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Nuclear Steam Supply System Transient Tests at ANO-2 Revision 1

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Nuclear Steam Supply System Transient Tests at ANO-2
Revision 1

NP-1708, Revision 1
Research Project 1358-1

Final Report, September 1983

Prepared by

COMBUSTION ENGINEERING, INC.
C-E Power Systems
1000 Prospect Hill Road
Windsor, Connecticut 06095

Principal Investigators
D. P. Siska
M. L. Kantrowitz

Prepared for

Electric Power Research Institute
3412 Hillview Avenue
Palo Alto, California 94304

EPRI Project Managers
J. A. Naser
R. N. Whitesel

Analysis and Testing Program
Nuclear Power Division

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Prepared by
Combustion Engineering, Inc.
Windsor, Connecticut

EPRI PERSPECTIVE

PROJECT DESCRIPTION

This report under RP1385-1, together with two companion reports, documents a series of test runs at Arkansas Nuclear One Unit-2 (ANO-2). The companion documents are EPRI Final Reports NP-1707, NSSS Design and Cycle 1 Operating History Data for Arkansas Nuclear One, Unit-2 and NP-1709, Reactor Transient Tests at ANO-2. These transient tests consisted of (1) complete loss of forced circulation from an operating power level near 80% of rated power, (2) drops of part-length and full-length control element assemblies from operating power levels near 50% of rated power, and (3) a turbine trip from an operating power level near 100% of rated power.

PROJECT OBJECTIVE

The objective of these transient tests is to gather high-quality data from an operating nuclear power plant for use in qualification of reactor system transient analysis computer codes such as RETRAN and MEKIN. Since ANO-2 is a PWR, these tests are complementary to the turbine trip and plant stability tests performed at Peach Bottom-2 BWR in 1977 and 1978 (EPRI Topical Reports NP-563 and NP-564 and EPRI Final Reports NP-971 and NP-972). The objective of these activities was to provide a basis for increased confidence in the ability of RETRAN, MEKIN, and other industry computer codes to predict the course of various operating transients.

PROJECT RESULTS

This report was revised to rectify a number of problems with the original publication. The digital filtering algorithm used on the data for all except the turbine trip test added time delays in the data. In some cases, since the filtering began before time zero of the transient, the initial trend of the data was in the incorrect direction.

In this revised report, for some cases this digital filtering was eliminated. This was usually in regions where the data changed rapidly since this is where the filtering was most misleading. In addition, the unfiltered data have been shown in all cases with the filtered data superimposed to allow a direct evaluation of the effects of the filtering algorithm. In other cases, the data from the data acquisition

system were not available over parts of the transient, and other data were used without identifying where this occurred. This, as well as from where the additional data was obtained is now identified.

Finally, some curves were previously presented, such as reactor coolant flow rates, that were calculated values without identifying how they were calculated or from what data (i.e., reactor coolant pump differential pressures and speeds). In this revision the calculational algorithms and data are included. The additional details of data in this revision are essential for comparing code-calculated results to the measured data.

In addition to these three companion reports, the data from each of the four tests were organized in files on a magnetic tape. This information will be useful and available to utility engineers who wish to model the ANO-2 system and test the ability of some particular transient analysis computer code to predict the measured data.

Joseph A. Naser, Project Manager
Robert N. Whitesel, Project Manager
Nuclear Power Division

FOREWORD

A comprehensive set of plant transient test data, derived from a series of four tests performed at Arkansas Nuclear One - Unit 2, are provided herein. These data are intended for use in the qualification of Nuclear Steam Supply System simulation codes. Two companion reports, "ANO-2 NSSS Design and Cycle One Operating History Data" and "Reactor Transient at ANO-2" document other design and test data which may be used in conjunction with this report.

Michael J. DiMonte
Program Manager
C-E Power Systems
Combustion Engineering, Inc.

Joseph A. Naser
Robert N. Whitesel
Project Managers
Electric Power Research Institute

ABSTRACT

This report documents experimental data generated from a series of plant transient tests performed at Arkansas Nuclear One - Unit 2 during December 1979 and January 1980. Four tests were conducted: complete loss of forced primary coolant flow, full length control element assembly (CEA) drop, part length CEA drop and turbine trip. These tests are part of a program to obtain plant transient test data which will be used for simulation code qualification. A companion report, "ANO-2 Design and Cycle 1 Operating History Data" provides the detailed plant layout data required for the simulation of the transients reported herein. The plant transient test program is jointly funded by Arkansas Power and Light, Combustion Engineering and the Electric Power Research Institute.

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SUMMARY

Four plant transient tests were performed at Arkansas Nuclear One - Unit 2 as part of the initial power ascension test program. The principal objective in performing these tests was to add to the data base used by the electric power industry for the qualification of computer codes which are used in the design and safety analysis of nuclear steam supply systems employing a Pressurized Water Reactor (PWR).

The principal dynamic measurements from all four tests were recorded using a PDP-11 minicomputer and the existing plant instrumentation. Off-line data reduction, digital filtering and plotting of the process parameters were also performed with the minicomputer.

The data provided herein represent typical PWR transients and establish a more comprehensive data base of integral test data than was previously available for PWR simulation code qualification.

Section 1

INTRODUCTION

OBJECTIVES

This report documents the results of a series of plant transient tests performed at Arkansas Nuclear One-Unit 2 (ANO-2) during December, 1979, and January, 1980. The principal objective in performing these tests was to add to the data base used by the electric power industry for qualifying computer codes which are used in the design and safety analysis of nuclear steam supply systems (NSSSs) employing a Pressurized Water Reactor (PWR). The tests included in this program represent typical PWR transients so that the computer codes can be qualified in a comprehensive manner. The data recorded during these tests are expected to improve the confidence in the accuracy of computer codes used in the design and safety analysis of PWR equipped NSSSs.

BACKGROUND

In accordance with general design criteria (1) established by the Nuclear Regulatory Commission (NRC), all NSSSs built in the United States must meet a specific set of acceptance criteria for each of a wide range of postulated events. These design basis events (DBEs) are evaluated using computer codes to simulate the dynamic response of the reactor core and the NSSS. Since the overall acceptability of the NSSS design is contingent upon showing acceptable results for each of the DBEs, these codes must provide a realistic representation of the actual NSSS response.

In assessing the overall accuracy of the simulation codes, it is important to compare the calculated transient response of the NSSS with experimental data. Prior to the performance of these tests, there was little in the way of a data base available in the public literature for that purpose. Separate effects tests, which are useful when examining a specific model or section of a code, are not in themselves sufficient, since they cannot account for the numerous feedback mechanisms inherent in such a complex system. Other data, such as those obtained during startup testing, are intended to determine the acceptability of the overall plant performance and are generally not suitable for computer code qualification. This program, therefore,

establishes a data base of integral test data which may be used for comparison with NSSS simulation codes for the purpose of computer code qualification.

TEST PLAN

Four NSSS transient tests were performed at the ANO-2 PWR as part of the initial power ascension test program. The tests were: a complete loss of forced primary coolant (LOF), full length CEA drop (FLCEAD), part length CEA drop (PLCEAD), and a turbine trip (TT). This combination of tests provides a diverse set of NSSS transient conditions suitable for simulation code qualification.

The LOF was initiated from approximately 80 percent power by simultaneously tripping all four reactor coolant pumps. This test is aimed at measuring the NSSS response to a power/cooling mismatch transient initiated from the primary system. An accurate recording, and subsequent computer code simulation, of the NSSS response to this event is important since the LOF is a design basis event which results in rapid changes to the core heat flux.

The FLCEAD and PLCEAD tests were initiated from approximately 50 percent power by opening the disconnect circuit breaker providing power to the appropriate control element drive mechanism. These tests are aimed at measuring the NSSS response to a core reactivity event. The CEA locations chosen for these tests are aligned with steam generator 2 hot leg (Figure 1-1) so that the secondary system response will show the largest observable change. Precise measurement and simulation of these transients are important since CEA drops are not uncommon in PWRs and may cause significant power density changes in the core. The FLCEAD and PLCEAD differ in that part length rod has a lower reactivity worth and, since most of the absorbing material is in the bottom half, it can induce significant axial power distortions as well as radial power distortions.

The TT was initiated from 100 percent power by manually tripping the main turbine from the control room. This test is designed to measure the NSSS response to a load rejection transient initiated from the secondary system. The acquisition of high quality data for the simulation of this event is important since it is a design basis event which results in a rapid increase in primary and secondary system pressures.

For all four tests, the most important dynamic measurements were recorded with a PDP-11 mini-computer capable of sampling up to 48 data channels at a maximum fre-

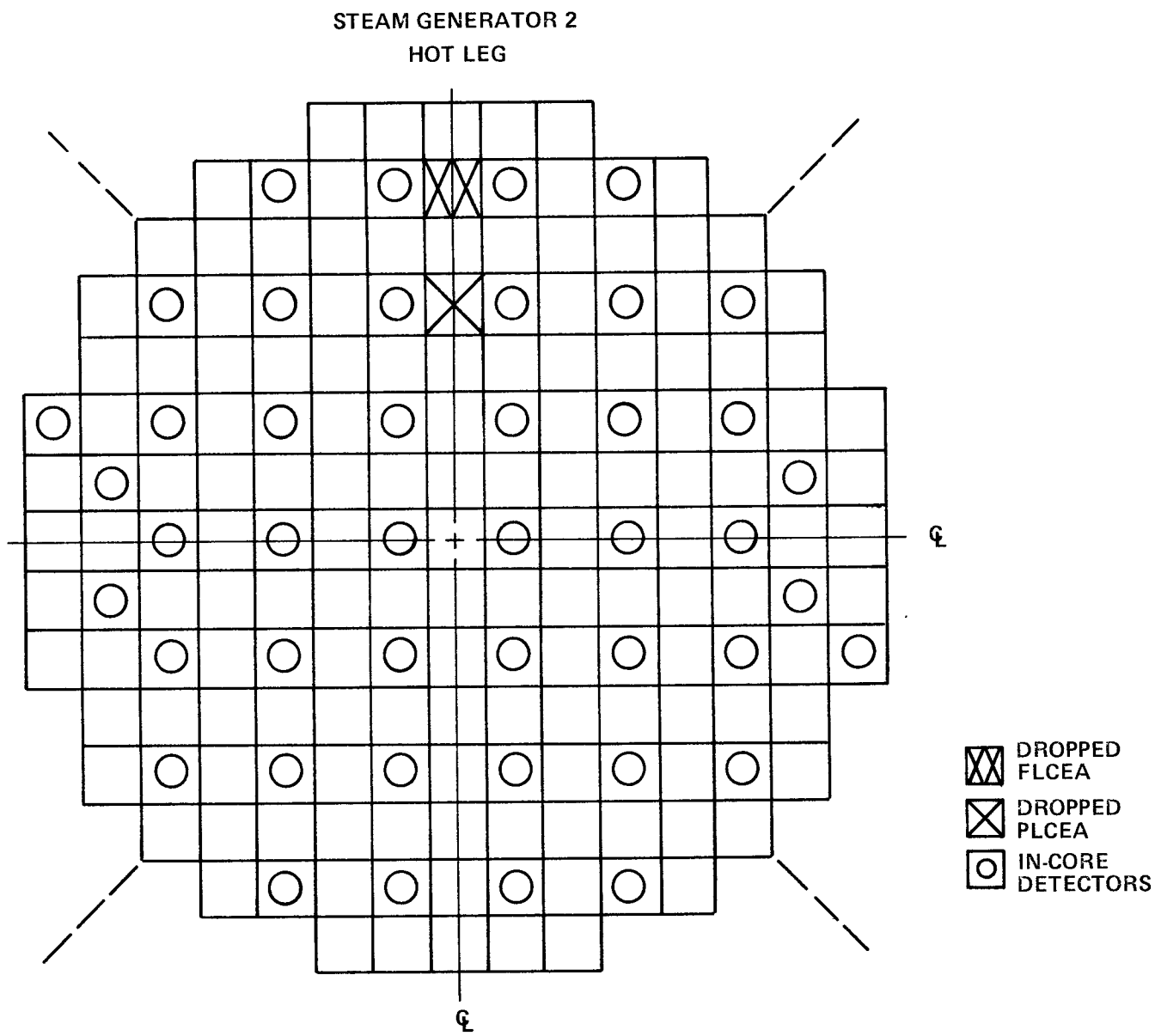

Figure 1-1. Dropped CEA Locations

quency of 10 samples/second. Honeywell model 122-A or 123-A Accudata amplifiers were used for isolating, conditioning and filtering most of the input signals prior to the analog to digital conversion. Backup and supplementary dynamic measurements were recorded using the plant computer and strip chart recorders.

Section 2

PRE-TEST PREPARATIONS

PLANT DESCRIPTION

Arkansas Nuclear One-Unit 2 is equipped with a pressurized water reactor supplied by Combustion Engineering, Inc. The architect-engineering firm that constructed the plant was Bechtel Power Corporation. Arkansas Power and Light Company owns and operates the plant which is located on a peninsula in the Dardanelle Reservoir on the Arkansas River in Pope County, Arkansas.

The reactor core consists of 177 fuel assemblies with a three-batch, mixed central zone arrangement. The core has an active length of 150 inches and is designed to operate at a rated thermal power of 2815 megawatts, which corresponds to a net electrical output of 912 megawatts.

The NSSS is characterized by four primary coolant loops, two steam generators and a full power mass flow rate (including bypass flow) of approximately 133.0×10^6 lbm/hr. The primary system is designed to operate at a nominal pressure of 2250 psia and a full power core average coolant temperature of 579°F. Normal secondary system pressure during full power operation is approximately 900 psia.

Details of the ANO-2 nuclear steam supply system as well as its various instrumentation, control and safety systems are provided in the Final Safety Analysis Report (2). A complete description of the design and operating characteristics of ANO-2, including the detailed plant data required for the simulation of the transients reported herein, is documented in a companion report (3).

TEST EQUIPMENT DESCRIPTION

Data Acquisition System

The primary data acquisition system used during these tests employed a PDP-11 minicomputer consisting of the following equipment (refer to Figure 2-1).

1. Centralized patch panel. This component contained up to 60 analog test signals originating from existing plant instrumentation.

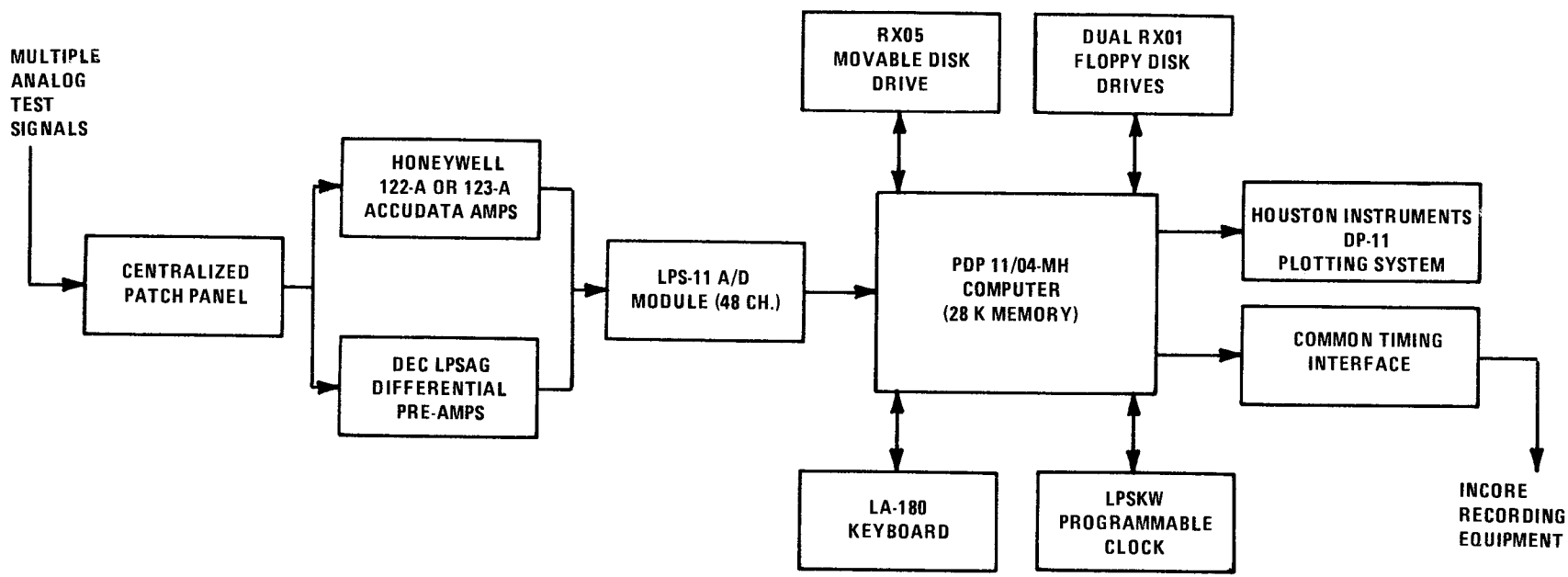

Figure 2-1. Data Acquisition System

2. Honeywell 122-A or 123-A Accudata amplifiers. These signal conditioning amplifiers used a pre-determined set of coefficients to filter, bias and gain the input signal such that the resulting analog signal would more accurately represent the process parameter over the expected range of values.

3. Digital Equipment Corporation (DEC) LPSAG variable range differential pre-amplifiers. Those signals which did not require a high degree of accuracy (reactor trip breaker status, SDBCS demand signals, reactor coolant pump breaker status, etc.) used the DEC LPSAG pre-amps for signal conditioning. Each pre-amp was set prior to the test with a bias voltage and gain which was dependent upon the specific parameter being monitored.

4. DEC LPS-11 analog to digital module (48 channels). This component took the analog output from either the Honeywell Accudata amplifiers or the DEC LPSAG pre-amps and converted that signal to a digital form suitable for storage on the mini-computer.

5. DEC LPSKW programmable clock. This system controlled the sampling frequency of all 48 data channels. The clock was programmed prior to each test with up to 10 different sampling frequencies (maximum sampling rate was 10 samples/second).

6. DEC 11/04-MH computer. The computer recorded the digitized voltage input from the analog to digital module then output this information to the RX05 main desk. The system is characterized by a core memory of 28,000 16 bit words and a KD-11 central processor. It has interfaces with all peripheral devices and was powered by a non-interruptable AC source.

7. DEC RX05 movable head disk drive. The RX05 was the primary storage medium for all software used for these tests. In addition, all data taken during this program were originally recorded on this device. After each test the data were transferred to the floppy disk for subsequent data reduction.

8. DEC RX01 floppy disk drives. The floppy disks were used for data reduction (all raw data was transferred to floppy disks) and also for filtering the converted data. Floppy disks function as storage devices for data and/or software and may be used for the same functions as the RX05 movable head disk (except the storage capacity is significantly smaller).

9. DEC LA-180 keyboard. The LA-180 keyboard was utilized as the input device for initiating the appropriate software (data acquisition, data conversion, plotting, etc.) and the output device for printing out the converted data. It was used as the primary means of interacting with the PDP-11.

10. Houston Instruments DP-11 COMPLOT plotting system. This system plotted the reduced data in a user-specified format.

11. Common Timing Interface (CTI). The CTI generated a 5 volt DC signal each time the programmable clock initiated a data sweep by the PDP-11. The 5 volt signal was input to the in-core recording equipment and was used to correlate the data collected by the mini-computer with in-core data*.

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* Self Power Neutron Detector (SPND) signals and selected CEA position indications were recorded during the loss of flow test and both CEA drop tests. Documentation of these data has been prepared and is presented in a companion report (4).

The data acquisition software developed for these tests sampled 48 data channels with up to 10 different sampling intervals. Table 2-1 shows the sampling rates and intervals used for each of the plant transient tests. Tables 2-2, 2-3 and 2-4 give the Honeywell Accudata amplifier specifications and the range of the analog signals that were monitored for each test. As discussed in paragraph 3 above, some parameters were processed with DEC LPSAG variable range differential pre-amps. Table 2-5 provides the specifications and ranges for these signals.

In addition to the PDP-11 mini-computer, data were collected using the plant computer, Brush 260 strip chart recordings and various control room process recorders. These additional recording systems were used to record the sequence of events and supplementary trend data.

Data Acquisition System Setup and Uncertainties

Based on the results of system transient analyses (described later in this section), the amplifier settings (filter cutoff frequencies, bias voltages and gains) needed for optimum range and resolution of the monitored parameters were determined (Tables 2-2 through 2-4). Prior to each plant transient test, all channels were tested by simulating the predicted range of the transducer output with a voltage standard and confirming the digitized output to be within 1 percent of the standard. In addition to the calibration check against the voltage standard, an integrated systems check was performed by comparing the minicomputer recordings with plant computer readings. The purpose of this test was to verify that each signal being recorded by the minicomputer was within 1 percent of the same signal being recorded by the plant computer (i.e. cross-calibration). After the plant transient test and data acquisition were completed, the integrated systems check was performed a second time to verify that the signals being recorded by the mini-computer were still within 1 percent of the same values monitored by the plant computer.

The overall uncertainty associated with the transient measurements can be attributed to the following components:

1. Sensor calibration and response characteristics,
2. Recording system calibration procedure,
3. Signal conditioning amplifier linearity and drift,
4. Analog to digital conversion.

Table 2-1

SAMPLING RATES AND INTERVALS USED FOR DATA ACQUISITION

Test	Interval	Transient Time (sec)	Sampling Rate
LOF[a]	1	Start: -119.5 End: -7.5	2 samples/second
	2	Start: -7.4 End: +74.5	10 samples/second
	3	Start: 75.0 End: 617.0	2 samples/second
FLCEAD[b]	1	Start: -501.0 End: -81.0	1 sample/5 seconds
	2	Start: -80.5 End: -8.0	2 samples/second
	3	Start: -7.9 End: +83.0	10 samples/second
	4	Start: 83.5 End: 234.0	2 samples/second
	5	Start: 239.0 End: 1834.0	1 sample/5 seconds
PLCEAD[b]	1	Start: -73.1 End: -3.1	1 sample/second
	2	Start: -3.0 End: 96.8	10 samples/second
	3	Start: 97.3 End: 226.8	2 samples/second
	4	Start: 227.8 End: 526.8	1 sample/second
	5	Start: 531.8 End: 1851.8	1 sample/5 seconds

(a) Time zero corresponds to the time the pumps were tripped.

(b) Time zero corresponds to the time the rod was dropped.

Table 2-1 (continued)

Test	Interval	Transient Time (sec)	Sampling Rate
Turbine Trip[c]	1	Start: -112.3 End: -8.3	1 sample/second
	2	Start: -8.2 End: +66.7	10 samples/second
	3	Start: 67.2 End: 206.7	2 samples/second
	4	Start: 307.7 End: 606.5	1 sample/second
	5	Start: 611.5 End: 1206.5	1 sample/5 seconds
	6	Start: 1218.5 End: 5659.2	1 sample/10 seconds

(c) Time zero corresponds to the time of turbine trip.

Table 2-2

AMPLIFIER SPECIFICATIONS FOR THE LOF TEST

Signal	Model	Gain	Offset (volts)	Filter Cutoff Frequency (Hz)	Range
Pressurizer Pressure Wide Range	122-4	50	0.7667	100	1750-2500 psia
Pressurizer Pressure Narrow Range	122-4	50	0.7800	10	2100-2350 psia
Pressurizer Level	122-4	20	0.4500	10	0-62.5%
Steam Generator-1 Hot Leg Temperature	122-4	20	0.5833	10	550-643.8°F
Steam Generator-2 Hot Leg Temperature	122-4	20	0.5833	10	550-643.8°F
Reactor Coolant Pump-1A Cold Leg Temperature	123-4	100	0.9300	10	510-585°F
Reactor Coolant Pump-1B Cold Leg Temperature	122-4	20	0.690	10	510-603.8°F
Reactor Coolant Pump-2A Cold Leg Temperature	123-4	20	0.690	10	510-603.8°F
Reactor Coolant Pump-2B Cold Leg Temperature	122-4	20	0.490	10	530-592.5°F
Steam Generator-1 Pressure	122-4	20	0.7833	10	500-1250 psia

Table 2-2 (continued)

Signal	Model	Gain	Offset (volts)	Filter Cutoff Frequency (Hz)	Range
Steam Generator-2 Pressure	123-4	20	0.7833	10	500-1250 psia
Steam Generator-1 Level	122-4	20	0.6500	10	25-87.5%
Steam Generator-2 Level	122-4	20	0.6500	10	25-87.5%
Steam Generator-1 Feedwater Nozzel ΔP	122-4	10	0.7000	10	0-1000" Water
Steam Generator-2 Feedwater Nozzle ΔP	122-4	10	0.7000	10	0-1000" Water
Steam Generator-1 Header Pressure	123-4	10	0.7000	10	850-1100 psia
Steam Generator-2 Header Pressure	123-4	10	0.7000	10	850-1100 psia
Steam Generator-1 Steam Header ΔP	123-4	10	0.7000	10	0-1000" Water
Steam Generator-2 Steam Header ΔP	123-4	10	0.7000	10	0-1000" Water
Control Channel A Nuclear Power	123-4	1	5.000	10	0-125%
Reactor Coolant Pump-1A ΔP	122-4	10	0.7000	10	0-162.5 psid
Reactor Coolant Pump-1B ΔP	123-4	10	0.7000	10	0-162.5 psid
Reactor Coolant Pump-2A ΔP	122-4	10	0.7000	10	0-162.5 psid

Table 2-2 (continued)

Signal	Model	Gain	Offset (volts)	Filter Cutoff Frequency (Hz)	Range
Reactor Coolant Pump-2B ΔP	123-4	10	0.7000	10	0-162.5 psid
Reactor Coolant Pump-1A Speed	123-4	2	2.5000	10	0-929.2 rpm
Reactor Coolant Pump-1B Speed	122-4	2	2.5000	10	0-929.2 rpm
Reactor Coolant Pump-2A Speed	123-4	2	2.5000	10	0-929.2 rpm
Reactor Coolant Pump-2B Speed	123-4	2	2.5000	10	0-929.2 rpm

Table 2-3

AMPLIFIER SPECIFICATIONS FOR THE CEA DROP TESTS

Signal	Model	Gain	Offset (volts)	Filter Cutoff Frequency (Hz)	Range
Pressurizer Pressure Wide Range	122-4	20	0.7833	10	1250-3125 psia
Pressurizer Pressure Narrow Range	122-4	20	0.6500	10	1750-2375 psia
Pressurizer Level	122-4	20	0.4500	10	0-62.5%
Steam Generator-1 Hot Leg Temperature	122-4	20	0.5833	10	550-643.8°F
Steam Generator-2 Hot Leg Temperature	122-4	20	0.5833	10	550-643.8°F
Reactor Coolant Pump-1A Cold Leg Temperautre	123-4	20	0.9167	10	350-725°F
Reactor Coolant Pump-1B Cold Leg Temperature	122-4	20	0.690	10	510-603.8°F
Reactor Coolant Pump-2A Cold Leg Temperature	123-4	20	0.690	10	510-603.8°F
Reactor Coolant Pump-2B Cold Leg Temperature	122-4	20	0.450	10	525-587.5°F
Steam Generator-1 Pressure	122-4	10	0.7000	10	0-1500 psia
Steam Generator-2 Pressure	122-4	10	0.7000	10	0-1500 psia

Table 2-3 (continued)

Signal	Model	Gain	Offset (volts)	Filter Cutoff Frequency (Hz)	Range
Steam Generator-1 Level	122-4	20	0.6500	10	25-87.5%
Steam Generator-2 Level	122-4	20	0.650	10	25-87.5%
Steam Generator-1 Feedwater Nozzle ΔP	122-4	20	0.450	10	0-500" Water
Steam Generator-2 Feedwater Nozzle ΔP	122-4	20	0.450	10	0-500" Water
Steam Generator-1 Header Pressure	122-4	5	0.800	10	750-1250 psia
Steam Generator-2 Header Pressure	122-4	5	0.800	10	750-1250 psia
Steam Generator-1 Steam Header ΔP	123-4	20	0.450	10	0-500" Water
Steam Generator-2 Steam Header ΔP	123-4	20	0.4500	10	0-500" Water
Nuclear Power	123-4	2	2.5000	10	0-62.5%
Nuclear Power	123-4	2	2.5000	10	0-62.5%
Turbine 1st Stage Pressure	123-4	10	0.9000	10	0-740 psia
Reactor Coolant Pump-1A ΔP	122-4	10	0.7000	10	0-162.5 psid
Reactor Coolant Pump-1B ΔP	123-4	10	0.7000	10	0-162.5 psid
Reactor Coolant Pump-1A Speed	123-4	2	2.5000	10	0-929.2 rpm

Table 2-3 (continued)

Signal	Model	Gain	Offset (volts)	Filter Cutoff Frequency (Hz)	Range
Reactor Coolant Pump-1B Speed	122-4	2	2.5000	10	0-929.2 rpm
Reactor Coolant Pump 2A Speed	123-4	2	2.5000	10	0-929.2 rpm
Reactor Coolant Pump-2B Speed	123-4	2	2.5000	10	0-929.2 rpm

Table 2-4

AMPLIFIER SPECIFICATIONS FOR THE TURBINE TRIP TEST

Signal	Model	Gain	Offset (volts)	Filter Cutoff Frequency (Hz)	Range
Pressurizer Pressure Narrow Range	122-4	10	0.7000	10	1500-2750 psia
Pressurizer Level	122-4	10	0.7000	10	0-125%
Steam Generator-1 Hot Leg Temperature	122-4	20	0.5833	10	550-643.8°F
Steam Generator-2 Hot Leg Temperature	122-4	20	0.5833	10	550-643.8°F
Reactor Coolant Pump-1A Cold Leg Temperature	122-4	20	0.9167	10	350-725°F
Reactor Coolant Pump-1B Cold Leg Temperature	123-4	20	0.6900	10	510-603.8°F
Reactor Coolant Pump-2A Cold Leg Temperature	122-4	20	0.6900	10	510-603.8°F
Reactor Coolant Pump-2B Cold Leg Temperature	123-4	20	0.4500	10	525-587.5°F
Steam Generator-1 Pressure	122-4	10	0.7000	10	0-1500 psia
Steam Generator-2 Pressure	122-4	10	0.7000	10	0-1500 psia
Steam Generator-1 Level	122-4	10	0.7000	10	0-125%
Steam Generator-2 Level	123-4	10	0.7000	10	0-125%
Steam Generator-1 Feedwater Nozzle ΔP	122-4	10	0.7000	10	0-1000" Water

Table 2-4 (continued)

Signal	Model	Gain	Offset (volts)	Filter Cutoff Frequency (Hz)	Range
Steam Generator-2 Feedwater Nozzle ΔP	122-4	10	0.7000	10	0-1000" Water
Steam Generator-1 Header Pressure	122-4	5	0.8000	10	750-1250 psia
Steam Generator-2 Header Pressure	122-4	5	0.8000	10	750-1250 psia
Steam Generator-1 Steam Header ΔP	122-4	10	0.7000	10	0-1000" Water
Steam Generator-2 Steam Header ΔP	123-4	10	0.7000	10	0-1000" Water
Nuclear Power	123-4	1	5.00	10	0-125%
Nuclear Power	123-4	1	5.00	10	0-125%
Turbine First Stage Pressure	123-4	5	1.40	10	0-925 psia
Steam Generator-1 Emergency Feedwater Flow	123-4	2	2.50	10	0-600 gpm
Steam Generator-1 Emergency Feedwater Flow	123-4	2	2.50	10	0-600 gpm
Steam Generator-1 Feedwater Reg. Valve Position	123-4	1	5.00	10	0-100%
Steam Generator-2 Feedwater Reg. Valve Position	123-4	1	5.00	10	0-100%
Reactor Coolant Pump-1A Speed	123-4	2	2.50	10	0-929.2 rpm
Reactor Coolant Pump-1B Speed	123-4	2	2.50	10	0-929.2 rpm

Table 2-4 (continued)

Signal	Model	Gain	Offset (volts)	Filter Cutoff Frequency (Hz)	Range
Reactor Coolant Pump-2A Speed	123-4	2	2.5000	10	0-929.2 rpm
Reactor Coolant Pump-2B Speed	123-4	2	2.5000	10	0-929.2 rpm
Reactor Coolant Pump-1A ΔP	123-4	10	0.7000	10	0-162.5 psid
Reactor Coolant Pump-1B ΔP	123-4	10	0.7000	10	0-162.5 psid
Reactor Coolant Pump-2A ΔP	123-4	10	0.7000	10	0-162.5 psid
Reactor Coolant Pump-2B ΔP	122-4	10	0.7000	10	0-162.5 psid
Steam Generator-2 Emergency Feedwater Flow	123-4	2	2.5000	10	0-600 gpm
Steam Generator-2 Emergency Feedwater Flow	122-4	2	2.5000	10	0-600 gpm

Table 2-5

SIGNALS MONITORED ON THE PDP-11 MINICOMPUTER USING
INPUT FROM DEC VARIABLE RANGE DIFFERENTIAL PREAMPLIFIERS

Test	Signal	Range (volts)	Offset (volts)	Range (Eng. Units)
LOF	SDBCS Demand Signal to Turbine Bypass Valve 1A	0 - 2.0	0.0	0-100%
	SDBCS Demand Signal to Turbine Bypass Valve 1B	0 - 2.0	0.0	0-100%
	SDBCS Demand Signal to Turbine Bypass Valve 2B	0 - 2.0	0.0	0-100%
	SDBCS Demand Signal to Atmospheric Dump Valve 1A	0 - 2.0	0.0	0-100%
	SDBCS Demand Signal to Atmospheric Dump Valve 2A	0 - 2.0	0.0	0-100%
	SDBCS Demand Signal to Atmospheric Dump Valve 1B	0 - 2.0	0.0	0-100%
	SDBCS Demand Signal to Atmospheric Dump Valve 2B	0 - 2.0	0.0	0-100%
	Reactor Trip Breaker Status*	0 - 10.0	0.0	6.3-0 Units **
	Reactor Coolant Pump-1A Breaker Status	0 - 10.0	0.0	0-20 Units
	Reactor Coolant Pump-1B Breaker Status	0 - 10.0	0.0	0-20 Units
	Reactor Coolant Pump-2A Breaker Status	0 - 10.0	0.0	0-20 Units
	Reactor Coolant Pump-2B Breaker Status	0 - 10.0	0.0	0-20 Units

Table 2-5 (continued)

Test	Signal	Range (volts)	Offset (volts)	Range (Eng. Units)
FLCEAD	Reactor Coolant Pump-2A Differential Pressure	0 - 2.0	0.0	0-130 psid
	Reactor Coolant Pump-2B Differential Pressure	0 - 2.0	0.0	0-130 psid
PLCEAD	Reactor Coolant Pump-2A Differential Pressure	0 - 2.0	0.0	0-130 psid
	Reactor Coolant Pump-2B Differential Pressure	0 - 2.0	0.0	0-130 psid
TT	Reactor Trip Breaker Status*	0 - 10.0	0.0	6.3-0 Units
	Turbine Trip Breaker Status	0 - 10.0	0.0	
	Reactor Coolant Pump-1A Breaker Status	0 - 10.0	0.0	0-100 Units
	Reactor Coolant Pump-1B Breaker Status	0 - 10.0	0.0	0-100 Units
	Reactor Coolant Pump-2B Breaker Status	0 - 10.0	0.0	0-100 Units

* Reactor Trip Breaker Status is energized during power operation (~6.3 volt signal) and de-energized after a reactor trip.

** The range of engineering units associated with a breaker status is insignificant since it is a measurement of whether or not the breaker has been energized (or de-energized).

Of these components, the sensor response time represents the major source of uncertainty. It has been calculated that this component may contribute as much as 2% (of the initial value) uncertainty. The impact that the sensor response times have on measurement uncertainties is discussed in greater detail in the Pre-test Analyses Section.

The impact that the recording system calibration procedure had on the overall uncertainty was shown to be less than 1% of the steady state parameter value. This was accomplished by demonstrating that the data being recorded on the mini-computer stayed within 1% of the data recorded on the plant computer before and after the transient. Thus, errors introduced through the calibration procedure were generally attributed to errors in the original calibration of the plant instrumentation ($\pm$ 2°F on the absolute temperatures and $\pm$ 15 psia on the absolute pressures).

Errors due to signal conditioning amplifier linearity and drift as well as due to the analog to digital conversion were minimized by allowing the amplifiers to reach a thermal equilibrium prior to each test and cross checking the digitized output from the mini-computer with a voltage standard. This test demonstrated that the overall uncertainty generated from these two components was less than 1% (full scale). Thus, the overall measurement uncertainty of the data acquisition system was primarily due to the delay times associated with the existing plant instrumentation and was estimated to be no greater than 5% of the initial steady state parameter values.

PRE-TEST ANALYSES

System Transient Analysis

As part of the initial phase of this program, pre-test predictions of the four NSSS transient tests were performed using Combustion Engineering's Systems Excursion Code, CESEC (5). The analysis was performed to determine the expected trends and characteristic variations of the monitored NSSS variables. The results of this study were used to establish recording instrument ranges, evaluate the adequacy of the existing plant sensors and show that the plant would remain in a safe condition throughout the tests.

Sensor Response Time Study

Data acquired during the plant transient tests were obtained using existing plant instrumentation (Figure 2-2). An analysis has been performed to quantify the impact

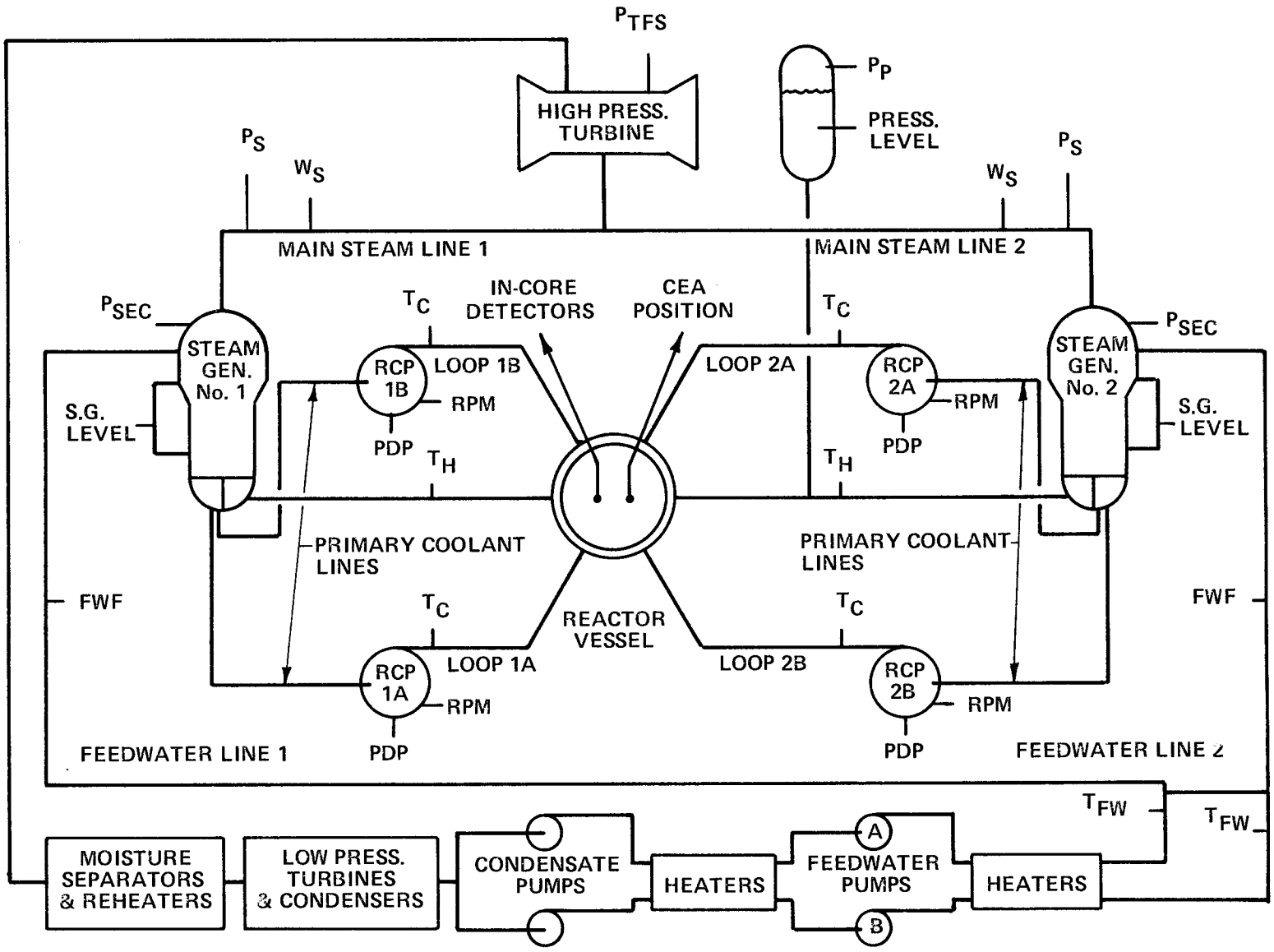


Figure 2-2. Sensor Locations

that the sensor response times have on measurement uncertainties, thereby demonstrating the adequacy of these instruments. The procedure used to evaluate the sensor response time impact was as follows:

1. Define realistic instrument response times through measurement,
2. Model system transients using CESEC,
3. Model sensor output using a first order lag function, and;
4. Compare calculated system transient and sensor output.

Instrument Response Time Measurements. The total response time associated with an instrument loop typically consists of three components; sonic response, sensor response, and process loop response. The sonic response time is the time required for a pressure wave to travel the length of the instrument line from a system component to the associated pressure or level transducer. For diaphram displacement transducers the sonic response time also includes the time associated with the diaphram displacement volume. All of the pressure transducers discussed herein are Bourdon tube type transducers and do not include diaphram displacement response times. All of the level transducers are diaphram displacement type instruments which do include a diaphram displacement response time component.

The response of the sensor is characterized by a time shift(s) and a time constant (τ). The time shift results from the dead band of the sensor and the time constant is the time required for the sensor output to reach 63.2 percent of the total change resulting from a step input function, i.e., the "rise time".

The process loop response time, which is also characterized by a time shift and time constant, is comprised of the response time of amplifiers, transmitters, or isolators within a given instrument electrical circuit.

Methods of Measurement. The instrument response time associated with Resistance Temperature Detector (RTD) temperature measurement is characterized by the sensor response time and the associated process loop response time. The RTD sensor response time was measured by plunging each RTD into an Indium-Gallium bath maintained at 550 $\pm$ 50°F. This procedure simulates a step change in the fluid temperature with a surface heat transfer coefficient representative of the high fluid velocity that exists in a reactor vessel hot leg or cold leg. The process loop response time for the RTD's was measured by disconnecting the sensor and inputting a simulated sensor output. For the cold leg RTD's, a step change in sensor output from 553.5 °F to 583.5°F

was input to the instrument loop. For the hot leg RTD's a 612.5°F to 642.5°F step change was used. The response times are shown in Table 2-6.

The pressurizer pressure and steam generator pressure instrument response times are comprised of sonic, sensor and process loop response times. The sonic response times were determined by assuming the pressure changes traveled at sonic velocity through the entire length of the instrument line. The sensor and process loop response times were derived from measurements obtained using a test ring in which a 10 percent step change in system pressure was simulated. The response times were extracted from plant data records which are also listed in Table 2-6.

System Transient Modeling. The NSSS simulation code CESEC was used to predict the overall NSSS response to the four plant transient tests. Although these predictions utilized the best data available at that time, they should not be used for comparison to the test data presented in this report. Control system and safety system setpoints, as well as initial conditions and relief valve capacities were significantly different during the actual test than they were during this analysis. Thus, the figures presented in this section should be used only to quantify the impact that the sensor response times have on selected NSSS variables.

Sensor Modeling. Using the CESEC predictions as the "true" plant response, the sensor output was determined by modeling the sensor with a first order lag function. The differential equation describing this model is as follows:

$$\frac{d\phi(t)}{dt} + \frac{\phi(t)}{\tau} - \frac{I(t)}{\tau} = 0 \qquad (2\text{-}1)$$

where: $\phi(t)$ = sensor output
$I(t)$ = sensor input (as predicted by CESEC)
τ = time constant of the sensor (seconds)

Assuming that,

$$\frac{d\phi(t)}{dt} \cong \frac{\phi(t) - \phi(t - t)}{\Delta t} \text{ for small } \Delta t\text{'s} \qquad (2\text{-}2)$$

Equation (2-1) can be solved for $\phi(t)$; the sensor response.

$$\phi(t) = \frac{I(t)\ \Delta t + \phi(t - \Delta t)\ \tau}{\tau + \Delta t} \qquad (2\text{-}3)$$

Table 2-6

TOTAL RESPONSE TIME DATA (MEASURED)

Instrument	Delay Component(1)	Response Time (Milliseconds) Sonic	Sensor	Process Loop(2)	Total
Pressurizer Pressure	τ	NA	5 ± 1	0	5 ± 1
	S	11	11 ± 6	2 ± 2	24 ± 8
Steam Generator Pressure	τ	NA	13 ± 2	0	13 ± 2
	S	13	9 ± 4	2 ± 2	24 ± 6
Pressurizer Level	τ	NA	181 ± 34	0	181 ± 34
	S	14	58 ± 13	2 ± 2	74 ± 15
Hot Leg Temperature	τ	NA	4747 ± 520	6 ± 1	4753 ± 520
	S	NA	NA	2 ± 2	2 ± 2
Cold Leg Temperature	τ	NA	4893 ± 520	5 ± 1	4898 ± 520
	S	NA	NA	2 ± 2	2 ± 2

(1) τ is the sensor time constant; S is the response time shift

(2) includes delay time of the isolators

where: $\phi(t)$ = present output value from the sensor
$\phi(t - \Delta t)$ = past output value from the sensor
$I(t)$ = present input value to the sensor (from CESEC)
Δt = time step (seconds)
τ = time constant of the sensor (seconds)

Table 2-7 shows the time constants used for this analysis and compares them with the measured values.

System Transient and Sensor Output Comparison. The largest differences between the "true" plant response (as predicted by CESEC) and the calculated sensor output (modeled with equation 2-1) occurred during the full power load rejection (turbine trip). Figures 2-3 through 2-7 graphically compare the predicted plant response with the calculated sensor output for several of the important NSSS variables. These plots show that the largest measurement uncertainty resulted from the rapid change in hot leg temperature (Figure 2-6). The maximum difference between the "true" response and the sensor output was 10°F (approximately 1.7% error) at 10 seconds into the transient. Since the maximum error is predicted to occur in the measurement of the hot leg temperature during the turbine trip test, and the rate of change of the hot leg temperature calculated by CESEC is approximately equal to that observed during the actual test, the uncertainties due to sensor response time characteristics are expected to be less than 2 percent for all tests.

Conclusion. This study shows that, even when conservative sensor delay times are used (relative to measured delay times), the existing plant instrumentation can adequately respond to changes in system parameters during a transient. Therefore, the sensors installed at ANO-2 are sufficient to display the significant features of the plant transient tests.

OPERATING HISTORY

A description of the operating history of Arkansas Nuclear One-Unit 2 from initial criticality (December 1978) through the completion of the transient tests (January 1980) has been prepared and is reported in (3).

Table 2-7

SENSOR RESPONSE TIMES ASSUMED FOR ANALYTICAL CALCULATIONS

Parameters	Assumed Delay Times (milliseconds)	Measured Delay Times (milliseconds)
Pressurizer Pressure	650	29 ± 9
Steam Generator Pressure	425	37 ± 10
Pressurizer Level	425	255 ± 49
Hot Leg Temperature	5000	4755 ± 523
Cold Leg Temperature	5000	4900 ± 523

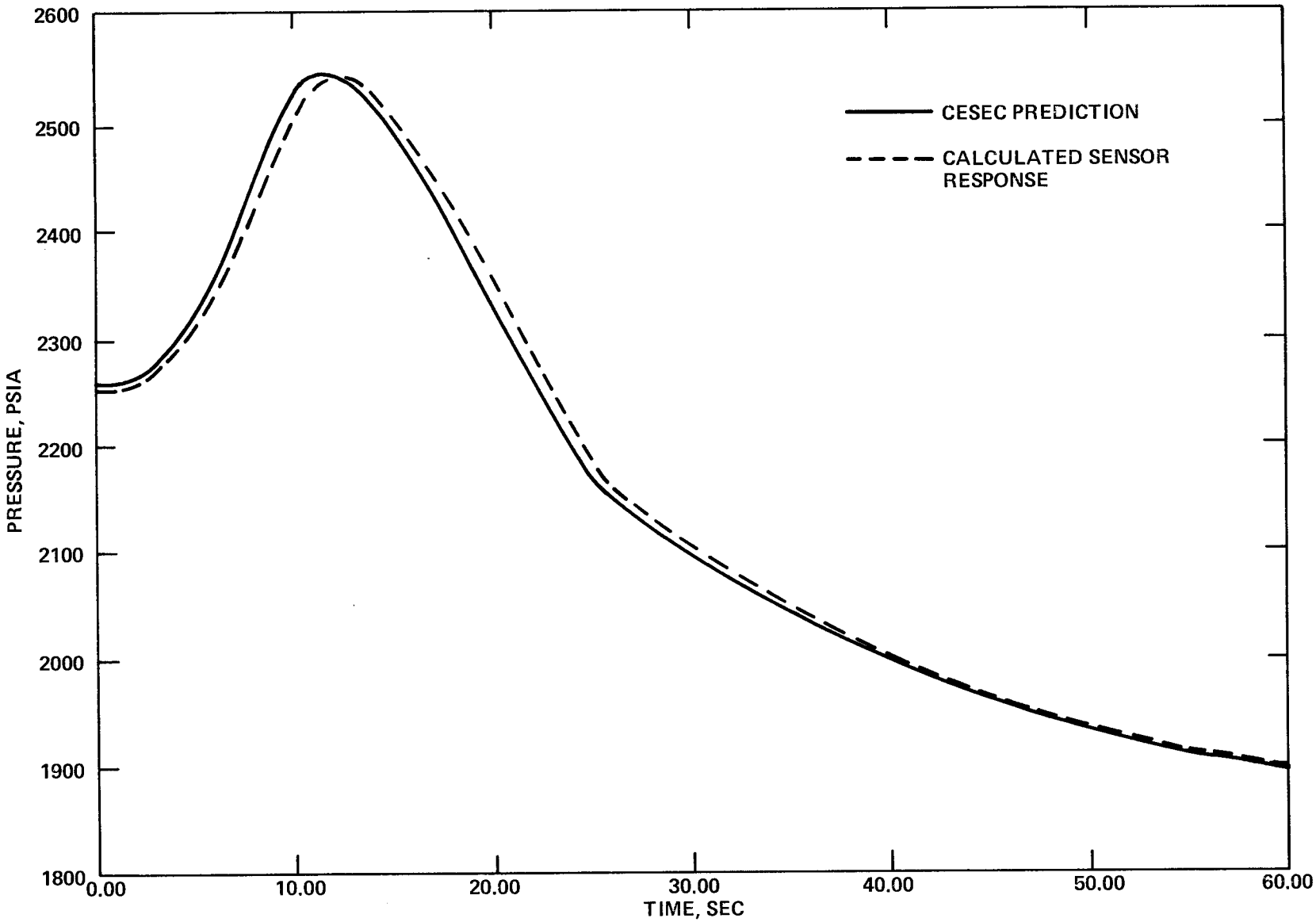


Figure 2-3. Sensor Response Analysis - Pressurizer Pressure

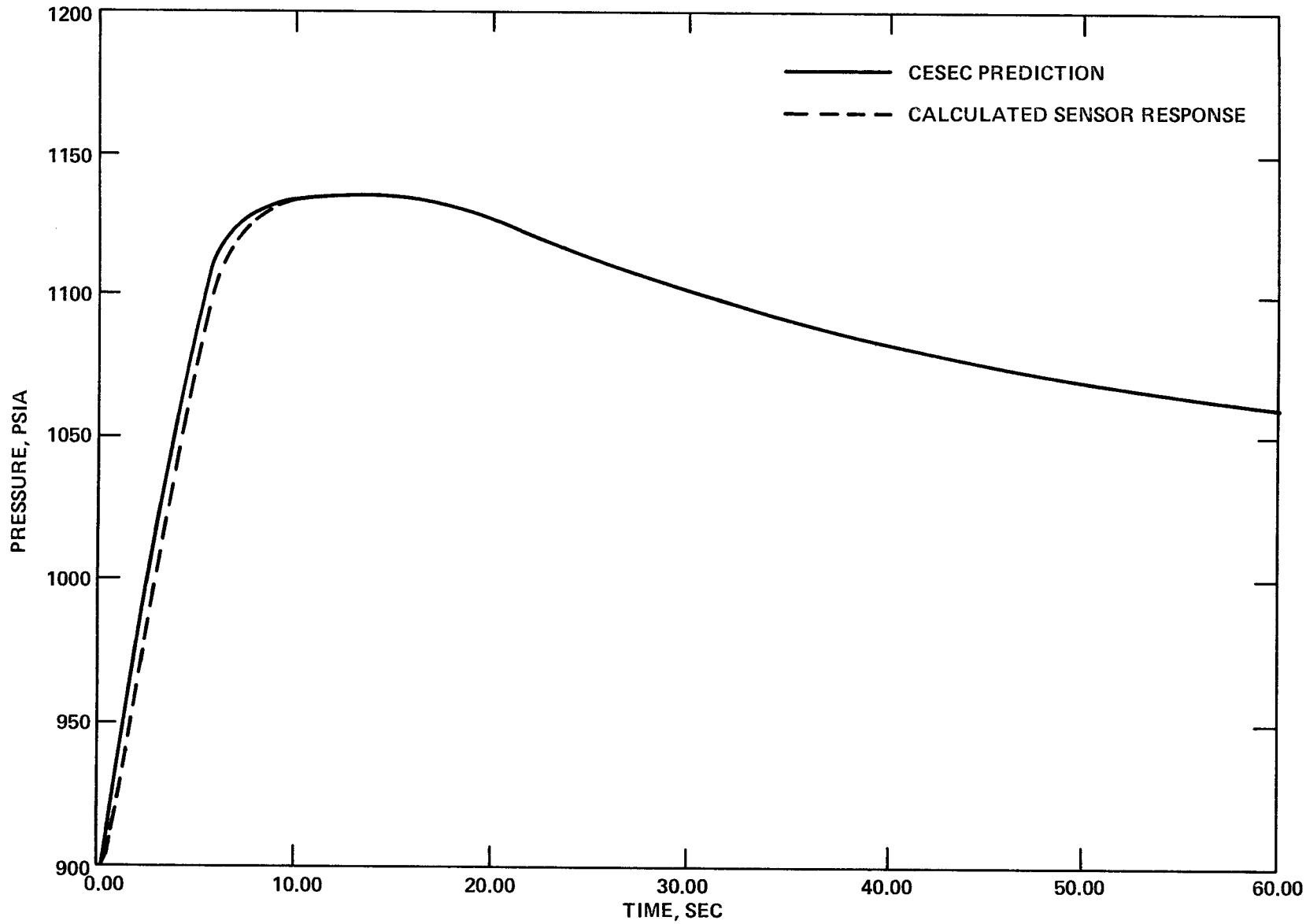


Figure 2-4. Sensor Response Analysis - Steam Generator Pressure

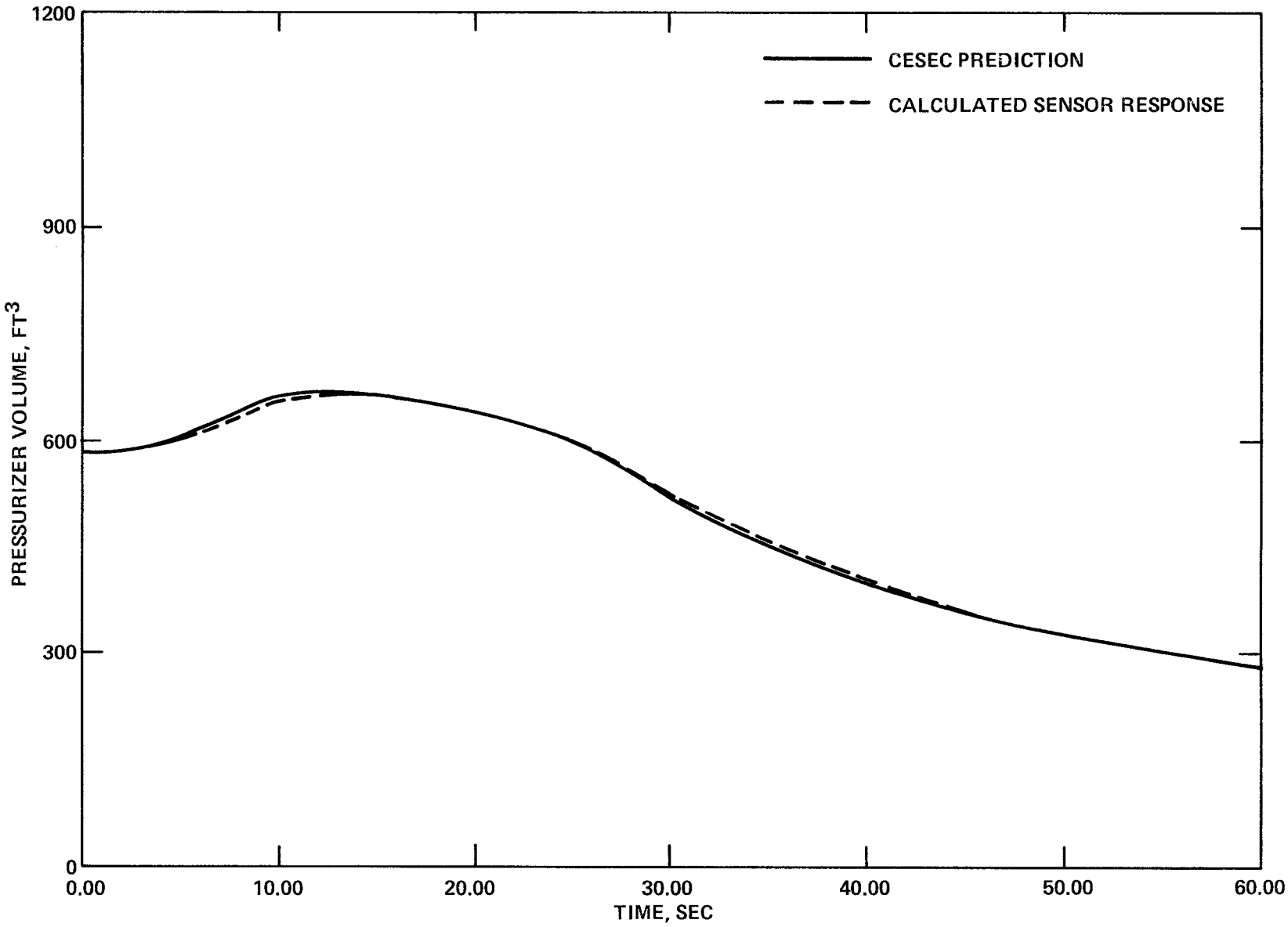


Figure 2-5. Sensor Response Analysis - Pressurizer Volume

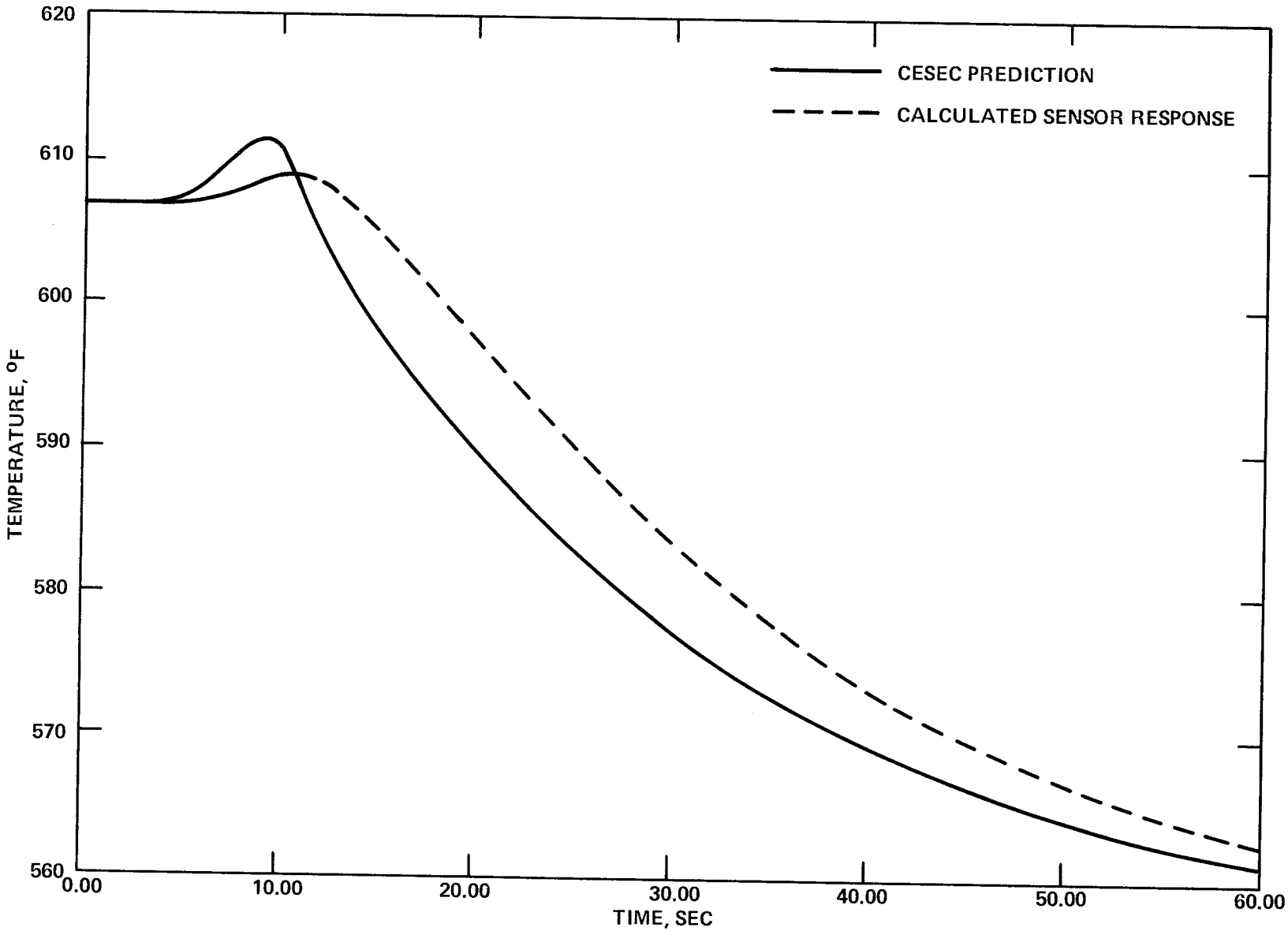


Figure 2-6. Sensor Response Analysis - Hot Leg Temperature

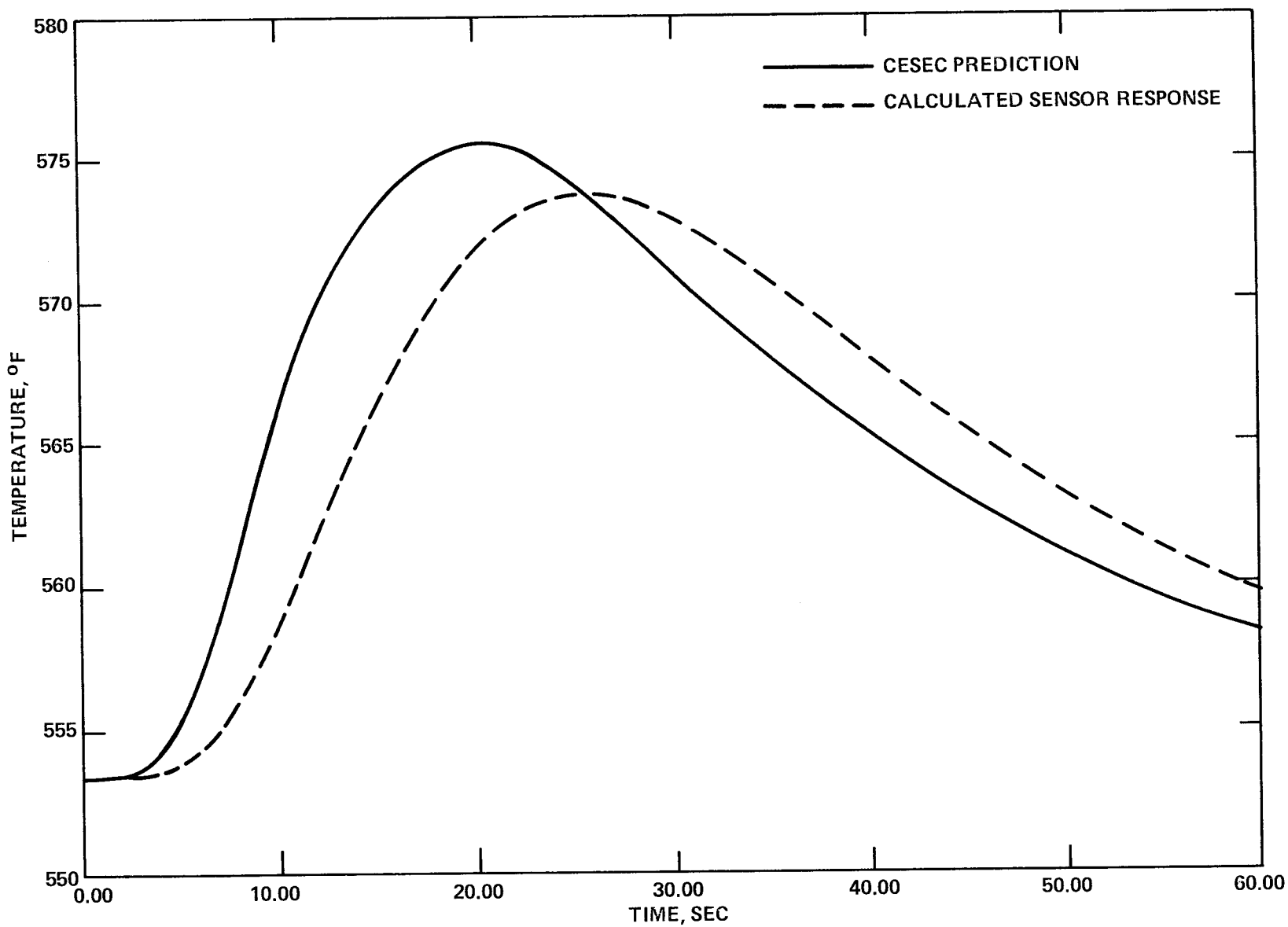


Figure 2-7. Sensor Response Analysis - Cold Leg Temperature

Section 3

TEST PROCEDURES

GENERAL REQUIREMENTS

The following steps were performed prior to, and/or during, each of the four plant transient tests:

1. Verify that each channel of the data acquisition system (DAS) is properly set up. This procedure utilizes a voltage standard to simulate the transducer output (amplifier input) and the DAS to read and display the digitized output. Each channel is verified over the full range of expected transducer output.

2. Perform an integrated systems check and cross-calibrate the NSSS variables being monitored on the DAS with the plant computer.* This is accomplished by taking steady-state data simultaneously with the DAS and the plant computer. Each parameter being recorded on the DAS is verified to be within 1 percent (full scale) of the same parameter being monitored by the plant computer.

3. Select optimum DAS sampling frequencies. The fastest sampling rates are used during the initial portion of each transient.

4. Set up the plant computer to record a pre-determined set of NSSS parameters during the transient (i.e., the appropriate computer trend groups) and verify the initial conditions selected for the test.

5. Start the DAS and initiate the appropriate transient (refer to the following section outlining the specific requirements of each test).

6. Once the data acquisition has been completed, perform a second cross-calibration check to verify that the plant computer and the DAS are still in good agreement (within 1 percent).

7. Transfer the raw data (digitized voltage) to a floppy disk and initiate the data conversion to engineering units. This is performed on the mini-computer by multiplying the raw data file by a data conversion matrix. The basic equation used for data conversion is as follows:

$$y = \frac{\left(\frac{x}{409.6} - 5.0 + V_b G - A_{ot} G\right) * r_{te} + A_{oe}}{r_{tv}\, G} \qquad (3\text{-}1)$$

* All plant instrumentation providing input to the plant computer are calibrated at the factory (prior to installation), then verified during the pre-test hot functional testing. In addition, all RTD's are tested for consistency prior to performing the NSSS calorimetric power determination at each power plateau (0, 20, 50, 80 and 100% power). By showing agreement among all RTD's (within 1°F) it is assumed that all have retained their factory calibration.

where: y = Converted output in engineering units

X = Digitized voltage stored by the minicomputer

V_b = Amplifier voltage offset

G = Amplifier gain

A_{ot} = Transducer voltage offset

A_{oe} = Transducer engineering units offset

r_{te} = Transducer engineering units range

r_{tv} = Transducer voltage range

Tables 3-1 through 3-3 show the data conversion matrix used for each of the four plant transient tests.

8. Using a digital filtering algorithm to minimize quantization errors and other noise components, smooth the converted data. The filtering algorithm is a recursive equation:

$$y(t) = N_1\, x(t) - D_1\, y(t - T) - D_2\, y(t - 2T) \qquad (3\text{-}2)$$

where: $y(t)$ = filtered data point at time t

$y(t - T)$ = filtered data point at previous time step

$y(t - 2T)$ = filtered data point at 2 previous time steps

$x(t)$ = unfiltered data point at time t

D_1 = $2e^{-\delta\omega_o T} \cos\left(\omega_o \sqrt{1 - \delta^2}\, T\right)$

D_2 = $e^{-2\delta\omega_o T}$

N_1 = $1 + D_1 + D_2$

and, δ = damping ratio

ω_o = $2\pi f_o$; f_o = cutoff frequency

T = time step (sampling interval)

This algorithm was utilized because of its similarity to an analog (RC) filter and its ability to smooth the raw data with a minimal time delay and good phase characteristics (i.e. little distortion). It has been tested with data from operating C-E reactors and has resulted in good agreement between the filtered and unfiltered data.

Use of this algorithm incorporates a time delay between the filtered and unfiltered data. This delay is insignificant when describing the long term response of the process parameters since these plots are used only to show characteristic trends during a transient. However, it is more significant when describing the short term response of the NSSS. When filtering the data for short term (1 minute) plots, special care was exercised (including graphical comparisons of the filtered and unfiltered data) to ensure that the delay time introduced through this algorithm was minimized. The maximum delay in the short term plots is approximately 1 to 2 seconds. Most parameters were filtered such that the delay was less than 1 second.

Table 3-1

DATA CONVERSION MATRIX FOR THE LOF

Channel No.	Parameter	Amplifier Gain	Amplifier Offset	Preamp Range	Preamp Offset	Transducer Units Range	Transducer Units Offset	Transducer Voltage Range	Transducer Voltage Offset
1	SDBCS demand signal to Bypass Valve 1A	1.000	0.000	2.000	0.000	100.000	0.000	0.800	0.200
2	SDBCS demand signal to Bypass Valve 1B	1.000	0.000	2.000	0.000	100.000	0.000	0.800	0.200
3	SDBCS demand signal to Bypass Valve 2B	1.000	0.000	2.000	0.000	100.000	0.000	0.800	0.200
4	SDBCS demand signal to Atmos. Dump Valve 1A	1.000	0.000	2.000	0.000	100.000	0.000	0.800	0.200
5	SDBCS demand signal to Atmos. Dump Valve 2A	1.000	0.000	2.000	0.000	100.000	0.000	0.800	0.200
6	SDBCS demand signal to Atmos. Dump Valve 1B	1.000	0.000	2.000	0.000	100.000	0.000	0.800	0.200
7	SDBCS demand signal to Atmos. Dump Valve 2B	1.000	0.000	2.000	0.000	100.000	0.000	0.800	0.200
8	Unused	1.000	0.000	2.000	0.000	100.000	0.000	0.800	0.200
9	RCP-A Breaker Status	1.000	0.000	2.000	0.000	2.000	0.000	1.000	0.200
10	RCP-B Breaker Status	1.000	0.000	10.000	0.000	2.000	0.000	1.000	0.000
11	RCP-C Breaker Status	1.000	0.000	10.000	0.000	2.000	0.000	1.000	0.000
12	RCP-D Breaker Status	1.000	0.000	10.000	0.000	2.000	0.000	1.000	0.000
13	Unused	1.000	0.000	2.000	0.000	2.000	0.000	1.000	0.000
14	Unused	1.000	0.000	2.000	0.000	2.000	0.000	1.000	0.000
15	Reactor Trip Breaker Status	1.000	0.000	10.000	0.000	2.000	0.000	1.000	0.000

Table 3-1 (continued)

Channel No.	Parameter	Amplifier Gain	Amplifier Offset	Preamp Range	Preamp Offset	Transducer Units Range	Transducer Units Offset	Transducer Voltage Range	Transducer Voltage Offset
16	Unused	1.000	0.000	10.000	0.000	2.000	0.000	1.000	0.000
17	Pressurizer Pressure (Wide Range)	50.000	0.767	0.000	0.000	3000.000	0.000	0.800	0.200
18	Pressurizer Pressure (Narrow Range)	50.000	0.780	0.000	0.000	1000.000	1500.000	0.800	0.200
19	Pressurizer Level	20.000	0.450	0.000	0.000	100.000	0.000	0.800	0.200
20	T-hot (SG-1)	20.000	0.583	0.000	0.000	150.000	525.000	0.800	0.200
21	T-hot (SG-2)	20.000	0.583	0.000	0.000	150.000	525.000	0.800	0.200
22	T-cold (Loop 1A)	100.000	0.930	0.000	0.000	600.000	0.000	0.800	0.200
23	T-cold (Loop 1B)	20.000	0.690	0.000	0.000	150.000	465.000	0.800	0.200
24	T-cold (Loop 2A)	20.000	0.690	0.000	0.000	150.000	465.000	0.800	0.200
25	T-cold (Loop 2B)	20.000	0.490	0.000	0.000	100.000	525.000	0.800	0.200
26	SG-1 Pressure	20.000	0.783	0.000	0.000	1200.000	0.000	0.800	0.200
27	SG-2 Pressure	20.000	0.783	0.000	0.000	1200.000	0.000	0.800	0.200
28	Nuclear Power (Control Channel 1)	1.000	5.000	0.000	0.000	125.000	0.000	10.000	0.000
29	SG-2 Level	20.000	0.650	0.000	0.000	100.000	0.000	0.800	0.200
30	SG-1 Feedwater ΔP	10.000	0.700	0.000	0.000	795.300	0.000	0.800	0.200
31	SG-2 Feedwater ΔP	10.000	0.700	0.000	0.000	790.600	0.000	0.800	0.200
32	SG-1 Header Pressure	10.000	0.700	0.000	0.000	200.000	850.000	0.800	0.200
33	SG-2 Header Pressure	10.000	0.700	0.000	0.000	200.000	850.000	0.800	0.200
34	SG-1 Header ΔP	10.000	0.700	0.000	0.000	842.900	0.000	0.800	0.200
35	SG-2 Header ΔP	10.000	0.700	0.000	0.000	823.700	0.000	0.800	0.200
36	SG-1 Level	20.000	0.650	0.000	0.000	100.000	0.000	0.800	0.200
37	RCP-A ΔP	10.000	0.700	0.000	0.000	130.000	0.000	0.800	0.200

Table 3-1 (continued)

Channel No.	Parameter	Amplifier Gain	Amplifier Offset	Preamp Range	Preamp Offset	Transducer Units Range	Transducer Units Offset	Transducer Voltage Range	Transducer Voltage Offset
38	RCP-B ΔP	10.000	0.700	0.000	0.000	130.000	0.000	0.800	0.200
39	RCP-C ΔP	10.000	0.700	0.000	0.000	130.000	0.000	0.800	0.200
40	RCP-D ΔP	10.000	0.700	0.000	0.000	130.000	0.000	0.800	0.200
41	RCP-A Speed	2.000	2.500	0.000	0.000	920.000	0.000	5.000	0.000
42	RCP-B Speed	2.000	2.500	0.000	0.000	920.000	0.000	5.000	0.000
43	RCP-C Speed	2.000	2.500	0.000	0.000	920.000	0.000	5.000	0.000
44	RCP-D Speed	2.000	2.500	0.000	0.000	920.000	0.000	5.000	0.000
45	Unused	1.000	0.000	0.000	0.000	920.000	0.000	1.000	0.000
46	Unused	1.000	0.000	0.000	0.000	920.000	0.000	1.000	0.000
47	Unused	1.000	0.000	0.000	0.000	920.000	0.000	1.000	0.000
48	Unused	1.000	0.000	0.000	0.000	920.000	0.000	1.000	0.000

Table 3-2

DATA CONVERSION MATRIX FOR THE CEA DROPS

Channel No.	Parameter	Amplifier Gain	Amplifier Offset	Preamp Range	Preamp Offset	Transducer Units Range	Transducer Units Offset	Transducer Voltage Range	Transducer Voltage Offset
1	RCP-C ΔP	1.000	0.000	2.000	0.000	130.000	0.000	0.800	0.200
2	RCP-D ΔP	1.000	0.000	2.000	0.000	130.000	0.000	0.800	0.200
3	Unused	1.000	0.000	2.000	0.000	100.000	0.000	0.800	0.200
4	Unused	1.000	0.000	2.000	0.000	100.000	0.000	0.800	0.200
5	Unused	1.000	0.000	2.000	0.000	100.000	0.000	0.800	0.200
6	Unused	1.000	0.000	2.000	0.000	100.000	0.000	0.800	0.200
7	Unused	1.000	0.000	2.000	0.000	100.000	0.000	1.000	0.000
8	Unused	1.000	0.000	2.000	0.000	100.000	0.000	1.000	0.000
9	RCP-A Breaker Status	1.000	0.000	10.000	0.000	2.000	0.000	1.000	0.000
10	RCP-B Breaker Status	1.000	0.000	10.000	0.000	2.000	0.000	1.000	0.000
11	RCP-C Breaker Status	1.000	0.000	10.000	0.000	2.000	0.000	1.000	0.000
12	RCP-D Breaker Status	1.000	0.000	10.000	0.000	2.000	0.000	1.000	0.000
13	Unused	1.000	0.000	2.000	0.000	2.000	0.000	1.000	0.000
14	Unused	1.000	0.000	2.000	0.000	2.000	0.000	1.000	0.000
15	Unused	1.000	0.000	10.000	0.000	2.000	0.000	1.000	0.000
16	Unused	1.000	0.000	10.000	0.000	2.000	0.000	1.000	0.000
17	Pressurizer Pressure (Wide Range)	20.000	0.783	0.000	0.000	3000.000	0.000	0.800	0.200
18	Pressurizer Pressure (Narrow Range)	20.000	0.650	0.000	0.000	1000.000	1500.000	0.800	0.200
19	Pressurizer Level	20.000	0.450	0.000	0.000	100.000	0.000	0.800	0.200

Table 3-2 (continued)

Channel No.	Parameter	Amplifier Gain	Amplifier Offset	Preamp Range	Preamp Offset	Transducer Range	Units Offset	Transducer Range	Voltage Offset
20	T-hot (SG-1)	20.000	0.583	0.000	0.000	150.000	525.000	0.800	0.200
21	T-hot (SG-2)	20.000	0.583	0.000	0.000	150.000	525.000	0.800	0.200
22	T-cold (Loop 1A)	20.000	0.917	0.000	0.000	600.000	0.000	0.800	0.200
23	T-cold (Loop 1B)	20.000	0.690	0.000	0.000	150.000	465.000	0.800	0.200
24	T-cold (Loop 2A)	20.000	0.690	0.000	0.000	150.000	465.000	0.800	0.200
25	T-cold (Loop 2B)	20.000	0.450	0.000	0.000	100.000	525.000	0.800	0.200
26	SG-1 Pressure	10.000	0.700	0.000	0.000	1200.000	0.000	0.800	0.200
27	SG-2 Pressure	10.000	0.700	0.000	0.000	1200.000	0.000	0.800	0.200
28	SG-1 Level	20.000	0.650	0.000	0.000	100.000	0.000	0.800	0.200
29	SG-2 Level	20.000	0.650	0.000	0.000	100.000	0.000	0.800	0.200
30	SG-1 Feedwater ΔP	20.000	0.450	0.000	0.000	800.000	0.000	0.800	0.200
31	SG-2 Feedwater ΔP	20.000	0.450	0.000	0.000	800.000	0.000	0.800	0.200
32	SG-1 Header Pressure	5.000	0.800	0.000	0.000	200.000	850.000	0.800	0.200
33	SG-2 Header Pressure	5.000	0.800	0.000	0.000	200.000	850.000	0.800	0.200
34	SG-1 Header ΔP	20.000	0.450	0.000	0.000	800.000	0.000	0.800	0.200
35	SG-2 Header ΔP	20.000	0.450	0.000	0.000	800.000	0.000	0.800	0.200
36	Nuclear Power (Control Channel 1)	2.000	2.500	0.000	0.000	125.000	0.000	10.000	0.000
37	Nuclear Power (Control Channel 2)	2.000	2.500	0.000	0.000	125.000	0.000	10.000	0.000
38	Turbine First Stage Pressure	10.000	0.900	0.000	0.000	740.000	0.000	1.600	0.400
39	RCP-A ΔP	10.000	0.700	0.000	0.000	130.000	0.000	0.800	0.200
40	RCP-B ΔP	10.000	0.700	0.000	0.000	130.000	0.000	0.800	0.200

Table 3-2 (continued)

Channel No.	Parameter	Amplifier Gain	Amplifier Offset	Preamp Range	Preamp Offset	Transducer Units Range	Transducer Units Offset	Transducer Voltage Range	Transducer Voltage Offset
41	Unused	2.000	2.500	0.000	0.000	920.000	0.000	5.000	0.000
42	RCP-A Speed	2.000	2.500	0.000	0.000	920.000	0.000	5.000	0.000
43	RCP-B Speed	2.000	2.500	0.000	0.000	920.000	0.000	5.000	0.000
44	RCP-C Speed	2.000	2.500	0.000	0.000	920.000	0.000	5.000	0.000
45	RCP-D Speed	2.000	2.500	0.000	0.000	920.000	0.000	5.000	0.000
46	Unused	1.000	0.000	0.000	0.000	0.000	0.000	1.000	0.000
47	Unused	1.000	0.000	0.000	0.000	0.000	0.000	1.000	0.000
48	Unused	1.000	0.000	0.000	0.000	0.000	0.000	1.000	0.000

Table 3-3

DATA CONVERSION MATRIX FOR THE TURBINE TRIP

Channel No.	Parameter	Amplifier Gain	Amplifier Offset	Preamp Range	Preamp Offset	Transducer Units Range	Transducer Units Offset	Transducer Voltage Range	Transducer Voltage Offset
1	Reactor Trip Breaker Status	1.000	0.000	10.000	0.000	100.000	0.000	6.300	0.000
2	RCP-A Breaker Status	1.000	0.000	10.000	0.000	100.000	0.000	10.000	0.000
3	Turbine Trip Breaker Status	1.000	0.000	10.000	0.000	100.000	0.000	10.000	0.000
4	RCP-C Breaker Status	1.000	0.000	10.000	0.000	100.000	0.000	10.000	0.000
5	RCP-D Breaker Status	1.000	0.000	10.000	0.000	100.000	0.000	10.000	0.000
6	Unused	1.000	0.000	10.000	0.000	100.000	0.000	10.000	0.000
7	Unused	1.000	0.000	10.000	0.000	100.000	0.000	10.000	0.000
8	Unused	1.000	0.000	10.000	0.000	100.000	0.000	10.000	0.000
9	Unused	1.000	0.000	10.000	0.000	100.000	0.000	10.000	0.000
10	RCP-D ΔP	10.000	0.700	0.000	0.000	130.000	0.000	0.800	0.200
11	SG-2 Emergency Feedwater Flow	1.000	0.000	0.000	0.000	600.000	0.000	5.000	0.000
12	SG-2 Emergency Feedwater Flow	1.000	0.000	0.000	0.000	600.000	0.000	5.000	0.000
13	Unused	1.000	0.000	10.000	0.000	100.000	0.000	10.000	0.000
14	Unused	1.000	0.000	10.000	0.000	100.000	0.000	10.000	0.000
15	Unused	1.000	0.000	10.000	0.000	100.000	0.000	10.000	0.000
16	Unused	1.000	0.000	10.000	0.000	100.000	0.000	10.000	0.000
17	Pressurizer Pressure (Narrow Range)	10.000	0.700	0.000	0.000	1000.000	1500.000	0.800	0.200

Table 3-3 (continued)

Channel No.	Parameter	Amplifier Gain	Amplifier Offset	Preamp Range	Preamp Offset	Transducer Units Range	Transducer Units Offset	Transducer Voltage Range	Transducer Voltage Offset
18	Pressurizer Level	10.000	0.700	0.000	0.000	100.000	0.000	0.800	0.200
19	T-hot (SG-1)	20.000	0.583	0.000	0.000	150.000	525.000	0.800	0.200
20	T-hot (SG-2)	20.000	0.583	0.000	0.000	150.000	525.000	0.800	0.200
21	T-cold (Loop 1A)	20.000	0.917	0.000	0.000	600.000	0.000	0.800	0.200
22	T-cold (Loop 1B)	20.000	0.690	0.000	0.000	150.000	465.000	0.800	0.200
23	T-cold (Loop 2A)	20.000	0.690	0.000	0.000	150.000	465.000	0.800	0.200
24	T-cold (Loop 2B)	20.000	0.450	0.000	0.000	100.000	525.000	0.800	0.200
25	SG-1 Pressure	10.000	0.700	0.000	0.000	1200.000	0.000	0.800	0.200
26	SG-2 Pressure	10.000	0.700	0.000	0.000	1200.000	0.000	0.800	0.200
27	SG-1 Level	10.000	0.700	0.000	0.000	100.000	0.000	0.800	0.200
28	SG-2 Level	10.000	0.700	0.000	0.000	100.000	0.000	0.800	0.200
29	SG-1 Feedwater ΔP	10.000	0.700	0.000	0.000	795.260	0.000	0.800	0.200
30	SG-2 Feedwater ΔP	10.000	0.700	0.000	0.000	790.630	0.000	0.800	0.200
31	SG-1 Header Pressure	5.000	0.800	0.000	0.000	200.000	850.000	0.800	0.200
32	SG-2 Header Pressure	5.000	0.800	0.000	0.000	200.000	850.000	0.800	0.200
33	SG-1 Header ΔP	10.000	0.700	0.000	0.000	842.860	0.000	0.800	0.200
34	SG-2 Header ΔP	10.000	0.700	0.000	0.000	823.670	0.000	0.800	0.200
35	Nuclear Power (Control Channel 1)	1.000	5.000	0.000	0.000	125.000	0.000	10.000	0.000
36	Nuclear Power (Control Channel 2)	1.000	5.000	0.000	0.000	125.000	0.000	10.000	0.000
37	Turbine First Stage Pressure	5.000	1.400	0.000	0.000	740.000	0.000	1.600	0.400
38	SG-1 Emergency Feedwater Flow	1.000	0.000	0.000	0.000	600.000	0.000	5.000	0.000

Table 3-3 (continued)

Channel No.	Parameter	Amplifier Gain	Amplifier Offset	Preamp Range	Preamp Offset	Transducer Units Range	Transducer Units Offset	Transducer Voltage Range	Transducer Voltage Offset
39	SG-1 Emergency Feedwater Flow	1.000	0.000	0.000	0.000	600.000	0.000	5.000	0.000
40	SG-1 Feedwater Valve Position	1.000	5.000	0.000	0.000	100.000	0.000	10.000	0.000
41	SG-2 Feedwater Valve Position	1.000	5.000	0.000	0.000	100.000	0.000	10.000	0.000
42	RCP-A Speed	2.000	2.500	0.000	0.000	892.000	0.000	4.800	0.000
43	RCP-B Speed	2.000	2.500	0.000	0.000	892.000	0.000	4.800	0.000
44	RCP-C Speed	2.000	2.500	0.000	0.000	892.000	0.000	4.800	0.000
45	RCP-D Speed	2.000	2.500	0.000	0.000	892.000	0.000	4.800	0.000
46	RCP-A ΔP	10.000	0.700	0.000	0.000	130.000	0.000	0.800	0.200
47	RCP-B ΔP	10.000	0.700	0.000	0.000	130.000	0.000	0.800	0.200
48	RCP-C ΔP	10.000	0.700	0.000	0.000	130.000	0.000	0.800	0.200

Due to the recursive nature of this algorithm, a unique set of cutoff frequencies and damping ratios are required each time the sampling rate is changed. The filter specifications used for plotting the process parameters are contained in Tables 3-4 through 3-6. No filtering was performed for the Turbine Trip data since the noise component associated with this data was much smaller than the ones associated with data of the previous three tests. Thus, all plots of the Turbine Trip data which appear in Section 4 of this report have not utilized this algorithm prior to plotting.

9. Plot the converted and filtered data. Long term (30 minutes) and short term (1 minute) plots of the monitored NSSS variables appear in Section 4 of this report.

TRANSIENT SPECIFIC TEST PROCEDURES

Loss of Flow

Appropriate initial conditions were achieved and clearance was obtained from the load dispatcher prior to tripping the reactor coolant pumps (RCPs). A one minute countdown was initiated approximately 5 minutes before the trip. At two minutes prior to the test, the data acquisition system was started. At time zero, the transient was initiated by tripping the four RCPs simultaneously. Data acquisition continued for approximately 10 minutes, followed by verification of natural circulation by observing gradually decreasing hot leg temperatures.

Once the data acquisition was completed, the raw data was converted to engineering units and the test results were evaluated to verify that all post-test acceptance criteria were met. These criteria were:

1. Maximum reactor coolant system pressure during the first 60 seconds of the transient did not exceed 2280 psia.
2. The minimum saturation margin at any time during the transient was greater than 20°F.
3. The power to flow ratio did not exceed 21.165 watt hr/lbm once natural circulation was established. This is the nominal value when the NSSS is at full power and the reactor coolant pumps are delivering full flow.
4. Once natural circulation was established, the hot leg temperature did not exceed 600°F and the cold leg temperature did not fall below 500°F.

Full and Part Length CEA Drops

Once the proper initial conditions were achieved (including equilibrium Xenon for the full length CEA drop) and the Control Element Assembly Calculators (CEACs) were taken out of service, a five minute countdown was initiated. At time zero the selected CEA was dropped by opening the appropriate CEA disconnect circuit breaker; breaker number 60 for the full length CEA (5-60) drop, and breaker number 24 for

Table 3-4

FILTER SPECIFICATIONS FOR THE LOF PLOTS

Parameter	Cut-Off Frequency (Hz.)	Damping Ratio
Pressurizer Pressure	0.25	0.50
Pressurizer Level	0.25	0.50
Steam Generator 1 Hot Leg Temperature	0.25	0.50
Steam Generator 1 Cold Leg Temperature (Loop 1A)	0.25	0.50
Steam Generator 1 Cold Leg Temperature (Loop 1B)	0.25	0.50
Steam Generator 2 Hot Leg Temperature	0.50	0.75
Steam Generator 2 Cold Leg Temperature (Loop 2A)	0.25	0.50
Steam Generator 2 Cold Leg Temperature (Loop 2B)	0.25	0.50
Steam Generator 1 Feedwater Flow Rate	0.50	0.90
Steam Generator 1 Main Steam Flow Rate	0.25	0.50
Steam Generator 1 Level	N/A	N/A
Steam Generator 2 Feedwater Flow Rate	0.25	0.50
Steam Generator 2 Main Steam Flow Rate	0.25	0.50
Steam Generator 2 Level	0.50	0.75
Steam Generator 1 Pressure	0.25	0.50
Steam Generator 2 Header Pressure	0.25	0.50

Table 3-5

FILTER SPECIFICATIONS FOR THE FLCEAD PLOTS

Parameters	Cut-Off Frequency (Hz.)	Damping Ratio
Pressurizer Pressure (Wide Range)	N/A	N/A
Pressurizer Pressure (Narrow Range)	N/A	N/A
Pressurizer Level	N/A	N/A
Control Channel 1 Nuclear Power	1.50	0.90
Control Channel 2 Nuclear Power	0.90	0.90
Turbine Power	0.50	0.50
Steam Generator 1 Hot Leg Temperature	0.50	0.90
Steam Generator 1 Cold Leg Temperature (Loop 1A)	0.25	0.50
Steam Generator 1 Cold Leg Temperature (Loop 1B)	0.50	0.90
Steam Generator 2 Hot Leg Temperature	0.50	0.90
Steam Generator 2 Cold Leg Temperature (Loop 2A)	0.25	0.50
Steam Generator 2 Cold Leg Temperature (Loop 2B)	0.50	0.90
Steam Generator 1 Feedwater Flow Rate	0.10	0.90
Steam Generator 1 Main Steam Flow Rate	0.25	0.90
Steam Generator 1 Level	0.10	0.75
Steam Generator 2 Feedwater Flow Rate	0.10	0.90
Steam Generator 2 Main Steam Flow Rate	0.25	0.75
Steam Generator 2 Level	0.1	0.75

Table 3-5 (continued)

Parameters	Cut-Off Frequency (Hz.)	Damping Ratio
Steam Generator 1 Pressure	N/A	N/A
Steam Generator 1 Header Pressure	0.75	0.50
Steam Generator 2 Pressure	N/A	N/A
Steam Generator 2 Header Pressure	0.25	0.50
Turbine First Stage Pressure	0.50	0.50

Table 3-6

FILTER SPECIFICATIONS FOR THE PLCEAD PLOTS

Parameter	Cut-Off Frequency (Hz.)	Damping Ratio
Pressurizer Pressure (Wide Range)	0.75	0.95
Pressurizer Pressure (Narrow Range)	0.75	0.95
Pressurizer Level	0.75	0.50
Control Channel 1 Nuclear Power	0.25	0.50
Control Channel 2 Nuclear Power	0.25	0.50
Turbine Power	0.25	0.50
Steam Generator 1 Hot Leg Temperature	0.50	0.90
Steam Generator 1 Cold Leg Temperature (Loop 1A)	0.25	0.50
Steam Generator 1 Cold Leg Temperature (Loop 1B)	0.50	0.90
Steam Generator 2 Hot Leg Temperature	0.50	0.90
Steam Generator 2 Cold Leg Temperature (Loop 2A)	0.25	0.50
Steam Generator 2 Cold Leg Temperature (Loop 2B)	0.50	0.90
Steam Generator 1 Feedwater Flow Rate	0.10	0.90
Steam Generator 1 Main Steam Flow Rate	0.25	0.75
Steam Generator 1 Level	0.25	0.75
Steam Generator 2 Feedwater Flow Rate	0.10	0.90
Steam Generator 2 Main Steam Flow Rate	0.10	0.90
Steam Generator 2 Level	0.10	0.90

Table 3-6 (continued)

Parameter	Cut-Off Frequency (Hz.)	Damping Ratio
Steam Generator 1 Pressure	0.25	0.50
Steam Generator 1 Header Pressure	0.10	0.75
Steam Generator 2 Pressure	0.25	0.50
Steam Generator 2 Header Pressure	0.10	0.75
Turbine First Stage Pressure	0.25	0.50

the part length CEA (P-24) drop. The turbine load limit was immediately adjusted to match the core power and to maintain a constant core average temperature. Data acquisition continued for approximately 30 minutes following the drop. After one hour had elapsed, the dropped CEA was returned to the fully withdrawn position while maintaining a constant core power level through RCS boration. Immediately following the test, the results were evaluated to verify that the physics design codes adequately predicted the change in the reactor core power distribution.

Turbine Trip

After achieving the appropriate initial conditions, an observer was stationed to observe the operation of the atmospheric dump valves. Clearance was obtained from the load dispatcher to trip the reactor and a five minute countdown was initiated. Two minutes prior to the initiation of this transient the data acquisition system was started and at time zero the main turbine was manually tripped from the control room. Due to the unusual nature of this test, data acquisition continued for approximately an hour and a half following the trip.

Immediately following the test, the raw data were converted to engineering units and the test results were evaluated to verify that all post-test acceptance criteria were met. These criteria were:

1. Maximum reactor coolant system pressure during any portion of the transient was less than 2500 psia.
2. The pressurizer did not completely fill with liquid.
3. All plant control systems functioned automatically following the turbine trip.
4. The plant operating procedures and operator actions were adequate to maintain the plant and all equipment in a safe condition.

Section 4

TEST RESULTS

LOSS OF FLOW

Initial Conditions

The 4-pump loss of forced primary coolant flow (LOF) was initiated from the test conditions shown in Table 4-1. Prior to the test, steam generator blowdown was secured and the first and second stage reheater tube bundles of both moisture separation reheaters were isolated. All four reactor coolant pumps were running and all four channels of the Plant Protection System (PPS) were operative.

All of the plant control systems were in the automatic mode and operating normally, except for the Steam Dump and Bypass Control System (SDBCS). Due to hardware problems, one turbine bypass valve and one atmospheric dump valve were isolated. The two atmospheric dump valves located upstream of the main steam isolation valves were placed in the manual mode and were therefore unavailable during the test. With the operable valves -- two turbine bypass valves and one atmospheric dump valve -- the SDBCS could achieve a maximum dump capacity equivalent to approximately 30 percent of the full power main steam flow rate.

Sequence of Events

The test was initiated at 1119 on December 30, 1979, by tripping all four reactor coolant pumps simultaneously. The Plant Protection System subsequently tripped the reactor on a (projected*) low departure from nucleate boiling ratio (DNBR) signal. Immediately following the reactor trip, an automatic turbine trip was generated and the reactor trip override feature of the Feedwater Control System began to ramp the feedwater flow to 5 percent of the full power feedwater flow rate. Due to a temporary loss of heat removal capabilities by the secondary

*The PPS installed at ANO-2 utilizes a digital computer system to continuously monitor certain core parameters and project, in time, the minimum DNBR that would occur during the loss of flow transient. The system will trip the reactor prior to reaching a safety limit, thus precluding the possibility of violating the Specified Acceptable Fuel Design Limit during the LOF test.

system, primary system temperatures and pressures increased slightly, but then began to fall rapidly as the shutdown CEAs entered the core.

The rapidly increasing secondary pressure (resulting from closure of the turbine admission valve) caused the SDBCS to generate quick-open signals to both turbine bypass valves. The valves were in the full open position approximately two seconds into the transient and remained fully open for about 10 seconds. Since the bypass capacity was not sufficient to remove all the excess heat, one atmospheric dump valve also opened to vent the additional steam flow to the atmosphere.

After the initial rise in pressurizer pressure and primary system temperatures, all of the monitored NSSS variables (except secondary pressure) decreased rapidly as the shutdown CEAs began to reduce core power. The CEAs were fully inserted in approximately 3 seconds, reducing the core power to less than 5 percent (decay heat).

The RCS cooldown associated with the reactor trip caused a reduction in pressurizer pressure and level. As the level decreased below a predetermined setpoint, the Pressurizer Level Control System (PLCS) automatically started a second charging pump and began to throttle back the letdown flow. The minimum pressurizer pressure and pressurizer level reached were 2008 psia and 26.2 percent respectively, approximately 40 seconds after the reactor trip.

Secondary system pressure peaked about 60 seconds into the transient, with a maximum value of 1041 psia being recorded in the main steam header of steam generator 1. Following this, pressure decreased slowly to around 1000 psia, where it remained essentially constant as the RCS cooldown continued. A detailed sequence of events for this transient is presented in Table 4-2. Pertinent operating characteristics of the SDBCS are shown in Table 4-3.

Process Parameter Transients

Figures 4-1 through 4-22 show the 10 minute response of the monitored NSSS variables to the LOF. These data were digitally filtered using the algorithm described in Section 3 and plotted with the Houston Instruments DP-11 plotting system described in Section 2. All data, except for primary and secondary system flow rates, were direct measurements utilizing the existing plant instrumentation. Primary system flow rates were derived from measured values of reactor

coolant pump differential pressures and speeds. The methodology and algorithms used to determine the primary system flow rates are described in Appendix A. Secondary system flow rates (i.e., feedwater and main steam flow rates) were calculated using measured values of differential pressures along with secondary system temperatures and pressures. The methodology and algorithms used to determine the secondary system flow rates are described in Appendix B.

Figures 4-23 through 4-57 show the response of the monitored NSSS variables to the LOF during the first 60 seconds following the pump trip. In all cases, the unfiltered data for each of the measured parameters are shown. For those parameters for which the data were digitally filtered (using the algorithm described in Section 3), the filtered data are shown superimposed on the unfiltered data.

As described in Section 3, a side effect of digital filtering is the introduction of a small artificial time delay between the filtered and unfiltered data. This delay is not significant when slow changes occur; however, it can distort the transient data for those variables which show rapid changes. Therefore, it was decided that for those variables which show rapid changes, digital filtering would not be employed during the time interval in which the rapid changes occur. In this way, the plots more accurately represent the actual NSSS response. For the LOF test, four of the monitored variables which were digitally filtered exhibited these rapid changes - steam generator 1 main steam flow rate (Figure 4-47), steam generator 1 level (Figure 4-48), steam generator 2 header pressure (Figure 4-52), and steam generator 2 main steam flow rate (Figure 4-53). The time interval over which digital filtering was not applied is indicated on each of the four figures.

During the performance of the LOF test, four of the Honeywell Accudata Amplifiers (all of which were previously tested) developed problems which resulted in unacceptable data for four of the monitored variables. For the wide range pressurizer pressure (Figure 4-55), the cross-calibration check of the data from the Data Acquisition System (DAS) and the plant computer before and after the test showed a parameter difference of greater than 1% of its initial steady state value, thus falling outside the limits of the acceptance criteria; therefore, the data from the DAS for this parameter was considered invalid. For each of three other monitored variables -- control channel nuclear power, steam generator 1 header pressure and steam generator 2 pressure -- the corresponding amplifier was

saturated prior to the test so that no useful data was obtained. However, although valid data were not available from the DAS for the four parameters mentioned above, data for these variables were available from other sources, as described below:

- There were two diverse channels of the DAS allocated for recording pressurizer pressure. The wide range indication was monitoring between 1250 psia and 2750 psia while the narrow range indication was monitoring between 2100 psia and 2375 psia. Additionally, both indications were being trended by the plant computer. Thus, a combination of the narrow range indication and values taken from the plant computer trend groups provided an accurate time history of the pressurizer pressure during the event.

- Steam generator 2 pressure and steam generator 1 header pressure were also being monitored on the plant computer. Values taken from the trend groups show both steam generators exhibiting nearly identical trends. The peak values occur at the same time and are within 5 psia of each other. Even though the valve configurations which existed during the test were asymmetric, this asymmetry was small. Therefore, the pressures and header pressures of the two steam generators were quite close, so that the data recorded for the variables for one steam generator can be taken as indicative of the behavior of the same variables for other steam generator also.

- The control channel nuclear power was also being backed up by the plant computer. Additionally, the data being recorded by the DAS for the first 3 or 4 seconds following the trip were accurate. Amplifier problems surfaced only after the core power had decreased to less than 5 percent. Thus, Figure 4-23 is a combination of DAS and plant computer values.

In addition to the amplifier problems described above, three of the measured quantities -- narrow range pressurizer pressure (Figures 4-19 and 4-56), steam generator 1 level (Figures 4-15 and 4-48) and steam generator 2 level (Figures 4-18 and 4-54) -- reached instrumentation setpoints. In each of these cases, the missing data were filled in with backup data from the plant computer trend groups. For the steam generator level measurement, plant computer trend group data were used when the steam generator level decreased below 25 percent. For the narrow range pressurizer pressure, plant computer trend group data were used when the pressurizer pressure decreased below 2100 psia. The time interval over which plant computer trend group data were used in each case is indicated on the corresponding short term plot (Figures 4-48, 4-54 and 4-56).

It should be noted that the uncertainties in the primary system flow rates shown in the figures increase as the primary system flow rate decreases. This is due to the fact that since there is no direct measurement of primary system flow, this quantity must be inferred from measurements of both the pump speed and the differential pressure across the pump. Unfortunately, however, as the differential pressure across a pump decreases, the differential pressure sensors become less and less accurate, until, under natural circulation conditions, the uncertainty of the differential pressure sensor is equal to or greater than the differential pressure itself. Therefore, primary system flow measurements in the low flow regime are estimates only and should not be construed as an accurate indication of the true flow.

For similar reasons, the uncertainties in the secondary system flow rates (feedwater and main steam flow rates) also increase as the flow rate decreases. Furthermore, since the secondary system flow rate calculation is not nearly as detailed as that for the primary system flow rates (which are directly related to thermal margin and hence must be known in much greater detail), the uncertainties in the secondary system flow rates are slightly larger than those for the primary system flow rates. In addition, the response time associated with the differential pressure sensors is longer than the time it takes for the turbine admission valves to close. Therefore, the actual steam flow rates (Figures 4-47 and 4-53) go from their steady-state values down to zero in approximately 0.2 seconds, then increase rapidly as the steam dump valves open. The response time of the sensor is not fast enough to detect this.

FULL LENGTH CEA DROP

Initial Conditions

The full length CEA drop was initiated from the test conditions shown in Table 4-4. The reactor core was stable with all rods out (ARO), equilibrium xenon conditions, 700 PPM boron, approximately 2300 Mwd/T burnup, and an Axial Shape Index (ASI) near 0.0. All four reactor coolant pumps were running, and all plant control systems were in the automatic mode. CEA 5-60 was chosen to be dropped for this test because it was aligned with the steam generator 2 hot leg (Figure 1-1). By aligning the dropped CEA with the steam generator hot leg, the experimental data were expected to show the largest observable change.

Following the pre-test verification and prior to initiating the CEA drop, the common timing connections between the PDP-11 minicomputer and the CEA position recorders failed. Thus, it was necessary to develop an alternative method for determining the exact time at which the CEA entered the core. By correlating the response of the ex-core neutron detectors with CEA position during the part length CEA drop, it was possible to determine the time that CEA 5-60 entered the core to within ± 0.5 seconds.

During the full length CEA drop, a constant mass flow rate through the core of 134.0×10^6 lbm/hr was assumed.

Sequence of Events

The test was initiated at 0030 on January 11, 1980, by opening the CEA 5-60 disconnect circuit breaker. Immediately following the CEA drop, the turbine load limit was adjusted to match the new average core power level. The core power decreased by approximately 7 percent of rated power.

Due to the location of CEA 5-60, the results of this test show an asymmetric system transient. The hot and cold leg temperatures associated with steam generator 2 drop at a faster rate and to slightly lower values than those associated with steam generator 1. The hot leg temperature associated with steam generator 2 shows a drop of almost 8°F during the first 90 seconds of the transient while the hot leg temperature associated with the steam generator 1 decreases only about 5°F during the same time period. The cold leg temperatures show the same trends. Similar asymmetries are noted for the feedwater and main steam flow rates. In all cases, the initial drop of the monitored variable is followed by a gradual return to values which correspond to the new steady-state power level (approximately 43 percent of rated power).

The control channel ex-core neutron detectors (located on opposite sides of the core) also show an asymmetric system transient. Although these detectors are subject to decalibration when a CEA enters the core, they do indicate a substantial tilt in the core power distribution. Table 4-5 provides a sequence of events for this transient.

Process Parameter Transients

Figures 4-58 through 4-80 show the 30 minute response of the monitored NSSS variables to the full length CEA drop. These data were digitally filtered using the algorithm described in Section 3 and plotted with the Houston Instruments DP-11 plotting system described in Section 2. All data, except for secondary system flow rates and turbine power, were direct measurements from the existing plant instrumentation. Secondary system flow rates (i.e., feedwater and main steam flow rates) were calculated using measured values of differential pressures along with secondary system temperatures and pressures. The methodology and algorithms used to determine these values are described in Appendix B. Turbine power was calculated by an empirical equation which expresses the turbine power as a third-order polynomial in the turbine first stage pressure. This algorithm is also given in Appendix B.

It should be pointed out that for the full length (and part length) CEA drops, the turbine power is the best indication of the actual core power. The core power as determined from the ex-core detectors (control channel nuclear power) is less accurate due to the fact that the ex-core detectors become decalibrated when a CEA enters the core. In addition, the nuclear power as determined from each control channel is influenced by the location of the dropped CEA relative to the position of each ex-core detector.

Figures 4-81 through 4-115 show the response of the monitored NSSS variables to the full length CEA drop during the first 60 seconds following the drop. In all cases, the unfiltered data for each of the measured parameters is shown. For those parameters for which the data were digitally filtered (using the algorithm described in Section 3), the filtered data are shown superimposed on the unfiltered data. Each parameter was cross-checked against the plant computer for consistency both before and after the test and was found to be well within the acceptance criteria.

As discussed previously, digital filtering was not employed for those variables which show rapid changes during the time interval in which the rapid changes occur. For the full length CEA test, two of the monitored variables which were digitally filtered exhibited these rapid changes -- control channel 1 nuclear power (Figure 4-81) and control channel 2 nuclear power (Figure 4-82). The time interval over which digital filtering was not applied is indicated on each of the two figures.

PART LENGTH CEA DROP

Initial Conditions

The part length CEA drop was initiated from the test conditions shown in Table 4-6. This test was performed approximately 12 hours after the full length CEA drop with all rods out (ARO), 702 PPM boron and an ASI of approximately 0.0. All four reactor coolant pumps were running and all plant control systems were in the automatic mode. The part length CEA chosen to be dropped for this test was also aligned with the steam generator 2 hot leg (Figure 1-1).

Since the full length CEA drop was performed just 12 hours earlier, a slight xenon oscillation was present at the time of the test. However, the amplitude of this oscillation was relatively small (±0.03 ASI units) and the period very long (approximately 28 hours) in comparison with the actual test transient. Thus, the xenon oscillation did not have a measurable impact on the results of this test.

As was the case for the full length CEA drop, a constant mass flow rate through the core of 134.0×10^6 lbm/hr was assumed for the entire transient.

Sequence of Events

The test was initiated at 1315 on January 11, 1980, by opening the CEA P-24 disconnect circuit breaker. Immediately following the CEA drop, the turbine load limit was adjusted to match the resulting average core power. The core power decreased by approximately 7 percent of rated power.

Due to the smaller amount of negative reactivity inserted, the monitored NSSS variables restabilized at new steady-state values approximately 5 minutes after the drop. Table 4-7 provides a sequence of events for this transient.

Process Parameter Transients

Figures 4-116 through 4-138 show the 30 minute response of the monitored NSSS variables to the part length CEA drop. These data were digitally filtered using the algorithm described in Section 3 and plotted with the Houston Instruments DP-11 system. All data, except for secondary system flow rates and turbine power, were direct measurements utilizing the existing plant instrumentation. Secondary system flow rates (i.e., feedwater and main steam flow rates) were calculated using measured values of differential pressures along with secondary system

temperatures and pressures. The methodology and algorithms used to determine these values are described in Appendix B. Turbine power was calculated by an empirical equation which expresses the turbine power as a third-order polynomial in the turbine first stage pressure. This algorithm is also given in Appendix B.

Figures 4-139 through 4-173 show the response of the monitored NSSS variables to the part length CEA drop during the first 60 seconds following the drop. In all cases, the unfiltered data for each of the measured parameters is shown. For those parameters for which the data were digitally filtered (using the algorithm described in Section 3), the filtered data are shown superimposed on the unfiltered data. Each parameter was cross-checked against the plant computer for consistency both before and after the test and was found to be well within the acceptance criteria.

