15.1 Increase in Heat Removal From the Primary System

A number of events that could result in an increase in heat removal from the reactor coolant system are postulated. Detailed analyses are presented for the events that have been identified as limiting cases.

Discussions of the following reactor coolant system cooldown events are presented in this section:

- Feedwater system malfunctions causing a reduction in feedwater temperature
- Feedwater system malfunctions causing an increase in feedwater flow
- Excessive increase in secondary steam flow
- Inadvertent opening of a steam generator relief or safety valve
- Steam system piping failure
- Inadvertent operation of the passive residual heat removal (PRHR) heat exchanger

The preceding events are Condition II events, with the exception of small steam system piping failures, which are considered to be Condition III, and large steam system piping failure Condition IV events. Subsection 15.0.1 contains a discussion of classifications and applicable criteria.

The accidents in this section are analyzed. The most severe radiological consequences result from the main steam line break accident discussed in subsection 15.1.5. The radiological consequences are reported only for that limiting case.

15.1.1 Feedwater System Malfunctions that Result in a Decrease in Feedwater Temperature

15.1.1.1 Identification of Causes and Accident Description

Reductions in feedwater temperature cause an increase in core power by decreasing reactor coolant temperature. Such transients are attenuated by the thermal capacity of the secondary plant and of the reactor coolant system. The overpower/overtemperature protection (neutron overpower, overtemperature, and overpower ΔT trips) prevents a power increase that could lead to a departure from nucleate boiling ratio (DNBR) that is less than the design limit values.

A reduction in feedwater temperature may be caused by a low-pressure heater train or a high-pressure heater train out of service or bypassed. At power, this increased subcooling creates an increased load demand on the reactor coolant system.

With the plant at no-load conditions, the addition of cold feedwater may cause a decrease in reactor coolant system temperature and a reactivity insertion due to the effects of the negative moderator coefficient of reactivity. However, the rate of energy change is reduced as load and feedwater flows decrease, so the no-load transient is less severe than the full-power case. The net effect on the reactor coolant system due to a reduction in feedwater temperature is similar to the effect of increasing secondary steam flow; that is, the reactor reaches a new equilibrium condition at a power level corresponding to the new steam generator ΔT.

A decrease in normal feedwater temperature is classified as a Condition II event, an incident of moderate frequency.

The protection available to mitigate the consequences of a decrease in feedwater temperature is the same as that for an excessive steam flow increase, as discussed in subsection 15.0.8 and listed in Table 15.0-6.

15.1.1.2 Analysis of Effects and Consequences

15.1.1.2.1 Method of Analysis

This transient is analyzed by calculating conditions at the feedwater pump inlet following the removal of a low-pressure feedwater heater train from service. These feedwater conditions are then used to recalculate a heat balance through the high-pressure heaters. This heat balance gives the new feedwater conditions at the steam generator inlet.

The following assumptions are made:

- Initial plant power level corresponding to 100-percent nuclear steam supply system thermal output.
- The worst single failure in the pre-heating section of the Main Feedwater System, resulting in the maximum reduction in feedwater temperature, occurs.

Plant characteristics and initial conditions are further discussed in subsection 15.0.3.

15.1.1.2.2 Results

A fault in the feedwater heaters section of the Feedwater System causes a reduction in feedwater temperature that increases the thermal load on the primary system. The maximum reduction in feedwater temperature, due to a single failure in the feedwater system, is lower than 71.5°F. This reduction results in an increase in heat load on the primary system of less than 10-percent full power.

15.1.1.3 Conclusions

The decrease in feedwater temperature transient is less severe than the increase in feedwater flow event or the increase in secondary steam flow event (see subsections 15.1.2 and 15.1.3). Based on the results presented in subsections 15.1.2 and 15.1.3, the applicable Standard Review Plan subsection 15.1.1 evaluation criteria for the decrease in feedwater temperature event are met.

15.1.2 Feedwater System Malfunctions that Result in an Increase in Feedwater Flow

15.1.2.1 Identification of Causes and Accident Description

Addition of excessive feedwater causes an increase in core power by decreasing reactor coolant temperature. Such transients are attenuated by the thermal capacity of the secondary plant and the reactor coolant system. The overpower/overtemperature protection (neutron overpower, overtemperature, and overpower ΔT trips) prevents a power increase that leads to a DNBR less than the safety analysis limit value.

An example of excessive feedwater flow is a full opening of a feedwater control valve due to a feedwater control system malfunction or an operator error. At power, this excess flow causes an increased load demand on the reactor coolant system due to increased subcooling in the steam generator.

With the plant at no-load conditions, the addition of cold feedwater may cause a decrease in reactor coolant system temperature and a reactivity insertion due to the effects of the negative moderator coefficient of reactivity.

Continuous addition of excessive feedwater is prevented by the steam generator high-2 water level signal trip, which closes the feedwater isolation valves and feedwater control valves and trips the turbine, main feedwater pumps, and reactor.

An increase in normal feedwater flow is classified as a Condition II event, fault of moderate frequency.

Plant systems and equipment available to mitigate the effects of the accident are discussed in subsection 15.0.8 and listed in Table 15.0-6.

In meeting the requirements of GDC 17 of 10 CFR Part 50, Appendix A, a loss of offsite power is assumed to occur as a consequence of the turbine trip for the excessive feedwater flow case initiated from full-power conditions. As discussed in subsection 15.0.14, an excessive feedwater flow transient initiated with the plant at no-load conditions need not consider a consequential loss of offsite power. With the plant initially at zero-load, the turbine would not have been connected to the grid, so any subsequent reactor or turbine trip would not disrupt the grid and produce a consequential loss of offsite ac power.

15.1.2.2 Analysis of Effects and Consequences

15.1.2.2.1 Method of Analysis

The excessive heat removal due to a feedwater system malfunction transient primarily is analyzed by using the LOFTRAN computer code (Reference 1). LOFTRAN simulates a multiloop system, neutron kinetics, pressurizer, pressurizer safety valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables, including temperatures, pressures, and power level.

For that portion of the feedwater malfunction transient that includes a primary coolant flow coastdown caused by the consequential loss of offsite power, a combination of three computer codes is used to perform the DNBR analysis. First the LOFTRAN code is used to predict the nuclear power transient, the flow coastdown, the primary system pressure transient, and the primary coolant temperature transient. The FACTRAN code (Reference 5) is then used to calculate the heat flux based on the nuclear power and flow from LOFTRAN. Finally, the VIPRE-01 code (see Section 4.4) is used to calculate the DNBR during the transient, using the heat flux from FACTRAN and the flow from LOFTRAN.

The transient is analyzed to demonstrate plant behavior if excessive feedwater addition occurs because of system malfunction or operator error that allows a feedwater control valve to open fully. The following two cases are analyzed assuming a conservatively large negative moderator temperature coefficient:

- Accidental opening of one feedwater control valve with the reactor just critical at zero load conditions.
- Accidental opening of one feedwater control valve with the reactor in automatic control at full power.

The reactivity insertion rate following a feedwater system malfunction is calculated with the following assumptions:

- For the feedwater control valve accident at full power, one feedwater control valve is assumed to malfunction resulting in a step increase to 120 percent of nominal feedwater flow to one steam generator.
- For the feedwater control valve accident at zero-load condition, a feedwater control valve malfunction occurs, which results in a step increase in flow to one steam generator from 0 in 120 percent of the nominal full-load value for one steam generator.
- For the zero-load condition, feedwater temperature is at a conservatively low value of 40°F.
- No credit is taken for the heat capacity of the reactor coolant system and steam generator thick metal in attenuating the resulting plant cooldown.
- The feedwater flow resulting from a fully open control valve is terminated by a steam generator high-2 level trip signal, which closes feedwater control and isolation valves and trips the main feedwater pumps, the turbine, and the reactor.

Plant characteristics and initial conditions are further discussed in subsection 15.0.3.

Normal reactor control systems are not required to function. The protection and safety monitoring system may function to trip the reactor because of overpower or high-2 steam generator water level conditions. No single active failure prevents operation of the protection and safety monitoring system. A discussion of anticipated transients without trip considerations is presented in Section 15.8.

The analysis assumes that the turbine trip during the case initiated from full power results in a consequential loss of offsite power that produces the coastdown of the reactor coolant pumps. As described in subsection 15.0.14, the loss of offsite power is modeled to occur 3.0 seconds after the turbine trip. The excessive feedwater flow analysis conservatively delays the start of rod insertion until 2.0 seconds after the reactor trip signal is generated, while assuming that the turbine trip occurs with a zero time delay following the generation of the turbine trip signal. The interaction of these assumptions produces maximum core power with minimum core coolant flow during the period of reactor coolant pump coastdown and thereby minimizes the predicted DNBRs.

15.1.2.2.2 Results

In the case of an accidental full opening of one feedwater control valve with the reactor at zero power and the preceding assumptions, the maximum reactivity insertion rate is less than the maximum reactivity insertion rate analyzed in subsection 15.4.1 for an uncontrolled rod cluster control assembly (RCCA) bank withdrawal from a subcritical or low-power startup condition. Therefore, the results of the analysis are not presented here. If the incident occurs with the unit just critical at no-load, the reactor may be tripped by the power range high neutron flux trip (low setting) set at approximately 25-percent nominal full power.

The full-power case (maximum reactivity feedback coefficients, automatic rod control) results in the greatest power increase. Assuming the rod control system to be in the manual control mode results in a slightly less severe transient.

When the steam generator water level in the faulted loop reaches the high-2 level setpoint, the feedwater control valves and feedwater isolation valves are automatically closed and the main feedwater pumps are tripped. This prevents continuous addition of the feedwater. In addition, a turbine trip and a reactor trip are initiated.

Transient results show the increase in nuclear power and ΔT associated with the increased thermal load on the reactor (see Figures 15.1.2-1 and 15.1.2-2). A new equilibrium condition is reached and all the plant parameters, except for the SG water level, remain almost constant. Following the turbine trip, the consequential loss of offsite power produces the reactor coolant system flow coastdown shown in Figure 15.1.2-3. The minimum DNBR is predicted to occur before the reactor trip and the reactor coolant pump coastdown caused by the loss of offsite power. The minimum DNBR predicted is 2.14 using the WRB-2 equation, which is well above the design limit described in Section 4.4. Following the reactor trip, the plant approaches a stabilized and safe condition; standard plant shutdown procedures may then be followed to further cool down the plant.

Because the power level rises by a maximum of about 12 percent above nominal during the excessive feedwater flow incident, the fuel temperature also rises until after reactor trip occurs. The core heat flux lags behind the neutron flux response because of the fuel rod thermal time constant. Therefore, the peak value does not exceed 118 percent of its nominal value (the assumed high neutron flux trip setpoint). The peak fuel temperature thus remains well below the fuel melting temperature.

The transient results show that departure from nucleate boiling (DNB) does not occur at any time during the excessive feedwater flow incident. Thus, the capability of the primary coolant to remove heat from the fuel rods is not reduced and the fuel cladding temperature does not rise significantly above its initial value during the transient.

The calculated sequence of events for this accident is shown in Table 15.1.2-1.

15.1.2.3 Conclusions

The results of the analysis show that the minimum DNBR encountered for an excessive feedwater addition at power is above the design limit value. The DNBR design basis is described in Section 4.4.

Additionally, the reactivity insertion rate that occurs at no-load conditions following excessive feedwater addition is less than the maximum value considered in the analysis of the rod withdrawal from subcritical condition analysis (see subsection 15.4.1).

15.1.3 Excessive Increase in Secondary Steam Flow

15.1.3.1 Identification of Causes and Accident Description

An excessive increase in secondary system steam flow (excessive load increase incident) results in a power mismatch between the reactor core power and the steam generator load demand. The plant control system is designed to accommodate a 10-percent step load increase or a 5-percent-per-minute ramp load increase in the range of 25- to 100-percent full power. Any loading rate in excess of these values may cause a reactor trip actuated by the protection and safety monitoring system. Steam flow increases greater than 10 percent are analyzed in subsections 15.1.4 and 15.1.5.

This accident could result from either an administrative violation such as excessive loading by the operator or an equipment malfunction in the steam dump control or turbine speed control.

During power operation, turbine bypass to the condenser is controlled by reactor coolant condition signals. A high reactor coolant temperature indicates a need for turbine bypass. A single controller malfunction does not cause turbine bypass. An interlock blocks the opening of the valves unless a large turbine load decrease or a turbine trip has occurred.

Protection against an excessive load increase accident is provided by the following protection and safety monitoring system signals:

- Overpower ΔT
- Overtemperature ΔT
- Power range high neutron flux

An excessive load increase incident is considered to be a Condition II event, as described in subsection 15.0.1.

In meeting the requirements of GDC 17 of 10 CFR Part 50, Appendix A, an analysis has been performed to evaluate the effects produced by a possible consequential loss of offsite power during the excessive load increase event. As discussed in subsection 15.0.14, the loss of offsite power need be considered only as a direct consequence of a turbine trip occurring while the plant is operating at power. For the four excessive load increase cases presented, reactor and turbine trips are not predicted to occur. However, to address the loss of offsite power issue, analysis has been performed that conservatively assumes a reactor trip and an associated turbine trip occur at the time of peak power. Consistent with the discussion in subsection 15.0.14, the analysis then models a loss of offsite power occurring 3.0 seconds after the turbine trip. The primary effect of the loss of offsite power is to cause the reactor coolant pumps to coast down.

15.1.3.2 Analysis of Effects and Consequences

15.1.3.2.1 Method of Analysis

This accident is primarily analyzed using the LOFTRAN computer code (Reference 1). LOFTRAN simulates the neutron kinetics, reactor coolant system, pressurizer, pressurizer safety valves, pressurizer spray, steam generator, steam generator safety valves, and feedwater system. The code computes pertinent plant variables including temperatures, pressures, and power level.

For the excessive load increase analysis that includes a primary coolant flow coastdown caused by the consequential loss of offsite power, a combination of three computer codes is used to perform the DNBR analysis. First the LOFTRAN code is used to predict the nuclear power transient, the flow coastdown, the primary system pressure transient, and the primary coolant temperature transient. The FACTRAN code (Reference 5) is then used to calculate the heat flux based on the nuclear power and flow from LOFTRAN. Finally, the VIPRE-01 code (see Section 4.4) is used to calculate the DNBR during the transient, using the heat flux from FACTRAN and the flow from LOFTRAN.

Four cases are analyzed to demonstrate plant behavior following a 10-percent step load increase from rated load. These cases are as follows:

- Reactor control in manual with minimum moderator reactivity feedback
- Reactor control in manual with maximum moderator reactivity feedback
- Reactor control in automatic with minimum moderator reactivity feedback
- Reactor control in automatic with maximum moderator reactivity feedback

For the minimum moderator feedback cases, the core has the least negative moderator temperature coefficient of reactivity; therefore, reductions in coolant temperature have the least impact on core power. For the maximum moderator feedback cases, the moderator temperature coefficient of reactivity has its highest absolute value. This results in the largest amount of reactivity feedback due to changes in coolant temperature. For all the cases analyzed both with and without automatic rod control, no credit is taken for ΔT trips on overtemperature or overpower in order to demonstrate the inherent transient capability of the plant. Under actual operating conditions, such a trip may occur, after which the plant quickly stabilizes.

A 10-percent step increase in steam demand is assumed, and each case is analyzed without credit being taken for pressurizer heaters. At initial reactor power, reactor coolant system pressure and temperature are assumed to be at their full power values. Uncertainties in initial conditions are included in the limit DNBR as described in WCAP-11397-P-A (Reference 2). Plant characteristics and initial conditions are further discussed in subsection 15.0.3.

In addressing the consequential loss of offsite power, limiting cases are analyzed that model a reactor trip and an associated turbine trip occurring at the time of peak power during the limiting excessive load increase transient. The analysis has been performed conservatively assuming a reactor trip with a coincident turbine trip followed by a loss of offsite power 3.0 seconds later, as discussed in subsection 15.0.14. The primary effect of the loss of offsite power is to cause the reactor coolant pumps to coast down.

Normal reactor control systems and engineered safety systems are not required to function.

15.1.3.2.2 Results

Figures 15.1.3-1 through 15.1.3-10 show the transient with the reactor in the manual control mode and no reactor trip signals occur. For the minimum moderator feedback case, there is a slight power increase and the average core temperature shows a large decrease. This results in a DNBR that increases above its initial value. For the maximum moderator feedback manually controlled case, there is a much faster increase in reactor power due to the moderator feedback. A reduction in the DNBR occurs, but the DNBR remains above the design limit (see Section 4.4).

Figures 15.1.3-11 through 15.1.3-20 show the transient assuming the reactor is in the automatic control mode. A reactor trip signal setpoint is reached but, conservatively, reactor trip is not credited. Both the minimum and maximum moderator feedback cases show that core power increases and thereby reduces the rate of decrease in coolant average temperature and pressurizer pressure. For both of these cases, the minimum DNBR remains above the design limit (see Section 4.4).

For the cases with no reactor trip signal, the plant power stabilizes at an increased power level. Normal plant operating procedures are followed to reduce power. Because of the measurement errors assumed in the setpoints, it is possible that reactor trip could actually occur for the automatic control and maximum feedback cases. The plant reaches a stabilized condition following the trip.

For the analysis performed modeling a loss of offsite power and the subsequent reactor coolant pump coastdown, the results show that the minimum DNBRs predicted during the excessive load increase cases occur prior to the time the flow coastdown begins. Therefore, the DNB ratio results provided in Figures 15.1.3-5, 15.1.3-10, 15.1.3-15, and 15.1.3-20 are bounding, and the minimum DNBR during the flow coastdown remains well above the design limit defined in Section 4.4. Since the loss of offsite power is delayed for 3.0 seconds after the turbine trip, the RCCAs are inserted well into the core before the reactor coolant system flow coastdown begins. The resulting power reduction compensates for the reduced flow encountered once power to the reactor coolant pumps is lost.

The excessive load increase incident is an overpower transient for which the fuel temperature rises. Reactor trip may not occur for some of the cases analyzed, and the plant reaches a new equilibrium condition at a higher power level corresponding to the increase in steam flow.

Because DNB does not occur during the excessive load increase transients, the capability of the primary coolant to remove heat from the fuel rod is not reduced. Thus, the fuel cladding temperature does not rise significantly above its initial value during the transient.

The calculated sequence of events for the excessive load increase cases with no reactor trip are shown in Table 15.1.2-1.

15.1.3.3 Conclusions

The analysis presented in this subsection demonstrates that for a 10-percent step load increase, the DNBR remains above the design limit. The design basis for DNB is described in Section 4.4. The plant rapidly reaches a stabilized condition following the load increase.

15.1.4 Inadvertent Opening of a Steam Generator Relief or Safety Valve

15.1.4.1 Identification of Causes and Accident Description

The most severe core conditions resulting from an accidental depressurization of the main steam system are associated with an inadvertent opening of a single steam dump, relief, or safety valve. The analyses performed assuming a rupture of a main steam line are given in subsection 15.1.5.

The steam release, as a consequence of this accident, results in an initial increase in steam flow which decreases during the accident as the steam pressure falls. The energy removal from the reactor coolant system causes a reduction of coolant temperature and pressure. In the presence of a negative moderator temperature coefficient, the cooldown results in an insertion of positive reactivity.

The analysis is performed to demonstrate that the following Standard Review Plan subsection 15.1.4 evaluation criterion is satisfied.

Assuming the most reactive stuck RCCA, with offsite power available, and assuming a single failure in the engineered safety features system, there will be no consequential damage to the fuel or reactor coolant system after reactor trip for a steam release equivalent to the spurious opening, with failure to close, of the largest of any single steam dump, relief, or safety valve. This criterion is met by showing the DNB design basis is not exceeded.

Accidental depressurization of the secondary system is classified as a Condition II event as described in Section 15.1.

The following systems provide the necessary protection against an accidental depressurization of the main steam system:

- Core makeup tank actuation from one of the following signals:
  - Safeguards (“S”) signal
    - Two out of four low pressurizer pressure signals
    - Two out of four high-2 containment pressure signals
    - Two out of four low T_{cold} signals in any one loop
    - Two out of four low steam line pressure signals in any one loop
  - Two out of four low-2 pressurizer level signals
- The overpower reactor trips (neutron flux and ΔT) and the reactor trip occurring in conjunction with receipt of the “S” signal

- Redundant isolation of the main feedwater lines

  Sustained high feedwater flow causes additional cooldown. Therefore, in addition to the normal control action that closes the main feedwater valves following reactor trip, an "S" signal rapidly closes the feedwater control valves and feedwater isolation valves, and trips the main feedwater pumps.

- Redundant isolation of the startup feedwater system

  Sustained high startup feedwater flow causes additional cooldown. Therefore, the low T_{cold} signal closes the startup feedwater control and isolation valves.

- Trip of the fast-acting main steam line isolation valves (assumed to close in less than 10 seconds) on one of the following signals:

  – Two out of four low steam line pressure signals in any one loop (above permissive P-11)
  – Two out of four high negative steam pressure rates in any loop (below permissive P-11)
  – Two out of four low T_{cold} signals in any one loop
  – Two out of four high-2 containment pressure signals

  Plant systems and equipment available to mitigate the effects of the accident are discussed in subsection 15.0.8 and listed in Table 15.0.6.

15.1.4.2 Analysis of Effects and Consequences

15.1.4.2.1 Method of Analysis

The following analyses of a secondary system steam release are performed:

- A full plant digital computer simulation using the LOFTRAN code (Reference 1) to determine reactor coolant system temperature and pressure during cooldown, and the effect of core makeup tank injection

- Analyses to determine that there is no damage to the fuel or reactor coolant system

The following conditions are assumed to exist at the time of a secondary steam system release:

- End-of-life shutdown margin at no-load, equilibrium xenon conditions, and with the most reactive RCCA stuck in its fully withdrawn position. Operation of RCCA mechanical shim and axial offset banks during core burnup is restricted by the insertion limits so that shutdown margin requirements are satisfied.

- The most negative moderator coefficient corresponding to the end-of-life rodded core with the most reactive RCCA in the fully withdrawn position. The variation of the coefficient with temperature is included. The k_{eff} (considering moderator temperature and density effects) versus temperature corresponding to the negative moderator temperature coefficient used is shown in Figure 15.1.4-1. The core power is modeled as a function of core mass flow, core boron concentration, and core inlet temperature.

- Minimum capability for injection of boric acid solution corresponding to the most restrictive single failure in the passive core cooling system. Low-concentration boric acid must be swept from the core makeup tank lines downstream of isolation valves before delivery of boric acid (3400 ppm) to the reactor coolant loops. This effect has been accounted for in the analysis.

- The case studied is a steam flow of 520 pounds per second at 1200 psia with offsite power available. This conservatively models the maximum capacity of any single steam dump, relief, or safety valve. Initial hot shutdown conditions at time zero are assumed because this represents the most conservative initial conditions.

Should the reactor be just critical or operating at power at the time of a steam release, the reactor is tripped by the normal overpower protection when power level reaches a trip point. Following a trip at power, the reactor coolant system contains more stored energy than at no-load. This is because the average coolant temperature is higher than at no-load, and there is appreciable energy stored in the fuel. The additional stored energy is removed via the cooldown caused by the steam release before the no-load conditions of the reactor coolant system temperature and shutdown margin assumed in the analyses are reached.

After the additional stored energy is removed, the cooldown and reactivity insertions proceed in the same manner as in the analysis, which assumes no-load condition at time zero. However, because the initial steam generator water inventory is greatest at no-load, the magnitude and duration of the reactor coolant system cooldown are less for steam line release occurring at power:

- In computing the steam flow, the Moody Curve (Reference 3) for f(L/D) = 0 is used.

- Perfect moisture separation occurs in the steam generator.

- Offsite power is available, because this maximizes the cooldown.

- Maximum cold startup feedwater flow is assumed.

- Four reactor coolant pumps are initially operating.

- Manual actuation of the PRHR system at time zero is conservatively assumed to maximize the cooldown.

15.1.4.2.2 Results

The results presented conservatively indicate the events that would occur assuming a secondary system steam release because it is postulated that the conditions just described occur simultaneously.

Figures 15.1.4-2 through 15.1.4-12 show the transient results for a steam flow of 520 pounds per second at 1200 psia.

The assumed steam release is typical of the capacity of any single steam dump, relief, or safety valve. Core makeup tank injection and the associated tripping of the reactor coolant pumps are initiated automatically by the low T_{cold} "S" signal. Boron solution at 3400 ppm enters the reactor coolant system, providing enough negative reactivity to prevent a significant return to power and core damage. Later in the transient, as the reactor coolant pressure continues to fall, the accumulators actuate and inject boron solution at 2600 ppm.

The transient is conservative with respect to cooldown, because no credit is taken for the energy stored in the system metal other than that of the fuel elements and steam generator tubes, and the PRHR system is assumed to be actuated at time zero. Because the limiting portion of the transient occurs over a period of about 5 minutes, the neglected stored energy is likely to have a significant effect in slowing the cooldown.

The calculated time sequence of events for this accident is listed in Table 15.1.2-1.

15.1.4.3 Margin to Critical Heat Flux

The analysis demonstrates that the DNB design basis, as described in Section 4.4, is met for the inadvertent opening of a steam generator relief or safety valve. As shown in Figure 15.1.4-2, no significant return to power occurs and, therefore, DNB does not occur. The minimum DNBR is conservatively calculated and is above the 95/95 limit.

15.1.4.4 Conclusions

The analysis shows that the criterion stated in this subsection is satisfied. For an inadvertent opening of any single steam dump or a steam generator relief or safety valve, the DNB design basis is met.

15.1.5 Steam System Piping Failure

15.1.5.1 Identification of Causes and Accident Description

The steam release arising from a rupture of a main steam line results in an initial increase in steam flow, which decreases during the accident as the steam pressure falls. The energy removal from the reactor coolant system causes a reduction of coolant temperature and pressure. In the presence of a negative moderator temperature coefficient, the cooldown results in an insertion of positive reactivity.

