OVERPRESSURE PROTECTION REPORT

FOR

BYRON/BRAIDWOOD NUCLEAR POWER PLANT
UNITS 1 & 2

AS REQUIRED BY

ASME BOILER AND PRESSURE VESSEL CODE
SECTION III, ARTICLE NB-7300

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1.0 Purpose of Report

This report documents the overpressure protection provided for the Reactor Coolant System (RCS) in accordance with the ASME Boiler and Pressure Vessel Code, Section III, NB-7300.

2.0 Description of Overpressure Protection

2.1 Overpressure protection is provided for the RCS and its components to prevent a rise in pressure of more than 10% above the system design pressure of 2485 psig, in accordance with NB-7400. This protection is afforded for the following events which envelope those credible events which could lead to overpressure of the RCS if adequate over pressure protection were not provided.

1. Loss of Electrical Load and/or Turbine Trip
2. Uncontrolled Rod Withdrawal at Power
3. Loss of Reactor Coolant Flow
4. Loss of Normal Feedwater
5. Loss of Offsite Power to the Station Auxiliaries

2.2 The extent of the RCS is as defined in 10CFR50 and includes:

1. The reactor vessel including control rod drive mechanism housings.
2. The reactor coolant side of the steam generators.
3. Reactor coolant pumps.
4. A pressurizer attached to one of the reactor coolant loops.
5. Safety and relief valves.
6. The interconnecting piping, valves and fittings between the principal components listed above.
7. The piping, fittings and valves leading to connecting auxiliary or support systems up to and including the second isolation valve (from the high pressure side) on each line.

2.3 The pressurizer provides volume surge capacity and is designed to mitigate pressure increases (as well as decreases) caused by load transients. A pressurizer spray system condenses steam at a rate sufficient to prevent the pressurizer pressure from reaching the setpoint of the power-operated relief valves during a step reduction in power level equivalent to ten percent of full rated load.

The spray nozzle is located in the top head of the pressurizer. Spray is initiated when the pressure controlled spray demand signal is above a given setpoint. The spray rate increases proportionally with increasing compensated error signal until it reaches a maximum value. The compensated error signal is the output of a proportional plus integral controller, the input to which is an error signal based on the difference between actual pressure and a reference pressure.

The pressurizer is equipped with 2 power-operated relief valves which limit system pressure for a large power mismatch to avoid actuation of the fixed high pressure reactor trip. The relief valves are operated automatically or by remote manual control. The operation of these valves also limits the frequency of opening of the spring-loaded safety valves. Remotely operated stop valves are provided to isolate the power-operated relief valves if excessive leakage occurs. The relief valves are designed to limit the pressurizer pressure to a value below the high pressure trip setpoint for all design transients up to and including the design percentage step load decrease with steam dump but without reactor trip.

Isolated output signals from the pressurizer pressure protection channels are used for pressure control. These are used to control pressurizer spray and power-operated relief valves in the event of increase in RCS pressure.

In the event of unavailability of the pressurizer spray or power operated relief valves, and a complete loss of steam flow to the turbine, protection of the RCS against overpressure is afforded by the pressurizer safety valves in conjunction with the steam generator safety valves and a reactor trip initiated by the Reactor Protection System.

There are 3 safety valves with a minimum required capacity of 420,000 lb/hour for each valve at system design pressure plus 3% allowance for accumulation. The pressurizer safety valves are totally enclosed pop-type, spring loaded, self-activated valves with back pressure compensation. The set pressure of the safety valves will be no greater than system design pressure of 2485 psig in accordance with section NB7511. The pressurizer safety valves and power operated relief valves discharge to the pressurizer relief tank (PRT). Rupture disks are installed on the pressurizer relief tank to prevent PRT overpressurization.

Figure 1 shows a schematic arrangement of the pressure relieving devices.

3.0 Sizing of Pressurizer Safety Valves

3.1 The sizing of the pressurizer safety valves is based on analysis of a complete loss of steam flow to the turbine with the reactor operating at 102% of Engineered Safeguards Design Power. In this analysis, feedwater flow is also assumed to be

lost, and no credit is taken for operation of pressurizer power operated relief valves, pressurizer level control system, pressurizer spray system, rod control system, steamdump system or steam line power operated relief valves. The reactor is maintained at full power (no credit for reactor trip), and steam relief through the steam generator safety valves is considered. The total pressurizer safety valve capacity is required to be at least as large as the maximum surge rate into the pressurizer during this transient.

This sizing procedure results in a safety valve capacity well in excess of the capacity required to prevent exceeding 110% of system design pressure for the events listed in Section 2.1. The conservative nature of this sizing procedure is demonstrated in the following section.

