CESEC SIMULATION

OF

NSSS TRANSIENTS TESTS

AT

ANO-2

October, 1980

Plant System Analysis
Plant Engineering
C-E Power Systems
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1.0 INTRODUCTION

This report documents the results obtained with Combustion Engineering's System Excursion Code, CESEC, (Reference 1) in the simulation of plant tests performed during the power ascension of Arkansas Nuclear One-Unit 2 (ANO-2). The comparison of CESEC against plant test data responds to a Nuclear Regulatory Commission (NRC) request (References 2 and 3) that this experimental data be used in the verification of the safety analysis system computer code used for the ANO-2 Final Safety Analysis Report, FSAR, (Reference 4). The particular tests simulated included a turbine trip from 98.2 percent power, a four pump loss of flow from 81 percent power, a full length control element assembly (FLCEA) drop from 49.4 percent power, and a part length control element assembly (PLCEA) drop from 49.2 percentpower.

In general, the input data was prepared for each test according to the measured initial conditions in the plant. The forcing functions for the analyses were the measured steam flow, the feedwater flow and enthalpy, the primary system flow, and the time of reactor trip.

The transient data for all four tests shown in this report were recorded using a PDP-11 minicomputer and the existing plant instrumentation.

2.0 BACKGROUND

The NRC requested that Arkansas Power and Light (AP&L) perform tests during the ANO-2 power ascension program in order to obtain data for the qualification of CESEC. AP&L gained approval to use four tests from their existing power ascension program. These four tests were selected to represent a range of typical PWR transients which would examine the capability of CESEC to predict system response in a comprehensive manner. The turbine trip test from 98.2 percent power provides the NSSS response to a load rejection transient initiated from the secondary system. The loss of flow test from 81 percent power provides the NSSS response to a power/cooling mismatch transient initiated from the primary system. The FLCEA and PLCEA tests from 49 percent power provide the NSSS response to an anomaly in the core.

In preparation for the tests, AP&L reviewed the test procedures to ensure that all data needed to verify CESEC would be recorded, and developed pretest predictions of all four tests. The predictions were used in identifying the expected trends and the characteristic variations of the monitored NSSS parameters.

3.0 CESEC

CESEC is a simulation tool developed at C-E for the analysis of normal and abnormal (non-LOCA) occurrences in a Nuclear Steam Supply System (NSSS) employing a Pressurized Water Reactior (PWR) design. The program is used in licensing analyses and for best estimate predictions of the dynamic response of the NSSS. CESEC utilizes the node-flowpath concept and is self-initializing for a consistent set of reactor operating conditions. The fluid in the primary system, outside of the pressurizer, is treated as homogeneous and can be either subcooled or saturated. The pressurizer fluid is treated in separate water and steam regions that may or may not be in equilibrium. The code assumes 100 percent effectiveness of the spray flow in condensing vapor in the pressurizer. The secondary system is explicitly modeled up to the turbine admission valve. A detailed description of the code is provided in Reference 1.

4.0 PLANT DESCRIPTIONS

The ANO-2 plant includes a PWR NSSS supplied by C-E. The NSSS is characterized by four primary coolant loops and two steam generators. The reactor core consists of 177 assemblies with an active length of 150 inches. The rated thermal output of the reactor is 2815 megawatts and the net electrical output is 912 megawatts. The primary system is designed to operate at a nominal pressure of 2250 psia, a full power core mass flow rate of 133.0×10^6 lbm/hr, and a full power core average coolant temperature of 579°F. The normal secondary system pressure during full power operation is approximately 900 psia. A complete plant description is provided in Reference 4.

5.0 TURBINE TRIP

5.1 SUMMARY

The turbine trip test performed during the ANO-2 power ascension program was initiated from a power of 2764 Mwt (98.2%). The turbine trip is an event which results in a rapid increase in primary and secondary system pressures. With the plant control systems fully operational they can response automatically to stablize the system behavior without a reactor trip.

However, this particular ANO-2 turbine trip event was initiated with three out of the four dump valves in the steam dump and bypass control system (SDBCS) unavailable (one isolated and two in manual mode). Therefore, the reactor tripped early in the transient on a low steam generator water level signal because the reduced dump and bypass capacity of the steam dump and bypass system resulted in a rapid decrease in steam generator water level. In addition, the test unintentionally included one stuck open dump valve (failed to close after opening) and one partially stuck open perssurizer spray valve (fails to reseat after getting close signal). Therefore, following the initial primary and secondary pressure increases, the subsequent cooldown was enhanced by the valve failures. This excessive cooldown caused the pressurizer level to drop below the indicating range and the safety injection system was actuated on a low pressurizer pressure signal. As per NRC directives the four reactor coolant pumps (RCPs) were tripped following the safety injection actuation signal (SIAS). The cooldown was terminated by closure of the main steam isolation valves and the pressurizer subsequently refilled.

5.2 PRETEST PREDICTION

The CESEC pretest prediction for the turbine trip test assumed that all the plant control systems would function automatically with the SDBCS operating at its full dump and bypass capacity, i.e., 85 percent of the full power steam flow. The resulting analysis showed that the initiation of the quick open signals to the dump and bypass valves upon turbine closure coupled with the operation of the reactor regulating system (RRS) would prevent a reactor trip. The plant would then stabilize by automatic modulation of the SDBCS.

As a result of the differences in pretest prediction assumptions and the actual test conditions outlined in Section 5.1, the pretest prediction results are not comparable to the test results.

5.3 SEQUENCE OF EVENTS

The turbine trip test was initiated from the initial conditions shown in Table 5-1. The plant control systems were all in the automatic mode and operating normally except for the SDBCS. As previously mentioned in Section 5.1, one atmospheric dump valve (ADV) located downstream of the main steam isolation valves (MSIVs) was isolated and the two atmospheric dump valves located upstream of the MSIVs were in the manual mode. Table 5-2 provides additional information relating to the operating characteristics of the SDBCS at the time of the test.

The test was initiated by manually tripping the main turbine from the control room. The SDBCS responded to the turbine closure by initiating quick open signals to the dump and bypass valves. However, the capacity of the valves to pass steam was degraded to about 45 percent of the full power steam flow. The main feedwater flow which tried to match steam flow was also degraded. Therefore, as a result of the mismatch between energy generation and energy removal, both the primary and secondary systems internal energies increased, the primary and secondary temperatures increased, the primary and secondary pressures increased, and the steam generator level decreased. The pressurizer spray flow also increased in an attempt to moderate the increase in pressurizer pressure. At 6.1 seconds into the transient, the reactor tripped on a steam generator low level water signal. Following the reactor trip, the pressure increases terminated.

After the primary and secondary pressures reached peak values, the pressures began to decline and signals were generated to close both the pressure spray valve and the steam dump and bypass valves. The three turbine bypass valves fully closed, but the pressurizer spray valve failed to reseat and one atmospheric dump valve remained fully open. The unexpected failures of these valves enhanced the cooldown of the system. All three charging pumps were automatically activated and a SIAS was generated. The pressurizer pressure and temperature continued to decrease and the pressurizer enptied. Following NRC's directive, the operator shut off all four RCPs after the SIAS was generated. After isolation of the ADV by closure of the MSIVs, following a main steam isolation valve signal (MSIS), the cooldown was terminated and the pressure began to refill. Table 5-3 presents a detailed sequence of events for the transient.

5.4 POST TEST COMPARISON

The CESEC post test comparison for the turbine trip test was performed using the initial conditions shown in Table 5-4. The core outlet temperature and the steam generator pressure are calculated by the code during the initialization process. Comparison of the initial conditions in Table 5-4 with the test initial conditions (see Table 5-1) indicates good agreement. The impact on transients results of the slight difference in reactor power and core mass flow rate is minimal because of the closeness of other key parameters. The initial pressurizer level is off by 0.6 percent which is within the 1 percent measurement error. The normal steady state charging and letdown flow (40 gpm each) were used in the CESEC simulation. The plant recorded a charging flow of 45.2 gpm. However, this flow accounts for leakage through the RCPs seals. The seal leakage was not simulated in CESEC.

Preparation of the input data which was used in the simulation included the following assumptions:

1. After the CEAs are fully inserted upon reactor trip the reactor kinetics calculation in the code was bypassed. The ANS decay heat curve based on 30 days of continuous operation at full power was used to simulate the power level for the remainder of the transient. Parametric studies show negligible sensitivity on the transient results to variations in the values of the decay heat curve used.

2. The fraction of primary system flow through each steam generator loop was input to CESEC in table form as a function of time. The flow through each steam generator loops was held constant at its initial value until the pumps were tripped. The RCPs were tripped by the operator at slightly different times (see Table 5-3). The costdown curves are shown in Figures 5-1 and 5-2 for loops 1 and 2, respectively. CESEC was driven with the coastdown of curves measured in the test. A natural circulation flow of 4 percent was assumed for the remainder of the remainder of the transient.

3. The steam flow out of each steam generator was calculated by the code from a user input table of steam flow as a function of time. The steam flow tables were generated from the plant measured data. The steam flow out of each steam generator is provided in Figures 5-3 and 5-4. THe non-symmetric response results from two bypass valves and the single operable dump valve being connected to the steam generator 1 steam line header, while the third bypass valve was connected to the steam generator 2 steam line header. As seen from Figures 5-3 and 5-4 the steam flows drop suddenly from the initial values at the time of the turbine trip. Once the SDBCS triggers the opening of the bypass and atmospheric valves, the steam flow increases again. Subsequent closing of the bypass valves (while the dump valve sticks open) causes a decrease in the steam flow. The steam flows level out at a dump capacity of about 12 percent until the MSIVs are closed. Closure of the MSIVs should terminate all steam flow. However, the reduced data indicates a small flow fraction. This inconsistency is believed to be due to uncertainty in the ΔP measurement used to calculate the steam flow rate at a low flow conditions. The CESEC analysis assumed the steam flows to go to zero upon closure of the MSIVs.

4. In the same manner, the feedwater flow of each steam generator represented by a table of flow as a function of time. The main feedwater flows for each steam generator are provided in Figures 5-5 and 5-6. The curves only represent the main feedwater flow contribution. The

emergency feedwater flow was not measured because the test circuitry used to measure this parameter was not available for the test. The emergency feedwater was activated on steam generator low water level at 6.1 seconds into the transient.

Initially, the main feedwater flow follows the steam flow through the automatic control of the feedwater control system (FWCS). After reactor trip (6.1 seconds) the main feedwater flow ramps down to a value of about 10 percent of the full power value. The ramped down design value is 5 percent. This inconsistency can also be attributed, as with the steam flow, to uncertainty in the ΔP measurement at low flow conditions. The CESEC analysis assumed the ramped down design value for the main feedwater flow to be 5 percent. In addition, a value of 2.0 percent of the full power feedwater flow was assumed for the emergency feedwater after trip. This value corresponds to the design capacity of the emergency feedwater system. After the MSIS, the main feedwater isolation valves close terminating the feedwater. Therefore, the CESEC analysis assumed the feedwater decays linearly to the value for the emergency feedwater flow as the isolation valves close.

5. The main feedwater enthalpy remained nearly constant at 420 Btu/lbm, according to the plant recording of the temperature. The temperature or enthalpy of the emergency feedwater was not measured in the test. A value of 58 Btu/lbm was assumed. The time dependant table of feedwater enthalpy input to CESEC assumed a constant value of 420 Btu/lbm until the feedwater flow ramp down started. The enthalpy was then ramped down to a value of 58 Btu/lbm and remained constant thereafter. The 200 second rampdown is based on the estimated volume to be swept out of the feedlines and the steam generator downcomers (150 ft^3 and 250 ft^3, respectively) by the emergency feedwater flow.

6. The spray flow in the analysis was assumed to increase proportionally with pressure. Once the maximum value of 376 gpm is reached, the proportional spray remains constant at 376 gpm until the RCPs are tripped. After the pumps are tripped, the spray flow is terminated. The spray flow enthalpy is assumed to correspond to the cold leg water enthalpy.

7. The safety injection actuation setpoint and the HPSI (high pressure safety injection) pump shut off head were input at the design values of 1740 and 1440 psia, respectively. The flow rates as a function of system pressure are input to the code in tabular form. Two HPSI pumps were assumed available.

The steam generators 1 and 2 pressure responses are given in Figures 5-7 and 5-8, respectively, The pressure responses exhibit non-symmetric behavior caused by the non-symmetric steam flow. Steam generator 1 experiences a lower peak pressure and a lower minimum pressure than steam generator 2. This is consistent with the steam flow behavior which is caused by having two bypass valves and the single operable dump valve connected to the steam generator 1 steam line header and only the third bypass valve connected to the steam generator 2 steam line header. The calculated CESEC results agree well with the experimental results as seen from Figures 5-7 and 5-8. The MSIS is predicted by CESEC to occur at about the same time as in the test (231.3 seconds (CESEC) versus 241.5 seconds (test)). The peak pressures calculated by CESEC are about 40 to 50 psi higher than those recorded in the test. This difference in secondary peak pressure can be partly attributed to the selection of the data values for steam flow which were used for driving the CESEC code during this initial transient time period.

Figure 5-9 shows the response of the pressurizer pressure. The pressurizer pressure calculated by CESEC agrees well with the test results over the entire transient time simulated. The agreement is within the range of uncertainty one would expect to exist from the assumptions made in the analysis and from uncertainty within the data. The pressurizer water level was not directly recorded until about 22 minutes into the event. However, Figure 5-10 shows a comparison of the CESEC predicted water volume in the pressurizer against that calculated by related test data.

The recorded RCS cold leg temperature for loops 1 and 2 are shown in Figures 5-11 through 5-13. The CESEC model assumes both A and B loops to be lumped together for both steam generators 1 and 2. Thus, in Figures 5-11 and 5-12 the test data is compared against the CESEC results for loop 1. In Figure 5-13 the CESEC results for loop 2 are compared against the test data for loop 2A. Since the mini-computer recording for the cold leg temperature in loop 2B is unreliable because of the settings used, no comparison is shown for this loop.

The hot leg temperature comparison between CESEC and the test data is shown in Figure 5-14. The CESEC results agree as well with the test data as previously shown for the cold leg temperature comparison. The test data plotted combines information recorded from the mini-computer and the plant computer. This combination of data was necessitated because the lower range of the mini-computer was too high for the event which occurred. This problem would not have happened if the event would have proceeded as originally planned. The comparison between CESEC results and test data is only shown for loop 1, since similar agreement was obtained for loop 2.

The sequence of events as predicted by CESEC is provided in Table 5-5. Comparison of key events with data (see Table 5-3) shows good agreement. The CESEC maximum pressurizer pressure (2362 psia) is predicted to occur at 9.55 seconds, while the recorded data values for the pressurizer peak pressure and its time of occurrence are 2832 psia and 8.0 seconds, respectively. The secondary peak pressures and their times of occurrence were predicted by CESEC to be 1071 psia/18.5 seconds (steam generator 1) and 1134 psia/18.3 seconds (steam generator 2). The data shows the peak secondary pressures occurred at 12.7 seconds with values of 1029 psia and 1091 psia for steam generators 1 and 2, respectively. CESEC predicted a minimum pressurizer pressure of 1229 psia as compared to the test data value of 1350 psia. The time at which the pressurizer starts to refill demonstrates once again the closeness of the CESEC prediction with test data (323.4 seconds (CESEC) versus 308.0 seconds (test)).

TABLE 5-1

Initial Conditions for Turbine Trip Test

Core Power, Mwt	2764 (98.2%)
Core Inlet Temperature, °F	552
Core Outlet Temperature, °F	610
Vessel Mass Flow Rate, 10^6 lbm/hr	133
Pressurizer Pressure, psia	2256
Pressurizer Level, percent	49.2
Steam Generator Pressure, psia	908
Charging Flow, gpm	45.2 (one pump)
Letdown Flow, gpm	40.4
Control System Status	
- Pressurizer Pressure	Automatic
- Presurizer Level	Automatic
- Reactor Regulating	Automatic
- Feedwater	Automatic
- Steam Dump and Bypass	Automatic

TABLE 5-2

Operating Status of the SDBCS Valves During Turbine Trip Test

Valve Description	Capacity (lbm/hr)	Status
13% Turbine Bypass	1.24×10^6	Operable
5% Turbine Bypass	0.69×10^6	Operable
13% Turbine Bypass	1.24×10^6	Operable
13% Atmospheric Dump	0.94×10^6	Isolated
13% Atmospheric Dump	0.94×10^6	Operable
13% Atmospheric Dump	0.94×10^6	Manual
13% Atmospheric Dump	0.94×10^6	Manual

TABLE 5-3

Sequence of Events for the Turbine Trip Test

Time (sec)	Event	Value
0.0	Manual trip of main turbine	-
2.0	Three turbine bypass valves and the atmospheric dump valve receive a quick-open signal from the SDBCS.	-
2.0	Pressurizer spray valve opens on signal from PPCS.	-
3.0	Turbine bypass valves and atmospheric dump valves full-open.	-
6.1	Reactor trip initiated on low steam generator water level. Emergency feedwater actuation signal generated.	49%
8.0	Maximum pressurizer pressure	2382 psia
12.7	Maximum steam generator pressure	1091 (loop 2) 1029 (loop 1)
21.0	Pressurizer spray valve gets close signal but fails to reseat.	-
21.0	Turbine bypass valves and atmospheric dump valve receive close signals. Atmospheric dump valve remains open.	-
29.0	Turbine bypass valves fully closed. Atmospheric dump valve remained full open.	-
52.0	All three charging pumps in operation; Letdown flow being throttled back to minimum value.*	133.0 GPM (charging)
102.6	Low pressurizer pressure generates safety injection actuation signal (SIAS).	1740 psia

* Due to a failure of the plant computer to printout all the trend groups, this was the first indication of maximum charging flow. Maximum charging flow was actually initiated before this time via a signal from the pressurizer level control system.

TABLE 5-3
(Continued)

Sequence of Events for the Turbine Trip Test

Time (sec)	Event	Value
107.6	Hot leg temperature (steam generator 1) drops off-scale low	<550
117.4	Hot leg temperature (steam generator 2) drops off-scale low	<550
144.0	Pressurizer empties	-
200.0	Reactor coolant pumps 1A & 1B tripped	-
201.0	Reactor coolant pumps 2A & 2B tripped	-
205.0	Hot leg temperatures increasing; natural circulation begins	525°F
241.5	Low steam generator 1 pressure generates main steam isolation signal (MSIS)	728 psia
248.0	Minimum pressurizer pressure	1350 psia
274.0	Manually closed atmospheric dump valve	-
308.0	Pressurizer level back on-scale	>0%
1001.	Hot leg temperatures back on-scale	>550°F
1440.	Pressurizer pressure recovered	2100 psia

TABLE 5-4

CESEC Initial Conditions for Turbine Trip Test

Core Power, Mwt	2815
Core Inlet Temperature, °F	552
Core Outlet Temperature, °F	609
Vessel Mass Flow Rate, 10^6 lbm/hr	127
Pressurizer Pressure, psia	2257
Pressurizer Water Volume, ft^3	583 (level=48.6%)
Steam generator pressure, psia	909
Charging Flow, gmp	40.0 (one pump)
Letdown Flow, gpm	40.0
Control System Status:	
- Pressurizer Pressure	Automatic
- Pressurizer Level	Automatic
- Reactor Regulating	Not Used
- Feedwater	Not Used
- Steam Dump and Bypass	Not Used

TABLE 5-5

CESEC Sequence of Events for the Turbine Trip Test

Time (sec)	Event	Value
0.0	Manual trip of main turbine	-
3.2	Spray valve starts to open	-
5.3	Spray valve fully open	376 gpm
6.1	Reactor trip manually Feedwater started to ramp down to 5% full power flow rate plus 2.0% emergency feedwater	-
9.55	Maximum pressurizer pressure	2362 psia
18.3 18.5	Maximum steam generator pressure	1134 (loop 2) 1071 (loop 1)
30.0	All three charging pumps in operation Letdown flow	128.0 gpm (charging) 29.0 gpm (letdown)
72.0	Low pressurizer pressure generates safety injection actuation signal (SIAS)	1740 psia
165.0	Pressurizer empties	-
200.	Reactor coolant pumps 1A and 1B tripped	-
201.	Reactor coolant pumps 2A and 2B tripped	-
213.	Hot leg temperature starts to increase, natural circulation begins	$525^{o}F$
231.3	Low steam generator 1 pressure generates MSIS	728 psia
235.1	MSIV closed, steam flow terminated	
245.0	Minimum pressurizer pressure	1299 psia
323.4	Pressurizer starts to refill	-
1270.0	Pressurizer pressure recovered	2100 psia