If the most reactive RCCA is assumed stuck in its fully withdrawn position after reactor trip, there is an increased possibility that the core becomes critical and returns to power. A return to power following a steam line rupture is a potential problem mainly because of the existing high-power peaking factors, assuming the most reactive RCCA to be stuck in its fully withdrawn position. The core is ultimately shut down by the boric acid solution delivered by the passive core cooling system.

The analysis of a main steam line rupture is performed to demonstrate that the following Standard Review Plan subsection 15.1.5 evaluation criterion is satisfied.

Assuming the most reactive stuck RCCA with or without offsite power and assuming a single failure in the engineered safety features system, the core cooling capability is maintained. As shown in subsection 15.1.5.4, radiation doses are within the guidelines.

DNB and possible cladding perforation following a steam pipe rupture are not necessarily unacceptable. The following analysis shows that the DNB design basis is not exceeded for any steamline rupture, assuming the most reactive assembly stuck in its fully withdrawn position.

A major steam line rupture is classified as a Condition IV event.

Effects of minor secondary system pipe breaks are bounded by the analysis presented in this section. Minor secondary system pipe breaks are classified as Condition III events, as described in subsection 15.0.1.3.

The major rupture of a steam line is the most limiting cooldown transient and is analyzed at zero power with no decay heat. Decay heat retards the cooldown and thereby reduces the likelihood that the reactor returns to power. A detailed analysis of this transient with the most limiting break size, a double-ended rupture, is presented here.

Certain assumptions used in this analysis are discussed in WCAP-9226 (Reference 4). WCAP-9226 also contains a discussion of the spectrum of break sizes and power levels analyzed.

The following functions provide the protection for a steam line rupture (see subsection 7.2.1.1.2):

- Core makeup tank actuation from any of the following:
  - Two out of four low pressurizer pressure signals
  - Two out of four high-2 containment pressure signals
  - Two out of four low steam line pressure signals in any loop
  - Two out of four low T_{cold} signals in any one loop
  - Two out of four low-2 pressurizer level signals
- The overpower reactor trips (neutron flux and ΔT) and the reactor trip occurring in conjunction with receipt of the “S” signal
- Redundant isolation of the main feedwater lines

  Sustained high feedwater flow causes additional cooldown. Therefore, in addition to the normal control action that closes the main feedwater control valves, the “S” signal rapidly closes the feedwater control valves and feedwater isolation valves, and trips the main feedwater pumps.
- Redundant isolation of the startup feedwater system

  Sustained high startup feedwater flow causes additional cooldown. Therefore, the low T_{cold} signal closes the startup feedwater control and isolation valves.
- Fast-acting main steam line isolation valves (assumed to close in less than 10 seconds) on any of the following:
  - Two out of four high-2 containment pressure

– Two out of the four low steam line pressure signals in any one loop (above permissive P-11)

– Two out of four high negative steam pressure rates in any one loop (below permissive P-11)

– Two out of four low T_{cold} signals in any one loop

A fast-acting main steam isolation valve is provided in each steam line. These valves are assumed to fully close within 10 seconds of actuation following a large break in the steam line. For breaks downstream of the main steam line isolation valves, closure of at least one valve in each line terminates the blowdown.

For any break in any location, no more than one steam generator would experience an uncontrolled blowdown even if one of the main steam line isolation valves fails to close. A description of steam line isolation is included in Chapter 10.

Flow restrictors are installed in the steam generator outlet nozzle, as an integral part of the steam generator. The effective throat area of the nozzles is 1.4 ft^2, which is considerably less than the main steam pipe area; thus, the flow restrictors serve to limit the maximum steam flow for a break at any location.

Design criteria and methods of protection of safety-related equipment from the dynamic effects of postulated piping ruptures are provided in Section 3.6.

15.1.5.2 Analysis of Effects and Consequences

15.1.5.2.1 Method of Analysis

The analysis of the steam pipe rupture is performed to determine the following:

- The core heat flux and reactor coolant system temperature and pressure resulting from the cooldown following the steam line break. The LOFTRAN code (Reference 1) is used to model the system transient.

- The thermal-hydraulic behavior of the core following a steam line break. A detailed thermal-hydraulic digital computer code, VIPRE-01, is used to determine if DNB occurs for the core transient conditions computed by the LOFTRAN code.

The following conditions are assumed to exist at the time of a main steam line break accident:

- End-of-cycle shutdown margin at no-load, equilibrium xenon conditions, and the most reactive rod control assembly stuck in its fully withdrawn position. Operation of the control rod mechanical shim and axial offset banks during core burnup is restricted by the insertion limits so that shutdown margin requirements are satisfied.

- A negative moderator coefficient corresponding to the end-of-life rodded core with the most reactive RCCA in the fully withdrawn position. The variation of the coefficient with temperature is included. The k_{eff} (considering moderator temperature and density effects) versus temperature corresponding to the negative moderator temperature coefficient used is shown in Figure 15.1.4-1. The core power is modeled as a function of core mass flow, core boron concentration, and core inlet temperature.

The core properties used in the LOFTRAN mode for feedback calculations are generated by combining those in the sector nearest the affected steam generator with those associated with the remaining sector. The resultant properties reflect a combination process that accounts for inlet plenum fluid mixing and a conservative weighing of the fluid properties from the coldest core sector.

In verifying the conservatism of this method, the power predictions of the LOFTRAN modeling are confirmed by comparison with detailed core analysis for the limiting conditions of the cases considered. This core analysis conservatively models the hypothetical core configuration (that is, stuck RCCA, nonuniform inlet temperatures, pressure, flow, and boron concentration) and directly evaluates the total reactivity feedback including power, boron, and density redistribution in an integral fashion. The effect of void formation is also included.

Comparison of the results from the detailed core analysis with the LOFTRAN predictions verify the overall conservatism of the methodology. That is, the specific power, temperature, and flow conditions used to perform the DNB analysis are conservative.

- The core makeup tanks and the accumulators are the portions of the passive core cooling system used in mitigating a steam line rupture. There are no single failures that prevent core makeup tank injection. In modeling the core makeup tanks and the accumulators, conservative assumptions are used that minimize the capability to add borated water. Specifically, the core makeup tank injection line characteristics modeled reflect the failure of one core makeup tank discharge valve.

- The maximum overall fuel-to-coolant heat transfer coefficient is used to maximize the rate of cooldown.

- Because the steam generators are provided with integral flow restrictors with a 1.4-ft^2 throat area, any rupture in a steam line with a break area greater than 1.4 ft^2, regardless of location, has the same effect on the primary plant as the 1.4-ft^2 double-ended rupture. The limiting case considered in determining the core power and reactor coolant system transient is the complete severance of a pipe, with the plant initially at no-load conditions and full reactor coolant flow with offsite power available. The results of this case bound the loss of offsite power case for the following reasons:

  – Loss of offsite power results in an immediate reactor coolant pump coastdown at the initiation of the transient. This reduces the severity of the reactor coolant system cooldown by reducing primary-to-secondary heat transfer. The lessening of the cooldown, in turn, reduces the magnitude of the return to power.

  – Following actuation, the core makeup tank provides borated water that injects into the reactor coolant system. Flow from the core makeup tank increases if the reactor coolant pumps have coasted down. Therefore, the analysis performed with offsite power and continued reactor coolant pump operation reduces the rate of boron injection into the core and is conservative.

– The protection system automatically provides a safety-related signal that initiates the coastdown of the reactor coolant pumps in parallel with core makeup tank actuation. Because this reactor coolant pump trip function is actuated early during the steam line break event (right after core makeup tank actuation), there is very little difference in the predicted DNBR between cases with and without offsite power.

– Because of the passive nature of the safety injection system, the loss of offsite power does not delay the actuation of the safety injection system.

- Power peaking factors corresponding to one stuck RCCA are determined at the end of core life. The coldest core inlet temperatures are assumed to occur in the sector with the stuck rod. The power peaking factors account for the effect of the local void in the region of the stuck RCCA during the return to power phase following the steam line break. This void in conjunction with the large negative moderator coefficient partially offsets the effect of the stuck assembly. The power peaking factors depend upon the core power, temperature, pressure, and flow and, therefore, may differ for each case studied.

The analysis assumes initial hot standby conditions at time zero in order to present a representative case which will yield limiting post-trip DNBR results for this transient. If the reactor is just critical or operating at power at the time of a steam line break, the reactor is tripped by the overpower protection system when power level reaches a trip point.

Following a trip at power, the reactor coolant system contains more stored energy than at no-load because the average coolant temperature is higher than at no-load, and there is energy stored in the fuel. The additional stored energy reduces the cooldown caused by the steam line break before the no-load conditions of reactor coolant system temperature and shutdown margin assumed in the analyses are reached.

After the additional stored energy has been removed, the cooldown and reactivity insertions proceed in the same manner as in the analysis that assumes a no-load condition at time zero.

- In computing the steam flow during a steam line break, the Moody Curve (Reference 3) for f(L/D) = 0 is used.

- Perfect moisture separation occurs in the steam generator.

- Maximum cold startup feedwater flow plus nominal 100 percent main feedwater flow is assumed.

- Four reactor coolant pumps are initially operating.

- Manual actuation of the PRHR system at time zero is conservatively assumed to maximize the cooldown.

15.1.5.2.2 Results

The calculated sequence of events for the analyzed case is shown in Table 15.1.2-1. The results presented conservatively indicate the events that would occur assuming a steam line rupture because it is postulated that the conditions described occur simultaneously.

15.1.5.2.3 Core Power and Reactor Coolant System Transient

Figures 15.1.5-1 through 15.1.5-13 show the reactor coolant system transient and core heat flux following a main steam line rupture (complete severance of a pipe) at initial no-load condition.

Offsite power is assumed available so that, initially, full reactor coolant flow exists. During the course of the event, the reactor protection system initiates a trip of the reactor coolant pumps in conjunction with actuation of the core makeup tanks. The transient shown assumes an uncontrolled steam release from only one steam generator. Steam release from more than one steam generator is prevented by automatic trip of the main steam isolation valves in the steam lines by high containment pressure signals or by low steam line pressure signals. Even with the failure of one valve, release is limited to approximately 10 seconds for the other steam generator while the one generator blows down. The main steam isolation valves fully close in less than 10 seconds from receipt of a closure signal.

As shown in Figure 15.1.5-1, the core attains criticality with the RCCAs inserted (with the design shutdown assuming the most reactive RCCA stuck) before boron solution at 3400 ppm (from core makeup tanks) or 2600 ppm (from accumulators) enters the reactor coolant system. A peak core power significantly lower than the nominal full-power value is attained.

The calculation assumes that the boric acid is mixed with and diluted by the water flowing in the reactor coolant system before entering the reactor core. The concentration after mixing depends upon the relative flow rates in the reactor coolant system and from the core makeup tanks or accumulators (or both). The variation of mass flow rate in the reactor coolant system due to water density changes is included in the calculation. The variation of flow rate from the core makeup tanks or accumulators (or both) due to changes in the reactor coolant system pressure and temperature and the pressurizer level is also included. The reactor coolant system and passive injection flow calculations include line losses.

At no time during the analyzed steam line break event does the core makeup tank level approach the setpoint for actuation of the automatic depressurization system. During non-LOCA events, the core makeup tanks remain filled with water. The volume of injection flow leaving the core makeup tank is offset by an equal volume of recirculation flow that enters the core makeup tanks via the reactor coolant system cold leg balance lines.

The PRHR system provides a passive, long-term means of removing the core decay and stored heat by transferring the energy via the PRHR heat exchanger to the in-containment refueling water storage tank (IRWST). The PRHR heat exchanger is normally actuated automatically when the steam generator level falls below the low wide-range level. For the main steam line rupture case analyzed, the PRHR exchanger is conservatively actuated at time zero to maximize the cooldown.

15.1.5.2.4 Margin to Critical Heat Flux

The case presented in subsection 15.1.5.2.2 conservatively models the expected behavior of the plant during a steam system piping failure. This includes the tripping of the reactor coolant pumps coincident with core makeup tank actuation. A DNB analysis is performed using limiting assumptions that bound those of subsection 15.1.5.2.2.

Under the low flow (natural circulation) conditions present in the AP1000 transient, the return to power is severely limited by the large negative feedback due to flow and power. The minimum DNBR is conservatively calculated and is above the 95/95 limit.

15.1.5.3 Conclusions

The analysis shows that the DNB design basis is met for the steam system piping failure event. DNB and possible cladding perforation following a steam pipe rupture are not precluded by the criteria. The preceding analysis shows that no DNB occurs for the main steam line rupture assuming the most reactive RCCA stuck in its fully withdrawn position.

15.1.5.4 Radiological Consequences

The evaluation of the radiological consequences of a postulated main steam line break outside containment assumes that the reactor has been operating with the design basis fuel defect level (0.25 percent of power produced by fuel rods containing cladding defects) and that leaking steam generator tubes have resulted in a buildup of activity in the secondary coolant.

Following the rupture, startup feedwater to the faulted loop is isolated and the steam generator is allowed to steam dry. Any radioiodines carried from the primary coolant into the faulted steam generator via leaking tubes are assumed to be released directly to the environment. It is conservatively assumed that the reactor is cooled by steaming from the intact loop.

15.1.5.4.1 Source Term

The only significant radionuclide releases due to the main steam line break are the iodines and alkali metals that become airborne and are released to the environment as a result of the accident. Noble gases are also released to the environment. Their impact is secondary because any noble gases entering the secondary side during normal operation are rapidly released to the environment.

The analysis considers two different reactor coolant iodine source terms, both of which consider the iodine spiking phenomenon. In one case, the initial iodine concentrations are assumed to be those associated with equilibrium operating limits for primary coolant iodine activity. The iodine spike is assumed to be initiated by the accident with the spike causing an increasing level of iodine in the reactor coolant.

The second case assumes that the iodine spike occurs prior to the accident and that the maximum resulting reactor coolant iodine concentration exists at the time the accident occurs.

The reactor coolant noble gas and alkali metal concentrations are assumed to be those associated with the design basis fuel defect level.

The secondary coolant is assumed to have an iodine source term of 0.1 μCi/g dose equivalent I-131. This is 10 percent of the maximum primary coolant activity at equilibrium operating conditions. The secondary coolant alkali metal concentration is also assumed to be 10 percent of the primary concentration.

15.1.5.4.2 Release Pathways

There are three components to the accident releases:

- The secondary coolant in the steam generator of the faulted loop is assumed to be released out the break as steam. Any iodine and alkali metal activity contained in the coolant is assumed to be released.

- The reactor coolant leaking into the steam generator of the faulted loop is assumed to be released to the environment without any credit for partitioning or plateout onto the interior of the steam generator.

- The reactor coolant leaking into the steam generator of the intact loop would mix with the secondary coolant and thus raise the activity concentrations in the secondary water. While the steam release from the intact loop would have partitioning of non-gaseous activity, this analysis conservatively assumes that any activity entering the secondary side is released.

Credit is taken for decay of radionuclides until release to the environment. After release to the environment, no consideration is given to radioactive decay or to cloud depletion by ground deposition during transport offsite.

15.1.5.4.3 Dose Calculation Models

The models used to calculate doses are provided in Appendix 15A.

15.1.5.4.4 Analytical Assumptions and Parameters

The assumptions and parameters used in the analysis are listed in Table 15.1.5-1.

15.1.5.4.5 Identification of Conservatisms

The assumptions and parameters used in the analysis contain a number of significant conservatisms:

- The reactor coolant activities are based on a fuel defect level of 0.25 percent. The expected fuel defect level is far less than this (see Section 11.1).

- The assumed leakage of 150 gallons of reactor coolant per day into each steam generator is conservative. The leakage is expected to be a small fraction of this during normal operation.

- The conservatively selected meteorological conditions are present only rarely.

15.1.5.4.6 Doses

Using the assumptions from Table 15.1.5-1, the calculated total effective dose equivalent (TEDE) doses for the case with accident-initiated iodine spike are determined to be less than 0.6 rem at the site boundary for the limiting 2-hour interval (0 to 2 hours) and 1.1 rem at the low population zone outer boundary. These doses are small fractions of the dose guideline of 25 rem TEDE identified in 10 CFR Part 50.34. A "small fraction" is defined, consistent with the Standard Review Plan, as being 10 percent or less. The TEDE doses for the case with pre-existing iodine spike are determined to be less than 0.5 rem at the site boundary for the limiting 2-hour interval (0 to 2 hours) and 0.4 rem at the low population zone outer boundary. These doses are within the dose guidelines of 10 CFR Part 50.34.

At the time the main steam line break occurs, the potential exists for a coincident loss of spent fuel pool cooling with the result that the pool could reach boiling and a portion of the radioactive iodine in the spent fuel pool could be released to the environment. The loss of spent fuel pool cooling has been evaluated for a duration of 30 days. There is no contribution to the 2-hour site boundary dose because the pool boiling would not occur until after the first 2 hours. The 30-day contribution to the dose at the low population zone boundary is less than 0.01 rem TEDE. When this is added to the dose calculated for the main steam line break, the resulting total dose remains less than the values reported above.

15.1.6 Inadvertent Operation of the PRHR Heat Exchanger

15.1.6.1 Identification of Causes and Accident Description

The inadvertent actuation of the PRHR heat exchanger causes an injection of relatively cold water into the reactor coolant system. This produces a reactivity insertion in the presence of a negative moderator temperature coefficient. To prevent this reactivity increase from causing reactor power increase, a reactor trip is initiated when either PRHR discharge valve comes off of its fully shut seat.

The inadvertent actuation of the PRHR heat exchanger could be caused by operator error or a false actuation signal, or by malfunction of a discharge valve. Actuation of the PRHR heat exchanger involves opening one of the isolation valves, which establishes a flow path from one reactor coolant system hot leg, through the PRHR heat exchanger, and back into its associated steam generator cold leg plenum.

The PRHR heat exchanger is located above the core to promote natural circulation flow when the reactor coolant pumps are not operating. With the reactor coolant pumps in operation, flow through the PRHR heat exchanger is enhanced. The heat sink for the PRHR heat exchanger is provided by the IRWST, in which the PRHR heat exchanger is submerged. Because the fluid in the heat exchanger is in thermal equilibrium with water in the tank, the initial flow out of the PRHR heat exchanger is significantly colder than the reactor coolant system fluid. Following this initial insurge, the reduction in cold leg temperature is limited by the cooling capability of the PRHR heat exchanger. Because the PRHR heat exchanger is connected to only one reactor coolant system loop, the cooldown resulting from its actuation is asymmetric with respect to the core.

The response of the plant to an inadvertent PRHR heat exchanger actuation with the plant at no-load conditions is bounded by the analyses performed for the inadvertent opening of a steam generator relief or safety valve event (subsection 15.1.4) and the steam system piping failure event (subsection 15.1.5). Both of these events are conservatively analyzed assuming PRHR heat exchanger actuation coincident with the steam line depressurization. Therefore, only the response of the plant to an inadvertent PRHR initiation with the core at power is considered.

In meeting the requirements of GDC 17 of 10 CFR Part 50, Appendix A, the effects of a possible consequential loss of ac power during an inadvertent PRHR heat exchanger actuation event have been evaluated to not adversely impact the analysis results. This conclusion is based on a review of the time sequence associated with a consequential loss of ac power in comparison to the reactor shutdown time for an inadvertent PRHR heat exchanger actuation event. The primary effect of the loss of ac power is to cause the reactor coolant pumps (RCPs) to coast down. The protection and safety monitoring system includes a 5-second minimum delay between the reactor trip and the turbine trip. In addition, a 3-second delay between the turbine trip and the loss of offsite ac power is assumed, consistent with Section 15.1.3 of NUREG-1793. Considering these delays between the time of the reactor trip and RCP coastdown due to the loss of ac power, it is clear that the plant shutdown sequence will have passed the critical point and the control rods will have been completely inserted before the RCPs begin to coast down. Therefore, the consequential loss of ac power does not adversely impact this inadvertent PRHR heat exchanger actuation analysis because the plant will be shut down well before the RCPs begin to coast down.

The inadvertent actuation of the PRHR heat exchanger event is a Condition II event, a fault of moderate frequency. Plant systems and equipment available to mitigate the effects of the accident are discussed in subsection 15.0.8 and listed in Table 15.0.6. The following reactor protection system functions are available to provide protection in the event of an inadvertent PRHR heat exchanger actuation:

- PRHR discharge valve not closed
- Overpower/overtemperature reactor trips (neutron flux and ΔT)
- Two out of four low pressurizer pressure signals

Due to the potential consequences as a result of the reactivity excursion, a reactor trip has been designed so that upon an inadvertent PRHR actuation, a reactor trip will occur. This reactor trip is generated when either of the discharge valves is not closed. This ensures that the reactor will be tripped prior to a power increase due to the cold water injection.

15.1.6.2 Analysis of Effects and Consequences

Since a reactor trip is initiated as soon as the PRHR discharge valves are not fully closed, this event is essentially a reactor trip from the initial condition and requires no separate transient analysis.

15.1.6.3 Conclusions

Inadvertent actuation of the PRHR does not result in violation of the core thermal design limits (DNB and linear power generation) or RCS overpressure.

15.1.7 Combined License Information

This section has no requirement for additional information to be provided in support of the Combined License application.

15.1.8 References

1. Burnett, T. W. T., et al., "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary), and WCAP-7907-A (Nonproprietary), April 1984.

2. Friedland, A. J., and Ray, S., "Revised Thermal Design Procedure," WCAP-11397-P-A (Proprietary) and WCAP-11397-A (Nonproprietary), April 1989.

3. Moody, F. S., "Transactions of the ASME, Journal of Heat Transfer," Figure 3, page 134, February 1965.

4. Wood, D. C., and Hollingsworth, S. D., "Reactor Core Response to Excessive Secondary Steam Releases," WCAP-9226 (Proprietary) and WCAP-9227 (Nonproprietary), January 1978.

5. Hargrove, H. G., "FACTRAN - A FORTRAN-IV Code for Thermal Transients in a UO_2 Fuel Rod," WCAP-7908-A, December 1989.

6. "AP1000 Code Applicability Report," WCAP-15644-P (Proprietary) and WCAP-15644-NP (Nonproprietary), Revision 2, March 2004.

Table 15.1.2-1 (Sheet 1 of 2)

TIME SEQUENCE OF EVENTS FOR INCIDENTS THAT RESULT IN AN INCREASE IN HEAT REMOVAL FROM THE PRIMARY SYSTEM

Accident	Event	Time (seconds)
Excessive increase in secondary steam flow		
– Manual reactor control (minimum moderator feedback)	10-percent step load increase	0.0
	Equilibrium conditions reached (approximate time only)	250.0
– Manual reactor control (maximum moderator feedback)	10-percent step load increase	0.0
	Equilibrium conditions reached (approximate time only)	70.0
– Automatic reactor control (minimum moderator feedback)	10-percent step load increase	0.0
	Equilibrium conditions reached (approximate time only)	125.0
– Automatic reactor control (maximum moderator feedback)	10-percent step load increase	0.0
	Equilibrium conditions reached (approximate time only)	50.0
Feedwater system malfunctions that result in an increase in feedwater flow	One main feedwater control valve fails fully open	0.0
	Turbine trip/feedwater isolation and reactor trip on high steam generator level	201.9
	Rod motion begins	203.9
	Loss of offsite power occurs	204.9
	Minimum DNBR occurs	205.8
Inadvertent operation of the PRHR	PRHR discharge valves go fully open	0.0
	Reactor trip setpoint reached	0.0
	Rod motion begins	1.25
	Rods fully inserted	3.95

Table 15.1.2-1 (Sheet 2 of 2)

TIME SEQUENCE OF EVENTS FOR INCIDENTS THAT RESULT IN AN INCREASE IN HEAT REMOVAL FROM THE PRIMARY SYSTEM

Accident	Event	Time (seconds)
Inadvertent opening of a steam generator relief or safety valve	Inadvertent opening of one main steam safety or relief valve	0.0
	"S" actuation signal on safeguards low T_{cold}	120.3
	Core makeup tank actuation	137.3
	Boron reaches core	152.6
Steam system piping failure	Steam line ruptures	0.0
	"S" actuation signal on safeguards low steam line pressure	1.4
	Criticality attained	28.0
	Boron reaches core	33.2
	Pressurizer empty	58.2

Table 15.1.5-1

PARAMETERS USED IN EVALUATING THE RADIOLOGICAL CONSEQUENCES OF A MAIN STEAM LINE BREAK

Reactor coolant iodine activity	
– Accident-initiated spike	Initial activity equal to the equilibrium operating limit for reactor coolant activity of 1.0 μCi/g dose equivalent I-131 with an assumed iodine spike that increases the rate of iodine release from fuel into the coolant by a factor of 500 (see Appendix 15A). Duration of spike is 3.6 hours.
– Preaccident spike	An assumed iodine spike that has resulted in an increase in the reactor coolant activity to 60 μCi/g of dose equivalent I-131 (see Appendix 15A)
Reactor coolant noble gas activity	Equal to the operating limit for reactor coolant activity of 280 μCi/g dose equivalent Xe-133
Reactor coolant alkali metal activity	Design basis activity (see Table 11.1-2)
Secondary coolant initial iodine and alkali metal activity	10% of reactor coolant concentrations at maximum equilibrium conditions
Duration of accident (hr)	72
Atmospheric dispersion (χ/Q) factors	See Table 15A-5 in Appendix 15A
Steam generator in faulted loop	
– Initial water mass (lb)	3.03 E+05
– Primary to secondary leak rate (lb/hr)	52.14[a]
– Iodine partition coefficient	1.0
– Steam released (lb) 0 - 2 hr 2 - 72 hr	 3.031E+05 3.65 E+03
Steam generator in intact loop	
– Primary to secondary leak rate (lb/hr)	52.14[a]
– Iodine partition coefficient	1.0
– Steam released (lb) 0 - 2 hr 2 - 72 hr	 3.031E+05 3.65 E+03
Nuclide data	See Table 15A-4

Note:

a. Equivalent to 150 gpd cooled liquid at 62.4 lb/ft^3.