As discussed previously, digital filtering was not employed for those variables which show rapid changes during the time interval in which the rapid changes occur. For the part length CEA test, two of the monitored variables which were digitally filtered exhibited these rapid changes -- control channel 1 nuclear power (Figure 4-139) and control channel 2 nuclear power (Figure 4-140). The time interval over which digital filtering was not applied is indicated on each of the two figures.

A spurious electrical noise spike was observed in the steam generator 2 cold leg temperature (loop 2B) data (see Figure 4-147) approximately 25 seconds after the CEA drop. This spike was eliminated prior to digital filtering using a wild-point editing scheme. The unwanted spike was replaced by linearly interpolated data between the last good data point before the spike and the first good data point after the spike. The time interval over which the wild-point editing was employed is indicated in Figure 4-147.

TURBINE TRIP

Initial Conditions

The turbine trip was initiated from the test conditions shown in Table 4-8. The plant control systems were all in the automatic mode and operating normally except for the Steam Dump and Bypass Control System (SDBCS). One atmospheric dump valve located downstream of the main steam isolation valves (MSIVs) was isolated and the

two atmospheric dump valves located upstream of the MSIVs were placed in the manual mode. Table 4-9 provides additional information relating to the operating characteristics of the SDBCS at the time of the test.

Sequence of Events

The test was initiated at approximately 1900 on January 29, 1980, by manually tripping the main turbine from the control room. Immediately following the turbine trip (approximately 2 seconds into the transient), three turbine bypass valves and one atmospheric dump valve received quick-open signals from the SDBCS. The valves were full-open about one second later and were relieving secondary steam at the rate of about 4100 klbm/hr. Since the dump capacity was not sufficient to match reactor power, primary system temperatures and pressures began to increase and steam generator levels began to decrease. Due to the increase in primary pressure, the pressurizer pressure control system generated an open signal to a pressurizer spray valve. At 6.1 seconds, the reactor tripped automatically on a low steam generator level signal, which also generated an emergency feedwater actuation signal.

The primary and secondary system pressures reached peak values of 2382 psia at 8.0 seconds and 1091 psia at 12.7 seconds, respectively. After these pressures began to decline, both the pressurizer spray valve and steam dump valves received close signals. The three turbine bypass valves were fully closed approximately 8 seconds later, but the pressurizer spray valve failed to reseat properly and the atmospheric dump valve remained full-open. These two factors caused a continued reduction in primary system pressure and temperature, and resulted in several of the monitored variables falling to values below the range of the measuring instrumentation.

Approximately 100 seconds after the turbine trip, a safety injection actuation signal (SIAS) was generated on low pressurizer pressure (1740 psia). Pressure and temperature continued to decrease causing the pressurizer to empty. The steam header pressure and hot leg temperature also continued to decrease and eventually fell off-scale.

The RCS cooldown continued until the operators manually tripped the four reactor coolant pumps and natural circulation was established.* This terminated the uncontrolled cooldown of the primary system but did not have an immediate effect on the decreasing primary and secondary system pressures. This decrease in pressure continued until steam generator 1 pressure dropped to the low steam generator pressure setpoint (728 psia), which generated a main steam isolation signal (MSIS). The MSIS terminated all steam flow from steam generator 1. Shortly after the MSIS, the primary system pressure reached a minimum value (1350 psia) and started to increase. The minimum difference between the measured hot leg temperature and the saturation temperature of the primary coolant during this period was calculated to be approximately 57°F. A detailed sequence of events for this transient is presented in Table 4-10.

Process Parameter Transients

Figures 4-174 through 4-199 show the 30 minute response of the monitored NSSS variables to the turbine trip. Figures 4-200 through 4-240 show the response of the monitored NSSS variables during the first 60 seconds following the turbine trip. The measured data were considered sufficiently smooth that digital filtering was not necessary; therefore, all of the above figures are plots of unfiltered data.

All data, except for primary and secondary system flow rates and turbine power, were direct measurements from the existing plant instrumentation. Primary system flow rates were derived from measured values of reactor coolant pump differential pressures and speeds. The methodology and algorithms used to determine the primary system flow rates are described in Appendix A. Secondary system flow rates (i.e., main steam and feedwater flow rates) were calculated from measured values of differential pressures along with secondary system temperatures and pressures. The methodology and algorithms used to determine these values are described in Appendix B. Turbine power was calculated by an empirical equation which expresses the turbine power as a third-order polynomial in the turbine first stage pressure. This algorithm is also given in Appendix B.

*Recent changes to PWR emergency procedures call for tripping all four reactor coolant pumps once an SIAS is generated.

It should be noted that the feedwater flow rates presented in Figures 4-183, 4-186, 4-212 and 4-220 do not include emergency feedwater flow. This is due to the fact that the measurement of feedwater differential pressure occurs at a point upstream of the location at which the emergency feedwater enters into the system. Furthermore, it was discovered that the special test instrumentation necessary for monitoring emergency feedwater flow had been disassembled prior to the test. Thus, no information regarding emergency feedwater flow was available.

For three of the monitored NSSS variables -- steam generator 1 hot leg temperature (Figure 4-177), steam generator 2 hot leg temperature (Figure 4-180) and narrow range pressurizer pressure (Figure 4-194) -- the values of the measured quantities reached instrumentation setpoints during the long-term (30 minute) response. However, in addition to being recorded on the DAS, each of these parameters was backed up with plant computer trend group data and/or strip chart recordings. Thus, in each of the three cases, a portion of the data which appears in the figures was obtained from backup data rather than directly measured by the DAS. For the steam generator hot leg temperatures, backup data were used when the hot leg temperatures were below 550°F. This occurred from approximately 1 minute to approximately 16 minutes into the transient for steam generator 1, and from approximately 1 minute to approximately 17.5 minutes into the transient for steam generator 2. For the narrow range pressurizer pressure, backup data were used when the pressurizer pressure was below 1500 psia. This occurred from approximately 3 minutes to approximately 7.5 minutes into the transient.

A similar situation also occurred for the steam generator header pressures. As shown in Figures 4-190 and 4-193, the steam generator header pressures remained essentially constant after approximately 2.5 minutes into the transient. This was due to a decrease in the steam generator header pressures below the range of the pressure transmitters. Unfortunately, in this case no backup data were available from either the plant computer trend groups or strip chart recordings, so that the missing portions of the curves could not be reconstructed. The actual values of the steam generator header pressures after 2.5 minutes were substantially lower than the 850 psia shown in the figures.

The graph of pressurizer level during the first minute of the transient (Figure 4-240) is a hand plot resulting from calculations performed by the resident Nuclear Engineer at the ANO-2 site. The fact that no measured data was available was due to failure of the equipment transmitting pressurizer level to the DAS just

prior to the transient. In addition, no backup data were available from either the plant computer trend groups or strip chart recordings. However, due to the overriding concern that a steam bubble may have formed in the upper head of the reactor vessel, detailed calculations of the actual pressurizer level during the test were performed. These calculations, reviewed by the NRC, included safety injection and charging flow, letdown flow, and shrink and swell of the primary coolant. Therefore, although not the result of a direct measurement, Figure 4-240 represents the best available information regarding the pressurizer level as a function of time during the turbine trip transient.

As noted previously, the uncertainties in the primary and secondary system flow rates shown in the figures increase as the flow rate decreases. The calculation of these quantities is dependent upon an accurate measurement of the applicable differential pressure. Unfortunately, as the differential pressure across a pump decreases, the differential pressure sensor becomes less and less accurate until ultimately, under natural circulation conditions, the uncertainty of the differential pressure sensor is equal to or greater than the differential pressure itself. Therefore, flow calculations (from differential pressures) in the low flow regime are estimates only and, although calculated using state-of-the art methods, should not be construed as an accurate indication of the true flow.

Table 4-1

INITIAL CONDITIONS FOR THE TOTAL LOSS OF FLOW

Core Power, Mwt	2295 (81%)
Core Inlet Temperature, °F	552
Core Outlet Temperature, °F	596
Core Mass Flow Rate, 10^6 lbm/hr	133
Pressurizer Pressure, psia	2240
Pressurizer Level, percent	46.4
Steam Generator Pressure, psia	926
Steam Generator Level, percent*	70.0
Control System Status:	
- Pressurizer Pressure	Automatic
- Pressurizer Level	Automatic
- Feedwater	Automatic
- Reactor Regulating	Automatic
- Steam Dump and Bypass	Automatic
Charging Flow, GPM	44.5
- 1 pump operating	
- 1 pump in standby	
- 1 pump isolated	
Letdown Flow, GPM	40.4

* Level indication in percent of 13.9 ft. instrument span. 0 percent level corresponds to a liquid level 24.5 ft. above the steam generator tube sheet. See Reference 3 for further steam generator details.

Table 4-2

SEQUENCE OF EVENTS FOR THE TOTAL LOSS OF FLOW

Time	Event	Value
0.0	Manual trip of all 4 reactor coolant pumps	-
0.2	Reactor trip initiated on low DNBR signal	1.19 *
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) 599.9 (SG-2)
2.0	Pressurizer spray valve opens	-
2.0	Turbine bypass valves full-open	-
2.0	Atmospheric dump valve opens to vent excess 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 reduced	24.5 GPM
18.0	Turbine bypass valves fully closed	-
35.0	Minimum steam generator level	18.8% (SG-1) 15.4% (SG-2)
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
61.0	Maximum steam generator header pressure	1041 (SG-1) 1040 (SG-2)
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
787.0	Turbine bypass valve closed	-

* Projected

Table 4-3

OPERATING STATUS OF THE STEAM DUMP AND BYPASS CONTROL SYSTEM VALVES DURING THE LOF

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	isolated
13%* Atmospheric Dump	0.94×10^6	isolated

*Percentages are descriptors referring to the design capacities of the SDBCS valves. The actual capacities of the valves are somewhat lower.

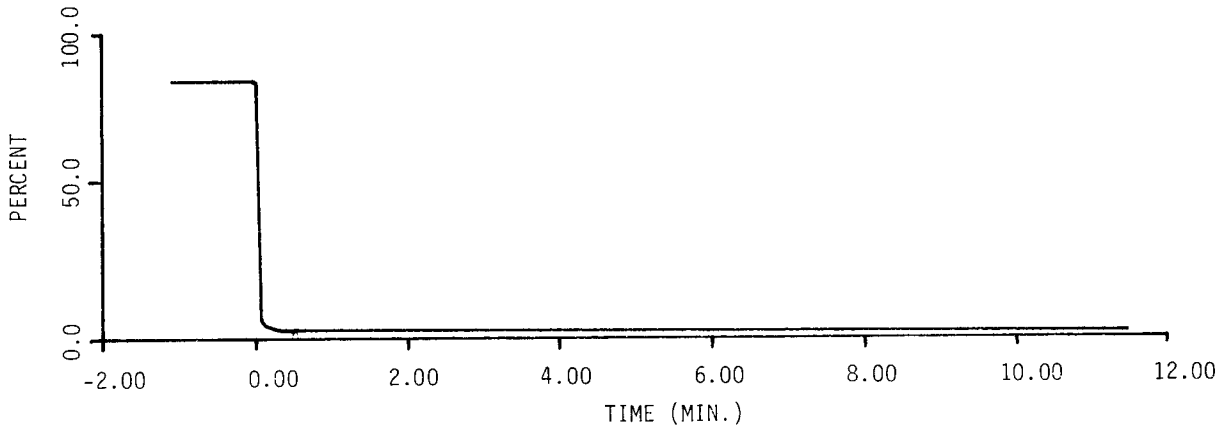


Figure 4-1. Loss of Flow-Control Channel 1 Nuclear Power

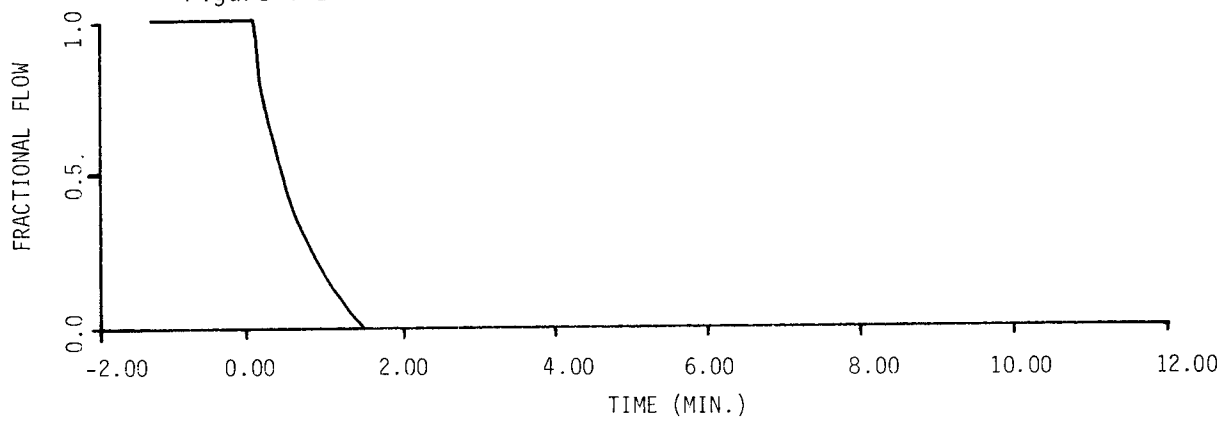


Figure 4-2. Loss of Flow-Normalized Reactor Coolant Pump Flow Rate

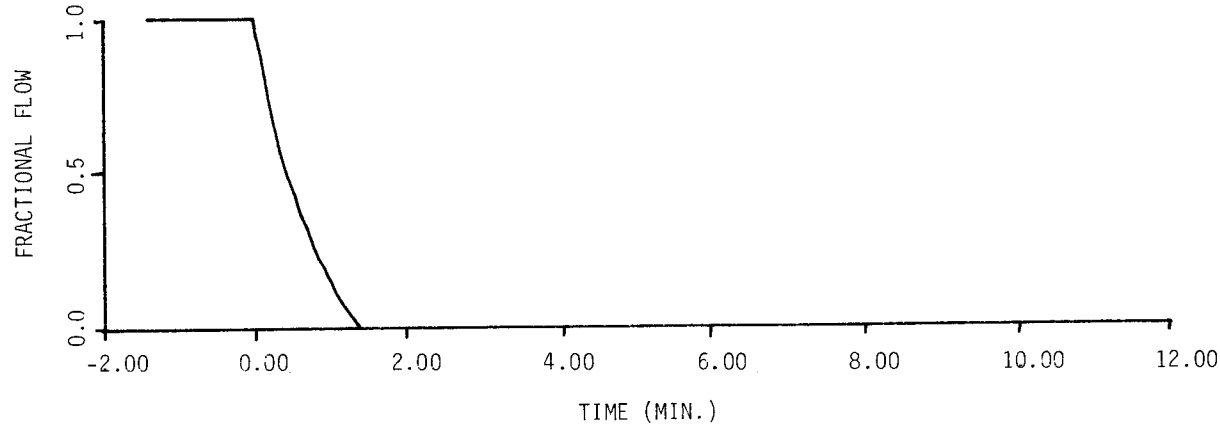


Figure 4-3. Loss of Flow-Normalized Reactor Coolant Pump 1A Flow Rate

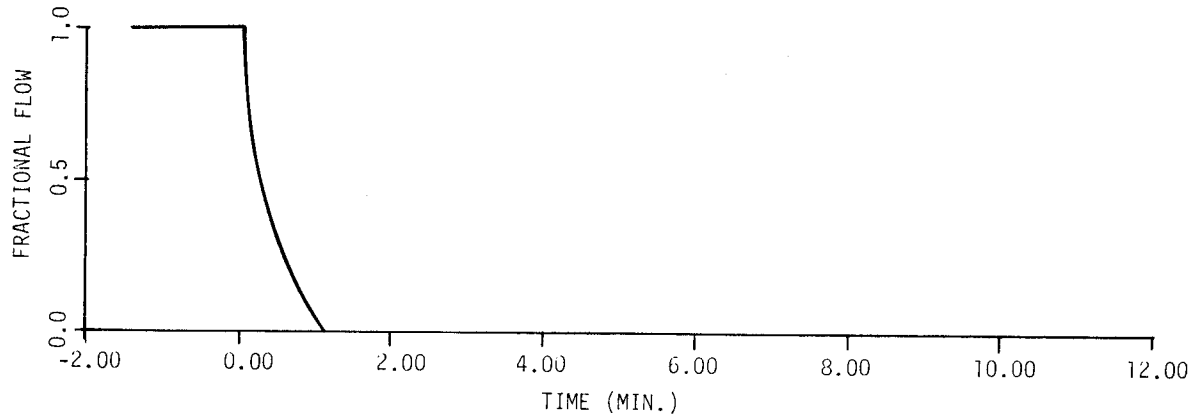


Figure 4-4. Loss of Flow - Reactor Coolant Pump 1B Flow Rate

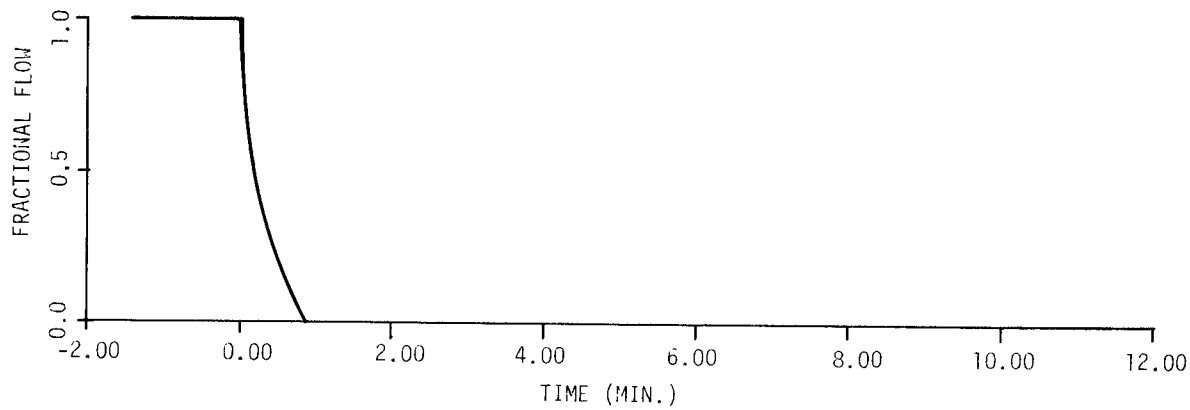


Figure 4-5. Loss of Flow - Reactor Coolant Pump 2A Flow Rate

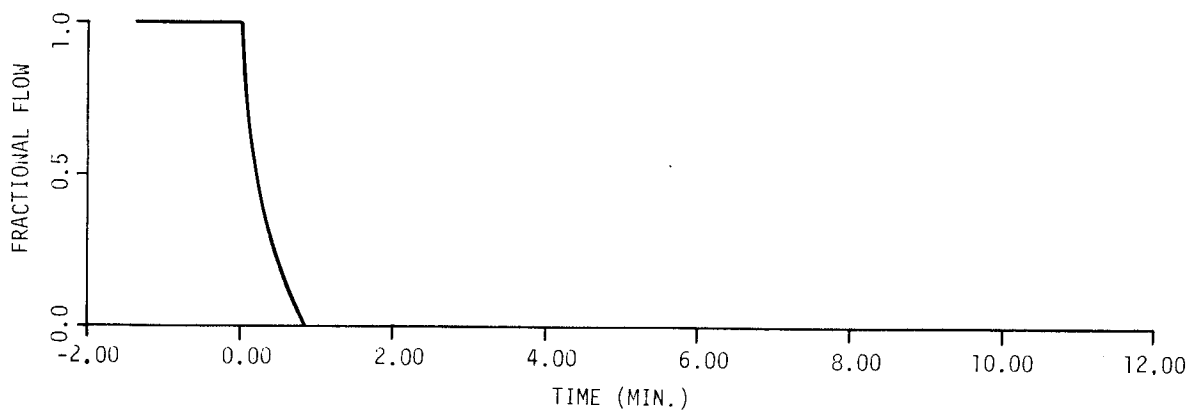


Figure 4-6. Loss of Flow - Reactor Coolant Pump 2B Flow Rate

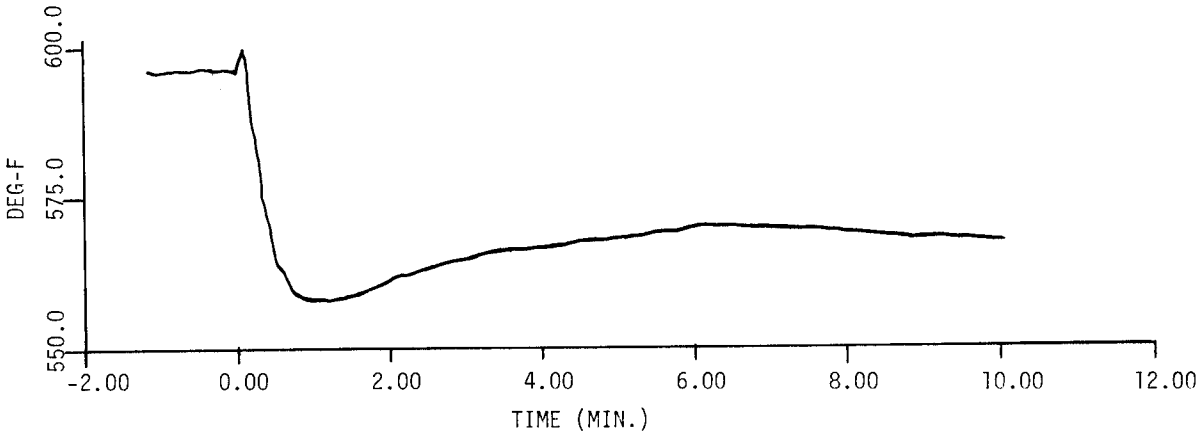


Figure 4-7. Loss of Flow-Steam Generator 1 Hot Leg Temperature

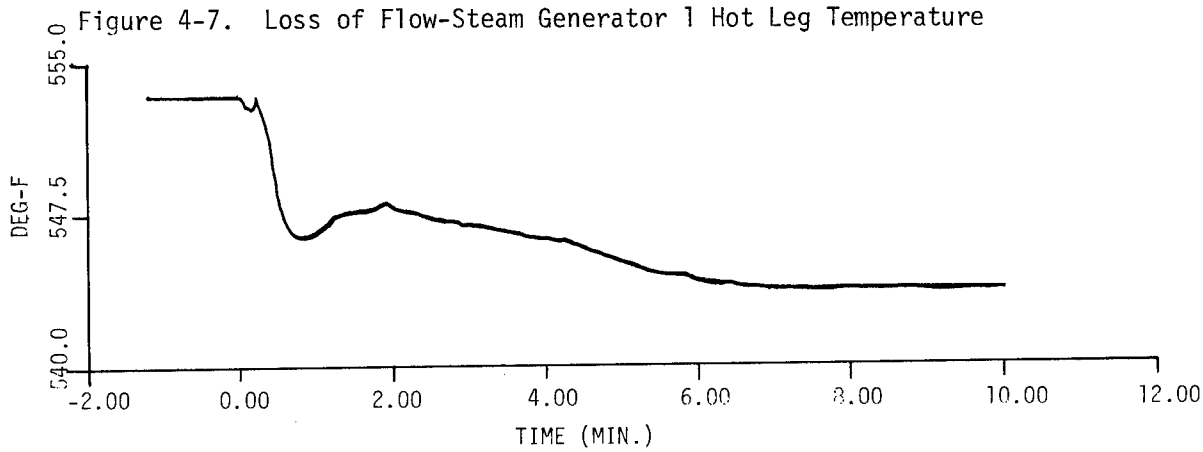


Figure 4-8. Loss of Flow-Steam Generator 1 Cold Leg Temperature (Loop 1A)

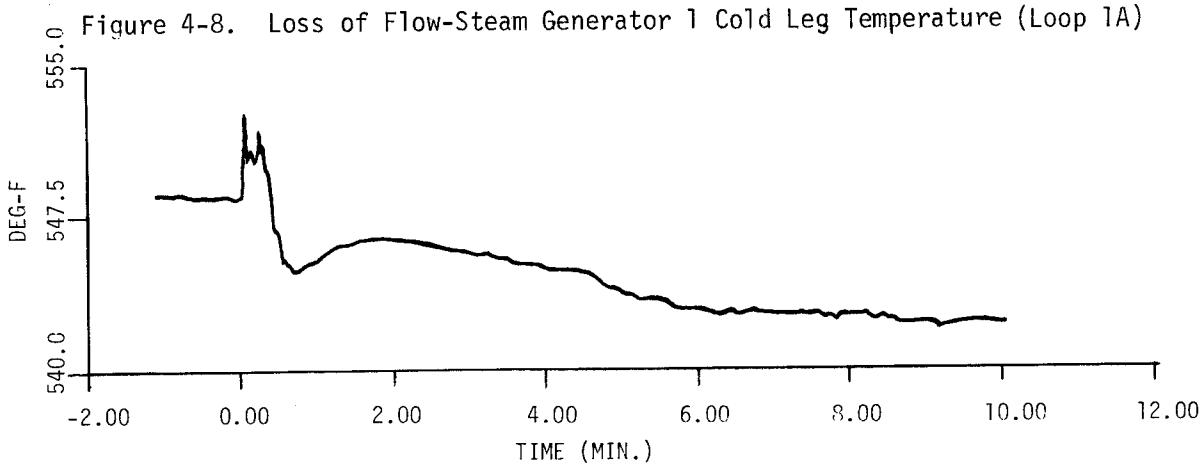


Figure 4-9. Loss of Flow-Steam Generator 1 Cold Leg Temperature (Loop 1B)

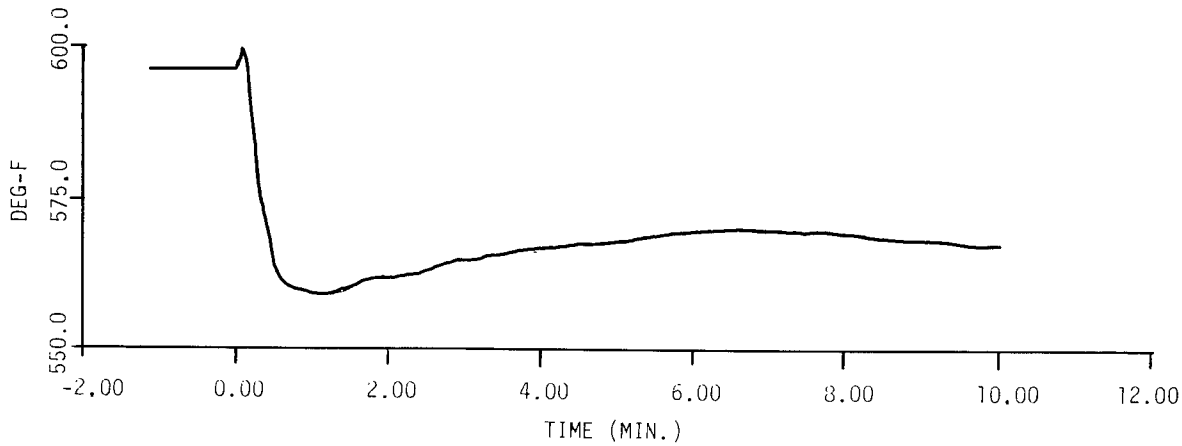


Figure 4-10. Loss of Flow - Steam Generator 2 Hot Leg Temperature

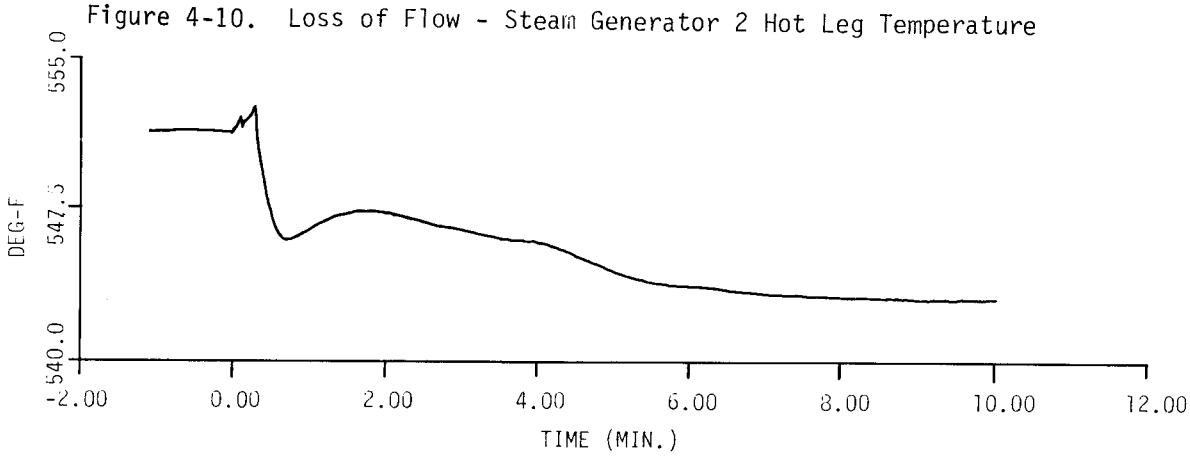


Figure 4-11. Loss of Flow - Steam Generator 2 Cold Leg Temperature (Loop 2A)

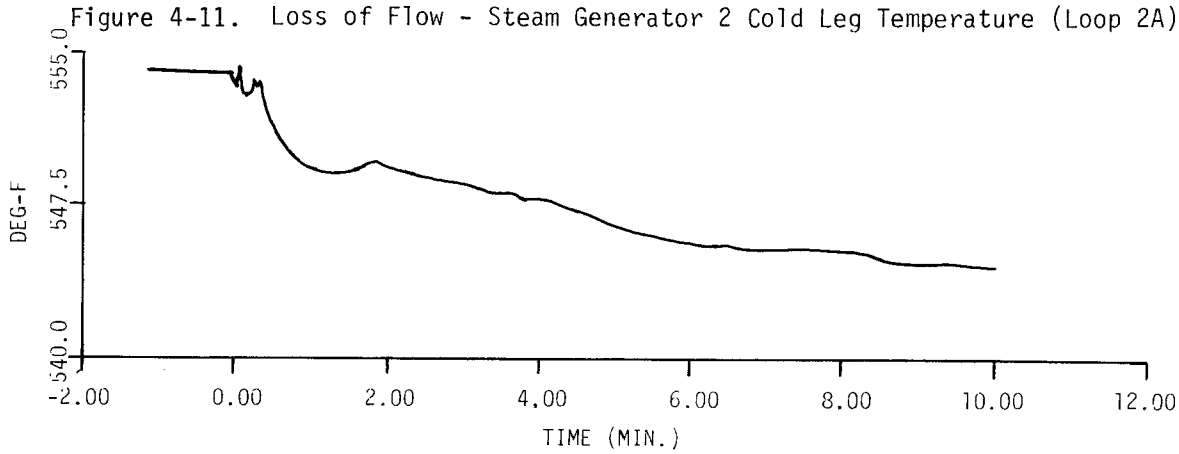


Figure 4-12. Loss of Flow - Steam Generator 2 Cold Leg Temperature (Loop 2B)

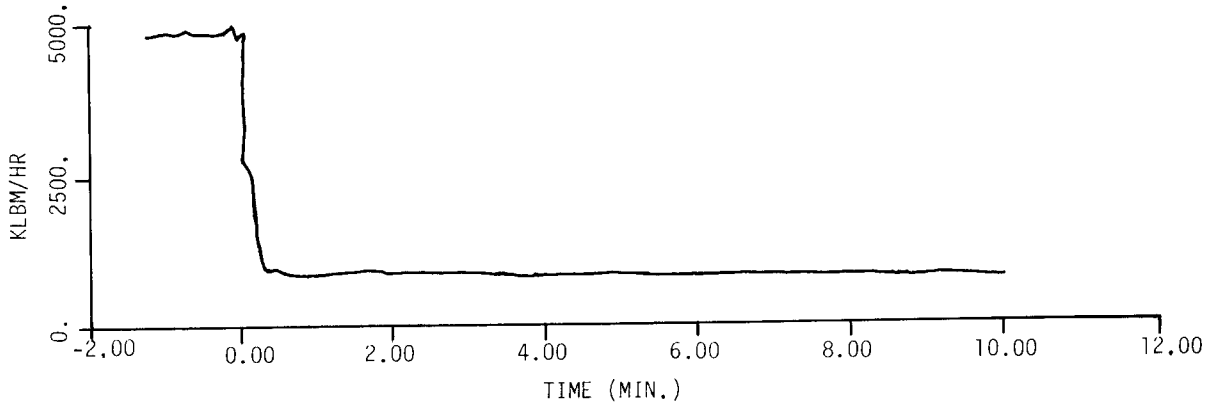


Figure 4-13. Loss of Flow - Steam Generator 1 Feedwater Flow Rate

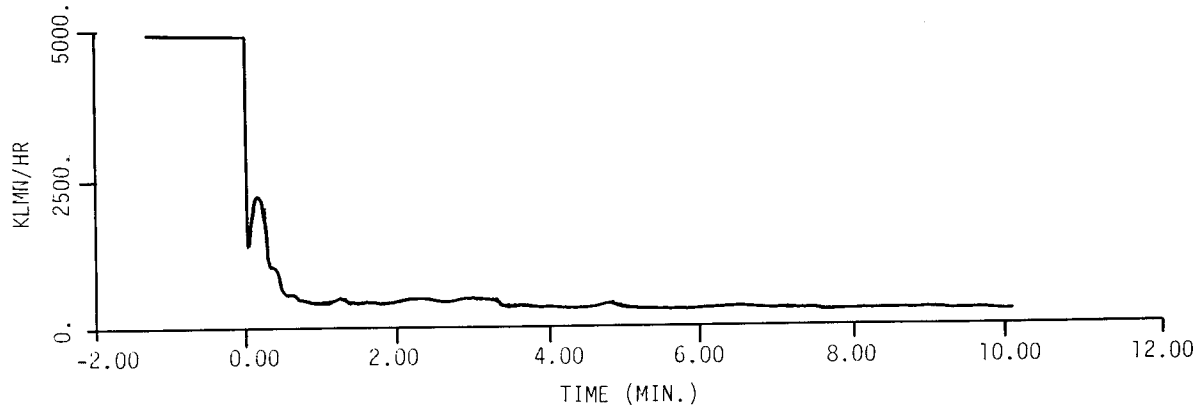


Figure 4-14. Loss of Flow - Steam Generator 1 Main Steam Flow Rate

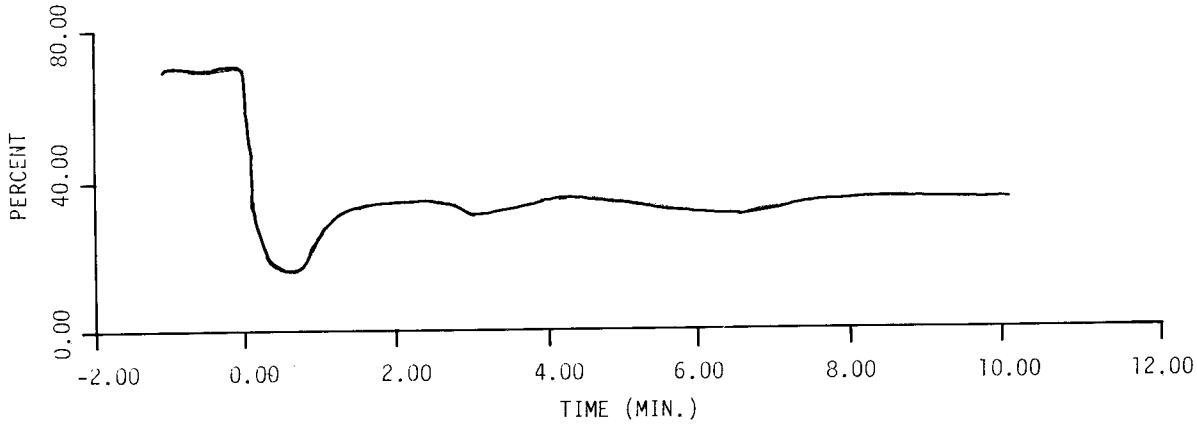


Figure 4-15. Loss of Flow - Steam Generator 1 Level

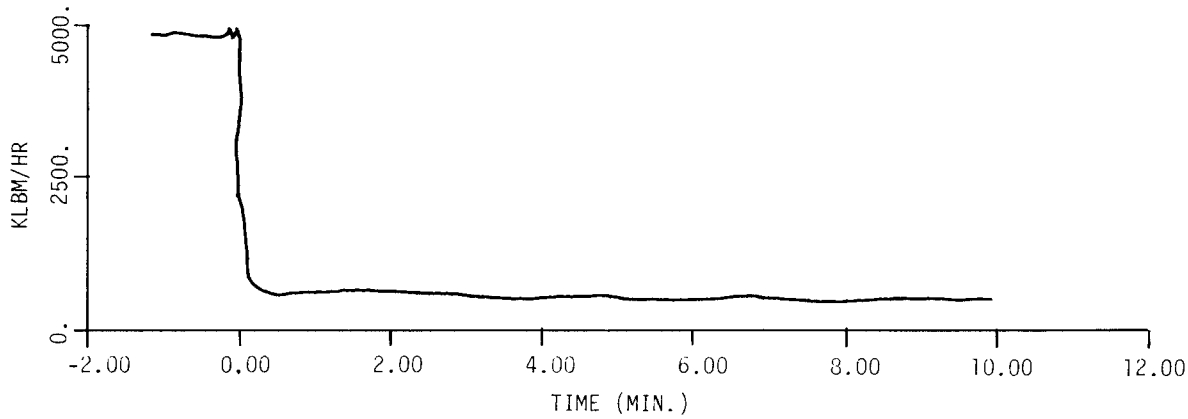


Figure 4-16. Loss of Flow - Steam Generator 2 Feedwater Flow Rate

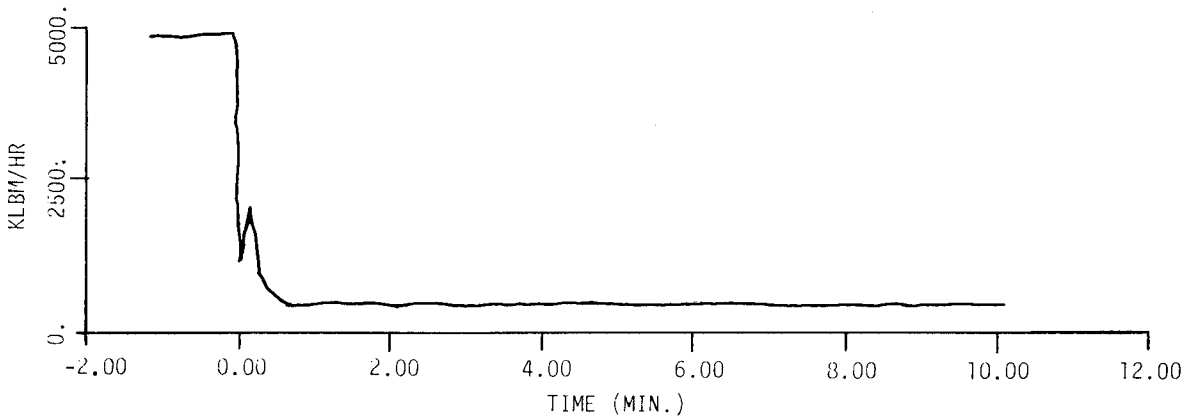


Figure 4-17. Loss of Flow - Steam Generator 2 Main Steam Flow Rate

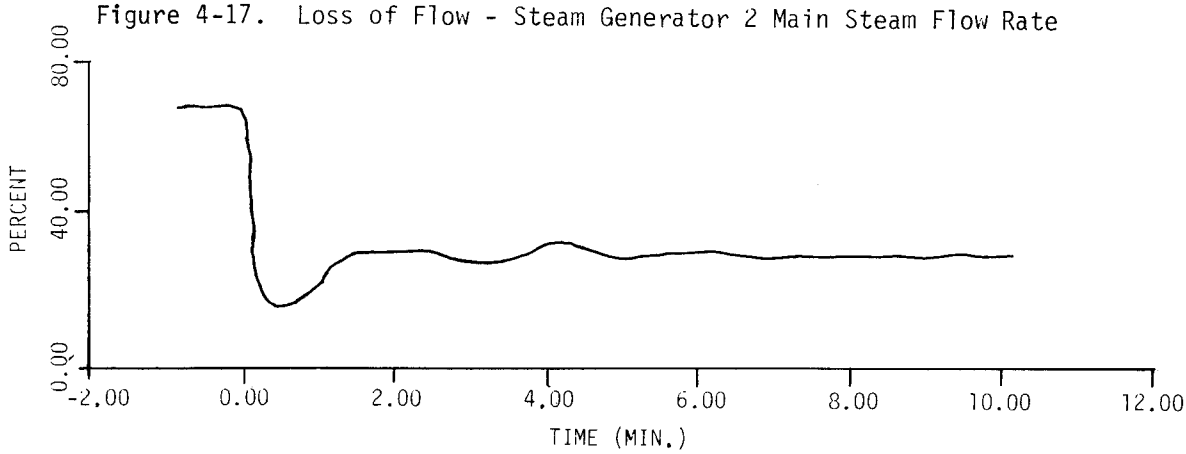


Figure 4-18. Loss of Flow - Steam Generator 2 Level

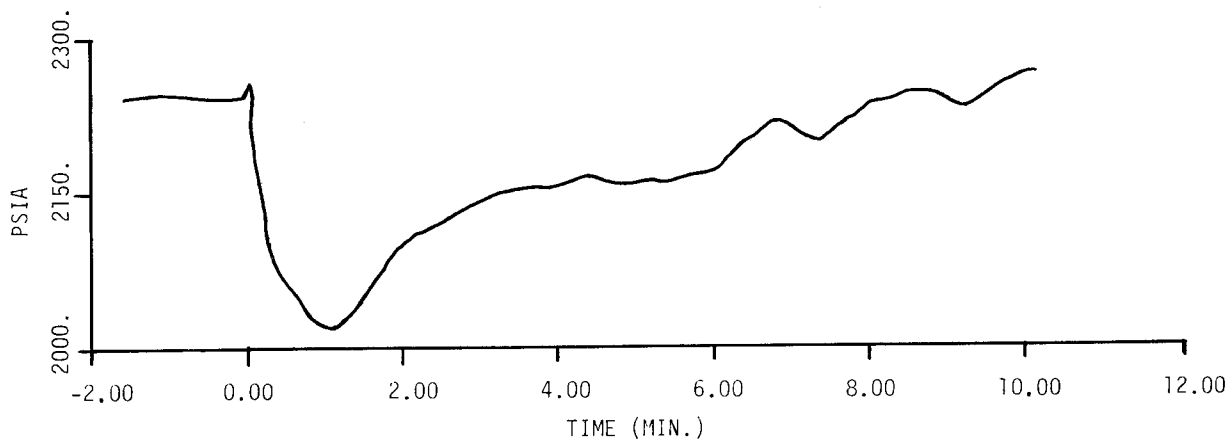


Figure 4-19. Loss of Flow - Pressurizer Pressure, Narrow Range

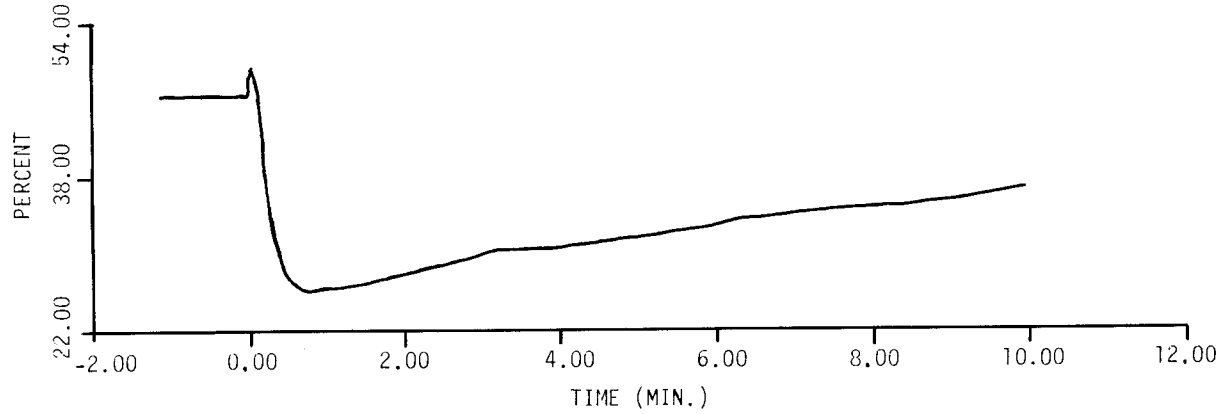


Figure 4-20. Loss of Flow - Pressurizer Level

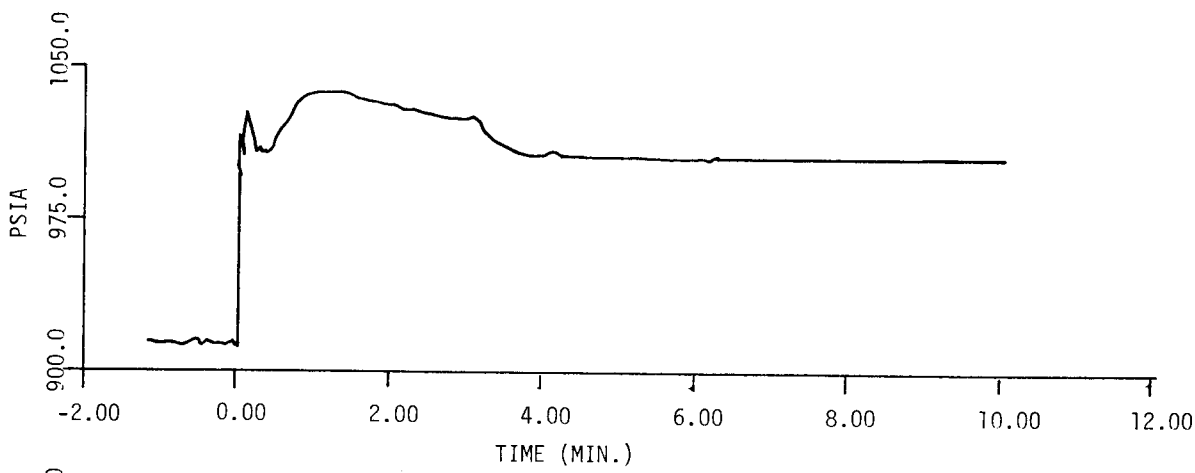


Figure 4-21. Loss of Flow-Steam Generator 2 Header Pressure

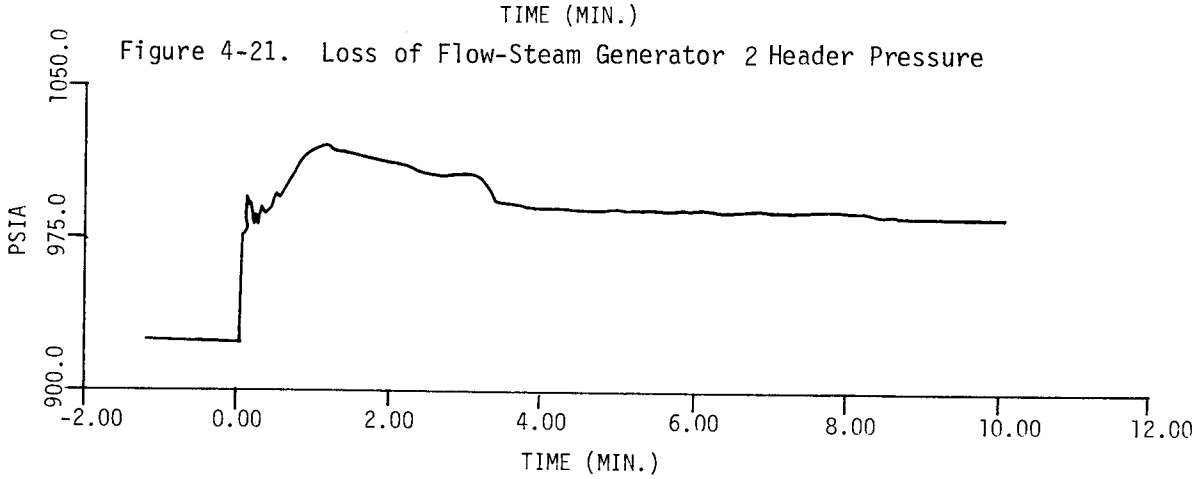


Figure 4-22. Loss of Flow-Steam Generator 1 Pressure

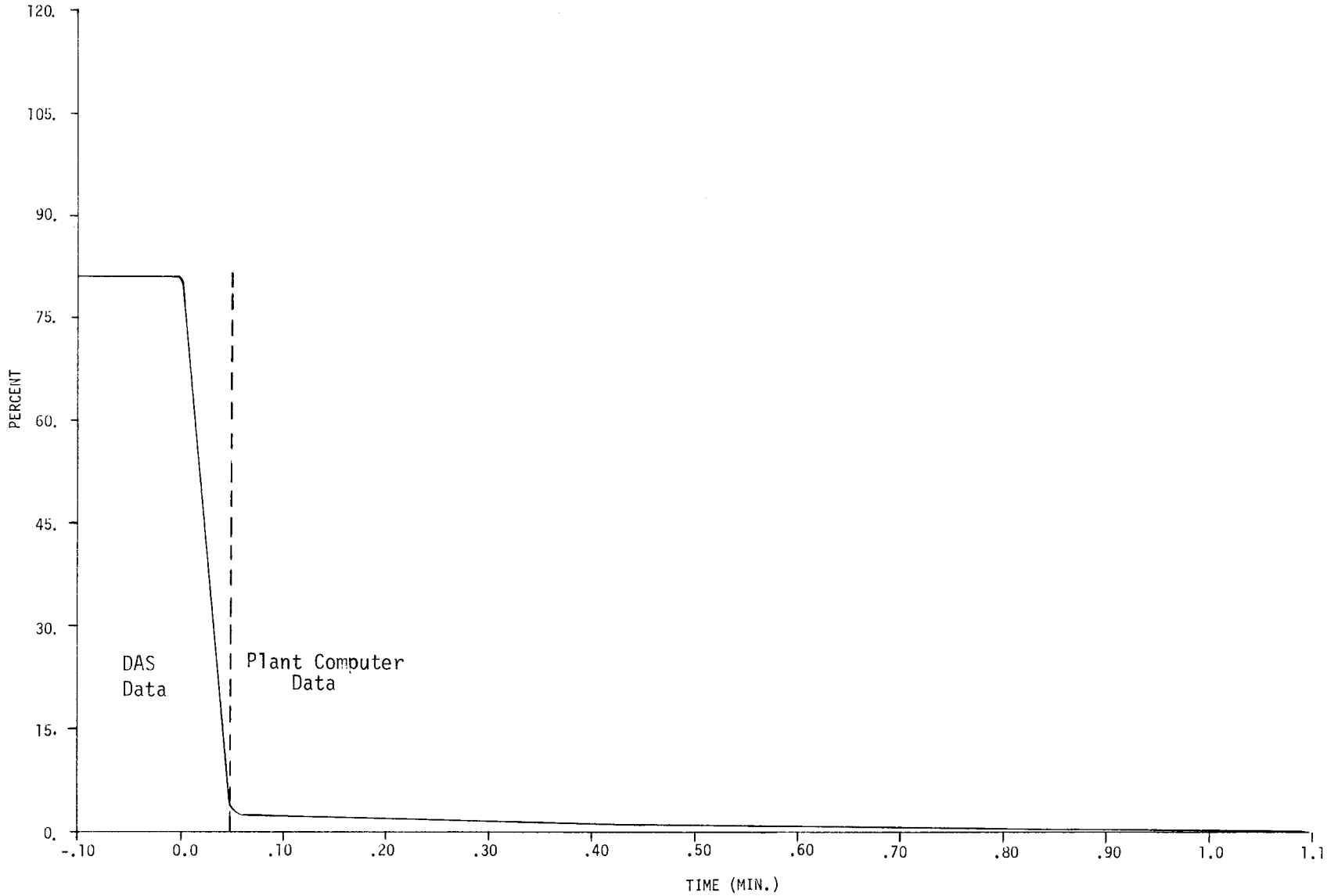


Figure 4-23. Loss of Flow - Control Channel 1 Nuclear Power

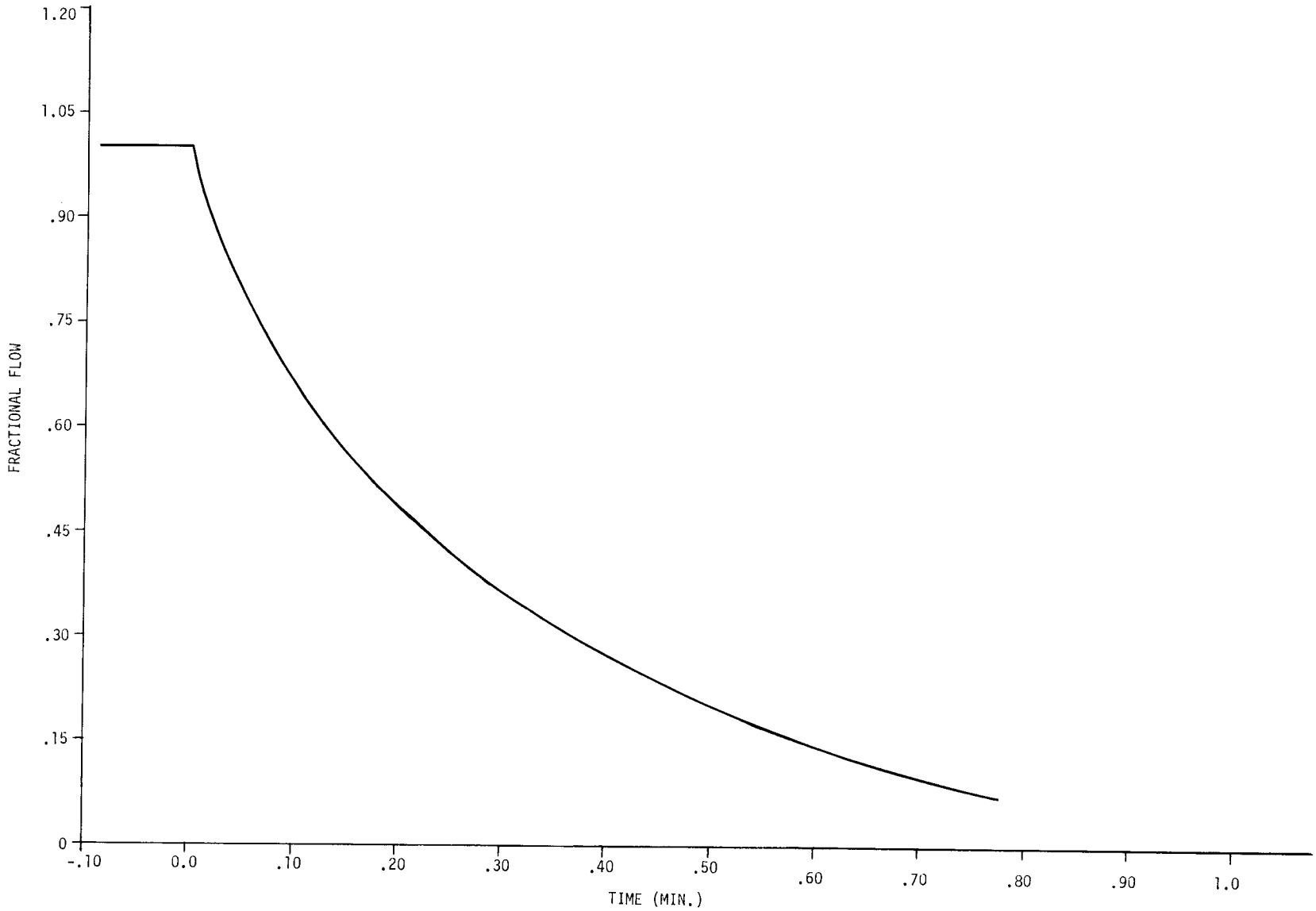


Figure 4-24. Loss of Flow - Total Core Flow Rate

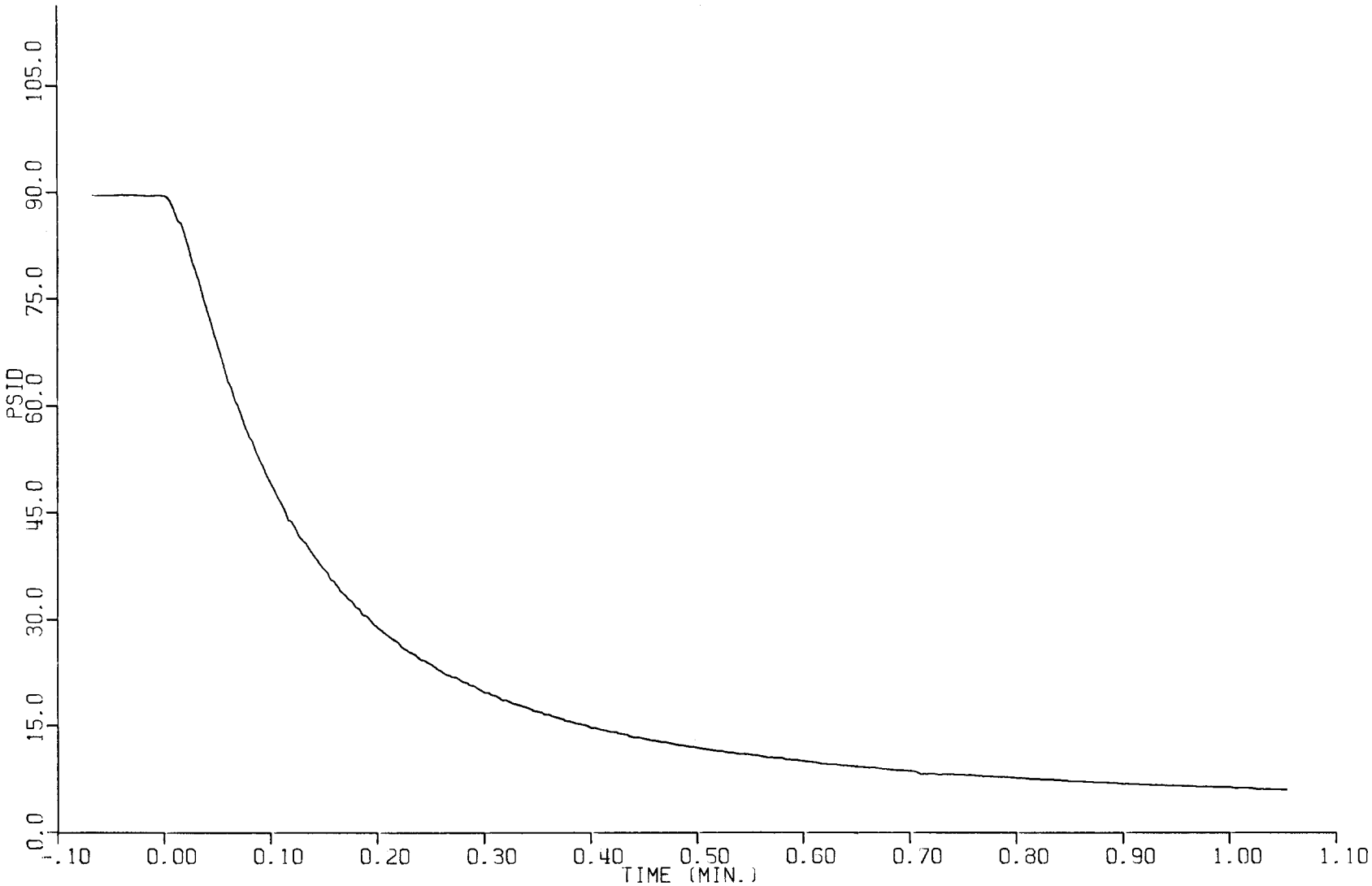


Figure 4-25. Loss of Flow - Reactor Coolant Pump 1A Differential Pressure

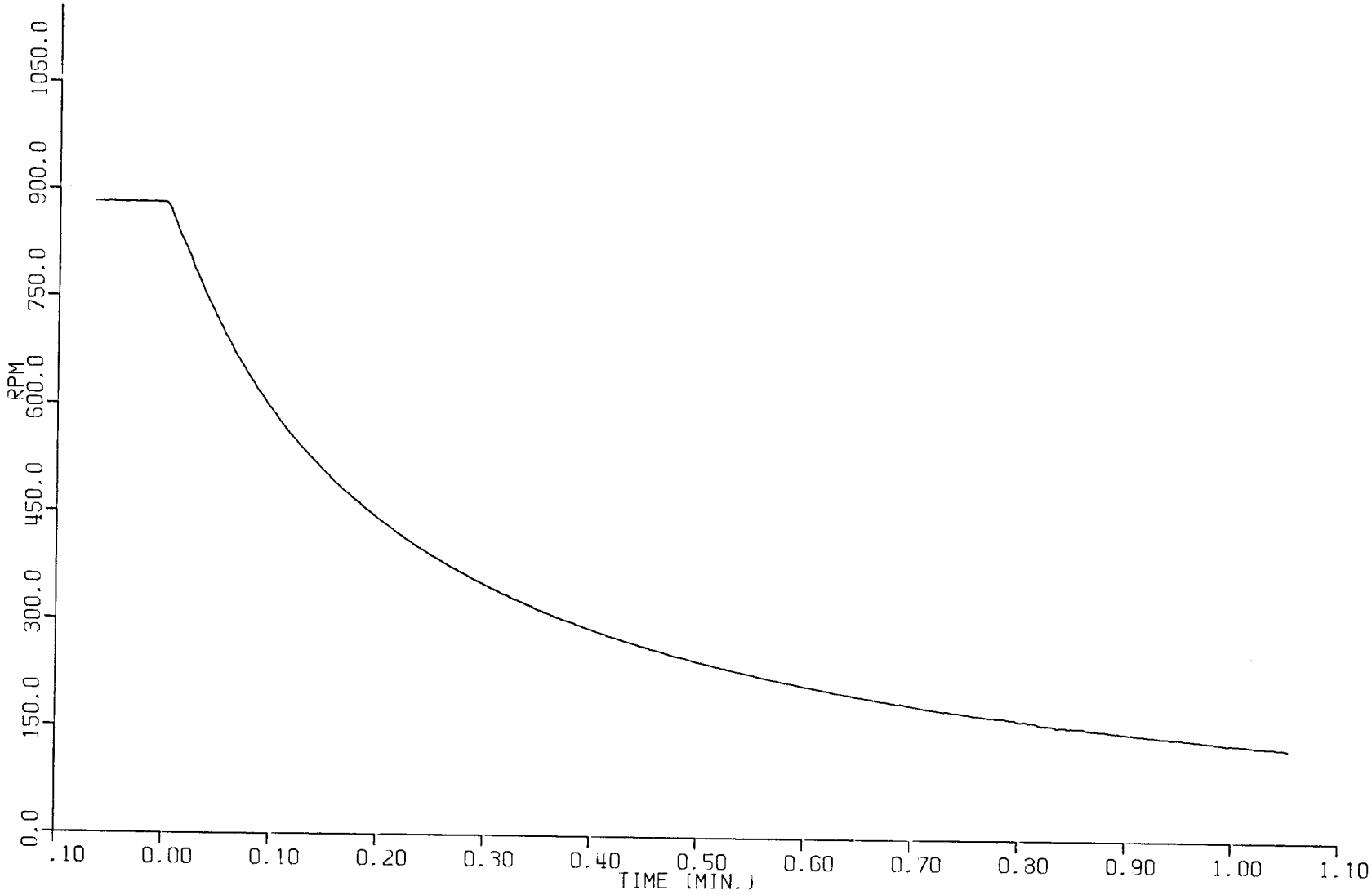


Figure 4-26. Loss of Flow - Reactor Coolant Pump 1A Speed

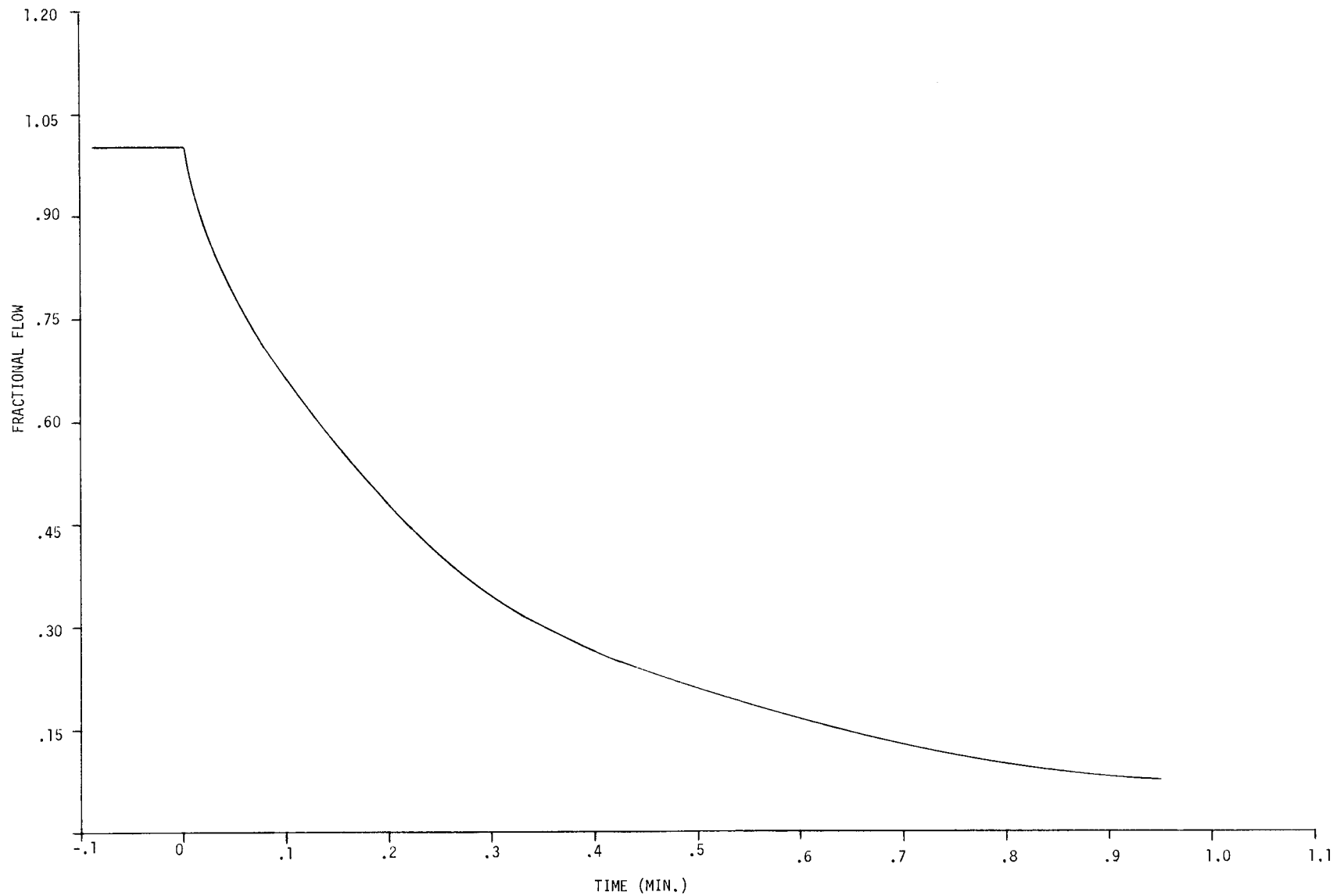


Figure 4-27. Loss of Flow - Reactor Coolant Pump 1A Flow Rate

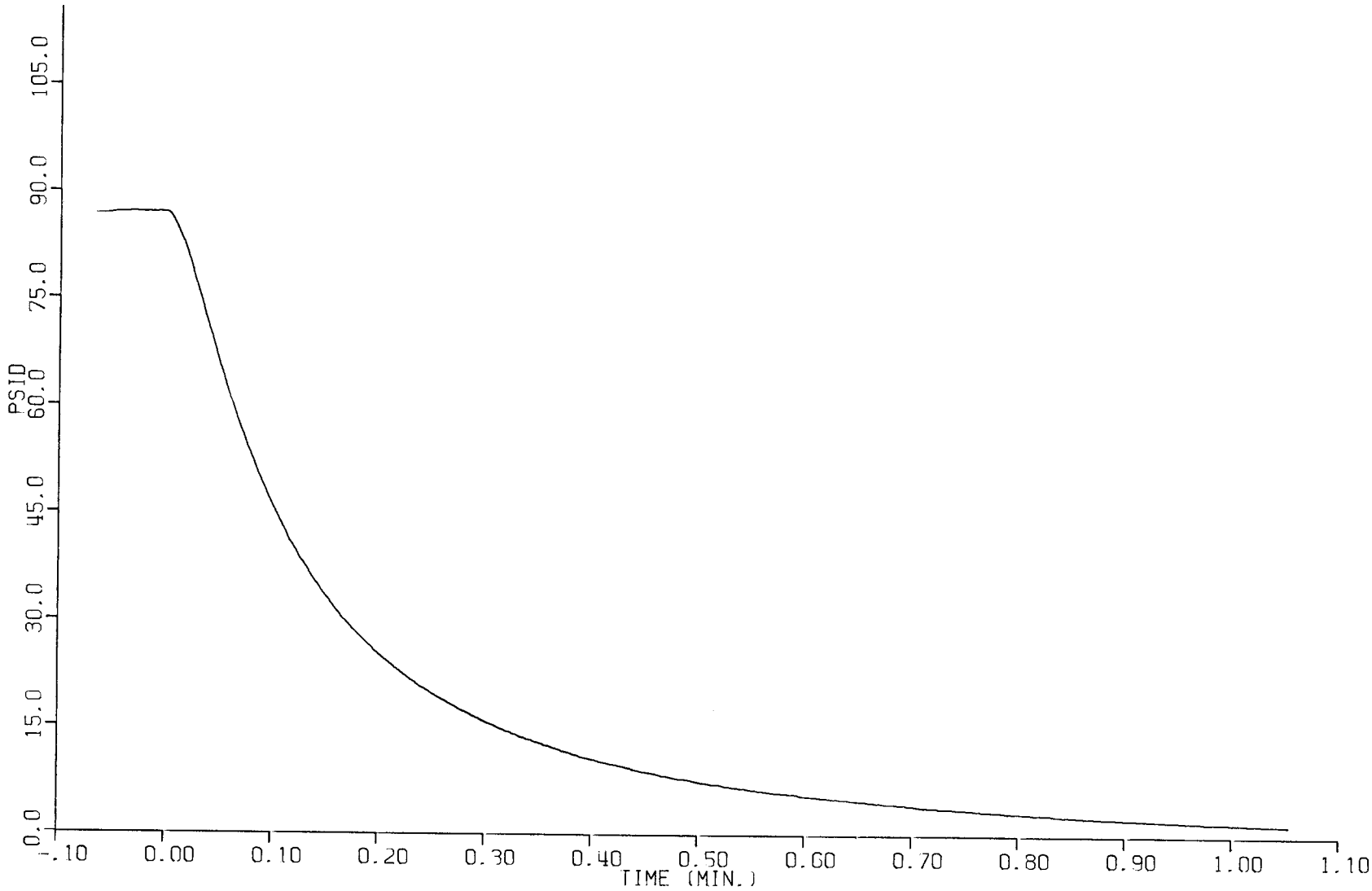


Figure 4-28. Loss of Flow - Reactor Coolant Pump 1B Differential Pressure

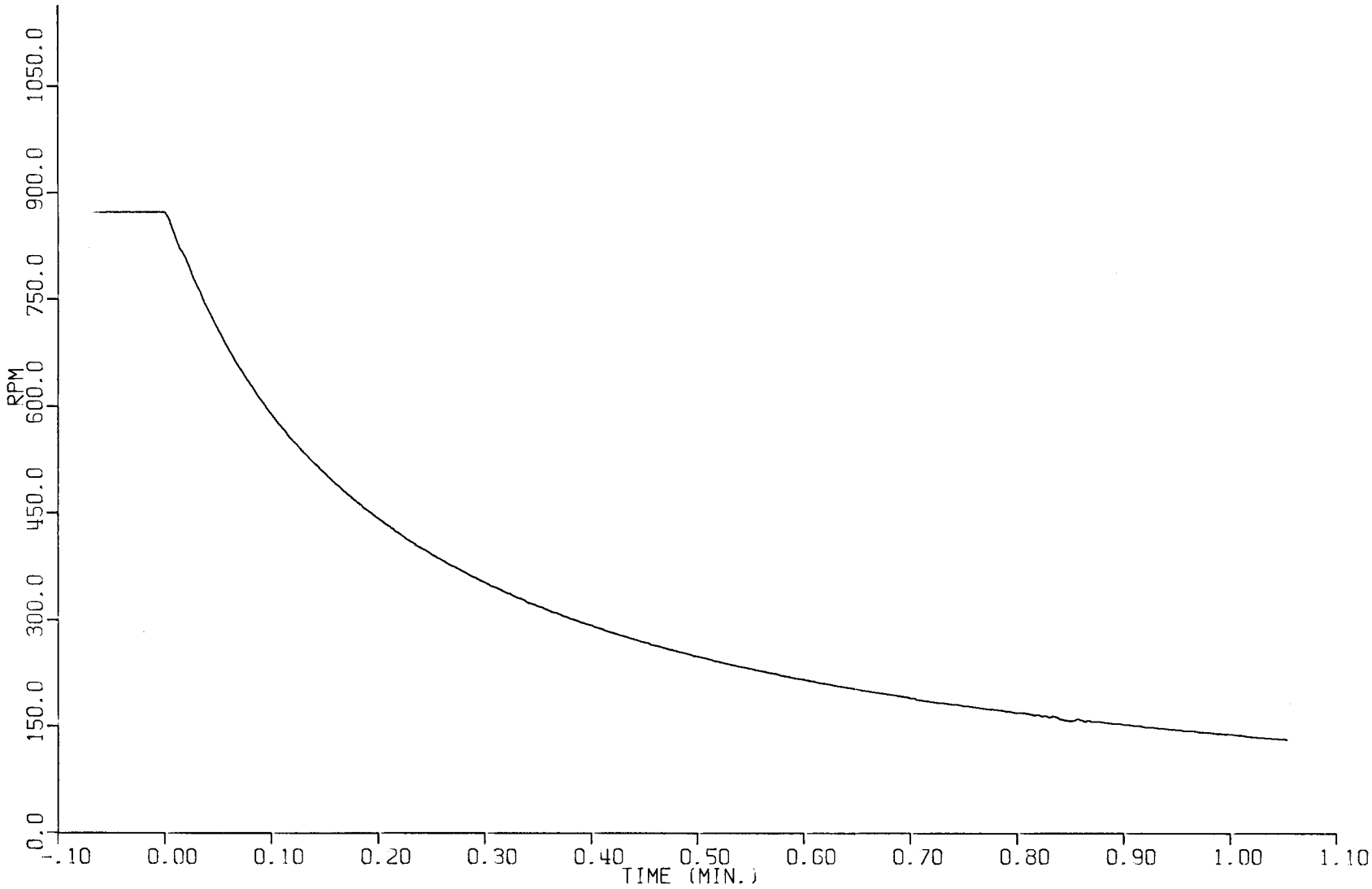


Figure 4-29. Loss of Flow - Reactor Coolant Pump 1B Speed

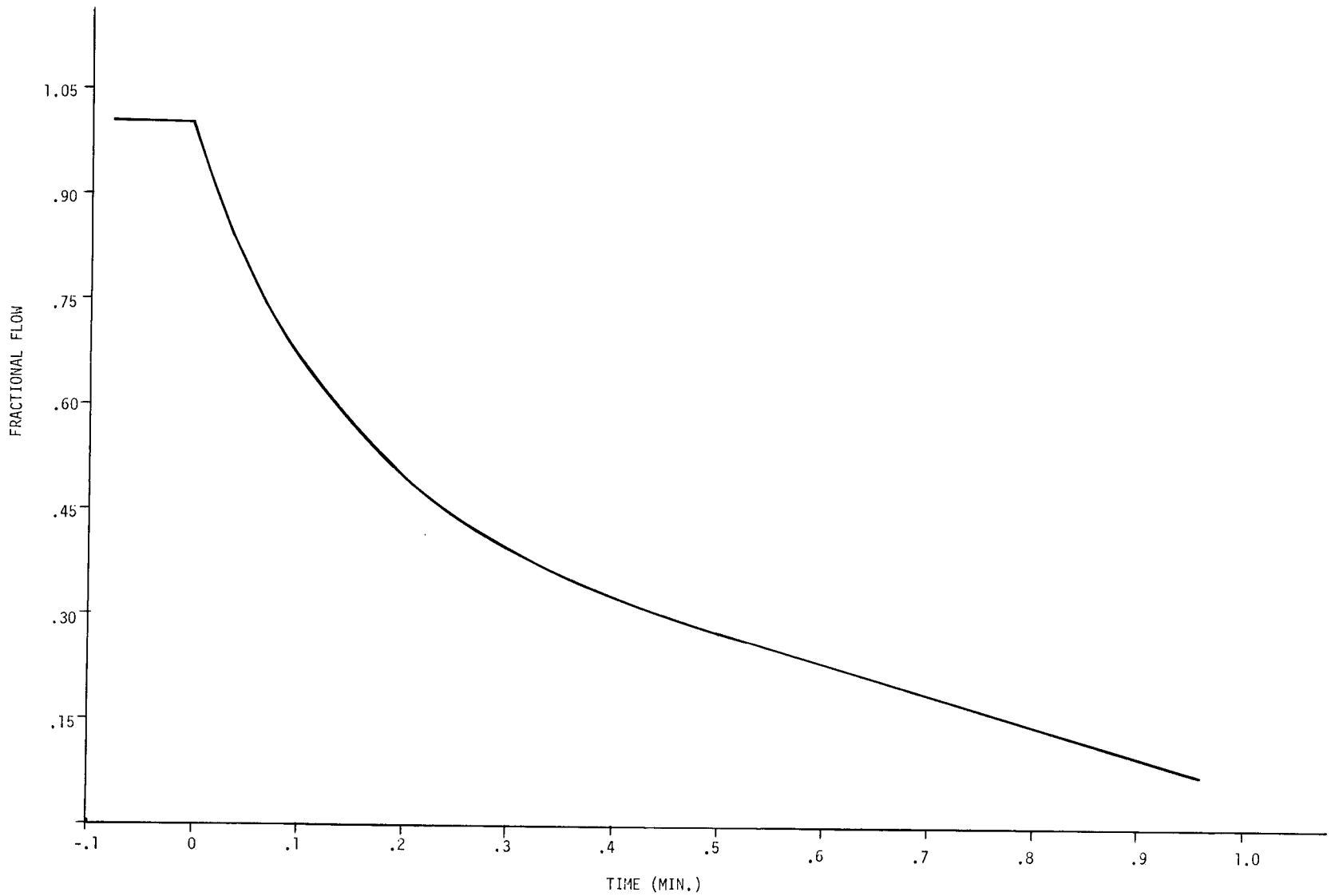


Figure 4-30. Loss of Flow - Reactor Coolant Pump 1B Flow Rate

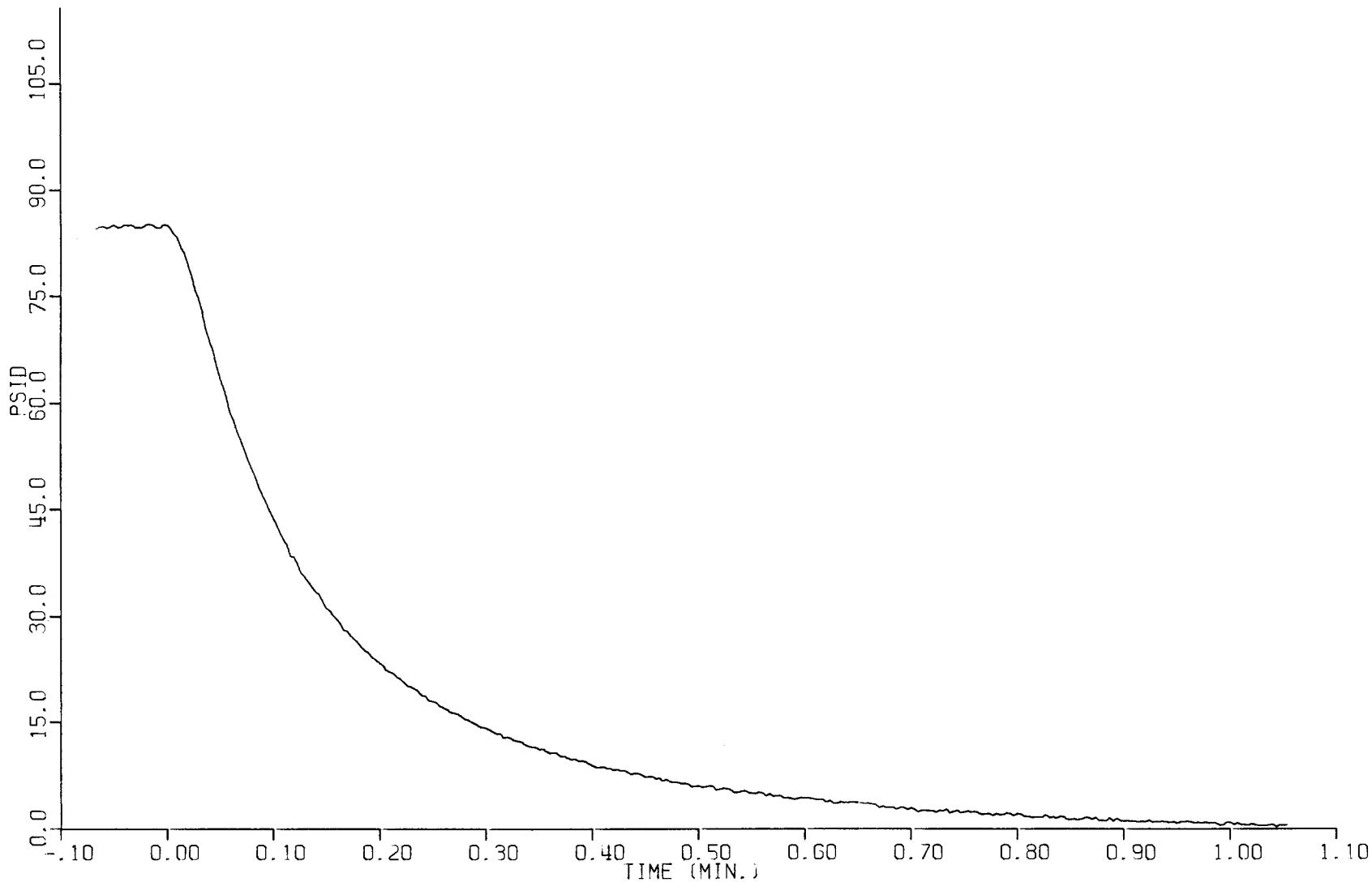


Figure 4-31. Loss of Flow - Reactor Coolant Pump 2A Differential Pressure

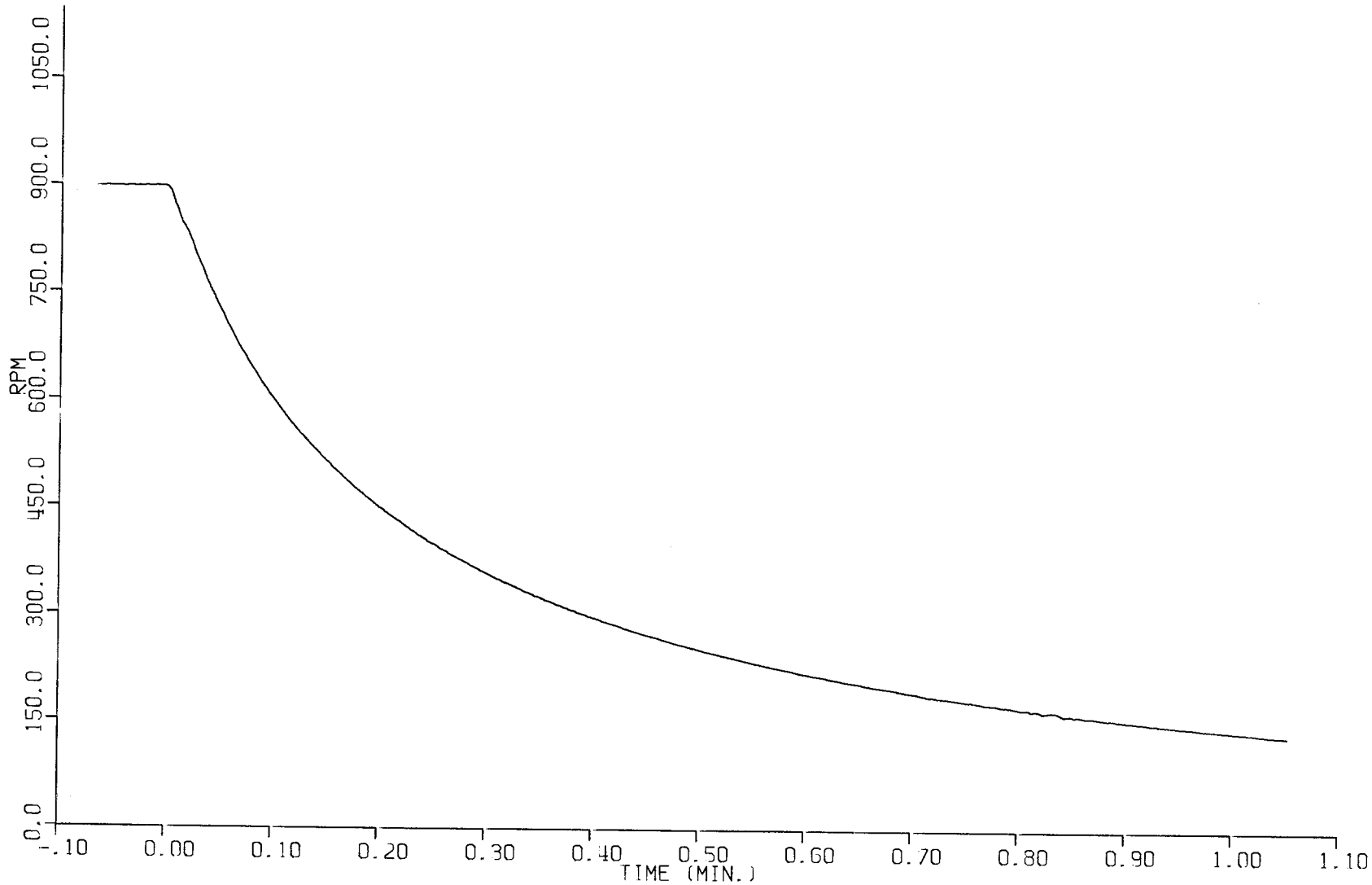


Figure 4-32. Loss of Flow - Reactor Coolant Pump 2A Speed

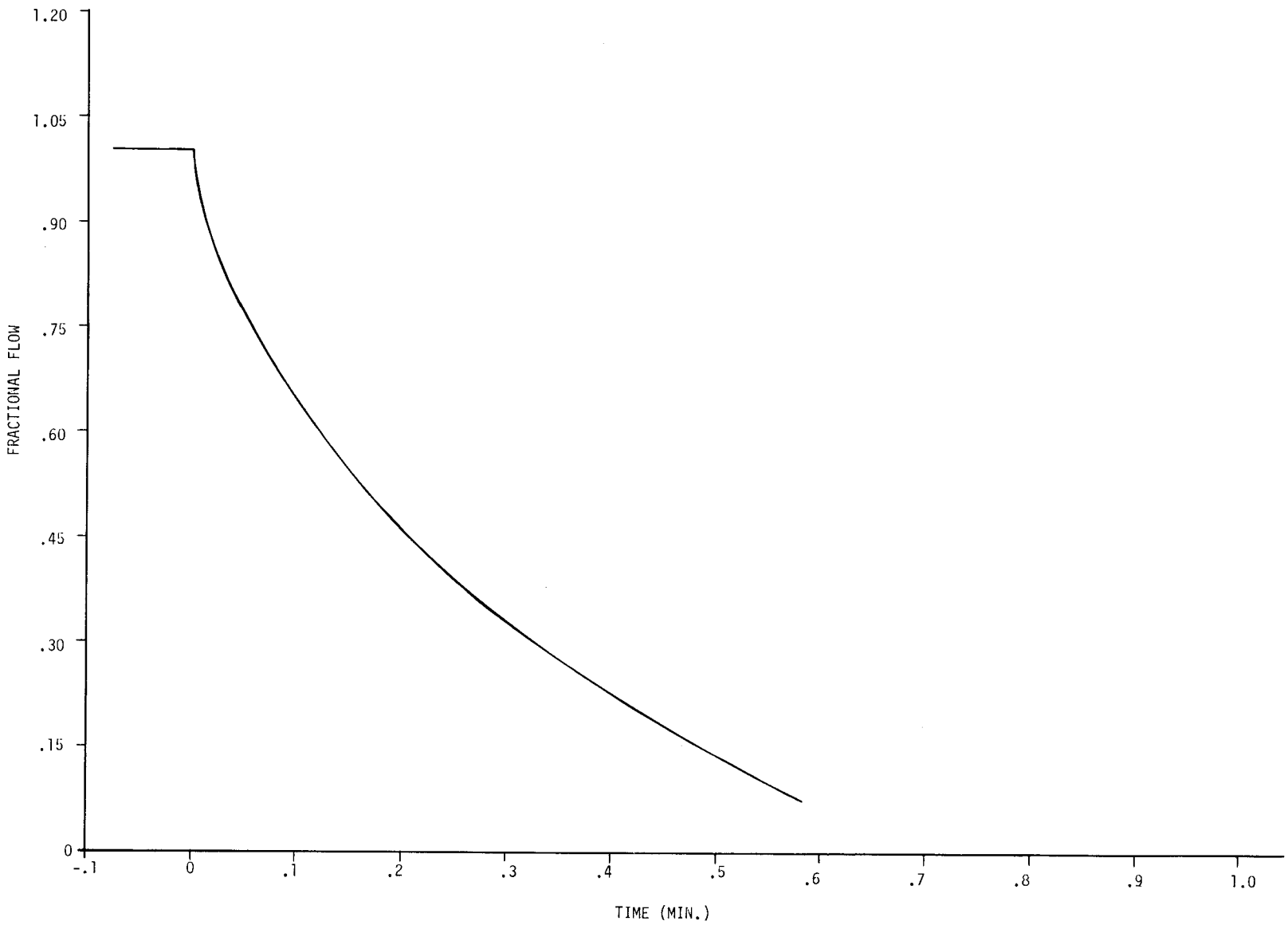


Figure 4-33. Loss of Flow - Reactor Coolant Pump 2A Flow Rate

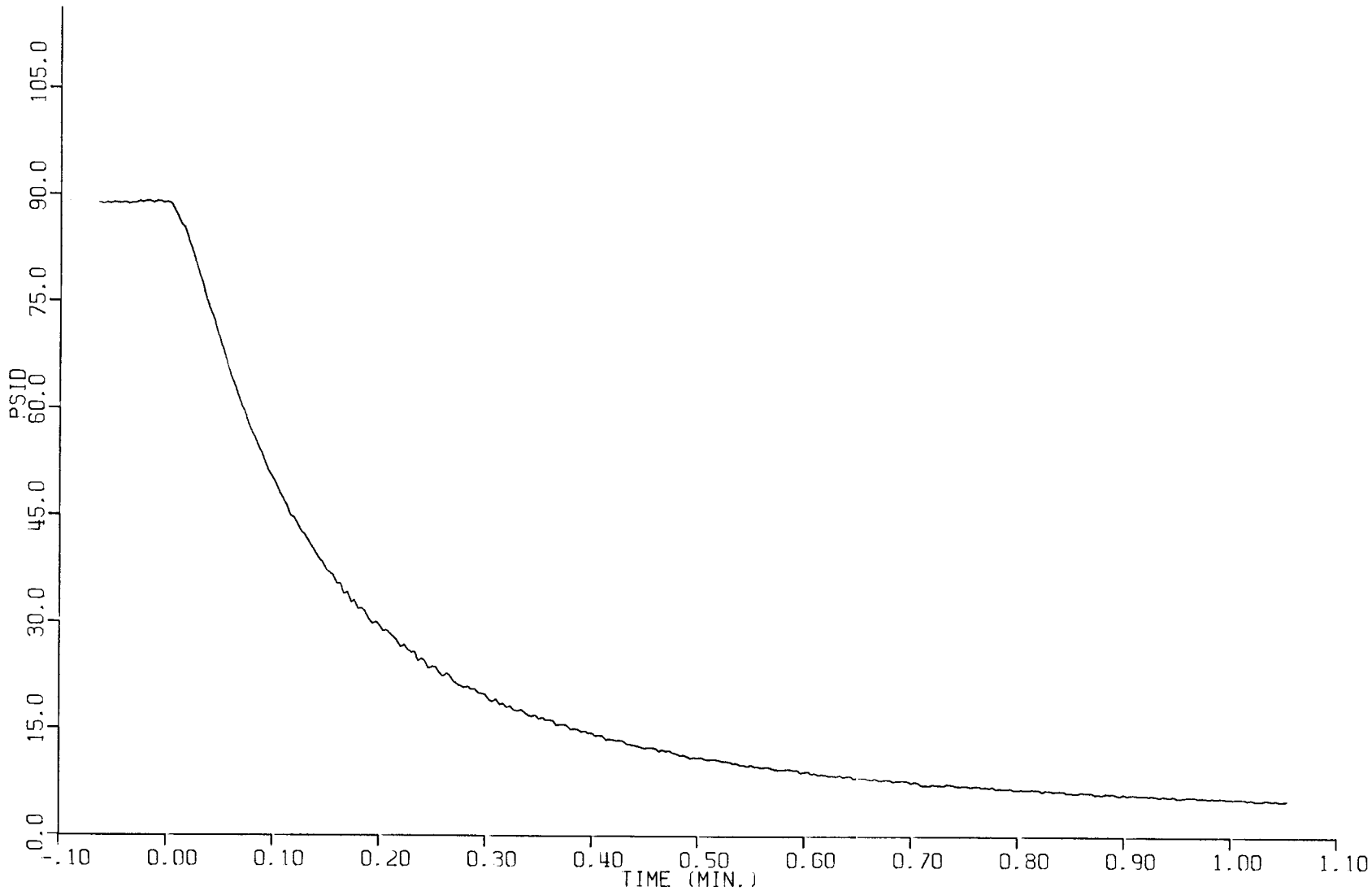


Figure 4-34. Loss of Flow - Reactor Coolant Pump 2B Differential Pressure

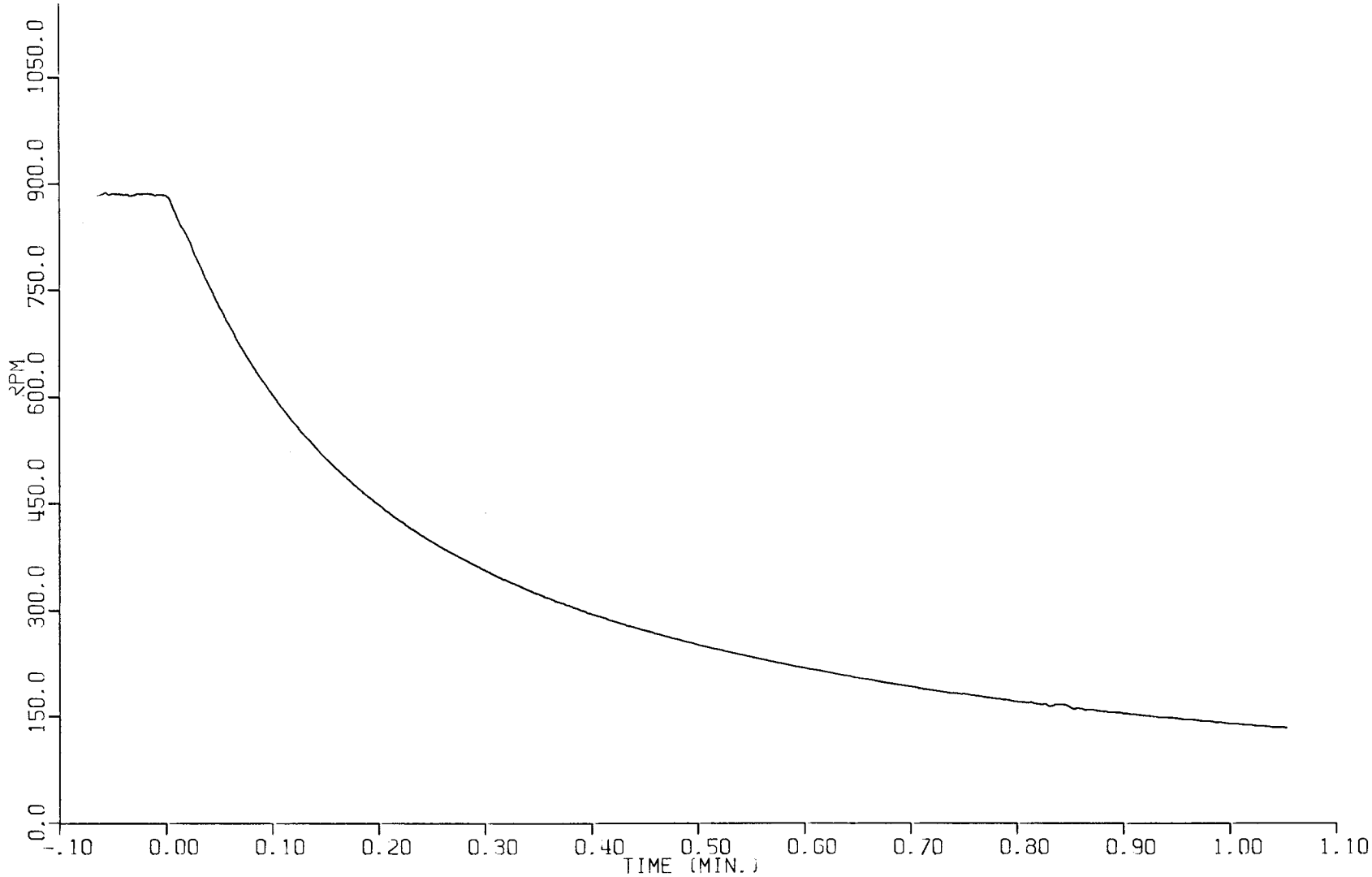


Figure 4-35. Loss of Flow - Reactor Coolant Pump 2B Speed

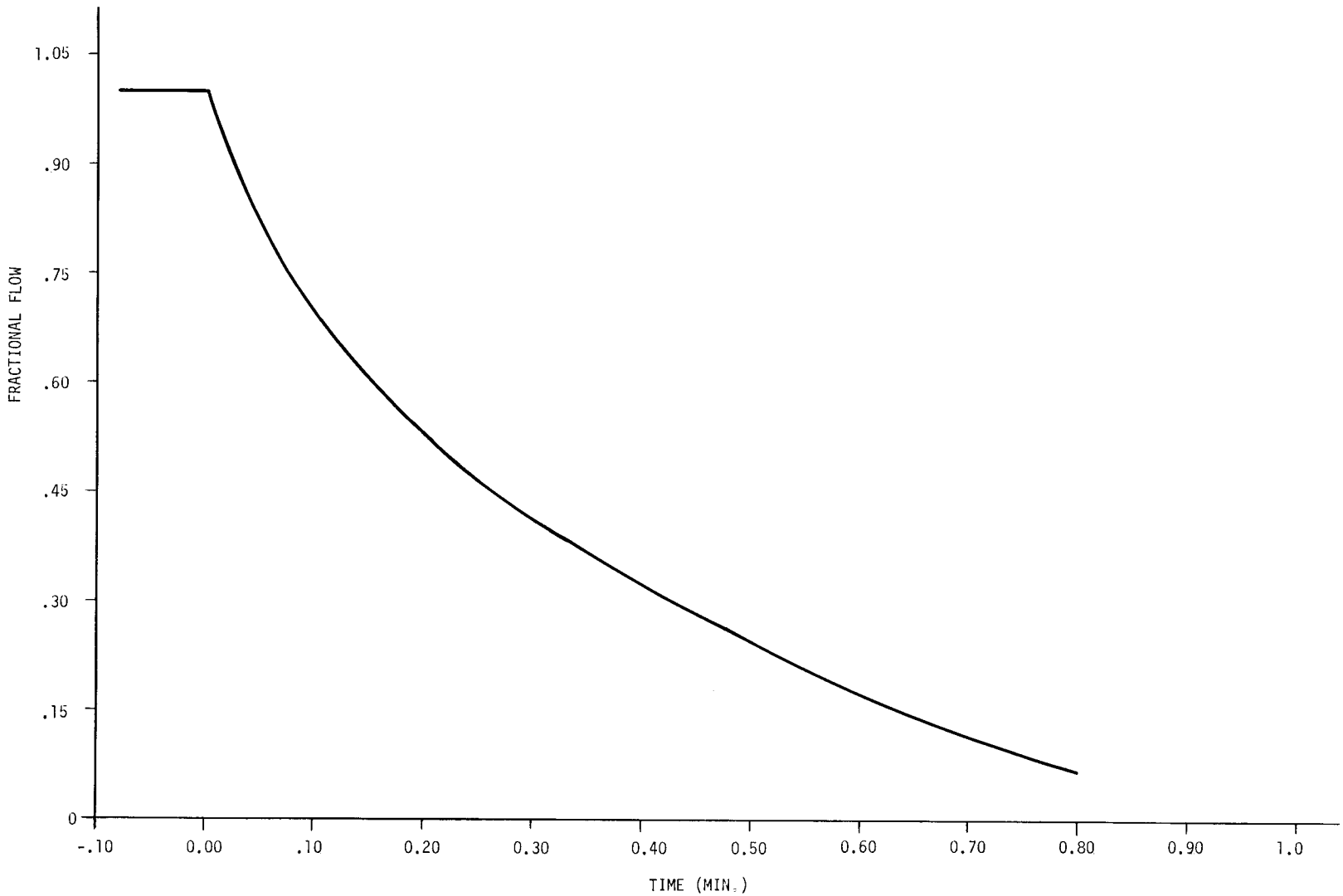


Figure 4-36. Loss of Flow - Reactor Coolant Pump 2B Flow Rate

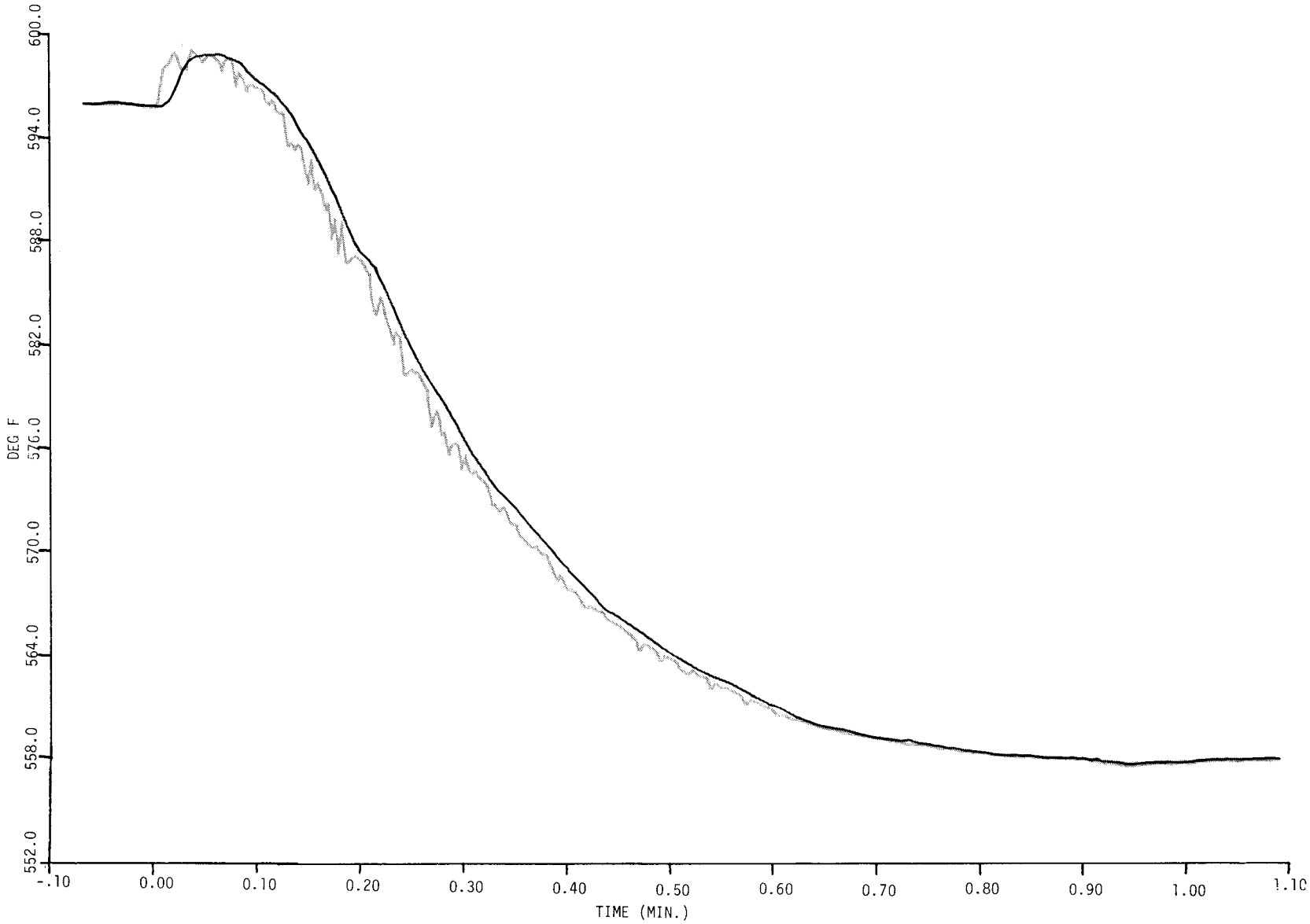


Figure 4-37. Loss of Flow - Steam Generator 1 Hot Leg Temperature

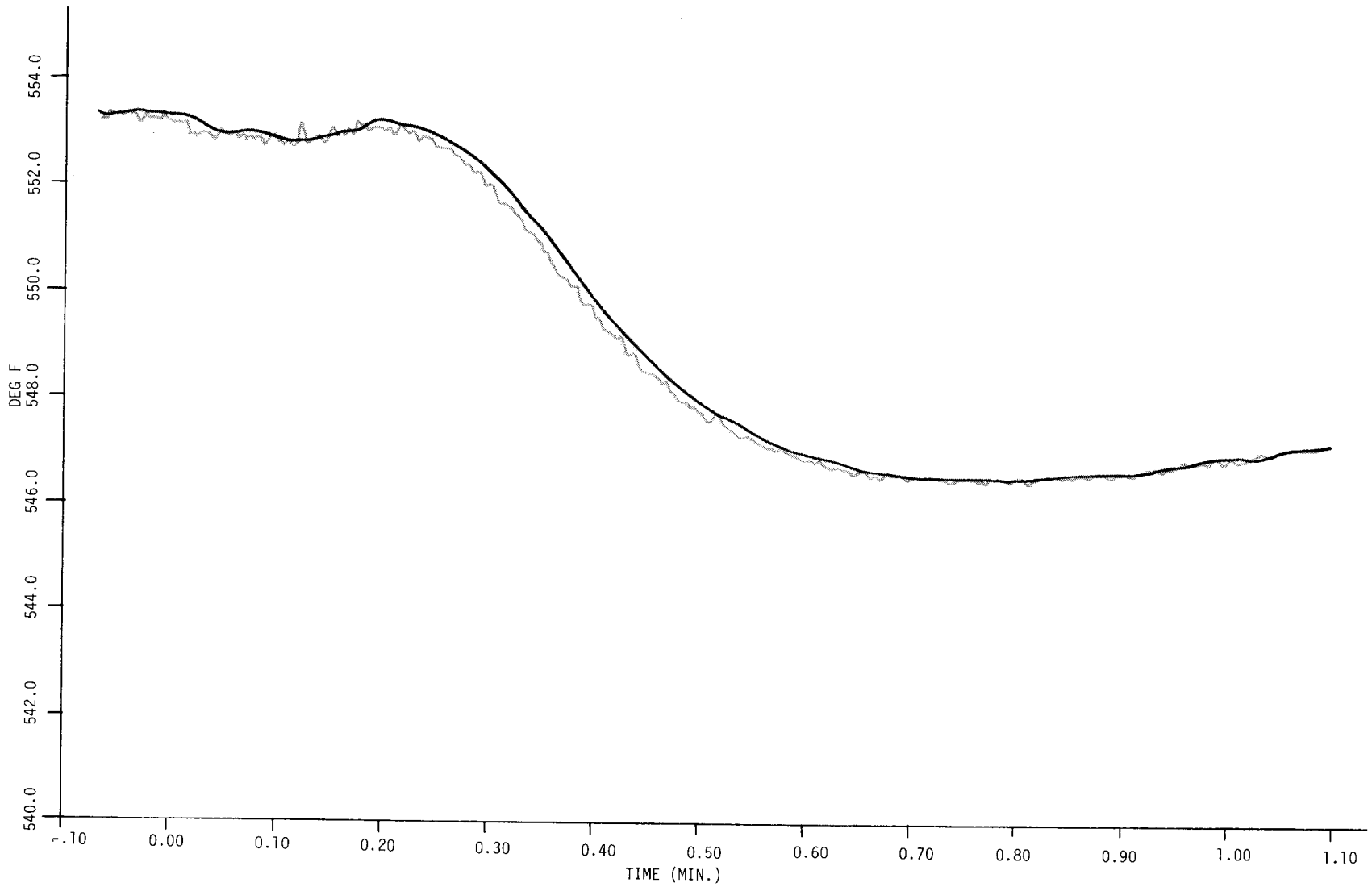


Figure 4-38. Loss of Flow - Steam Generator 1 Cold Leg Temperature (Loop 1A)

