressure. Safety Injection Isolation Signals (SIAS) are generated from low pressurizer pressure. The SBCS is in part responsible for maintaining pressurizer pressure above the SIAS setpoint.

From a commercial standpoint, steam generator pressure was acceptable although some adjustment to the control system will be made to optimize its response. The single-value acceptance criteria was met, and the FSAR's acceptance criteria of acceptable control of main steam pressure was also met. The SBCS was thus considered to have performed acceptably.

GRAPH II

REACTOR COOLANT SYSTEM TEMPERATURES

(See following page for discussion.)



DISCUSSION OF GRAPH II: REACTOR COOLANT SYSTEM TEMPERATURES

Reactor coolant system temperatures are affected by control system operation (the SBCS) and the reactor trip itself. Hot leg temperatures do not immediately decrease at the turbine trip because the CEAs require approximately one second to enter the top of the core and start to affect power and the hot leg temperature measuring devices are located approximately one second's fluid travel time from the core. There is also a small time lag between changes in fluid temperature surrounding the RTDs and their response.

The cold leg temperatures reflect changes in heat transfer in the steam generators produced by changes in steam pressure. For instance, the rise in cold leg temperature starting at six seconds and cresting at eleven seconds is a reflection of steam generator pressure, as shown by overlaying Graphs I and II.

Hot leg temperatures also reflect changes in cold leg temperature. For instance, starting at twelve seconds and continuing through eighteen there is a departure in the curve's shape which is brought about by hotter water which has passed through the core from the cold leg. The main change in hot leg temperature is due to decreased core heat; however, cold leg temperature changes also play a part.

Stored heat, and fission coastdown and decay heat are substantial until a minute or more post trip as shown by the difference between hot and cold leg temperatures. The temperature difference decreases with time, as shown by the convergence of the two during the second minute.

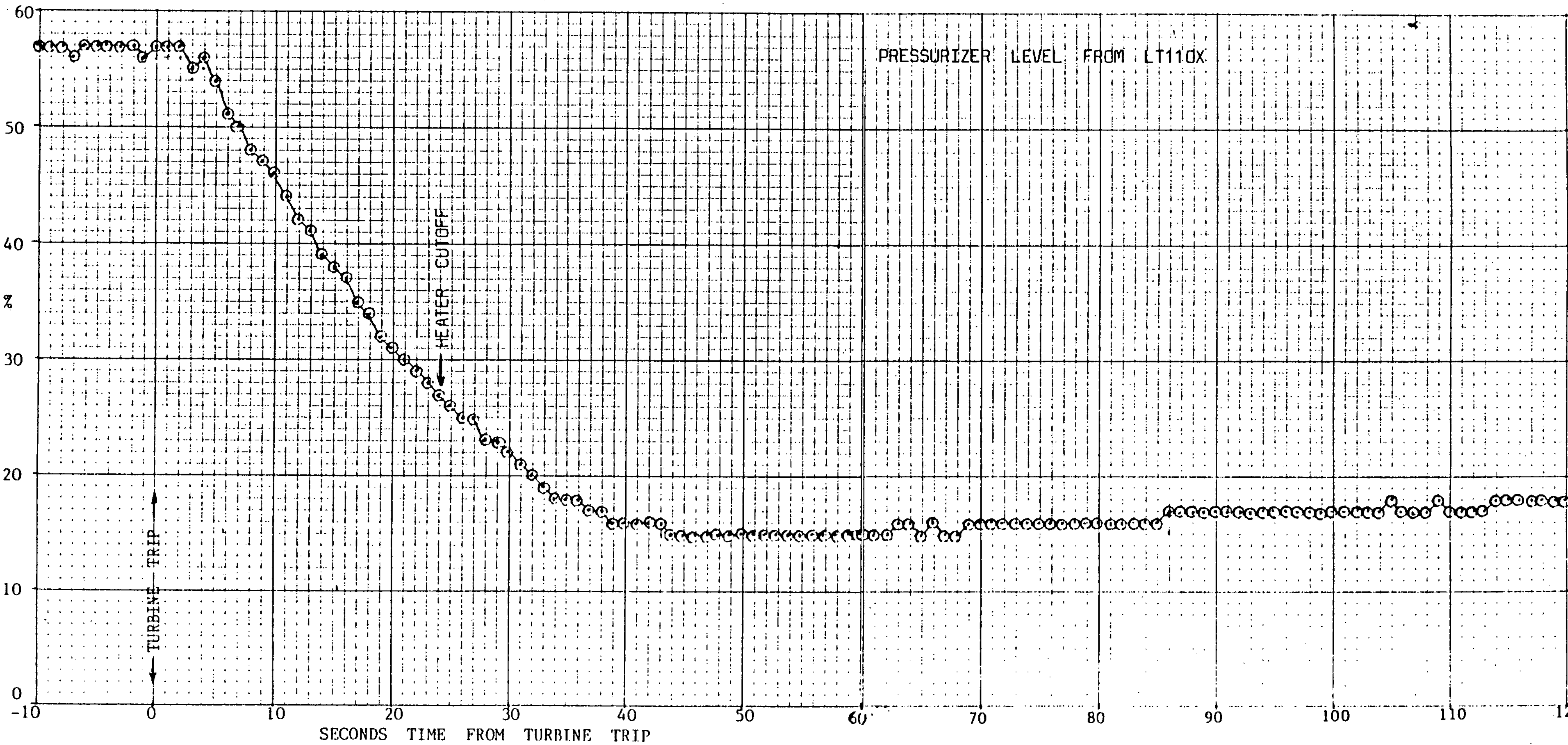
The reactor trip and RCS temperatures performed as expected and acceptably.

GRAPH III

PRESSURIZER LEVEL

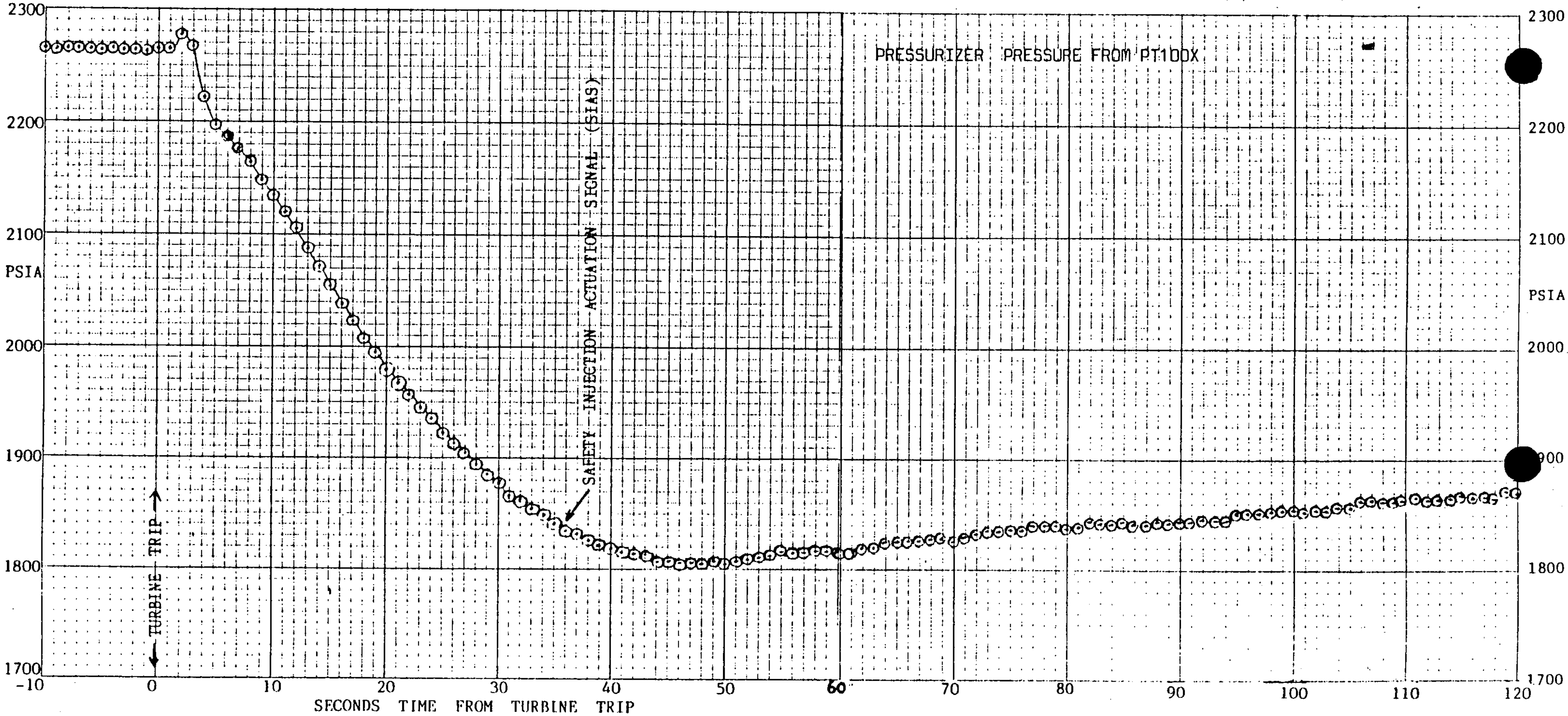
Shown below is pressurizer level versus time after the turbine trip. The rate and magnitude of its decrease are controlled mainly by changes in average reactor coolant system temperature (Taverage), which decreased approximately 40°F. Taverage was also greatly affected by SBCS operation, so SBCS has a considerable influence on pressurizer level.

