Tennessee Valley Authority, Post Office Box 2000, Spring City, Tennessee 37381-2000

July 29, 2011

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U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555-0001

Watts Bar Nuclear Plant, Unit 2
NRC Docket No. 50-391

Subject: **Watts Bar Nuclear Plant (WBN) Unit 2 – Response to Request for Additional Information (RAI) Regarding June 28, 2011 NRC Audit – Steam Line Break (SLB) and other Miscellaneous RAIs**

References:

1. NRC letter to TVA dated April 27, 2011, "Watts Bar Nuclear Plant, Unit 2 - Audit Report of Westinghouse Documents Relating to Final Safety Analysis Report Accident Analyses (TAC NO. ME4620)"
2. TVA letter to NRC dated May 13, 2011, "Watts Bar Nuclear Plant (WBN) Unit 2 – Additional Responses to Request for Additional Information Regarding (1) Large Break Loss of Coolant Accident, (2) Steam Line Break, and (3) Miscellaneous Analysis"
3. Westinghouse Letter WBT-D-3349 dated July 28, 2011, "Response to June 28 to June 30 2011 NRC Audit RAIs on FRD"
4. Westinghouse Letter WBT-D-3350 dated July 27, 2011, "Response to June 28 to June 30, 2011 NRC Audit RAI on Steamline Break"
5. Westinghouse Letter WBT-D-3355 dated July 29, 2011, "WBS 5.10 Response to NRC RAIs on FIV for Watts Bar Unit 2"
6. TVA letter to NRC dated June 10, 2011, "Watts Bar Nuclear Plant (WBN) Unit 2 – Instrumentation and Controls Staff Information Requests"
7. NRC letter to TVA dated July 27, 2011, "Watts Bar Nuclear Plant, Unit 2 - Request for Additional Information Regarding Incore Instrumentation System (TAC NO. ME3091)"

The purpose of this letter is to provide responses to requests for additional information (RAIs) identified during a June 28, 2011 NRC audit at Westinghouse concerning (1) fuel rod burst during a Steam Line Break (SLB); (2) SLB transient response and inadvertent boron dilution for

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Operational Modes 3, 4, and 5; and (3) flow induced vibration (FIV) on the incore instrument tube assemblies (IITA). Reference 1 documented an audit performed by the NRC of various Final Safety Analysis Report (FSAR) Chapter 15 accident analyses for WBN Unit 2. TVA provided responses to a number of the items identified in the audit report in Reference 2. The NRC subsequently concluded that a second audit should be performed to address remaining open items as well as additional questions. During the audit the week of June 28, 2011, an additional question was raised regarding a fuel rod burst during a SLB. Enclosure 1 of this letter provides a response to this issue (Reference 3).

Enclosure 2 provides additional information as discussed in the June audit with regard to SLB transient response (Reference 4). Specific items include a SLB case with unit 1's reactivity model and FSAR mark-ups. In addition, one question remained regarding boron dilution in different Operational Modes. This question is also addressed in Enclosure 2. Enclosure 3 includes the FSAR mark-ups.

Enclosure 4 (Reference 5) provides a clarification to RAIs addressed in Reference 6 (Enclosure 1, Question 4, I&C matrix item 376, starting on page E1-4) regarding a concern with FIV on the IITAs as requested by Reference 7.

If you have any questions, please contact Bill Crouch at (423) 365-2004.

I declare under penalty of perjury that the foregoing is true and correct. Executed on the 29th day of July, 2011.

Respectfully,

David Stinson
Watts Bar Unit 2 Vice President

Enclosures:

1. Fuel Rod Design (FRD) Response to Additional Tennessee Valley Authority (TVA) Audit Questions
2. Watts Bar Unit 2 Completion Program – Responses to Additional NRC Non-LOCA RAIs
3. FSAR mark-ups for SLB transients
4. Behavior of the WBN Unit 2 Incore Instrument Thimble Assemblies (IITAs) Against Mechanical Wear Resulting from Flow-Induced Vibration (FIV)

cc (Enclosures):

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Fuel Rod Design (FRD) Response to Additional Tennessee Valley Authority (TVA) Audit Questions

As part of a Nuclear Regulatory Commission (NRC) audit held at Westinghouse for Tennessee Valley Authority (TVA) Watts Bar Unit 2 during the week of June 28, 2011, an issue was raised regarding cladding burst during a steamline break (SLB) event. The question was whether clad burst was evaluated during hot zero power (HZP) SLB accidents.

Response:

During HZP SLB events, the fuel cladding temperatures do not rise significantly as compared with other Condition III / IV accidents. At these lower clad temperatures, the integrity of the fuel rod end plug weld is expected to fail before clad burst will occur. The integrity of the weld during HZP SLB depressurization events is evaluated by the Westinghouse Fuel Rod Design (FRD) group on a cycle-specific basis. Therefore, it is not necessary to evaluate clad burst for HZP SLB accidents.