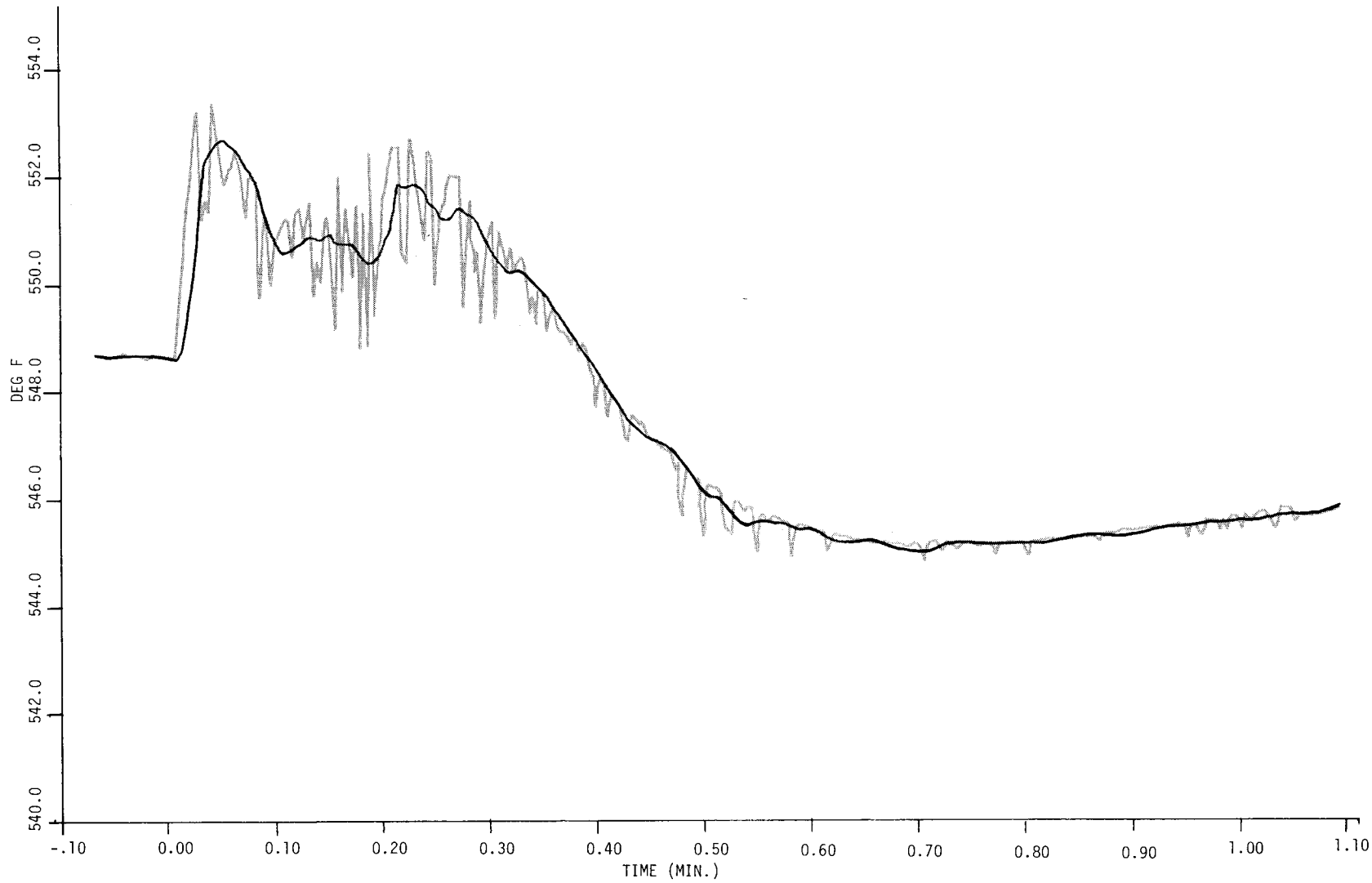


Figure 4-39. Loss of Flow - Steam Generator 1 Cold Leg Temperature (Loop 1B)

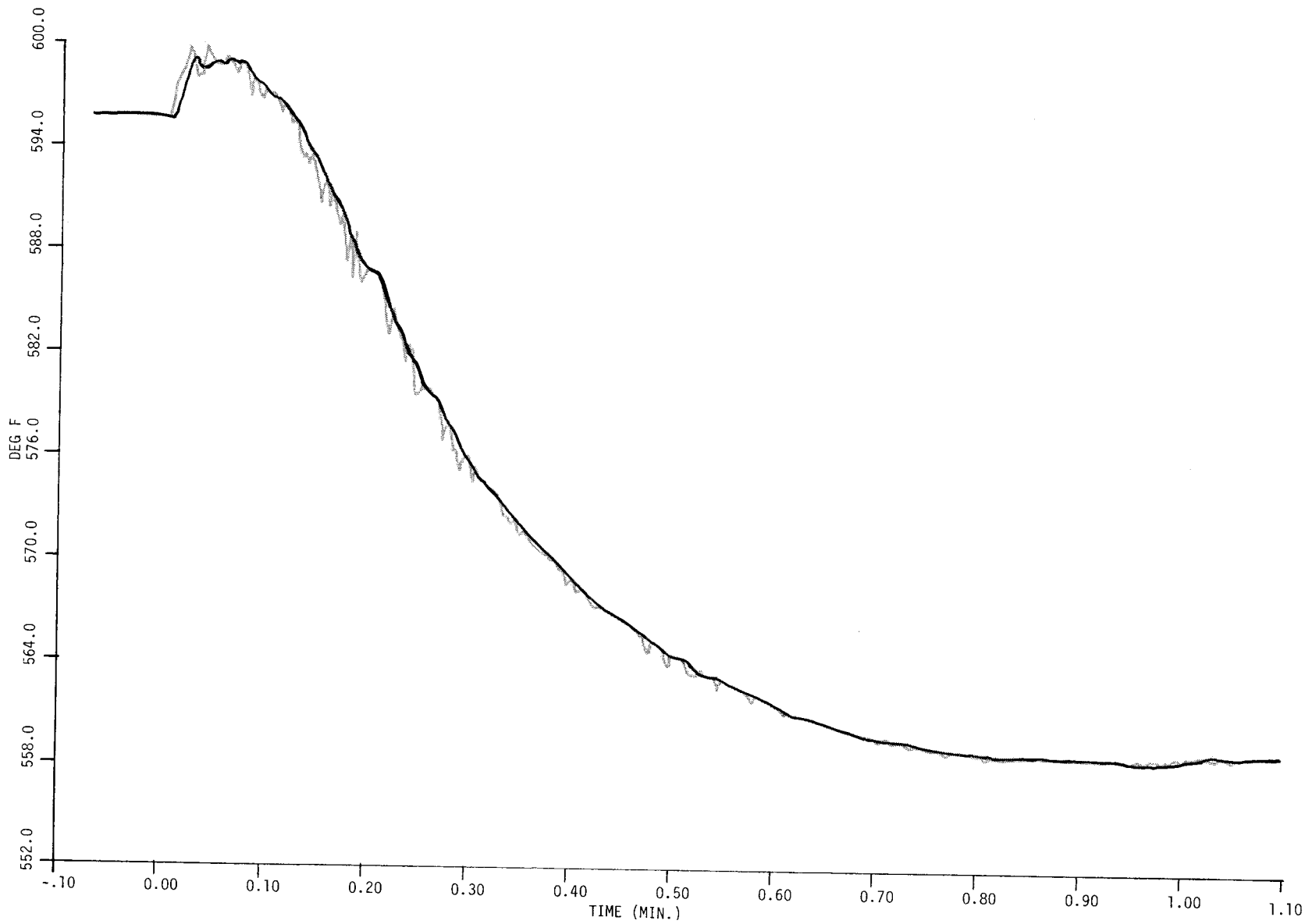


Figure 4-40. Loss of Flow - Steam Generator 2 Hot Leg Temperature

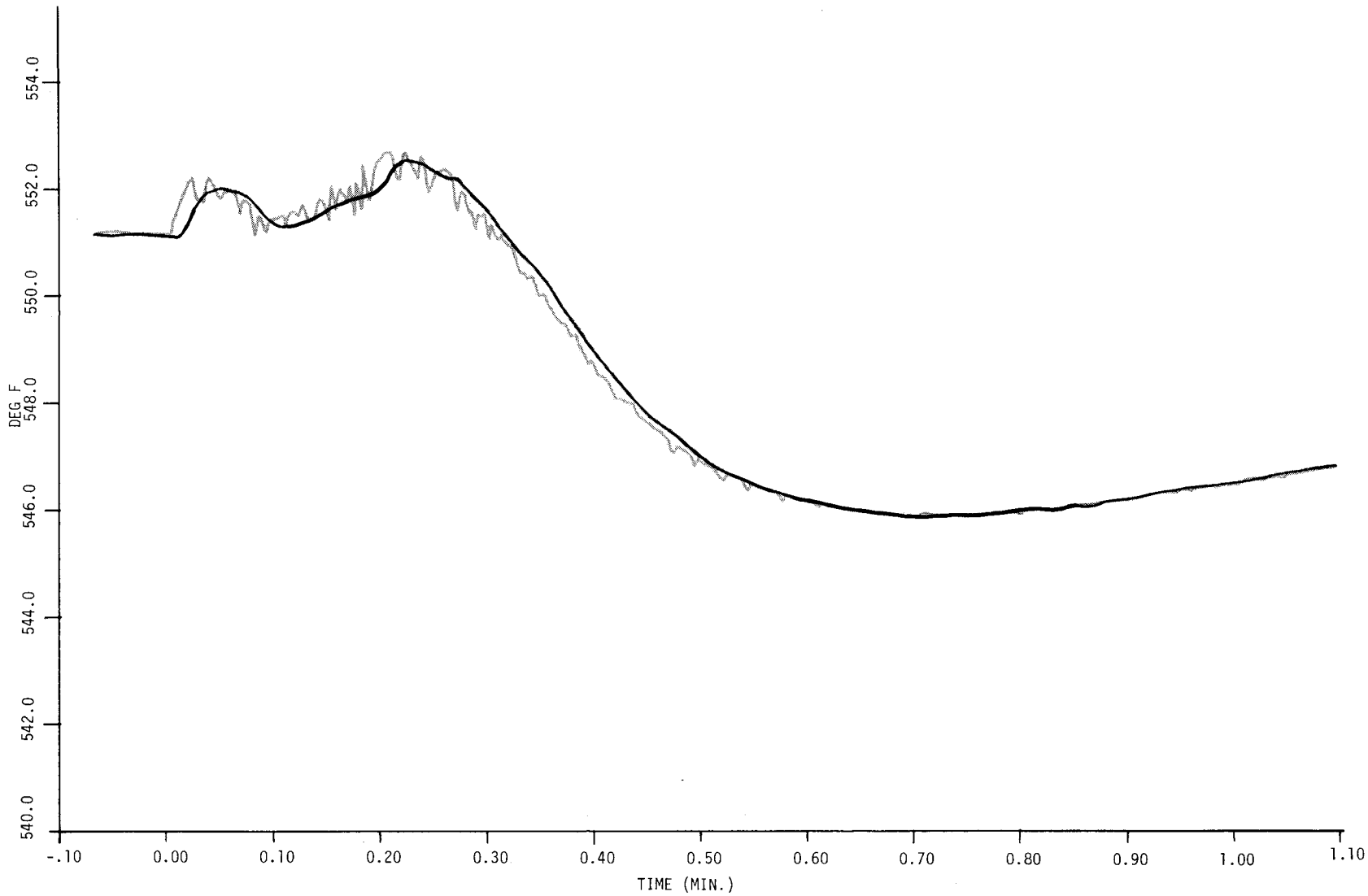


Figure 4-41. Loss of Flow - Steam Generator 2 Cold Leg Temperature (Loop 2A)

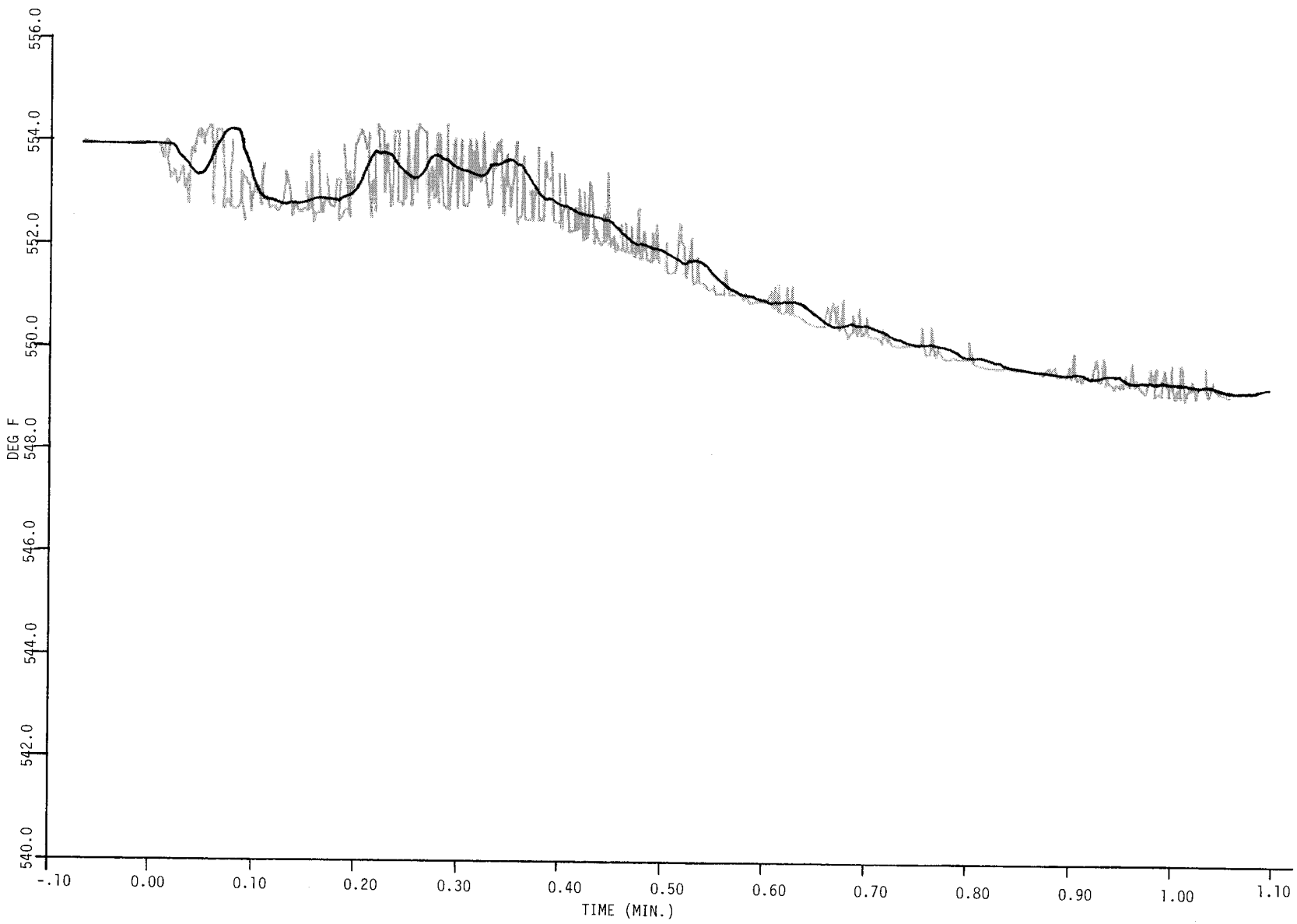


Figure 4-42. Loss of Flow - Steam Generator 2 Cold Leg Temperature (Loop 2B)

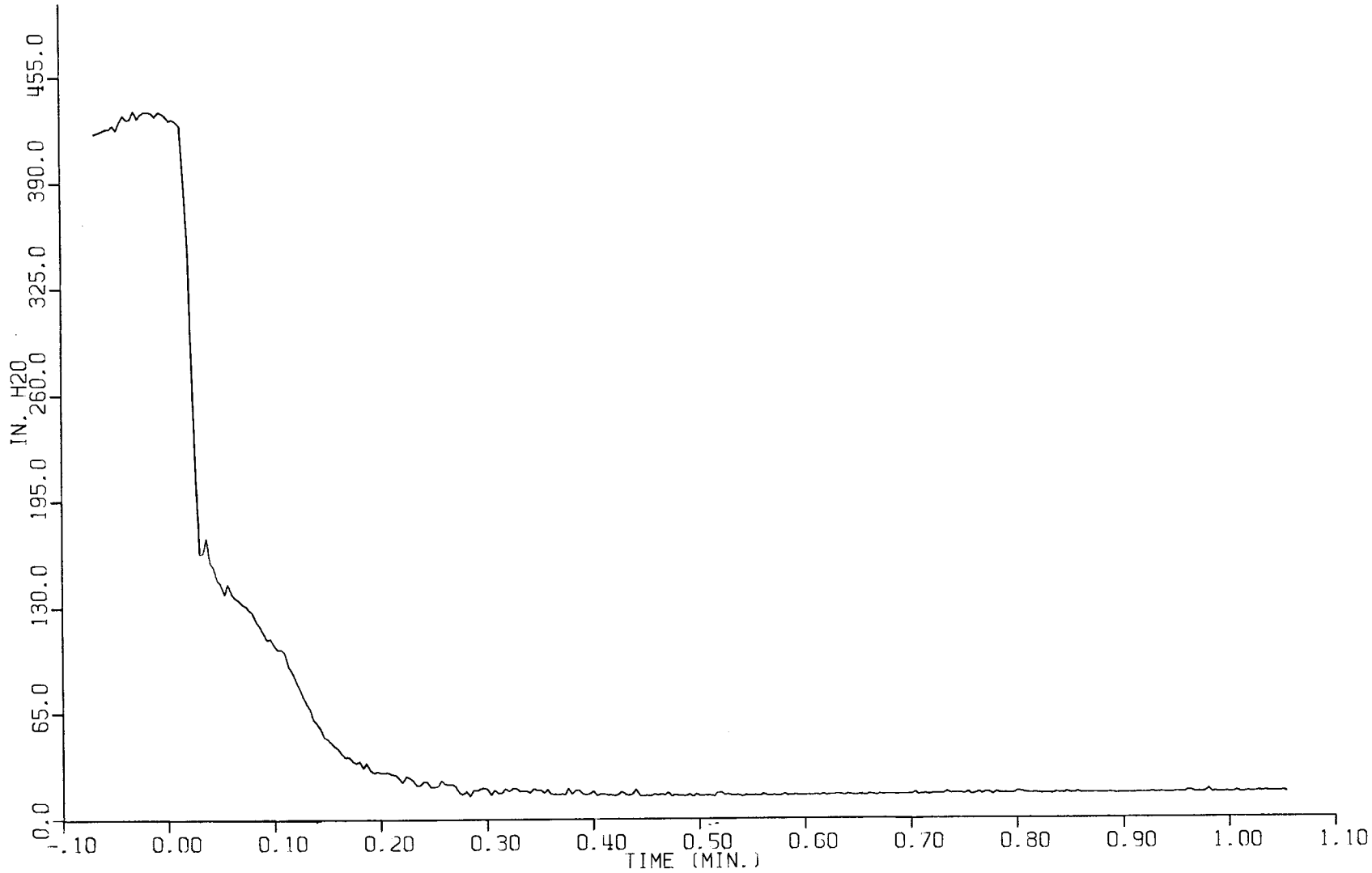


Figure 4-43. Loss of Flow - Steam Generator 1 Feedwater Differential Pressure

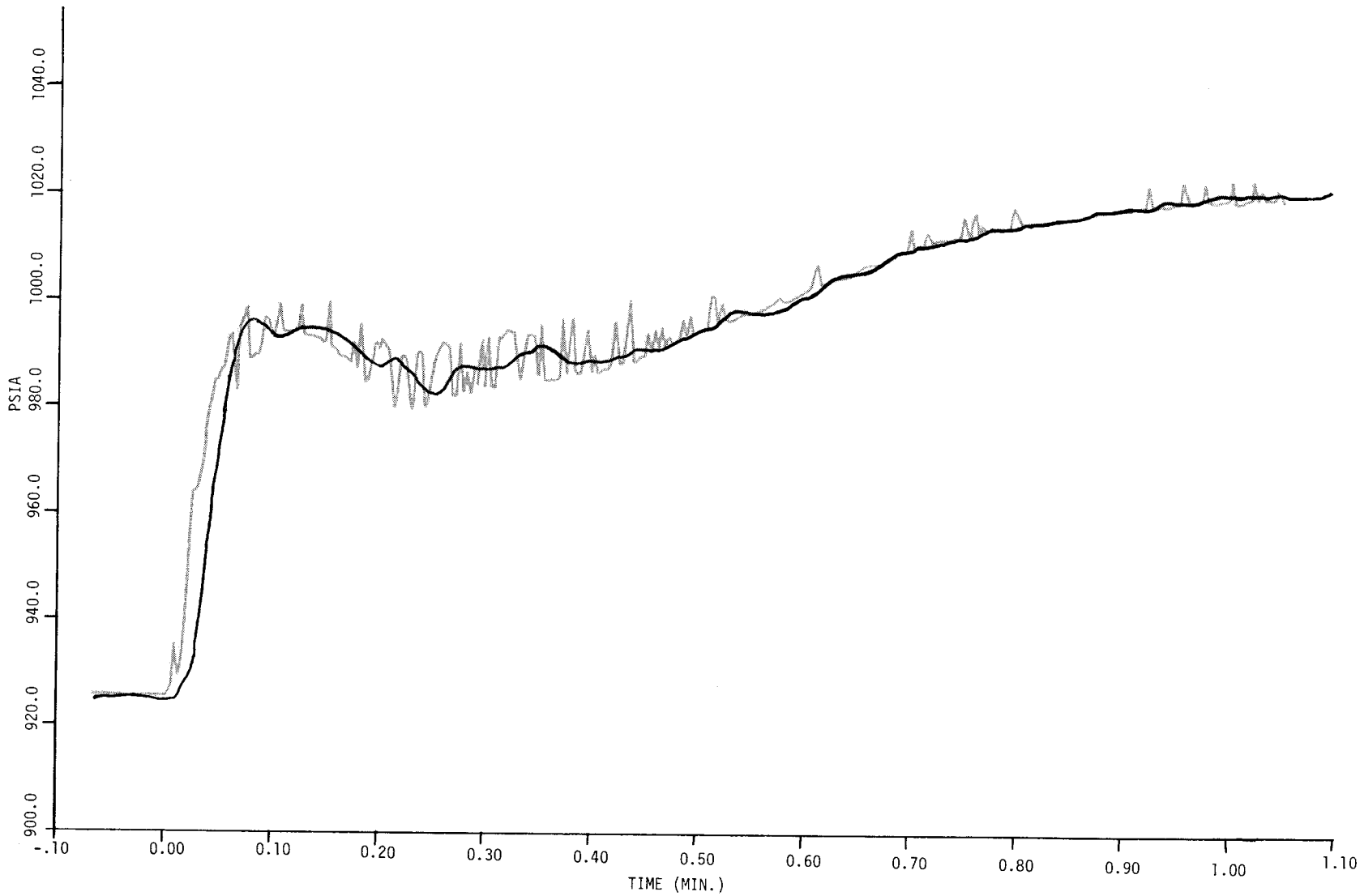


Figure 4-44. Loss of Flow - Steam Generator 1 Pressure

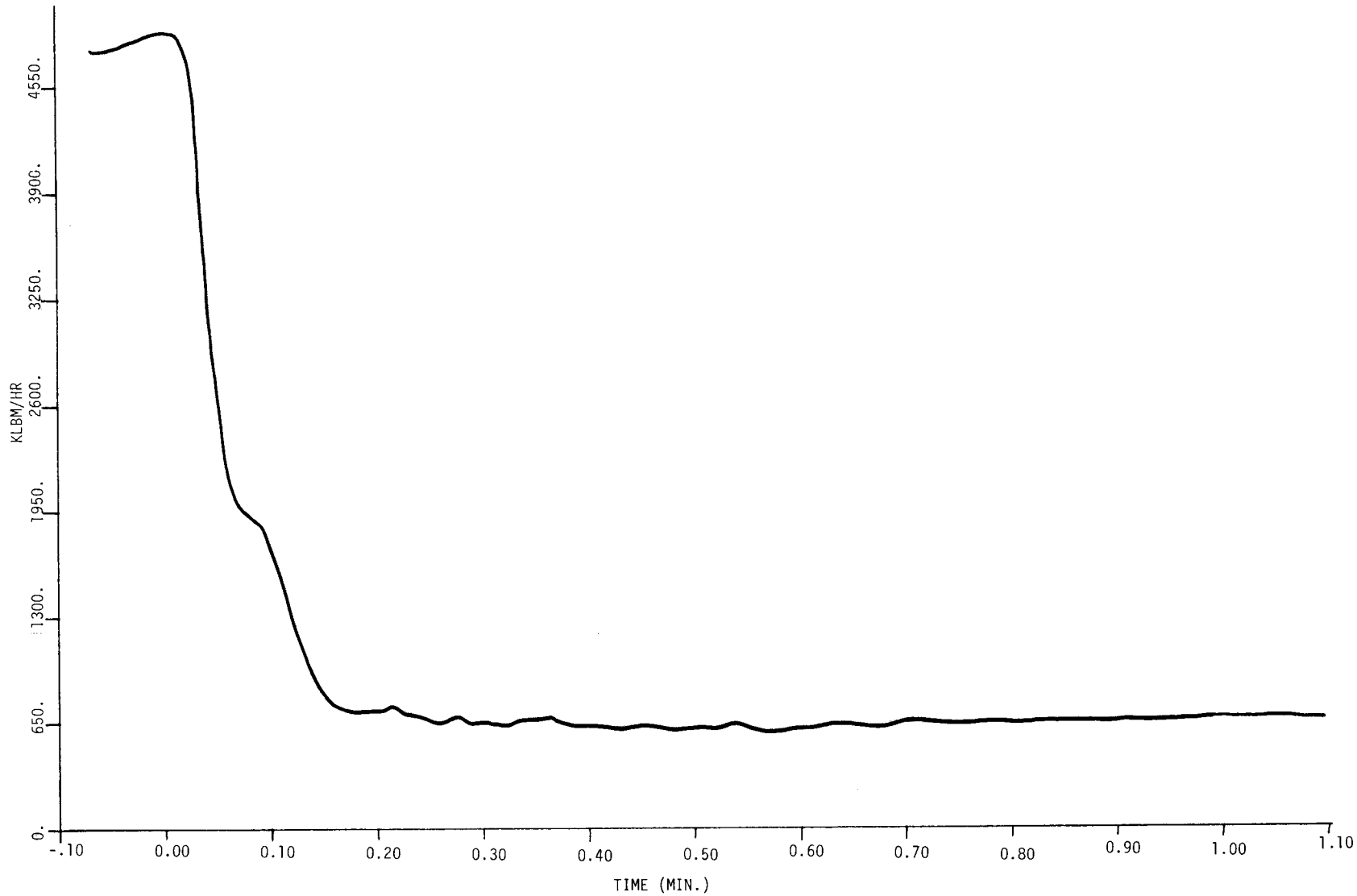


Figure 4-45. Loss of Flow - Steam Generator 1 Feedwater Flow Rate

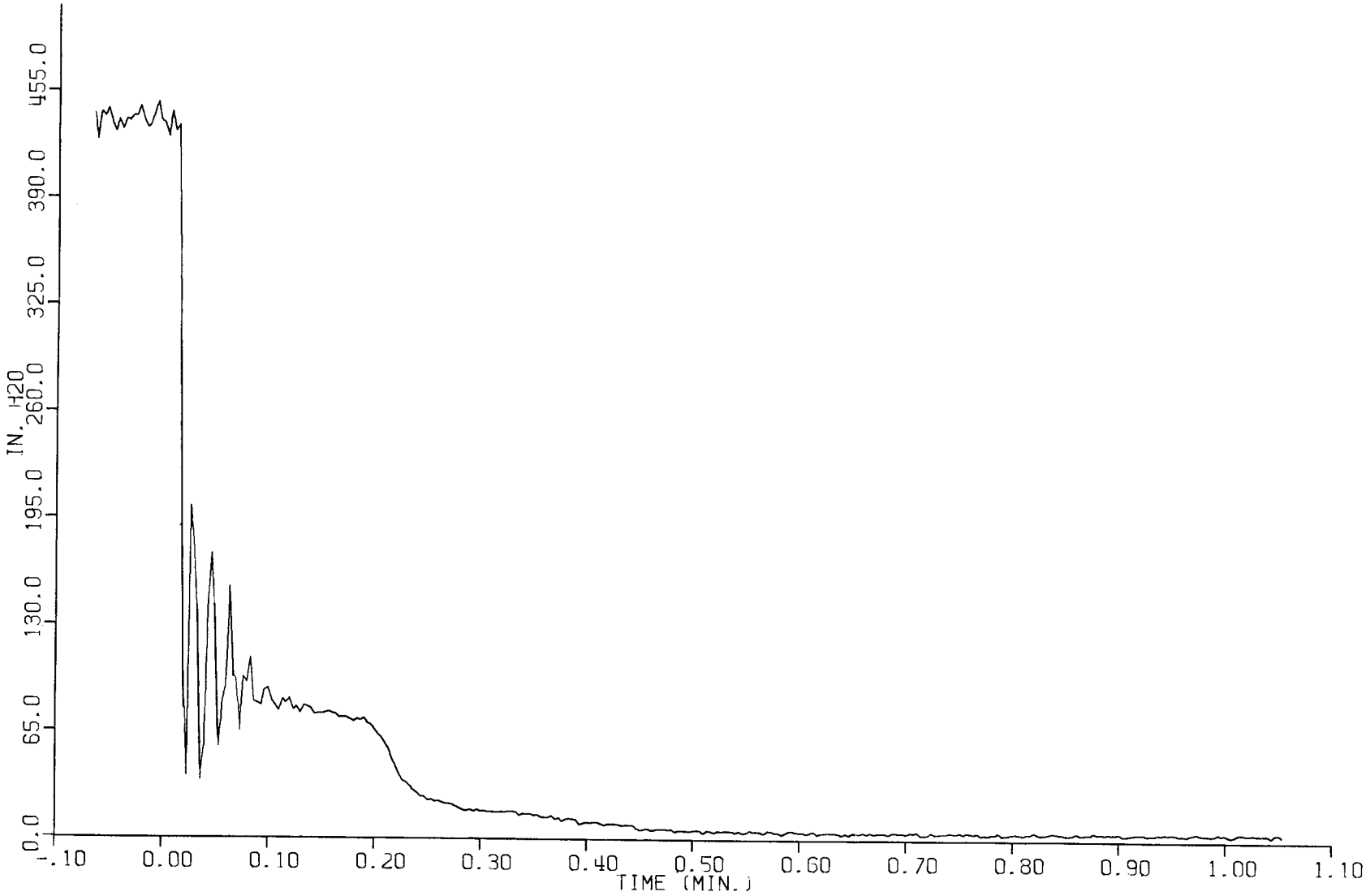


Figure 4-46. Loss of Flow - Steam Generator 1 Header Differential Pressure

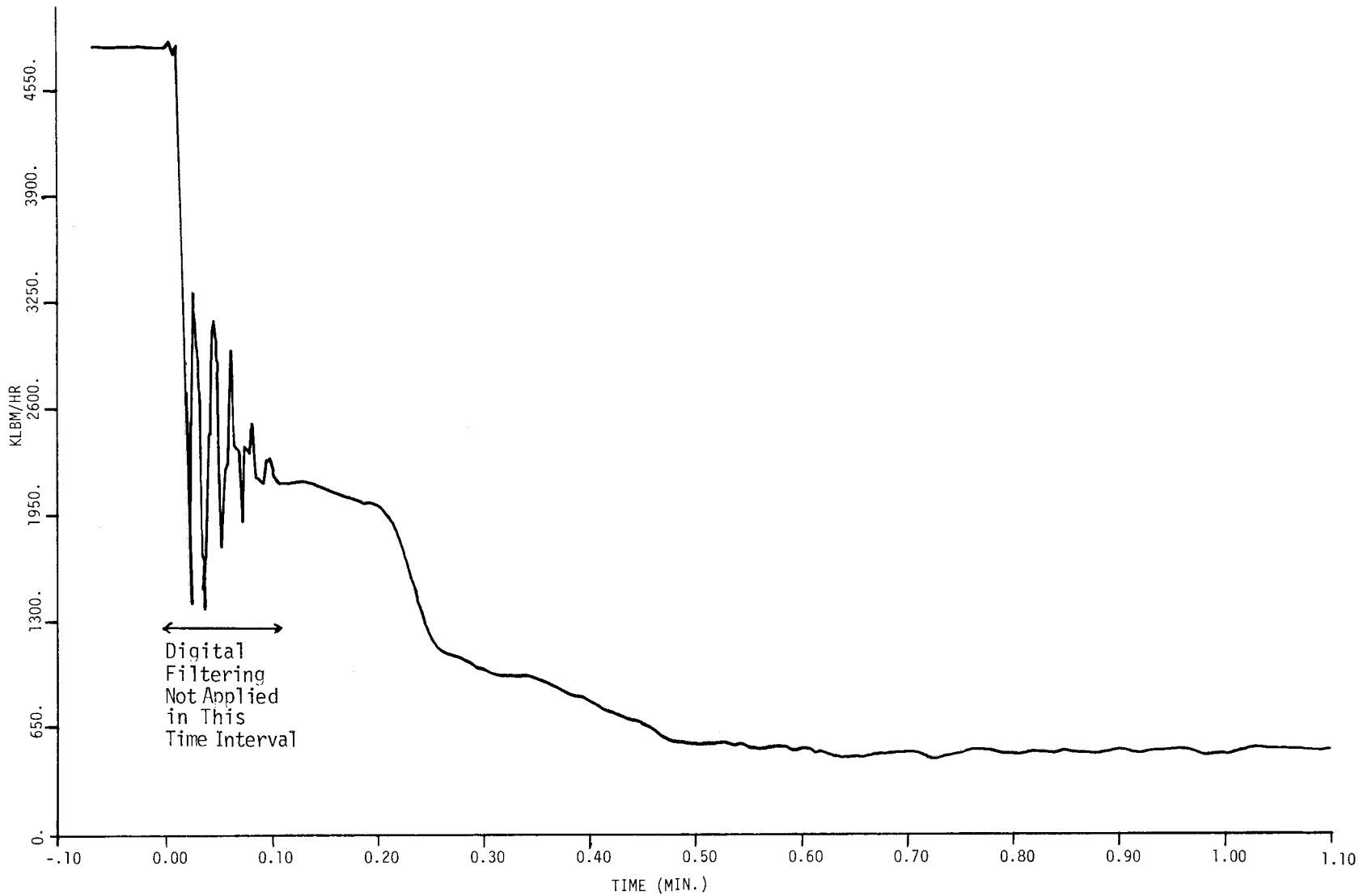


Figure 4-47. Loss of Flow - Steam Generator 1 Main Steam Flow Rate

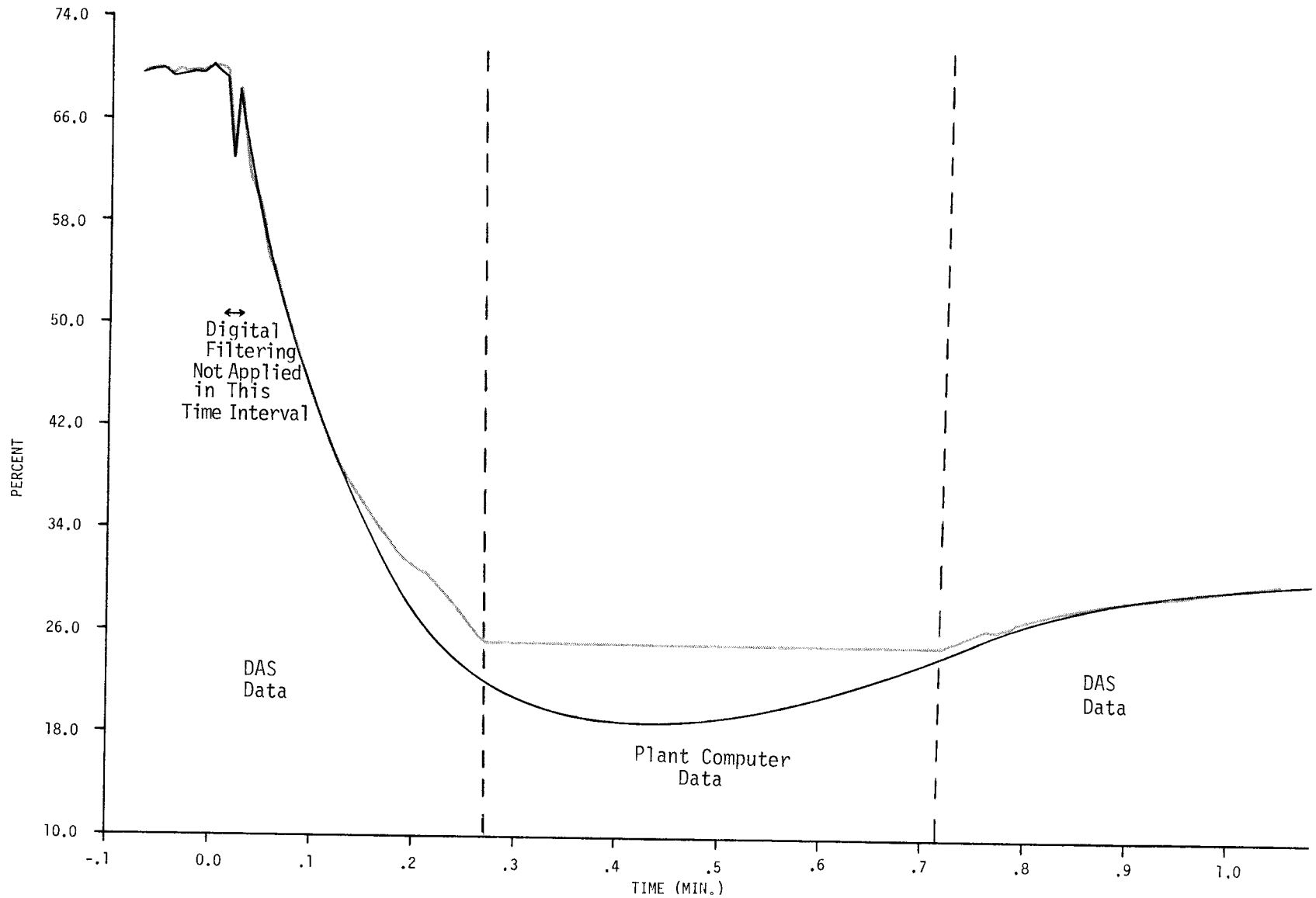


Figure 4-48. Loss of Flow - Steam Generator 1 Level

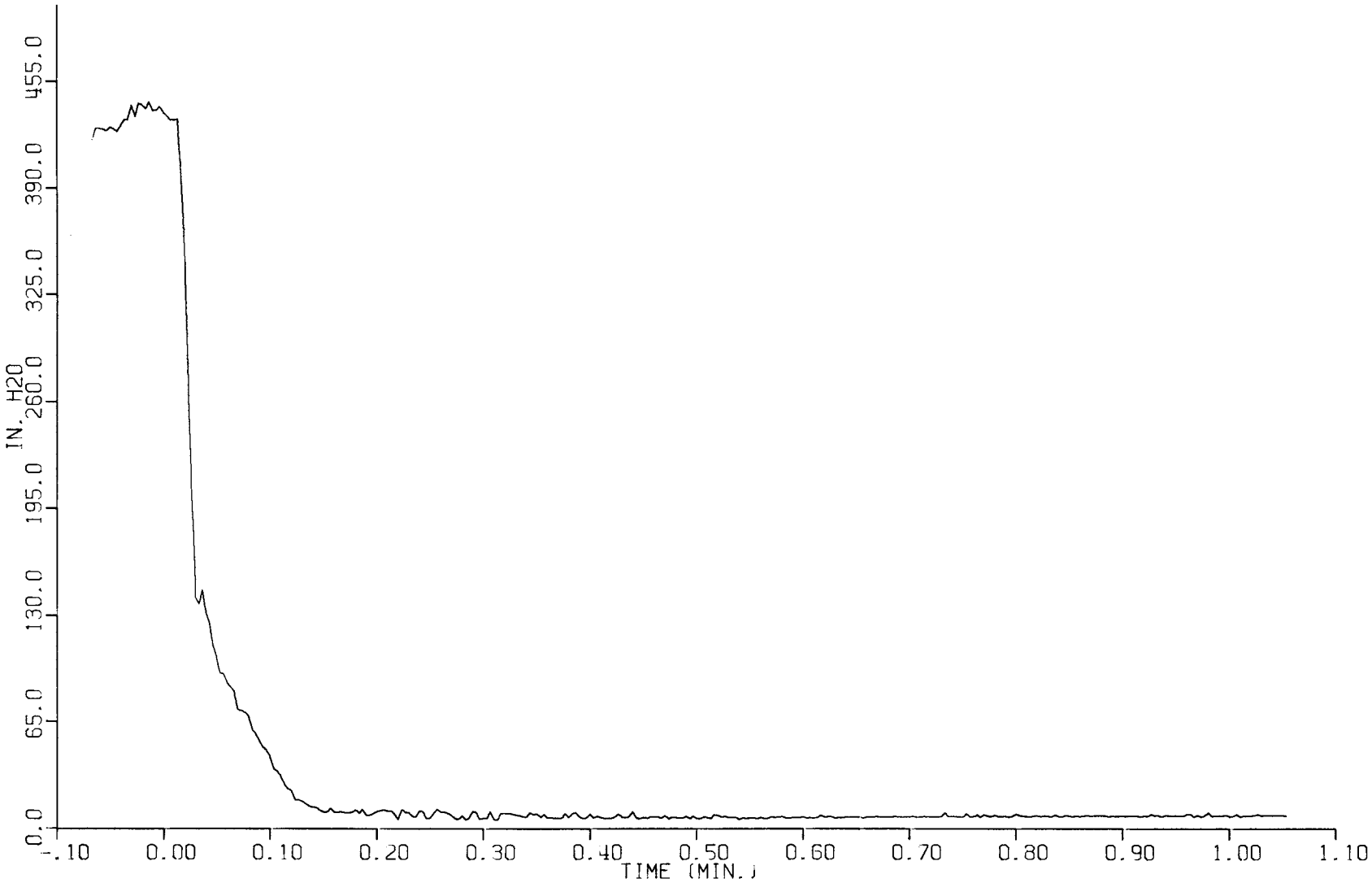


Figure 4-49. Loss of Flow - Steam Generator 2 Feedwater Differential Pressure

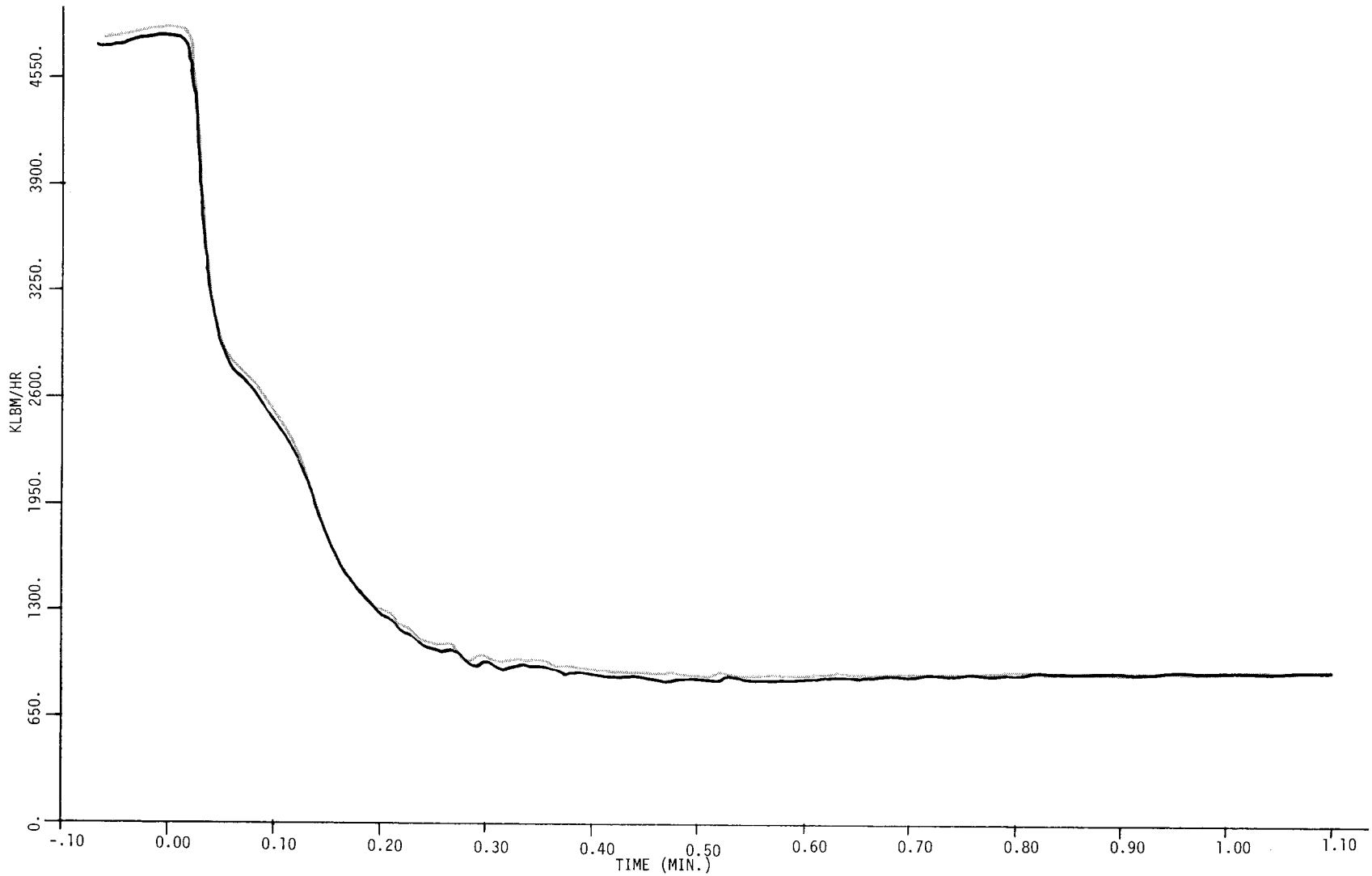


Figure 4-50. Loss of Flow - Steam Generator 2 Feedwater Flow Rate

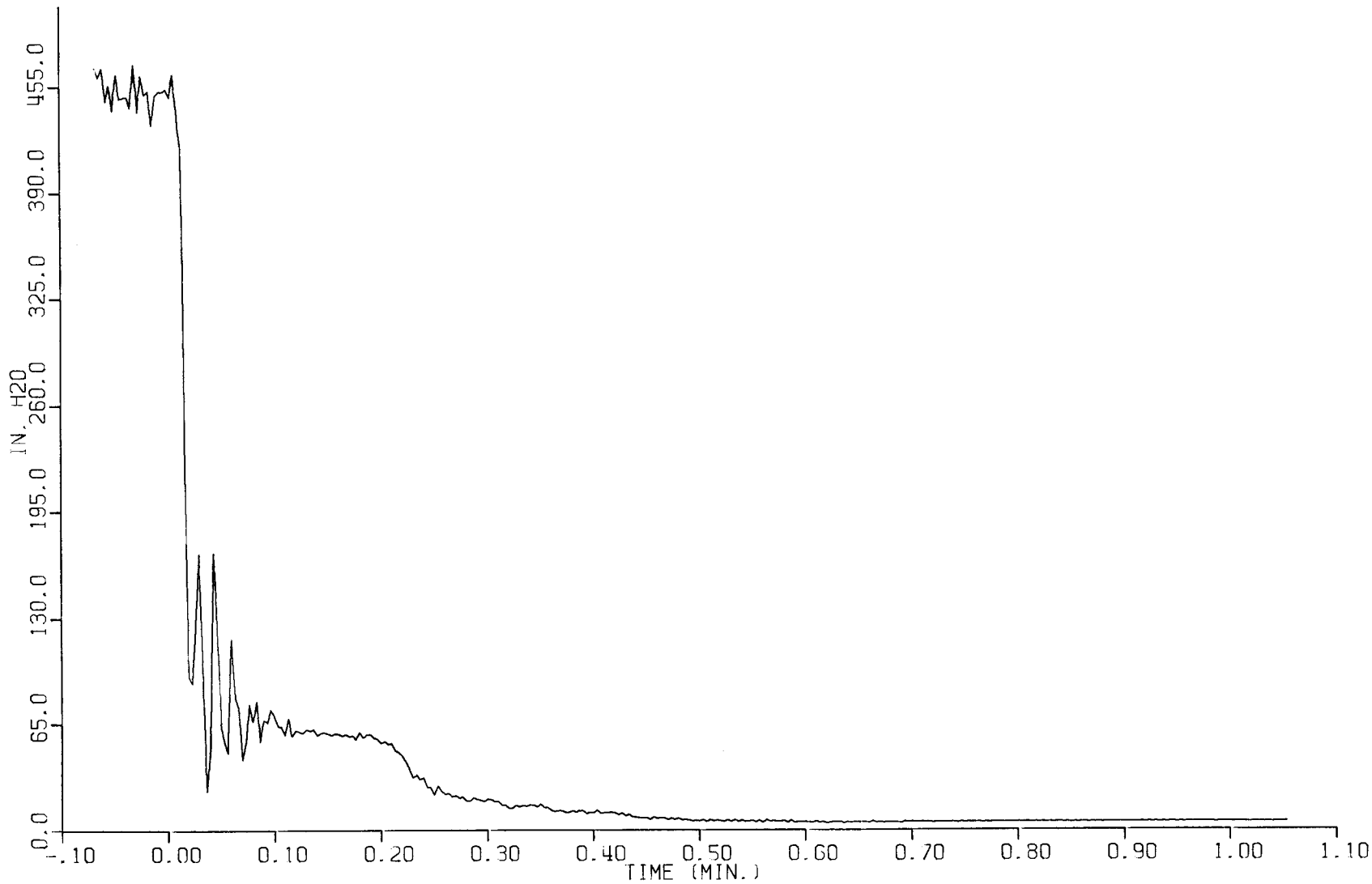


Figure 4-51. Loss of Flow - Steam Generator 2 Header Differential Pressure

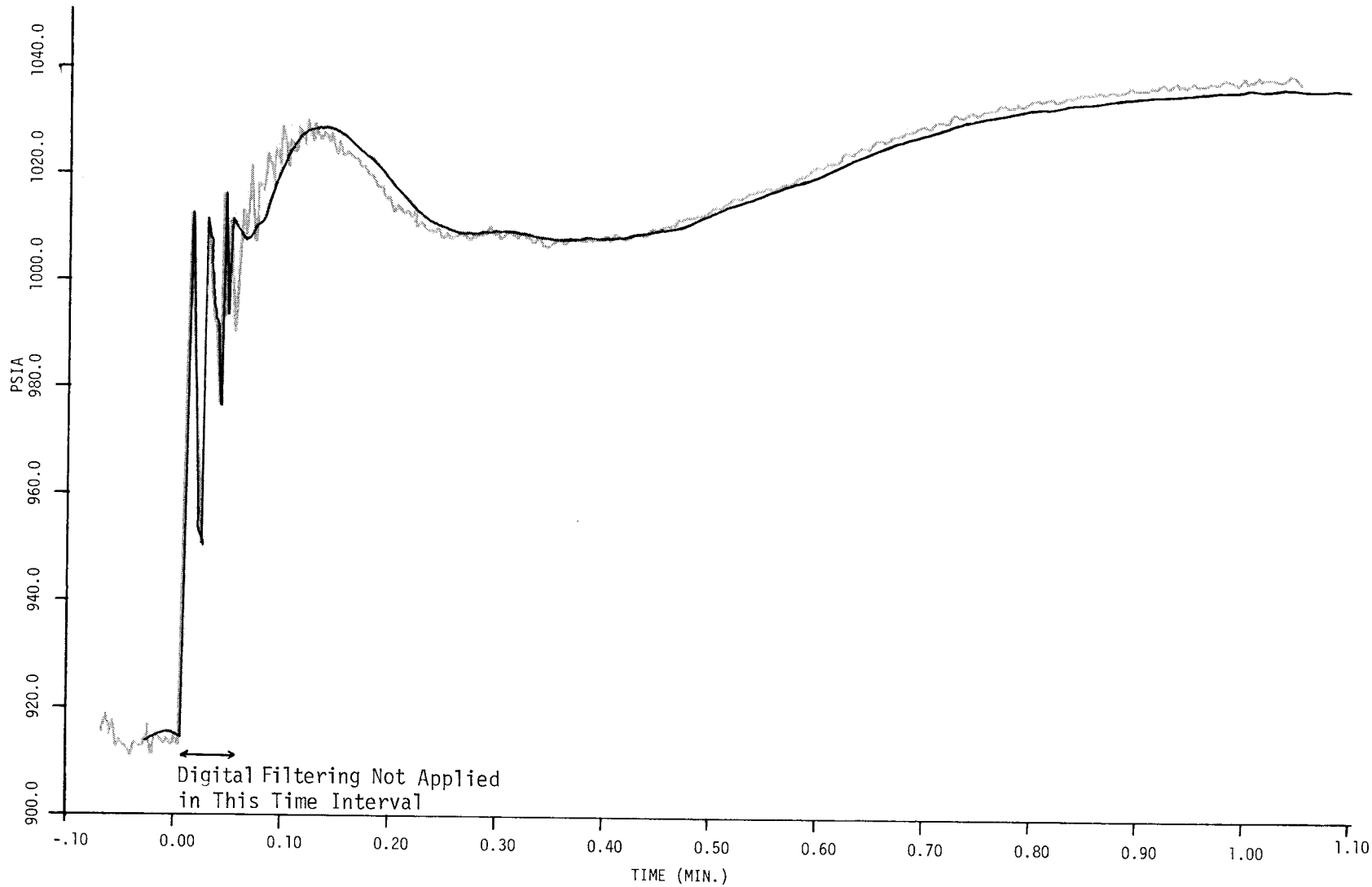


Figure 4-52. Loss of Flow - Steam Generator 2 Header Pressure

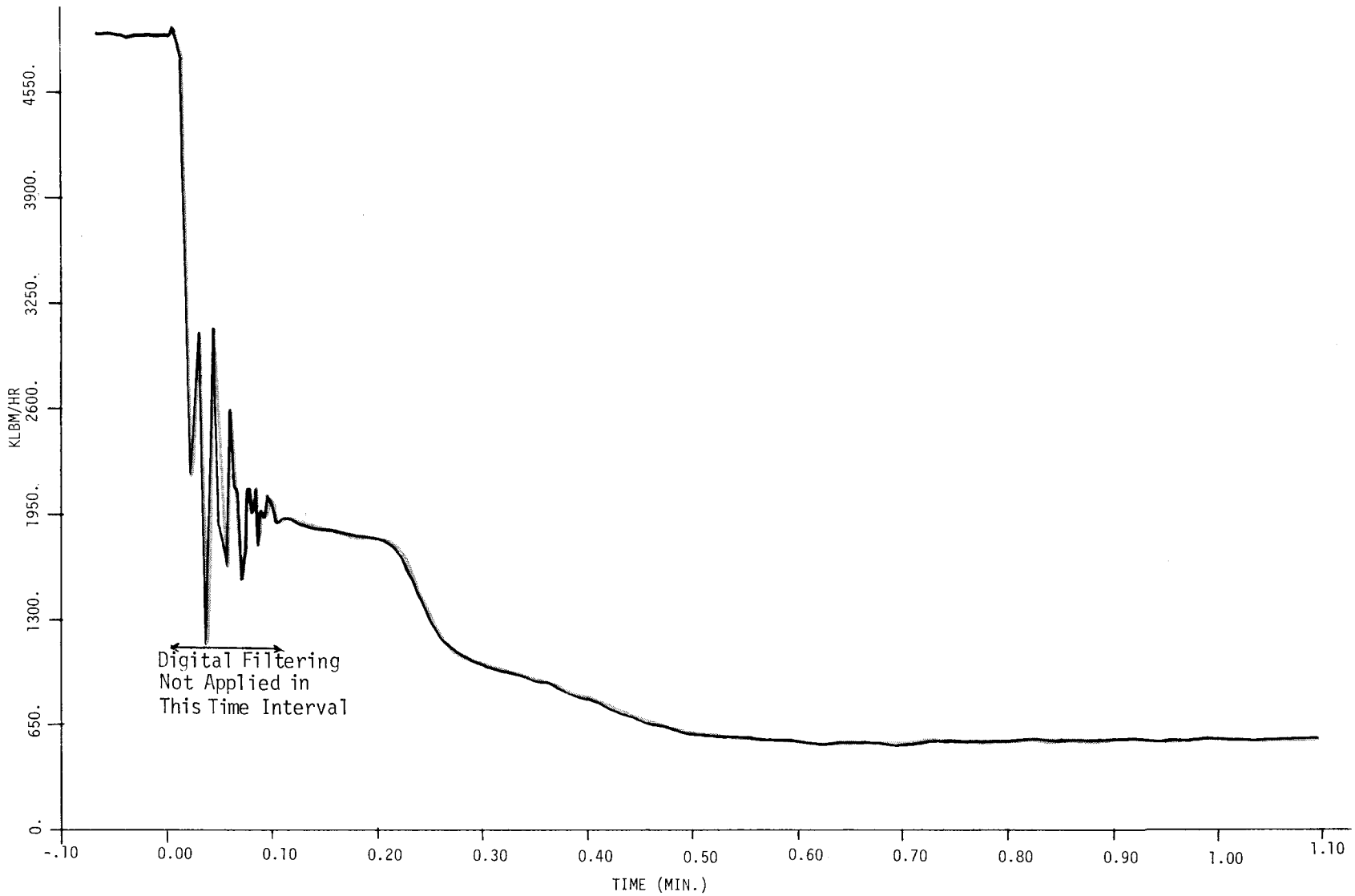


Figure 4-53. Loss of Flow - Steam Generator 2 Main Steam Flow Rate

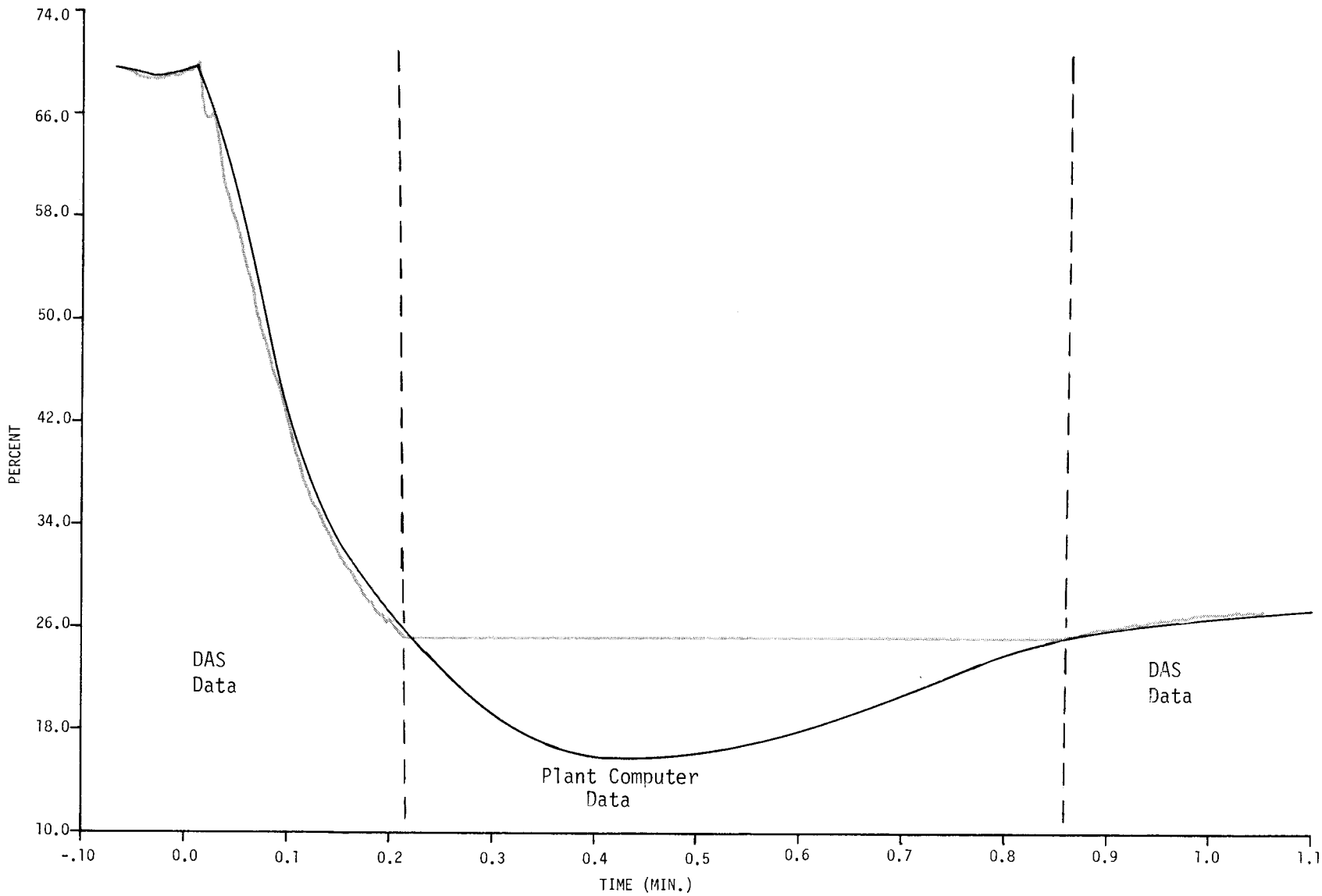


Figure 4-54. Loss of Flow - Steam Generator 2 Level

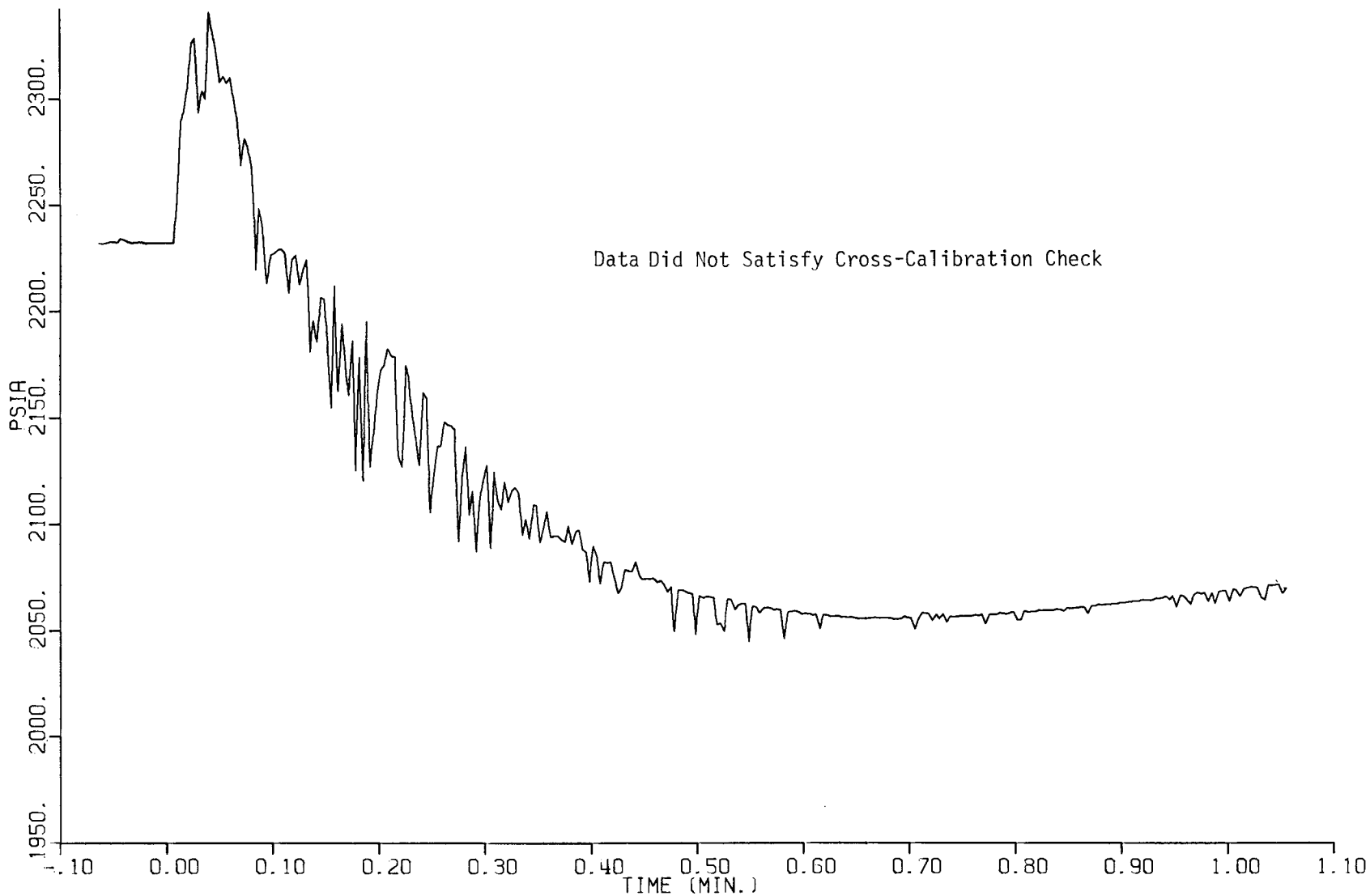


Figure 4-55. Loss of Flow - Pressurizer Pressure (Wide Range)

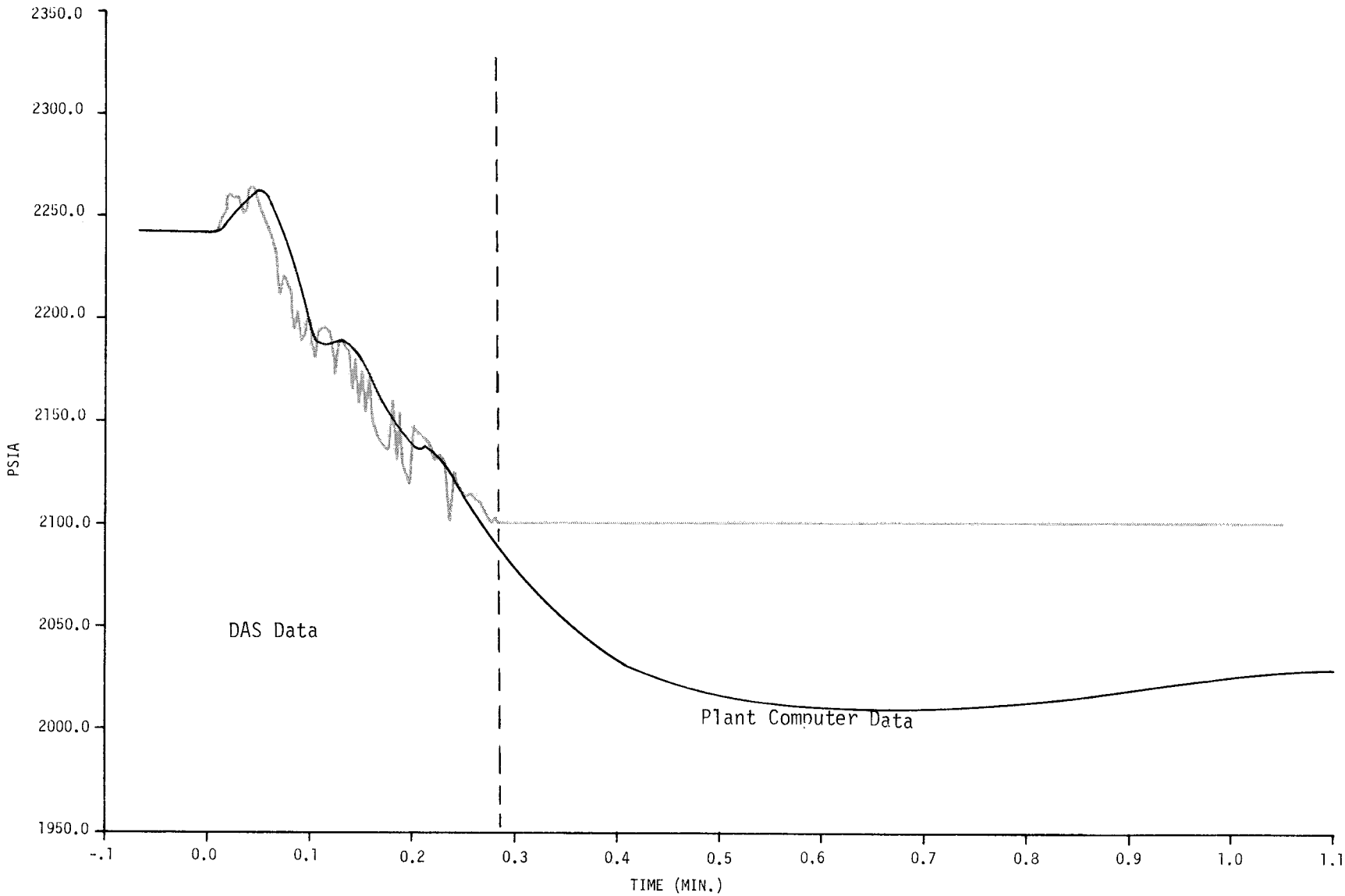


Figure 4-56. Loss of Flow - Pressurizer Pressure (Narrow Range)

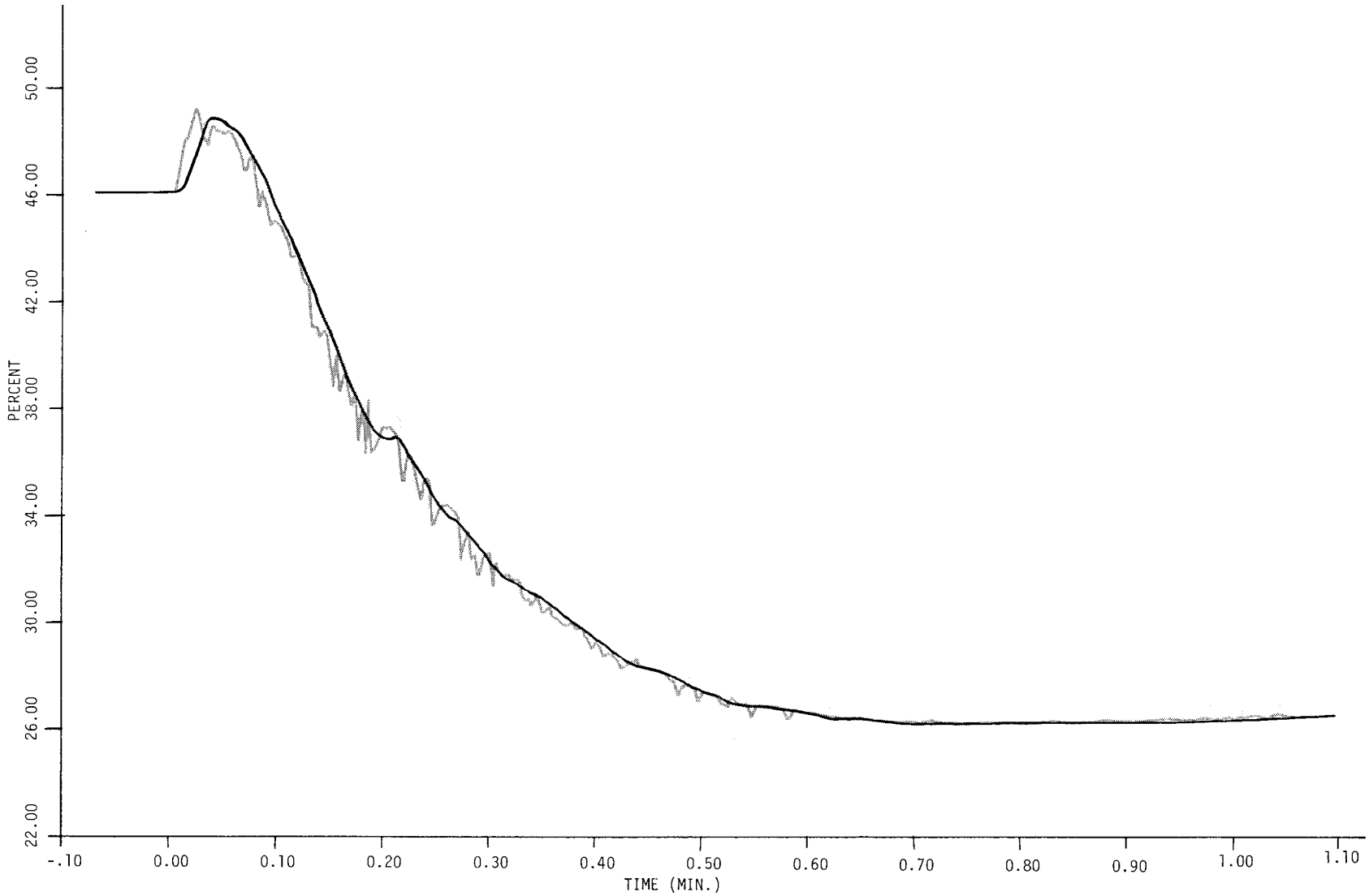


Figure 4-57. Loss of Flow - Pressurizer Level

Table 4-4

INITIAL CONDITIONS FOR THE FULL LENGTH CEA(5-60) DROP

Core Power, Mwt	1391	(49.4%)
Core Inlet Coolant Temperature, °F	546	
Core Outlet Coolant Temperature, °F	577	
Core Mass Flow Rate, 10^6 lbm/hr	134.0	
Pressurizer Pressure, psia	2246	
Pressurizer Level, percent	39.1	
Steam Generator Pressure, psia	932	
Steam Generator Level, percent *	70	
Charging Flow, GPM	44.5	
Letdown Flow, GPM	39.6	
Boron Concentration, PPM	700	
Axial Shape Index, ASIU	∿0.0	
Core Average Burnup, MwD/T	∿2300	
Control System Status:		
- Pressurizer Pressure	Automatic	
- Pressurizer Level	Automatic	
- Feedwater	Automatic	
- Reactor Regulating	Automatic	
- Steam Dump and Bypass	Automatic	

* Level indication in percent of 13.9 ft. instrument span. 0 percent level corresponds to a liquid level 24.5 ft. above the steam generator tube sheet. See Reference 3 for further steam generator details.

Table 4-5

SEQUENCE OF EVENTS FOR THE FULL LENGTH CEA(5-60) DROP

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	571°F
600.	Reactor stable at slightly reduced core average power level	43%

* Power recorded by ex-core neutron detector closest to the dropped CEA.

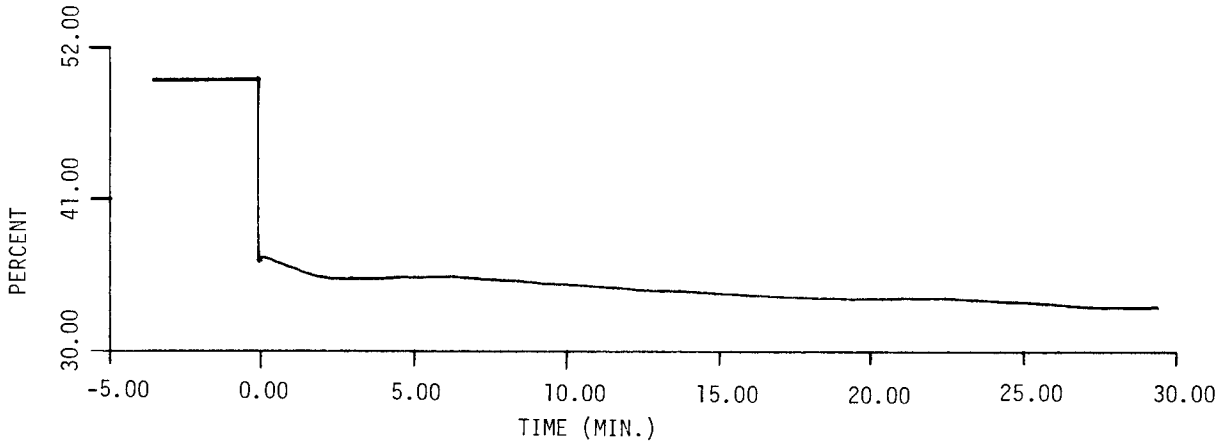


Figure 4-58. Full Length CEA Drop-Control Channel 2 Nuclear Power

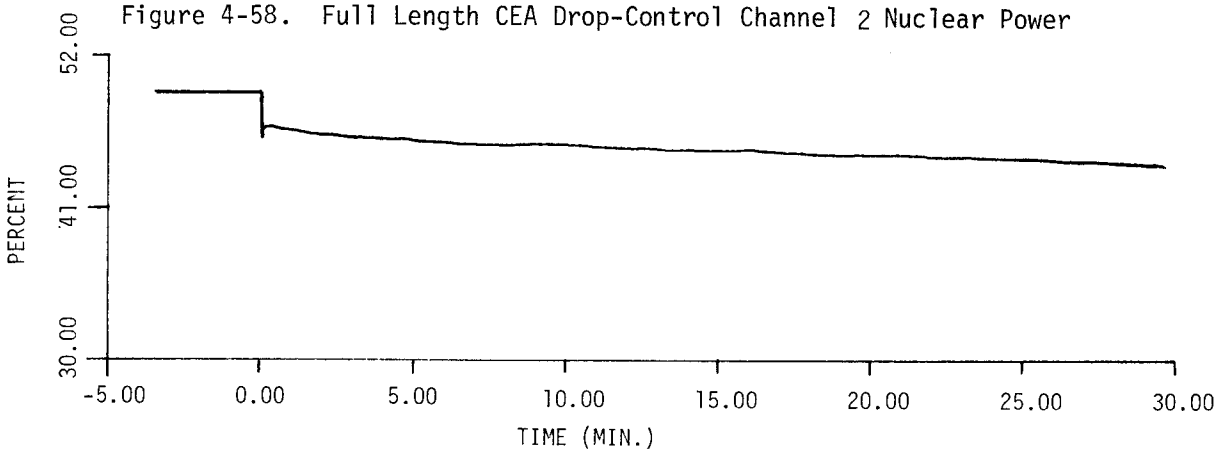


Figure 4-59. Full Length CEA Drop-Control Channel 1 Nuclear Power

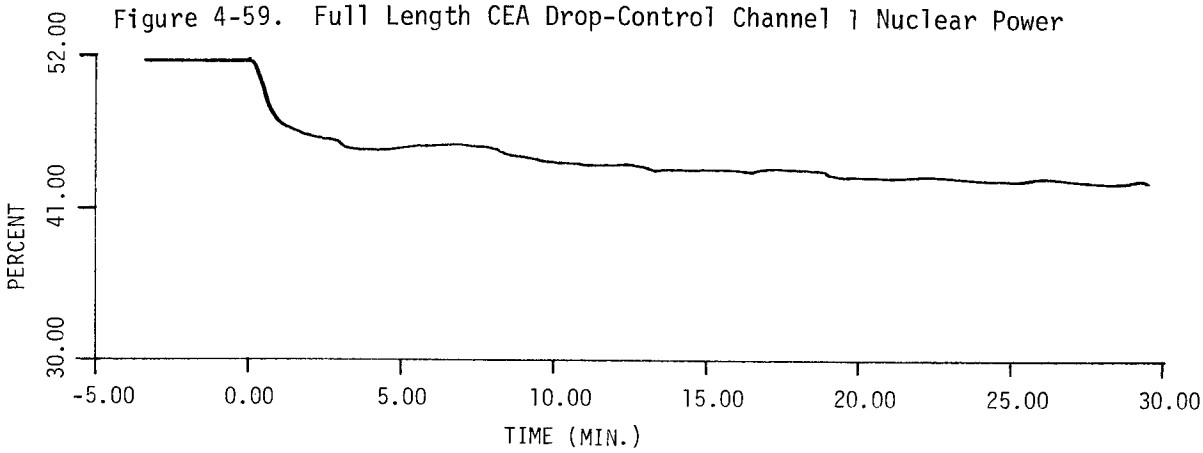


Figure 4-60. Full Length CEA Drop-Turbine Power

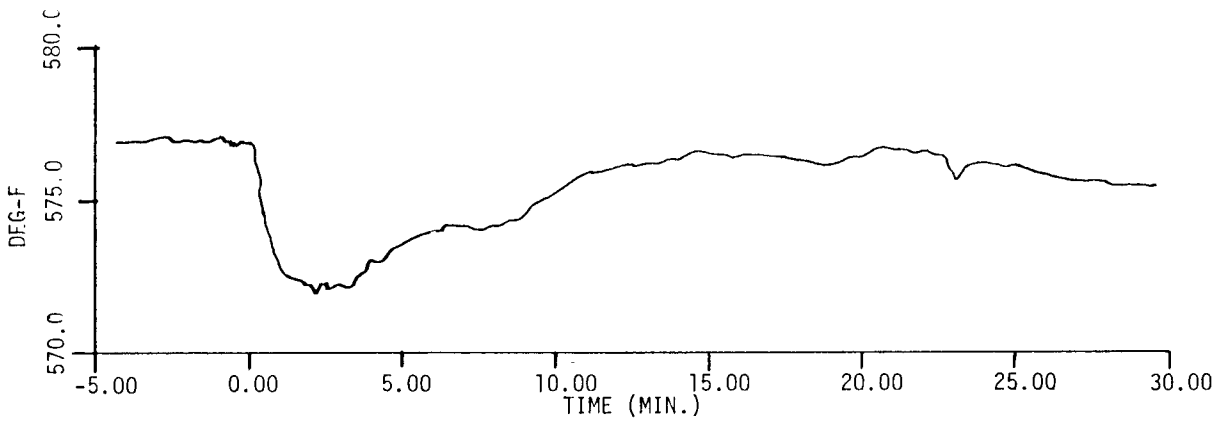


Figure 4-61. Full Length CEA Drop-Steam Generator 1 Hot Leg Temperature

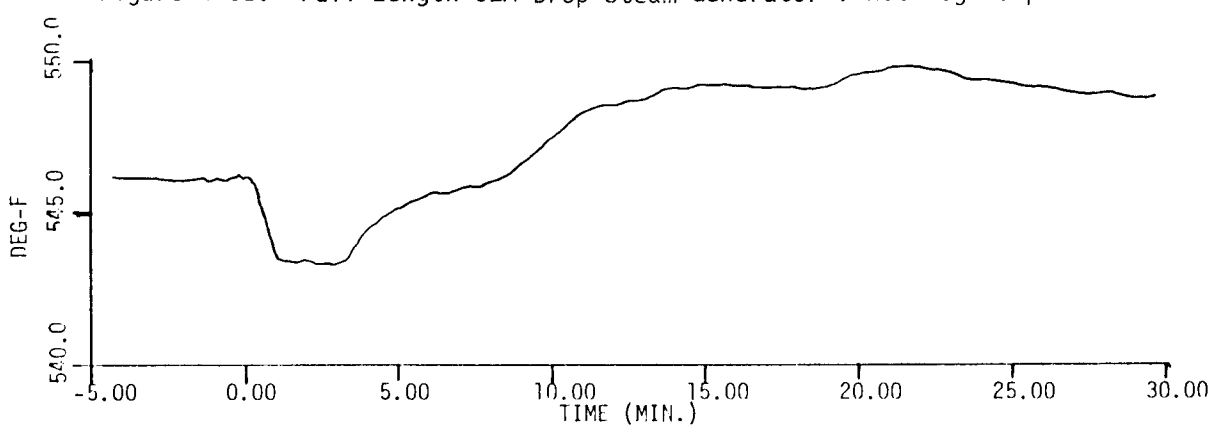


Figure 4-62. Full Length CEA Drop-Steam Generator 1 Cold Leg Temperature (Loop 1A)

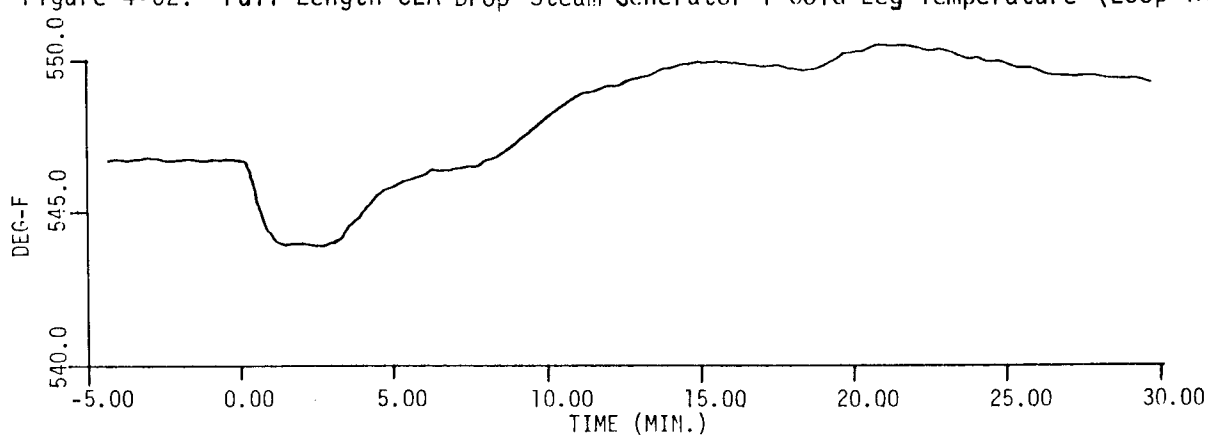


Figure 4-63. Full Length CEA Drop-Steam Generator 1 Cold Leg Temperature (Loop 1B)

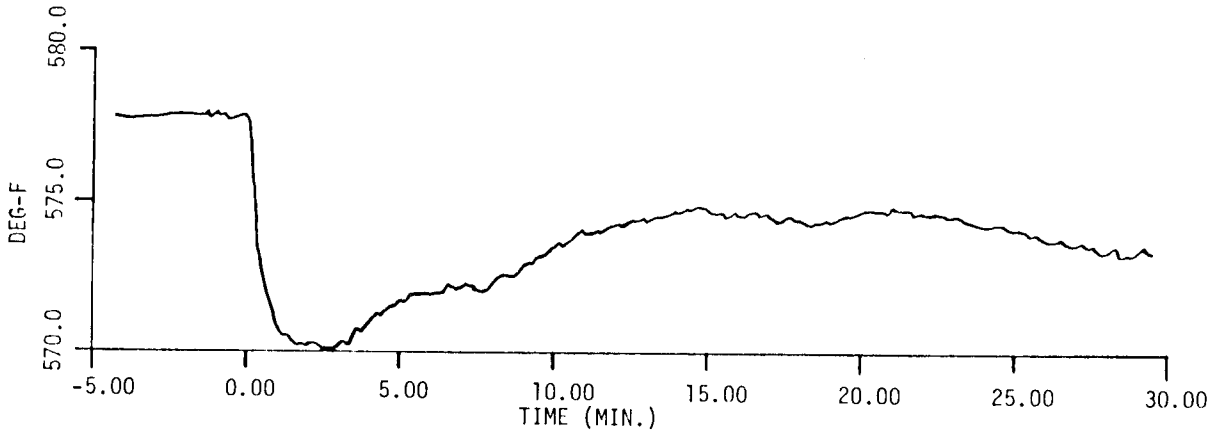


Figure 4-64. Full Length CEA Drop-Steam Generator 2 Hot Leg Temperature

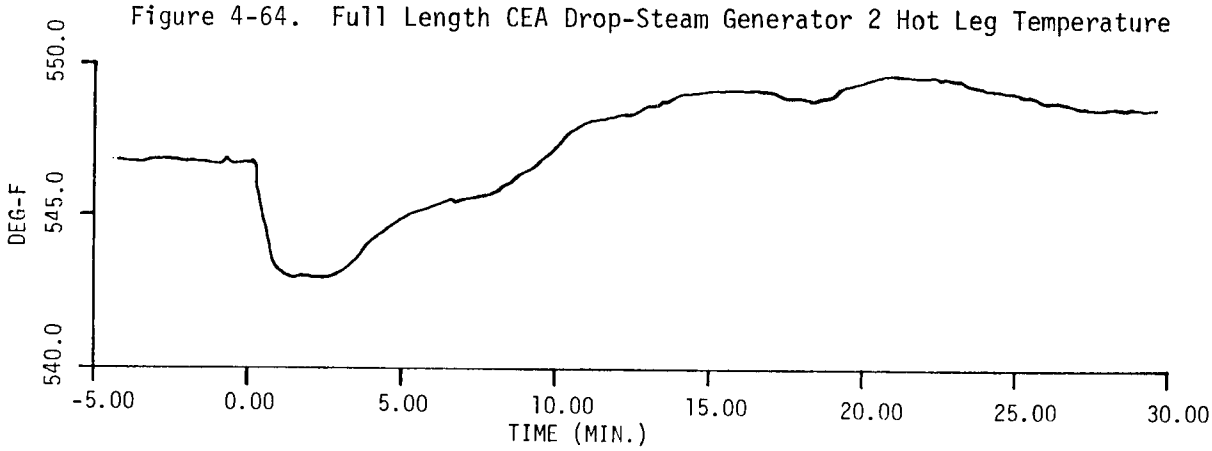


Figure 4-65. Full Length CEA Drop-Steam Generator 2 Cold Leg Temperature (Loop 2A)

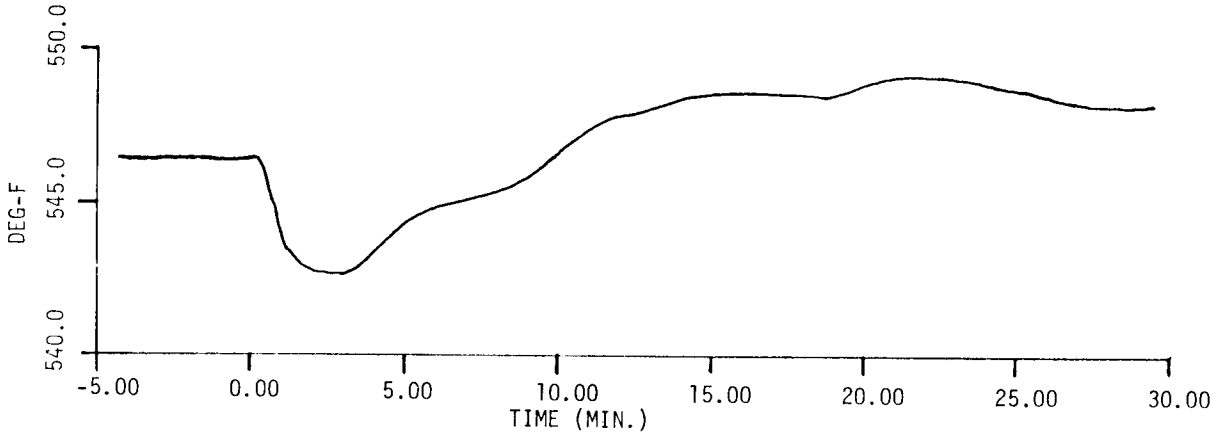


Figure 4-66. Full Length CEA Drop-Steam Generator 2 Cold Leg Temperature (Loop 2B)