Heater cutoff at 27% level is where pressurizer heaters are deenergized to prevent their burnout from being energized while uncovered. Heater cutoff occurred as designed at 27%.



GRAPH IV
PRESSURIZER PRESSURE

Pressurizer pressure responds almost entirely to changes in pressurizer level in the short time of a trip (a minute or less). The increase at approximately 2 seconds was due to expansion of fluid in the reactor coolant system because the turbine stop valves had shut in approximately 0.2 seconds, thereby temporarily removing the secondary heat sink, while the control rods require approximately one second to enter the core and reduce the primary's heat source. A brief mismatch in heat source and heat sink cause the RCS to heat slightly and the expansion is accommodated by the pressurizer. An increase in level compresses the pressurizer's steam, which causes an increase in pressure. (Continued on next page.)



(Pressurizer pressure discussion, continued)

The slope of pressure decrease is characteristic of depressurizations. The pressurizer's water is almost saturated, so any significant decrease in pressure will cause it to boil and the steam which results tends to slow the depressurization. The rapid initial decrease occurs as the boiling boundary moves downward from the surface of the water. As more water starts to boil, steam is evolved which slows the rate of depressurization.

An outsurge from the pressurizer causes the depressurization. The outsurge in this case was caused by the control rods (CEAs) falling into the core and stopping core power production. Core exit temperatures decreased rapidly and the average temperature of the RCS also decreased. Decreased temperature caused the fluid in the RCS to contract, and the pressurizer's fluid exited through the 12" surge line to the RCS.

The control systems which operate the pressurizer's heaters and spray system functioned as designed. The spray valve had no chance to open fully, but the heaters were energized and deenergized as designed. Four of the heaters were energized before the trip because the reactor operators were equalizing RCS and pressurizer boron concentration. Equalization is accomplished by energizing the backup heaters and increasing pressurizer pressure to the point where the spray valves open slightly. Spray then flushes the pressurizer over a few hours and the backup heaters are turned off.

The backup heaters are designed to energize when pressure falls and at five seconds the remaining backup heaters were energized, as designed. However, all heaters are deenergized when low water level could uncover and cause them to burn out. All heaters were deenergized at the low level cutoff of 27% level at twenty four seconds.

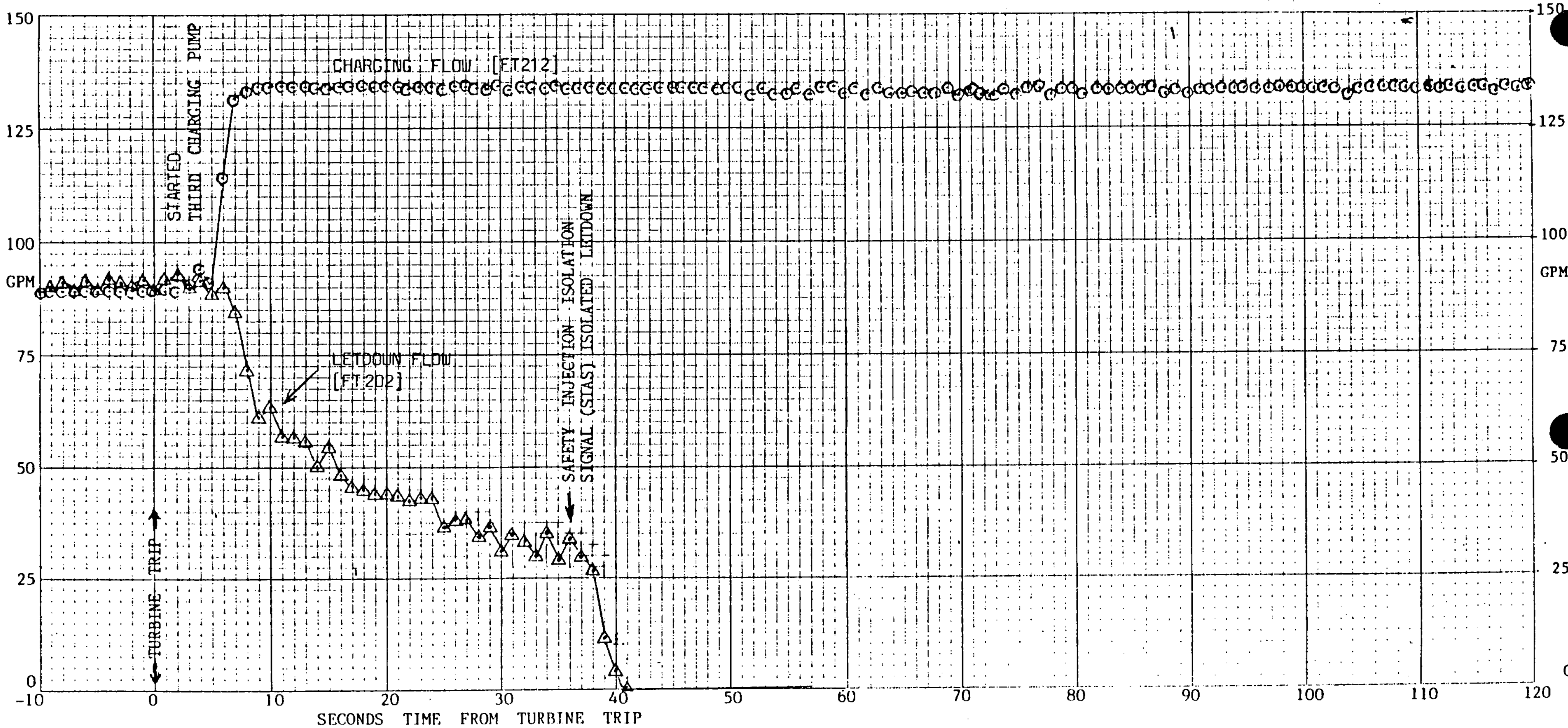
During a rapid transient such as a 100% power turbine trip, the response of the pressurizer is controlled almost entirely in the short term by SCBCS and CEA motion. Pressurizer control systems don't have a great effect. However, the transient did show that the pressure control system functioned as designed.

The chemical volume control system also plays a part in pressurizer level and pressure as described below.