For other accident events where the fuel cladding temperatures are significantly increased, clad burst is evaluated by the appropriate Westinghouse safety groups (e.g. Loss of Coolant Accident [LOCA] Integrated Services)

Enclosure 2
TVA Letter Dated July 29, 2011

Watts Bar Unit 2 Completion Program – Responses to Additional NRC Non-LOCA RAIs

RAI Responses

Response to Item A.1.1

The plots requested were provided to the NRC in TVA submittal dated 11-09-10 in response to RAI 15.3.2 - 1.1. See page 43 and 252 of the 11-09-10 submittal.

Response to Items A.1.2 and A.1.3

Based upon the NRC audit held on June 28th through 30th at Westinghouse's Cranberry Woods Facility it was agreed upon that Westinghouse would provide the following information to the NRC to close out the concerns raised in these RAIs.

1. A comparison of the differences between the Watts Bar Unit 1 and Watts Bar Unit 2 analyses.
2. A quantification of the benefit for Watts Bar Unit 2 to maintaining a shutdown margin of 1.6% compared to a shutdown margin of 1.3%.
3. A revised steamline break analysis modeling the more conservative Unit 1 reactivity model. This will ensure that the peak power reached in the with offsite power case bounds the peak power reached in the without offsite power case.

The response to these items is documented below:

1. The licensing basis hot zero power steamline break analysis for Watts Bar Unit 2 results in a peak heat flux of 1.6%. The Watts Bar Unit 1 licensing basis analysis results in a peak heat flux of 4.4%. Since the two plants are nearly identical (Unit 1 has replacement steam generators and has had a small uprate), their steamline break results should be similar. The purpose of this document is to quantitatively identify the differences between the two analyses and the impact on peak heat flux of each difference.

The Zero Power Steamline break analysis for Unit 2 (Watts Bar Unit 1 prior to the steam generator replacement program) was taken as the starting point. Incremental changes were made to the input deck to demonstrate the impact of the various changes on the analysis. The table below describes the changes made and the effect on peak power.

Case Description	Core Heat Flux (FON)	Time (sec)
Base Case	1.6%	56.2
Doppler Temperature Coefficient	7.9%	56.2
Difference in steam generator heat transfer coefficients, between the OSGs and RSGs	6.5%	62.4
Increased secondary mass 30,000 lbm per generator	6.0%	67.8
Primary Side Pressure drops, volume changes and SG initial conditions related to RSGs	5.0%	66.0
Accumulator Boron from 1900 ppm to 2400 ppm and updated Accumulator resistances	4.8%	65.4
MUR*	4.9%	67.8
Pump Heat**	4.3%	65.8
All Other Changes	4.4%	65.6

*Actual change was 0.03% power, which caused the power to round up to the higher decimal place.

**Unit 2 analysis does not credit any pump heat, the Unit 1 analysis credits a bounding minimum pump heat.

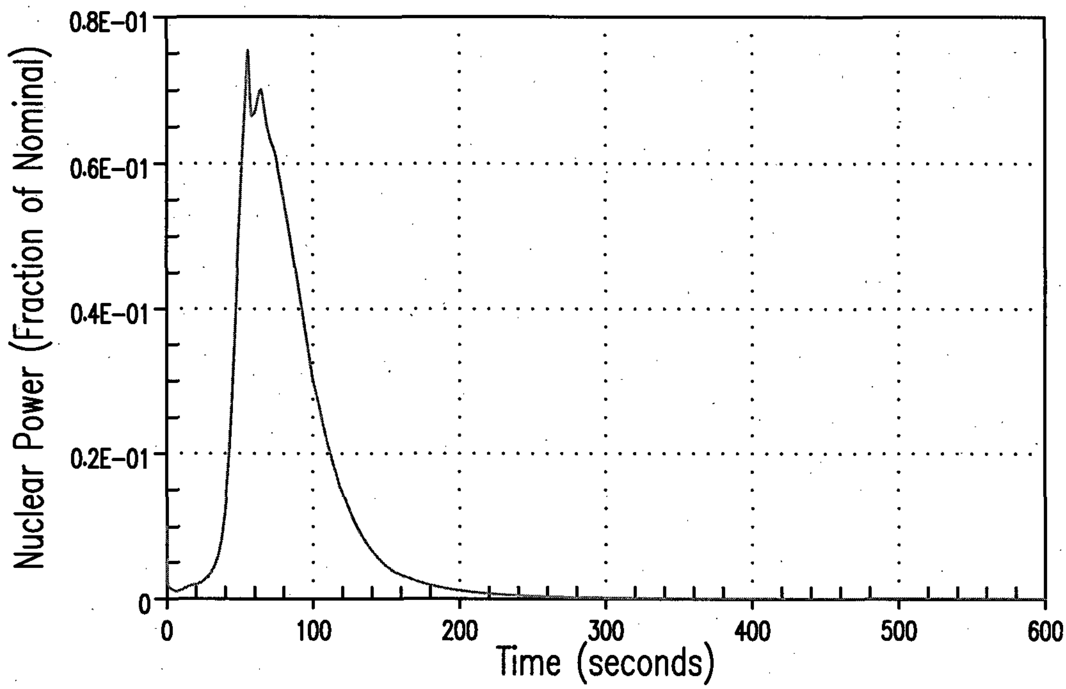
The results of this table show that the Unit 2 analysis assumed a less limiting Doppler temperature coefficient, which contributed to the lower return to power. The difference in steam generator types resulted in a small benefit in the analysis. When the differences in steam generator types and reactivity coefficients are accounted for the Unit 2 heat flux is within 0.6% of the Unit 1 heat flux. The majority of the remainder of the difference is due to the pump heat modeled. The Unit 1 analysis models a bounding minimum pump heat, where the Unit 2 analysis does not take credit for any pump heat. The pump heat modeled in both analyses is conservative compared to the expected pump heat.

