SECL 90-469
Customer Reference No(s).
N/A
Westinghouse Reference No(s).
N/A

WESTINGHOUSE NUCLEAR SAFETY
SAFETY EVALUATION CHECK LIST

1) NUCLEAR PLANT(S) : BYRON/BRAIDWOOD UNITS 1 & 2

2) SUBJECT (TITLE): RELAXATION OF MSSV SETPOINT TOLERANCE TO +/-3%

3) The written safety evaluation of the revised procedure, design change or modification required by 10CFR50.59 (b) has been prepared to the extent required and is attached. If a safety evaluation is not required or is incomplete for any reason, explain on Page 2.

Parts A and B of this Safety Evaluation Check List are to be completed only on the basis of the safety evaluation performed.

CHECK LIST - PART A 10CFR50.59(a)(1)

(3.1) Yes X No ___ A change to the plant as described in the FSAR?
(3.2) Yes ___ No X A change to procedures as described in the FSAR?
(3.3) Yes ___ No X A test or experiment not described in the FSAR?
(3.4) Yes X No ___ A change to the plant technical specifications? (See note on Page 2.)

4) CHECK LIST - Part B 10CFR50.59(a)(2) (Justification for Part B answers must be included on Page 2.)

(4.1) Yes ___ No X Will the probability of an accident previously evaluated in the FSAR be increased?
(4.2) Yes ___ No X Will the consequences of an accident previously evaluated in the FSAR be increased?
(4.3) Yes ___ No X May the possibility of an accident which is different than any already evaluated in the FSAR be created?
(4.4) Yes ___ No X Will the probability of a malfunction of equipment important to safety previously evaluated in the FSAR be increased?
(4.5) Yes ___ No X Will the consequences of a malfunction of equipment important to safety previously evaluated in the FSAR be increased?
(4.6) Yes ___ No X May the possibility of a malfunction of equipment important to safety different than any already evaluated in the FSAR be created?
(4.7) Yes ___ No X Will the margin of safety as defined in the bases to any technical specifications be reduced?

NOTES:

If the answers to any of the above questions are unknown, indicate under 5) REMARKS and explain below.

If the answers to any of the above questions in Part A 3.4 or Part B cannot be answered in the negative, based on the written safety evaluation, the change review would require an application for license amendment as required by 10CFR50.59(c) and submitted to the NRC pursuant to 10CFR50.90.

5) REMARKS:

The following summarizes the justification based upon the written safety evaluation[1], for answers given in Part A 3.4 and Part B of this safety evaluation check list:

See Attached Evaluation

[1]Reference to documents containing written safety evaluation:

FOR FSAR UPDATE

Section: various Pages: ________ Tables: ________ Figures: ________

Reason for/Description of Change:

Table 15.0-2, Table 15.0-5, Figure 15.0-1, and Section 15.2.3 were revised based on the new analyses (DT protection and LOL/TT).

6) SAFETY EVALUATION APPROVAL LADDER:

6.1) Prepared by (Nuclear Safety): B Rarig Date: 10/30/90
B. E. Rarig

6.2) Nuclear Safety Group Manager: R J Sterdis Date: 10/31/90
R. J. Sterdis

BYRON/BRAIDWOOD UNITS 1 AND 2
INCREASED MAIN STEAM SAFETY VALVE SETPOINT TOLERANCE
SAFETY EVALUATION

## 1.0 BACKGROUND

Commonwealth Edison Company (CECo) has found that over an operating cycle, the setpoint of the Main Steam Safety Valves (MSSV) changes by more than 1% from the original set-pressure. As a result, the plant is placed in an ACTION statement and must take immediate steps to avoid a violation.

The Technical Specifications specify the setpoint at which the valves must open and the tolerance (in percent of the setpoint) within which the valves must begin to lift when calibrated and/or tested. The specified tolerance of ±1% of the setpoint, has proven to be difficult to meet when the valves are tested. Therefore, CECo has requested that Westinghouse perform an evaluation to support a relaxation in MSSV setpoint tolerances from ±1% to ±3% as defined in Technical Specification Section 3/4.7. This safety evaluation will address the effects of the ±3% tolerance on FSAR Accident analyses (non-LOCA, LOCA, SGTR), the primary component design transients, and the plant Overpressure Protection Report. The impact on the Main Steam System and the MSSVs is not within Westinghouse scope of supply and is not addressed in this evaluation.

During normal surveillance, if the valves are found to be within ±3%, they will be within the bases of the accident analyses. However, as required per Reference 4, it is strongly recommended that the valves be reset to the specified design tolerance (±1%) to prevent future accumulation of drift beyond ±3%. Resetting of the valves if the ±1% tolerance is exceeded is consistent with the existing Technical Specification requirements and the recommended Technical Specification modifications provided in Appendix D. Thus, this evaluation permits a ±3% setpoint tolerance to address as-found conditions.

The operation of the MSSVs is governed by the ASME Code (Reference 2). The ASME Code requires that the valves lift within 1% of the specified setpoint (NB-7512.2). The code also states that the valves must attain rated lift (i.e., full flow) within 3% of the specified setpoint (NB-7512.1). This evaluation will form the basis for taking exception to the ASME Code with respect to the lift setpoint tolerances. As defined in NB-7512.2, exceptions can be made to the code providing the effects are accounted for in the accident analyses, specifically, the Overpressure Protection Report (Reference 3).

## 2.0 LICENSING BASIS

Title 10 of the Code of Federal Regulations, Section 50.59 (10 CFR 50.59) allows the holder of a license authorizing operation of a nuclear power facility the capacity to initiate certain changes, tests and experiments not described in the Final Safety Analysis Report (FSAR). Prior Nuclear Regulatory Commission (NRC) approval is not required to implement the modification provided that the proposed change, test or experiment does not involve an unreviewed safety question or result in a change to the plant technical specifications incorporated in the license. While the proposed change to the MSSV lift setpoint tolerances involves a change to the Byron and Braidwood technical specifications and requires a licensing amendment request, this evaluation will be performed using the method outlined under 10CFR50.59 to provide the bases for the determination that the proposed change does not involve an unreviewed safety question. In addition, an evaluation will demonstrate that the proposed change does not represent a significant hazards consideration, as required by 10CFR50.91 (a) (1) and will address the three test factors required by 10CFR50.92 (c).

## 3.0 EVALUATIONS

The results of the various evaluations from the Nuclear Safety related disciplines within Westinghouse scope are discussed in the following sections.

### 3.1 Non-LOCA Evaluation

#### 3.1.1 ΔT Protection

The increase in the MSSV lift setpoint tolerance has the potential to impact the Overtemperature ΔT and Overpower ΔT setpoint equations. Referring to UFSAR Figure 15.0-1, increasing the point at which the MSSVs lift will lower the steam generator safety valve line. If the current OTΔT setpoint coefficients (K1 through K3) result in protection lines that just bound the thermal core limits, it is possible that by lowering the SG safety valve line to the right, a portion of the core limits will be uncovered.

In order to evaluate the effects of the increase in the setpoint tolerance, the Overtemperature ΔT and Overpower ΔT setpoint equations (K1 through K6) were examined to determine if the equations remained valid assuming that all 20 MSSVs opened with a +3% tolerance. The results of that evaluation showed that there was sufficient margin in the generation of the current setpoint equations to offset the lowering of the SG safety valve line. The results of this calculation are presented as Figure 1.

#### 3.1.2 DNB Events

The transients identified in Table 1 are analyzed in the Byron/Braidwood UFSAR to demonstrate that the DNB design basis is satisfied. With one exception, these events are a) of such a short duration that they do not result in the actuation of the MSSVs, b) core-related analyses that focus on the active fuel region only, or c) cooldown events which result in a decrease in secondary steam pressure. The single exception is the loss of external load/turbine trip event which is addressed explicitly in Section 3.1.7 of this evaluation. Thus, based on the above, these non-LOCA DNB transients are not adversely impacted by the proposed change, and the results and conclusions presented in the UFSAR remain valid.

TABLE 1

DNB DESIGN BASIS TRANSIENTS

| EVENT | UFSAR Section |
|---|---|
| Feedwater System Malfunction: Reduction in Temperature | 15.1.1 |
| Feedwater System Malfunction: Increase in Feedwater Flow | 15.1.2 |
| Excessive Increase in Secondary Steam Flow | 15.1.3 |
| Inadvertent Opening of a SG Relief or Safety Valve | 15.1.4 |
| Steam System Piping Failure (Double-Ended Rupture - Core Response) | 15.1.5 |
| Partial Loss of Forced Reactor Coolant Flow | 15.3.1 |
| Complete Loss of Forced Reactor Coolant Flow | 15.3.2 |
| Reactor Coolant Pump Shaft Seizure (DNB & Overpressurization Concerns) | 15.3.3 |
| Reactor Coolant Pump Shaft Break (DNB & Overpressurization Concerns) | 15.3.4 |
| Uncontrolled RCCA Bank Withdrawal From a Subcritical Condition | 15.4.1 |
| Uncontrolled RCCA Bank Withdrawal at Power | 15.4.2 |
| RCCA Misalignment | 15.4.3 |
| Inadvertent Operation of the ECCS | 15.5.1 |
| Inadvertent Opening of a Pressurizer Safety or Relief Valve | 15.6.1 |
| Startup of an Inactive Reactor Coolant Pump | 15.4.4 |
| CVCS Malfunction (Boron Dilution) | 15.4.6 |

### 3.1.3 Dilution Events

The following dilution events are analyzed to demonstrate that the operators (or the automatic mitigation circuitry) have sufficient time to respond prior to reactor criticality once an alarm is generated. The secondary system is not modeled in the analysis of these events, and thus, changes to the MSSVs have no impact on these events. Therefore, the results and conclusions presented in the UFSAR remain valid.

| DILUTION EVENTS | UFSAR Section |
|---|---|
| Startup of an Inactive Reactor Coolant Pump | 15.4.4 |
| CVCS Malfunction (Boron Dilution) | 15.4.6 |

### 3.1.4 Steamline Break Mass & Energy Releases

For the steamline break mass and energy releases, the steam release calculations are insensitive to the changes in the MSSV lift setpoints since the vast majority of these calculations result in depressurizations of the secondary side such that the MSSVs are not actuated. For the smaller break cases that might result in a heatup, based on the existing analyses one MSSV per steam generator is sufficient to provide adequate heat removal following reactor trip and is bounded by the MSSV assumption used in the current non-LOCA accident analyses. Thus, secondary pressures will be no greater than those presently calculated.

| EVENT | UFSAR Section |
|---|---|
| Steamline Rupture Mass & Energy Releases Inside Containment | 6.2.1.4 |
| Steamline Rupture Mass & Energy Releases Outside Containment for Equipment Environmental Qualification | WCAP-10961-P-A |

### 3.1.5 Long-Term Heat Removal Events

The only non-LOCA transients remaining are the long-term heatup events. The long-term heat removal events are analyzed to determine if the auxiliary feedwater (AFW) heat removal capability is sufficient to ensure that the peak RCS and secondary pressures do not exceed allowable limits, the pressurizer does not fill (LONF/LOACP), and the core remains covered and in a coolable geometry (FLB). These transients are listed below.

| EVENT | UFSAR Section |
|---|---|
| Loss of Non-Emergency AC Power to Plant Auxiliaries (LOACP) | 15.2.6 |

Loss of Normal Feedwater (LONF) 15.2.7

Feedwater System Pipe Break (FLB) 15.2.8

These transients are impacted by the increase in the MSSV lift setpoint tolerance because the calculations determining the amount of AFW flow available must assume a maximum given steam generator backpressure in order to determine the amount of AFW that can be delivered. As the steam generator backpressure increases, the amount of AFW delivered will be reduced. For the loss of non-emergency AC power and the loss of normal feedwater events, flow control valves in the AFW lines, designed to limit flow to a preset value, are assumed to operate since they conservatively minimize the amount of AFW available for cooling. These transients assume an AFW flow rate of 153 gpm per steam generator. If the valves were inoperable or failed during operation, they would do so in the open position resulting in higher AFW flow rates. The valves will function such that the 153 gpm accident analysis assumption will be met independent of the increase in the generator backpressure.

The feedline break event results in a faulted steam generator that depressurizes to atmospheric pressure. As a result, the AFW flow control valves are assumed to fail, minimizing the amount of AFW available for long-term cooling. This assumption results in the AFW flow being preferentially fed to the faulted steam generator where it is lost out the break. In order to ensure that some amount of AFW is supplied to the remaining intact steam generators, passive orifice plates, installed in each of the AFW lines, are used to limit the flow to the faulted loop. Since there is no method available to throttle AFW flow, the overall flow provided to the intact steam generators during a feedline break event will be reduced as the backpressure increases. Therefore, the effects of the MSSV setpoint tolerance relaxation on AFW performance during a feedline break accident must be considered.

A calculation was performed to determine the maximum steam pressure inside an intact steam generator during the long-term cooling portion of the transient (i.e., after steamline isolation occurs). The results showed that the maximum steam pressure at Byron and Braidwood is 1250 psia. Note that this value bounds both cases with and without offsite power available. Based on subsequent calculations, it was determined that the resultant AFW flow (458 gpm to the three intact steam generators) will remain greater than that currently assumed in the licensing-basis feedline break analysis (420 gpm). Therefore, the results and conclusions presented in the UFSAR (15.2.8) remain valid.

The final concern is the potential for steam generator overpressurization following reactor trip for the other long-term heatup events. Based on the existing UFSAR loss of non-emergency AC power and loss of normal feedwater analyses, long-term cooling requires a maximum of 1-3% of nominal plant steam flow from each steam generator or a plant total of 4-12% of nominal steam flow (depending on the transient). In order to pass the required flow, the two lowest set MSSVs would be required to lift. With a 3% lift tolerance, this condition would result in full open pressures for the two valves of 1249.5 and 1265.3 psia, respectively. The relief capacity of the first 2 MSSVs full open on each steam generator bounds 12% nominal steam flow. Thus, the steam flow requirement would be satisfied and resultant steam pressure of ~1265 psia would not exceed 110% of the secondary design pressure (1320 psia). As discussed above, the maximum expected pressure for a feedline break event is 1250 psia which is also less than the limit. Therefore, the proposed change does not adversely impact the long-term cooling overpressurization requirements.

Thus, based on the discussions presented above, only one UFSAR transient is impacted such that a new analysis must be performed in order to address the effects of the MSSV lift setpoint tolerance increase from $\pm1\%$ to $\pm3\%$. This event is the loss of external load/turbine trip accident. For the remaining transients, the results and conclusions presented in the Byron/Braidwood UFSAR remain valid.

3.1.6 -3% Tolerance

Secondary steam releases are generated for the offsite dose calculations for the following non-LOCA transients: the steam system piping failure (UFSAR Table 15.1-3), the loss of external load (UFSAR Table 15.2-4), and the RCP shaft seizure (locked rotor - UFSAR Table 15.3-3). The methodology used to calculate these masses is based on determining the amount of secondary side inventory required to cool down the RCS. During the first two hours (0-2 hours), the operators are assumed to lower the RCS average temperature to no-load conditions (557°F) by bleeding steam. Over the next 6 hours (2-8 hours), the operators will cool the plant down such that Mode 4 operation (hot shutdown) can be entered.

The existing steam release calculations for the 0-2 hour period used enthalpies corresponding to saturated conditions at both the nominal full power RCS average temperature and the no-load temperature (588°F and 557°F, respectively). Thus, as long as the increased lift setpoint tolerance (-3%) does not result in the MSSVs remaining open at a saturation temperature outside of the range identified above, the existing mass releases remain valid.

The existing mass release calculations were performed using the temperatures previously identified (588°F and 557°F). Per the Byron/Braidwood Technical Specifications, the lowest set MSSV on each steam generator will open at 1190 psia (1175 psig) not including any tolerance. Based on the ASME Steam Tables (Reference 6) at saturated conditions, 557°F corresponds to 1106.4 psia and represents the lowest steam pressure considered in the mass calculations. Thus, the existing releases include a reseat pressure equal to 7% below the lowest Technical Specification lift setpoint. As long as the valves continue to reseat within this pressure range, the current mass releases remain valid.

### 3.1.7 Analysis Summary

#### 3.1.7.1 Loss of External Load/Turbine Trip

The loss of external load/turbine trip event is presented in Section 15.2.3 of the Byron/Braidwood UFSAR. This transient is caused by a turbine-generator trip which results in the immediate termination of steam flow. Since no credit is taken for a direct reactor trip on turbine trip, primary and secondary pressure and temperature will begin to increase, actuating the pressurizer and steam generator safety valves. The reactor will eventually be tripped by one of the other reactor protection system (RPS) functions; specifically, overtemperature $\Delta T$, high pressurizer pressure, or low-low steam generator water level.

The turbine trip event is the limiting non-LOCA event for potential overpressurization, i.e., this transient forms the design basis for the primary and secondary safety valves. Since the MSSVs will now potentially be opening at a higher pressure due to the increase in the lift setpoint tolerance, it is necessary to analyze this transient in order to demonstrate that all the applicable acceptance criteria are satisfied. A turbine trip is classified as an ANS condition II event, a fault of moderate frequency. As such, the appropriate acceptance criteria are DNBR, peak primary pressure, and peak secondary pressure. The transient is described in greater detail in the UFSAR.

The turbine trip event is analyzed using a modified version of the LOFTRAN digital computer code (Reference 7). The program simulates neutron kinetics, reactor coolant system, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generators, and main steam safety valves. With the modified code, the MSSVs are explicitly modeled as a bank of 5 valves on each steam generator with staggered lift setpoints. Since higher steam pressures are conservative for this event, no blowdown or hysteresis behavior was assumed.

Consistent with the existing UFSAR analysis, the following assumptions were used in this analysis:

a. Initial power, temperature, and pressure were at their nominal values consistent with ITDP methodology (WCAP-8567).

b. Turbine trip was analyzed with both minimum and maximum reactivity feedback corresponding to beginning-of-life and end-of-life conditions, respectively.

c. Turbine trip was analyzed both with and without pressurizer pressure control. The PORVs and sprays were assumed operable in the cases with pressure control. The cases with pressure control minimize the increase in primary pressure which is conservative for the DNBR transient. The cases without pressure control maximize the increase in pressure which is conservative for the RCS overpressurization criterion.

d. The steam generator PORV and steam dump valves were not assumed operable. This assumption maximizes secondary pressure.

e. Main feedwater flow was assumed to be lost coincident with the turbine trip. This assumption maximizes the heatup effects.

f. Only the overtemperature $\Delta T$, high pressurizer pressure, and low-low steam generator water level reactor trips were assumed operable for the purposes of this analysis.

g. The MSSVs were assumed to lift 3% above the Technical Specification setpoints and were assumed to be full open 5% above the setpoints. This is consistent with the 2% difference between lift and rated flow currently included in the code.

h. An individual MSSV was assumed to have a full flow capacity of 249 lbm/sec.

3.1.7.2 Analysis Results

Four cases were analyzed: a) minimum feedback without pressure control, b) maximum feedback without pressure control, c) maximum feedback with pressure control, and d) minimum feedback with pressure control. The calculated sequence of events for the four cases is presented in Table 2.

Case A:

Figures 2 through 4 show the transient response for the turbine trip event under BOL conditions without pressure control. The reactor is tripped on high pressurizer pressure. The neutron flux remains essentially constant at full power until the reactor is tripped, and the DNBR remains above the initial value for the duration of the transient. The pressurizer safety valves are actuated and maintain primary pressure below 110% of the design value. The main steam safety valves are also actuated and maintain secondary pressure below 110% of the design value.

Case B:

Figures 5 through 7 show the transient response for the turbine trip event under EOL conditions without pressure control. The reactor is tripped on high pressurizer pressure. The DNBR increases throughout the transient and never drops below the initial value. The pressurizer safety valves are actuated and maintain primary pressure below 110% of the design value. The main steam safety valves are also actuated and maintain secondary pressure below 110% of the design value.

Case C:

Figures 8 through 10 show the transient response for the turbine trip event under EOL conditions with pressure control. The reactor is tripped on overtemperature $\Delta T$. The DNBR increases throughout the transient and never drops below the initial value. The pressurizer relief valves and sprays maintain primary pressure below 110% of the design value. The main steam safety valves are also actuated and maintain secondary pressure below 110% of the design value.

Case D:

Figures 11 through 13 show the transient response for the turbine trip event under BOL conditions with pressure control. The reactor is tripped on overtemperature $\Delta T$. The neutron flux remains essentially constant at full power until the reactor is tripped, and although the DNBR value decreases below the initial value, it remains well above the limit throughout the entire transient. The pressurizer relief valves and sprays maintain primary pressure below 110% of the design value. The main steam safety valves are also actuated and maintain secondary pressure below 110% of the design value.

3.1.7.3 Analysis Conclusions

Based on the results of these turbine trip analyses with a +3% tolerance on the MSSV lift setpoints, all of the applicable acceptance criteria are met. The minimum DNBR for each case is greater than the limit value. The peak primary and secondary pressures remain below 110% of design at all times.

TABLE 2

TURBINE TRIP SEQUENCE OF EVENTS

| ACCIDENT | EVENT | TIME (sec) |
|---|---|---|
| Without pressurizer control (minimum reactivity feedback) | Turbine trip, loss of main feedwater flow | 0.0 |
| | High pressurizer pressure reactor trip setpoint reached | 4.3 |
| | Rods begin to drop | 6.3 |
| | Initiation of steam release from the MSSVs | 6.5 |
| | Peak pressurizer pressure occurs | 7.5 |
| | Minimum DNBR occurs | (1) |
| Without pressurizer control (maximum reactivity feedback) | Turbine trip, loss of main feedwater flow | 0.0 |
| | High pressurizer pressure reactor trip setpoint reached | 4.3 |
| | Rods begin to drop | 6.3 |
| | Initiation of steam release from the MSSVs | 6.5 |
| | Peak pressurizer pressure occurs | 7.0 |
| | Minimum DNBR occurs | (1) |

(1) DNBR does not decrease below its initial value.

TABLE 2
(continued)

TURBINE TRIP SEQUENCE OF EVENTS

| ACCIDENT | EVENT | TIME (sec) |
|---|---|---|
| With pressurizer control (maximum reactivity feedback) | Turbine trip, loss of main feedwater flow | 0.0 |
| | Initiation of steam release from the MSSVs | 6.5 |
| | Overtemperature ΔT reactor trip setpoint reached | 7.4 |
| | Peak pressurizer pressure occurs | 7.5 |
| | Rods begin to drop | 9.4 |
| | Minimum DNBR occurs | (1) |
| With pressurizer control (minimum reactivity feedback) | Turbine trip, loss of main feedwater flow | 0.0 |
| | Initiation of steam release from the MSSVs | 6.5 |
| | Overtemperature ΔT reactor trip setpoint reached | 6.9 |
| | Rods begin to drop | 8.9 |
| | Minimum DNBR occurs | 10.0 |
| | Peak pressurizer pressure occurs | 10.5 |

(1) DNBR does not decrease below its initial value.

3.1.8 Overpressure Protection Report

The Overpressure Protection Report (Reference 3) is published to demonstrate that the limiting ANS Condition II pressurization transient (loss of load/turbine trip) does not result in primary and secondary pressures in excess of 110% of the design values. The Overpressure Protection Report has been reviewed as part of this safety evaluation. In order to determine the effects of the increases in the lift setpoint tolerances, the loss of load/turbine trip transient presented in the Overpressure Protection Report was analyzed. The new analysis was performed consistent with the existing report with the exception of the explicit MSSV modeling described in the LOFTRAN description above. The results of this analysis demonstrated that the peak RCS pressure, assumed to be at the outlet of the reactor coolant pumps, was below the limit value (2750 psia).

With respect to the secondary steam system, the transient analysis resulted in approximately 60% of the total MSSV relief capacity being used. It also showed that the maximum secondary steam pressure was less than the limit (1320 psia). Thus, the conclusions presented in the Overpressure Protection Report remain valid. Changes to this report are included in this report.

3.1.9 Non-LOCA Conclusions

The effects of increasing the as-found lift setpoint tolerance on the main steam safety valve have been examined, and it has been determined that, with one exception, the current accident analyses as presented in the UFSAR remain valid. The loss of load/turbine trip event was analyzed in order to quantify the impact of the setpoint tolerance relaxation. As previously demonstrated in this evaluation, all applicable acceptance criteria for this event have been satisfied and the conclusions presented in the UFSAR are still valid. Thus, the proposed Technical Specification change does not constitute an unreviewed safety question, and the non-LOCA accident analyses, as presented in the report, support the proposed change.

Changes to the UFSAR and the Overpressure Protection Report are included in this safety evaluation as appendices.

### 3.2 LOCA and LOCA Related Evaluations

The effects of increased tolerances for the Main Steam Safety Valve (MSSV) setpoints on the LOCA safety analyses has been previously performed for VANTAGE 5 fuel. The current Technical Specification setpoints with rated flow is given below for easy reference. The effect of either increasing or decreasing the setpoint by 3%, depending upon the direction of conservatism, has been evaluated for the LOCA analyses.

| MSSV NUMBER | T/S SETPOINT | RATED FLOW | ACTUAL FLOW |
|---|---|---|---|
| MS017A,B,C,D | 1190 (PSIA) | 841,427 | 934,918 |

| | | | |
|---|---|---|---|
| MS016A,B,C,D | 1205 (PSIA) | 852,039 | 946,710 |
| MS015A,B,C,D | 1220 (PSIA) | 862,652 | 958,502 |
| MS014A,B,C,D | 1235 (PSIA) | 873,265 | 970,294 |
| MS013A,B,C,D | 1250 (PSIA) | 883,878 | 982,087 |

Rated flow should be used for heat-up accidents and actual flow should be used for cooldown accidents. The following presents the effect of the proposed setpoint revision from ±1% to ±3% on the LOCA-related analyses.

3.2.1 Large Break LOCA (FSAR Chapter 15.6.5)

Calculations performed to determine the response to a hypothetical large break LOCA do not model the MSSVs, since a large break LOCA is characterized by a rapid depressurization of the reactor coolant system primary below the pressure of the steam generator secondaries. Thus, the calculated consequences of a large break LOCA are not dependent upon assumptions of MSSV performance. Therefore, the large break LOCA analysis results are not adversely affected by the proposed revised MSSV setpoint tolerances.

3.2.2 Small Break LOCA (FSAR Chapter 15.6.5)

Small Break LOCAs are dependent upon heat transfer from the Reactor Coolant System (RCS) primary to the steam generator secondary in order to limit the consequences of the accident. A period exists when the RCS primary pressure hangs above the steam generator secondary pressure and excess decay heat is transferred to the steam generators. Since a loss of offsite power is assumed to occur coincident with the small break LOCA, the steam dump system and power operated relief valves are assumed to be inactive. Thus, steam relief from the steam generator secondaries takes place through the MSSVs.

The small break LOCA analyses presented in Appendix C of the Byron/Braidwood Stations Units 1 and 2 VANTAGE 5 Reload Transition Safety Report were performed using a 3% higher safety valve setpoint pressure. The standard 3% accumulation between valve actuation and full flow was also accounted for in the analyses. These analyses calculated peak cladding temperatures well below the allowed 2200$^{o}$F limit as specified in 10CFR50.46. demonstrating that the proposed change to the MSSV technical specification can be accommodated for small break LOCAs.

A reduction in the MSSV setpoint tolerance would act to lower the secondary pressure. Since the RCS pressure is controlled by the steam generator secondary pressure through the MSSVs, a decrease in secondary pressure would also result in a lower RCS pressure. A lower RCS pressure would result in more safety injection flow delivered to the RCS. As such, the -3% MSSV setpoint tolerance would provide increased safety injection water to the RCS, which would act to reduce the calculated peak clad temperature. Therefore, a -3% MSSV setpoint tolerance would not adversely affect the small break LOCA analysis results.

While the PCT has increased due to the revised +3% MSSV setpoint tolerance, the calculated PCT remains below 2200°F. Therefore, it is concluded that the increase in the MSSV setpoint tolerances limit to plus or minus 3 percent does not adversely affect the small break LOCA analysis results.

3.2.3 LOCA Blowdown Reactor Vessel and RCS Loop Forces (FSAR Chapter 3.9)

The licensing basis LOCA hydraulic forces analysis results found in the FSAR calculate that the peak loads occur within the first 500 milliseconds of the transient. This occurrence is well before any automatically operated safety feature has responded to the LOCA and before steam generator pressures could reach the set-pressures of the MSSVs. Therefore, changes in the MSSV Technical Specification set-pressures do not change the calculated consequences appearing in the FSAR.

3.2.4 LOCA Mass and Energy Releases for Containment Integrity Analyses (FSAR Chapter 6.2)

There is no effect due to increasing the tolerance of the steam generator Main Steam Safety Valve (MSSV) setpoints from ±1% to ±3% on short or long term LOCA mass and energy release and the resulting containment integrity response. Since a large break LOCA rapidly decreases the RCS pressure below that of the steam generator secondary pressure, the philosophy for long term LOCA considerations is to release all steam generator metal energy and primary coolant to containment. Therefore, only secondary to primary heat transfer is important in determining the amount of energy released to containment. Benefits from any mechanisms, such as MSSVs, that may possibly reduce the amount of available steam generator stored energy are small. Therefore, MSSVs are not modeled in the analysis performed to calculate the consequences for the long term design basis LOCA event.

The short term mass and energy release calculation is terminated after a few seconds. This time duration is so short as to preclude any appreciable effect due to either secondary to primary heat transfer or potential MSSV actuation.

3.2.5 Steam Generator Tube Rupture (FSAR Chapter 15.6.3)

For the steam generator tube rupture (SGTR) event, the FSAR analysis was performed to evaluate the radiological consequences. The major factors that affect the radiological doses are the amount of primary coolant transferred to the secondary side of the ruptured steam generator through the ruptured tube, the steam released from the ruptured steam generator to the atmosphere and the amount of radioactivity in the reactor coolant. The impact on these parameters of changing the main steam safety valve setpoint tolerance from ±1% to ±3% has been determined.

For the FSAR SGTR analysis, the loss of inventory due to the tube rupture results in a decrease in pressurizer pressure. Reactor trip plus SI actuation were assumed to occur on low pressurizer pressure. A loss of offsite power was also assumed to occur at the time of reactor trip, thus the steam dump system was assumed to be unavailable. The energy transfer from the primary system following reactor and turbine trip causes the secondary side pressure to increase rapidly after reactor trip until the steam generator power operated relief valves (PORVs) and/or safety valves lift to dissipate the energy. For the SGTR analysis, it was assumed that the secondary pressure is maintained at the lowest secondary safety valve setpoint following reactor trip. After reactor trip and SI initiation, the RCS pressure was assumed to reach equilibrium at the point where the incoming SI flowrate equals the outgoing break flowrate, and the equilibrium pressure and break flowrate were assumed to persist until 30 minutes after the accident. A change in the main steam safety valve setpoint tolerance to -3% will result in the secondary pressure being maintained at a lower pressure during this 30 minute period, thereby increasing the primary to secondary pressure differential. This will result in an increase to the primary to secondary break flow and the atmospheric steam release via the ruptured steam generator.

An evaluation was performed to determine the effect of decreasing the safety valve setpoint by -3% with respect the SGTR analysis in the FSAR. It is noted that this evaluation was performed in conjunction with the other changes associated with the VANTAGE-5 fuel upgrade, specifically 15% steam generator tube plugging and a hot leg temperature range of 618.4$^{o}$F to 600.0$^{o}$F. The results of the evaluation indicated that the break flow increases slightly but is still less than the conservative value reported in the FSAR for the SGTR event by approximately 2%. It is noted that the reactor coolant activity assumed for the SGTR analysis in the FSAR is based on 1% fuel defects and is assumed to be independent of the transient conditions. Therefore this assumption would not be affected by the aforementioned changes.

A radiological analysis using the revised mass releases was completed which indicates that the slight increase in the steam release is offset by the margin in the primary to secondary break flow (which exists in the FSAR report), such that the offsite radiation doses are less than the results reported in the FSAR. Therefore, it is concluded that a change in the MSSV setpoint tolerance from ±1% to ±3% will not increase the consequences of a SGTR as reported in the FSAR.

3.2.6 Hot Leg Switchover of the ECCS to Prevent Potential Boron Precipitation (FSAR Chapter 6.3.2.5)

The calculations performed to determine the time (post-LOCA) at which the boron concentration in the reactor vessel would exceed the solubility limit do not require modeling of the main steam safety valves. However, an evaluation is required to assure that adequate ECCS flow is provided to prevent boron precipitation following the switchover to hot leg recirculation. The minimum time for hot leg switchover for the Byron/Braidwood Stations was calculated to be 18 hours based on large break LOCA assumptions. The calculated core boil-off rate at 18 hours would be approximately 20 lbm/sec. The minimum ECCS flow required for delivery to the hot legs following switchover is 1.5 times the boil-off rate for a large break LOCA or approximately 30 lbm/sec. The RCS pressure for a small break LOCA at the hot leg switchover time of 18 hours can conceivably be as high as the highest steam generator safety valve setpoint (approximately 1250 psia plus 3%). Conditions for a small break LOCA differ significantly from those for a large break LOCA such that the requirements to prevent boron precipitation are much less restrictive than those for a large break LOCA. Thus, under small break LOCA conditions, ECCS flow to both the hot and cold legs can be considered in satisfying the boil-off requirement. Thus the charging and safety injection pumps must meet or exceed 30 lbs/sec at 1288 psia in order to satisfy the boil-off requirement for a small break LOCA. A review of the ECCS shows that the safety injection pumps, when aligned in the hot leg recirculation mode, can deliver more than the required 30 lbm/sec at an RCS pressure of 1288 psia. Thus, the proposed change to the MSSV Technical Specification setpoint pressure tolerance from $\pm1\%$ to $\pm3\%$ will not alter the results or conclusions appearing in the FSAR regarding the switchover of the ECCS to hot leg recirculation.

#### 3.2.7 Post-LOCA Longterm Core Cooling (FSAR Chapter 15.6.5)

Since the post-LOCA subcriticality is based on large break requirements, deviations in MSSV set-pressures do not effect the boron concentration in the containment sump post-LOCA. Thus, the proposed change to the MSSV Technical Specification setpoint pressure tolerance from $\pm1\%$ to $\pm3\%$ will not alter the results or conclusions regarding the ability to keep the reactor cores subcritical on the boron provided by the ECCS.

#### 3.2.8 LOCA Conclusions

The effect of a increase in the allowable Main Steam Safety Valve set pressure tolerance from $\pm1\%$ to $\pm3\%$ on the FSAR LOCA analysis has been evaluated. In each case the applicable regulatory or design limit was satisfied. Specific analyses were performed for small break LOCA assuming the current MSSV Technical Specification set pressures plus the proposed additional 3% uncertainty. The calculated peak cladding temperatures were well below the 10 CFR 50.46 2200$^0$F limit.

