WATTS BAR DELETION OF REACTOR TRIP ON TURBINE TRIP BELOW 50 PERCENT POWER

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1.0 IDENTIFICATION OF CAUSES AND ACCIDENT DESCRIPTION

A major load loss on the plant can result from loss of external electrical load due to some electrical system disturbance. Offsite AC power remains available to operate plant components such as the reactor coolant pumps. Following the loss of generator load, an immediate fast closure of the turbine control valves will occur. 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, the 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.

For a loss of external electrical load without subsequent turbine trip, no direct reactor trip signal would be generated. The plant would be expected to trip from the Reactor Protection System. In the event that a safety limit is approached, protection would be provided by the high pressurizer pressure and overtemperature ΔT trips.

In the event the steam dump valves fail to open following a loss of load or turbine trip, the steam generator safety valves may lift and the reactor may be tripped by the high pressurizer pressure signal, the high pressurizer water level signal, or the overtemperature ΔT signal. The steam generator shell side pressure and reactor coolant temperatures will increase rapidly. The pressurizer safety valves and steam generator safety valves are, however, sized to protect the Reactor Coolant System (RCS) and steam generator against overpressure for all load losses without assuming the operation of the steam dump system, pressurizer spray, pressurizer power-operated relief valves, automatic rod cluster control assembly control or direct reactor trip on turbine trip.

The steam generator safety valve capacity is sized to remove the steam flow at the Engineered Safety Features Rating (105 percent of steam flow at rated power) from the steam generator without exceeding 110 percent of the steam system design pressure. The pressurizer safety valve capacity is sized based on a complete loss of heat sink with the plant initially operating at the maximum calculated turbine load along with operation of the steam generator safety valves. The pressurizer safety valves are then able to relieve sufficient steam to maintain the RCS pressure within 110 percent of the RCS design pressure.

The primary-side transient is caused by a decrease in heat transfer capability from primary to secondary due to a rapid termination of steam flow to the turbine, accompanied by an automatic reduction of feedwater flow. Should feed flow not be reduced, a larger heat sink would be available and the transient would be less severe. Termination of steam flow to the turbine following a loss of external load occurs due to automatic fast closure of the turbine control valves in approximately .25 seconds. Following a turbine trip event, termination of steam flow occurs via turbine stop valve closure, which occurs in approximately .25 seconds. Therefore, the transient in primary pressure, temperature, and water volume will not be dependent on the mode of steam flow termination; therefore, a detailed transient analysis is only presented for the turbine trip event.

For a turbine trip event, the reactor would be tripped directly (unless below approximately 50 percent power) from a signal derived from the turbine auto stop emergency trip fluid pressure and turbine stop valves. The turbine stop valves close rapidly on loss of trip-fluid pressure actuated by one of a number of possible turbine trip signals. Turbine-trip initiation signals include:

1. Generator trip
2. Low Condenser Vacuum
3. Loss of Lubricating Oil
4. Turbine Thrust Bearing Failure
5. Turbine Overspeed
6. Manual Trip

Upon initiation of stop valve closure, steam flow to the turbine stops abruptly. Sensors on the stop valves detect the turbine trip and initiate steam dump and, if above 50% power, a reactor trip. The loss of steam flow results in an almost immediate rise in secondary system temperature and pressure with a resultant primary system transient.

The automatic steam dump system would normally accommodate the excess steam generation. Reactor coolant temperatures and pressure do not signficantly increase if the steam dump system and pressurizer pressure control system are functioning properly (i.e. the better estimate case). If the turbine condenser was 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 insure 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, as discussed previously.

Normal power for the reactor coolant pumps is supplied through busses from a transformer connected to the generator. When a generator trip occurs, the busses are automatically transferred to a transformer supplied from external power lines, and the pumps will continue to supply coolant flow to the core. Following any turbine trip where there are no electrical faults which require tripping the generator from the network, the generator remains connected to the network for approximately 30 seconds. The reactor coolant pumps remain connected to the generator, thus ensuring flow for 30 seconds before any transfer is made.

Should the network bus transfer fail at or before 30 seconds, a complete loss of forced reactor coolant flow would result. The immediate effect of loss of coolant flow is a rapid increase in the coolant temperature in addition to the increased coolant temperature as a result of the turbine trip. This increase could result in DNB with subsequent fuel damage if the reactor were not tripped promptly.

The following signals provide the necessary protection against a complete loss of flow accident:

1. Reactor coolant pump power supply undervoltage.
2. Low reactor coolant loop flow.

The reactor trip on reactor coolant pump undervoltage is provided to protect against conditions which can cause a loss of voltage to all reactor coolant pumps, i.e., station blackout. This function is blocked below approximately 10 percent power (Permissive 7).

The reactor trip on low primary coolant loop flow is provided to protect against loss of flow conditions which affect only one reactor coolant loop. This function is generated by two out of three low flow signals per reactor coolant loop. Between approximately 10 percent power (Permissive 7) and the power level corresponding to Permissive 8, low flow in any two loops will actuate a reactor trip.

2.0 ANALYSIS OF EFFECTS AND CONSEQUENCES

Method of Analysis

In this analysis, the behavior of the unit is evaluated for a complete loss of steam load from 52 percent of full power without direct reactor trip. This shows the adequacy of the pressure relieving devices and also demonstrates the core protection margins; that is, the turbine is assumed to trip without actuating all the sensors for reactor trip until conditions in the RCS result in a trip due to other signals. Thus, the analysis assumed 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.

Following the loss of steam load but before a reactor trip, a fast bus transfer is attempted. The transfer to an external power source is assumed to fail at the time producing the most limiting DNB resulting in a complete loss of flow transient initiated from the loss of load conditions.

The loss of flow transient coincident with turbine trip transients are analyzed by employing the detailed digital computer code LOFTRAN[1]. The LOFTRAN Code calculates the loop and core flows following the initial loss of load. The LOFTRAN Code 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, power level, and DNB margin.

Major assumptions are summarized below:

1. Initial Operating Conditions - the initial reactor power and RCS temperatures are assumed at their maximum values consistent with the steady state 52 percent power operation including allowances for calibration and instrument errors.

(1) Burnett, T. W. T., et. al., "LOFTRAN Code Description", WCAP-7907, June, 1972.

The initial RCS pressure is assumed at a minimum value consistent with the steady state 52 percent power operation including allowances for calibration and instrument errors. The initial RCS flow is assumed to be consistent for four loop operation. This results in the maximum power difference for the load loss and the minimum margin to core protection limits at the intiation of the accident. Table 1 summarizes the initial conditions assumed.

2. Moderator and Doppler Coefficients of Reactivity - the turbine trip is analyzed with both a least negative moderator temperature coefficient and a large negative moderator temperature coefficient. Doppler power coefficients are adjusted to provide consistent minimum and maximum reactivity feedback cases.

3. 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 insert prior to trip and reduce the severity of the transient.

4. 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.

5. Pressurizer Spray and Power-Operated Relief Valves - two cases for both the minimum and maximum reactivity feedback cases are analyzed:

   a. Full credit is taken for the effect of pressurizer spray and power-operated relief valves in reducing or limiting the coolant pressure. Safety valves are also available.

   b. 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.

6. 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.

7. 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, low reactor coolant loop flow, and reactor coolant pump power supply undervoltage.

Except as discussed above, normal reactor control systems and Engineered Safety Systems are not required to function. The Reactor Protection System may be required to function following a turbine trip. Pressurizer safety valves and/or steam generator safety valves may be required to open to maintain system pressures below allowable limits. No single active failure will prevent operation of any system required to function.

Recently the NRC has expressed concerns regarding the potential increase in probability of a stuck-open pressurizer PORV following the implementation of the WRAP item "Deletion of Reactor Trip on Turbine Trip below 50% power." The NRC current position is addressed in NUREG-0660, Vol. 1, Requirement #10, Table C-3 and NUREG-0611, Paragraph 3.2.4.6: the anticipatory reactor trip function should not be deleted "until it has been shown on a plant-by-plant bases that the small break LOCA probability resulting from a stuck-open PORV is little affected by the modification"

The Westinghouse design criterion is that load rejections up to 50% should not require a reactor trip if all other functions operate properly. The power mismatch is taken up by the 40% steam dump and automatic rod insertion (10%). The PORV's are provided to reduce the likelihood of tripping the reactor on the high pressurizer pressure signal and opening the pressurizer safety valves, which cannot be isolated.

So in addition to the limiting transients described above, a better estimate transient was simulated assuming operation of the control systems that normally would be available. This is done in order to simulate a better estimate of the transient that would normally occur following a loss of load without subsequent reactor trip to show that the pressurizer PORV's would normally not open. Using the same initial operating conditions, the better estimate case assumed correct operation of the network buss transfer, steam dump, feedwater control system, and pressurizer pressure control system. Also for the better estimate case, automatic rod control and beginning of life reactivity feedback conditions were assumed. The same protection systems were available but not used for the better estimate transient.

3.0 RESULTS

The transient reponses for a turbine trip from 52 percent of full power operation are shown for five cases: two cases for minimum reactivity feedback, two cases for maximum reactivity feedback and one better estimate case (Figures 1 through 12). The calculated sequence of events for the transients is shown in Tables 2 and 3.