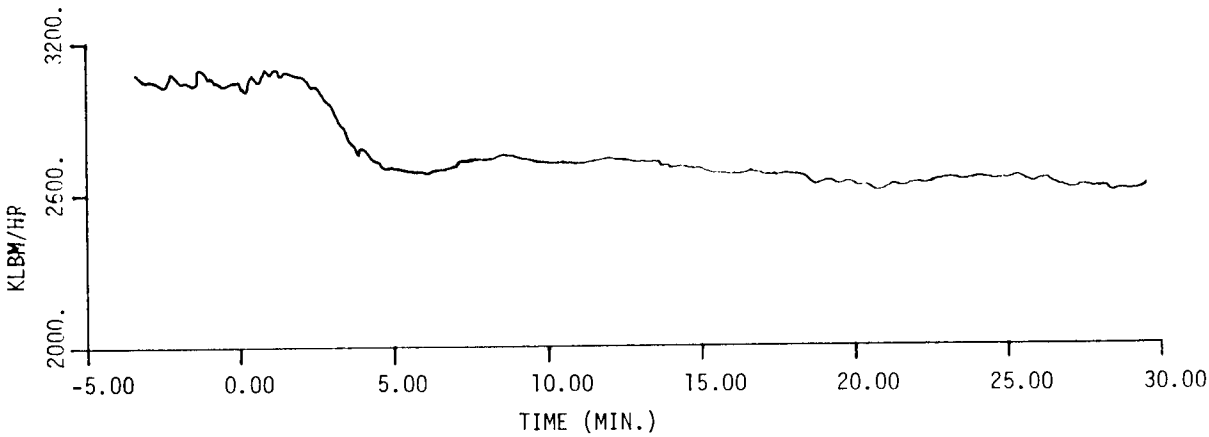


Figure 4-67. Full Length CEA Drop-Steam Generator 1 Feedwater Flow Rate

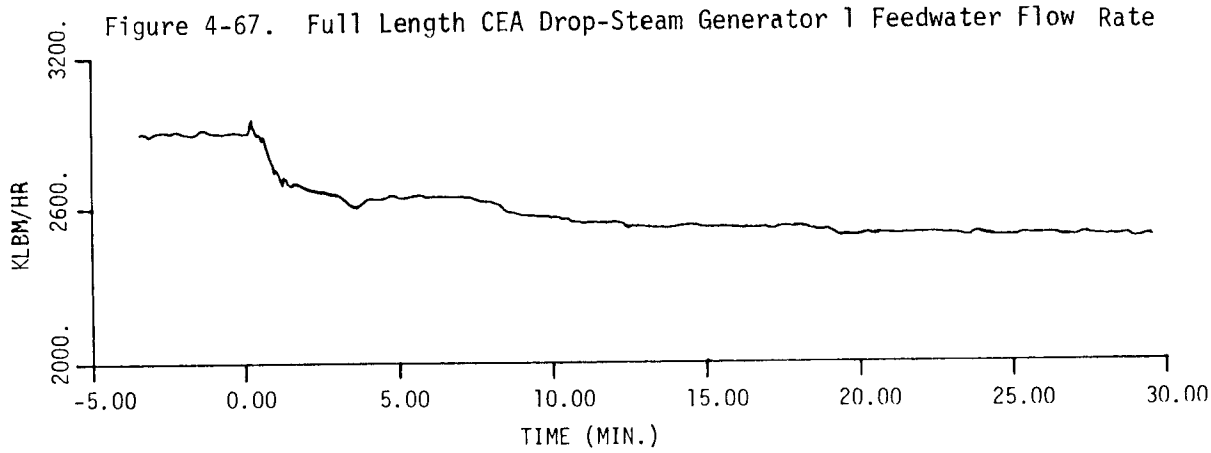


Figure 4-68. Full Length CEA Drop-Steam Generator 1 Main Steam Flow Rate

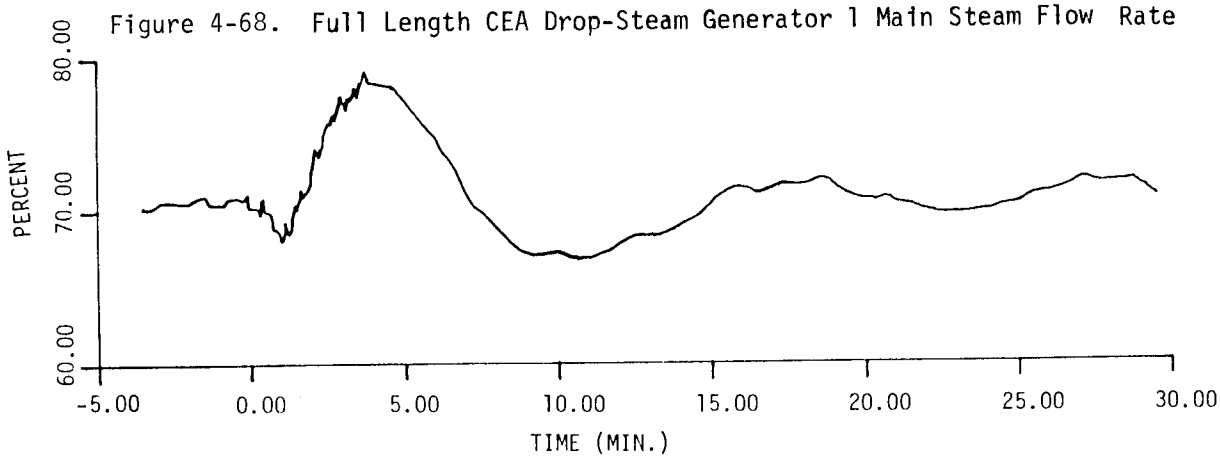


Figure 4-69. Full Length CEA Drop-Steam Generator 1 Level

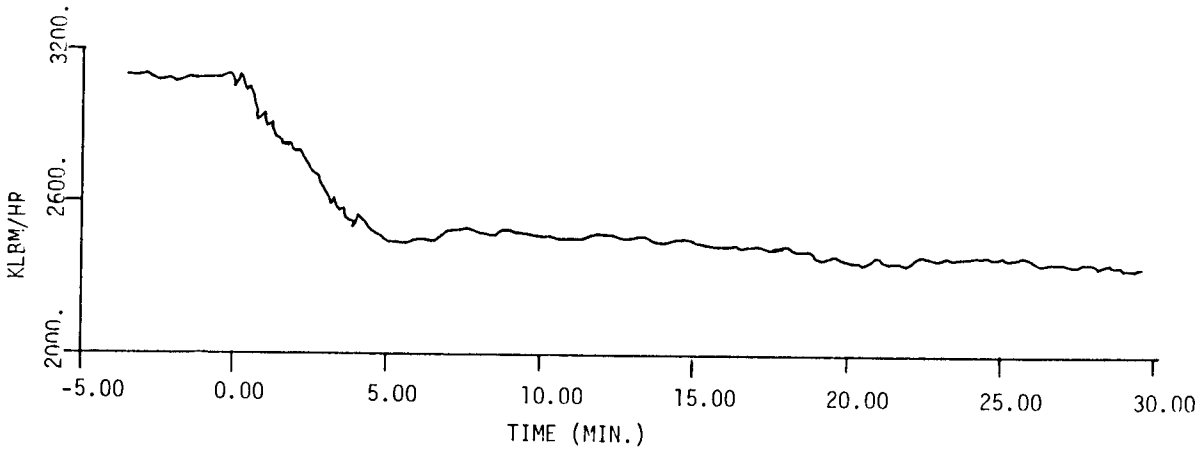


Figure 4-70. Full Length CEA Drop-Steam Generator 2 Feedwater Flow Rate

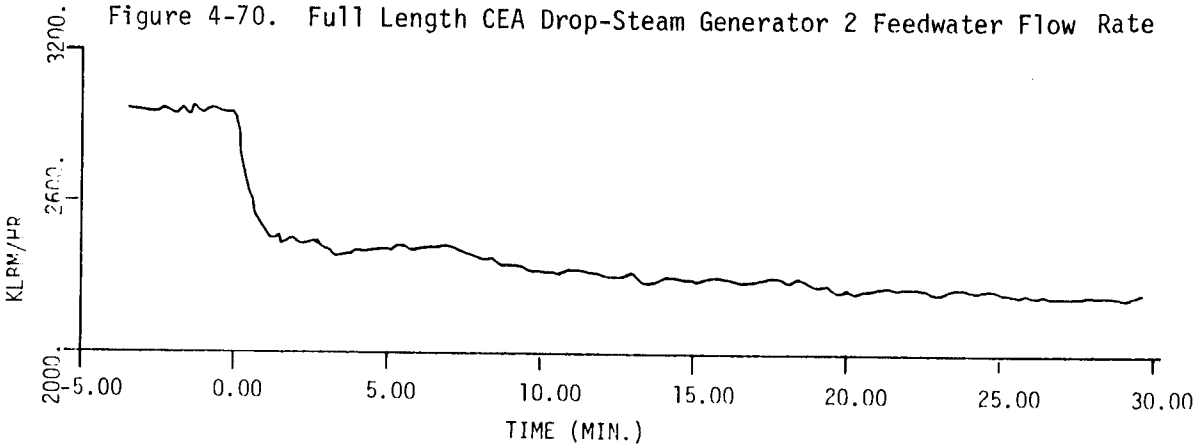


Figure 4-71. Full Length CEA Drop-Steam Generator 2 Main Steam Flow Rate

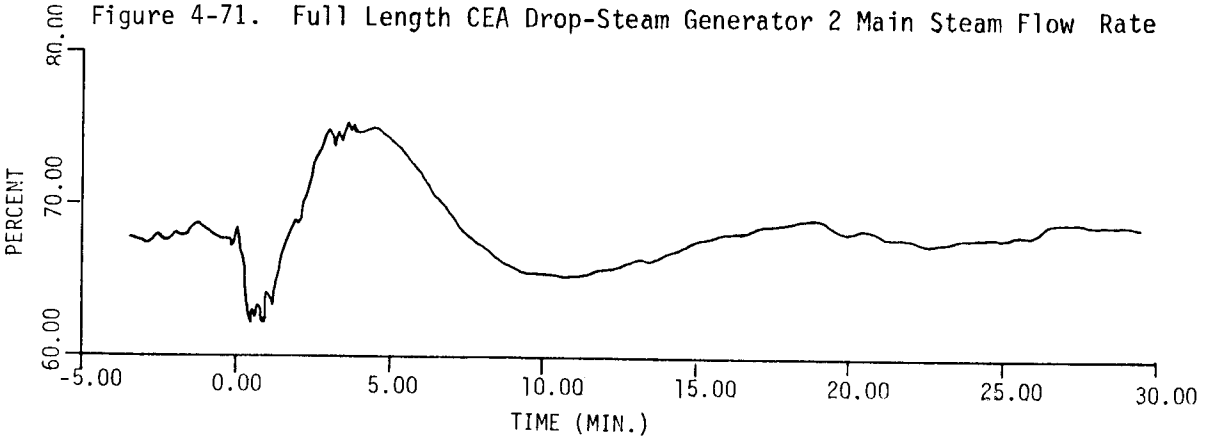


Figure 4-72. Full Length CEA Drop-Steam Generator 2 Level

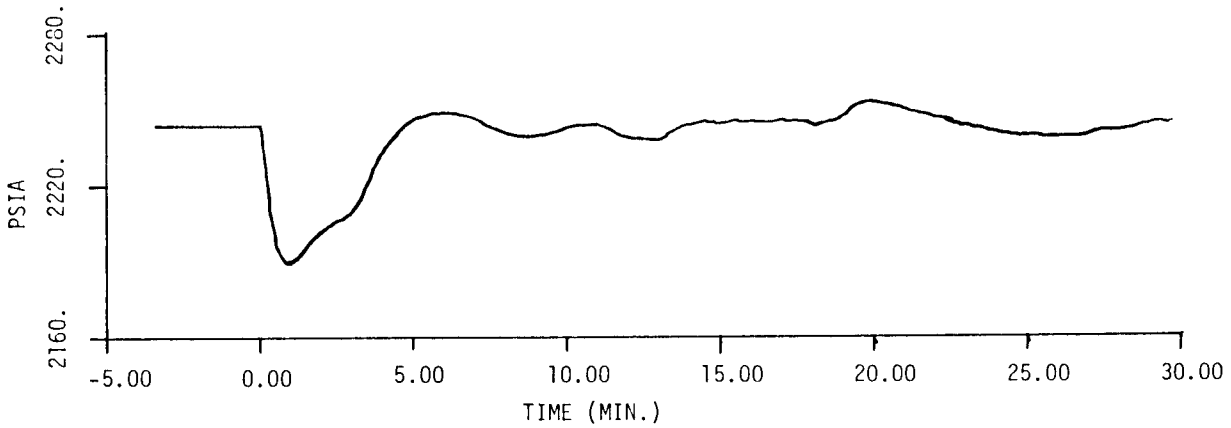


Figure 4-73. Full Length CEA Drop-Pressurizer Pressure, Wide Range

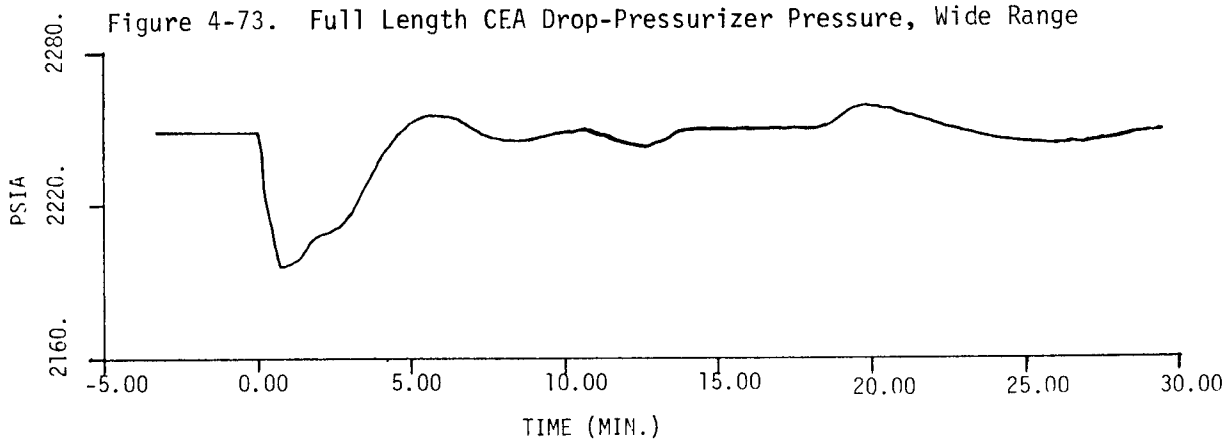


Figure 4-74. Full Length CEA Drop-Pressurizer Pressure, Narrow Range

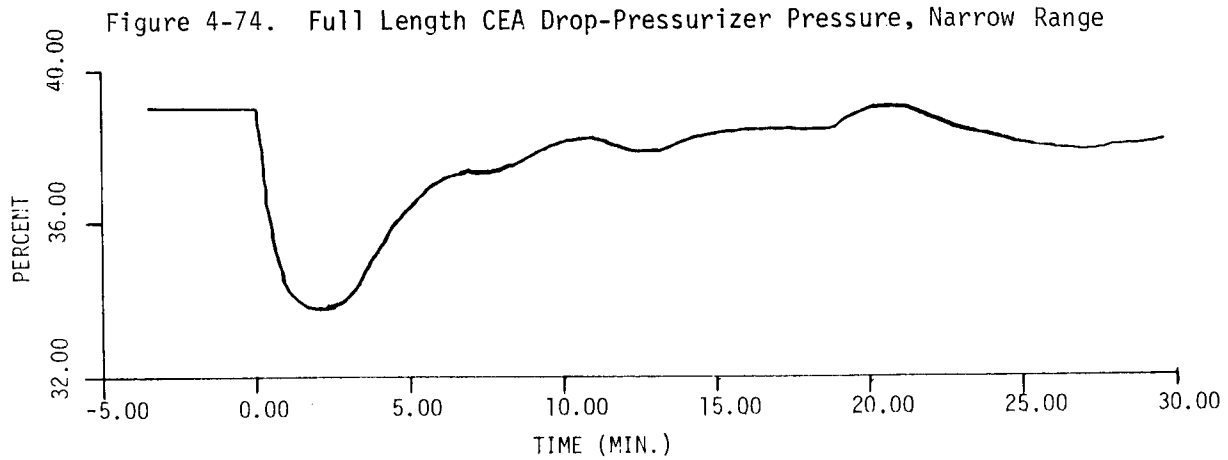


Figure 4-75. Full Length CEA Drop - Pressurizer Level

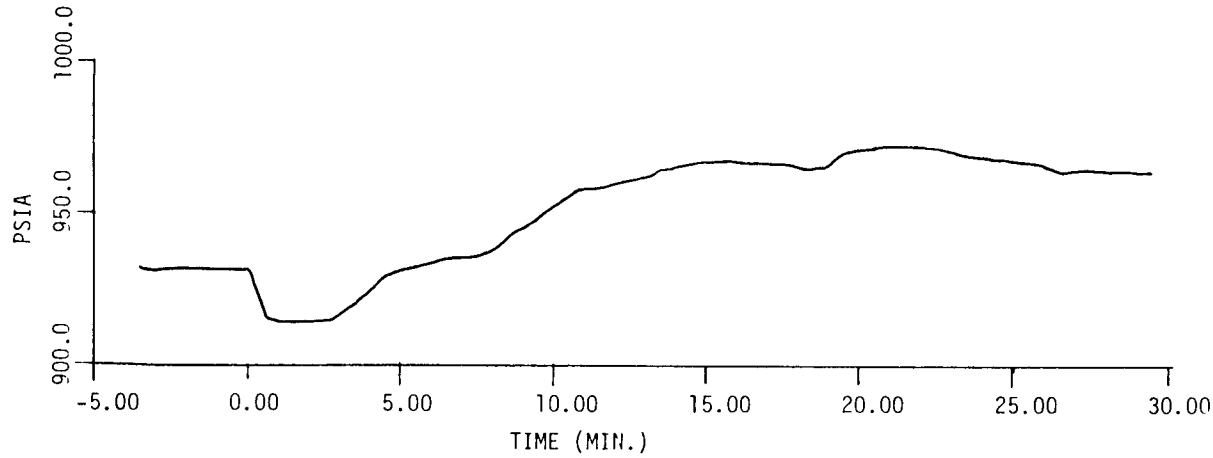


Figure 4-76. Full Length CEA Drop-Steam Generator 1 Pressure

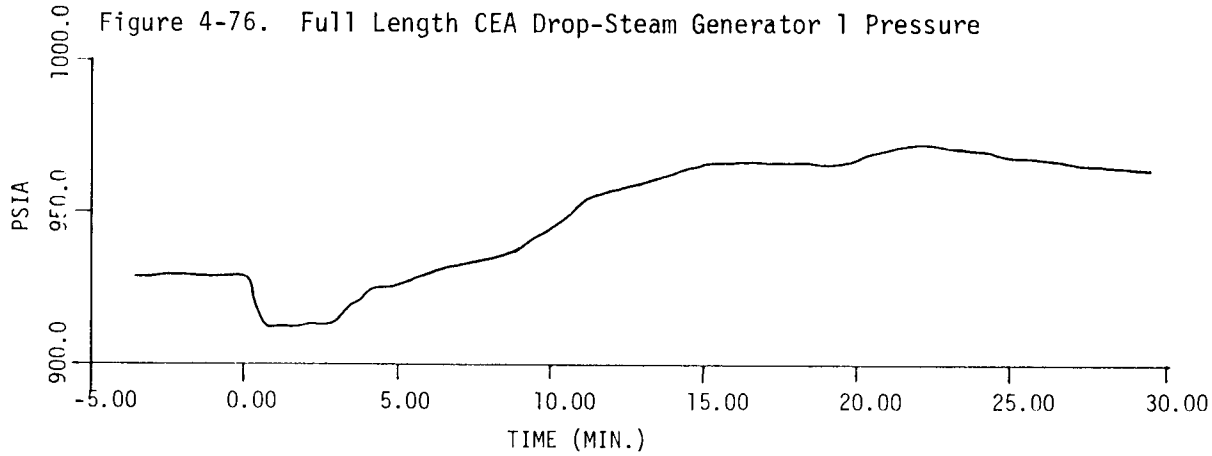


Figure 4-77. Full Length CEA Drop-Steam Generator 1 Header Pressure

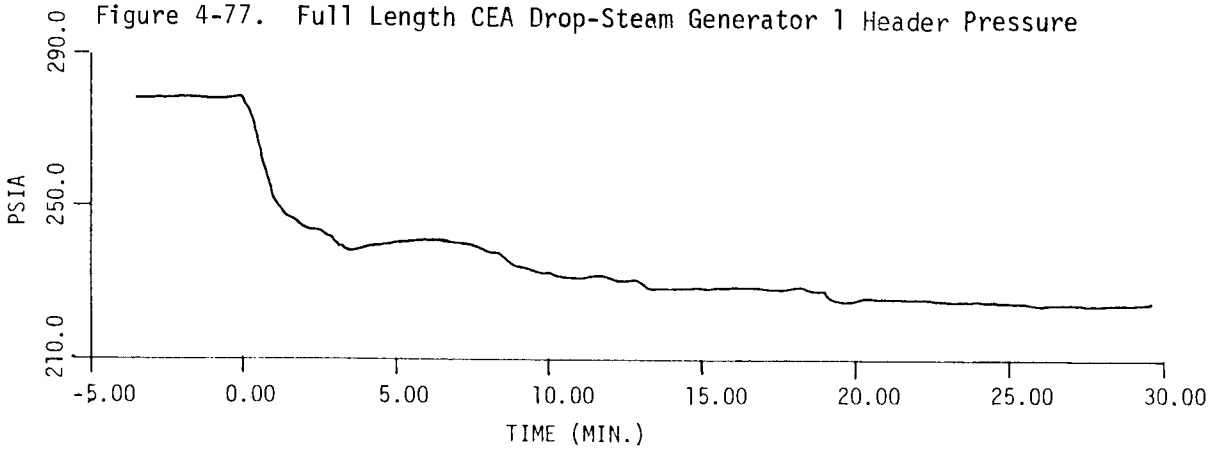


Figure 4-78. Full Length CEA Drop-Turbine First Stage Pressure

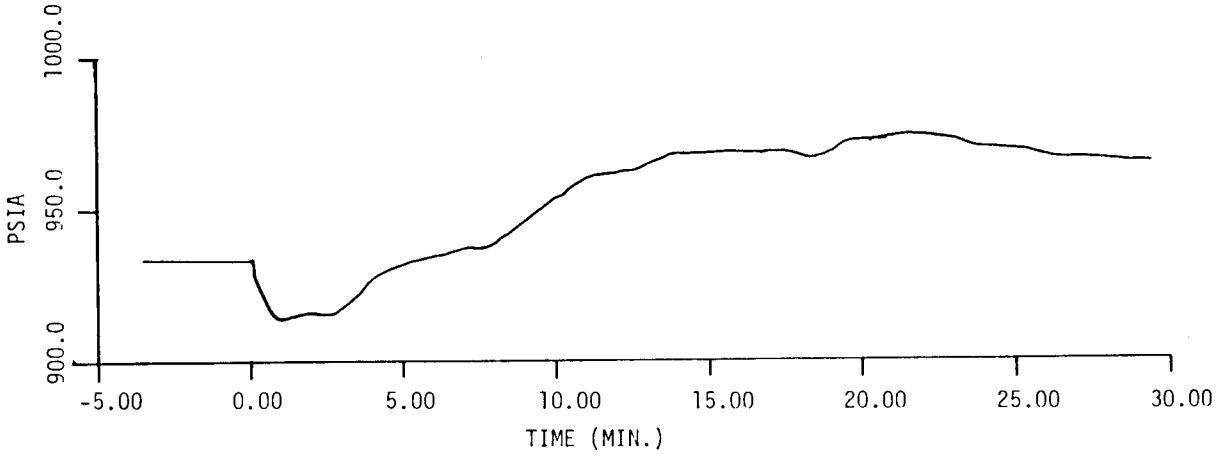


Figure 4-79. Full Length CEA Drop-Steam Generator 2 Pressure

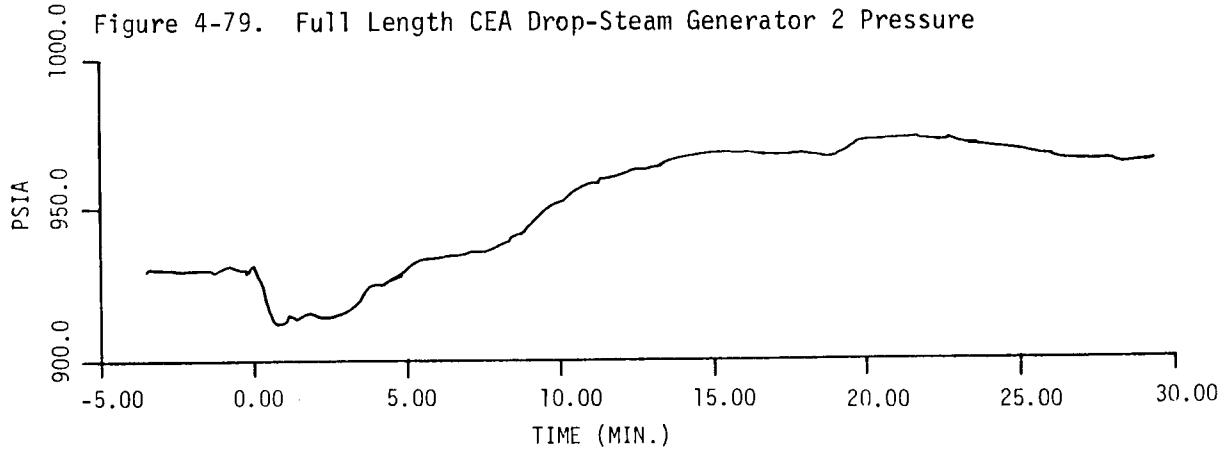


Figure 4-80. Full Length CEA Drop-Steam Generator 2 Header Pressure

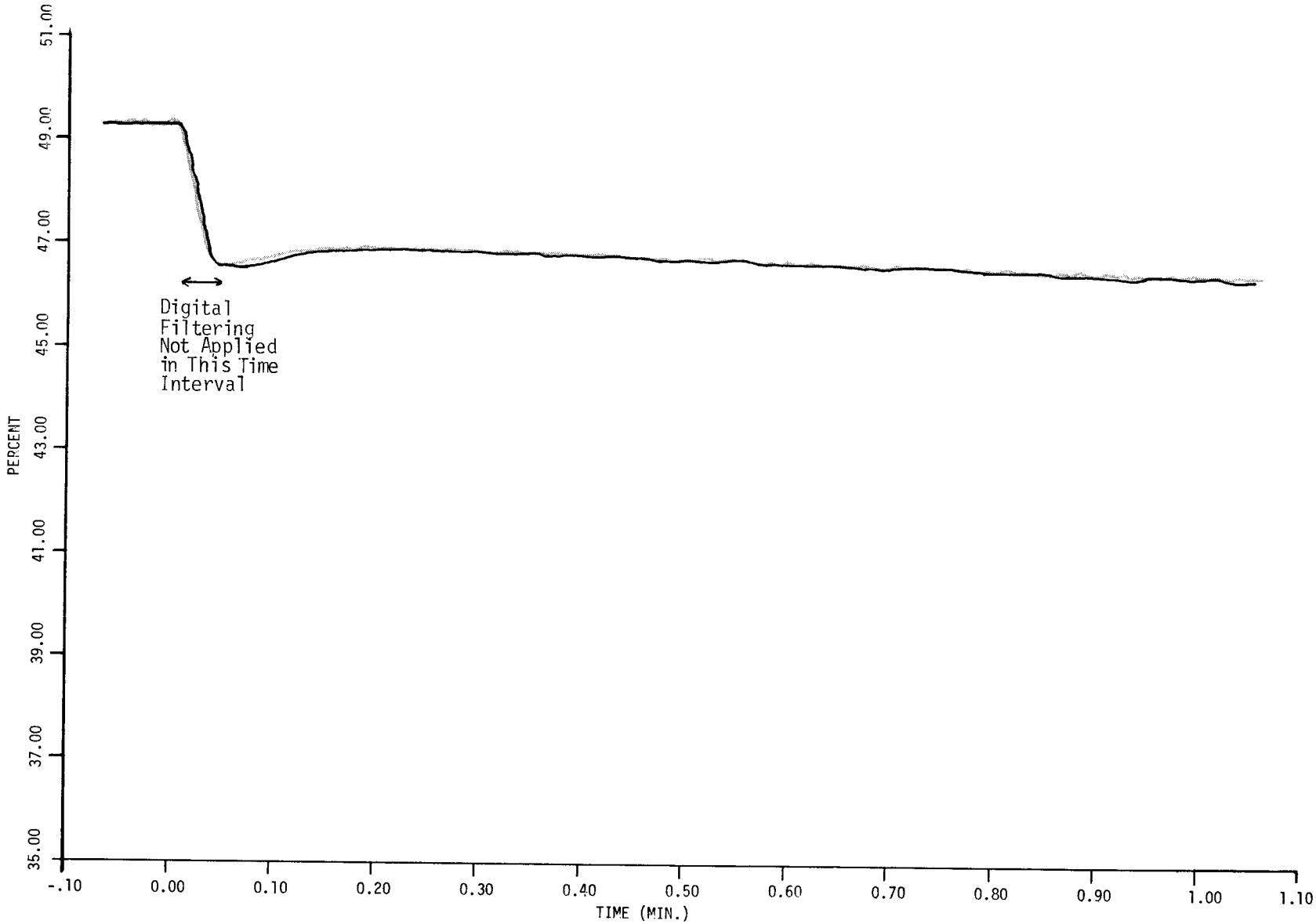


Figure 4-81. Full Length CEA Drop - Control Channel 1 Nuclear Power

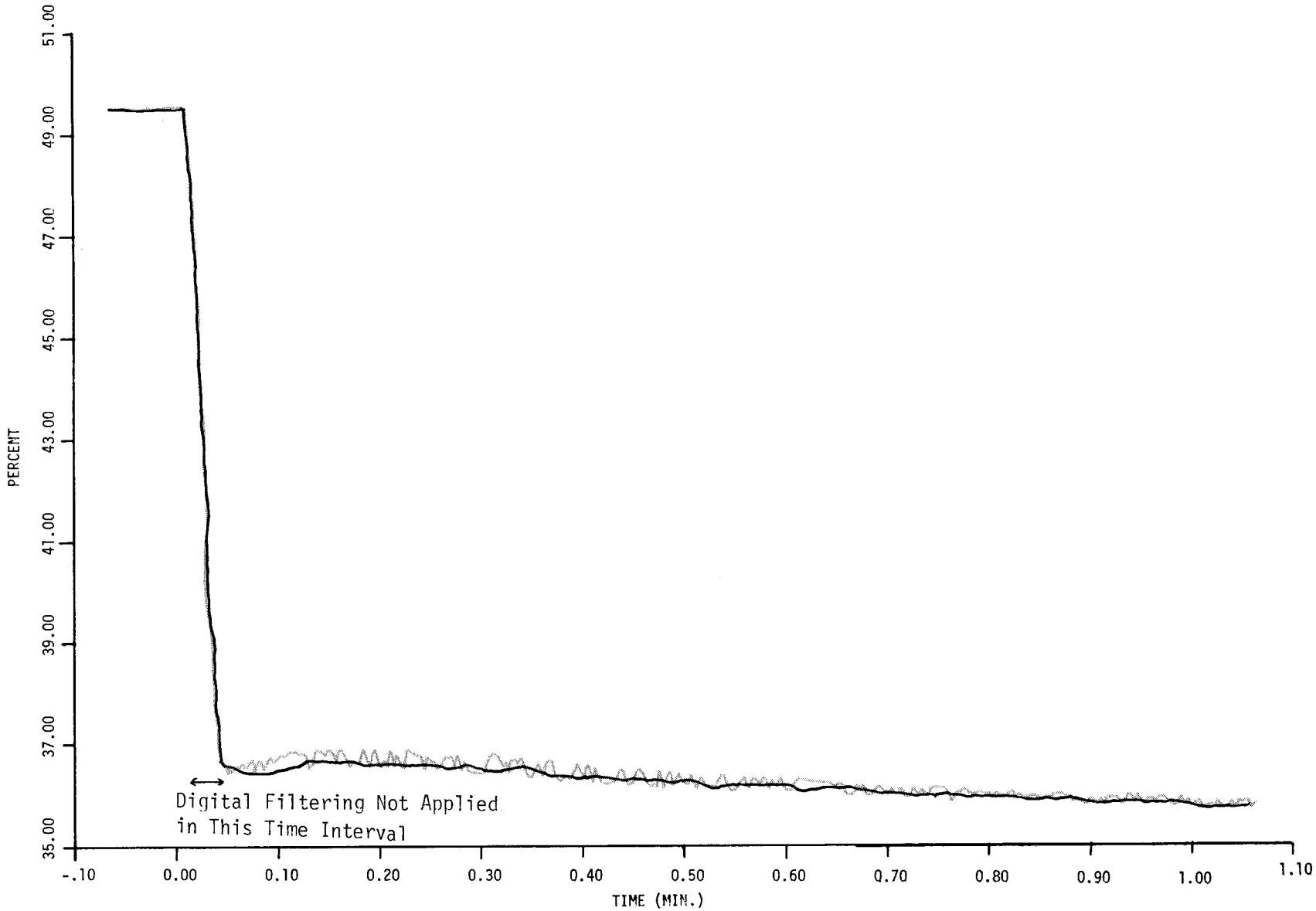


Figure 4-82. Full Length CEA Drop - Control Channel 2 Nuclear Power

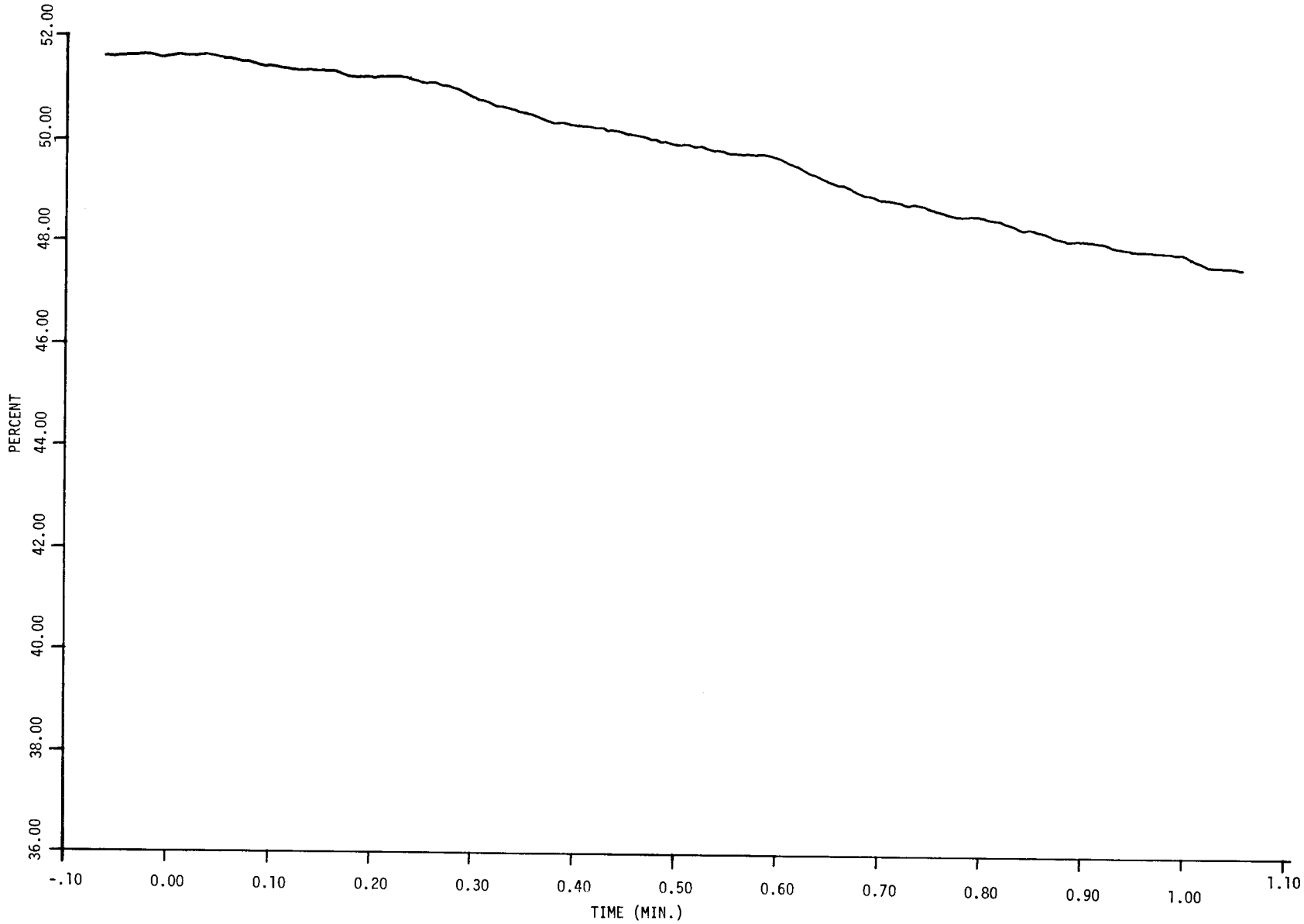


Figure 4-83. Full Length CEA Drop - Turbine Power

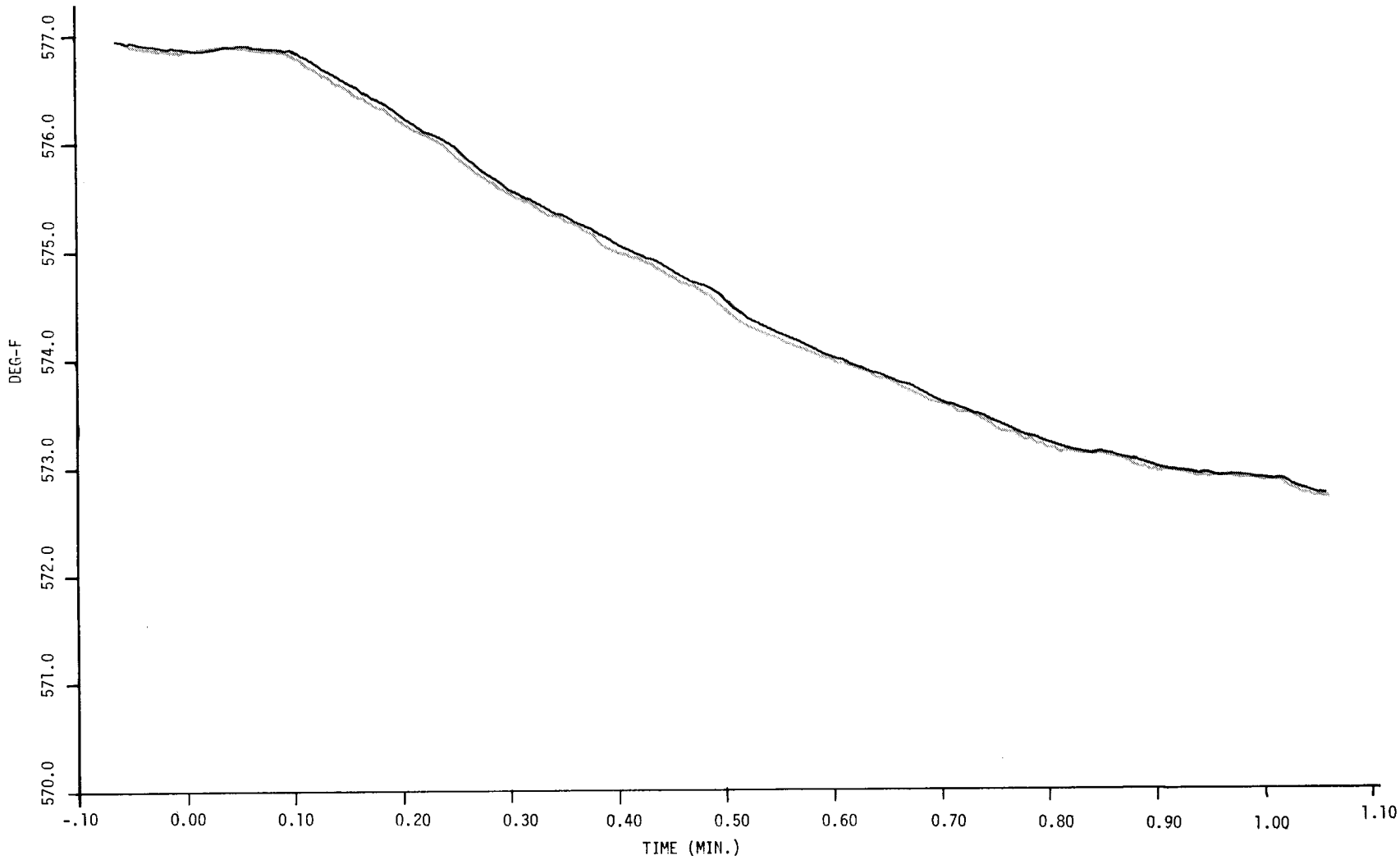


Figure 4-84. Full Length CEA Drop - Steam Generator 1 Hot Leg Temperature

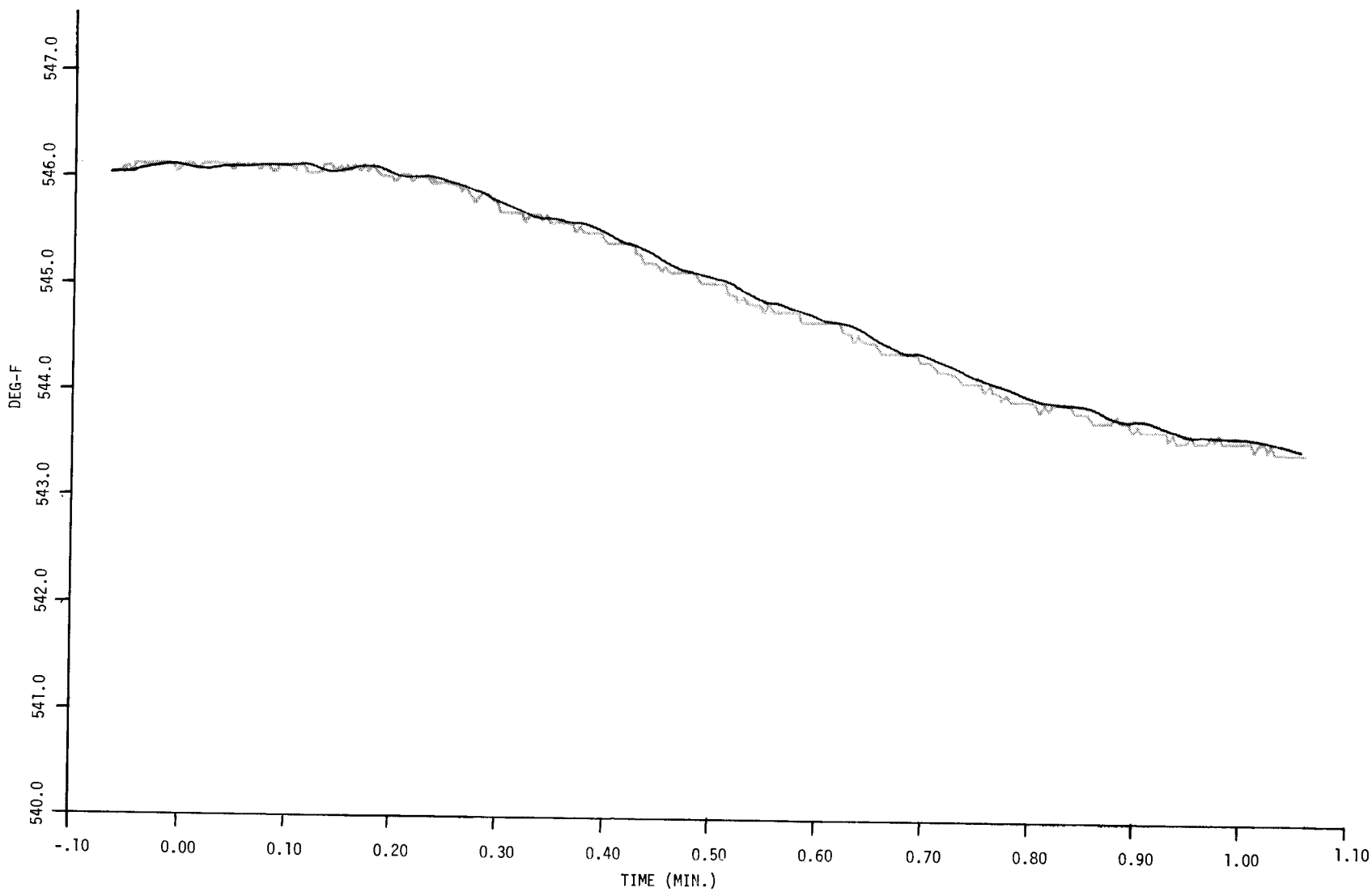


Figure 4-85. Full Length CEA Drop - Steam Generator 1 Cold Leg Temperature (Loop 1A)

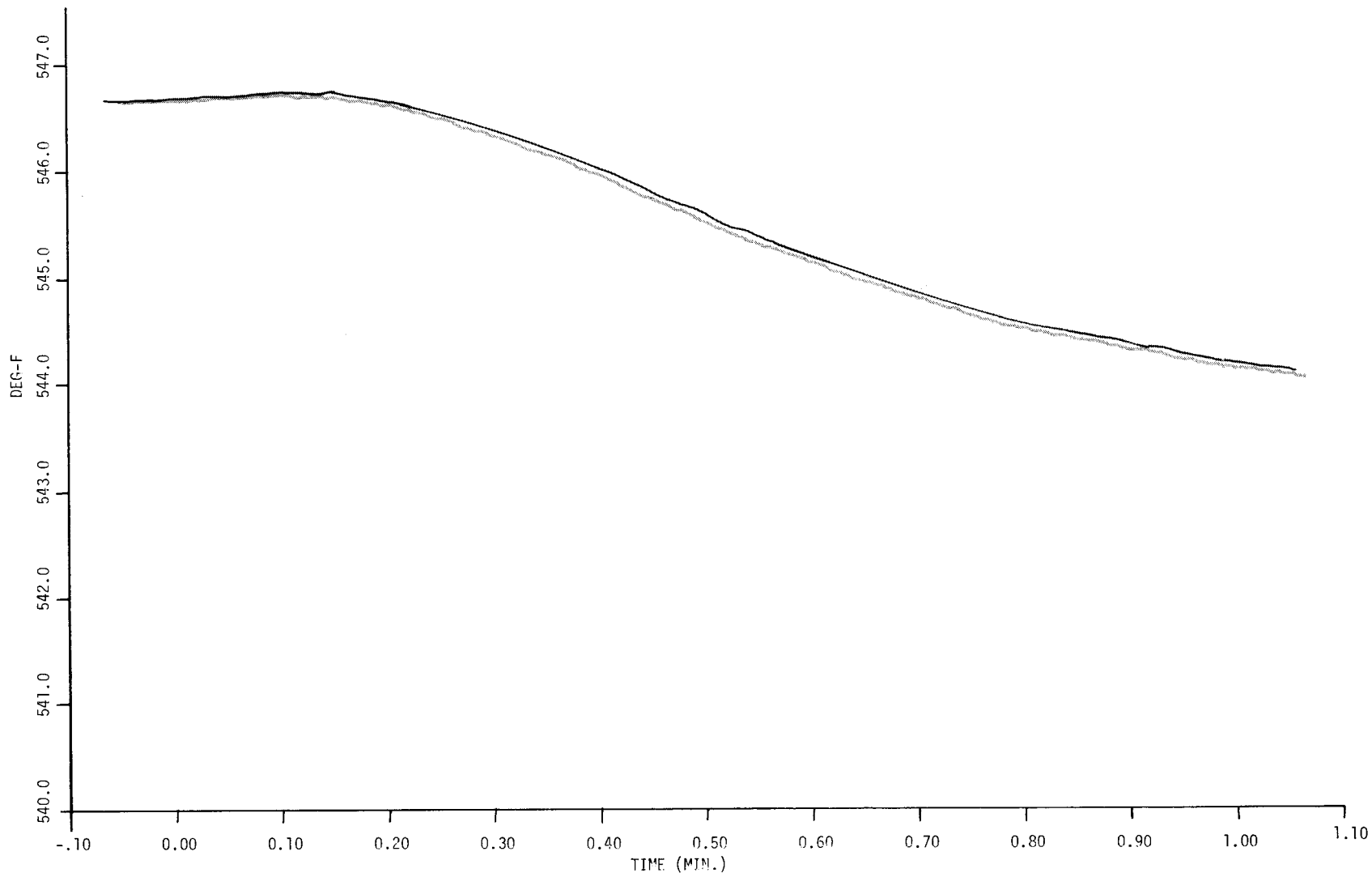


Figure 4-86. Full Length CEA Drop - Steam Generator 1 Cold Leg Temperature (Loop 1B)

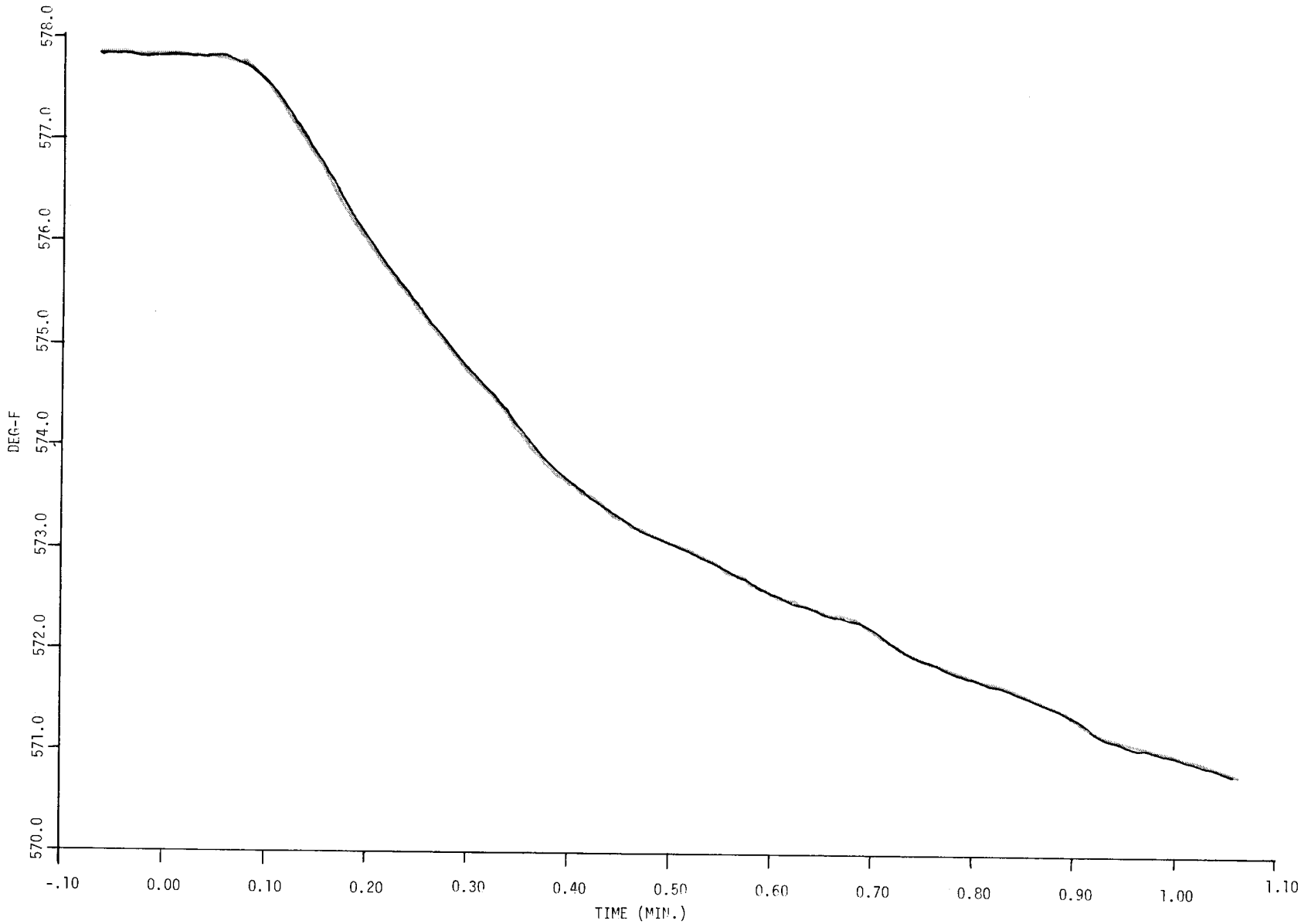


Figure 4-87. Full Length CEA Drop - Steam Generator 2 Hot Leg Temperature

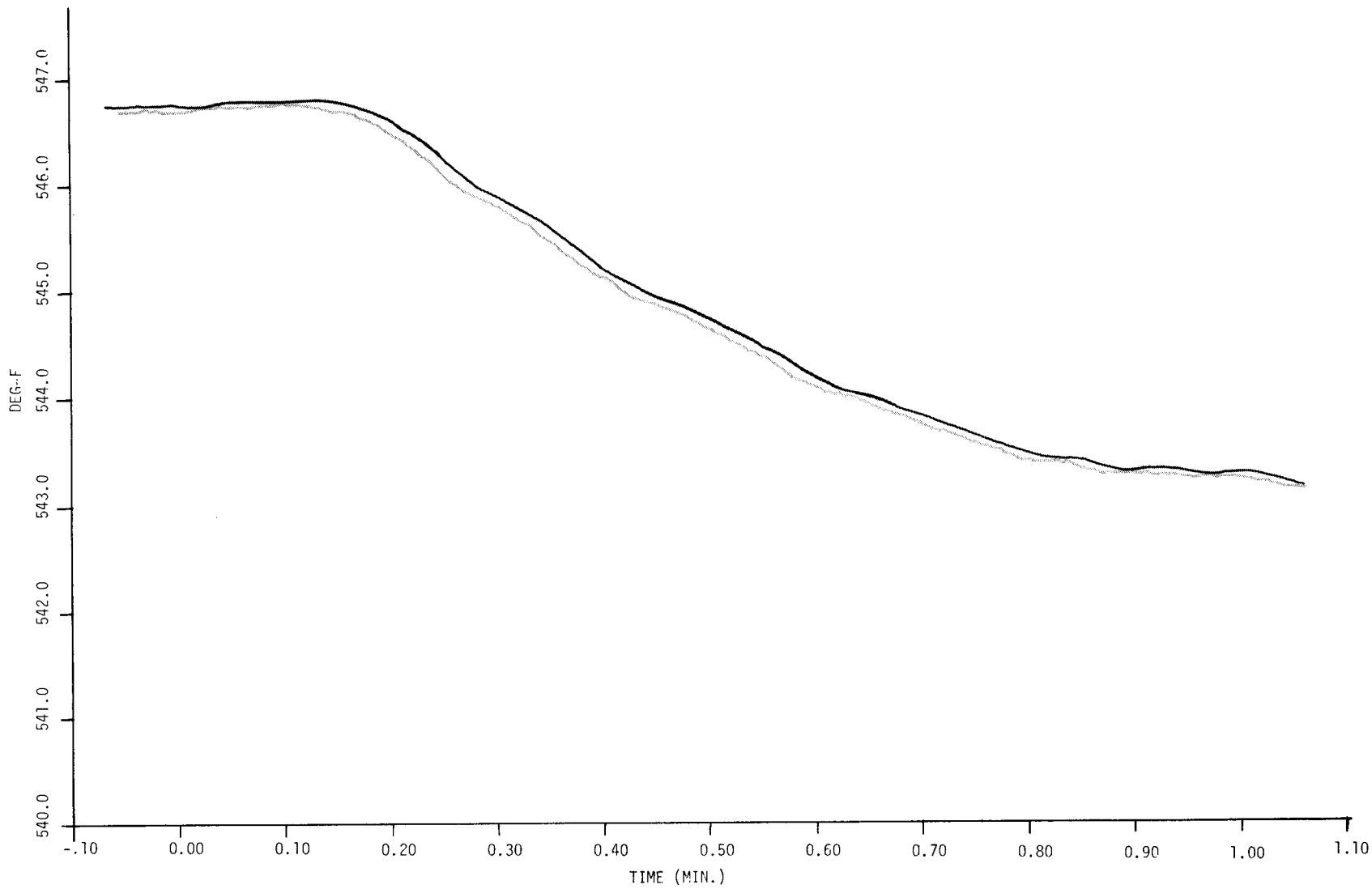


Figure 4-88. Full Length CEA Drop - Steam Generator 2 Cold Leg Temperature (Loop 2A)

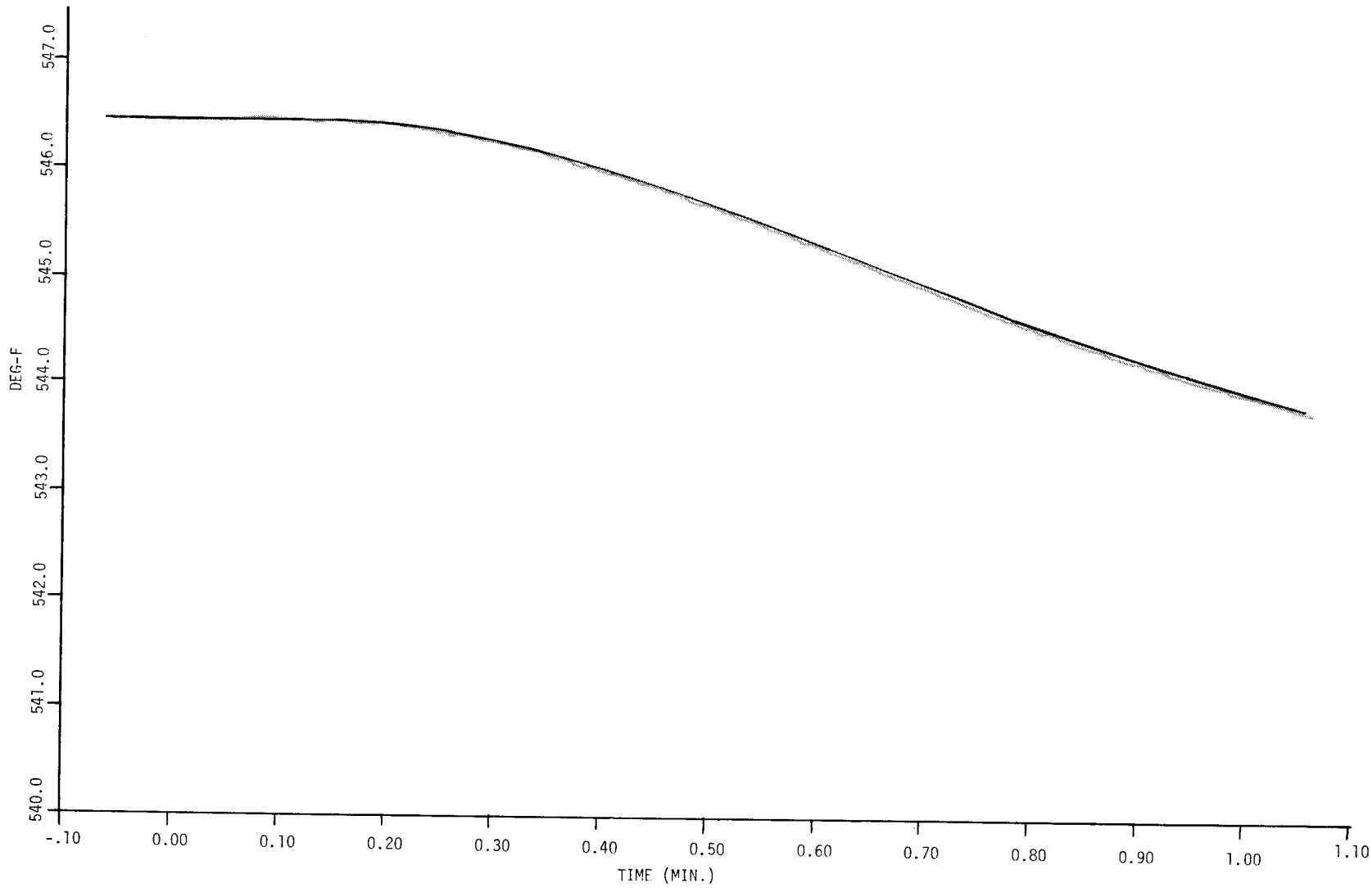


Figure 4-89. Full Length CEA Drop - Steam Generator 2 Cold Leg Temperature (Loop 2B)

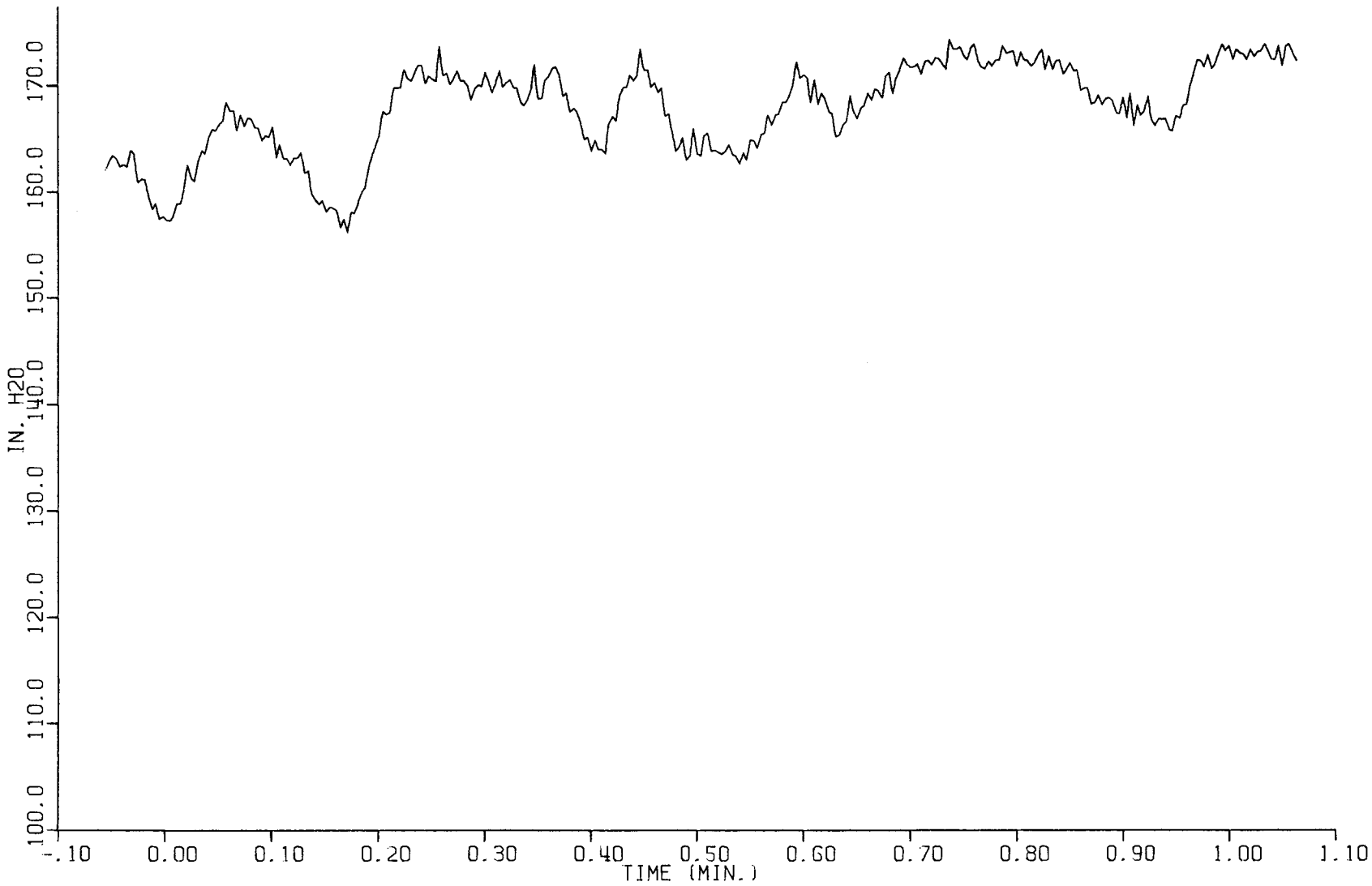


Figure 4-90. Full Length CEA Drop - Steam Generator 1 Feedwater Differential Pressure

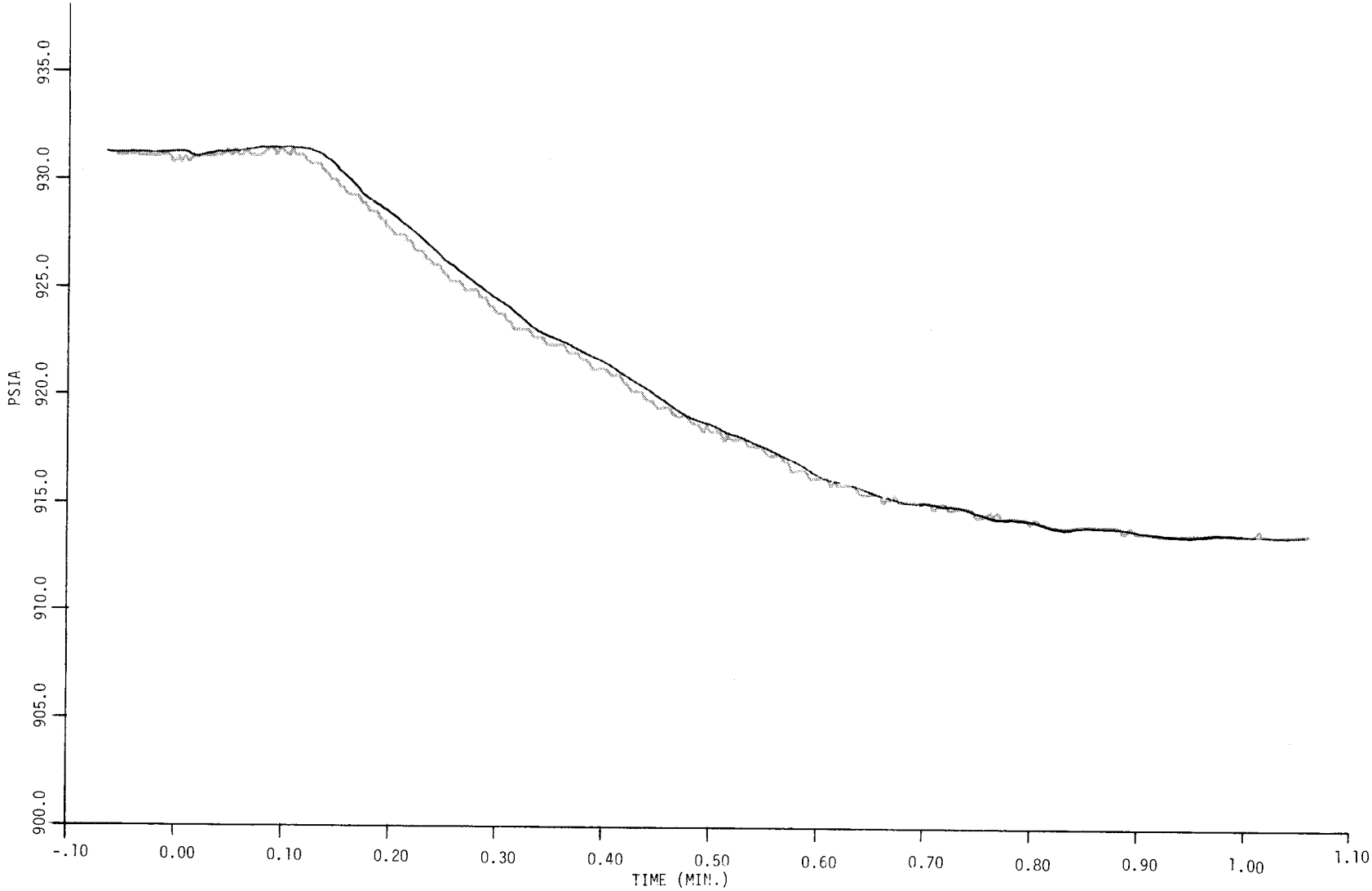


Figure 4-91. Full Length CEA Drop - Steam Generator 1 Pressure

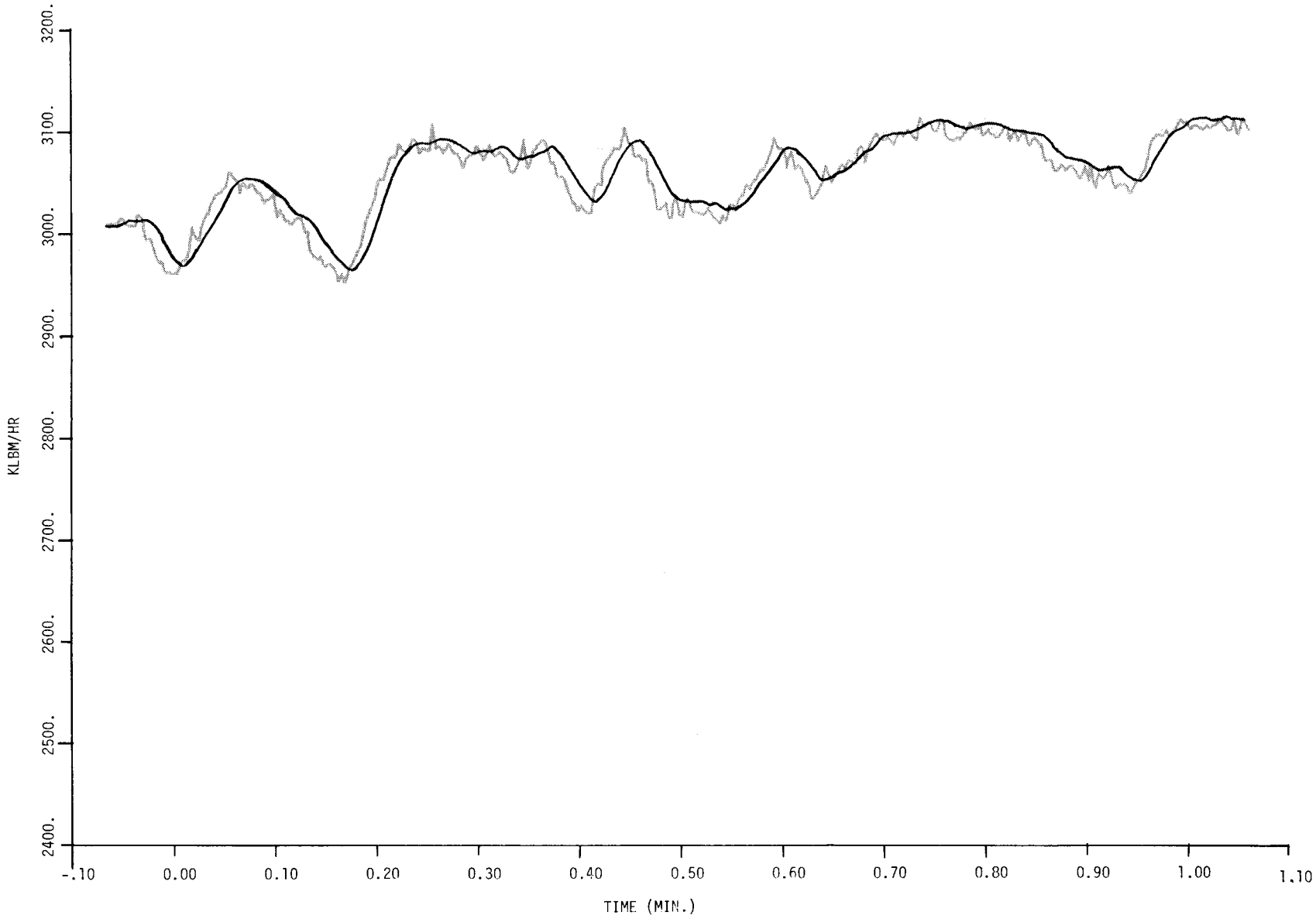


Figure 4-92. Full Length CEA Drop - Steam Generator 1 Feedwater Flow Rate

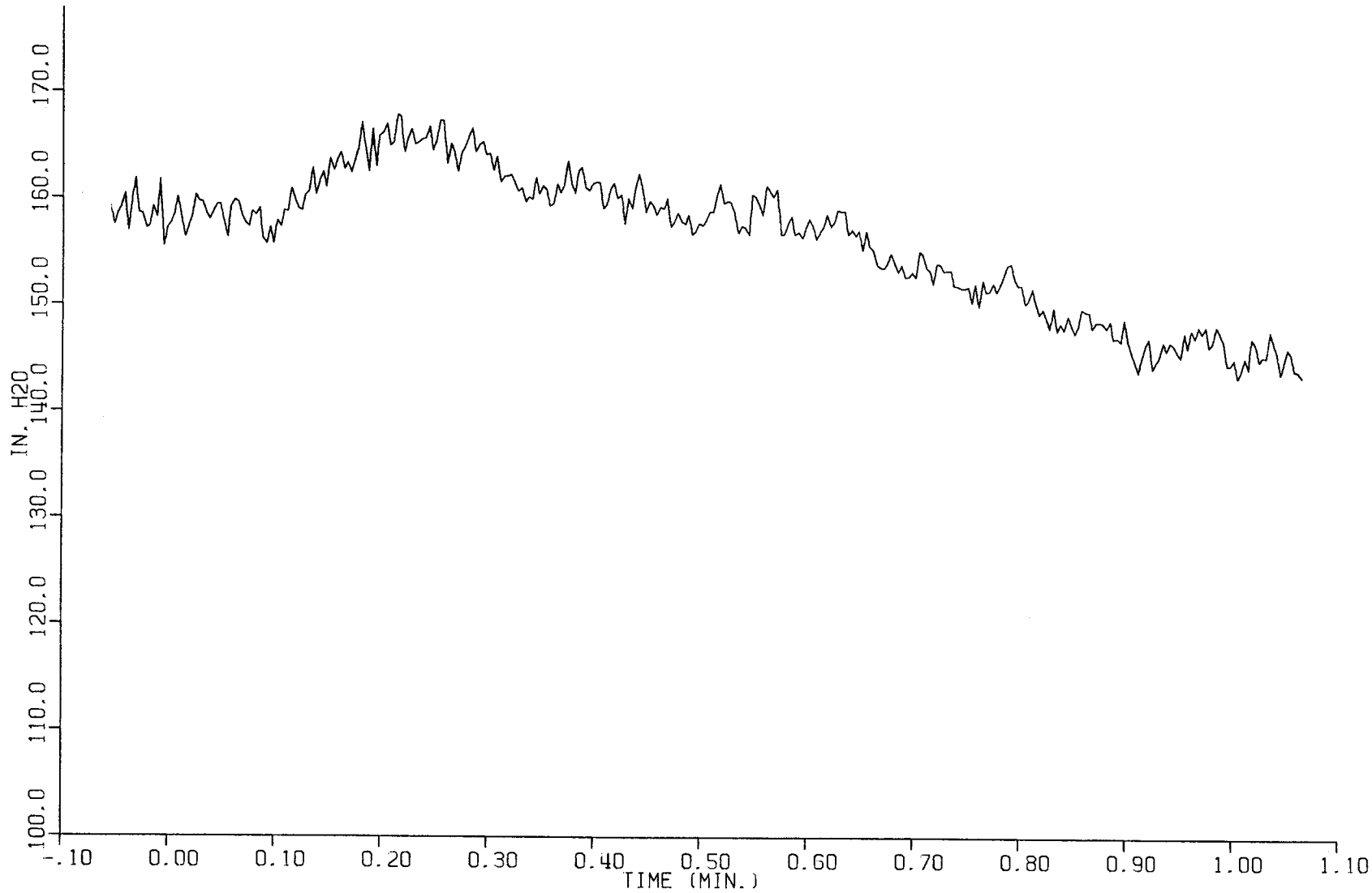


Figure 4-93. Full Length CEA Drop - Steam Generator 1 Header Differential Pressure

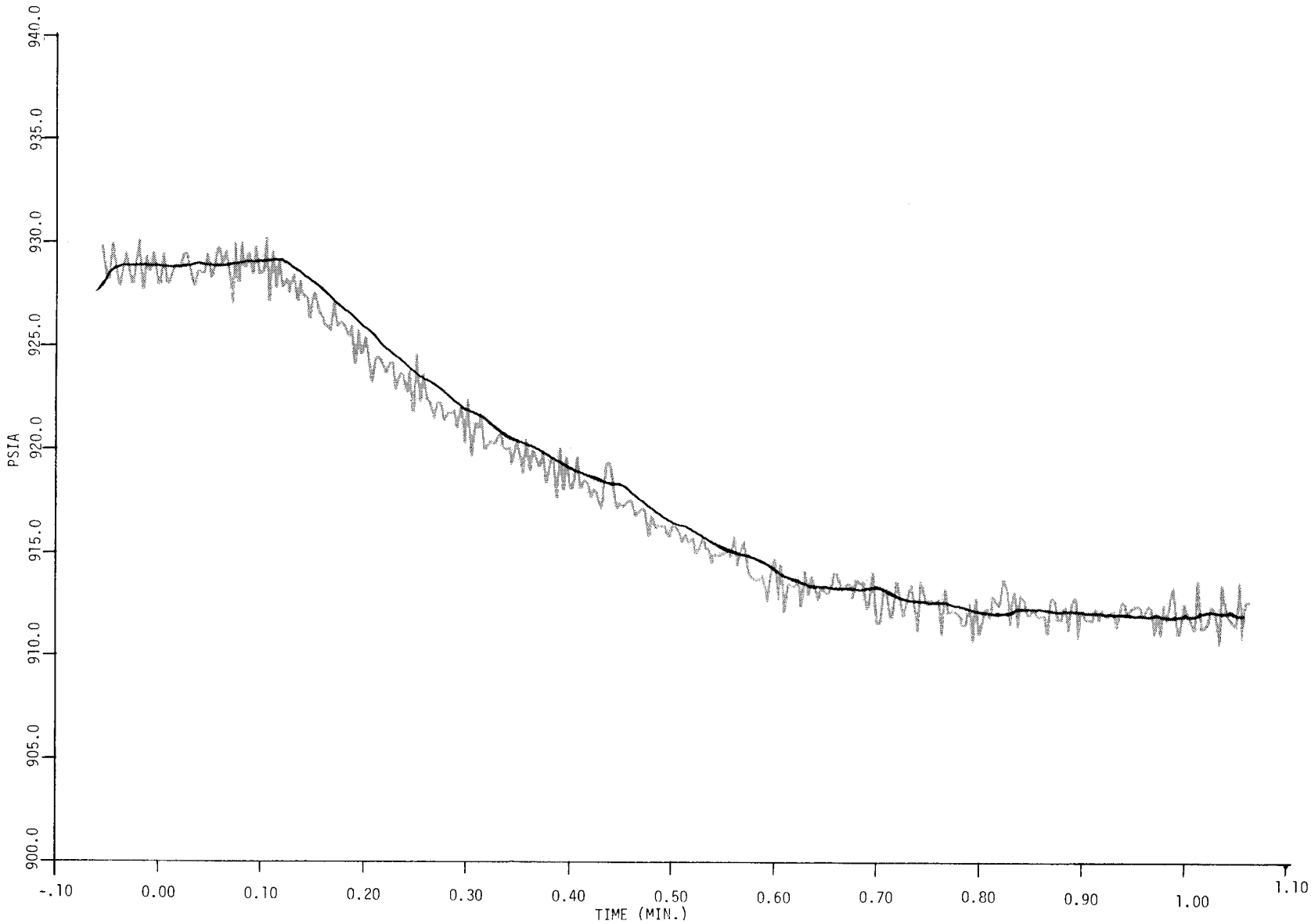


Figure 4-94. Full Length CEA Drop - Steam Generator 1 Header Pressure

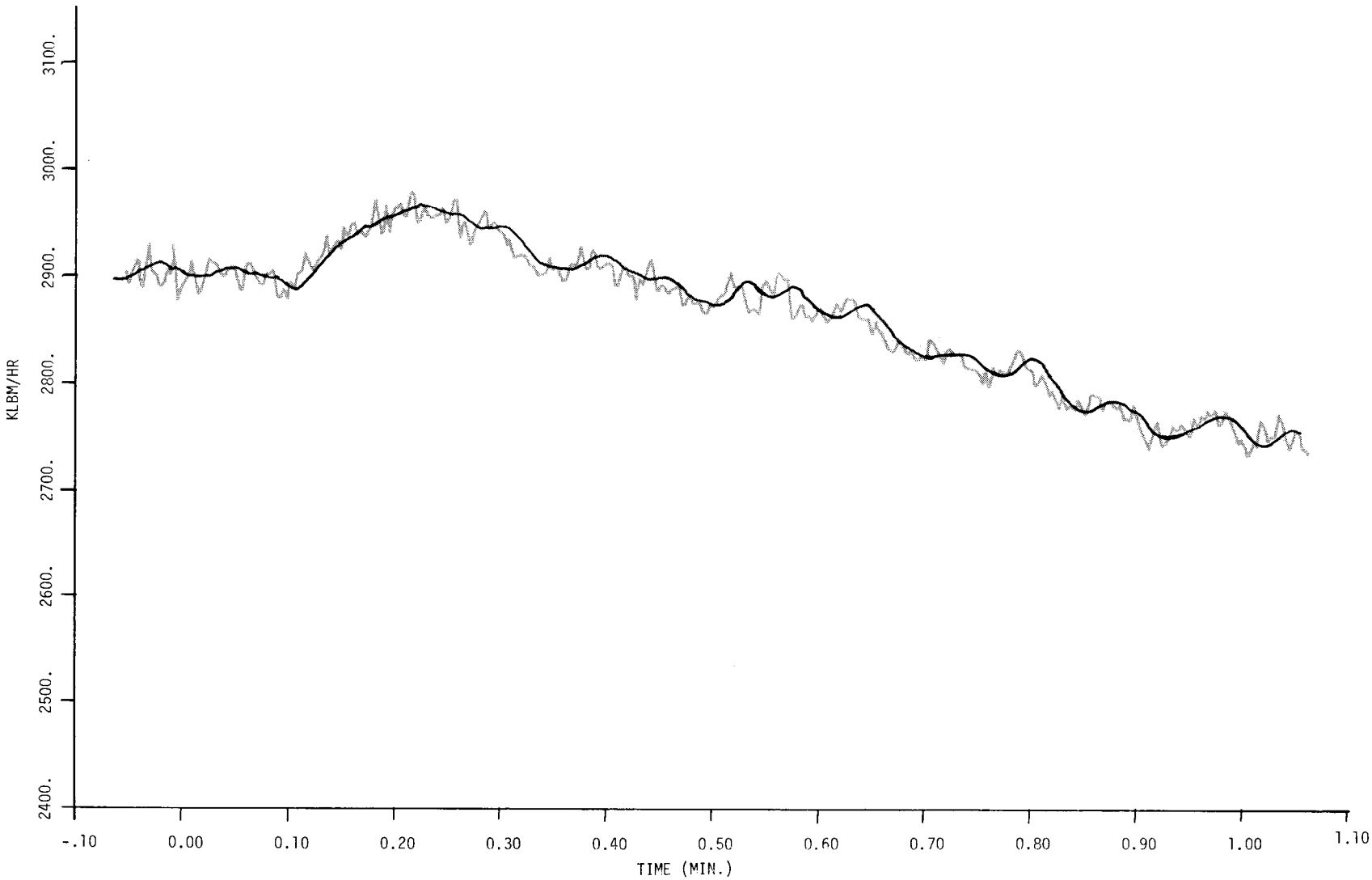


Figure 4-95. Full Length CEA Drop - Steam Generator 1 Main Steam Flow Rate

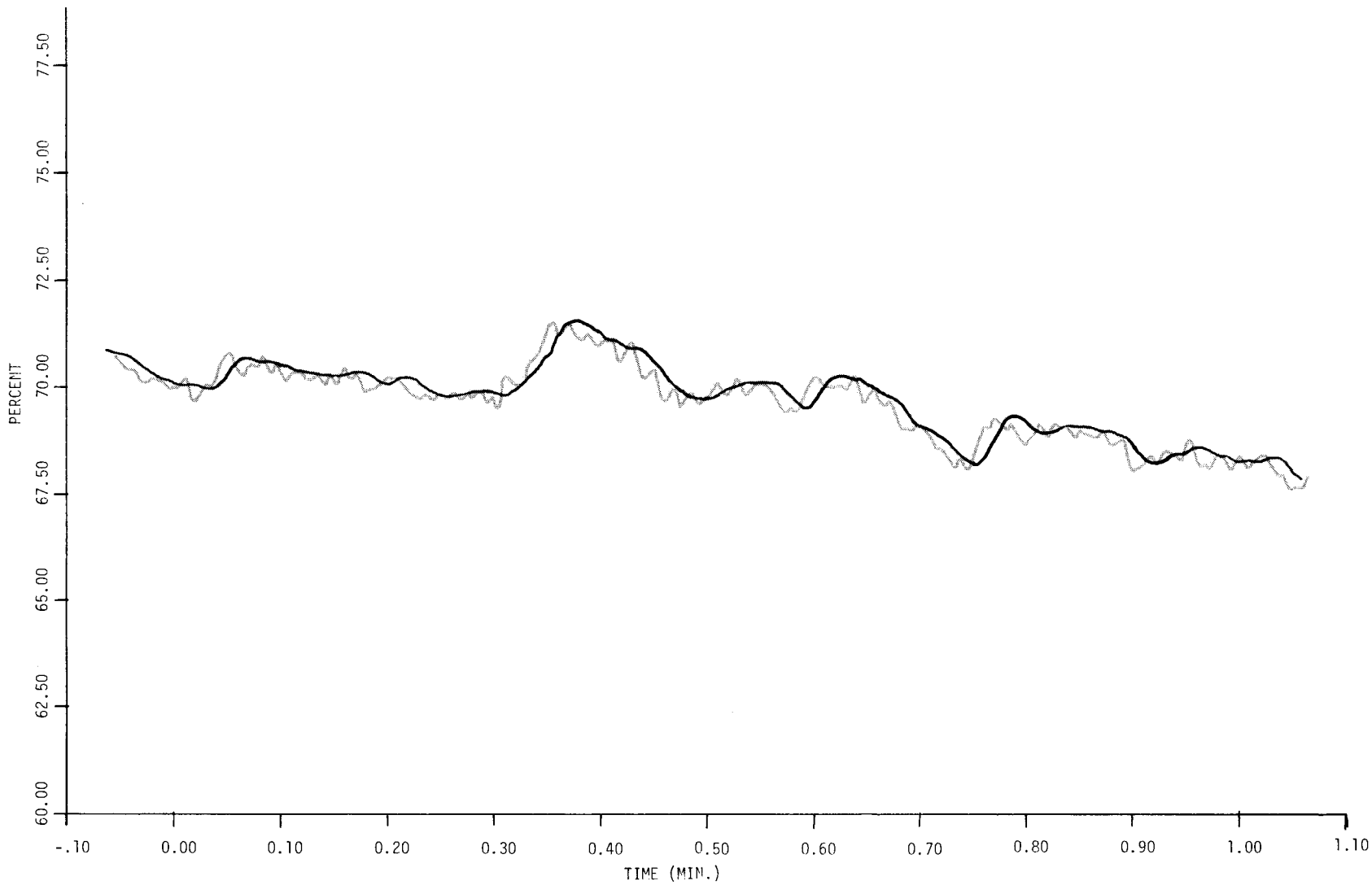


Figure 4-96. Full Length CEA Drop - Steam Generator 1 Level

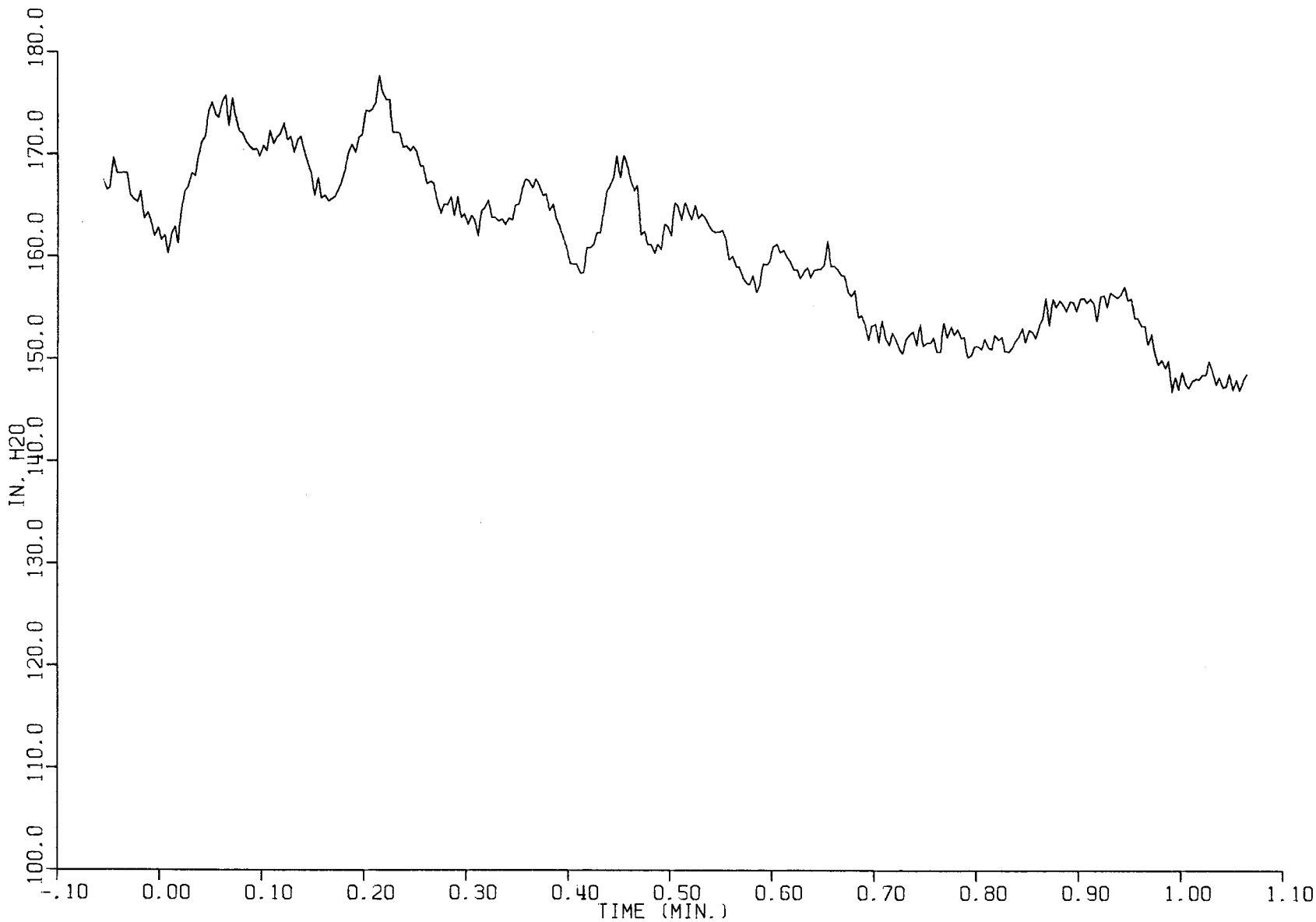


Figure 4-97. Full Length CEA Drop - Steam Generator 2 Feedwater Differential Pressure

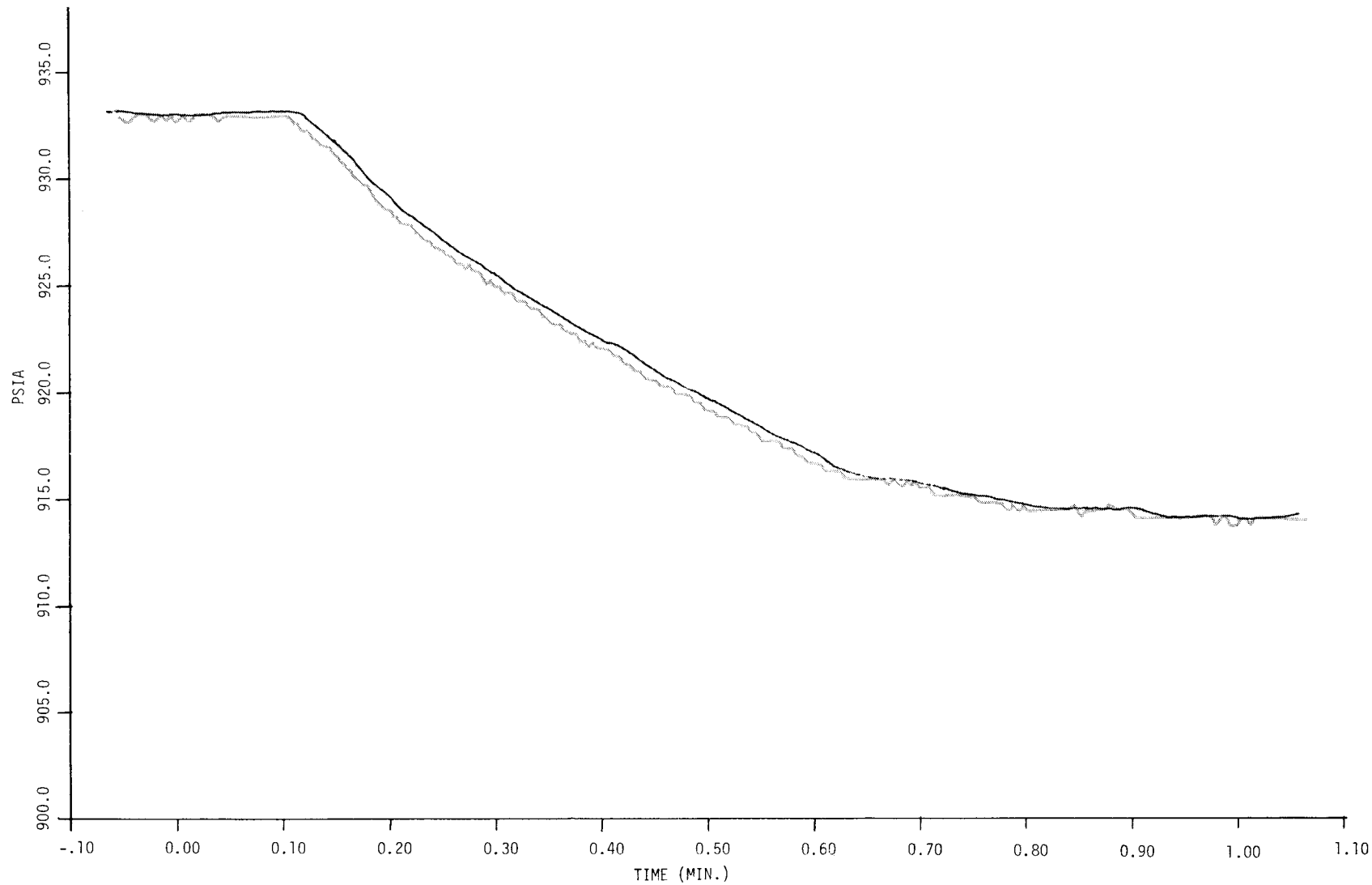


Figure 4-98. Full Length CEA Drop - Steam Generator 2 Pressure

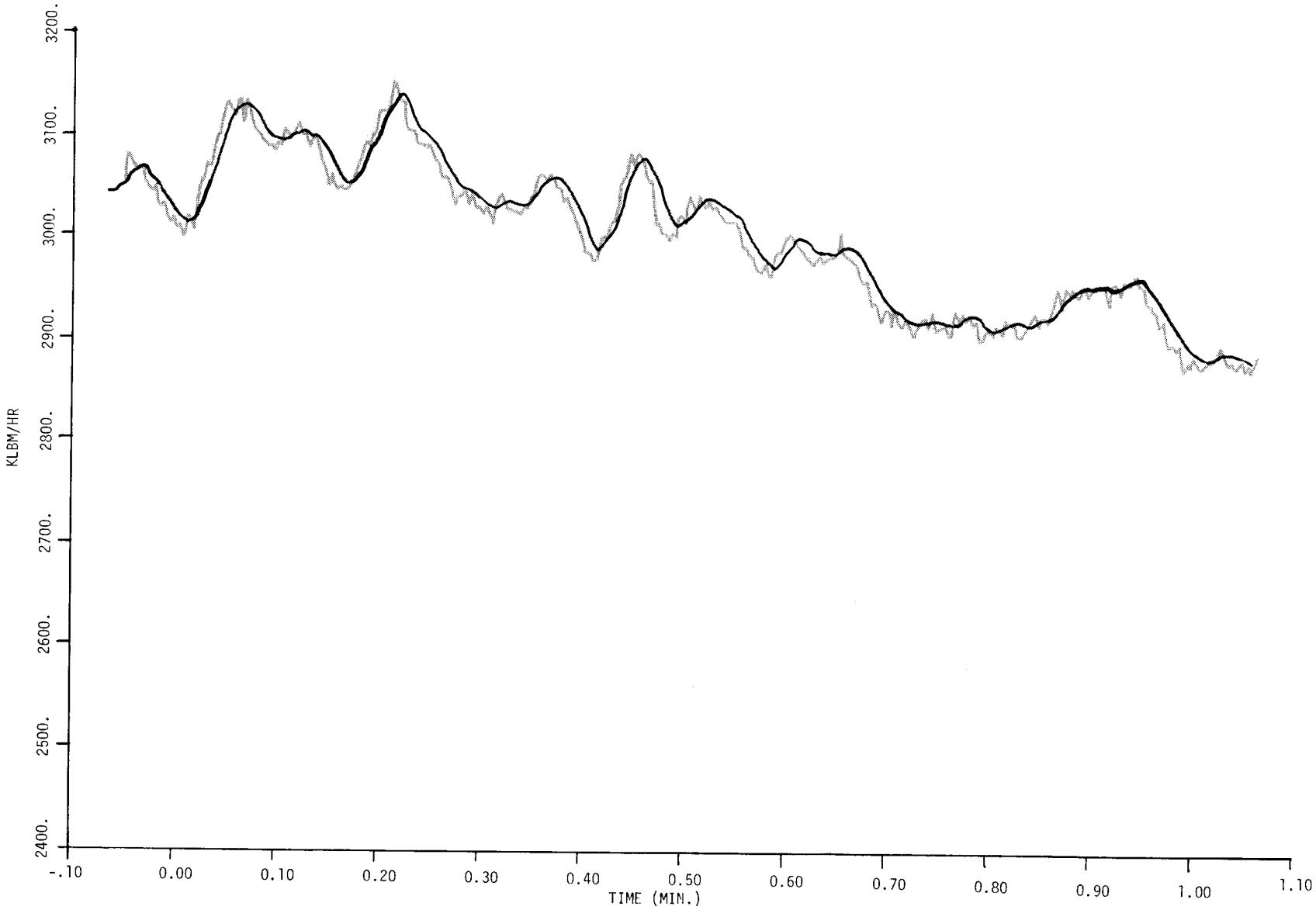


Figure 4-99. Full Length CEA Drop - Steam Generator 2 Feedwater Flow Rate

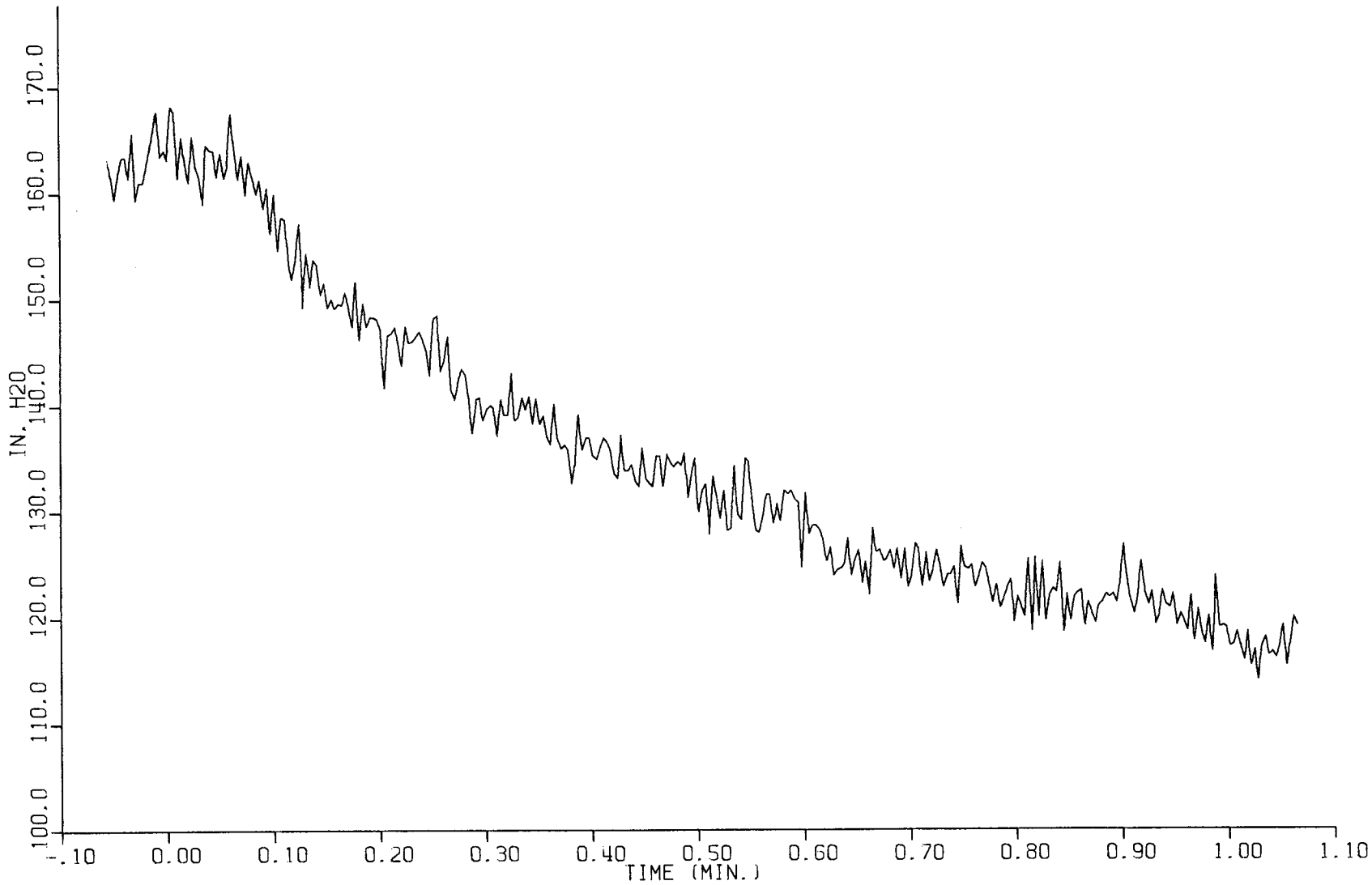


Figure 4-100. Full Length CEA Drop - Steam Generator 2 Header Differential Pressure

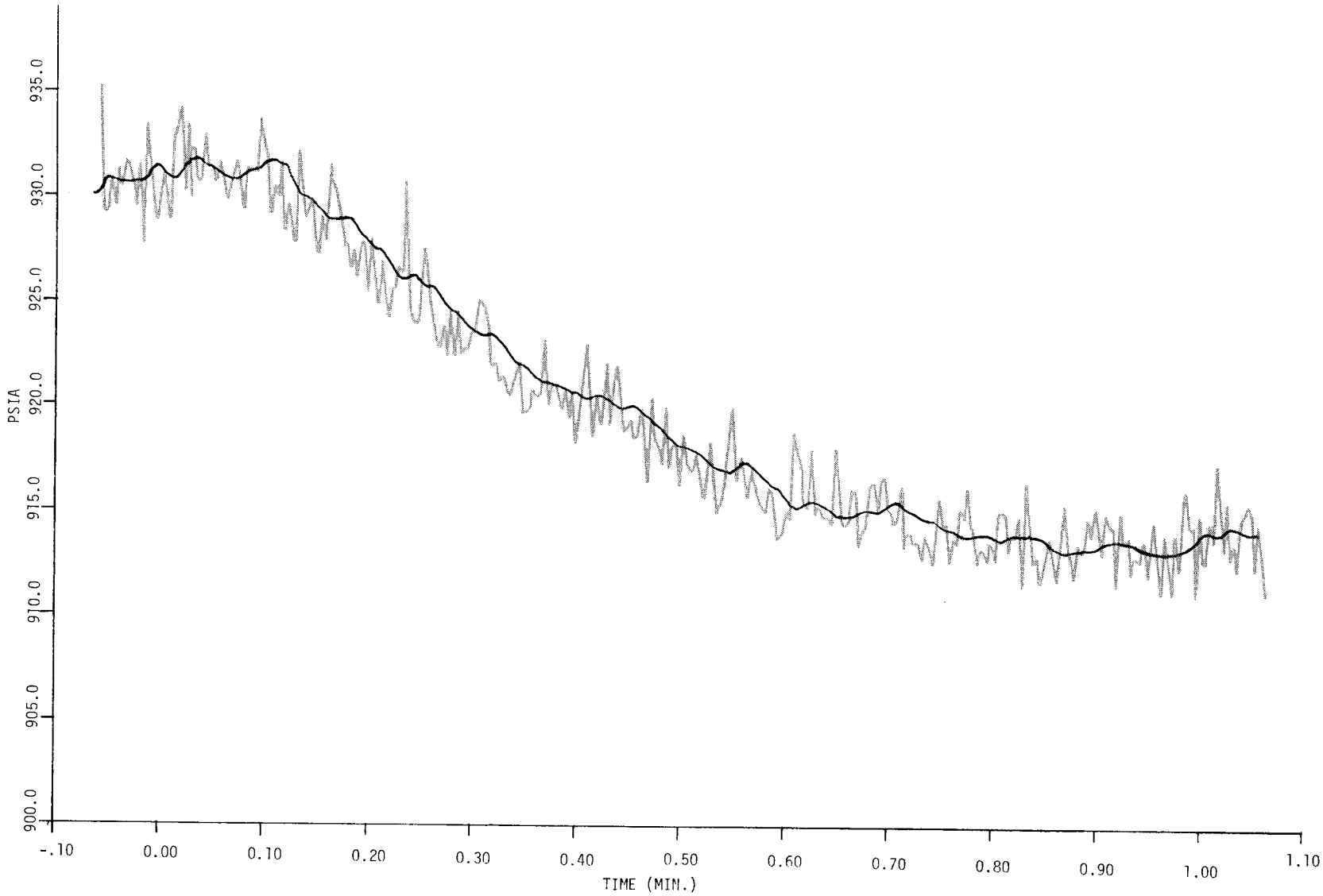


Figure 4-101. Full Length CEA Drop - Steam Generator 2 Header Pressure

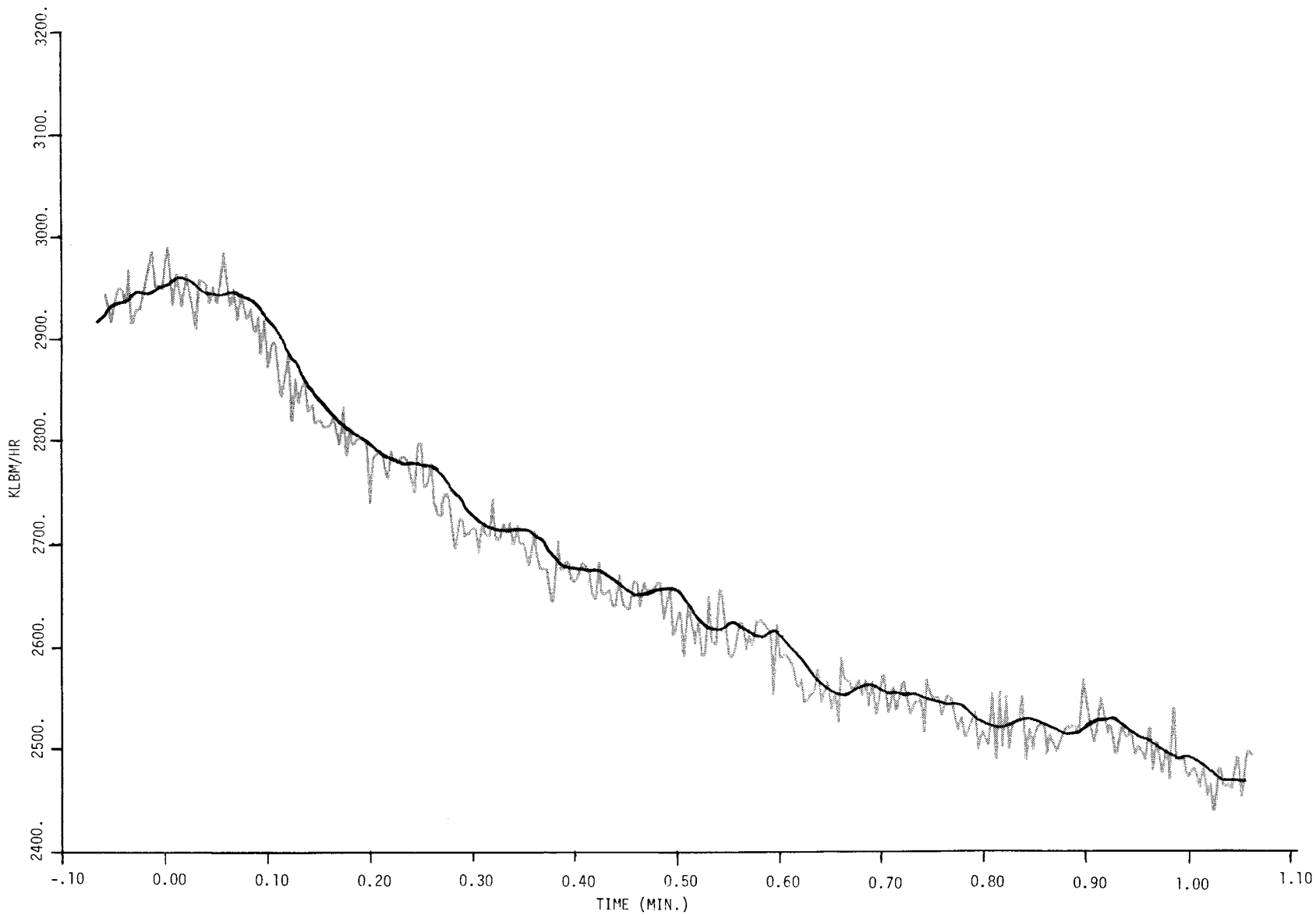


Figure 4-102. Full Length CEA Drop - Steam Generator 2 Main Steam Flow Rate

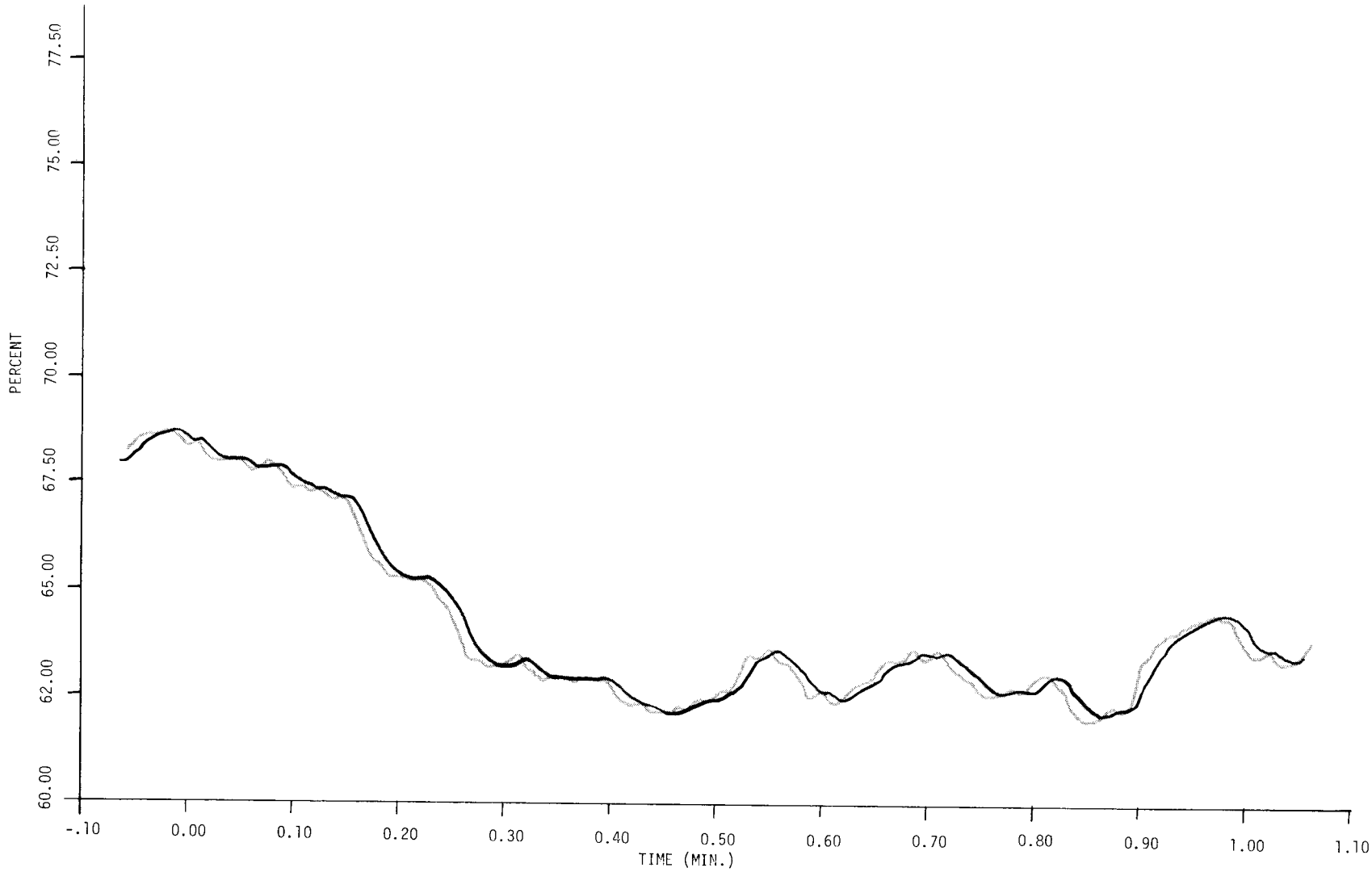


Figure 4-103. Full Length CEA Drop - Steam Generator 2 Level

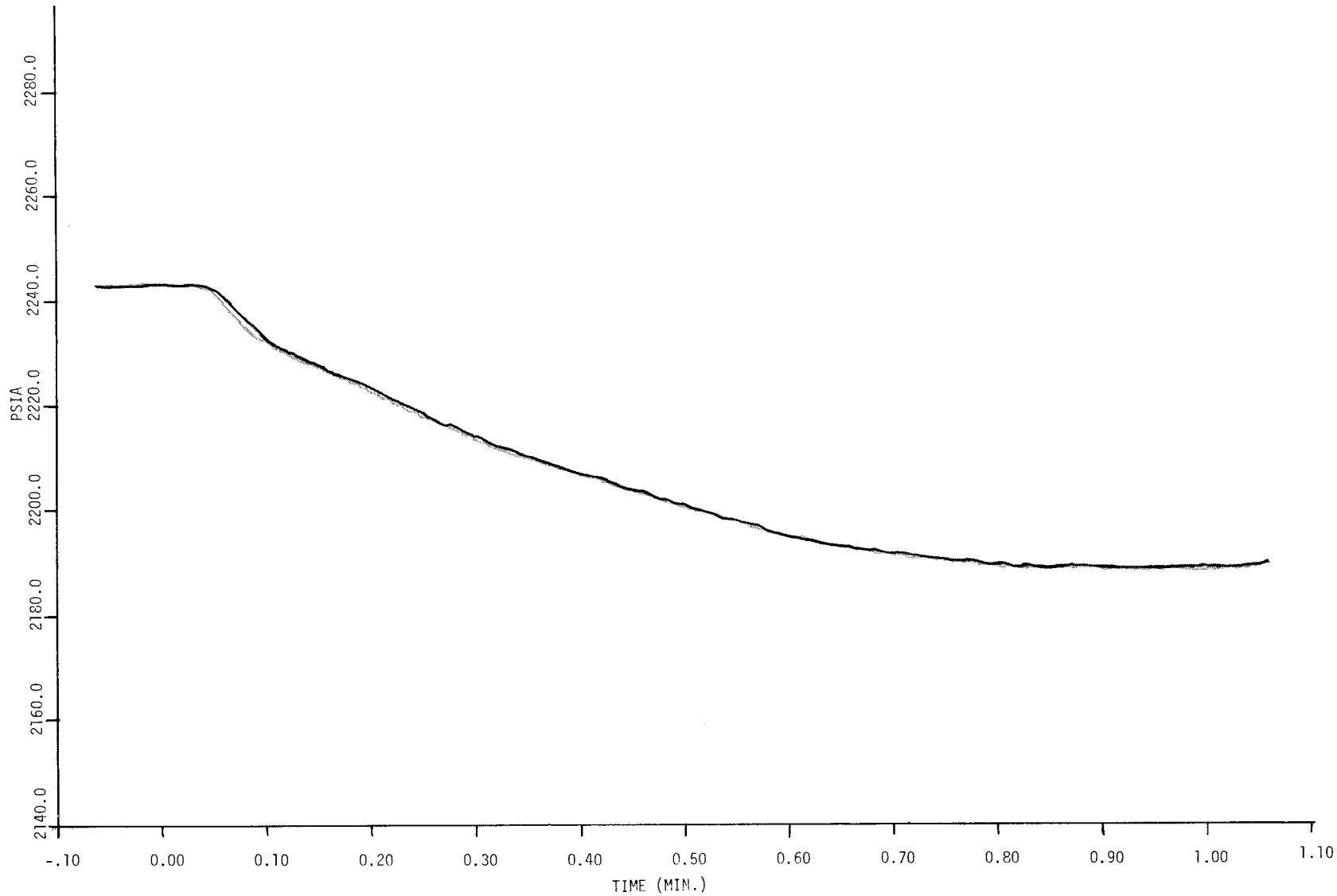


Figure 4-104. Full Length CEA Drop - Pressurizer Pressure (Wide Range)

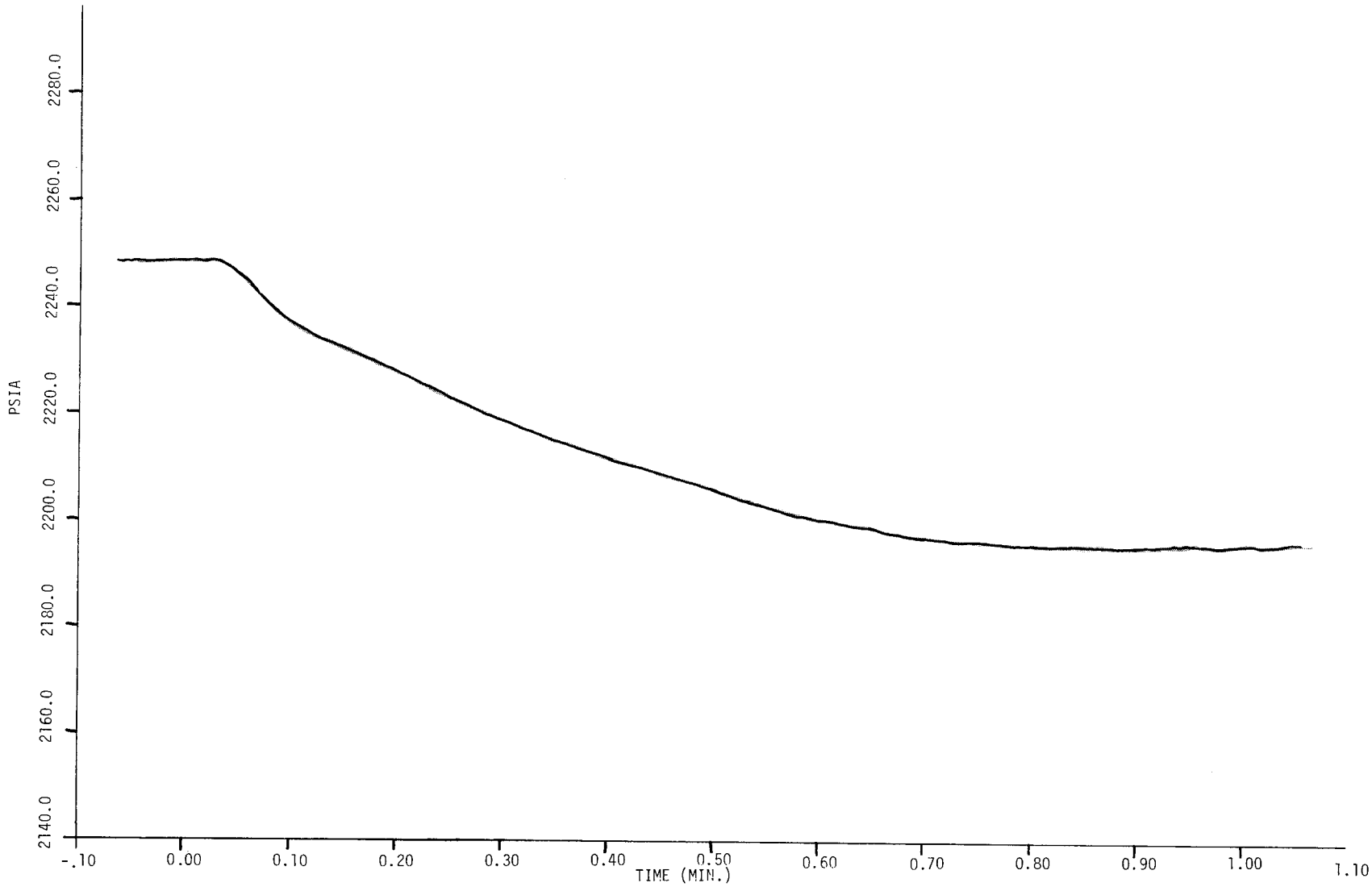


Figure 4-105. Full Length CEA Drop - Pressurizer Pressure (Narrow Range)

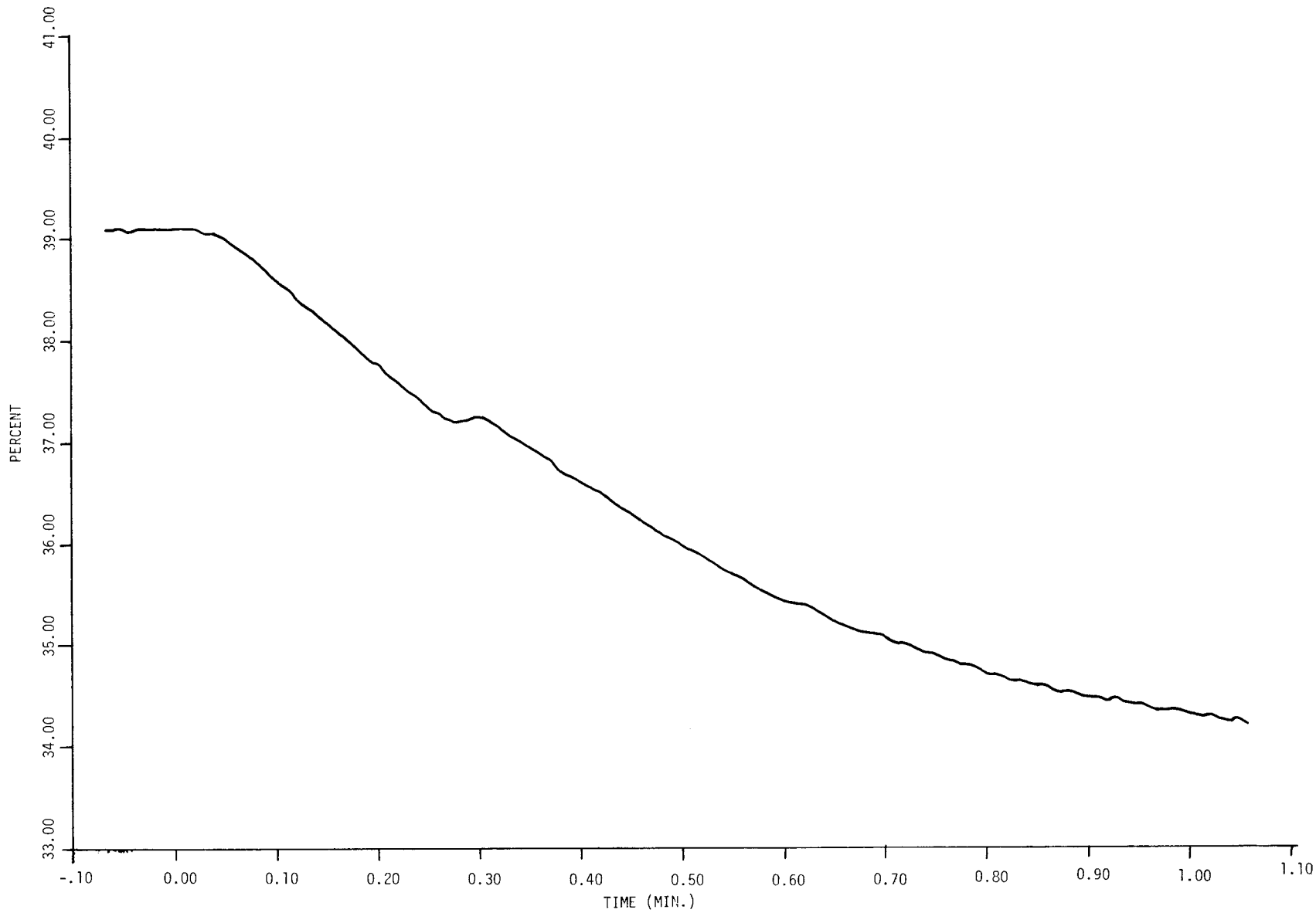


Figure 4-106. Full Length CEA Drop - Pressurizer Level

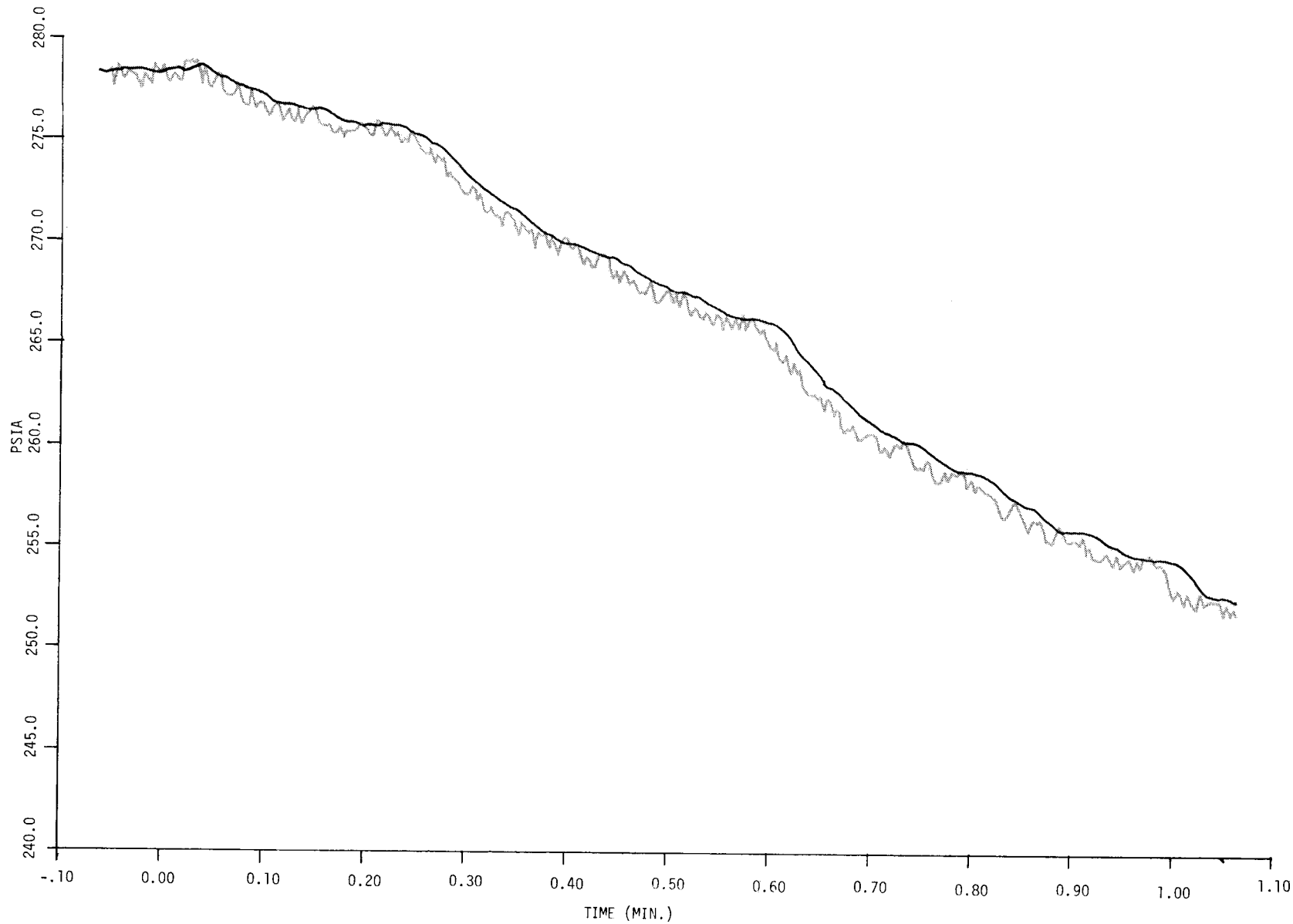


Figure 4-107. Full Length CEA Drop - Turbine First Stage Pressure

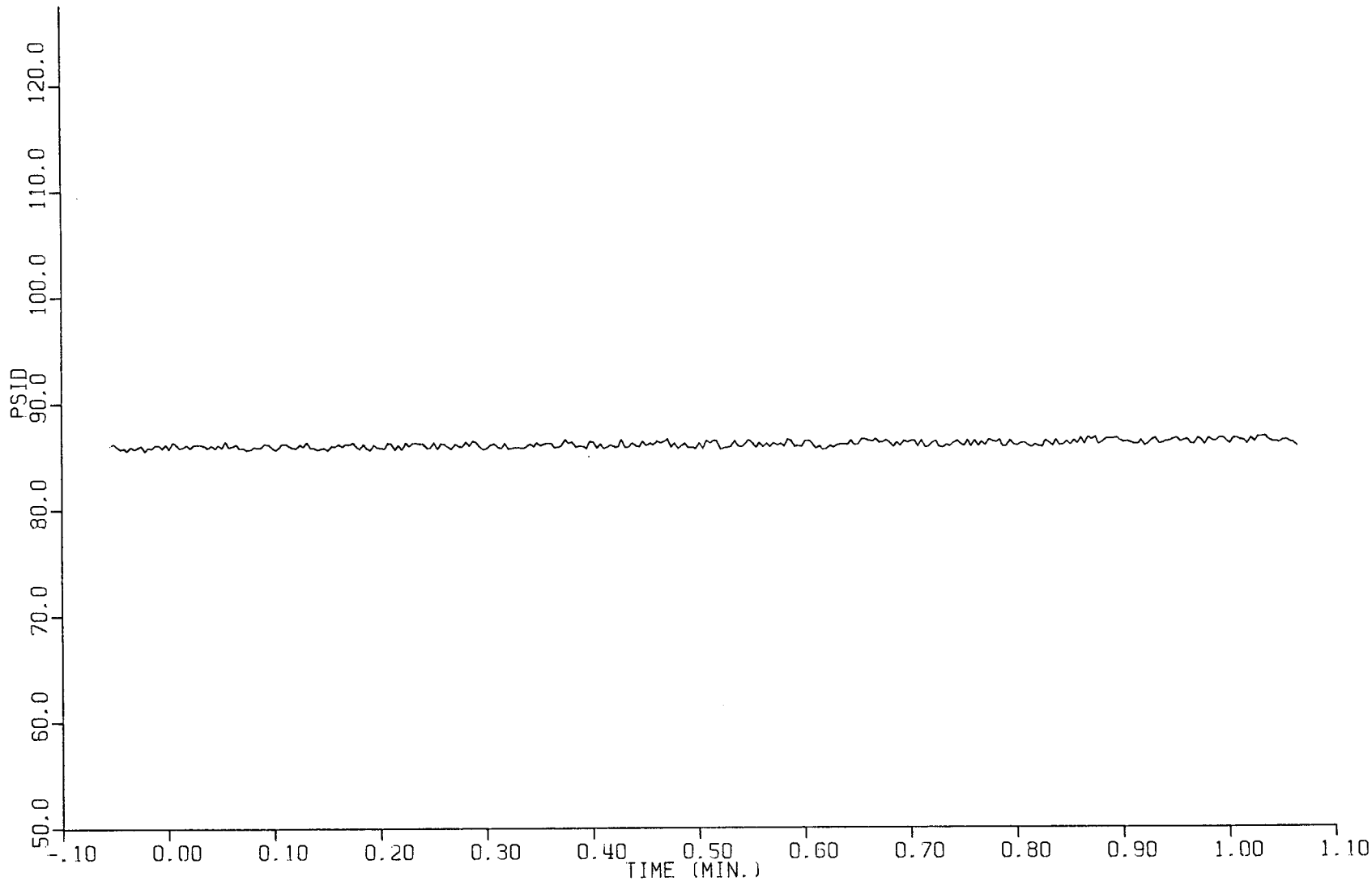


Figure 4-108. Full Length CEA Drop - Reactor Coolant Pump 1A Differential Pressure