GRAPH V

CHEMICAL VOLUME CONTROL SYSTEM (CVCS)

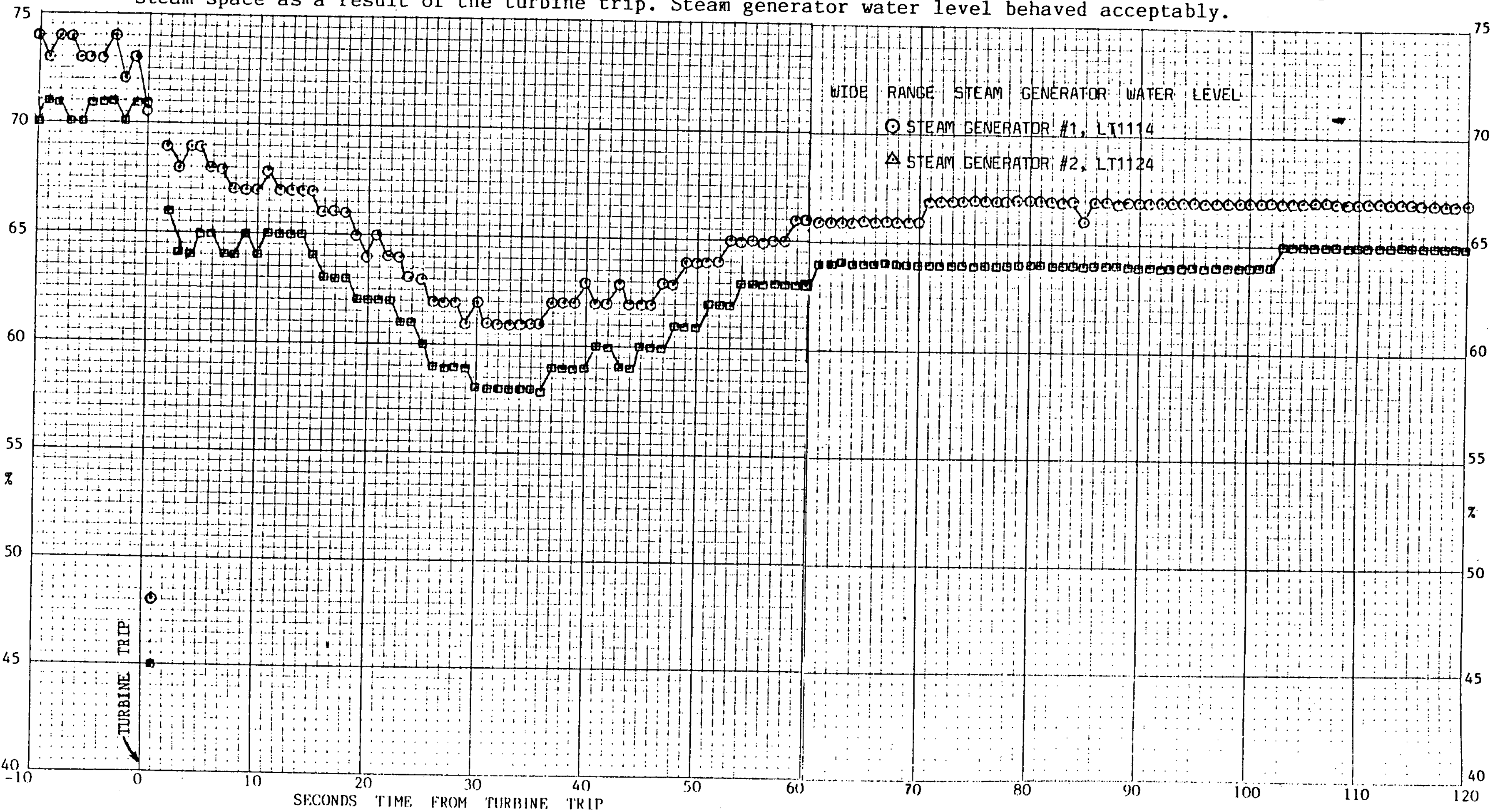
Charging and letdown, shown below, are a part of the Chemical Volume Control System (CVCS) and their behavior plays a second-order effect in pressurizer level. The graph below shows how CVCS was behaving as expected; as pressurizer level fell below setpoint for the existing Taverage, the remaining standby charging pump (the third pump) was started to bring charging to maximum. Letdown was reduced to maintain pressurizer level. Letdown continued to decrease as level fell until the Safety Injection Actuation Signal (SIAS) isolated letdown. Just before letdown was isolated, minimum flow of approximately 29 gpm had been established. Actuation of the third charging pump and reduction of letdown was automatically performed in concert with remote setpoints from the Reactor Regulating System (RRS).



GRAPH VI

WIDE RANGE STEAM GENERATOR WATER LEVEL

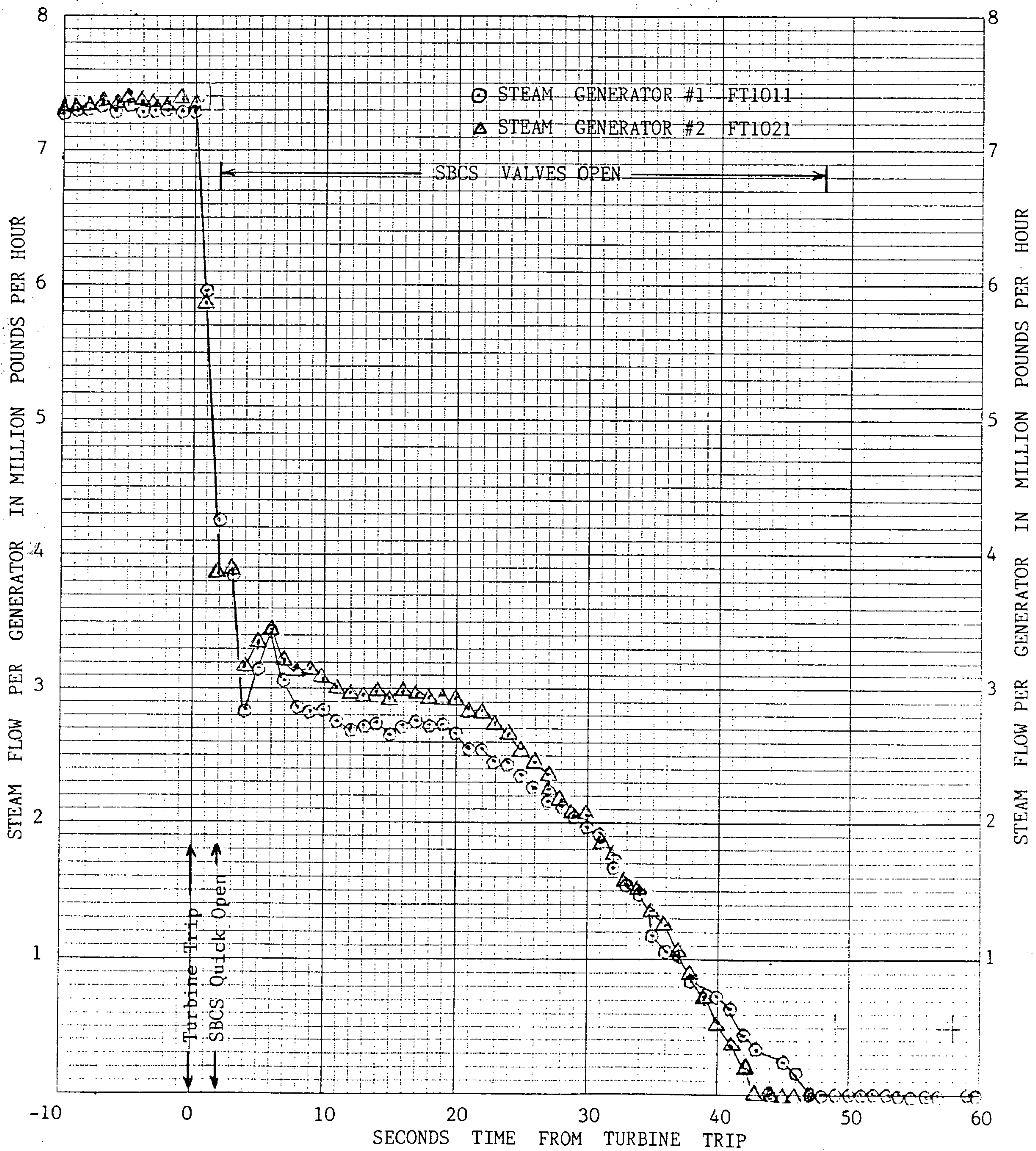
Wide range steam generator water level reflects that the generators remained relatively full of water thanks to brief operation of the main feedwater system, whose pumps tripped on high discharge pressure, and auxiliary feedwater. The apparent dip in water level at 1 second is believed due to pressure increase in the generator's steam space as a result of the turbine trip. Steam generator water level behaved acceptably.