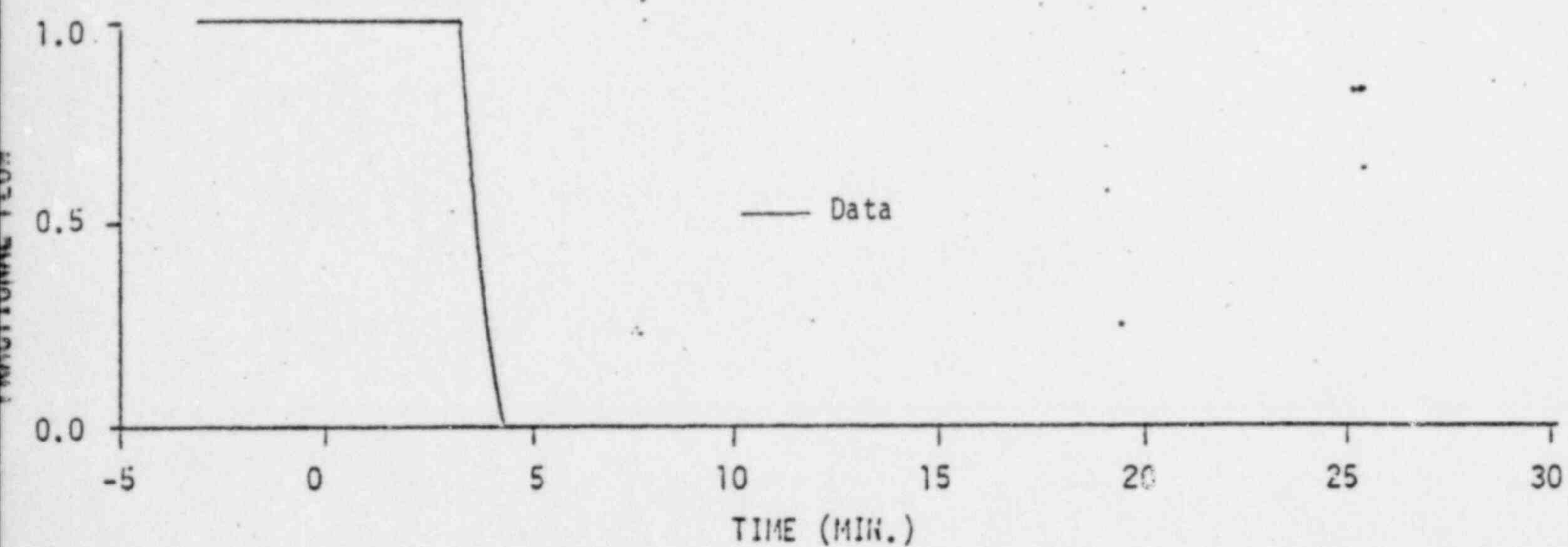

Figure 5-1. Turbine Trip - Normalized Reactor Coolant Pump 1 Flow Rate

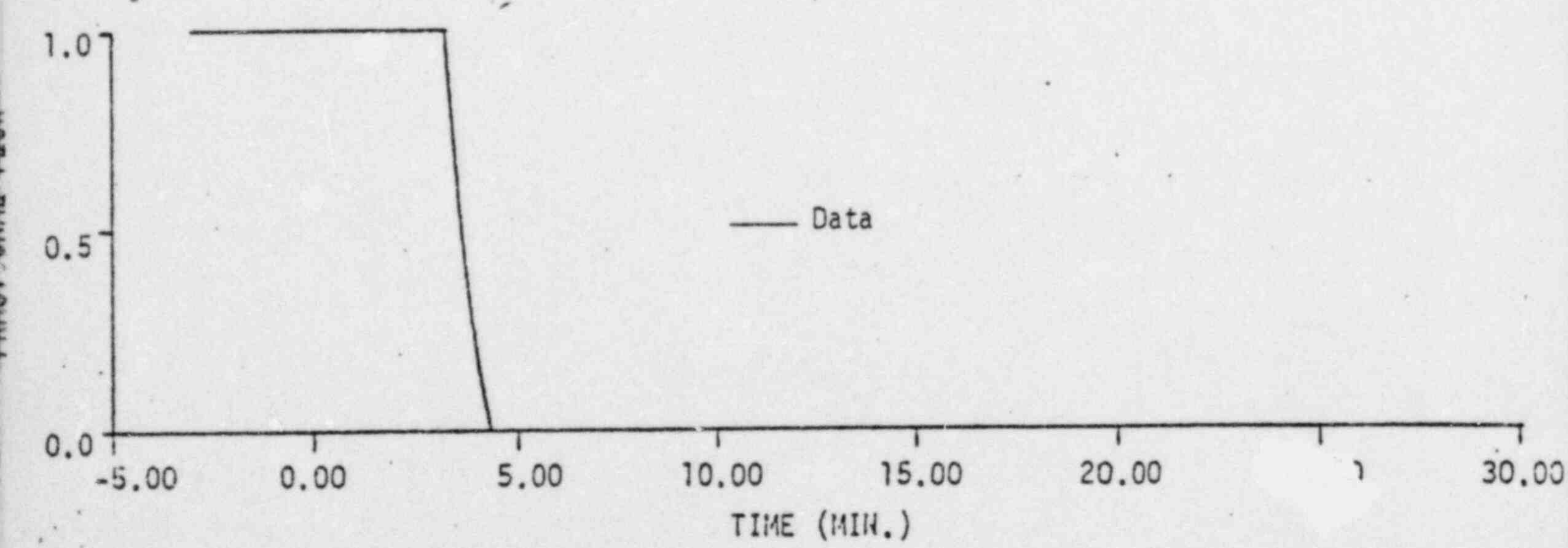

Figure 5-2. Turbine Trip - Normalized Reactor Coolant Pump 2 Flow Rate

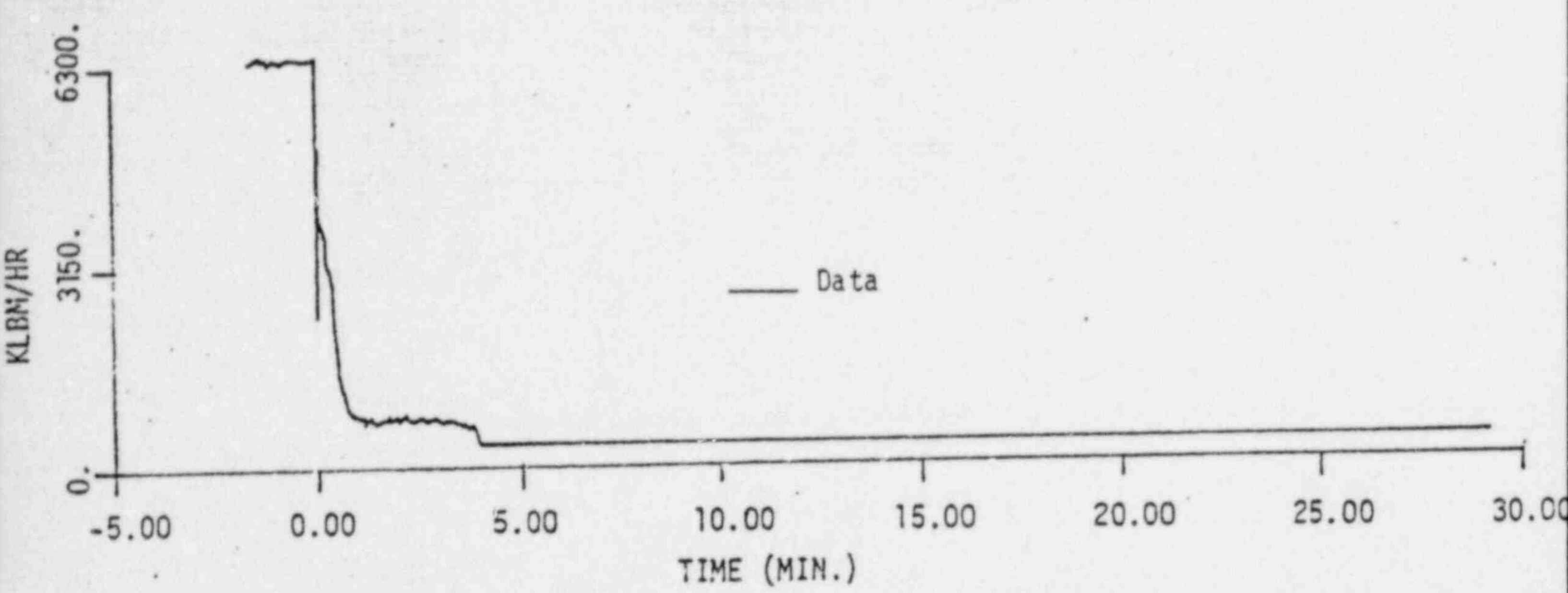

Figure 5-3. Turbine Trip-Steam Generator 1 Main Steam Flow Rate

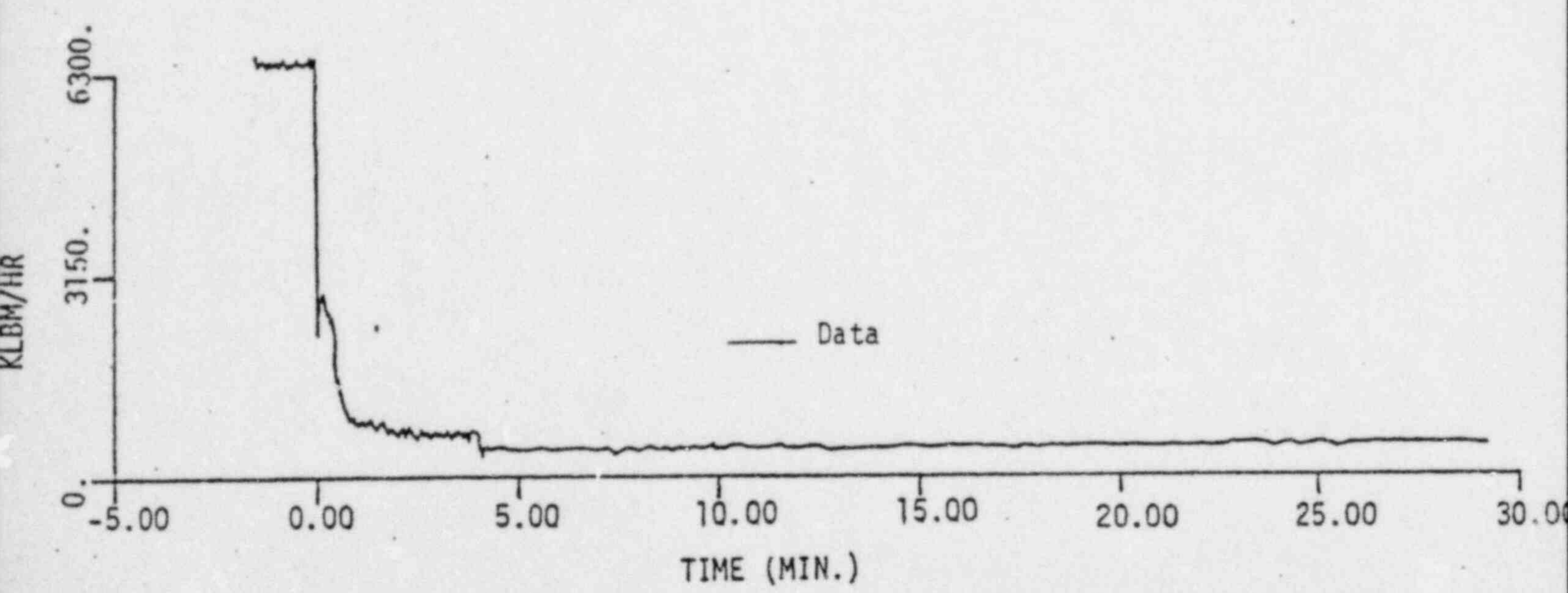

Figure 5-4. Turbine Trip-Steam Generator 2 Main Steam Flow Rate

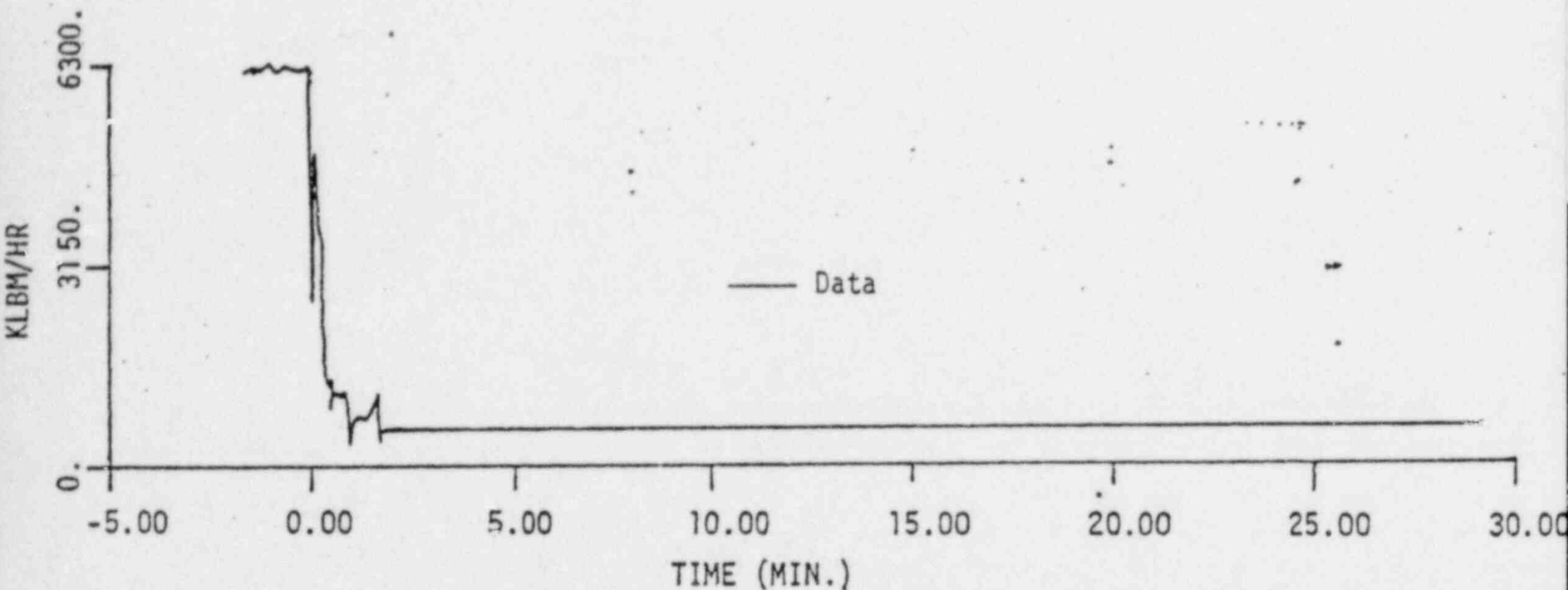

Figure 5- 5. Turbine Trip-Steam Generator 1 Feedwater Flow Rate

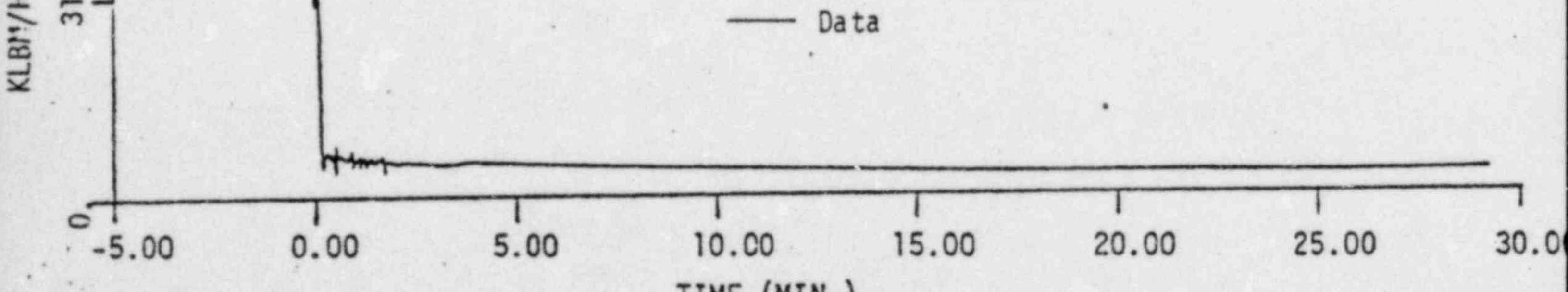

Figure 5-6. Turbine Trip-Steam Generator 2 Feedwater Flow Rate

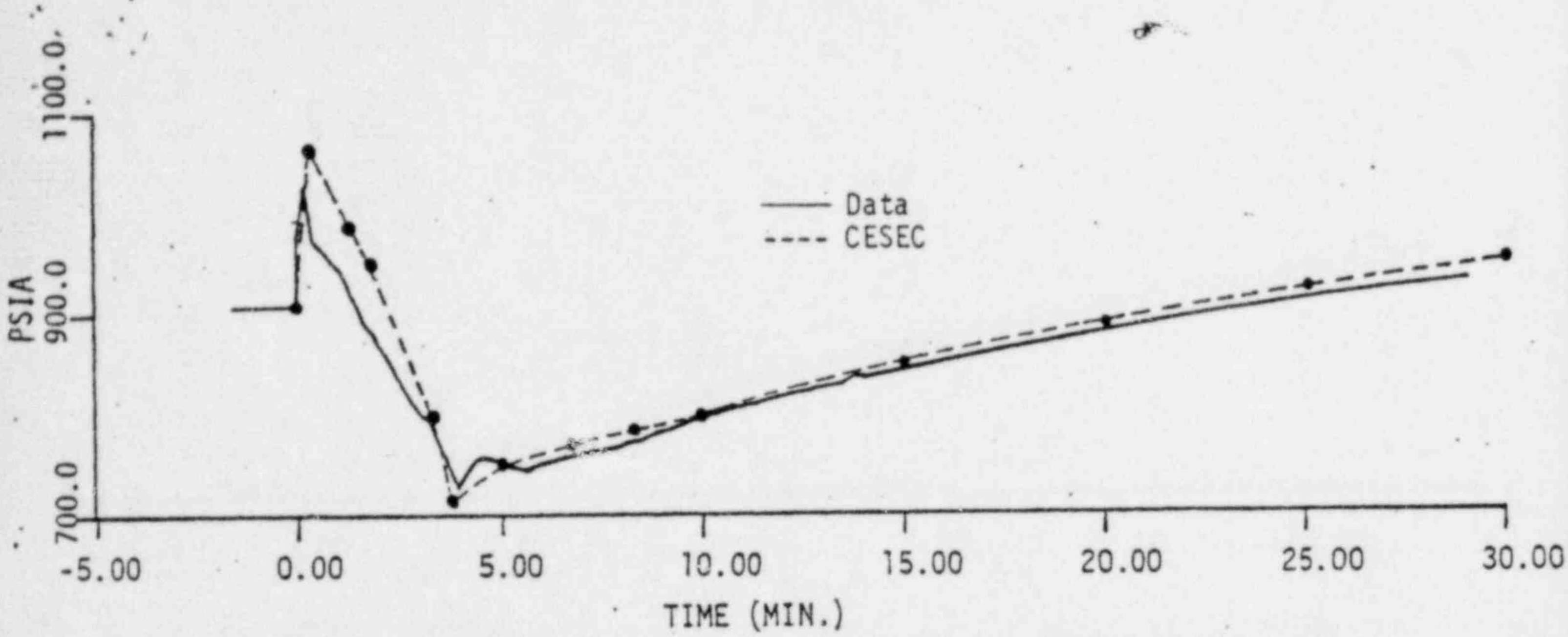

Figure 5-7. Turbine Trip - Steam Generator 1 Pressure

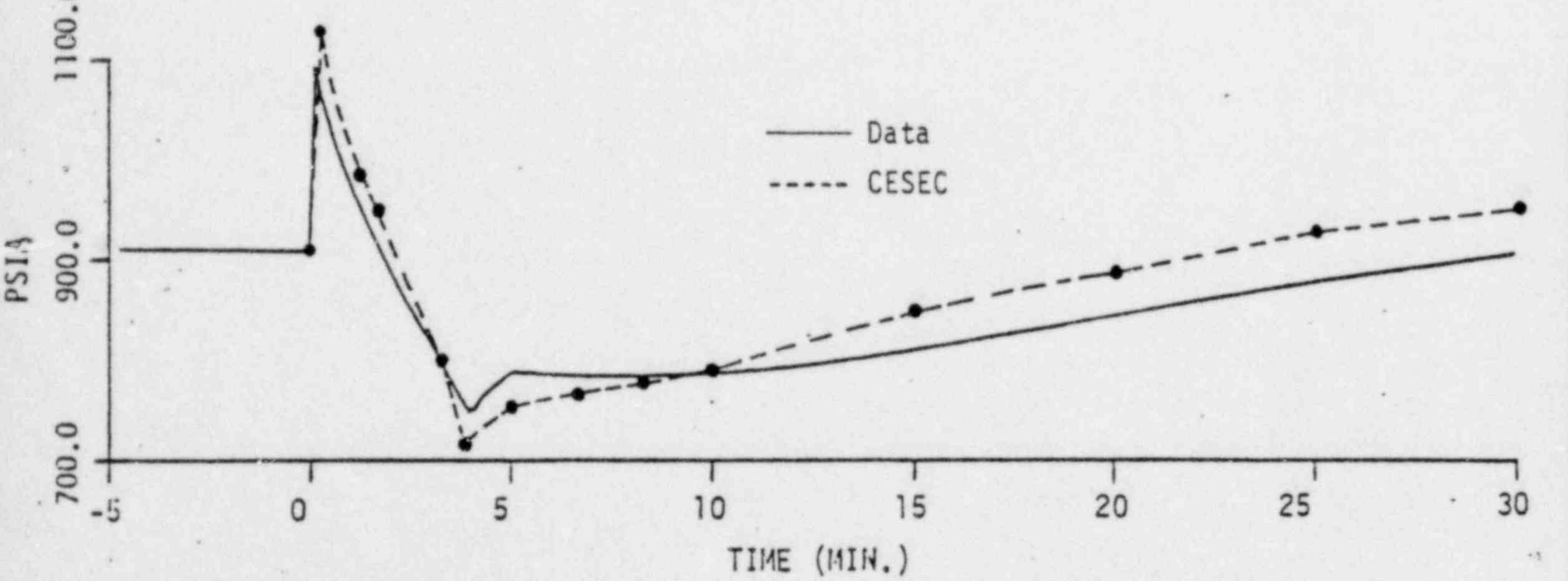

Figure 5-8. Turbine Trip - Steam Generator 2 Pressure

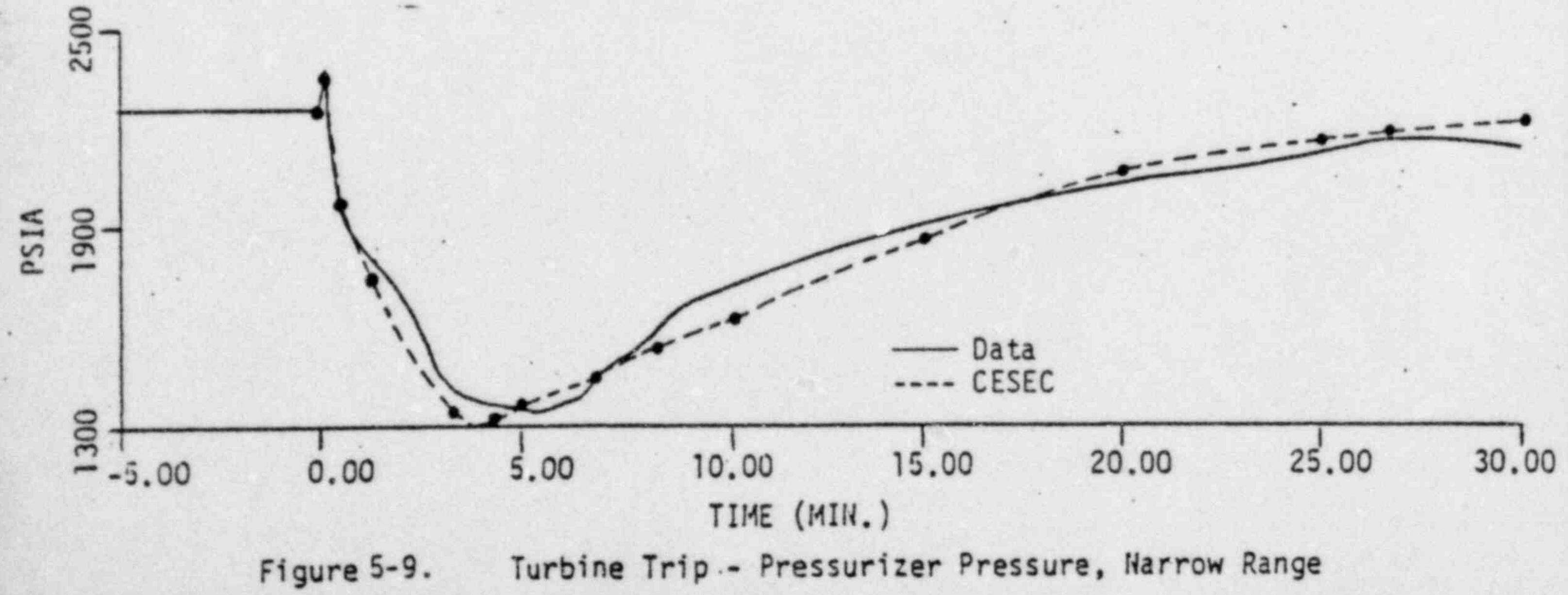

Figure 5-9. Turbine Trip - Pressurizer Pressure, Narrow Range

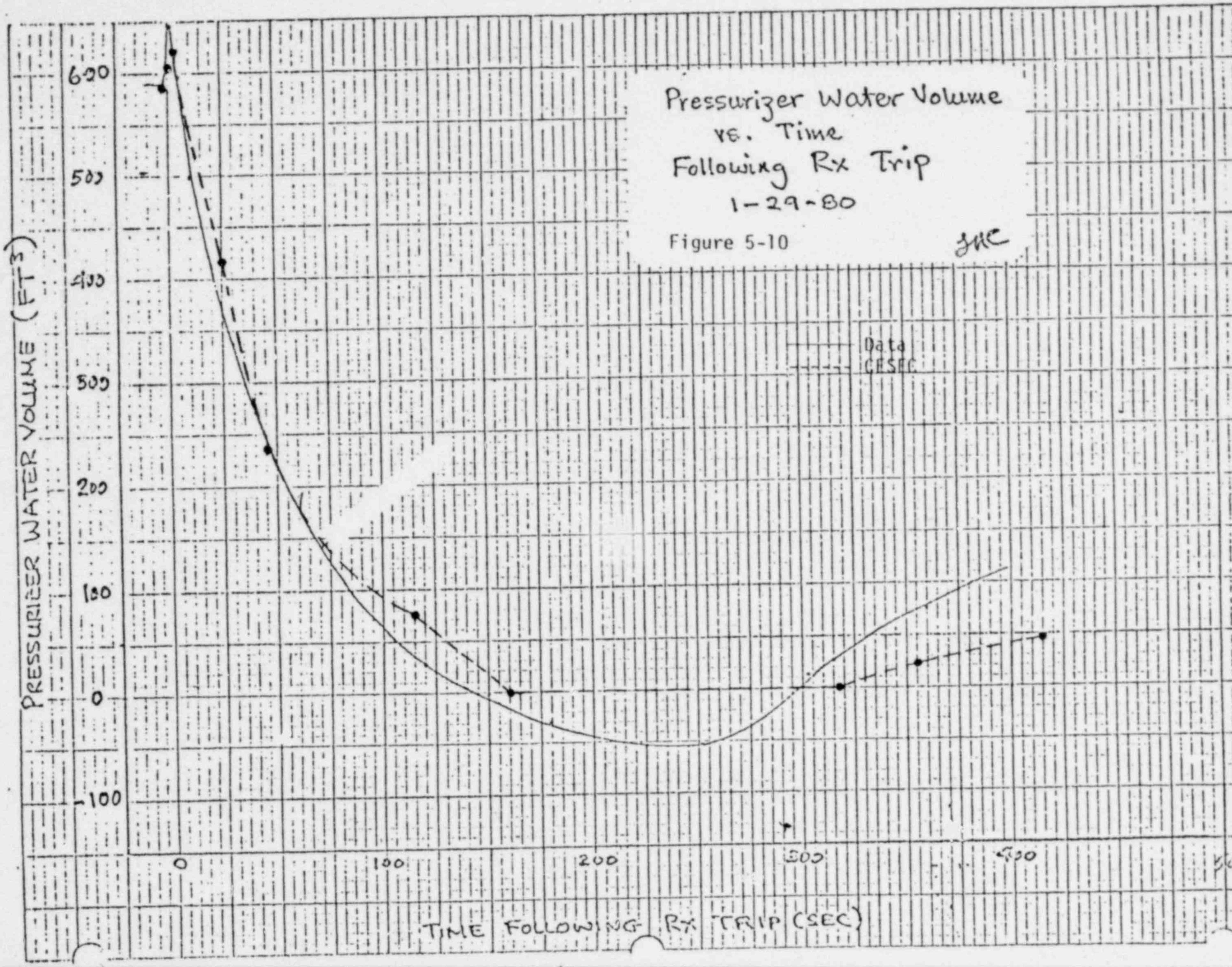
Pressurizer Water Volume
vs. Time
Following Rx Trip
1-29-80
JMC
Data
CESEC
PRESSURIZER WATER VOLUME (FT³)
600
500
400
300
200
100
0
-100
0
100
200
300
400
TIME FOLLOWING RX TRIP (SEC)

Figure 5-10

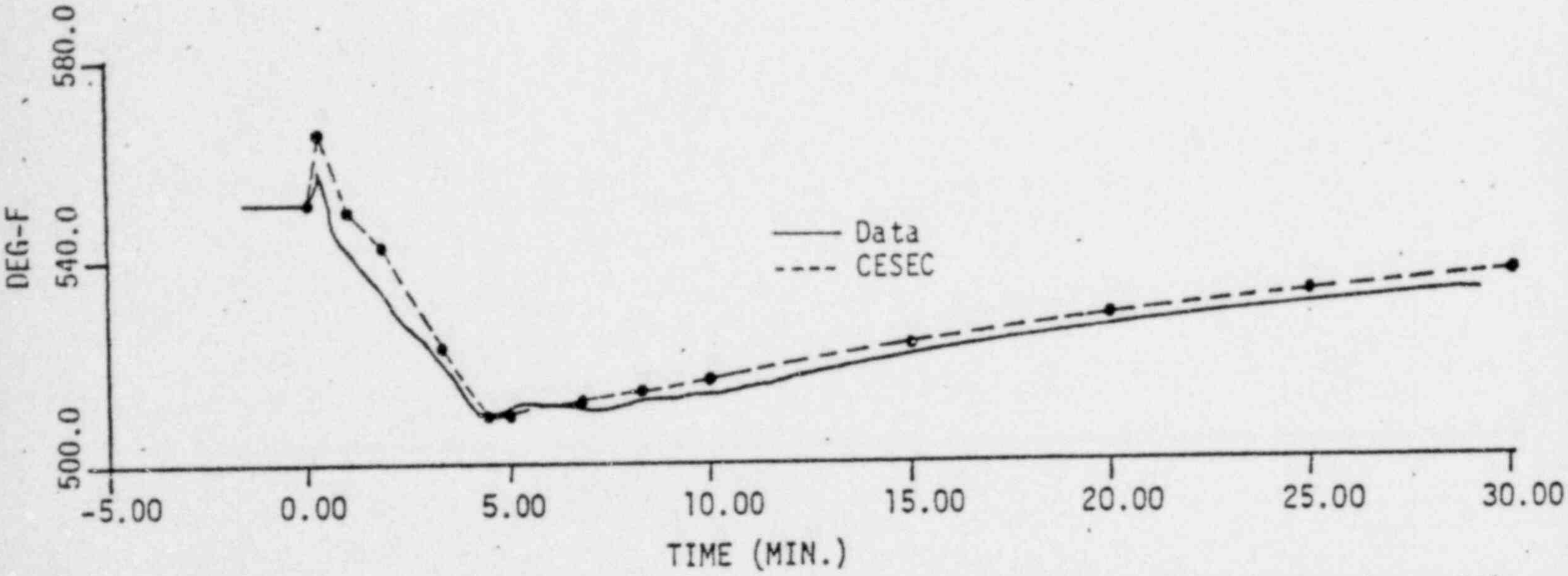

Figure 5-11. Turbine Trip-Steam Generator 1 Cold Leg Temperature (Loop 1A)

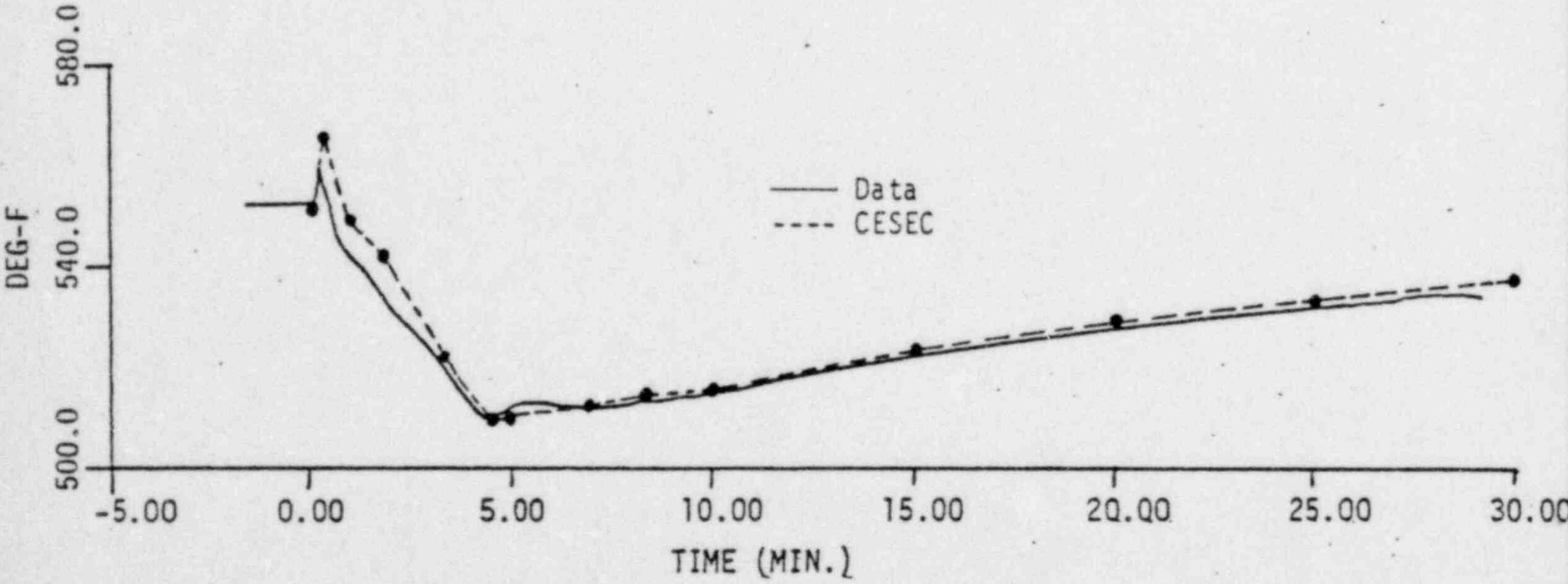

Figure 5-12 Turbine Trip-Steam Generator 1 Cold Leg Temperature (Loop 1B)