Figures 1 through 3 show the transient responses for the total loss of steam load with a least negative moderator temperature coefficient assuming full credit for the pressurizer spray and pressurizer power-operated relief valves. No credit is taken for steam dump. The buss transfer failure at 30 seconds results in an undervoltage trip of the reactor and the initiation of the loss of flow transient. The minimum DNBR remains well above the 1.3 limit. The pressurizer safety valves are actuated and maintain primary system pressure below 110% of the design value. The steam generator safety valves limit the secondary steam conditions to saturation at the safety valve setpoint.

Figures 4 and 5 show the responses for the total loss of steam load with a large negative moderator temperature coefficient. All other plant parameters are the same as above. The buss transfer failure at 30 seconds results in an undervoltage trip of the reactor and the initiation of the loss of flow transient. The minimum DNBR remains well above the 1.3 limit throughout the transient. Pressurizer relief valves and steam generator safety valves prevent overpressurization in primary and secondary systems, respectively. A plot of DNBR versus time is only given for the beginning of life cases since all other cases are significantly less limiting.

The turbine trip accident was also studied assuming the plant to be initially operating at 52 percent of full power with no credit taken for the pressurizer spray, pressurizer power-operated relief valves, or steam dump. The reactor is tripped on high pressurizer pressure signal. The fast bus transfer for this case is assumed to fail 1.2 seconds before rod drop time to produce the transient most limiting with respect to DNB and to assume the rod drop time from the high pressurizer pressure signal is coincident with the time from the undervoltage signal. Figures 6 through 8 show the transients with a least negative moderator coefficient. The neutron flux remains essentially constant at 52 percent of full power until the reactor is tripped. The DNBR remains above 1.3 throughout the transient. In this case the pressurizer safety valves are actuated and maintain system pressure below 110% of the design value.

Figures 9 and 10 are the transients with maximum reactivity feedback with the other assumptions being the same as in the preceeding case. The reactor is tripped on the high pressurizer pressure signal and the fast buss transfer to offsite power is assumed to fail 1.2 seconds before rod drop. Again, the minimum DNBR remains above 1.3 throughout the transient and the pressurizer safety valves are actuated to limit primary pressure.

A better estimate turbine trip accident was also simulated assuming the plant to be initially operating at 50 percent of full power with credit taken for pressurizer spray, steam dump, successful buss transfer, feedwater control system operational, automatic rod control, and beginning of life reactivity feedback conditions in mitigating the transient.

The control rods are inserted and the steam dump quickly actuated following the turbine trip event; primary side pressure increases very little, there is no reactor trip, and the plant is smoothly and quickly brought to hot shutdown condition. DNBR remains well above the 1.3 limit. Maximum pressurizer pressure is 2281 psia; maximum secondary pressure is 1110 psi . Neither the primary or secondary side pressure reaches the point where the pressure PORV's or the steam generator safety valves are actuated.

4.0 CONCLUSIONS

Results of the analyses show that the plant design is such that a turbine trip without a direct or immediate reactor trip presents no hazard to the integrity of the RCS or the main steam system. Pressure relieving devices incorporated in the two systems are adequate to limit the maximum pressures to within the design limits. The analysis also demonstrates that for a complete loss of forced reactor coolant flow initiated from the most adverse preconditions of a turbine trip, the DNBR does not decrease below 1.30 at any time during the transient. Thus, no fuel or clad damage is predicted, and all applicable acceptance criteria are met.

For normal plant operation with all normal control systems assumed operational, pressurizer pressure does not reach the point of pressurizer PORV activation. Therefore the Deletion of reactor trip on turbine trip below 50% power is not expected to significantly increase the probability of a small break LOCA due to a stuck-open PORV.

TABLE 1

INITIAL CONDITIONS

No. of Active Loops	4
Core Power, MWt	1781
Thermal Design Flow (TOTAL) GPM	390000
Reactor Coolant Average Temperature, °F	579.7
Reactor Coolant System Pressure, psia	2220

TABLE 2

TIME SEQUENCE OF EVENTS FOR A TURBINE TRIP WITH PRESSURIZER PRESSURE CONTROL

	Event	Time (sec.)
1. Minimum Feedback (BOL)		
	Turbine trip	0
	Initation of steam release from steam generator safety valves	8
	Peak pressurizer pressure occurs	10
	Fast bus transfer failure, flow coastdown begins, and undervoltage trip occurs	30
	Rods begin to fall	31.2
	Minimum DNBR occurs	33
2. Maximum Feedback (EOL)		
	Turbine Trip	0
	Minimum DNBR occurs	0
	Peak pressurizer pressure occurs	6.5
	Initiation of steam release from steam geneator safety valves	8
	Fast bus transfer failure, flow coastdown begins, and undervoltage trip occurs	30
	Rods begin to fall	31.2

TABLE 3

TIME SEQUENCE OF EVENTS FOR A TURBINE
TRIP WITHOUT PRESSURIZER PRESSURE CONTROL

	Event	Time (sec.)
1. Minimum Feedback (BOL)		
	Turbine Trip	0
	Initiation of steam release from steam generator safety valves	8
	Fast bus transfer failure, flow coastdown begins, and undervoltage trip occurs	8.5
	Rods begin to fall, high pressurizer pressure trip occurs	9.7
	Minimum DNBR occurs	11.5
	Peak pressurizer pressure occurs (2523 psia)	12
2. Maximum Feedback (EOL)		
	Turbine Trip	0
	Minimum DNBR occurs	0
	Initiation of steam release from steam generator safety valves	8
	Fast bus transfer failure, flow coastdown begins and undervoltage trip occurs	9.1
	Rods begin to fall and high pressurizer pressure trip occurs	10.3
	Peak pressurizer pressure occurs (2505 psia)	12.5