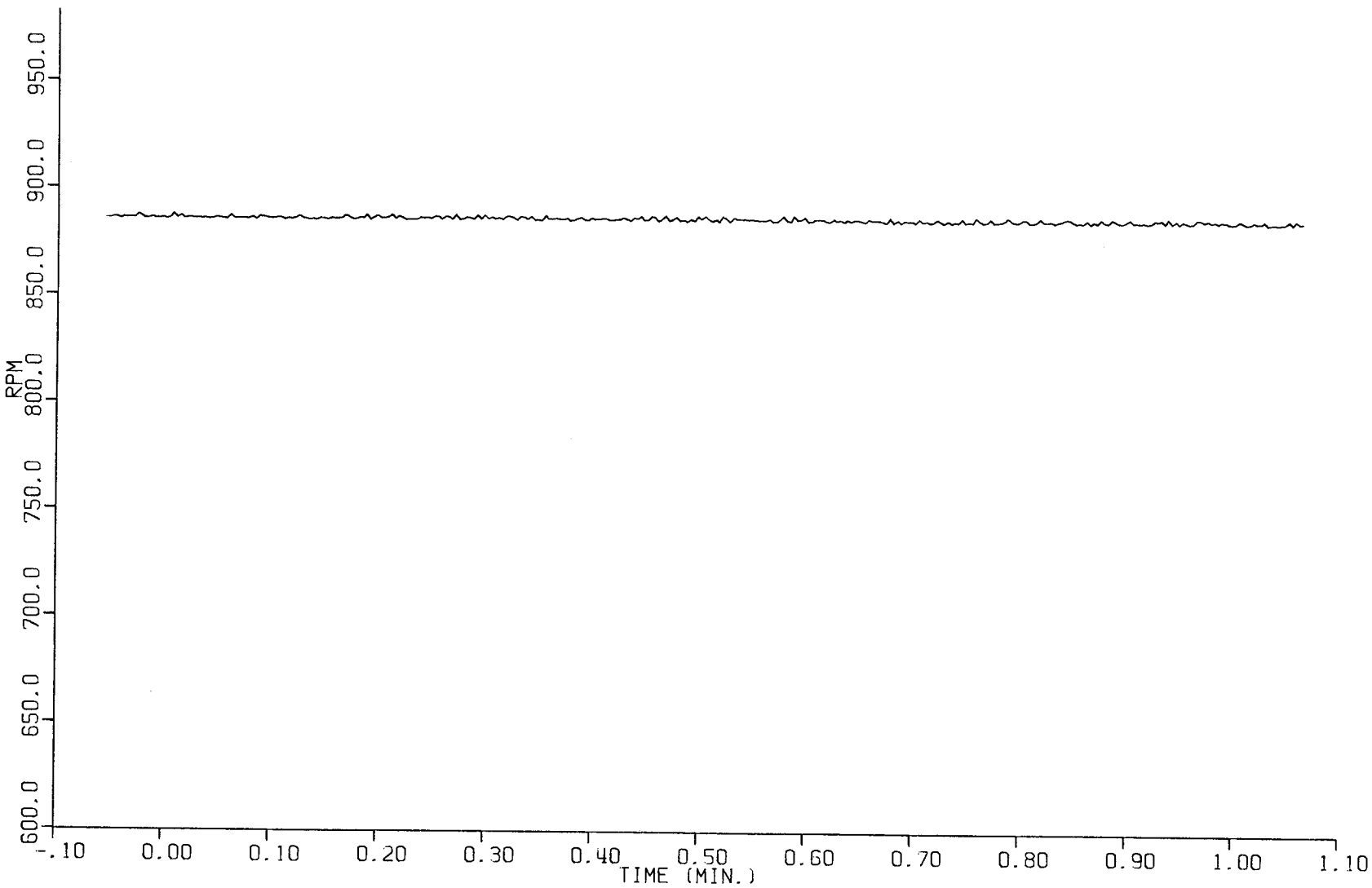


Figure 4-109. Full Length CEA Drop - Reactor Coolant Pump 1A Speed

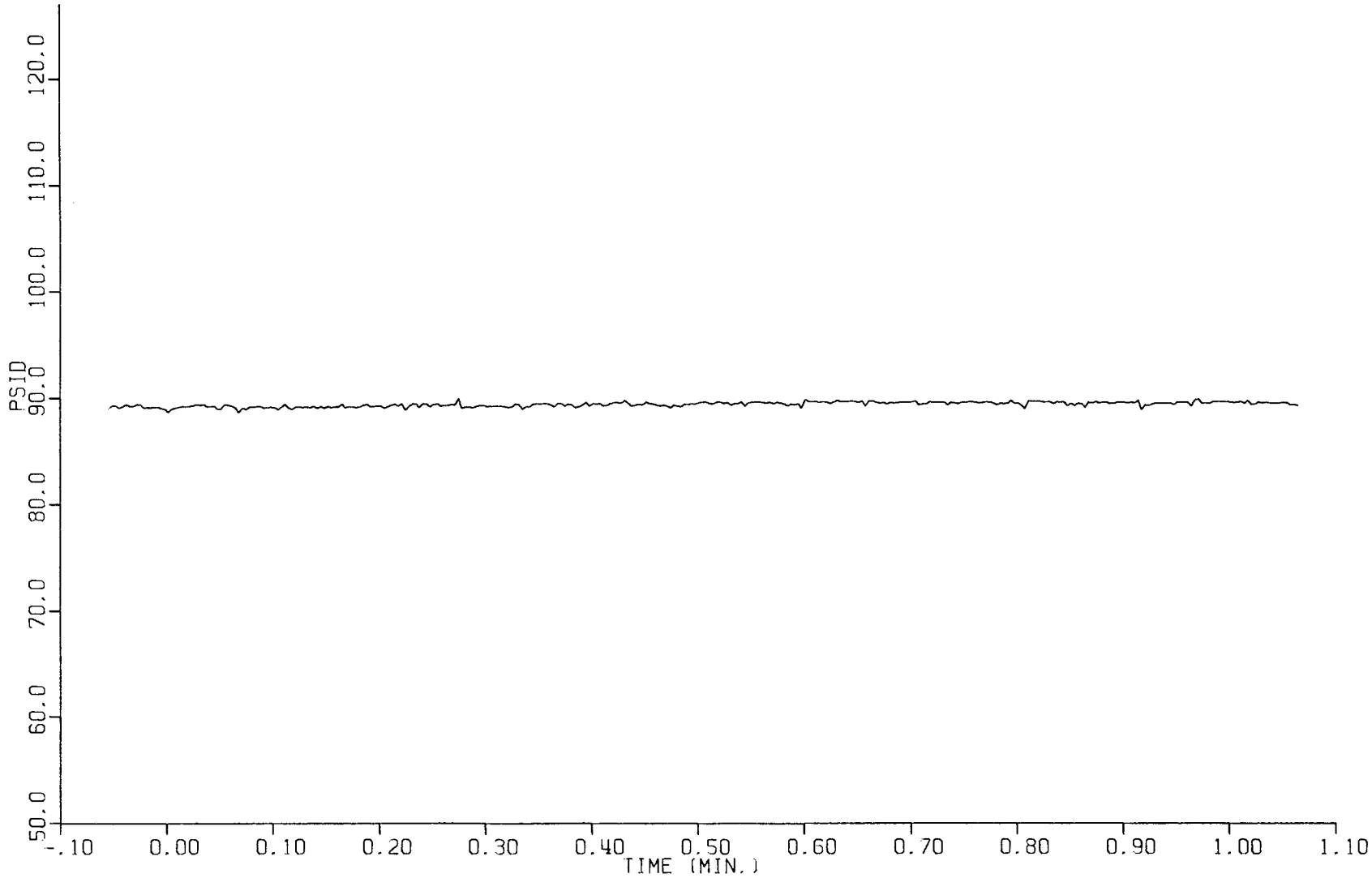


Figure 4-110. Full Length CEA Drop - Reactor Coolant Pump 1B Differential Pressure

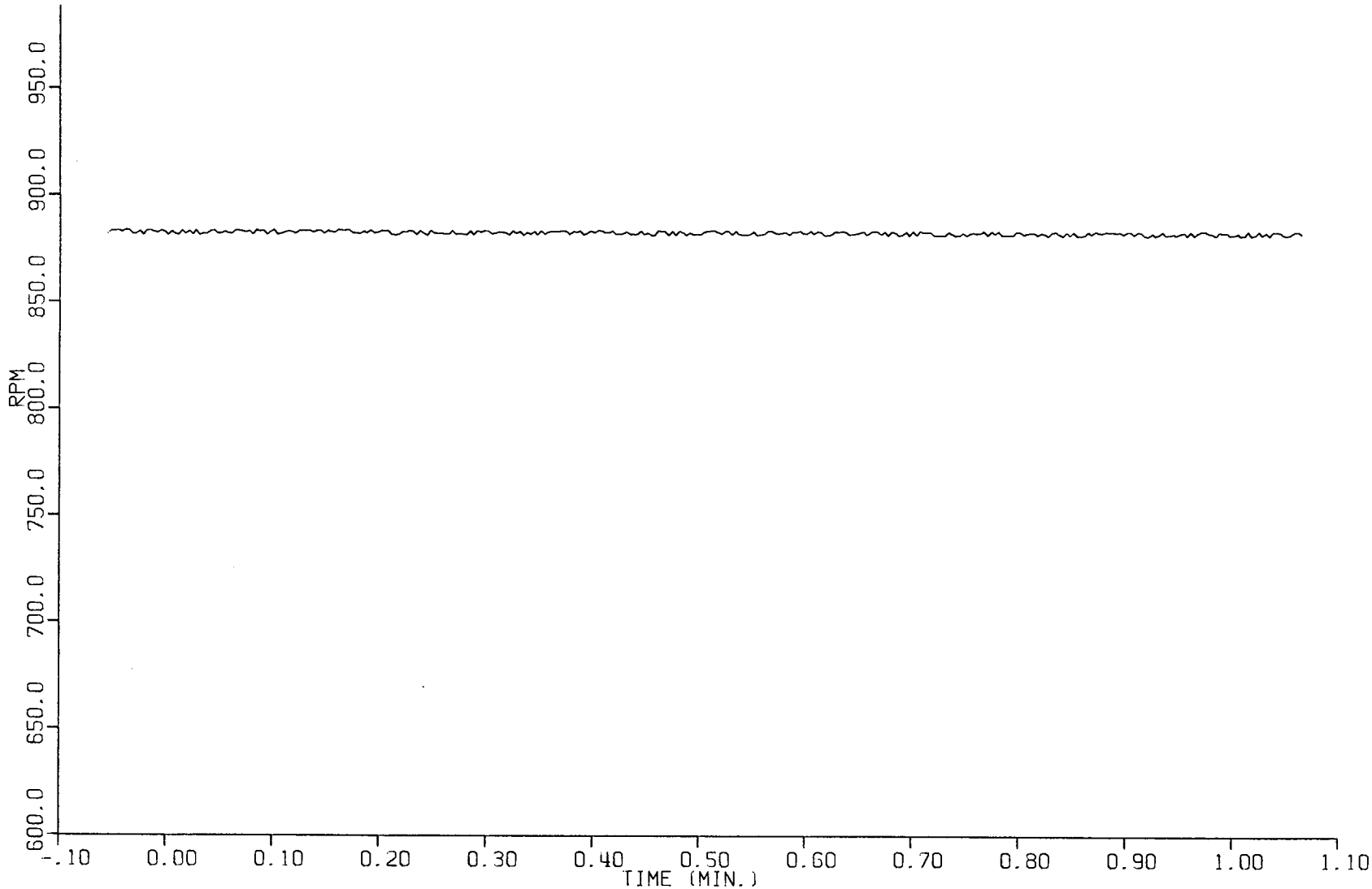


Figure 4-111. Full Length CEA Drop - Reactor Coolant Pump 1B Speed

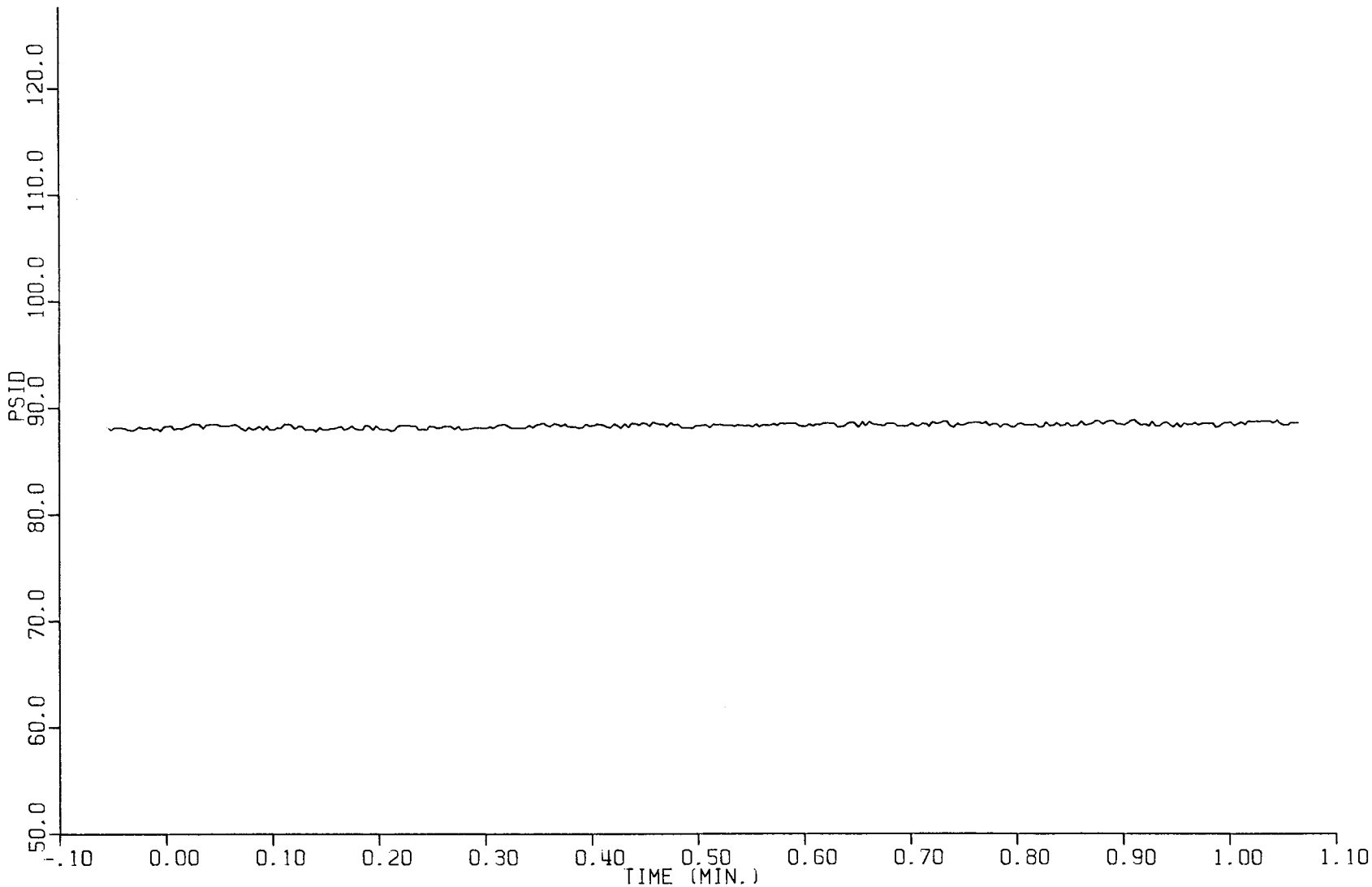


Figure 4-112. Full Length CEA Drop - Reactor Coolant Pump 2A Differential Pressure

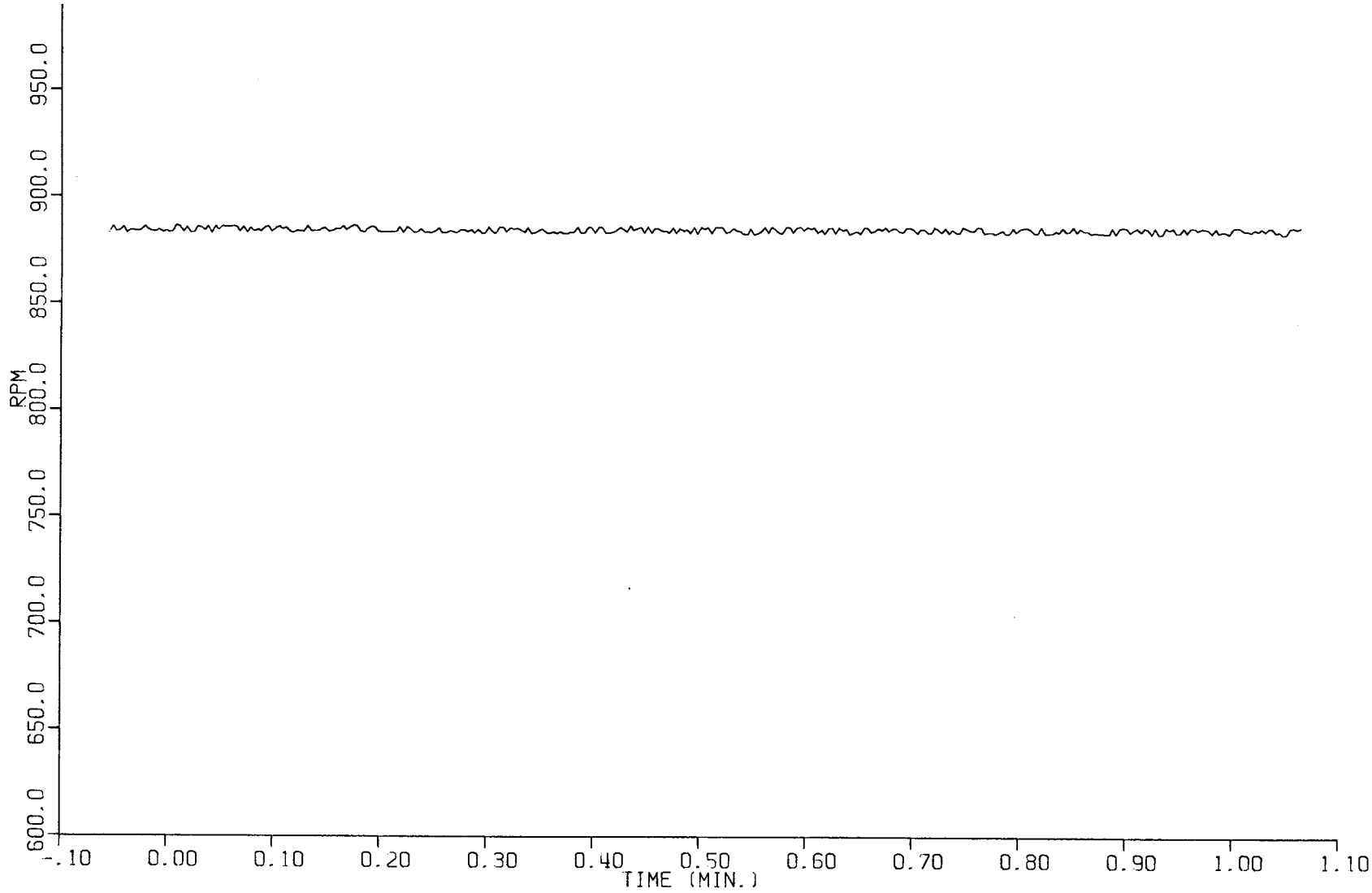


Figure 4-113. Full Length CEA Drop - Reactor Coolant Pump 2A Speed

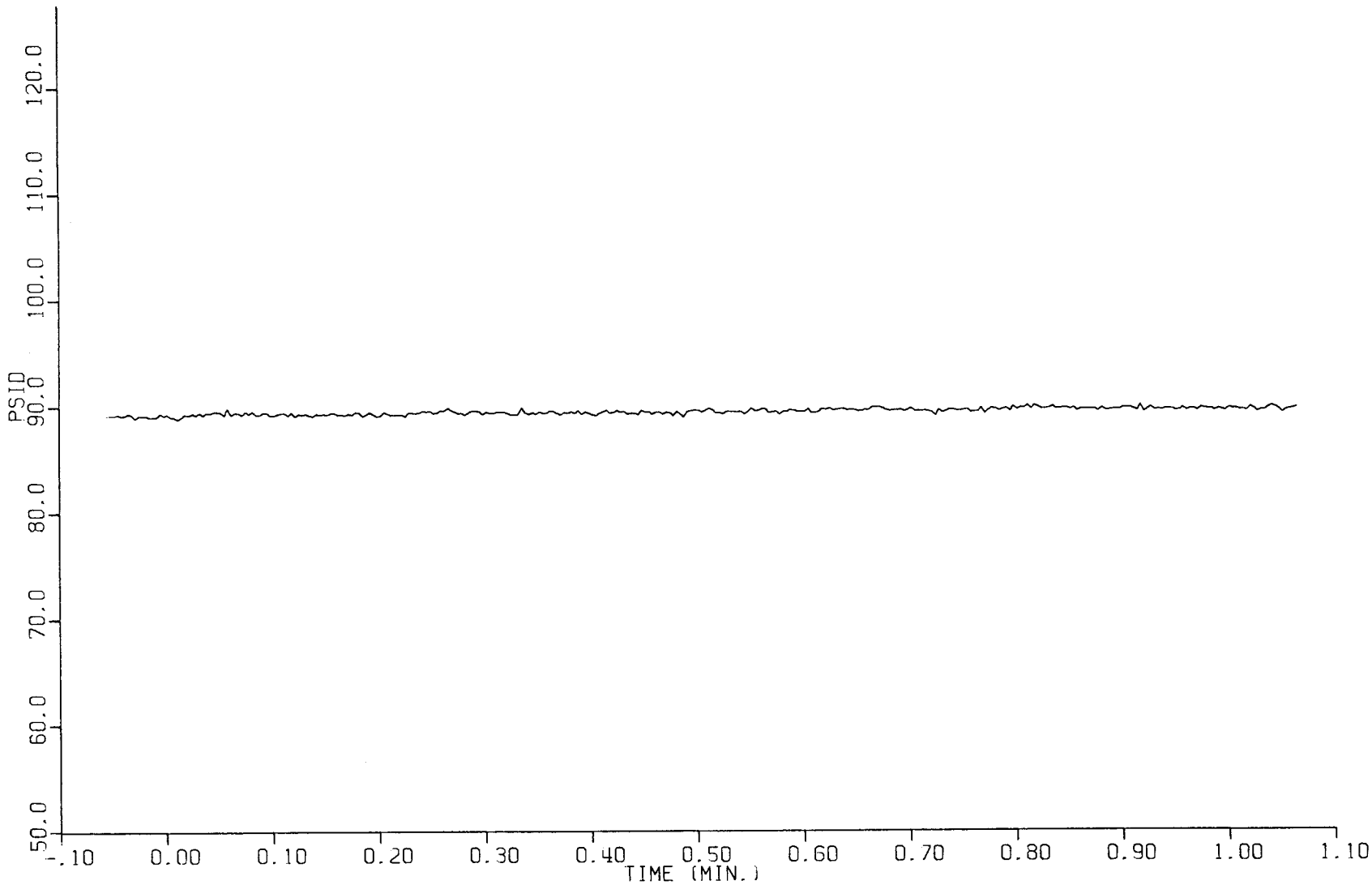


Figure 4-114. Full Length CEA Drop - Reactor Coolant Pump 2B Differential Pressure

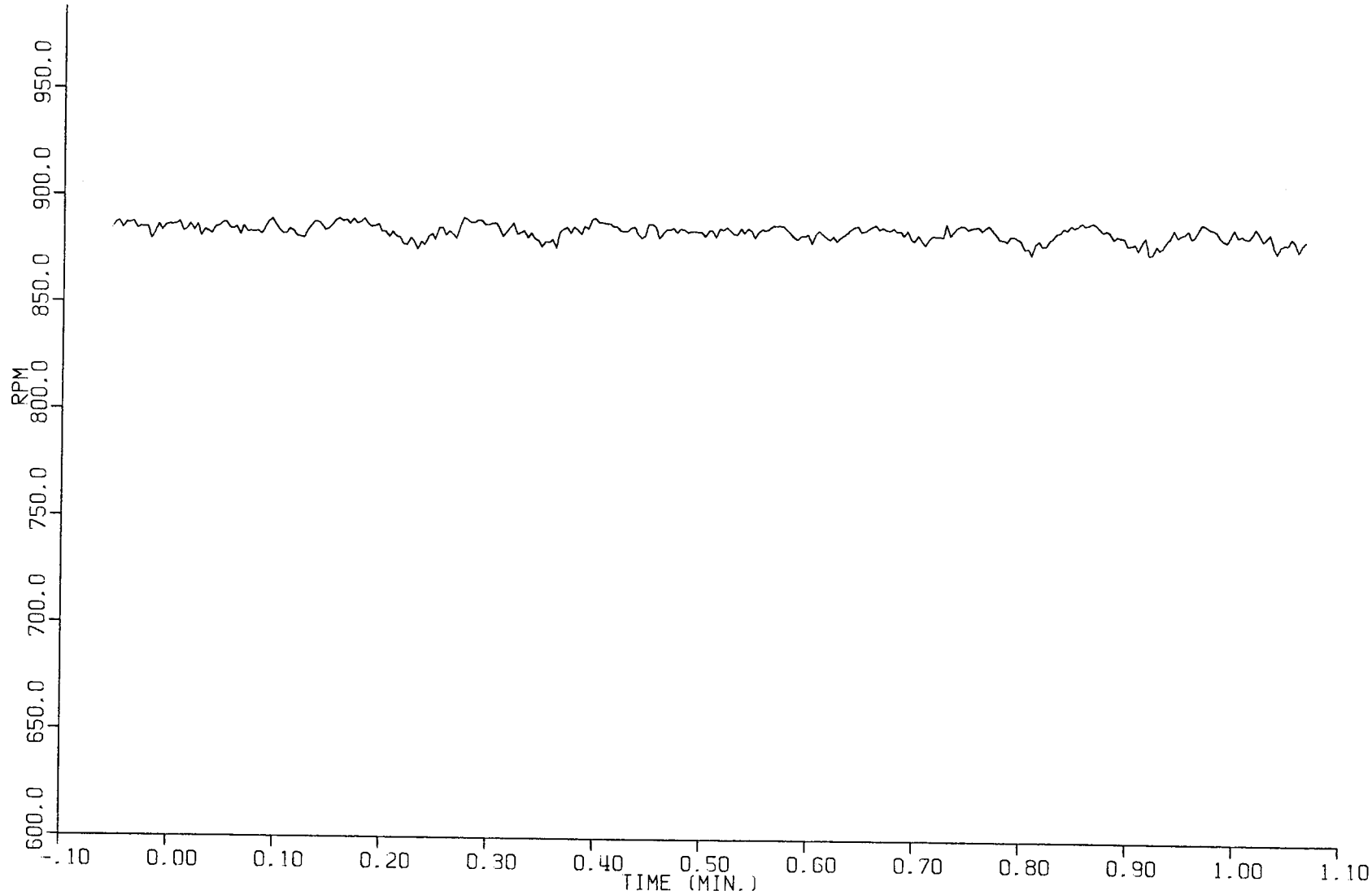


Figure 4-115. Full Length CEA Drop - Reactor Coolant Pump 2B Speed

Table 4-6

INITIAL CONDITIONS FOR THE PART LENGTH (P-24) CEA DROP

Core Power, Mwt	1384 (49.2%)
Core Inlet Coolant Temperature, °F	546
Core Outlet Coolant Temperature, °F	577
Core Mass Flow Rate, 10^6 lbm/hr	134.0
Pressurizer Pressure, psia	2247
Pressurizer Level, percent	39.4
Steam Generator Pressure, psia	931
Steam Generator Level, percent*	70
Charging Flow, GPM	44.5
Letdown Flow, GPM	38.4
Boron Concentration, PPM	702
Axial Shape Index. ASIU	∿0.0
Core Average Burnup, MwD/T	∿2300
Control System Status:	
- Pressurizer Pressure	Automatic
- Pressurizer Level	Automatic
- Feedwater	Automatic
- Reactor Regulating	Automatic
- Steam Dump and Bypass	Automatic

* Level indication in percent of 13.9 ft. instrument span. 0 percent level corresponds to a liquid level 24.5 ft. above the steam generator tube sheet. See Reference 3 for further steam generator details.

Table 4-7

SEQUENCE OF EVENTS FOR THE PART LENGTH (P-24) CEA DROP

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

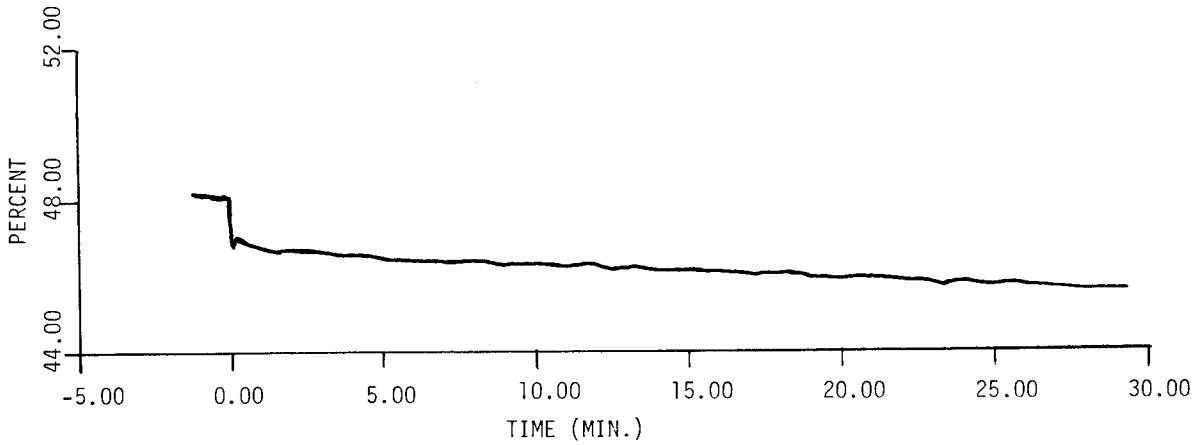


Figure 4-116. Part Length CEA Drop-Control Channel 1 Nuclear Power

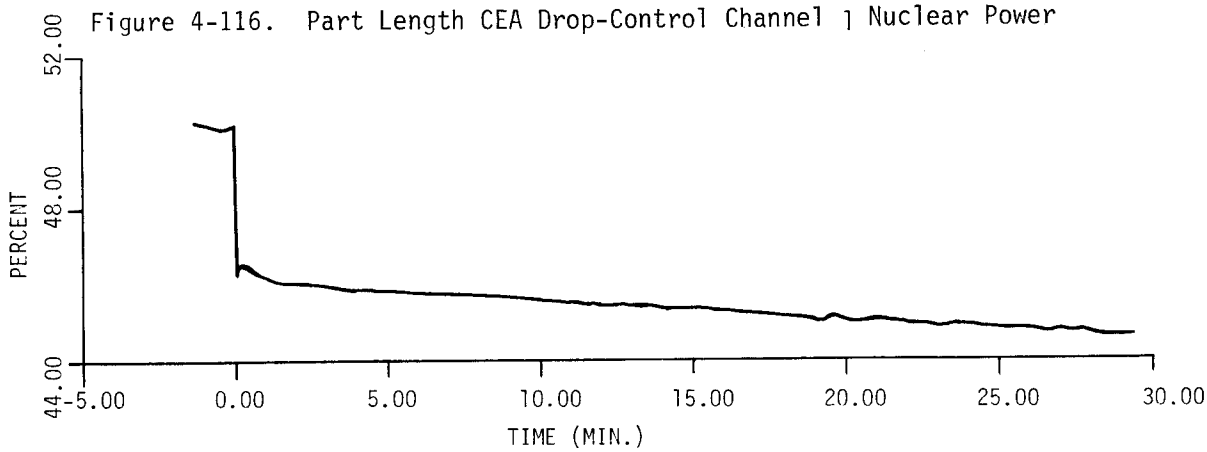


Figure 4-117. Part Length CEA Drop-Control Channel 2 Nuclear Power

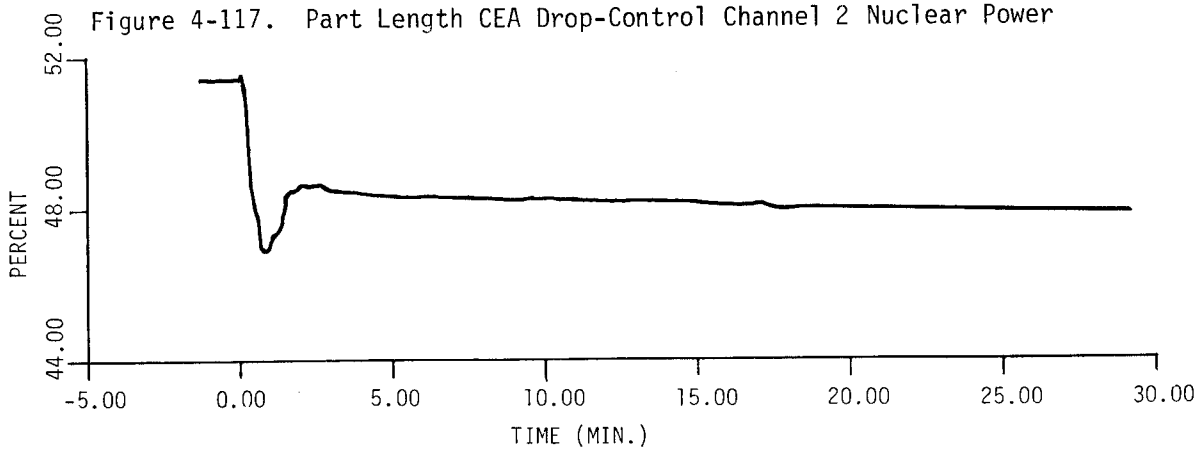


Figure 4-118. Part Length CEA Drop-Turbine Power

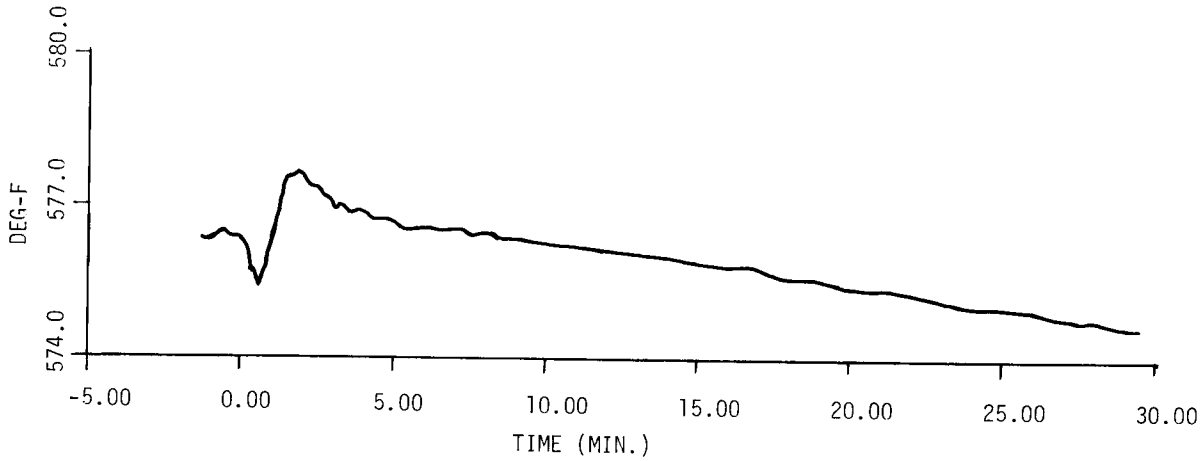


Figure 4-119. Part Length CEA Drop-Steam Generator 1 Hot Leg Temperature

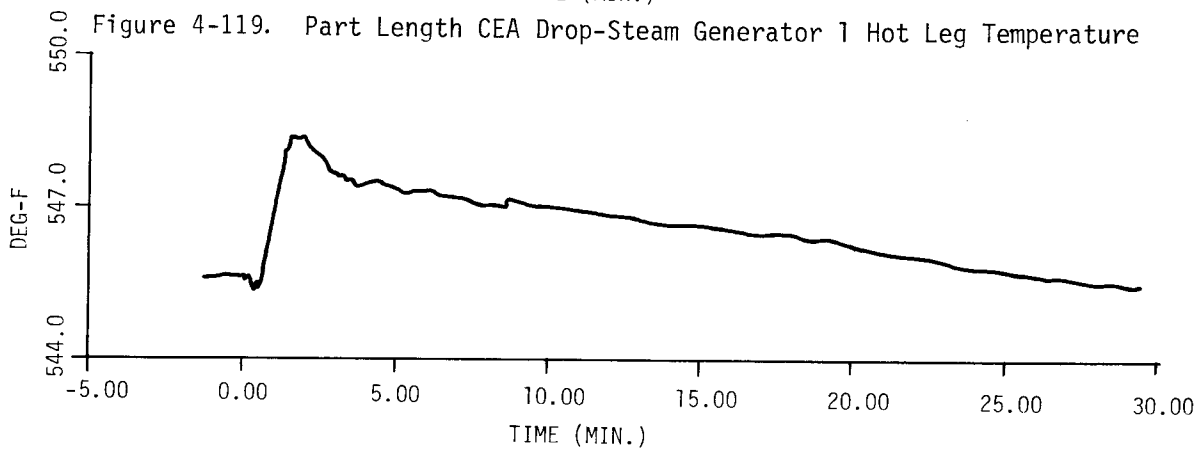


Figure 4-120. Part Length CEA Drop-Steam Generator 1 Cold Leg Temperature (Loop 1A)

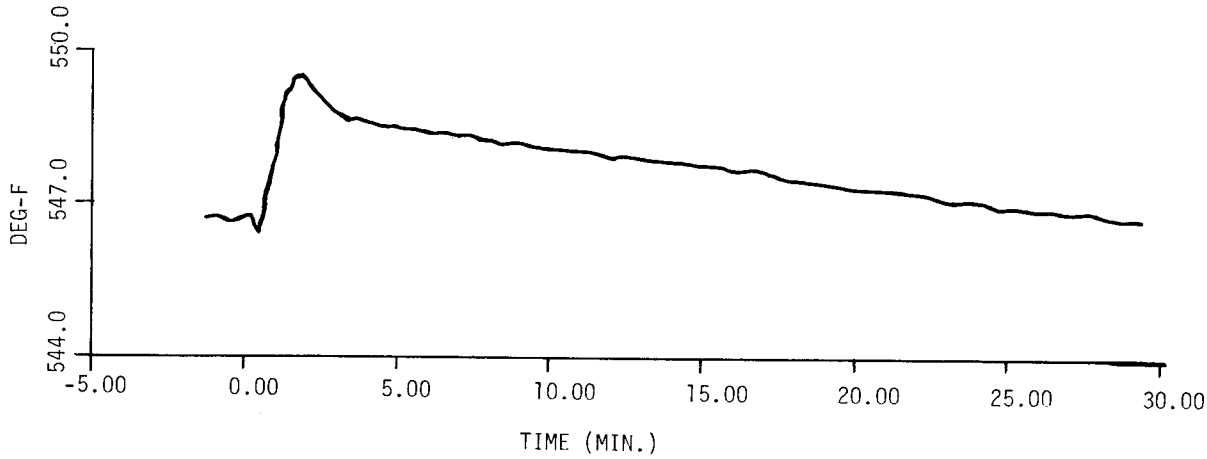


Figure 4-121. Part Length CEA Drop-Steam Generator 1 Cold Leg Temperature (Loop 1B)

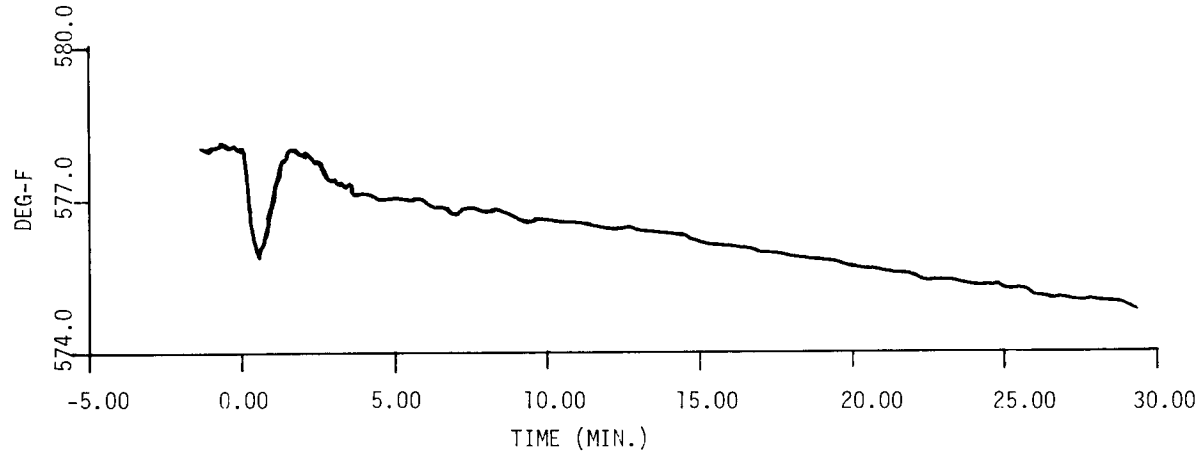


Figure 4-122. Part Length CEA Drop-Steam Generator 2 Hot Leg Temperature

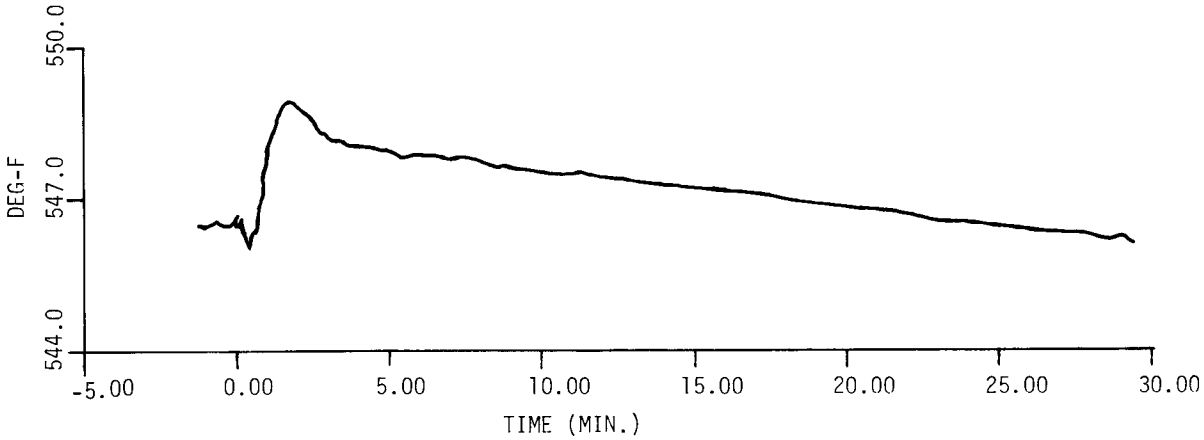


Figure 4-123. Part Length CEA Drop-Steam Generator 2 Cold Leg Temperature (Loop 2A)

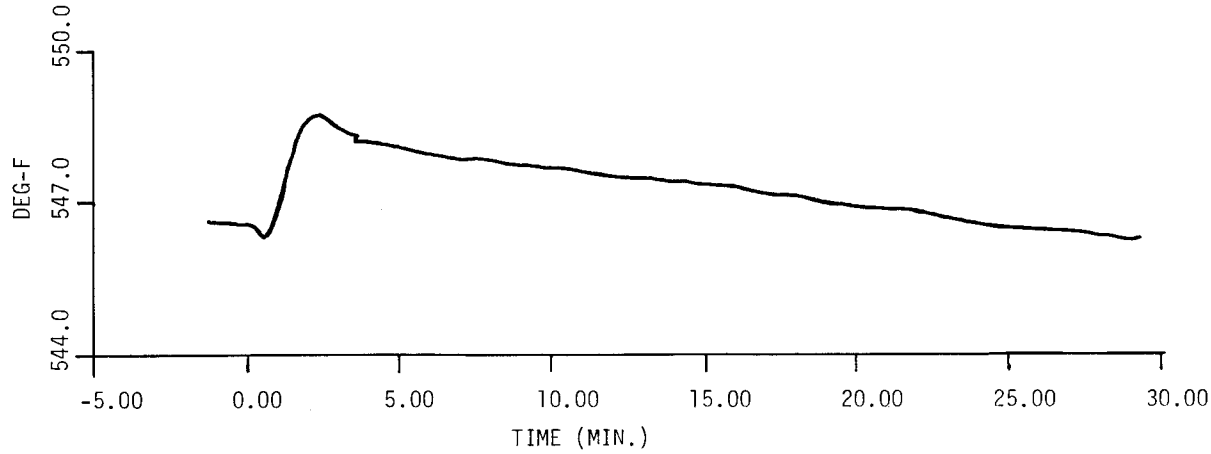


Figure 4-124. Part Length CEA Drop-Steam Generator 2 Cold Leg Temperature (Loop 2B)

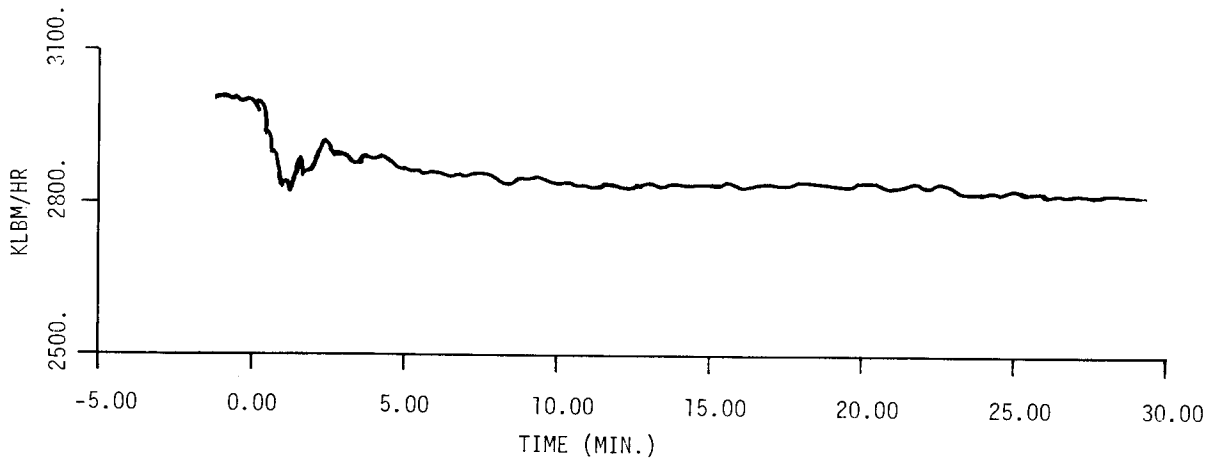


Figure 4-125. Part Length CEA Drop-Steam Generator 1 Feedwater Flow Rate

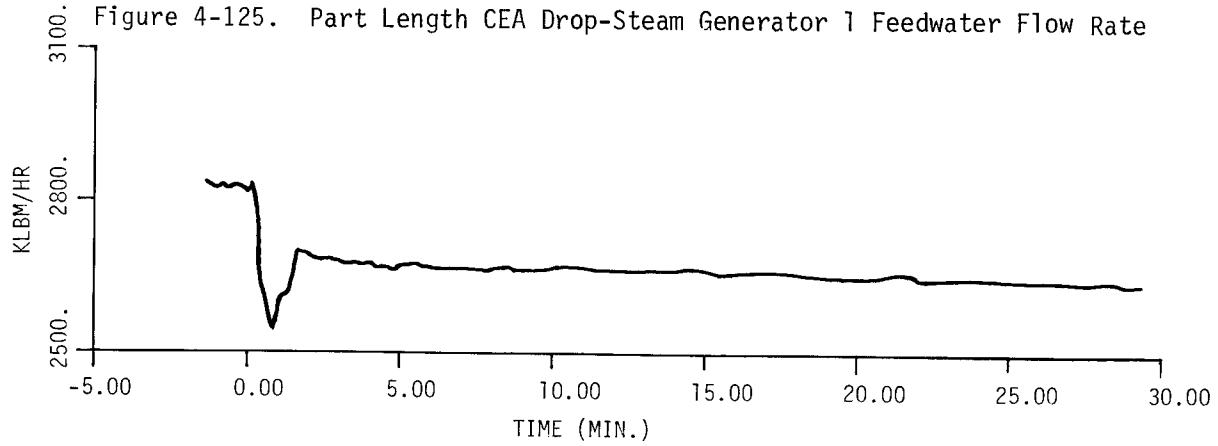


Figure 4-126. Part Length CEA Drop-Steam Generator 1 Main Steam Flow Rate

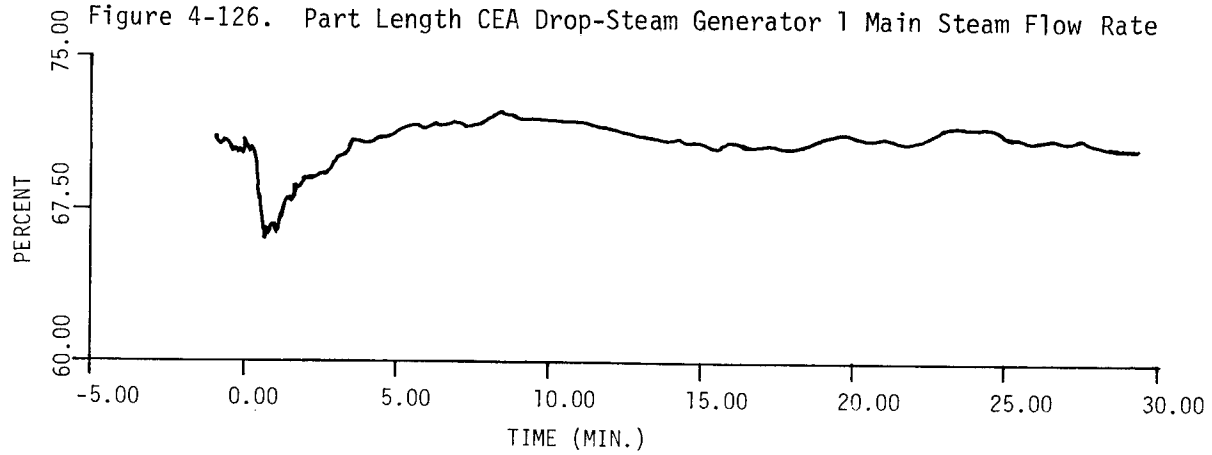


Figure 4-127. Part Length CEA Drop-Steam Generator 1 Level

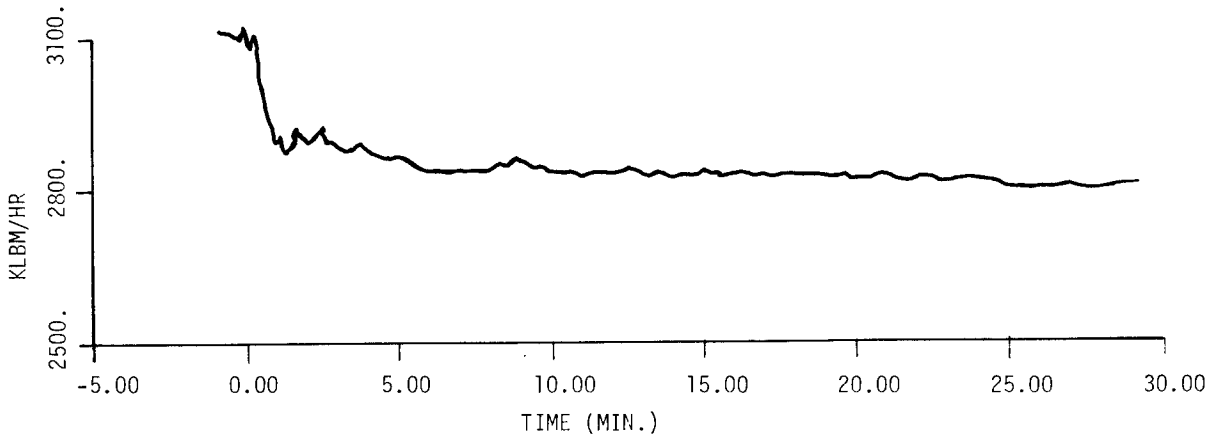


Figure 4-128. Part Length CEA Drop-Steam Generator 2 Feedwater Flow Rate

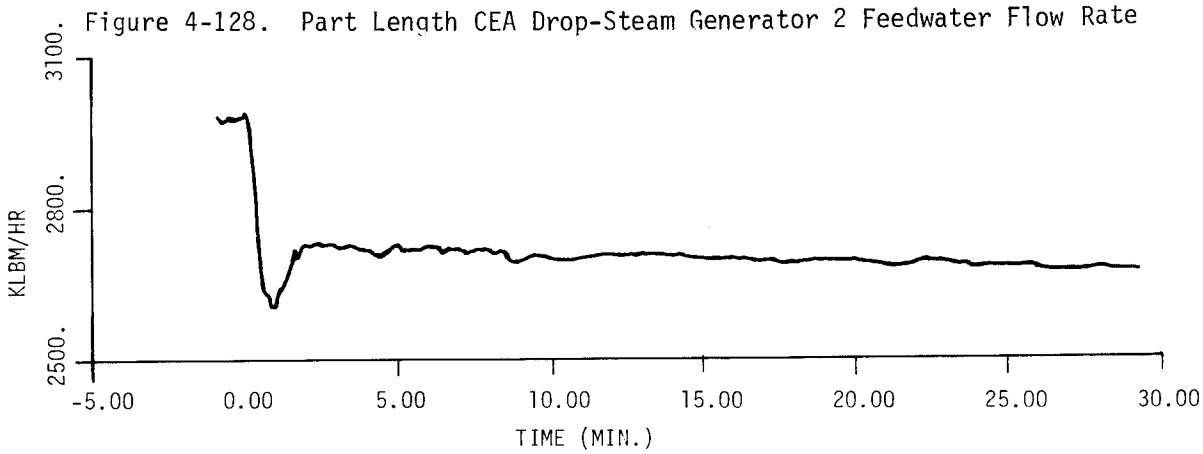


Figure 4-129. Part Length CEA Drop-Steam Generator 2 Main Steam Flow Rate

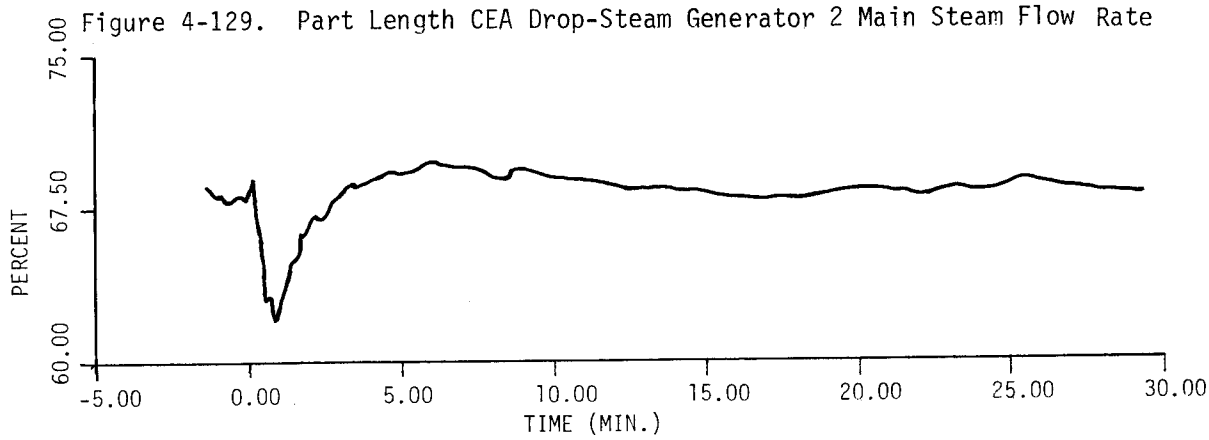


Figure 4-130. Part Length CEA Drop-Steam Generator 2 Level

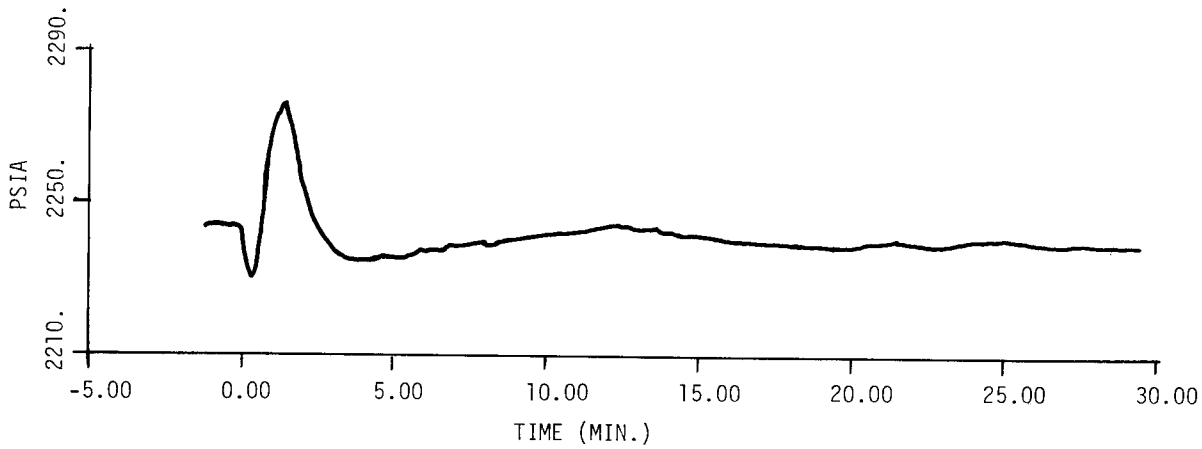


Figure 4-131. Part Length CEA Drop-Pressurizer Pressure, Wide Range

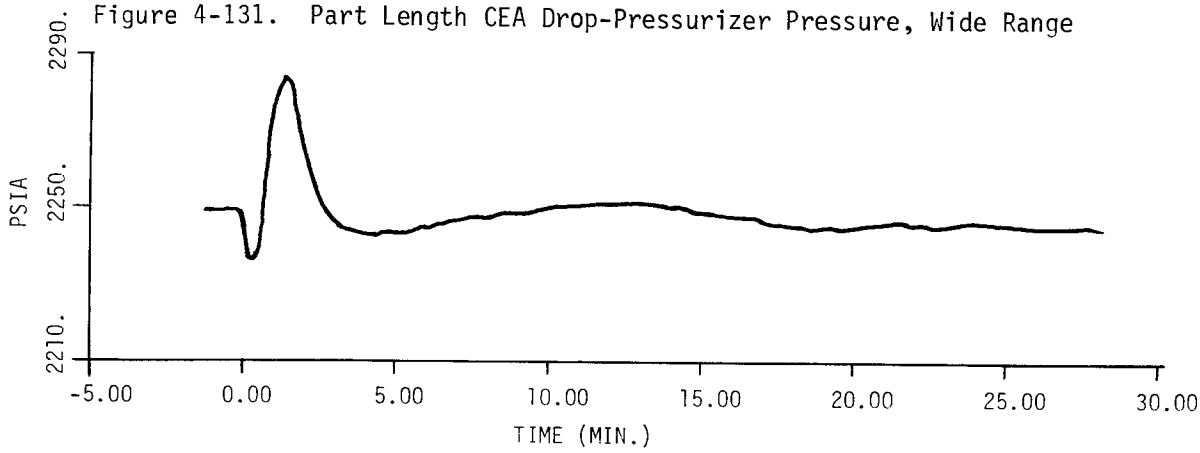


Figure 4-132. Part Length CEA Drop-Pressurizer Pressure, Narrow Range

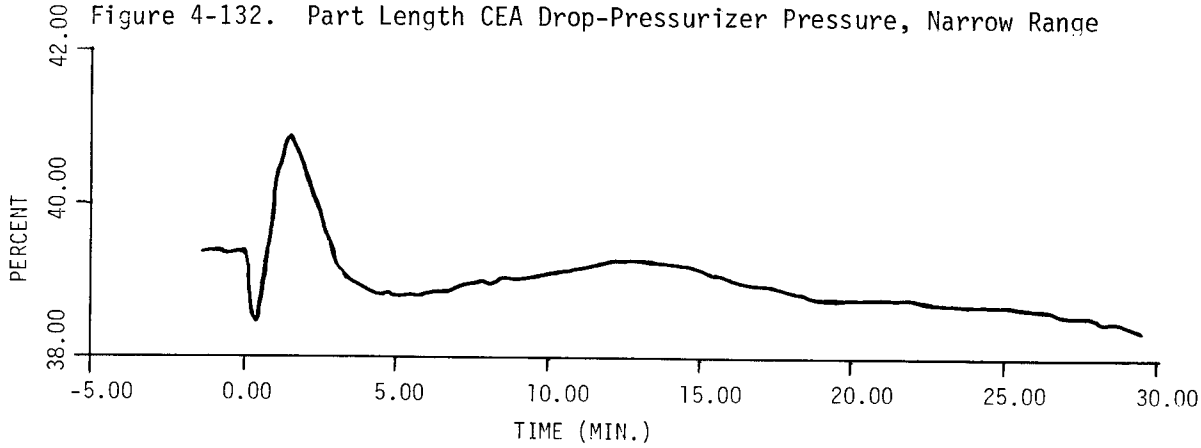


Figure 4-133. Part Length CEA Drop-Pressurizer Level

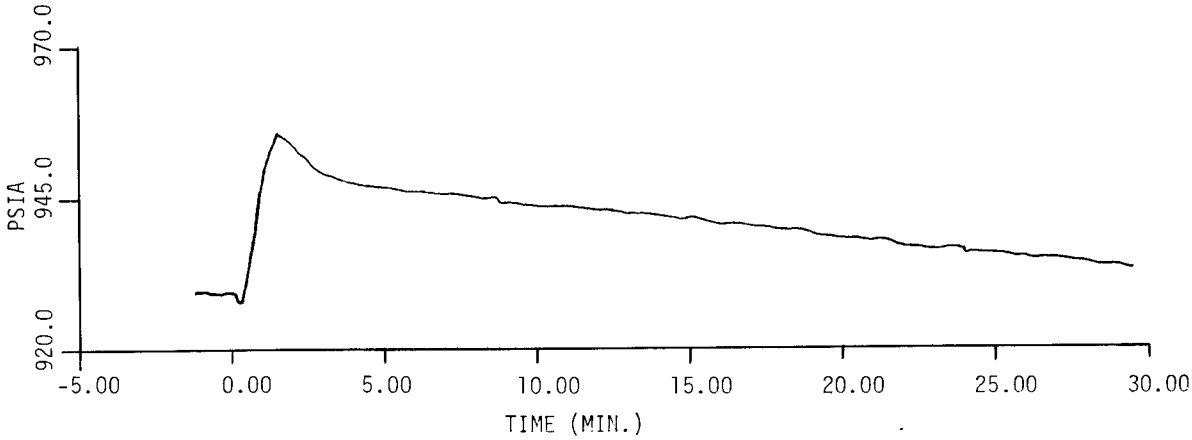


Figure 4-134. Part Length CEA Drop-Steam Generator 1 Pressure

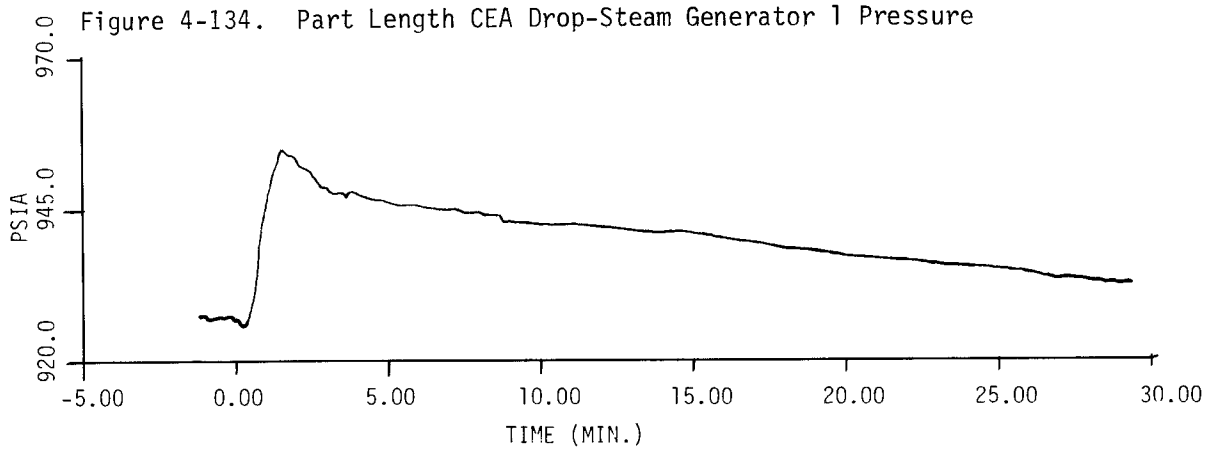


Figure 4-135. Part Length CEA Drop-Steam Generator 1 Header Pressure

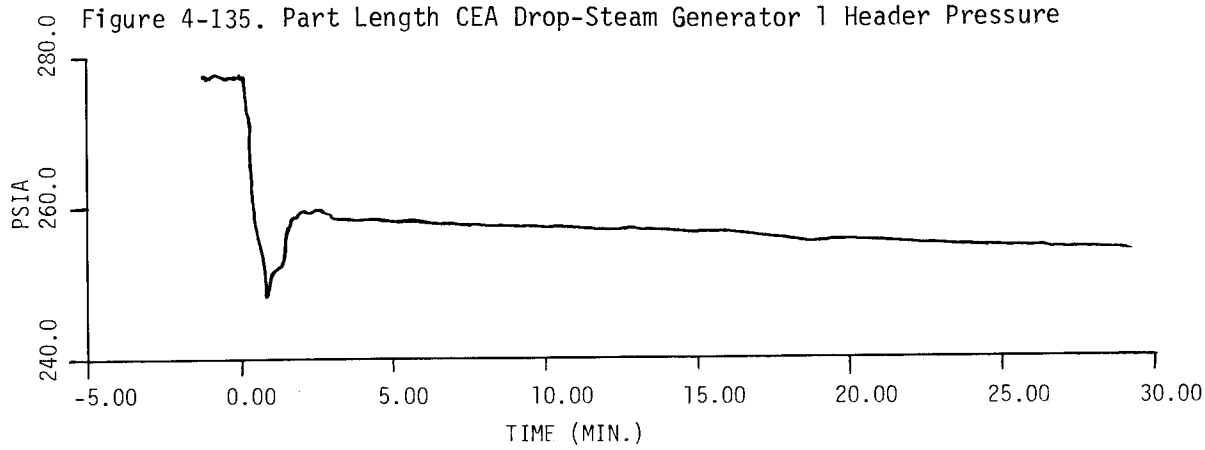


Figure 4-136. Part Length CEA Drop-Turbine First Stage Pressure

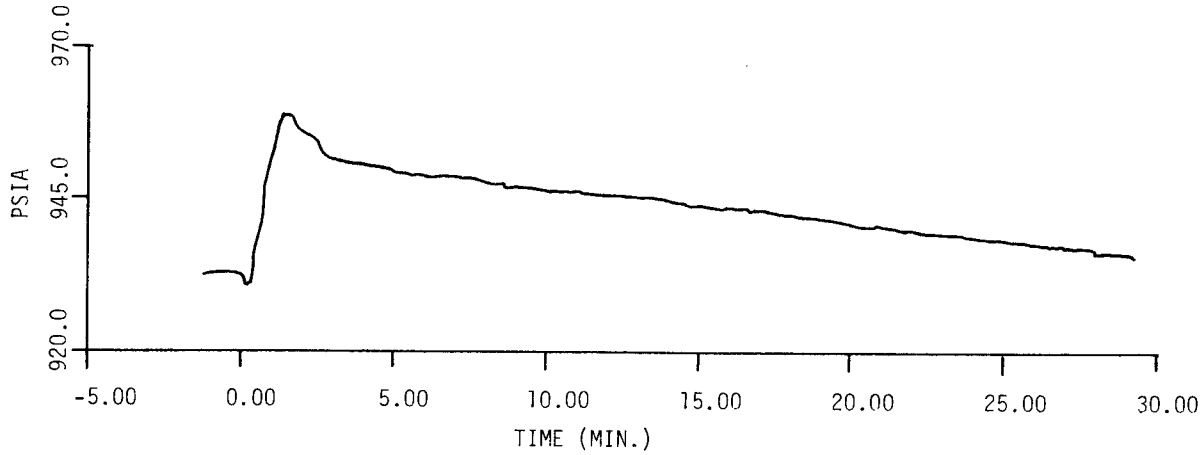


Figure 4-137. Part Length CEA Drop-Steam Generator 2 Pressure

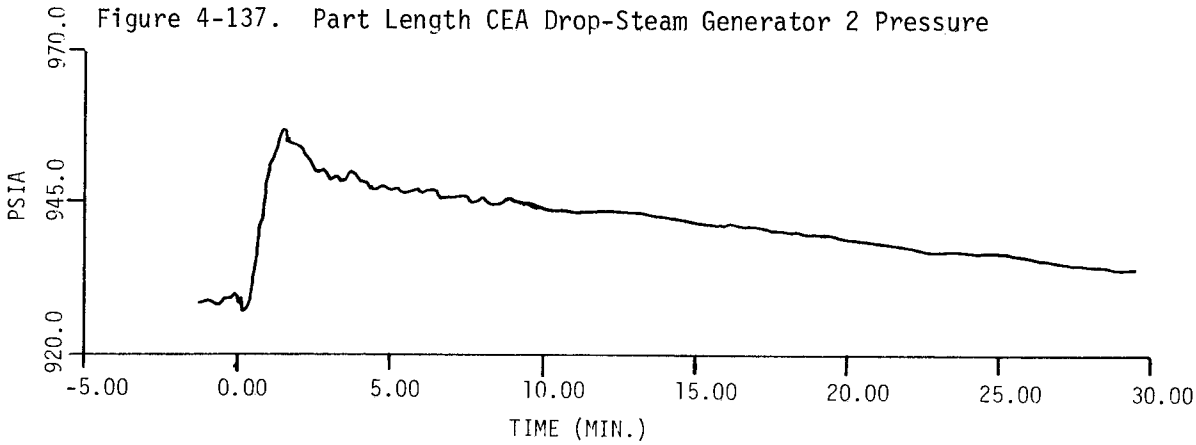


Figure 4-138. Part Length CEA Drop-Steam Generator 2 Header Pressure

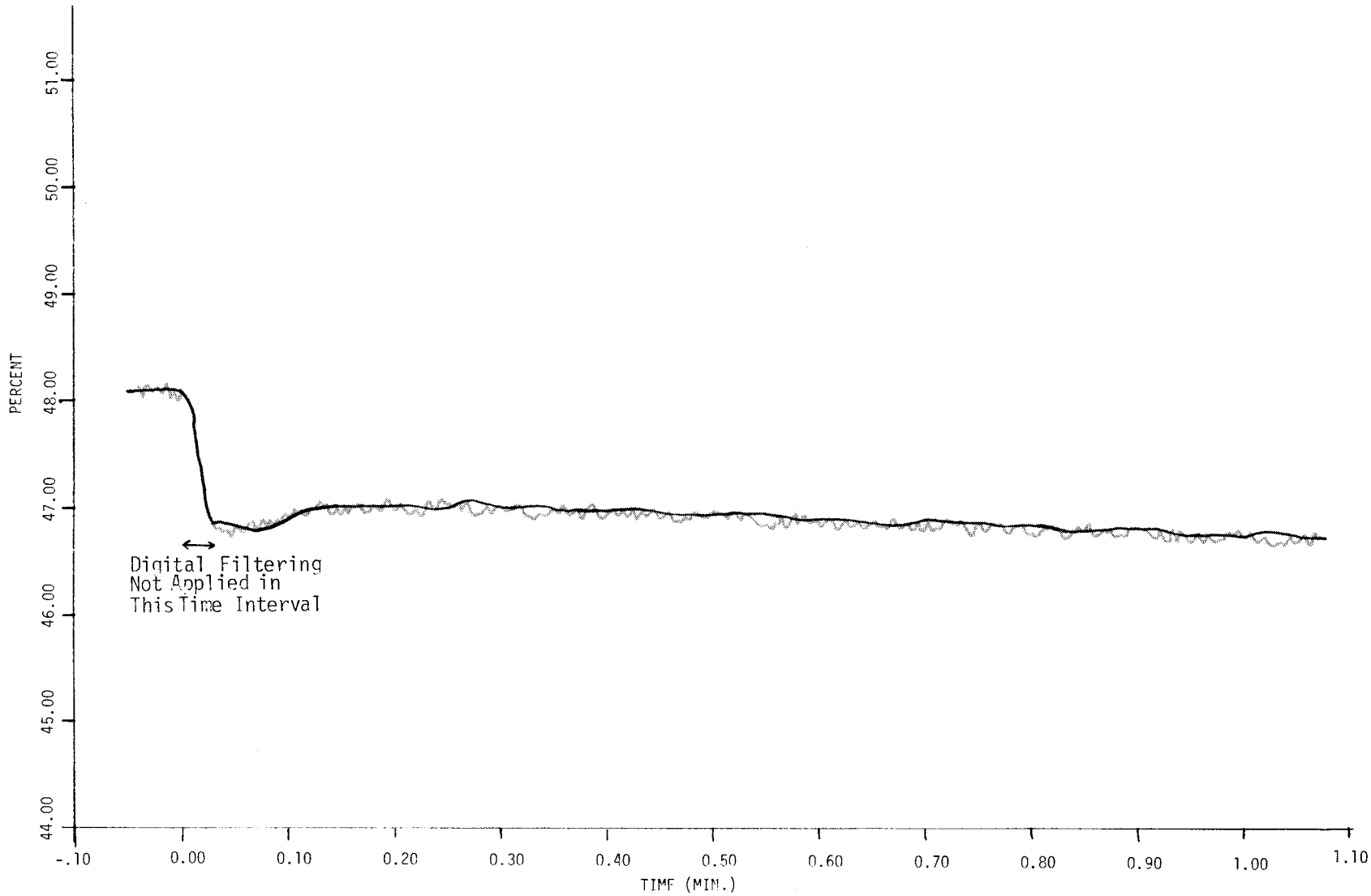


Figure 4-139. Part Length CEA Drop - Control Channel 1 Nuclear Power

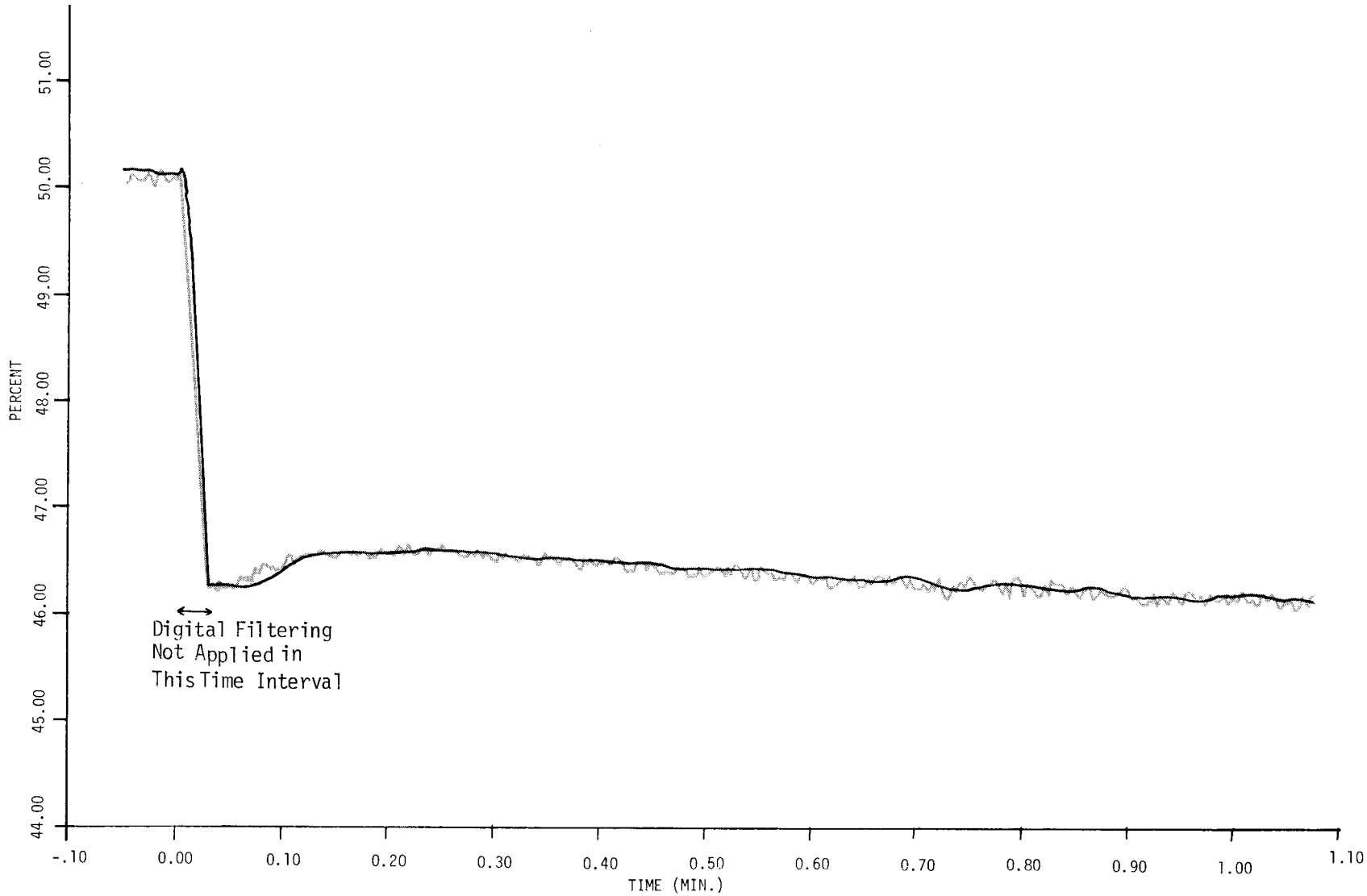


Figure 4-140. Part Length CEA Drop - Control Channel 2 Nuclear Power

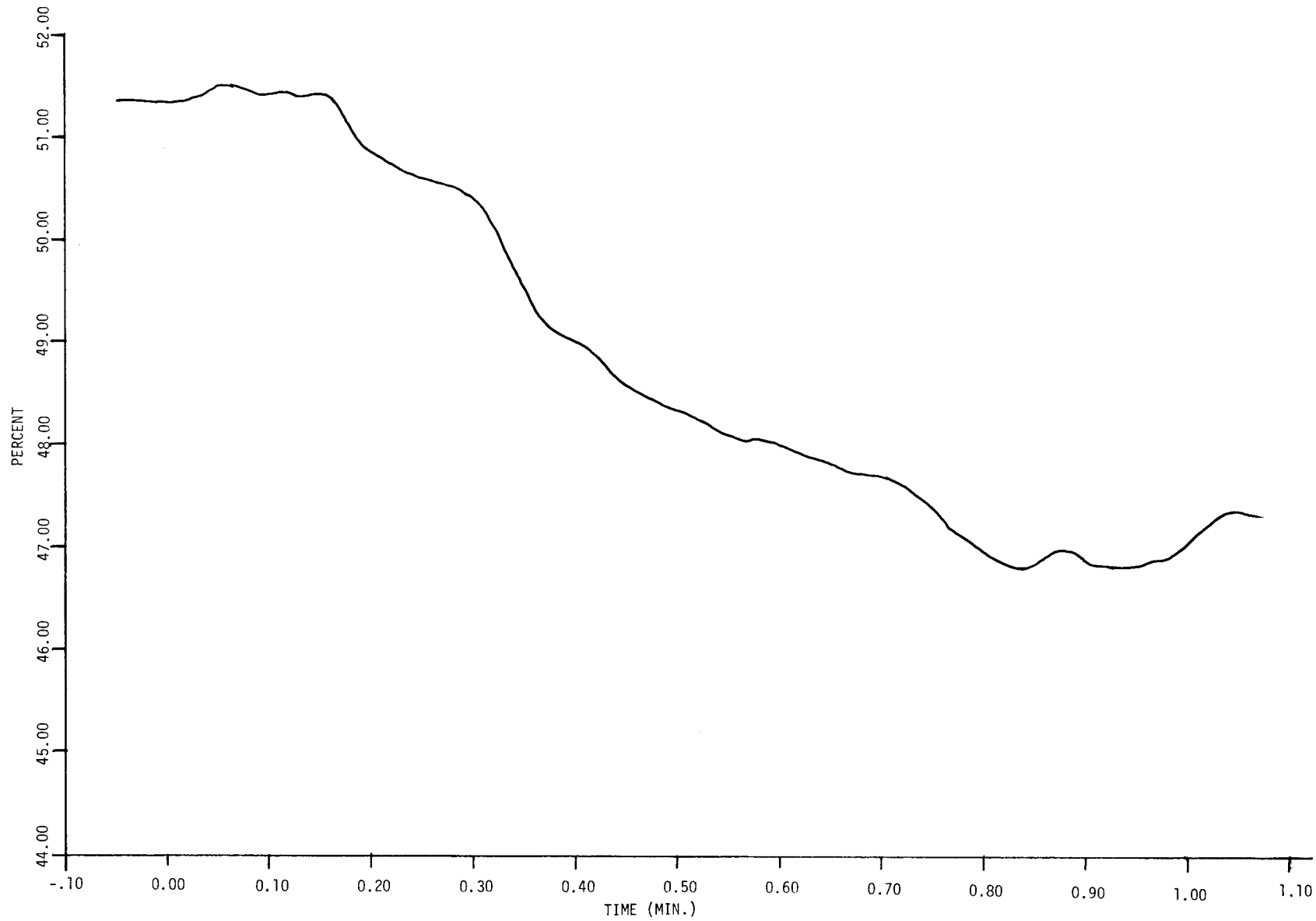


Figure 4-141. Part Length CEA Drop - Turbine Power

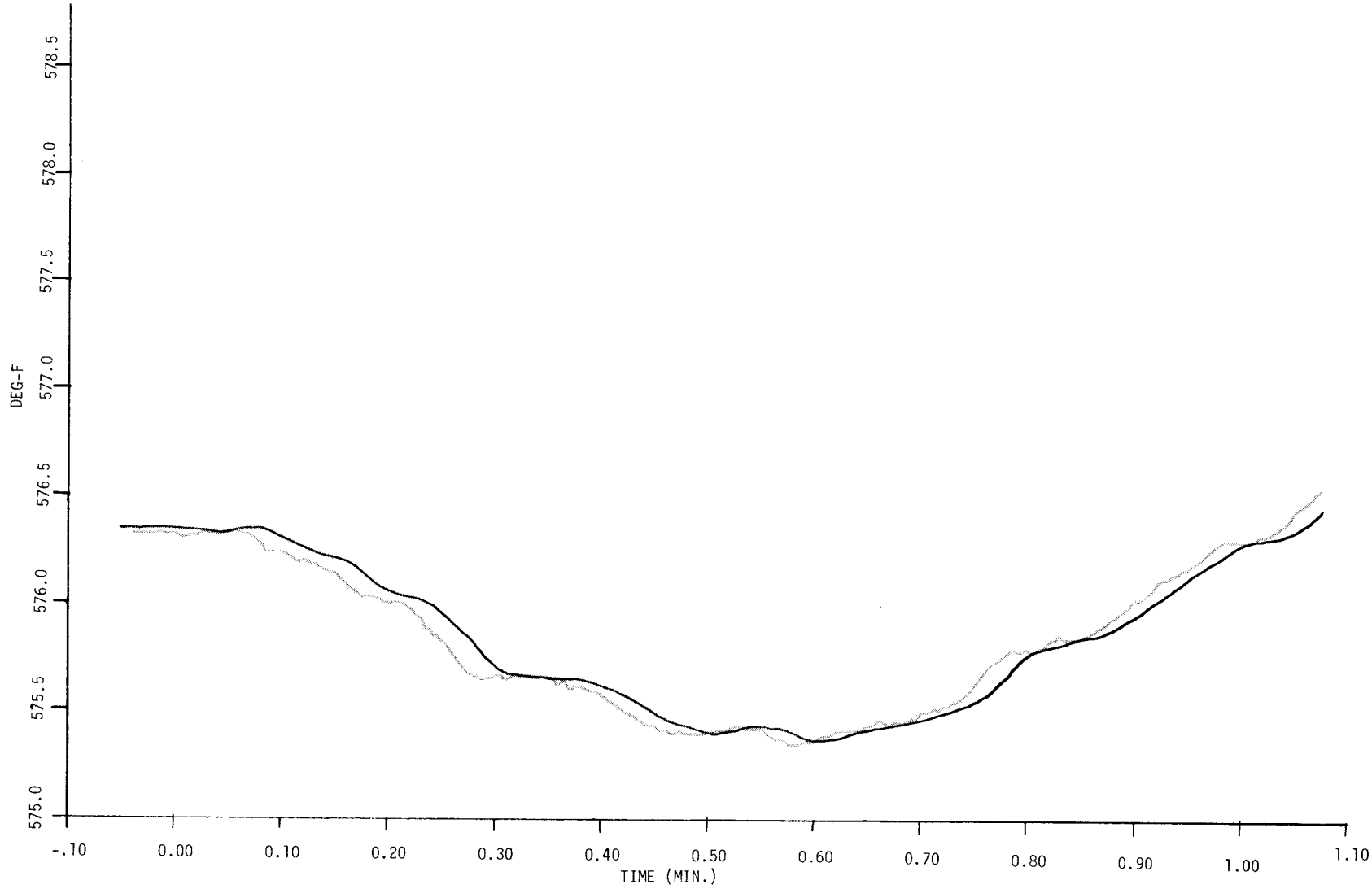


Figure 4-142. Part Length CEA Drop - Steam Generator 1 Hot Leg Temperature

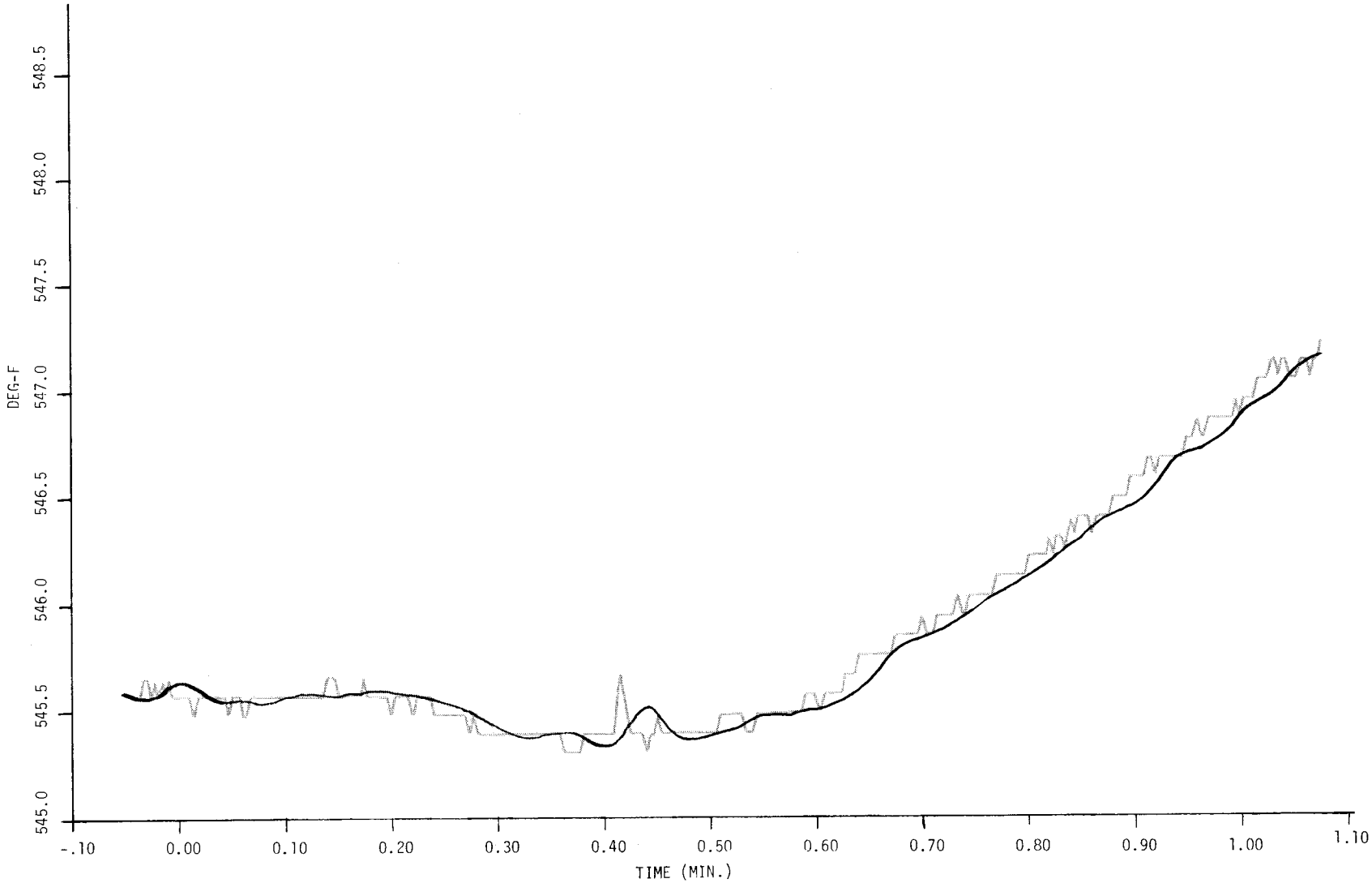


Figure 4-143. Part Length CEA Drop - Steam Generator 1 Cold Leg Temperature (Loop 1A)

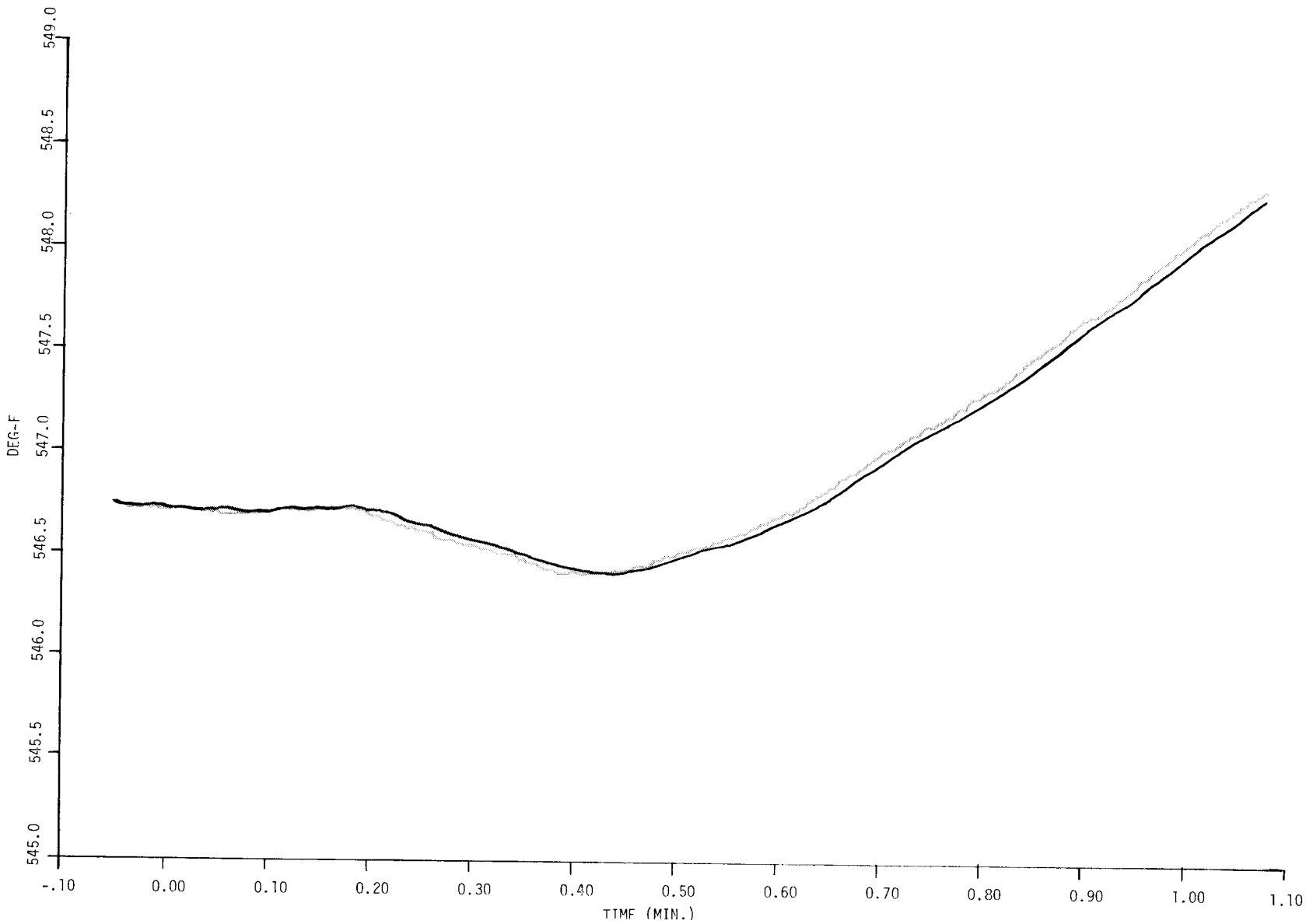


Figure 4-144. Part Length CEA Drop - Steam Generator 1 Cold Leg Temperature (Loop 1B)

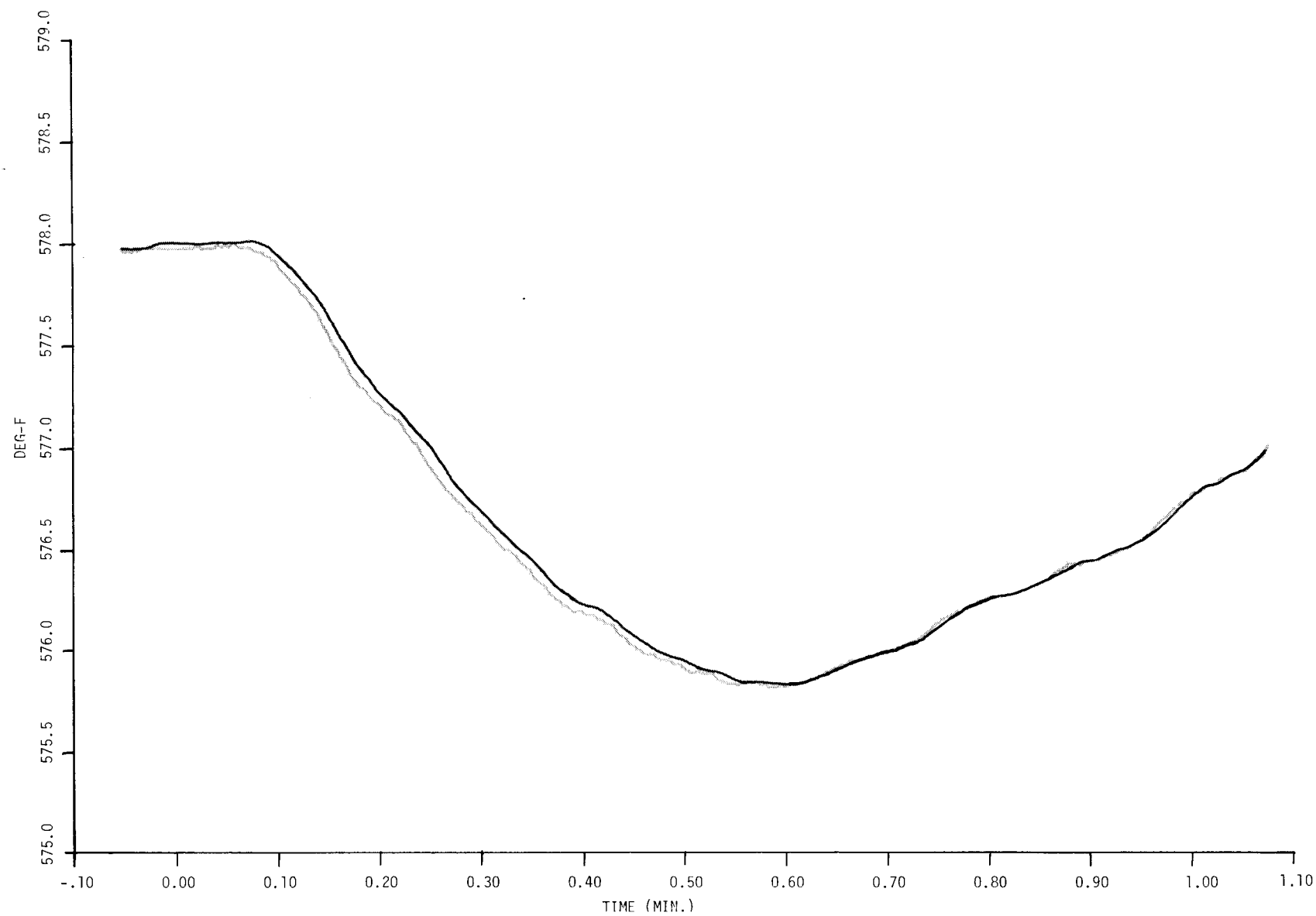


Figure 4-145. Part Length CEA Drop - Steam Generator 2 Hot Leg Temperature

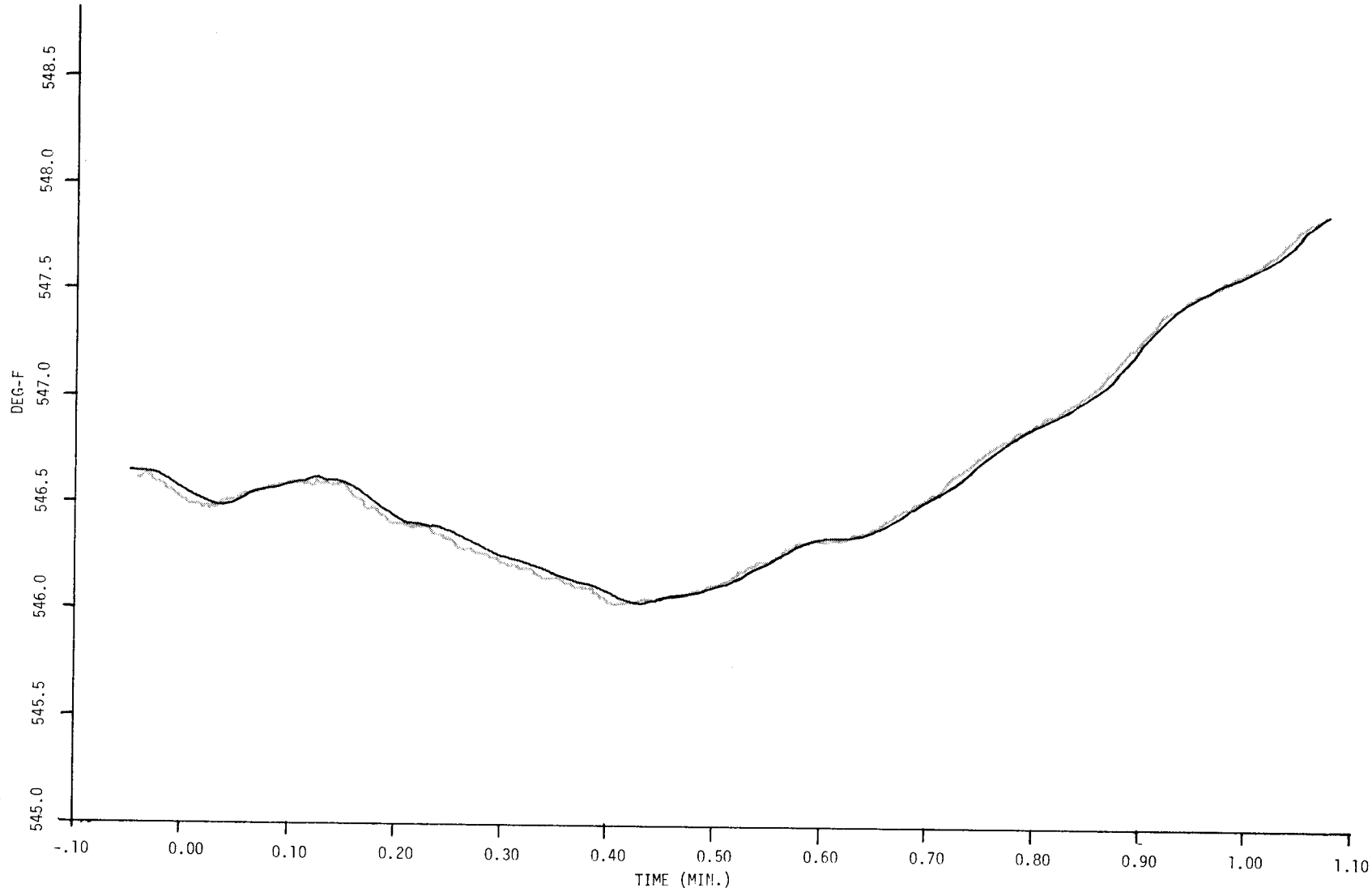


Figure 4-146. Part Length CEA Drop - Steam Generator 2 Cold Leg Temperature (Loop 2B)

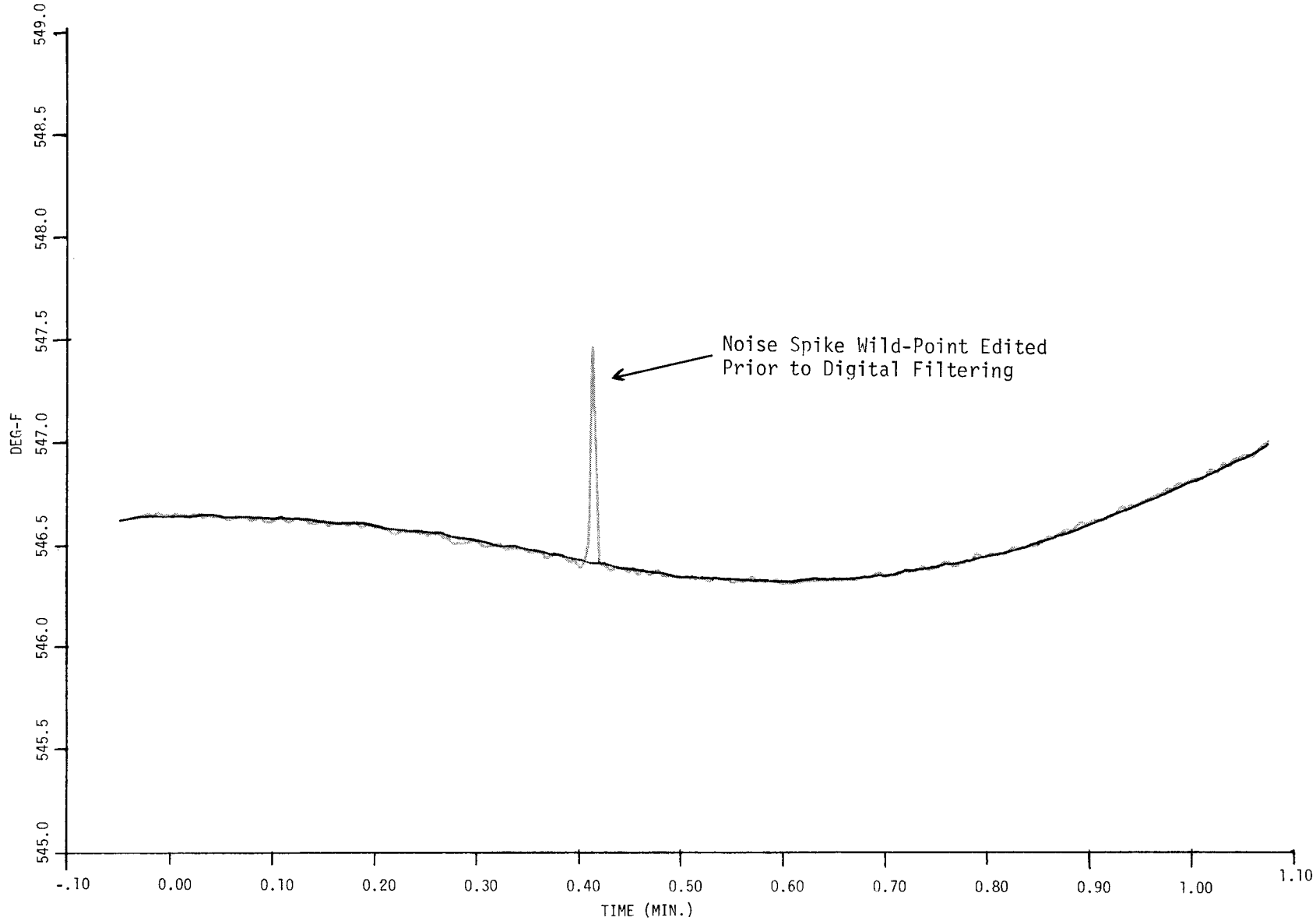


Figure 4-147. Part Length CEA Drop - Steam Generator 2 Cold Leg Temperature (Loop 2B)

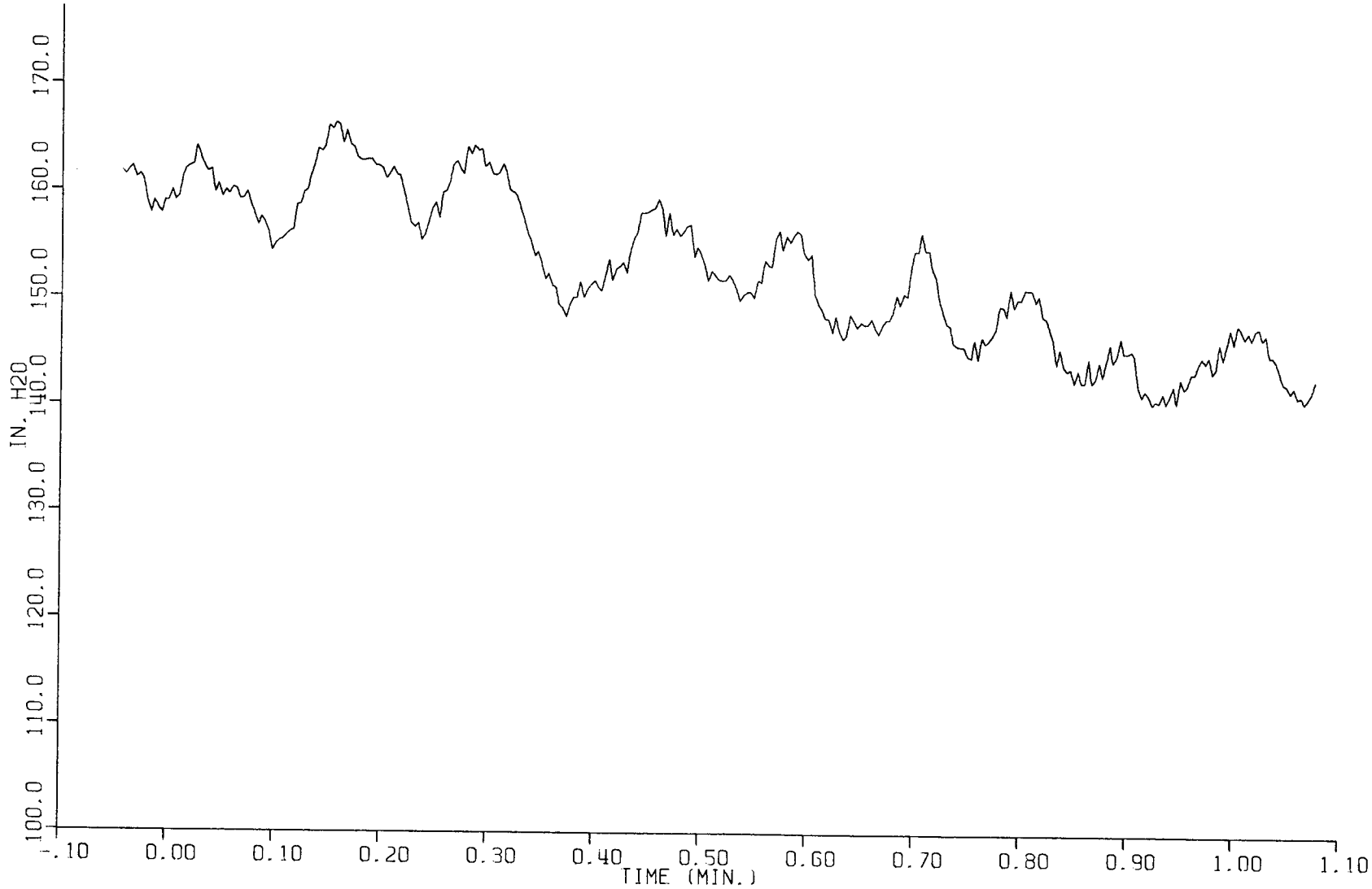


Figure 4-148. Part Length CEA Drop - Steam Generator 1 Feedwater Differential Pressure