2. Another contributor to the low return to power for Watts Bar Unit 2 is the shutdown margin. Watts Bar Unit 2 maintains a shutdown margin of 1.6% which is higher than most Westinghouse designed plants. A case was run with a shutdown margin of 1.3% to determine the impact of the shutdown margin on the Watts Bar analysis. With 1.3% shutdown margin the Watts Bar Unit 2 analysis reached a peak core heat flux of 8.1%. Also, the revised steamline break analysis using the Unit 1 reactivity model was run with the lower shutdown margin. The peak core heat flux increased from 7.9% to 12.1%. The analyses run with the lower shutdown margin reach a peak heat flux which is consistent with the return to power for other Westinghouse 4-Loop plants.

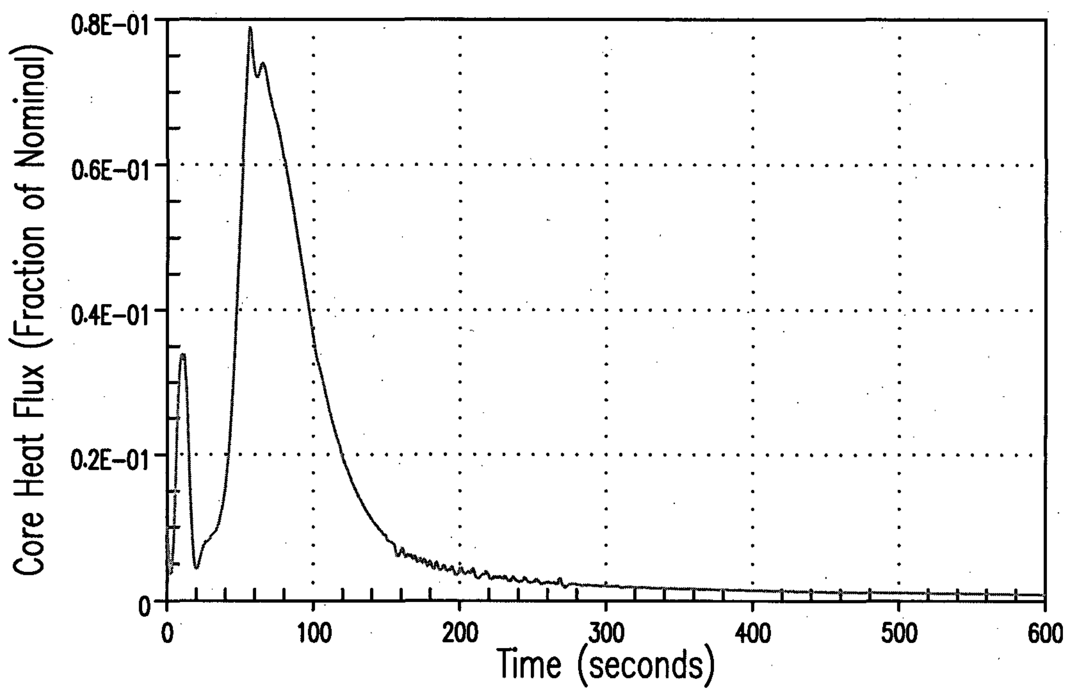
3. The Watts Bar Unit 2 analysis was revised to model the Doppler temperature coefficient that was used in the Unit 1 RSG analysis. This resulted in the peak power in the with offsite power case that is greater than the peak power in the without offsite power case. The limiting statepoint for the with and without offsite power cases are presented below along with a table which lists the sequence of events for each case. Additional plots of the key transient parameters are presented on the following pages.