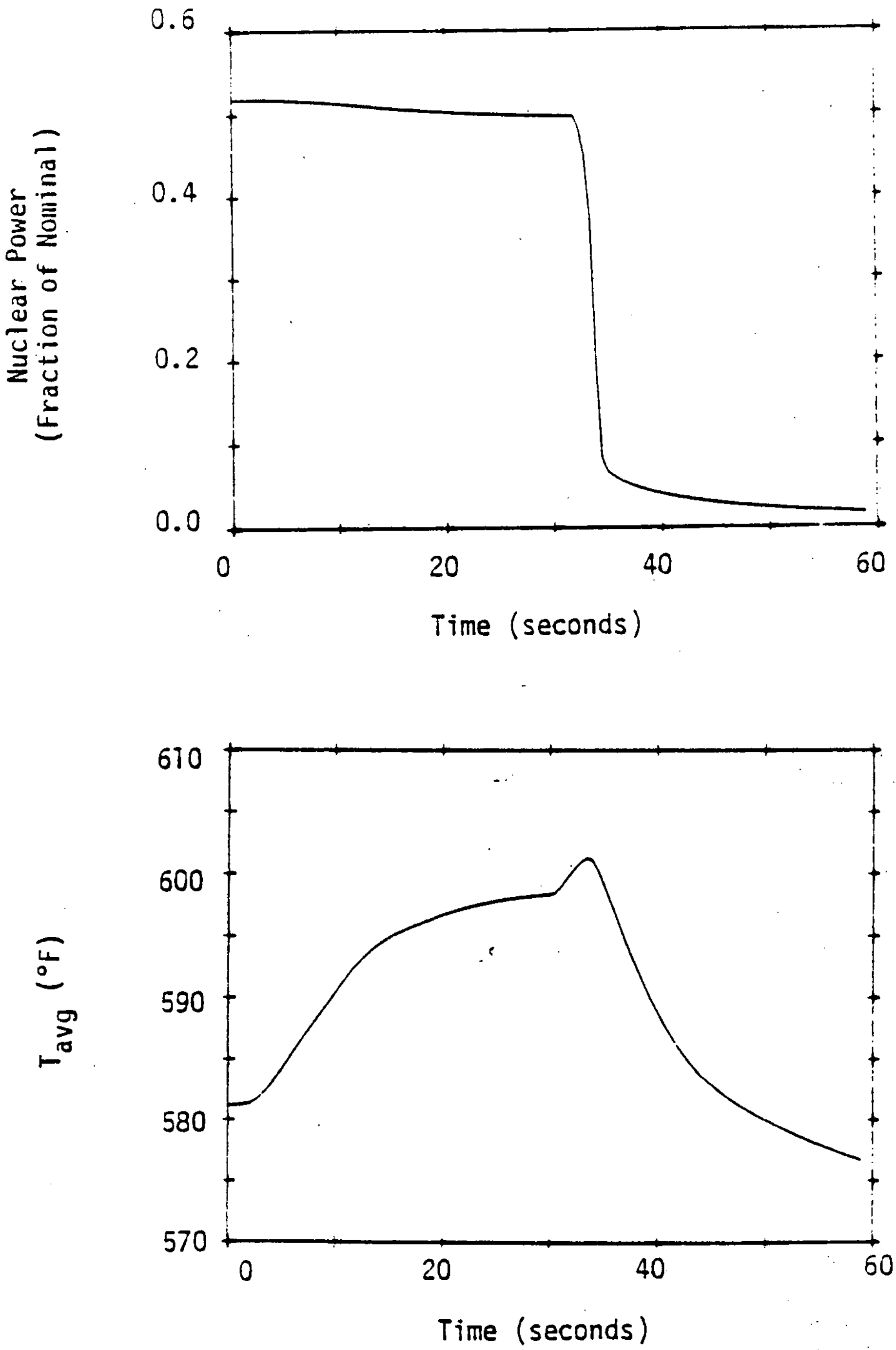


FIGURE 1 TURBINE TRIP WITH PRESSURE CONTROL - MINIMUM FEEDBACK - NUCLEAR POWER AND REACTOR COOLANT - AVERAGE TEMPERATURE

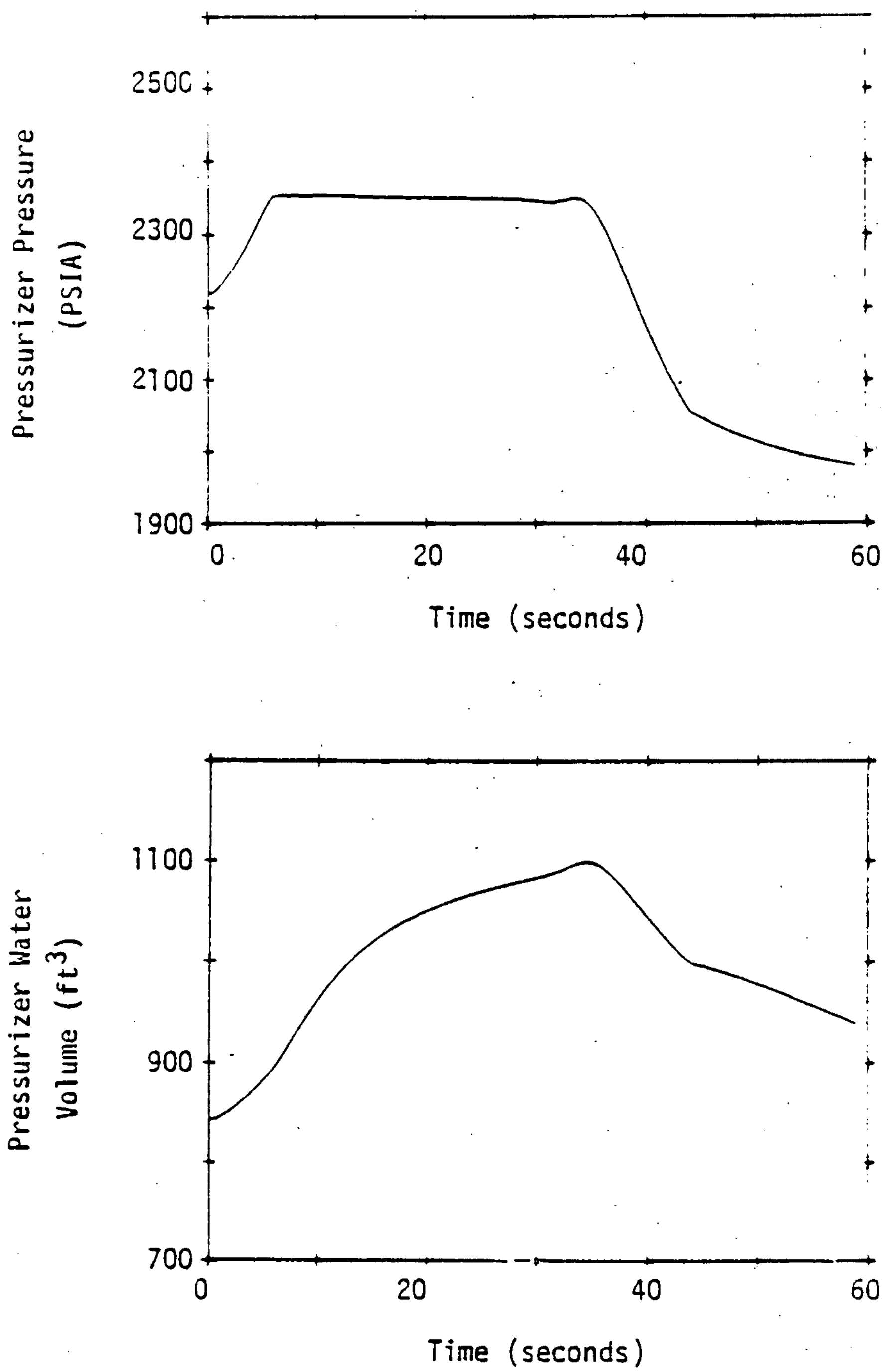


FIGURE 2 TURBINE TRIP WITH PRESSURE CONTROL - MINIMUM FEEDBACK - PRESSURIZER PRESSURE AND WATER VOLUME

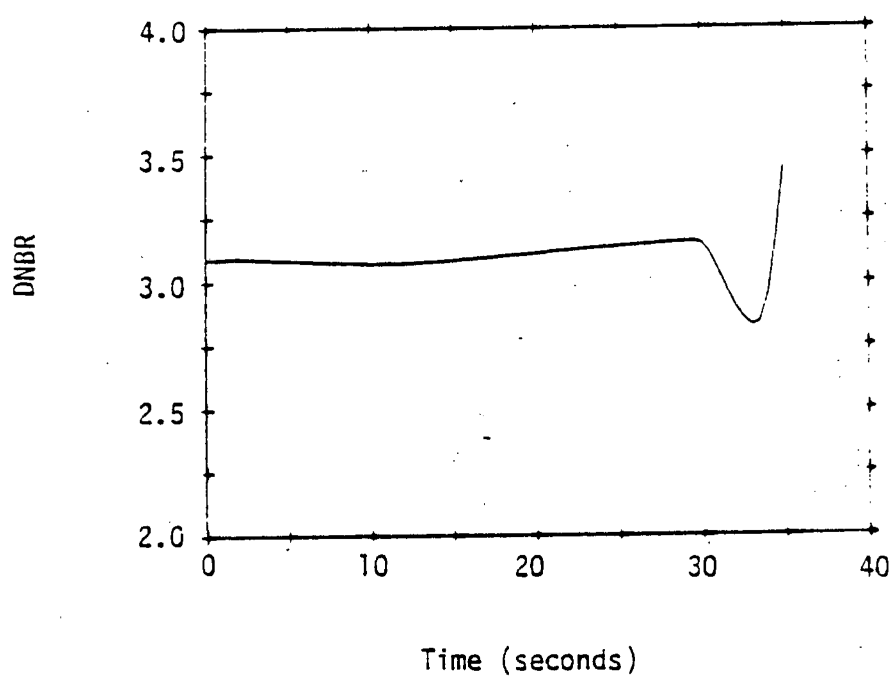


FIGURE 3 TURBINE TRIP WITH PRESSURE CONTROL - MINIMUM FEEDBACK - DNBR

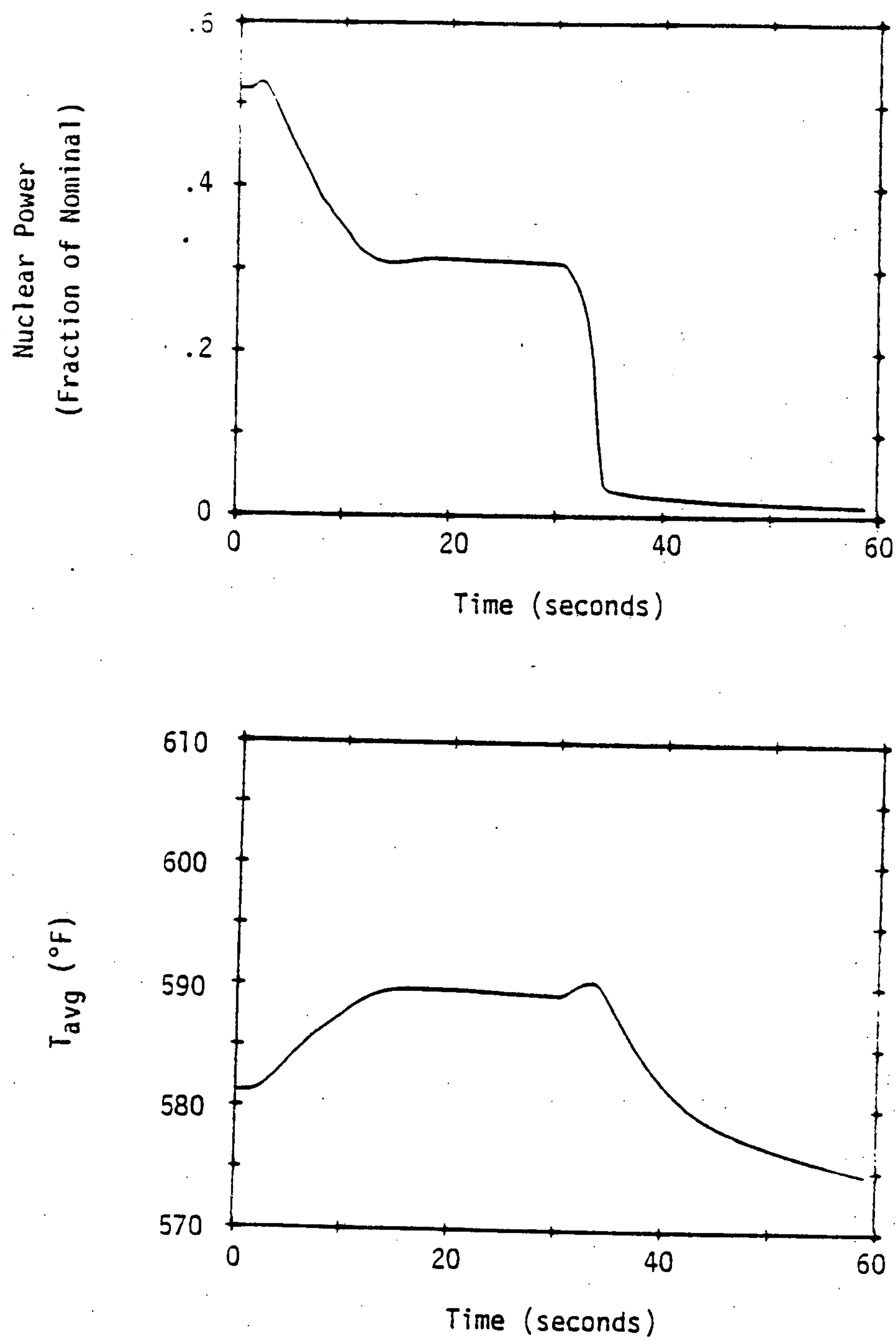