GRAPH VII

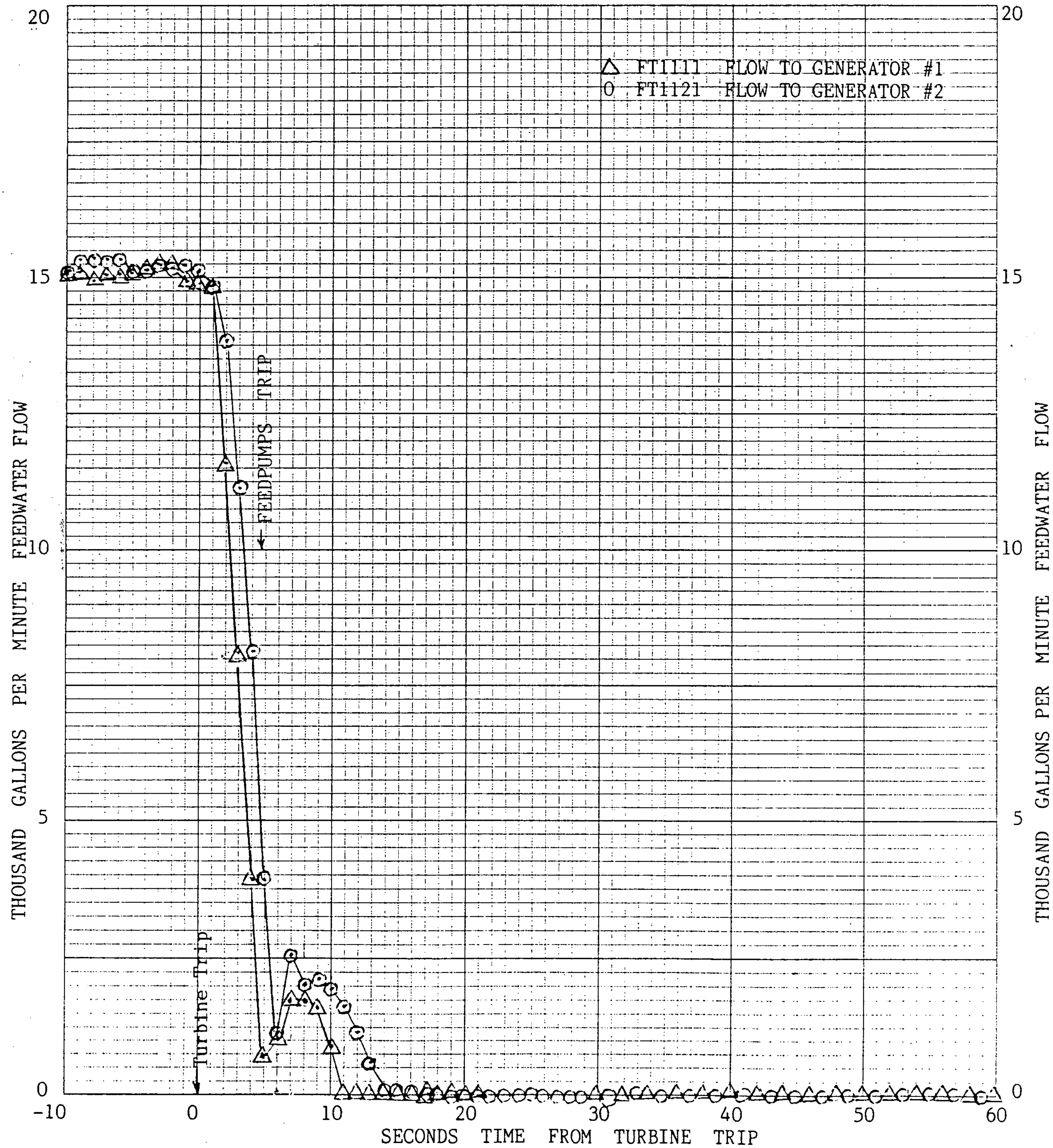
MAIN STEAM FLOW

Main steam flow from the steam generators is illustrated below and shows that the SBCS continued to pass steam well into the transient.



GRAPH VIII
MAIN FEEDWATER FLOW

Main feedwater flow decreased due to Reactor Trip Override (RTO) which ramps valve position to 5% open over 15 seconds. At 4.6 seconds the feedwater pumps tripped on high discharge pressure and main feedwater flow decreased to zero.



SECTION #4

CESEC PREDICTIONS WITH TURBINE TRIP DATA

(First Two Minutes)

Four of the five CESEC predictions have been overlayed with test data below and good agreement is shown. The graphs are steam generator pressure, pressurizer pressure, pressurizer level, and RCS hot leg temperature versus time. Only core power versus time is not included because quality data was not obtained.

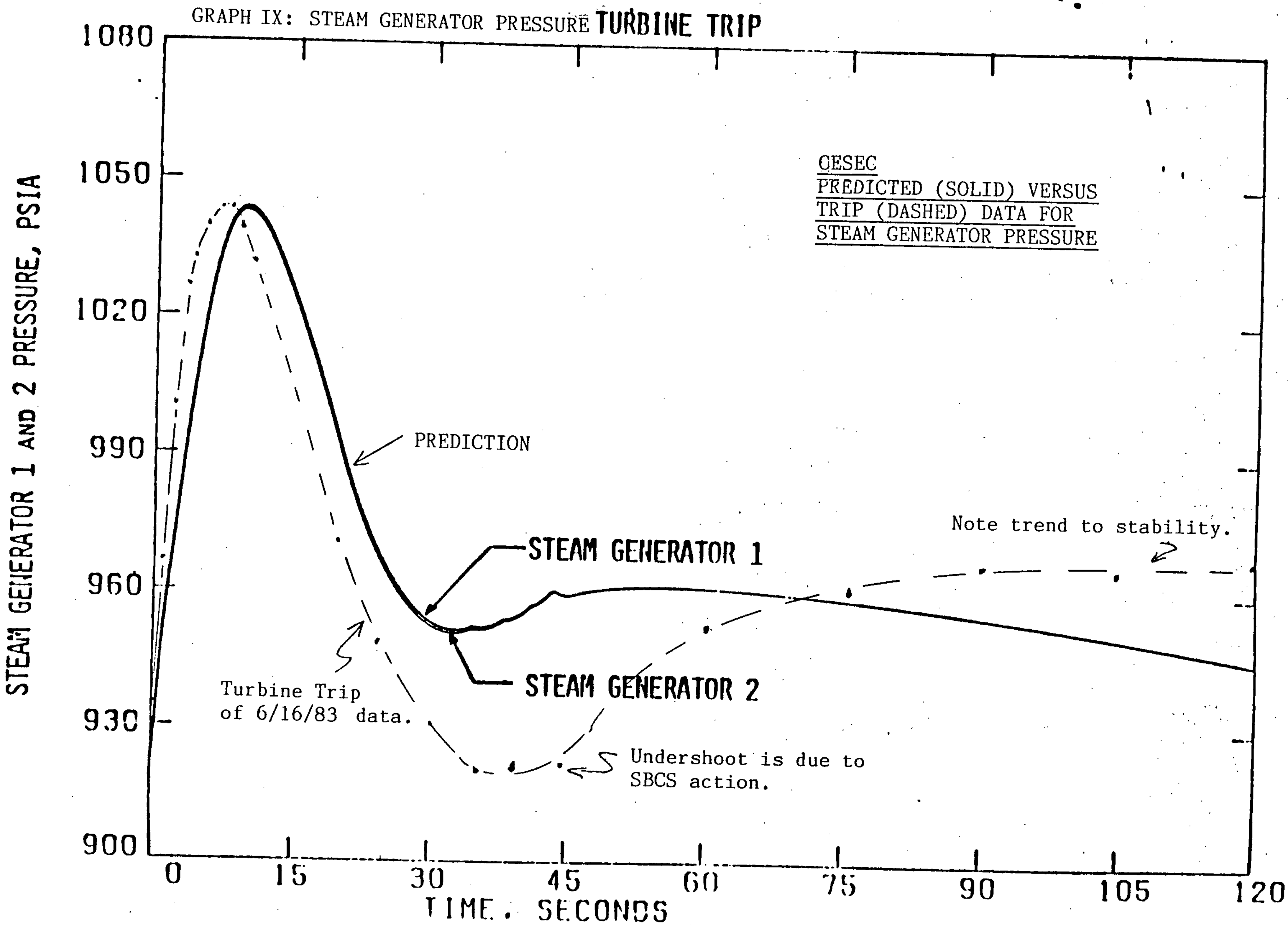
First, Graph IX, steam generator pressure, shows that peak pressure was predicted within one psi and two seconds. Minimum pressure was lower than predicted by approximately thirty psi and later by about five seconds because the SBCS valves failed to fast close. The SBCS has since been repaired and adjusted.