3.2 Each of the overpressure transients listed in Section 2.1 has been analyzed and reported in the Final Safety Analysis Report. The analysis methods, computer codes, plant initial conditions and relevant assumptions are discussed in the FSAR for each transient.

Review of these transients shows that the Turbine Trip results in the maximum system pressure and the maximum safety valve relief requirements. This transient is presented in detail below.

For a turbine trip event, the reactor would be tripped directly (unless below approximately 10 percent power) from a signal derived from the turbine stop emergency trip fluid pressure and turbine stop valves. The turbine stop valves close rapidly (typically 0.1 seconds) on loss of trip fluid pressure actuated by one of a number of possible turbine trip signals. This will cause a sudden reduction in steam flow, resulting in an increase in pressure and temperature in the steam generator shell. As a result, heat transfer rate in the steam generator is reduced, causing the reactor coolant temperature to rise, which in turn causes coolant expansion, pressurizer insurge, and RCS pressure rise.

The automatic steam dump system would normally accommodate the excess steam generation. Reactor coolant temperature and pressure do not significantly increase if the steam dump system and pressurizer pressure control system are functioning properly. If the turbine condenser were not available, the excess steam generation would be dumped to the atmosphere and main feedwater flow would be lost. For this situation feedwater flow would be maintained by the Auxiliary Feedwater System to ensure adequate residual and decay heat removal capability. Should the steam dump system fail to operate, the steam generator safety valves may lift to provide pressure control.

In this analysis, the behavior of the unit is evaluated for a complete loss of steam load from 102 percent of full power without direct reactor trip; that is, the turbine is assumed to trip without actuating all the sensors for reactor trip on the turbine stop valves. The assumption delays reactor trip until conditions in the RCS result in a trip due to other signals. Thus, the analysis assumes a worst transient. In addition, no credit is taken for steam dump. Main feedwater flow is terminated at the time of turbine trip, with no credit taken for auxiliary feedwater to mitigate the consequences of the transient.

The turbine trip transients are analyzed by employing the detailed digital computer program LOFTRAN. The program simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The program computes pertinent plant variables including temperatures, pressures, and power level.

Major assumptions are summarized below:

a. Initial operating conditions

   The initial reactor power and RCS temperatures are assumed at their maximum values consistent with the steady state full power operation including allowances for calibration and instrument errors. The initial RCS pressure is assumed at a minimum value consistent with the steady state full power operation including allowances for calibration and instrument errors. This results in the maximum power difference for the load loss, and the minimum margin to core protection limits at the initiation of the accident.

b. Moderator and Doppler coefficients of reactivity

   The analysis assumes both a least negative moderator coefficient and a least negative Doppler power coefficient, as this results in maximum pressure relieving requirements.

c. Reactor control

   From the standpoint of the maximum pressures attained it is conservative to assume that the reactor is in manual control. If the reactor were in automatic control, the control rod banks would move prior to trip and reduce the severity of the transient.

d. Steam release

No credit is taken for the operation of the steam dump system or steam generator power operated relief valves. The steam generator pressure rises to the safety valve setpoint where steam release through safety valves limits secondary steam pressure at the setpoint value.

e. Pressurizer spray and power operated relief valves

No credit is taken for the effect of pressurizer spray and power operated relief valves in reducing or limiting the coolant pressure. Safety valves are operable.

f. Feedwater flow

Main feedwater flow to the steam generators is assumed to be lost at the time of turbine trip. No credit is taken for auxiliary feedwater flow since a stabilized plant condition will be reached before auxiliary feedwater initiation is normally assumed to occur; however, the auxiliary feedwater pumps would be expected to start on a trip of the main feedwater pumps. The auxiliary feedwater flow would remove core decay heat following plant stabilization.

g. Reactor trip is actuated by the first Reactor Protection System trip setpoint reached with no credit taken for the direct reactor trip on the turbine trip. Trip signals are expected due to high pressurizer pressure, Overtemperature ΔT, high pressurizer water level, and low-low steam generator water level.

The results of the Turbine Trip transient are shown in Figures 2 and 3. Figure 2 shows the pressurizer pressure, the reactor coolant pump discharge pressure, which is the point of highest pressure in the RCS, and the pressurizer safety valve relief rate. Figure 3 shows steam generator shell side pressure, reactor coolant loop hot leg and cold leg temperature, and nuclear power. The reactor is tripped on a high pressurizer pressure signal for this transient.

The results of this analysis show that the overpressure protection provided is sufficient to maintain peak RCS pressure below the code limit of 110% of system design pressure. The plot of pressurizer safety valve relief rate also shows that adequate overpressure protection for this limiting event could be provided by two of the three installed safety valves.