FIGURE 4 TURBINE TRIP WITH PRESSURE CONTROL - MAXIMUM FEEDBACK - NUCLEAR POWER AND REACTOR COOLANT AVERAGE TEMPERATURE

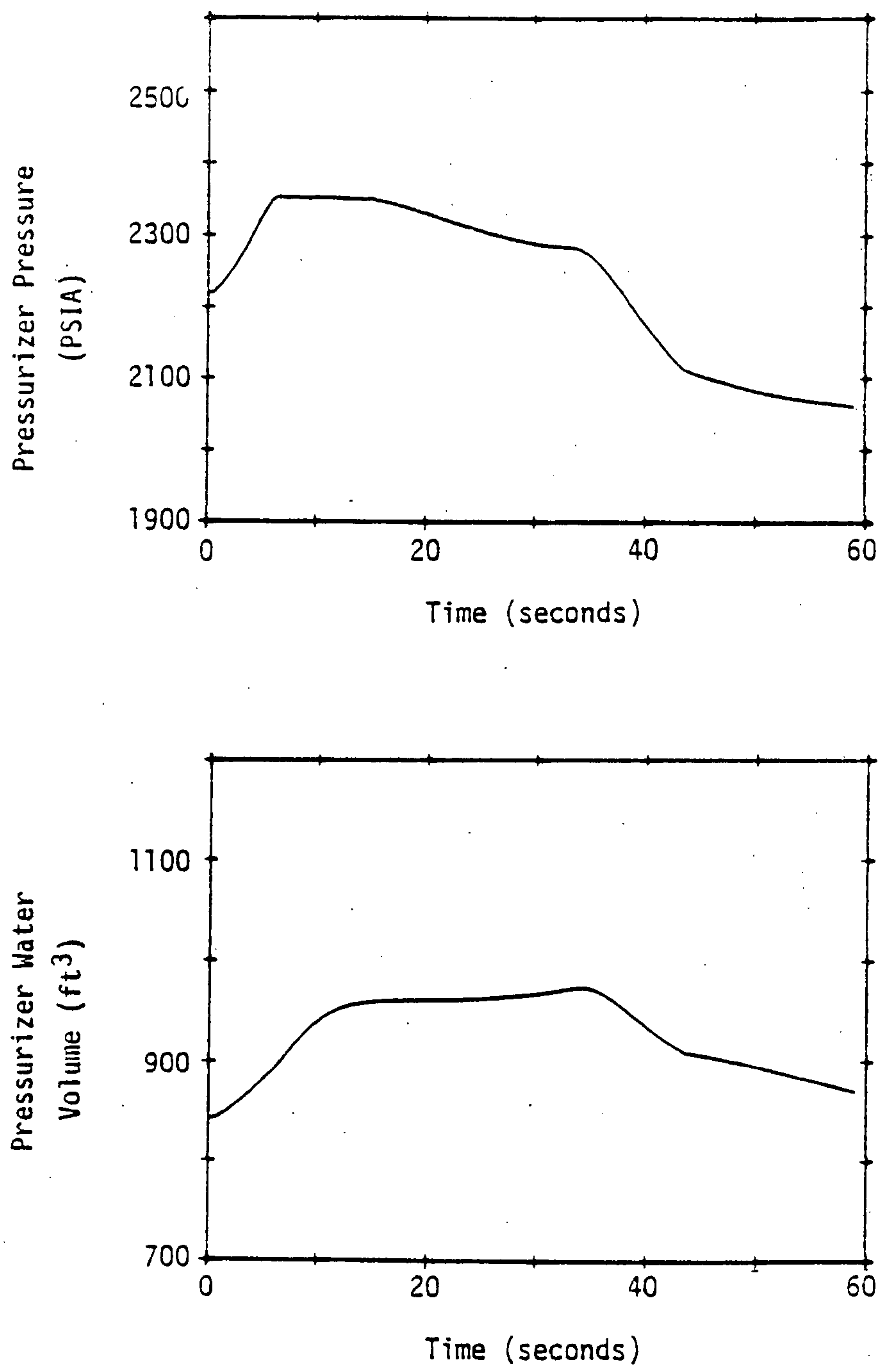


FIGURE 5 TURBINE TRIP WITH PRESSURE CONTROL - MAXIMUM FEEDBACK - PRESSURIZER PRESSURE AND WATER VOLUME

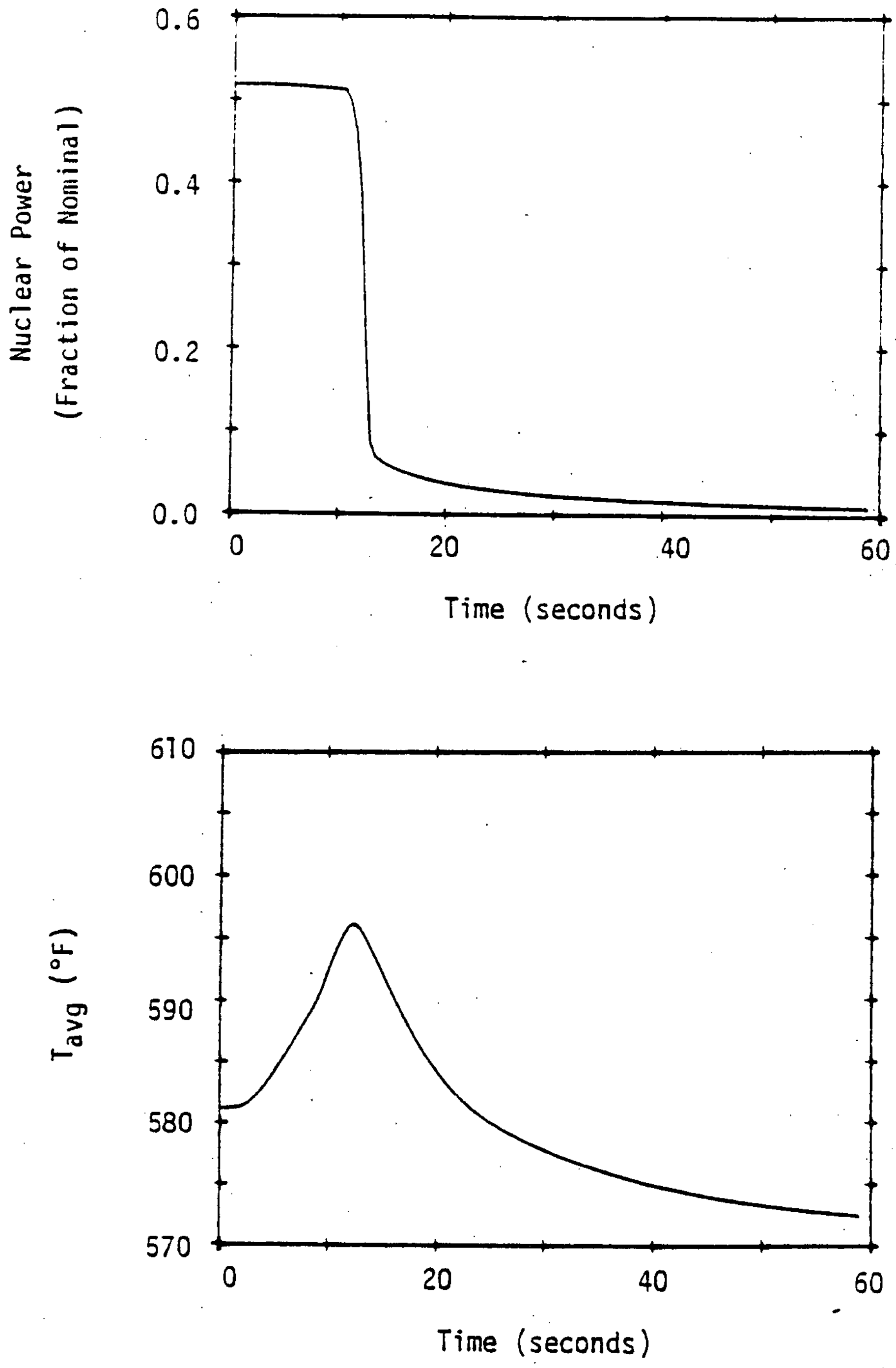


FIGURE 6 TURBINE TRIP WITHOUT PRESSURE CONTROL - MINIMUM FEEDBACK - NUCLEAR POWER AND REACTOR COOLANT AVERAGE TEMPERATURE