Second, Graph X, shows pressurizer pressure with time. Peak pressure was predicted better than minimum, which was affected by SBCS operation and steam generator pressure.

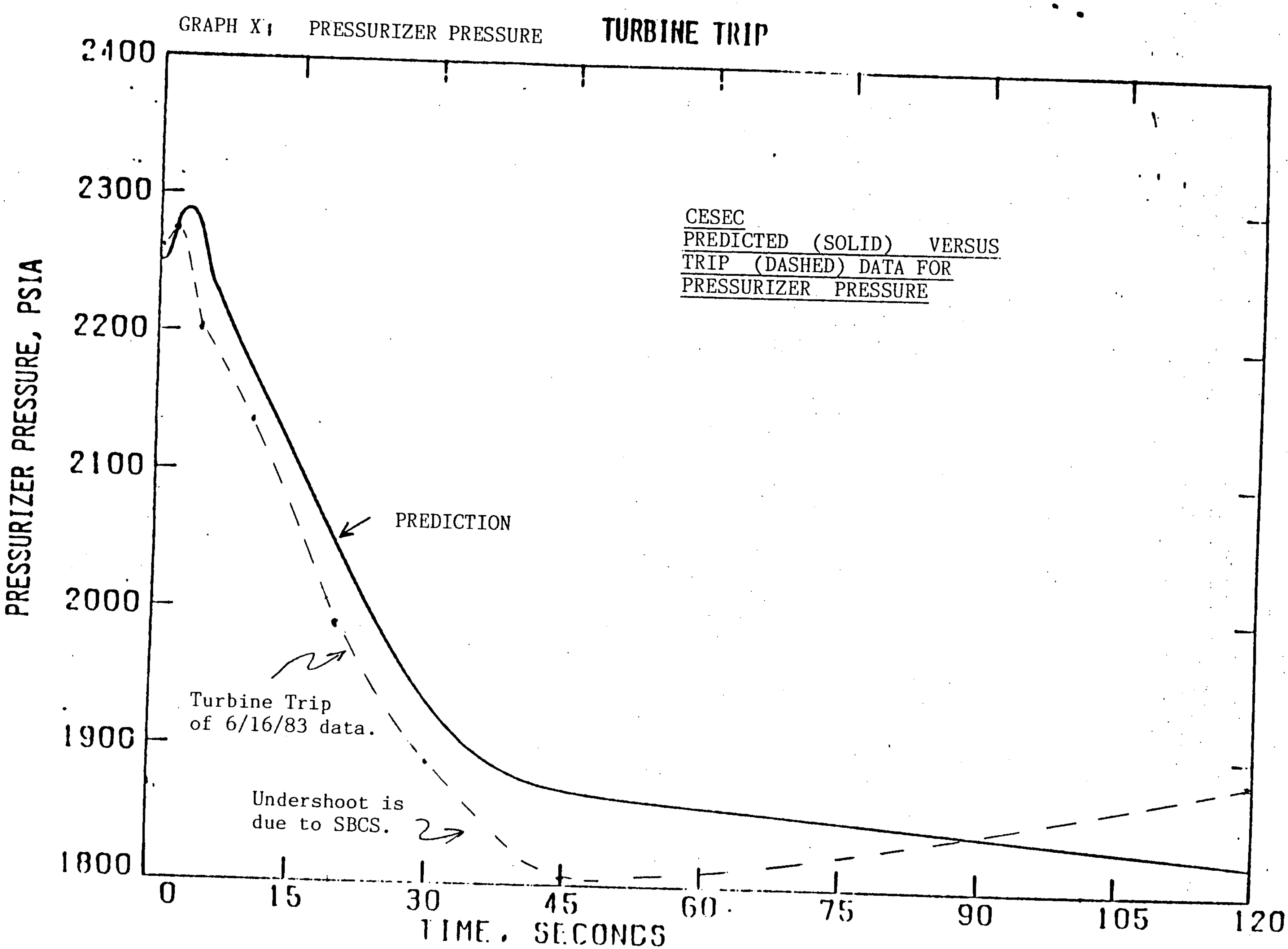
Third, Graph XI, is pressurizer level versus time.

Fourth and final Graph XII shows hot leg temperatures.

FIGURE 8.2-2

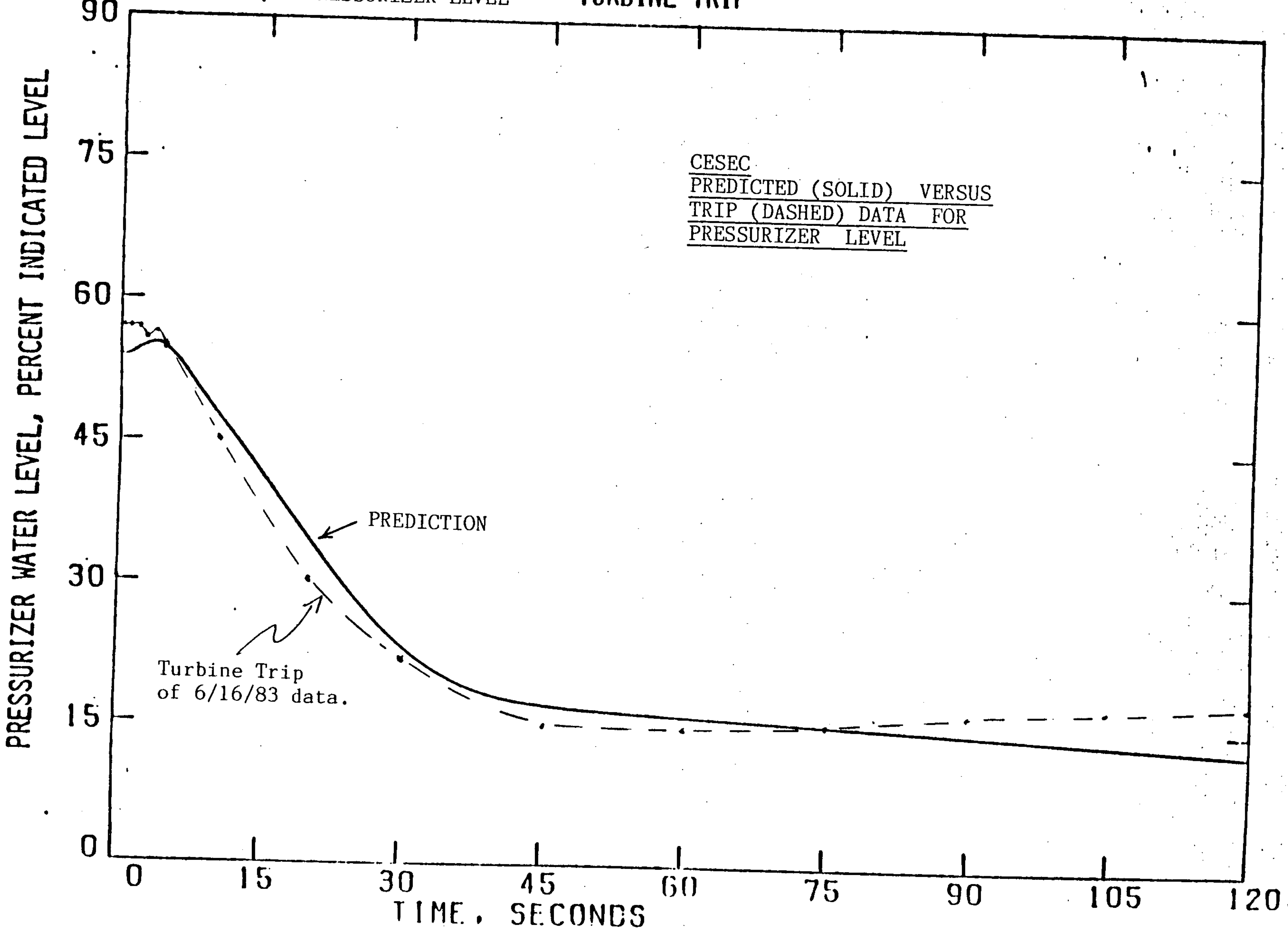


CESEC Predictions are for 100% Power Turbine Trip and represent the vendor's expected plant behavior.