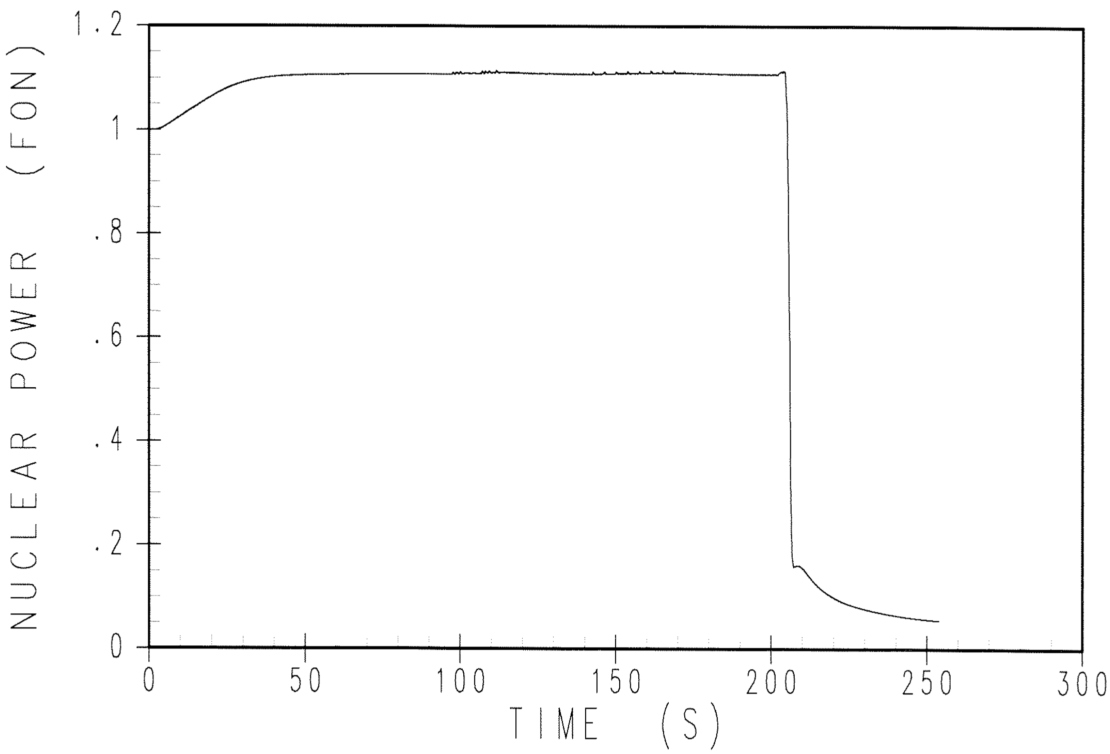

Figure 15.1.2-1

Feedwater Control Valve Malfunction Nuclear Power

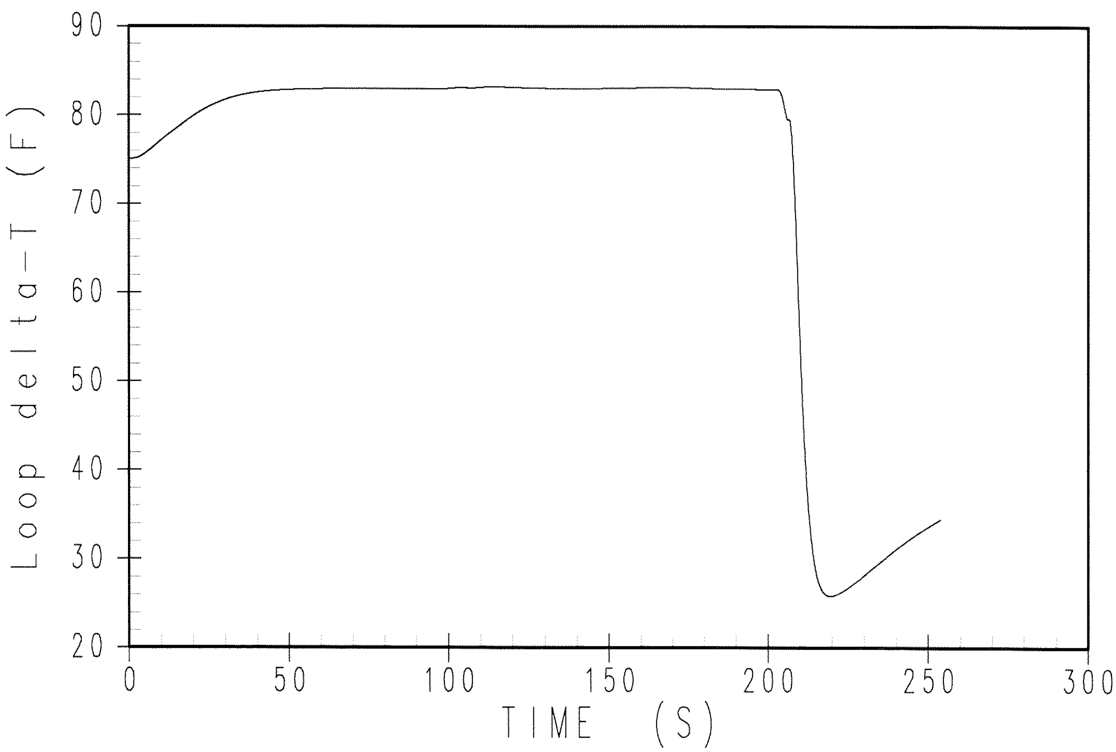

Figure 15.1.2-2

Feedwater Control Valve Malfunction Loop ΔT

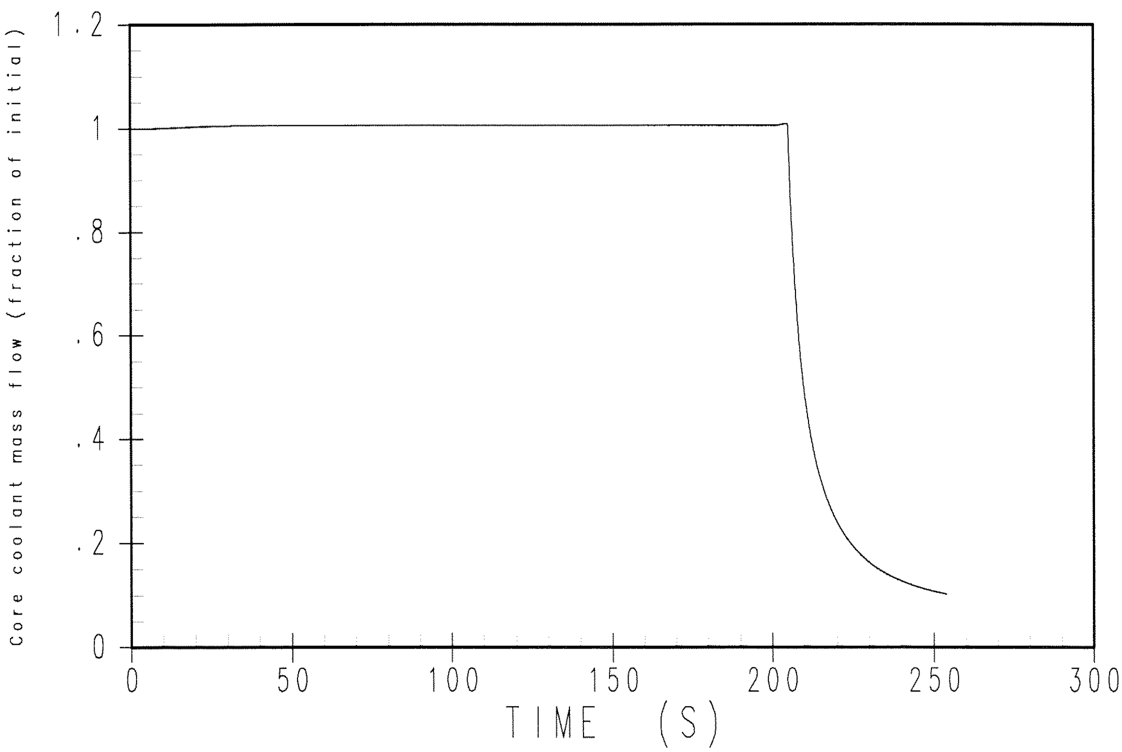

Figure 15.1.2-3

Feedwater Control Valve Malfunction Core Coolant Mass Flow

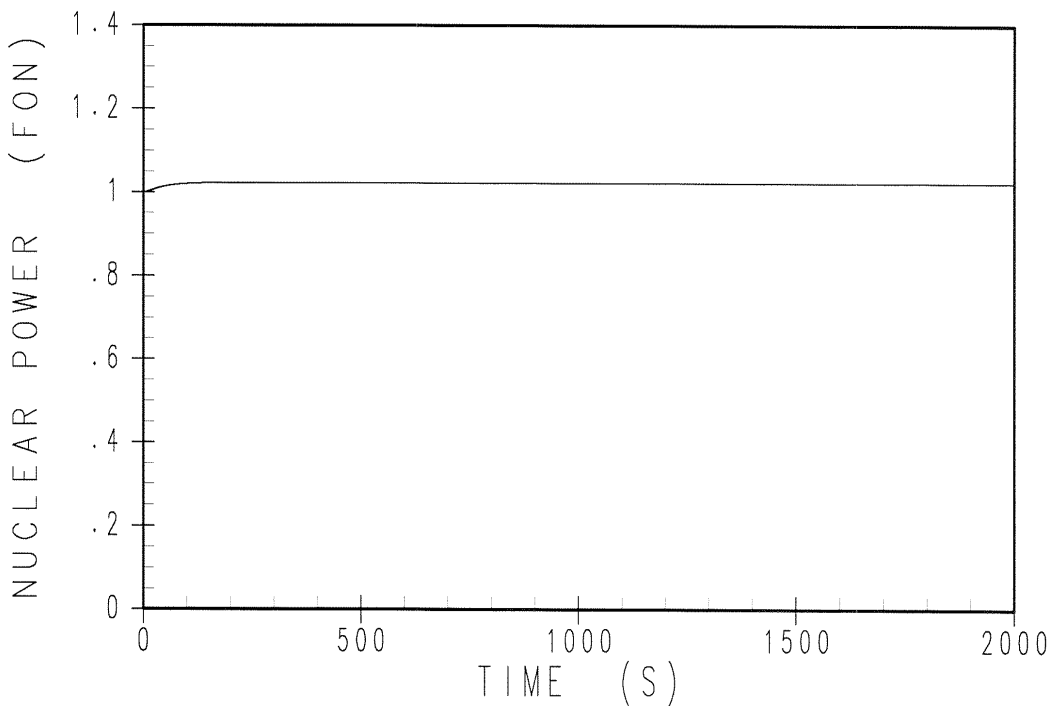

Figure 15.1.3-1

Nuclear Power (Fraction of Nominal) Versus Time for 10-percent Step Load Increase, Manual Control and Minimum Moderator Feedback

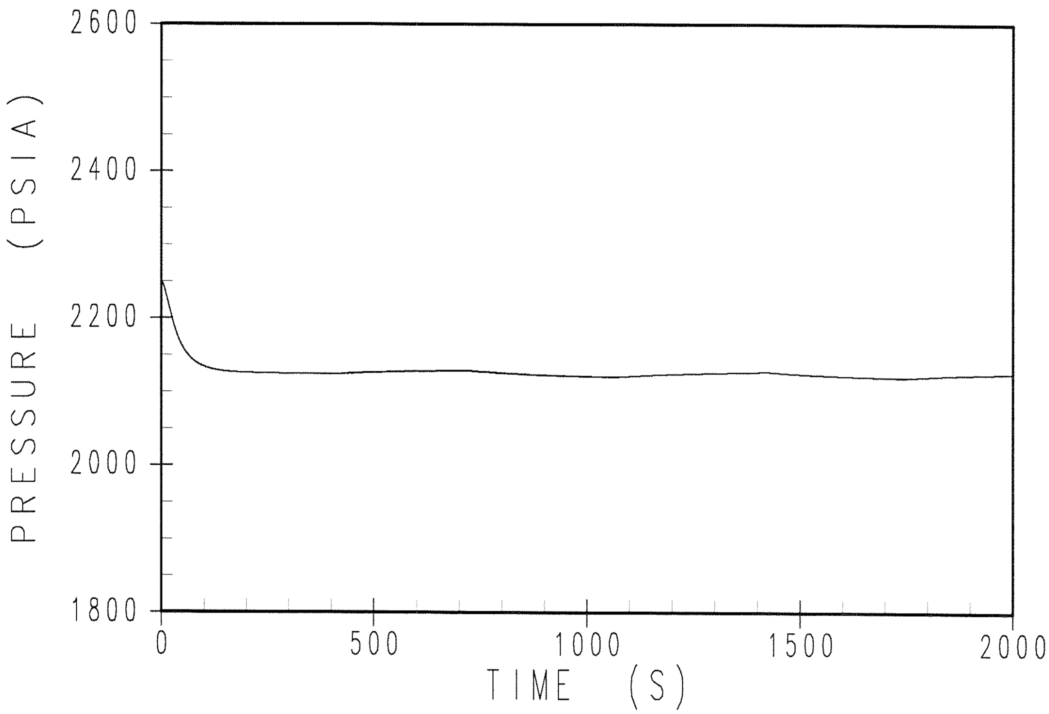

Figure 15.1.3-2

Pressurizer Pressure (psia) Versus Time for 10-percent Step Load Increase, Manual Control and Minimum Moderator Feedback

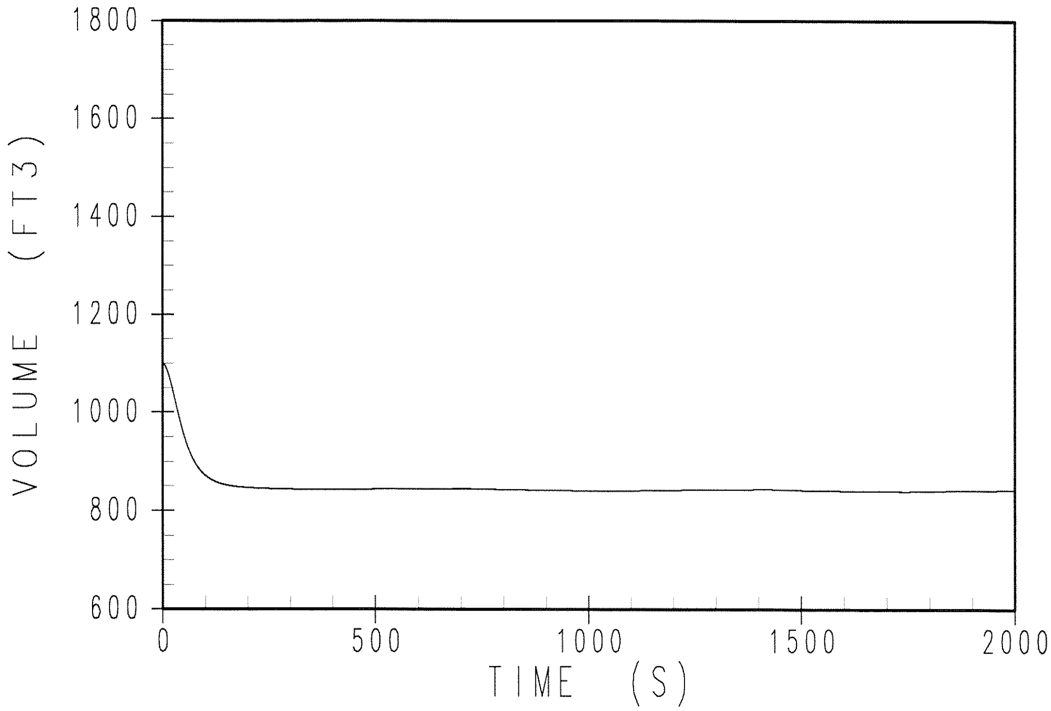

Figure 15.1.3-3

Pressurizer Water Volume (ft^3) Versus Time for 10-percent Step Load Increase, Manual Control and Minimum Moderator Feedback

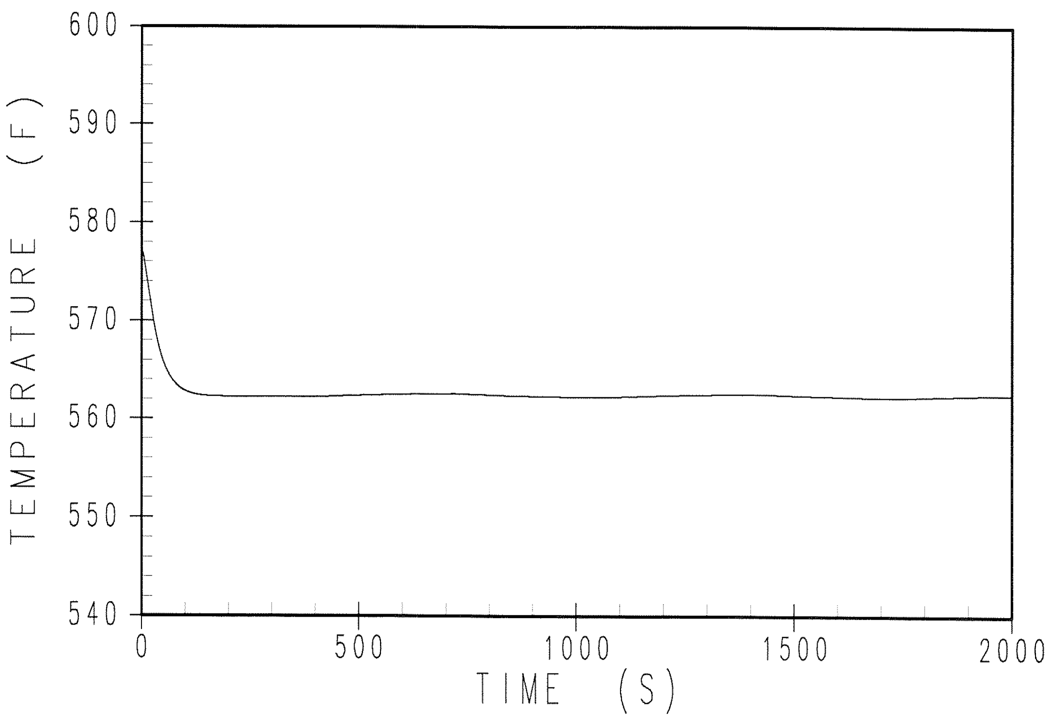

Figure 15.1.3-4

Core Average Temperature (°F) Versus Time for 10-percent Step Load Increase, Manual Control and Minimum Moderator Feedback

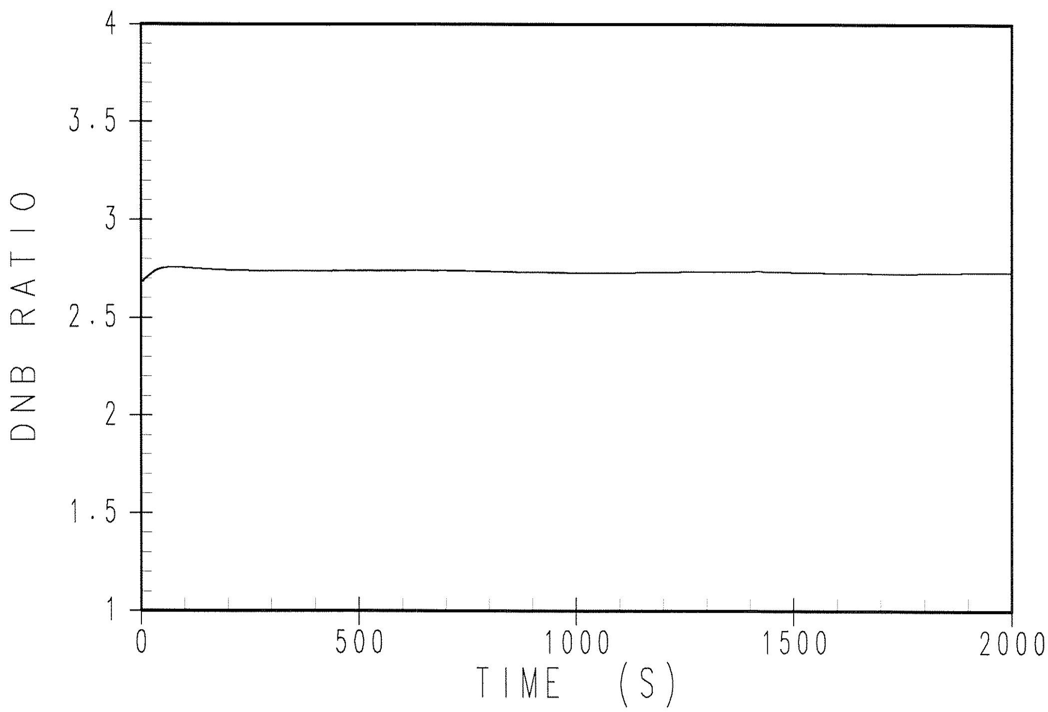

Figure 15.1.3-5

DNBR Versus Time for 10-percent Step Load Increase, Manual Control and Minimum Moderator Feedback

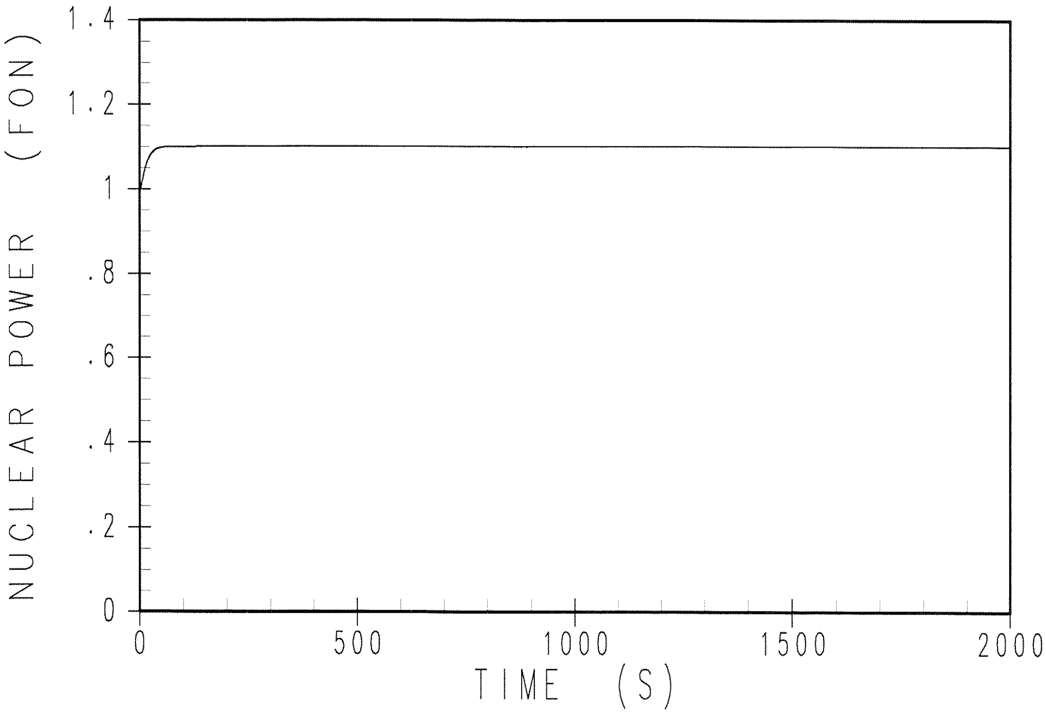

Figure 15.1.3-6

Nuclear Power (Fraction of Nominal) Versus Time for 10-percent Step Load Increase, Manual Control and Maximum Moderator Feedback

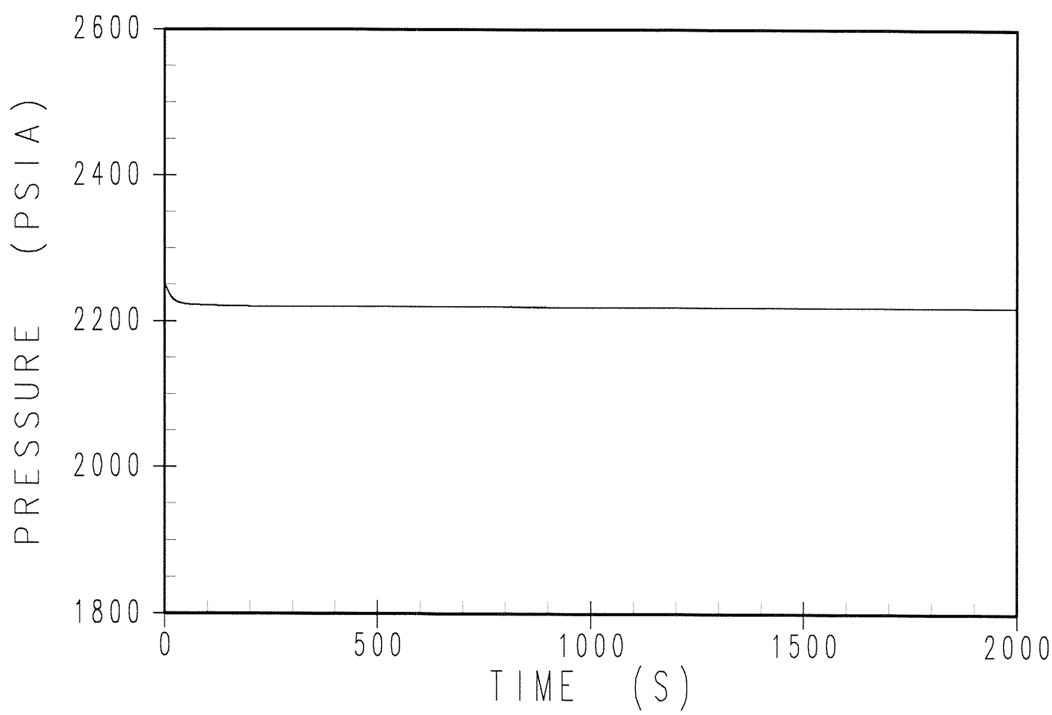

Figure 15.1.3-7

Pressurizer Pressure (psia) Versus Time for 10-percent Step Load Increase, Manual Control and Maximum Moderator Feedback