### 3.3 <u>Containment Integrity Evaluation</u>

Neither the mass and energy release to the containment following a postulated loss of coolant accident (LOCA), nor the containment response following the LOCA analysis, credit the MSSV in mitigating the consequences of an accident. Therefore, changing the MSSV lift setpoint tolerances would have no impact on the containment integrity analysis. In addition, based on the conclusion of the transient analysis, the change to the MSSV tolerance will not affect the calculated steamline break mass and energy releases inside containment. Consequently, the main steam line break containment integrity analysis is not impact by the change to the MSSV setpoint tolerances.

### 3.4 EOP Evaluation

In the Emergency Operating Procedures (EOPs), the MSSV setpoint pressures are used to determine when to trip the reactor coolant pumps (RCPs). The determination is conservative, taking into account instrument uncertainties. The conservatism, along with the small difference between the MSSV pressure used to determine the RCP trip setpoint for the EOPs and the in-plant first lift pressures of less than 5.6% leads to the conclusion that there is no significant impact on the EOPs in this area.

The MSSV pressures are also used in the EOPs on the heat sink status tree in determining which heat sink EOP is appropriate for implementation. These pressures are only involved in optional or yellow paths on the heat sink status tree. This means that the plant condition is such that the operator is not required to perform the heat sink EOPs called for by these yellow paths. Consequently, an inappropriate transition to these procedures would not cause the operator to forego an action required to maintain the plant in a safe condition. Thus, the variations found between the EOP MSSV setpoints and the MSSV in-plant lift pressures have negligible impact on the EOPs in this area. If the set pressures are within ±5%, use of these procedures will ensure that the secondary pressure remains within acceptable limits.

## 4.0 DETERMINATION OF UNREVIEWED SAFETY QUESTION

1. Will the probability of an accident previously evaluated in the SAR be increased?

   The ±3% tolerance on the MSSV setpoint does not increase the probability of an accident previously evaluated in the FSAR. There are no hardware modifications to the valves. Therefore, there is not an increase in the spurious opening of a MSSV. The MSSVs are actuated after an accident is initiated to protect the secondary systems from overpressurization. Sufficient margin exists between the normal steam system operating pressure and the valve setpoints with the increased tolerance to preclude an increase in the probability of actuating the valves. Therefore, the probability of an accident previously evaluated in the FSAR would not be increased as a result of increasing the MSSV lift setpoint tolerance by 3% above or below the current Technical Specification value.

2. Will the consequences of an accident previously evaluated in the SAR be increased?

   All of the applicable LOCA and non-LOCA design basis acceptance criteria remain valid both for the transients evaluated and the single event analyzed. Additionally, no new limiting single failure is introduced by the proposed change. The DNBR and PCT values remain within the specified limits of the licensing basis. Although increasing the valve setpoint will increase the steam release from the ruptured steam generator above the FSAR value by approximately 2%, the SGTR analysis indicates that the calculated break flow is still less than the value reported in the FSAR. Therefore, the radiological analysis indicates that the slight increase in the steam release is offset by the decrease in the break flow such that the offsite radiation doses are less than those reported in the FSAR. The evaluation also concluded that the existing mass releases used in the offsite dose calculations for the remaining transients (i.e., steamline break, rod ejection) are still applicable. Therefore, based on the above, there is no increase in the dose releases.

3. May the possibility of an accident which is different than any already evaluated in the SAR be created?

   The $\pm$3% tolerance on the MSSV setpoint does not create the possibility of an accident which is different than any already evaluated in the FSAR. Increasing the lift setpoint tolerance on the MSSVs does not introduce a new accident initiator mechanism. No new failure modes have been defined for any system or component important to safety nor has any new limiting single failure been identified. No accident will be created that will increase the challenge to the MSSVs and result in increased actuation of the valves. Therefore, the possibility of an accident different than any already evaluated is not created.

4. Will the probability of a malfunction of equipment important to safety previously evaluated in the SAR be increased?

   Although the proposed change takes place in equipment utilized to prevent overpressurization on the secondary side and to provide an additional heat removal path, increasing the as-found lift setpoint tolerance on the MSSVs will not adversely affect the operation of the reactor protection system, any of the protection setpoints, or any other device required for accident mitigation.

5. Will the consequences of a malfunction of equipment important to safety previously evaluated in the SAR be increased?

   No, as discussed in the response to Questions 2, there is no possibility of increasing the dose releases as a result of increasing the as-found lift setpoint tolerance on the MSSVs as defined in the attached safety evaluation.

6. May the possibility of a malfunction of equipment important to safety different than any already evaluated in the SAR be created?

   No, as discussed in Question 4, an increase in the as-found lift setpoint tolerance on the MSSVs will not impact any other equipment important to safety.

7. Will the margin of safety as defined in the bases to any technical specification be reduced?

No, as discussed in the attached safety evaluation, the proposed increase in the as-found MSSV lift setpoint tolerance will not invalidate the LOCA and non-LOCA conclusions presented in the UFSAR accident analyses. The new loss of load/turbine trip analysis concluded that all applicable acceptance criteria are still satisfied. For all the UFSAR non-LOCA transients, the DNB design basis, primary and secondary pressure limits, and dose release limits continue to be met. Peak cladding temperatures remain well below the limits specified in 10CFR50.46. Thus, there is no reduction in the margin tc safety.

## 5.0 CONCLUSIONS

The proposed change to main steam safety valve lift setpoint tolerances from ±1% to ±3% has been evaluated by Westinghouse. The preceding analyses and evaluations have determined that operation with the MSSV setpoints within a ±3% tolerance about the nominal values will have no adverse impact upon the licensing basis analyses, as well as the steamline break mass & energy release rates inside and outside of containment. In addition, it is concluded that the ±3% tolerance on the MSSV setpoint does not adversely affect the overpower or overtemperature protection system. As a result, adequate protection to the core limit lines continues to exists. Therefore, all licensing basis criteria continue to be satisfied and the conclusions in the FSAR remain valid.

The recommended Technical Specification and FSAR changes, along with a no significant hazards evaluation, are presented as attachments to this evaluation.

Based on the information presented above, it can be concluded that the proposed increase of main steam safety valve lift setpoint tolerances from ±1% to ±3% does not represent an unreviewed safety question per the definition and requirements defined in 10 CFR 50.59.

## 6.0 REFERENCES


1) Byron/Braidwood Technical Specifications through Amendments 37 and 23, respectively.

2) ANSI/ASME BPV-III-1-NB, "ASME Boiler and Pressure Vessel Code - Section III Rules for Construction of Nuclear Power Plant Components," ASME, 1983.

3) CAW-3581/CBW-3009,"Commonwealth Edison Company, Byron and Braidwood Stations - Units 1 and 2 Overpressure Protection Report," July 1981.

4) ANSI/ASME OM-1-1981, "Requirements for Inservice Performance Testing of Nuclear Power Plant Pressure Relief Devices," ASME, 1981

5) "Byron/Braidwood Stations Units 1 & 2 Updated Final Safety Analysis Report (UFSAR), Docket Numbers 50-454, 455, 456, and 457, December 1989.

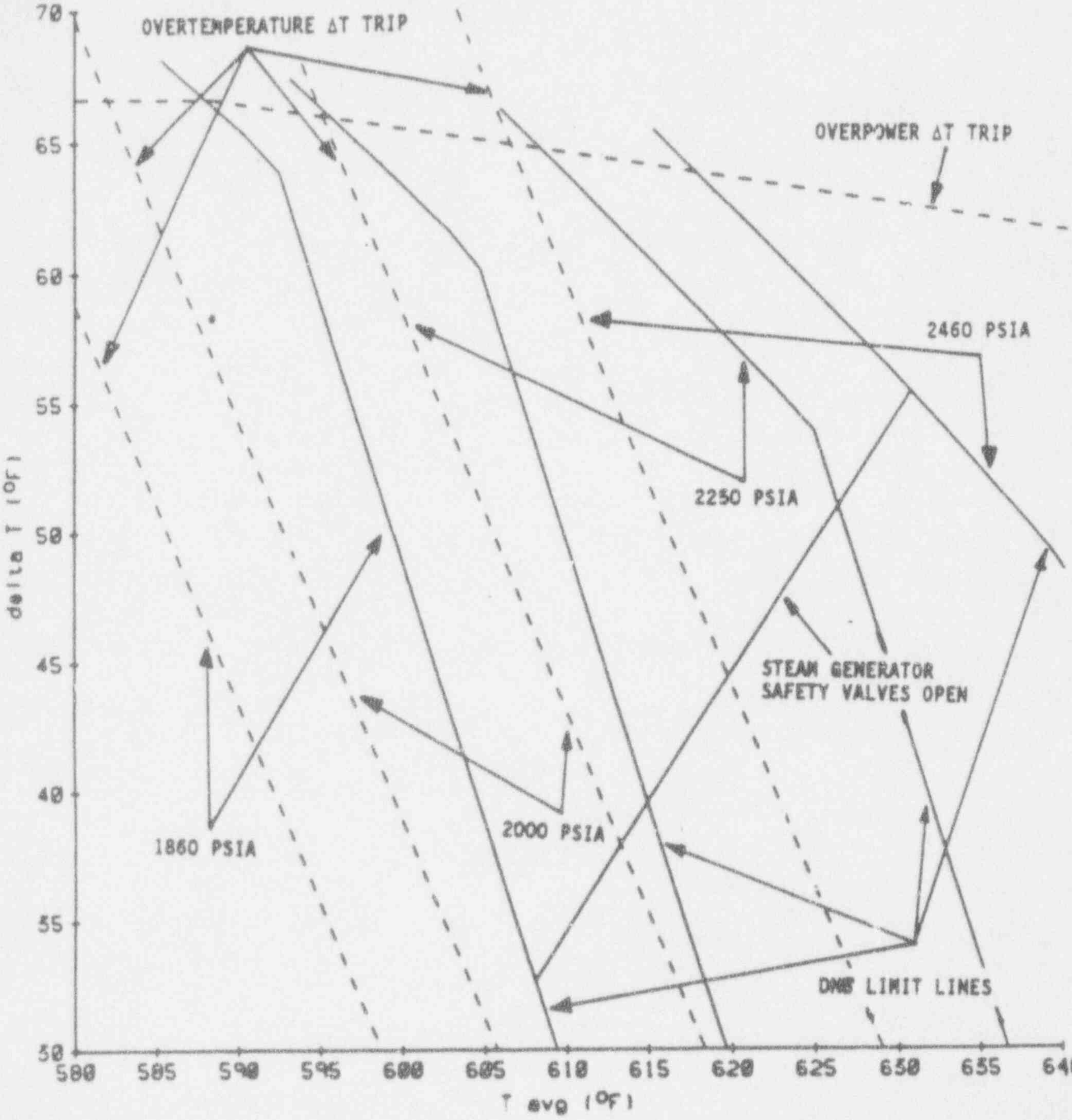
6) ASME Steam Tables, Fifth Edition, 1983.

7) Burnett, T.W.T., et al., "LOFTRAN Code Description," WCAP-7907-P-A, June 1972.

8) Chelemer, H. et al.,"Improved Thermal Design Procedure," WCAP-8567-P-A, February 1989.

9) DiTommaso, S.D. et al.,"Byron/Braidwood Thot Reduction Final Licensing Report," WCAP-11386-P, Revision 2, November 1987.

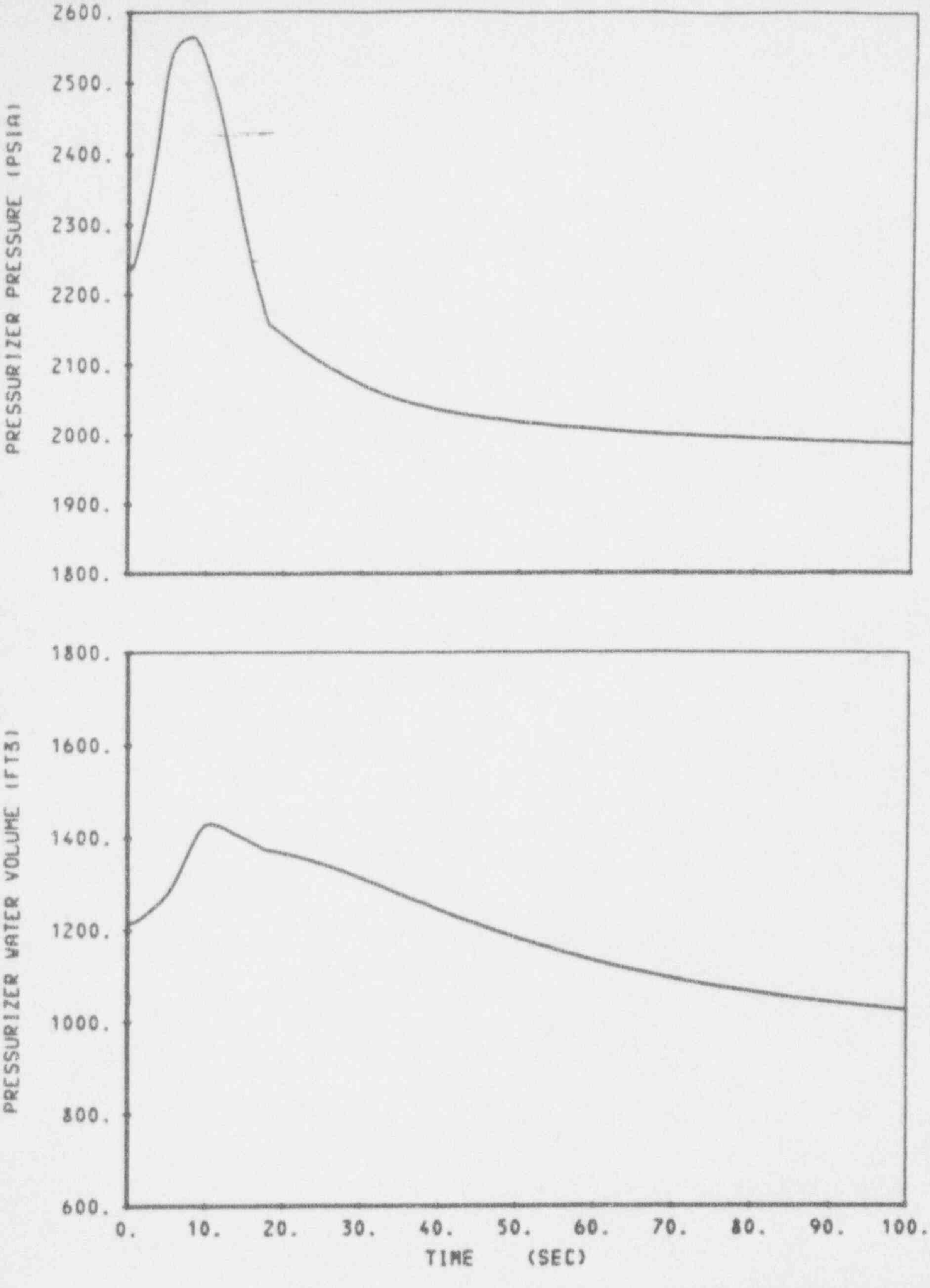
10) Butler, J.C. and D.S. Love,"Steamline Break Mass/Energy Releases for Equipment Environmental Qualification Outside Containment," WCAP-10961-P, October 1985.