4.0 References

1. ASME Boiler and Pressure Vessel Code, Section III. Article NB 7000, 1971 Edition Winter 1972 Addenda.

2. Topical Report - Overpressure Protection for Westinghouse Pressurizer Water Reactors, WCAP 7769, Rev. 1, June 1972.

3. Certified Safety Valve Capacity, Calculation No. CPA-70-44; FA-792, July 23, 1980, Corrected January 22, 1981.

4. CAE OFA Loss of Load Accident (FSAR Amendment), Calculation No. CN-PP-80-94, September, 1979.

5. CAE FSAR Loss of Load/Turbine Trip Calculation No. CN-RPA-78-65, April, 1978.

6. CAE Underfrequency/Loss of Flow/Locked Rotor Analysis for OFA-STAT ONB & Broken Pump Shaft, Calculation No. CN-PP-80-129, November, 1980.

7. CAE FSAR Loss of Flow & Locked Rotor; Broken Pump Shaft; Underfrequency Analysis Calculation No. CN-RPA-78-49, March, 1978.

8. CAE OFA Amendment - Loss of Normal Feedwater and Station Blackout, Calculation No. CN-PP-80-115, November, 1980.

9. CAE FSAR Loss of Normal Feedwater and Station Blackout, CN-RPA-77-219, November, 1977.

10. CAE OFA FSAR Amendment - Rod Withdrawal at Power Analysis, CN-PP-80-107, October, 1980.

11. CAE Rod Withdrawal at Power Calculation No. CN-RPA-78-36, February, 1978.

12. CAE OFA Turbine Trip for Overpressure Protection Report, Calculation No. CN-PP-81-2, January, 1981.

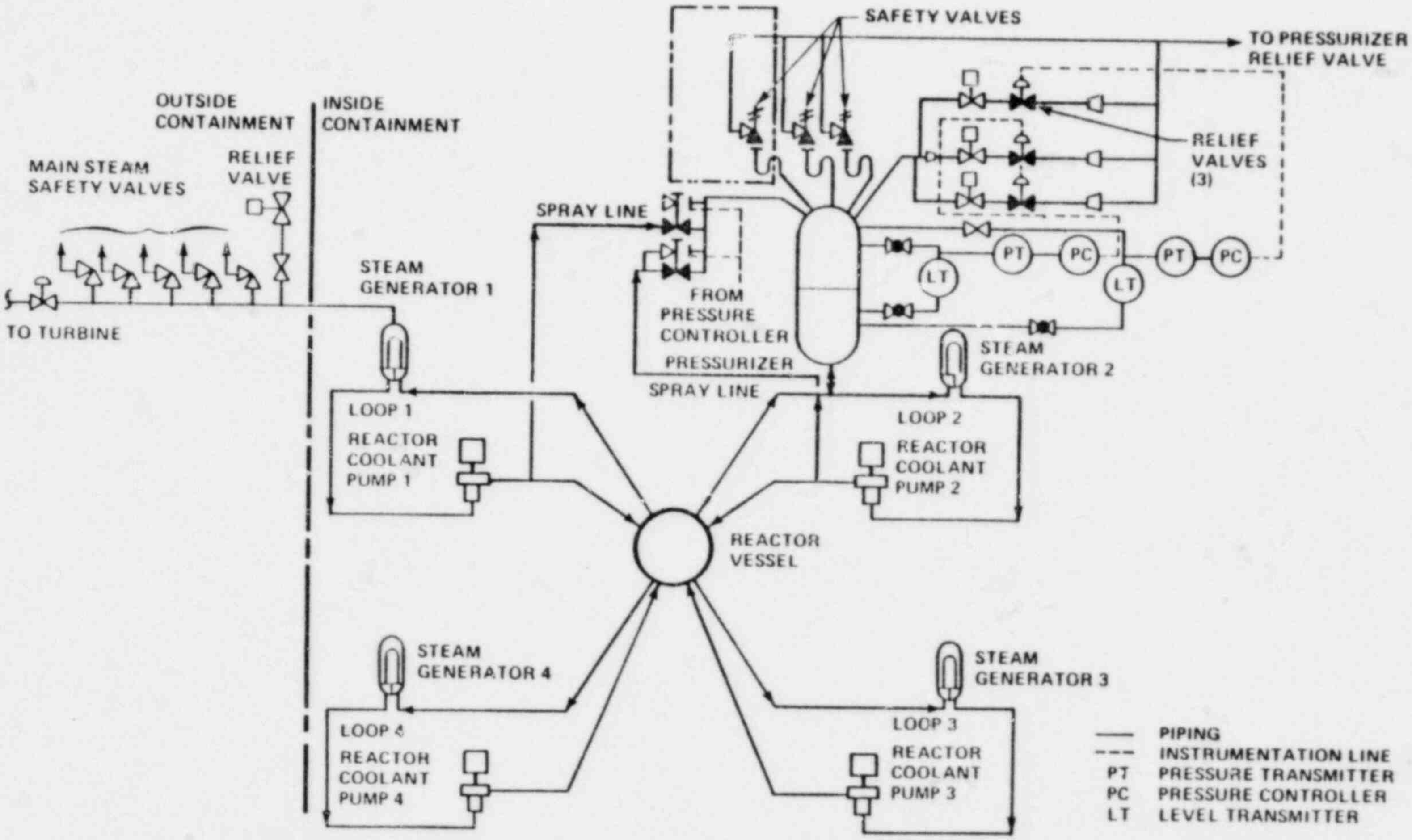

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Figure 1. Schematic Arrangement of Pressure Relieving Devices