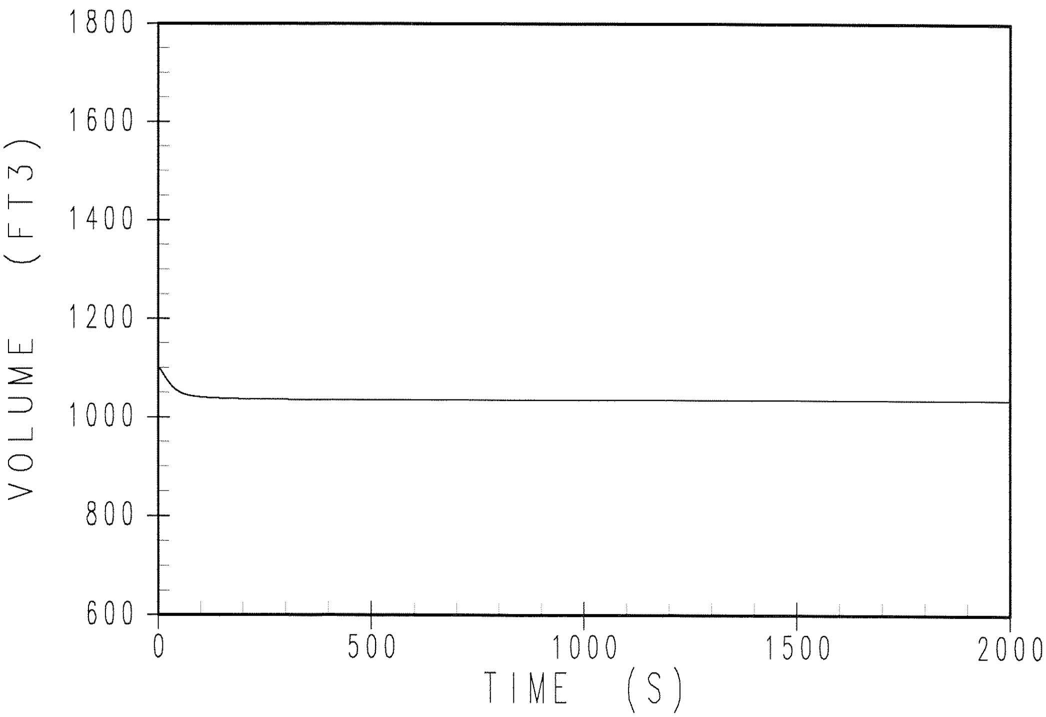

Figure 15.1.3-8

Pressurizer Water Volume (ft^3) Versus Time for 10-percent Step Load Increase, Manual Control and Maximum Moderator Feedback

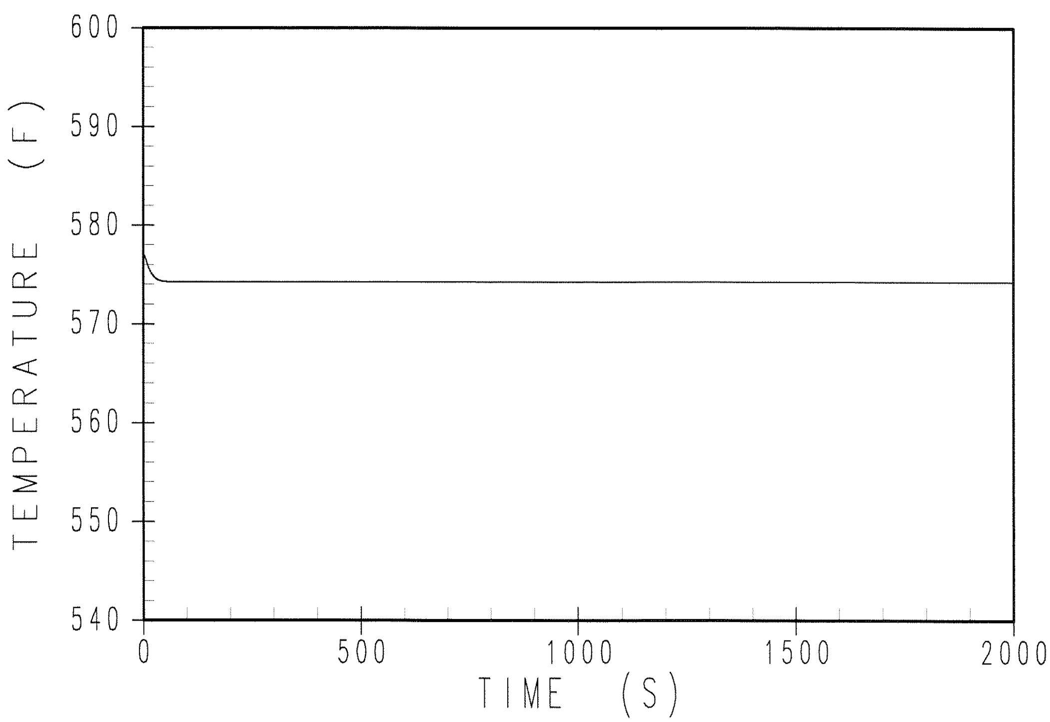

Figure 15.1.3-9

Core Average Temperature (°F) Versus Time for 10-percent Step Load Increase, Manual Control and Maximum Moderator Feedback

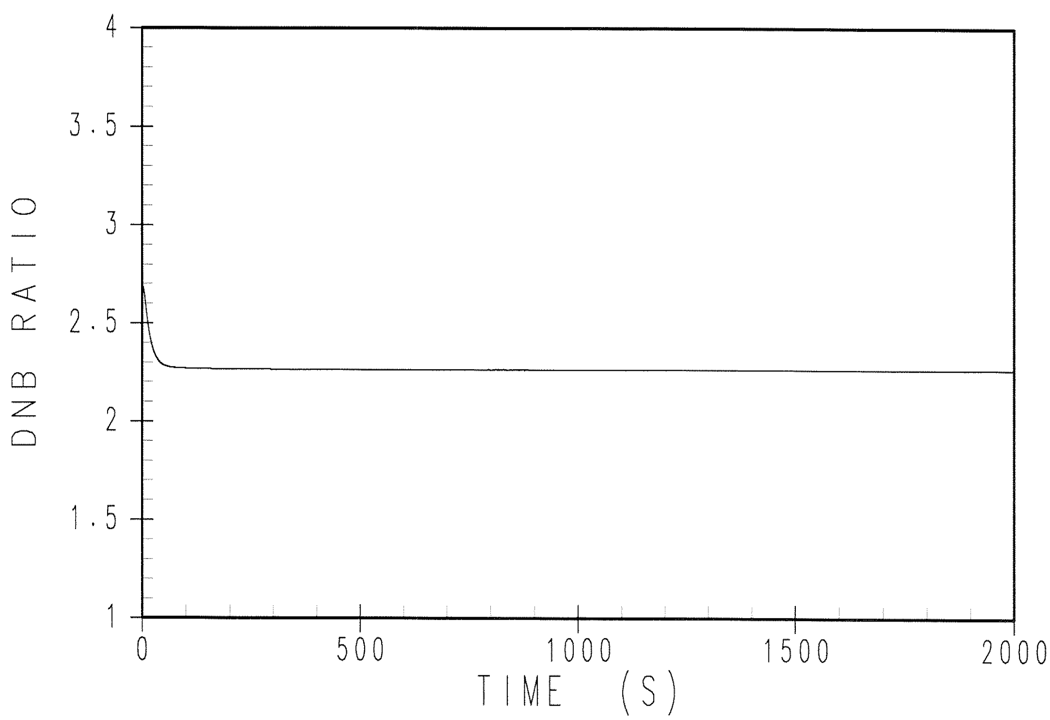

Figure 15.1.3-10

DNBR Versus Time for 10-percent Step Load Increase, Manual Control and Maximum Moderator Feedback

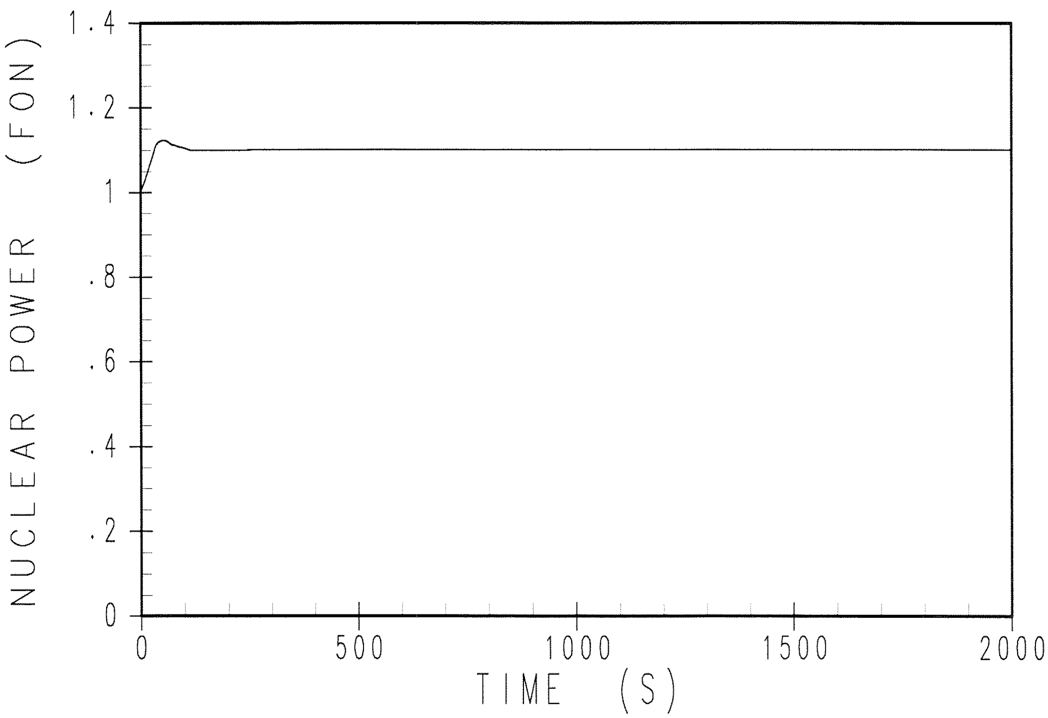

Figure 15.1.3-11

Nuclear Power (Fraction of Nominal) Versus Time for 10-percent Step Load Increase, Automatic Control and Minimum Moderator Feedback

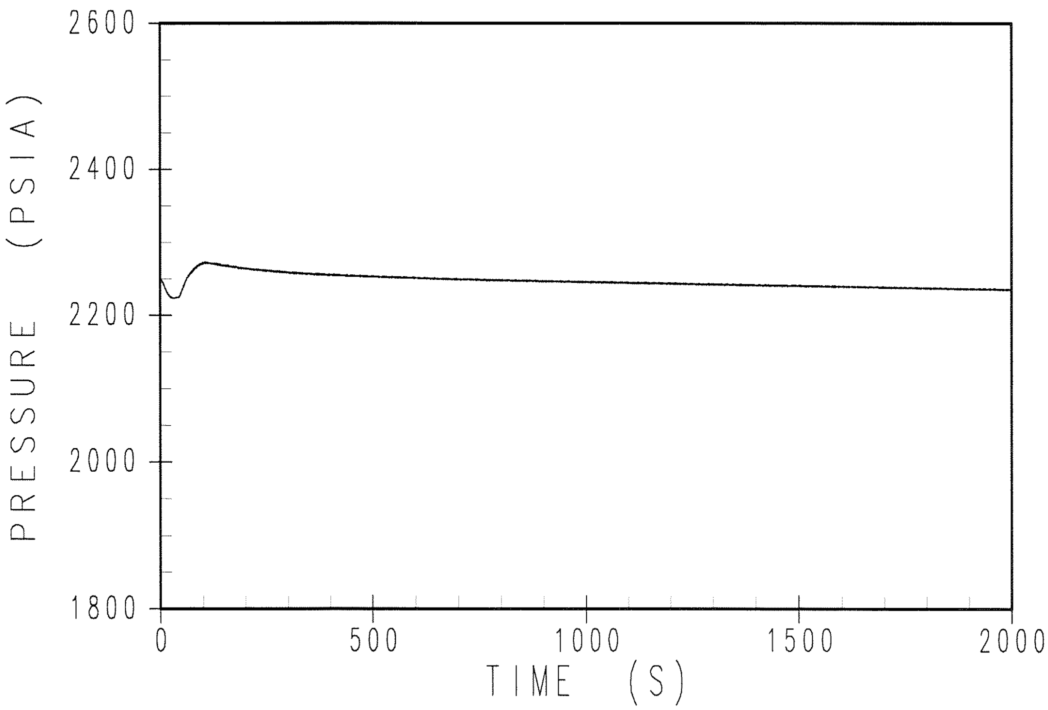

Figure 15.1.3-12

Pressurizer Pressure (psia) Versus Time for 10-percent Step Load Increase, Automatic Control and Minimum Moderator Feedback

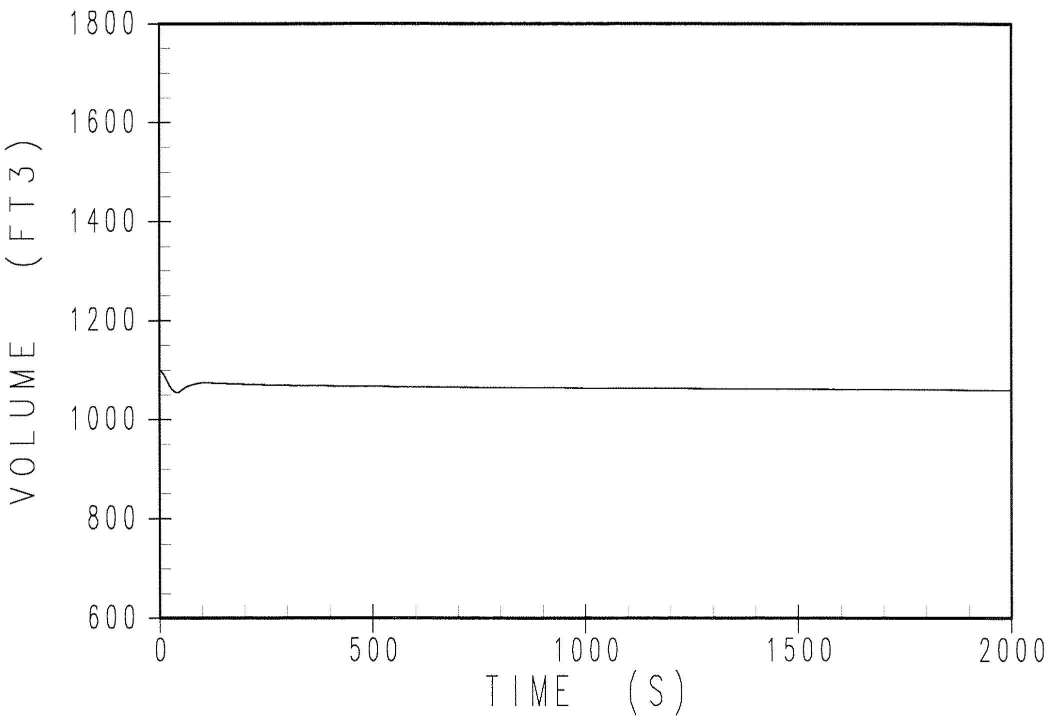

Figure 15.1.3-13

Pressurizer Water Volume (ft^3) Versus Time for 10-percent Step Load Increase, Automatic Control and Minimum Moderator Feedback

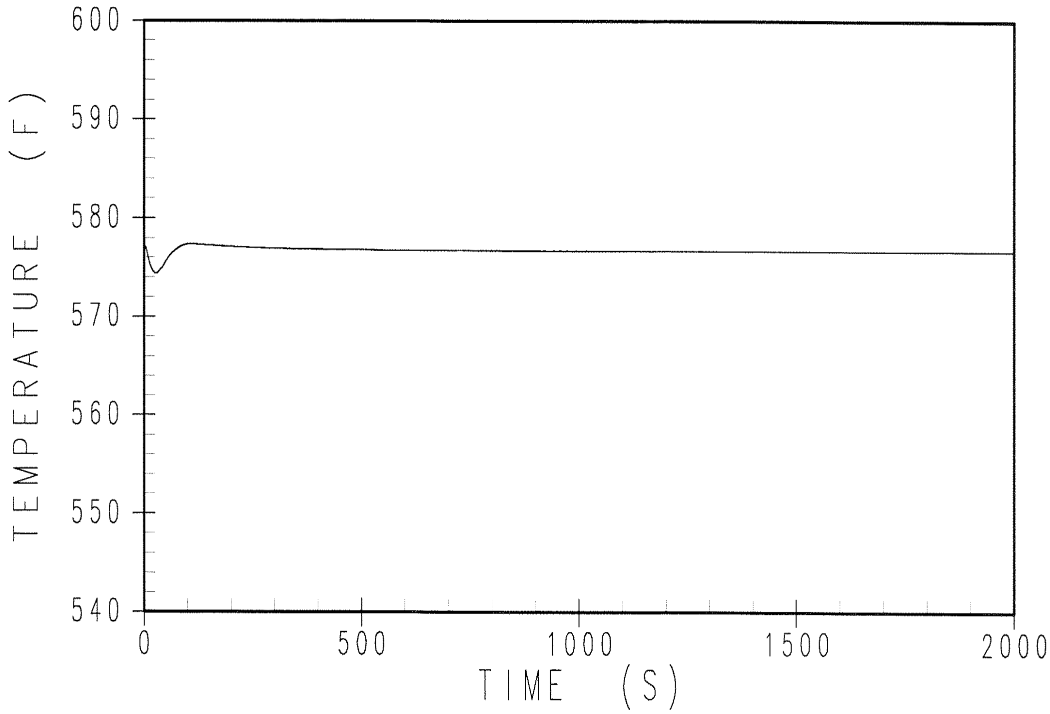

Figure 15.1.3-14

Core Average Temperature (°F) Versus Time for 10-percent Step Load Increase, Automatic Control and Minimum Moderator Feedback

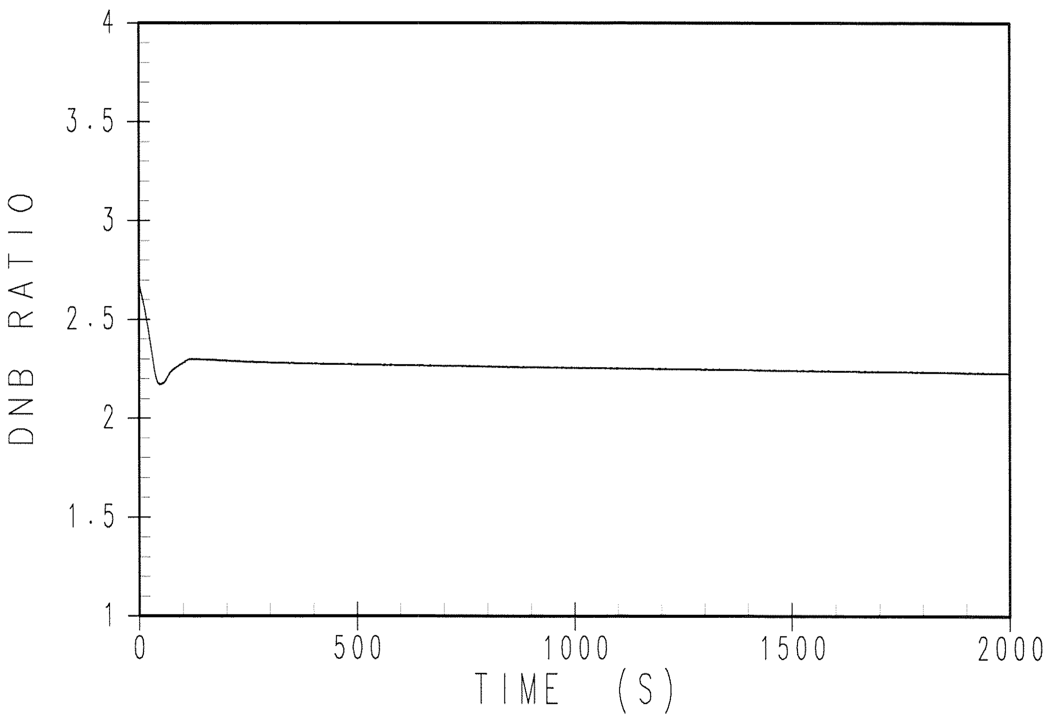

Figure 15.1.3-15

DNBR Versus Time for 10-percent Step Load Increase, Automatic Control and Minimum Moderator Feedback

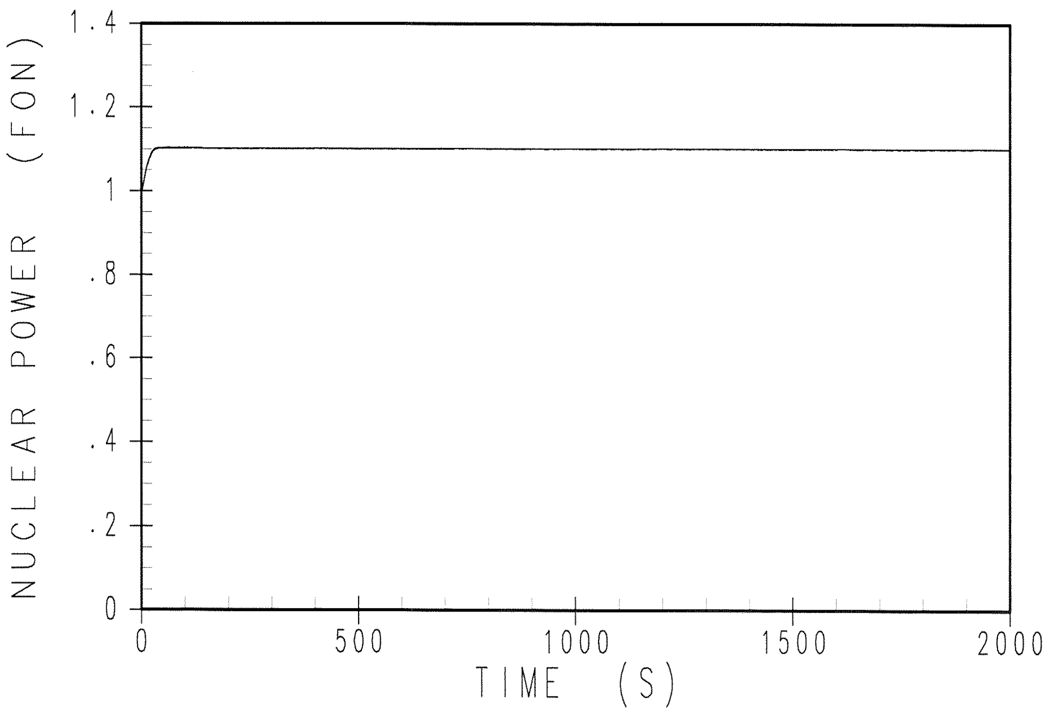

Figure 15.1.3-16

Nuclear Power (Fraction of Nominal) Versus Time for 10-percent Step Load Increase, Automatic Control and Maximum Moderator Feedback

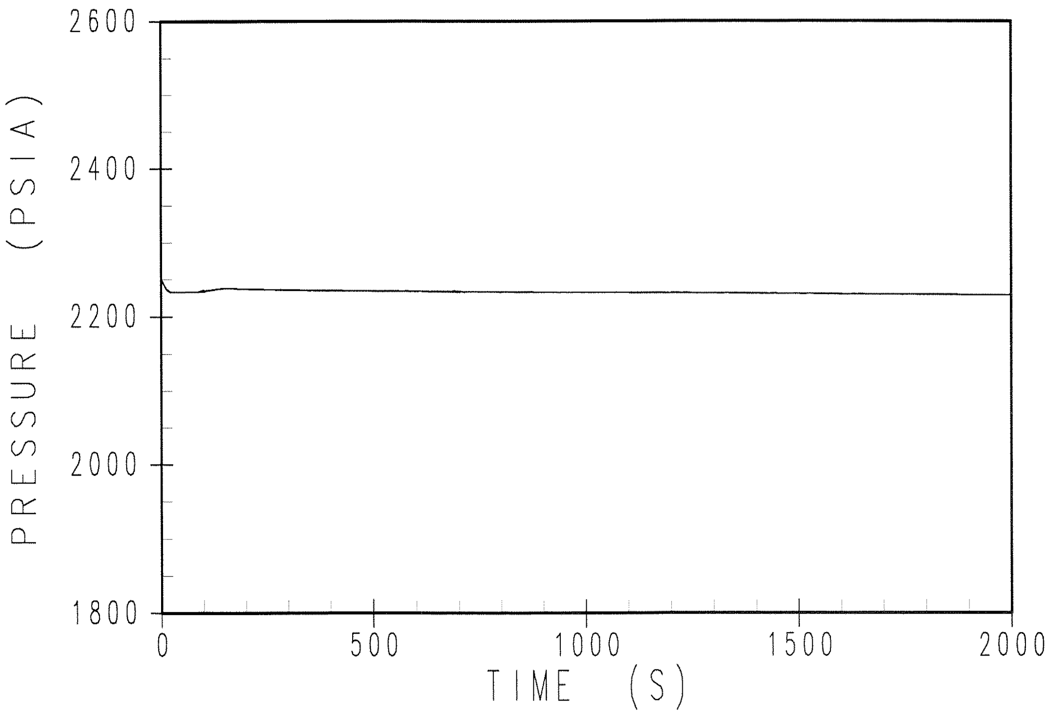

Figure 15.1.3-17

Pressurizer Pressure (psia) Versus Time for 10-percent Step Load Increase, Automatic Control and Maximum Moderator Feedback