BYRON/BRAIDWOOD STATIONS

FIGURE 1

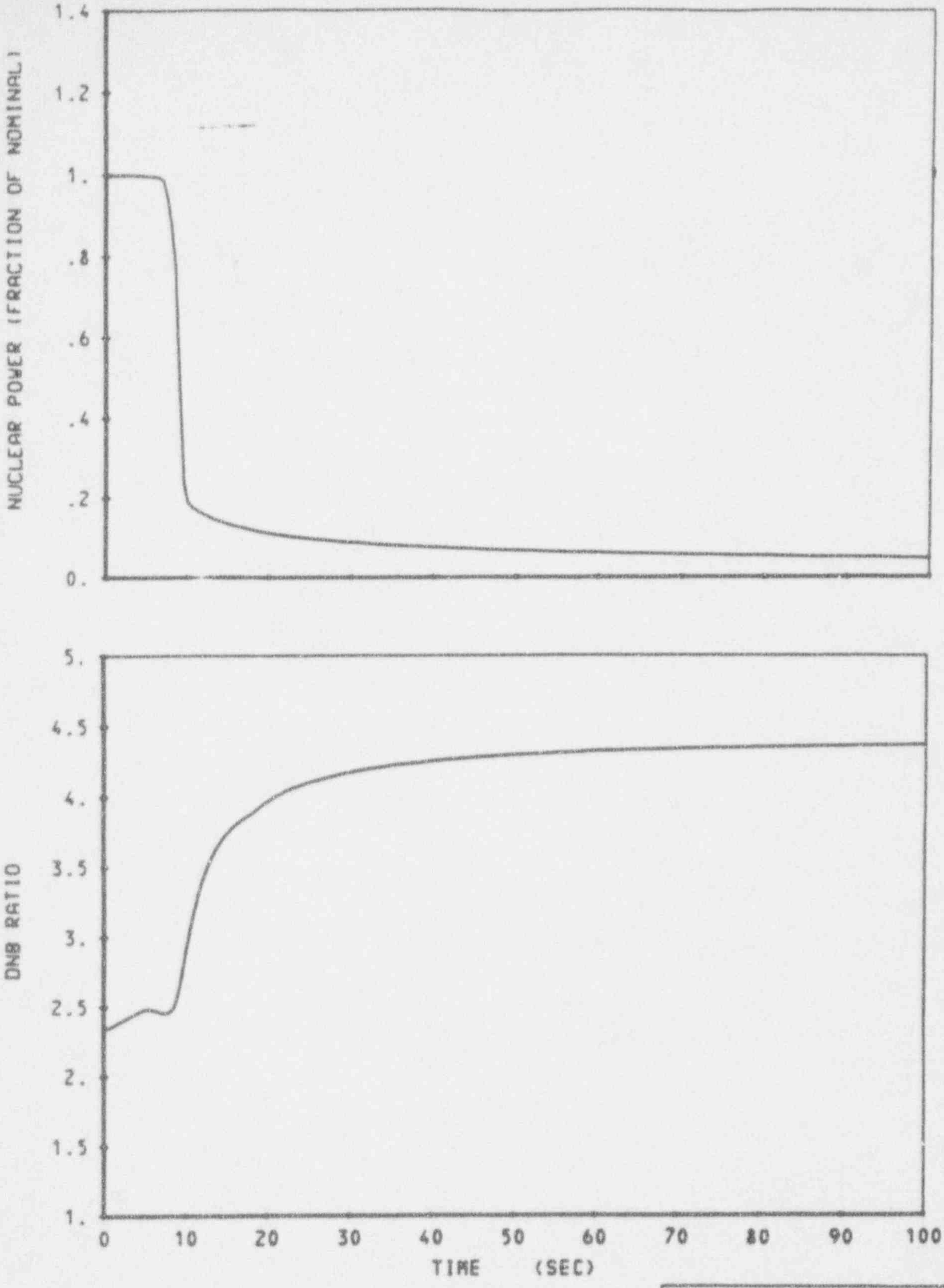
ILLUSTRATION OF OVERTEMPERATURE AND OVERPOWER DELTA T PROTECTION




BYRON/BRAIDWOOD STATIONS

FIGURE 2

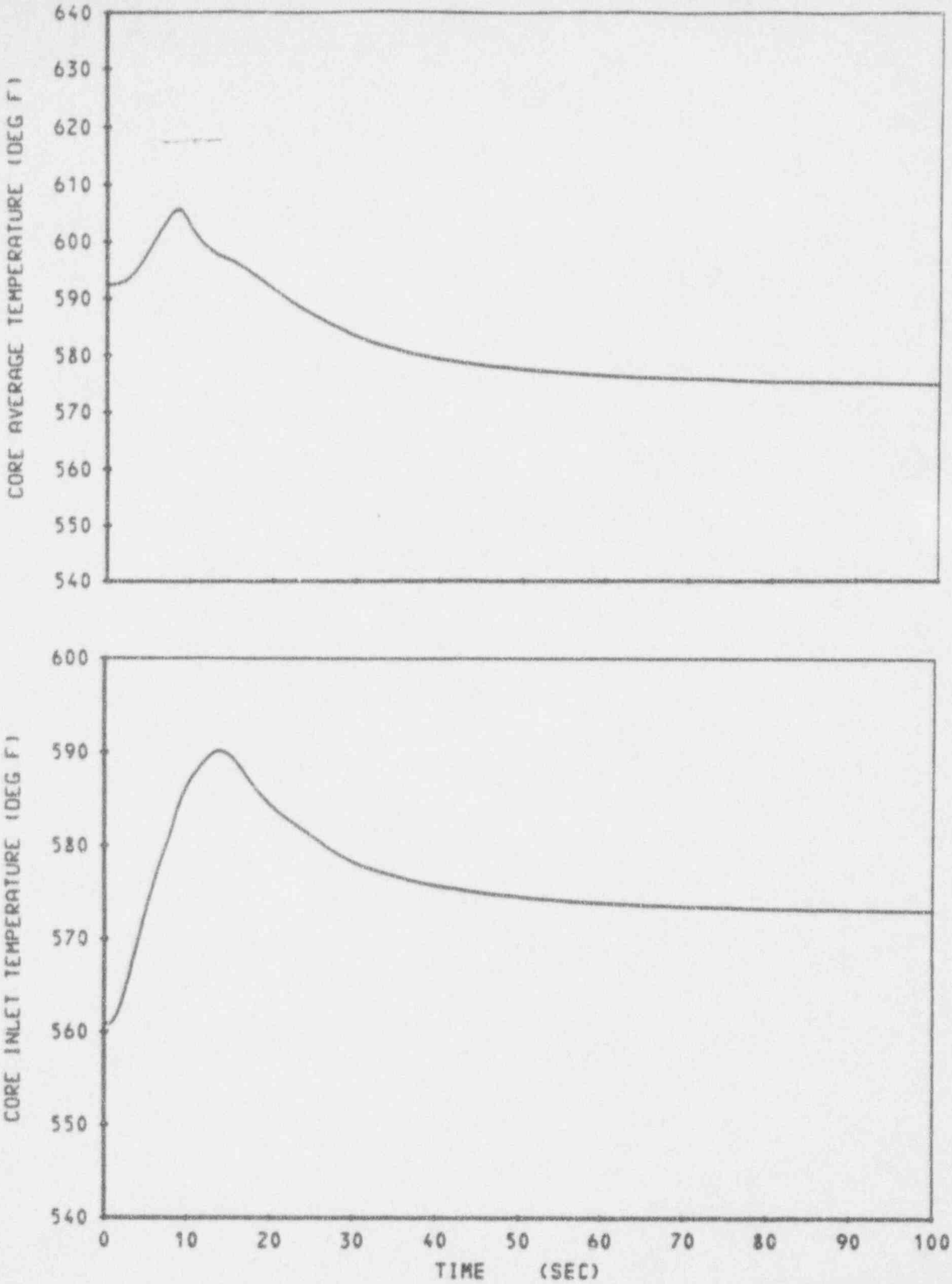
TURBINE TRIP EVENT WITHOUT PRESSURE CONTROL, MINIMUM REACTIVITY FEEDBACK




BYRON/BRAIDWOOD STATIONS

FIGURE 3

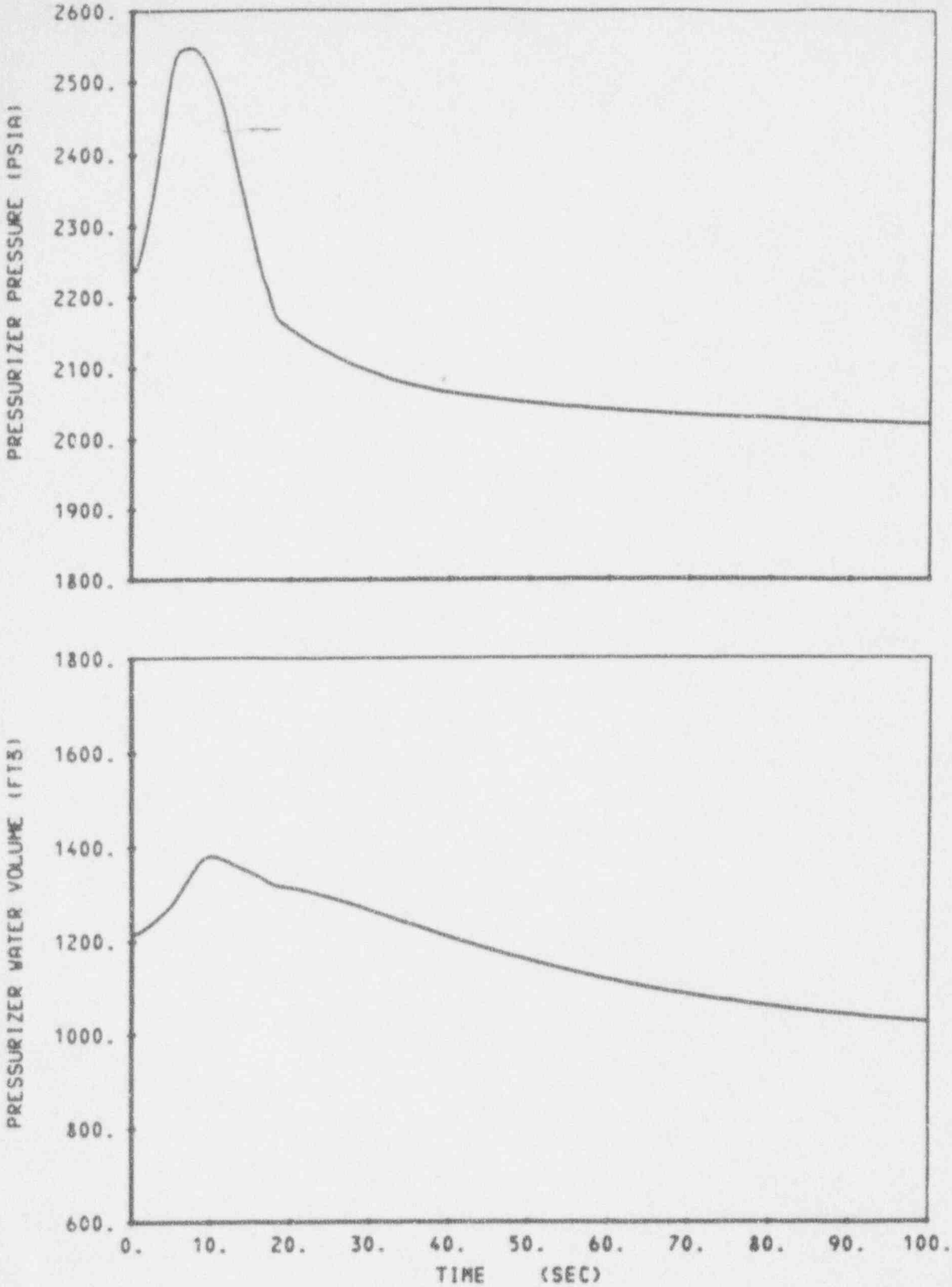
TURBINE TRIP EVENT WITHOUT
PRESSURE CONTROL,
MINIMUM REACTIVITY FEEDBACK




BYRON/BRAIDWOOD STATIONS

FIGURE 4

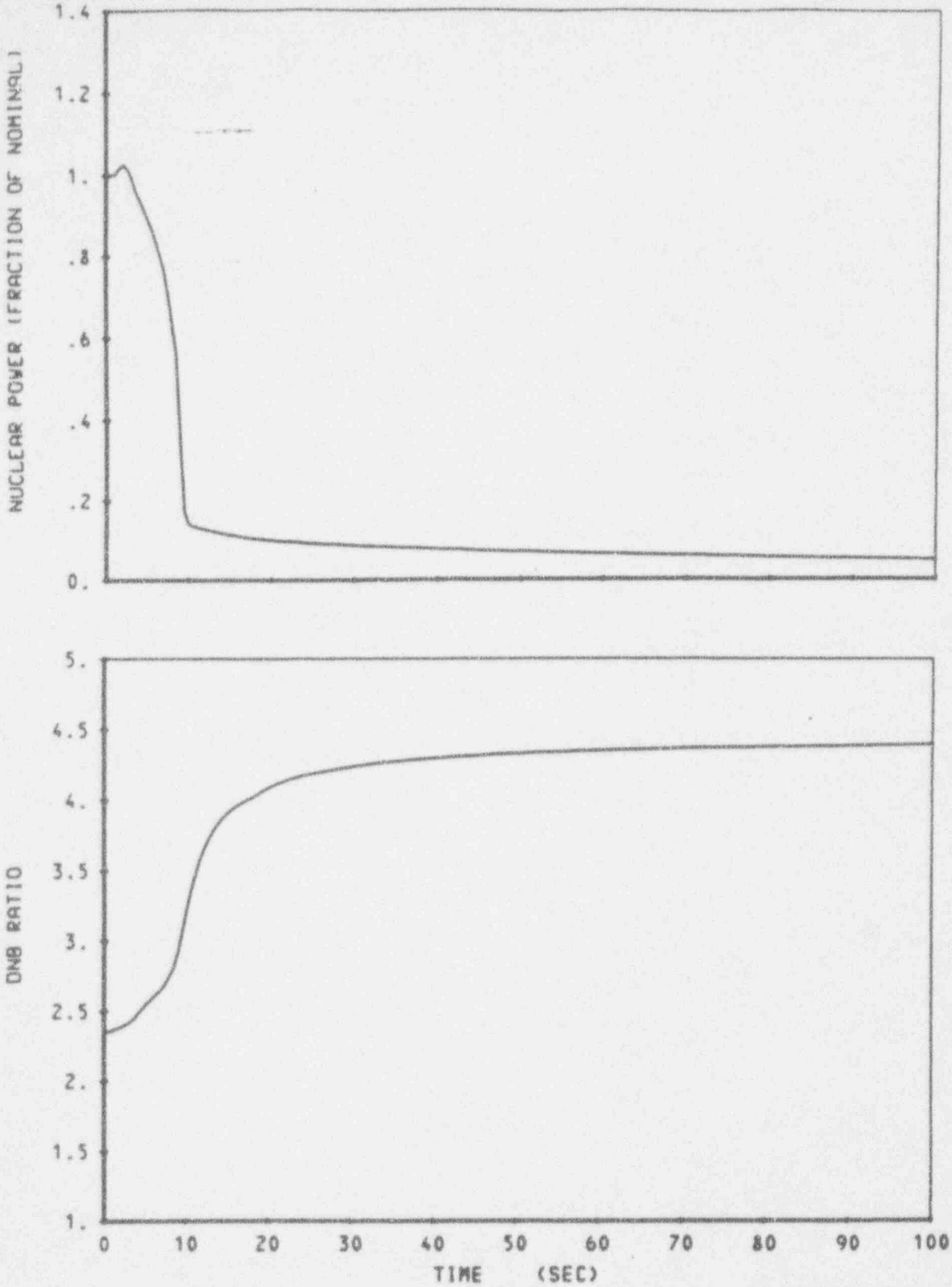
TURBINE TRIP EVENT WITHOUT PRESSURE CONTROL, MINIMUM REACTIVITY FEEDBACK




BYRON/BRAIDWOOD STATIONS

FIGURE 5

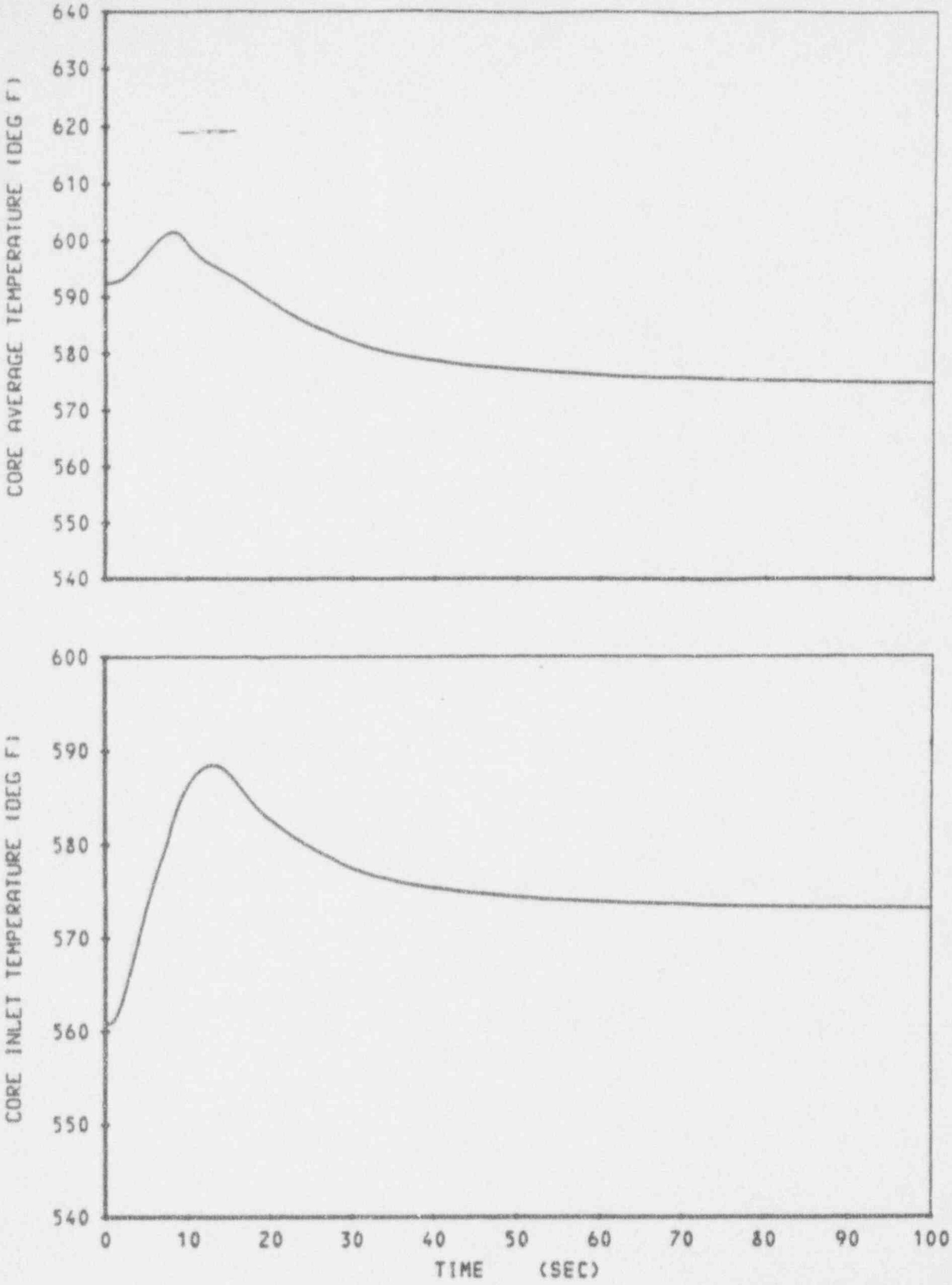
TURBINE TRIP EVENT WITHOUT PRESSURE CONTROL, MAXIMUM REACTIVITY FEEDBACK




BYRON/BRAIDWOOD STATIONS

FIGURE 6

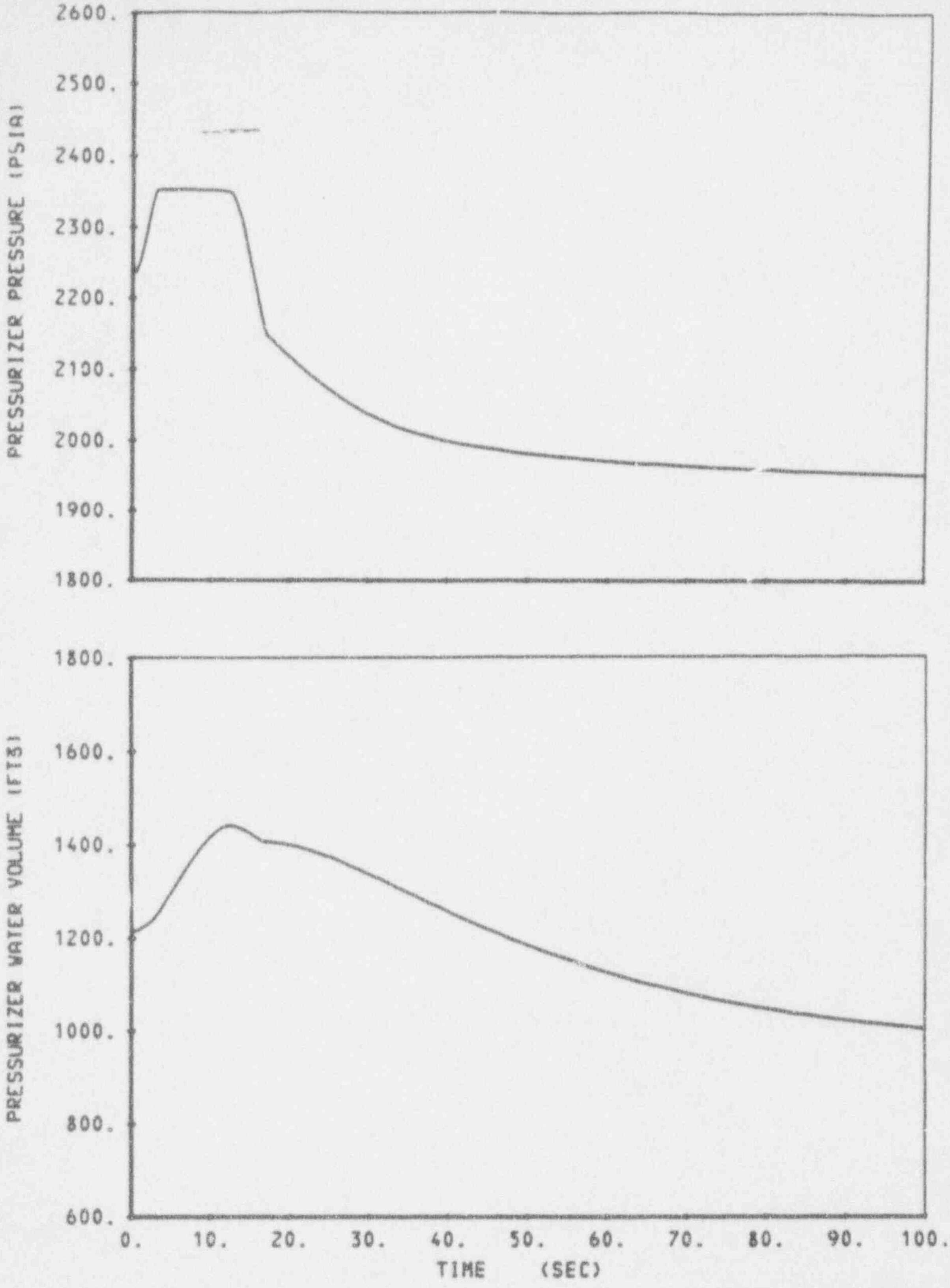
TURBINE TRIP EVENT WITHOUT
PRESSURE CONTROL,
MAXIMUM REACTIVITY FEEDBACK




BYRON/BRAIDWOOD STATIONS

FIGURE 7

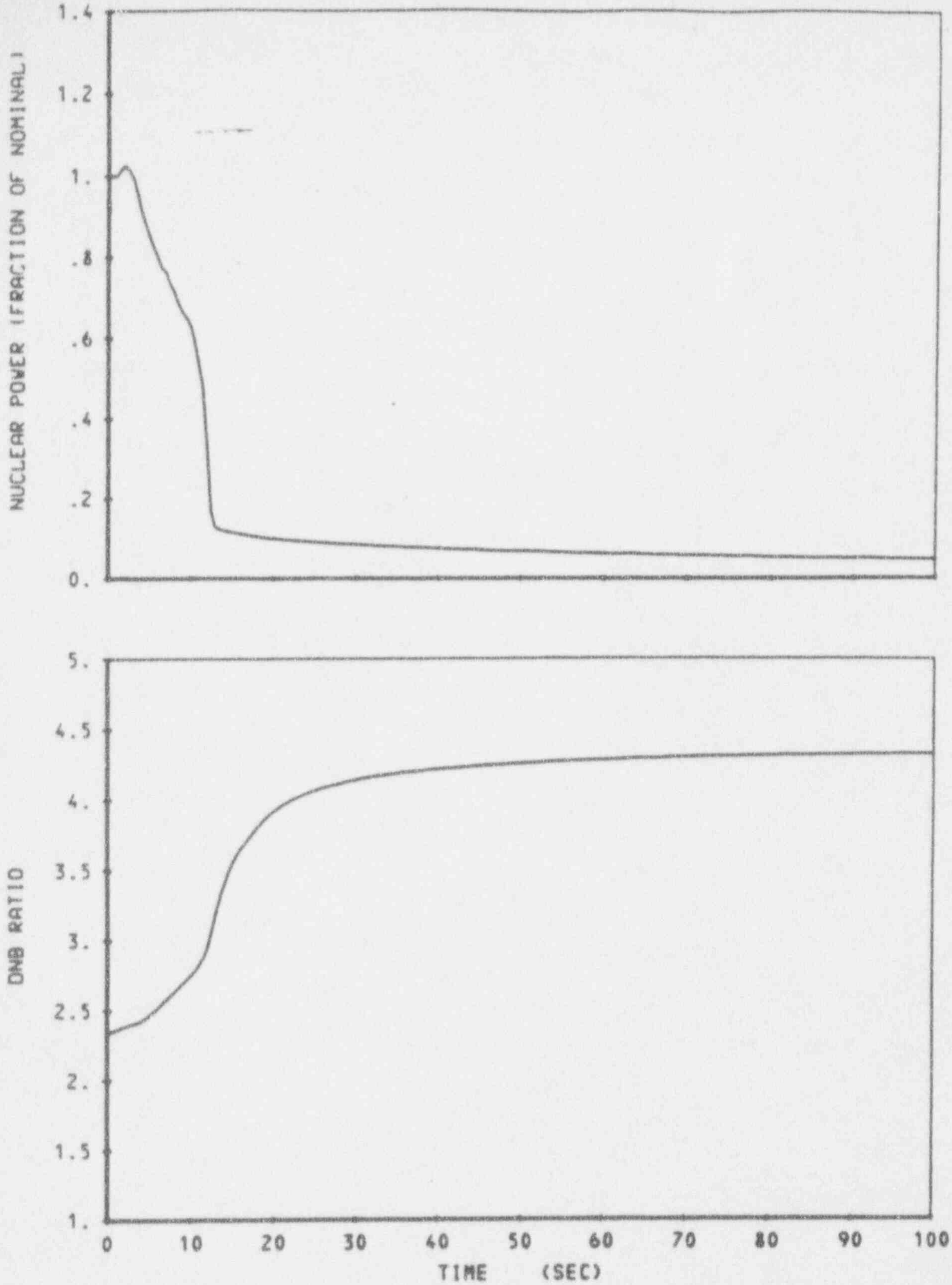
TURBINE TRIP EVENT WITHOUT PRESSURE CONTROL, MAXIMUM REACTIVITY FEEDBACK




BYRON/BRAIDWOOD STATIONS

FIGURE 8

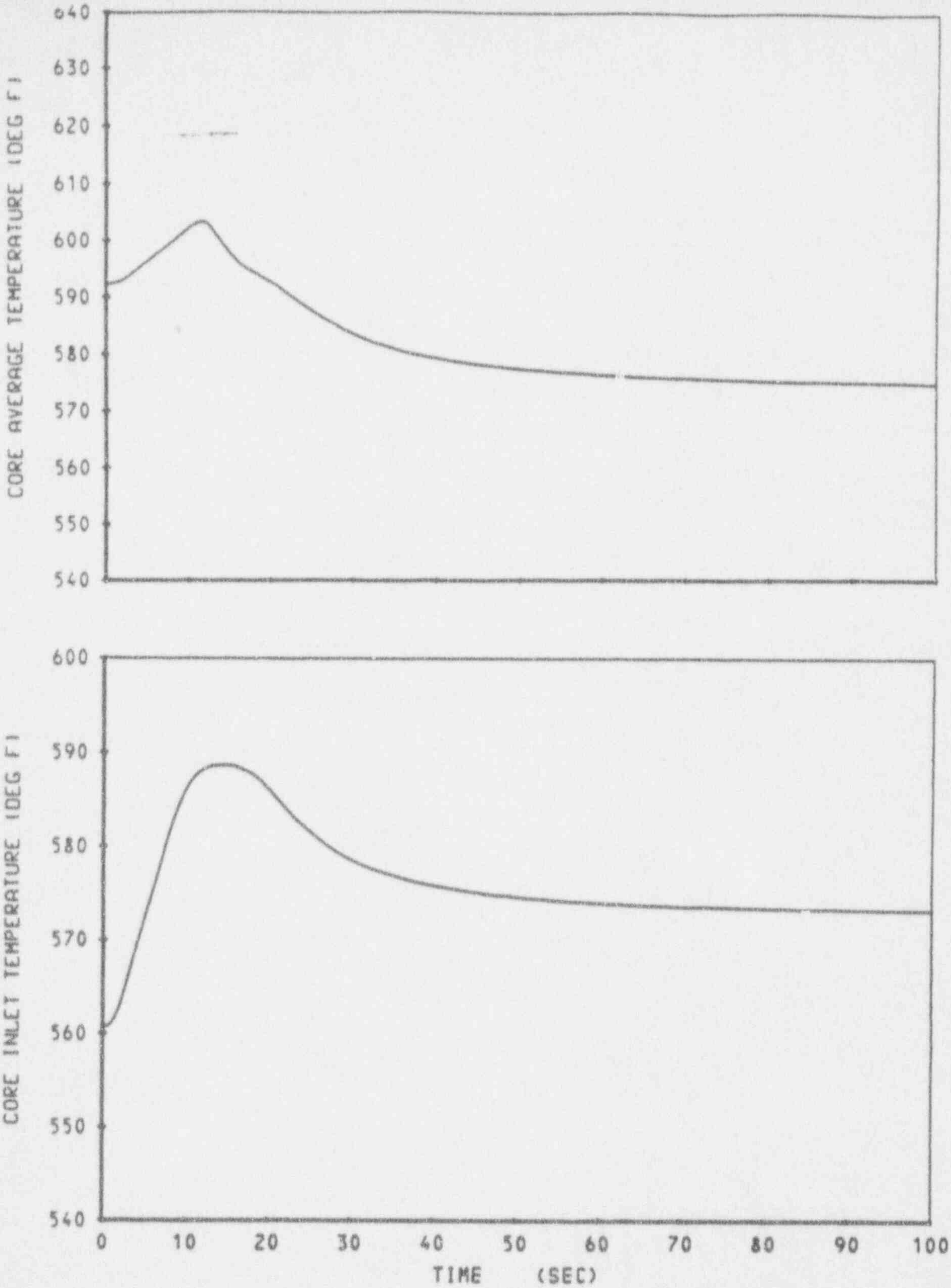
TURBIME TRIP EVENT WITH
PRESSURE CONTROL,
MAXIMUM REACTIVITY FEEDBACK




BYRON/BRAIDWOOD STATIONS

FIGURE 9

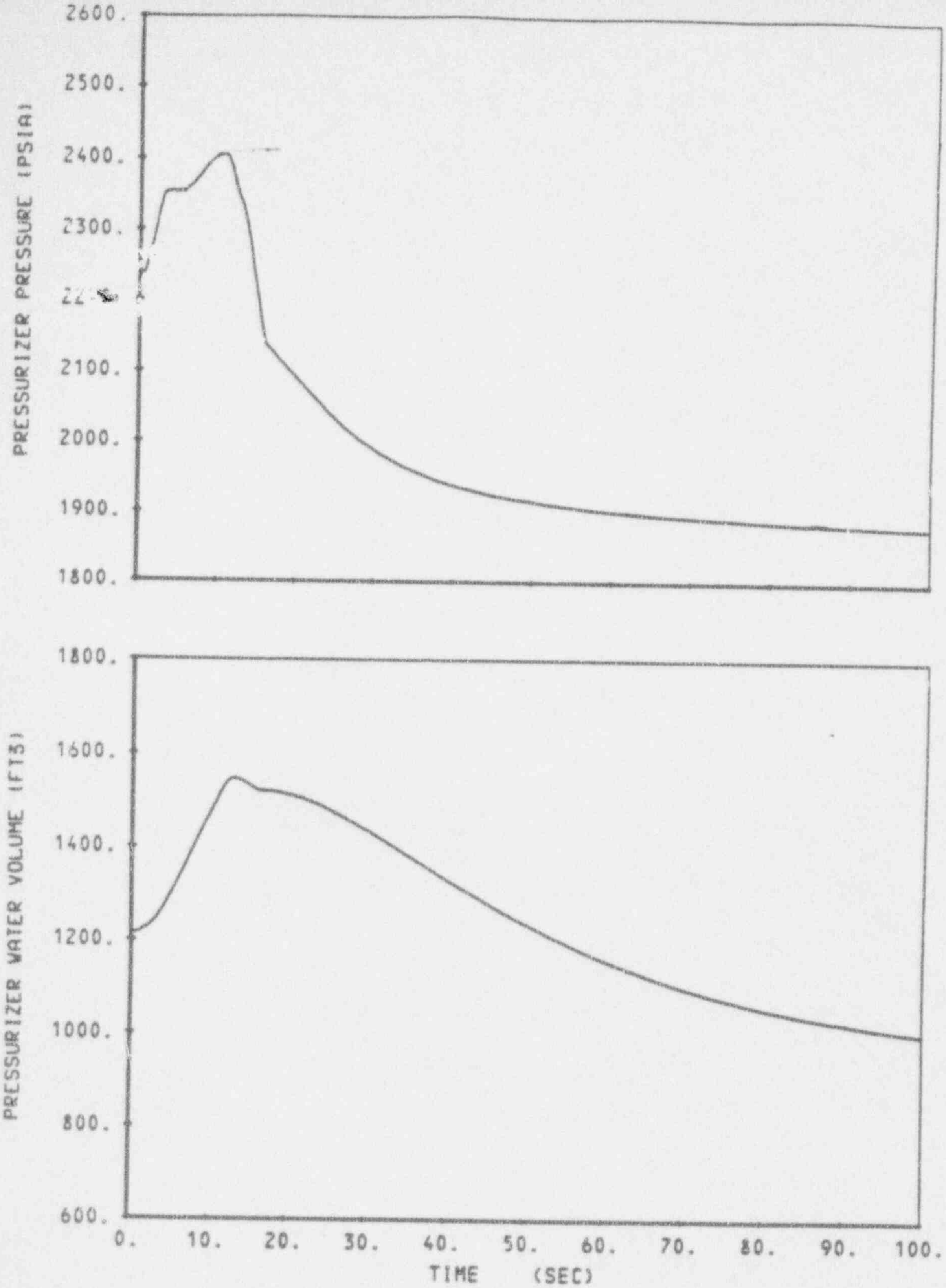
TURBINE TRIP EVENT WITH PRESSURE CONTROL, MAXIMUM REACTIVITY FEEDBACK




BYRON/BRAIDWOOD STATIONS

FIGURE 10

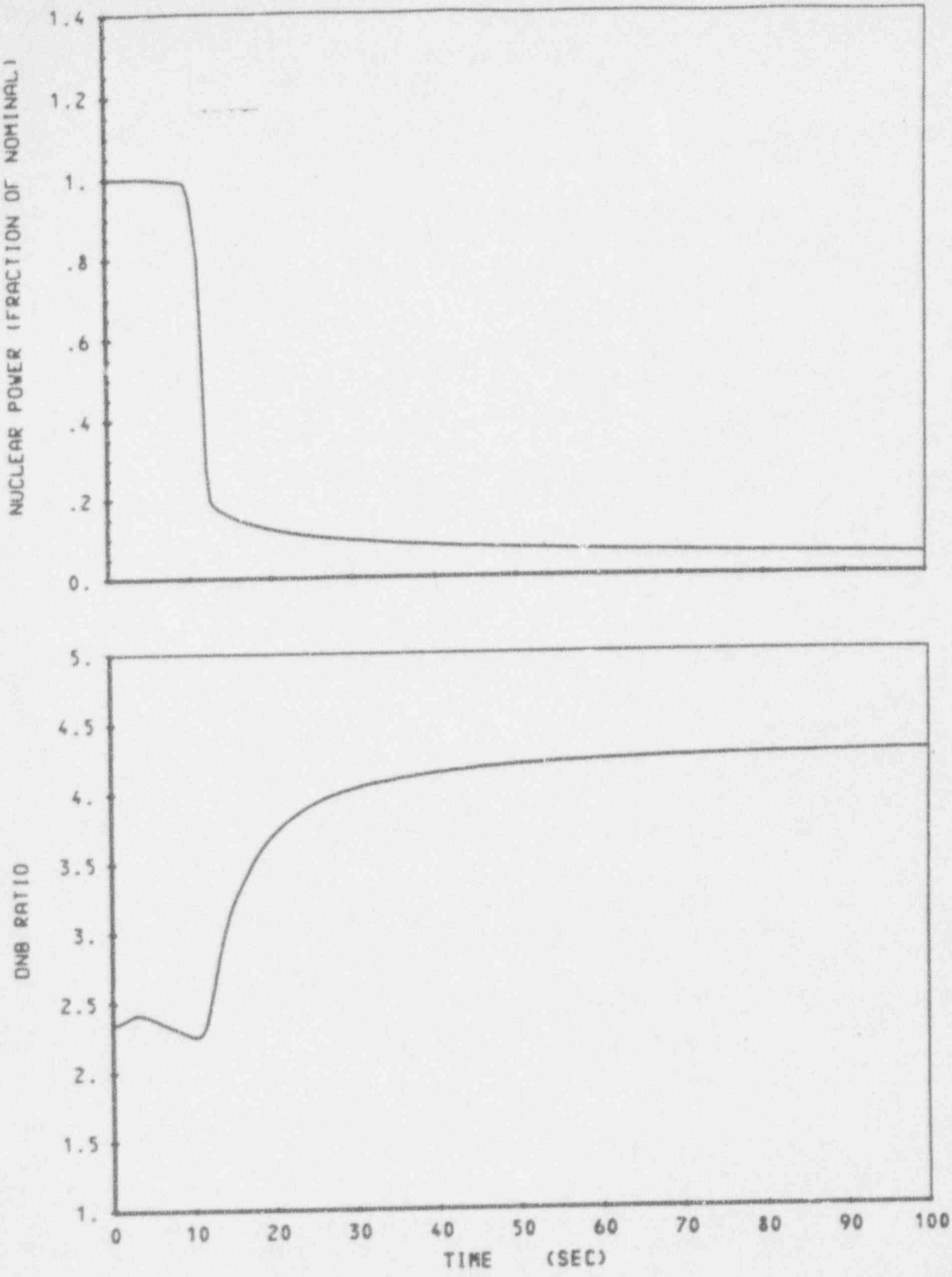
TURBINE TRIP EVENT WITH PRESSURE CONTROL, MAXIMUM REACTIVITY FEEDBACK




BYRON/BRAIDWOOD STATIONS

FIGURE 11

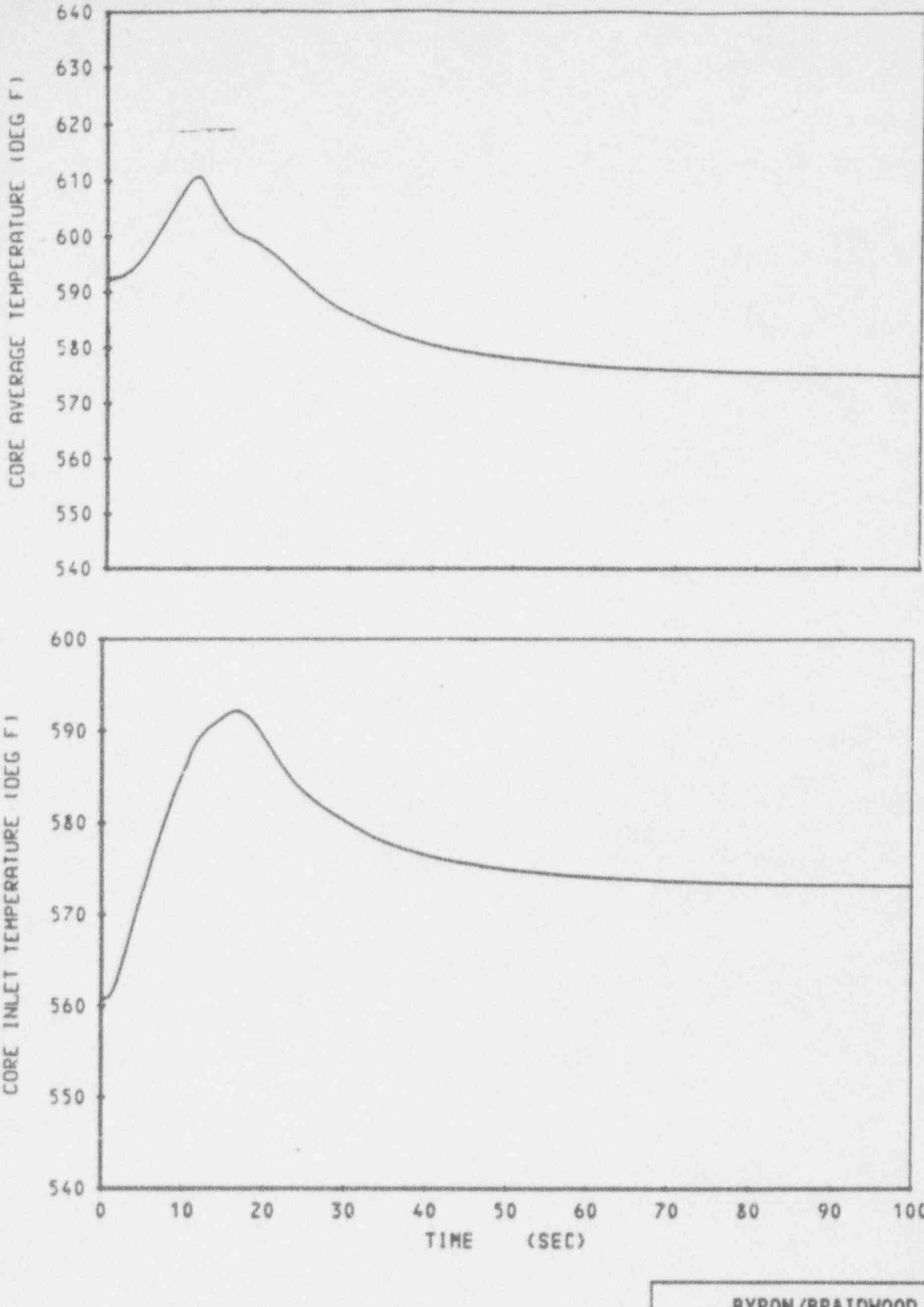
TURBINE TRIP EVENT WITH PRESSURE CONTROL, MINIMUM REACTIVITY FEEDBACK




BYRON/BRAIDWOOD STATIONS

FIGURE 12

TURBINE TRIP EVENT WITH
PRESSURE CONTROL,
MINIMUM REACTIVITY FEEDBACK




BYRON/BRAIDWOOD STATIONS

FIGURE 13

TURBINE TRIP EVENT WITH
PRESSURE CONTROL,
MINIMUM REACTIVITY FEEDBACK

# APPENDIX A

# OVERPRESSURE PROTECTION REPORT

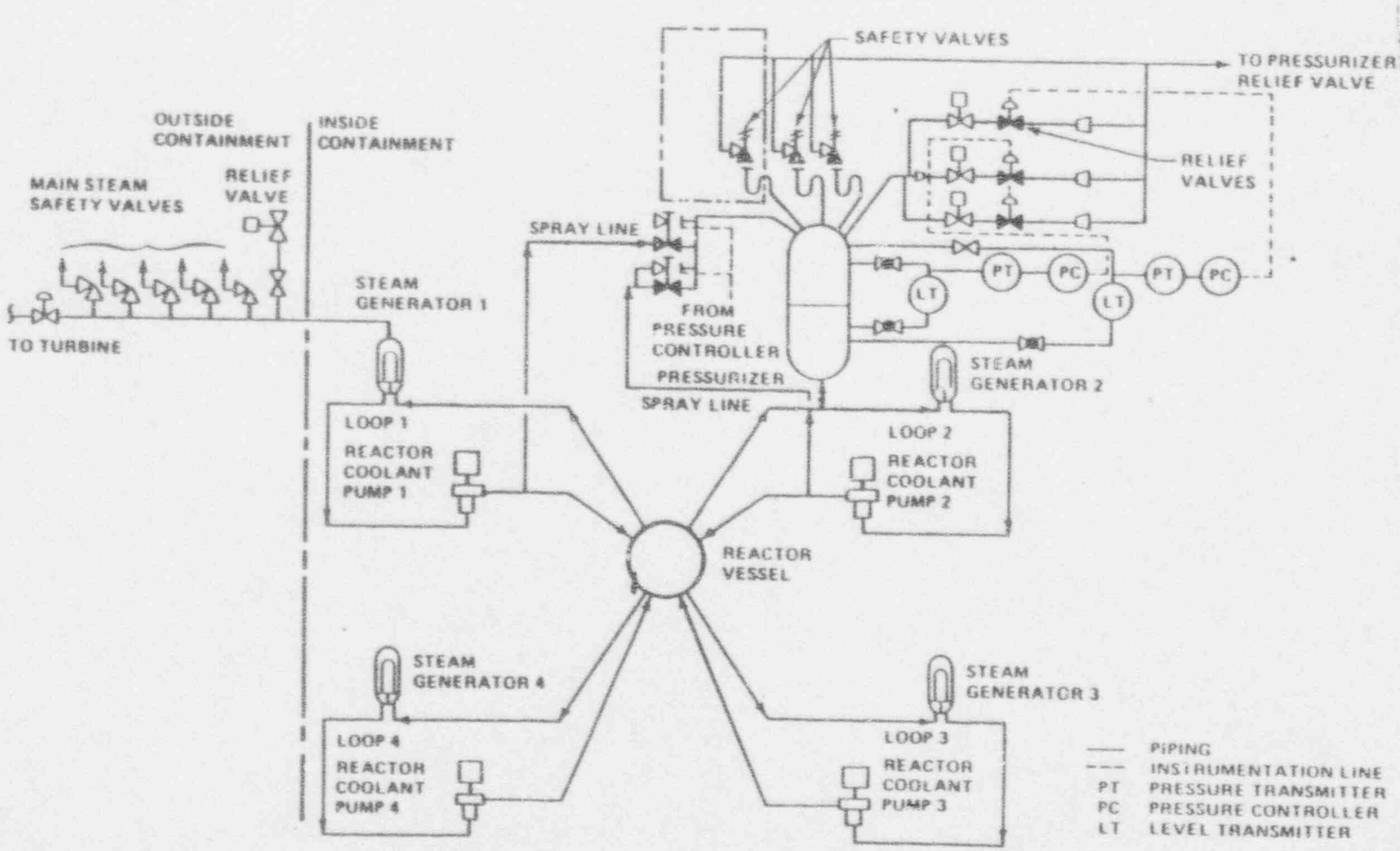



Figure 1 Schematic Arrangement of Pressure Relieving Devices

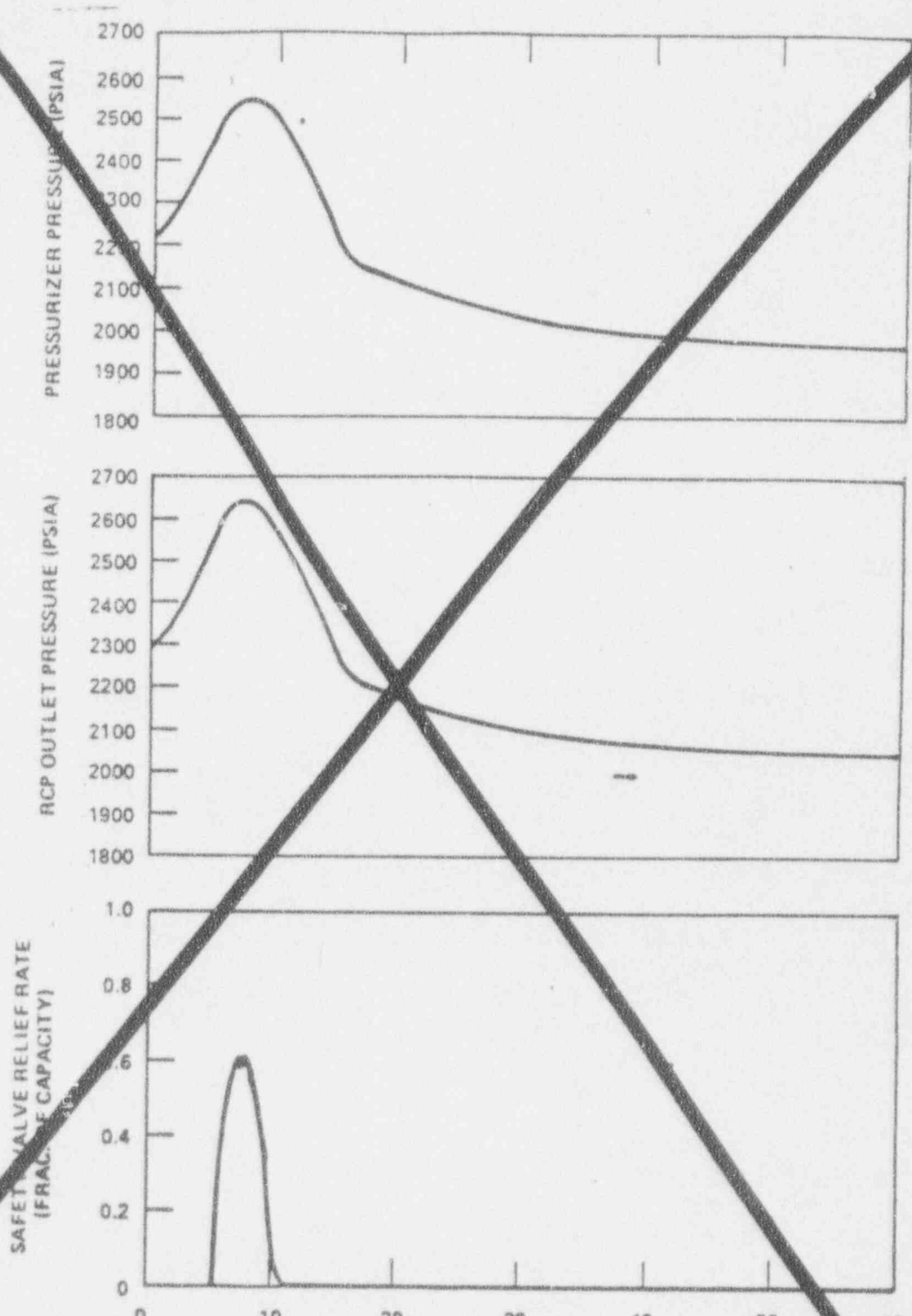



Figure 2.

Replace with the following Figure.