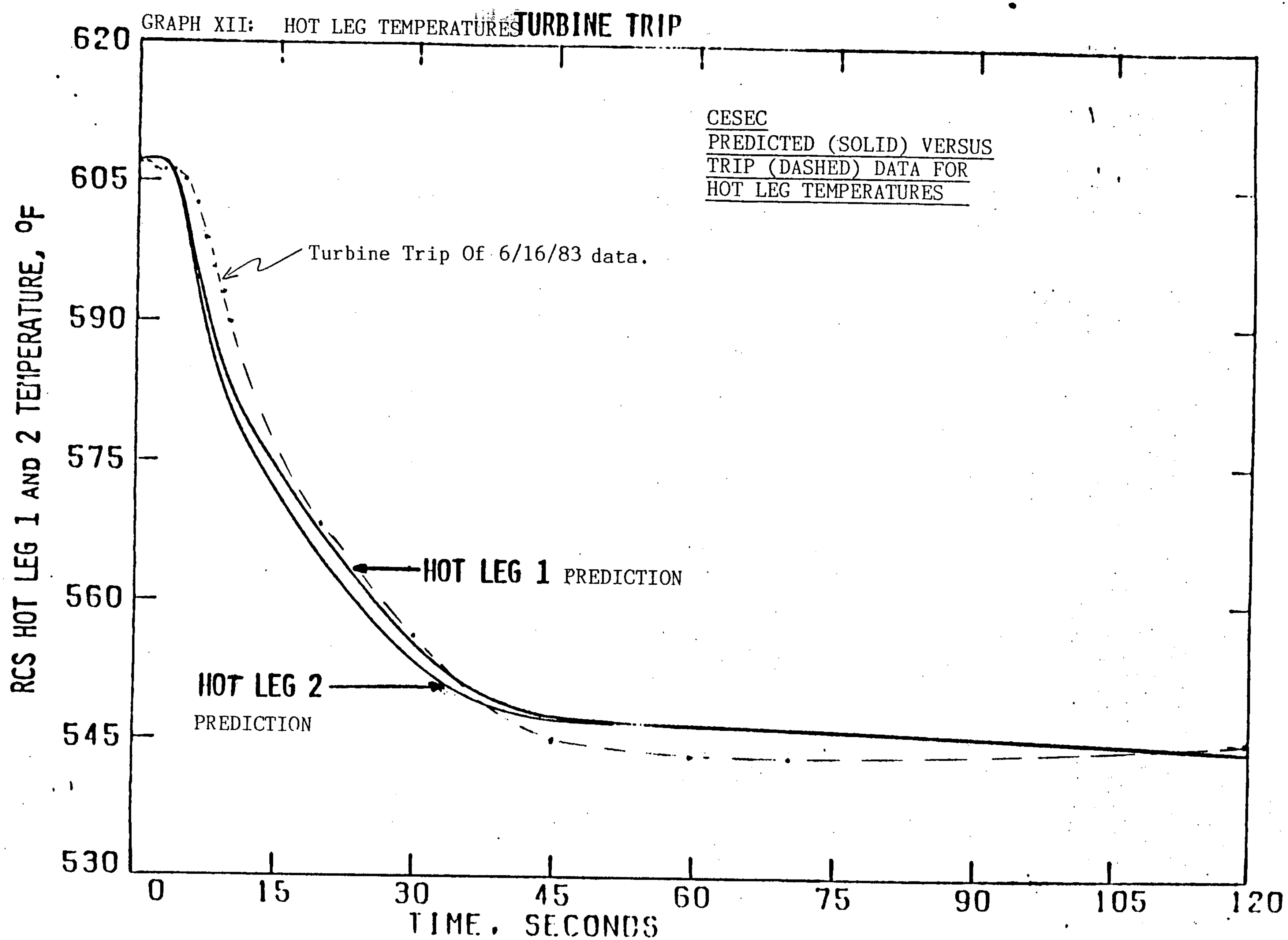


CESEC Predictions are for 100% Power Turbine Trip and represent the vendor's expected plant behavior.

GRAPH XI: PRESSURIZER LEVEL **TURBINE TRIP**



CESEC Predictions are for 100% Power Turbine Trip and represent the vendor's expected plant behavior.



CESEC Predictions are for 100% Power Turbine Trip and represent the vendor's expected plant behavior.