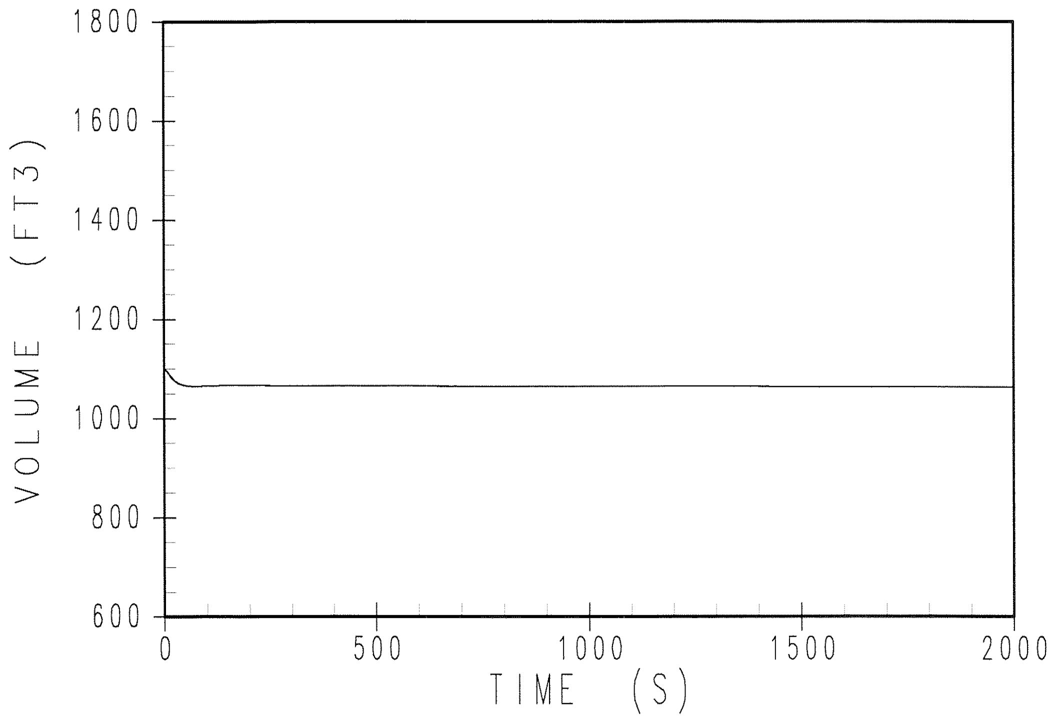

Figure 15.1.3-18

Pressurizer Water Volume (ft^3) Versus Time for 10-percent Step Load Increase, Automatic Control and Maximum Moderator Feedback

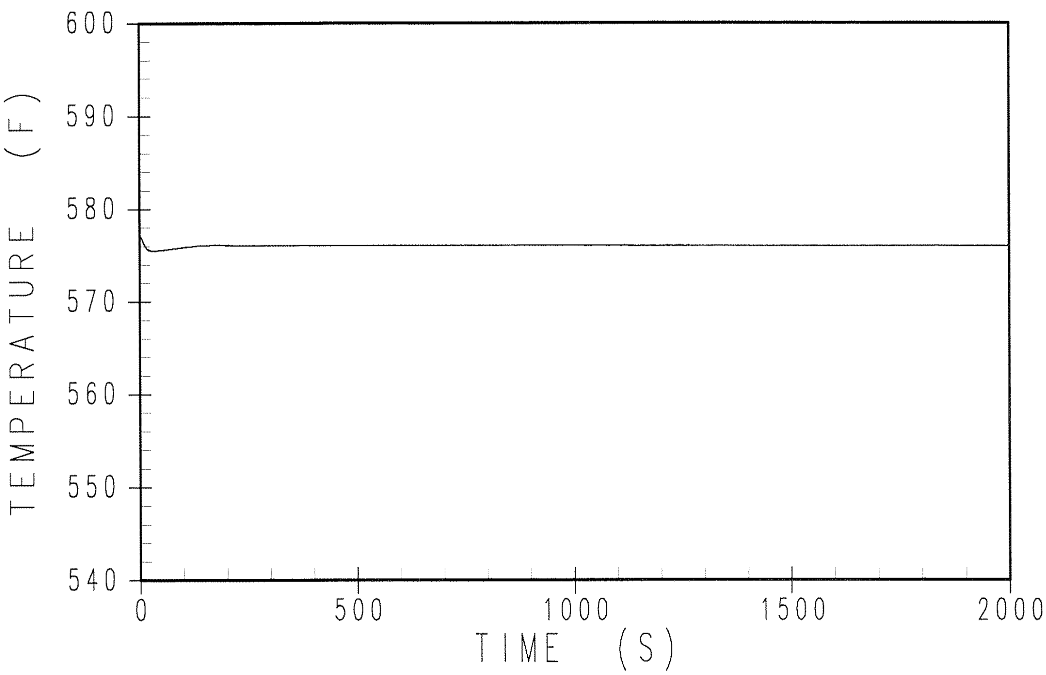

Figure 15.1.3-19

Core Average Temperature (°F) Versus Time for 10-percent Step Load Increase, Automatic Control and Maximum Moderator Feedback

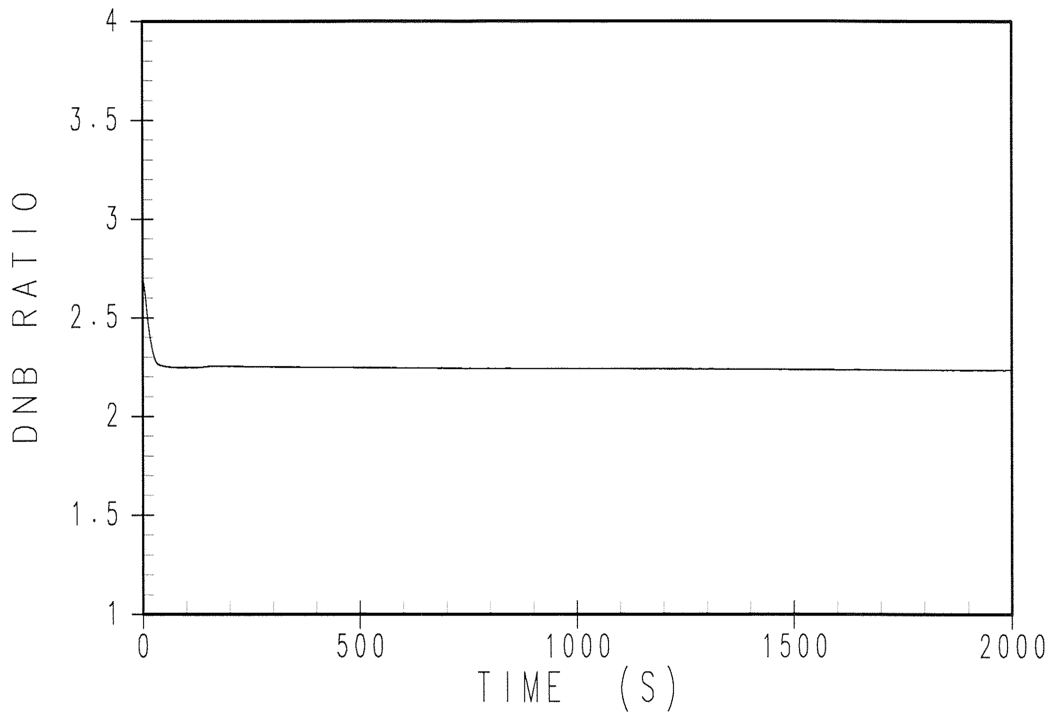

Figure 15.1.3-20

DNBR Versus Time for 10-percent Step Load Increase, Automatic Control and Maximum Moderator Feedback

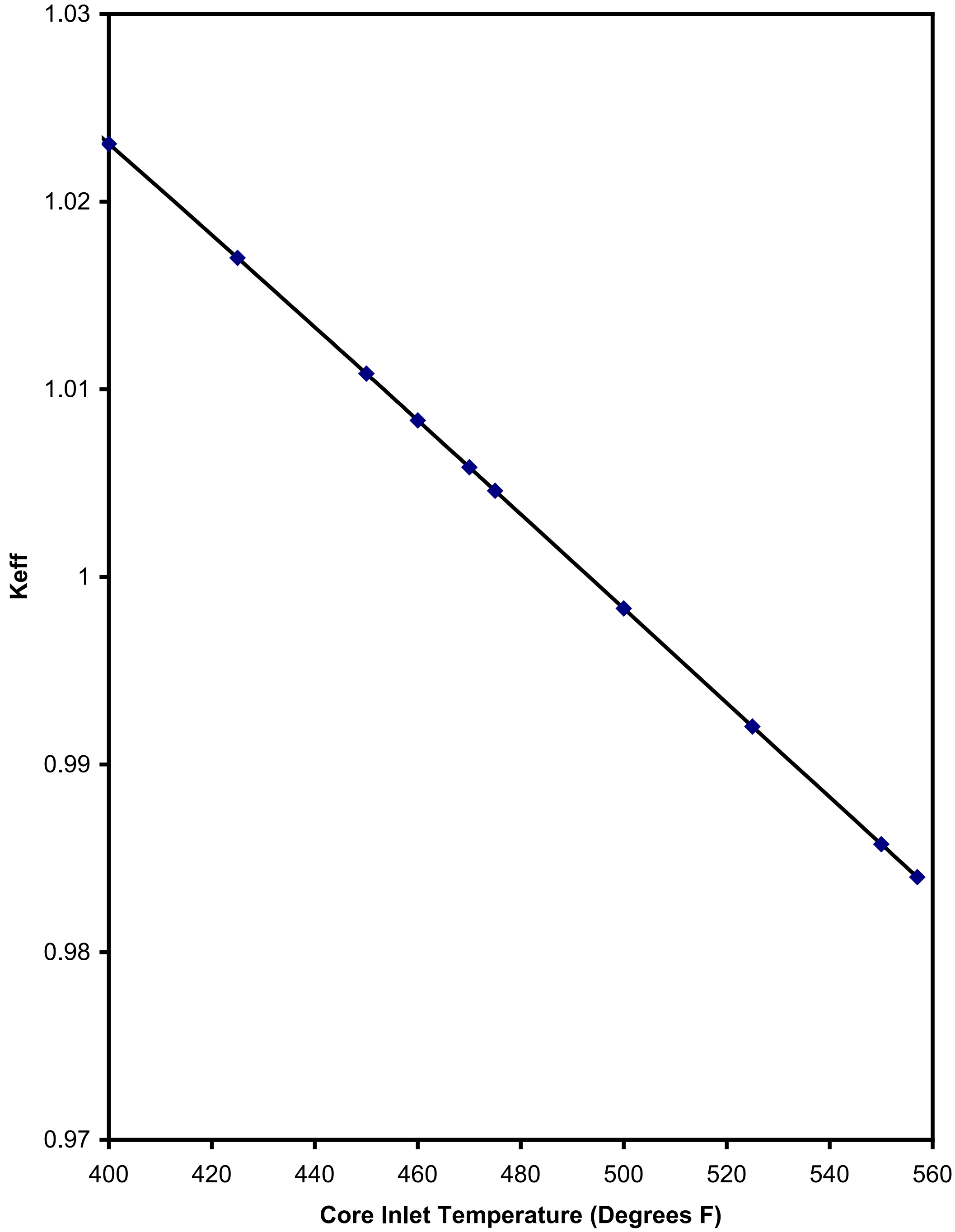

Figure 15.1.4-1

K_{eff} Versus Core Inlet Temperature
Steam Line Break Events

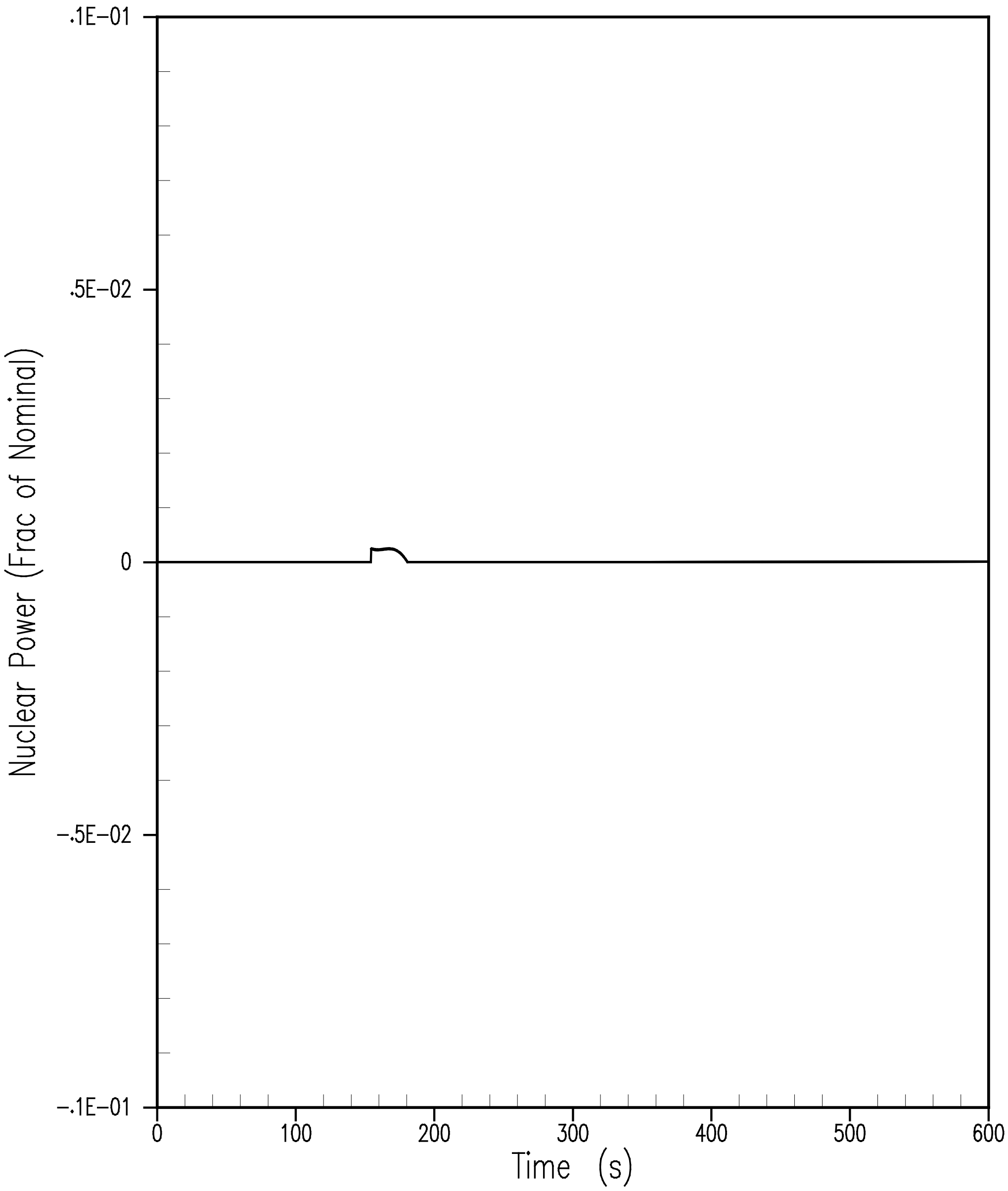

Figure 15.1.4-2

Nuclear Power Transient
Inadvertent Opening of a Steam Generator Relief or Safety Valve

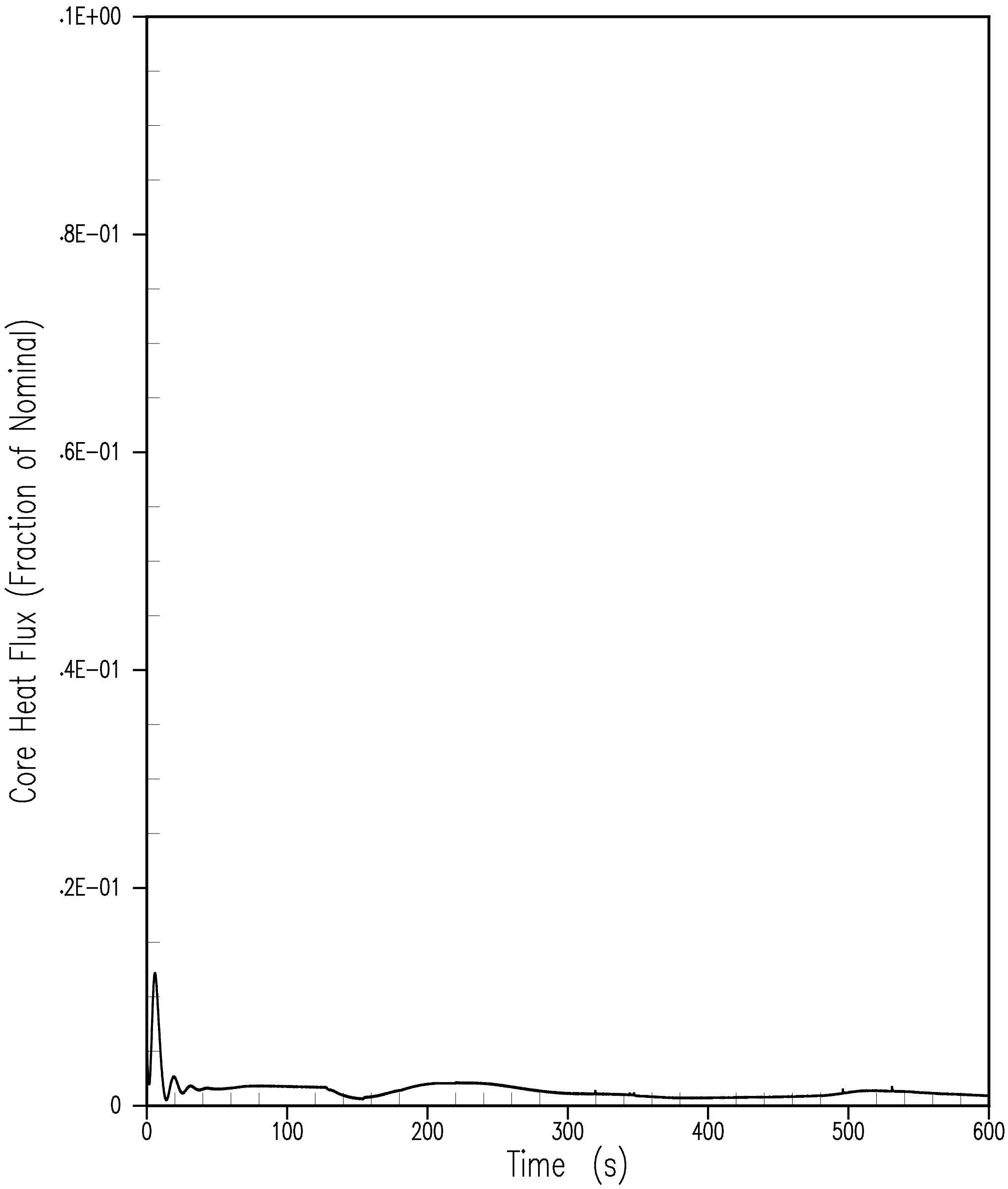

Figure 15.1.4-3

Core Heat Flux Transient
Inadvertent Opening of a Steam Generator Relief or Safety Valve

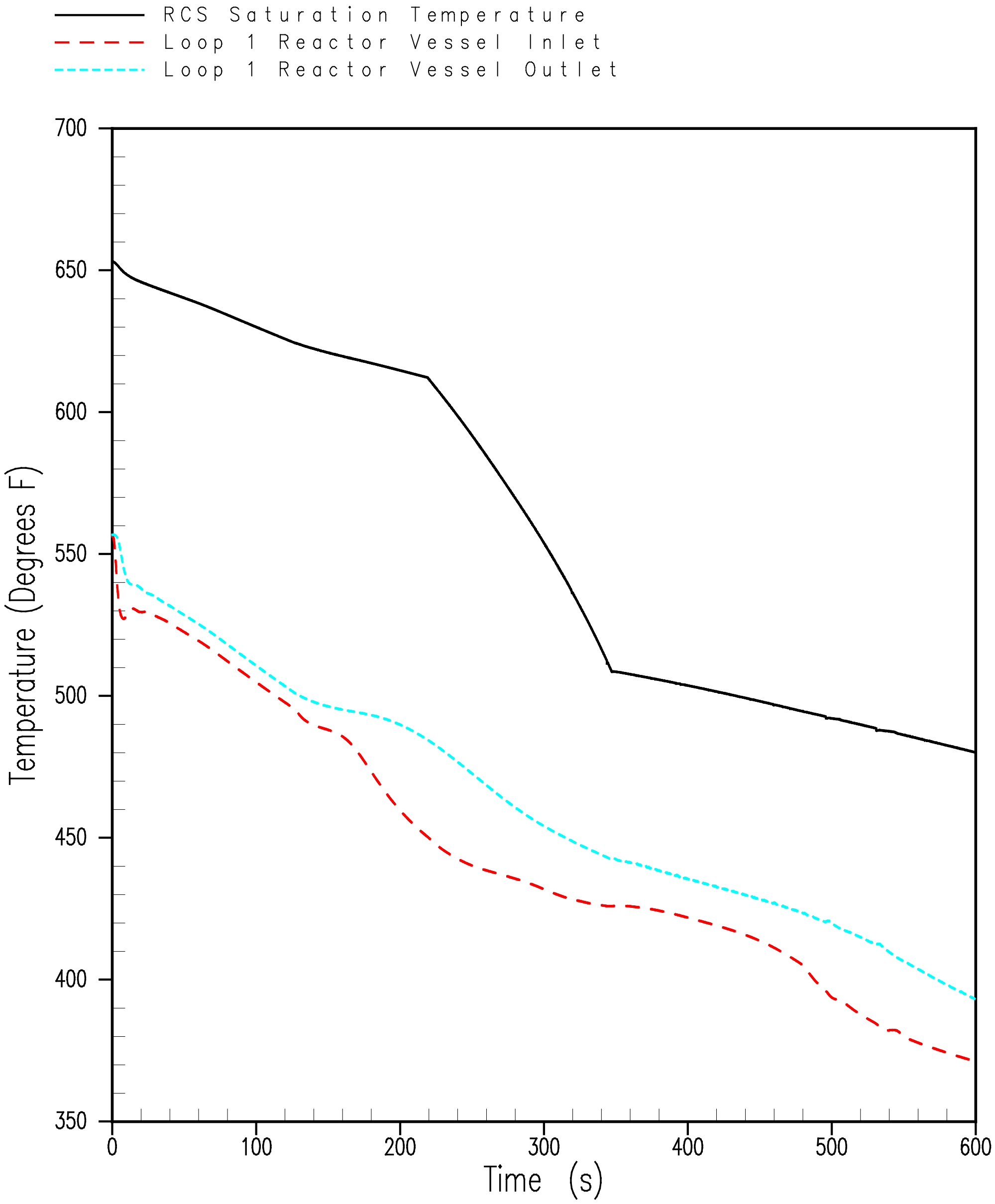

Figure 15.1.4-4

Loop 1 Reactor Coolant Temperatures
Inadvertent Opening of a Steam Generator Relief or Safety Valve

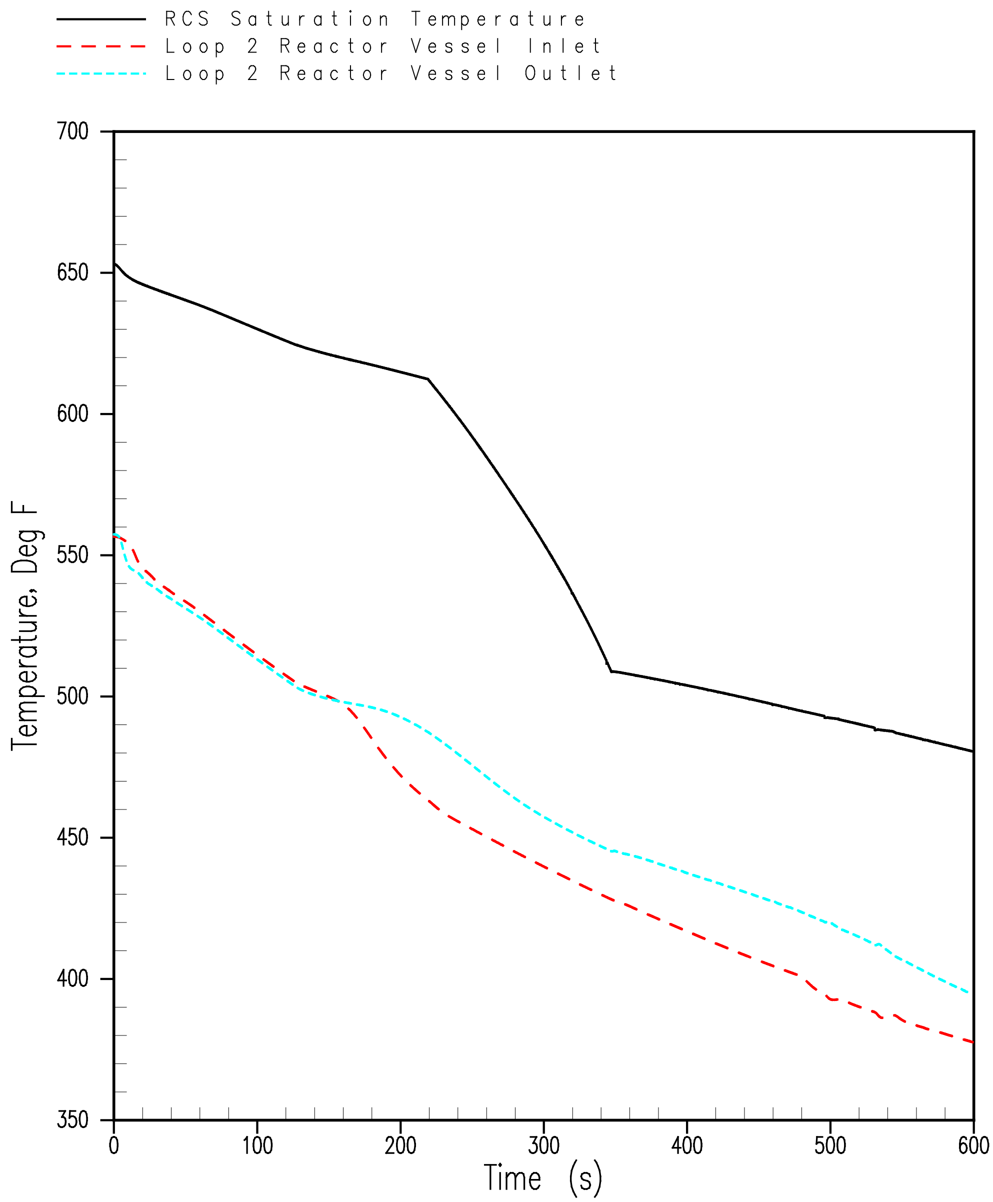

Figure 15.1.4-5

Loop 2 (Faulted Loop) Reactor Coolant Temperatures
Inadvertent Opening of a Steam Generator Relief or Safety Valve