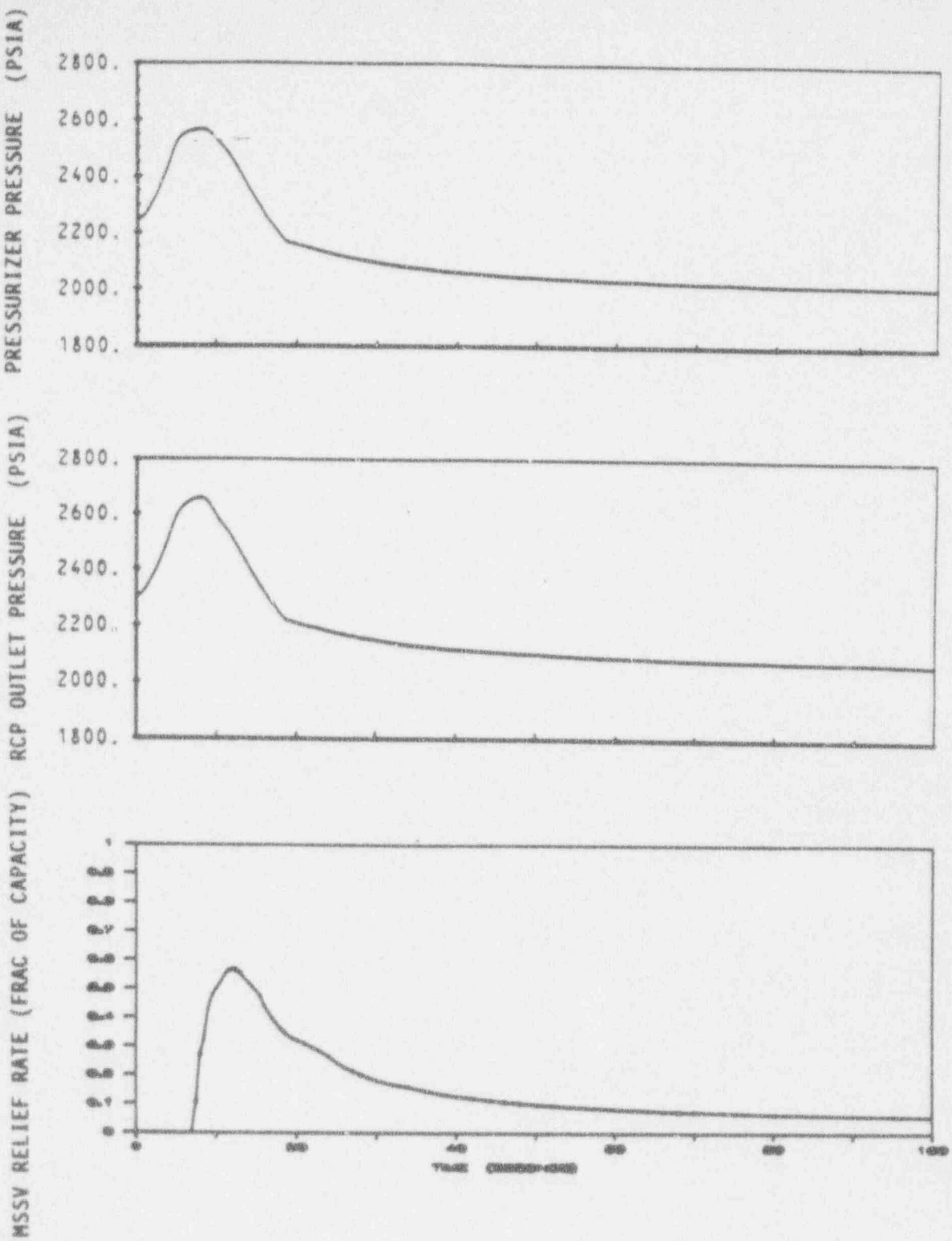

PRESSURIZER PRESSURE (PSIA)
2800.
2600.
2400.
2200.
2000.
1800.
RCP OUTLET PRESSURE (PSIA)
2800.
2600.
2400.
2200.
2000.
1800.
MSSV RELIEF RATE (FRAC OF CAPACITY)
1
0

FIGURE 2

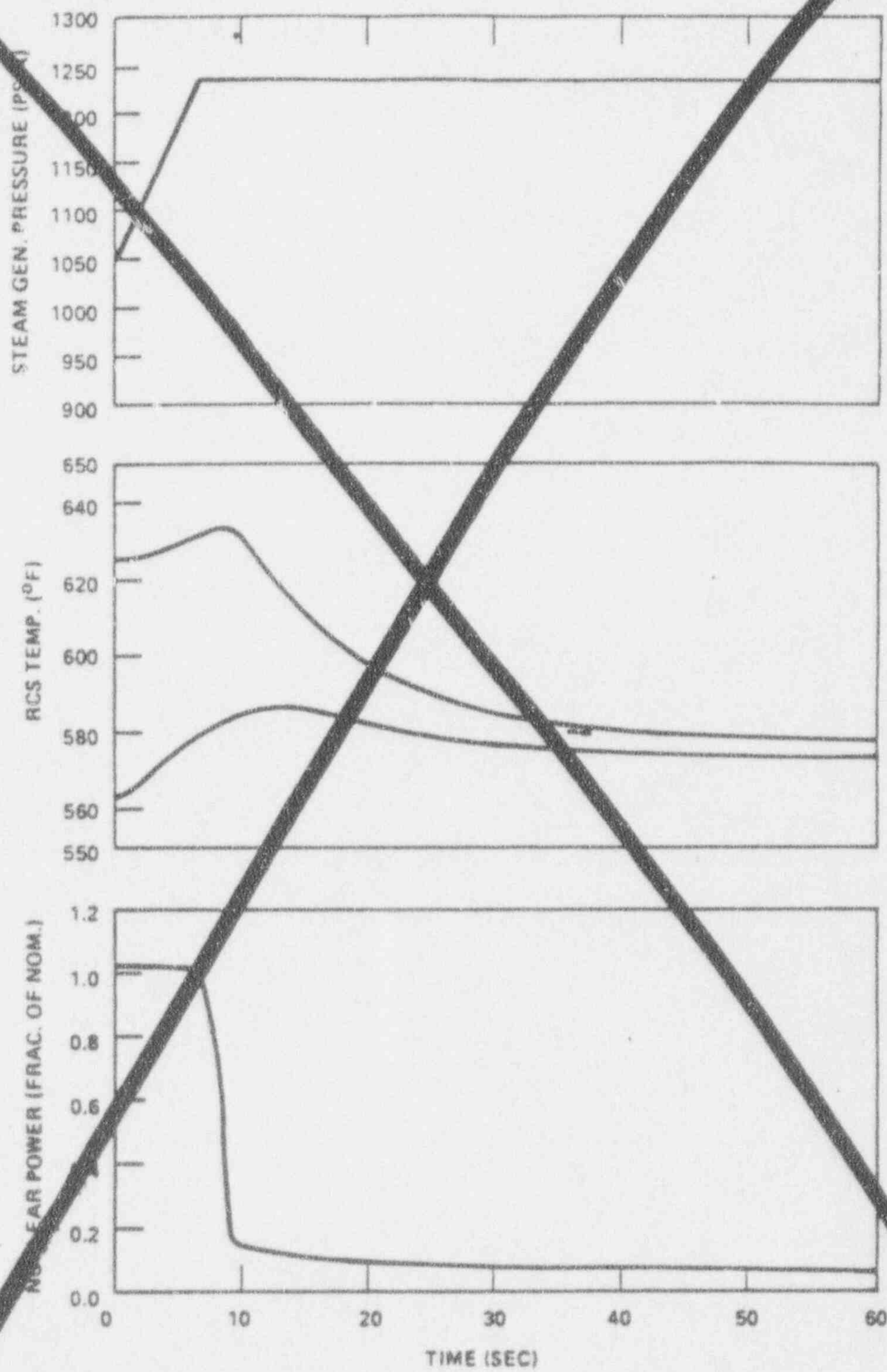



Figure 3

Replace with the following Figure.

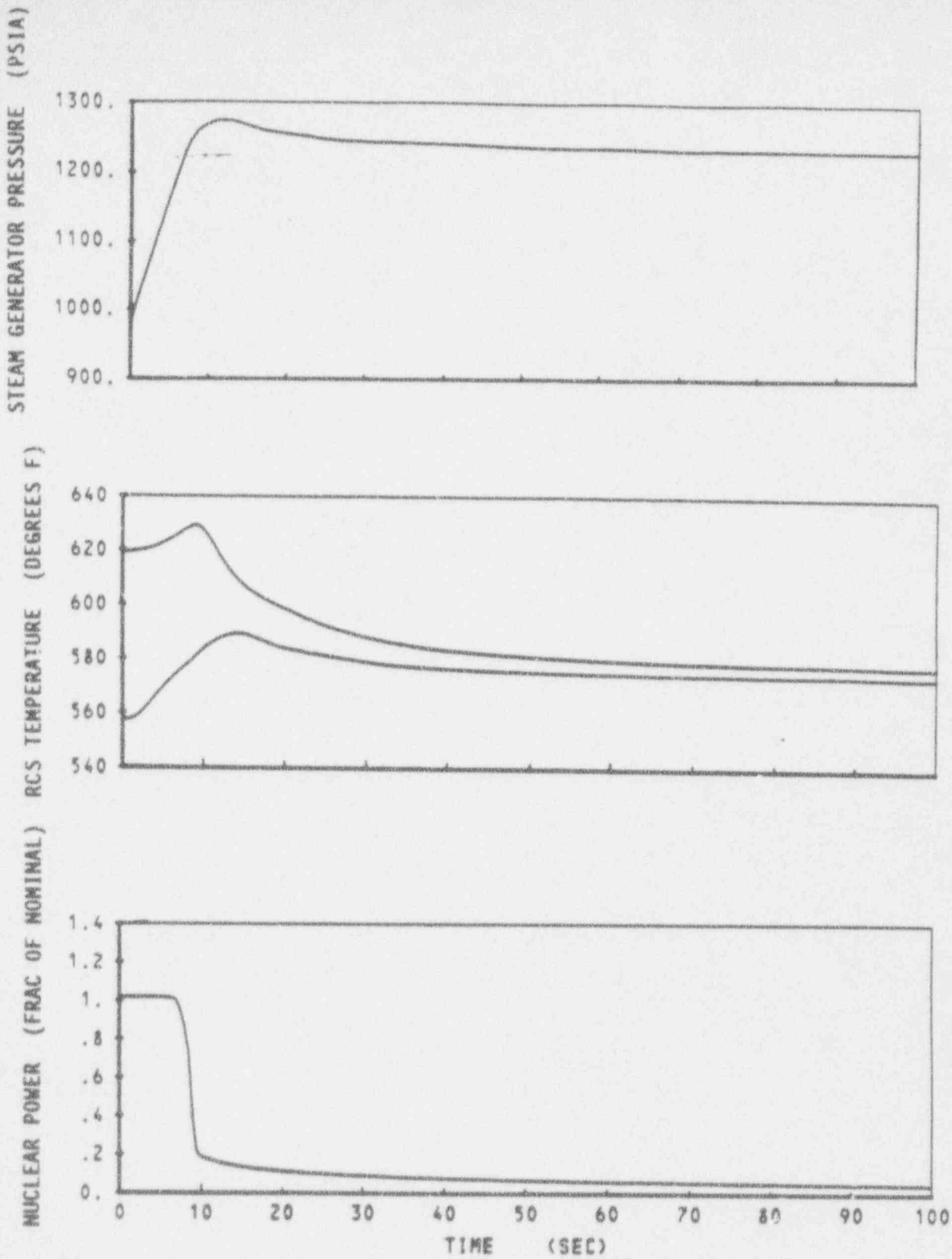

STEAM GENERATOR PRESSURE (PSIA)
1300.
1200.
1100.
1000.
900.
RCS TEMPERATURE (DEGREES F)
640
620
600
580
560
540
NUCLEAR POWER (FRAC OF NOMINAL)
1.4
1.2
1.
.8
.6
.4
.2
0.
0 10 20 30 40 50 60 70 80 90 100
TIME (SEC)

FIGURE 3

# APPENDIX B

# UFSAR MARKUPS

TABLE 15.0-2 (Cont'd)

| FAULTS | INITIAL NSSS THERMAL POWER OUTPUT (MWt) | REACTOR VESSEL COOLANT FLOW (GPM) | VESSEL AVERAGE TEMPERATURE (°F) | PRESSURIZER PRESSURE (PSIA) | PRESSURIZER WATER VOLUME ($ft^3$) | FEEDWATER TEMPERATURE (°F) |
|---|---|---|---|---|---|---|
| 15.1 Increase in Heat Removal by the Secondary System | | | | | | |
| - Feedwater System Malfunction Causing an Increase in Feedwater Flow | 0 and 3425 | 390,390 | 557 and 589.2 | 2250 | 450 and 1080 | 32 and 440 |
| - Excessive Increase in Secondary Steam Flow | 3425 | 390,390 | 589.2 | 2250 | 1090 | 440 |
| - Accidental Depressurization of the Main Steam System | 0 (Subcritical) | 377,600 | 557 | 2250 | 450 | 50 |
| - Steam System Piping Failure | 0 (Subcritical) | 377,600 | 557 | 2250 | 450 | 50 |
| 15.2 Decrease in Heat Removal by the Secondary System | | | | | | |
| - Loss of External Electrical Load and/or Turbine Trip | 3425 | 390,390 | ~~589.2~~ 590.1 | ~~2250~~ 2238 | 1090 | 440 |
| - Loss of Non-Emergency A-C Power to the Station Auxiliaries | 3579 | 377,600 | 565.5 | 2280 | 1150 | 442 |

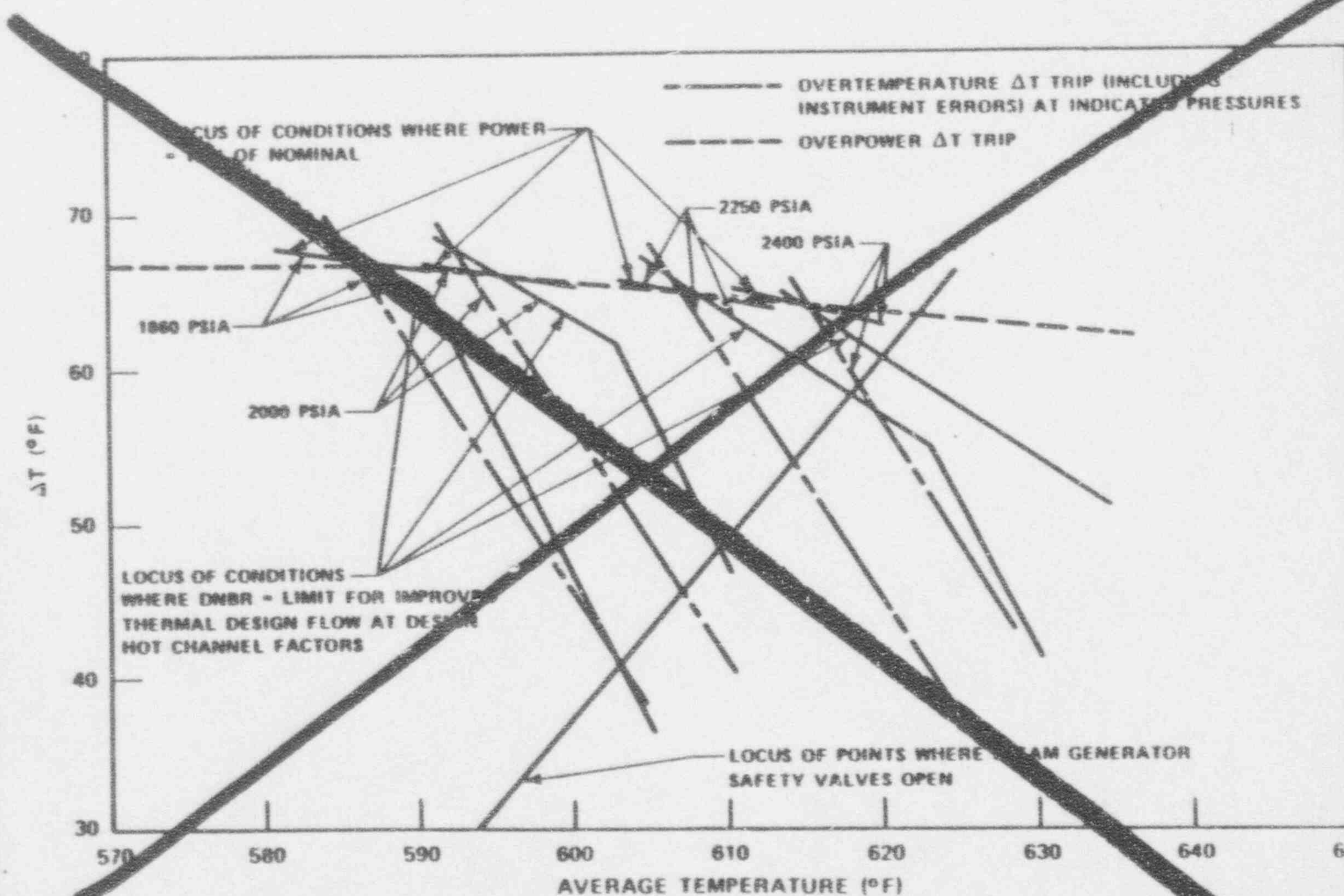
TABLE 15.0-5

TRIP POINTS AND TIME DELAYS TO TRIP
ASSUMED IN ACCIDENT ANALYSES

| TRIP FUNCTION | LIMITING TRIP POINT ASSUMED IN ANALYSIS | TIME DELAYS (SECONDS) |
|---|---|---|
| Power range high neutron flux, high setting | 118% | 0.5 |
| Power range high neutron flux, low setting | 35% | 0.5 |
| Overtemperature ΔT | Variable see Figure 15.0-1 | 8.0* |
| Overpower ΔT | Variable see Figure 15.0-1 | 8.0* |
| High pressurizer pressure | ~~2410~~ 2445 psig | 2.0 |
| Low pressurizer pressure | 1845 psig | 2.0 |
| Low reactor coolant flow (From loop flow detectors) | 87% loop flow | 1.0 |
| Undervoltage trip | 68% nominal | 1.5 |
| Turbine trip | Not applicable | 2.0 |
| Low-low steam generator level | 13.7% of narrow range level span | 2.0 |
| High steam generator level trip of the feedwater pumps and closure of feedwater system valves, and turbine trip | 87.4% of narrow range level span | 2.5 |

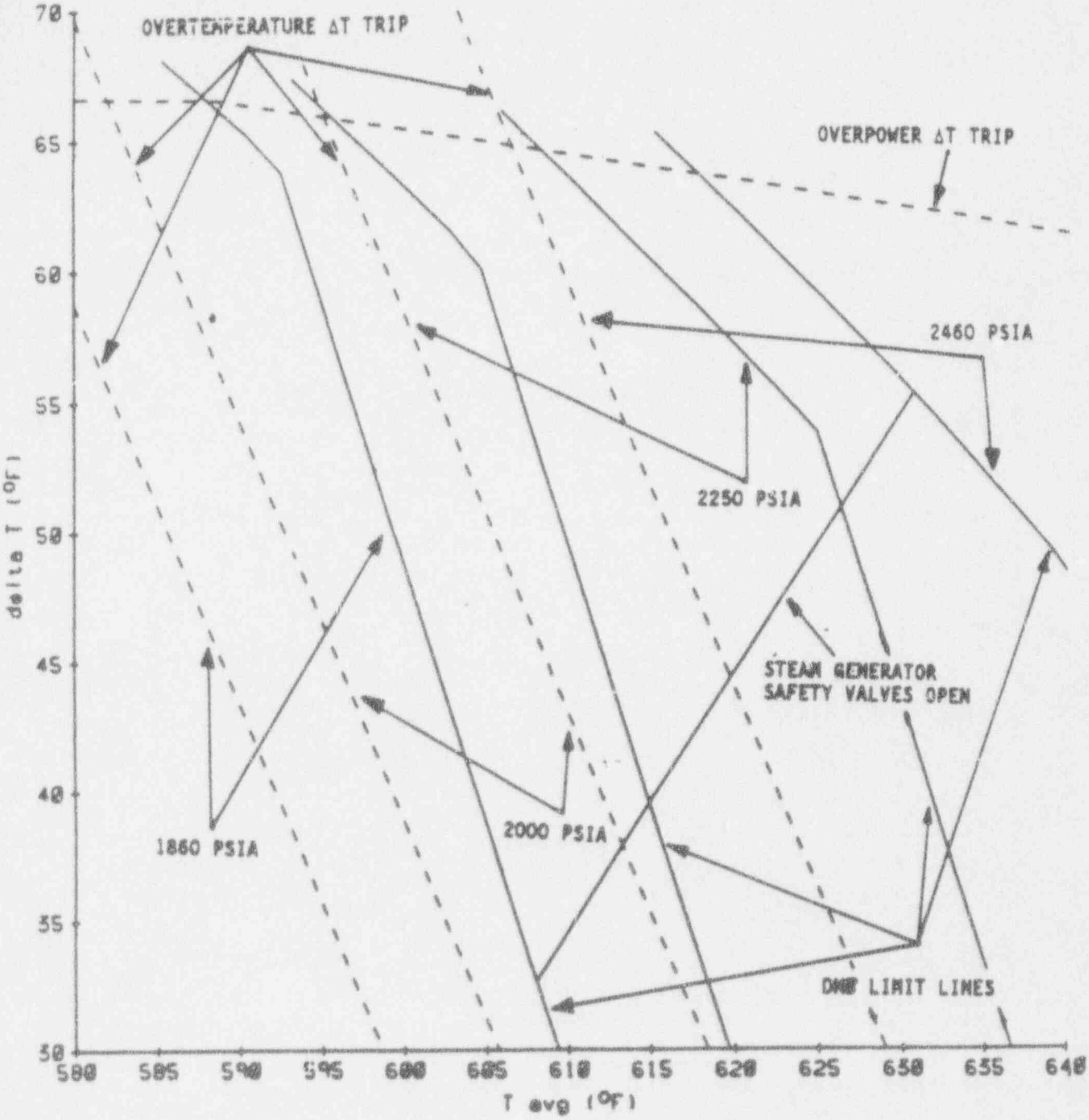
* Total time delay (including RTD bypass loop fluid transport delay effect, bypass loop thermal capacity, RTD time response, trip circuit delay time and channel electronics delay) from the time the temperature difference in the coolant loops exceeds the trip setpoint until the rods are free to fall.

REPLACE WITH
The following
Figure




BYRON/BRAIDWOOD STATIONS
UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 15.0-1
ILLUSTRATION OF OVERTEMPERATURE
AND OVERPOWER ΔT PROTECTION



OVERTEMPERATURE ΔT TRIP
OVERPOWER ΔT TRIP
2460 PSIA
2250 PSIA
STEAM GENERATOR
SAFETY VALVES OPEN
1860 PSIA
2000 PSIA
DNB LIMIT LINES
delta T (°F)
T avg (°F)
70
65
60
55
50
45
40
35
30
580
585
590
595
600
605
610
615
620
625
630
635
640


Figure 15.0-1

The reactor protection system may be required to function following a complete loss of external load to terminate core heat input and prevent DNB. Depending on the magnitude of the load loss, pressurizer safety valves and/or steam generator safety valves may be required to open to maintain system pressure below allowable limits. No single active failure will prevent operation of any system required to function. Refer to Reference 2 for a discussion of ATWT considerations.

#### 15.2.2.3 Radiological Consequences

Loss of external load from full power would result in the operation of the steam dump system. This system keeps the main turbine generator operating to supply auxiliary electrical loads. Operation of the steam dump system results in bypassing steam to the condenser. If steam dumps are not available, steam generator safety and relief valves relieve to the atmosphere. Since no fuel damage is postulated for this transient the radiological releases, given in Table 15.2-4, will be less severe than those for the steamline break accident analyzed in Subsection 15.1.5.3.

#### 15.2.2.4 Conclusions

Based on results obtained for the turbine trip event (Subsection 15.2.3) and considerations described in Subsection 15.2.2.1, the applicable acceptance criteria for a loss of external load event are met.

### 15.2.3 Turbine Trip

#### 15.2.3.1 Identification of Causes and Accident Description

For a turbine trip event, the turbine stop valves close rapidly (typically 0.1 sec.) on loss of trip fluid pressure actuated by one of a number of possible turbine trip signals. Turbine trip initiation signals include:

a. low condenser vacuum,

b. low bearing oil pressure,

c. turbine thrust bearing failure,

d. turbine overspeed,

e. DEH d-c power failure, and

f. 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. The loss of steam flow results in an almost immediate rise in secondary system temperature and pressure with a resultant primary system transient as described in Subsection 15.2.2.1 for the loss of external load event. For a turbine trip, the reactor would be tripped directly (unless below approximately 30% power on the units where the P-8 modification has been implemented or below approximately 10% power on the units where the P-8 modification has not been implemented) on a signal from the turbine auto stop oil pressure or the turbine stop valves.

The automatic steam dump system would normally accommodate the excess steam generation. Reactor coolant temperatures and pressure do not significantly increase if the steam dump system and pressurizer pressure control system are functioning properly. 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. See Subsection 15.2.2.1 for a further discussion of the transient.

A turbine trip is classified as an ANS condition II event, fault of moderate frequency. See Subsection 15.0.1 for a discussion of condition II events.

A turbine trip event is bounding for loss of external load, loss of condenser vacuum, and other turbine trip events. As such, this event has been analyzed in detail. Results and discussion of the analysis are presented in Subsection 15.2.3.2.

The plant systems and equipment available to mitigate the consequences of a turbine trip are discussed in Subsection 15.0.8 and listed in Table 15.0-7.

15.2.3.2 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 full power primarily to show the adequacy of the pressure relieving devices and also to demonstrate core protection margins. The reactor is not tripped until conditions in the RCS result in a trip. 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 (Reference 3). 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.

This accident is analyzed with the improved thermal design procedures as described in WCAP-8567. Plant characteristics and initial conditions are discussed in Subsection 15.0.3.

Major assumptions are summarized below:

a. Initial Operating Conditions - initial reactor power, pressure, and RCS temperatures are assumed to be at their nominal values. Uncertainties in initial conditions are included in the limit DNBR as described in WCAP-8567.

b. Moderator and Doppler Coefficients of Reactivity - the turbine trip is analyzed with both maximum and minimum reactivity feedback. The maximum feedback cases assume a large negative moderator temperature coefficient and the most negative Doppler power coefficient. The minimum feedback cases assume a least negative moderator temperature coefficient and the least negative Doppler coefficients. (See Figure 15.0-3.)

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 the reduce and 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 setpoints where steam release through safety valve limits secondary steam pressure at the setpoint value.

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

   1. 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.

   2. 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. 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. Trip signals are expected due to high pressurizer pressure, overtemperature $\Delta T$, high pressurizer water level, and low-low steam generator water level.

Except as discussed above, normal reactor control system and engineered safety systems are not required to function. Several cases are presented in which pressurizer spray and power-operated relief valves are assumed, but the more limiting cases where these functions are not assumed are also presented.

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. A discussion of ATWT considerations is presented in Reference 2.

Results

The transient responses for a turbine trip from full power operation are shown for four cases: two cases for minimum reactivity feedback and two cases for maximum reactivity feedback (Figures 15.2-1 through 15.2-8). The calculated sequence of events for the accident is shown in Table 15.2-1.

over temperature $\Delta T$

Figures 15.2-1 and 15.2-2 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 the steam dump. The reactor is tripped by the ~~high pressurizer pressure~~ trip channel. The minimum DNBR remains well above the limit value. The pressurizer ~~safety valves~~ are actuated and the primary system pressure remains below the 110% design value. The steam generator safety valves limit the secondary steam ~~conditions to saturation at the safety valve setpoint~~. pressure to less than 110% of the design value.

Figures 15.2-3 and 15.2-4 show the response for the total loss of steam load with a large negative moderator temperature coefficient. All other plant parameters are the same as the above. The DNBR increases throughout the transient and never drops below its initial value. Pressurizer relief valves and steam generator

power-operated relief valves

safety valves prevent overpressurization in primary and secondary systems, respectively. The pressurizer safety valves are not actuated for this case.

In the event that feedwater flow is not terminated at the time of turbine trip for this case, flow would continue under automatic control with the reactor at a reduced power. The operator would take action to terminate the transient and bring the plant to a stabilized condition. If no action were taken by the operator the reduced power operation would continue until the condenser hotwell was emptied. A low-low steam generator water level reactor trip would be generated along with auxiliary feedwater initiation signals. Auxiliary feedwater would then be used to remove decay heat with the results less severe than those presented in Subsection 15.2.7. [eventually

The turbine trip accident was also studied assuming the plant to be initially operating at full power with no credit taken for the pressurizer spray, pressurizer power-operated relief valves, or steam dump. The reactor is tripped on the high pressurizer pressure signal. Figures 15.2-5 and 15.2-6 show the transients with a least negative moderator coefficient (minimum reactivity feedback). The neutron flux remains essentially constant at full power until the reactor is tripped. The DNBR ~~increases throughout the transient and~~ never drops below its initial value. In this case the pressurizer safety valves are actuated, and maintain system pressure below 110% of the design value.

Figures 15.2-7 and 15.2-8 are the transients with maximum reactivity feedback with the other assumptions being the same as in the preceding case. Again, the DNBR increases throughout the transient and the pressurizer safety valves are actuated to limit primary pressure.

Reference 1 presents additional results of analysis for a complete loss of heat sink including loss of main feedwater. This analysis shows the overpressure protection that is afforded by the pressurizer and steam generator safety valves.

#### 15.2.3.3 Radiological Consequences

The turbine trip transient and steam released for this event are similar to the loss of load transient described in Subsection 15.2.2.3.

There are only minimal radiological consequences associated with this event, therefore, this event is not limiting. The radiological consequences resulting from atmosphere steam dump are less severe than the steamline break event analyzed in Subsection 15.1.5.3 since no fuel damage is postulated to occur.

#### 15.2.3.4 Conclusions

Results of the analyses, including those in Reference 1, show that the plant design is such that a turbine 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 integrity of the core is maintained by operation of the reactor protection system, i.e., the DNBR will be maintained above the limit value. The applicable acceptance criteria as listed in Subsection 15.0.1 have been met. The above analysis demonstrates the ability of the NSSS to safely withstand a full load rejection. The radiological consequences in this event will be less than the steam break event analyzed in Subsection 15.1.5.3.

### ~~15.2.4 Inadvertent Closure of Main Steam Isolation Valves~~

~~Inadvertent closure of the main steam isolation valves would result in a turbine trip. Turbine trips are discussed in Subsection 15.2.3.~~

### ~~15.2.5 Loss of Condenser Vacuum and Other Events Causing a Turbine Trip~~

~~Loss of condenser vacuum is one of the events that can cause a turbine trip. Turbine trip initiating events are described in Subsection 15.2.3. A loss of condenser vacuum would preclude the use of steam dump to the condenser; however, since steam dump is assumed not to be available in the turbine trip analysis, no additional adverse effects would result if the turbine trip were caused by loss of condenser vacuum. Therefore, the analysis results and conclusion contained in Subsection 15.2.3 apply to loss of condenser vacuum. In addition, analyses for the other possible causes of a turbine trip, as listed in Subsection 15.2.3.1 are covered by Subsection 15.2.3. Possible over-frequency effects due to a turbine overspeed condition are discussed in Subsection 15.2.2.1 and are not a concern for this type of event.~~

### ~~15.2.6 Loss of Nonemergency AC Power to the Plant Auxiliaries~~

#### ~~15.2.6.1 Identification of Causes and Accident Description~~

~~A complete loss of nonemergency ac power may result in the loss of all power to the plant auxiliaries, i.e., the reactor coolant pumps, condensate pumps, etc. The loss of power may be caused by a complete loss of the offsite grid accompanied by a turbine generator trip at the station, or by a loss of the onsite ac distribution system.~~

TABLE 15.2-1

TIME SEQUENCE OF EVENTS FOR INCIDENTS WHICH CAUSE A DECREASE IN HEAT REMOVAL BY THE SECONDARY SYSTEM

| ACCIDENT | EVENT | TIME (sec) |
|---|---|---|
| Turbine Trip | | |
| 1. With pressurizer control (minimum reactivity feedback) | Turbine trip, loss of main feedwater flow | 0.0 |
| | Overtemperature ΔT ~~High pressurizer pressure~~ reactor trip point reached | ~~7.0~~ 6.9 |
| | Initiation of steam release from steam generator safety valves | ~~8.5~~ 6.5 |
| | Rods begin to drop | ~~9.0~~ 8.9 |
| | Peak pressurizer pressure occurs (1) | 10.5 |
| | Minimum DNBR occurs | ~~(2)~~ 10.0 |

(1) Primary pressure is measured at the pressurizer in the plant. Although the peak pressure in the RCS is slightly higher than the pressurizer pressure, pressurizer pressure is reported for transients that do not challenge RCS integrity. For transients which challenge RCS integrity, peak RCS pressure is reported. For all transients, it is ensured that peak RCS pressure remains below 2750 psia.

~~(2) DNBR does not decrease below its initial value.~~

TABLE 15.2-1 (Cont'd)

| ACCIDENT | EVENT | TIME (sec) |
|---|---|---|
| 2. With pressurizer control (maximum reactivity feedback) | Turbine trip, loss of main feedwater flow | 0.0 |
| | Initiation of steam release from steam generator safety valves | ~~8.5~~ 6.5 |
| | Peak pressurizer pressure occurs | ~~9.8~~ 7.5 |
| | ~~Low-low steam generator~~ Overtemperature ΔT reactor trip point reached | ~~82~~ 7.4 |
| | Rods begin to drop | ~~84~~ 9.4 |
| | Minimum DNBR occurs | (1) |
| 3. Without pressurizer control (minimum reactivity feedback) | Turbine trip, loss of main feedwater flow | 0.0 |
| | High pressurizer pressure reactor trip point reached | ~~4.0~~ 4.3 |
| | Rods begin to drop | ~~6.0~~ 6.3 |
| | Peak pressurizer pressure occurs | ~~8.1~~ 7.5 |
| | Initiation of steam release from steam generator safety valves | ~~8.5~~ 6.5 |
| | Minimum DNBR occurs | (1) |
| 4. Without pressurizer control (maximum reactivity feedback) | Turbine trip, loss of main feedwater | 0.0 |
| | High pressurizer pressure reactor trip point reached | ~~4.0~~ 4.3 |

(1) DNBR does not decrease below its initial value.