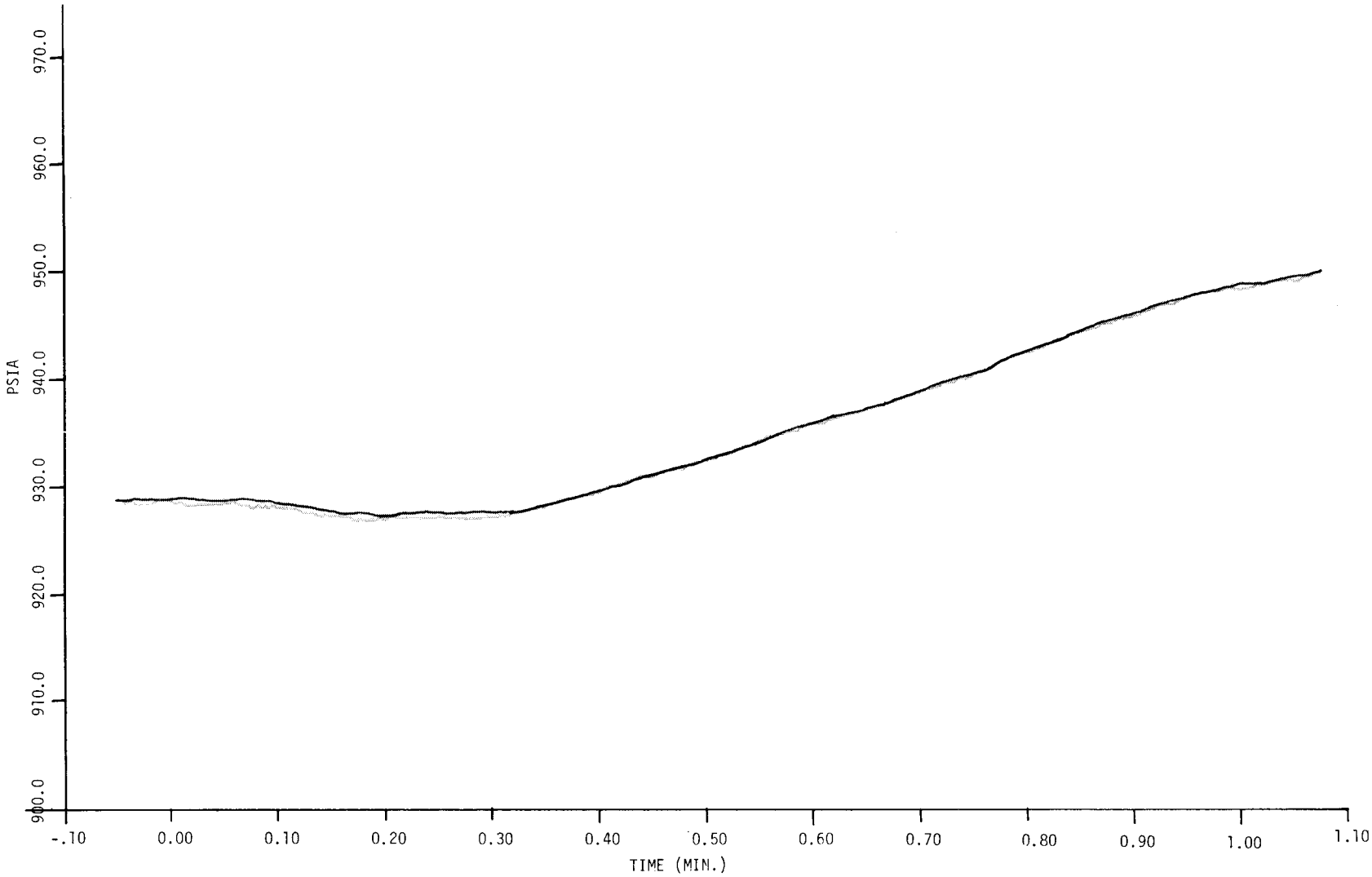


Figure 4-149. Part Length CEA Drop - Steam Generator 1 Pressure

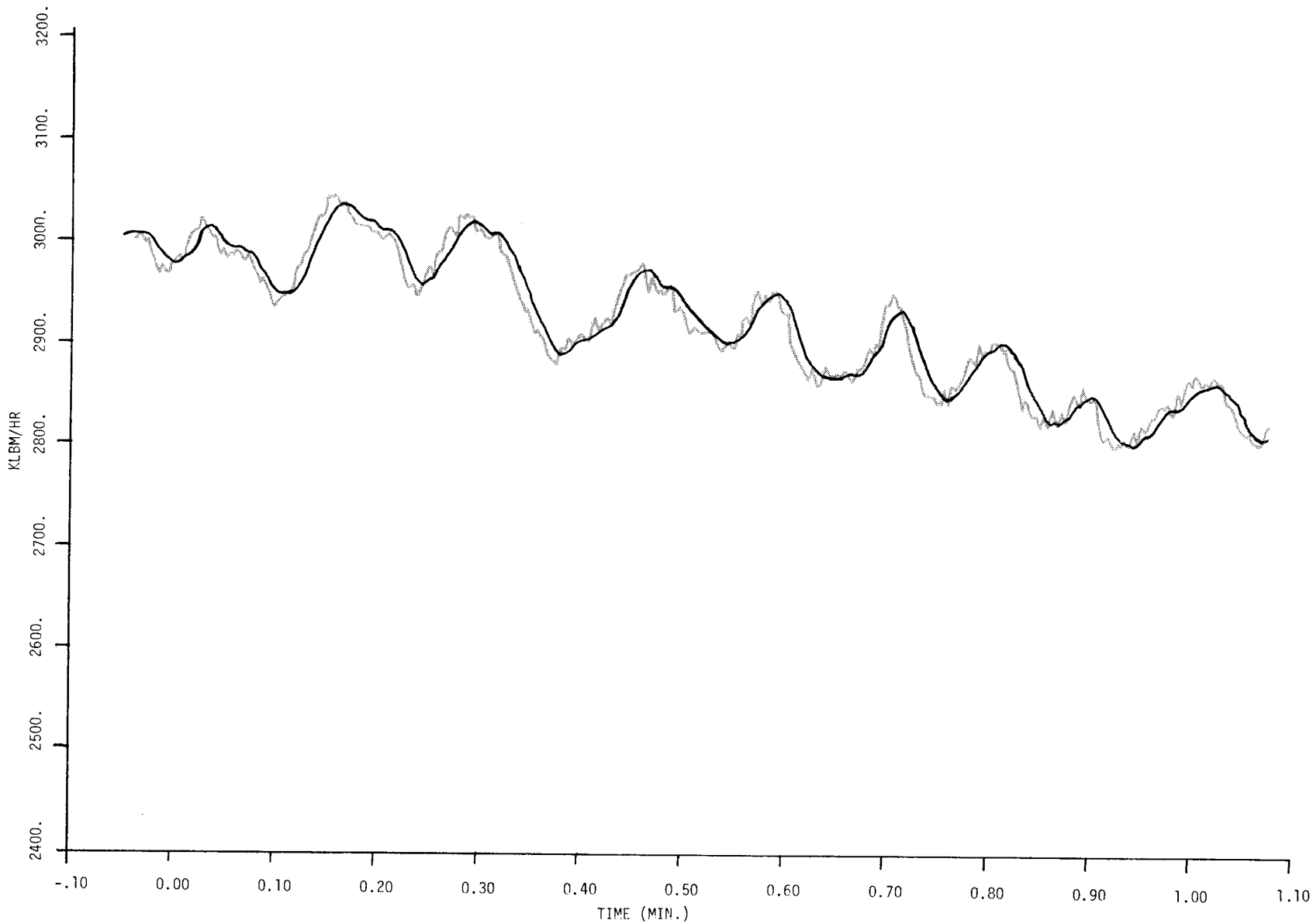


Figure 4-150. Part Length CEA Drop - Steam Generator 1 Feedwater Flow Rate

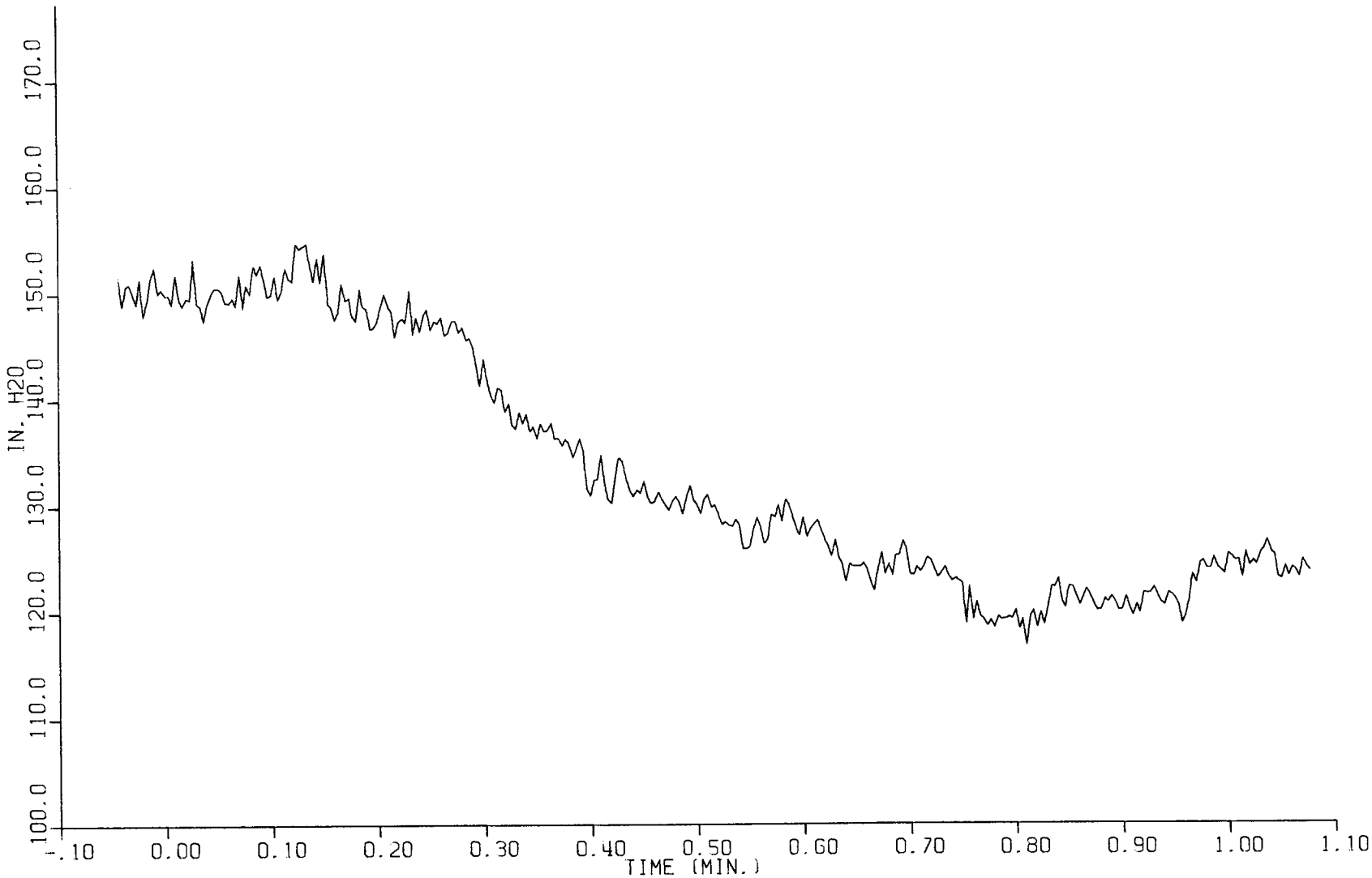


Figure 4-151. Part Length CEA Drop - Steam Generator 1 Header Differential Pressure

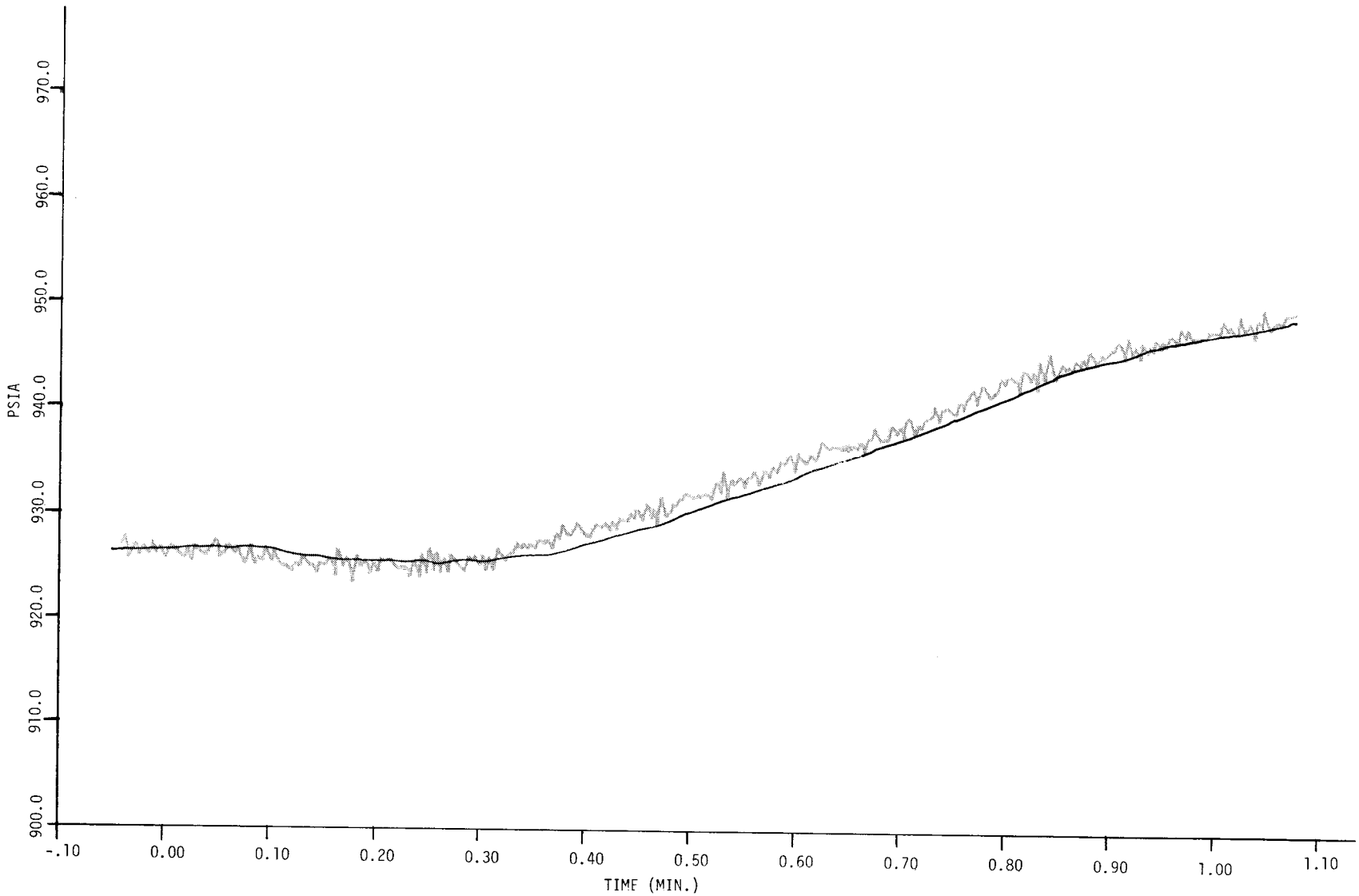


Figure 4-152. Part Length CEA Drop - Steam Generator 1 Header Pressure

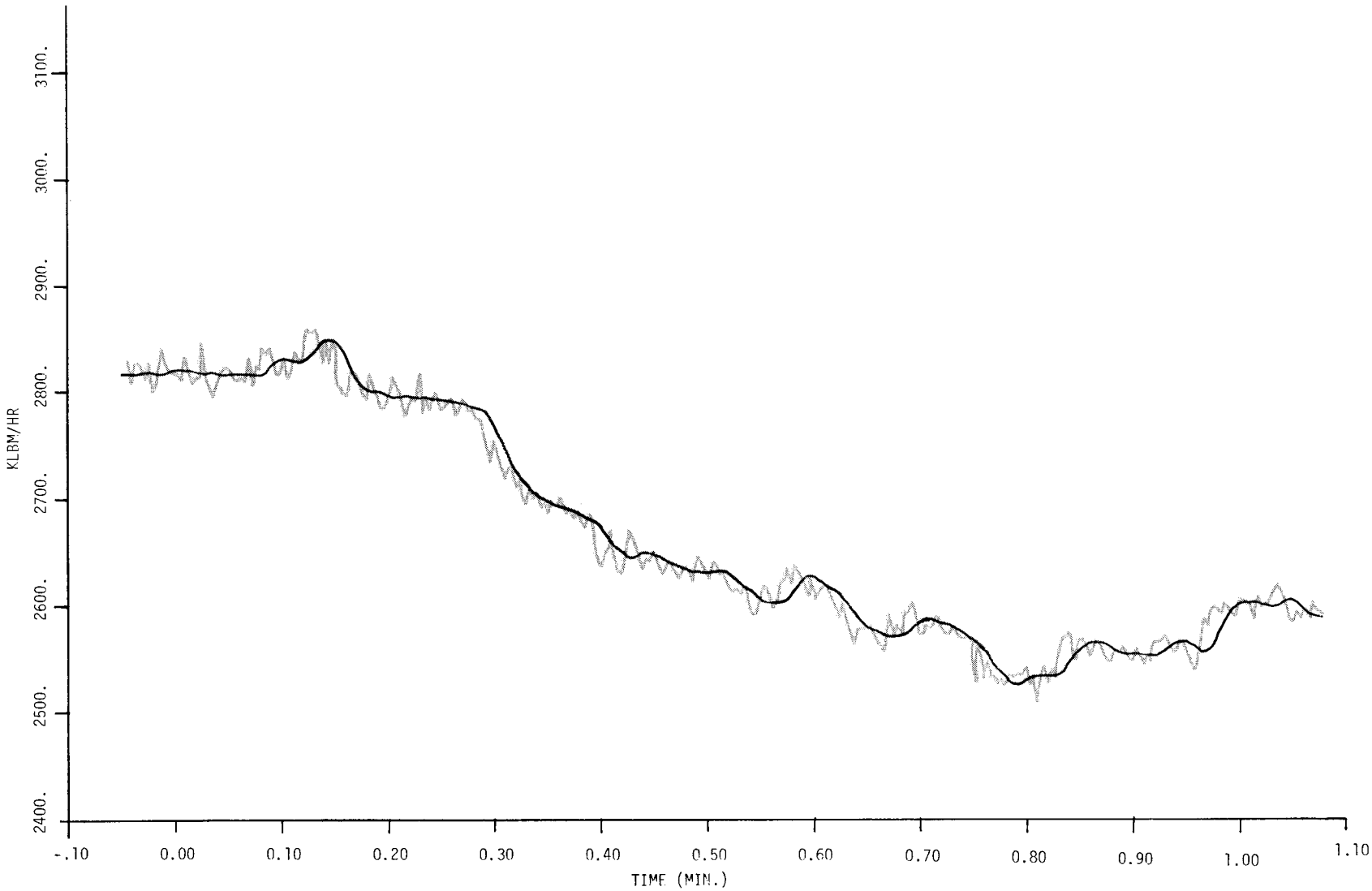


Figure 4-153. Part Length CEA Drop - Steam Generator 1 Main Steam Flow Rate

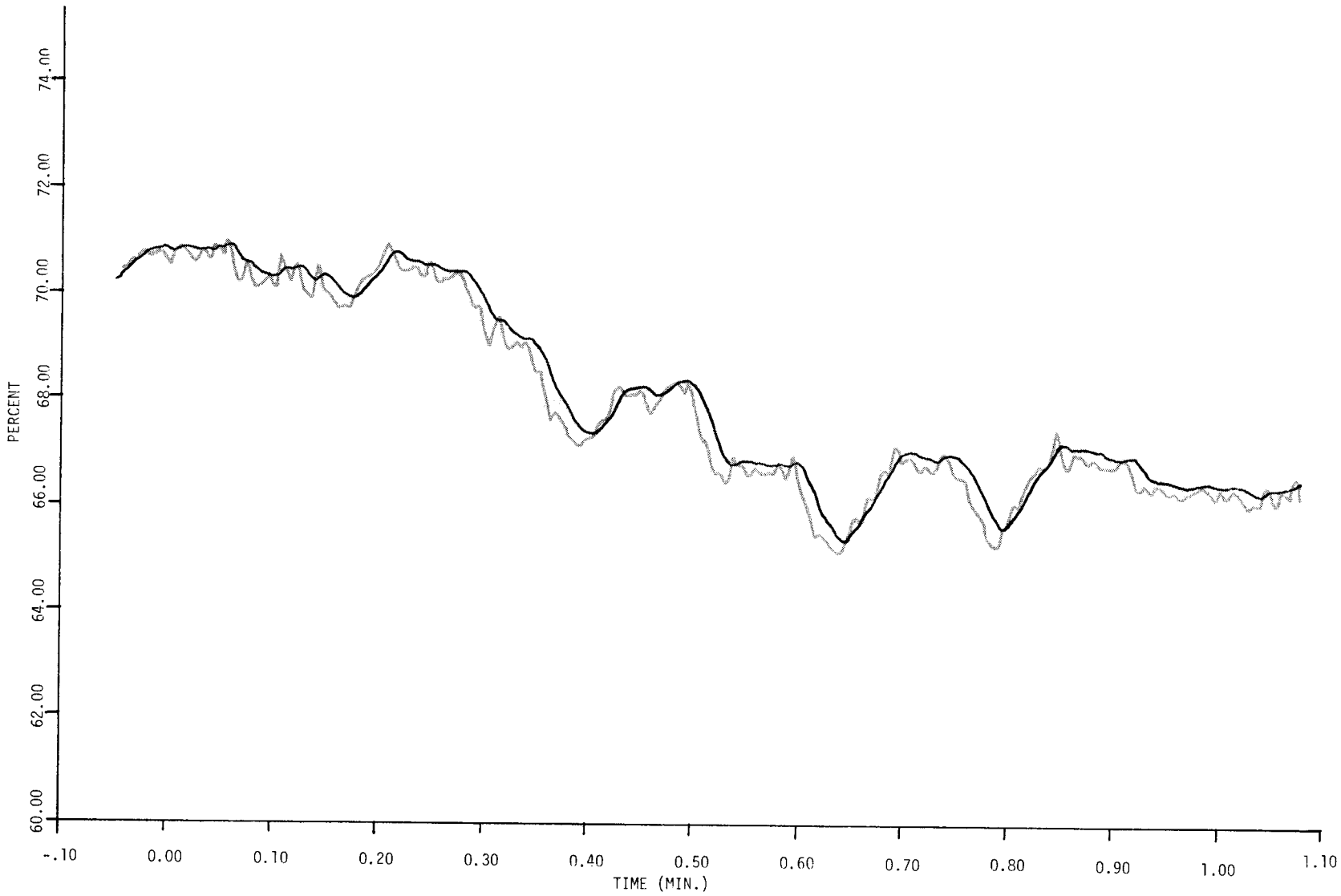


Figure 4-154. Part Length CEA Drop - Steam Generator 1 Level

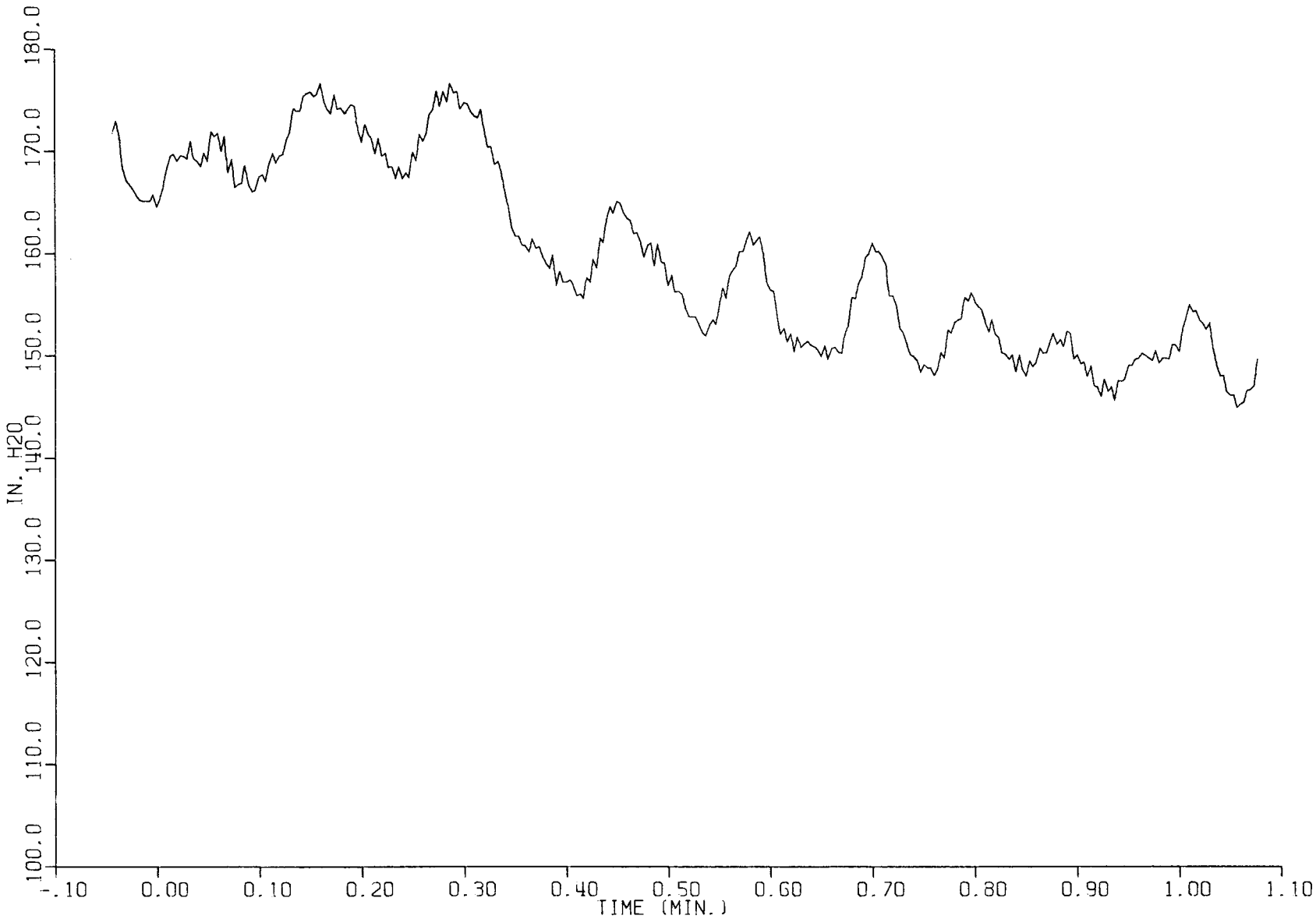


Figure 4-155. Part Length CEA Drop - Steam Generator 2 Feedwater Differential Pressure

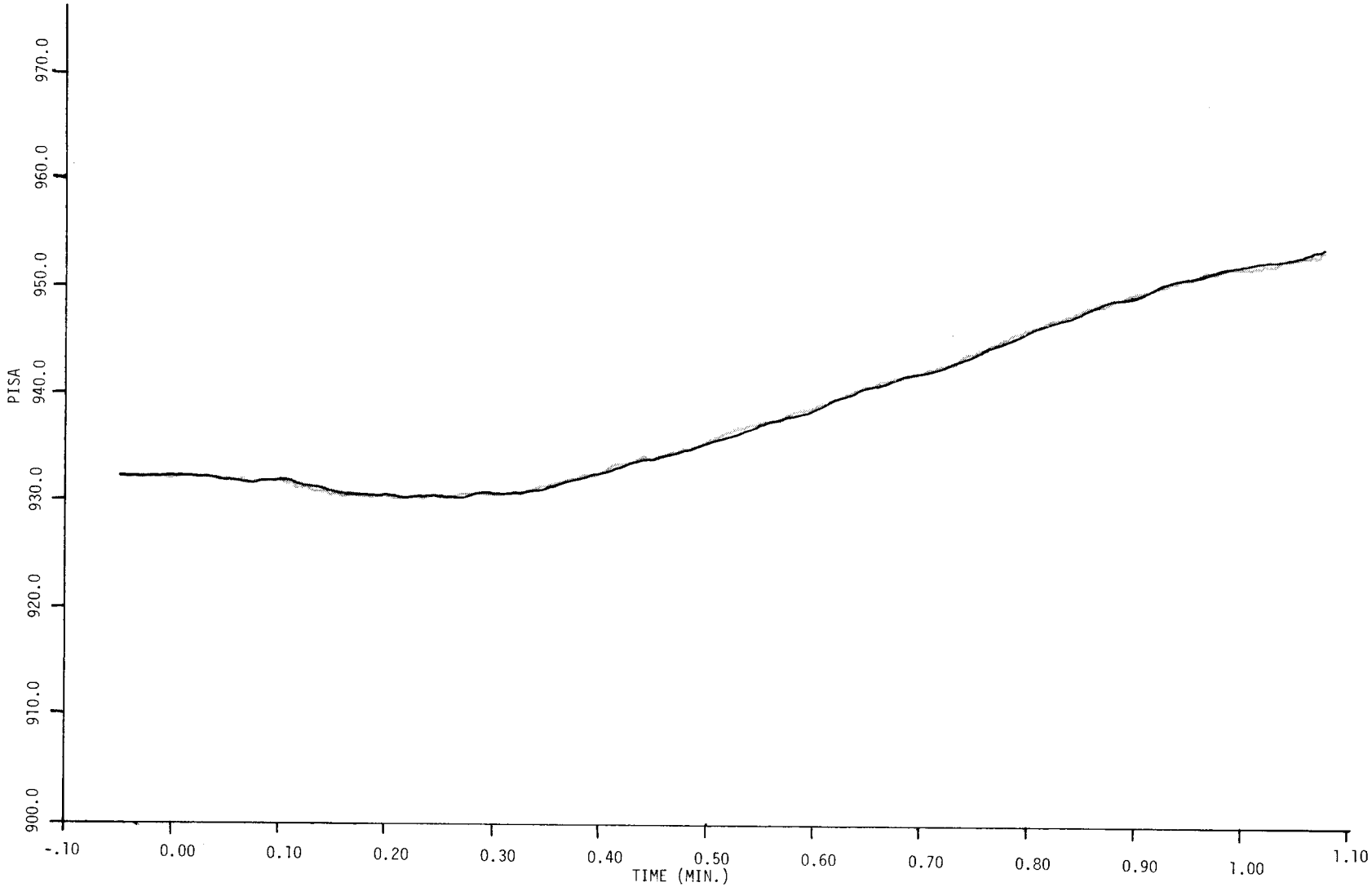


Figure 4-156. Part Length CEA Drop - Steam Generator 2 Pressure

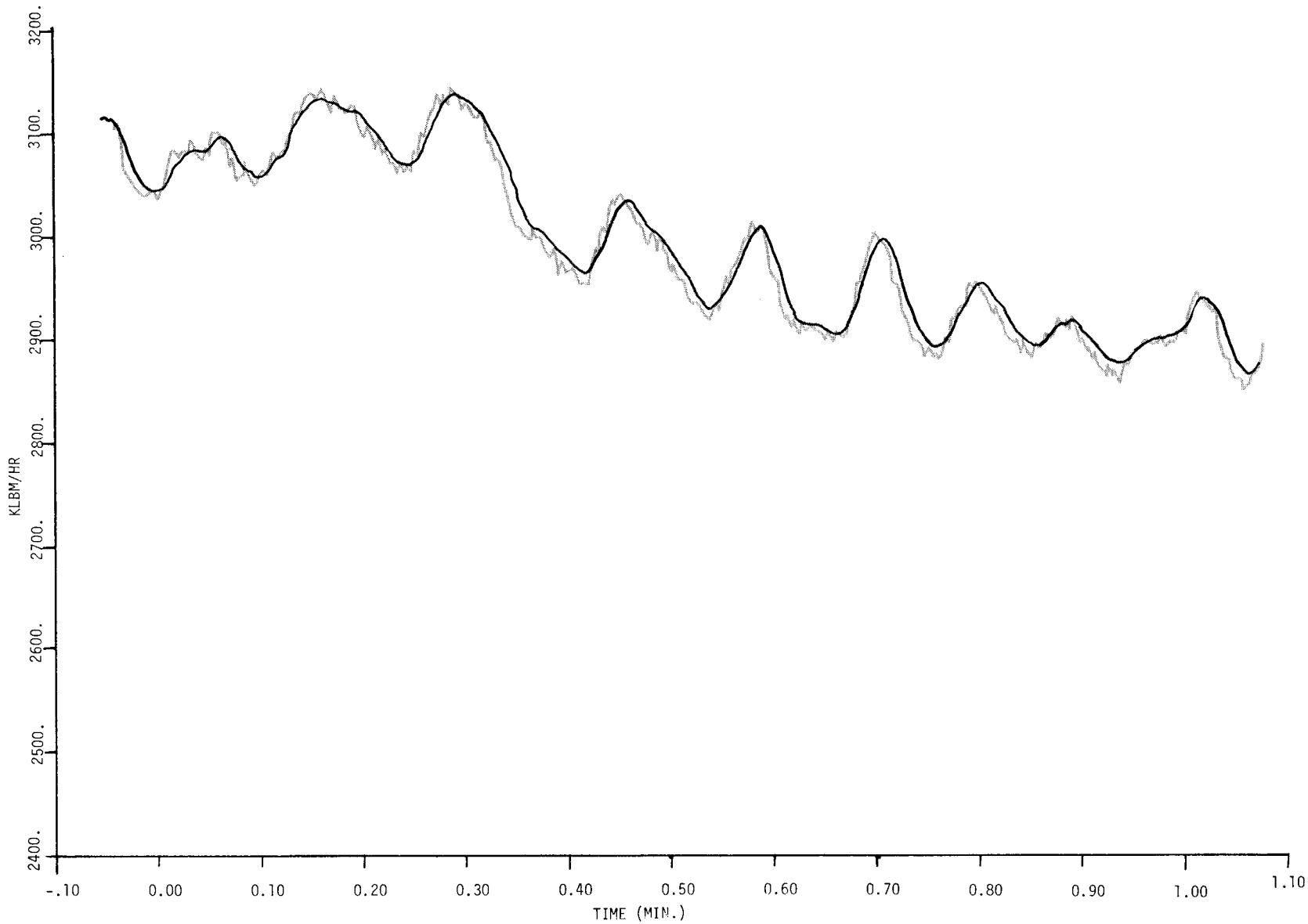


Figure 4-157. Part Length CEA Drop - Steam Generator 2 Feedwater Flow Rate

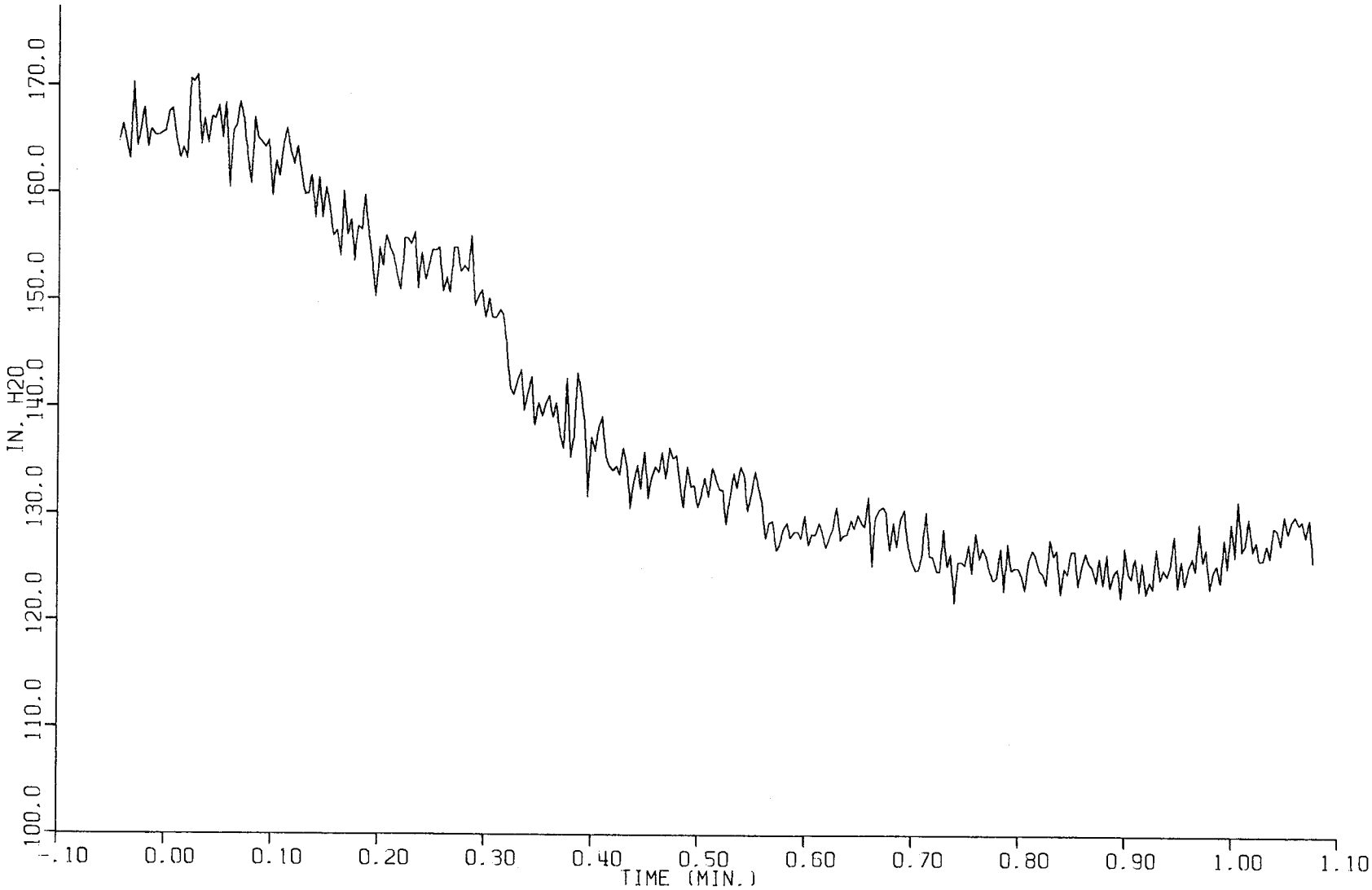


Figure 4-158. Part Length CEA Drop - Steam Generator 2 Header Differential Pressure

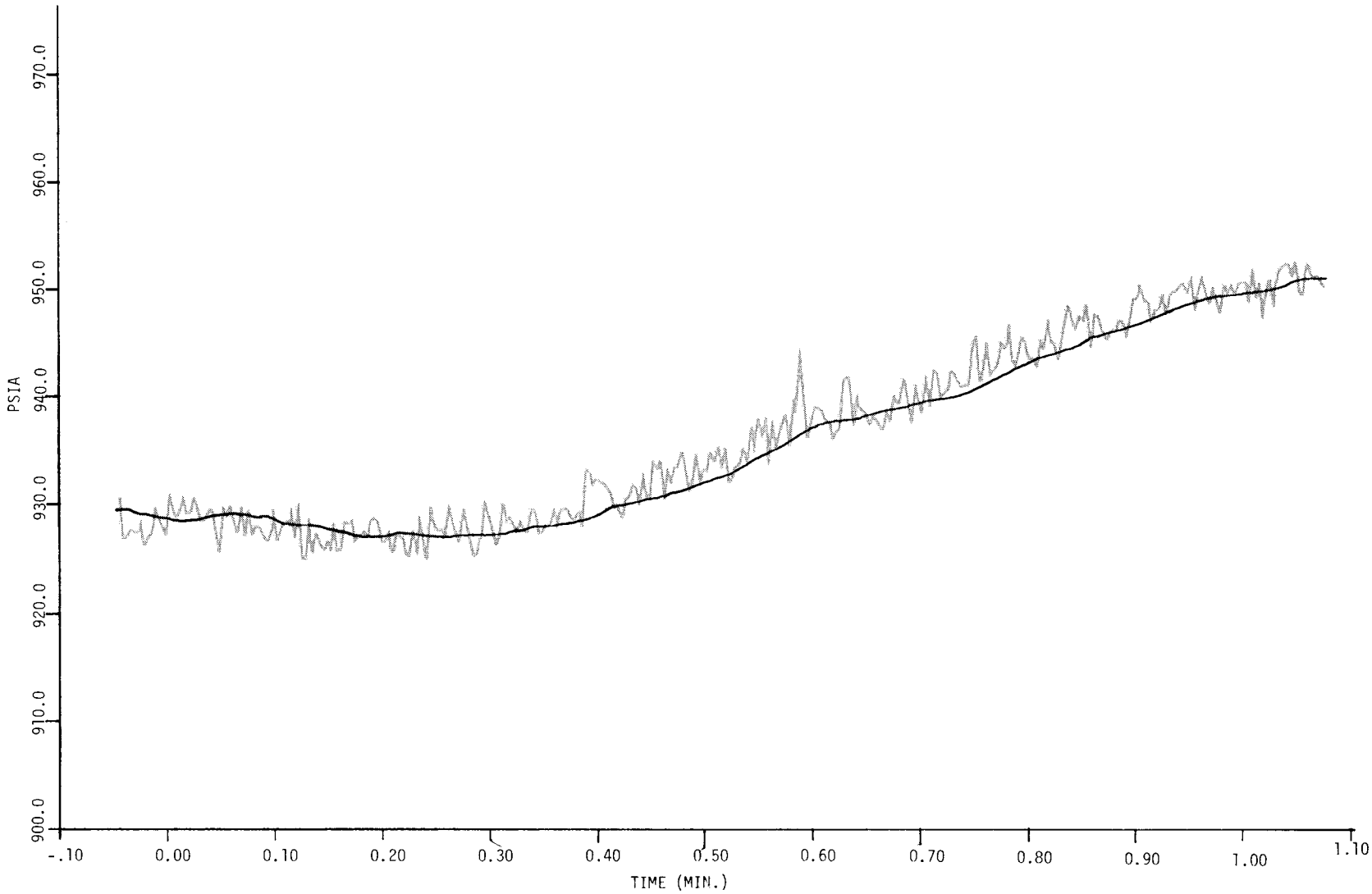


Figure 4-159. Part Length CEA Drop - Steam Generator 2 Header Pressure

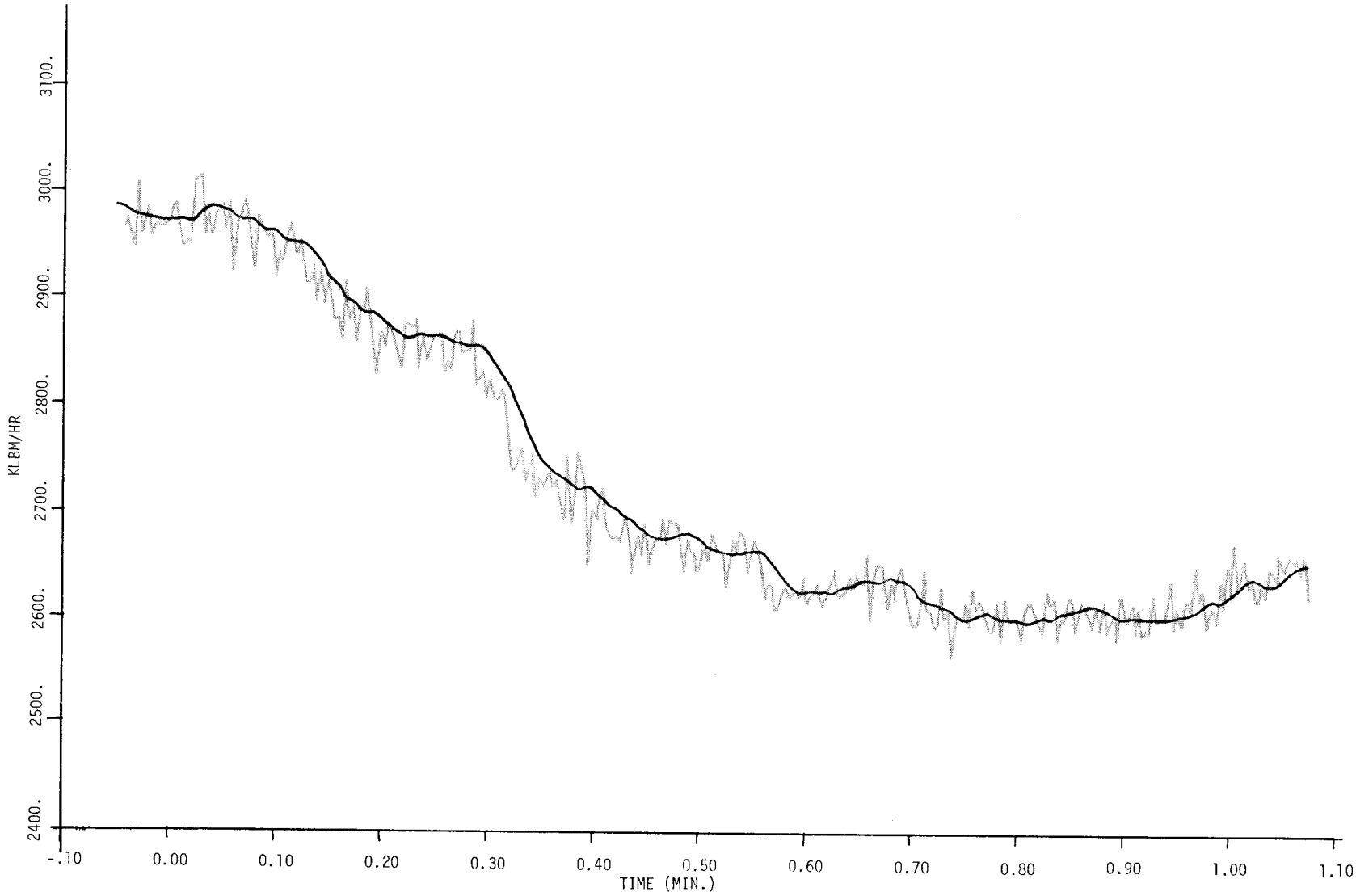


Figure 4-160. Part Length CEA Drop - Steam Generator 2 Main Steam Flow Rate

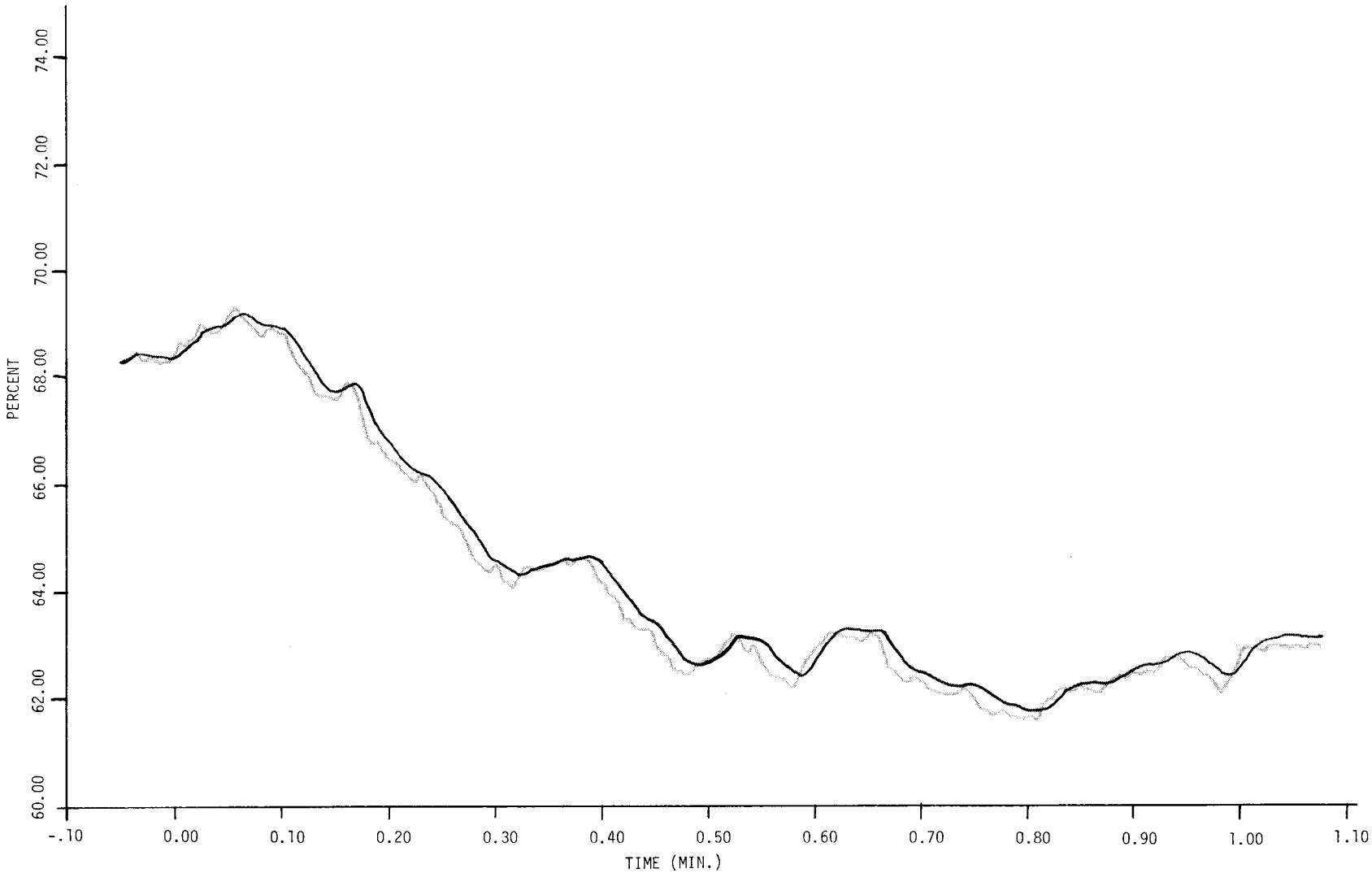


Figure 4-161. Part Length CEA Drop - Steam Generator 2 Level

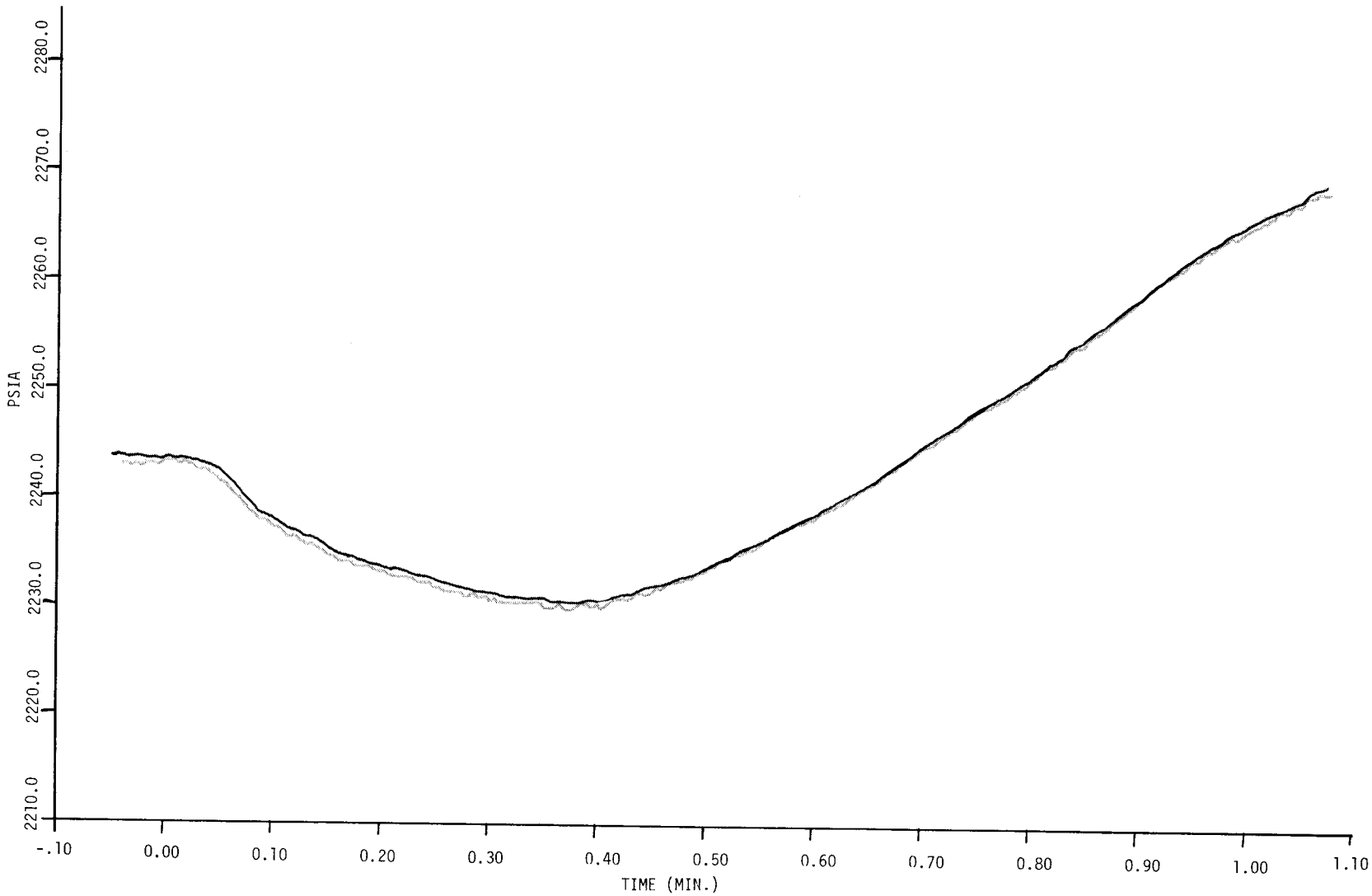


Figure 4-162. Part Length CEA Drop - Pressurizer Pressure (Wide Range)

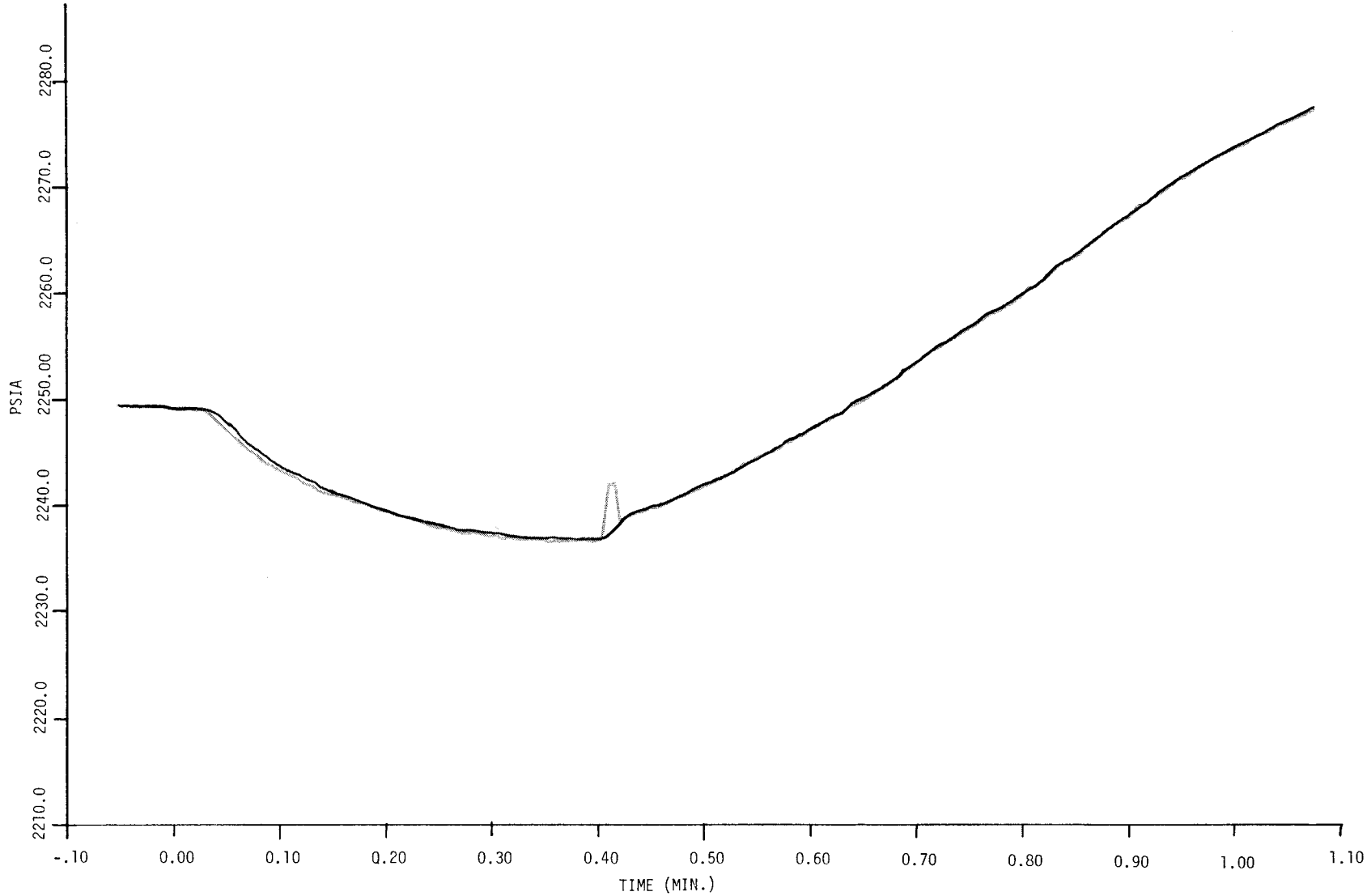


Figure 4-163. Part Length CEA Drop - Pressurizer Pressure (Narrow Range)

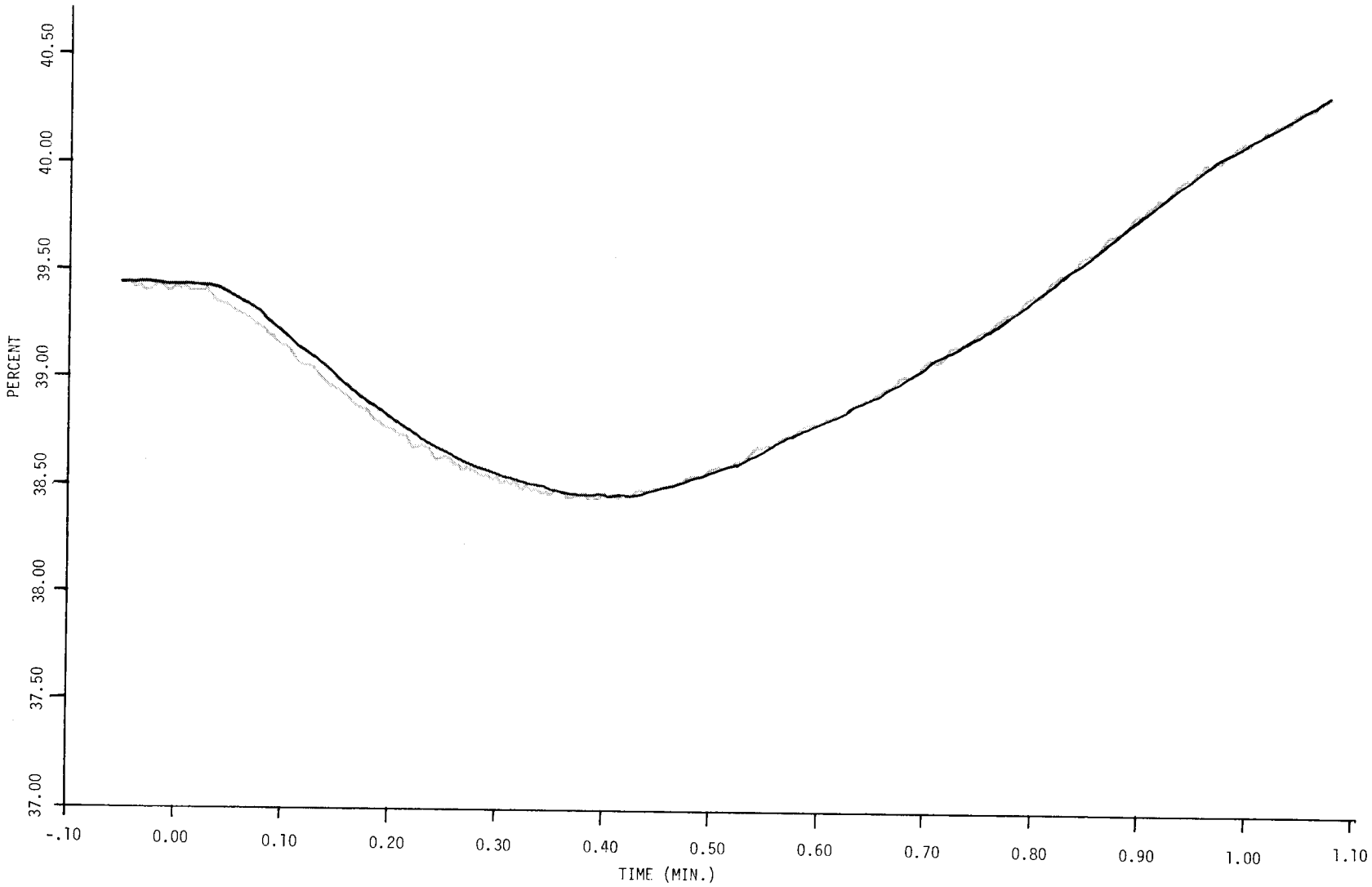


Figure 4-164. Part Length CEA Drop - Pressurizer Level

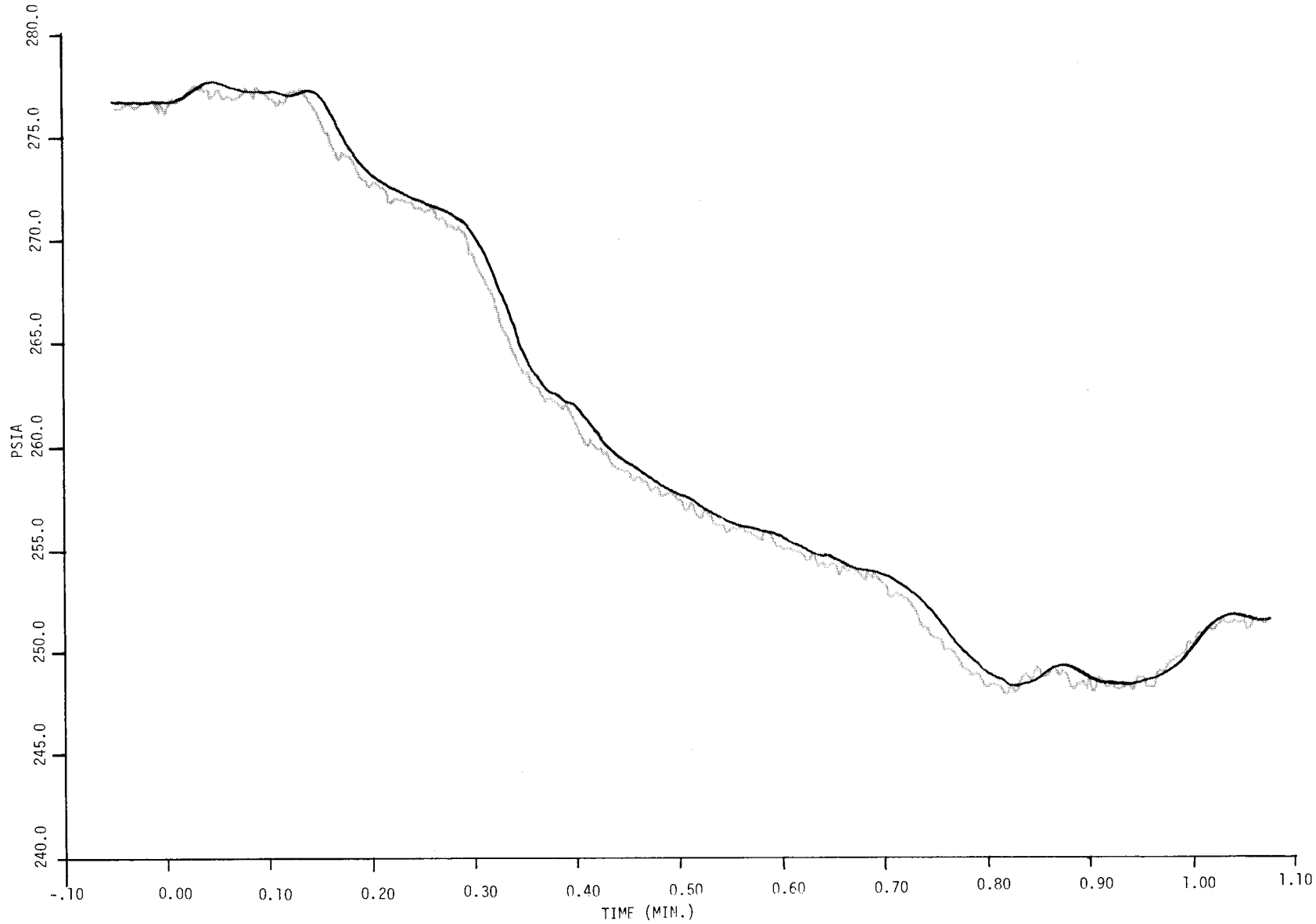


Figure 4-165. Part Length CEA Drop - Turbine First Stage Pressure

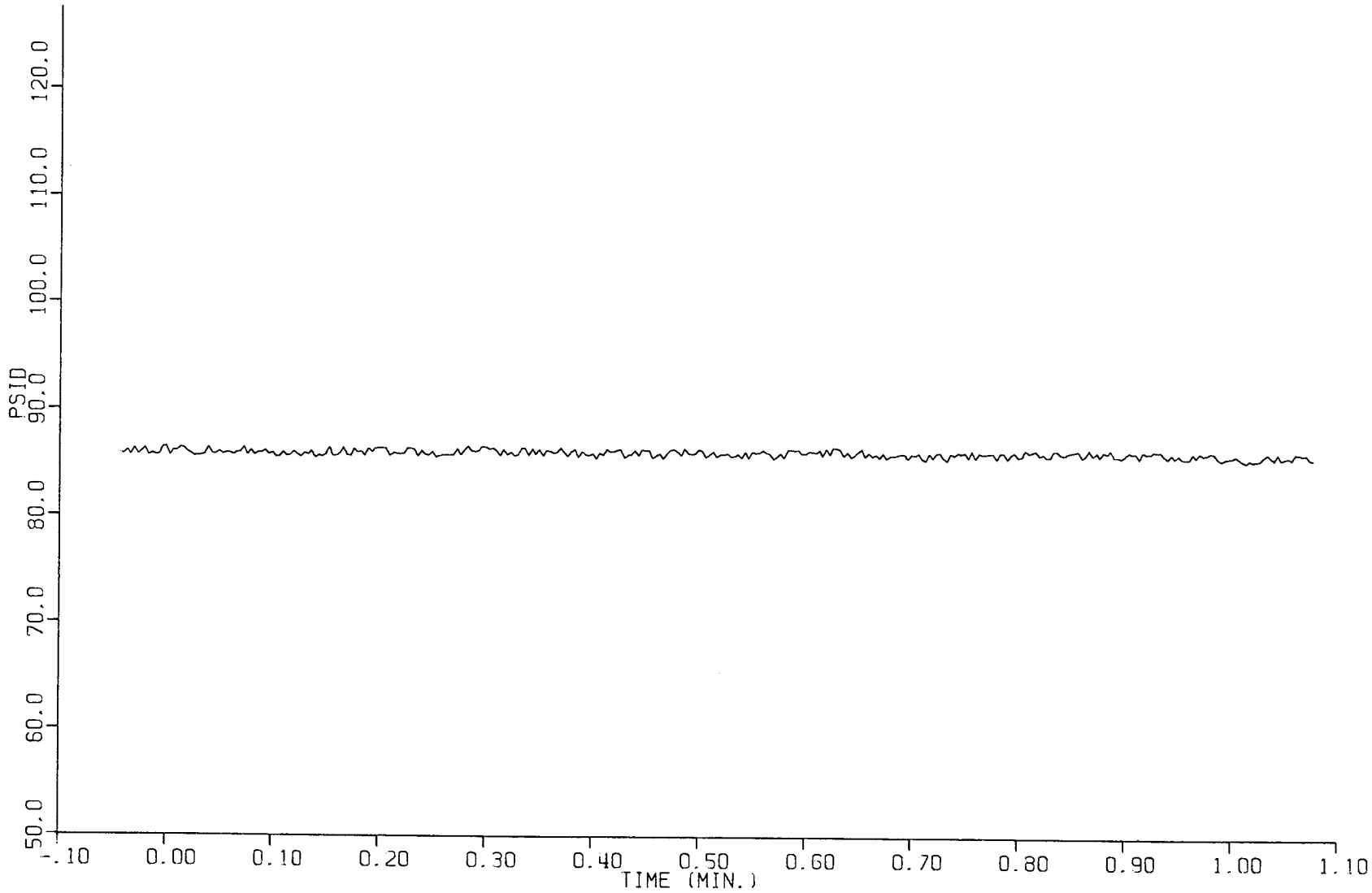


Figure 4-166. Part Length CEA Drop - Reactor Coolant Pump 1A Differential Pressure

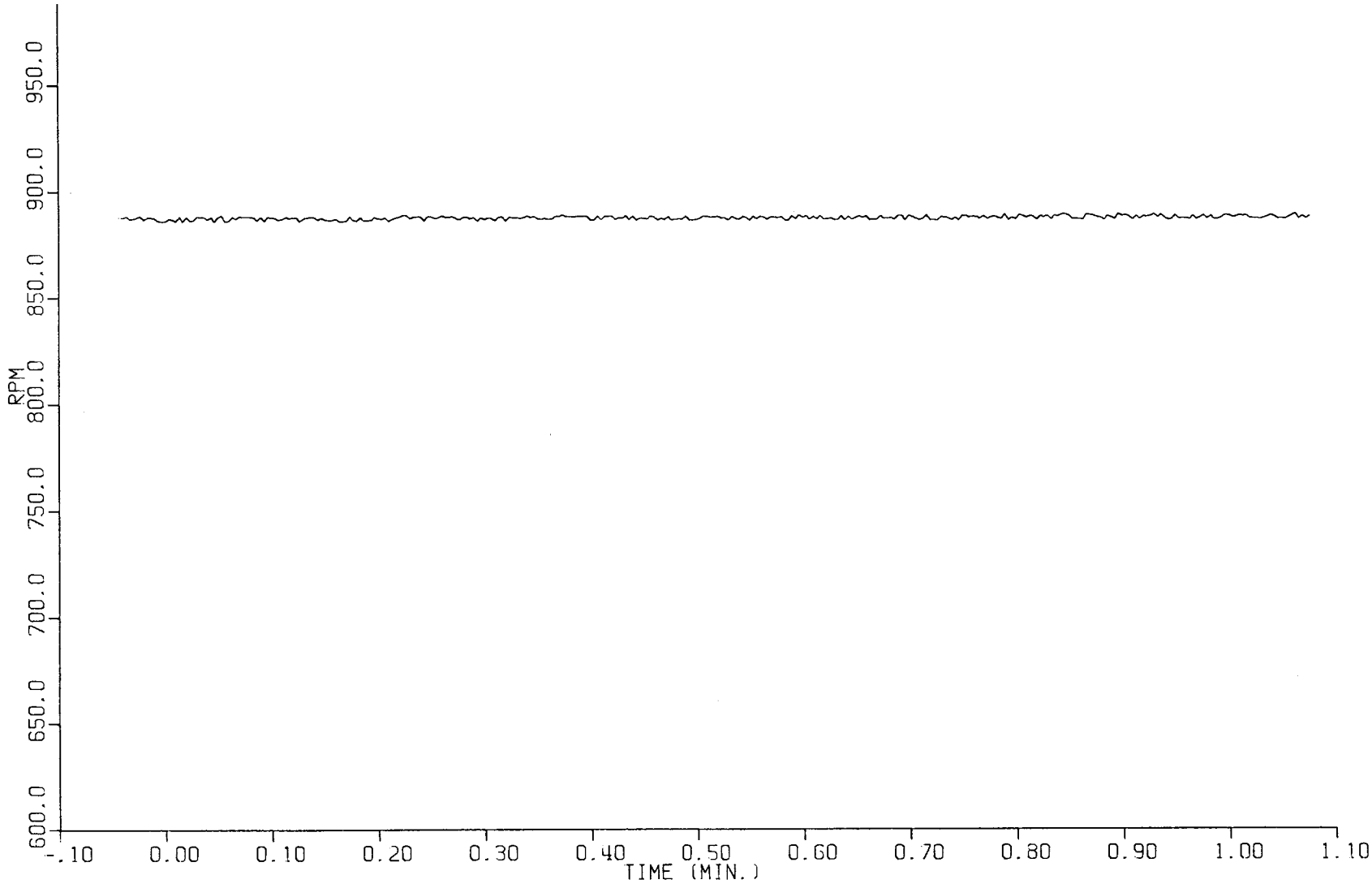


Figure 4-167. Part Length CEA Drop - Reactor Coolant Pump 1A Speed

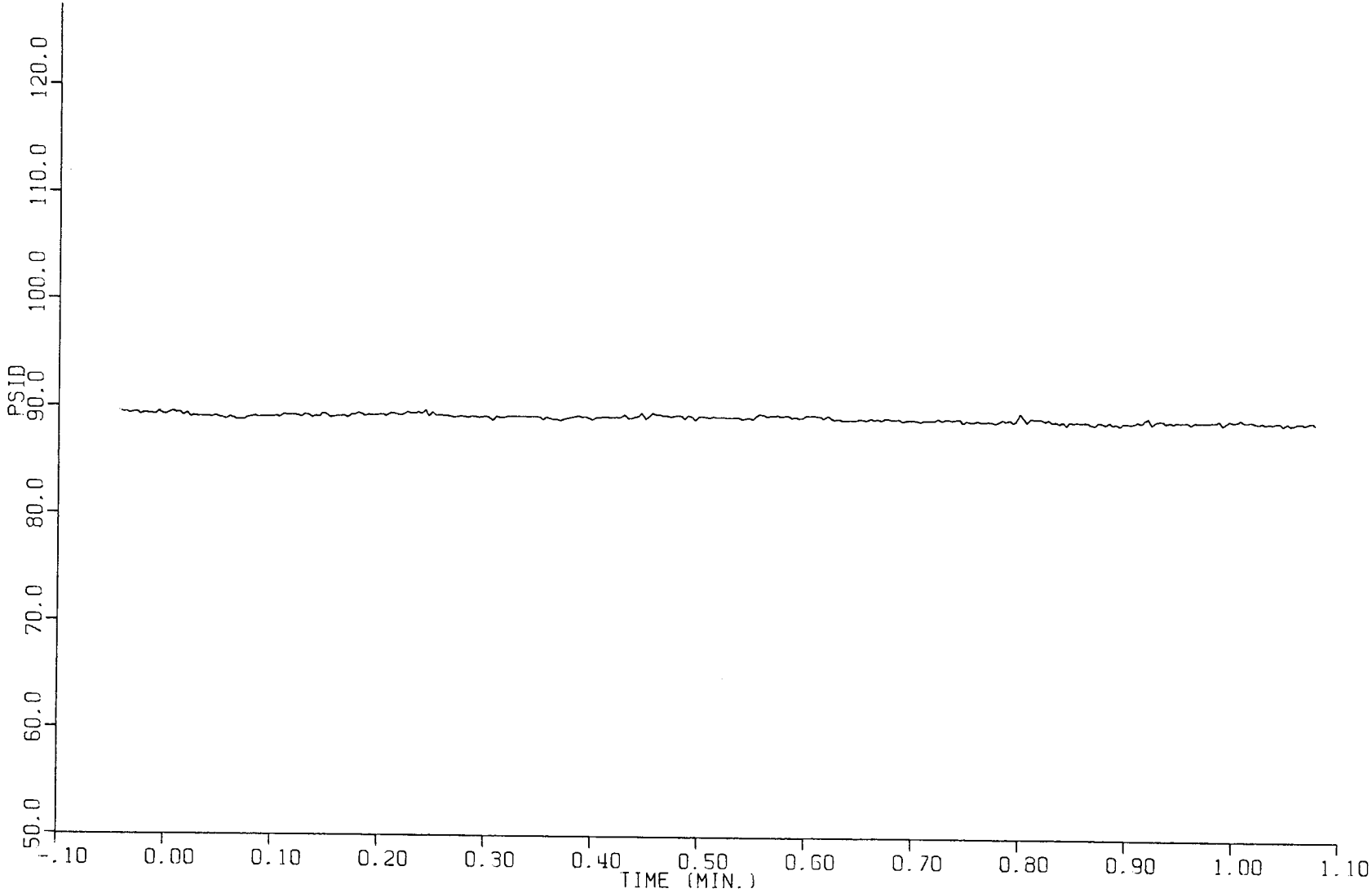


Figure 4-168. Part Length CEA - Reactor Coolant Pump 1B Differential Pressure

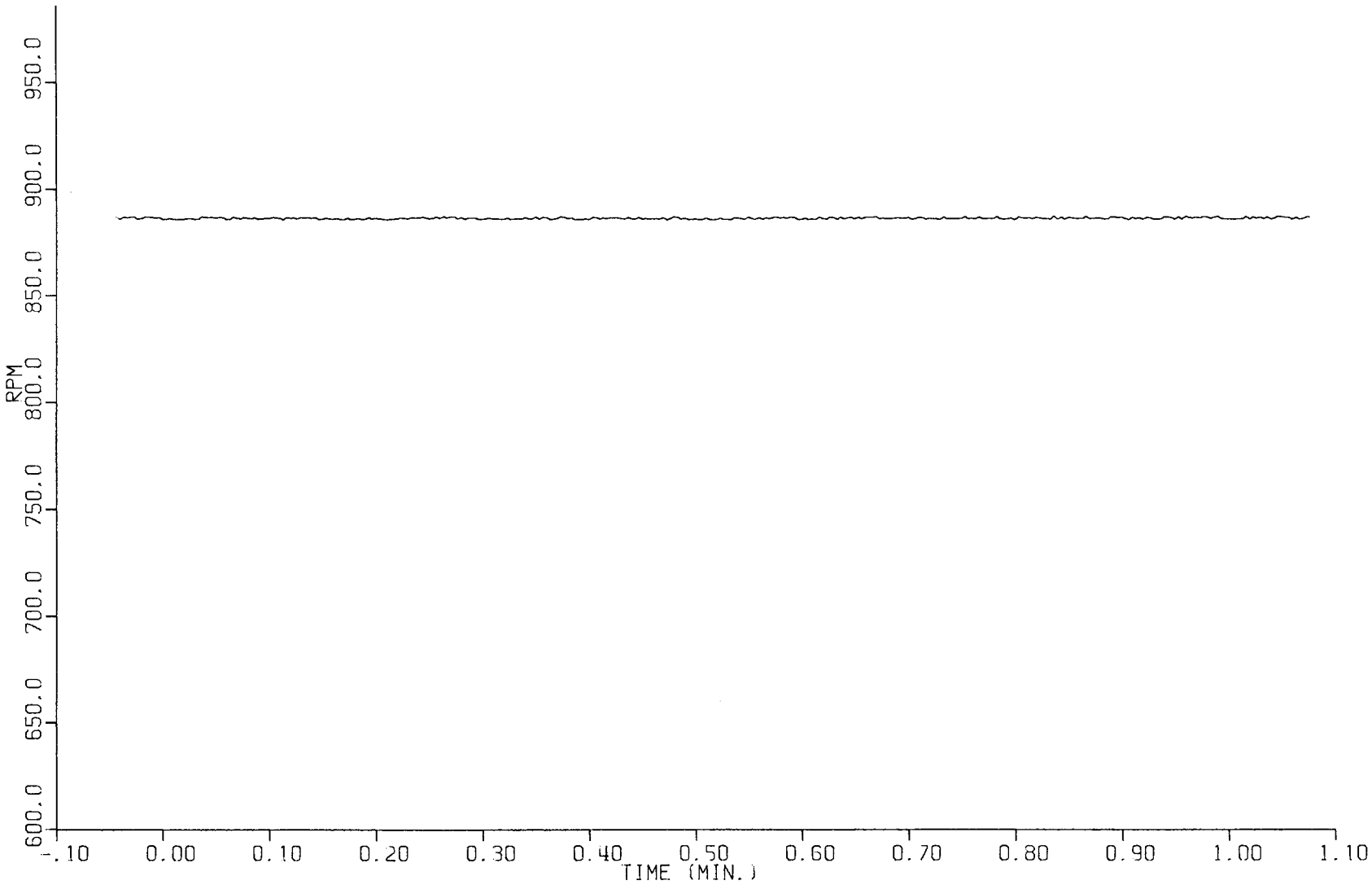


Figure 4-169. Part Length CEA Drop - Reactor Coolant Pump 1B Speed

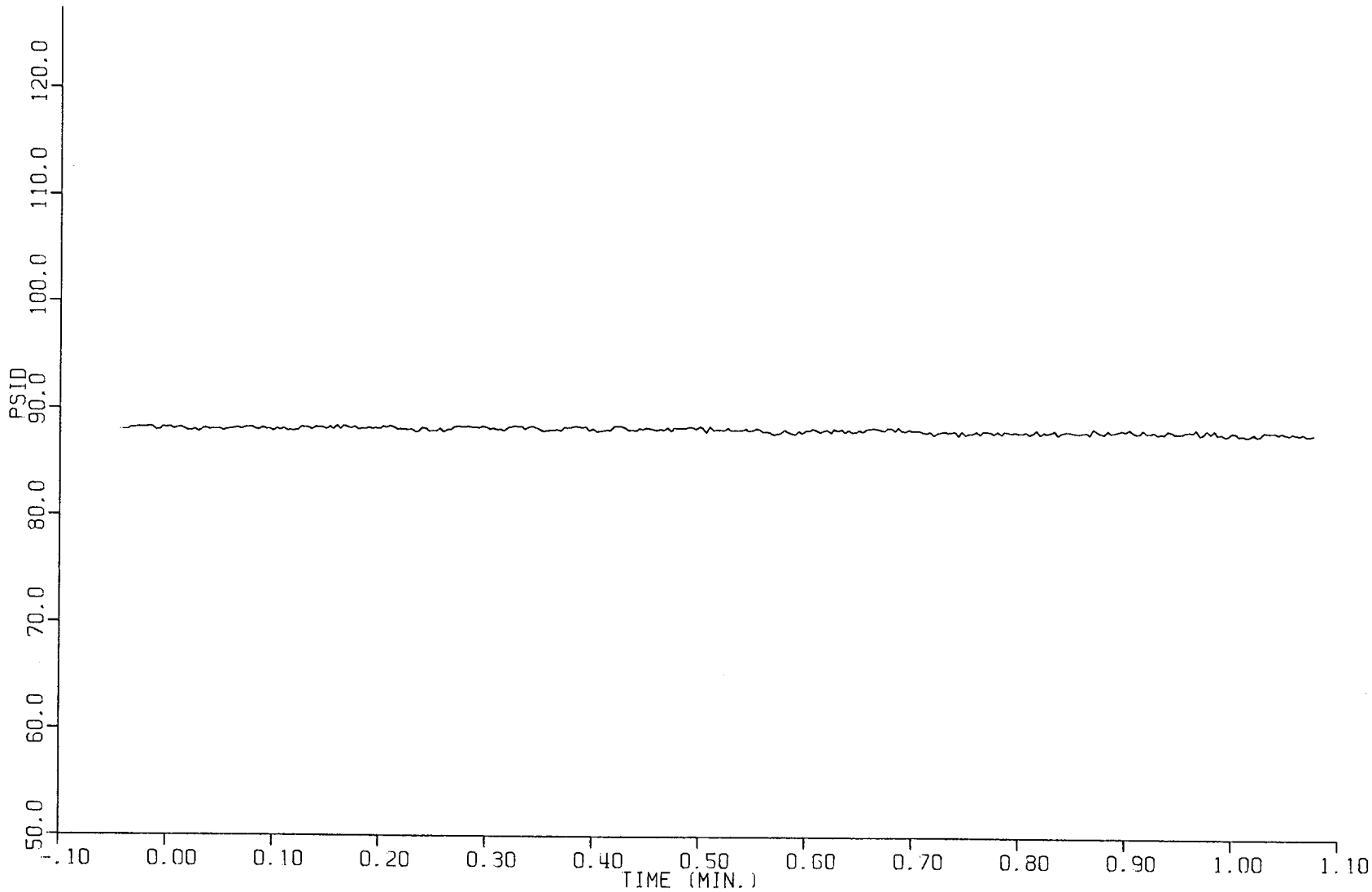


Figure 4-170. Part Length CEA Drop - Reactor Coolant Pump 2A Differential Pressure

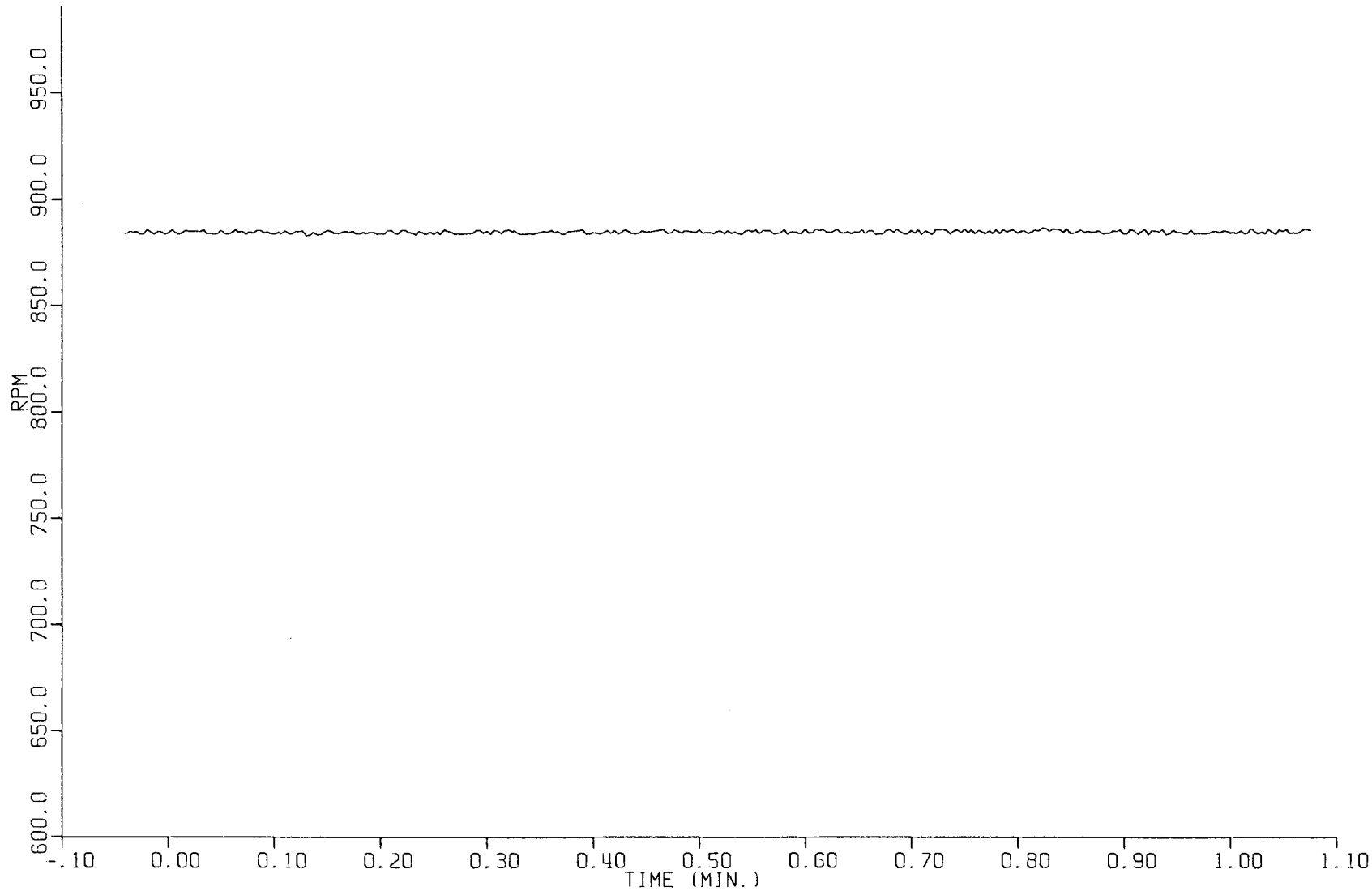


Figure 4-171. Part Length CEA Drop - Reactor Coolant Pump 2A Speed

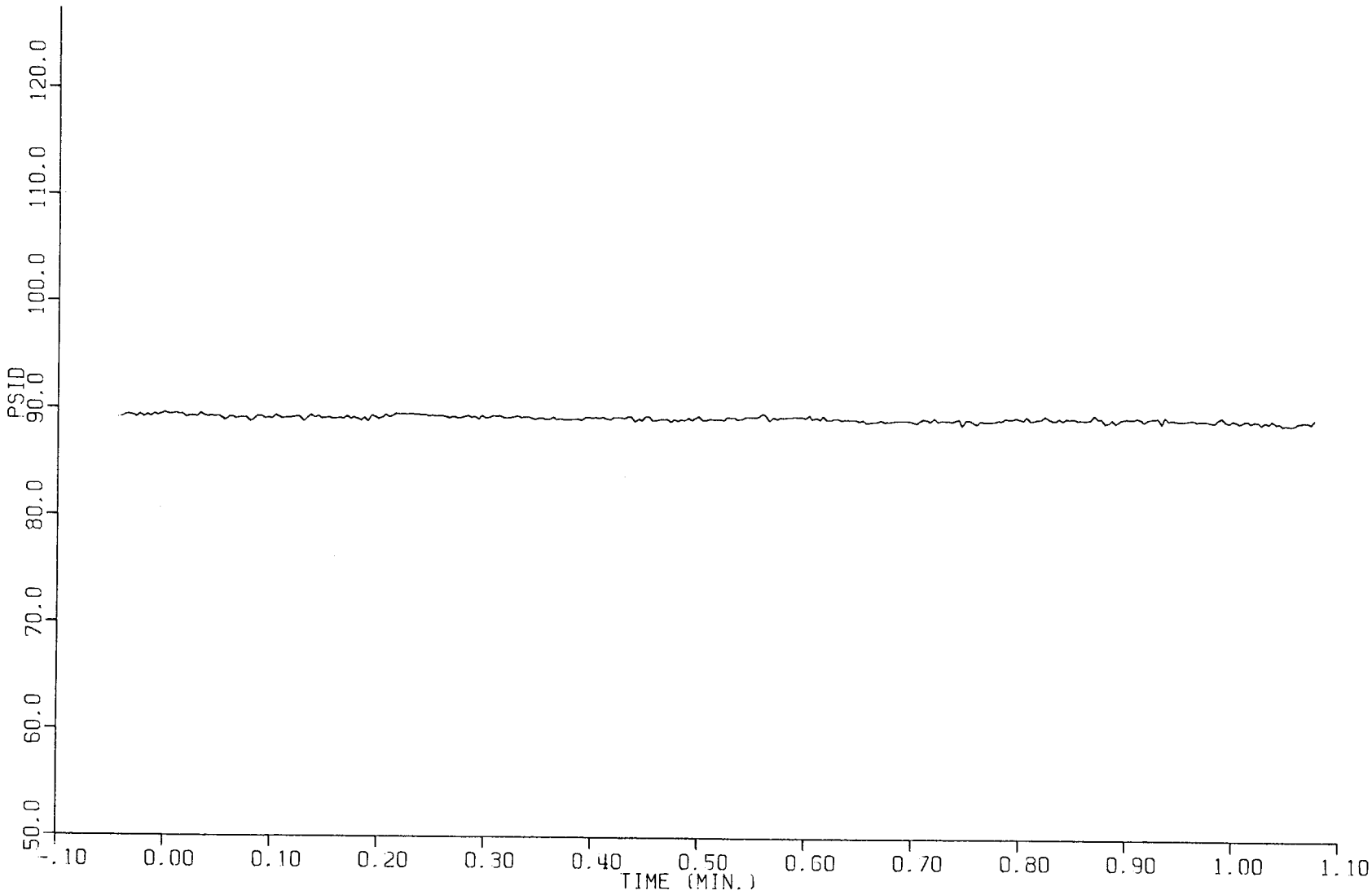


Figure 4-172. Part Length CEA Drop - Reactor Coolant Pump 2B Differential Pressure

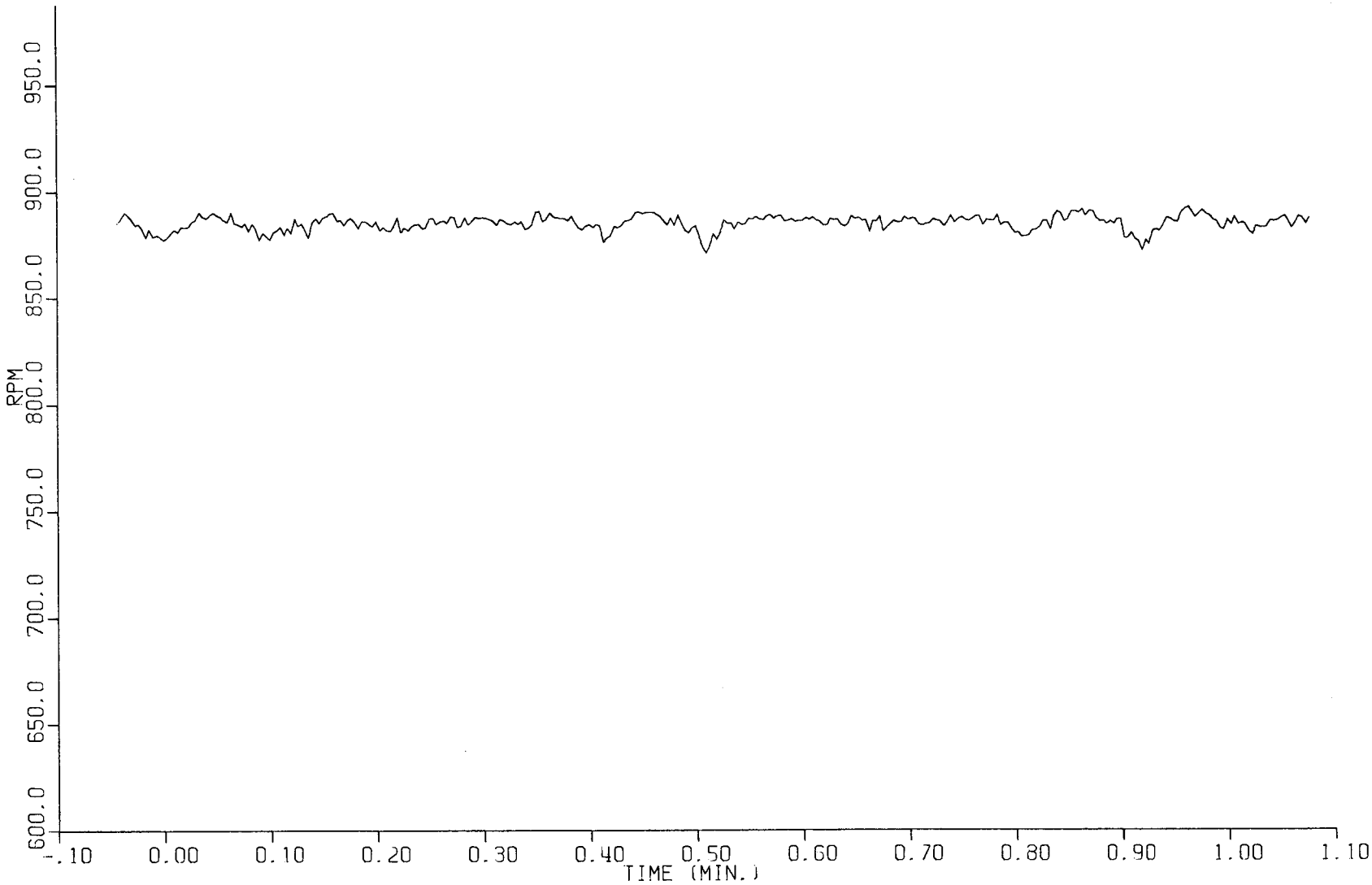


Figure 4-173. Part Length CEA Drop - Reactor Coolant Pump 2B Speed

Table 4-8

INITIAL CONDITIONS FOR THE TURBINE TRIP

Core Power, Mwt	2764 (98.2%)
Core Inlet Coolant Temperature, °F	552
Core Outlet Coolant Temperature, °F	610
Core Mass Flow Rate, 10^6 lbm/hr	133.0
Pressurizer Pressure, psia	2256
Pressurizer Level, percent	49.2
Steam Generator Pressure, psia	908
Steam Generator Level, percent *	72
Boron Concentration, PPM	599
Control System Status:	
- Pressurizer Pressure	Automatic
- Pressurizer Level	Automatic
- Reactor Regulating	Automatic
- Feedwater	Automatic
- Steam Dump and Bypass	Automatic
Charging Flow, GPM	45.2
- 1 pump operating	
- 2 pumps in standby	
Letdown Flow, GPM	40.4

* Level indication in percent of 13.9 ft. instrument span. 0 percent level corresponds to a liquid level 24.5 ft. above the steam generator tube sheet. See Reference 3 for further steam generator details.

Table 4-9

OPERATING STATUS OF THE STEAM DUMP AND BYPASS CONTROL SYSTEM VALVES DURING THE TT

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

*Percentages are descriptors referring to the design capacities of the SDBCS valves. The actual capacities of the valves are somewhat lower.