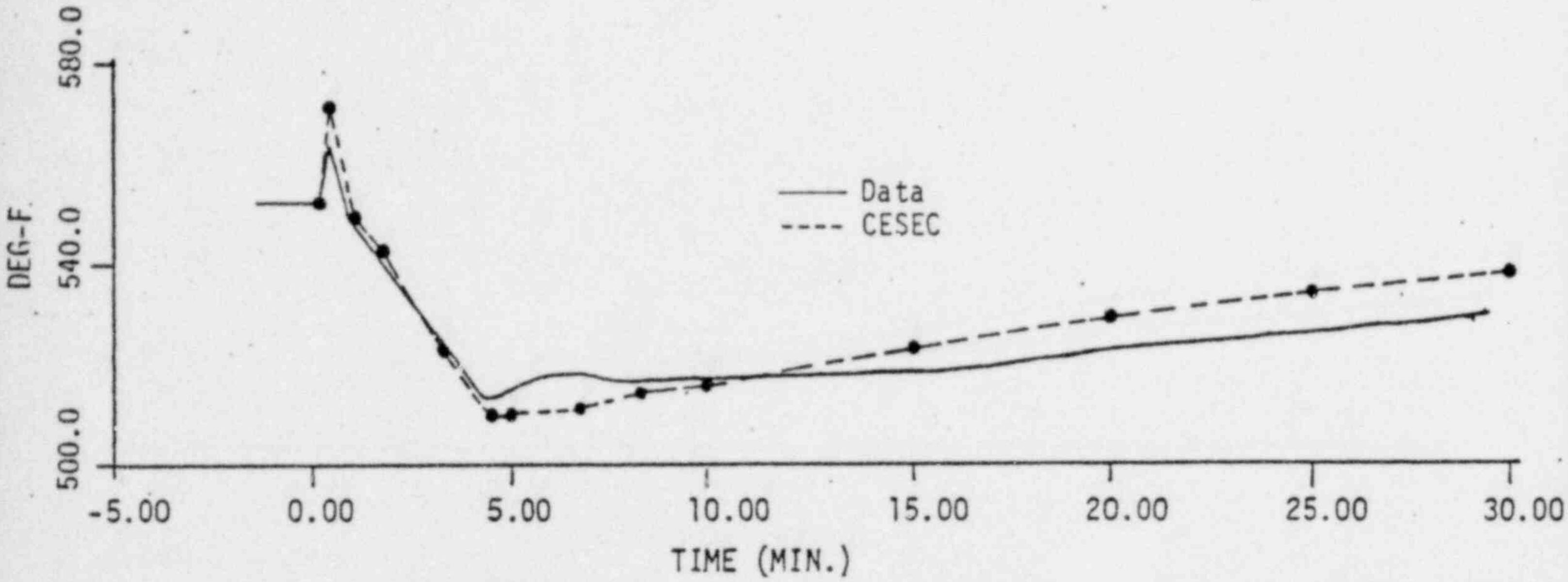

Figure 5-13 Turbine Trip-Steam Generator 2 Cold Leg Temperature (Loop 2A)

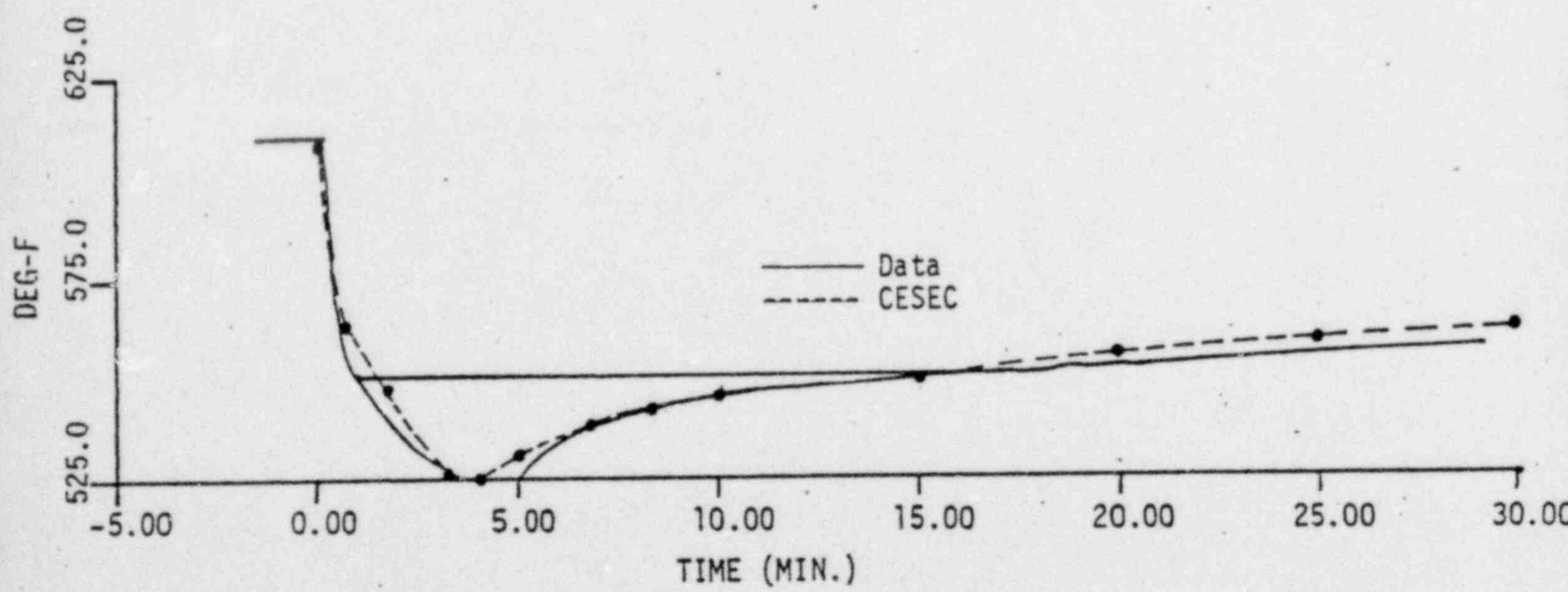

Figure 5-14 Turbine Trip-Steam Generator 1 Hot Leg Temperature

6.0 FOUR PUMP LOSS OF FLOW

6.1 SUMMARY

The four pump loss of forced primary coolant flow test performed during the ANO-2 power ascension program was initiated from a power of 2295 Mwt (81%). The four pump loss of flow results in a rapid decrease in the core flow. The transient is initiated by simultaneously tripping all four reactor coolant pumps, which will cause a CPC low DNBR reactor trip followed by a turbine-generator trip.

The event was initiated with all plant control systems in the automatic mode and operating normally, except the SDBCS. Due to hardware problems, one turbine bypass valve and one atmospheric dump valve were isolated. Additionally, the two atmospheric dump valves located upstream of the MSIVs were placed in the manual mode and, thus, unavailable for the test. With the two available turbine bypass valves and one atmospheric dump valve, the dump capacity of the SDBCS was reduced to about 31 percent of the full power steam flow. One charging pump was also isolated.

Soon after the four reactor coolant pumps were simultaneously tripped, the reactor tripped on a low DNBR signal. The following turbine trip resulted in the termination of steam flow through the turbine admission valves. The loss of forced flow through the RCS combined with the temporary loss of heat removal capability by the secondary system, produced a power/cooling mismatch causing the RCS and secondary system pressures to increase. To control the pressure response in the secondary system, the available two bypass valves and one atmospheric dump opened. Subsequent to the reactor trip, the RCS pressure peaked and then started to drop sharply. Termination of the pressure decay followed the modulated closure of the SDBCS valves prior to establishment of natural criculation flow.

6.2 PRETEST PREDICTION

The CESEC pretest prediction for the four pump loss of flow test assumed all plant control systems would function automatically. In addition, it was assumed that the SDBCS would operate at its full dump and bypass capacity, i.e., 85 percent of the full power steam flow. Finally the pretest prediction assumed that the feedwater enthalpy would follow power level (in the test, the feedwater enthalpy stayed constant).

As a result of the differences in pretest prediction assumptions and the actual test conditions as described in this section and Section 6.1, the pretest prediction results are not comparable to the test results.

6.3 SEQUENCE OF EVENTS

The four pump loss of flow test was initiated from the initial conditions shown in Table 6-1. The plant control systems were all in the automatic mode and operating normally except the SDBCS. As previously mentioned in Section 6-1, one turbine bypass valve and one atmospheric dump valve were isolated and unavailable. In addition, the two atmospheric dump valves located upstream of the MSIVs were in the manual mode and also unavailable for the test. Table 6-2 provides additional information relating to the operating characteristics of the SDBCS at the time of the test.

The transient was initiated by silmultaneously tripping all four reactor coolant pumps. Due to the loss of flow the reactor tripped very quickly (0.2 seconds) on a low DNBR signal. Subsequent to the reactor trip, the turbine tripped (0.4 seconds). The SDBCS responded to the turbine admission valve closure by initiating a quick open signal to the SDBCS (1.0 second). Due to the temporary loss of heat removal capability by the secondary system and the loss of forced flow in the RCS, the internal energies of both the RCS and the secondary system increased, the temperatures increased, and the pressures increased. As the CEAs started to enter the core the RCS pressure peaked (2265 psia at 2.2 seconds) and subsequently started to decay rapidly. Once the CEAs were fully inserted the core power reduced to decay heat levels.

The bypass capacity (fully open at 2 seconds) was not sufficient to remove all the excess heat and, thus, the single available atmospheric valve opened to vent the additional steam to the atmosphere (2.0 seconds). The bypass valves remained fully open for about 10 seconds, while the atmospheric dump valve remained fully open for about 4 seconds. The bypass valves fully closed at 18 seconds into the transient.

The RCS cooldown triggered the second charging pump to automatically start and the letdown flow was reduced. The minimum pressurizer pressure reached was 2008 psia at about 40 seconds after reactor trip. The steam generator pressure peaked about 64 seconds into the transient with a maximum value of 1028 psia in steam generator 2. Subsequently the steam generator pressure stabilized through the modulation of the bypass valves.

Table 6-3 presents a detailed sequence of events forthe transient.

6.4 POST-TEST COMPARISON

The CESEC post-test comparison for the four pump loss of flow test was performed using the initial conditions shown in Table 6-4. As previously stated in Section 5.4, the core outlet temperature and the steam generator pressure are calculated by the code during the initialization process. Comparison of the initial conditions in Table 6-4 with the test initial conditions (see Table 6-1) indicates good agreement. Basically the only difference is in the vessel mass flow rate which shows a deviation of about 3 percent between CESEC and the test data. The difference in charging flow result from CESEC not simulating the RCP seal leakage flow.

Preparation of the input data which was used in the simulation included the following assumptions:

1. CESEC does not include a CPC DNBR algorithm and, thus, the reactor trip was simulated by forcing a trip at the measured time value. After the CEAs are fully inserted upon reactor trip, the reactor kinetics calculation in the code was bypassed. the ANS decay heat curve based on 30 days of continuous operation at full power was used to simulate the power level for the remainder of the transient. This power level is slightly larger than the power level recorded in the test after the CEAs were fully inserted.

2. The fraction of primary system flow through each steam generator was input to CESEC in table form as a function of time. Figure 6-1 shows the RCS flow coastdown after tripping of the RCPs. CESEC was driven with the coastdown curve measured in the test. A natural circulation flow of 4 percent was subsequently assumed for the remainder of the event.

3. The steam flow out of each steam generator was obtained from the plant test data and modelled using the SDBCS algorithm in CESEC. The measured flows are provided for steam generators 1 and 2 in Figures 6-2 and 6-3, respectively. The non-symmetric response results from one operable bypass valve and the single operable dump valve being connected to the steam generator 1 steam line header, while the other operable bypass valve was connected to the steam generator 2 steam line header. As seen from Figures 6-2 and 6-3 the steam flows drop suddenly from the initial values at the time of the turbine trip. Once the SDBCS triggers the opening of the bypass and atmospheric valves, the steam flow increases again. Closing of the valves causes a decay of the steam flows. As seen in Figures 6-2 and 6-3, the steam flow appears to stabilize at about 12 percent of the full power flow. Existence of this relatively high steam flow at this time in the transient is questionable since the bypass valves are modulated to control the secondary pressure and

temperature. The uncertainty in the ΔP measurement used to generate the steam flow rate from data during low flow conditions is also high. Therefore, the SDBCS algorithm in CESEC was used for sumulating the post-trip steam system transient behavior in order to overcome this uncertainty. CESEC results are shown in Figures 6-2 and 6-3.

4. The feedwater flow for each steam generator was represented by a table of flow as a function of time. The feedwater flows for each steam generator are provided in Figures 6-4 and 6-5. However, once the feedwater flow is ramped down after reactor trip, CESEC assumes the design value of 5 percent for the duration of the event. Again, uncertainty in the ΔP measurement during low flow conditions is the reason for using the design value in the CESEC simulation.

5. The main feedwater enthalpy is kept constant at a value of 420 Btu/lbm according to the plant measurement. This value was assumed in the CESEC simulation.

6. The spray flow which was turned on at 2.0 seconds into the transient and was turned off at 4.0 seconds has no significant impact on the CESEC calculations.

The steam generator 1 pressure response is shown in Figure 6-6. The pressure increases sharply following the closure of the turbine admission valve. Once the bypass and dump valves open, a temporary dip in the recorded pressure is observed. The recorded pressure starts to rise again once the SDBCS valves close. The measured peak pressure is reached while the SDBCS is modulating the secondary pressure and temperature behavior. The CESEC prediction follows the plant test data within 20 psi. The CESEC peak pressure is calculated to be about the same as that from plant data (1016 psia (CESEC) versus 1023 psia (test data)).

Figures 6-7 through 6-14 show the comparison between data and CESEC predictions for the pressurizer pressure, the pressurizer level, the RCS hot leg temperatures, and the RCS cold leg temperatures, respectively. The CESEC predictions for the above parameters agree well with the test data. The biggest difference in results was observed in the hot leg temperatures response. This results from CESEC over-predicting the pressurizer level drop and, thus, sending more saturated fluid into the system. The CESEC pressurizer level starts to rise with the increase in charging flow and the reduction in the letdown flow. The pressurizer pressure increases accordingly and, thus, the CESEC hot leg temperature rises also staying above the measured data. Thereafter, the CESEC response is basically controlled by the modulation of the SDBCS.

The sequence of events as predicted by CESEC is provided in Table 6-5. Comparison of key events with data (see Table 6-3) shows good agreement. the maximum hot let temperatures predicted by CESEC are within 2.4°F and 3.2°F of the test data values for steam generators 1 and 2, respectively.

The maximum and minimum pressurizer pressures predicted by CESEC are, respectively, within 7 psi and 5 psi of the test data values. CESEC predicted a maximum pressurizer level which is 2.7 percent lower than the test data value. The times of occurrence for all of the above key events were predicted by CESEC to be within 17 seconds of the recorded values.

TABLE 6-1

Initial Conditions for the Total Loss of Flow Test

Core Power, Mwt	2295 (81%)
Core Inlet Temperature, °F	552
Core Outlet Temperature, °F	596
Vessel Mass Flow Rate, 10^6 lbm/hr	133
Pressurizer Pressure, psia	2240
Pressurizer Level, percent	46.4
Steam Generator Pressure, psia	926
Charging Flow, gpm	44.5 (one pump)
Letdown Flow, gpm	40.4
Control System Status:	
- Pressurizer Pressure	Automatic
- Pressurizer Level	Automatic
- Feedwater	Automatic
- Reactor Regulating	Automatic
- Steam Dump and Bypass	Automatic

TABLE 6-2

Operating Status of the SDBCS Valves During Four Pump Loss of Flow Test

Valve Description	Capacity (lbm/hr)	Status
13% Turbine Bypass	1.24×10^6	Operable
5% Turbine Bypass	0.69×10^6	Operable
13% Turbine Bypass	1.24×10^6	Isolated
13% Atmospheric Dump	0.94×10^6	Isolated
13% Atmospheric Dump	0.94×10^6	Operable
13% Atmospheric Dump	0.94×10^6	Manual
13% Atmospheric Dump	0.94×10^6	Manual

TABLE 6-3

Sequence of Events for the Total Loss of Flow Test

Time (sec.)	Event	Value
0.0	Manual trip of all 4 reactor coolant pumps	-
0.2	Reactor trip initiated on low DNBR signal	1.3
0.4	Automatic turbine trip initiated on reactor trip	-
1.0	Turbine bypass valves receive quick-open signal	-
1.3	Maximum hot-leg temperature	599.1 (SG-1)
2.0	Pressurizer spray valve opens	-
2.0	Turbine bypass valves full-open (Relief capacity 2000 klbm/hr)	-
2.0	Atmospheric dump valve opens to vent remaining steam flow to atmosphere	-
2.2	Maximum pressurizer pressure	2265 psia
3.0	CEAs fully inserted; core power reduced to $<5\%$	-
4.0	Pressurizer spray valve closed	-
6.0	Atmospheric dump valve closed	-
12.0	Turbine bypass valves begin to close	-
17.0	Second charging pump started; charging flow reaches maximum value	88.5 GPM
17.0	Letdown flow throttled back	24.5 GPM
18.0	Turbine bypass valves fully closed	-
39.0	Minimum pressurizer pressure	2008 psia
42.0	Minimum pressurizer level	26.2%
53.5	Turbine bypass valve opened to control secondary pressure and temperature	-
57.0	Letdown flow reduced to minimum value	13.2 GPM

64.0	Maximum steam generator pressure	1023 (SG-1) 1028 (SG-2)
637.0	Second charging pump turned off; normal charging flow established	44.5 GPM
667.0	Letdown flow increased	26.5 GPM
787.0	Turbine bypass valve closed	-

TABLE 6-5

CESEC Sequence of Events for the Total Loss of Flow Test

Time	Event	Value
0.0	Manual trip of all 4 reactor coolant pumps	--
0.2	Reactor trip manually	--
0.4	Automatic turbine trip initiated on reactor trip	--
3.3	Maximum hot-leg temperature	596.7 (SG-1) 596.7 (SG-2)
3.5	Maximum pressurizer pressure	2259
9.0	Letdown flow throttled back	29 GPM
12.0	Second charging pump started; charging flow reaches maximum value	84 GPM
53.6	Minimum pressurizer pressure	2003 psia
58.0	Minimum pressurizer level	23.5%
57.5	Letdown flow reduced to minimum value	13.2 GPM
47.2	Maximum steam generator pressure	1016 (SG-1) 1016 (SG-2)