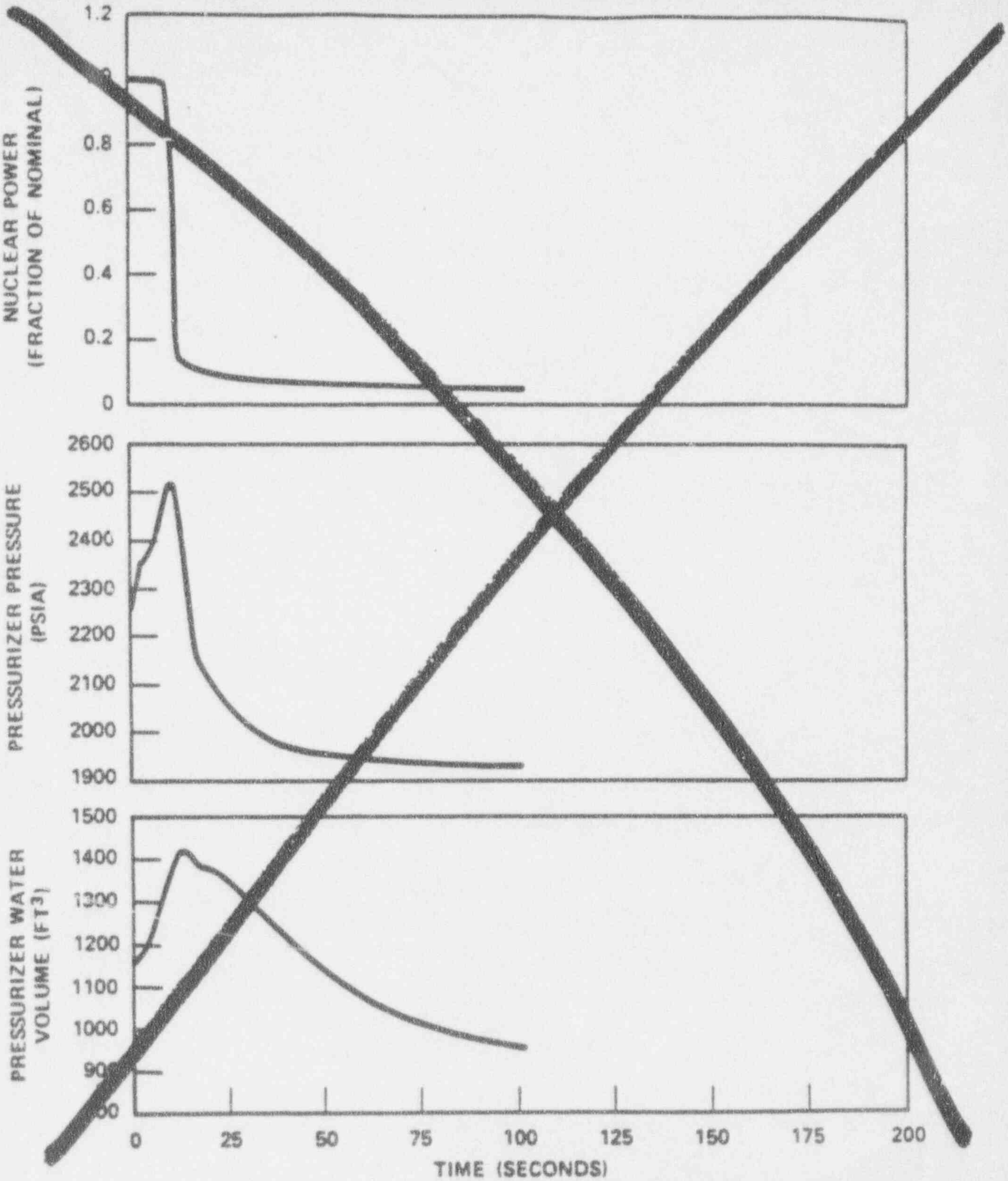
TABLE 15.2-1 (Cont'd)

| ACCIDENT | EVENT | TIME (sec) |
|---|---|---|
| | Rods begin to drop | ~~6.0~~ 6.3 |
| | Peak pressurizer pressure occurs | ~~7.5~~ 7.0 |
| | Initiation of steam release from steam generator safety valves | ~~8.5~~ 6.5 |
| | Minimum DNBR occurs | (1) |
| ~~Loss of Nonemergency~~ ac Power | ~~Main feedwater flow~~ stops | ~~10~~ |
| | Low-low steam generator water level trip | 52 |
| | Rods begin to drop | 54 |
| | Reactor coolant pumps begin to coastdown | 54 |
| | Four steam generators begin to receive auxiliary feedwater from one motor driven auxiliary feedwater pump | 113 |
| | Cold auxiliary feedwater is delivered to the steam generators | 259 |
| | Peak water level in pressurizer occurs | 310 |
| | Core decay heat decreases to auxiliary feedwater heat removal capacity | ~325 |
| Loss of Normal Feed-water Flow | Main feedwater flow stops | 10 |
| | Low-low steam generator water level trip | 52 |
| | Rods begin to drop | 54 |

TABLE 15.2-1 (Cont'd)

| ACCIDENT | EVENT | TIME (sec) |
| --- | --- | --- |
| | Peak water level in pressurizer occurs | 113 |

(1) DNBR does not decrease below its initial value.




REPLACE WITH
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FIGURE 15.2-1

TURBINE TRIP EVENT WITH PRESSURIZER SPRAY AND POWER-OPERATED RELIEF VALVES, MINIMUM REACTIVITY FEEDBACK

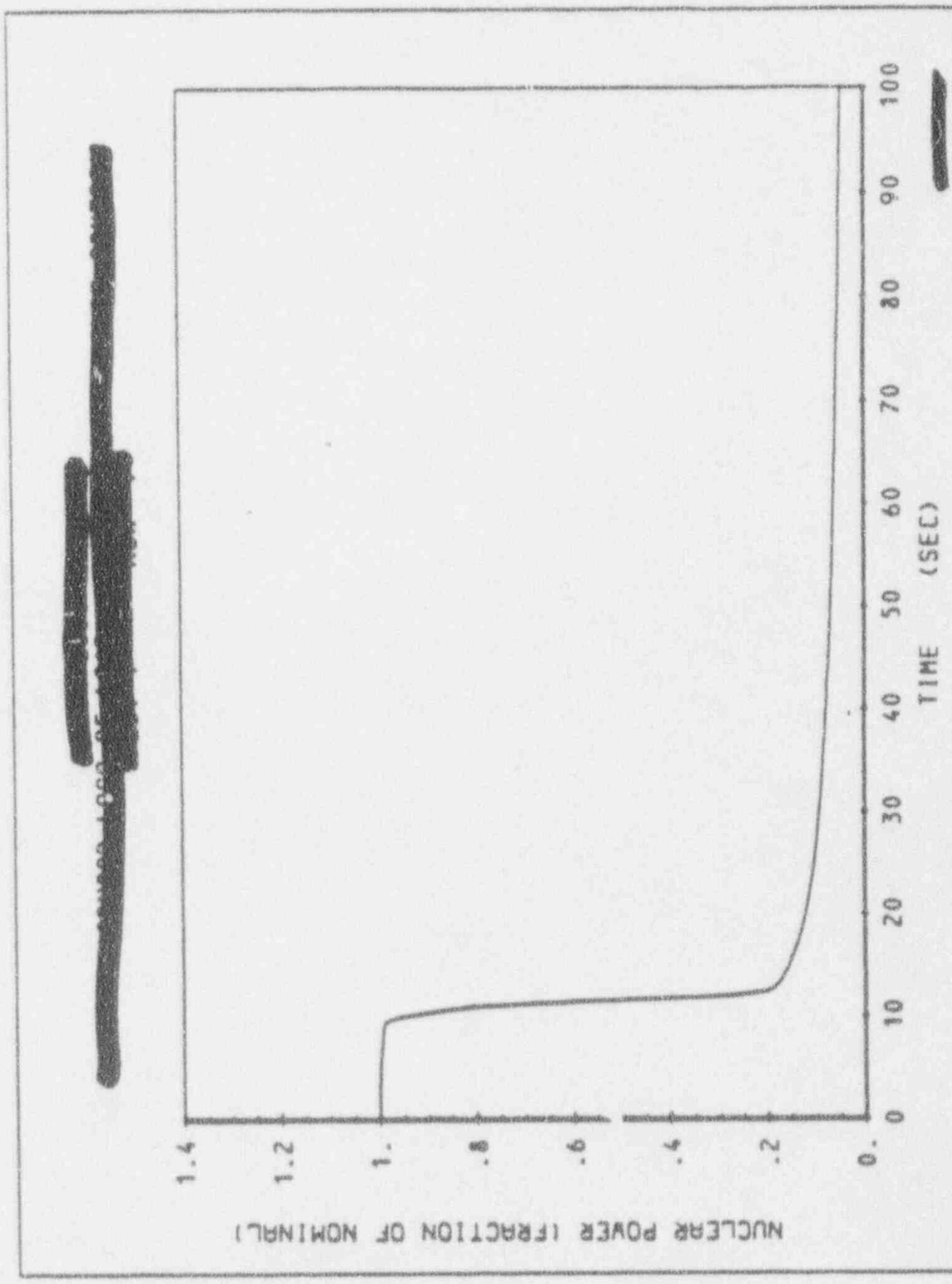


Figure 15.2-1

1of3

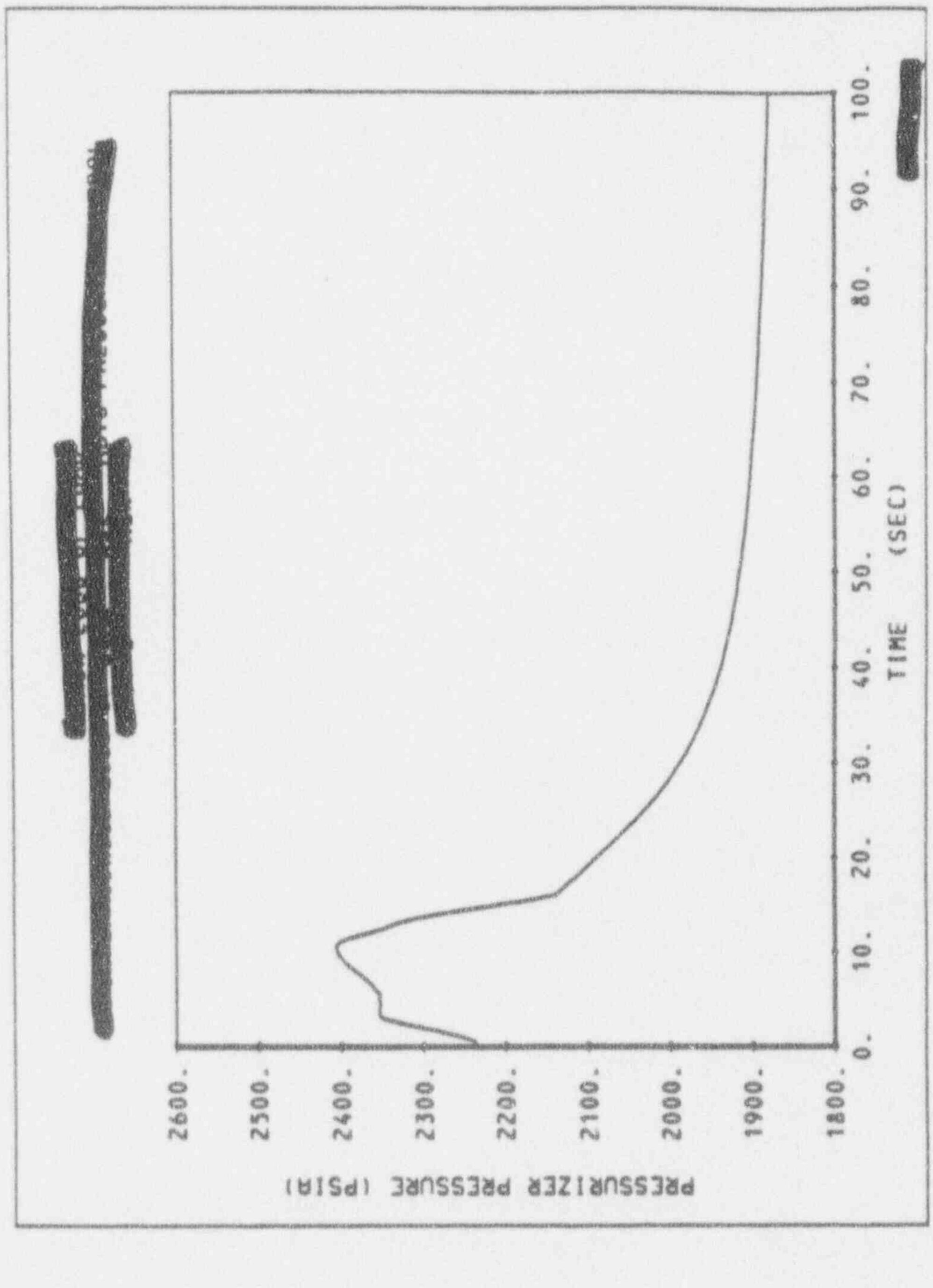


Figure 15.2-1

2 of 3

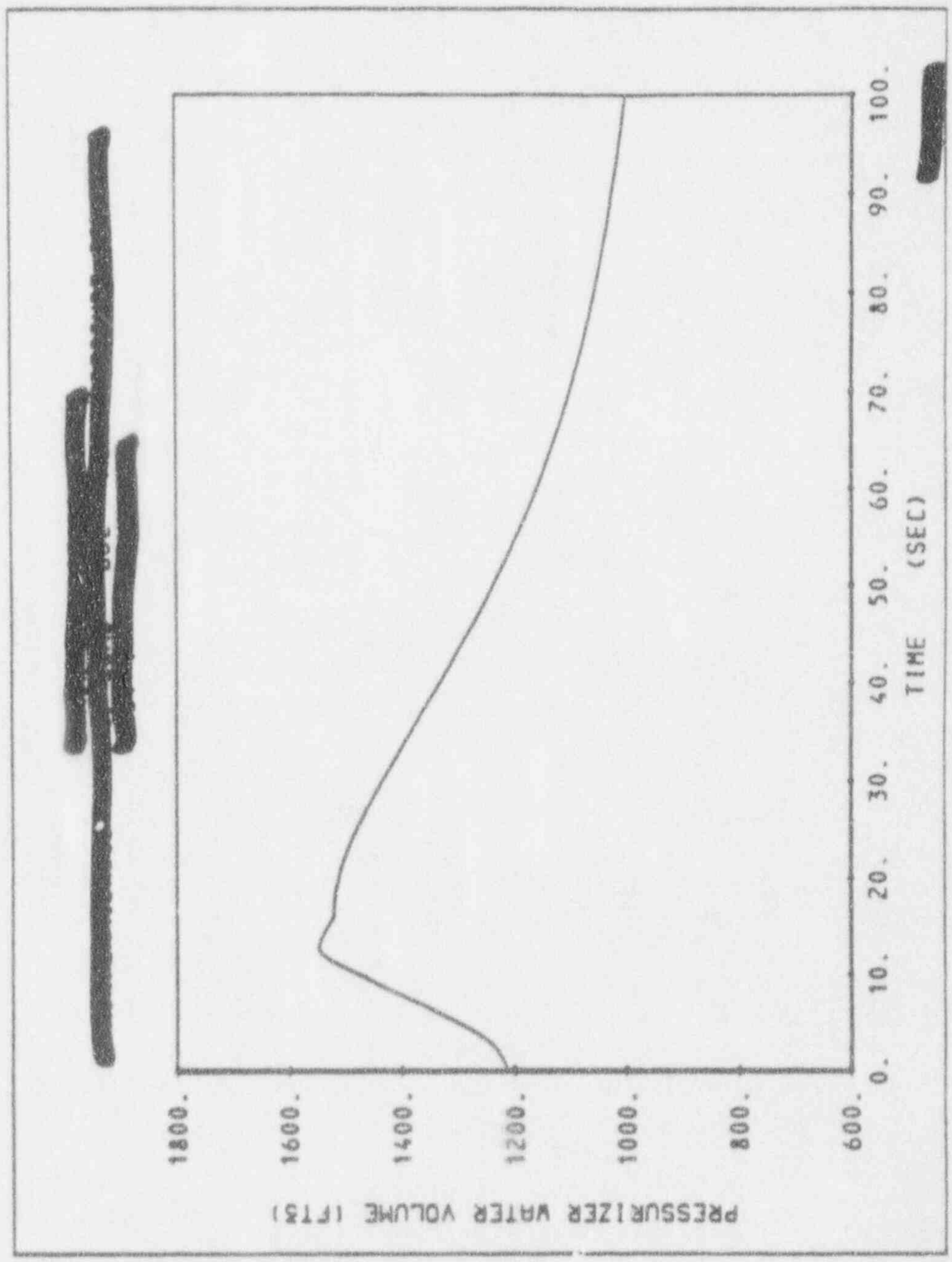


Figure 15.2-1

3 of 3

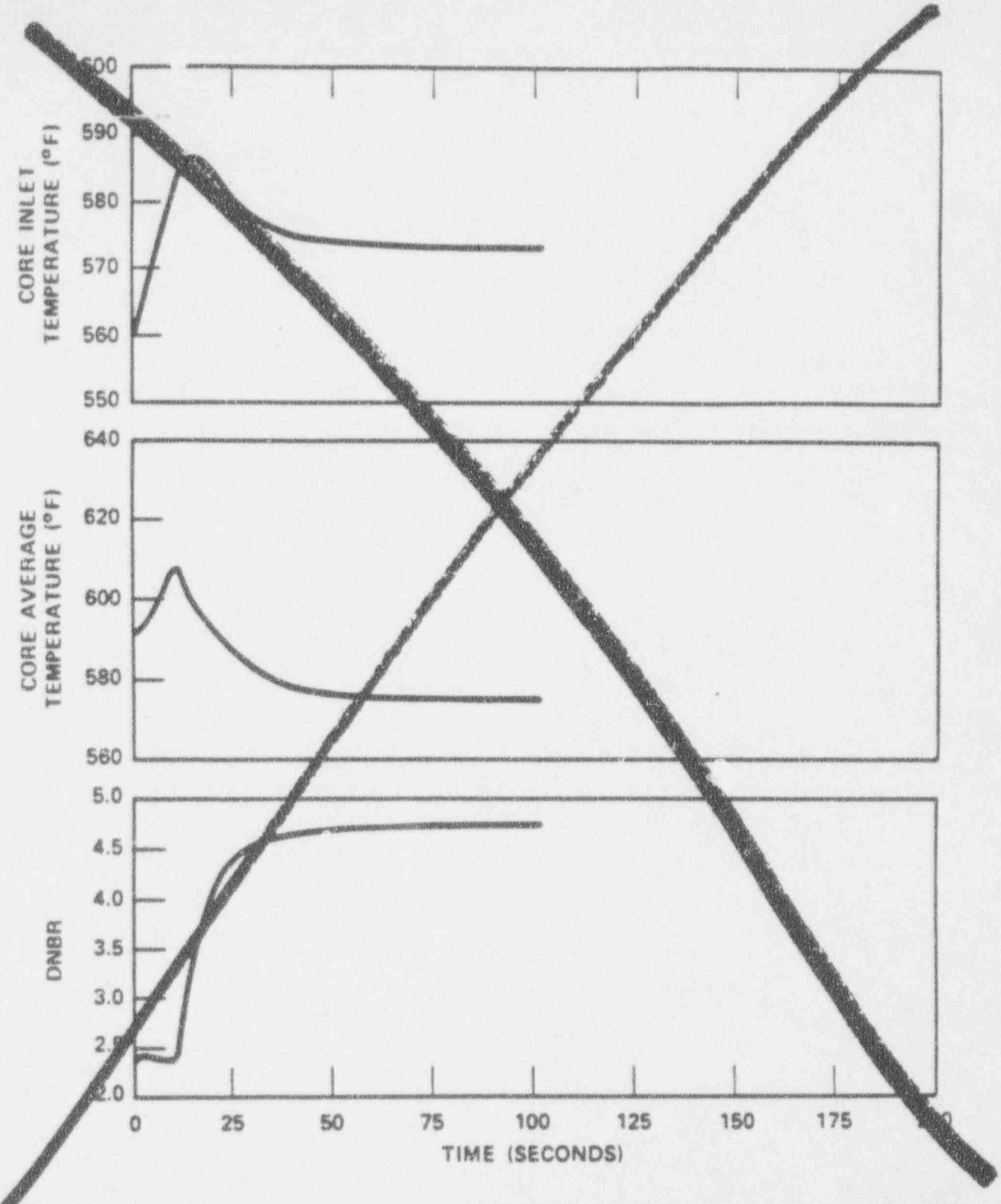


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FIGURE 15.2-2

TURBINE TRIP EVENT WITH PRESSURIZER SPRAY AND POWER-OPERATED RELIEF VALVES, MINIMUM REACTIVITY FEEDBACK

2

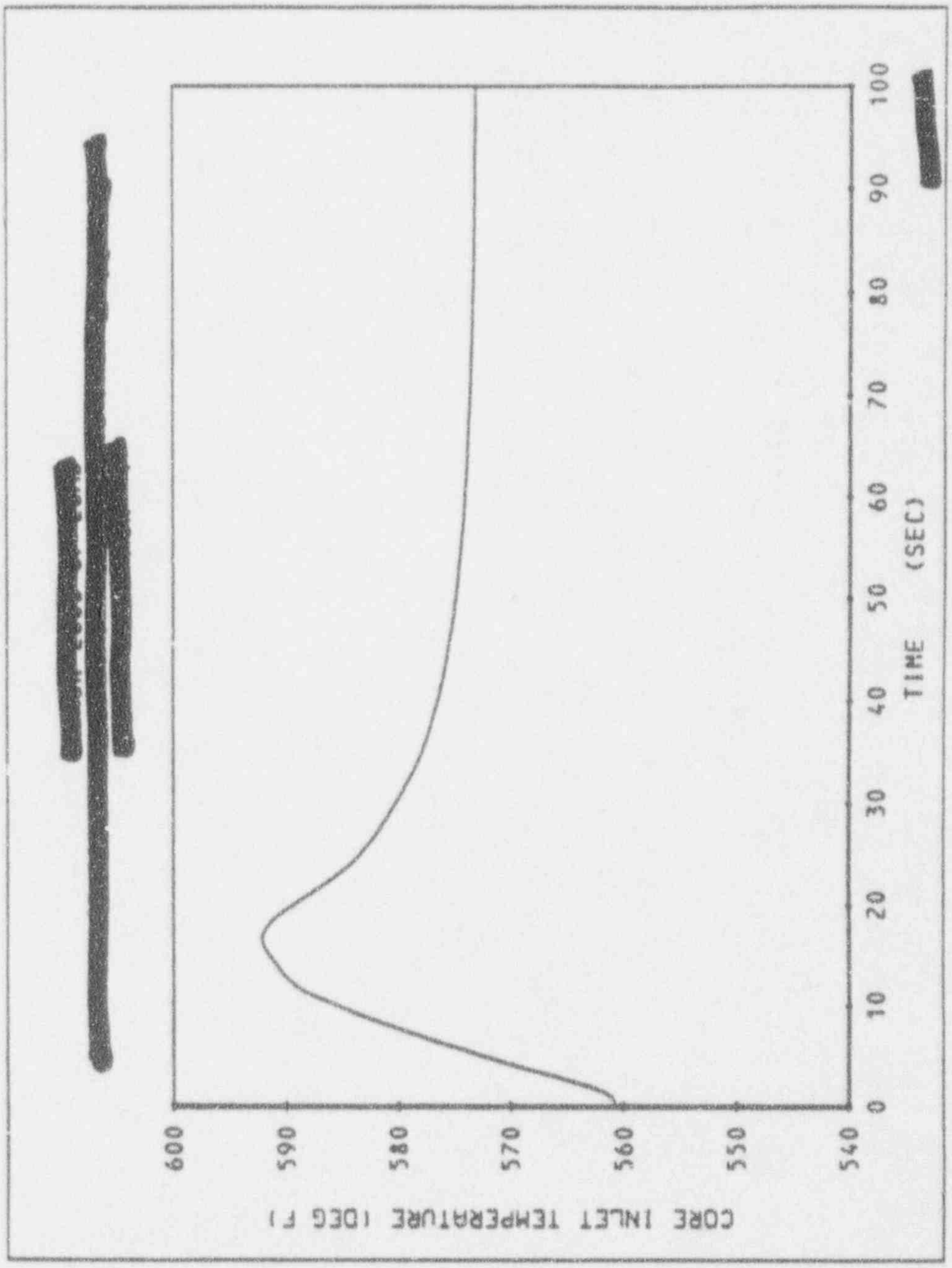


Figure 15.2-2

1 of 3

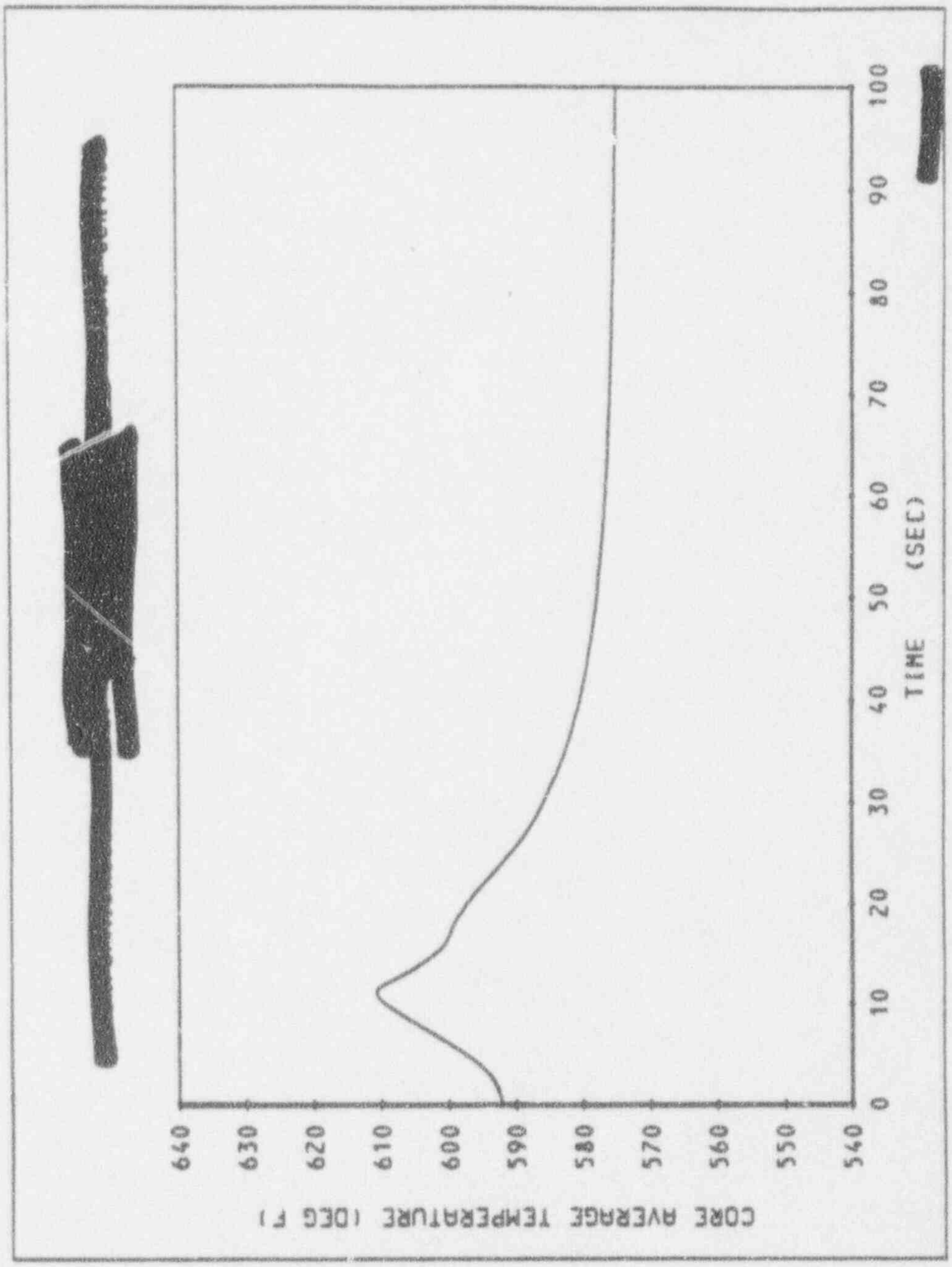


Figure 15.2-2

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Figure 15.2-2
3 of 3

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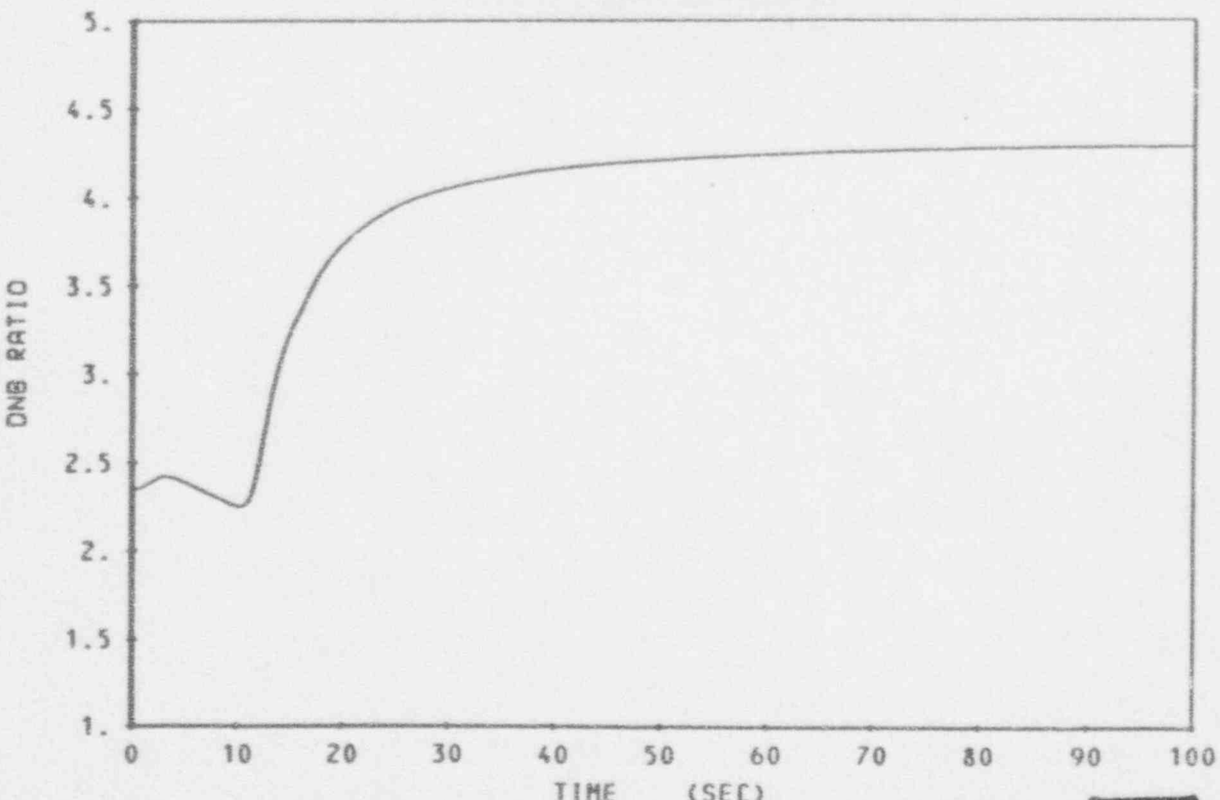


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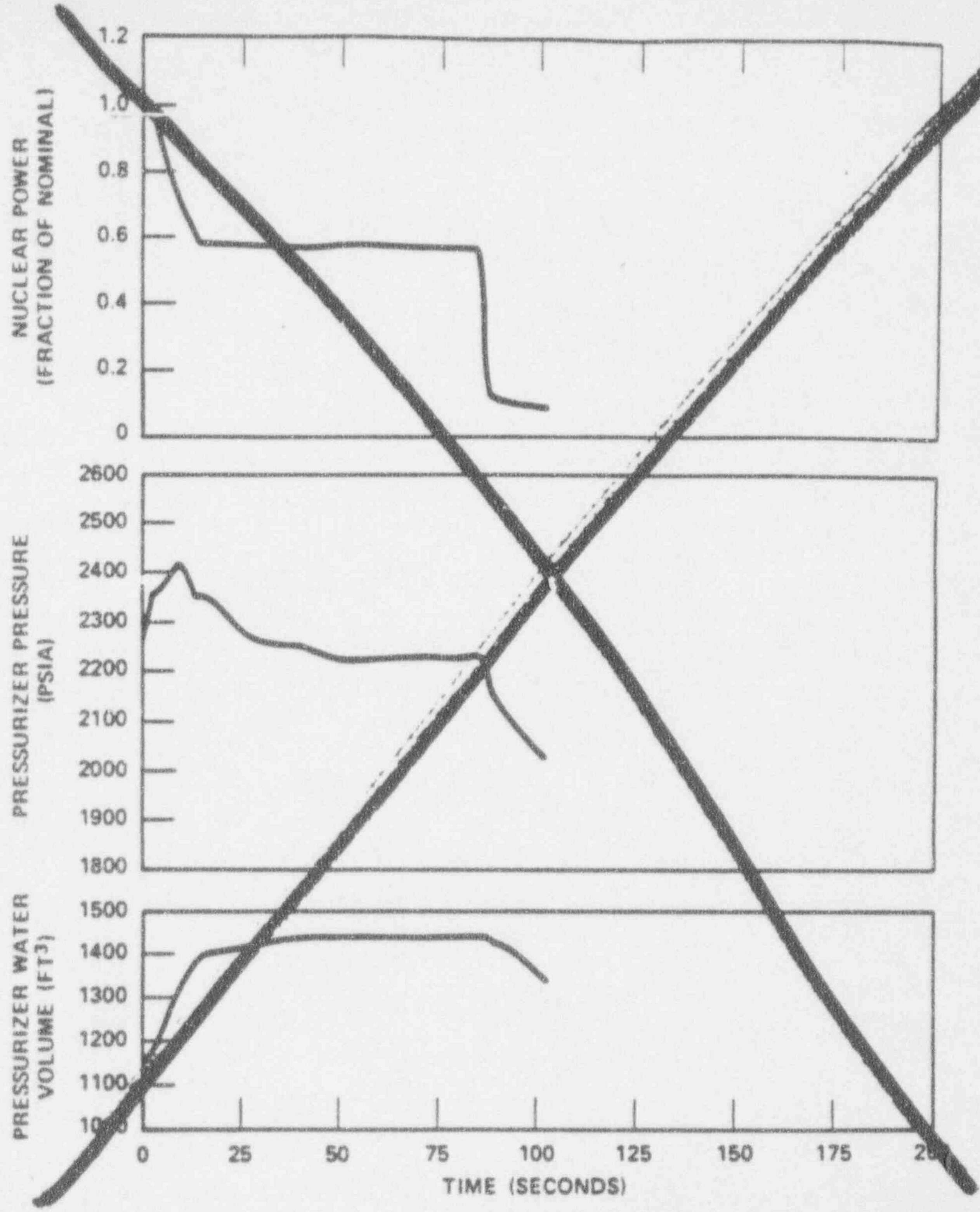