Steamline Break Sequence of Events		
		Time (seconds)
Complete severance of a pipe, offsite power available	Steam Line Ruptures	0.0
	Low Steam Pressure Setpoint Reached	0.67
	Pressurizer Empties	11.0
	Criticality Attained	30.0
	Boron Reaches Core	33.6
	Accumulators Actuated	54.4
		Time (seconds)
Complete severance of a pipe, loss of offsite power simultaneous with the break and initiation of safety injection signal	Steam Line Ruptures	0.0
	Low Steam Pressure Setpoint Reached	0.67
	Pressurizer Empties	12.2
	Criticality Attained	38.4
	Boron Reaches Core	46.2
	Accumulators Actuated	N/A

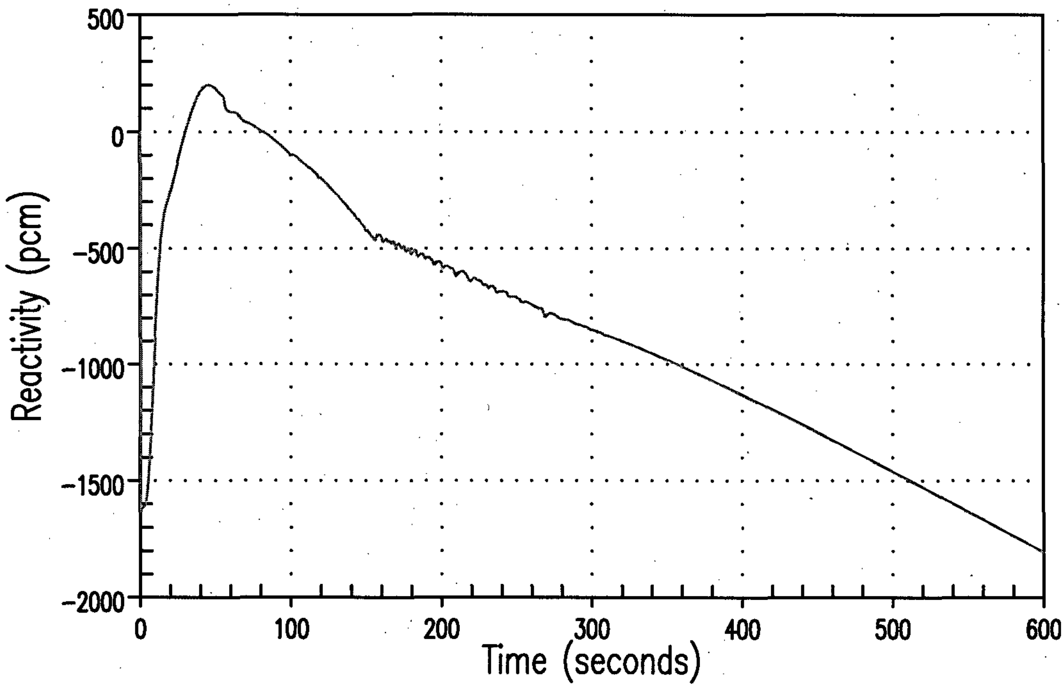
Steamline Break Statepoints		
	With Offsite Power	Without Offsite Power
Reactor vessel inlet temperature (°F)		
-Faulted SG Loop	402.9	333.2
-Intact SG Loops	485.9	495.8
RCS pressure (psia)	616.73	848.59
RCS flow fraction of nominal (%)	100	7
Heat flux fraction of nominal (%)	7.90	5.10
Reactivity (%ρ)	0.105	0.023
Density (gm/cc)	0.824	0.815
Boron (ppm)	7.85	9.20
Time (seconds)	56.8	121.8



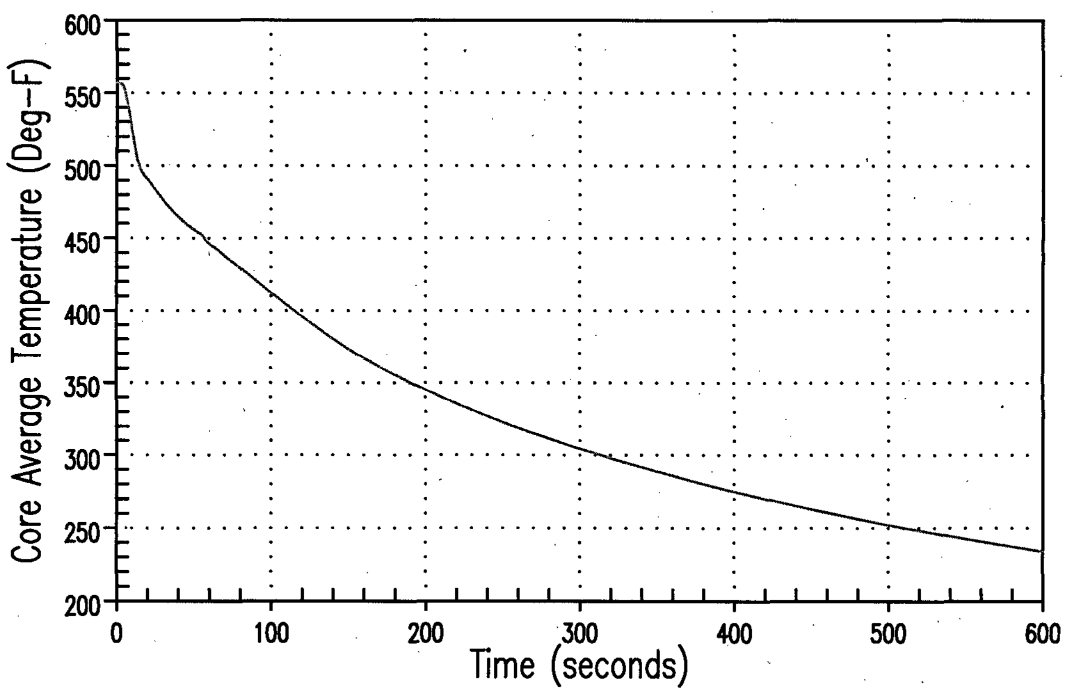
Watts Bar Unit 2 Hot Zero Power Steam Line Break with Offsite Power Available –Nuclear Power Versus Time