Table 4-10

SEQUENCE OF EVENTS FOR THE TURBINE TRIP

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 (ESFAS) generated	49%
8.0	Maximum pressurizer pressure	2382 psia
12.7	Maximum steam generator pressure	1029 (SG-1) 1091 (SG-2)
21.	Pressurizer spray valve gets close signal but fails to reseat.	-
21.	Turbine bypass valves and atmospheric dump valve receive close signals. Atmospheric dump valve remains open.	-
29.	Turbine bypass valves fully closed. Atmospheric dump valve remained full open.	-
52.	All three charging pumps in operation; Letdown flow being throttled back to minimum value*.	133.0 GPM (charging) 19.2 GPM (letdown)
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 4-10 (continued)

SEQUENCE OF EVENTS FOR THE TURBINE TRIP

Time (sec)	Event	Value
107.6	Hot leg temperature (steam generator 1) drop off-scale low.	<550°F
117.4	Hot leg temperature (steam generator 2) drops off-scale low.	<550°F
131.7	Main Steam header pressure (loop 1) drops off-scale low	<850 psia
144.	Pressurizer empties	-
155.1	Main steam header pressure (loop 2) drops off-scale low	<850 psia
176.5	Pressurizer pressure drops off-scale low	<1500 psia
200.	Reactor coolant pumps 1A & 1B tripped	-
201.	Reactor coolant pumps 2A & 2B tripped	-
205.	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.	Minimum pressurizer pressure	1350 psia
258.	Steam generator 2 level drops off-scale low	-
274.	Manually closed atmospheric dump valve	-
308.	Pressurizer level back on-scale	>0%
1001.	Hot leg temperatures back on-scale	>550°F
1440.	Pressurizer pressure recovered	2100 psia
1740.	All safety injection pumps stopped	-

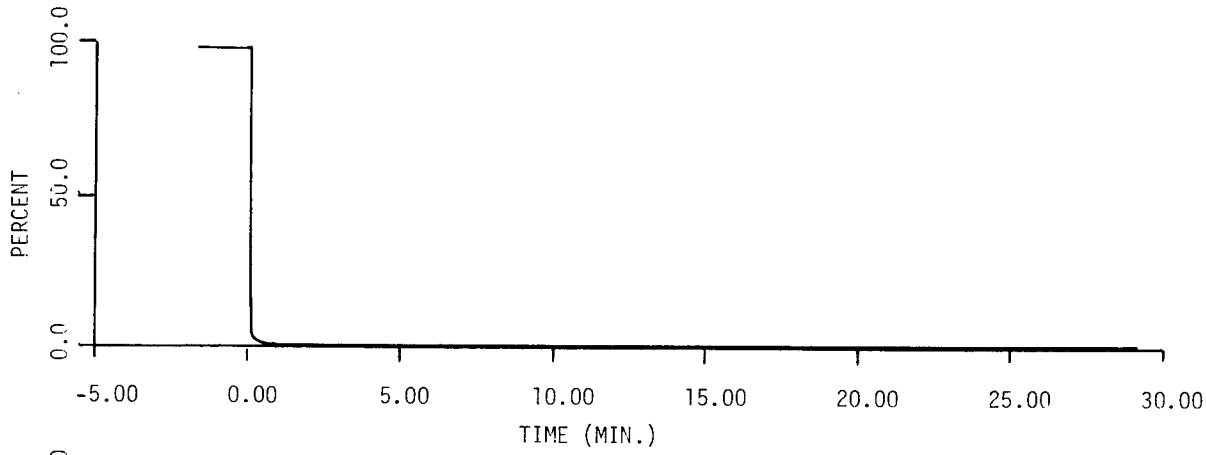


Figure 4-174. Turbine Trip-Control Channel 1 Nuclear Power

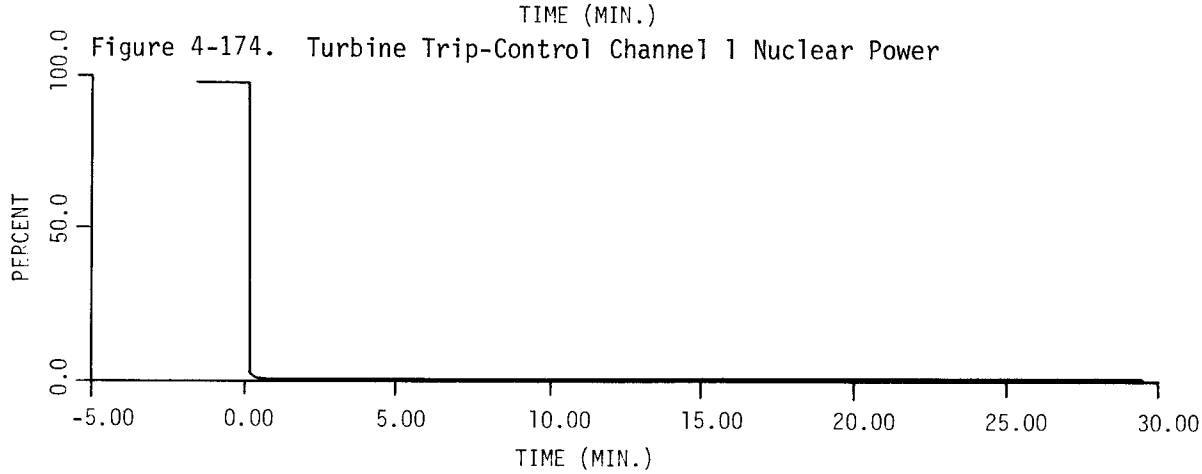


Figure 4-175. Turbine Trip-Control Channel 2 Nuclear Power

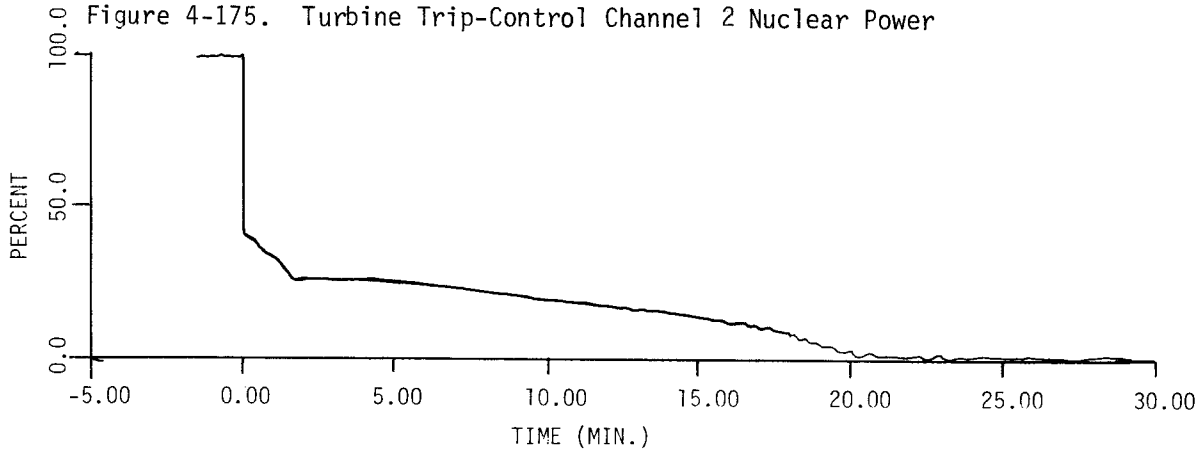


Figure 4-176. Turbine Trip-Turbine Power

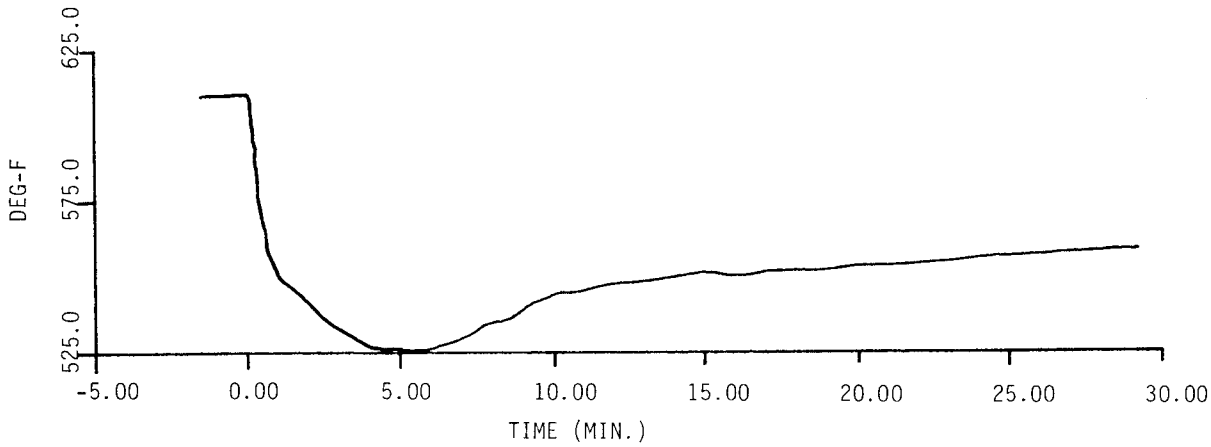


Figure 4-177. Turbine Trip-Steam Generator 1 Hot Leg Temperature

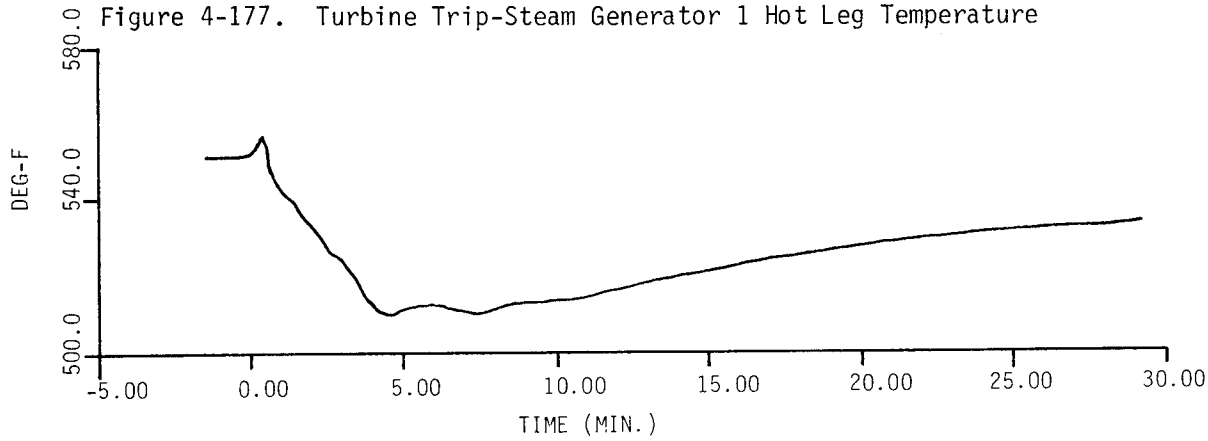


Figure 4-178. Turbine Trip-Steam Generator 1 Cold Leg Temperature (Loop 1A)

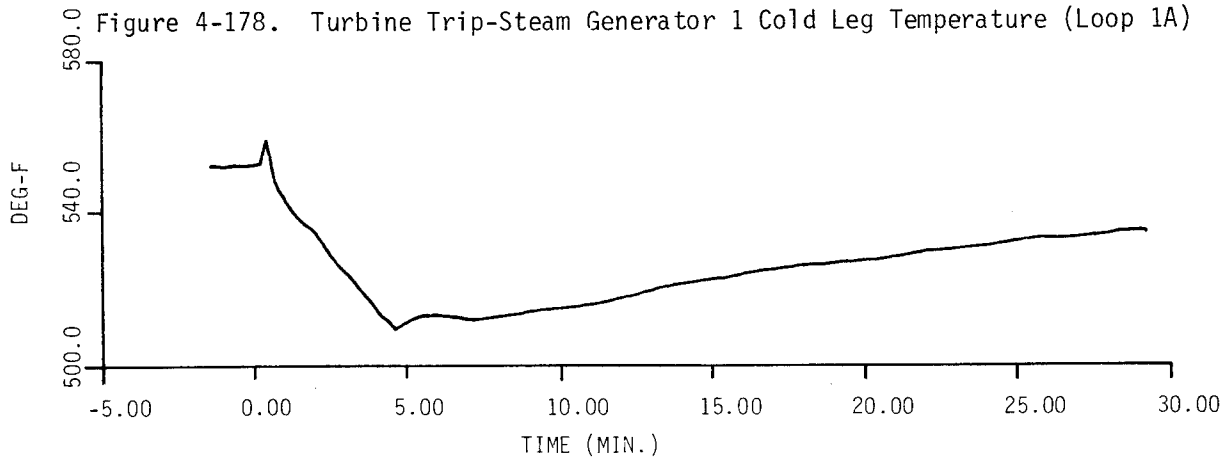


Figure 4-179. Turbine Trip-Steam Generator 1 Cold Leg Temperature (Loop 1B)

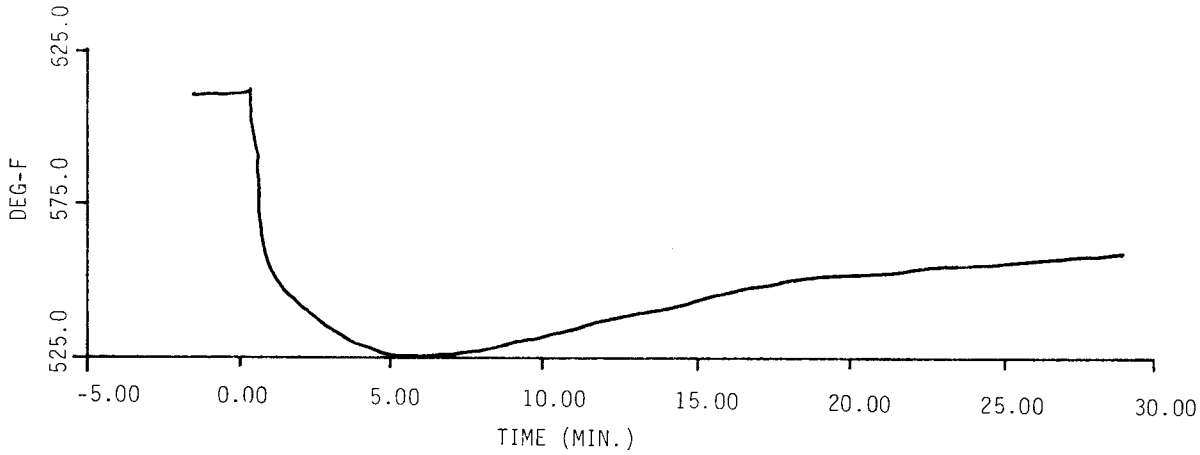


Figure 4-180. Turbine Trip-Steam Generator 2 Hot Leg Temperature

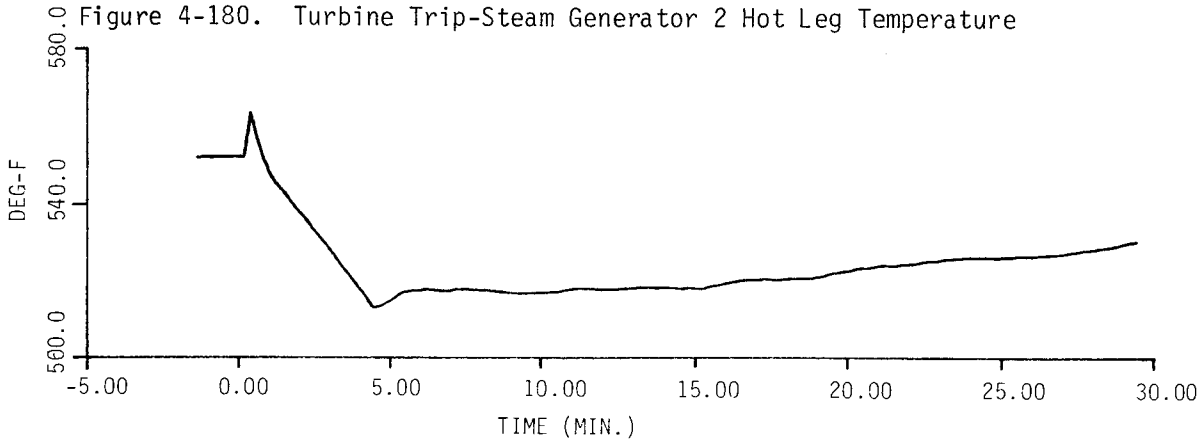


Figure 4-181. Turbine Trip-Steam Generator 2 Cold Leg Temperature (Loop 2A)

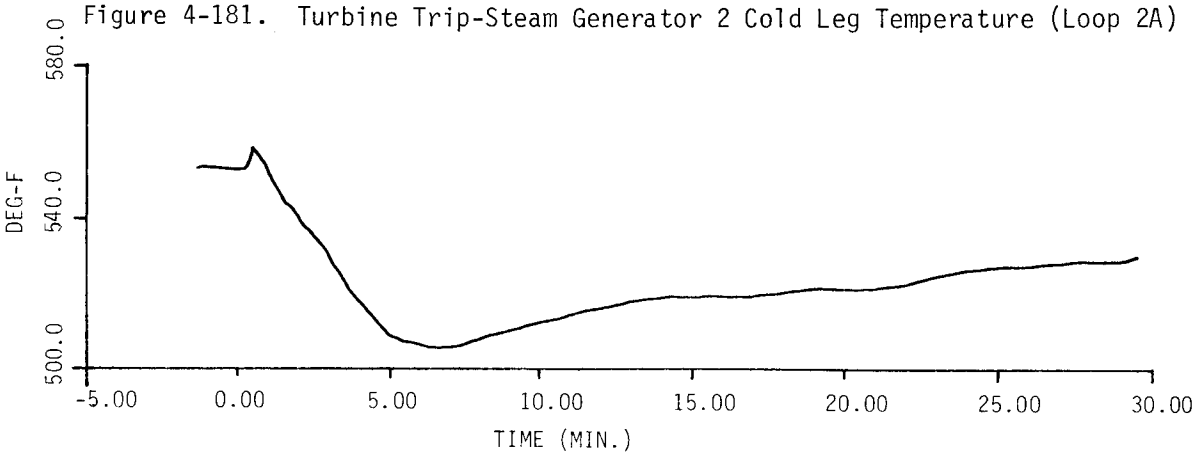


Figure 4-182. Turbine Trip-Steam Generator 2 Cold Leg Temperature (Loop 2B)

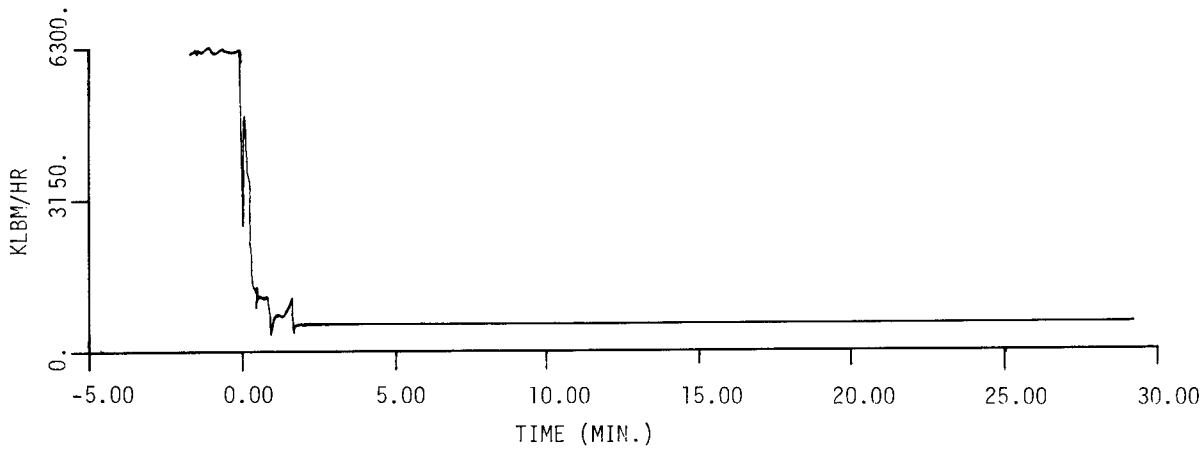


Figure 4-183. Turbine Trip-Steam Generator 1 Feedwater Flow Rate

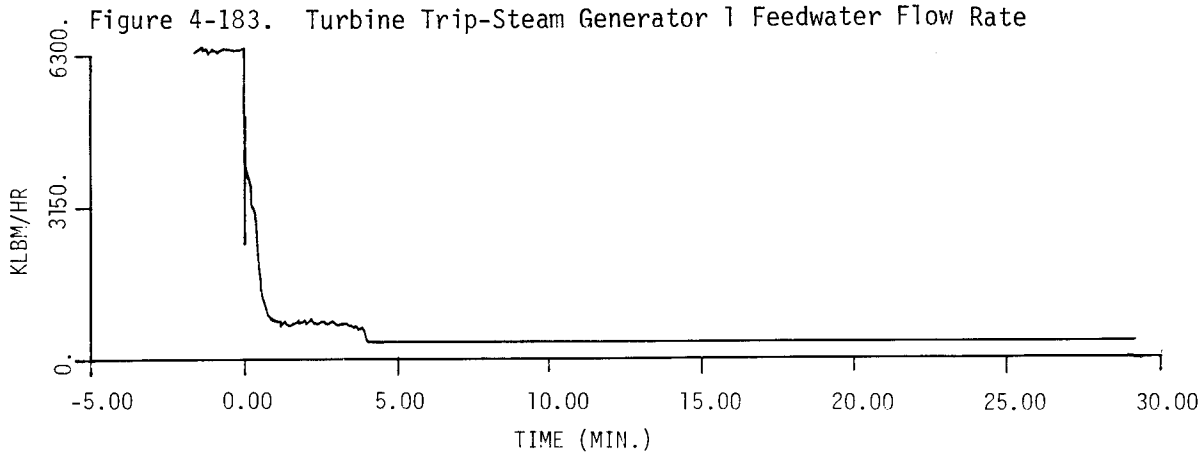


Figure 4-184. Turbine Trip-Steam Generator 1 Main Steam Flow Rate

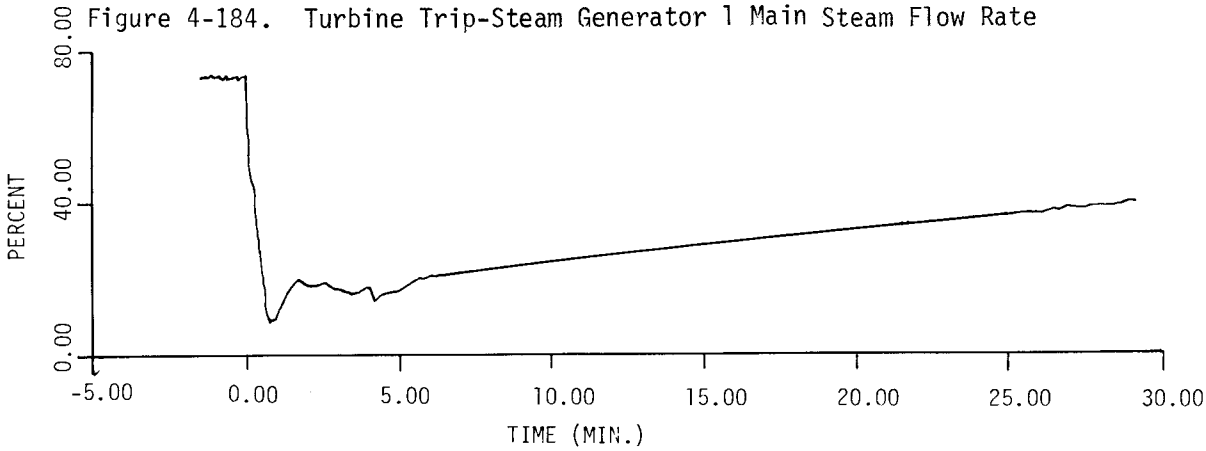


Figure 4-185. Turbine Trip-Steam Generator 1 Level

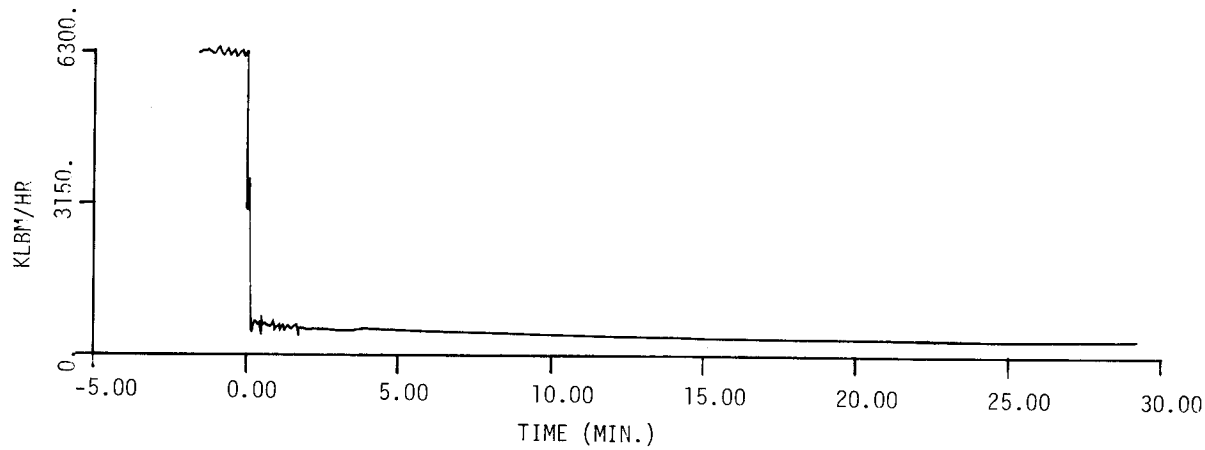


Figure 4-186. Turbine Trip-Steam Generator 2 Feedwater Flow Rate

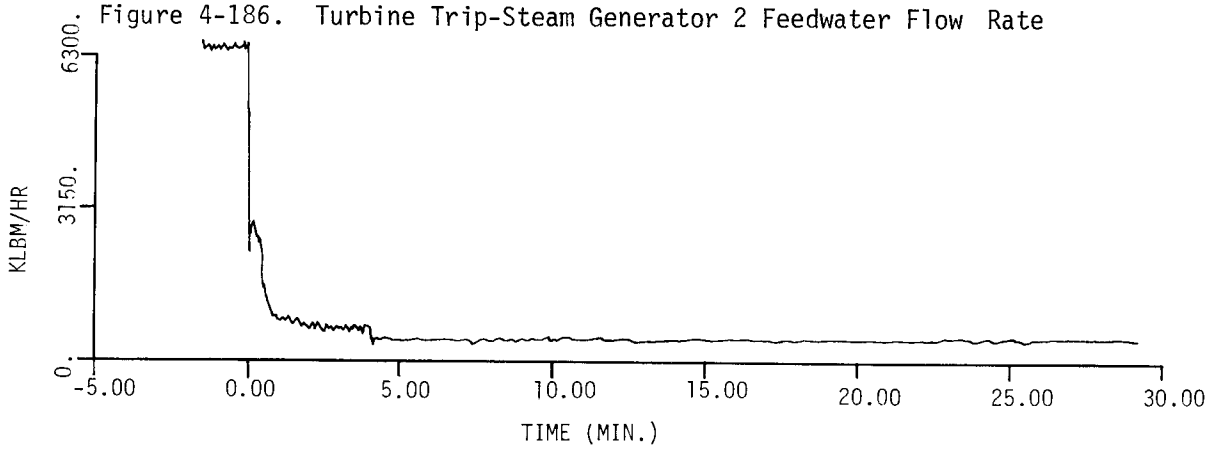


Figure 4-187. Turbine Trip-Steam Generator 2 Main Steam Flow Rate

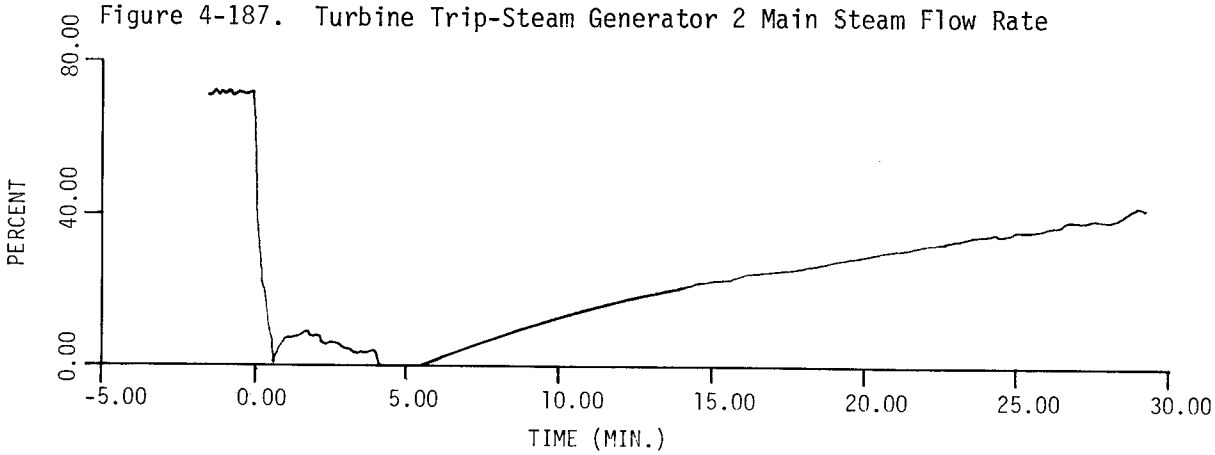


Figure 4-188. Turbine Trip-Steam Generator 2 Level

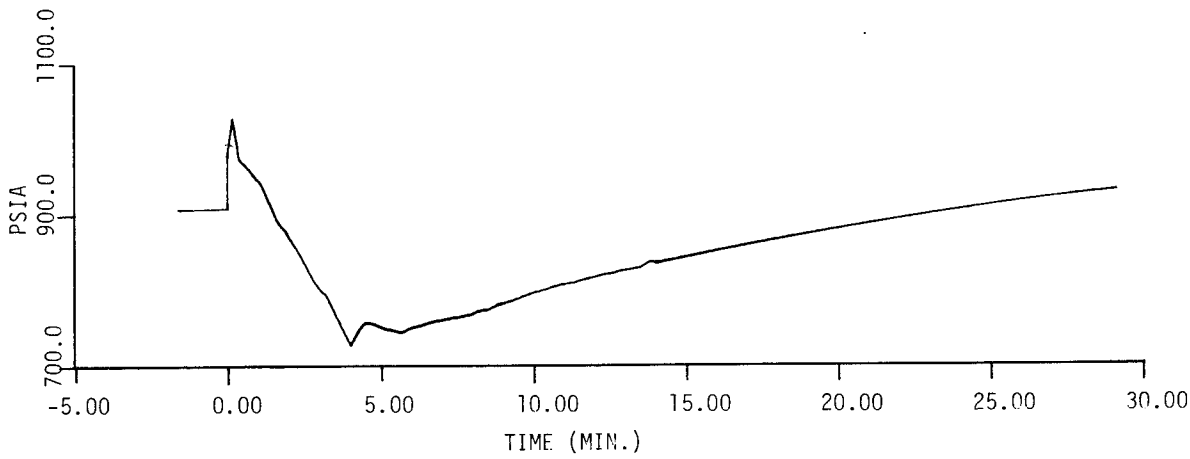


Figure 4-189. Turbine Trip - Steam Generator 1 Pressure

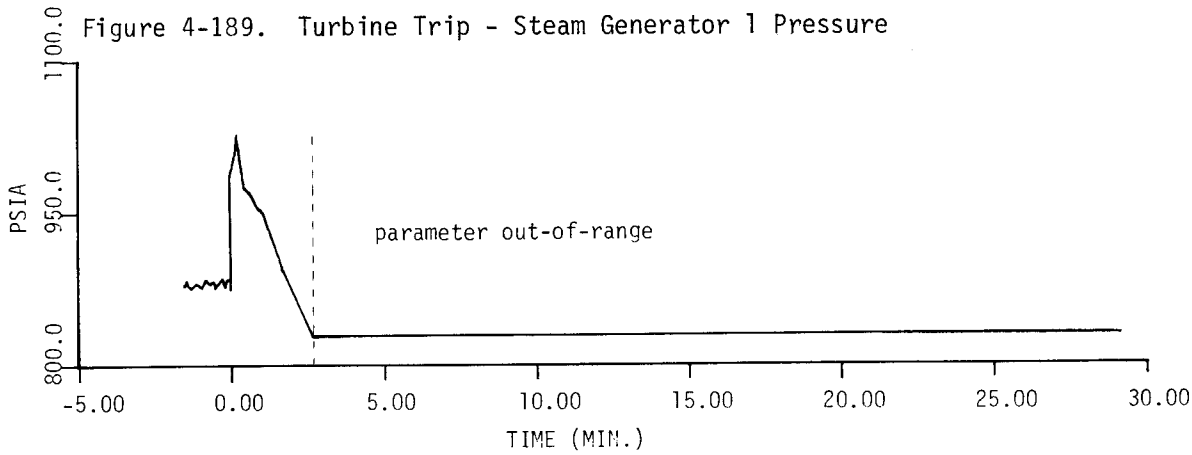


Figure 4-190. Turbine Trip - Steam Generator 1 Header Pressure

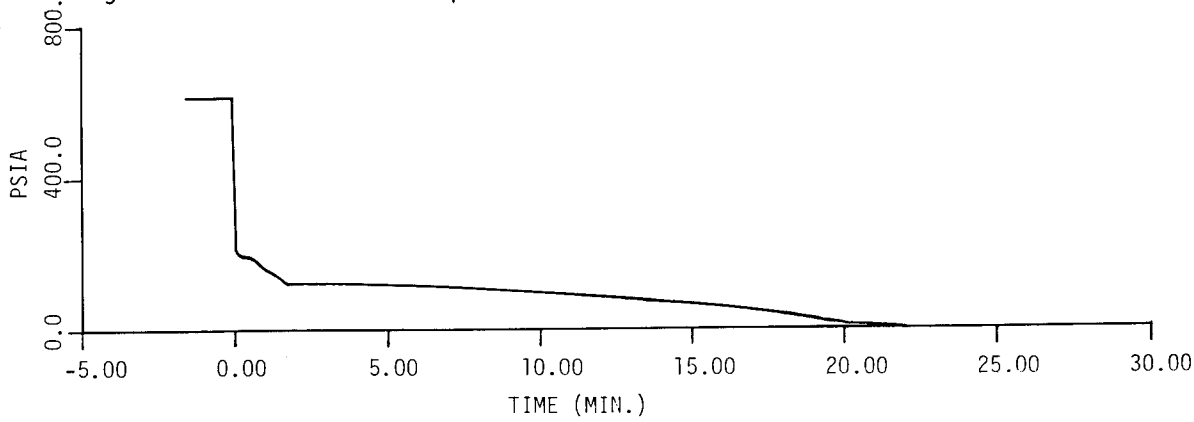


Figure 4-191. Turbine Trip - Turbine First Stage Pressure

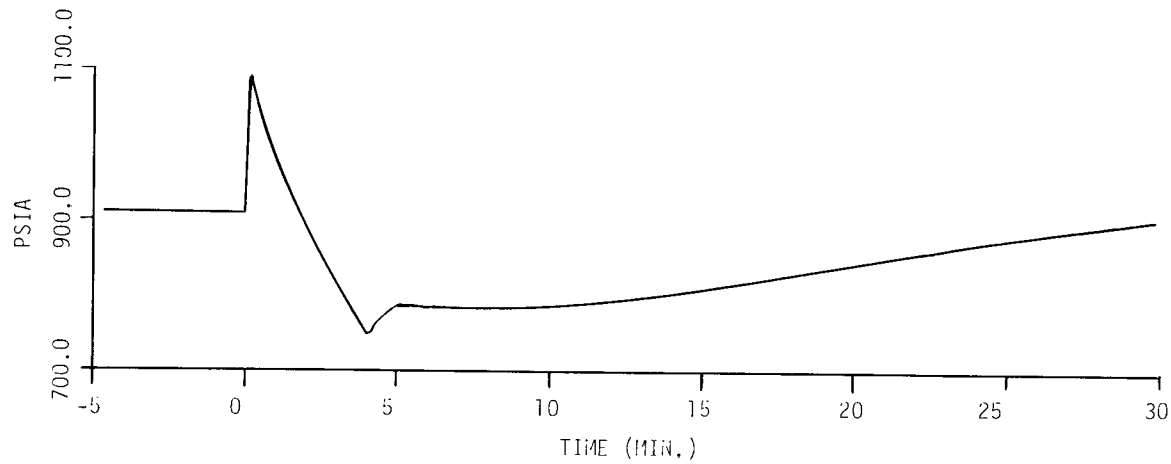


Figure 4-192. Turbine Trip - Steam Generator 2 Pressure

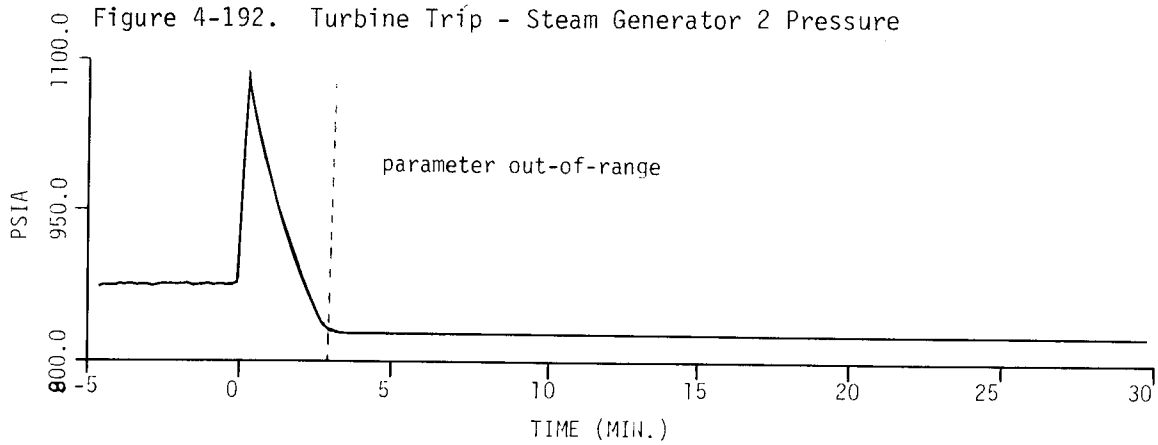


Figure 4-193. Turbine Trip - Steam Generator 2 Header Pressure

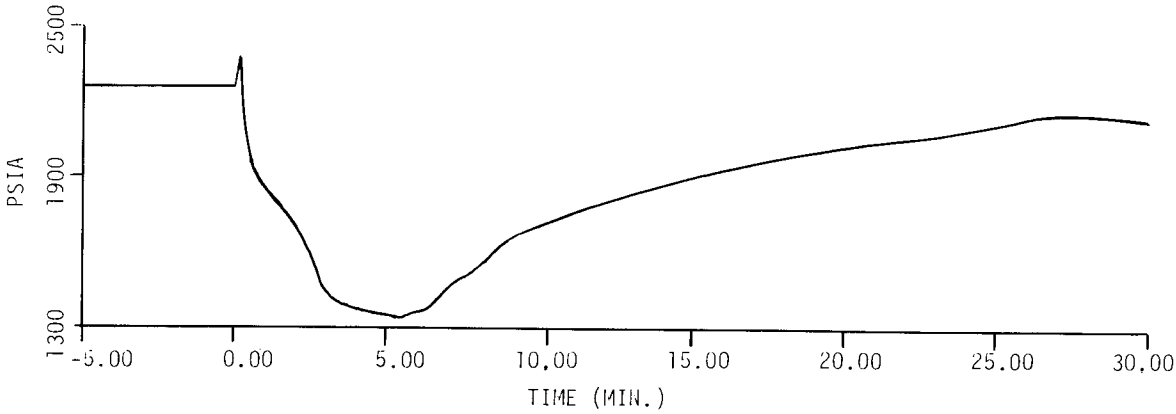


Figure 4-194. Turbine Trip - Pressurizer Pressure, Narrow Range

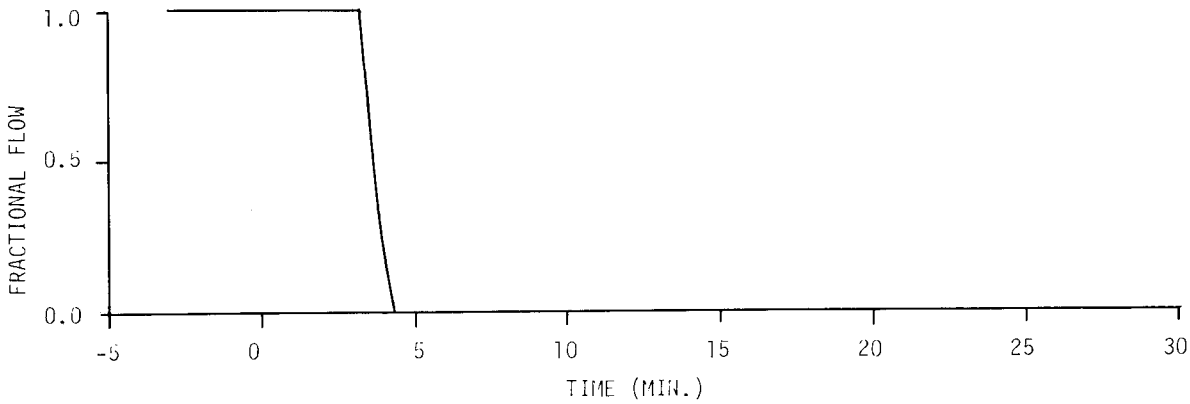


Figure 4-195. Turbine Trip - Normalized Reactor Coolant Pump 1A Flow Rate

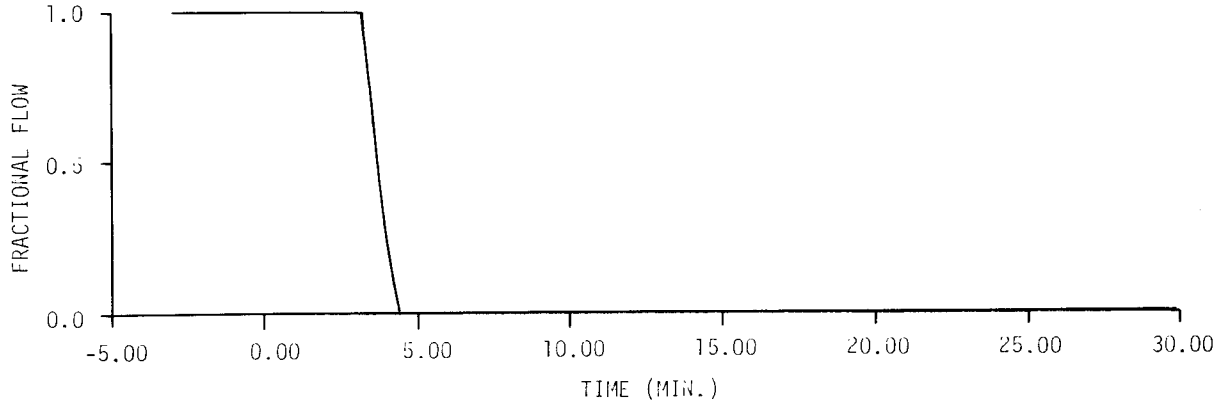


Figure 4-196. Turbine Trip - Normalized Reactor Coolant Pump 1B Flow Rate

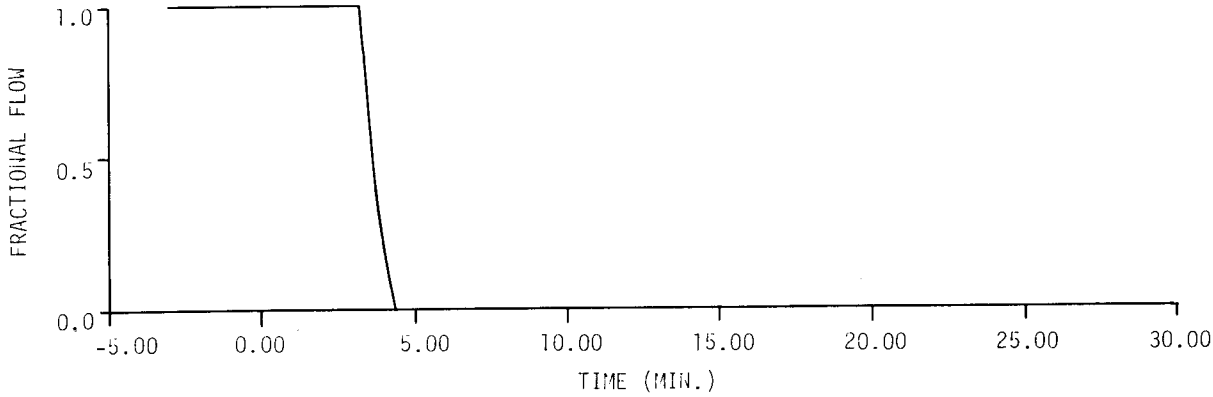


Figure 4-197. Turbine Trip - Normalized Reactor Coolant Pump 2A Flow Rate

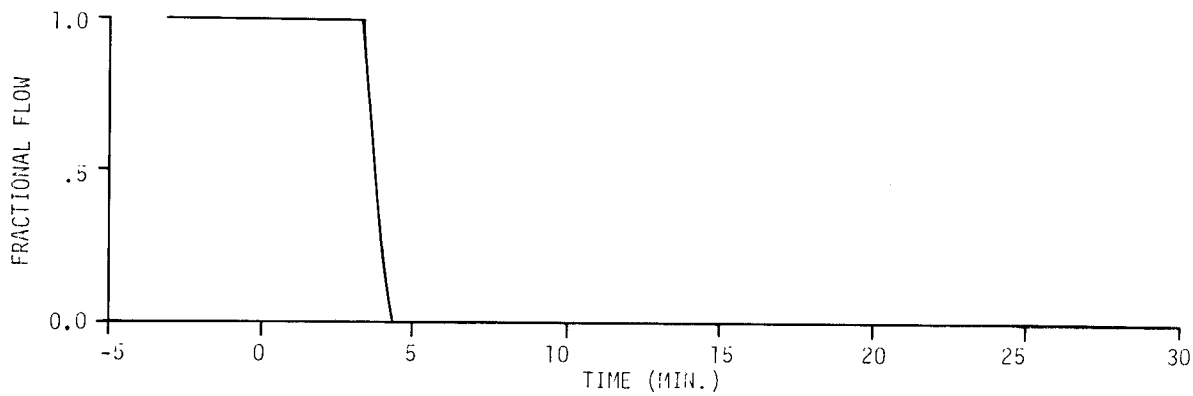


Figure 4-198. Turbine Trip - Normalized Reactor Coolant Pump 2B Flow Rate

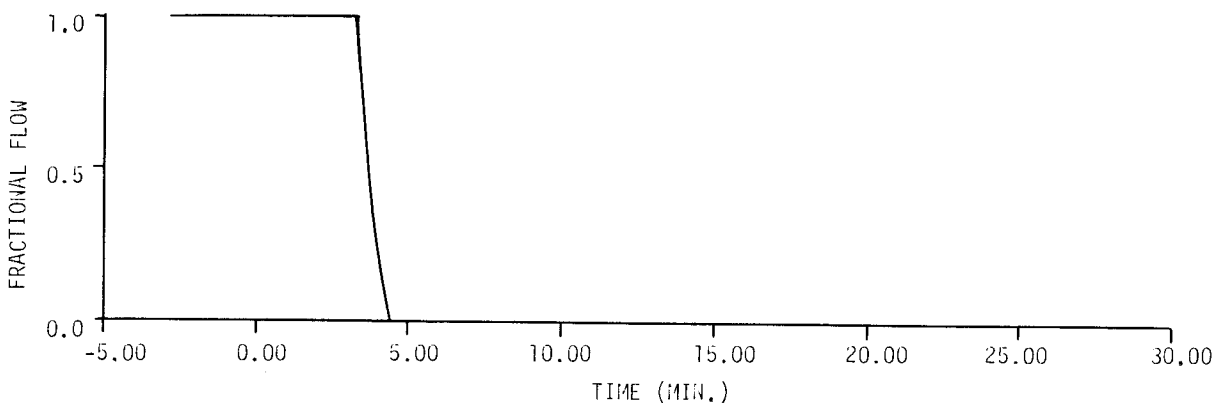


Figure 4-199. Turbine Trip - Normalized Reactor Coolant Pump Flow Rate

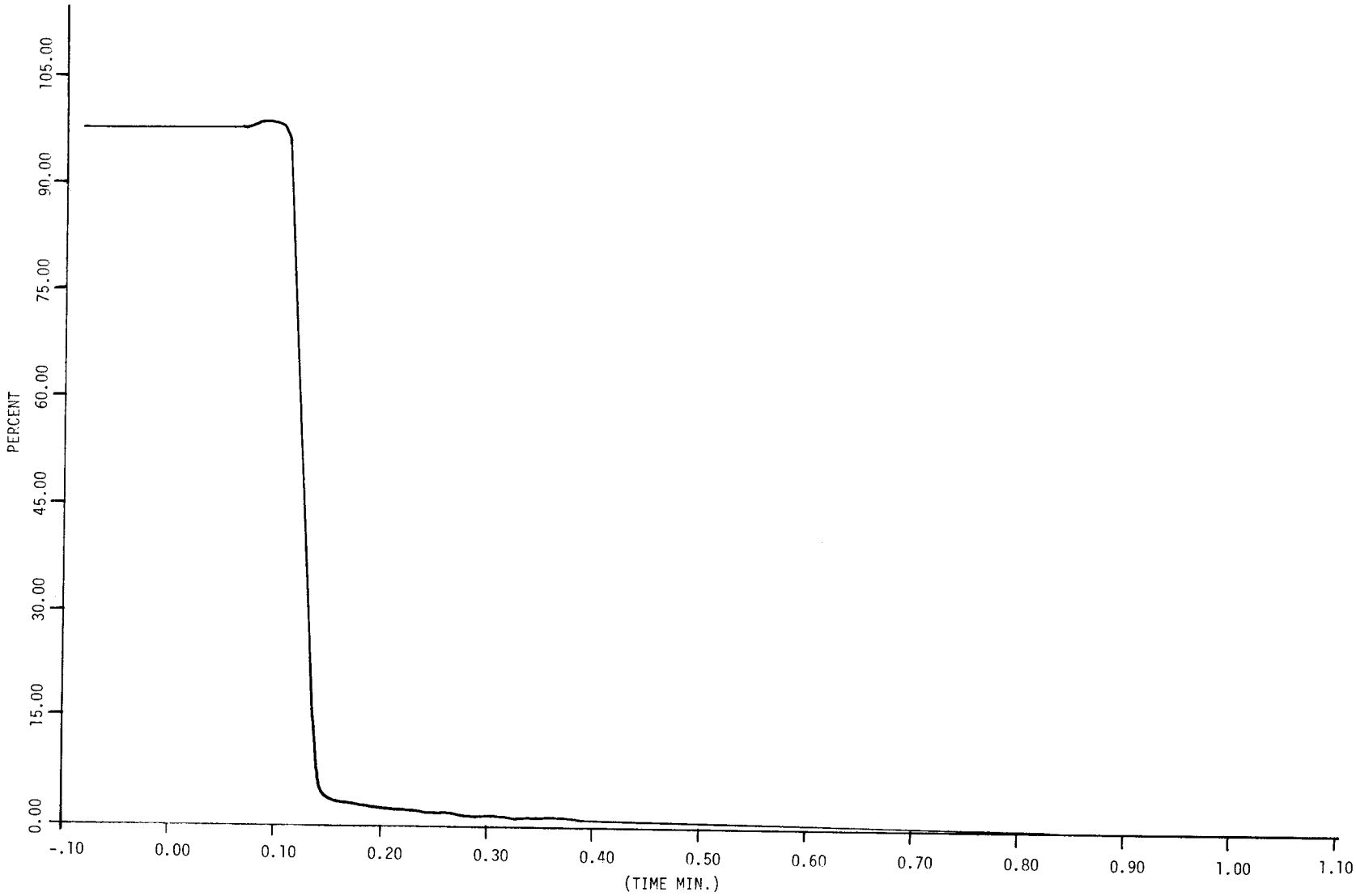


Figure 4-200. Turbine Trip - Control Channel 1 Nuclear Power

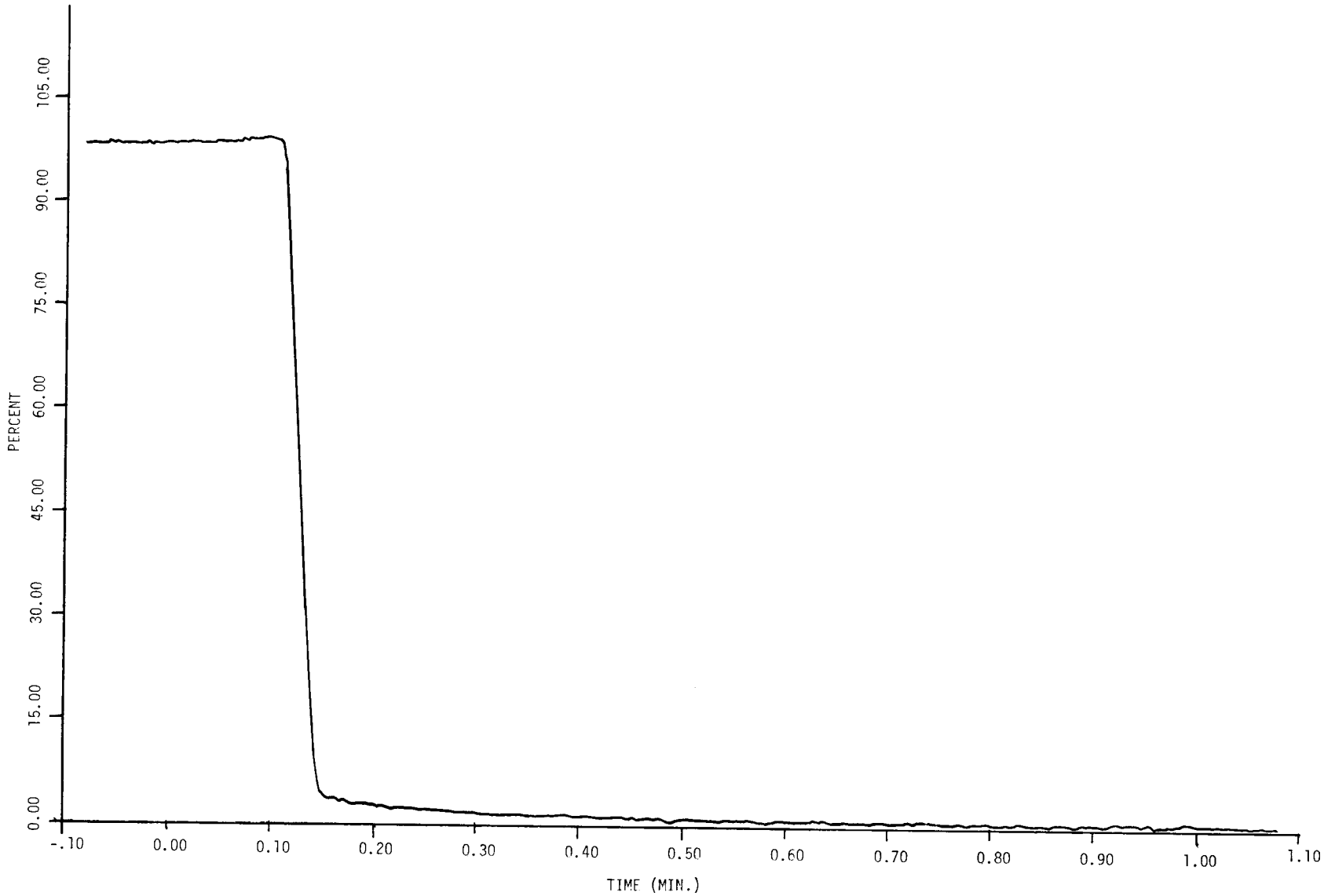


Figure 4-201. Turbine Trip - Control Channel 2 Nuclear Power

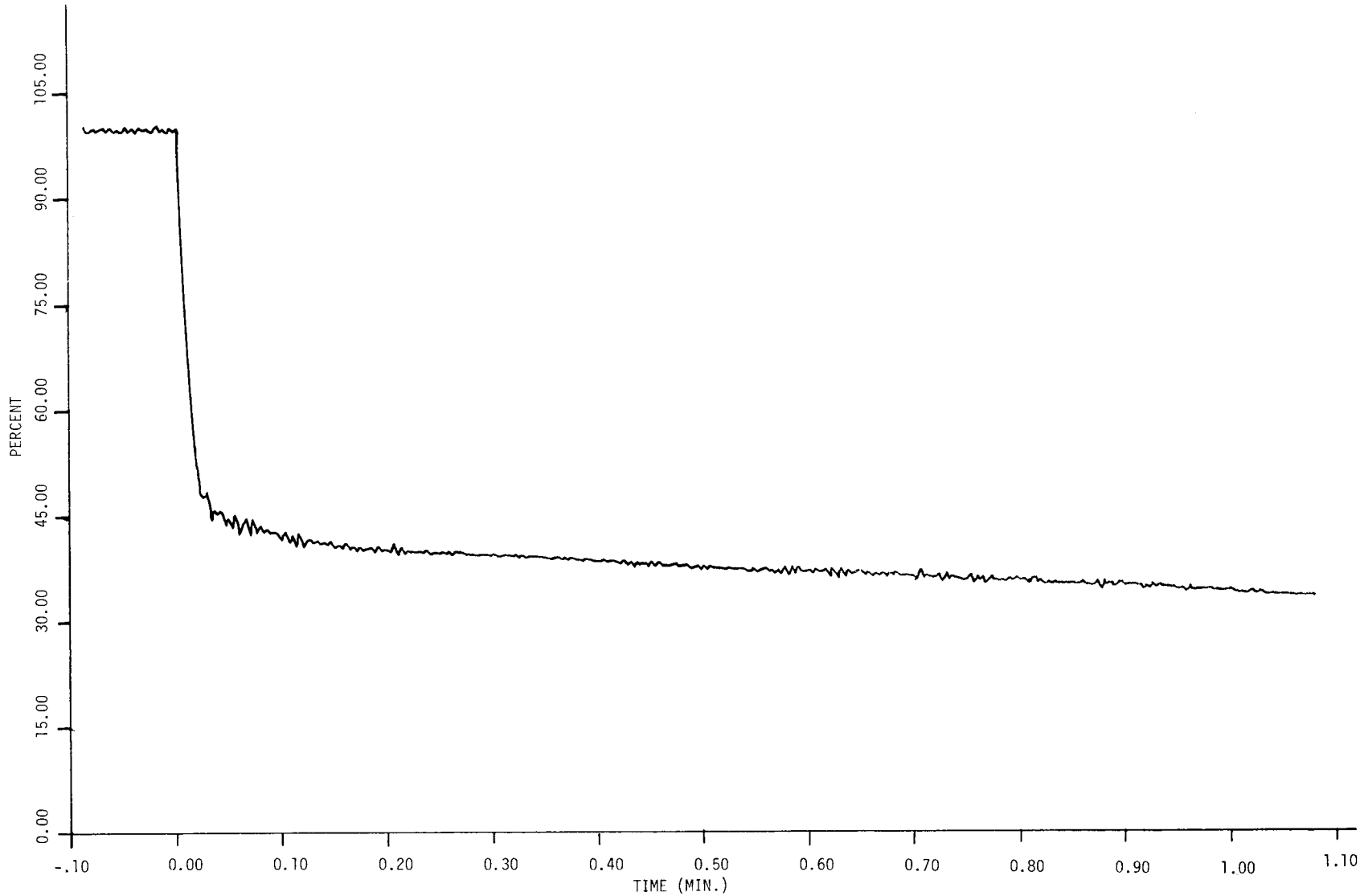


Figure 4-202. Turbine Trip - Turbine Power

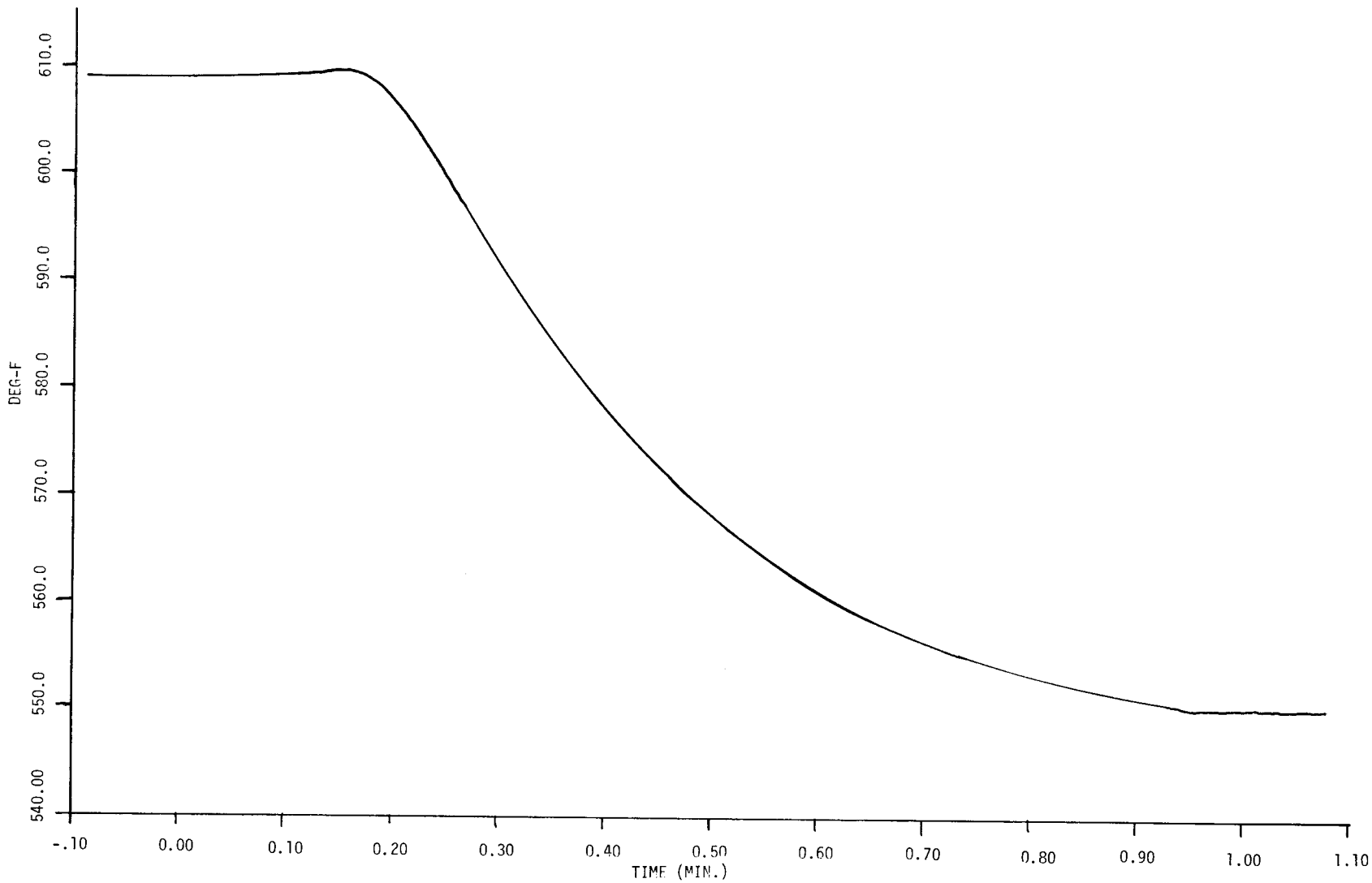


Figure 4-203. Turbine Trip - Steam Generator 1 Hot Leg Temperature

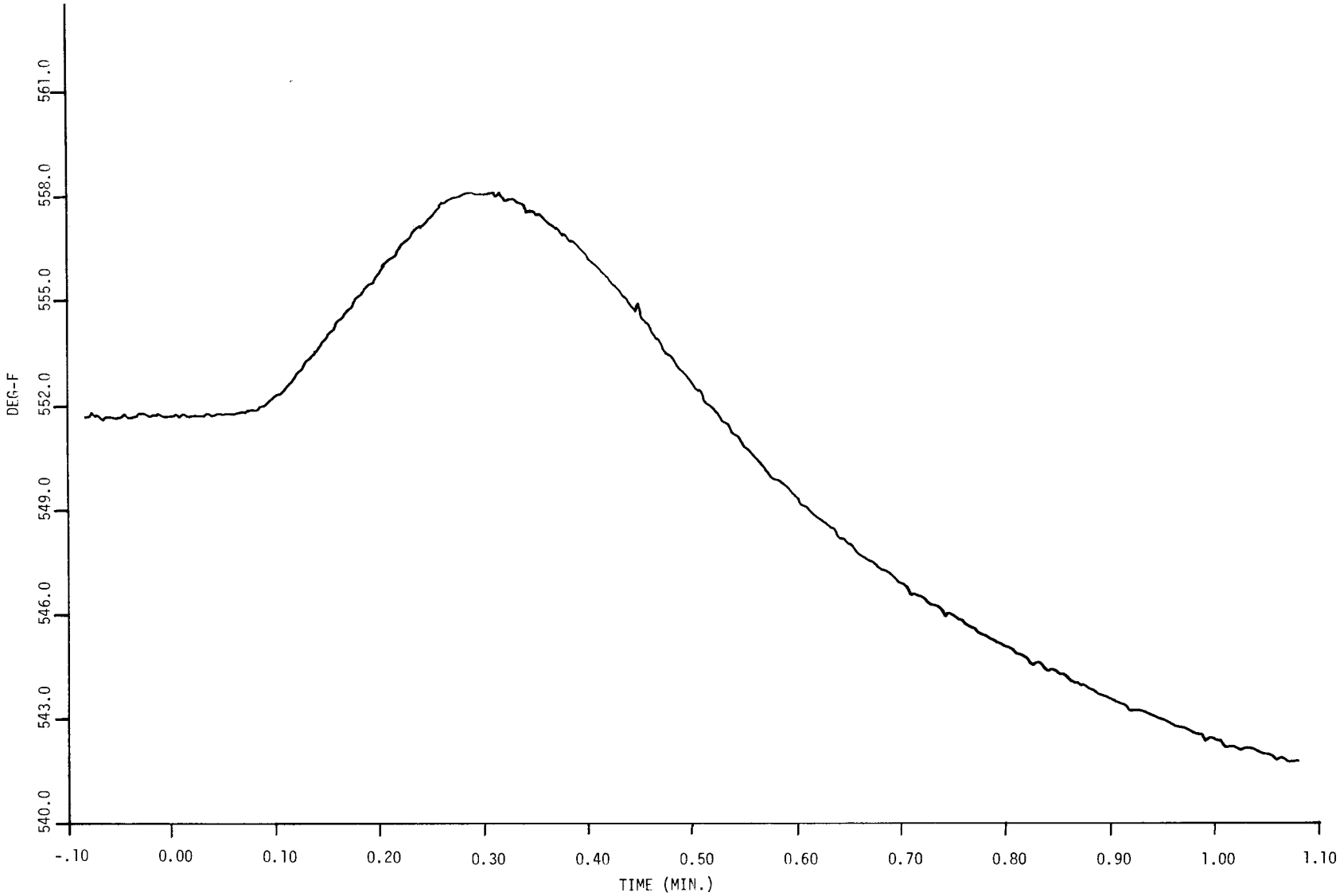


Figure 4-204. Turbine Trip - Steam Generator 1 Cold Leg Temperature (Loop 1A)

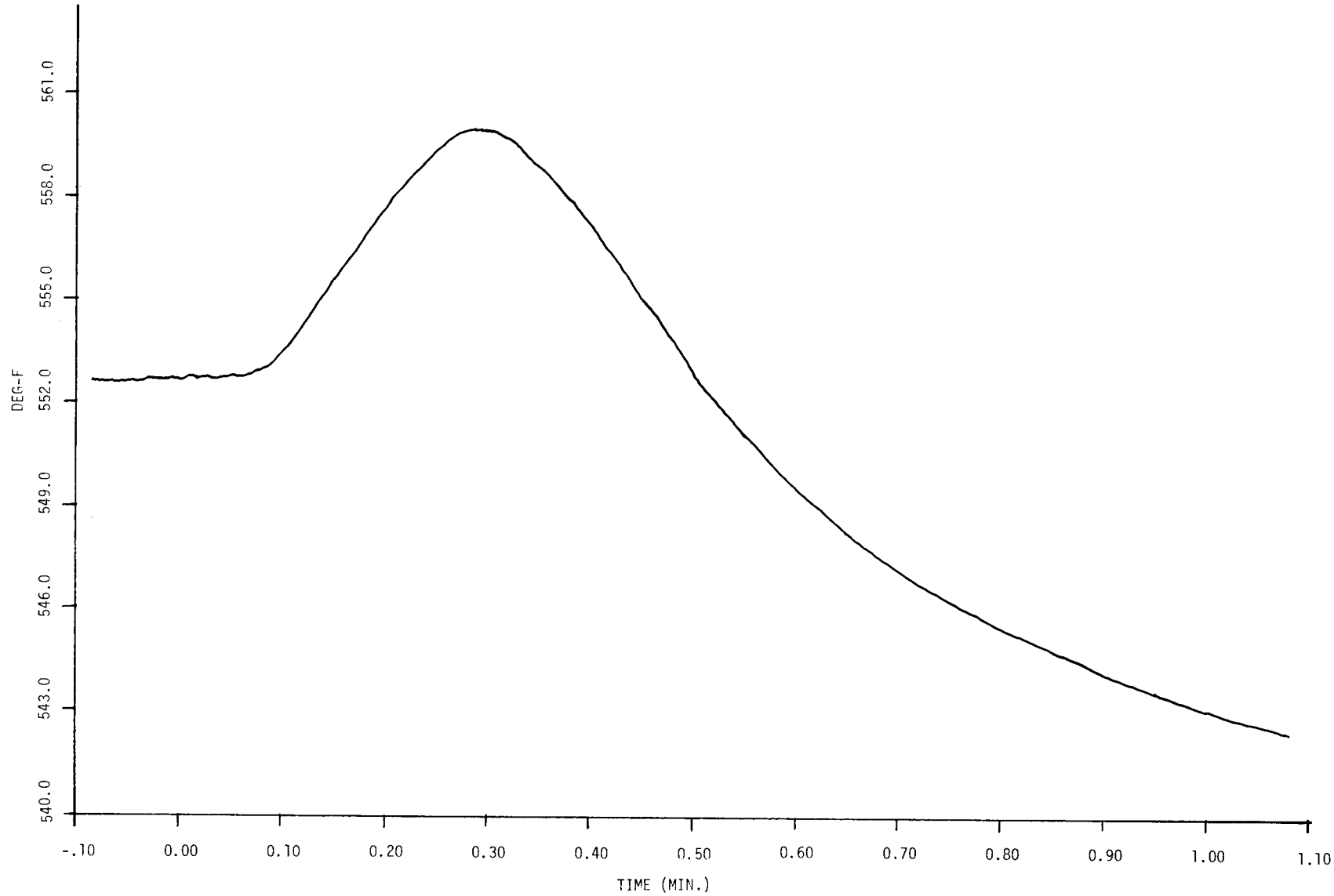


Figure 4-205. Turbine Trip - Steam Generator 1 Cold Leg Temperature (Loop 1B)

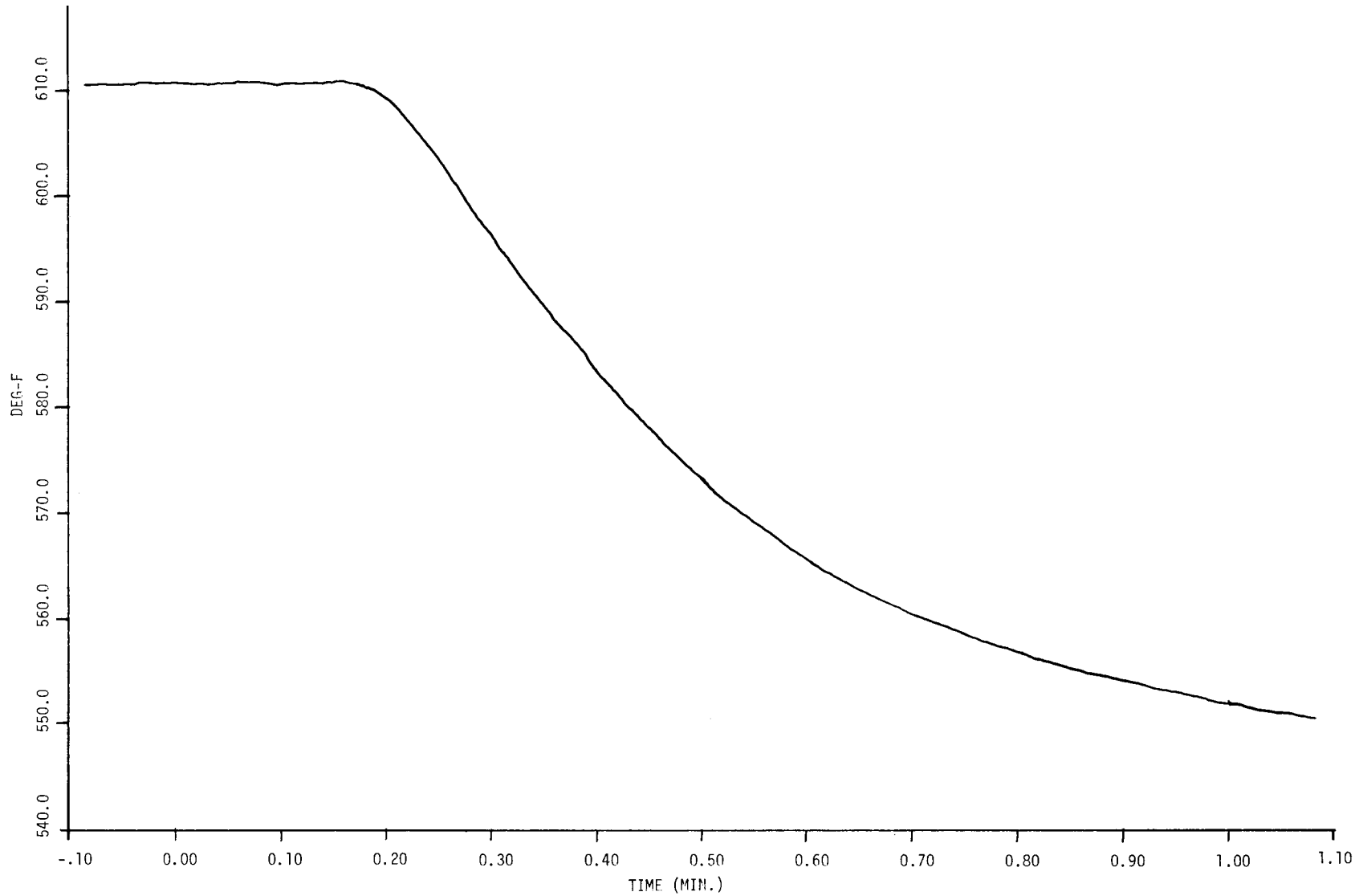


Figure 4-206. Turbine Trip - Steam Generator 2 Hot Leg Temperature

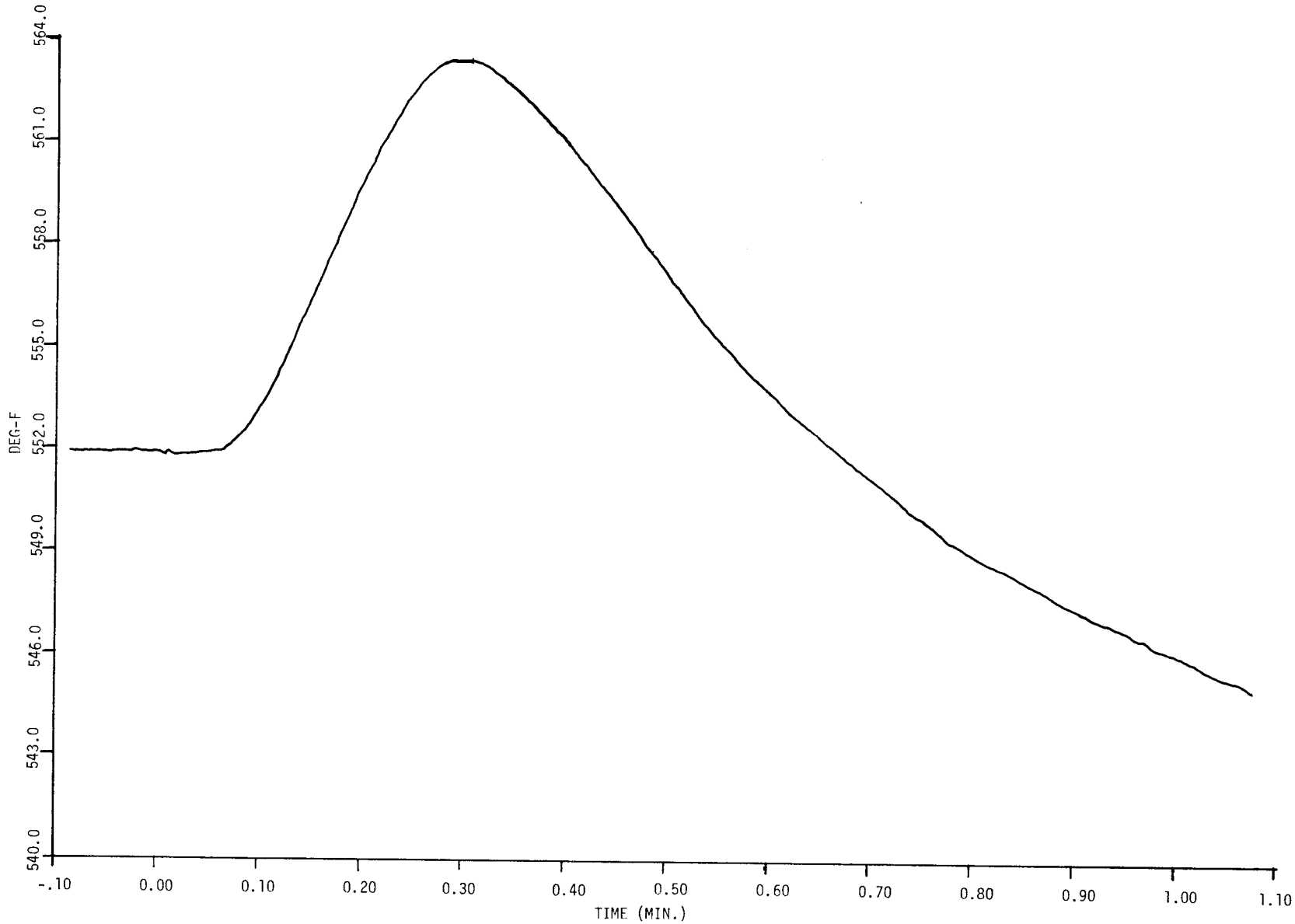


Figure 4-207. Turbine Trip - Steam Generator 2 Cold Leg Temperature (Loop 2A)

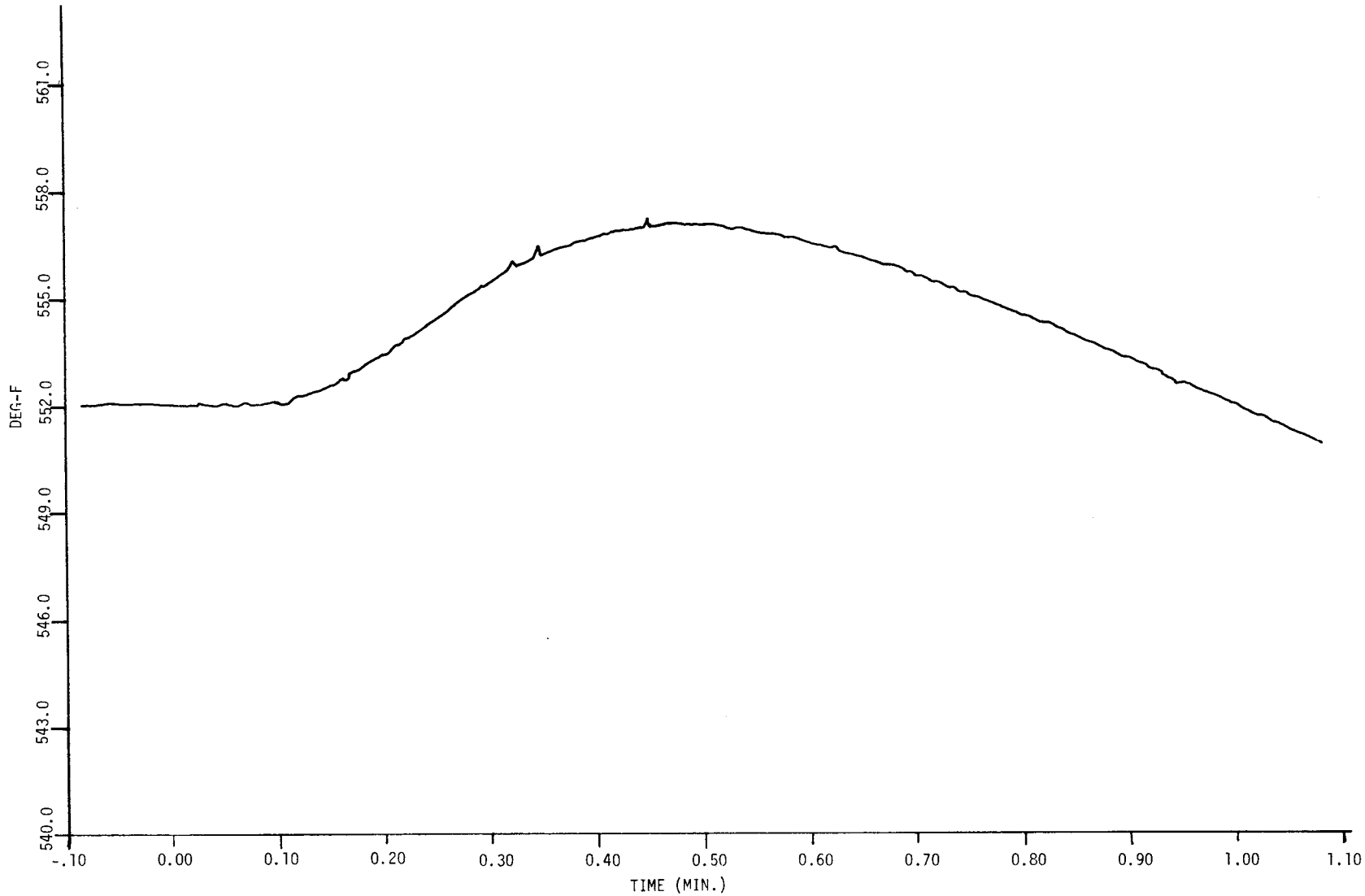


Figure 4-208. Turbine Trip - Steam Generator 2 Cold Leg Temperature (Loop 2B)