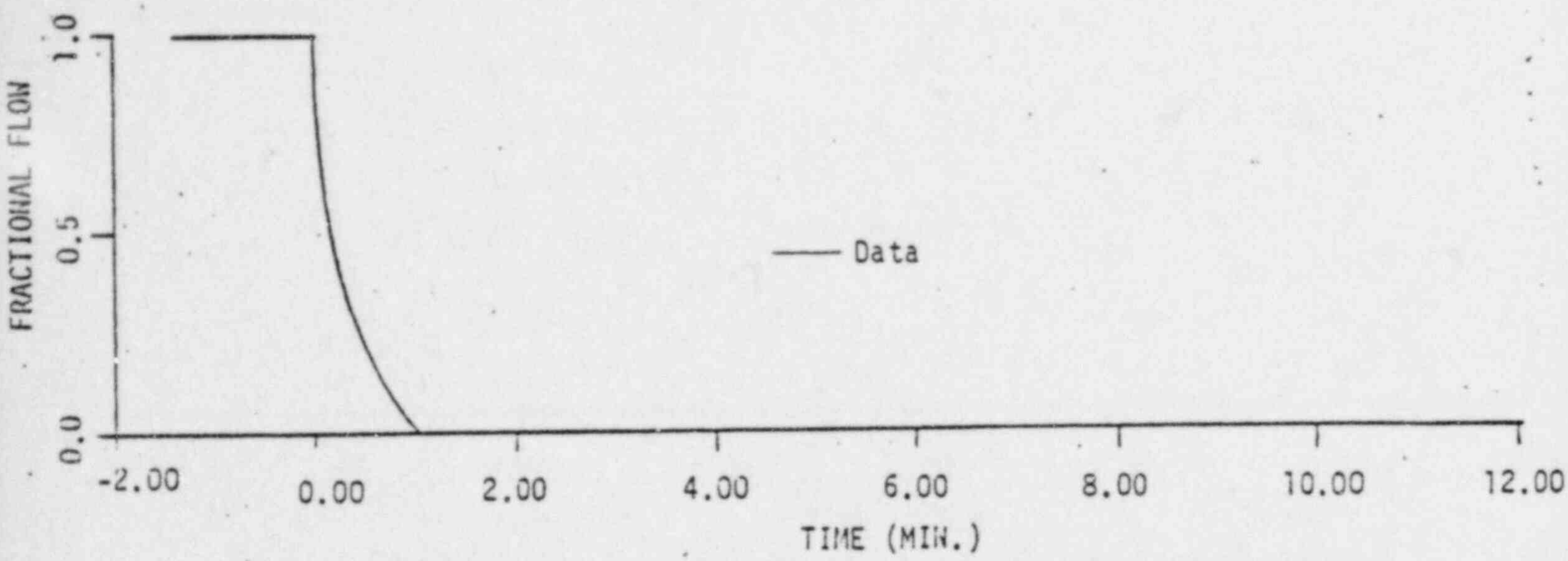

Figure 6-1. Loss of Flow-Normalized Reactor Coolant Pump Flow Rate

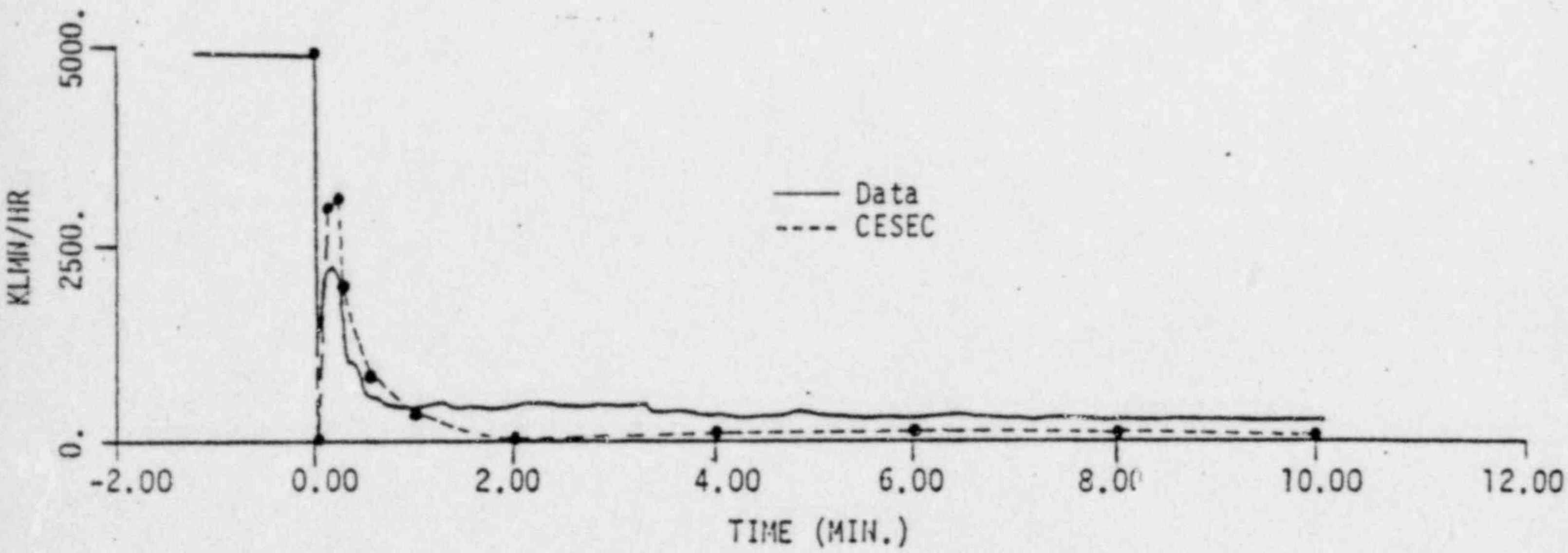

Figure 6-2. Loss of Flow - Steam Generator 1 Main Steam Flow Rate

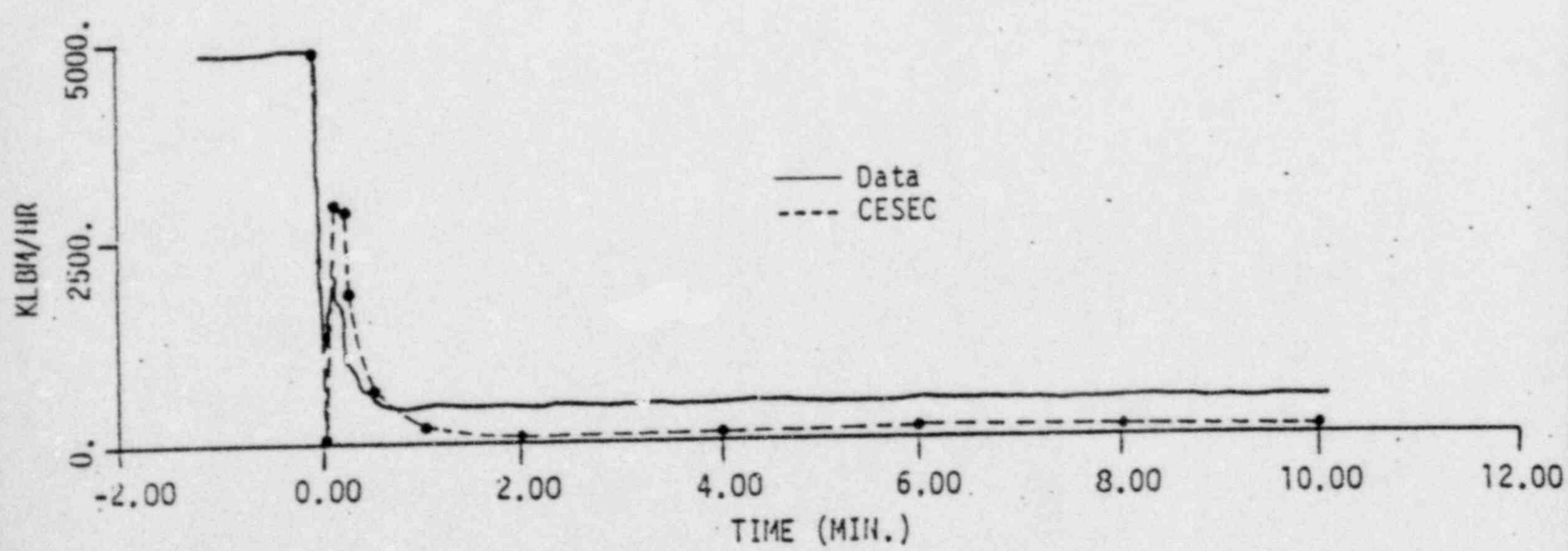

Figure 6-3. Loss of Flow - Steam Generator 2 Main Steam Flow Rate

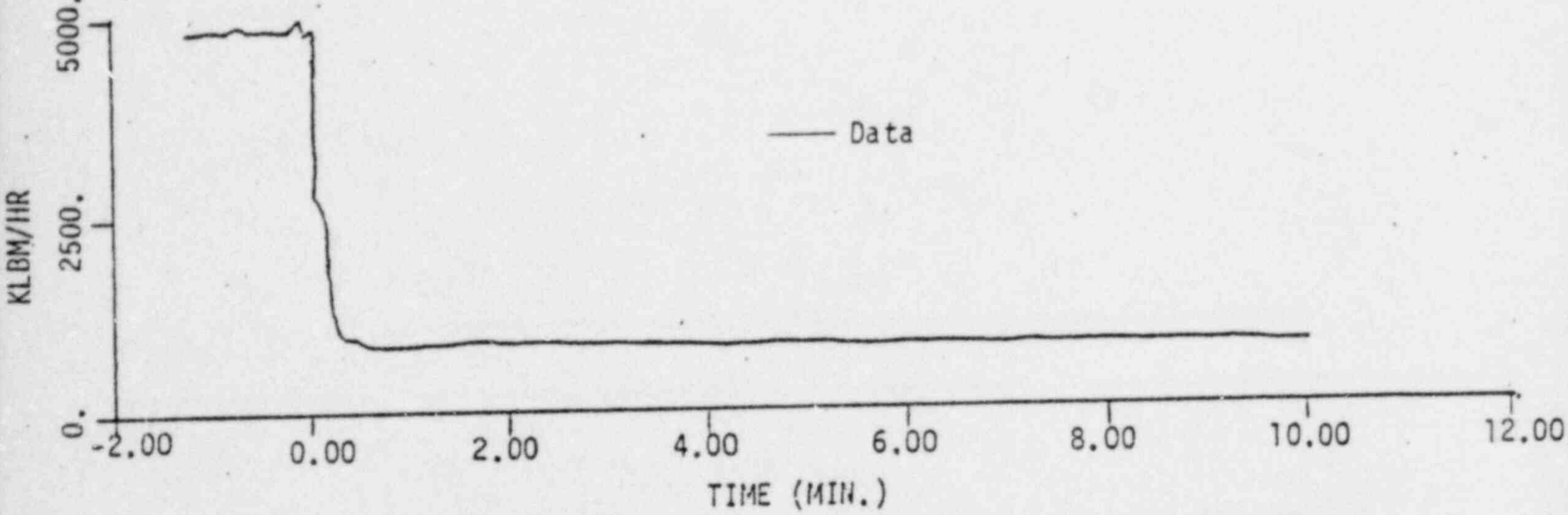

Figure 6-4. Loss of Flow - Steam Generator 1 Feedwater Flow Rate

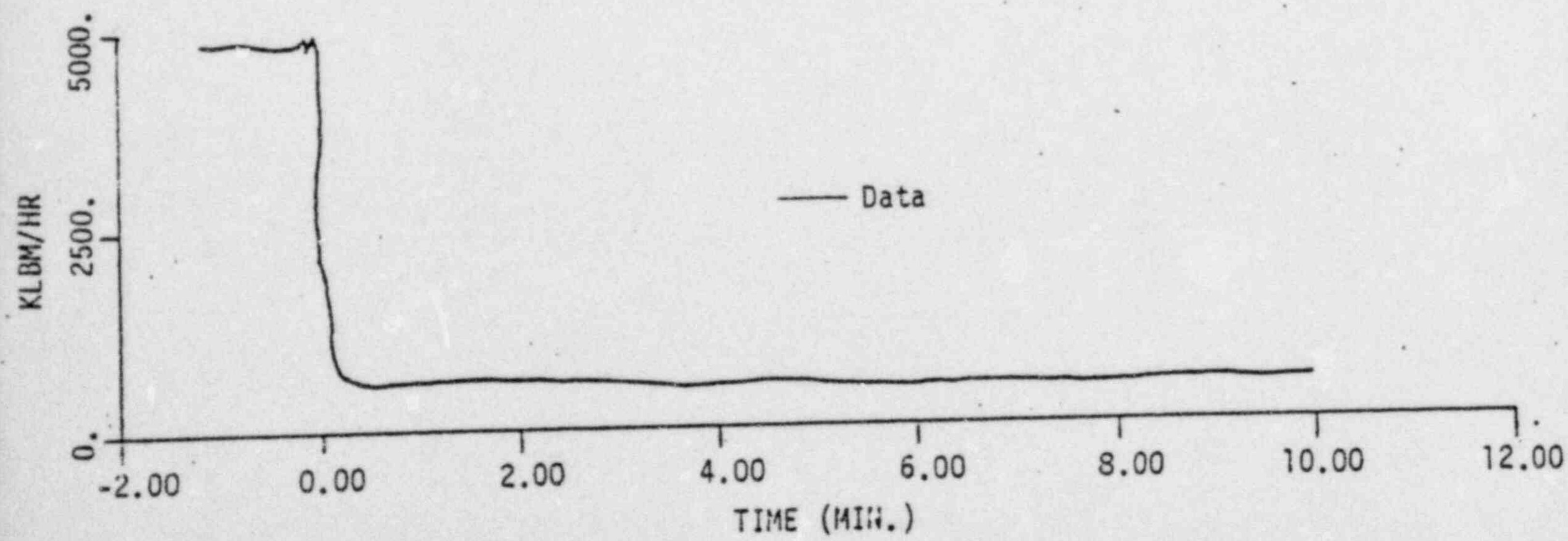

Figure 6-5. Loss of Flow - Steam Generator 2 Feedwater Flow Rate

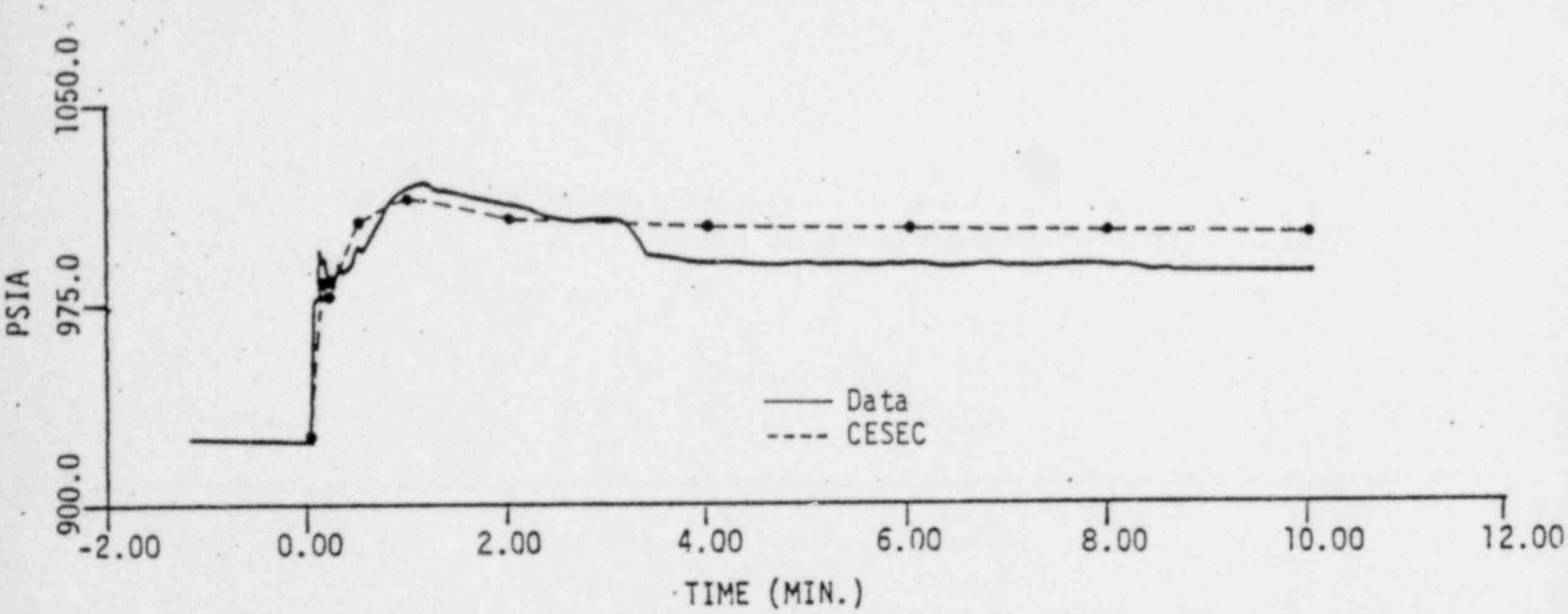

Figure 6-6. Loss of Flow-Steam Generator 1 Pressure

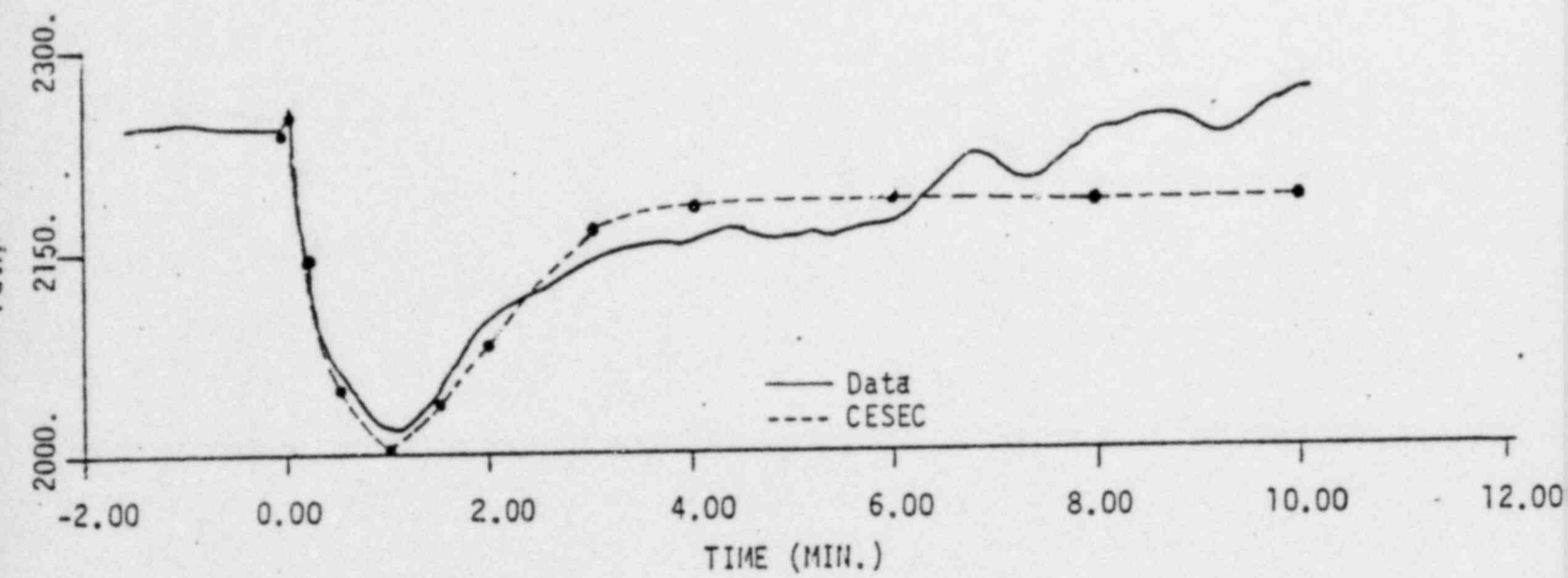

Figure 6-7. Loss of Flow - Pressurizer Pressure, Narrow Range

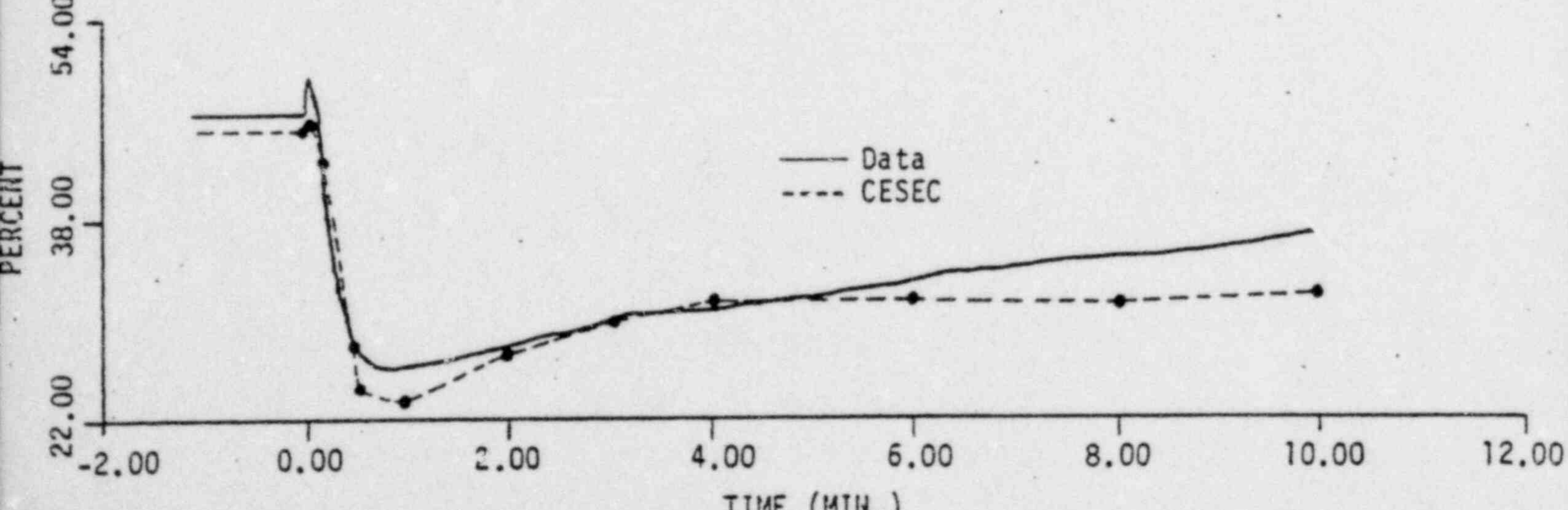

Figure 6-8. Loss of Flow - Pressurizer Level

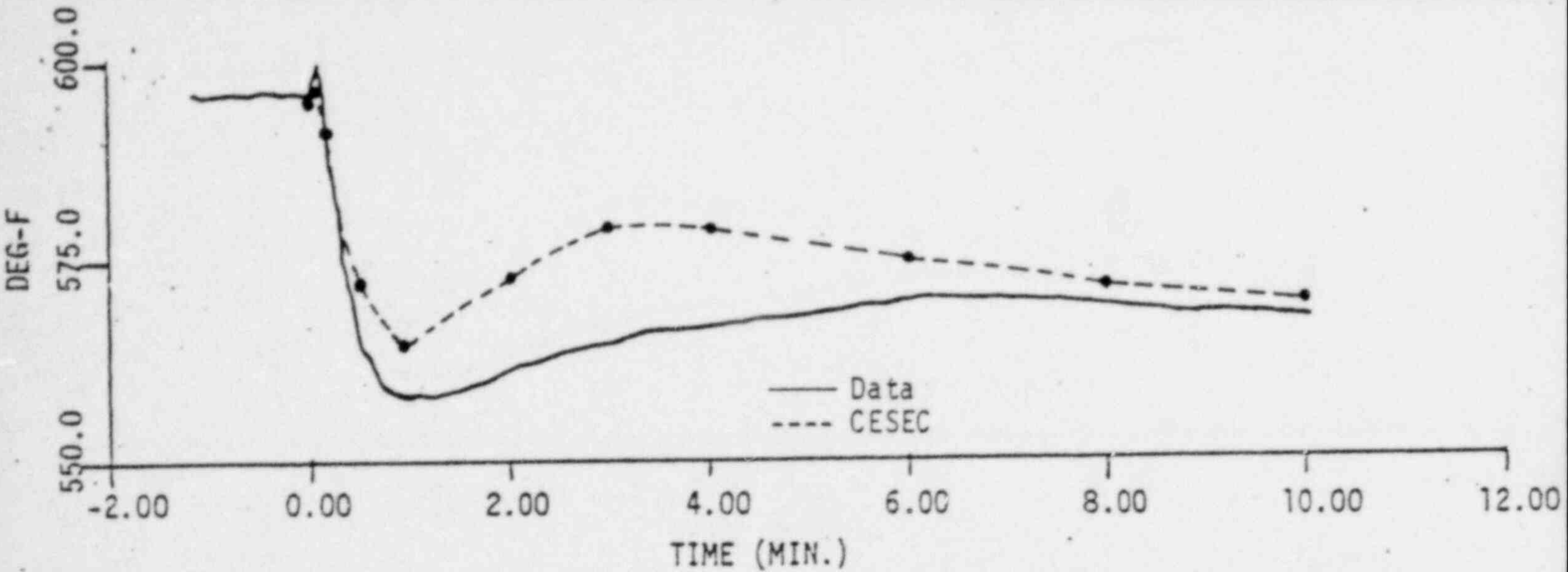

Figure 6-9. Loss of Flow-Steam Generator 1 Hot Leg Temperature

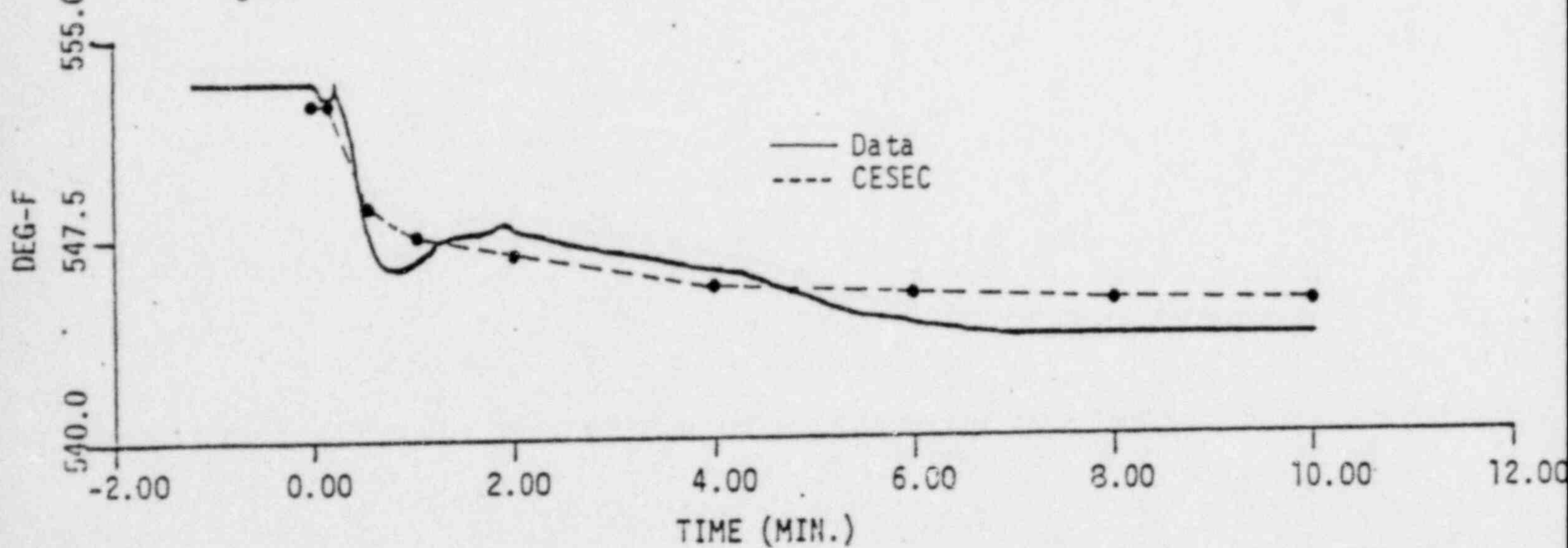

Figure 6-10. Loss of Flow-Steam Generator 1 Cold Leg Temperature (Loop 1A)

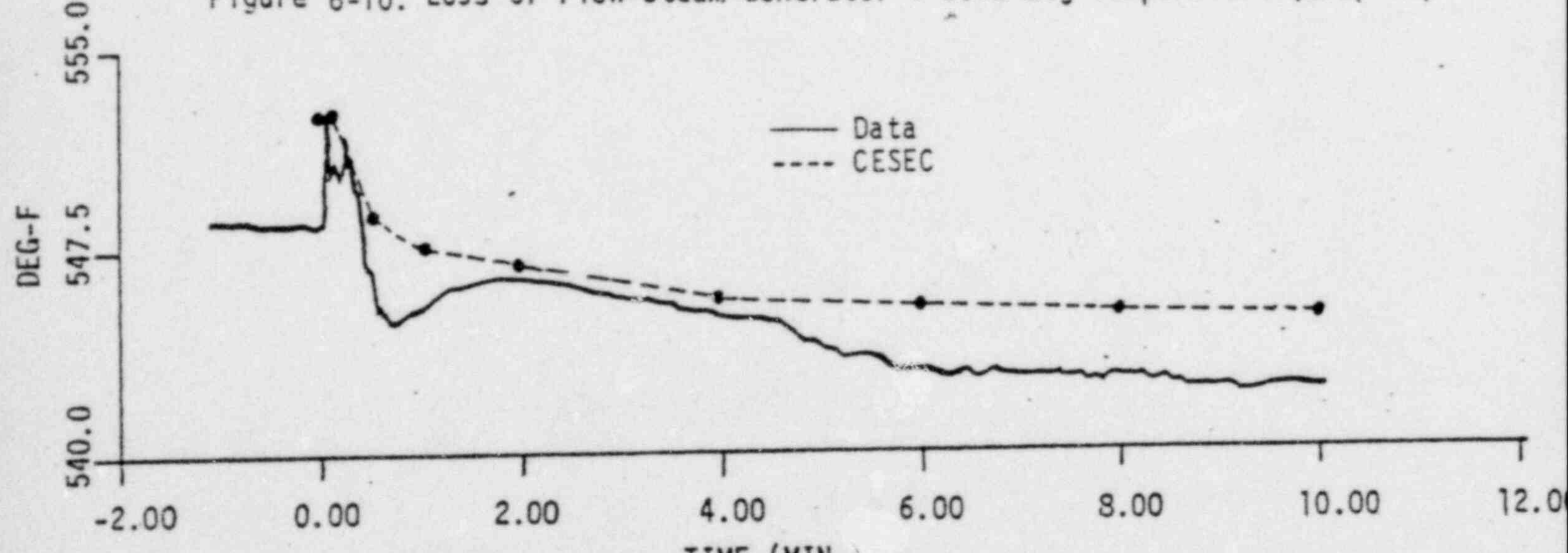

Figure 6-11. Loss of Flow-Steam Generator 1 Cold Leg Temperature (Loop 1B)

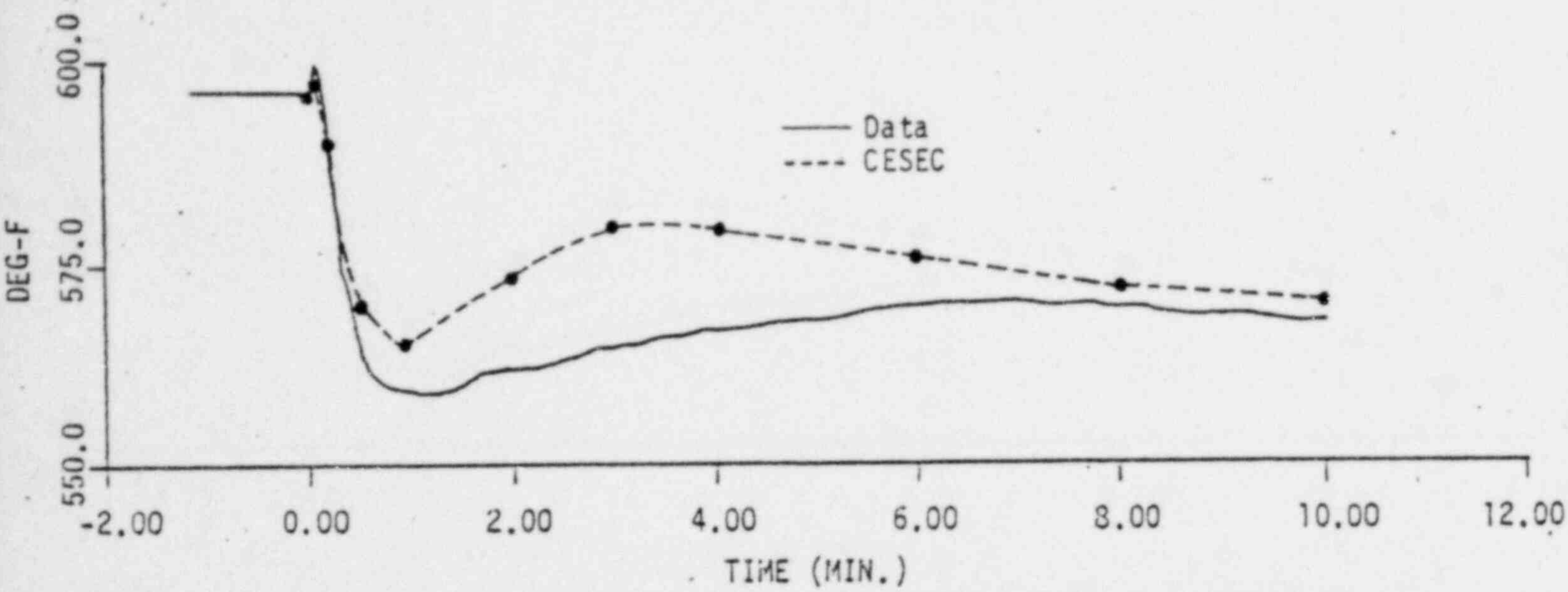

Figure 6-12. Loss of Flow - Steam Generator 2 Hot Leg Temperature

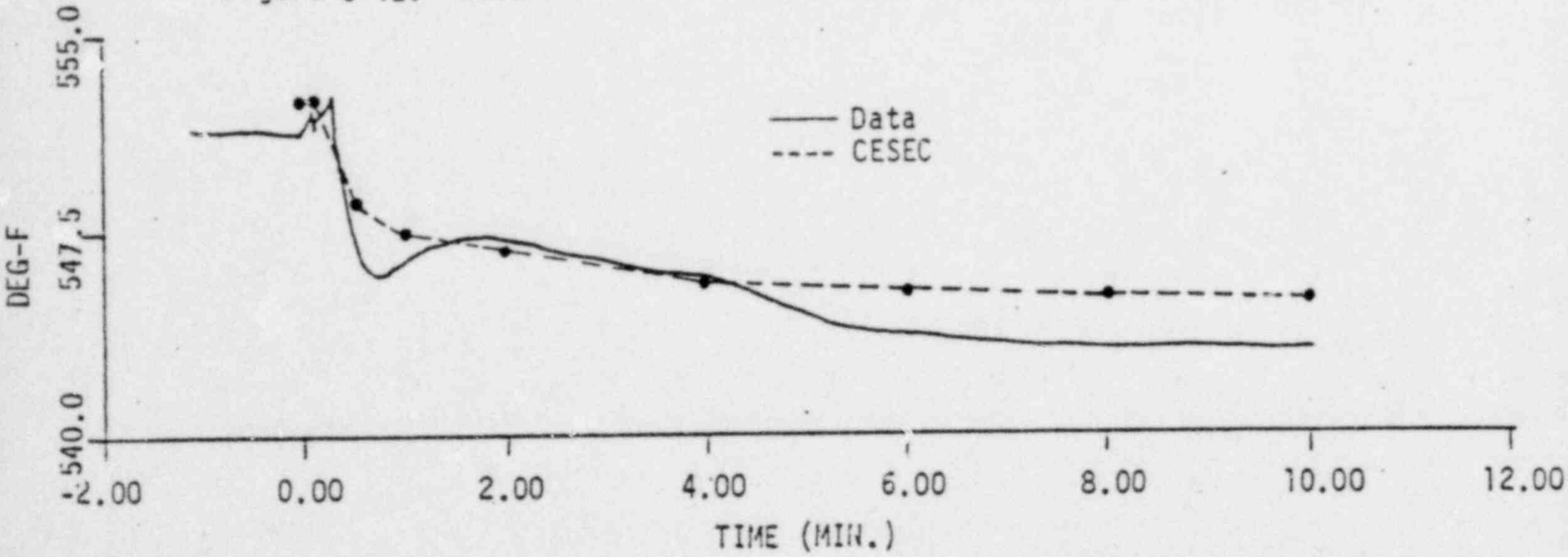

Figure 6-13. Loss of Flow - Steam Generator 2 Cold Leg Temperature (Loop 2A)