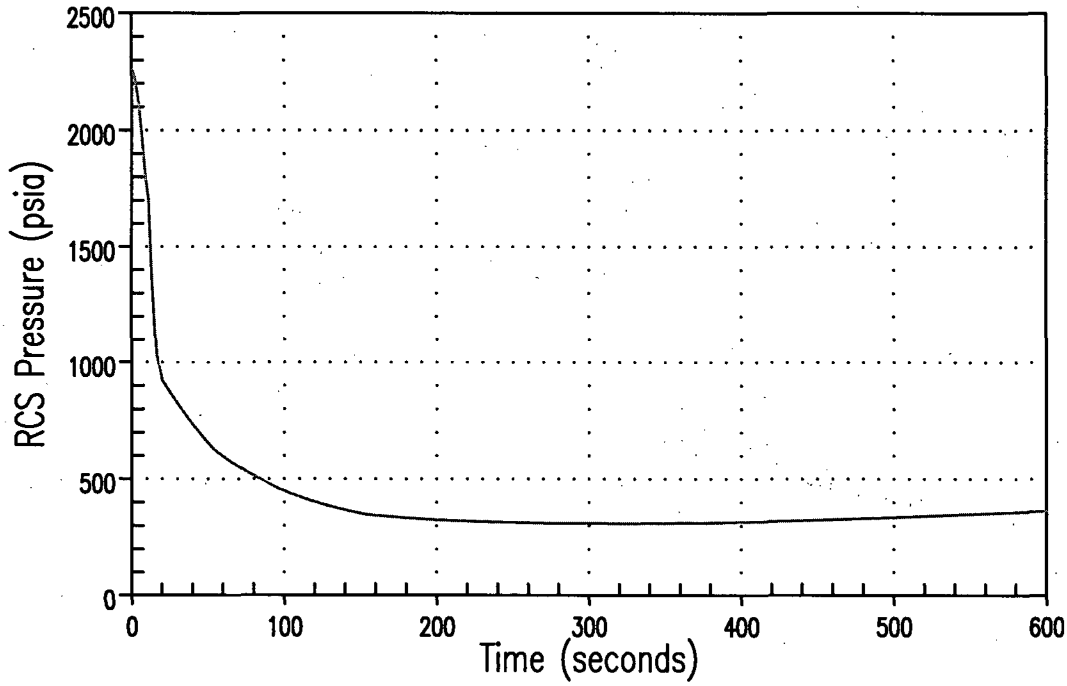
Watts Bar Unit 2 Hot Zero Power Steam Line Break with Offsite Power Available –Core Heat Flux Versus Time