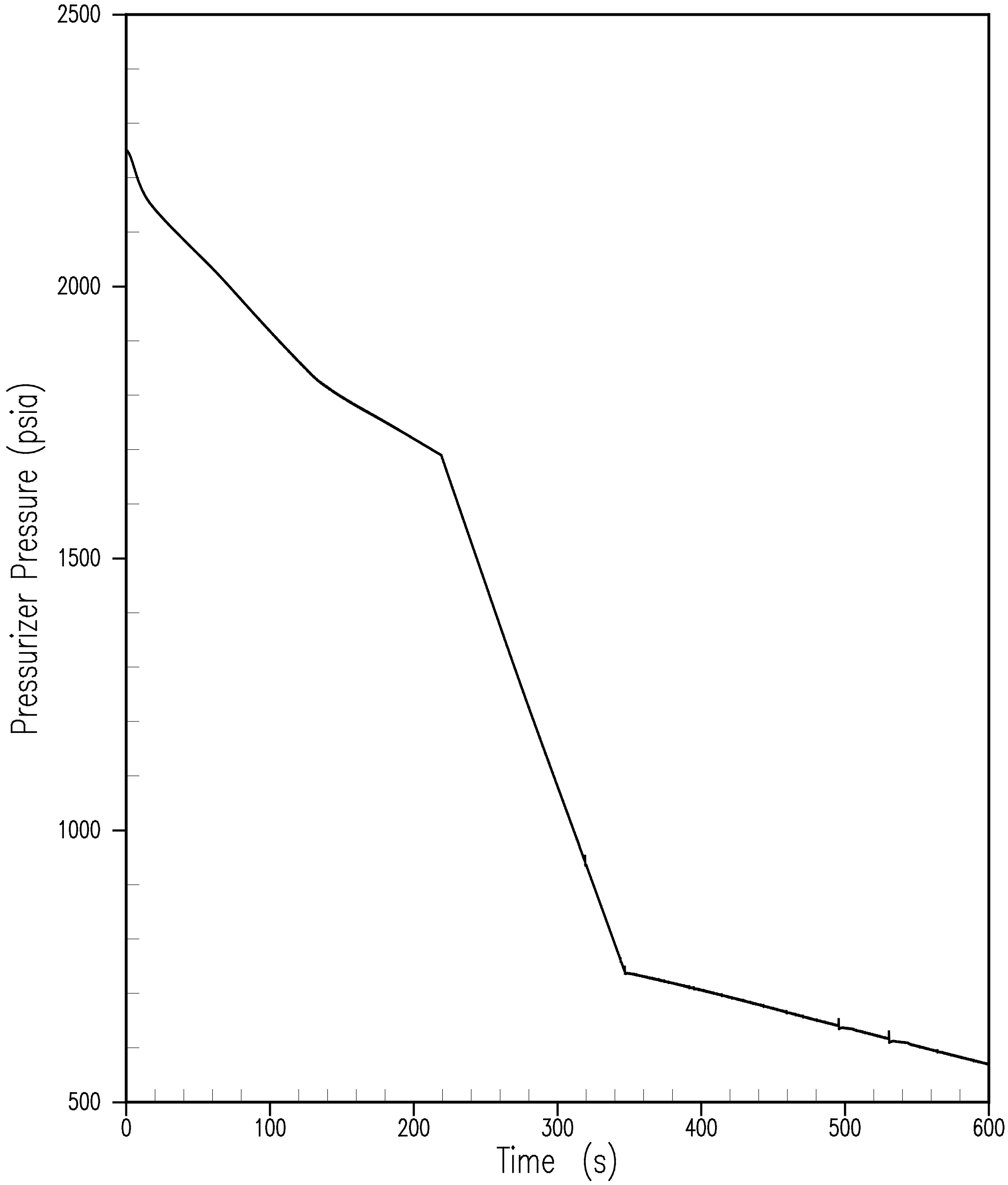

Figure 15.1.4-6

Reactor Coolant System Pressure Transient
Inadvertent Opening of a Steam Generator Relief or Safety Valve

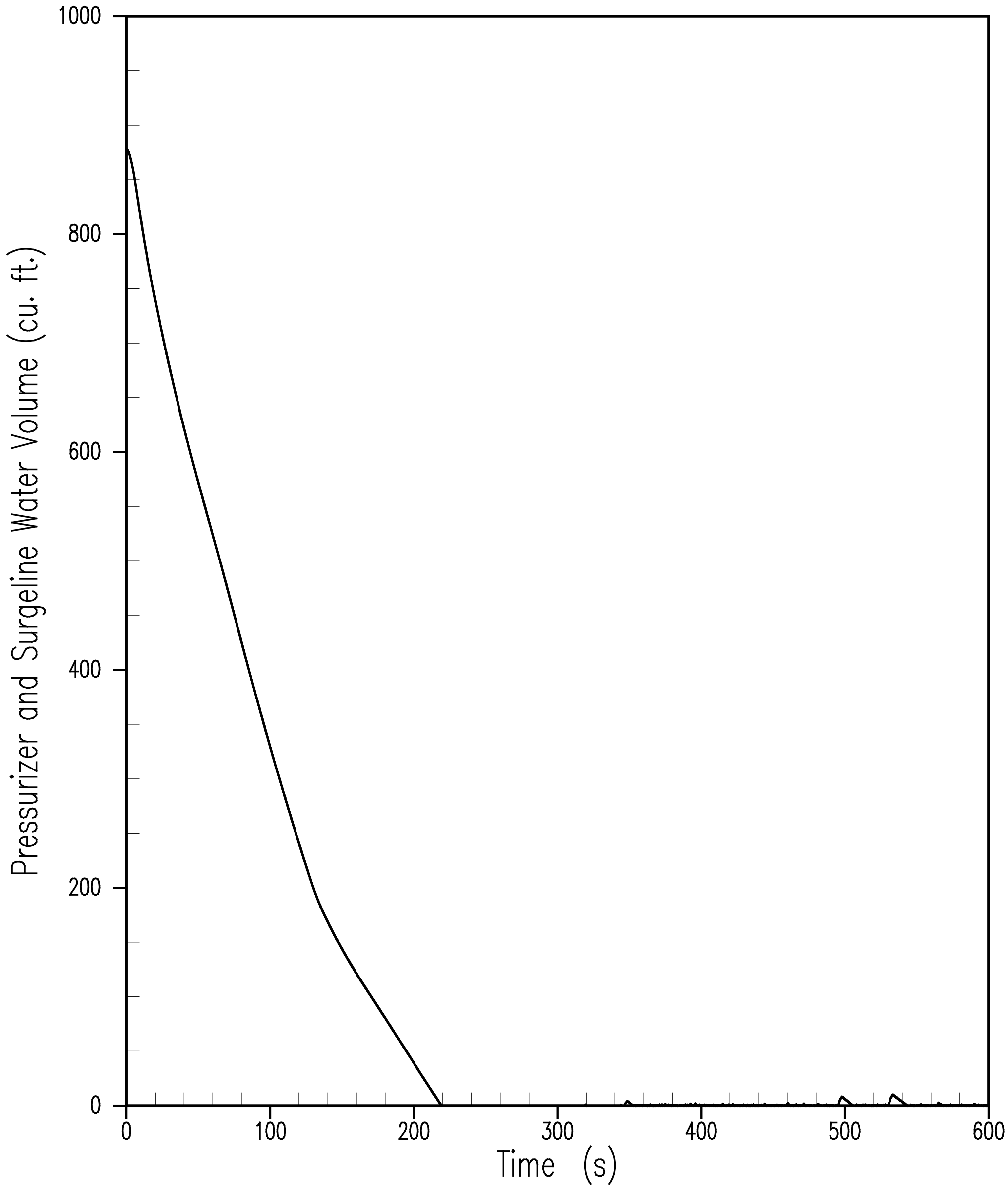

Figure 15.1.4-7

Pressurizer Water Volume Transient
Inadvertent Opening of a Steam Generator Relief or Safety Valve

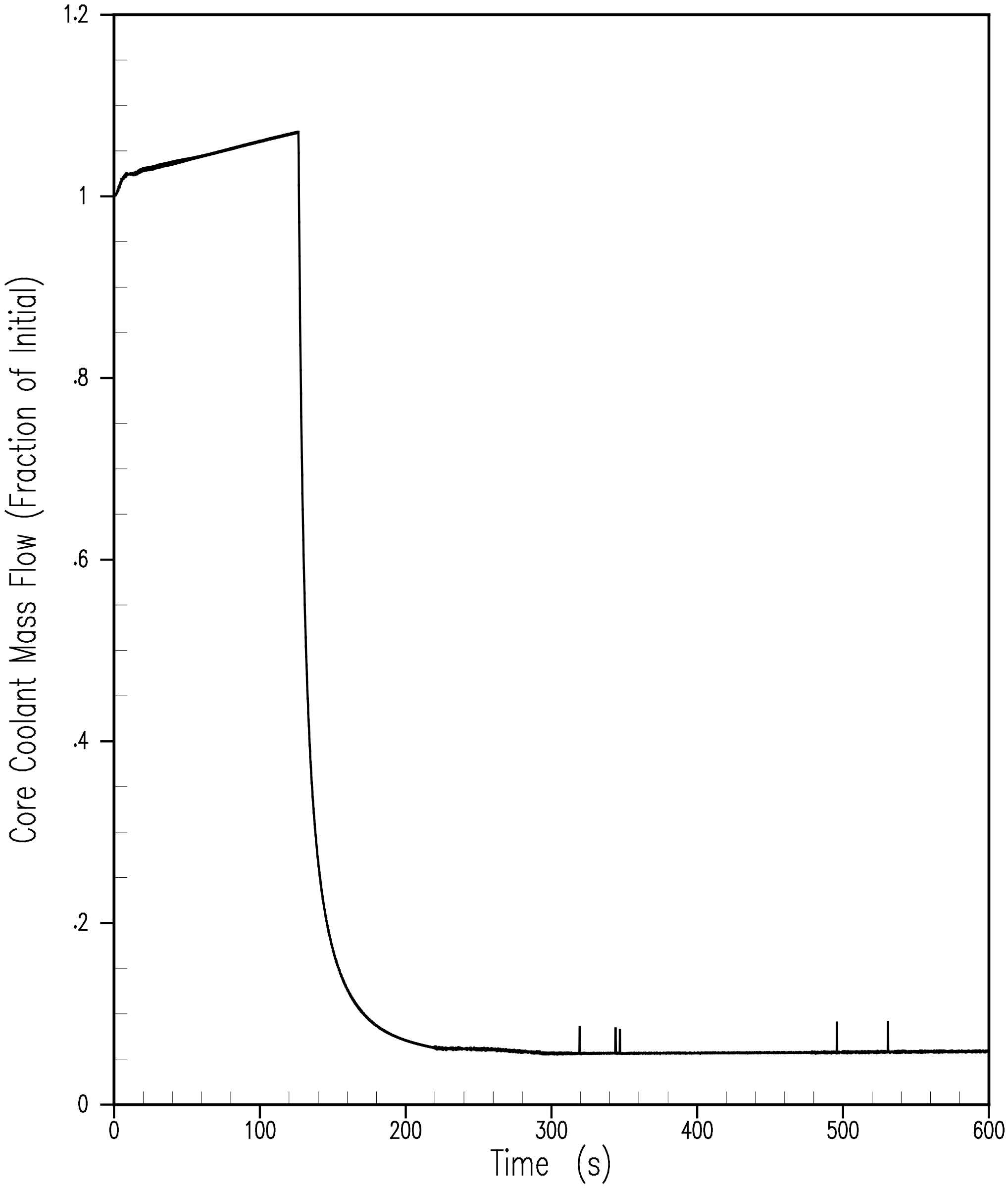

Figure 15.1.4-8

Core Flow Transient
Inadvertent Opening of a Steam Generator Relief or Safety Valve

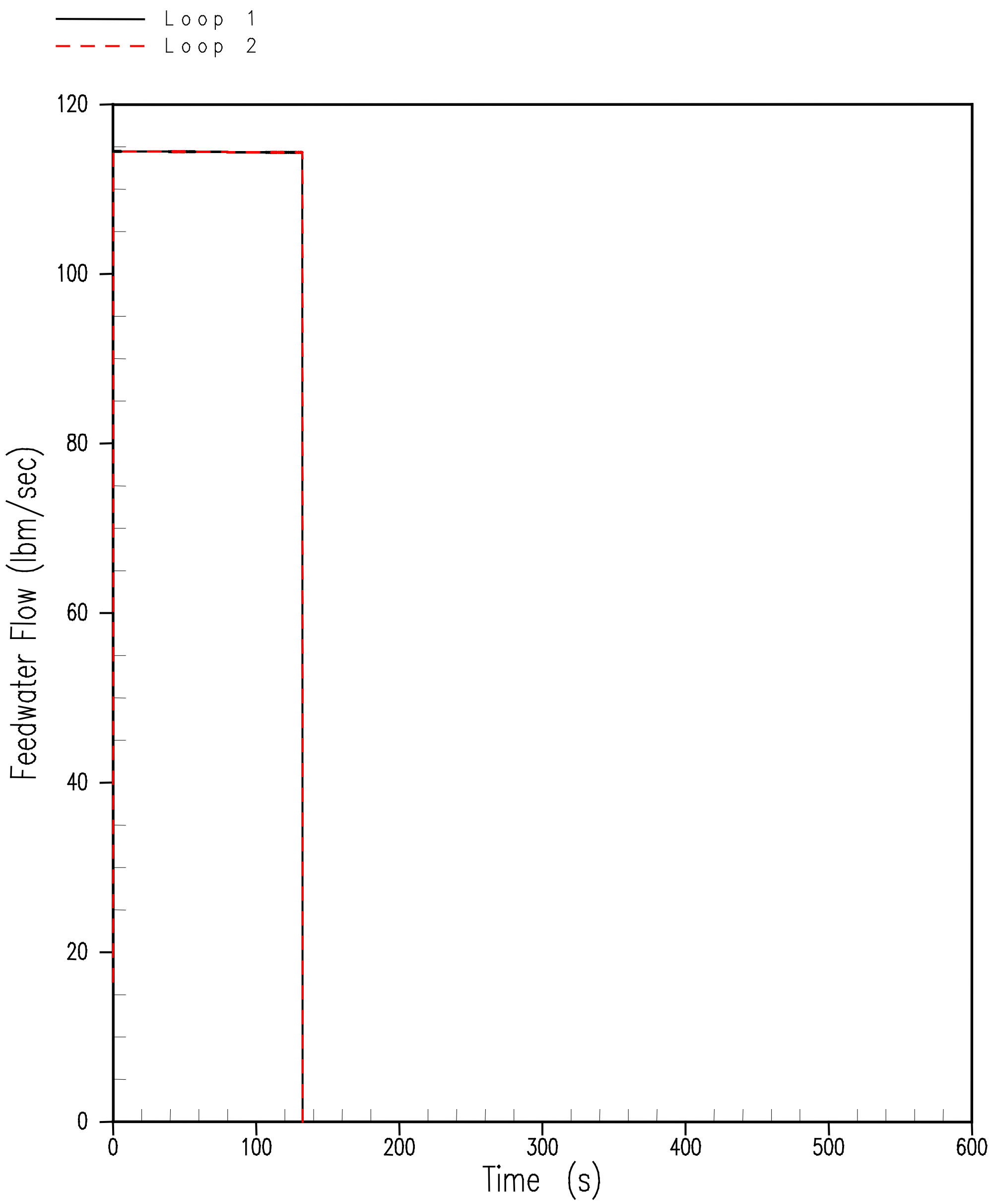

Figure 15.1.4-9

Feedwater Flow Transient
Inadvertent Opening of a Steam Generator Relief or Safety Valve

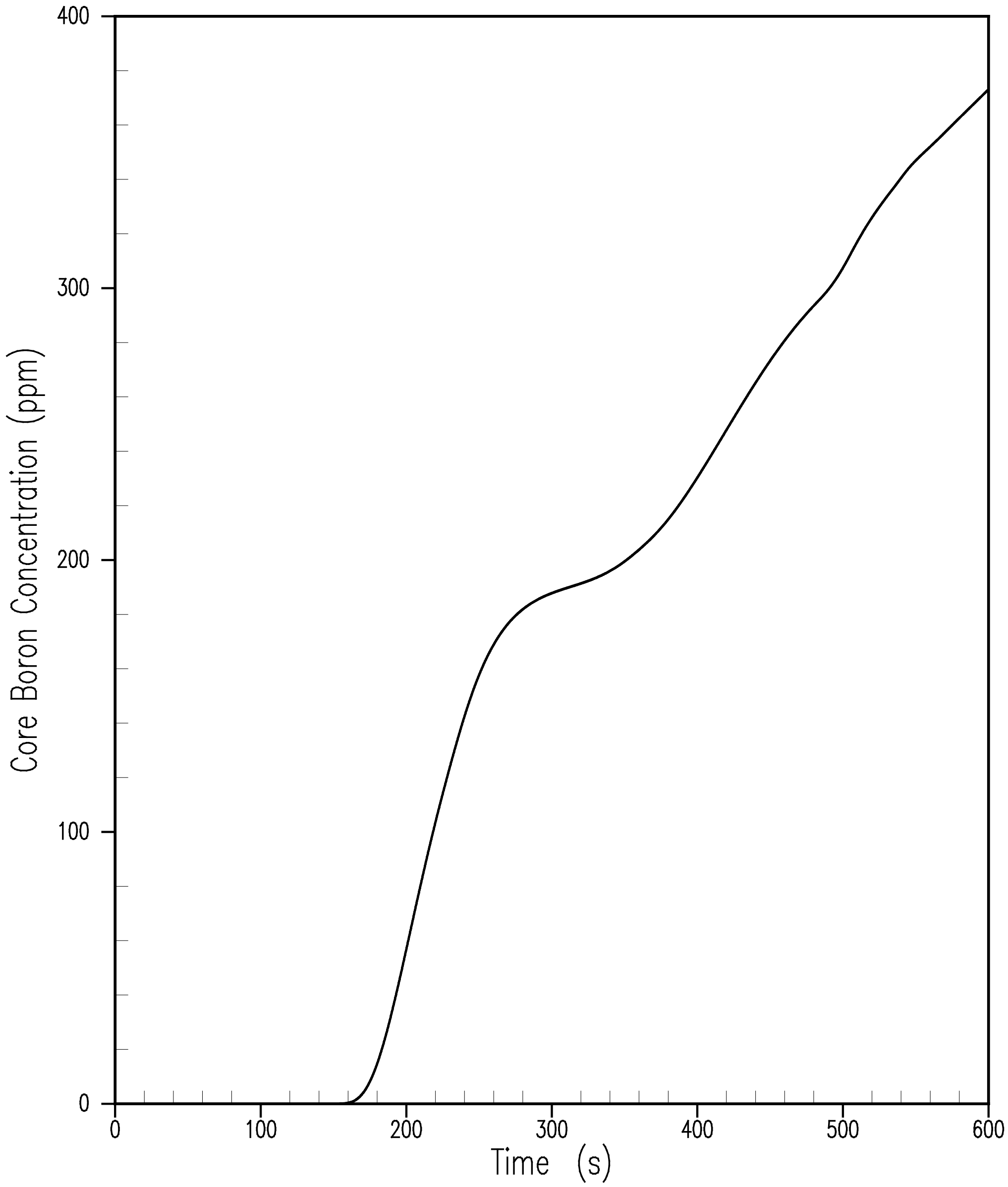

Figure 15.1.4-10

Core Boron Transient
Inadvertent Opening of a Steam Generator Relief or Safety Valve

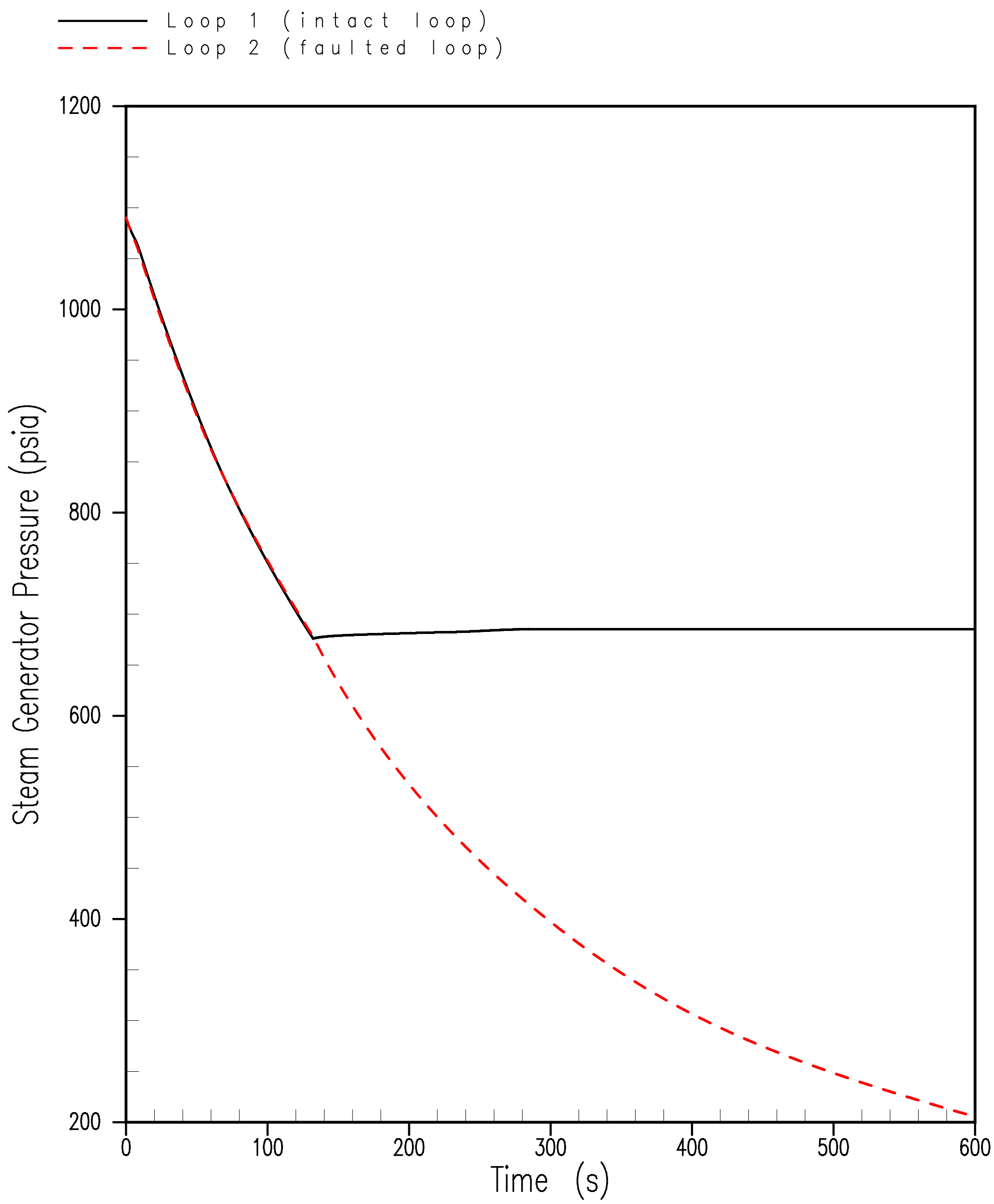

Figure 15.1.4-11

Steam Pressure Transient
Inadvertent Opening of a Steam Generator Relief or Safety Valve

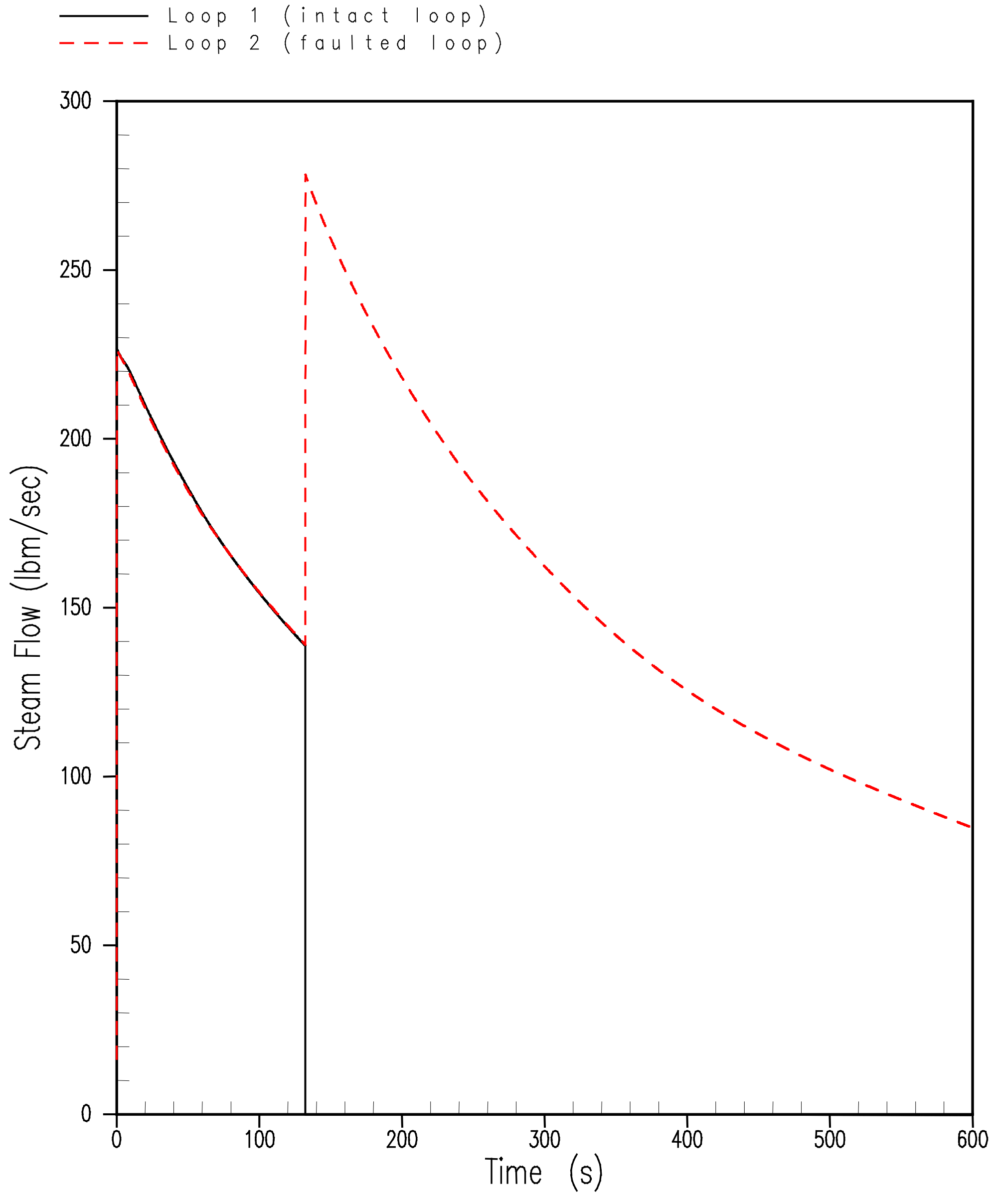

Figure 15.1.4-12

Steam Flow Transient
Inadvertent Opening of a Steam Generator Relief or Safety Valve