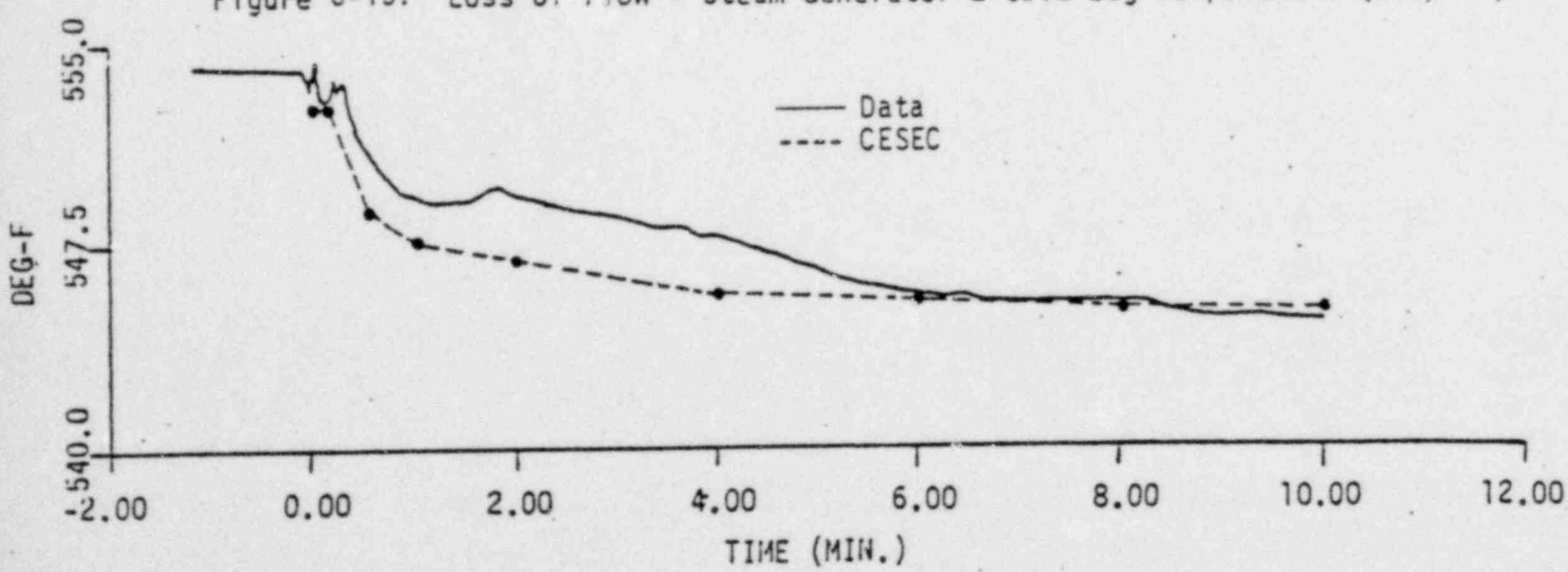

Figure 6-14. Loss of Flow - Steam Generator 2 Cold Leg Temperature (Loop 2B)

7.0 FULL LENGTH CEA DROP

7.1 SUMMARY

The FLCEA test performed furing the ANO-2 power ascension program was initiated from a power of 1391 Mwt (49.4%). The FLCEA test provides the NSSS response to a core reactivity event. The event was initiated with all plant control systems in the automatic mode except for the reactor regulating system. CEA 5-60 (see Figure 7-1) was selected for the test because of its alignment with the steam generator 2 hot leg. The alignment of the dropped CEA with the hot leg was expected to show the largest observable change in the NSSS response.

A sudden insertion of the FLCEA resulted in a step reduction in the reactor power which led to a drop in the pressure of the primary coolant system and the secondary system. Since the FLCEA dropped was aligned with the steam generator 2 hot leg, the results of the test show a non-symmetric response. Manual control of the turbine demand was exercised by the operator subsequently in order to stabilize the NSSS response.

7.2 PRETEST PREDICTION

The CESEC pretest prediction for the FLCEA drop test assumed all rods out, equilibrium xenon initial core conditions, all plant control systems are in the automatic mode, and no operator actions for at least sixty seconds after event initiation. Additionally, the pretest prediction was only run for 60 seconds of transient time.

In the test, the turbine load limit was adjusted to match the new average core power level immediately following the CEA drop. Thus, pretest predictions are not fully comparable to the test results.

7.3 SEQUENCE OF EVENTS

The FLCEA drop test was initiated from the initial conditions shown in Table 7-1. The plant control systems were all in the automatic mode except for the reactor regulating system which was removed from service to avoid any potential core related effects leading to a reactor trip during the test. The reactor was stable with all rods out and equilibrium xenon conditions.

The event was initiated by opening the CEA 5-60 disconnect circuit breaker. Following the CEA drop, the core power decreased causing an initial decrease in the internal energies of the RCS and the secondary system. Thus, the cold and hot leg temperatures decreased, the pressurizer pressure decreased, the pressurizer level decreased, and the secondary system pressure decreased. The operator, following the CEA drop, took action in order to adjust the turbine load limit to match the new core average power level. Reduction of the heat removal capability of the secondary system by balancing it with the heat generation of the reactor, allowed the system to be brought back to a stable condition.

Table 7-2 presents a sequence of events for the FLCEA transient.

7.4 POST-TEST COMPARISON

The CESEC post-test comparison for the FLCEA drop test was performed using the initial conditions shown in Table 7.3. Comparison of the initial conditions in table 6-3 with the test initial conditions (see table 7-1) indicates good agreement. The difference in charging flow results from CESEC not simulating the RCP seal leakage flow. As previously mentioned in Section 5-4, the core outlet temperature and the steam generator pressure are calculated by the code during the initialization process. Thus, the difference in the vessel mass flow rate (about 9 percent) results form the balancing needed to match as close as possible the CESEC initial conditions with the test data.

Preparation of the input data which was used in the simulation included the following assumptions:

1. The forcing functions used for the simulation of the FLCEA drop event were the dropped CEA reactivity woth versus time and the turbine load variation with time (see Figure 7-2). The dropped CEAreactivity variation with time table was obtained by combining design curves for rod worth versus fraction of rod inserted and rod insertion versus time.

2. The CESEC core algorithm models the average reactor core and, thus, CESEC implicity smulates the non-symmetric NSSS behavior resulting from the insertion of CEA 5-60.

3. The fraction of primary system flow through each steam generator was kept constant in time.

4. The steam flow out of each steam generator was calculated by forcing the turbine load demand (see Figure 7-2) as a function of time. The measured flows for steam generators 1 and 2 are provided in Figures 2-3 and 7-4, respectively.

5. The feedwater flow for each steam generator was assumed to follow the steam flow by using the feedwater control system. The measured flows for steam generators 1 and 2 are provided in Figures 7-5 and 7-6, respectively.

6. The main feedwater enthalpy was assumed to follow power.

Figure 7-7 shows the power fraction response as measured by detectors NR001 and NR002 (opposite sides of core). Detector NR002 is closer to the dropped CEA than detector NR001 and, thus, exhibits a larger drop in the power. The fractional power behavior as predicted by CESEC falls in between the two measured responses as seen from Figure 7-7.

Figures 7-8 through 7-15 show the comparison between data and CESEC predictions for the pressurizer pressure, the pressurizer level, the steam generator pressure responses, the RCS hot leg temperatures, and RCS cold leg temperatures, respectively. As seen from Figures 7-10 through 7-15 CESEC reasonably simulates the non-summetric response resulting from the dropped CEA. The RCS hot leg temperature data (Figures 7-12 and 7-14) shows a lower temperature response for the hot leg of steam generator 2 as expected, since it is closest to the dropped CEA. The non-symmetric effect is carried into the steam generators pressure response (Figures 7-10 and 7-11) and into the response of the RCS cold leg temperatures (Figures 7-13 and 7-15).

The CESEC feedwater control system algorithm assumes the feedwater flow to immediately follow the steam flow. That is, the delay in system response is not modelled by the CESEC algorithm. This effect is seen when comparing the CESEC results with the test data in Figures 7-5 and 7-6. The major difference in the initial value of the feedwater flows between CESEC and data results from CESEC maintaining a stable water level during steady state by balancing feedwater flow and steam flow. According to the measured data, the initial feedwater flow is about 120 Klbm/hr higher than the measured steam flow rate. This difference in initial conditions, that is, the excessive feedwater flow, can be attributed to be the steam generator blowdown rate. Thus, if the blowdown flow corrected steam generator feedwater flow is plotted, the CESEC results will compare more favorably with the measured data.

The pressurizer pressure response is shown in Figure 7-8. After the turbine load is reduced and the pressure recovered, the system stabilizes at about 2250 psi as seen from the data. One CESEC calculation predicted that the pressurizer pressure rise continues until the pressure is stabilized at 2275 psia. The proportional spray setpoint being set at 2275 psi comes on to terminate the pressure rise. However, when CESEC is run with the proportional spray setpoint at 2251 psia, the comparison between data and the CESEC prediction is improved. Thus, it is suspected that the operator may have taken manual action to control the pressure rise and/or the spray may have come in at a lower value as happened in the loss of flow test (see Section 6-4). This action, i.e., manual control of the PPCS, if taken was not recorded. The second case was selected as the reference CESEC case for this study.

The sequence of events as predicted by CESEC is provided in Table 7-4. Comparison of key events with data (see Table 7-2) and overall system response (see Figures 7-3 through 7-15) shows good agreement. The minimum pressurizer pressure and the time of its occurrence were predicted by CESEC to be 2194 psia and 62.4 seconds, respectively. (The recorded data values are 2191 psia and 51.4 seconds, respectively). The initial pressure drop predicted by CESEC provides an even better agreement between calculated and measured responses ((2250-2194=56 psi for CESEC) versus (2246-2191= 55 psi for test data)). The minimum hot leg temperature and the time of its occurrence were predicted by CESEC to be, respectively, within 1°F and 2 seconds of the measured values.

TABLE 7-1

Initial Conditions for the Full Length CEA(5-60) Drop Test

Core Power, Mwt	1391	(49.4%)
Core Inlet Coolant Temperature, °F	546	
Core Outlet Coolant Temperature, °F	577	
Vessel Mass Flow Rate, 10^6 lbm/hr	134.0	
Pressurizer Pressure, psia	2246	
Pressurizer Level, percent	39.1	
Steam Generator Pressure, psia	932	
Charging Flow, GPM	44.5	
Letdown Flow, GPM	39.6	
Control System Status:		
- Pressurizer Pressure	Automatic	
- Pressurizer Level	Automatic	
- Feedwater	Automatic	
- Steam Dump and Bypass	Automatic	

TABLE 7-2

Sequence of Events for the Full Length CEA(5-60) Drop Test

Time (sec)	Event	Value
0.0	CEA 5-60 trip breaker opened, CEA drop initiated	--
3.5	Asymptotic core power level achieved	36.5*
51.4	Minimum pressurizer pressure	2191 psia
152.	Minimum hot leg temperature	570°F
600.	Reactor stable at slightly reduced core average power level	43%

*Power recorded by ex-core neutron detector closest to the dropped CEA. Average core power is higher.

TABLE 7-3

CESEC Initial Conditions for the Full Length CEA(5-60) Drop Test

Core Power, Mwt	1388
Core Inlet Coolant Temperature, °F	547
Core Outlet Coolant Temperature, °F	577
Vessel Mass Flow Rate, 10^6 lbm/hr	122.0
Pressurizer Pressure, psia	2250
Pressurizer Water Volume, ft^3	469 (level = 39.1%)
Steam Generator Pressure, psia	932
Charging Flow, GPM	40.0
Letdown Flow, GPM	40.0
Control System Status:	
- Pressurizer Pressure	Automatic
- Pressurizer Level	Automatic
- Feedwater	Automatic
- Steam Dump and Bypass	Automatic

TABLE 7-4

CESEC Sequence of Events for the Full Length CEA(5-60) Drop Test

Time (sec)	Event	Value
0.0	CEA 5-60 trip breaker opened, CEA drop initiated	--
62.4	Minimum pressurizer pressure	2194 psia
150.0	Minimum hot leg temperature	571°F
1800.0	Final steadystate pressure	2252 psia