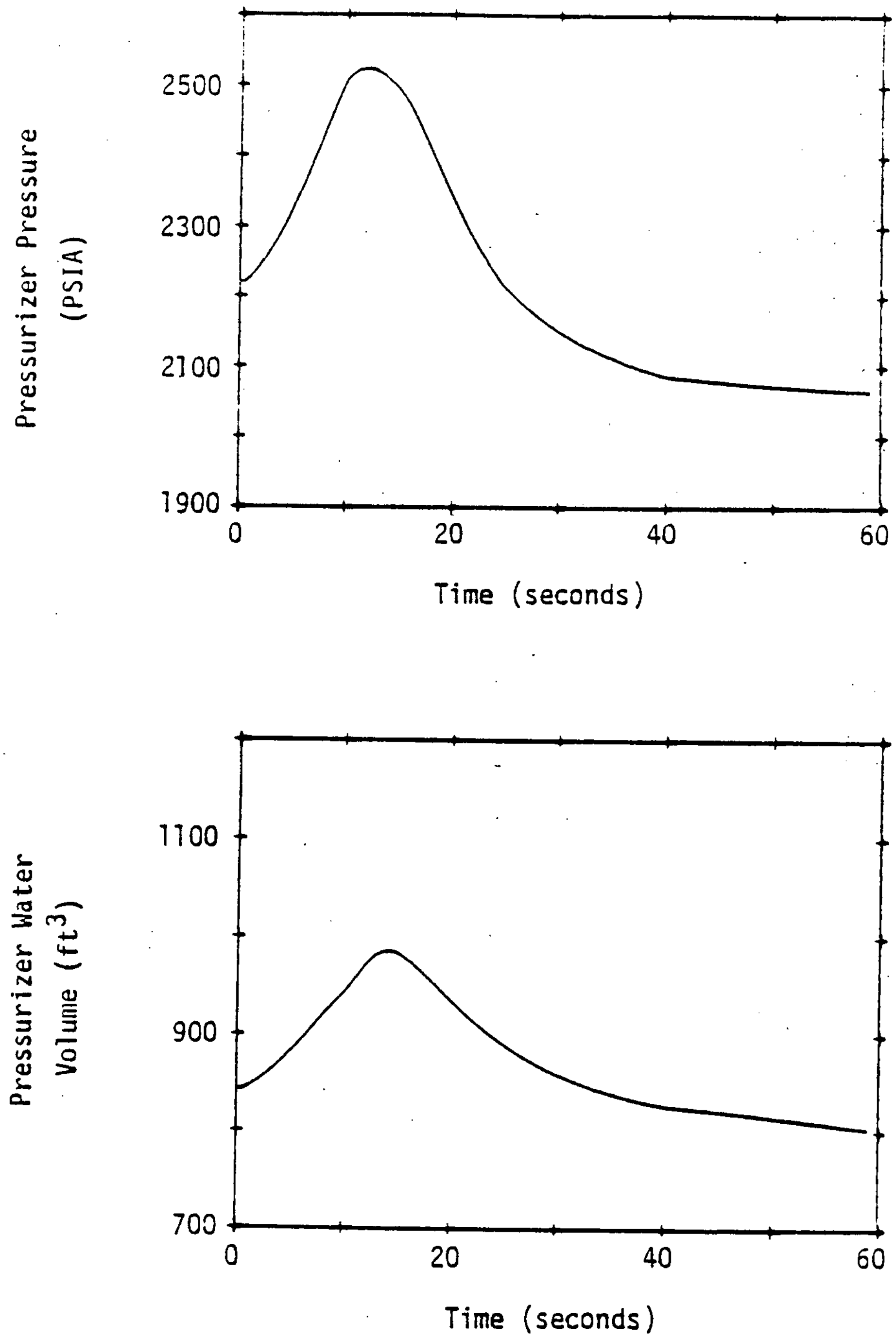


FIGURE 7 TURBINE TRIP WITHOUT PRESSURE CONTROL - MINIMUM FEEDBACK - PRESSURIZER PRESSURE AND WATER VOLUME

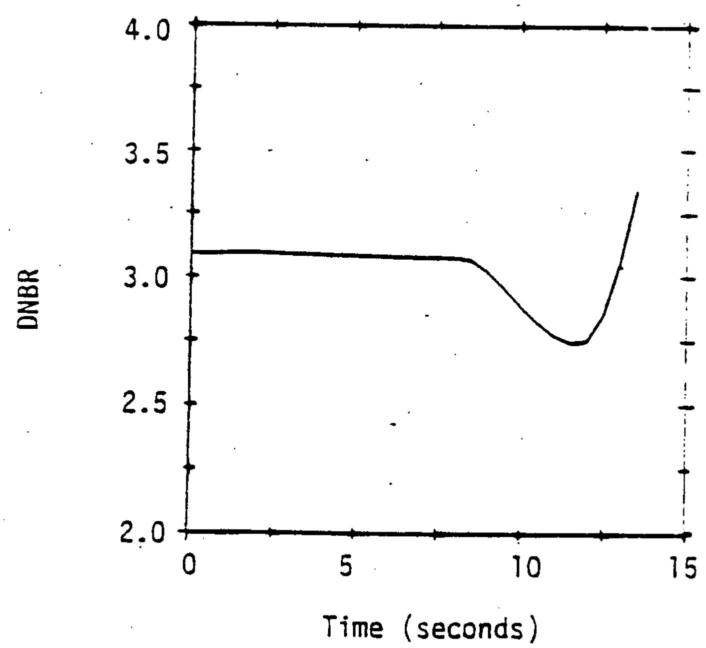
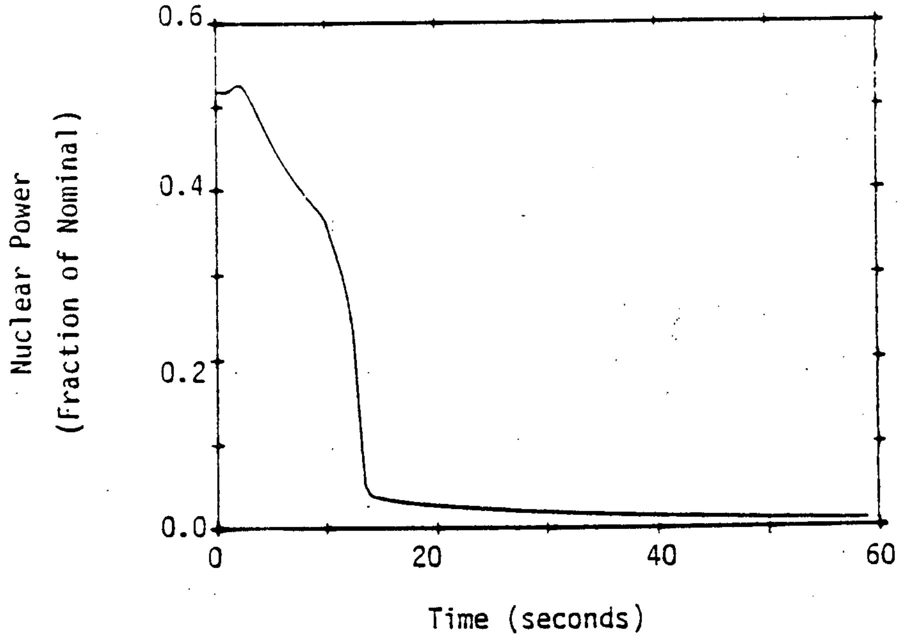