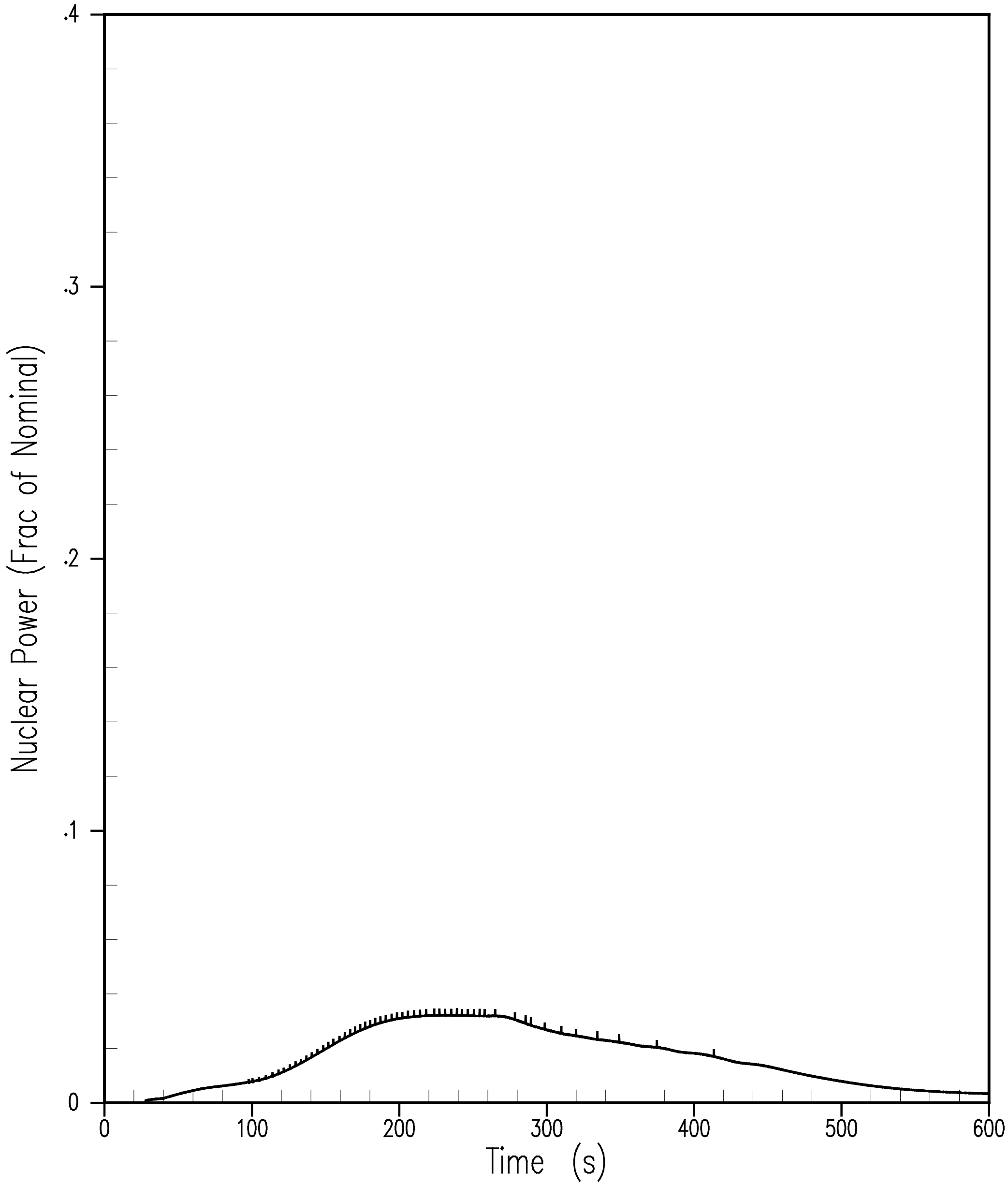

Figure 15.1.5-1

Nuclear Power Transient Steam System Piping Feature

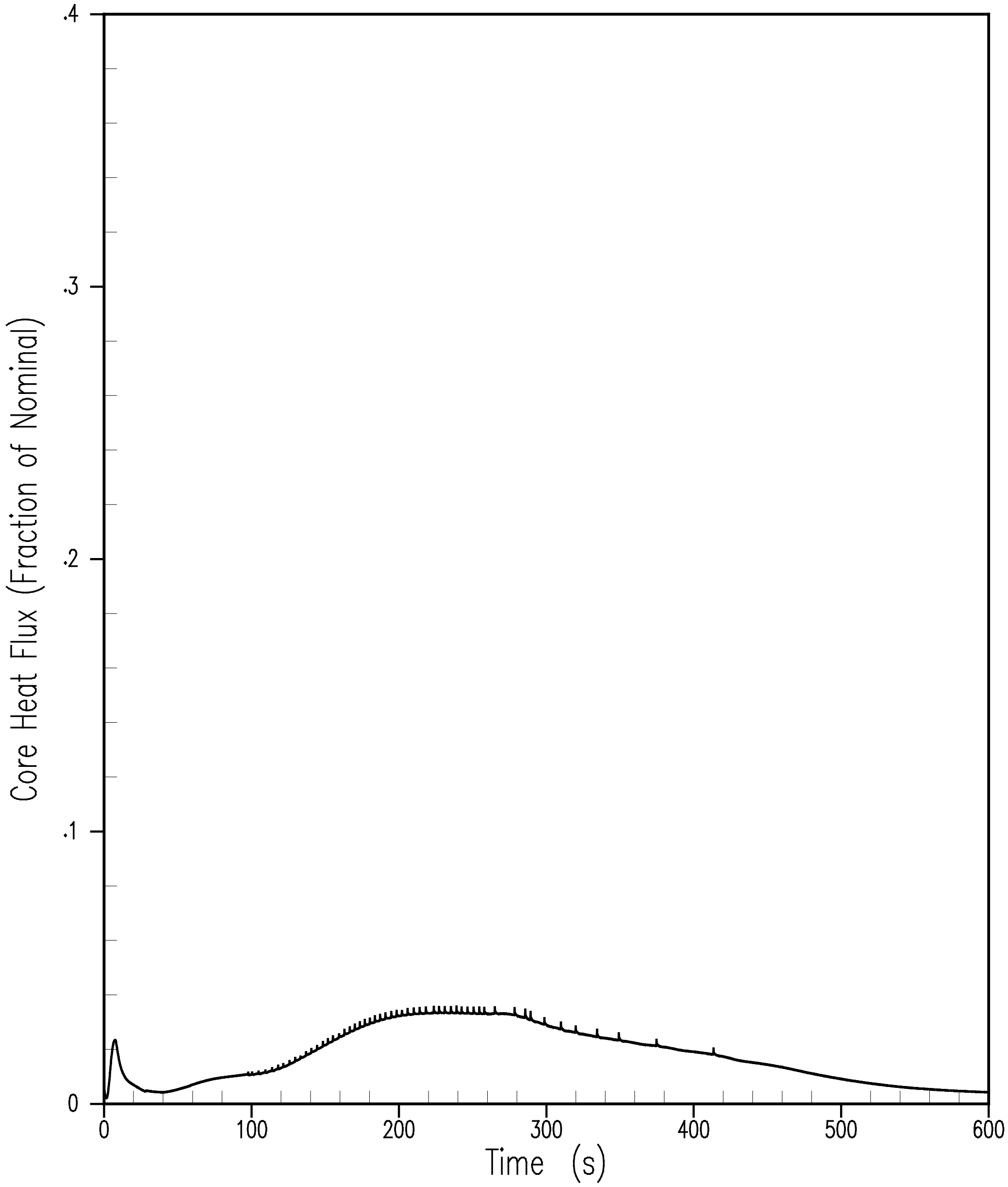

Figure 15.1.5-2

Core Heat Flux Transient Steam System Piping Failure

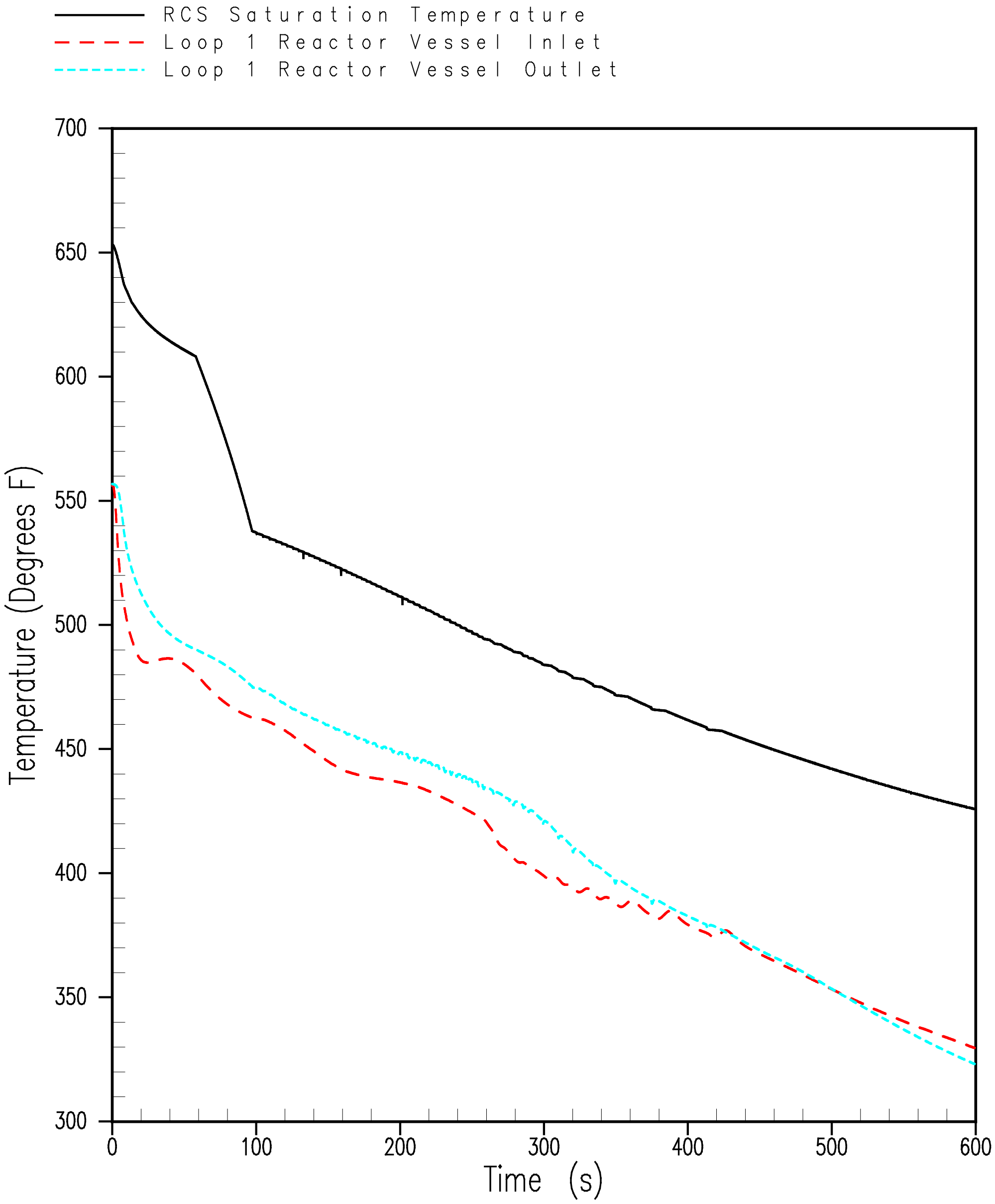

Figure 15.1.5-3

Loop 1 Reactor Coolant Temperatures Steam System Piping Failure

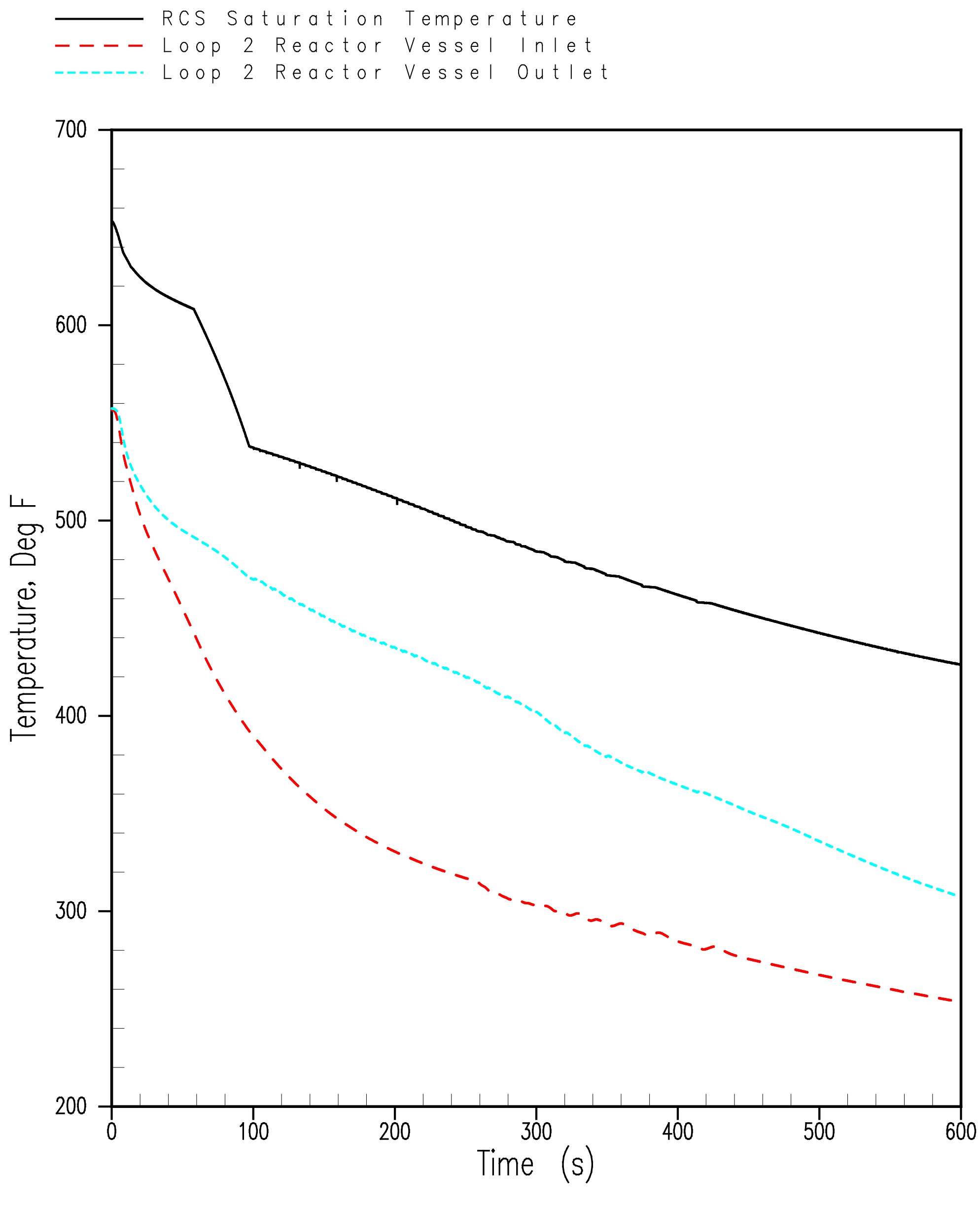

Figure 15.1.5-4

Loop 2 Reactor Coolant Temperatures
Steam System Piping Failure

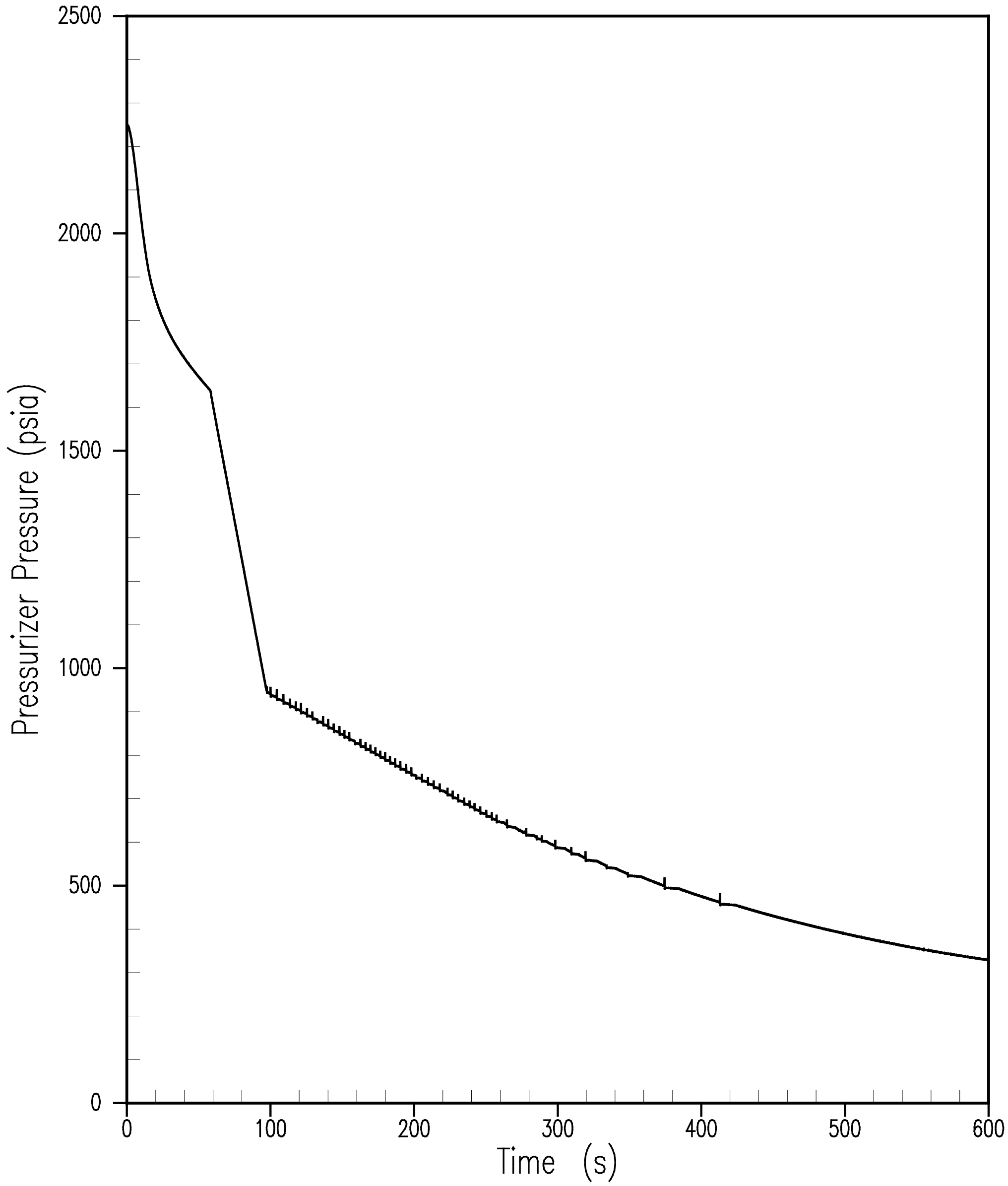

Figure 15.1.5-5

Reactor Coolant System Pressure Transient
Steam System Piping Failure

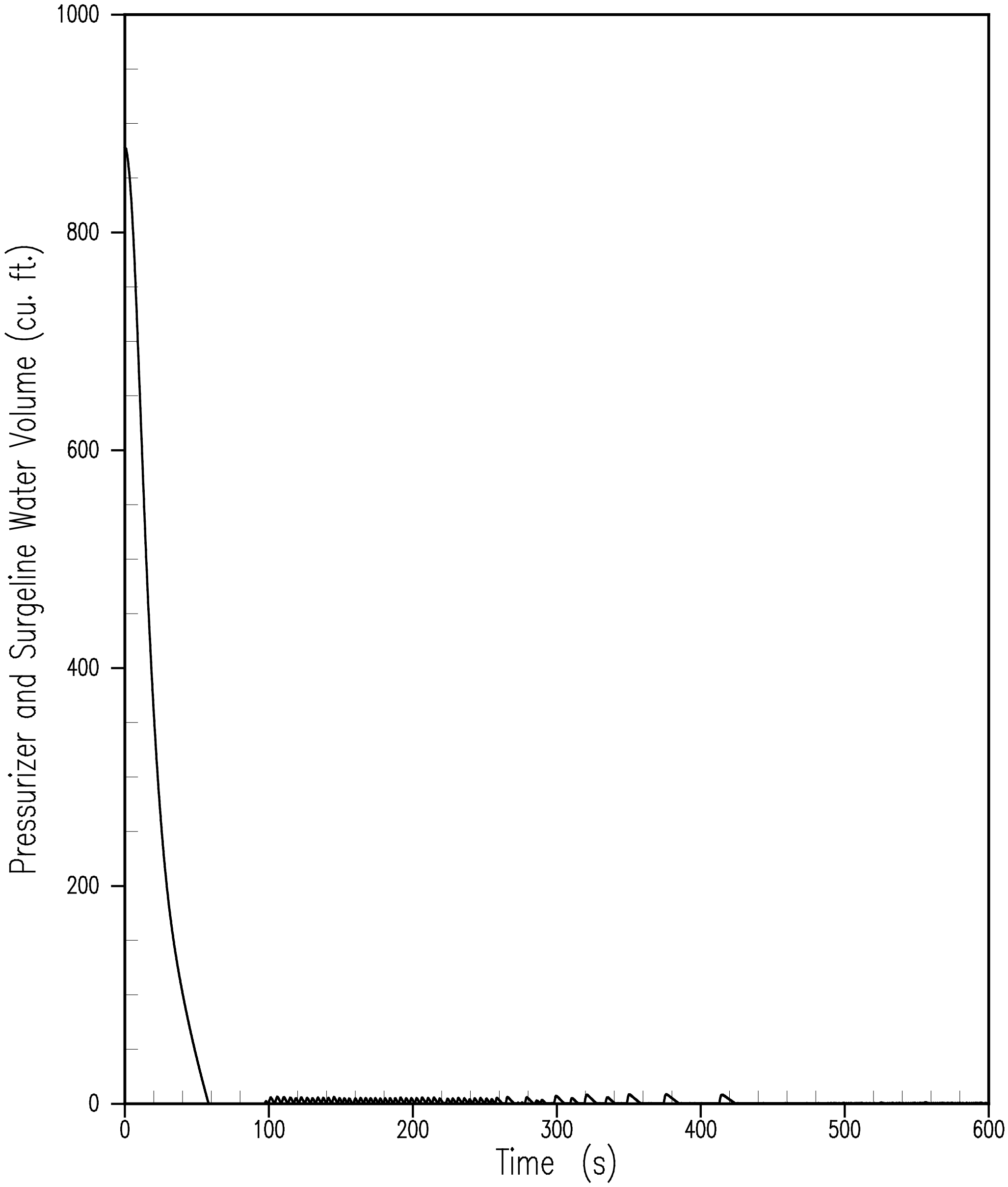

Figure 15.1.5-6

Pressurizer Water Volume Transient
Steam System Piping Failure

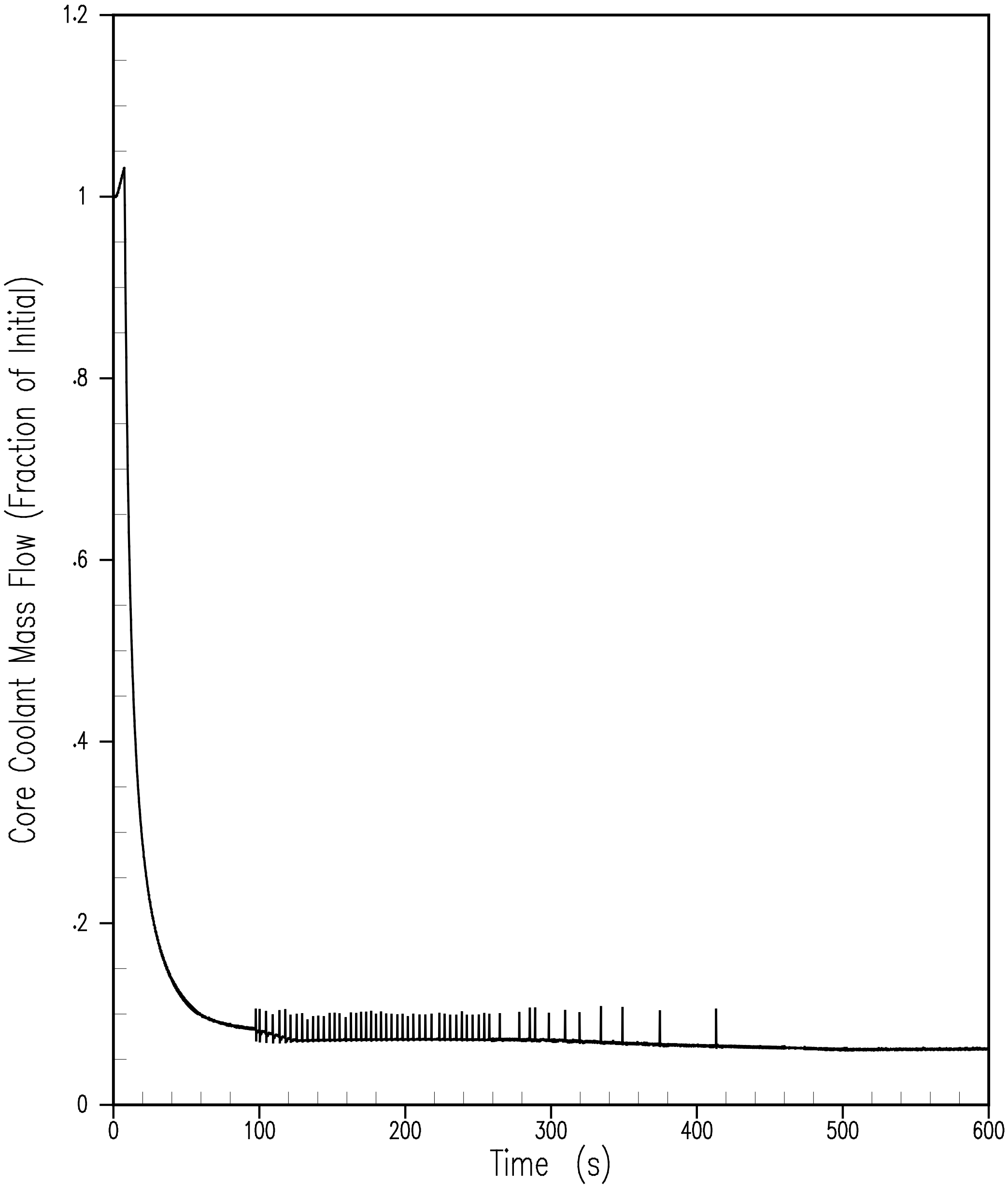

Figure 15.1.5-7