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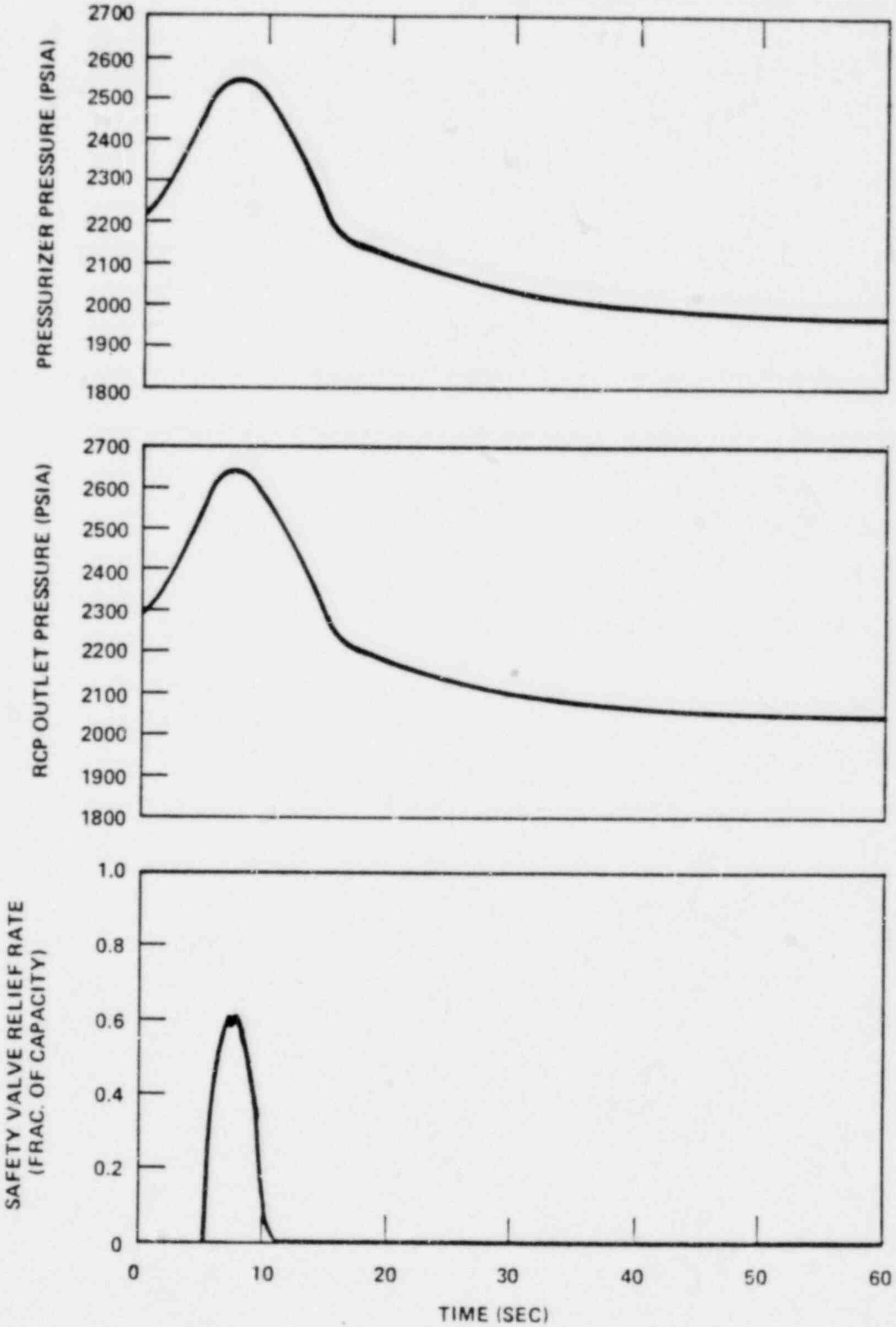
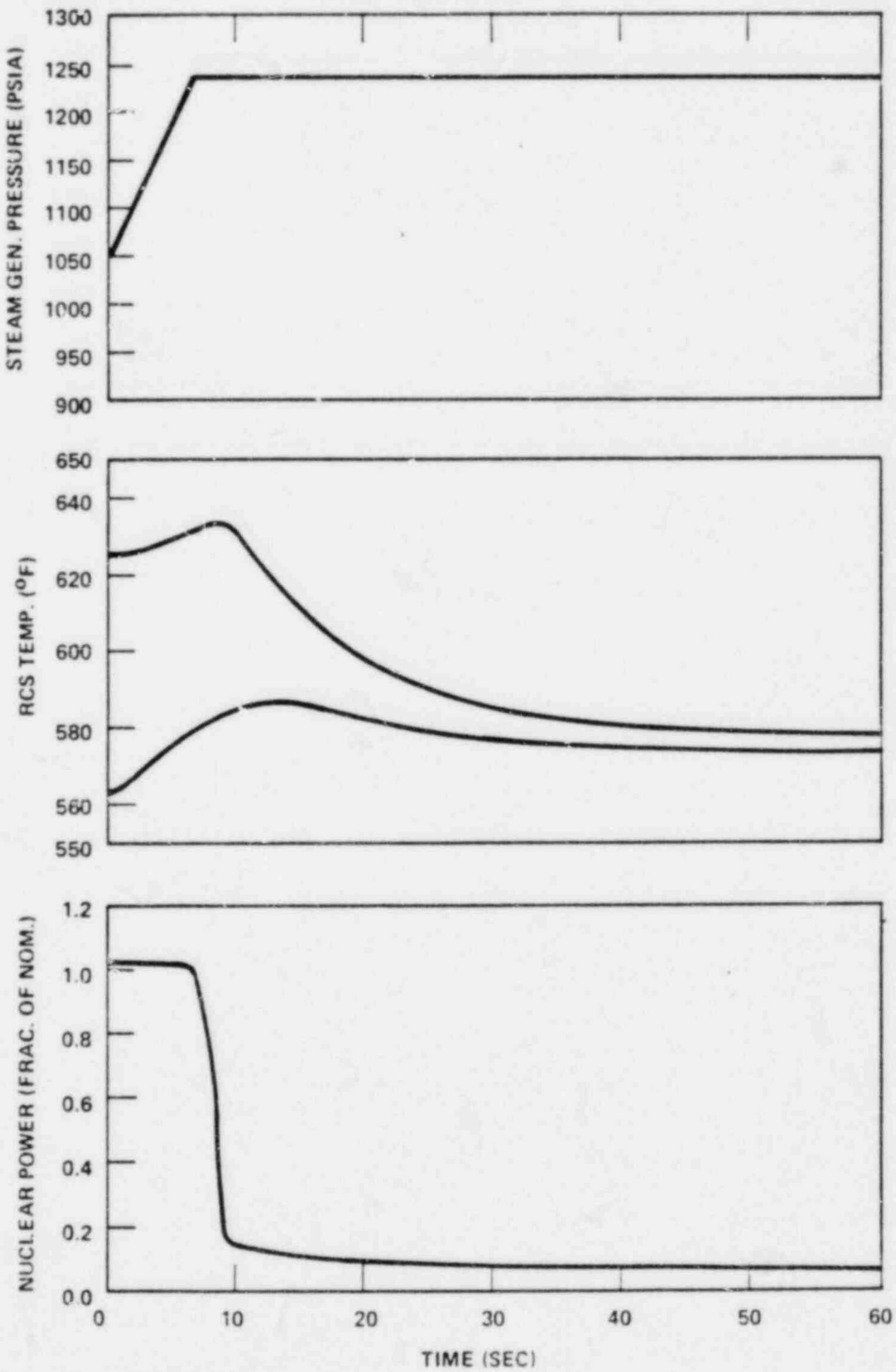


Figure 2.



STEAM GEN. PRESSURE (PSIA)
1300
1250
1200
1150
1100
1050
1000
950
900
RCS TEMP. (°F)
650
640
620
600
580
560
550
NUCLEAR POWER (FRAC. OF NOM.)
1.2
1.0
0.8
0.6
0.4
0.2
0.0
0
10
20
30
40
50
60
TIME (SEC)

Figure 3