FIGURE 8 TURBINE TRIP WITHOUT PRESSURE CONTROL - MINIMUM FEEDBACK - DNBR



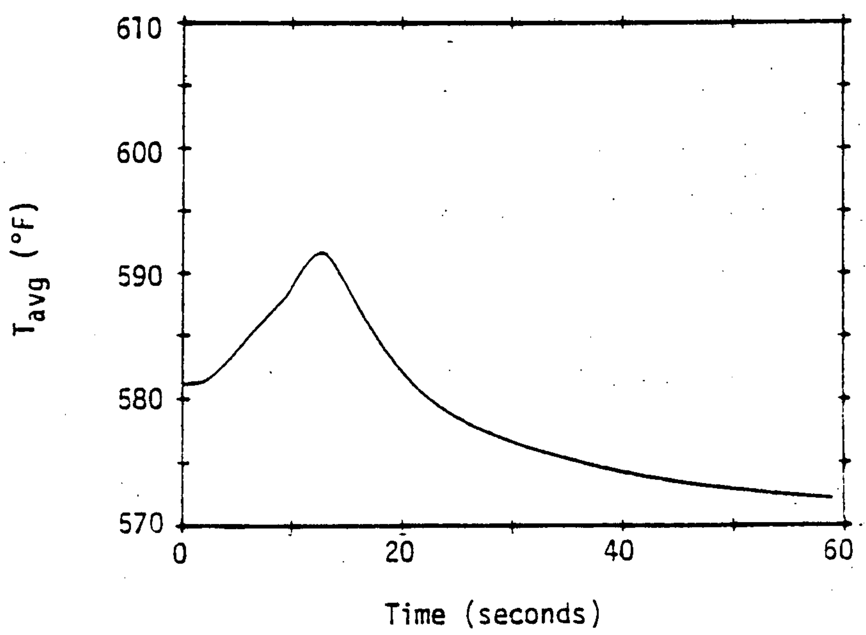


FIGURE 9 TURBINE TRIP WITHOUT PRESSURE CONTROL - MAXIMUM FEEDBACK - NUCLEAR POWER AND REACTOR COOLANT AVERAGE TEMPERATURE

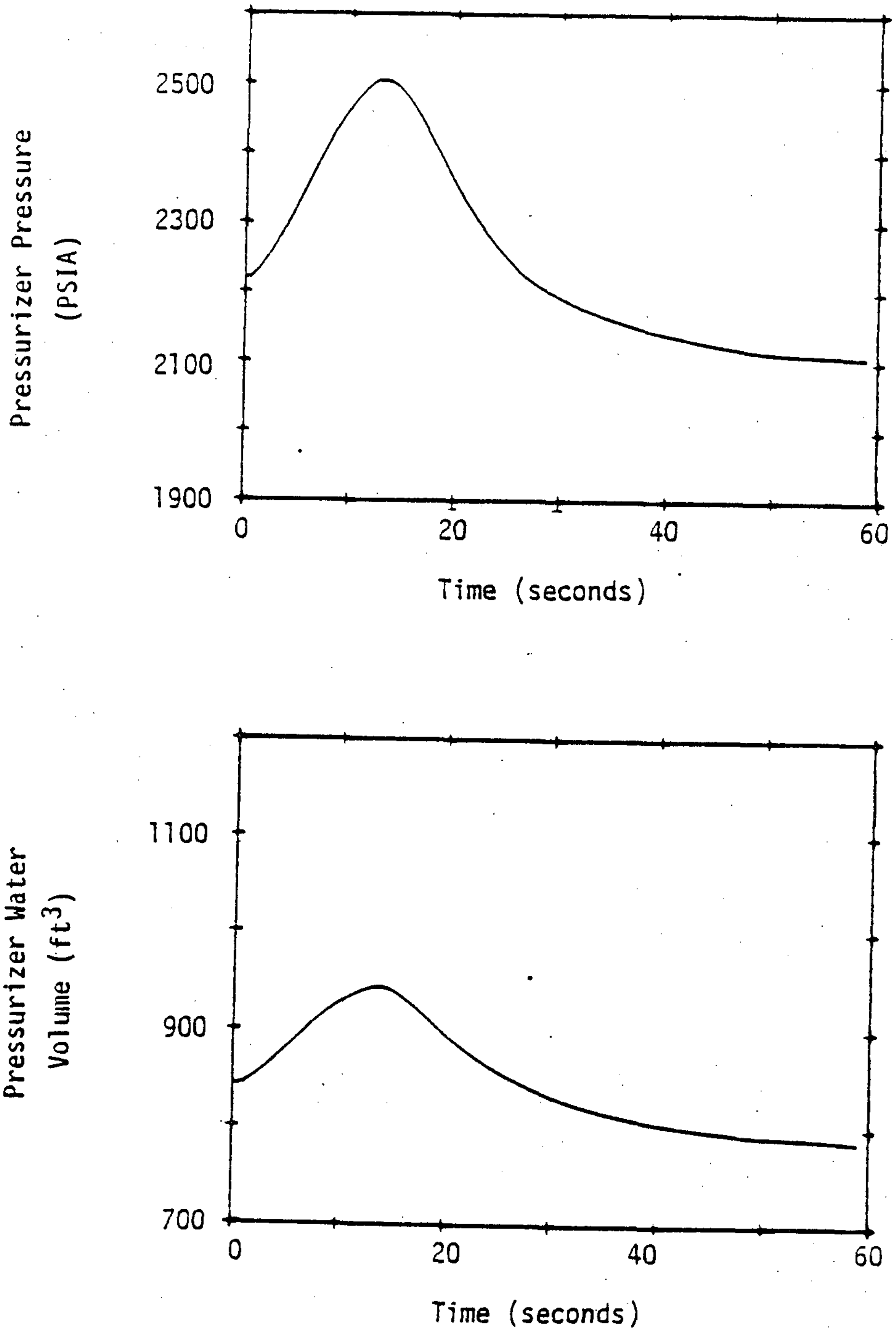


FIGURE 10 TURBINE TRIP WITHOUT PRESSURE CONTROL - MAXIMUM FEEDBACK - PRESSURIZER PRESSURE AND WATER VOLUME

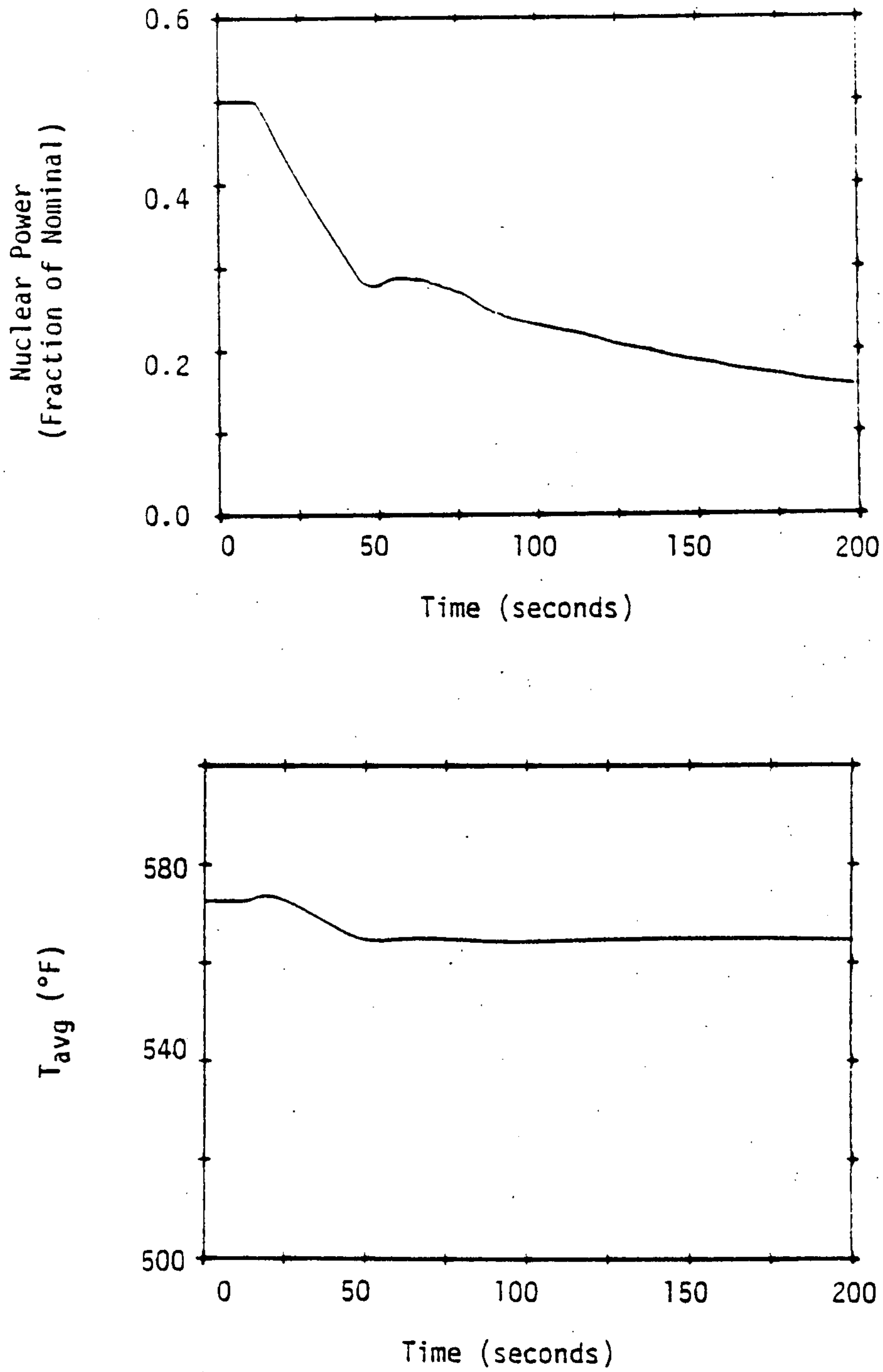


FIGURE 11 TURBINE TRIP WITH PRESSURE CONTROL - MIMIMUM FEEDBACK - STEAM DUMP - CONTROL ROD INSERTION - NO LOSS OF RCS FLOW - NUCLEAR POWER AND REACTOR COOLANT AVERAGE TEMPERATURE