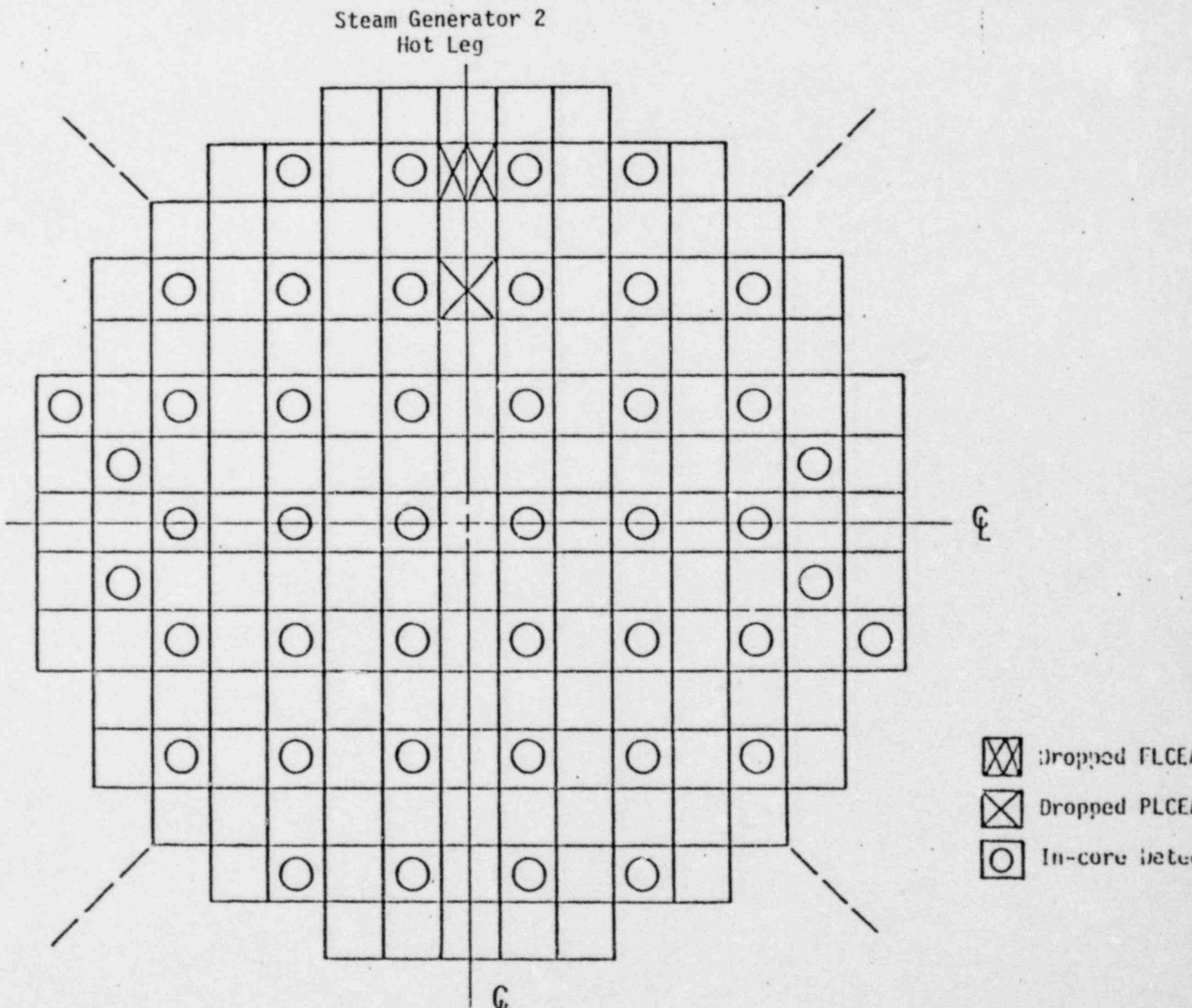

FIGURE 7-1. Dropped CEA Locations

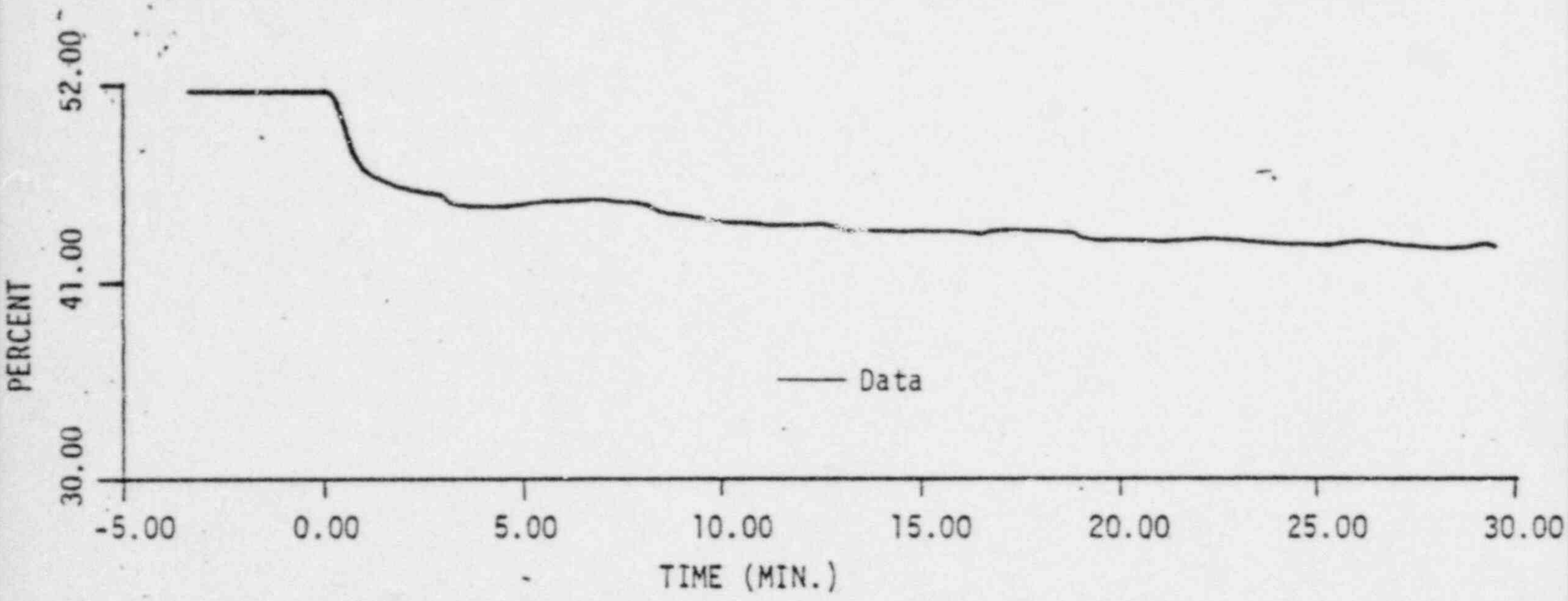

Figure 7-2. Full Length CEA Drop-Turbine Power

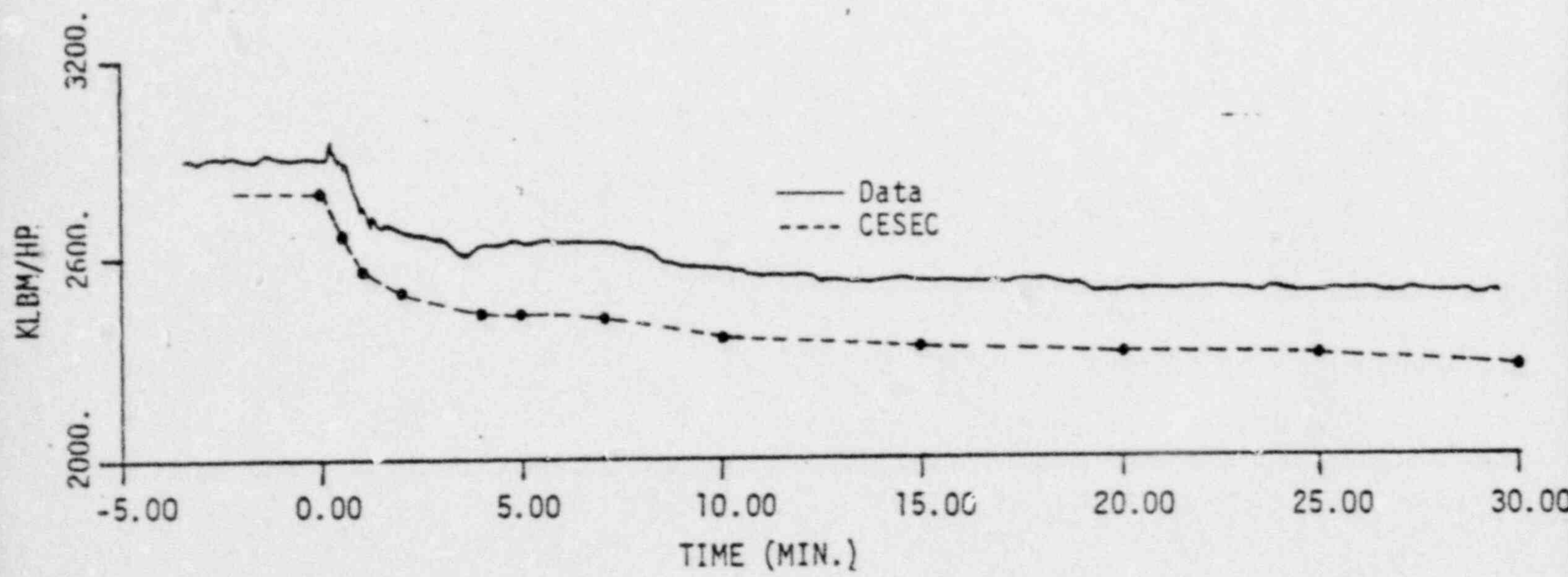

Figure 7-3. Full Length CEA Drop-Steam Generator 1 Main Steam Flow Rate

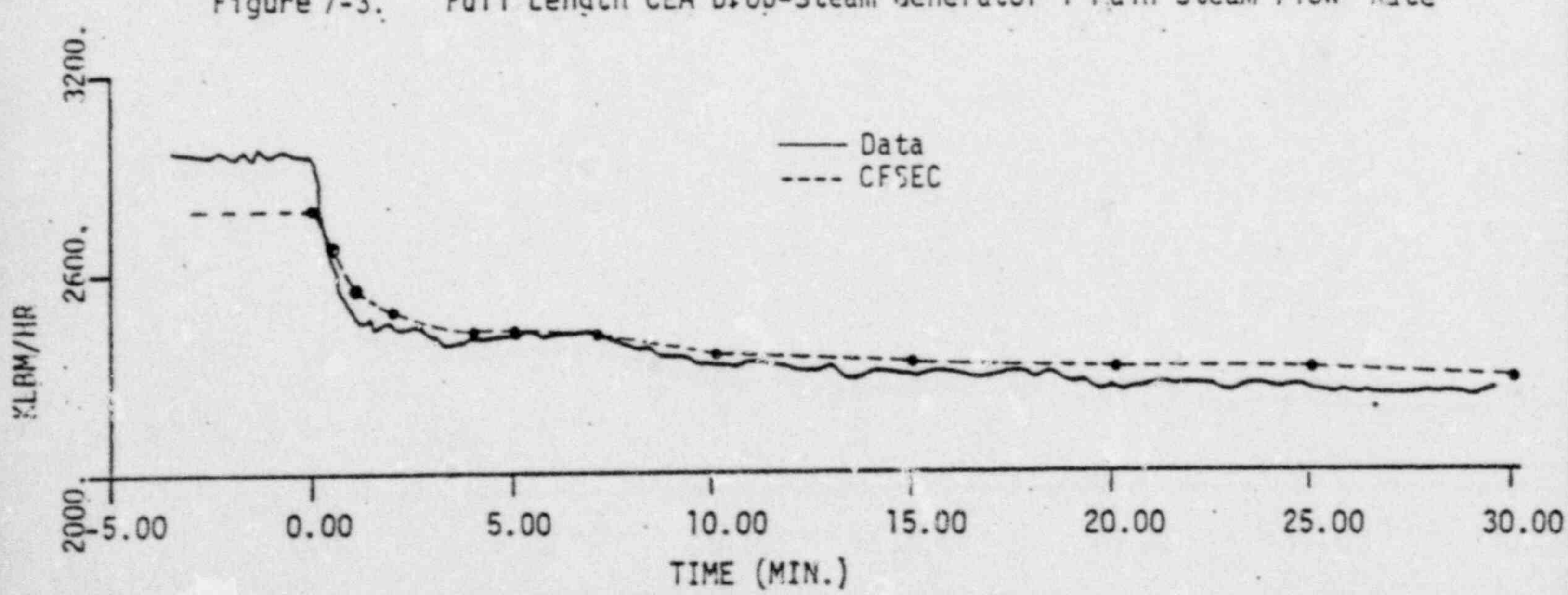

Figure 7-4. Full Length CEA Drop-Steam Generator 2 Main Steam Flow Rate

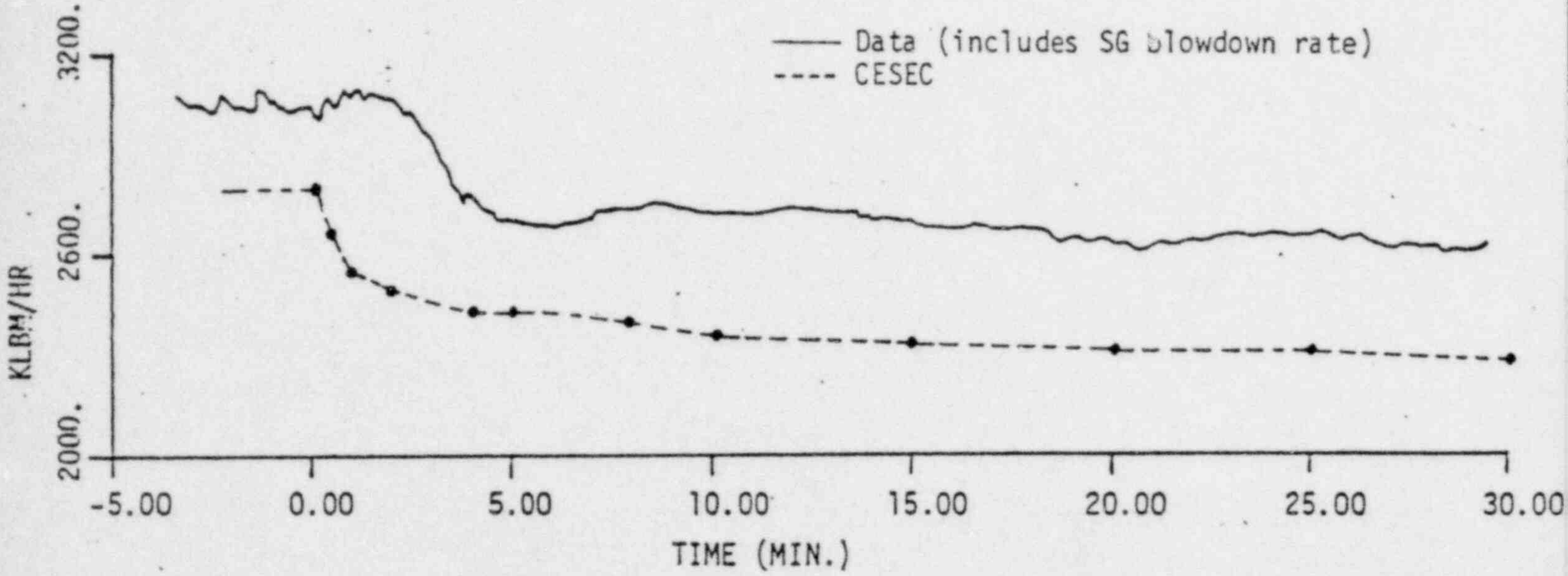

Figure 7.5. Full Length CEA Drop-Steam Generator 1 Feedwater Flow Rate

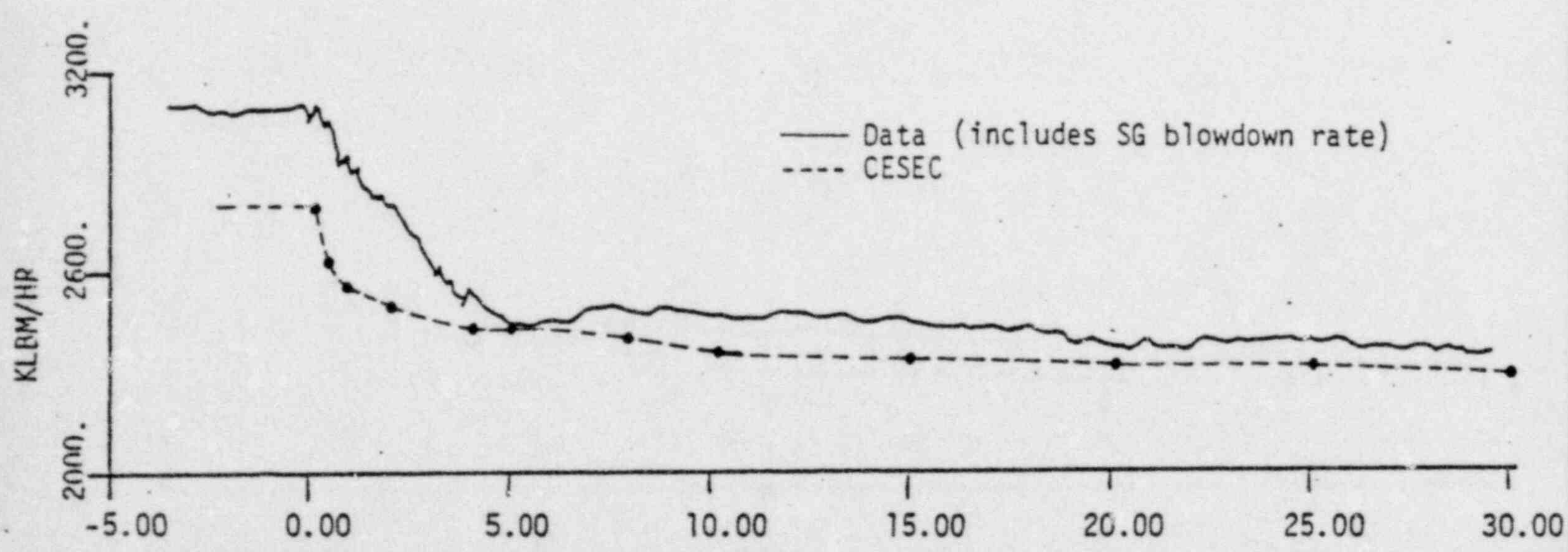

Figure 7-6. Full Length CEA Drop-Steam Generator 2 Feedwater Flow Rate

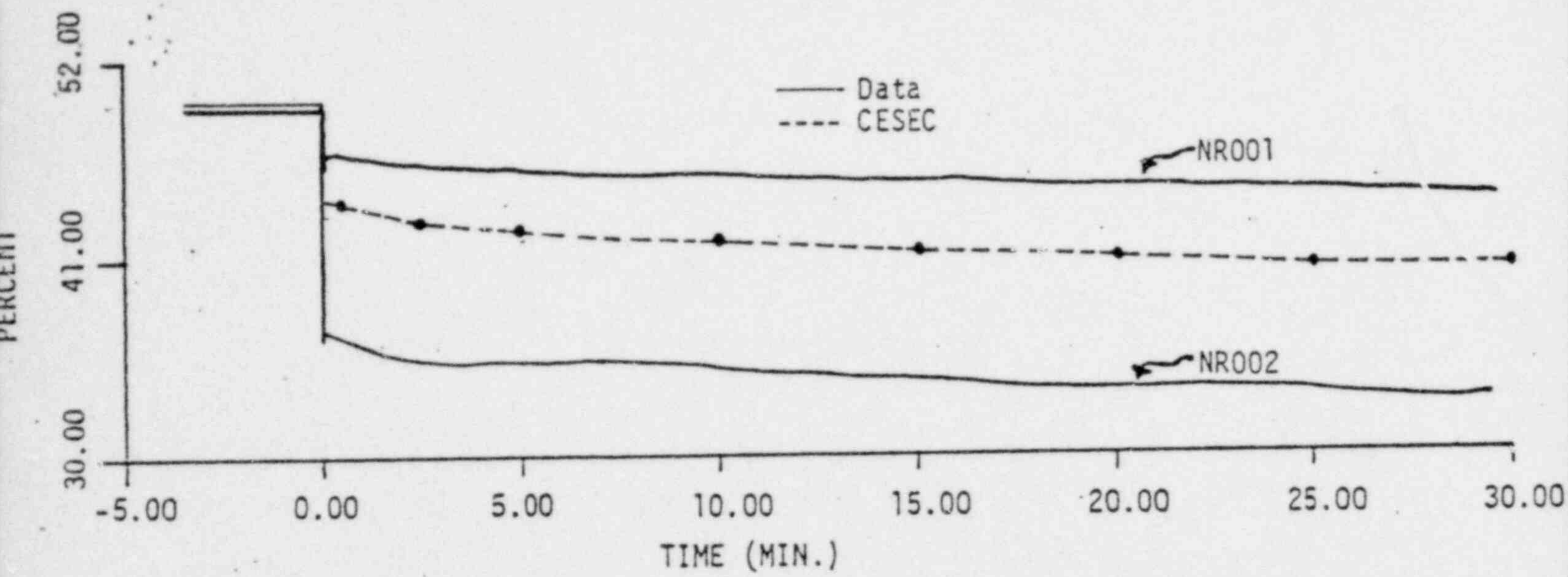

Figure 7-7. Full Length CEA Drop-Nuclear Power

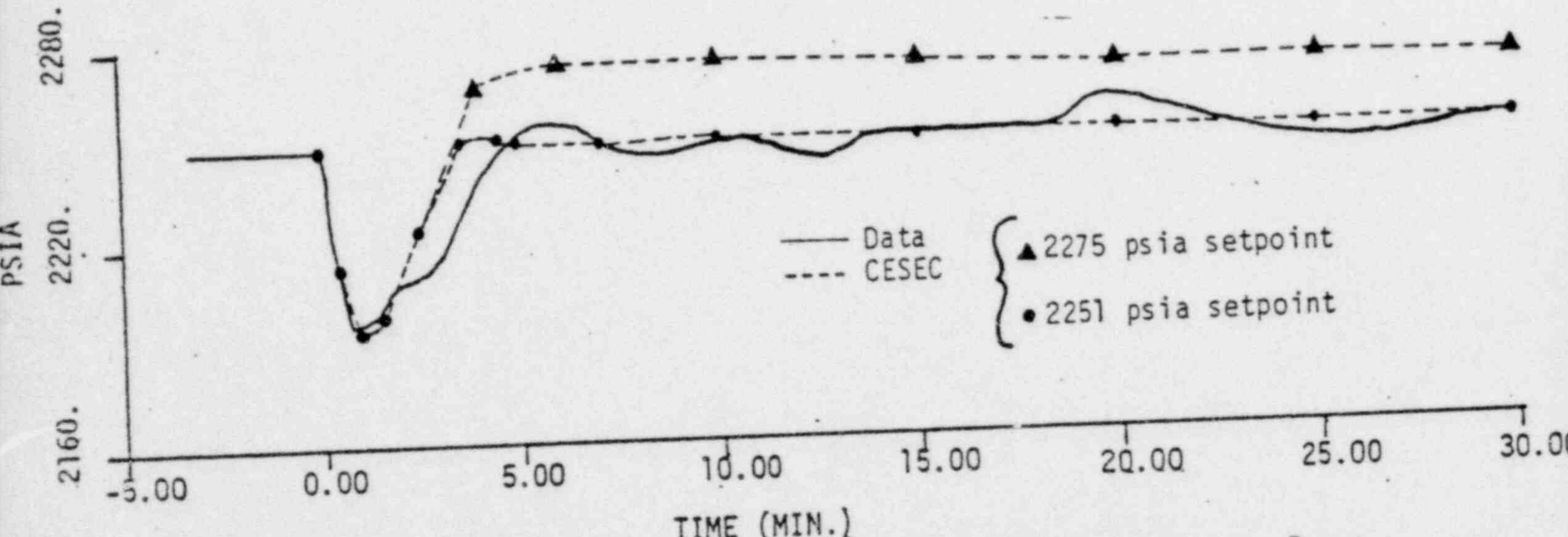

Figure 7-8. Full Length CEA Drop-Pressurizer Pressure, Narrow Range

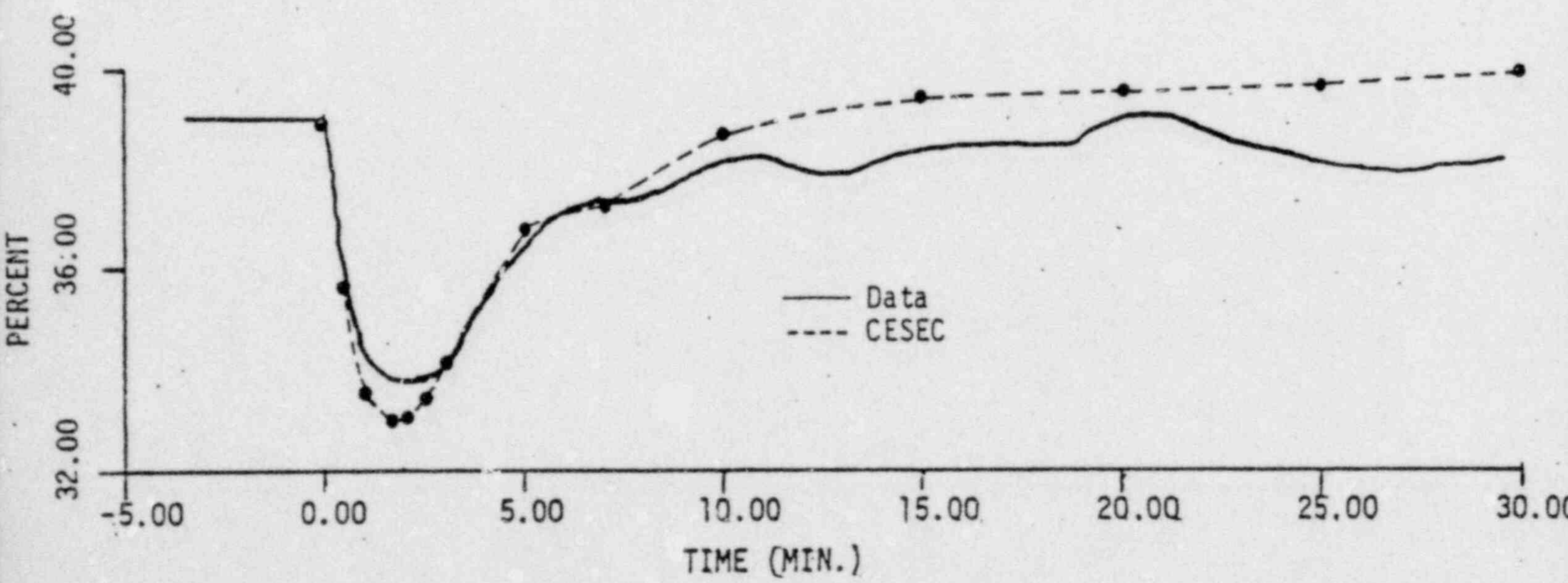

Figure 7-9. Full Length CEA Drop - Pressurizer Level

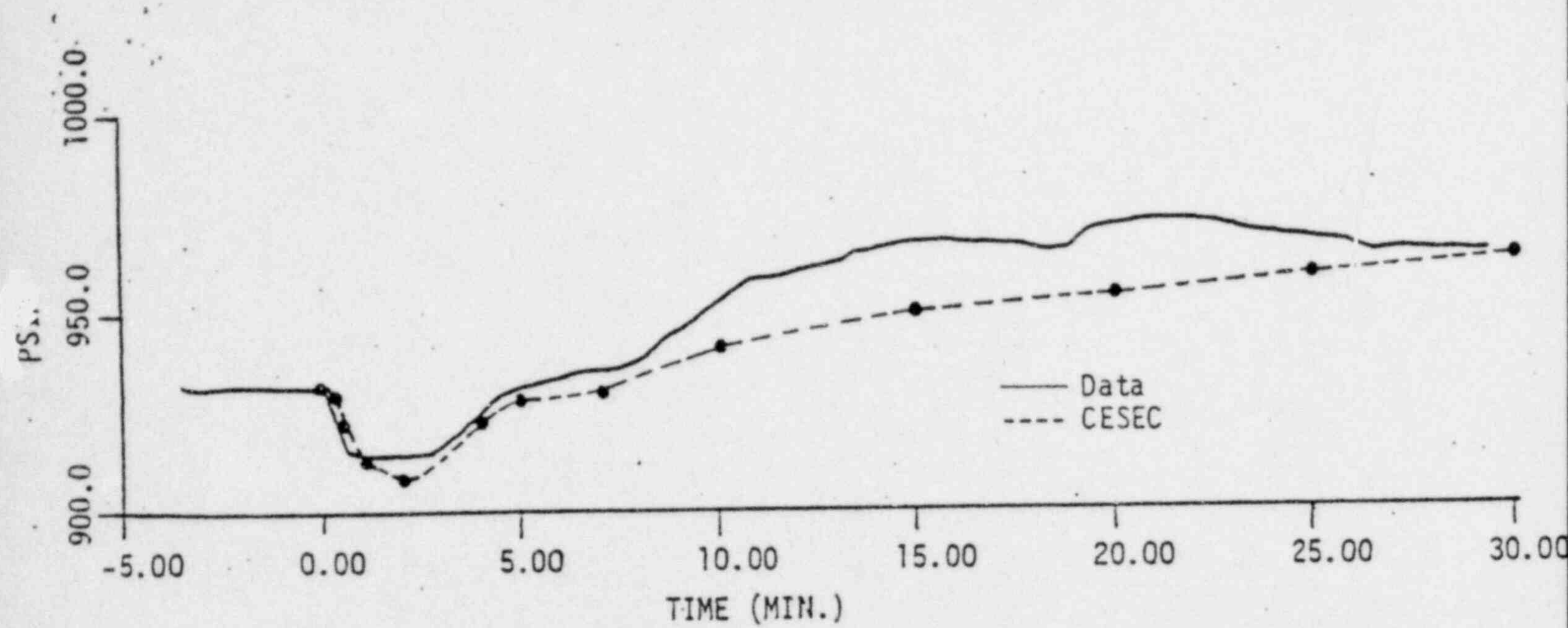

Figure 7-10. Full Length CEA Drop-Steam Generator 1 Pressure

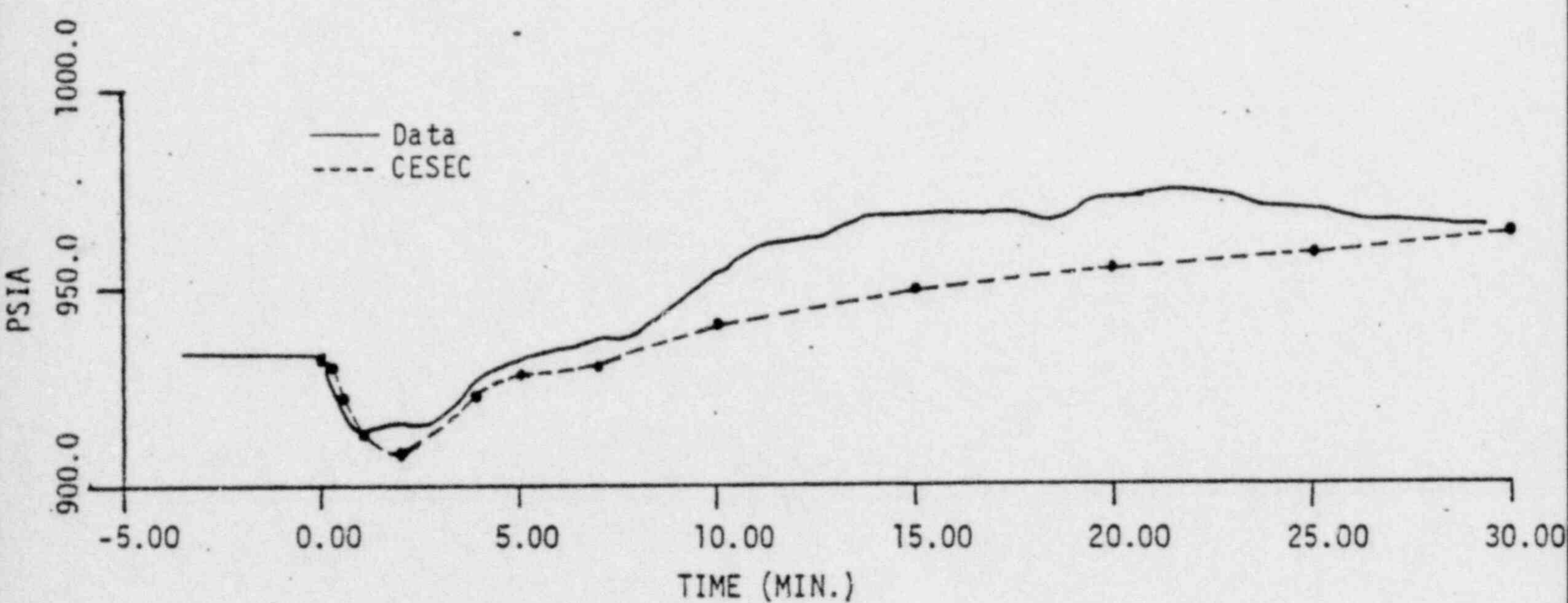

Figure 7-11. Full Length CEA Drop-Steam Generator 2 Pressure

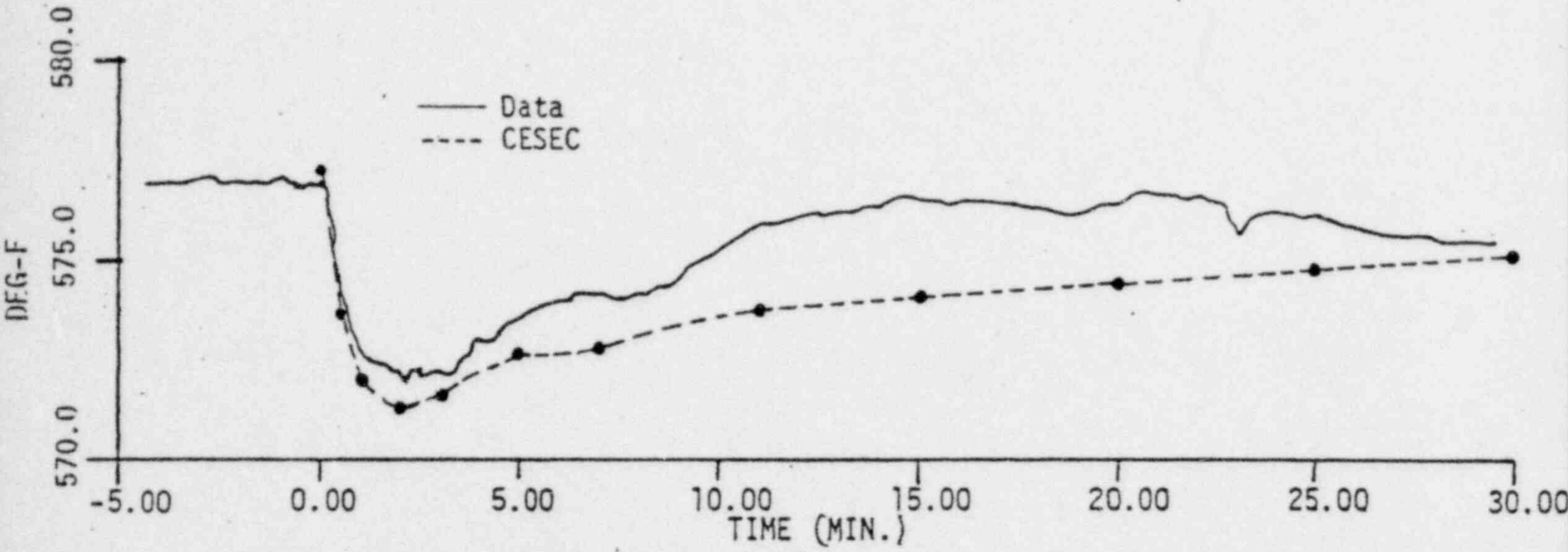

Figure 7-12. Full Length CEA Drop-Steam Generator 1 Hot Leg Temperature

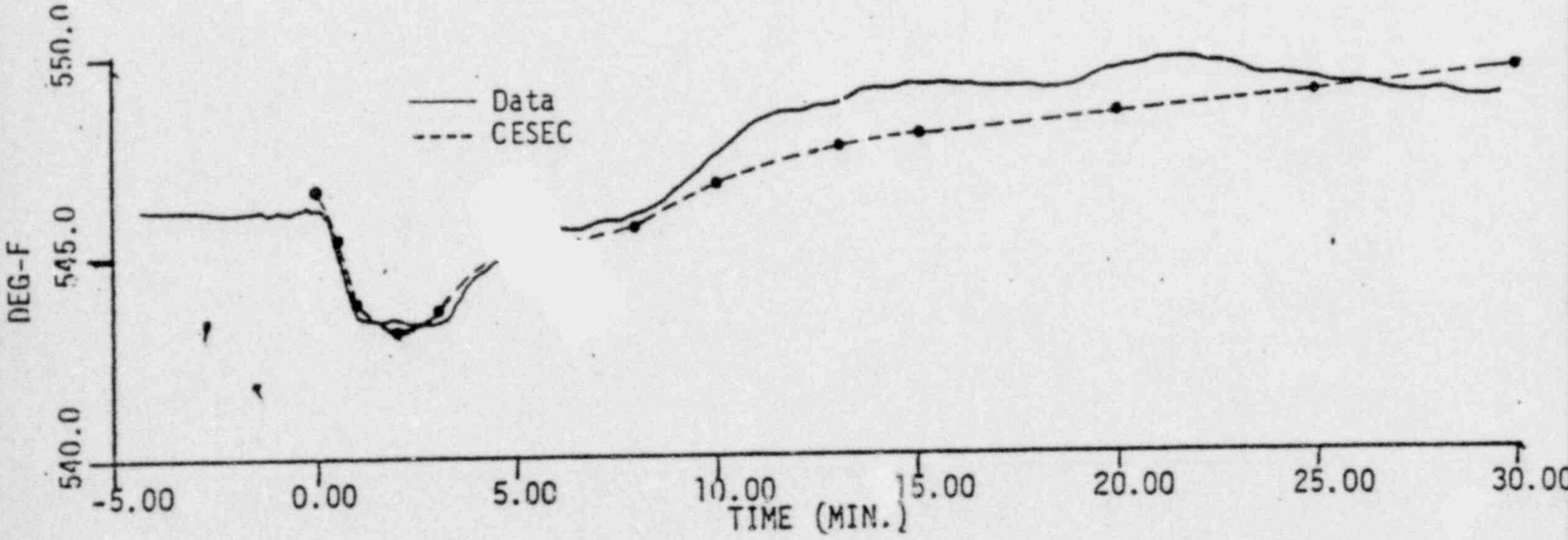

Figure 7-13. Full Length CEA Drop-Steam Generator 1 Cold Leg Temperature (Loop 1A