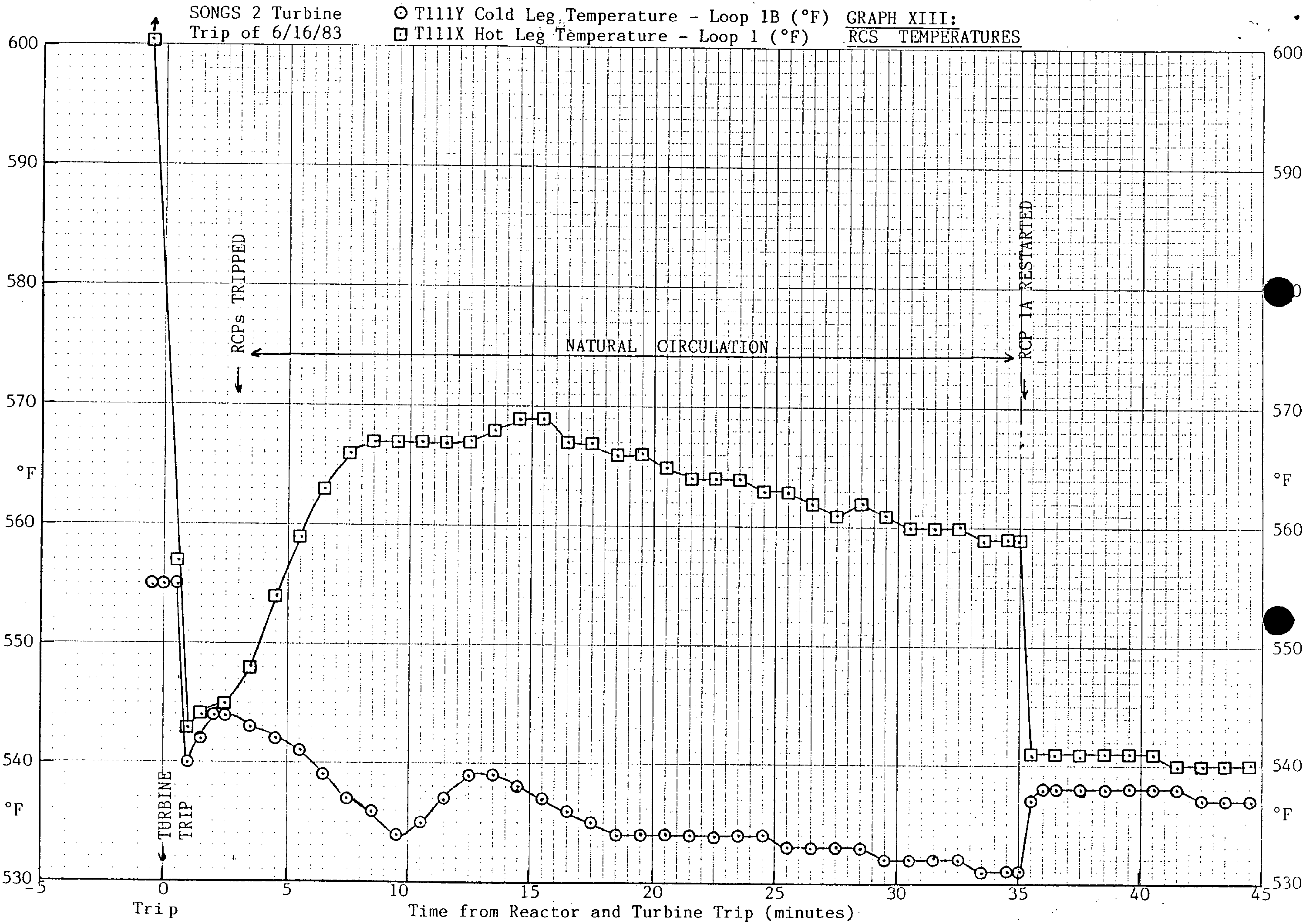
SECTION #5

LONG TERM PLOTS: NATURAL CIRCULATION AND RECOVERY

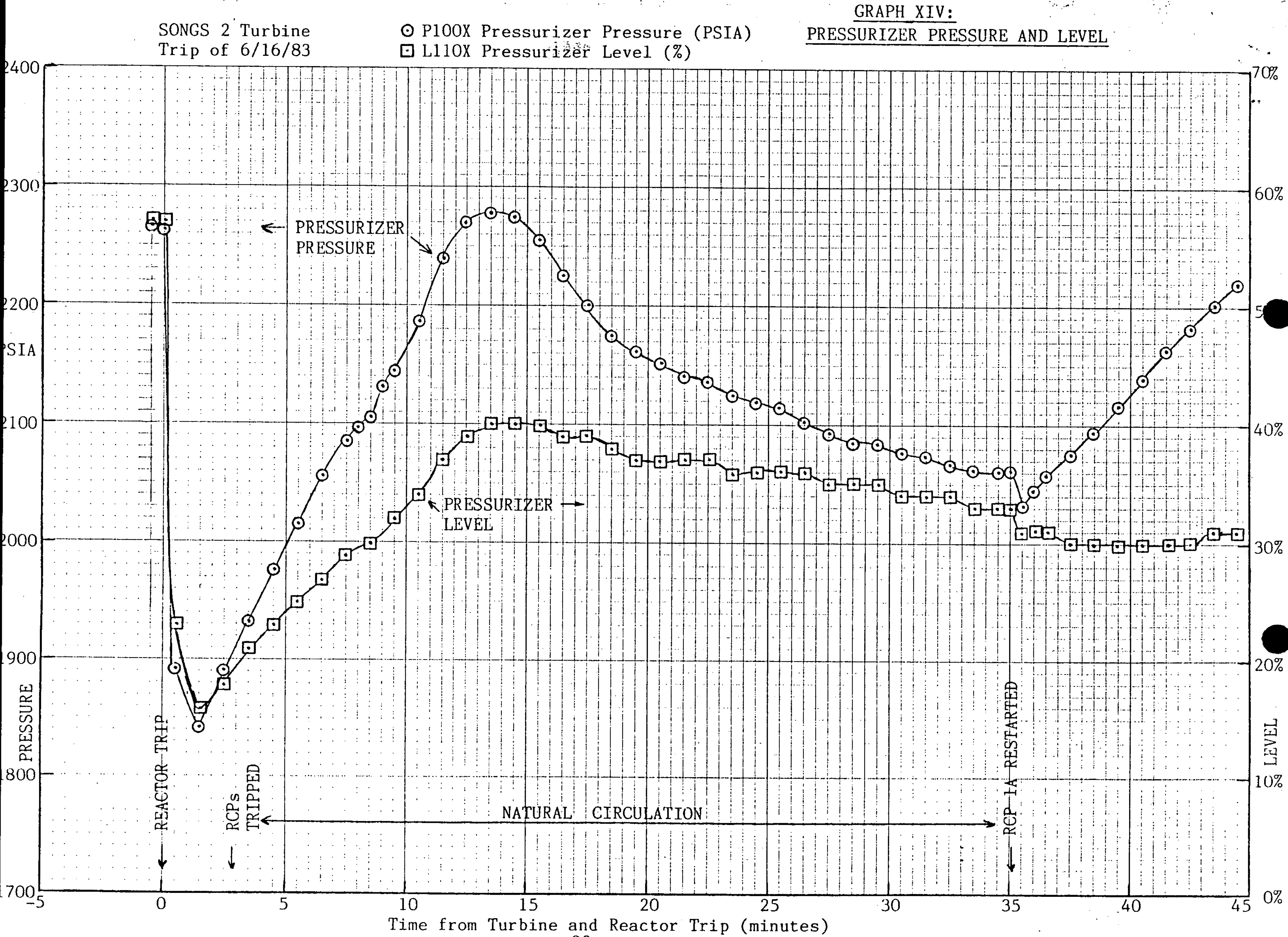
The following four graphs show forty six minutes of the turbine trip, from one minute before the trip until forty five minutes after. They show that natural circulation was attained and stabilized shortly after the reactor coolant pumps were deenergized. Natural circulation was entirely under the control of the reactor operators. After approximately thirty two minutes of natural circulation one reactor coolant pump (1A) was restarted and the plant was returned to stable forced circulation. Each of the graphs is discussed below.

GRAPH NUMBER	PARAMETERS AND SYSTEMS	COMMENTS
XIII	RCS Temperatures	Starting with RCP trip at 2 minutes, 50 seconds, hot leg temepraturе increased and cold leg temperature decreased. Stability was attained at approximately eight minutes, five minutes after the RCPs were tripped, and continued until thirty five minutes.
XIV	Pressurizer Pressure And Level	When the RCPs were tripped, pressurizer pressure and level increased due to the increase in RCS Taverage. The effect of Taverage can easily be seen if Graphs XIII and XIV are overlaid. RCS temperatures were stabilized starting at approximately fifteen minutes and resulted in stabilizing pressurizer pressure and level.
XV	Steam Generator Pressures	Steam generator pressure has a controlling effect on T cold and thus Taverage, as overlaying Graphs XV and XIII shows. Operator control of steam pressure showed how that the plant could be easily and stably controlled.
XVI	Wide Range Steam Generator Water Level	Wide range steam generator water level was controlled by controlling auxiliary feedwater flow, which is entirely under manual control.

In summary, the transition from forced to natural circulation, control of natural circulation, and return to forced flow and stable conditions was demonstrated. The natural circulation portion depended almost entirely upon operator control and demonstrated acceptable stable operation of the plant far beyond the original scope of the turbine trip procedure.