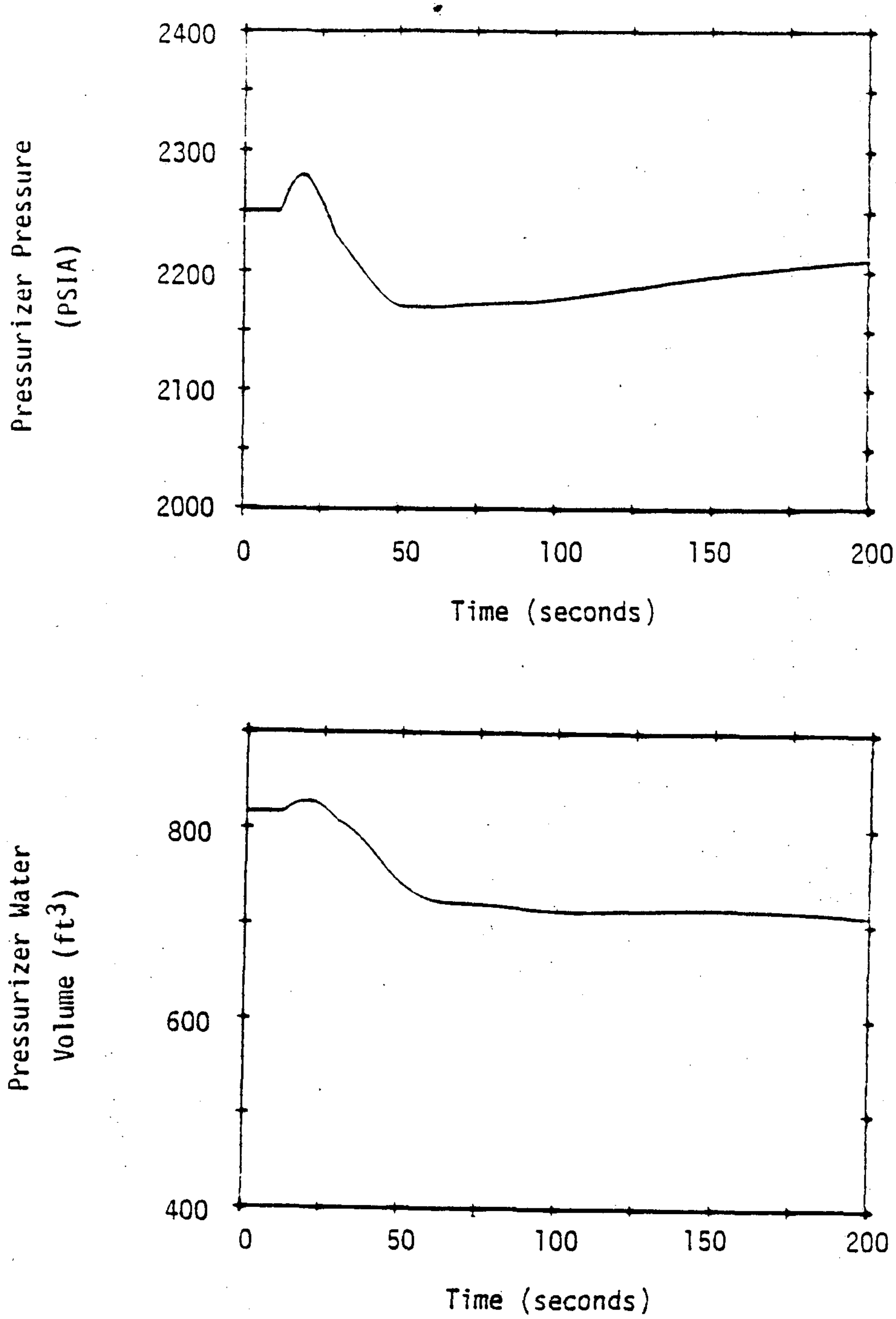


FIGURE 12 TURBINE TRIP WITH PRESSURE CONTROL - MINIMUM FEEDBACK - STEAM DUMP - CONTROL ROD INSERTION - NO LOSS OF RCS FLOW - PRESSURIZER PRESSURE AND WATER VOLUME

MAXIMUM DOSE RELEASE ANALYSIS

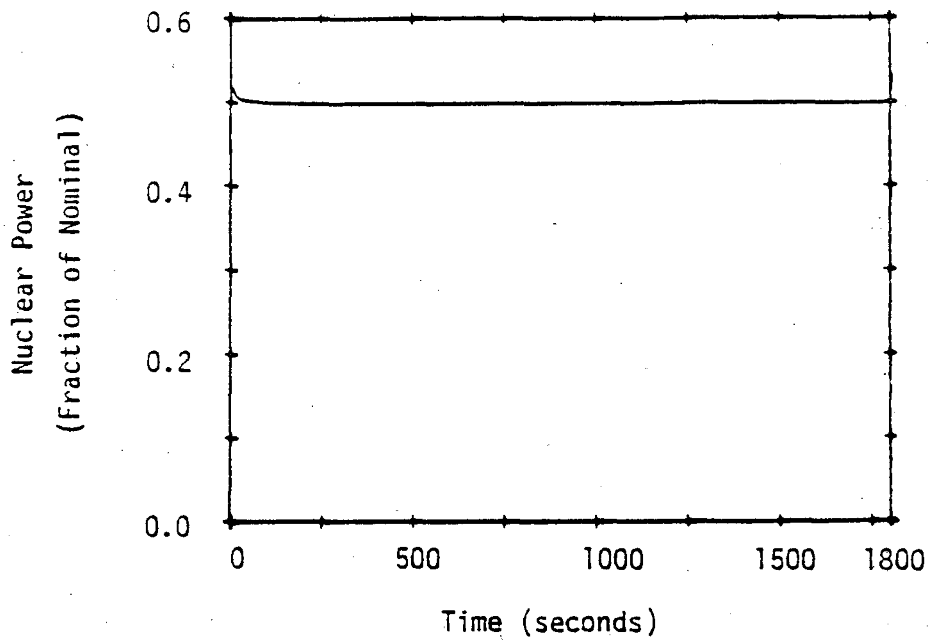
An analysis of the worst case steam releases was performed using the following basic assumptions:

1. Plant is in manual control mode
2. Pressurizer pressure control (spray and PORV relief)
3. BOL conditions (minimum moderator feedback)
4. No steam dump
5. Successful bus transfer to offsite power
6. Feedwater control system operational
7. No operator action for 30 minutes

A considerable amount of steam may be released during this transient through the Steam Generator Safety Valves to the environment. This is assumed to occur for 30 minutes due to operator action delay. However, the pressurizer PORV's and SG safety valves do not lift until 7 seconds into the transient (following primary to secondary pressure and temperature increases due to turbine trip). By 30 seconds the pressurizer PORV's and spray and SG safety valves and the plant conditions stabilize at approximately 50 percent power, a high DNBR, and 51 percent nominal steam flow out of the steam generator safety valves. It is the steam flow we are concerned with. Graphs of pertinent parameters are on the following pages.

Total flow through SG safety valves = 51.10 percent nominal flow
(.5110)(4204.24 lbm/S) (1800 sec - 7 sec) = 3852027.4

Since a Reactor Trip is not obtained and the plant stabilizes at a high power level and steam flow, this case is very conservative with respect to steam release for all cases presented in the main body of this report. Therefore, this release (3852027.4 lbm) is conservative and may be used to verify the acceptability of all transients with respect to radiological dose releases. The dose releases will be calculated by TVA as their part to verify the acceptability for the deletion of the reactor trip on turbine trip below 50 percent power for WATTS BAR Units 1 and 2. TVA should determine if the steam releases will be limited by the total amount of available secondary feedwater.