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FIGURE 15.2-3

TURBINE TRIP EVENT WITH PRESSURIZER SPRAY AND POWER-OPERATED RELIEF VALVES, MAXIMUM REACTIVITY FEEDBACK

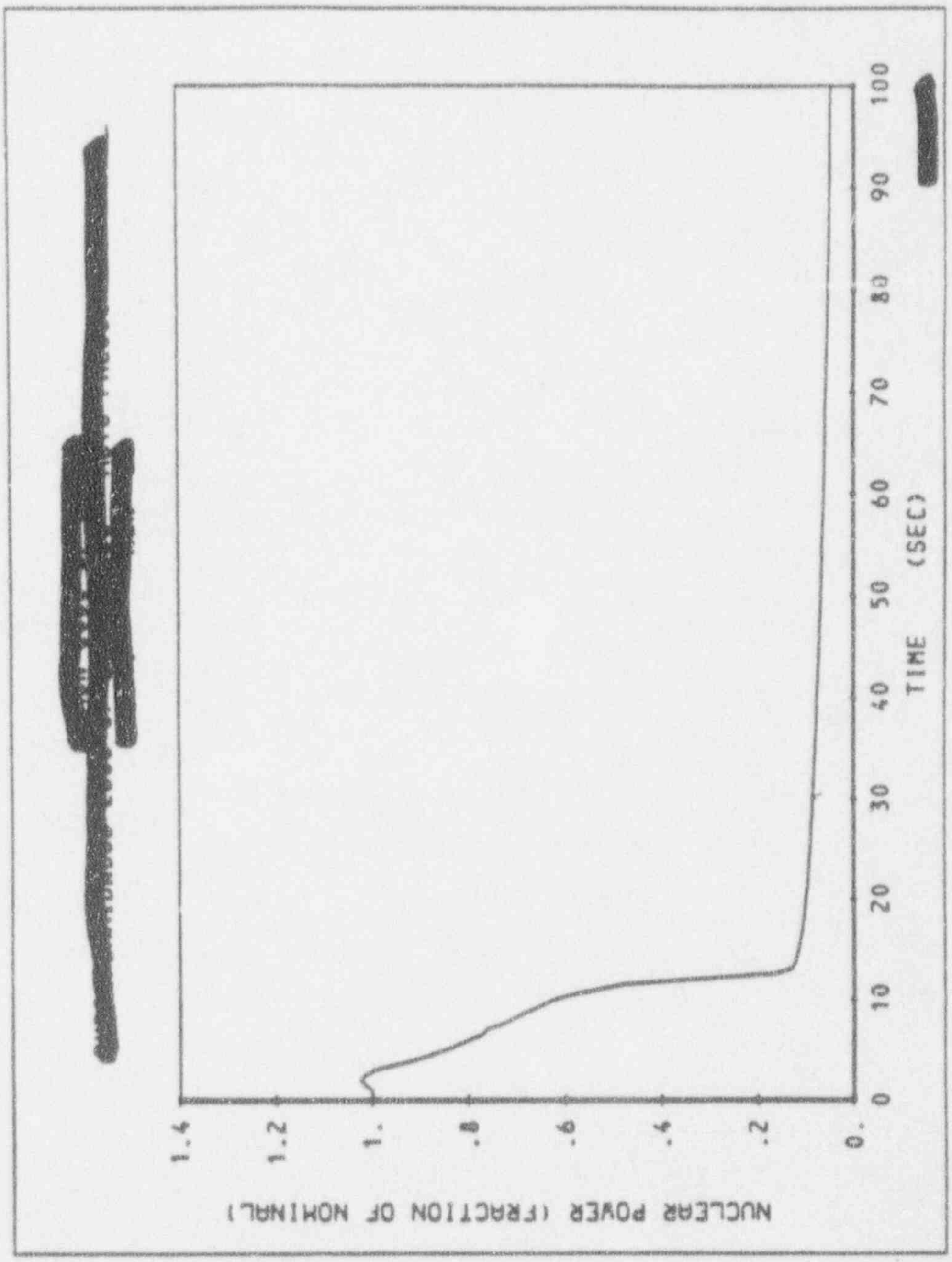
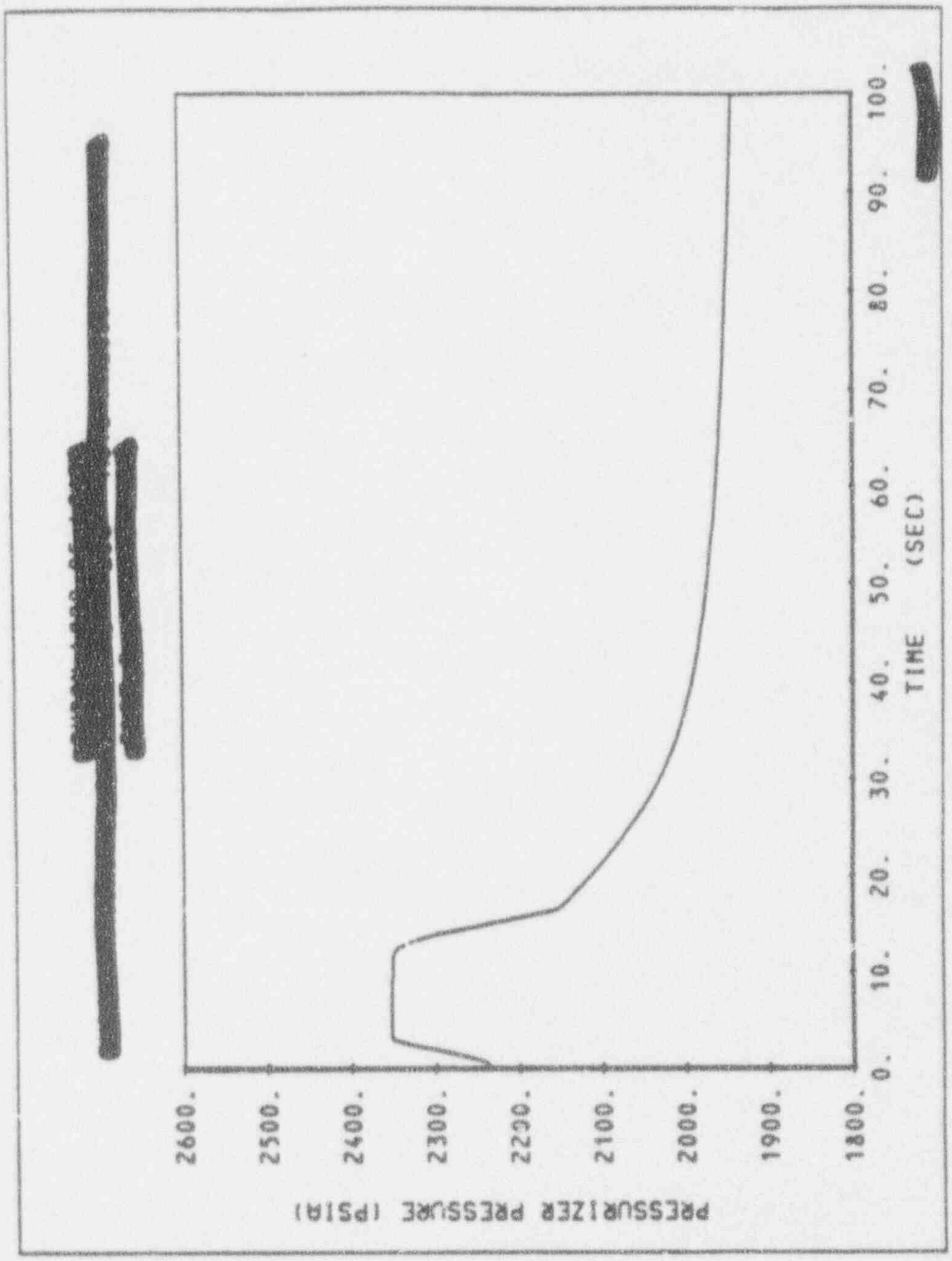



Figure 15.2-3

1 of 3

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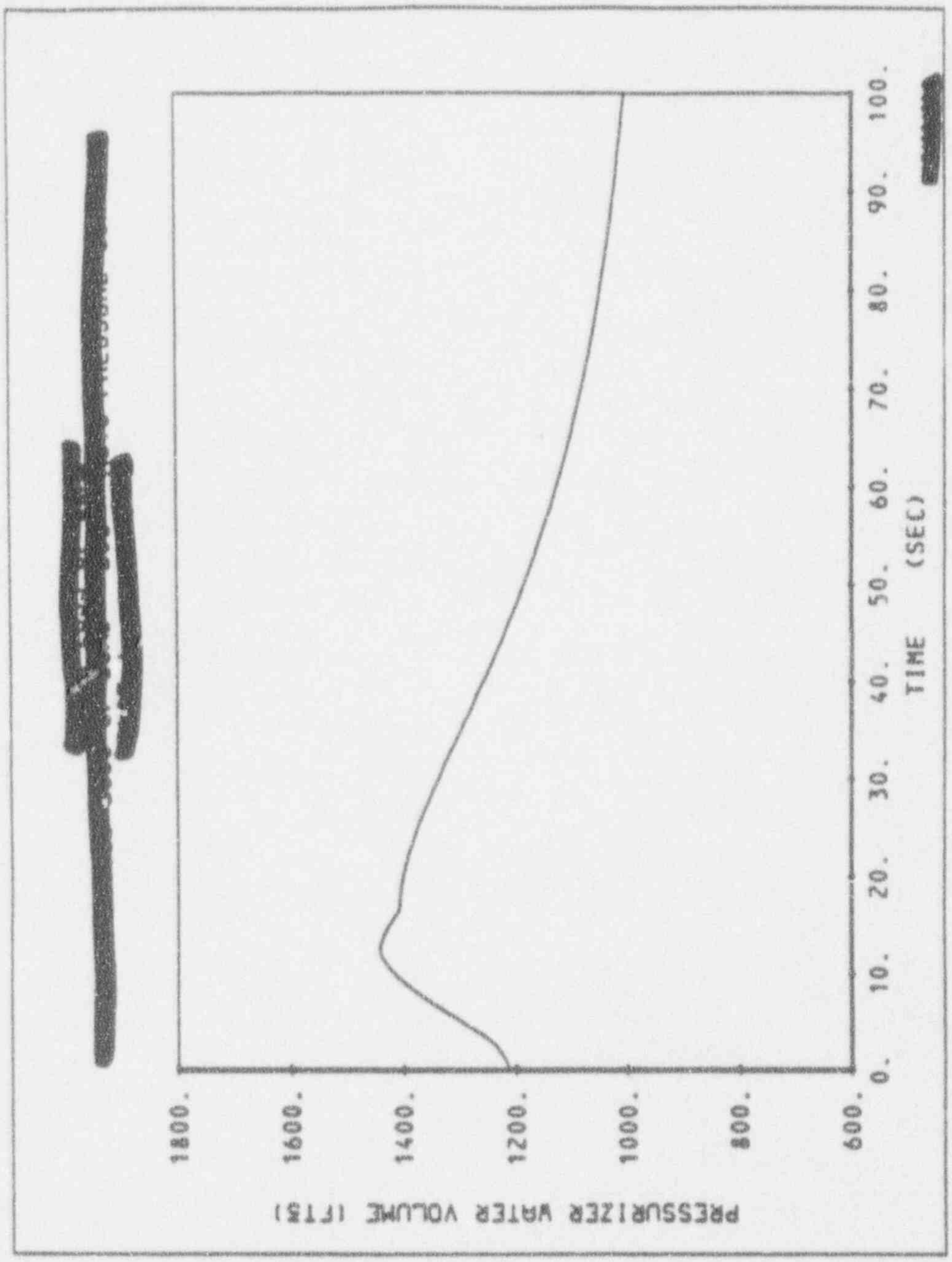


Figure 15.2-3

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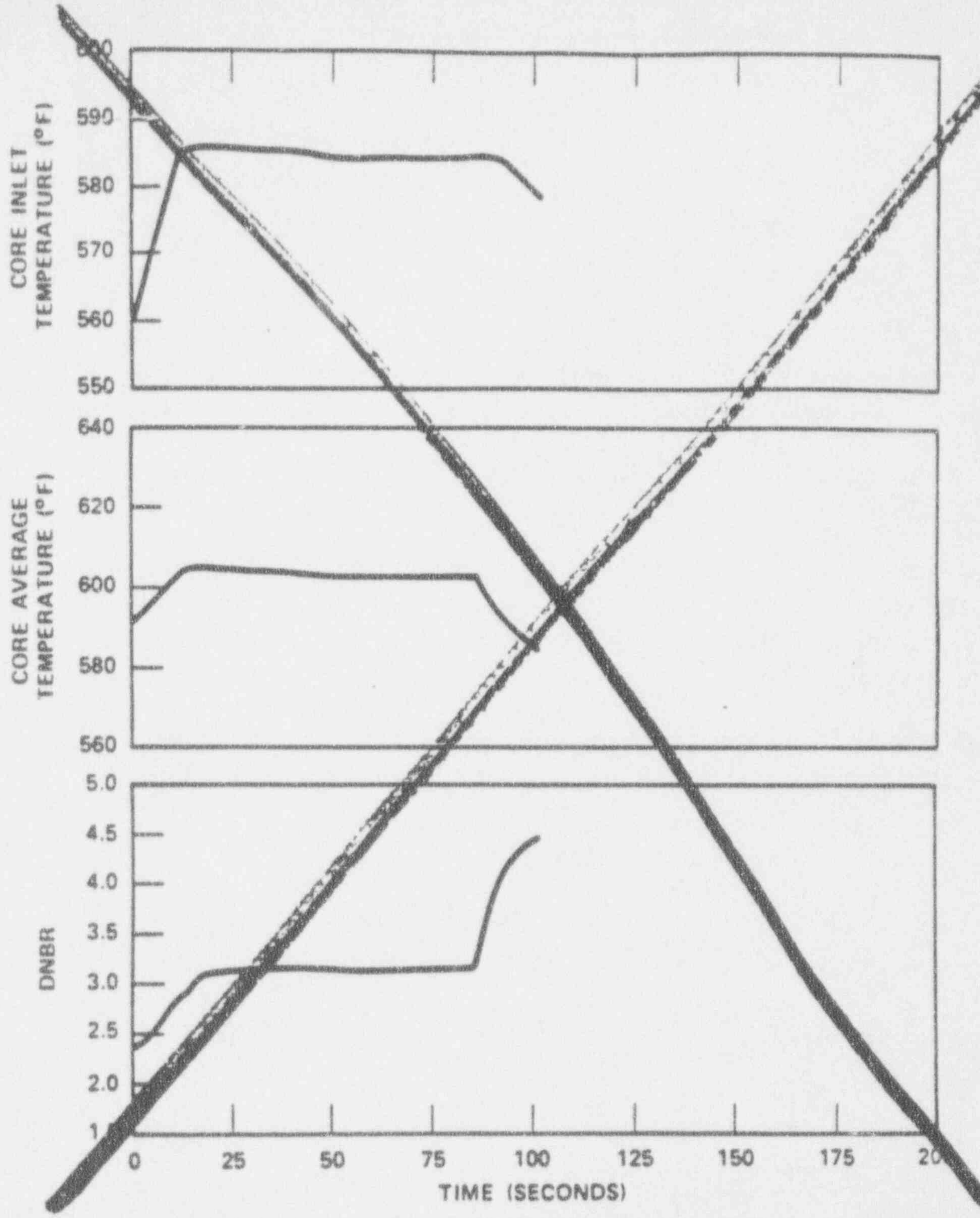


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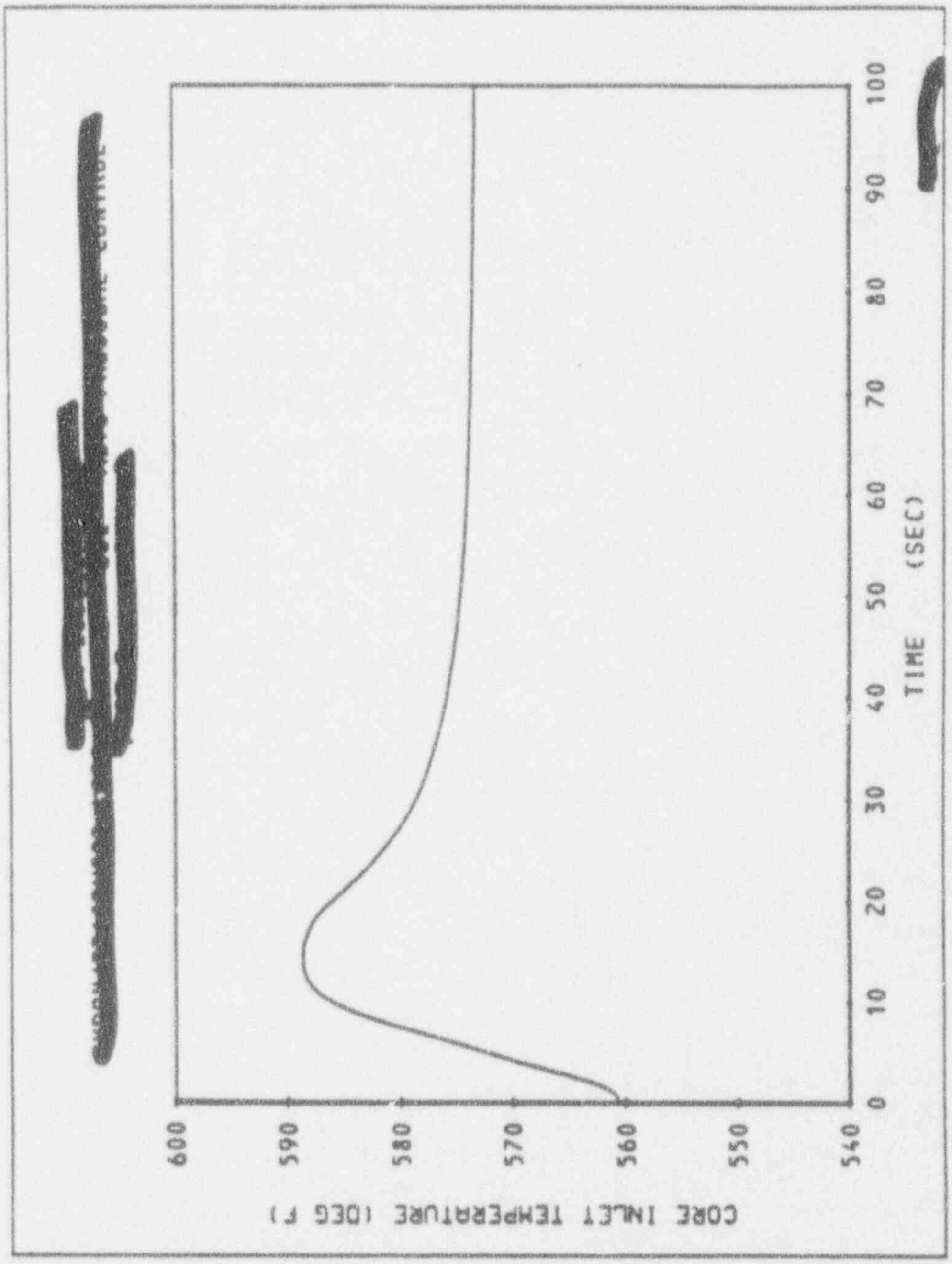
FIGURE 15.2-4

TURBINE TRIP EVENT WITH PRESSURIZER SPRAY AND POWER-OPERATED RELIEF VALVES, MAXIMUM REACTIVITY FEEDBACK

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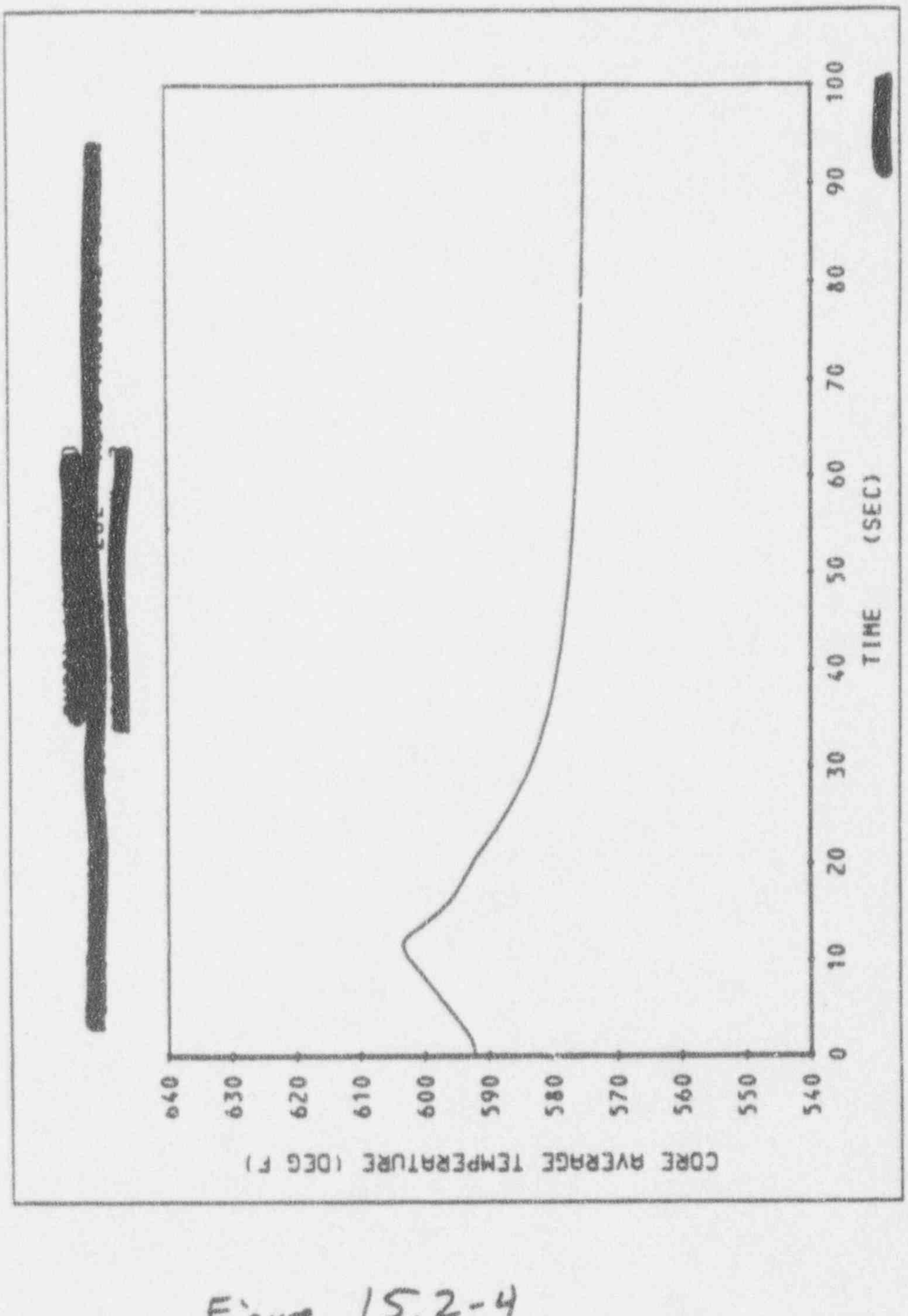
1 of 3

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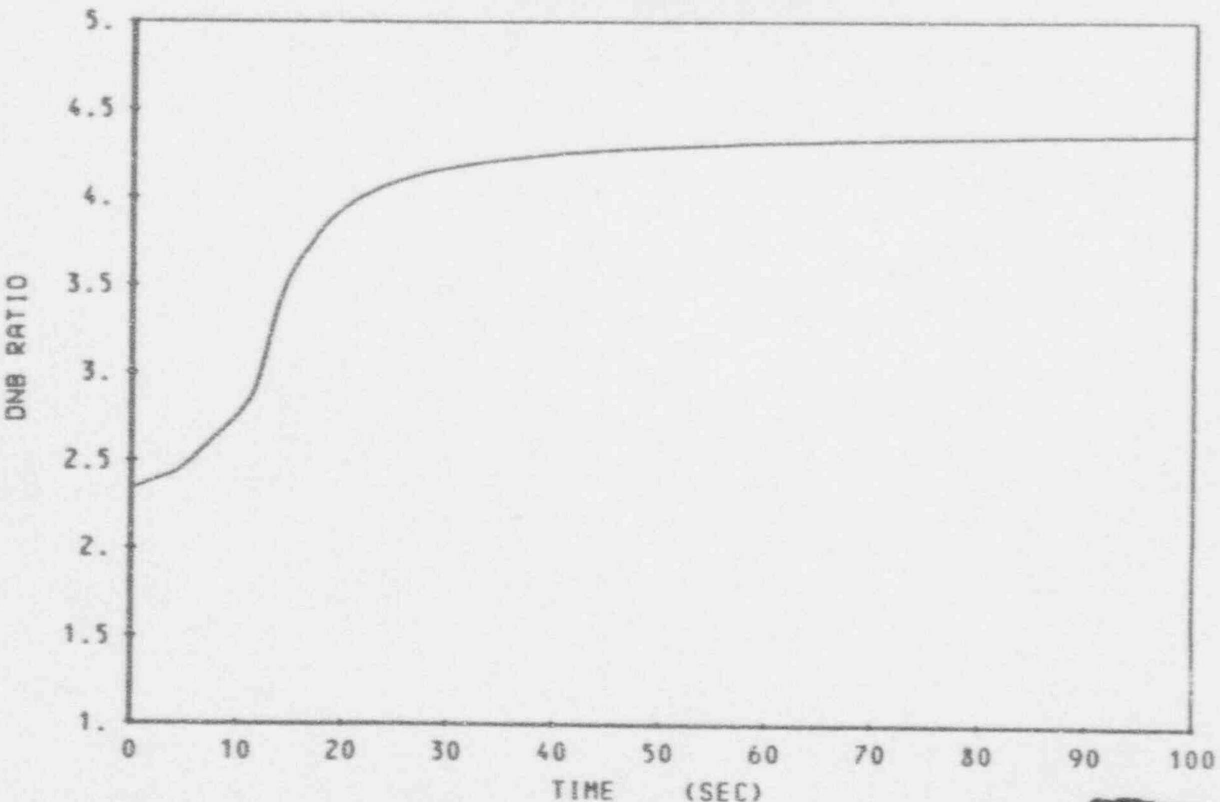