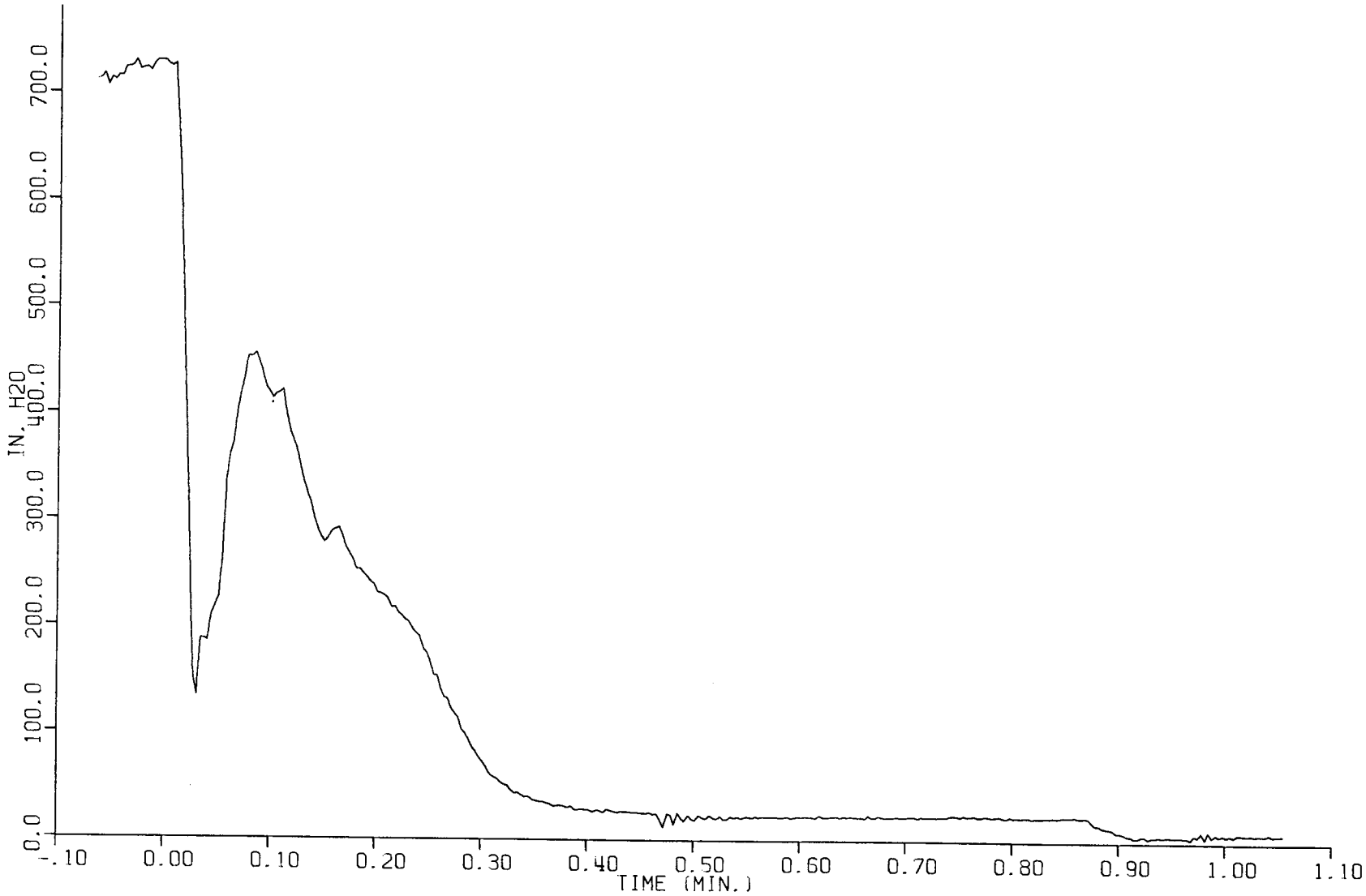


Figure 4-209. Turbine Trip - Steam Generator 1 Feedwater Differential Pressure

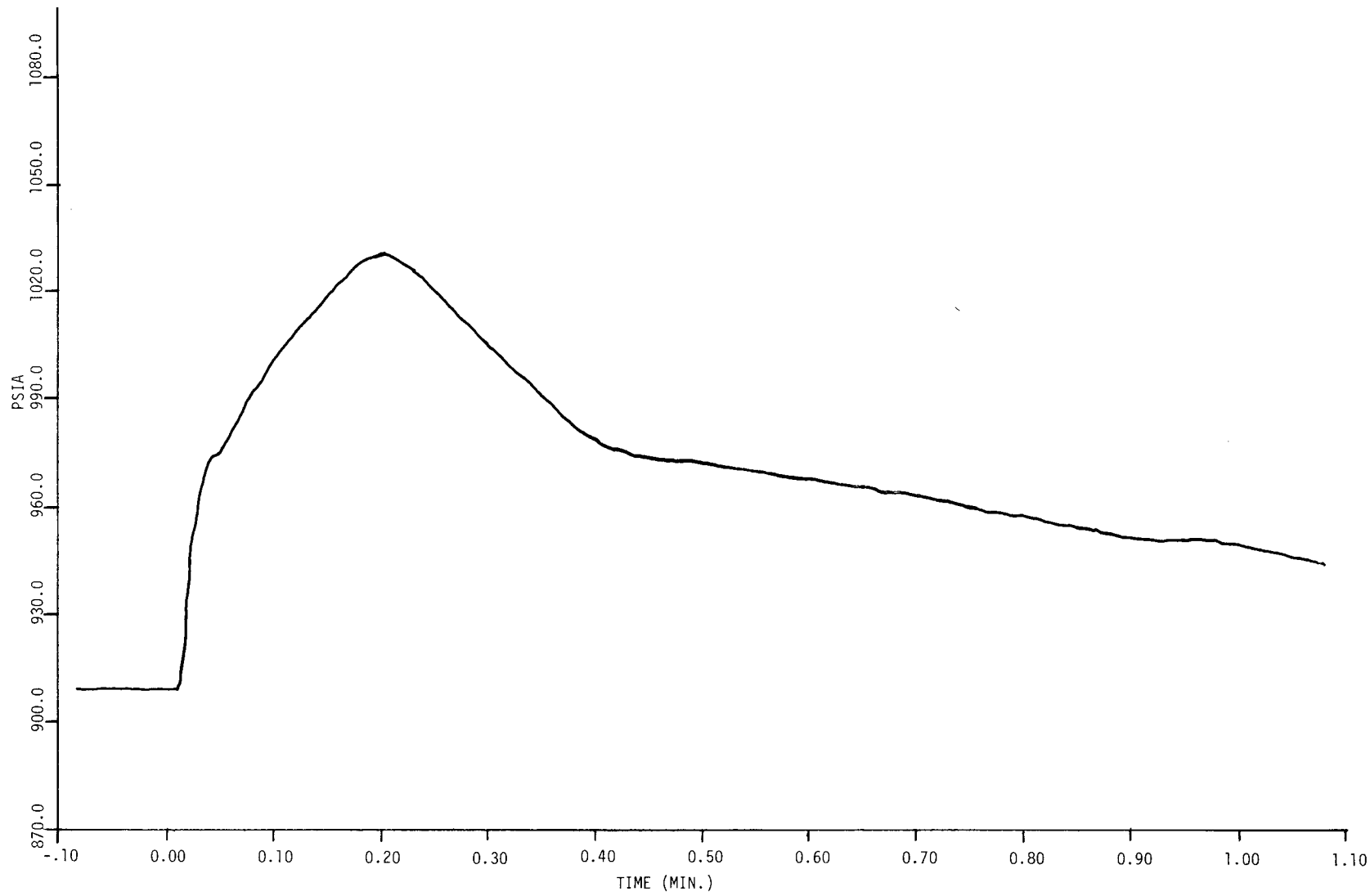


Figure 4-210. Turbine Trip - Steam Generator 1 Pressure

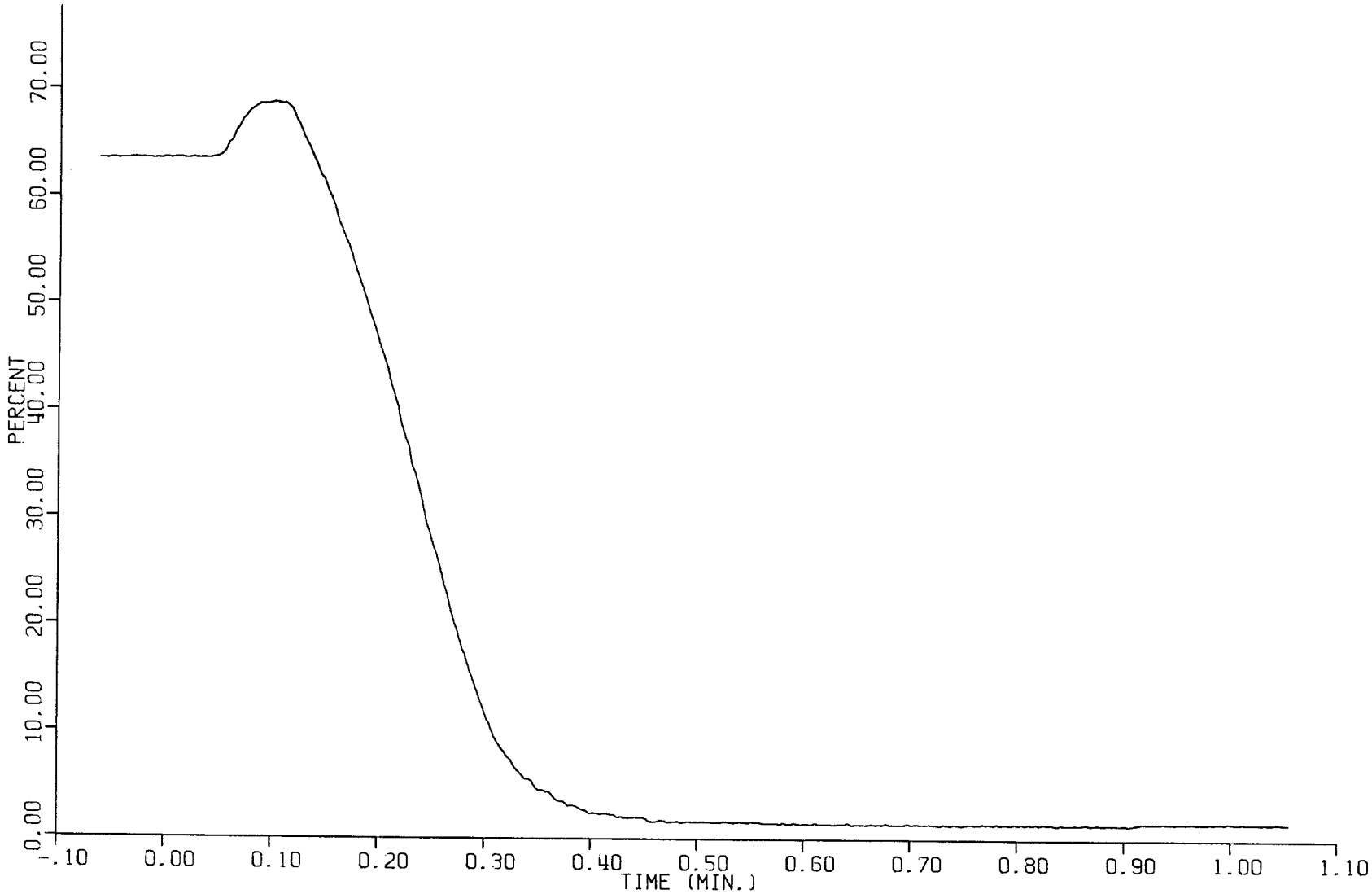


Figure 4-211. Turbine Trip - Steam Generator 1 Feedwater Valve Position

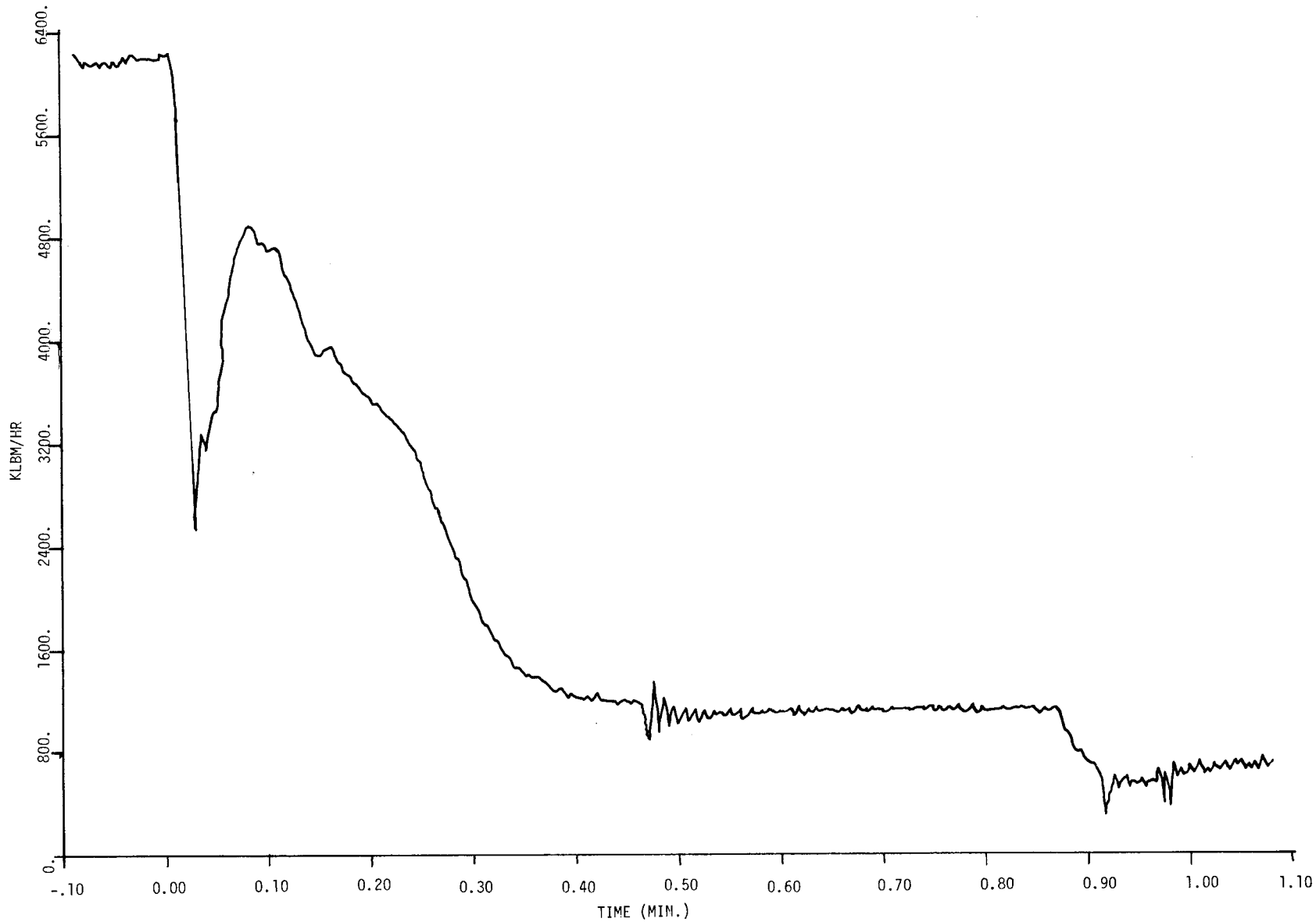


Figure 4-212. Turbine Trip - Steam Generator 1 Feedwater Flow Rate

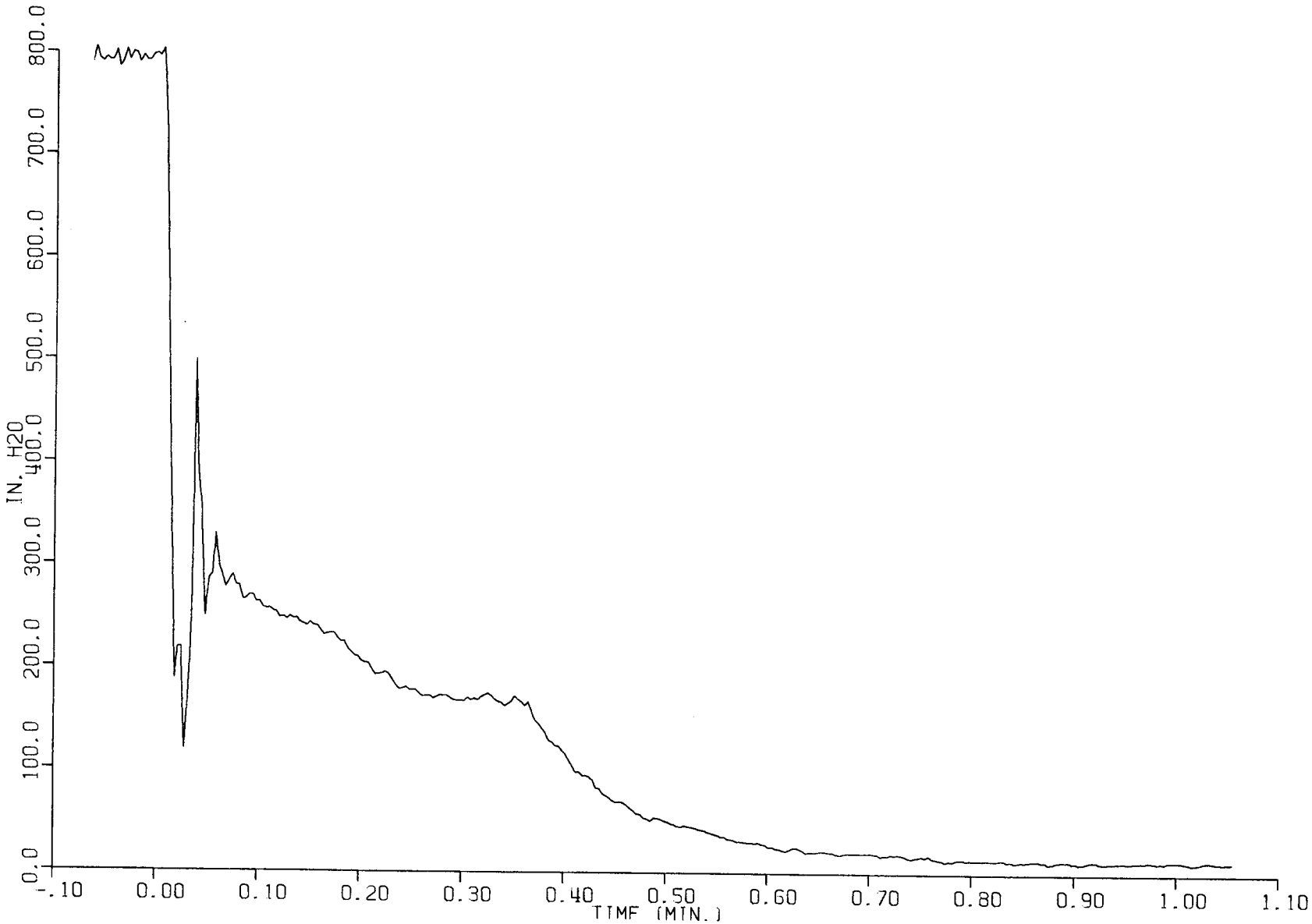


Figure 4-213. Turbine Trip - Steam Generator 1 Header Differential Pressure

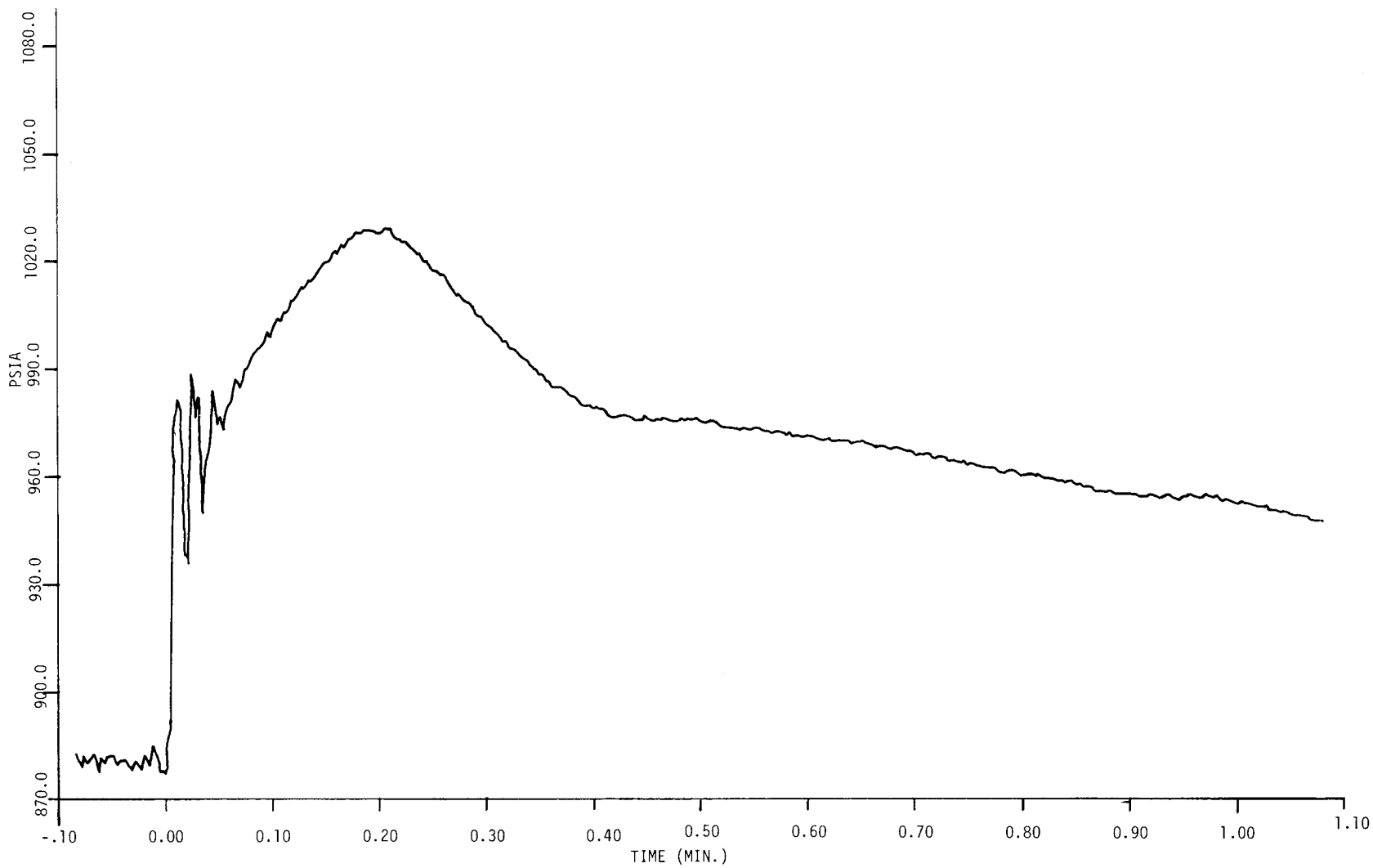


Figure 4-214. Turbine Trip - Steam Generator 1 Header Pressure

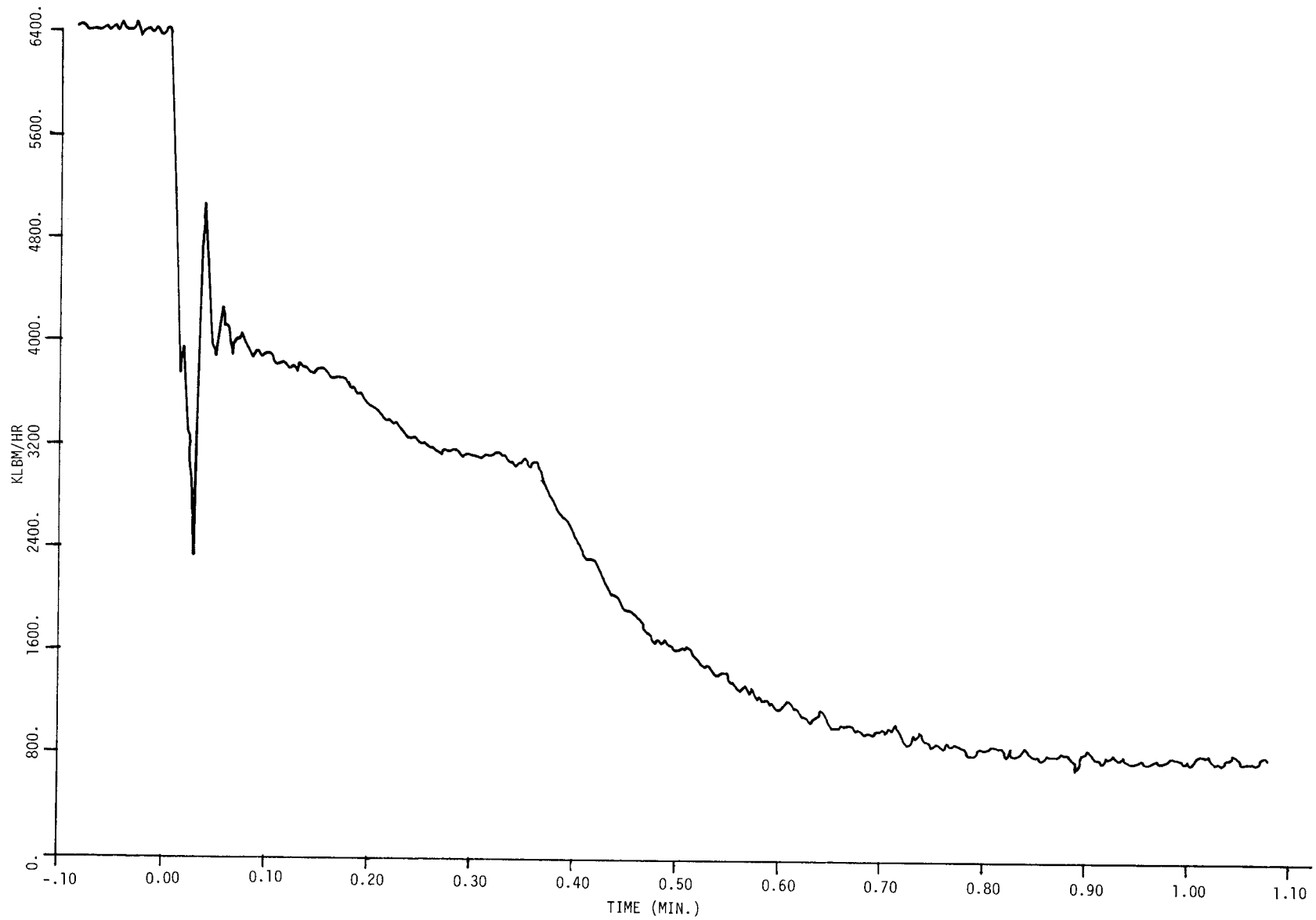


Figure 4-215. Turbine Trip - Steam Generator 1 Main Steam Flow Rate

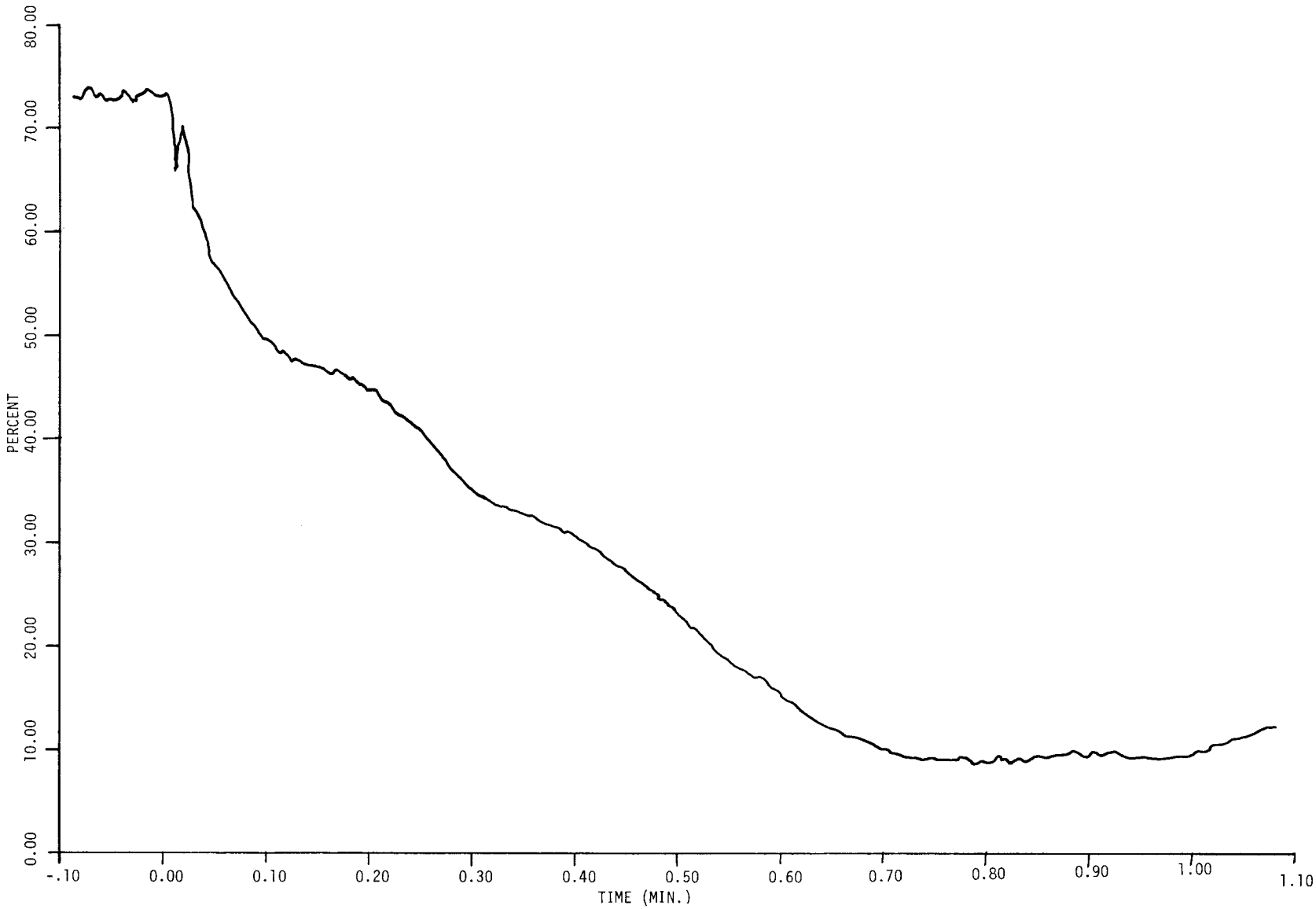


Figure 4-216. Turbine Trip - Steam Generator 1 Level

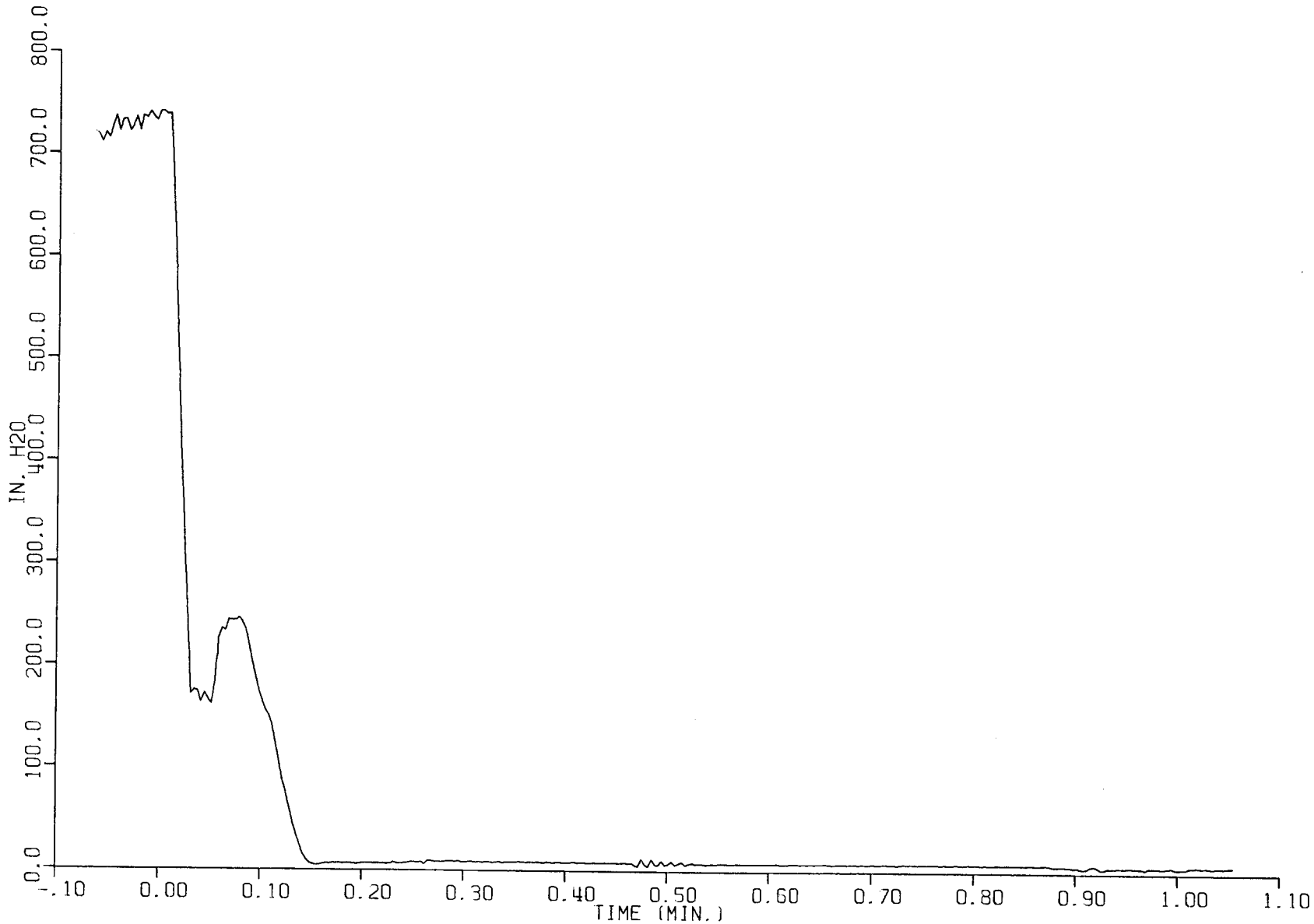


Figure 4-217. Turbine Trip - Steam Generator 2 Feedwater Differential Pressure

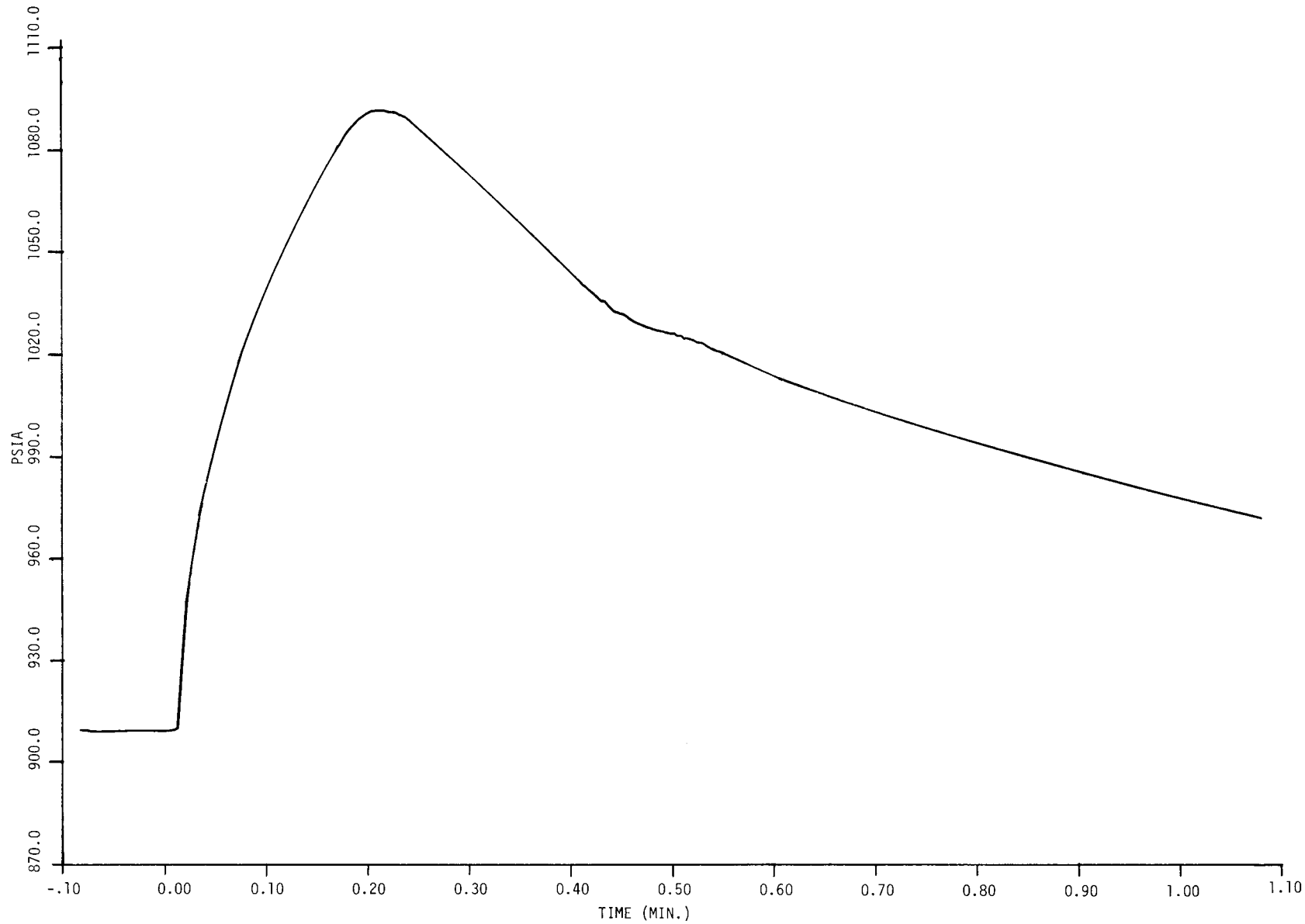


Figure 4-218. Turbine Trip - Steam Generator 2 Pressure

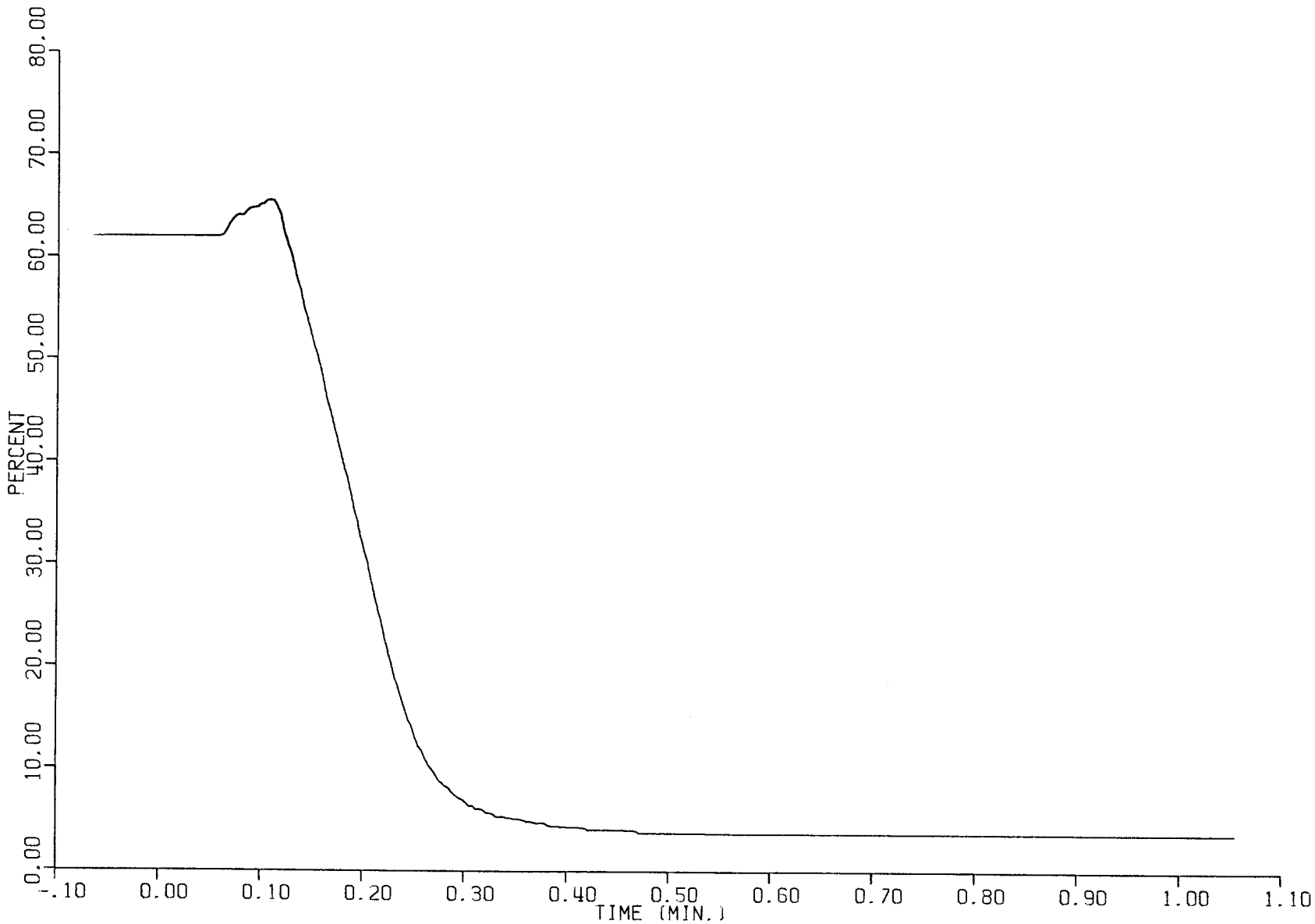


Figure 4-219. Turbine Trip - Steam Generator 2 Feedwater Valve Position

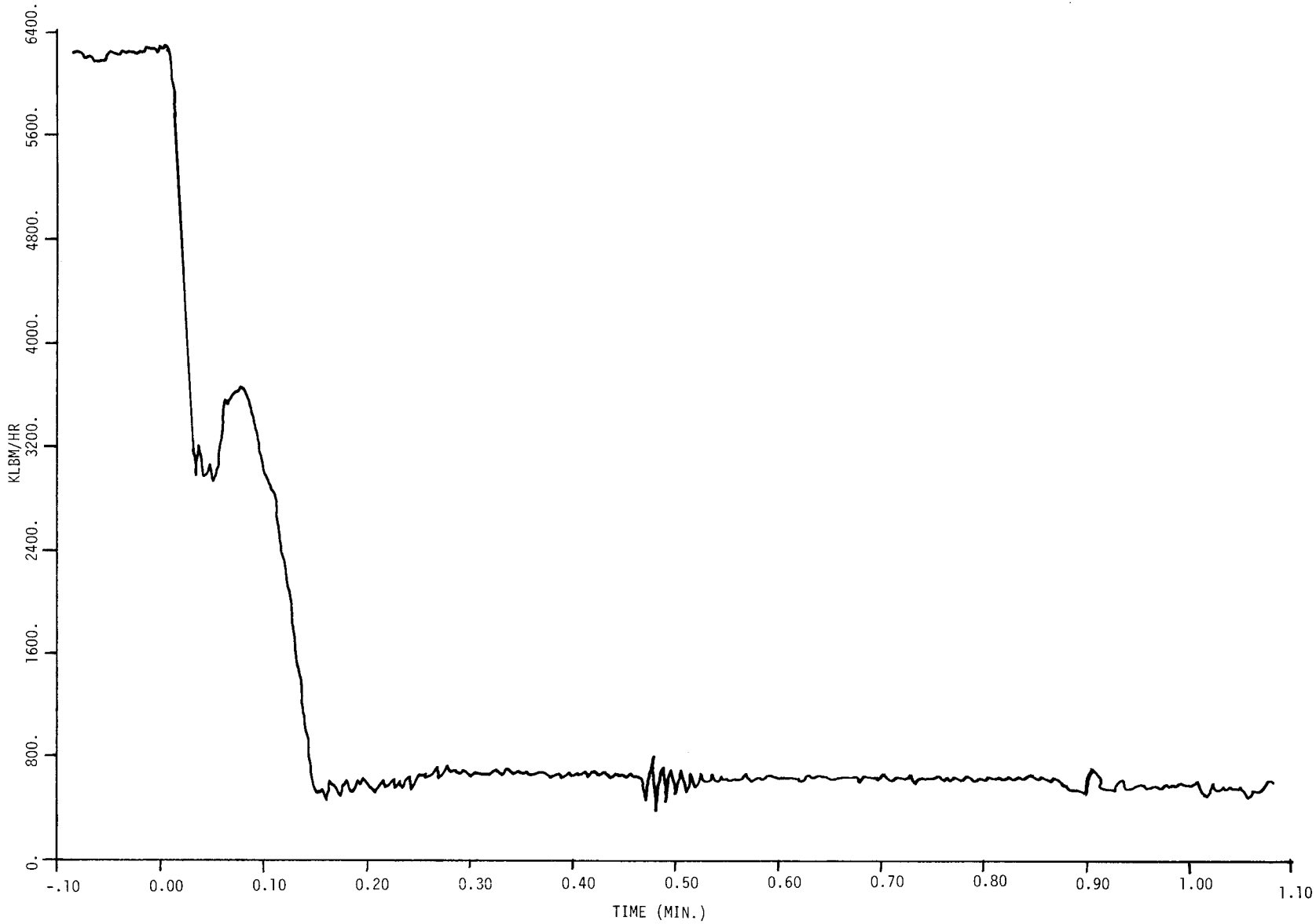


Figure 4-220. Turbine Trip - Steam Generator 2 Feedwater Flow Rate

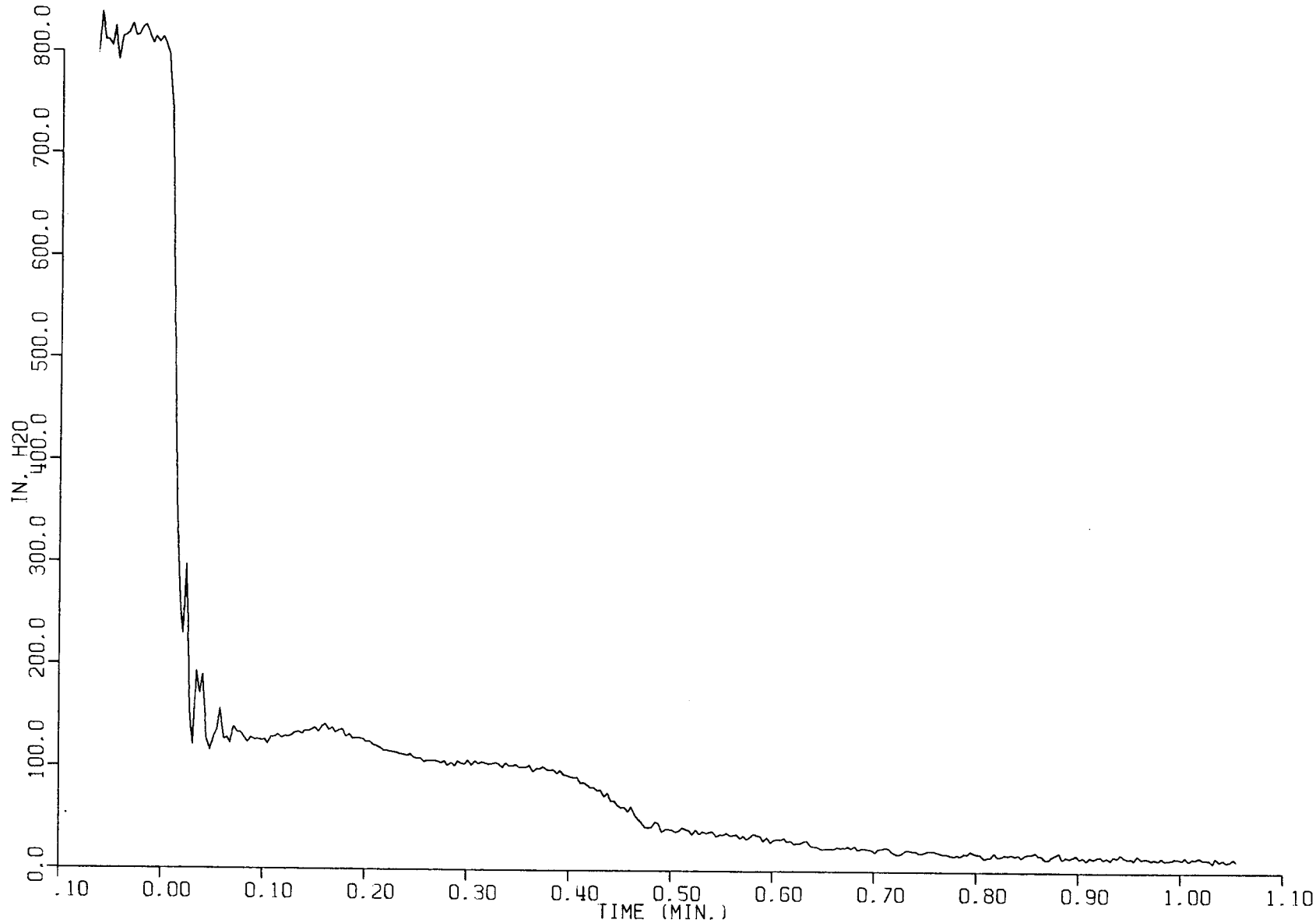


Figure 4-221. Turbine Trip - Steam Generator 2 Header Differential Pressure

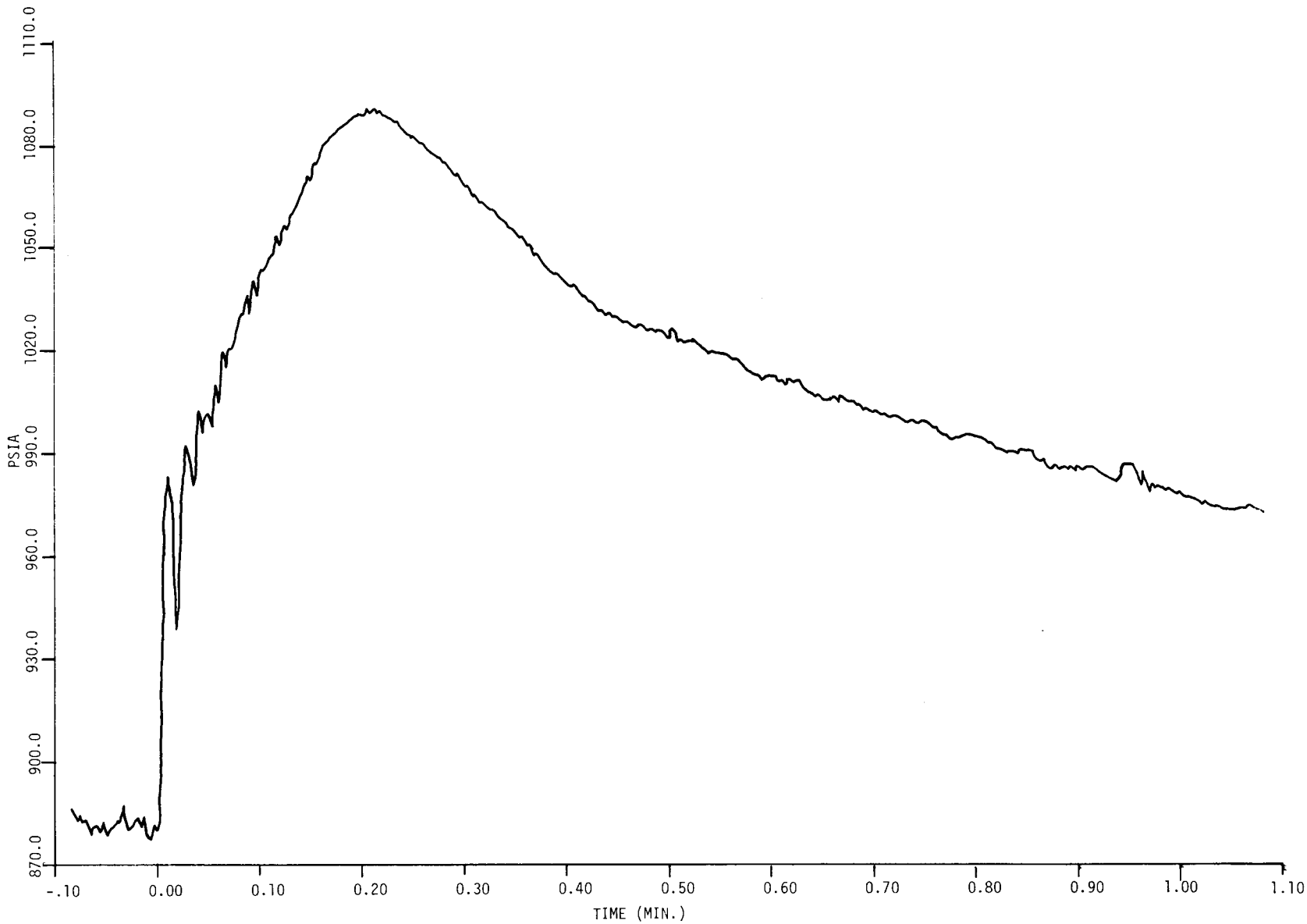


Figure 4-222. Turbine Trip - Steam Generator 2 Header Pressure

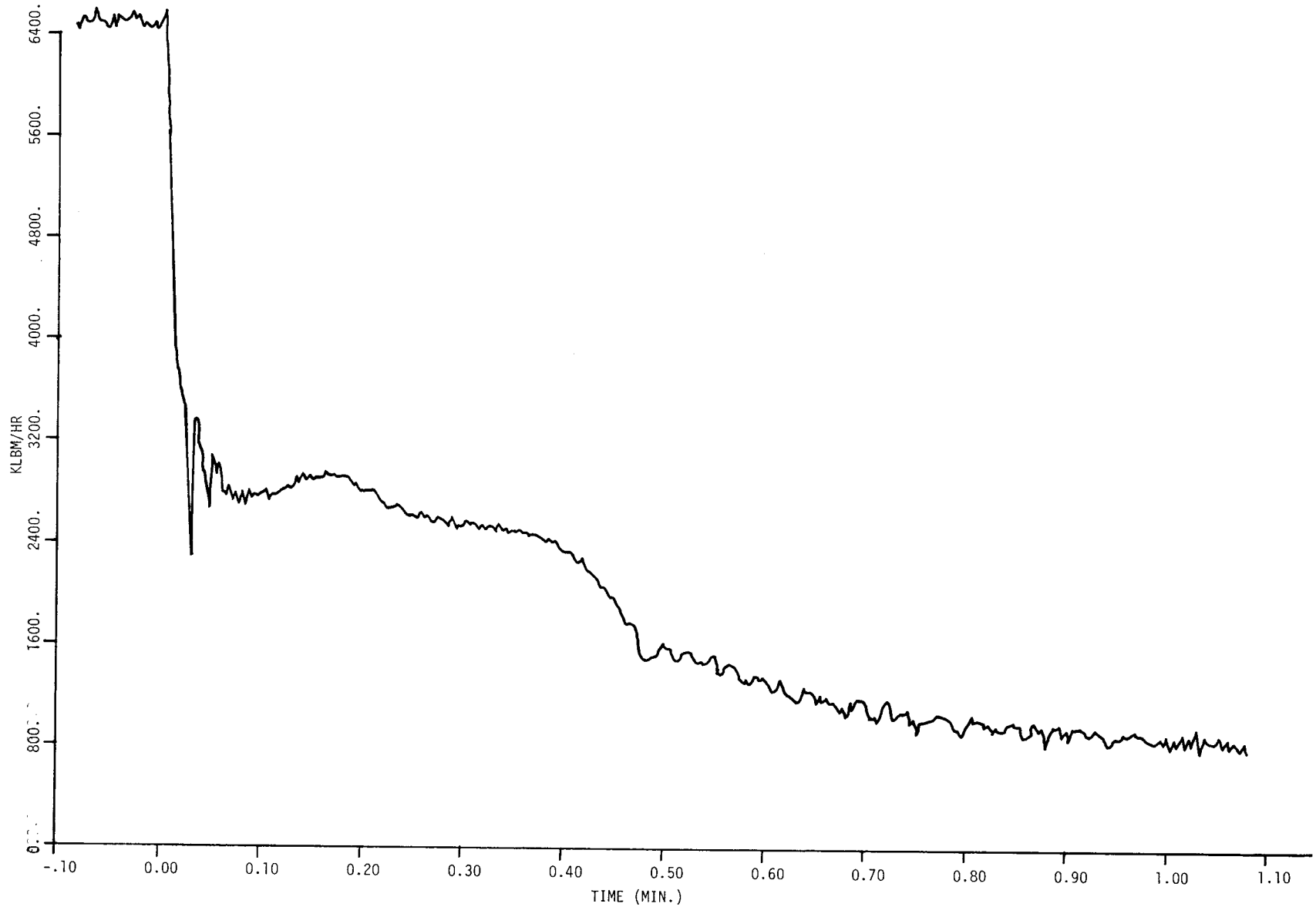


Figure 4-223. Turbine Trip - Steam Generator 2 Main Steam Flow Rate

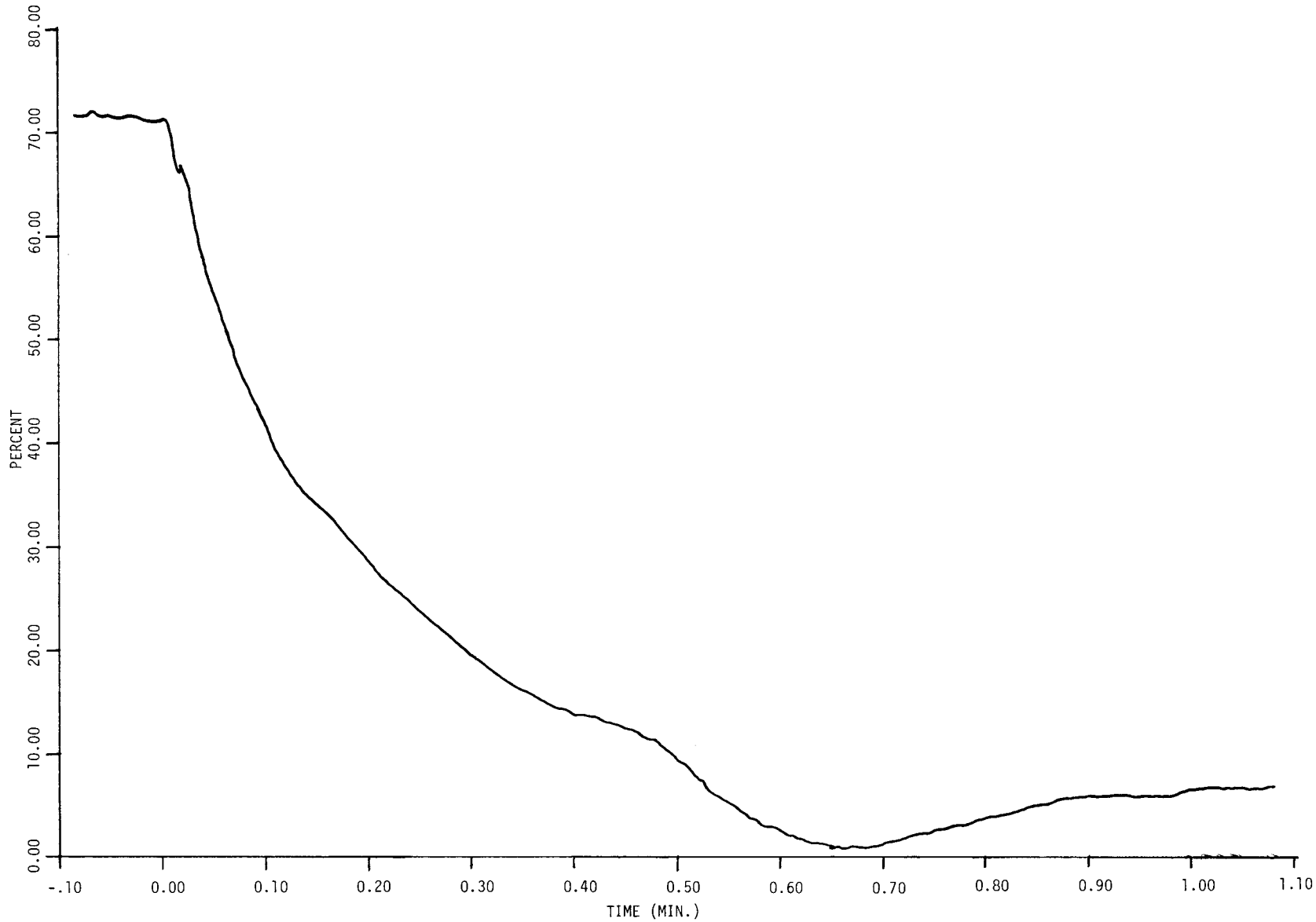


Figure 4-224. Turbine Trip - Steam Generator 2 Level

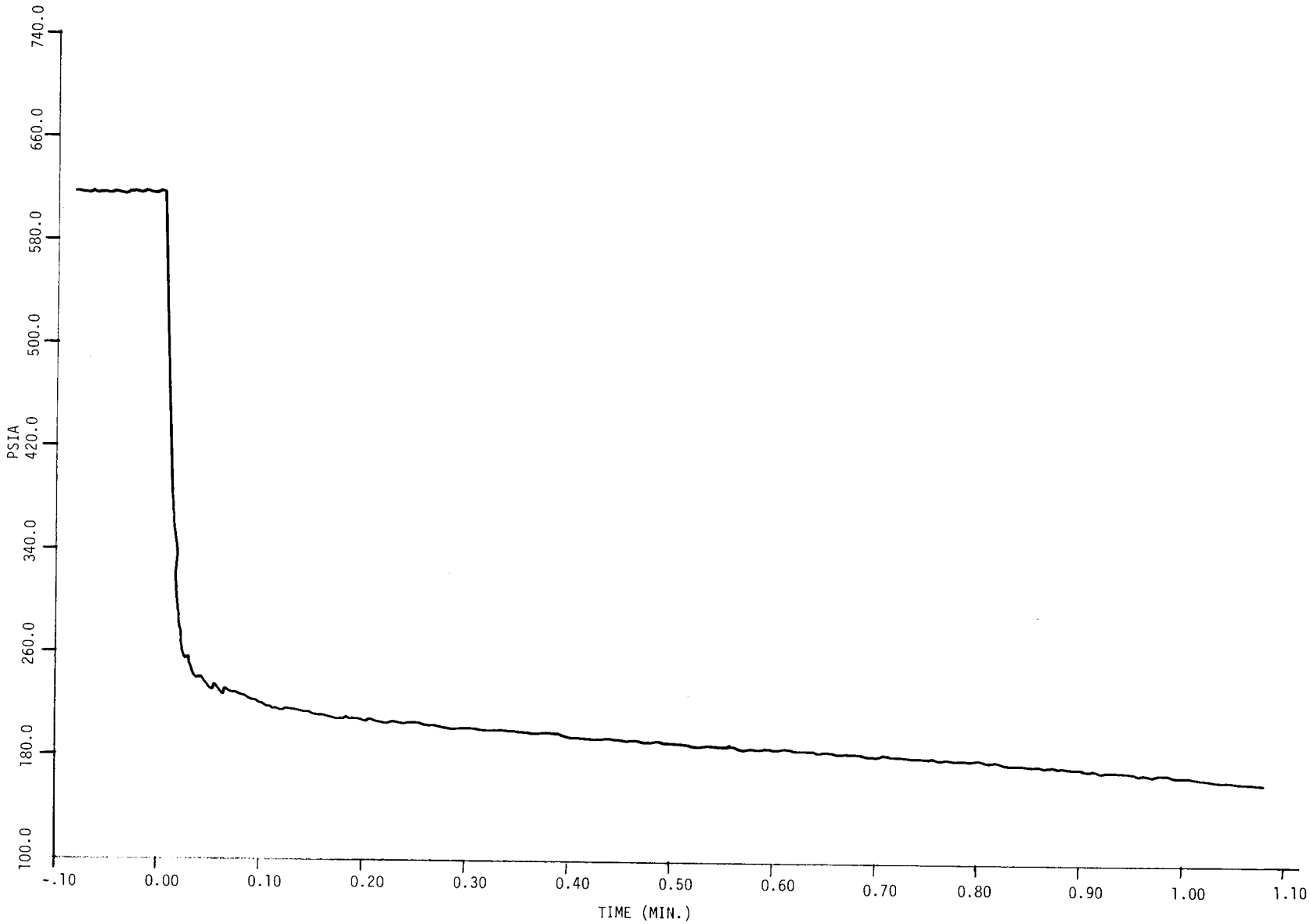


Figure 4-225. Turbine Trip - Turbine First Stage Pressure

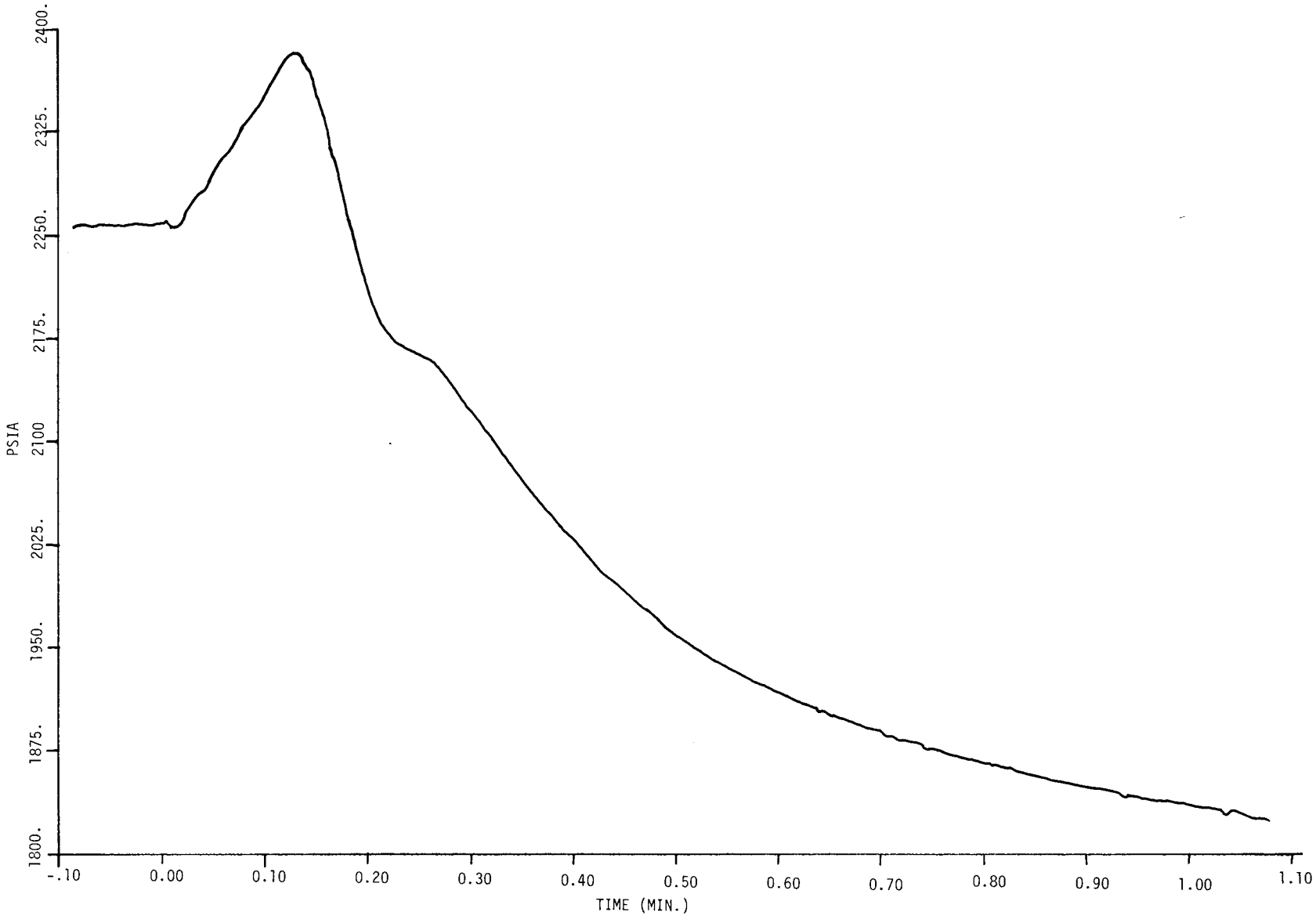


Figure 4-226. Turbine Trip - Pressurizer Pressure (Narrow Range)

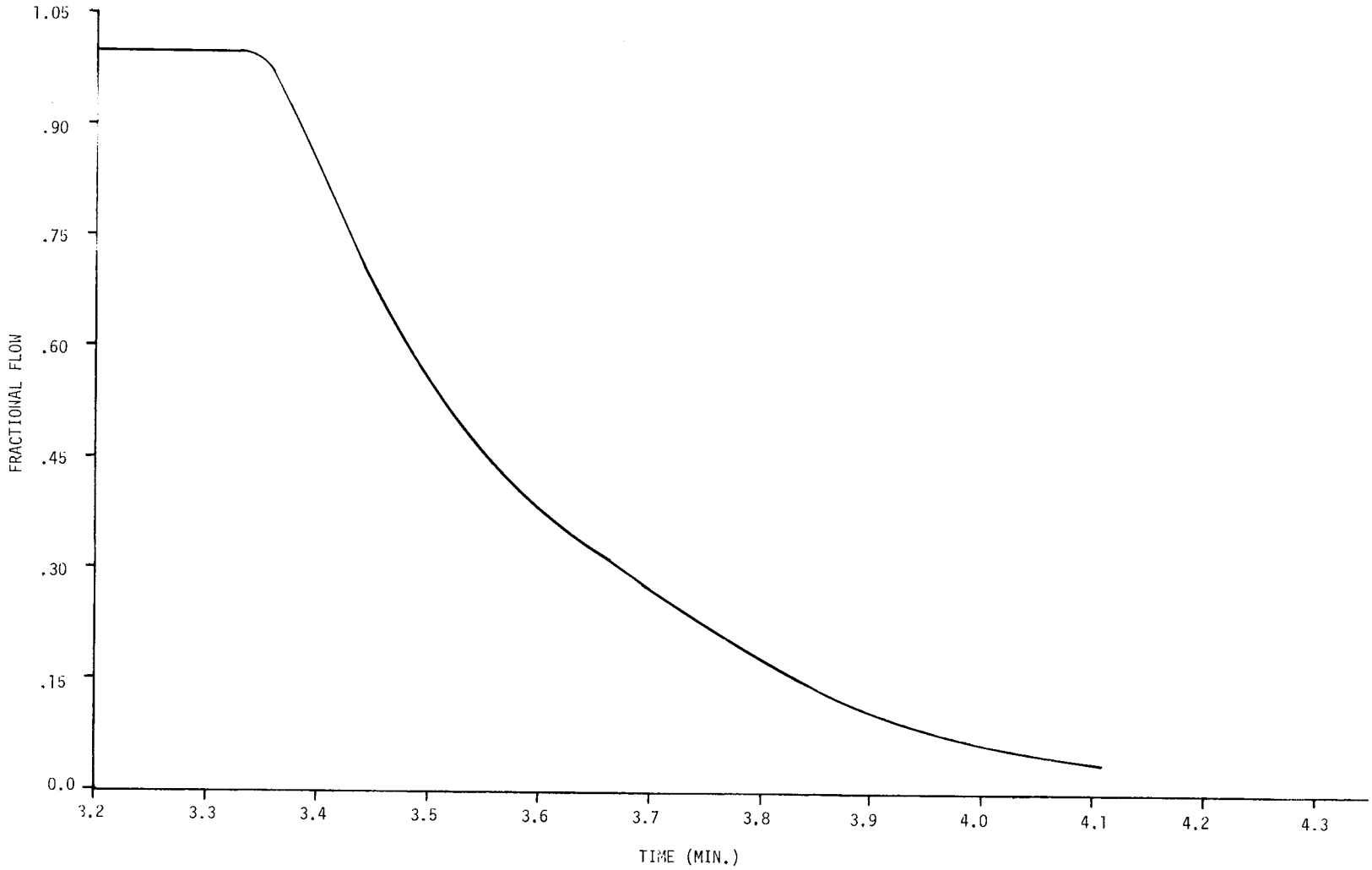


Figure 4-227. Turbine Trip - Total Core Flow Rate

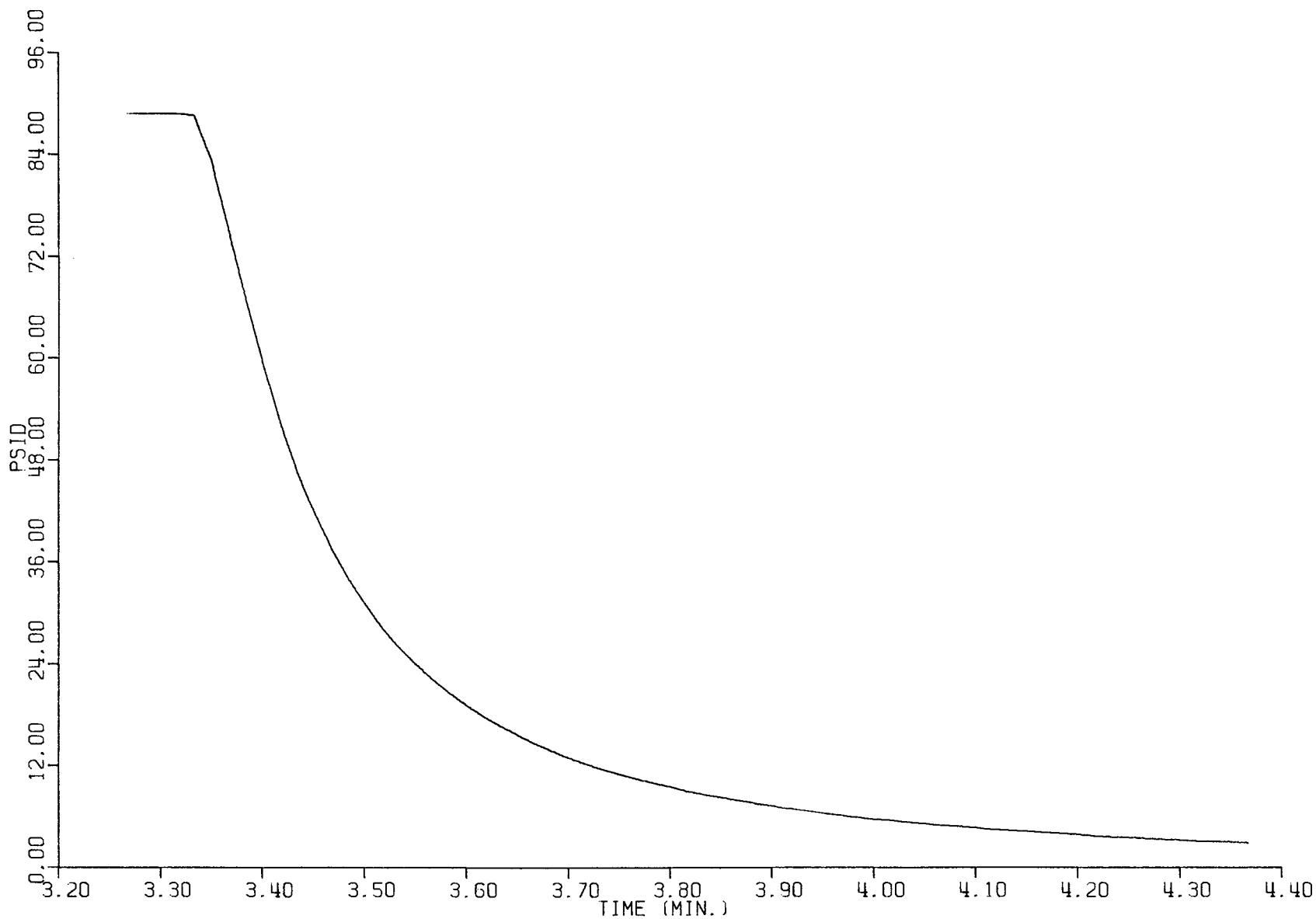


Figure 4-228. Turbine Trip - Reactor Coolant Pump 1A Differential Pressure

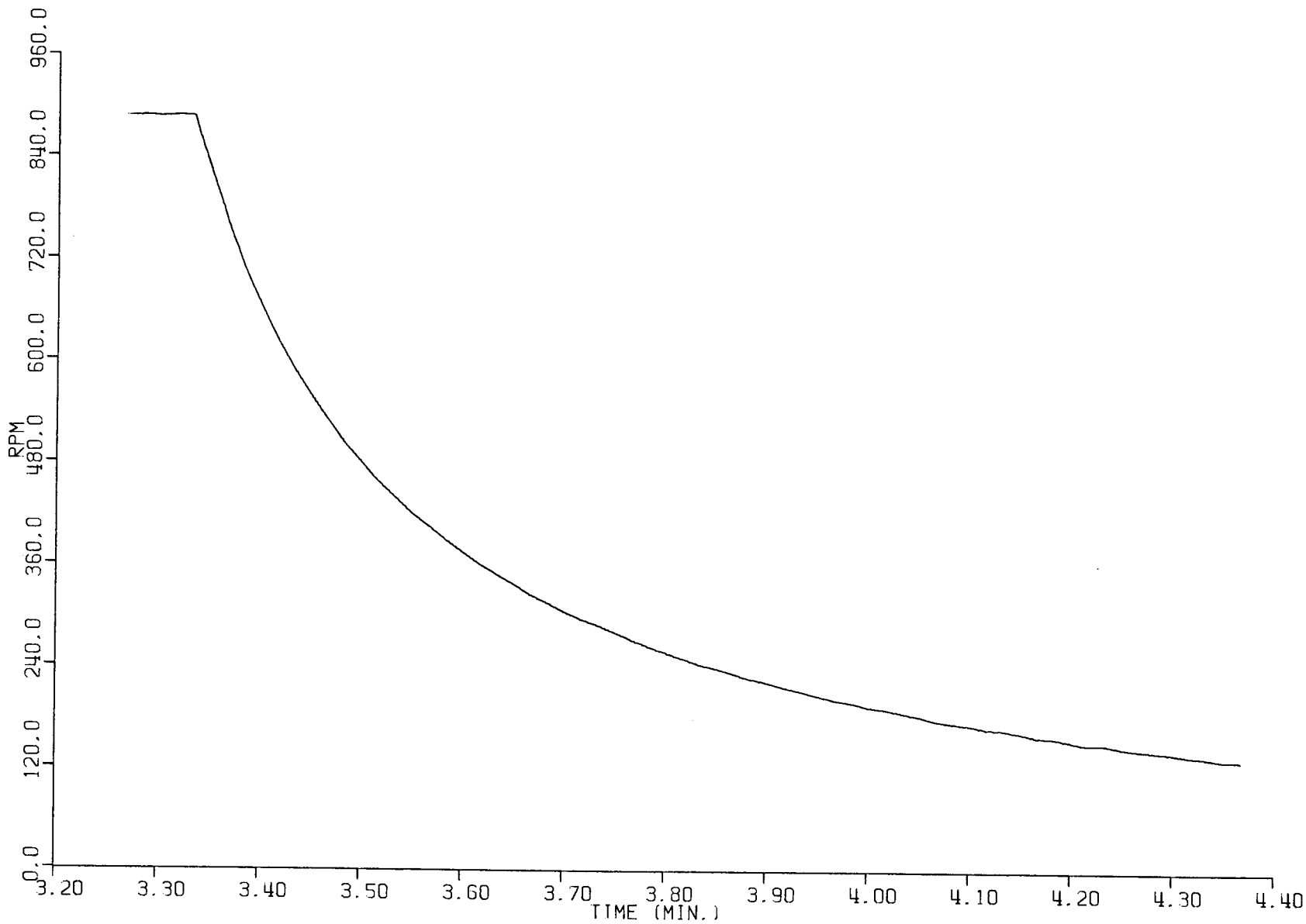


Figure 4-229. Turbine Trip - Reactor Coolant Pump 1A Speed

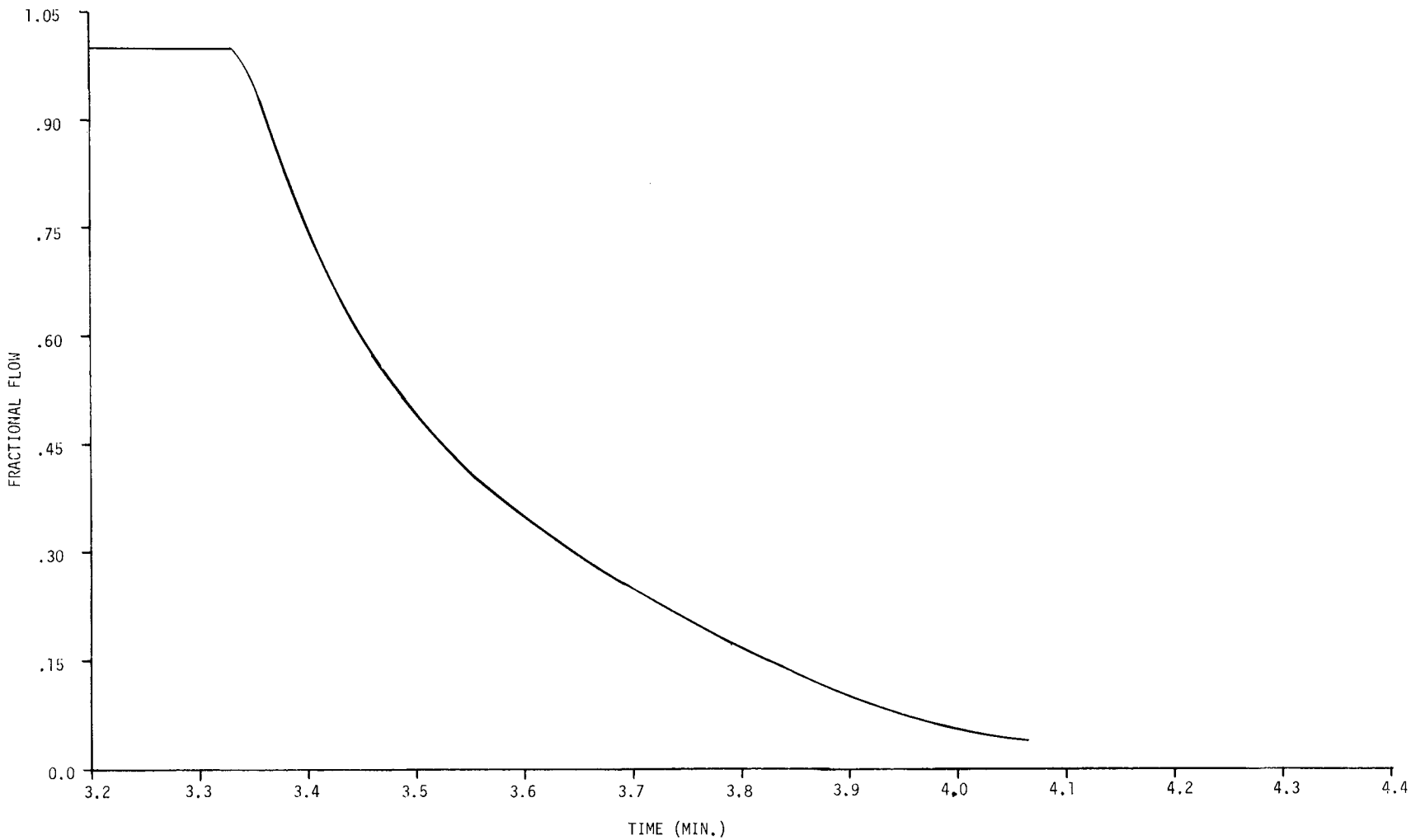


Figure 4-230. Turbine Trip - Reactor Coolant Pump 1A Flow Rate

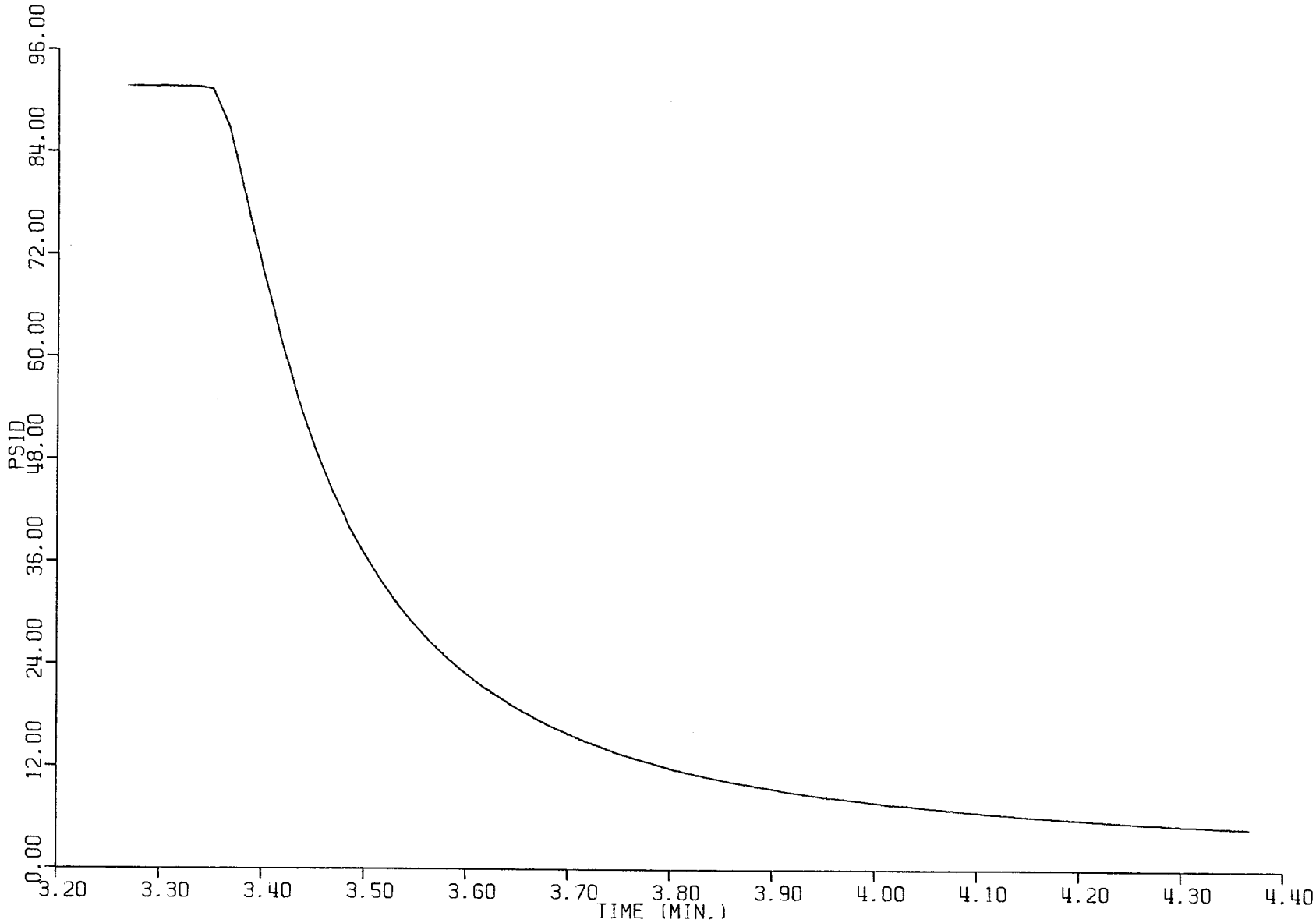


Figure 4-231. Turbine Trip - Reactor Coolant Pump 1B Differential Pressure

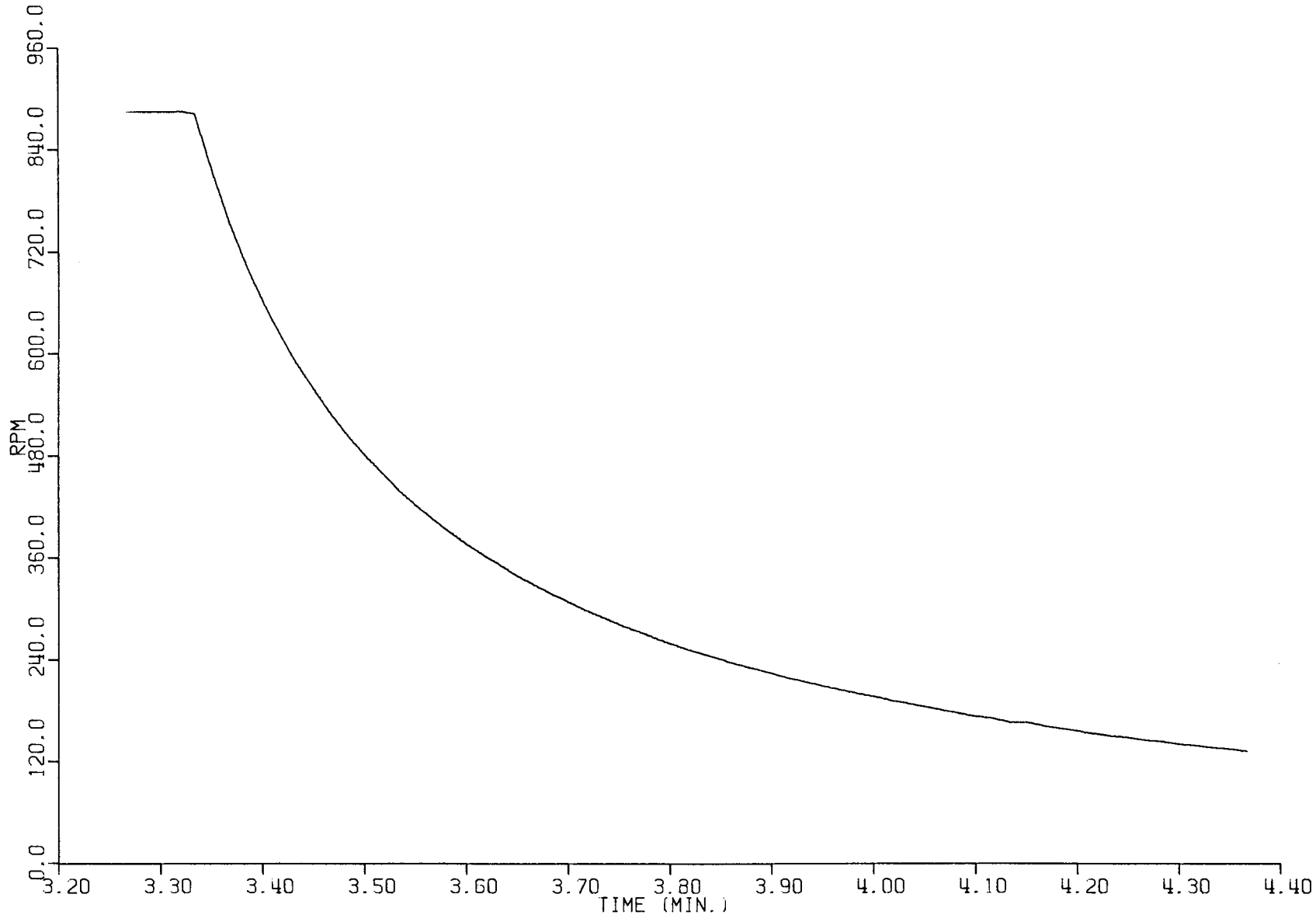


Figure 4-232. Turbine Trip - Reactor Coolant Pump 1B Speed

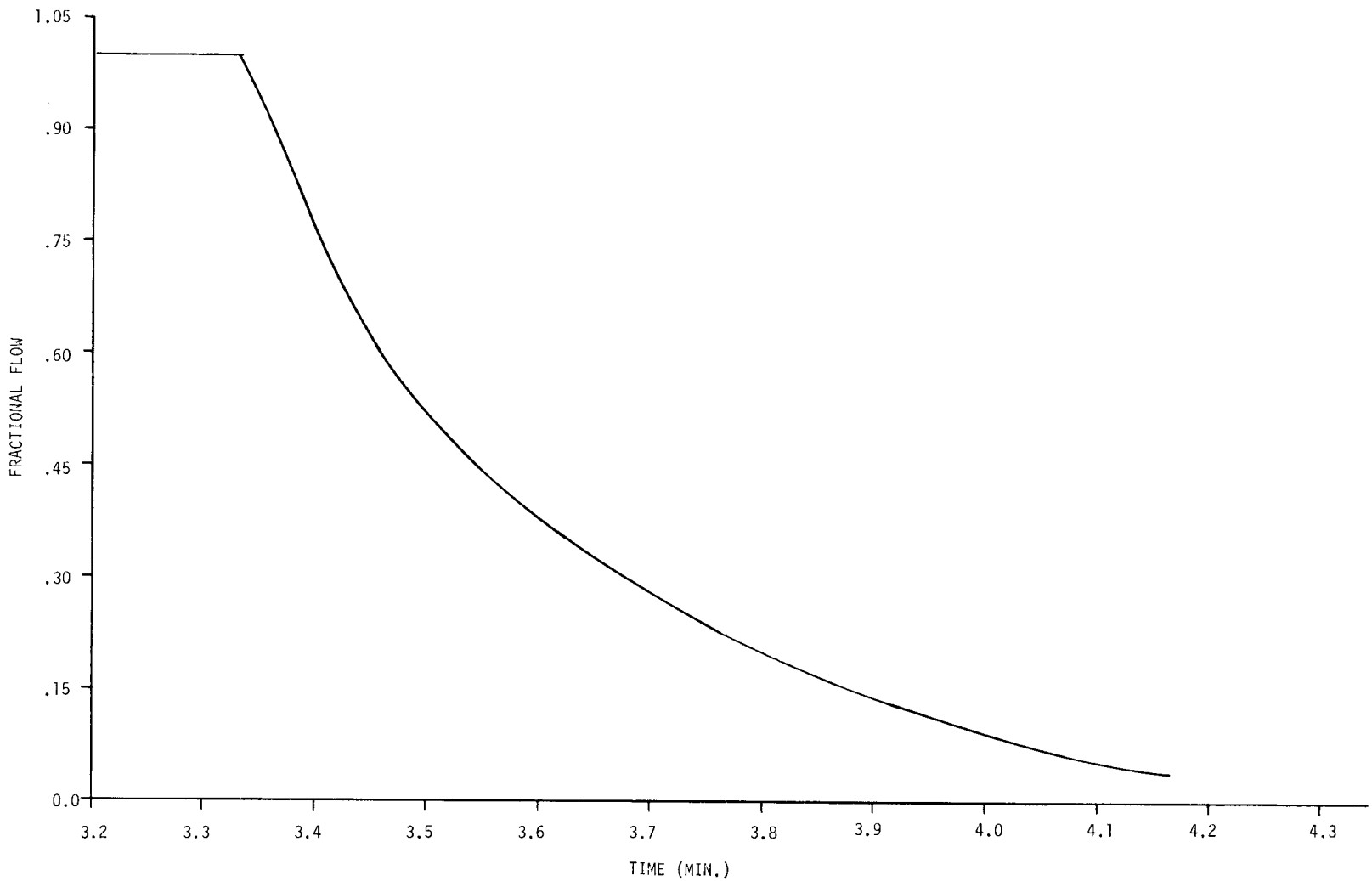


Figure 4-233. Turbine Trip - Reactor Coolant Pump 1B Flow Rate

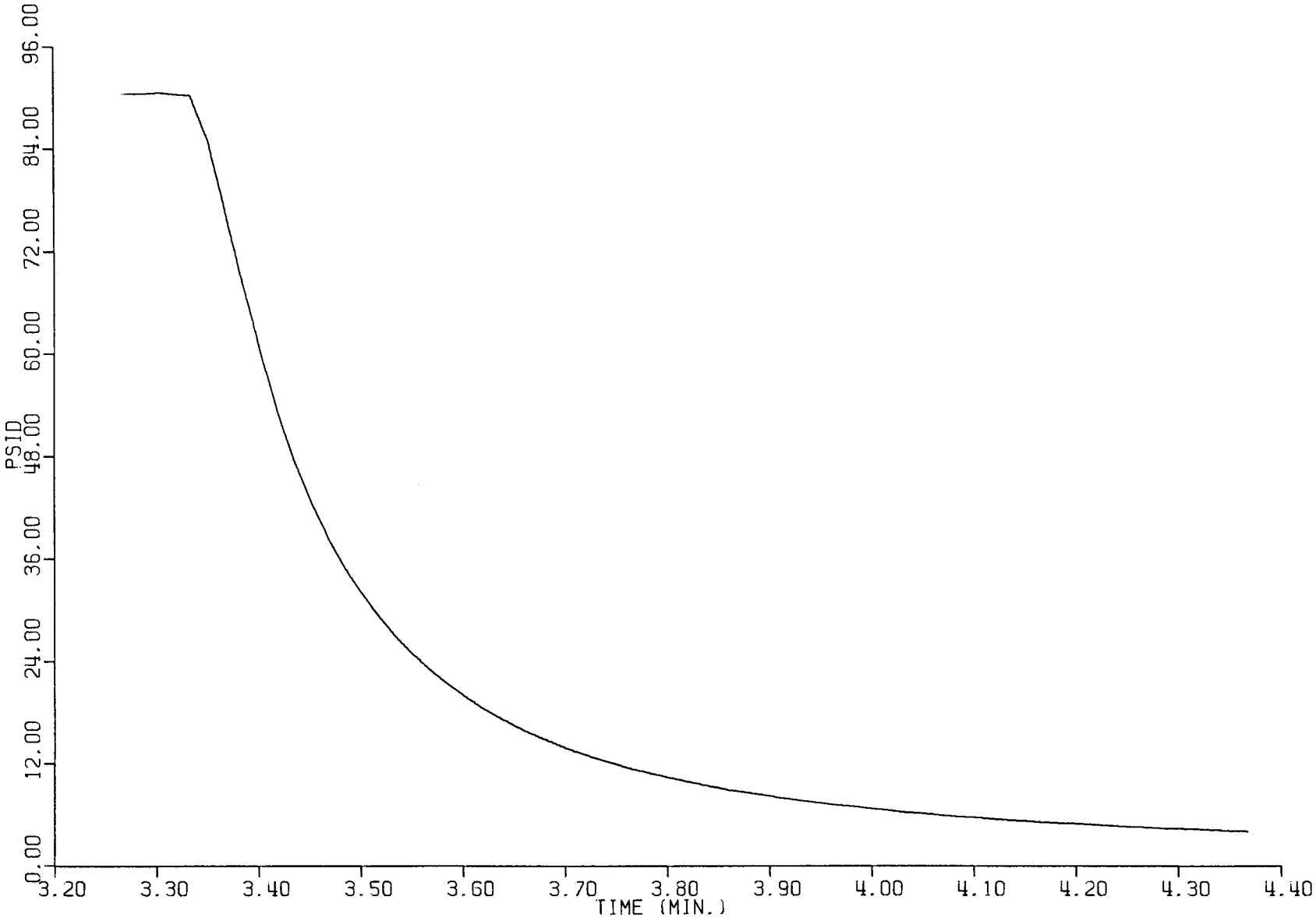


Figure 4-234. Turbine Trip - Reactor Coolant Pump 2A Differential Pressure

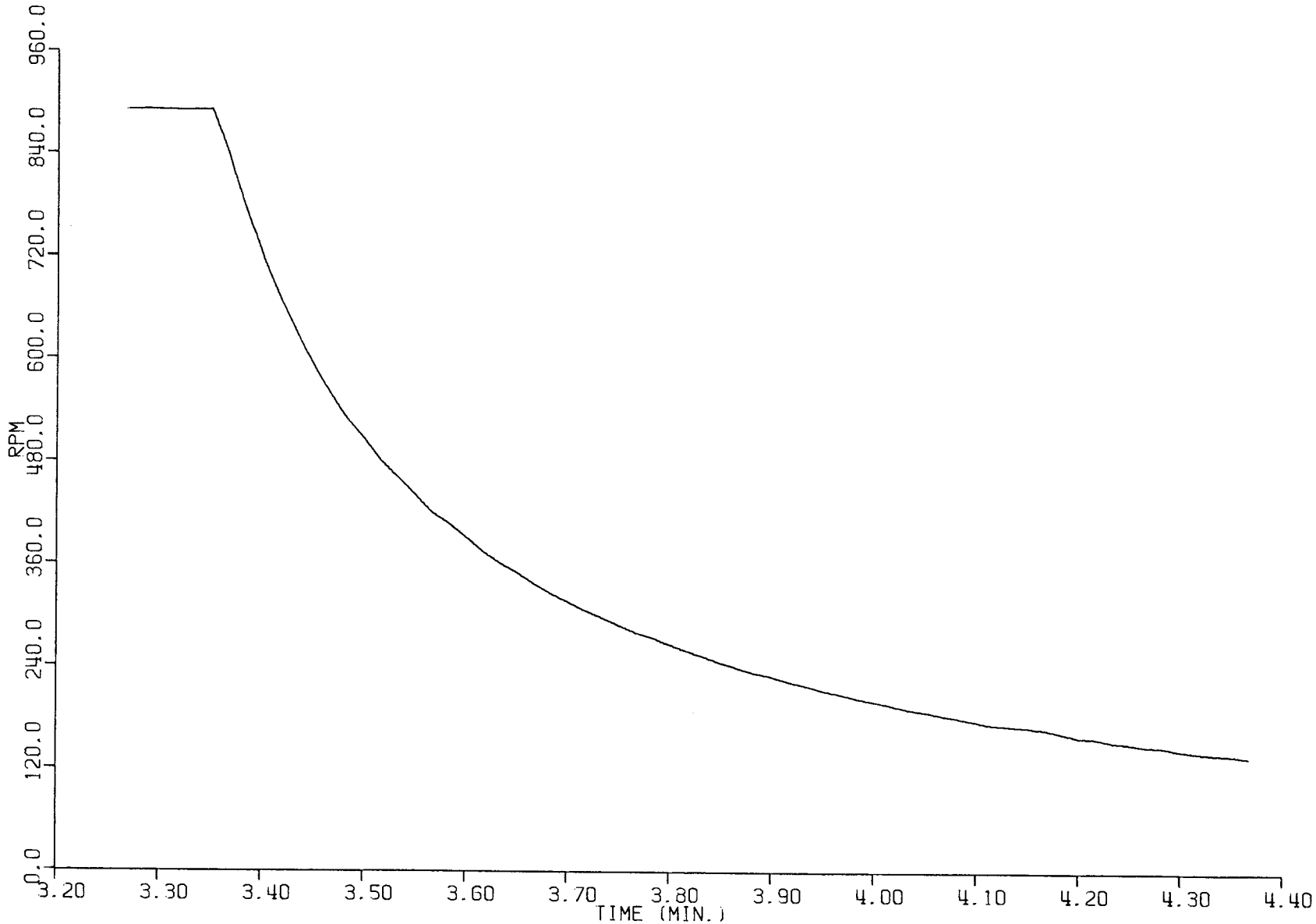


Figure 4-235. Turbine Trip - Reactor Coolant Pump 2A Speed

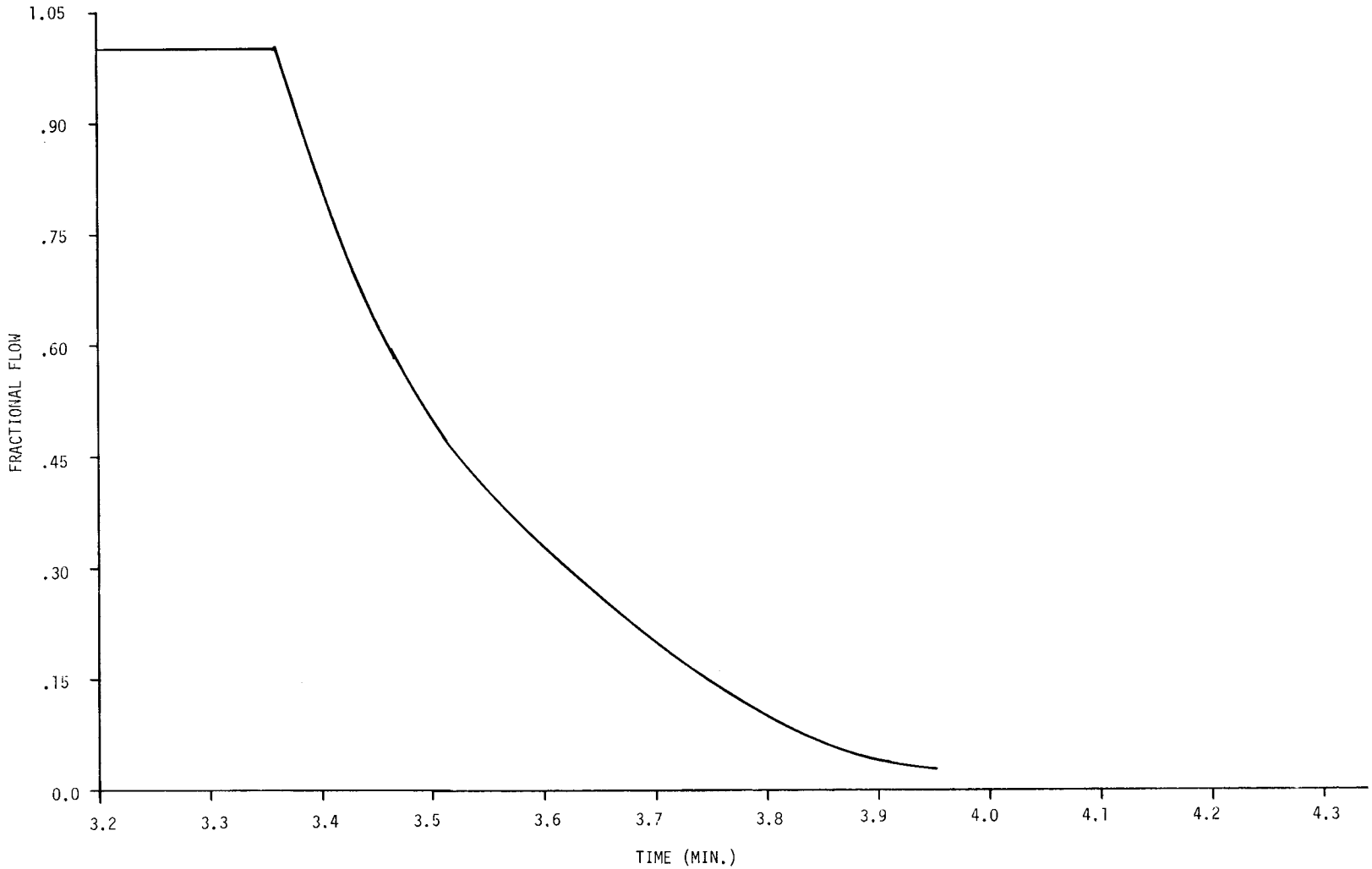


Figure 4-236. Turbine Trip - Reactor Coolant Pump 2A Flow Rate

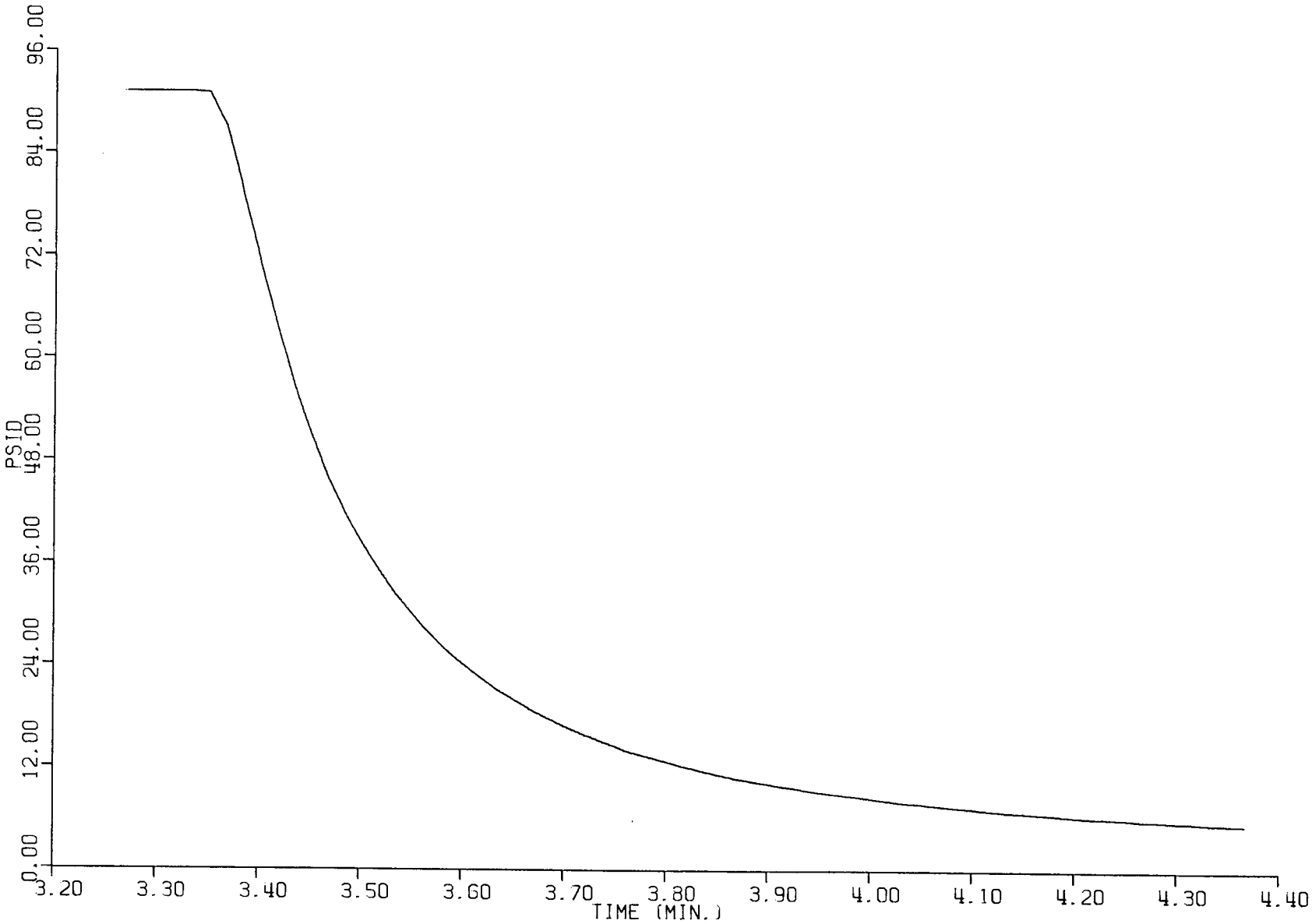


Figure 4-237. Turbine Trip - Reactor Coolant Pump 2B Differential Pressure

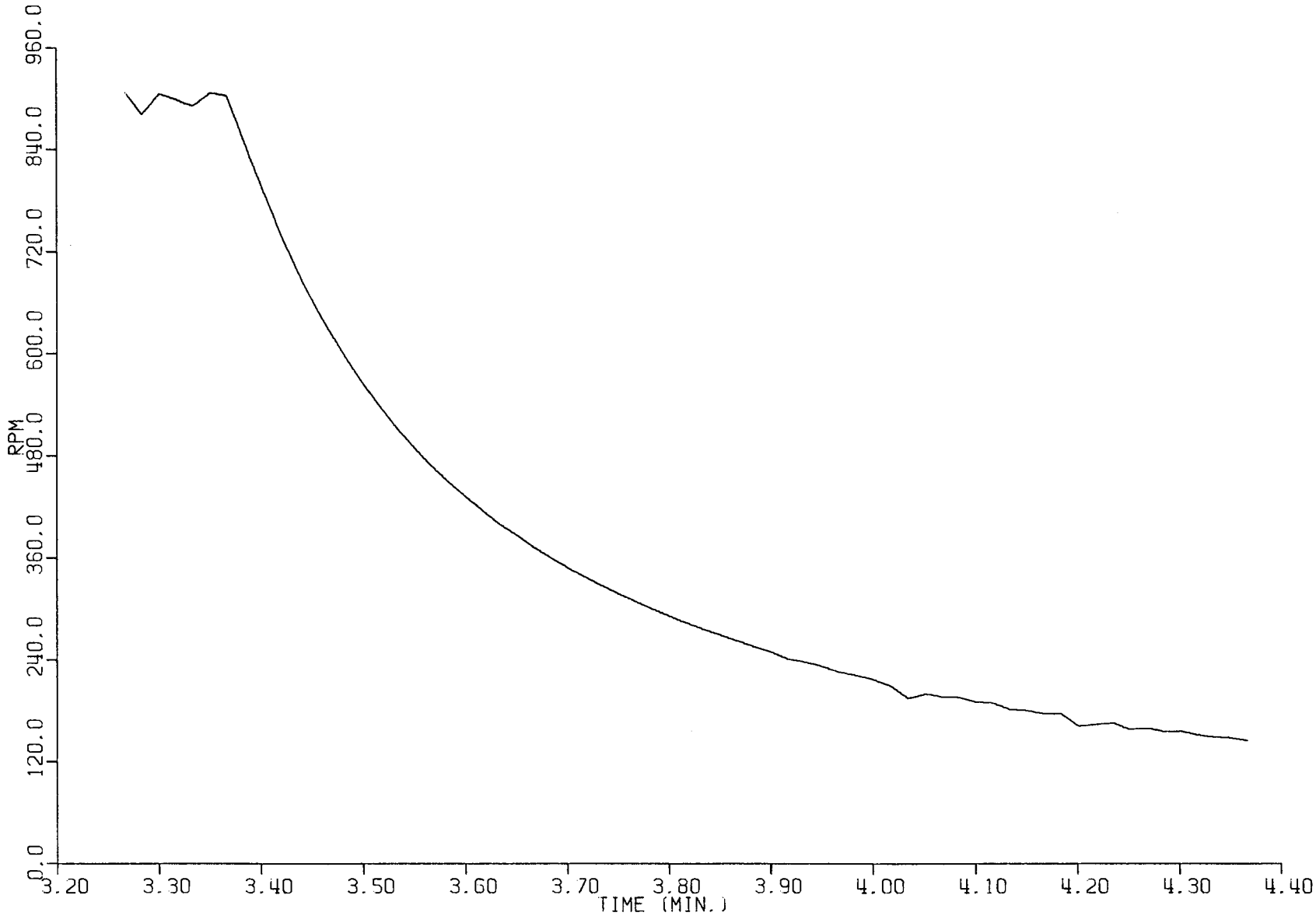


Figure 4-238. Turbine Trip - Reactor Coolant Pump 2B Speed

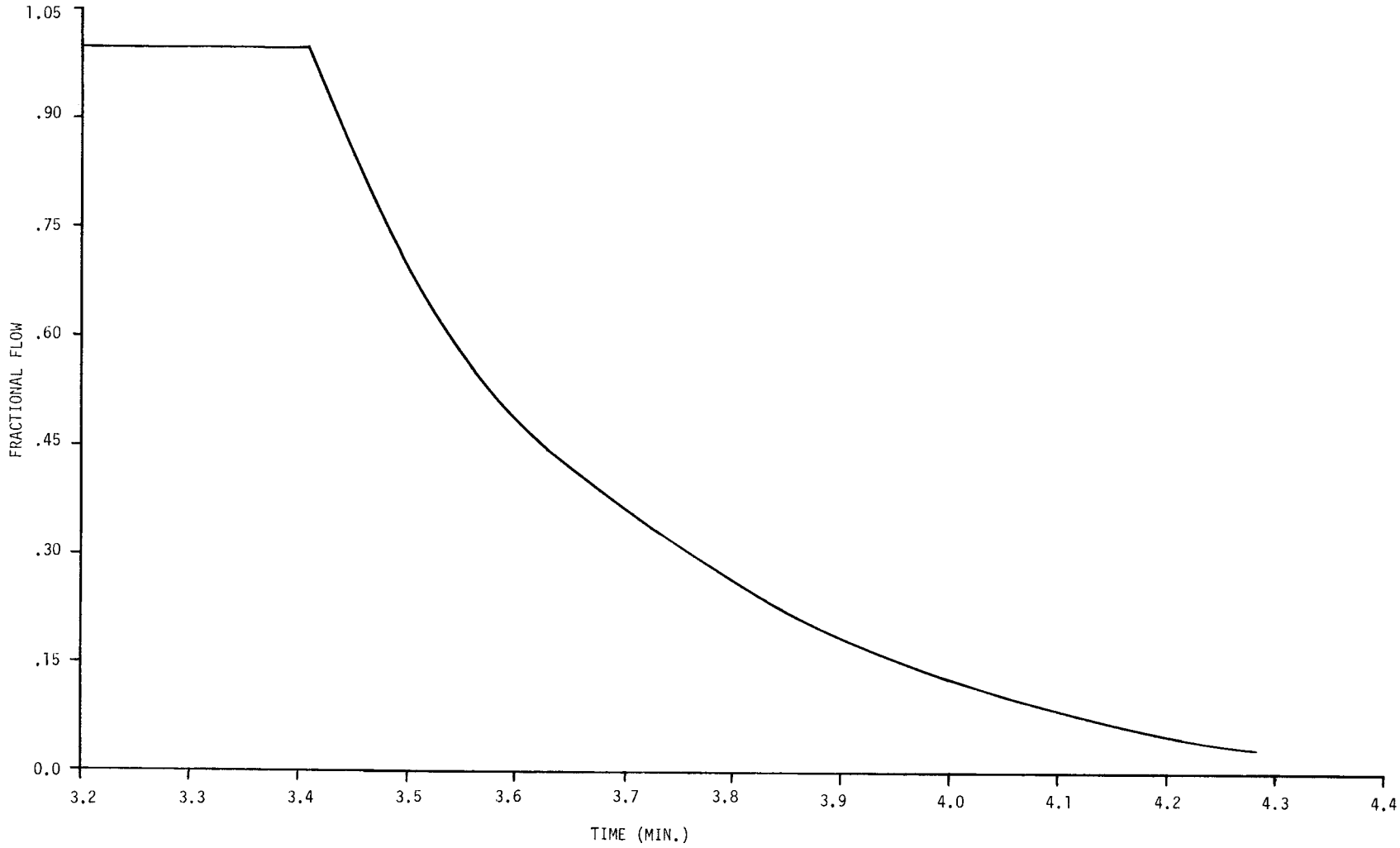


Figure 4-239. Turbine Trip - Reactor Coolant Pump 2B Flow Rate

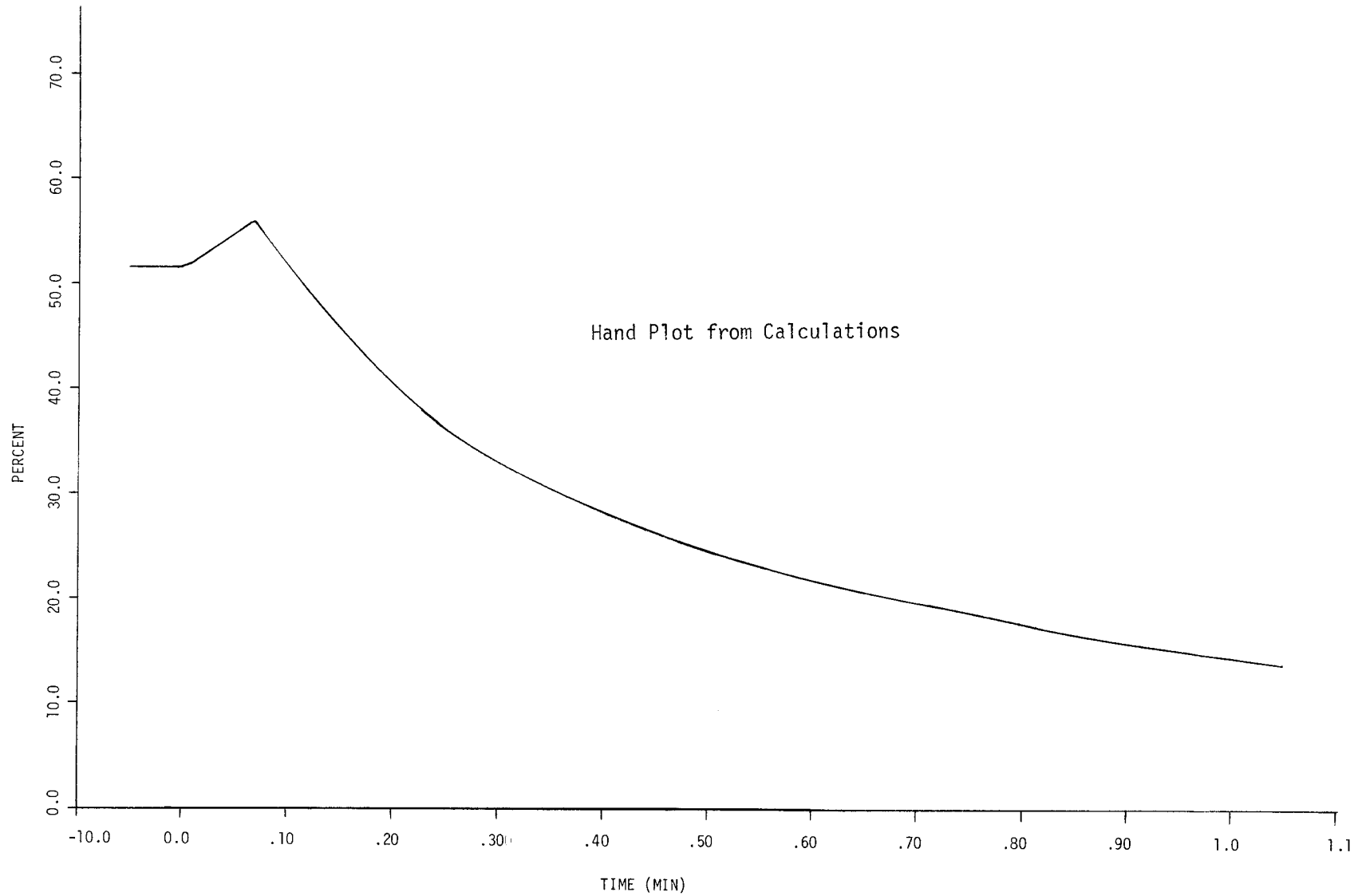


Figure 4-240. Turbine Trip - Pressurizer Level (Hand Calculated Values)

Section 5

CONCLUSIONS

The results of the PWR transient tests performed at ANO-2 provide a substantial addition to the data base for the electric power industry for qualifying NSSS simulation computer codes. Nearly all of the process parameters selected were successfully recorded during all of the tests. This data, which is derived from transients initiated both in the primary and secondary systems, includes a diverse set of NSSS transient conditions, thus allowing code qualification in a more comprehensive manner than was possible with previous available data.

The PDP-11 minicomputer proved to be a cost-effective tool for both recording and reducing the data. In addition, the minicomputer (and associated software) was utilized to digitally filter and plot the reduced data.

Although the Turbine Trip Test resulted in an unplanned sequence of events, the plant remained in a safe condition at all times. Moreover, the sequence of events that occurred during this test provides an unusually good opportunity to qualify NSSS simulation codes under abnormal transient conditions.

Section 6

REFERENCES

1. USNRC Regulatory Guide 1.70, Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants, Revision 2, September, 1975.

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

3. P. A. Gagne, ANO-2 NSSS Design and Cycle 1 Operating History Data, EPRI NP-1707, Electric Power Research Institute, March, 1981.

4. M. L. Kantrowitz and J. P. Thompson, Reactor Transient Tests at ANO-2, EPRI NP-1709, Electric Power Research Institute, October, 1982.

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

6. Technical Paper No. 410, Flow of Fluids Through Valves, Fittings, and Pipe, Crane Co., 1981.

APPENDIX A

PRIMARY SYSTEM FLOW RATES

Since primary system flow is directly proportional to core thermal margin, it is important that this quantity be determined accurately. The following sections describe the methodology and algorithms utilized to derive primary system flow rates from measured values of reactor coolant pump (RCP) differential pressures and speeds.

INSTRUMENTATION RESPONSE TIME CALCULATIONS

The calculation of RCP flow rates includes correction of the measured RCP differential pressure transmitter and speed sensor signals for the response times of the measuring instruments. Therefore, it was necessary to determine the response time constants of the eight Rosemount RCP differential pressure transmitters and the four RCP speed sensors used in the four transient tests.

To determine the response time constants of the differential pressure transmitters, a test rig was connected across each instrument in parallel with a fast-acting, high-response, reference transducer. For each differential pressure transmitter, known pressures varying between 20 and 130 psid were applied using a dead-weight test apparatus. The weights were used to generate a pressure transient similar in nature to that resulting from a complete RCP coastdown. The start of each pressure transient (initiated by the interruption of the pressure signal) was determined through the use of a quick-opening solenoid.

To determine the response time constants of the speed sensors, a square wave of frequency 327.07 Hz was input to the sensors using a signal generator. (A square wave of 327.07 Hz was previously determined to be characteristic of normal RCP operation.) A Brush recorder and Viscorder were used to continuously monitor the transient response. Each test consisted of several runs at a given pressure or operating speed.

DATA ACQUISITION AND REDUCTION

For all four transient tests, RCP speeds, RCP differential pressures, hot and cold leg temperatures and RCP breaker status were continuously monitored by the PDP-11/04 mini-computer. Coastdown data for the loss of flow test were taken at 100 millisecond intervals while coastdown data for the turbine trip test were taken every 1.0 seconds. The longer sampling time for the turbine trip test was the result of not knowing ahead of time when or if the pumps would be tripped. The pumps were tripped approximately 3 minutes into the turbine trip test when pressurizer pressure dropped low enough to generate a safety injection actuation signal (SIAS).

Following the completion of the test, the appropriate RCP data (differential pressures, speeds, etc.) were transferred to a floppy disk. The normalized RCP flow rates were then calculated using the methodology and algorithms described below. The results were then plotted by hand.

METHODOLOGY AND ALGORITHMS

Response Time Correction

The first step in the determination of RCP flow rates was to correct the measured RCP differential pressure transmitter and speed sensor signals for the instrument response times. This correction was performed using the following algorithm:

$$TIMCRT = PT2 + XTAU * \frac{(PT3 - PT1)}{2 * DT} , \qquad \text{(A-1)}$$

where

TIMCRT = time-corrected value at present time point,
PT2 = measured value at present time point,
PT3 = measured value at next time point,
PT1 = measured value at previous time point,
DT = elapsed time between samples,
XTAU = transmitter (sensor) time constant.

Calibration Correction

Next, calibration corrections for each Rosemount differential pressure transmitter were performed on the time-corrected RCP differential pressure data. This was done using calibration data points generated prior to the transient tests. The RCP differential pressures were calibration-corrected at each time point using the following interpolation:

$$DP_{cal} = \frac{(D - R_1) * (A_2 - A_1) + A_1}{(R_2 - R_1)} , \qquad \text{(A-2)}$$

where

DP_{cal} = calibration-corrected RCP differential pressure,

D = time-corrected RCP differential pressure,

R_2 = differential pressure read during transmitter calibration which lies directly above D,

R_1 = differential pressure read during transmitter calibration which lies directly below D,

A_2 = actual input corresponding to output R_2 taken from transmitter calibration sheets,

A_1 = actual input corresponding to output R_1 taken from transmitter calibration sheets.

Correction for Fluid Properties

The calibration-corrected RCP differential pressures were next corrected to reflect a specific gravity of 0.74. From the recorded primary system temperature and pressure data, the average RCS specific volume was obtained from the ASME Steam Tables. The RCP differential pressures at each time step were then corrected as follows:

$$DP_c = DP_{cal} * 46.102 \text{ lbm/ft}^3 * v_{avg} , \qquad \text{(A-3)}$$

where

DP_c = specific-gravity-corrected RCP differential pressure,

DP_{cal} = calibration-corrected RCP differential pressure,

v_{avg} = $v(T_{avg}, P_{avg})$ = average RCS specific volume obtained from ASME Steam Tables.

Zero Flow Correction

The next correction on the RCP differential pressures was to correct them for zero flow. (There is a non-zero differential pressure across each pump even for zero flow.) The correction is made as follows:

$$DP_F = DP_C - DP_{Co} \quad , \tag{A-4}$$

where

DP_F = zero-flow-corrected RCP differential pressure,
DP_C = specific-gravity-corrected RCP differential pressure,
DP_{Co} = RCP differential pressure for zero flow.

This correction is made at each time step for each of the four RCPs.

Pump Speed Correction

The RCP differential pressure vs. flow curves are based on a constant pump speed. However, during the loss of flow and turbine trip transients, the individual RCP pump speeds decrease with time, so that an accurate determination of the time-dependent flow cannot be obtained by directly using the transient zero-flow-corrected RCP differential pressure values (obtained from Equation (A-4)) in conjunction with the RCP differential pressure vs. flow curves. Rather, the transient zero-flow-corrected RCP differential pressure values (which correspond to a transient RCP pump speed) must first be transformed to an equivalent pseudo-steady-state RCP differential pressure value for a constant pump speed which is the same as that on which the RCP differential pressure vs. flow curves are based. This transformation was performed at each time step for each of the four RCPs as follows:

$$DP_{Fc} = DP_F * \left[\frac{RPM_C}{RPM}\right]^2 \quad , \tag{A-5}$$

where

DP_{Fc} = new RCP casing differential pressure,
DP_F = zero-flow-corrected RCP differential pressure values (from Equation (A-4)),
RPM_C = pump speed measured during pump case calibration test,
RPM = transient time-response-corrected pump speed.

Determination of Flow Rates

The individual pseudo-steady-state RCP volumetric flow rates were determined using the differential pressure values calculated in Equation (A-5) in conjunction with the appropriate Byron-Jackson RCP differential pressure vs. flow curves (Figures A-1 through A-4). The actual transient RCP volumetric flow rates at each time point were then obtained by scaling the pseudo-steady-state RCP volumetric flow rates downward to correspond to the measured transient RCP signals as follows:

$$Q_i(t) = Q_{i_{pseudo}}(t) * \frac{RPM}{RPM_C} , \qquad i = 1A, 1B, 2A, 2B \qquad \text{(A-6)}$$

where

Q_i = actual RCS loop volumetric flow rate,
$Q_{i_{pseudo}}$ = pseudo-steady-state RCS loop volumetric flow rate.

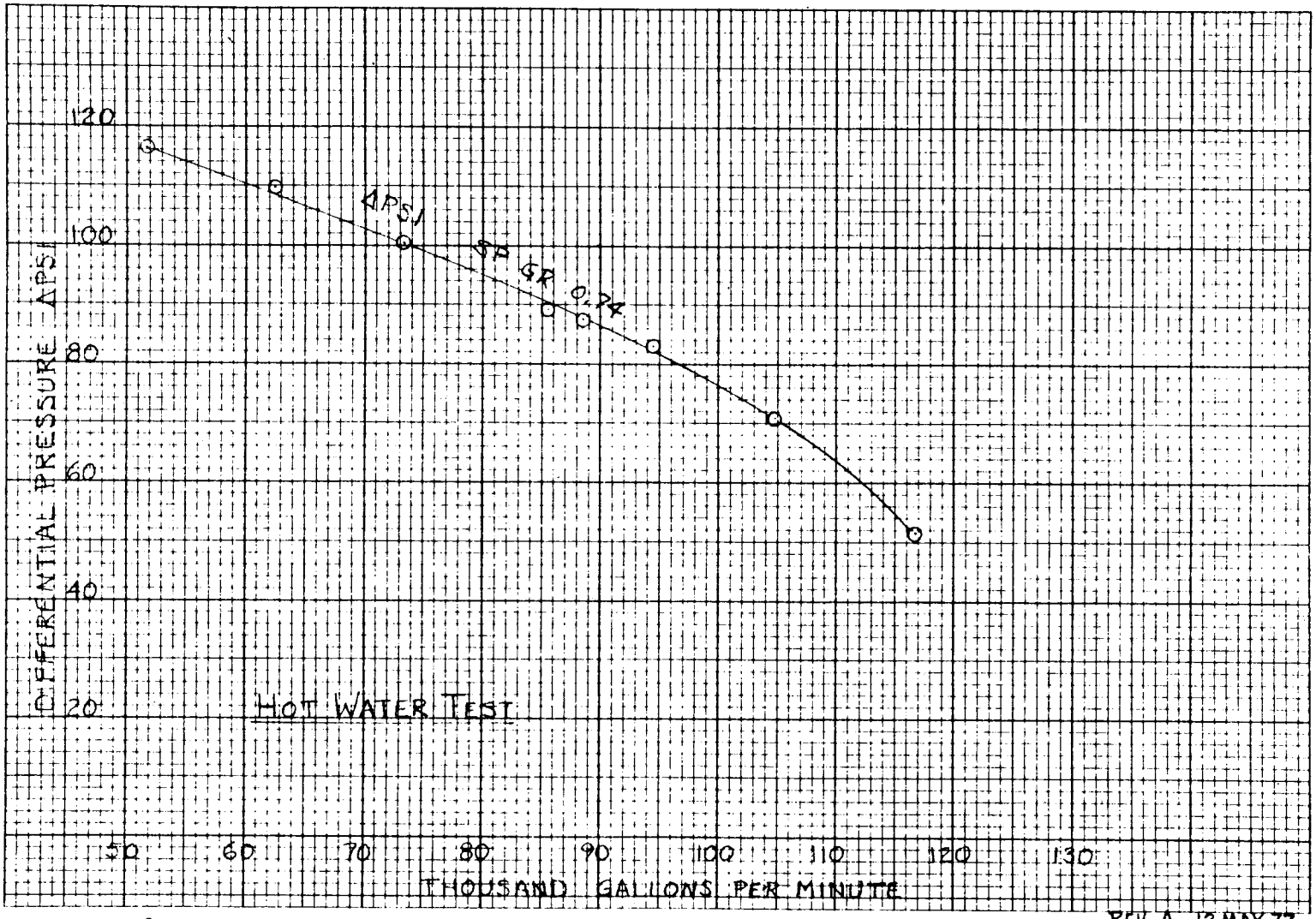
and RPM and RPM_C are as defined in Equation (A-5).

The normalized flow rate ($Q_{N_i}(t)$) for each loop is determined by dividing the loop flow rate at each time point by the corresponding steady-state flow rate, i.e.,

$$Q_{N_i}(t) = \frac{Q_i(t)}{Q_i \text{ (steady-state)}} . \qquad \text{(A-7)}$$

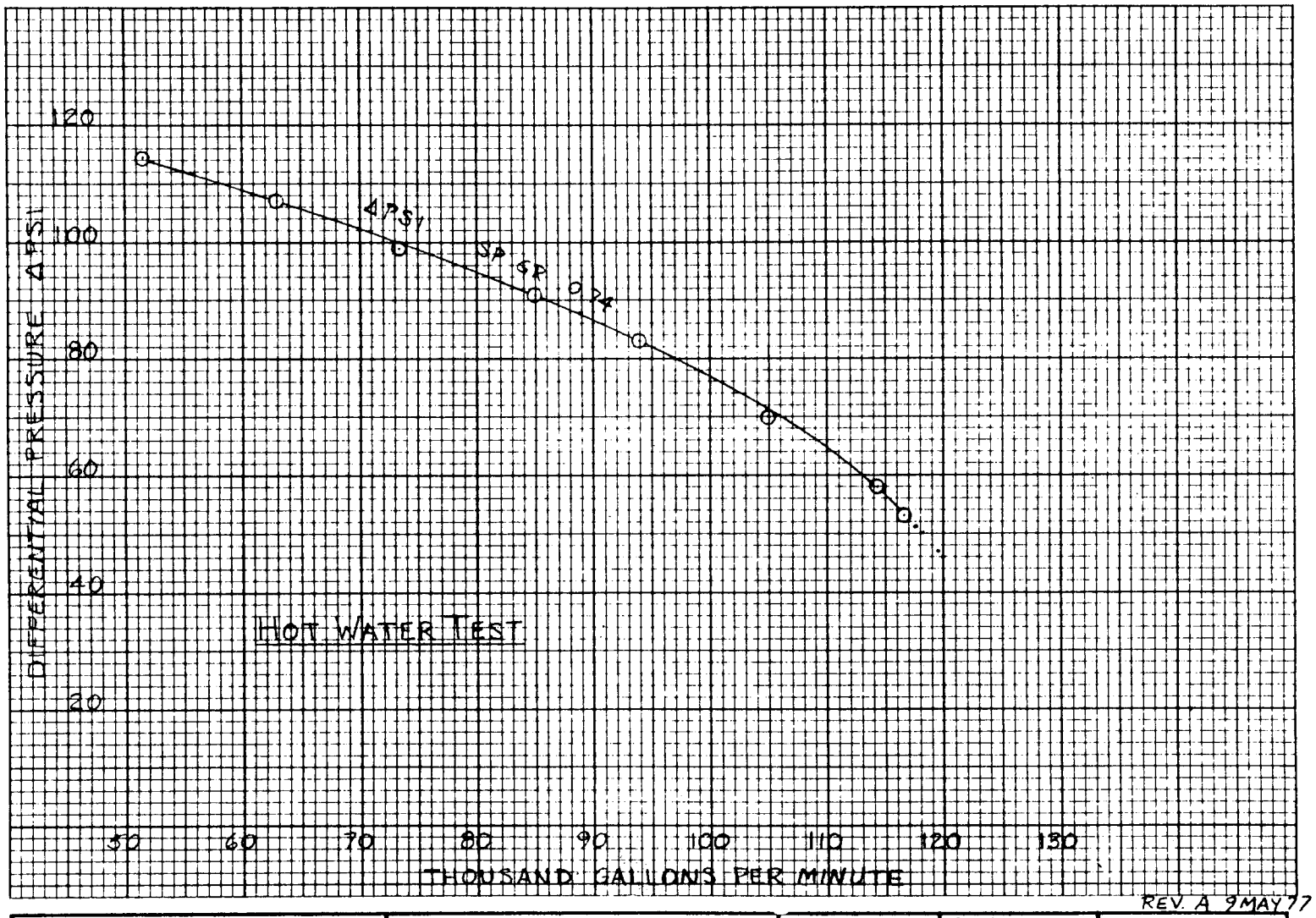
The total normalized RCS flow rate ($Q_N(t)$) for each time point is obtained by summing the individual normalized loop flow rates calculated in Equation (A-7), i.e.,

$$Q_N(t) = Q_{N_{1A}}(t) + Q_{N_{1B}}(t) + Q_{N_{2A}}(t) + Q_{N_{2B}}(t) . \qquad \text{(A-8)}$$



36 × 30 × 43 DFSS	PUMP CASE CALIBRATION ΔPSI vs CAPACITY	DATA BY: MA	JOB NO 701-N-0594	REV. A 12 MAY 77 T-34278-12A
		DRAWN BY MA	DATE 6-8-74	

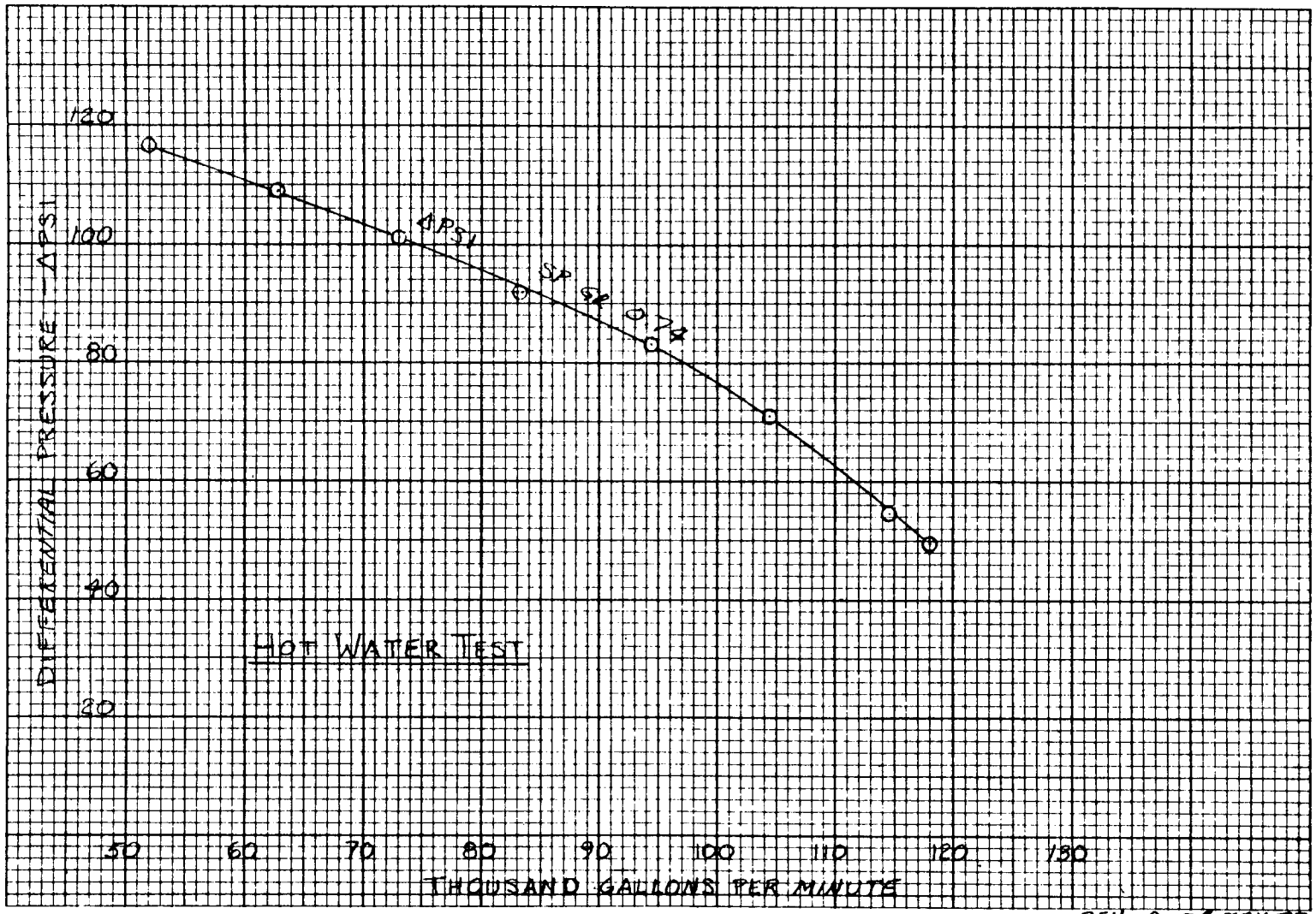
Figure A-1. Differential Pressure vs. Flow Curve for Reactor Coolant Pump 1A



REV. A 9MAY77

36×36×43 DFSS	PUMP CASE CALIBRATION ΔPSI vs CAPACITY	DATA BY: MA	JOB NO. 701-N-0592	T-33722-14A
		DRAWN BY MA	DATE 5-24-74	

Figure A-2. Differential Pressure vs. Flow Curve for Reactor Coolant Pump 1B



REV. A 24 MAY 77

36 x 36 x 43 DFSS	PUMP CASE CALIBRATION ΔPSI vs CAPACITY	DATA BY MA	JOB NO 701-N-0595	T-34325-9A
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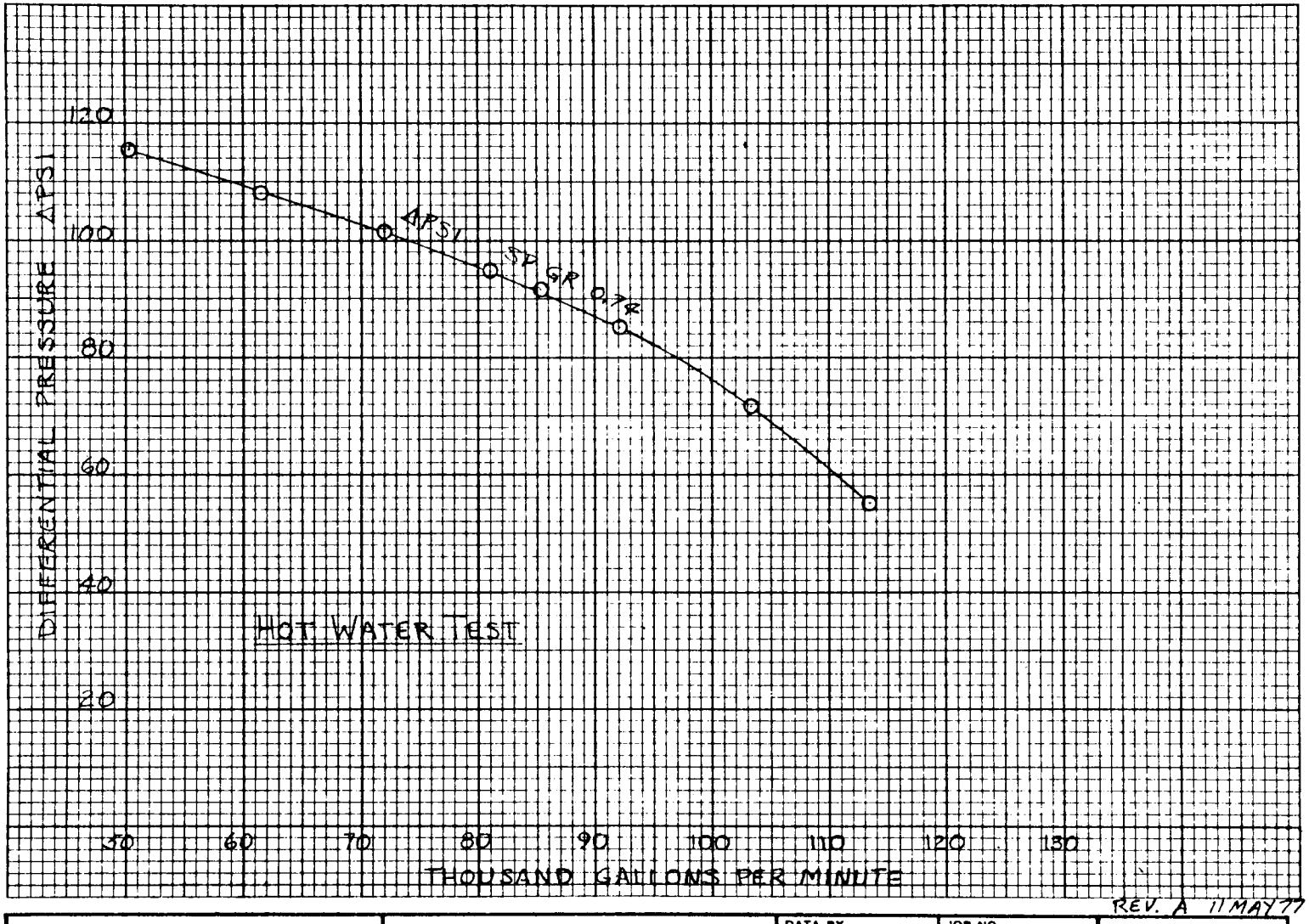
Figure A-3. Differential Pressure vs. Flow Curve for Reactor Coolant Pump 2A



REV. A 11 MAY 77

26 x 36 x 43 DFSS	PUMP CASE CALIBRATION ΔPSI vs CAPACITY	DATA BY: MA DRAWN BY: MA	JOB NO 701-N-0593 DATE: 5-31-74	T-34173-10A

Figure A-4. Differential Pressure vs. Flow Curve for Reactor Coolant Pump 2B

APPENDIX B

SECONDARY SYSTEM FLOW RATES AND TURBINE POWER

SECONDARY SYSTEM FLOW RATES

The secondary system flow rates -- feedwater and main steam flow rates -- during the four PWR transient tests were calculated using measured values of differential pressures along with secondary system temperatures and pressures. The calculations were performed separately for each steam generator.

Feedwater Flow Rates

For the calculation of feedwater flow rates, the feedwater differential pressures and steam generator pressures were measured and recorded on tape. It was then assumed that the feedwater pressure was equal to the steam generator pressure. The feedwater temperatures were measured but not recorded on tape; however, they were included as part of the recorded computer trend group data. The feedwater temperatures and pressures were then used to calculate feedwater specific volumes from the ASME Steam Tables. The feedwater flow rates were then calculated using the following algorithm:

$$FWF = (C1 + C2 * FWT) * (FWDP/SVF)^{\frac{1}{2}} , \qquad \text{(B-1)}$$

where

FWF = feedwater flow rate in klbm/hr,
FWT = feedwater temperature in °F,
FWDP = feedwater differential pressure in inches of water,
SVF = feedwater specific volume in ft^3/lbm,

and C1 and C2 are constants related to (1) the physical characteristics of the sections of pipe across which the feedwater differential pressures were measured, and (2) the properties of the fluid. At ANO-2, the feedwater differential pressures were measured across venturis; therefore, the constants C1 and C2 were calculated using the standard formula (6) for measuring the pressure drop across a venturi.

For steam generator 1,

$C1 = 31.808,$
$C2 = 6.5226 \times 10^{-4}.$

For steam generator 2,

$C1 = 31.891,$
$C2 = 6.54 \times 10^{-4}.$

The constants for the two steam generators are slightly different due to slight differences in the physical characteristics of the two venturis.

Main Steam Flow Rates

For the calculation of main steam flow rates, the header pressures and header differential pressures of the two steam generators were measured and recorded on tape. The steam temperatures were obtained by assuming dry saturated steam; that is, in each case, the steam temperature was taken to be that of dry saturated steam at that header pressure. The steam temperatures and header pressures were then used to calculate steam specific volumes from the ASME Steam Tables. The steam flow rates were then calculated using the following algorithm:

$$STF = C3 * (STDP/SVST)^{\frac{1}{2}} , \qquad \text{(B-2)}$$

where

STF = steam flow rate in klbm/hr,
STDP = header differential pressure in inches of water,
SVST = steam specific volume in ft^3/lbm,

and C3 is a constant related to the physical characteristics of the sections of pipe across which the steam generator header differential pressures were measured and the properties of the fluid. At ANO-2, the steam generator header differential pressures were measured across nozzles; therefore, the constant C3 was calculated using the standard formula (6) for measuring the pressure drop across a nozzle.

For steam generator 1,

$C3 = 160.18698.$

For steam generator 2,

$C3 = 160.30196.$

The constants for the two steam generators are slightly different due to slight differences in the physical characteristics of the two nozzles.

TURBINE POWER

Turbine power was calculated from the measured turbine first stage pressure using the following empirical fit:

$$BT = G1 + G2 * TFSP + G3 * (TFSP)^2 + G4 * (TFSP)^3 \quad , \qquad \text{(B-3)}$$

where

BT = turbine power in percent of rated power,
TFSP = turbine first stage pressure in psia,
G1 = 0.2632,
G2 = 0.2199846,
G3 = -1.548751×10^{-4},
G4 = 9.726557×10^{-8}.

APPENDIX C

LIST OF ACRONYMS AND SYMBOLS

ASI	Axial Shape Index
C-E	Combustion Engineering
CEA	Control Element Assembly
CEAC	Control Element Assembly Calculator
CTI	Common Timing Interface
DAS	Data Acquisition System
DEC	Digital Equipment Corporation
DNBR	Departure from Nucleate Boiling Ratio
FLCEAD	Full Length Control Element Assembly Drop
FWF	Feedwater Flow
LOF	Loss of Flow
MSIS	Main Steam Isolation Signal
MSIV	Main Steam Isolation Valve
P_{DP}	Pump Differential Pressure
P_P	Pressurizer Pressure
PPCS	Pressurizer Pressure Control System
P_S	Secondary Header Pressure
P_{Sec}	Secondary Pressure
PTFS	Pressure Turbine First Stage
ΔP	Differential Pressure
PLCEAD	Part Length Control Element Assembly Drop
PPM	Parts Per Million
PPS	Plant Protection System
RCP	Reactor Coolant Pump
RPM	Revolutions Per Minute
RTD	Resistance Temperature Detectors
S	Time Shift Associated with Sensor Response
SDBCS	Steam Dump and Bypass Control System
SG	Steam Generator
SIAS	Safety Injection Actuation Signal
SPND	Self Powered Neutron Detector
T_C	Cold Leg Temperature
T_H	Hot Leg Temperature

TFW	Feedwater Temperature
TT	Turbine Trip
W_S	Main Steam Flow
τ	Time Constant Associated with Sensor Response

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EPRI • 3412 Hillview Avenue, Palo Alto, California 94304 • PO Box 10412, Palo Alto, California 94303 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com