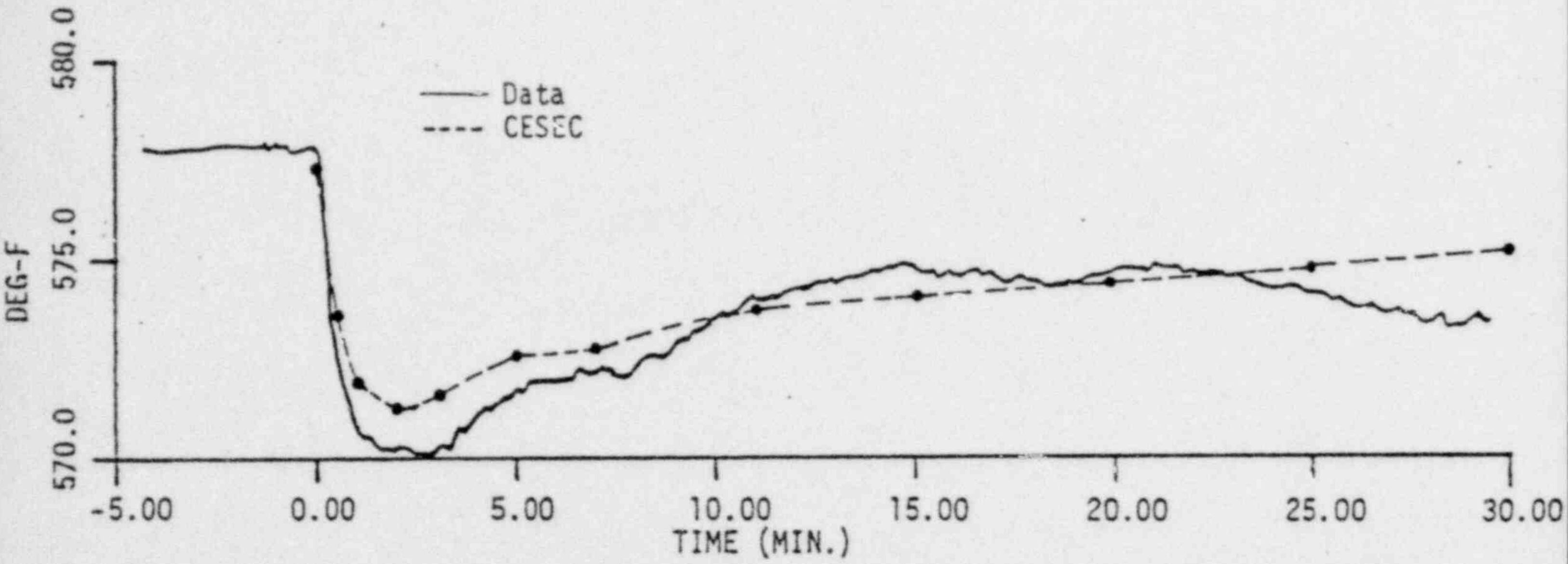

Figure 7-14. Full Length CEA Drop-Steam Generator 2 Hot Leg Temperature

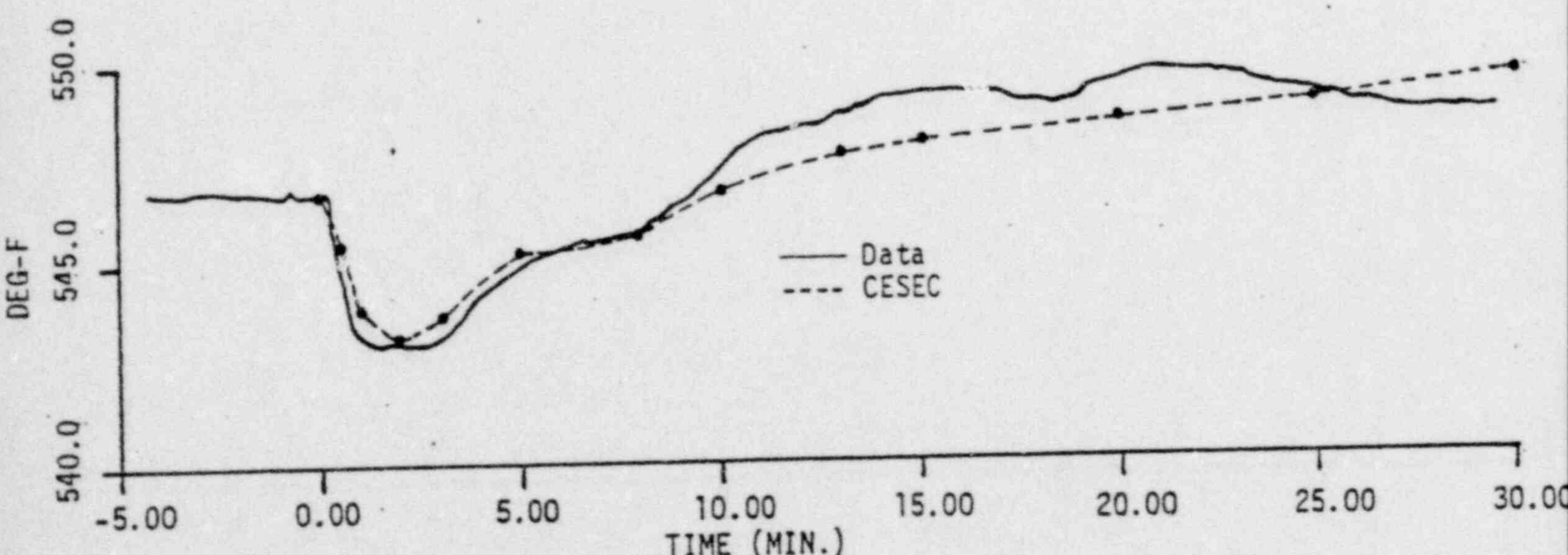

Figure 7-15. Full Length CEA Drop-Steam Generator 2 Cold Leg Temperature (Loop 2A

8.0 PART-LENGTH CEA DROP

8.1 SUMMARY

The PLCEA test performed during the ANO-2 power ascension programs was initiated from a power of 1384 Mwt (49.2%). The PLCEA test provides, the same as the FLCEA drop test, the NSSS response to a core reactivity event. The event was performed approximately twelve hours after the FLCEA drop test. All plant control systems except the reactor regulating system were in the automatic mode. The PLCEA selected was P-24 which is also aligned with the steam generator 2 hot leg (see Figure 7-1).

The insertion of the PLCEA resulted in an initial decrease in the reactor power. The power decrease was about half as for the FLCEA drop test, since the amount of negative reactivity inserted was smaller. The system response was similar to that observed for the FLCEA drop test. The operator again adjusted the turbine load limit to match the resulting average core power subsequent to the PLCEA being dropped in order to stabilize the NSSS response.

8.2 PRETEST PREDICTION

The CESEC pretest predictions for the PLCEA drop test are not fully comparable to the test results for the same reasons given in Section 7.2.

8.3 SEQUENCE OF EVENTS

The PLCEA drop test was initiated from the initial conditons shown in Table 8-1. The plant control system were all in the automatic mode except for the reactor regulating system. The reactor was stable with all rods out and a slight xenon oscillation of small amplitude and very long period relative to the transient and, thus, of negligible influence on the results.

The event was initiated by opening the CEA P-24 disconnect circuit breaker. Following the CEA drop, the core power and other system parameters initially decreased as observed for the FLCEA drop test. However, the initial decrease in the key parameters was smaller than for the FLCEA drop case, because of the smaller pertubation to the system. The operator again, as in the FLCEA drop test, took action to adjust the turbine load limit to match the reactor power to maintain a stable plant condition. However, unlike the smooth variation of the turbine load in the FLCEA drop test (Figure 7-2), a drastic drop in the turbine load for the PLCEA drop test was observed during the first minute of the event (Figure 8-1). This abrupt decrease in the turbine load (probably caused by a different operator and/or operator action) resulted in the subsequent pressurizer pressure increase in pressure for this test. Once the turbine load was returned to the value where it would balance the power generation, the pressurizer pressure decreased and started leveling off.

Table 8-2 presents a sequence of events for the FLCEA transient.

8.4 POST-TEST COMPARISON

The CESEC post-test comparison for the PLCEA drop test was performed using the initial conditions in Table 8-3. The CESEC initial conditions for this test are the same as those used in the CESEC simulation of the FLCEA drop test (Table 7-3). Therefore, remarks made in Section 7.4 regarding the initial conditions are also applicable for this test.

Preparation of the basedeck which was used in the simulation included similar assumptions to those discussed in Section 7.4. Basically, only the dropped CEA reactivity versus time table was changed to represent the variation with time of CEA P-24.

Figures 8-2 through 8-5 shows the comparison of the steam flows and feedwater flows as predicted by CESEC against the test data. The steam flow out of each steam generator follows the variation in the turbine load (Figure 8-1). The feedwater follows the steam flow. Observations made in Section 7.4 regarding the feedwater flow are also applicable for variation this comparison.

Figure 8-6 compares the power fraction as detected by the two nuclear power channels with the CESEC prediction. The CESEC prediction is within the range of uncertainty of the detectors in the low power range.

Figures 8-7 through 8-10 compare the CESEC RCS hot leg and cold leg temperatures with test data. The variation in the temperatures is small. this is consistent with the small pertubation introduced into the system.

Figures 8-11 and 8-12 show the comparison of the steam generators 1 and 2 pressure responses between CESEC and test data. Following the initial decrease in pressure, the subsequent pressure rise results from operator action in adjusting turbine load (Section 8.3). The difference in peak prssure is within the error range in the pressure measurement.

The pressurizer pressure and pressurizer level behavior are provided in Figures 8-13 and 8-14, respectively. The CESEC pressurizer pressure prediction compares very well to the plant data. Small deviations are within the 15 psi measurement error range. The difference in pressurizer pressure behavior between CESEC and test data after 10 minutes may have resulted from operator action (see Section 7-4 for similar comments). However, no operator actions, if any, were recorded. The pressurizer level prediction by CESEC is also good considering that the measurement of the water level exhibits a 1 percent error.

The sequence of events as predicted by CESEC is provided in Table 8-4. Key events predicted by CESEC agree well with data (minimum pressurizer pressure: 2236 psia at 29.0 seconds (CESEC) versus 2234 psia at 29.0 seconds (test data), maximum steam generator pressure:

949 psia at 83.2 seconds (CESEC) versus 957 psia at 83.8 seconds (test data), maximum pressurizer pressure: 2277 psia at 83.8 seconds (CESEC) versus 2280 psia at 85.7 seconds (test data)).

TABLE 8-1

Initial Conditions for the Part Length (P-24) CEA Drop Test

Core Power, Mwt	1384	(49.2%)
Core Inlet Coolant Temperature, °F	546	
Core Outlet Coolant Temperature, °F	577	
Vessel Mass Flow Rate, 10^6 lbm/hr	134.0	
Pressurizer Pressure, psia	2247	
Pressurizer Level, percent	39.4	
Steam Generator Pressure, psia	931	
Charging Flow, GPM	44.5	
Letdown Flow, GPM	36.4	
Control System Status:		
- Pressurizer Pressure	Automatic	
- Pressurizer Level	Automatic	
- Feedwater	Automatic	
- Reactor Regulating	Not Used	
- Steam Dump and Bypass	Automatic	

TABLE 8-2

Sequence of Events for the Part Length (P-24) CEA Drop Test

Time (sec)	Event	Value
0.0	CEA P-24 trip breaker opened; CEA drop initiated	--
2.4	Asymptotic core power level achieved	46.4%
29.0	Minimum pressurizer pressure	2234 psia
33.7	Minimum hot leg temperature	575°F
83.3	Maximum steam generator pressure	957 psia
85.7	Maximum pressurizer pressure	2280 psia
250.0	Reactor stable at slightly reduced core average power level	46%

TABLE 8-3

CESEC Initial Conditions for the Part Length (P-24) CEA Drop Test

Core Power, Mwt	1388
Core Inlet Coolant Temperature, °F	547
Core Outlet Coolant Temperature, °F	577
Vessel Mass Flow Rate, 10^6 lbm/hr	122.0
Pressurizer Pressure, psia	2250
Pressurizer Water Volume, ft^3	472 (level=39.4%)
Steam Generator Pressure, psia	932
Charging Flow, GPM	40.0
Letdown Flow, GPM	40.0
Control System Status:	
- Pressurizer Pressure	Automatic
- Pressurizer Level	Automatic
- Feedwater	Automatic
- Steam Dump and Bypass	Not used

TABLE 8-4

CESEC Sequence of Events for the Part Length (P-24) CEA Drop Test

Time (sec)	Event	Value
0.0	CEA P-24 trip breaker opened; CEA drop initiated	--
29.0	Minimum pressurizer pressure	2236 psia
31.2	Minimum hot leg temperature	576°F
83.2	Maximum steam generator pressure	949 psia
83.8	Maximum pressurizer pressure	2277 psia