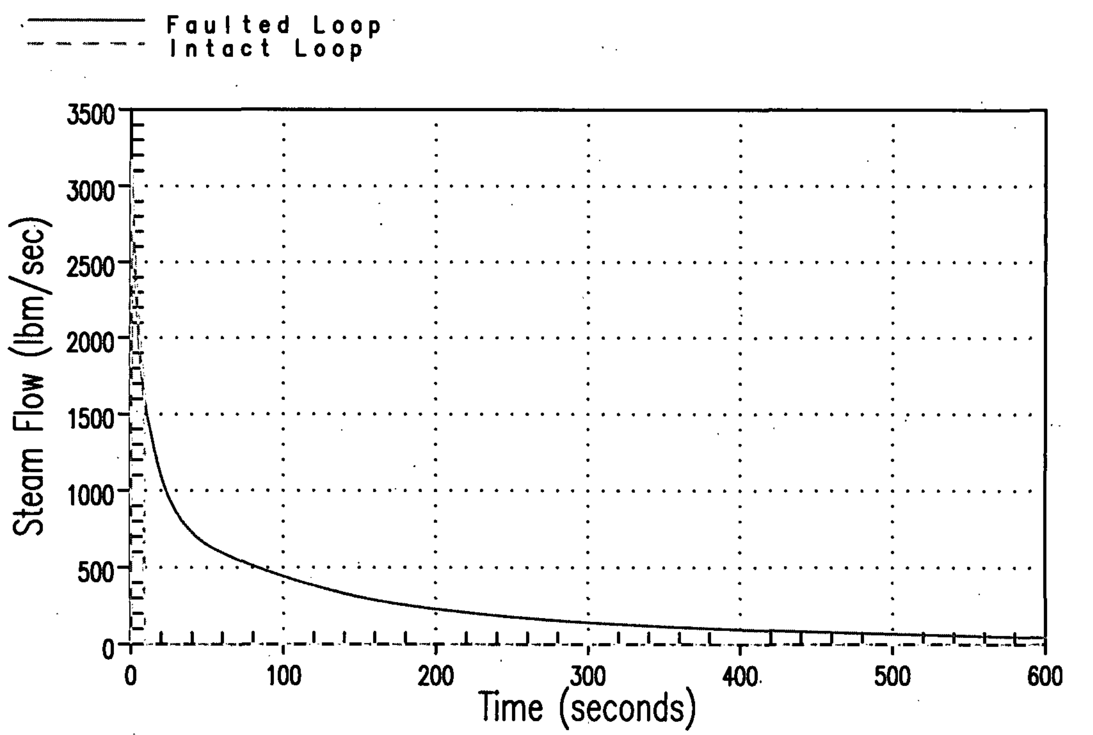
Watts Bar Unit 2 Hot Zero Power Steam Line Break with Offsite Power Available –Reactivity Versus Time



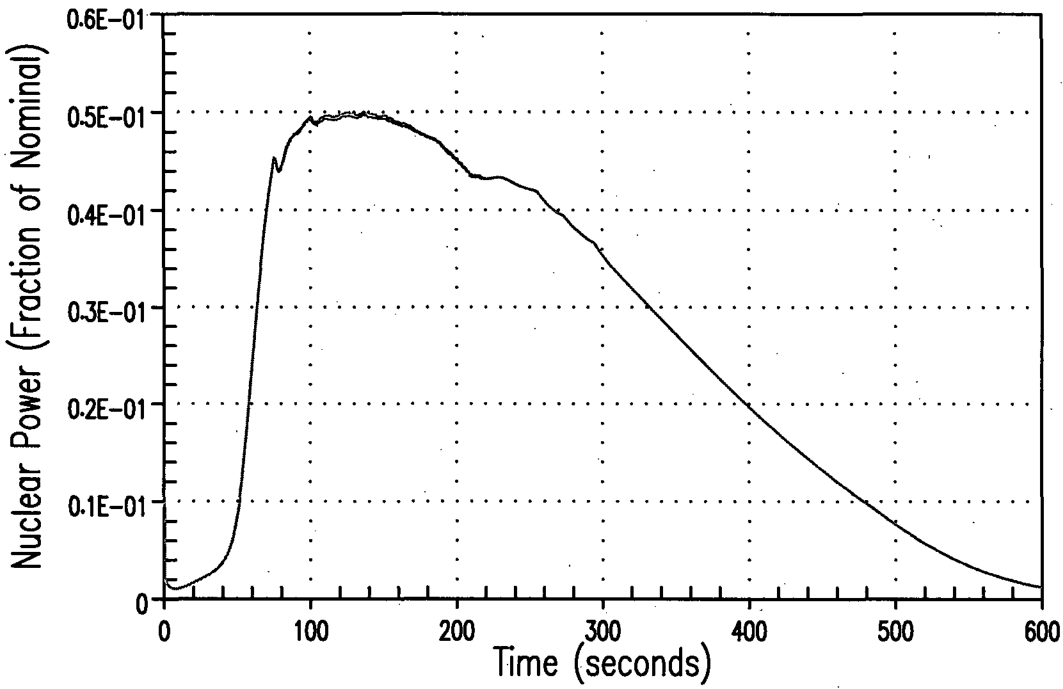
Watts Bar Unit 2 Hot Zero Power Steam Line Break with Offsite Power Available –Core Average Temperature Versus Time