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Figure 15.2-4
3 of 3

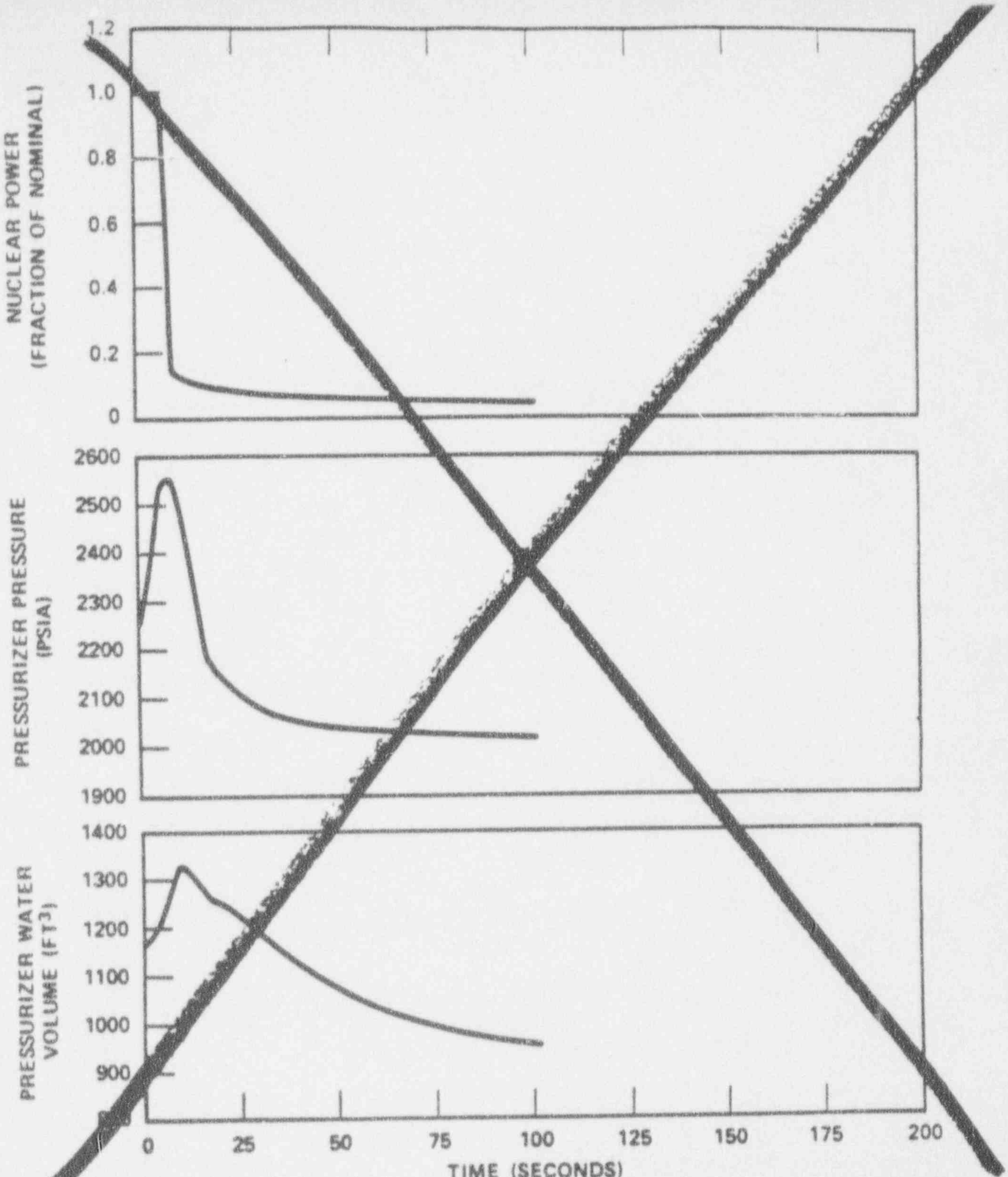


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FIGURE 15.2-5

TURBINE TRIP EVENT WITHOUT PRESSURIZER SPRAY AND POWER-OPERATED RELIEF VALVES, MINIMUM REACTIVITY FEEDBACK

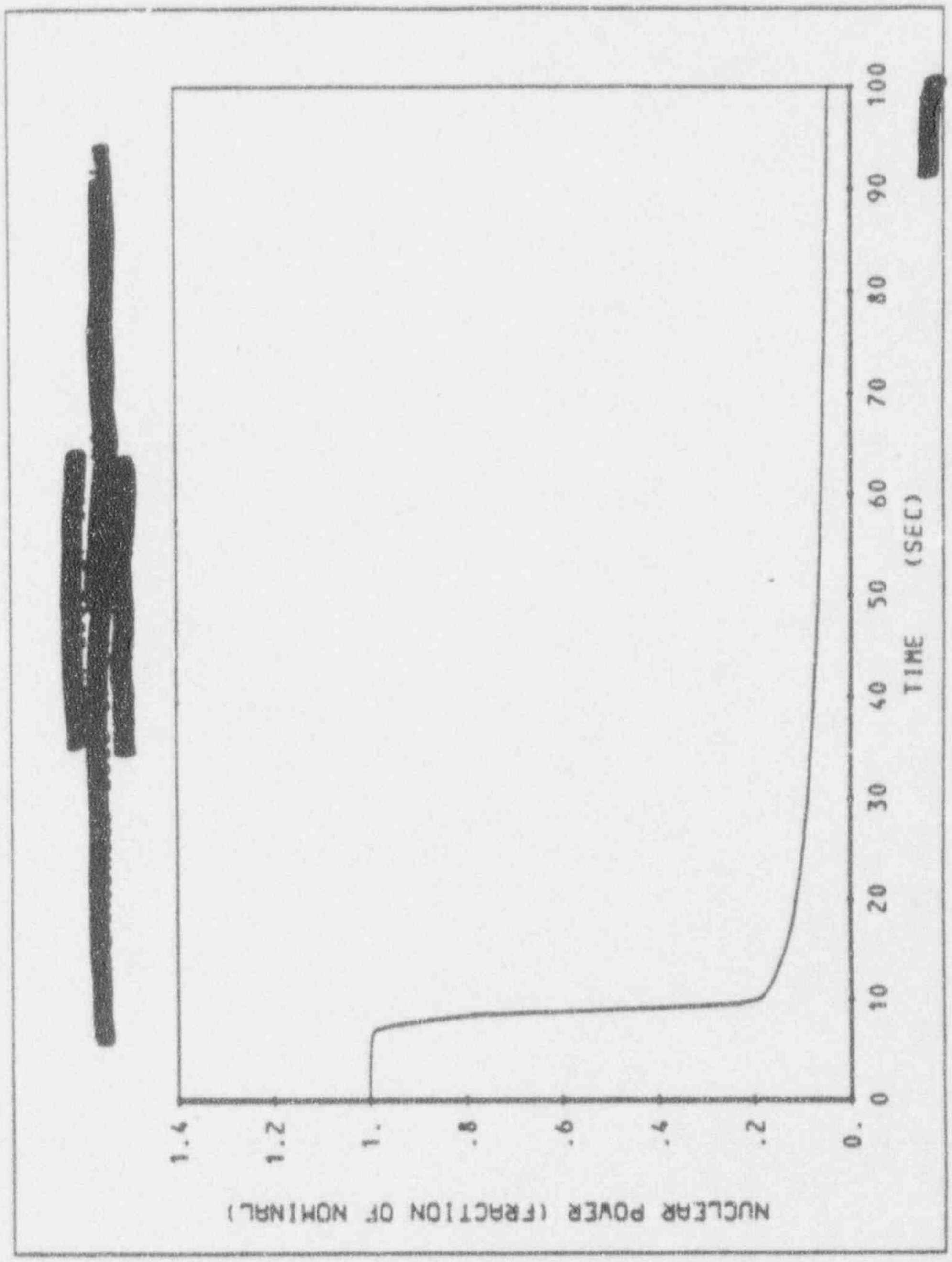


Figure 15.2-5

1 of 3

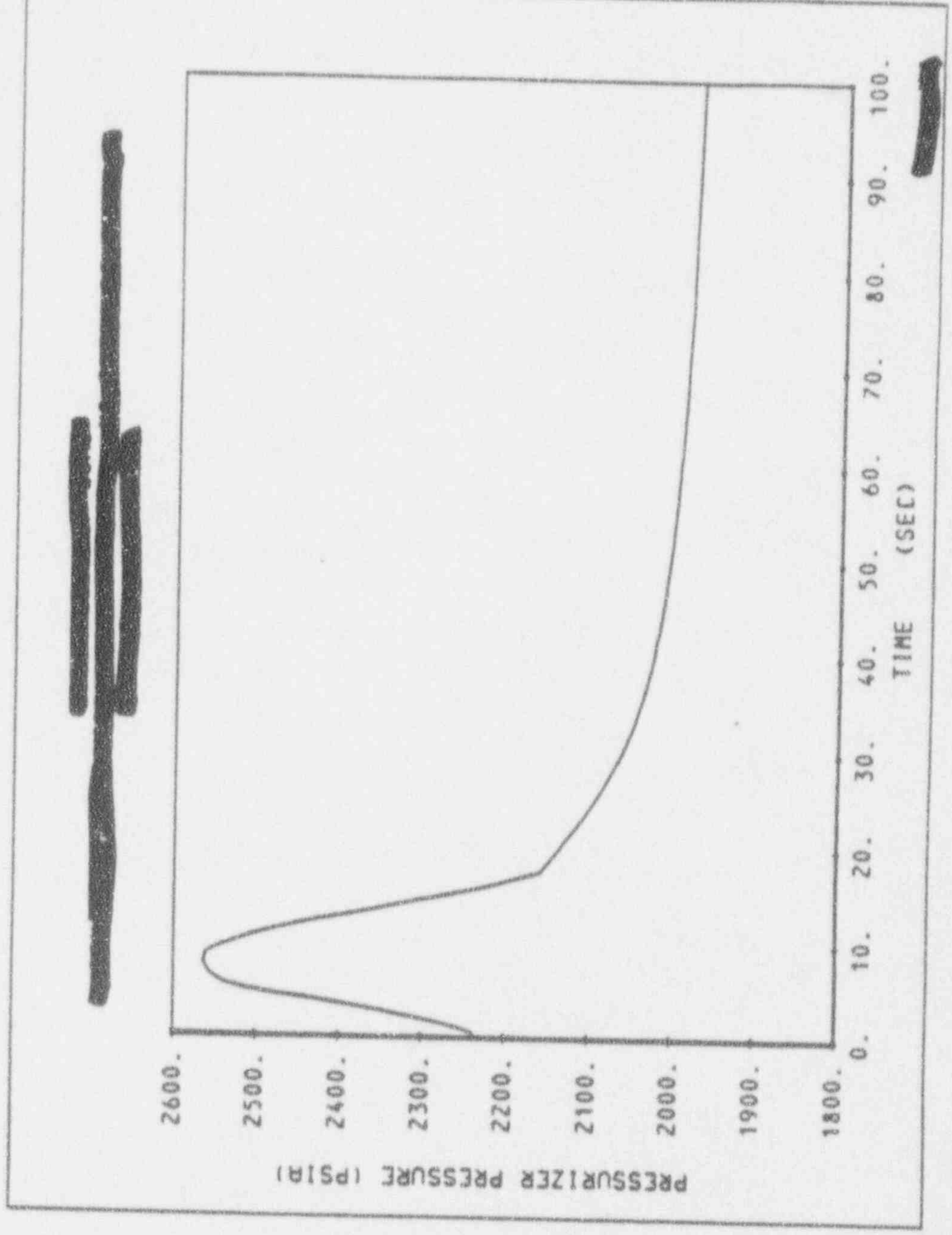


Figure 15.2-5

2 of 3

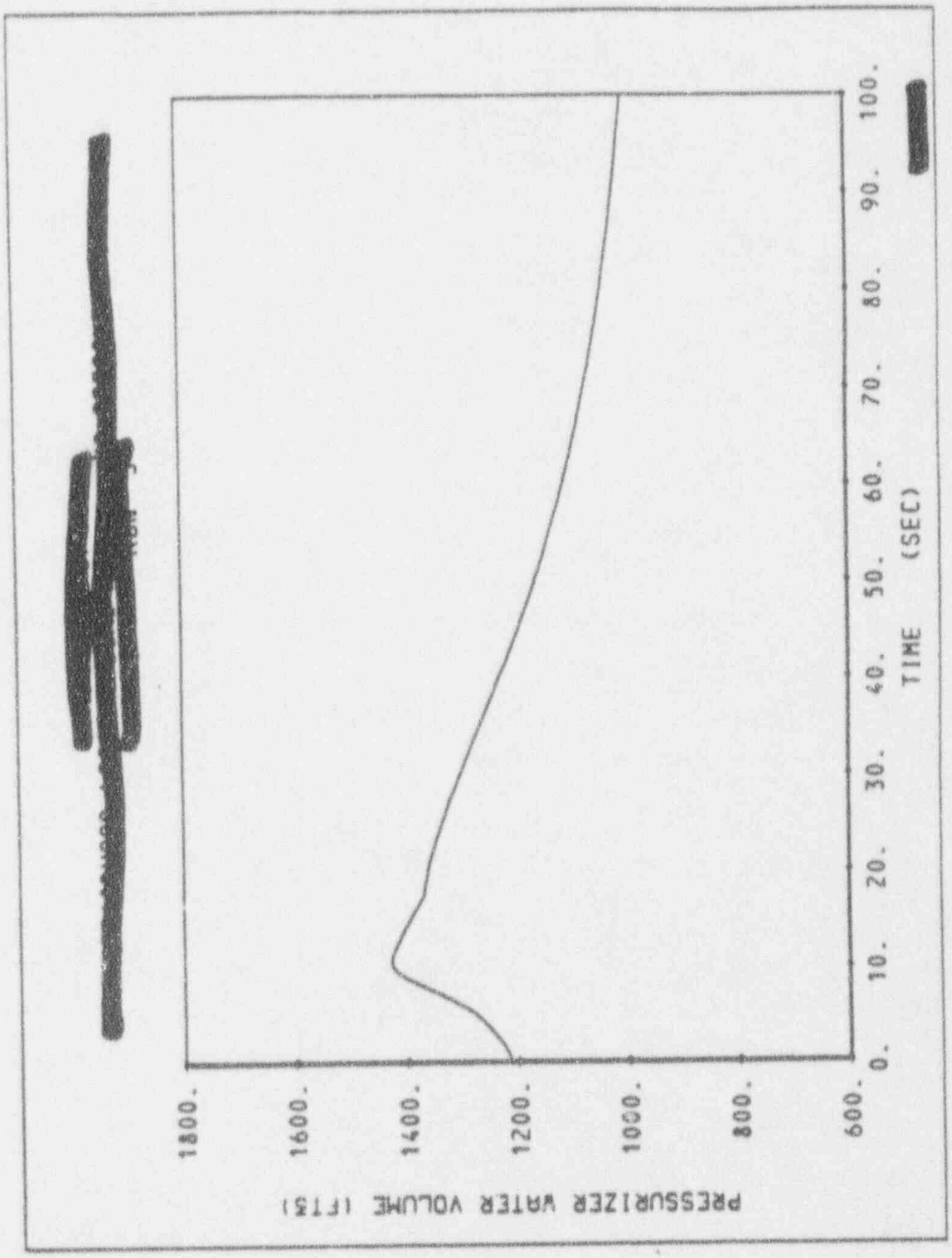


Figure 15.2-5

3 of 3

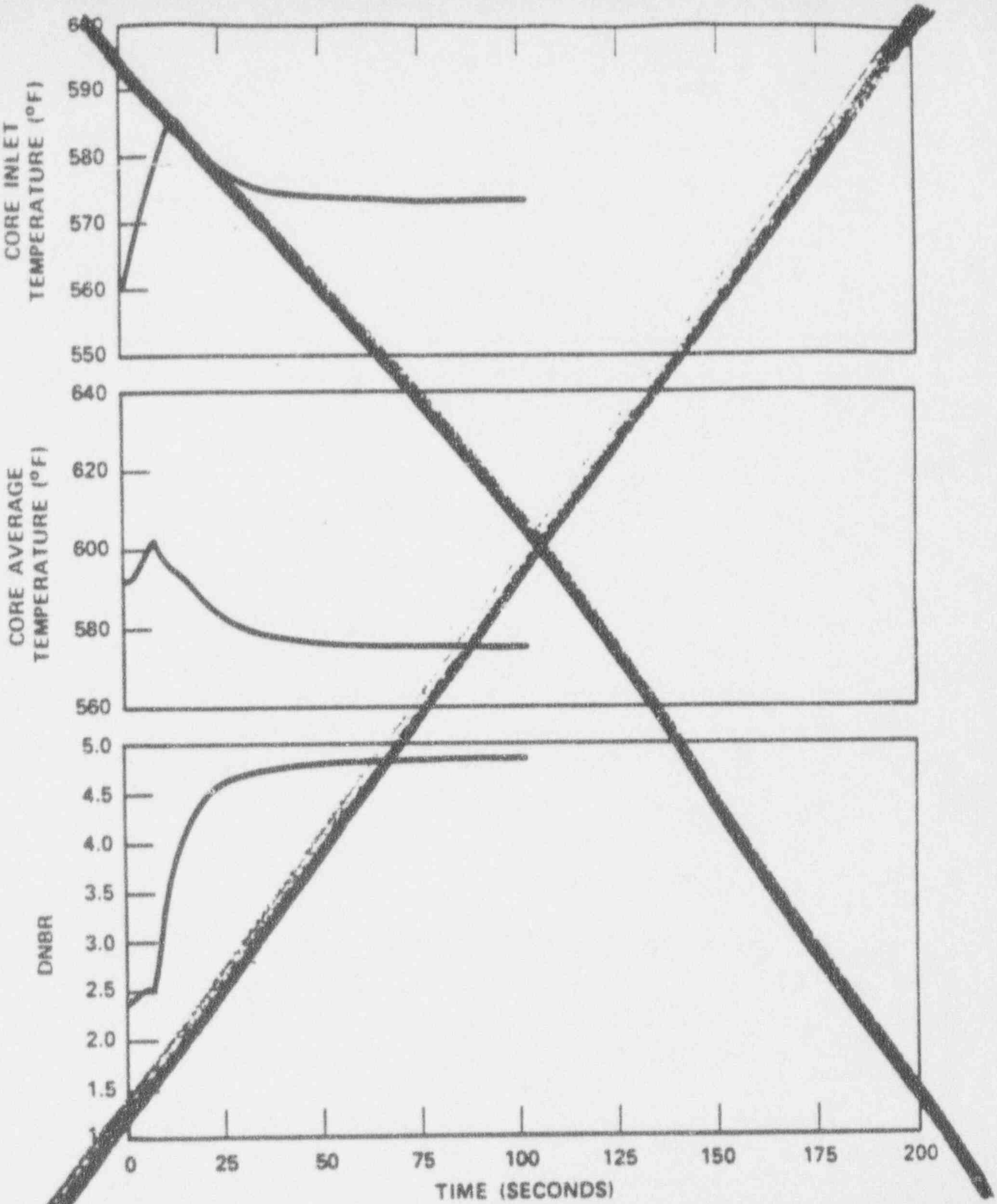


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FIGURE 15.2-6

TURBINE TRIP EVENT WITHOUT PRESSURIZER SPRAY AND POWER-OPERATED RELIEF VALVES, MINIMUM REACTIVITY FEEDBACK

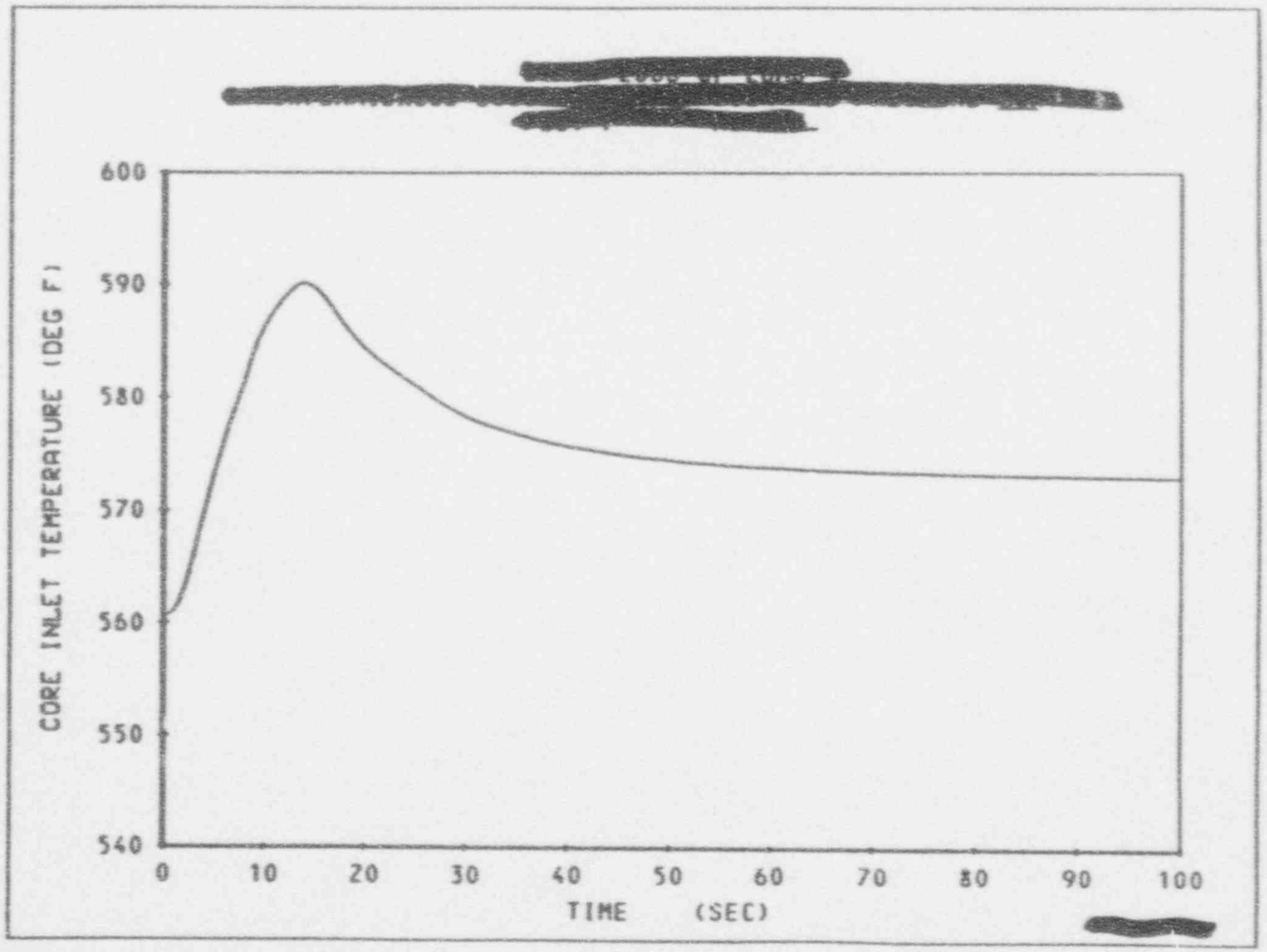



Figure 15.2-6

1 of 3

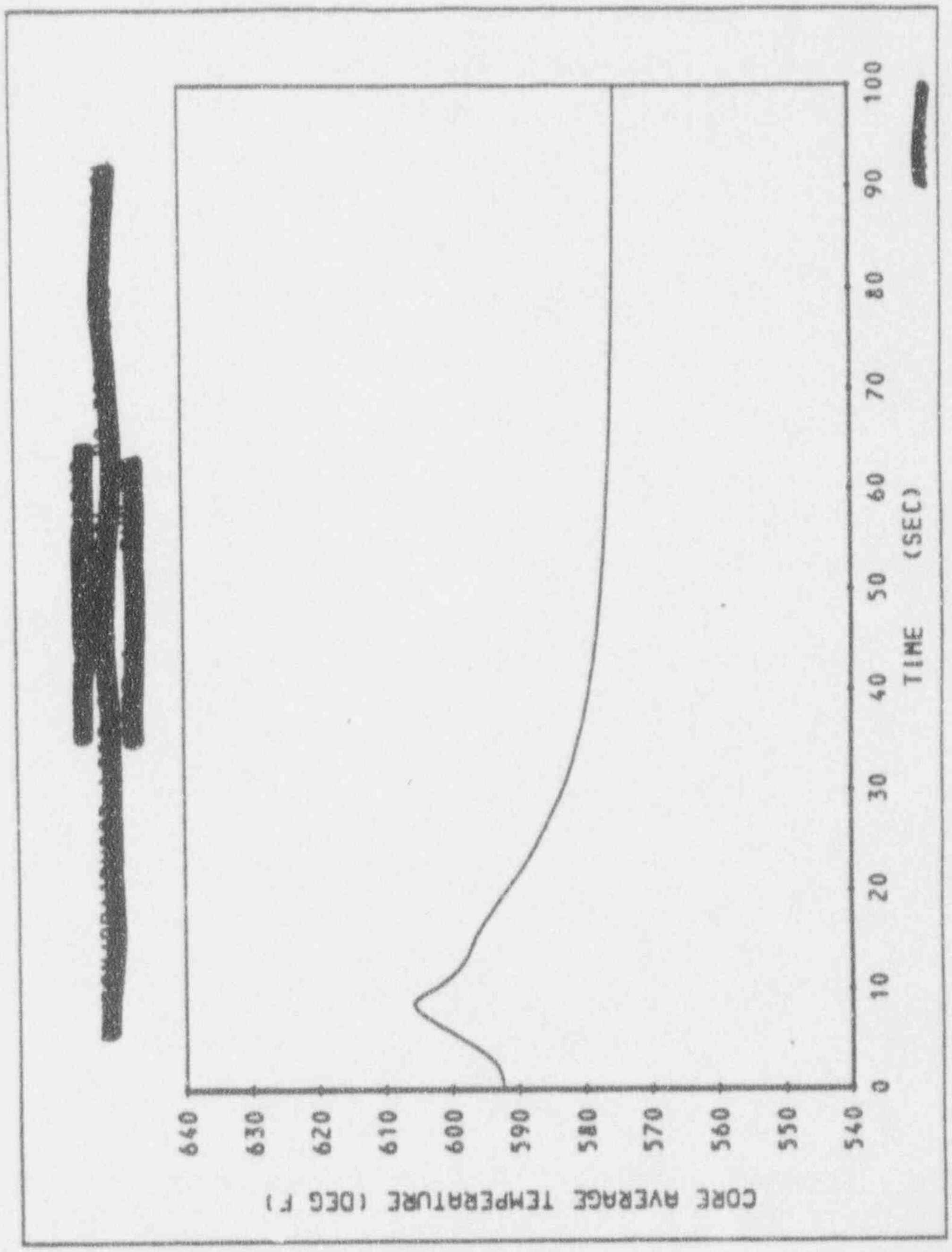
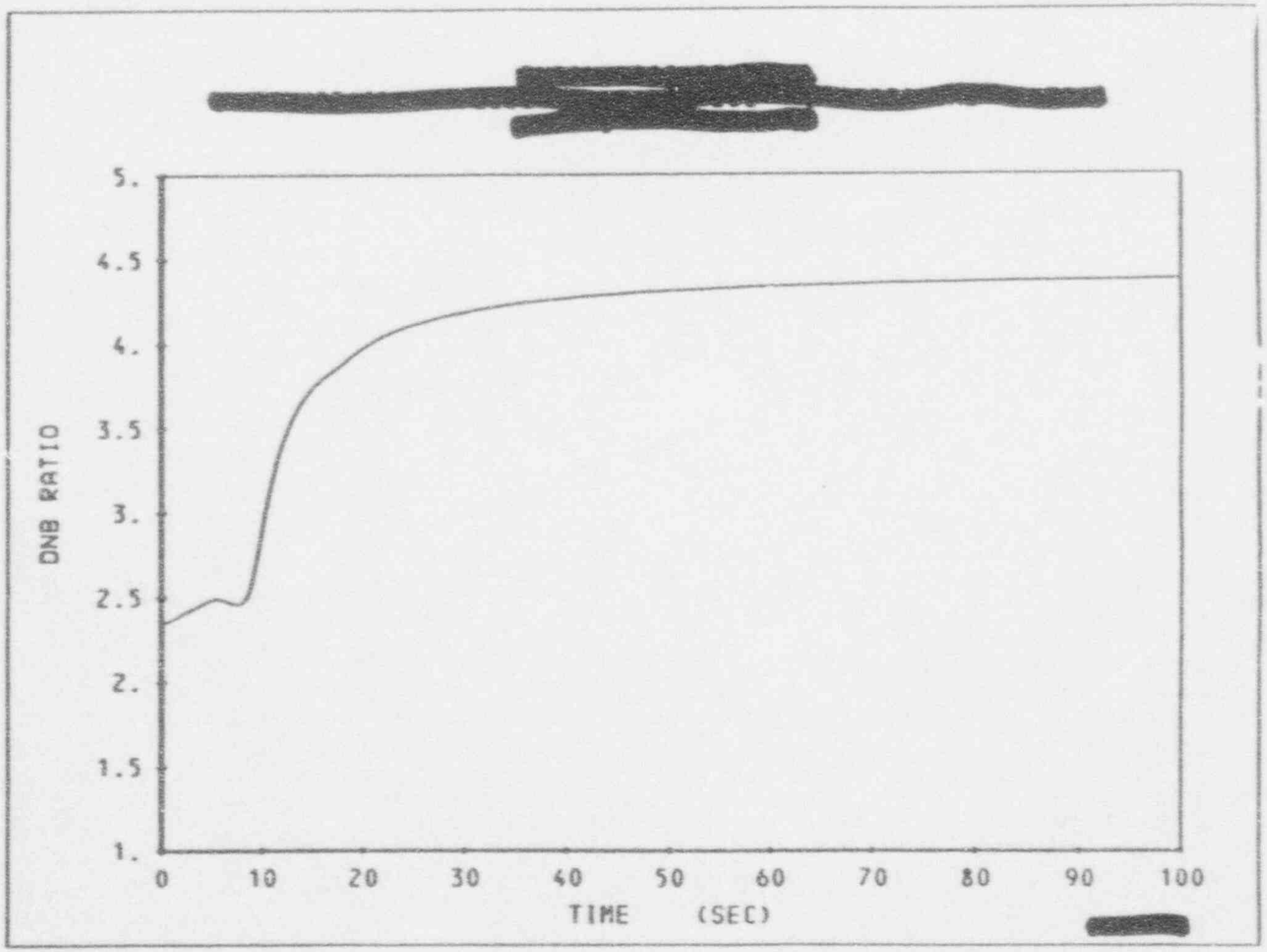



Figure 15.2-6

2 of 3

Figure 15.2-6
3 of 3



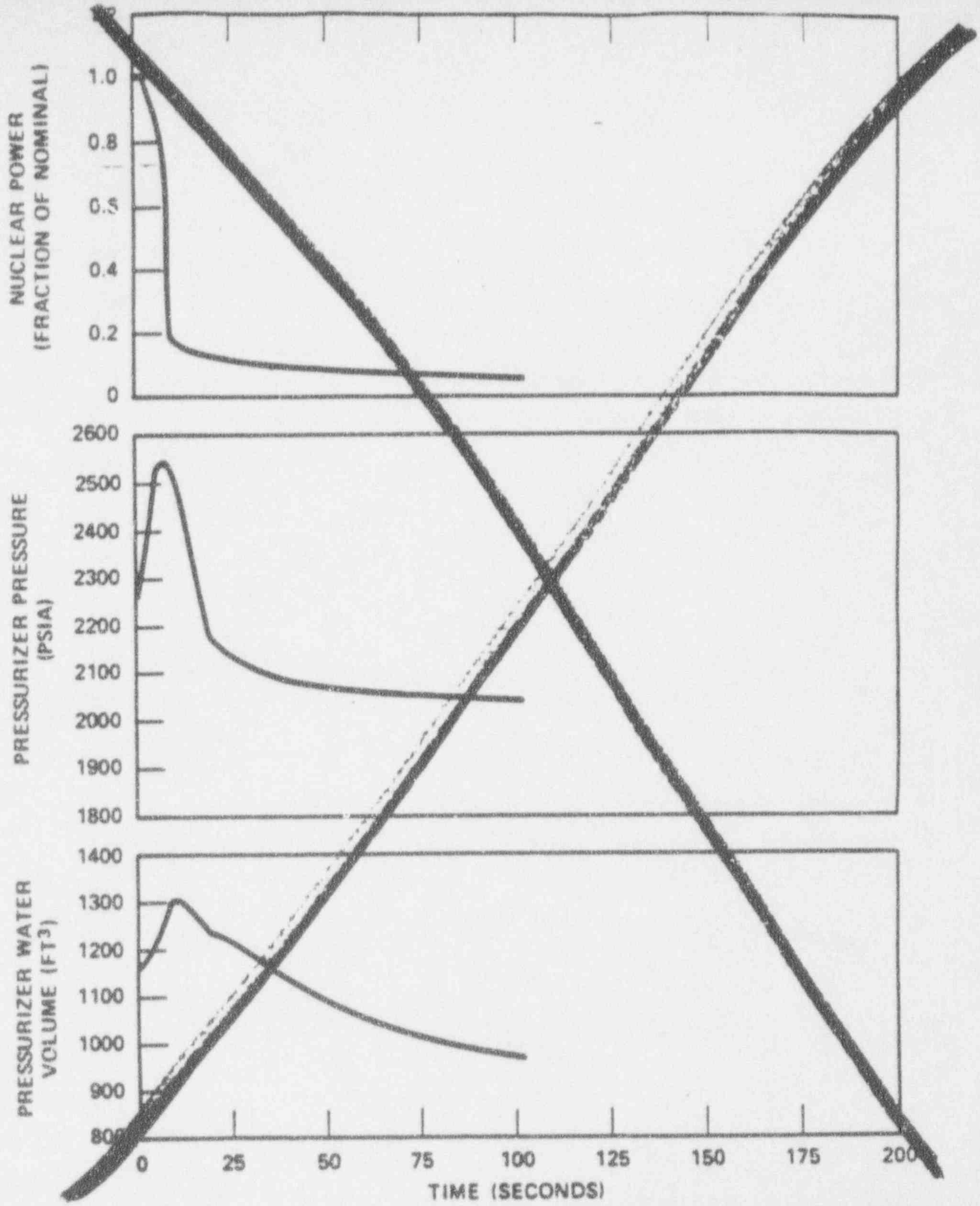



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FIGURE 15.2-7

TURBINE TRIP EVENT WITHOUT PRESSURIZER SPRAY AND POWER-OPERATED RELIEF VALVES. MAXIMUM REACTIVITY FEEDBACK

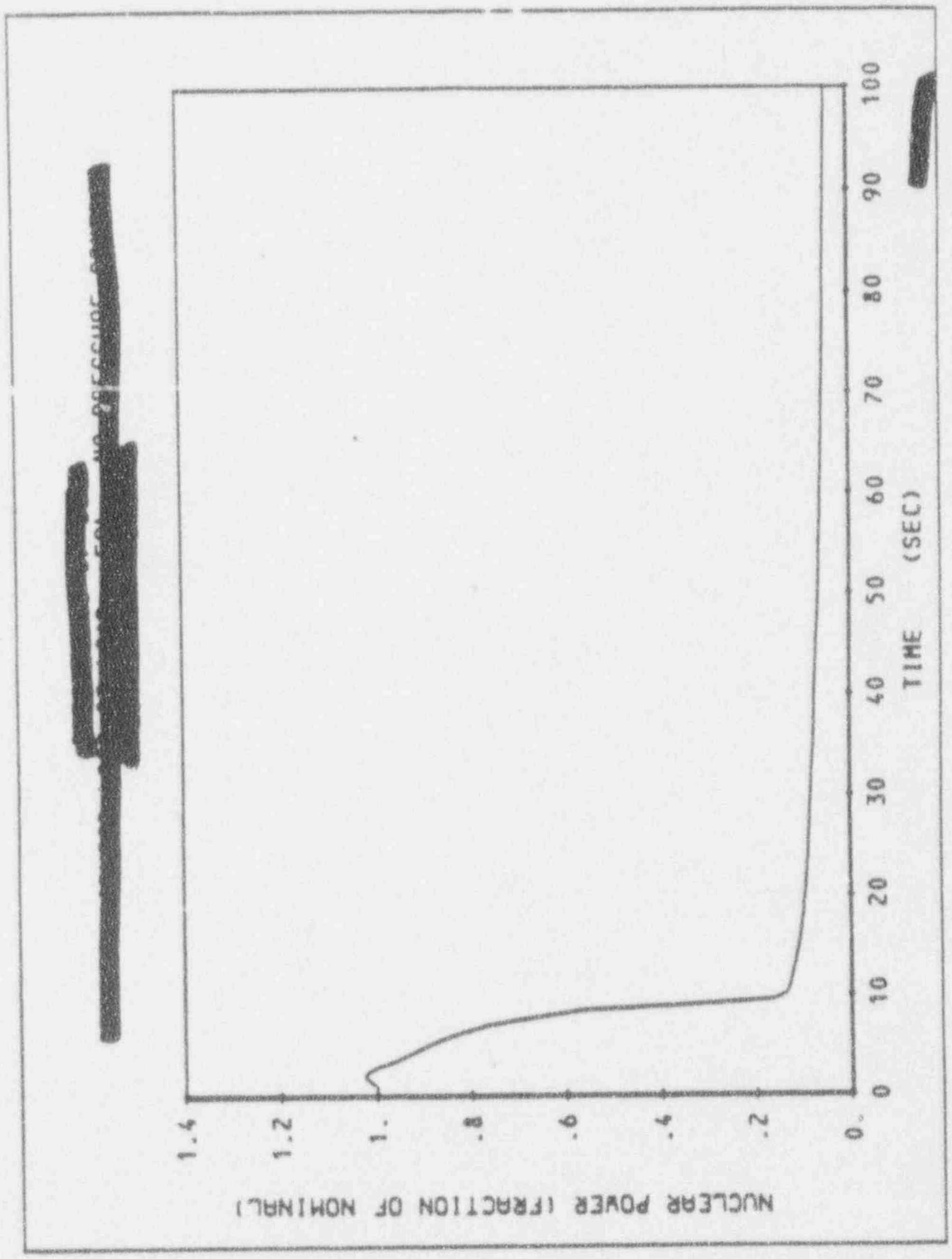
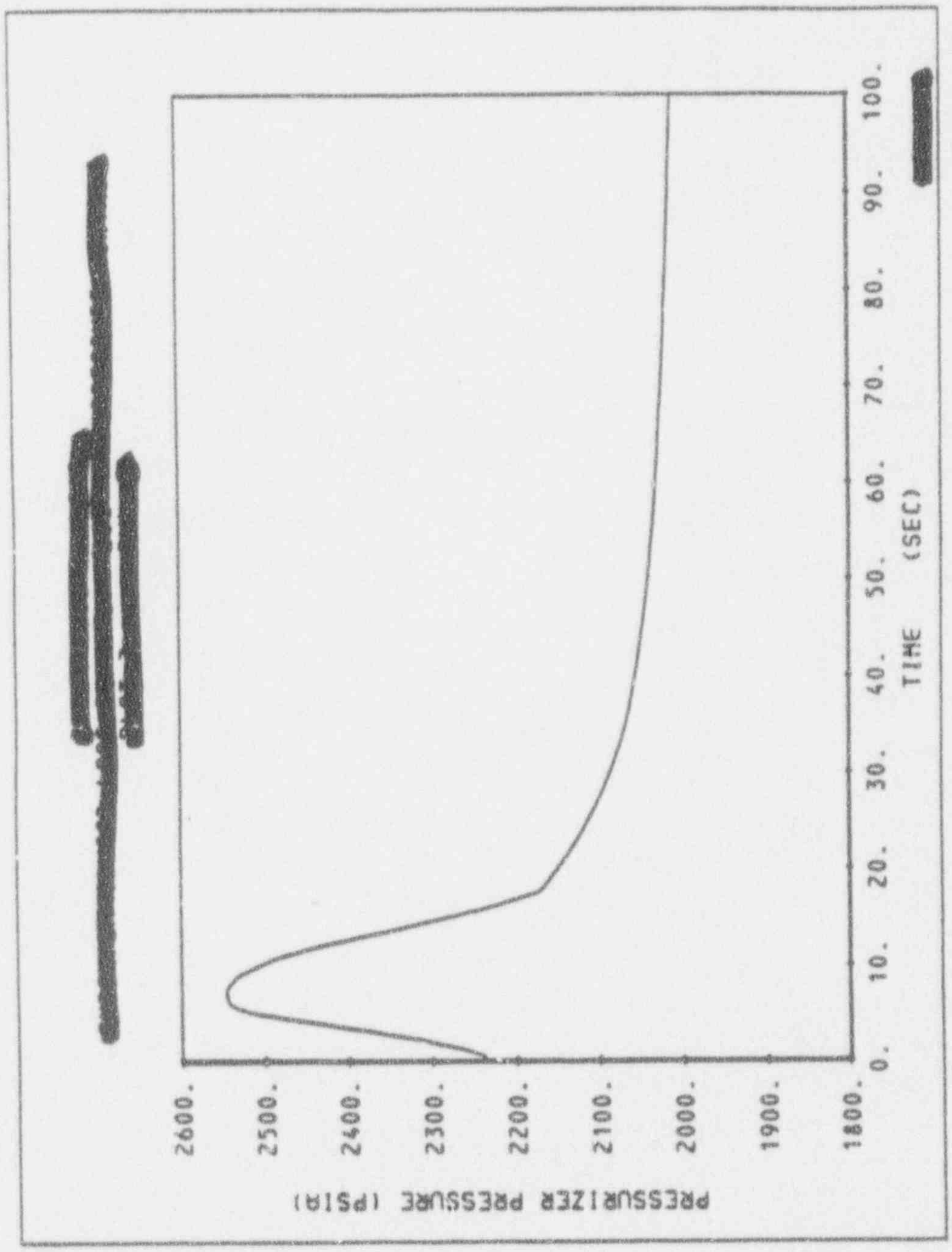