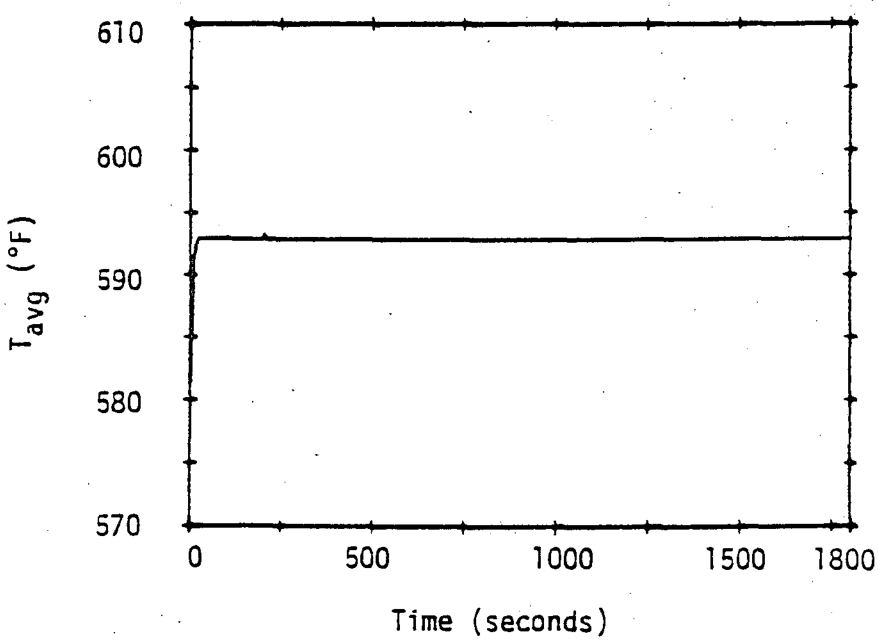


FIGURE 1 TURBINE TRIP WITH PRESSURE CONTROL - MINIMUM FEEDBACK - NUCLEAR POWER AND CORE AVERAGE TEMPERATURE

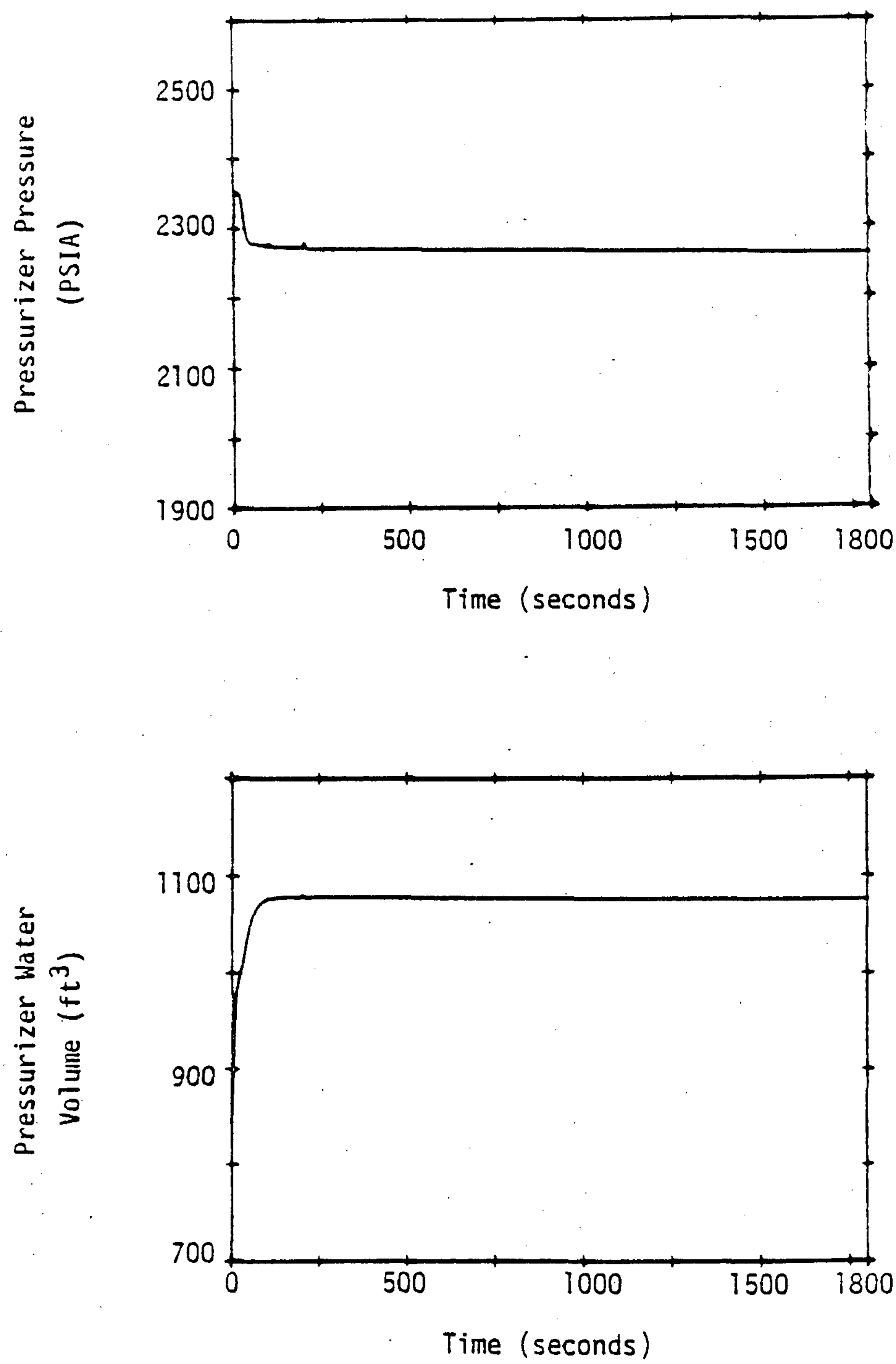


FIGURE 2 TURBINE TRIP WITH PRESSURE CONTROL - MINIMUM FEEDBACK - PRESSURIZER PRESSURE AND WATER VOLUME

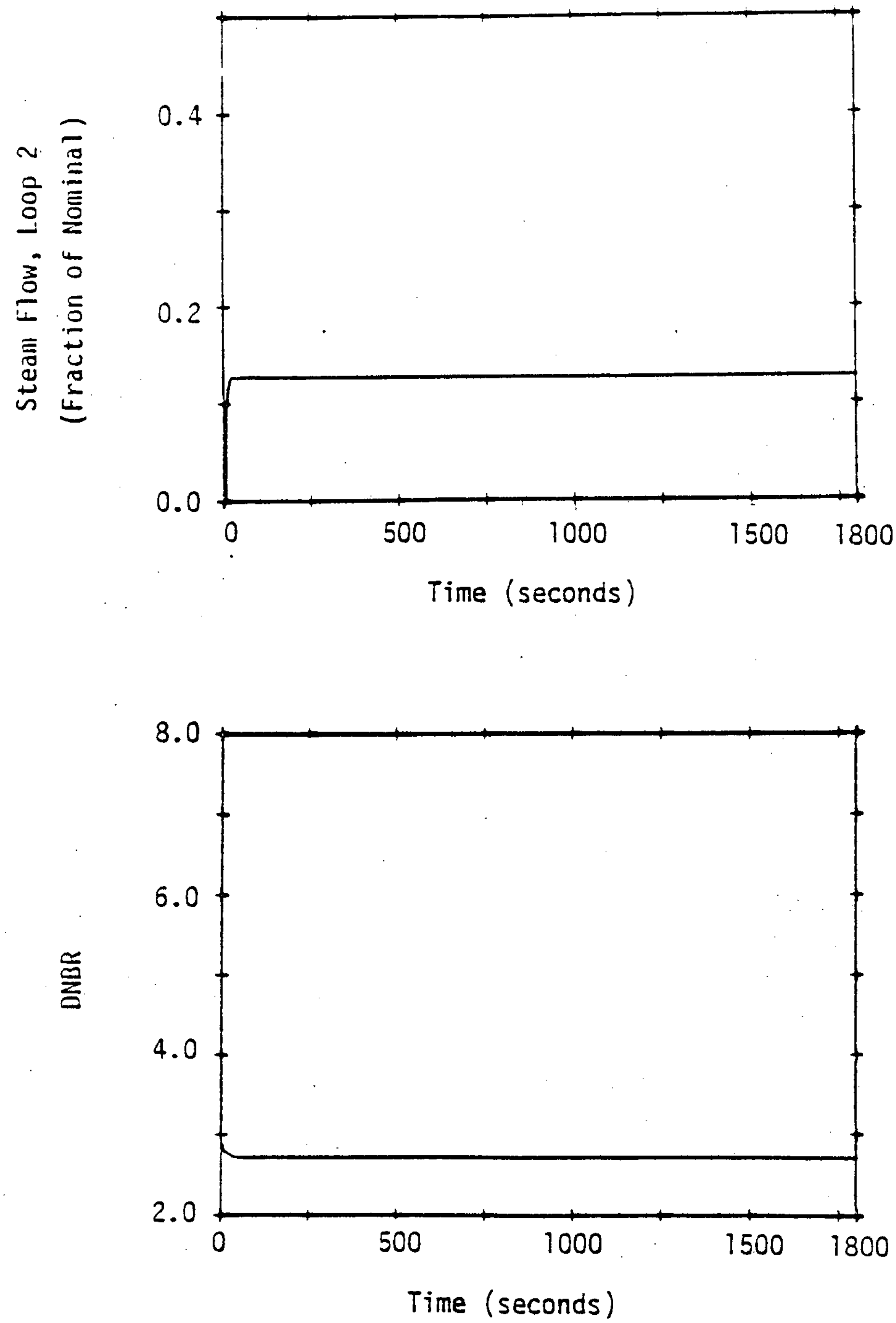


FIGURE 3 TURBINE TRIP WITH PRESSURE CONTROL - MINIMUM FEEDBACK - STEAMFLOW, LOOP 2 AND DNBR