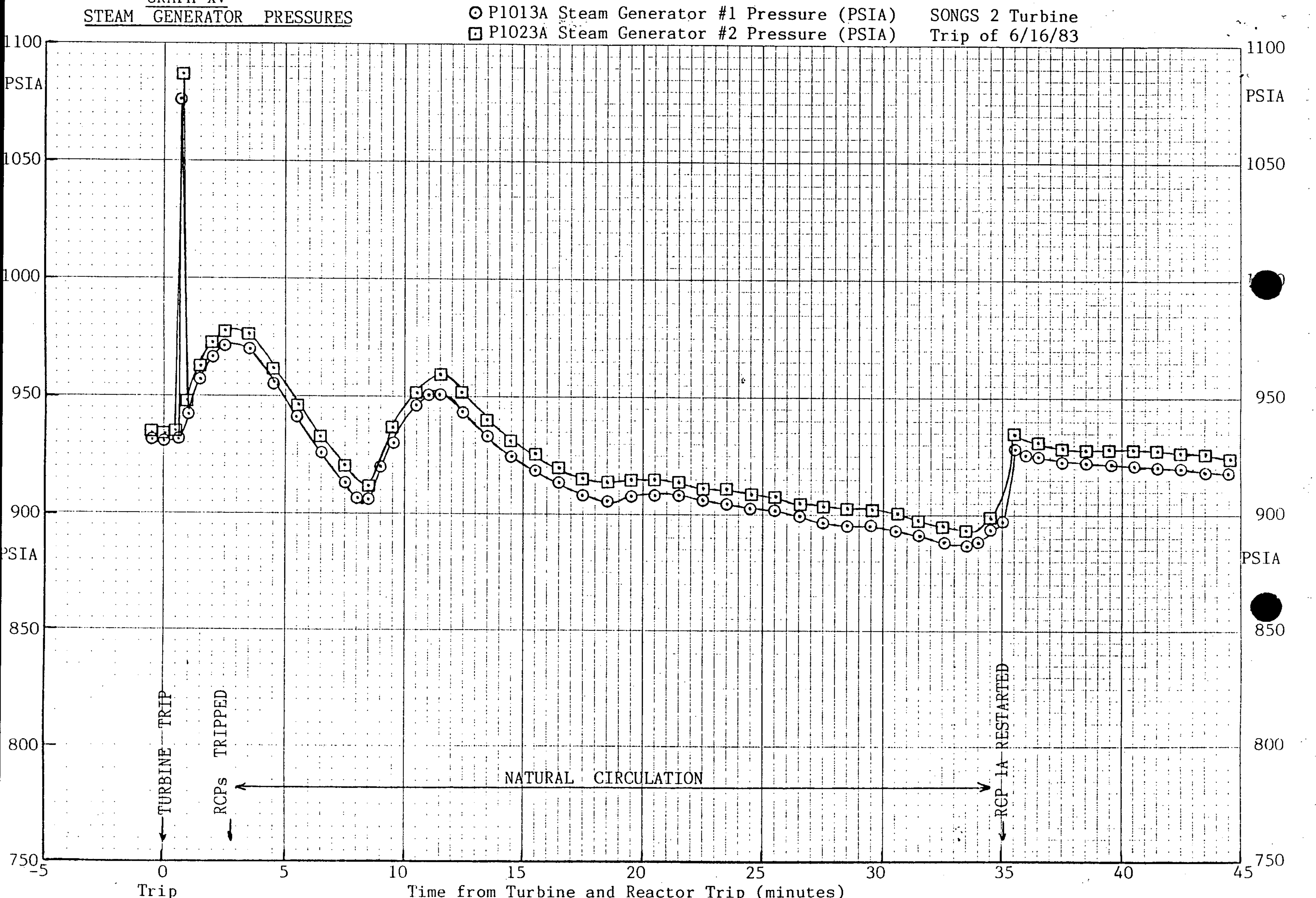
SONGS 2 Turbine
Trip of 6/16/83
⊙ T111Y Cold Leg Temperature - Loop 1B (°F)
⊡ T111X Hot Leg Temperature - Loop 1 (°F)
GRAPH XIII:
RCS TEMPERATURES
600
590
580
570
560
550
540
530
°F
RCPs TRIPPED
NATURAL CIRCULATION
RCP 1A RESTARTED
TURBINE TRIP
-5
0
5
10
15
20
25
30
35
40
45
Trip
Time from Reactor and Turbine Trip (minutes)

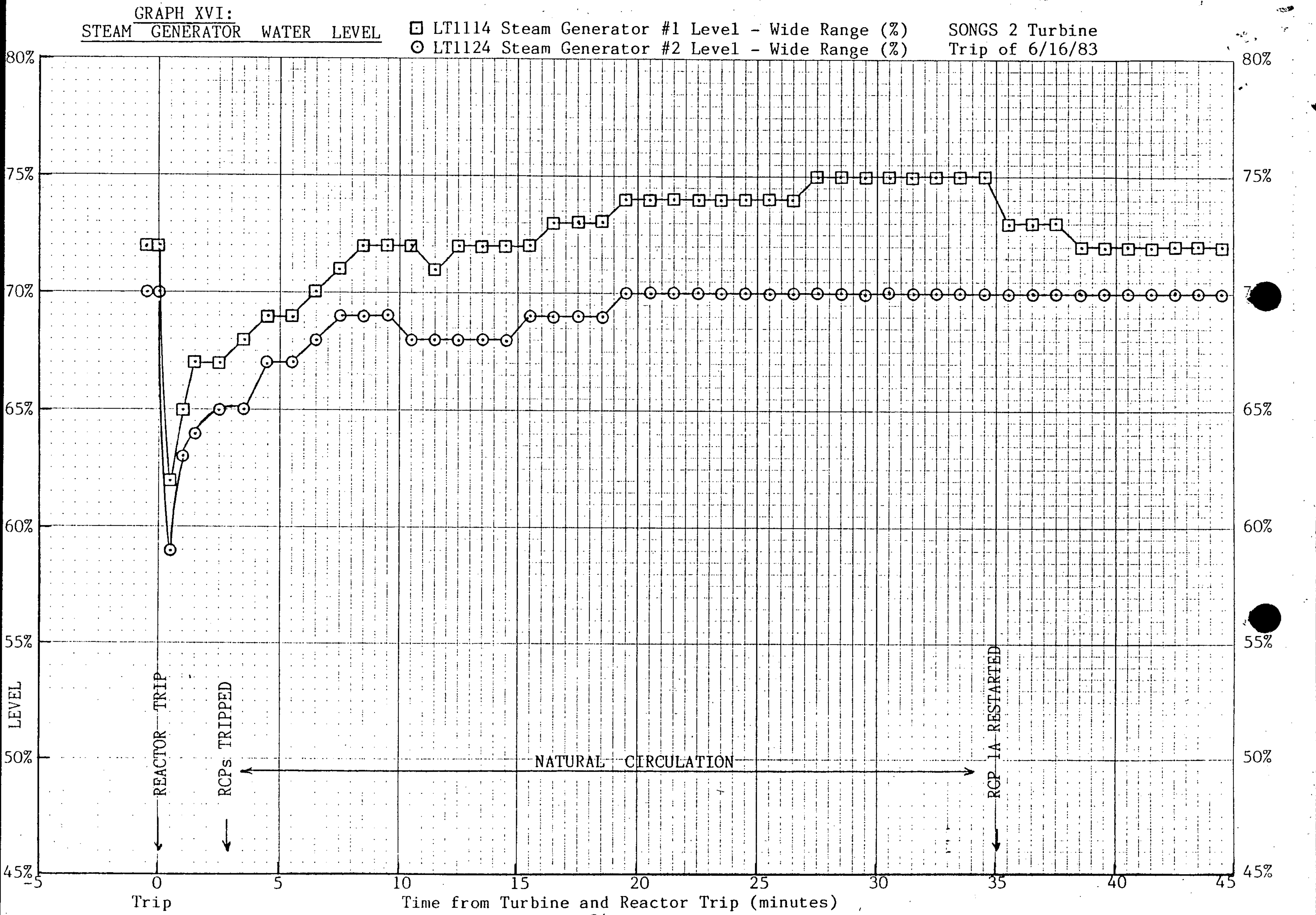


GRAPH XIV:
PRESSURIZER PRESSURE AND LEVEL
SONGS 2 Turbine
Trip of 6/16/83
P100X Pressurizer Pressure (PSIA)
L110X Pressurizer Level (%)
PRESSURIZER
PRESSURE
PRESSURIZER
LEVEL
REACTOR TRIP
RCPs
TRIPPED
NATURAL CIRCULATION
RCP 1A RESTARTED
PRESSURE
PSIA
LEVEL
2400
2300
2200
2100
2000
1900
1800
1700
70%
60%
40%
30%
20%
10%
0%
−5
0
5
10
15
20
25
30
35
40
45
Time from Turbine and Reactor Trip (minutes)

GRAPH XV

STEAM GENERATOR PRESSURES





GRAPH XVI:
STEAM GENERATOR WATER LEVEL
LT1114 Steam Generator #1 Level - Wide Range (%)
LT1124 Steam Generator #2 Level - Wide Range (%)
SONGS 2 Turbine
Trip of 6/16/83
80%
75%
70%
65%
60%
55%
50%
45%
LEVEL
REACTOR TRIP
RCPs TRIPPED
NATURAL CIRCULATION
RCP 1A RESTARTED
-5
0
5
10
15
20
25
30
35
40
45
Trip
Time from Turbine and Reactor Trip (minutes)