Figure 15.2-7

1 of 3

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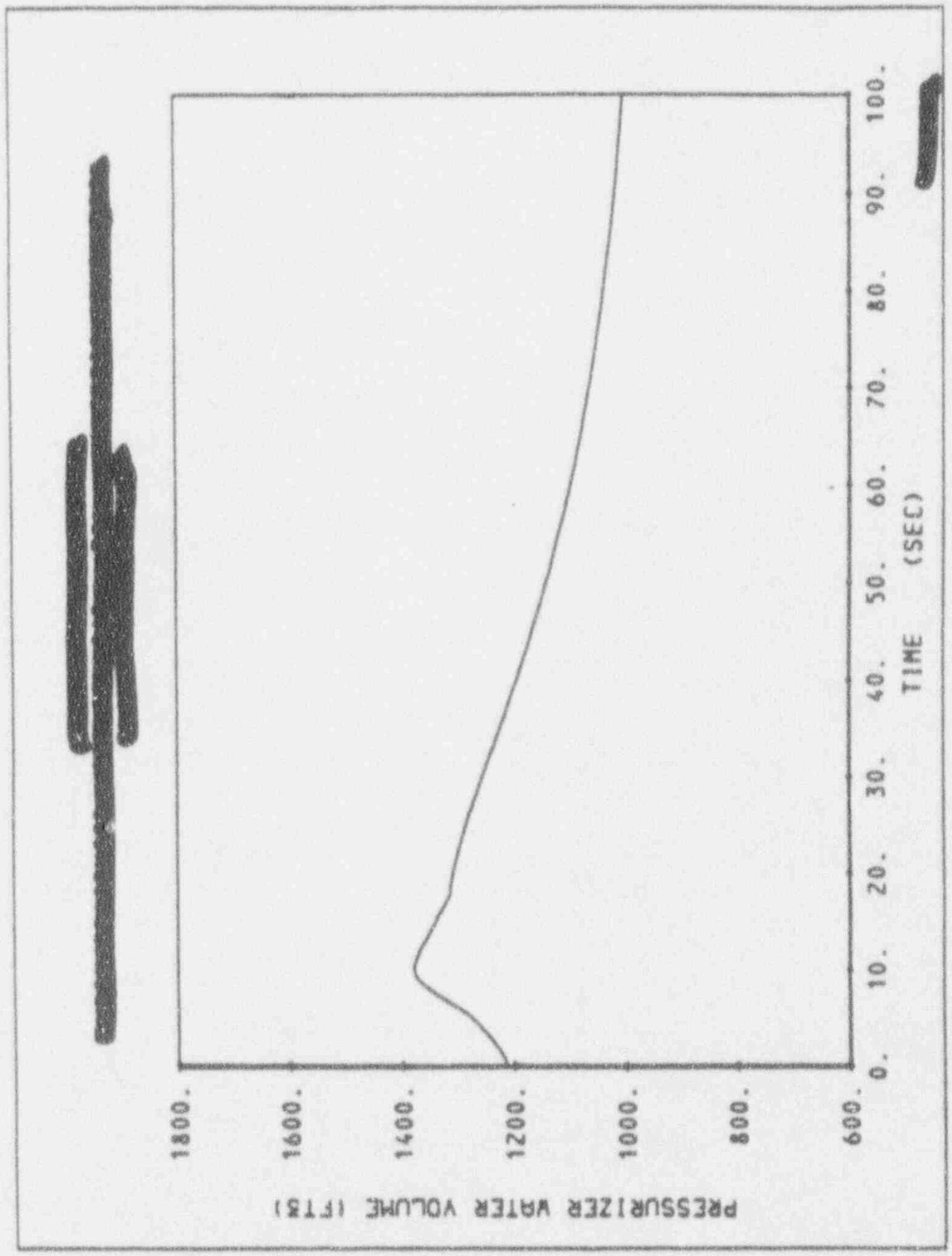
2 of 3

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3 of 3

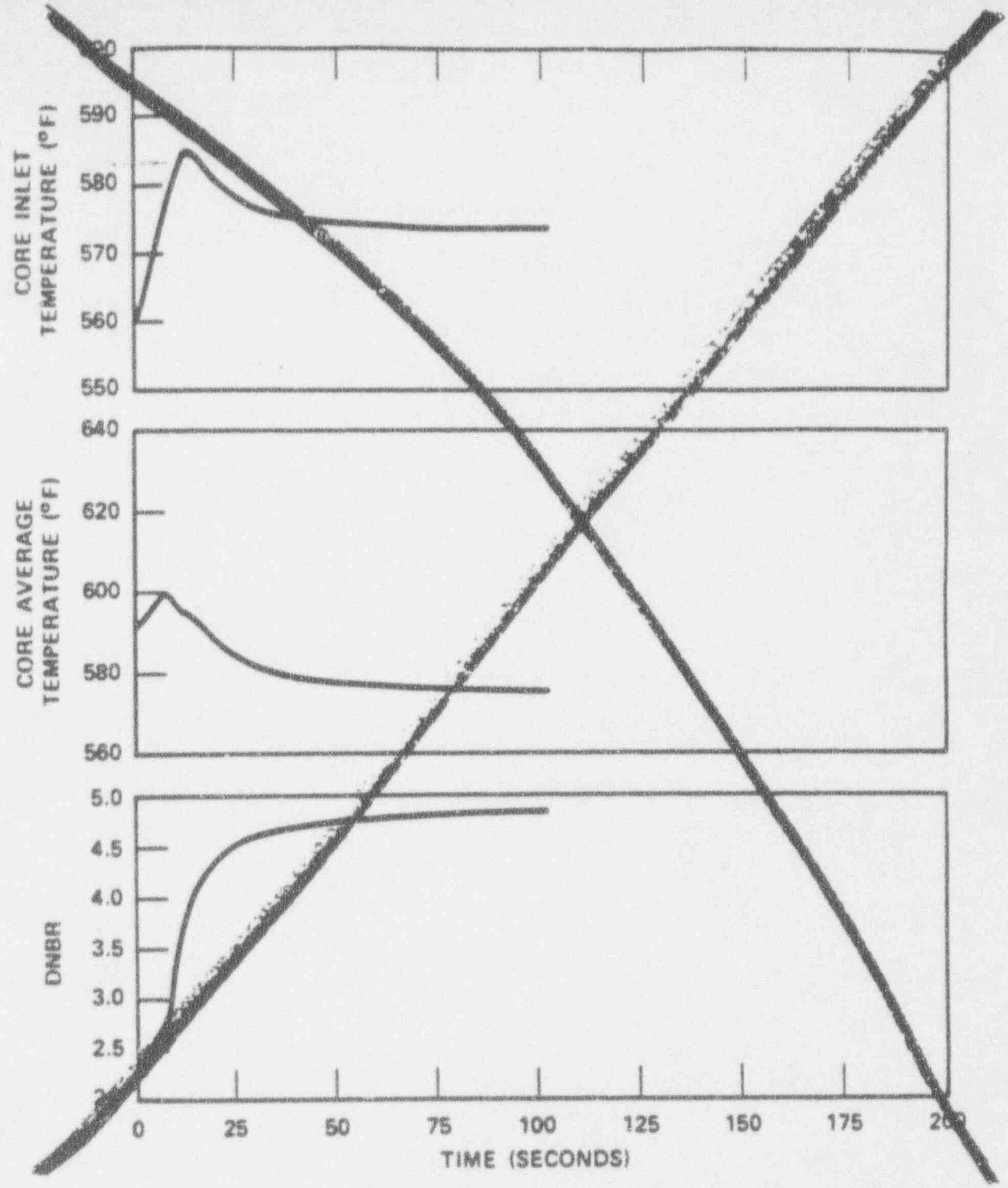


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FIGURE 15.2-8

TURBINE TRIP EVENT WITHOUT PRESSURIZER SPRAY AND POWER-OPERATED RELIEF VALVES, MAXIMUM REACTIVITY FEEDBACK

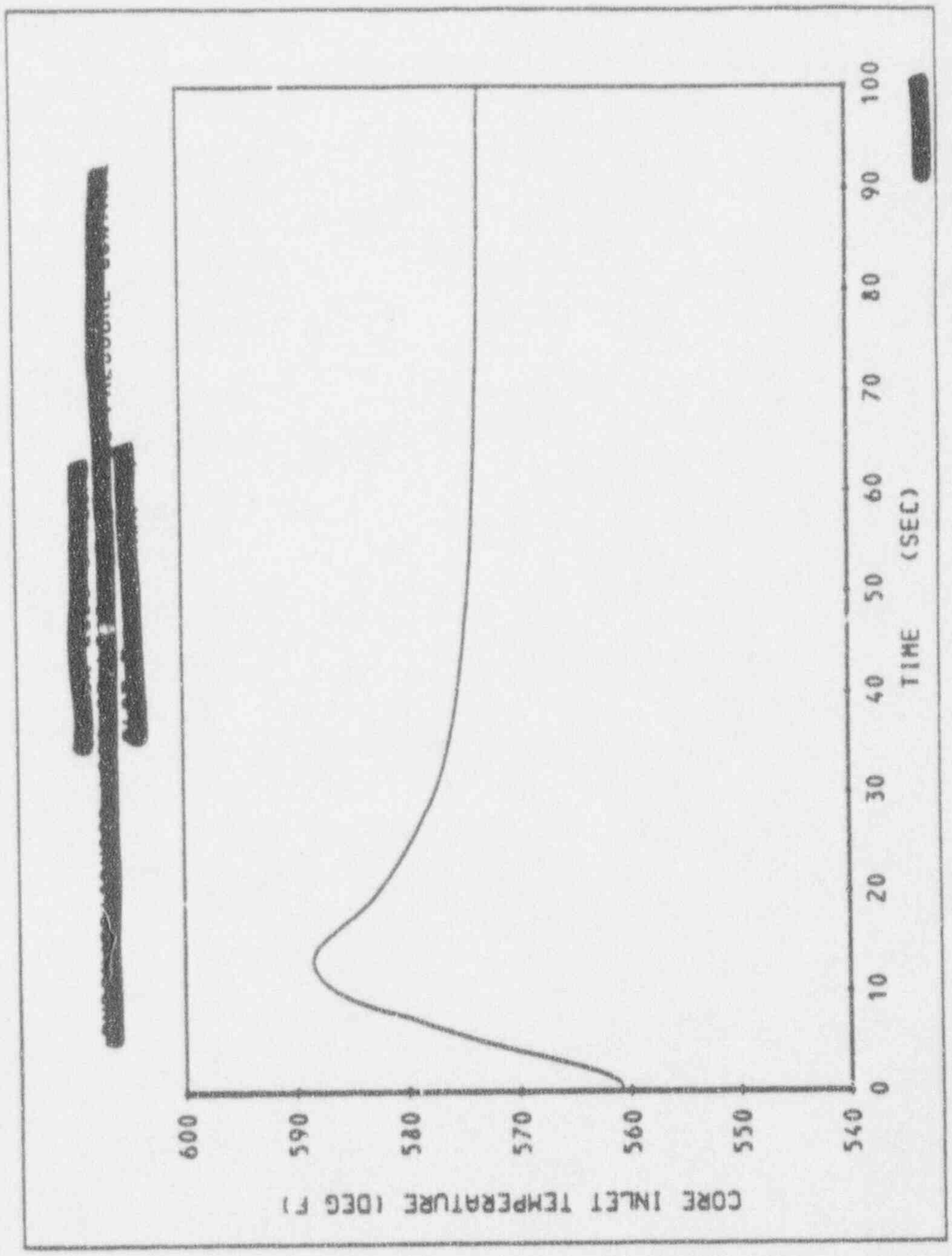


Figure 15.2-8
1 of 3

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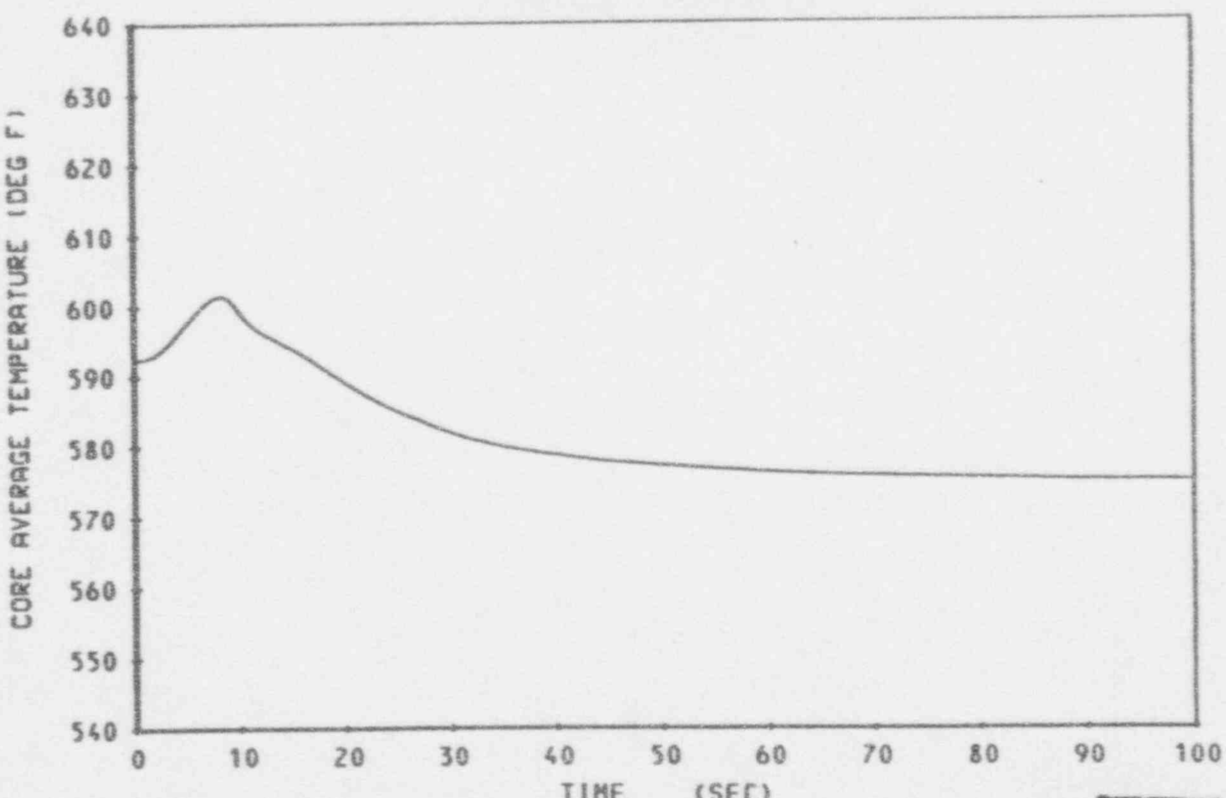


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Figure 15.2.8

2 of 3

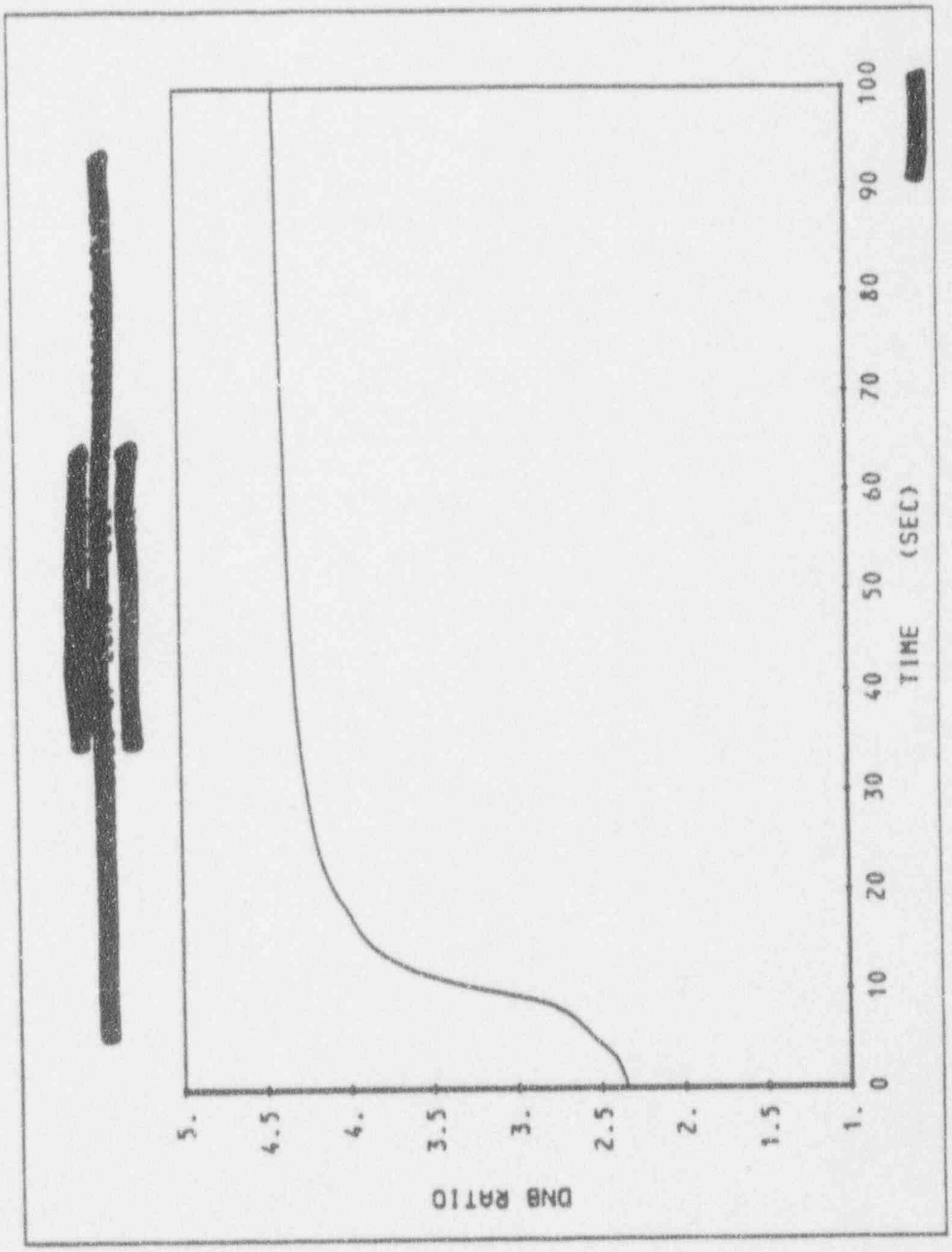


Figure 15.2-8
3 of 3

# APPENDIX C

# SIGNIFICANT HAZARDS EVALUATION

SIGNIFICANT HAZARDS EVALUATION
BYRON/BRAIDWOOD MSSV LIFT SETPOINT TOLERANCE
TECHNICAL SPECIFICATION CHANGE

INTRODUCTION:

Pursuant to 10CFR50.92, each application for amendment to an operating license must be reviewed to determine if the proposed change involves a significant hazards consideration. The Commission has provided standards for determining whether a significant hazards consideration exists (10CFR50.92(c)]. A proposed amendment to an operating license for a facility involves no significant hazards consideration if operation of the facility in accordance with the proposed amendment would not: 1) involve a significant increase in the probability or consequences of an accident previously evaluated, or 2) create the possibility of a new or different kind of accident from any accident previously evaluated, or 3) involve a significant reduction in a margin of safety.

DESCRIPTION OF AMENDMENT REQUEST:

The purpose of this amendment request is to revise Technical Specification Section 3/4.7 to relax the main steam safety valve (MSSV) lift setpoint tolerance from ±1% to ±3%. The currently specified tolerance of ±1% of the setpoint has been difficult to meet when the valves are tested. Commonwealth Edison Company (CECo) has found that over an operating cycle, the setpoint of the MSSVs changes by more than 1% from the original set-pressure. As a result, the plant is placed in an ACTION statement and must take immediate steps to avoid a violation.

The ASME Code requires that the valves lift within 1% of the specified setpoint (NB-7512.2). The code also states that the valves must attain rated lift (i.e., full flow) within 3% of the specified setpoint (NB-7512.1). This evaluation will form the basis for taking exception to the ASME Code with respect to the lift setpoint tolerances. As defined in NB-7512.2, exceptions can be made to the code providing the effects are accounted for in the accident analyses, specifically, the Overpressure Protection Report.

BASIS FOR NO SIGNIFICANT HAZARDS DETERMINATION:

The effects of increasing the as-found lift setpoint tolerance on the main steam safety valve have been examined, and it has been determined that, with one exception, the current accident analyses as presented in the UFSAR remain valid. The loss of load/turbine trip event was analyzed in order to quantify the impact of the setpoint tolerance relaxation. As previously demonstrated in this evaluation, all applicable acceptance criteria for this event have been satisfied and the conclusions presented in the UFSAR are still valid. Thus, the proposed Technical Specification change does not constitute an unreviewed safety question, and the non-LOCA accident analyses, as presented in the report, support the proposed change.

The effect of a increase in the allowable Main Steam Safety Valve set pressure tolerance from +1% to +3% on the FSAR LOCA analysis has been evaluated. In each case the applicable regulatory or design limit was satisfied. Specific analyses were performed for small break LOCA assuming the current MSSV Technical Specification set pressures plus the proposed additional 3% uncertainty. The calculated peak cladding temperatures were well below the 10CFR50.46 2200$^{O}$F limit.

Neither the mass and energy release to the containment following a postulated loss of coolant accident (LOCA), nor the containment response following the LOCA analysis, credit the MSSV in mitigating the consequences of an accident. Therefore, changing the MSSV lift setpoint tolerances would have no impact on the containment integrity analysis. In additon, based on the conclusion of the transient analysis, the change to the MSSV tolerance will not affect the calculated steamline break mass and energy releases inside containment.

The proposed change has been evaluated in accordance with the Significant Hazards criteria of 10CFR50.92. The results of the evaluation demonstrate that the change does not involve any significant hazards as described below.

1. A significant increase in the probability or consequences of an accident previously evaluated.

   Relaxation of the MSSV setpoint tolerance from $\pm$1% to $\pm$3% does not increase the probability or consequences of an accident previously evaluated. Component and system performance will not be adversely affected since equipment and system design criteria continue to be met. The MSSVs do not initiate any accident discussed in the FSAR. Neither the mass and energy release to the containment following a postulated loss of coolant accident (LOCA), nor the containment response following the LOCA analysis, credit the MSSV in mitigating the consequences of an accident. Therefore, changing the MSSV lift setpoint tolerances would have no impact on the consequences of an accident.

2. Create the possibility of a new or different kind of accident from any accident previously evaluated.

   The possibility for an accident or malfunction of a different type than evaluated previously in the safety analysis report is not created. Increasing the lift setpoint tolerance on the MSSVs does not introduce a new accident initiator mechanism. No new failure modes have been defined for any system or component important to safety nor has any new limiting single failure been identified.

3. Involve a significant reduction in a margin of safety.

   The margin of safety as defined in the basis of the Technical Specifications is not significantly reduced by the change in the MSSV lift setpoint tolerance. All acceptance criteria with respect to fuel, RCS pressure boundary, and containment integrity continue to be met.

# APPENDIX D

## MARKED UP TECHNICAL SPECIFICATION SECTIONS

## TABLE 3.7-2

## STEAM LINE SAFETY VALVES PER LOOP

| VALVE NUMBER | LIFT SETTING (±~~1~~3%)* # | ORIFICE SIZE |
|---|---|---|
| MS013(A-D) | 1235 psig | 16 $in^2$ |
| MS014(A-D) | 1220 psig | 16 $in^2$ |
| MS015(A-D) | 1205 psig | 16 $in^2$ |
| MS016(A-D) | 1190 psig | 16 $in^2$ |
| MS017(A-D) | 1175 psig | 16 $in^2$ |

*The lift setting pressure shall correspond to ambient conditions of the valve at nominal operating temperature and pressure.

# All tested valves shall be set to ±1% tolerance.

TABLE 3.7-2

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*The lift setting pressure shall correspond to ambient conditions of the valve at nominal operating temperature and pressure.

# ALL TESTED VALVES SHALL BE SET TO ± 1% tolerance.

## 3/4.7.1 TURBINE CYCLE

### 3/4.7.1.1 SAFETY VALVES

The OPERABILITY of the main steam line Code safety valves ensures that the Secondary Coolant System pressure will be limited to within 110% (1320 psia) of its design pressure of 1200 psia during the most severe anticipated system operational transient. The maximum relieving capacity is associated with a turbine trip from 102% RATED THERMAL POWER coincident with an assumed loss of condenser heat sink (i.e., no steam dumps to the condenser).

Add 'INSERT' Text here.

The specified valve lift settings and relieving capacities are in accordance with the requirements of Section III of the ASME Boiler and Pressure Code, 1971 Edition. The total relieving capacity for all valves on all of the steam lines is $17.958 \times 10^6$ lbs/h which is 119% of the total secondary steam flow of $15.135 \times 10^6$ lbs/h at 100% RATED THERMAL POWER. A minimum of two OPERABLE safety valves per steam generator ensures that sufficient relieving capacity is available for the allowable THERMAL POWER restriction in Table 3.7-1.

STARTUP and/or POWER OPERATION is allowable with safety valves inoperable within the limitations of the ACTION requirements on the basis of the reduction in Secondary Coolant System steam flow and THERMAL POWER required by the reduced Reactor trip settings of the Power Range Neutron Flux channels. The Reactor Trip Setpoint reductions are derived on the following bases:

For four loop operation:

$$SP = \frac{(X) - (Y)(V)}{X} \times (109).$$

Where:

SP = Reduced Reactor Trip Setpoint in percent of RATED THERMAL POWER,

V = Maximum number of inoperable safety valves per steam line,

## 3/4.7.1 TURBINE CYCLE

### 3/4.7.1.1 SAFETY VALVES

The OPERABILITY of the main steam line Code safety valves ensures that the Secondary Coolant System pressure will be limited to within 110% (1320 psia) of its design pressure of 1200 psia during the most severe anticipated system operational transient. The maximum relieving capacity is associated with a turbine trip from 102% RATED THERMAL POWER coincident with an assumed loss of condenser heat sink (i.e., no steam dumps to the condenser).

ADD 'INSERT' TEXT HERE

The specified valve lift settings and relieving capacities are in accordance with the requirements of Section III of the ASME Boiler and Pressure Code, 1971 Edition. The total relieving capacity for all valves on all of the steam lines is $17.958 \times 10^6$ lbs/h which is 119% of the total secondary steam flow of $15.135 \times 10^6$ lbs/h at 100% RATED THERMAL POWER. A minimum of two OPERABLE safety valves per steam generator ensures that sufficient relieving capacity is available for the allowable THERMAL POWER restriction in Table 3.7-1.

STARTUP and/or POWER OPERATION is allowable with safety valves inoperable within the limitations of the ACTION requirements on the basis of the reduction in Secondary Coolant System steam flow and THERMAL POWER required by the reduced Reactor trip settings of the Power Range Neutron Flux channels. The Reactor Trip Setpoint reductions are derived on the following bases:

For four loop operation:

$$SP = \frac{(X) - (Y)(V)}{X} \times (109).$$

Where:

SP = Reduced Reactor Trip Setpoint in percent of RATED THERMAL POWER,

V = Maximum number of inoperable safety valves per steam line,

## Insert

The Technical Specification requirement that Steam Line Safety Valves be set to within ±1% tolerance when found outside this range is consistent with Section XI of the ASME Boiler and Pressure Code. The specification that Steam Line Safety Valves may operate with setpoint tolerances to within ±3% is supported by "Commonwealth Edison Company, Byron & Braidwood Stations Units 1 & 2 Overpressure Protection Report."

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October 4, 1990
Project No. 8637-50
File Nos. 7.1, 7.5
(JGS-114)

Commonwealth Edison Company
Byron/Braidwood Stations Units 1 and 2
MAIN STEAM SAFETY VALVE SETPOINT
TOLERANCE INCREASE ANALYSIS
System Codes: AF, MS

Mr. R. E. Waninski
Nuclear Engineering Department
Commonwealth Edison Company
1400 Opus Place
Executive Towers West III, Suite 400
Downers Grove, Illinois 60515

Dear Mr. Waninski:

We recently completed a study to analyze a change in the Main Steam Safety Valve (1/2MS013A-D, 1/2MS014A-D, 1/2MS015A-D, 1/2MS016A-D, 1/2MS017A-D) setpoint tolerance as described in my June 25 and August 17, 1990, letters to you. The current system design is based on the setpoint tolerance per Technical Specification 3/4.7.1 of ±1%. The above referenced letters summarized the effect of a change in the positive tolerance to +3% on the Main Steam system piping, piping supports and piping penetrations and the Auxiliary Feedwater system capacity.

This letter is to confirm our recent conversation that a change in the negative tolerance to -3% does not affect the results of our previous analysis. The Main Steam system piping analysis and Auxiliary Feedwater system capacity design basis is not affected by a change in the negative tolerance. It should be noted however, that an increase in negative tolerance increases the potential for spurious valve openings.

If you have any questions concerning this matter, please feel free to contact either Mr. J. R. Meister at 312-269-6882 or me at 312-269-6708.

SARGENT & LUNDY
ENGINEERS
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Yours very truly,

J. G. Saltarelli

J. G. Saltarelli
Senior Mechanical Project
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August 17, 1990
Project No. 8637-50
File Nos. 7.1, 7.5
(JGS-110)

Commonwealth Edison Company
Byron/Braidwood Station Units 1 and 2
MAIN STEAM SAFETY VALVE SETPOINT
TOLERANCE INCREASE ANALYSIS
System Codes: AF, MS

Mr. R. E. Waninski
Commonwealth Edison Company
Nuclear Engineering Department
1400 Opus Place, Suite 400
Downers Grove, Illinois 60515

Dear Mr. Waninski:

We have completed the second phase of our study to analyze an increase in the Main Steam Safety Valve (1/2MS013A-D, 1/2MS014A-D, 1/2MS015A-D, 1/2MS016A-D, 1/2MS017A-D) setpoint tolerance as referenced in my June 25, 1990 letter to you. The current system design is based on the setpoint tolerance of ±1% as specified in Technical Specification 3/4.7.1. The affect on the Auxiliary Feedwater system capacity of the proposed change in positive tolerance to +3% was the second phase of our study.

The change in positive tolerance to +3% will result in an increase in the maximum steam generator pressure from 1225 psia, the current system design basis, to 1250 psia based on discussions with Westinghouse. The resultant affect of the increased steam generator pressure (1250 psia) on the Auxiliary Feedwater system capacity was evaluated for two limiting accident scenarios. In accordance with your request, AF system capacity was evaluated for the feedwater pipe rupture and loss of main feedwater (station blackout) accident scenarios at an unfaulted steam generator pressure of 1250 psia. The scenario results are summarized as follows:

<u>Feedwater Pipe Rupture</u>

- Three intact steam generators at 1250 psia
- One faulted steam generator at 14.7 psia
- One AF pump (motor driven) operating
- Resulting AF system flow to three intact steam generators is 458 gpm

Loss of Main Feedwater/Station Blackout

- Four intact steam generators at 1250 psia
- One AF pump (diesel driven) operating
- Resulting AF system flow to four intact steam generators is 763 gpm

The following listing summarizes the basis and assumptions utilized in the Auxiliary Feedwater system capacity evaluation:

- 1/2AF005A-H valves in full open position
- AF pump performance per vendor manual curves
- Condensate Storage Tank empty, water Elevation 399'-9" for Braidwood Station was utilized for conservatism
- Suction piping friction losses for Braidwood Station Unit 1, which has the highest calculated pressure drop of all four units, were utilized for conservatism.
- Discharge piping was modeled using Byron Unit 1 as-built piping isometrics. The physical differences between discharge piping at all four units will have a negligible affect on the calculated flow rates.
- Intact steam generator pressure was assumed to be 1250 psia as specified by Westinghouse and faulted pressure was conservatively assumed to be 14.7 psia.
- Pump discharge static head was based on pump centerline and a maximum intact steam generator water level of Elevation 448'-10½" which is the water level instrument upper tap centerline. A faulted steam generator water level of Elevation 439'-0", which corresponds to the upper steam generator nozzle elevation, was utilized.
- Piping frictional losses were conservatively calculated based on dirty (old) steel pipe with an absolute roughness of 0.036".
- A conservative pump recirculation flow rate of 100 gpm was assumed.

In conclusion the above results completes our evaluation of the Main Steam Safety Valve setpoint tolerance increase. We also request that you confirm with Westinghouse that the containment mass/energy release rates are not affected by the increased setpoint tolerance.

If you have any questions concerning this matter or require any additional flow scenario evaluations, please feel free to contact either Mr. J. R. Meister at 312-269-6882 or me at 312-269-6708.

Yours very truly,

J. G. Saltarelli

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Senior Mechanical Project
Engineer

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June 25, 1990
Project No. 8637-50
File Nos. 7.1, 7.5
(JGS-104)

Commonwealth Edison Company
Byron/Braidwood Stations Units 1 and 2
MAIN STEAM SAFETY VALVE SETPOINT
TOLERANCE INCREASE ANALYSIS
System Codes: AF, MS

Mr. R. E. Waninski
Commonwealth Edison Company
Nuclear Engineering Department
1400 Opus Place, Suite 400
Downers Grove, Illinois 60515

Dear Mr. Waninski:

We have recently completed the initial phase of our study to analyze a change in the Main Steam Safety Valve (1/2MS013A-D, 1/2MS014A-D, 1/2MS015A-D, 1/2MS016A-D, 1/2MS017A-D) setpoint tolerance. The current system design is based on the setpoint tolerance per Technical Specification 3/4.7.1 of ±1%. We are currently reviewing the affect of a change in the positive tolerance to +3%.

Our initial phase of the analysis was to evaluate the Main Steam piping due to the higher pressure at the maximum safety valve setpoint including positive tolerance. Piping, piping supports and piping penetrations associated with subsystems 1/2 MS01 were evaluated. Specifically the main steam piping from the MSIV to containment penetration and the safety valve vent lines were analyzed in detail. The analysis concluded that the existing system configuration can accommodate a change in the main steam safety valve tolerance to +3% without any modification.

The second phase of our evaluation is the affect of the tolerance increase on the Auxiliary Feedwater system capacity. This evaluation is currently ongoing and preliminary results are expected by July 2, 1990.

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If you have any questions concerning this matter, please feel free to contact either Mr. J. R. Meister at 312-269-6882 or me at 312-269-6708.

Yours very truly,

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JGS1/JGS104.wp

FDS
R22

April 25, 1990
RSA:90-039

Mr. E. D. Swartz

Subject: B/B Main Steam Safety Valve Setpoint Change Evaluation with respect to SGTR analysis

Reference: Letter to W. Naughton from C. A. Moerke dated March 13, 1990

Per PWR Systems request (Reference), NFS has evauated the proposal to relax the MSSV setpoints to ±3% as found and reset to ±1% on the results of the B/B SGTR Rev. 1 analysis. NFS has determined there would be no impact on SGTR. It did not decrease or increase either margin to overfill case results or offsite dose case results. The maximum pressure in the ruptured steam generators for both licensing cases never reached the lift setpoint corresponding to the lowest set MSSV with a -3% drift. Lift setpoints higher than nominal likewise have no impact on the results of either SGTR case.

As found setpoints would have to drift to 1111 psig to impact the SGTR results. At this lift pressure the MSSV would impact the margin to overfill case. Lift at 1111 psig represents a -5.4% drift. More significant impact would result from a drift below 1086.6 psig, especially for the offsite dose case. Additional radionuclides would be released increasing the offsite dose with this -8.7% drift on the lowest set MSSV.

Please note that the SGTR analysis of record was performed by Westinghouse as documented in the FSAR. A SGTR analysis performed by NFS was submitted to the NRC in August of 1988. In April of 1990, NFS provided a Revision 1 to the SGTR analysis, which superceded the previous report. It is not known when the staff will complete its review and issue an SER. Currently, NFS has not received any staff questions concerning SGTR analyses. Therefore, NFS recommends that the new MSSV setpoint tolerances also be evaluated against the SGTR analysis of record in order that no delays will be experienced in their implementation.

FGL

If you have any questions or comments, contact John Freeman at ext. 3856, General Office.

Kenneth N. Kovar

Kenneth N. Kovar
Safety Analysis Supervisor
Nuclear Fuel Services

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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

JUNE 1981


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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 valves setpoints where steam release through safety valves limits secondary steam pressure ~~at the setpoint value~~. to less than 110% of the design 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

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 $\Delta T$, 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.