Core Flow Transient Steam System Piping Failure

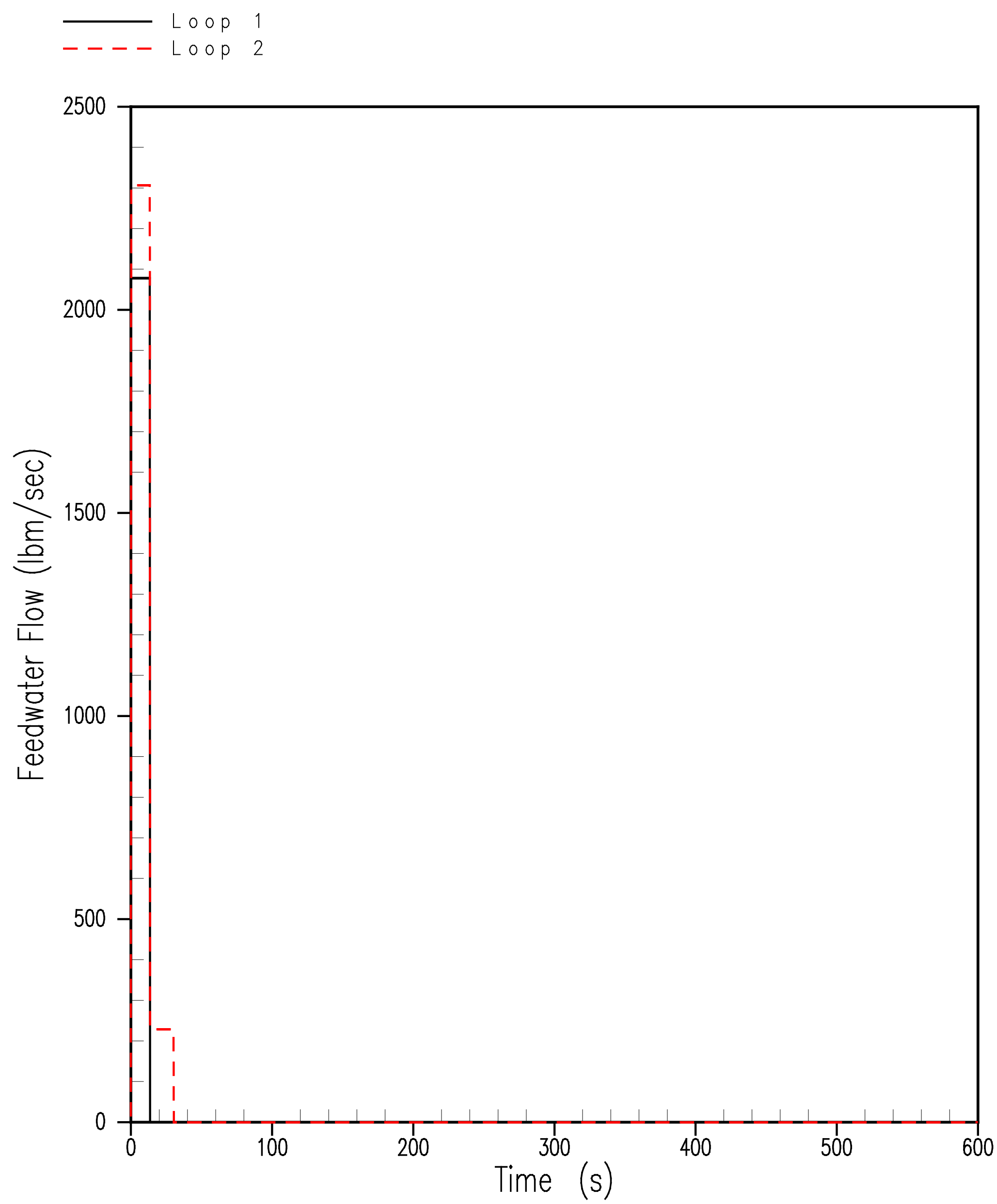

Figure 15.1.5-8

Feedwater Flow Transient Steam System Piping Failure

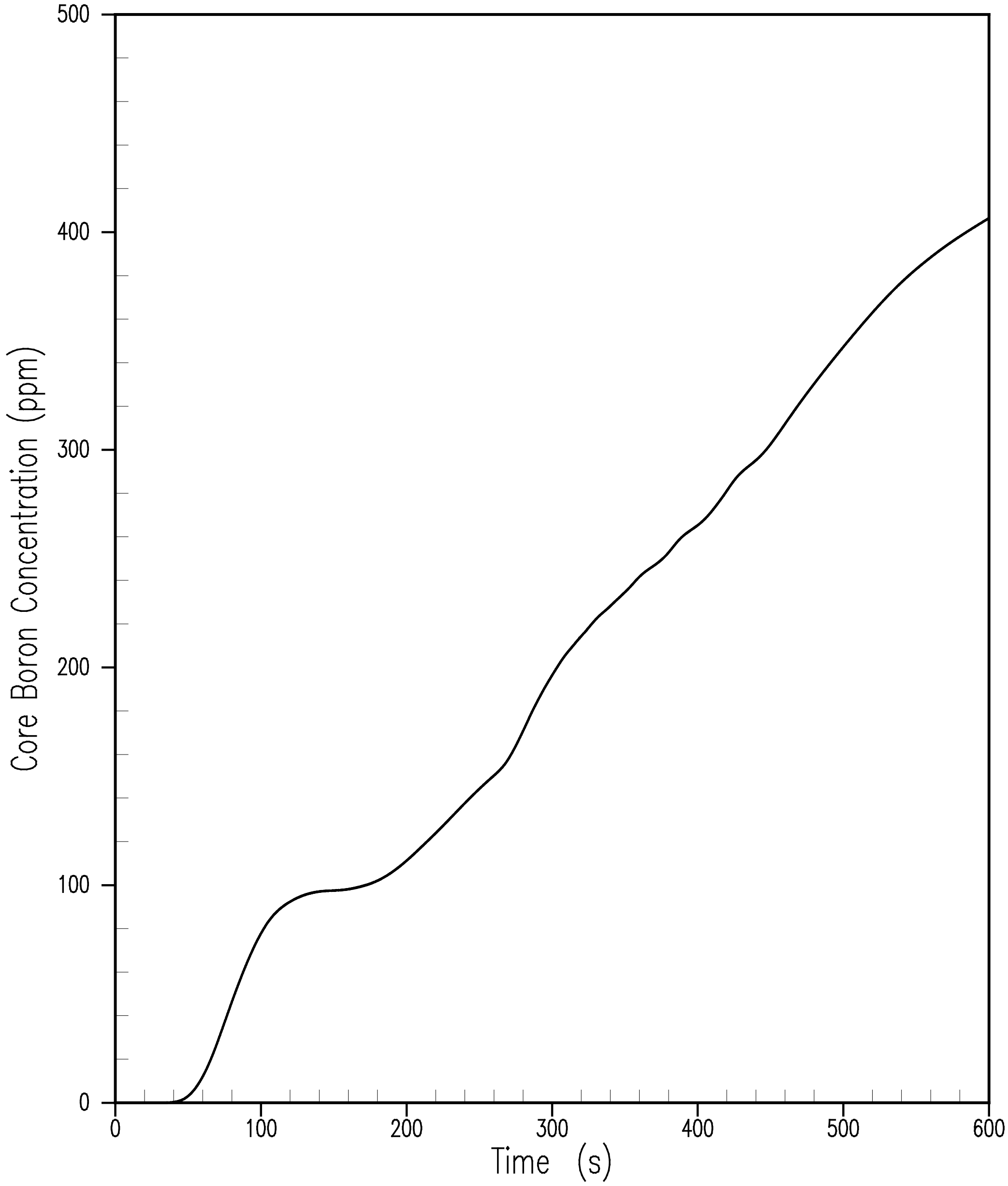

Figure 15.1.5-9

Core Boron Transient Steam System Piping Failure

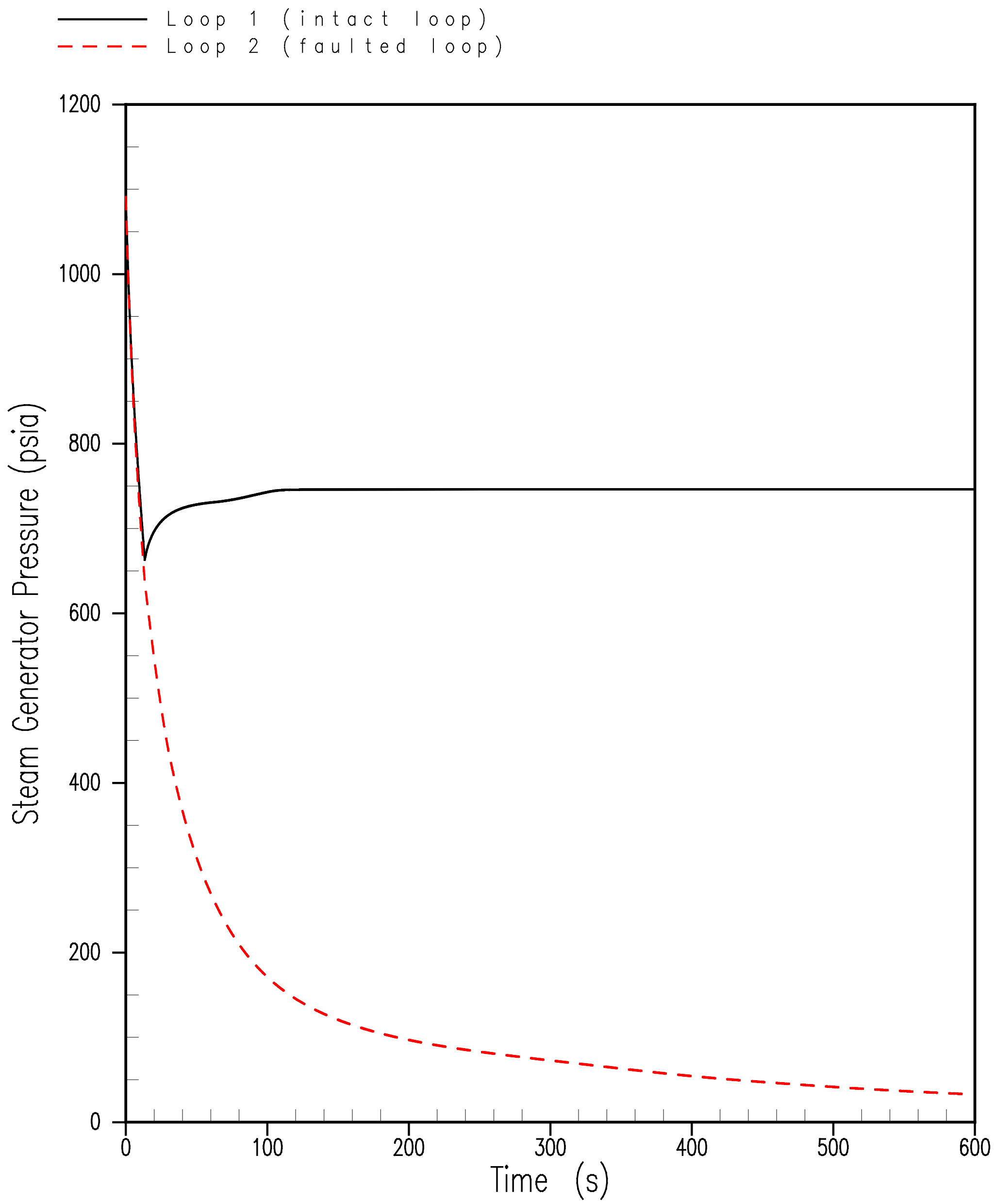

Figure 15.1.5-10

Steam Pressure Transient Steam System Piping Failure

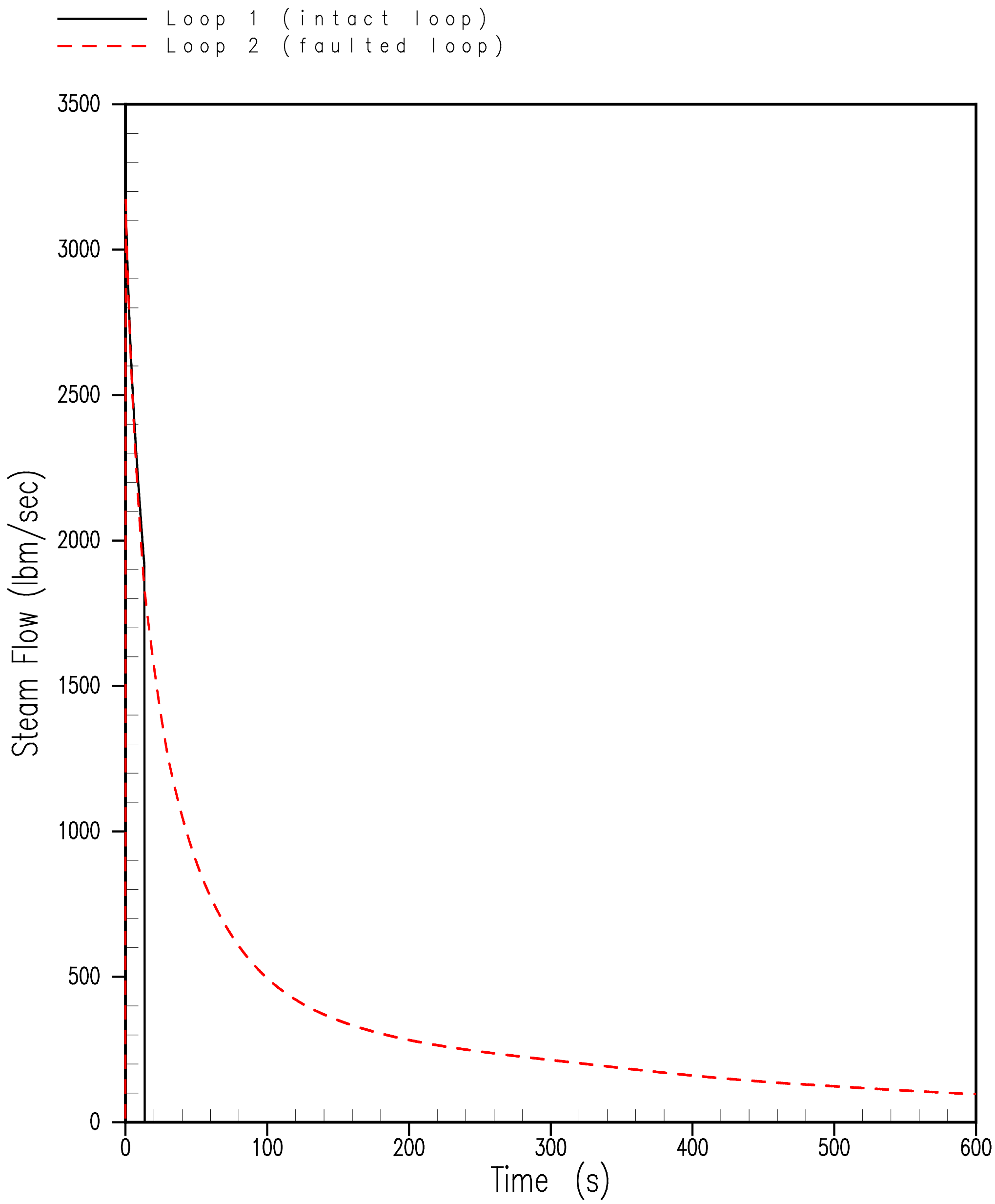

Figure 15.1.5-11

Steam Flow Transient Steam System Piping Failure

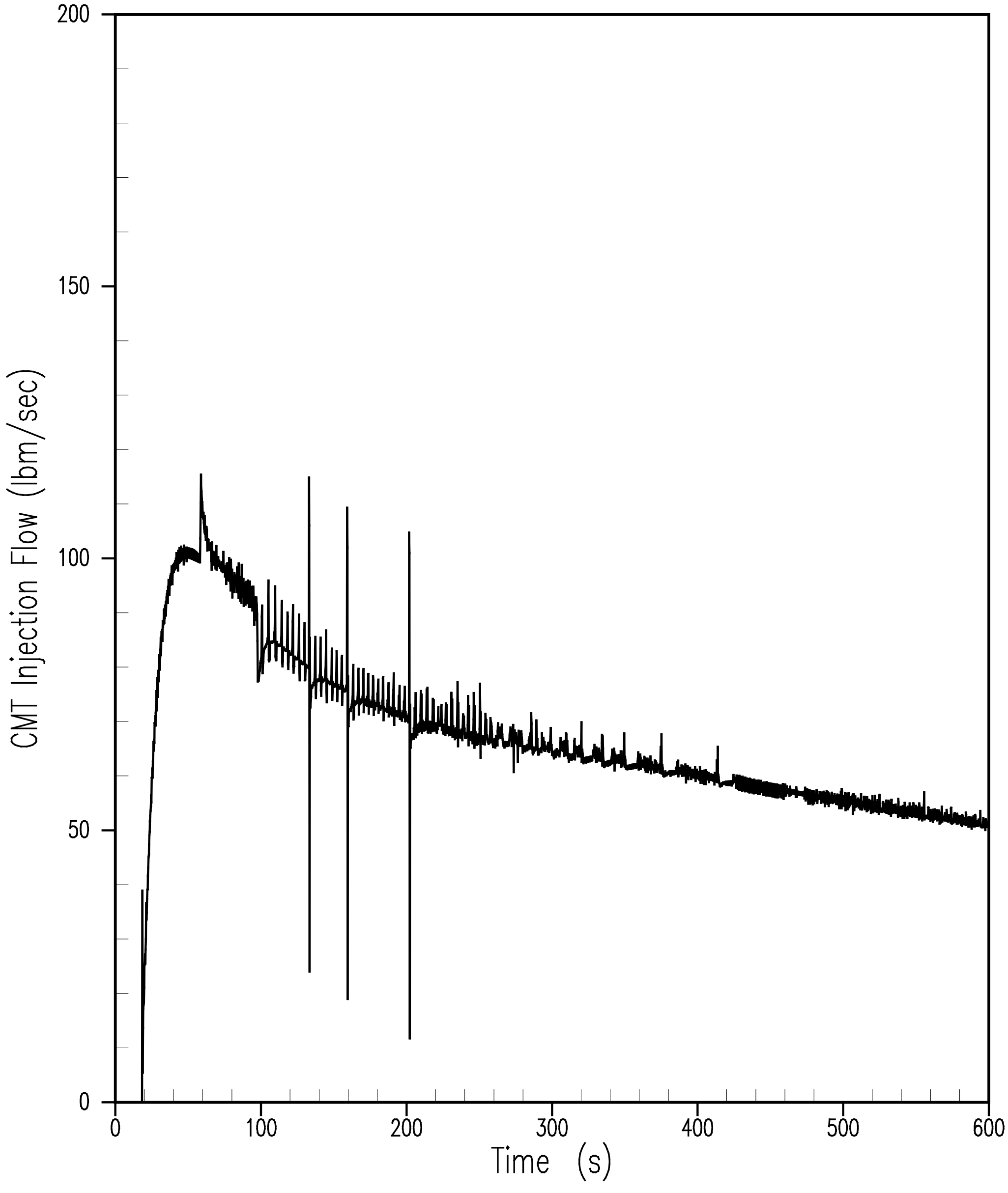

Figure 15.1.5-12

Core Makeup Tank Injection Flow
Steam System Piping Failure

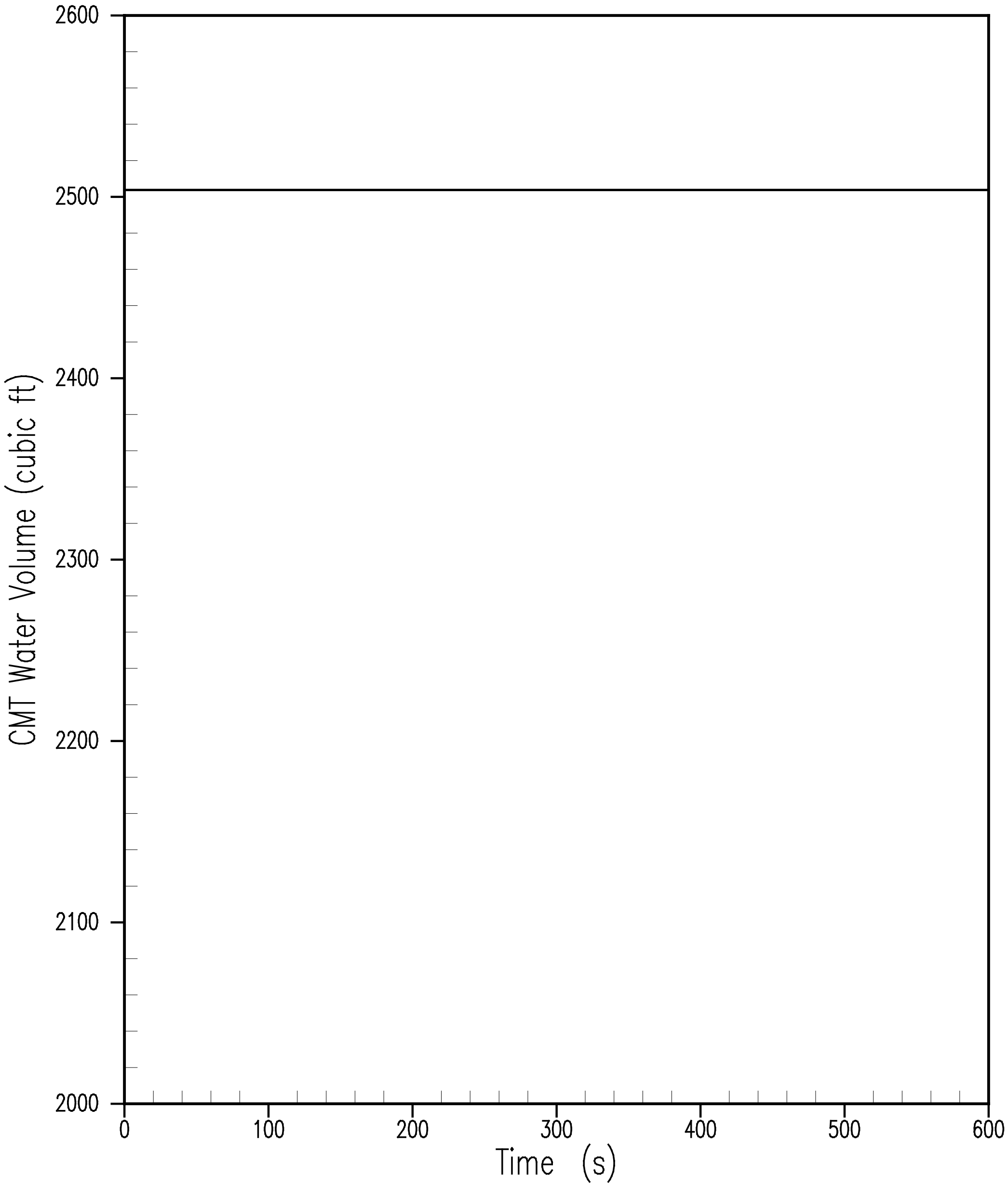

Figure 15.1.5-13

Core Makeup Tank Water Volume Steam System Piping Failure

Figures 15.1.6-1 through 15.1.6-8 not used.