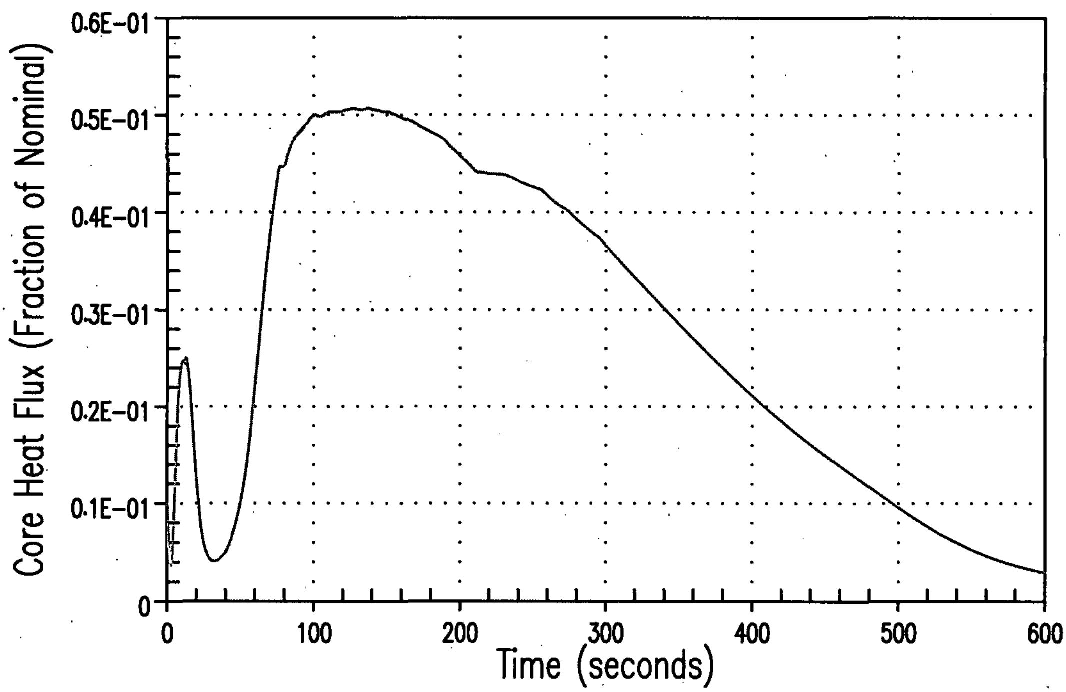
Watts Bar Unit 2 Hot Zero Power Steam Line Break with Offsite Power Available –RCS Pressure Versus Time



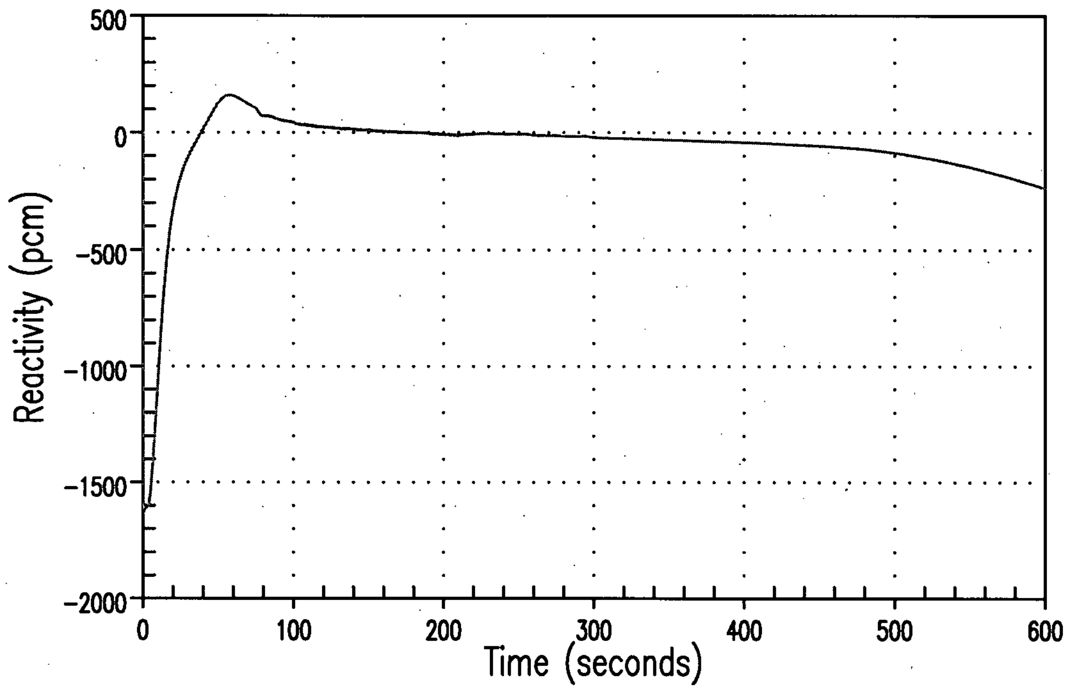
Watts Bar Unit 2 Hot Zero Power Steam Line Break with Offsite Power Available –Steam Flow Versus Time