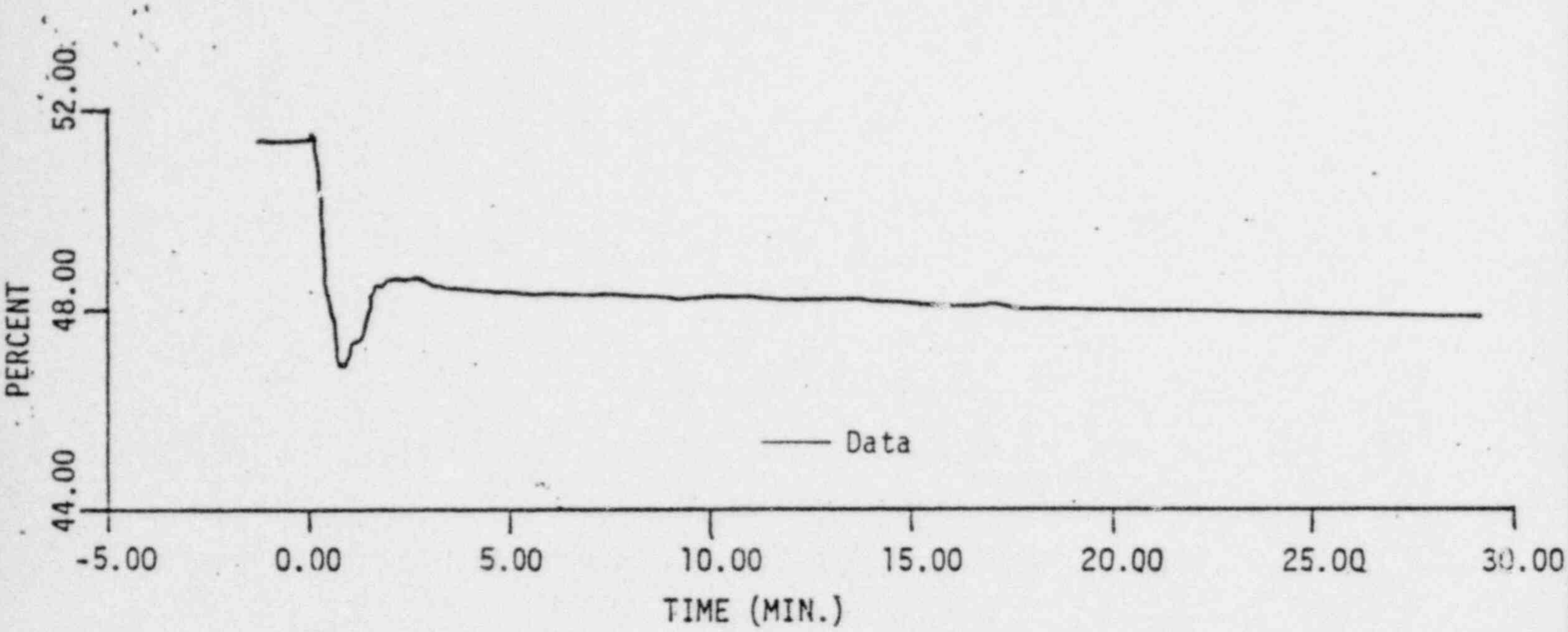

Figure 8-1. Part Length CEA Drop-Turbine Power

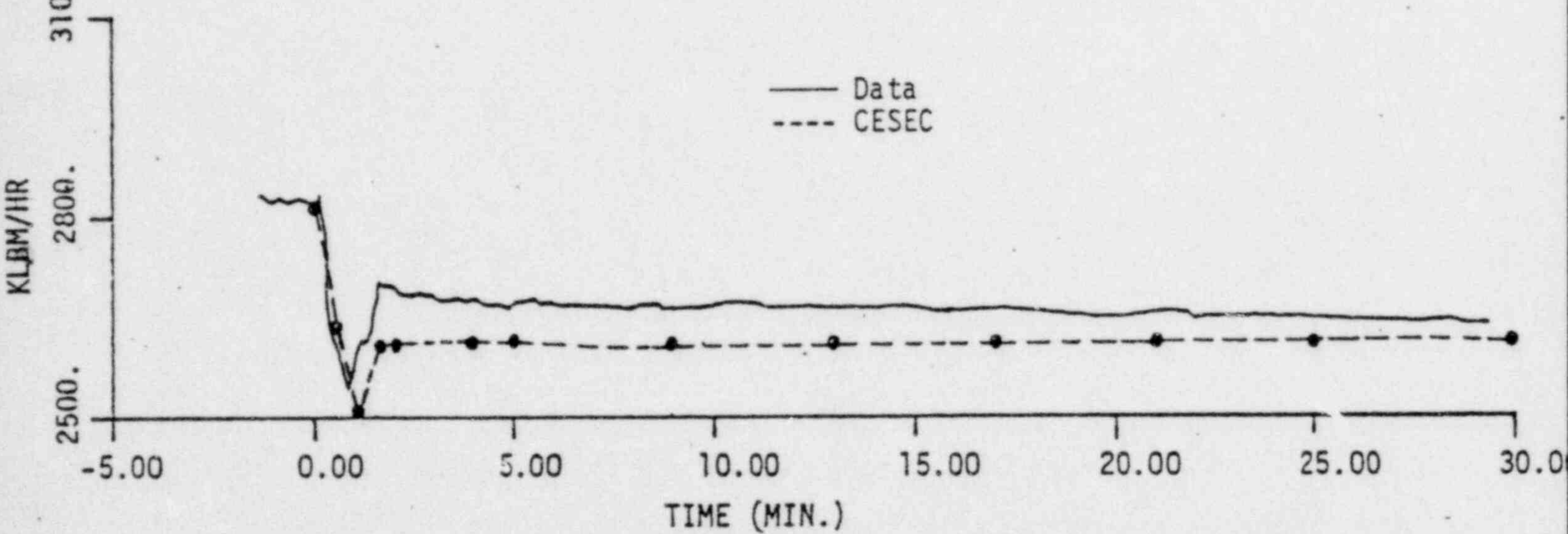

Figure 8-2 Part Length CEA Drop-Steam Generator 1 Main Steam Flow Rate

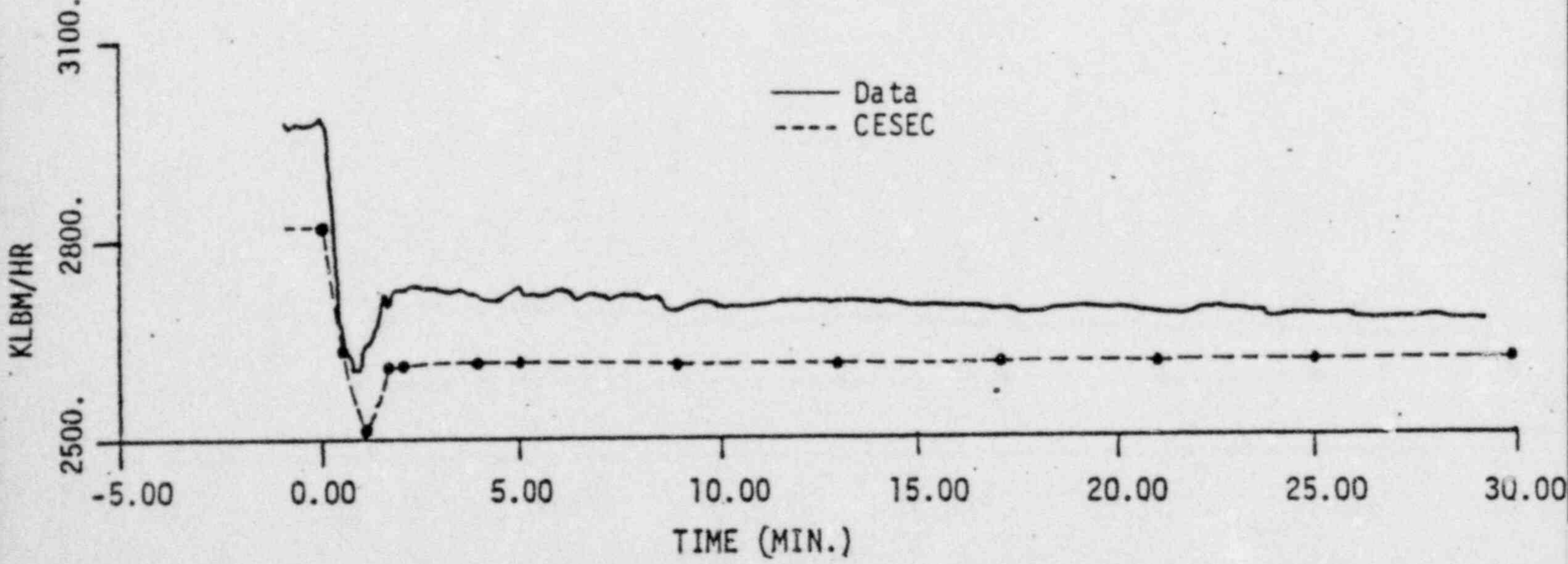

Figure 8-3. Part Length CEA Drop-Steam Generator 2 Main Steam Flow Rate

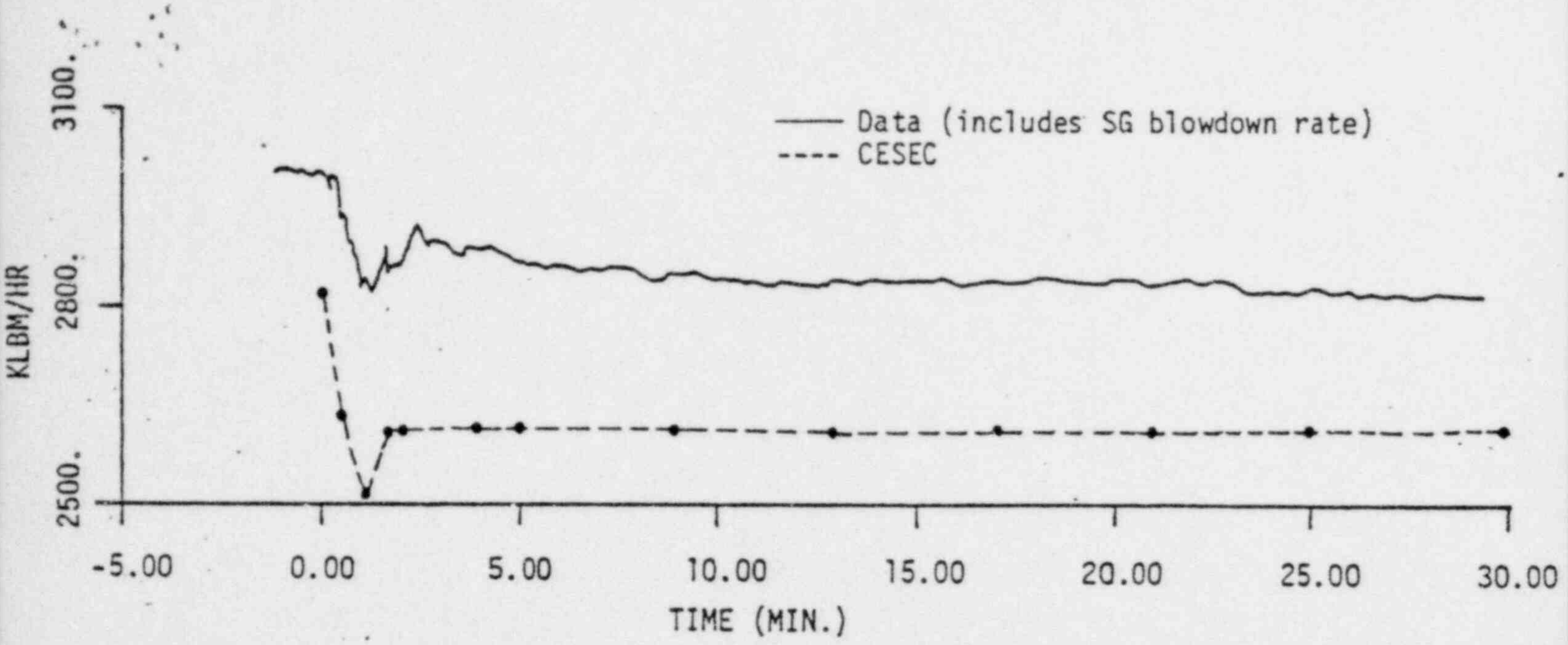

Figure 8-4. Part Length CEA Drop-Steam Generator 1 Feedwater Flow Rate

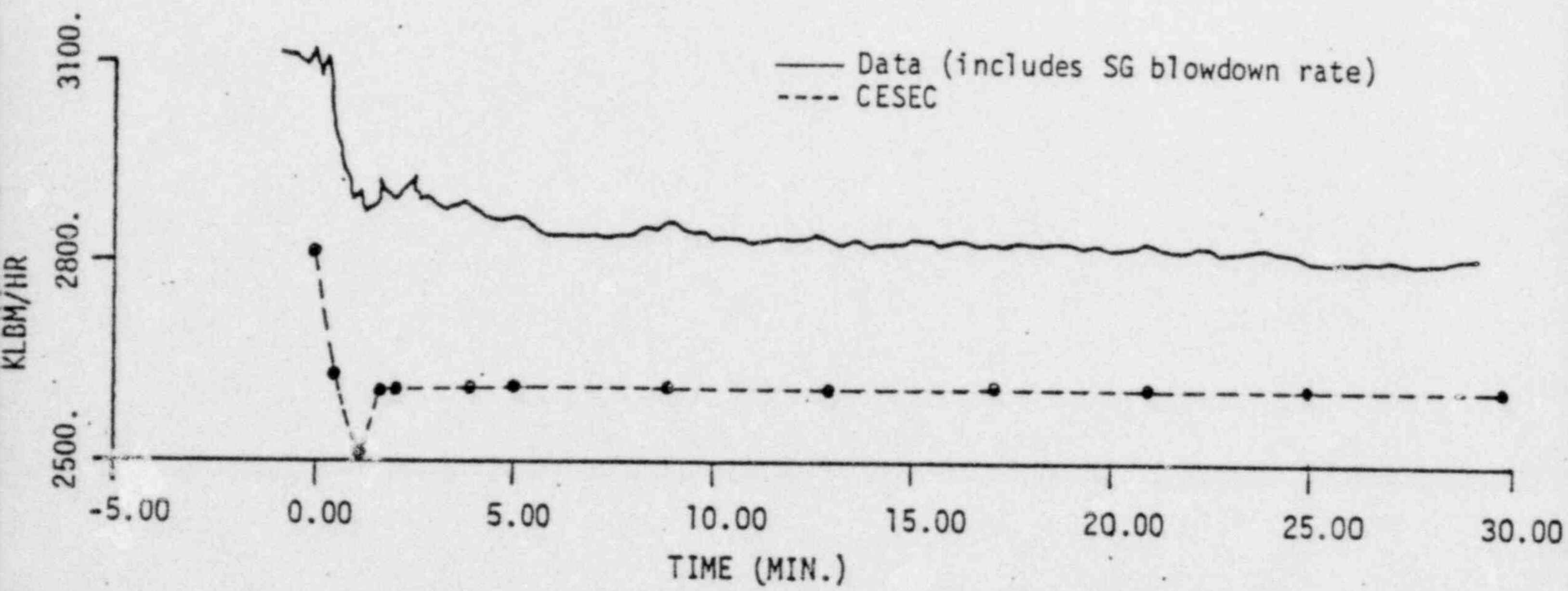

Figure 8-5. Part Length CEA Drop-Steam Generator 2 Feedwater Flow Rate

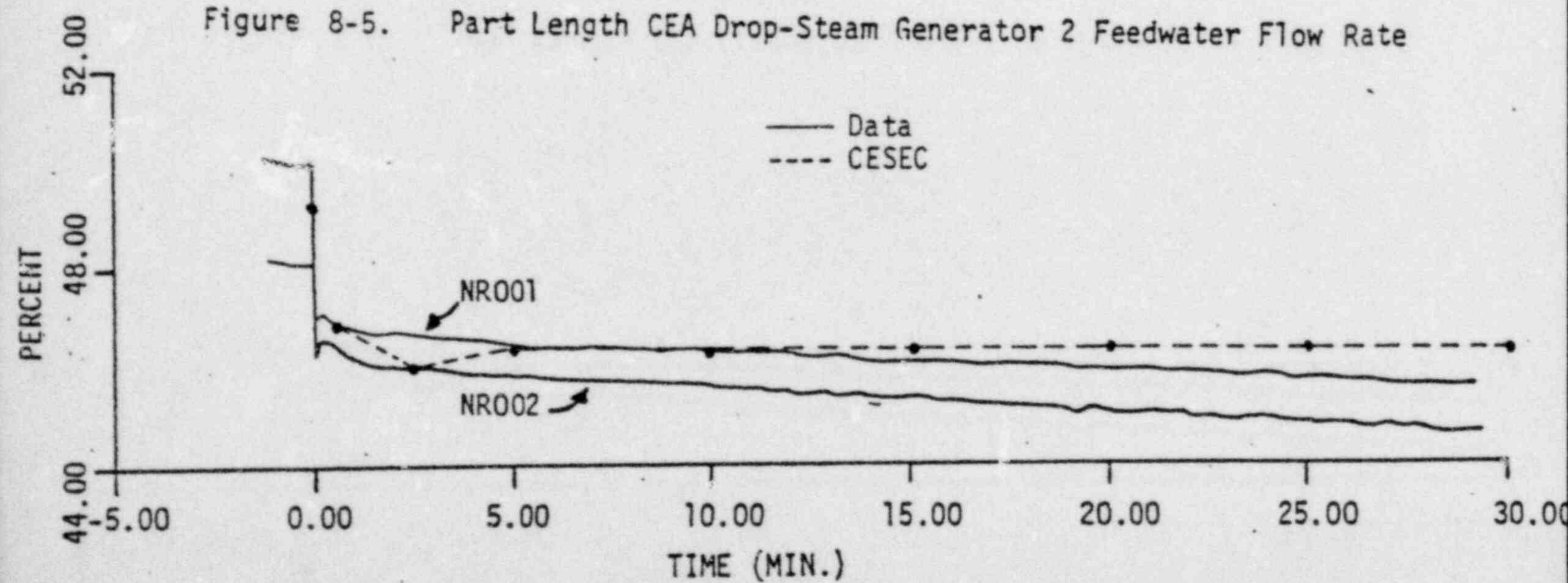

Figure 8-6. Part Length CEA Drop- Nuclear Power

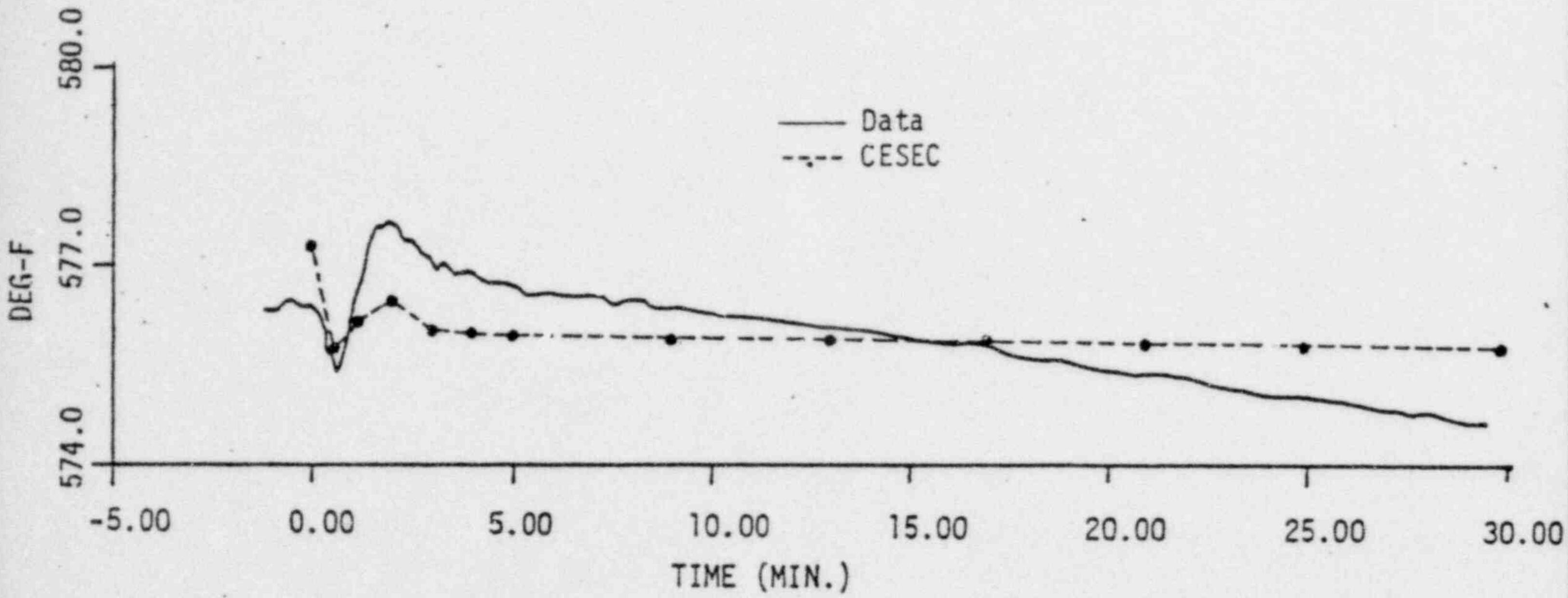

Figure 8-7. Part Length CEA Drop-Steam Generator 1 Hot Leg Temperature

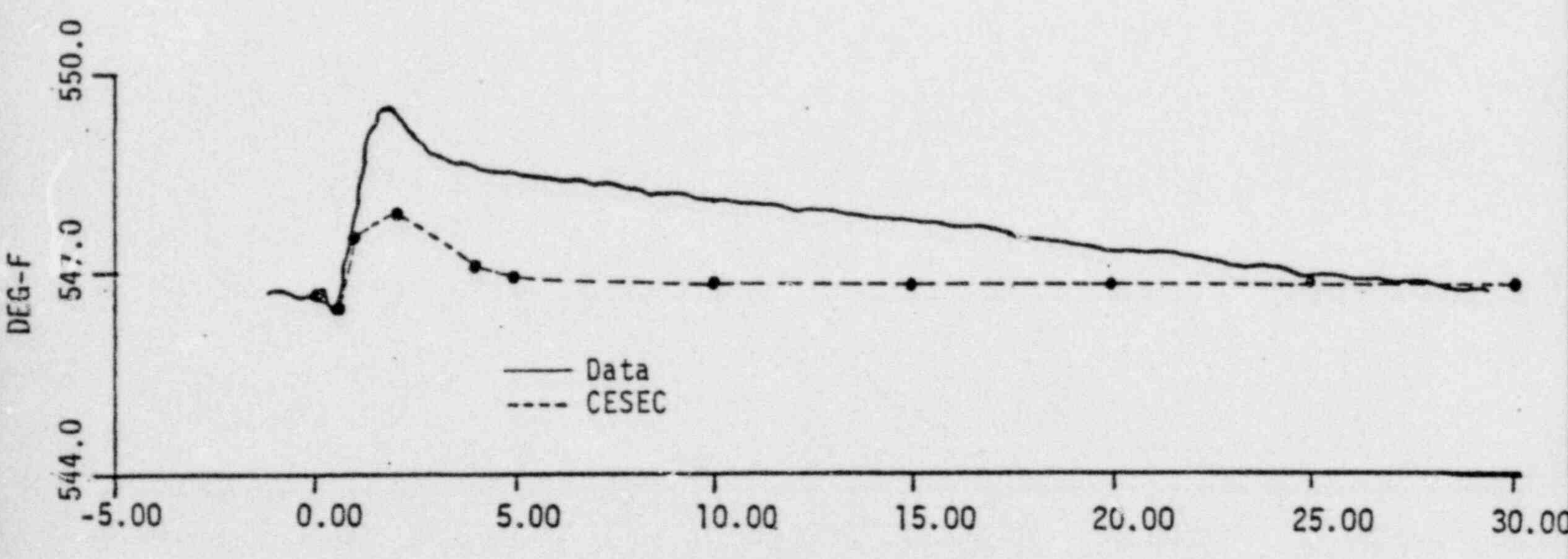

Figure 8-8. Part Length CEA Drop-Steam Generator 1 Cold Leg Temperature (Loop 1B)

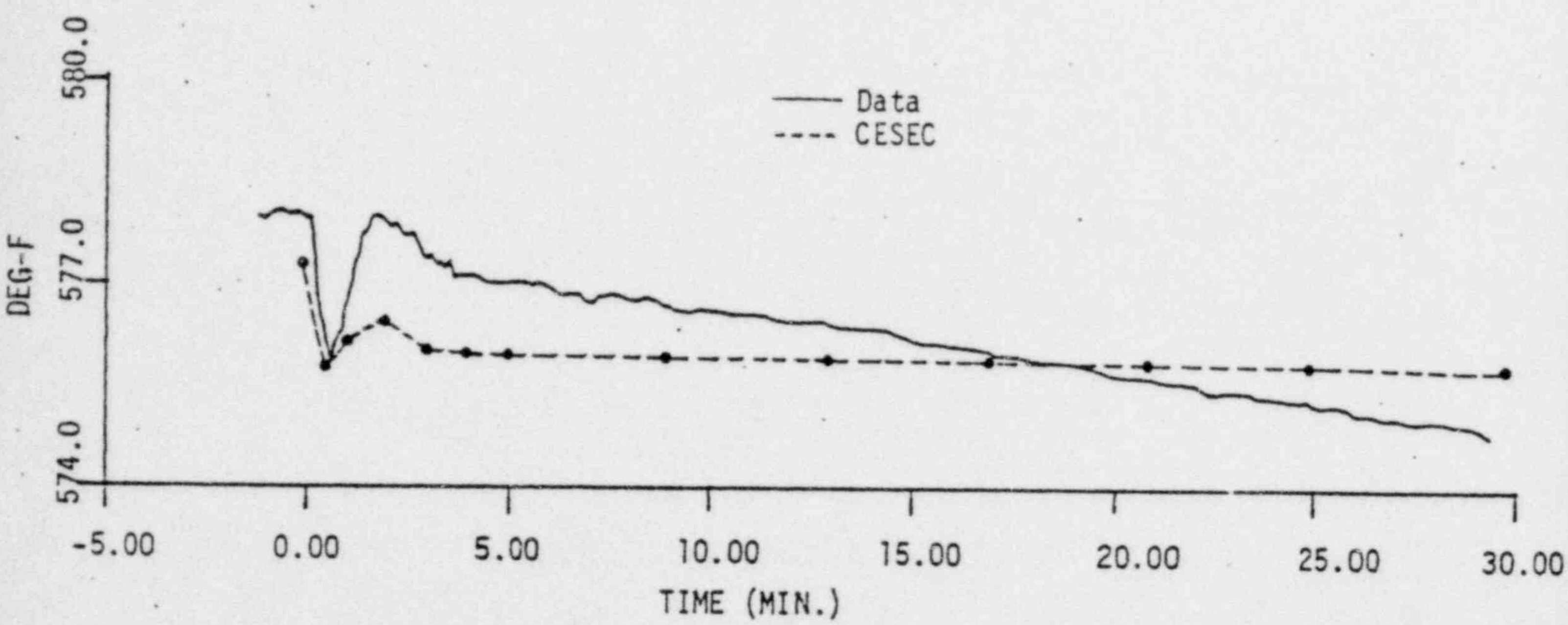

Figure 8-9. Part Length CEA Drop-Steam Generator 2 Hot Leg Temperature

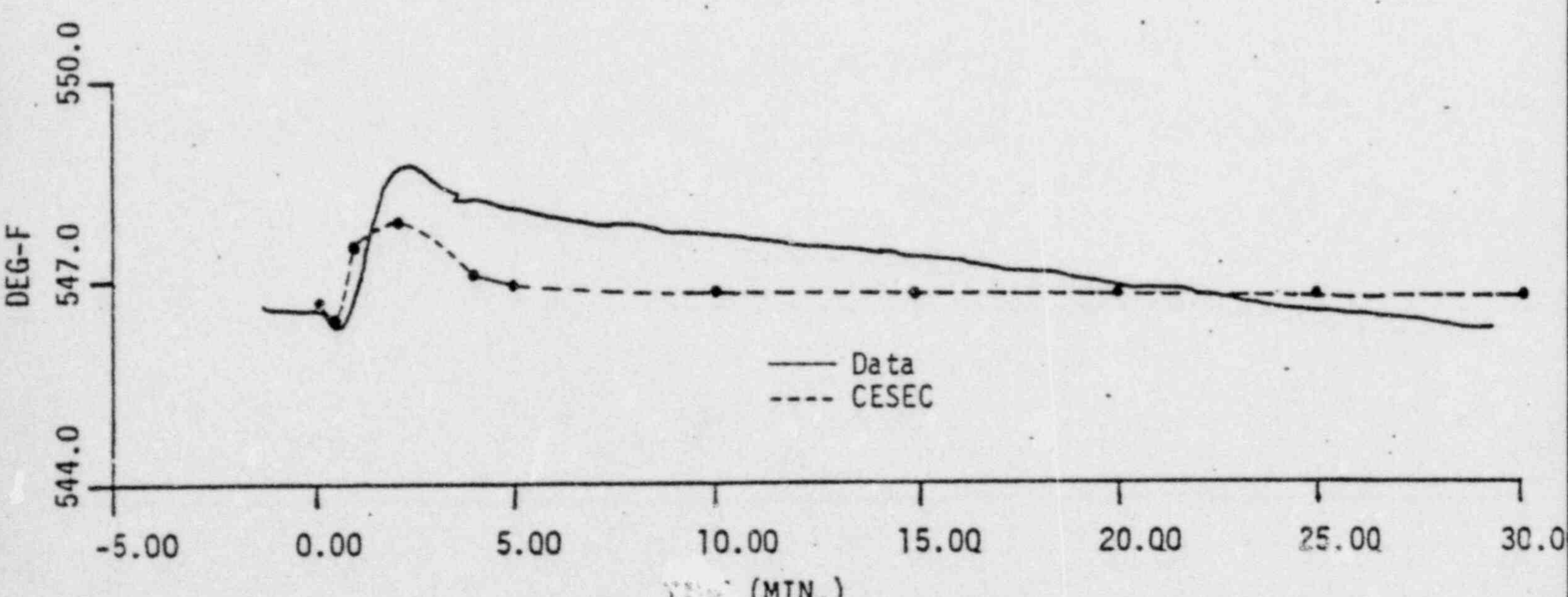

Figure 8-10. Part Length CEA Drop-Steam Generator 2 Cold Leg Temperature (Loop 2B

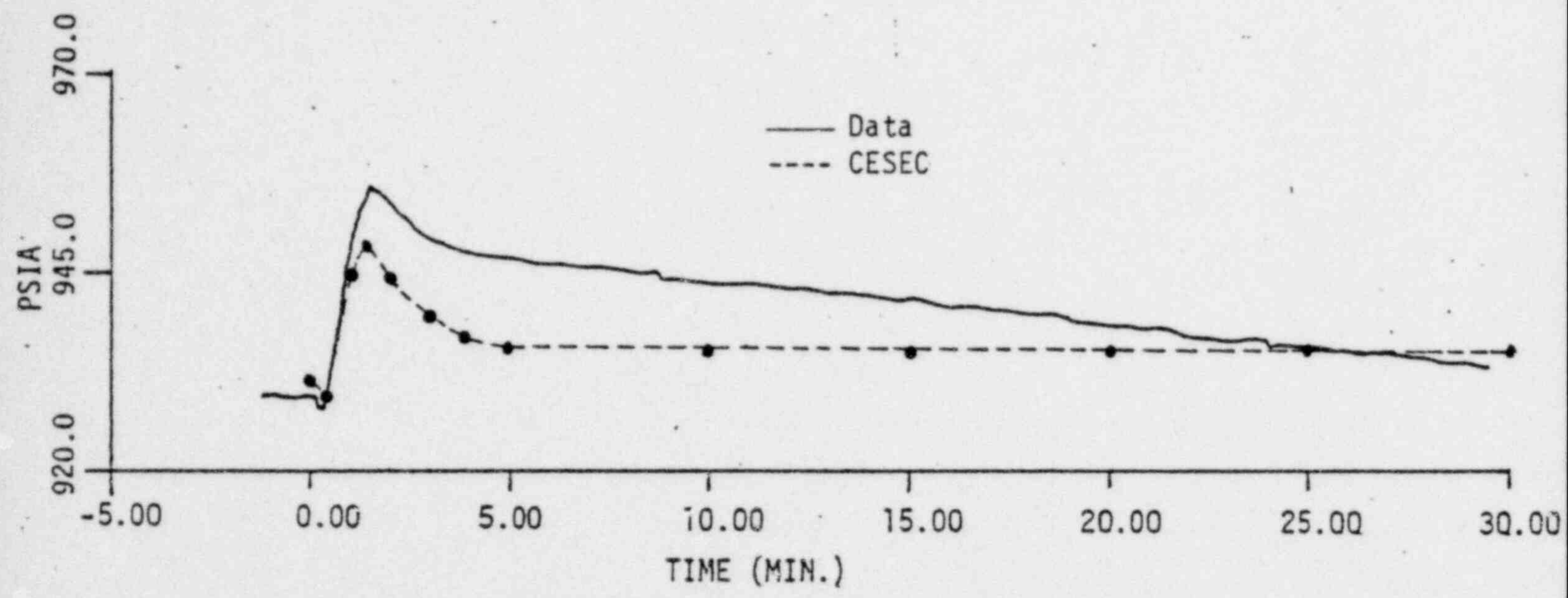

Figure 8-11. Part Length CEA Drop-Steam Generator 1 Pressure

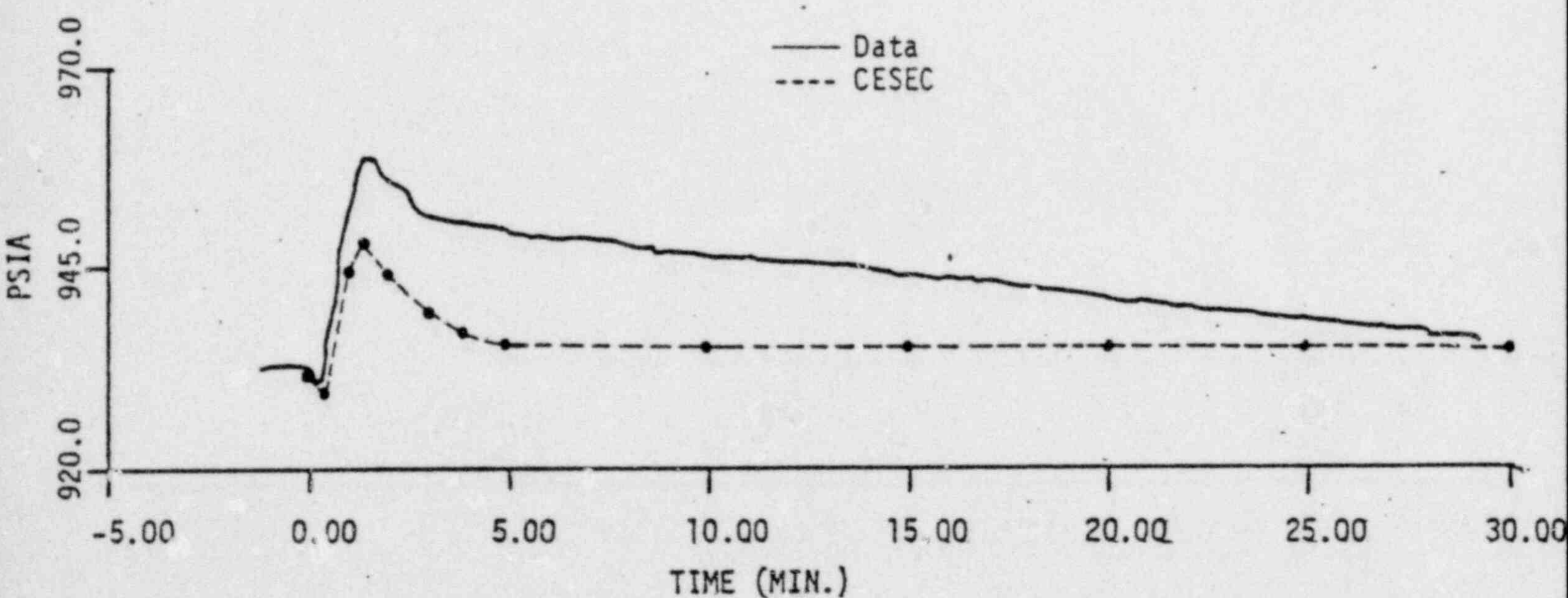

Figure 8-12. Part Length CEA Drop-Steam Generator 2 Pressure

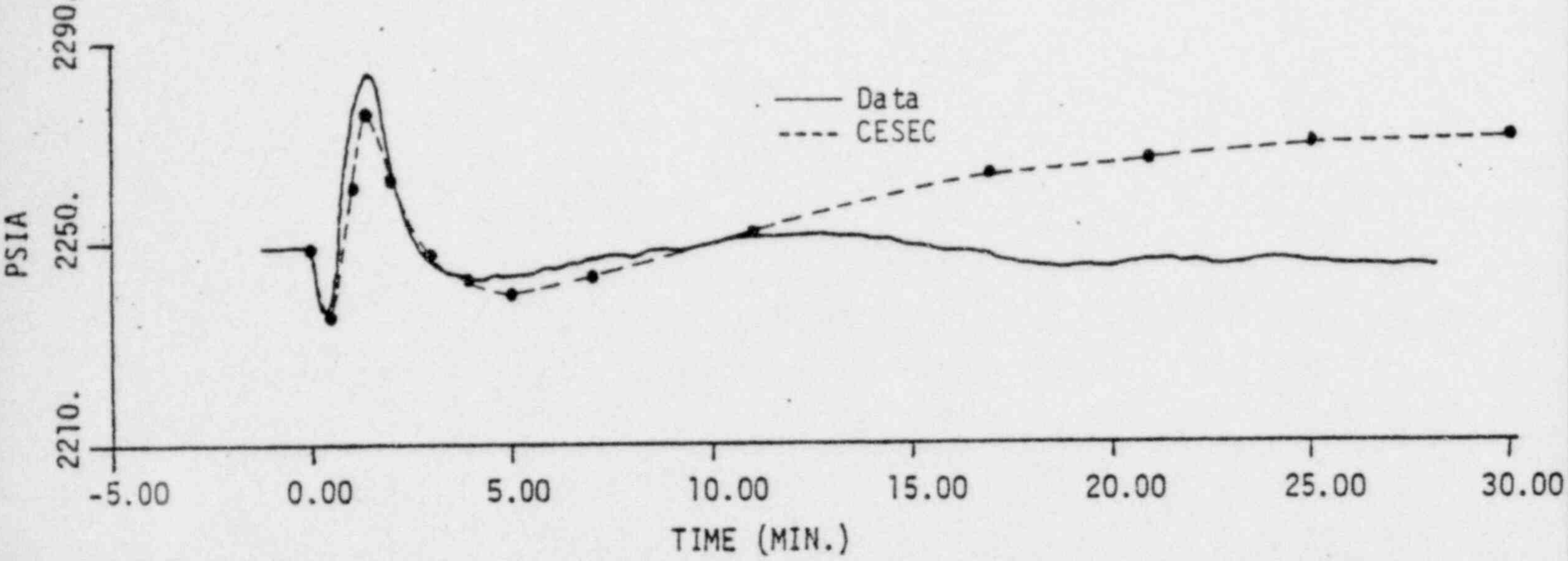

Figure 8-13. Part Length CEA Drop-Pressurizer Pressure, Narrow Range

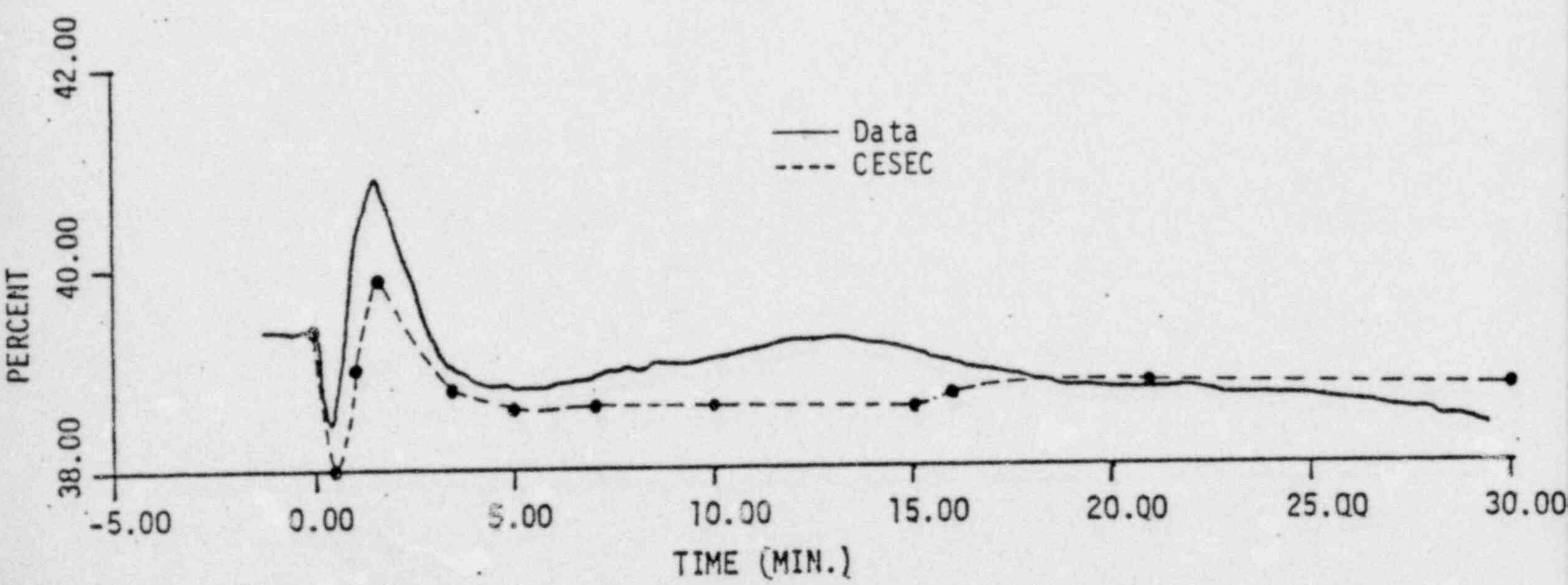

Figure 8-14. Part Length CEA Drop-Pressurizer Level

9.0 CONCLUSIONS

Observations that can be made concerning the results of this simulation are as follows:

1. CESEC is able to satisfactorily predict the transient response both qualitatively and quantitatively. The code was qualified against relevant test data and predicted results which are consistent with the physical assumptions made. Thus, assurance was obtained that the solution technique is stable, the solution is convergent, and that the code models, logic, and solution schemes appear to be correctly programmed.

2. CESEC deviations from test data are in most cases within the uncertainty of the measurement.

3. CESEC is basically a best estimate code. That is, the conservatism of the analysis performed in Chapter 15 of the safety analysis report for the non-LOCA events is mainly introduced through the input data rather than the code itself.

From this study it can be concluded that in CESEC C-E has a tool which is capable of predicting system response for PWR non-LOCA initiating events for a range of operating conditions. Thus, CESEC can be effectively used as a predictive tool for the non-LOCA events analyzed in Chapter 15 of the safety analysis report.

10.0 REFERENCES

1. CENPD-107, "CESEC: A Digital Simulation of a Combustion Engineering Steam Supply System", April, 1974.

2. J. F. Stolz (NRC) to W. Cavanaugh (AP&L), "Request for Additional Information", September 7, 1977.

3. J. F. Stolz (NRC) to W. Cavanaugh (AP&L), "Verification Testing for the CESEC Code", November 23, 1977.

4. "Arkansas Nuclear One-Unit 2 Final Safety Analysis Report", Arkansas Power and Light, Docket No. 50-368, May, 1974.