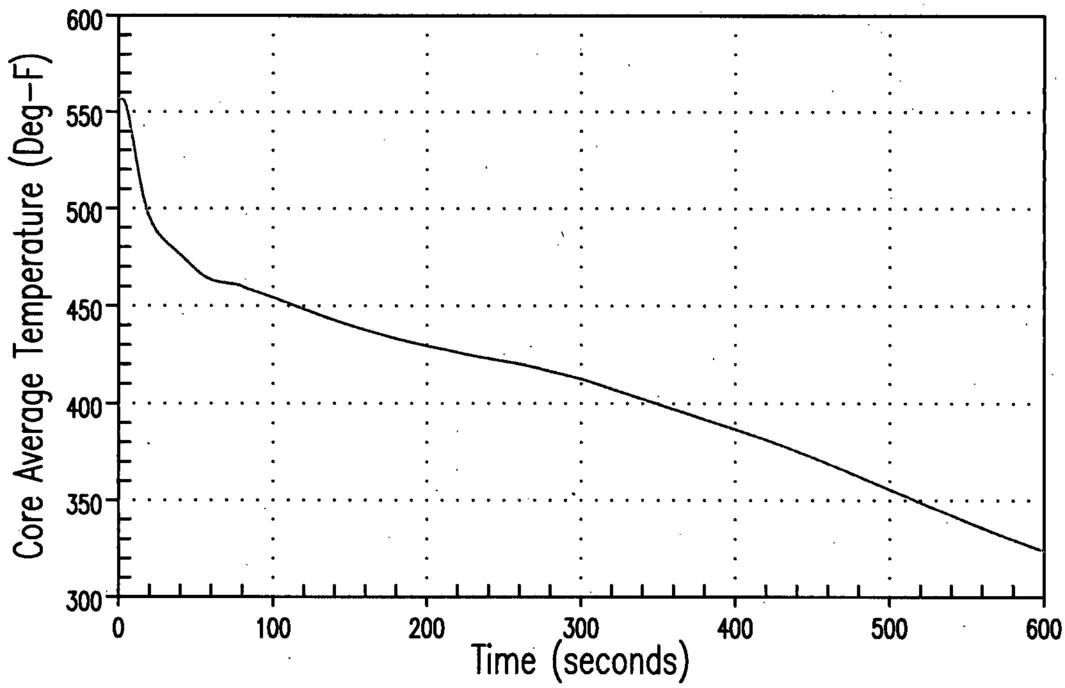
Watts Bar Unit 2 Hot Zero Power Steam Line Break without Offsite Power Available –Nuclear Power Versus Time



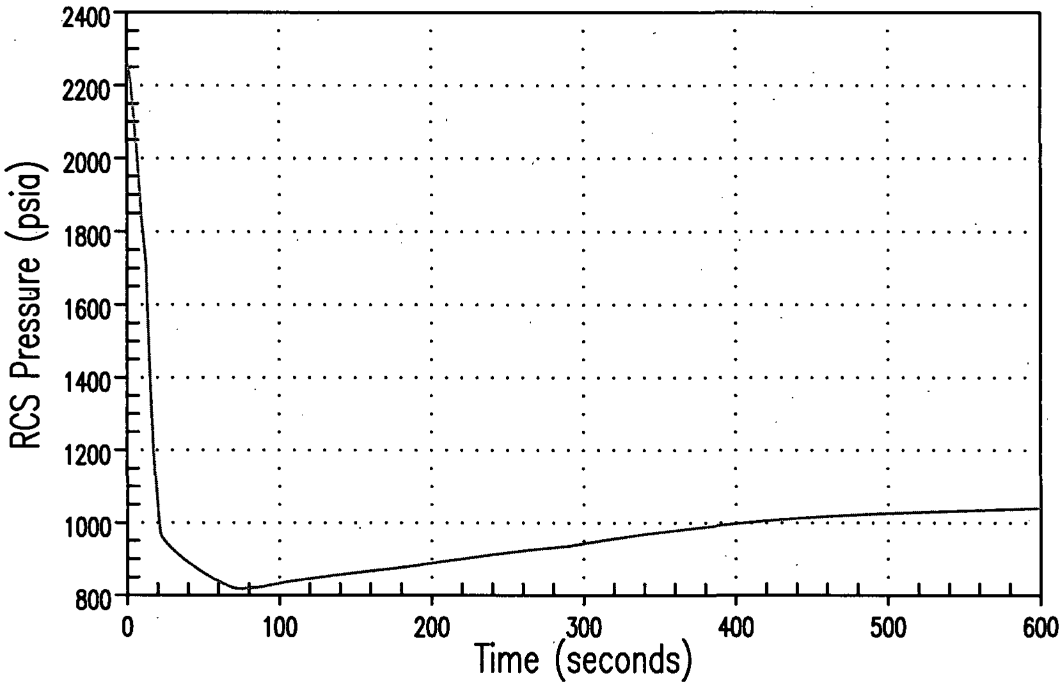
Watts Bar Unit 2 Hot Zero Power Steam Line Break without Offsite Power Available –Core Heat Flux Versus Time



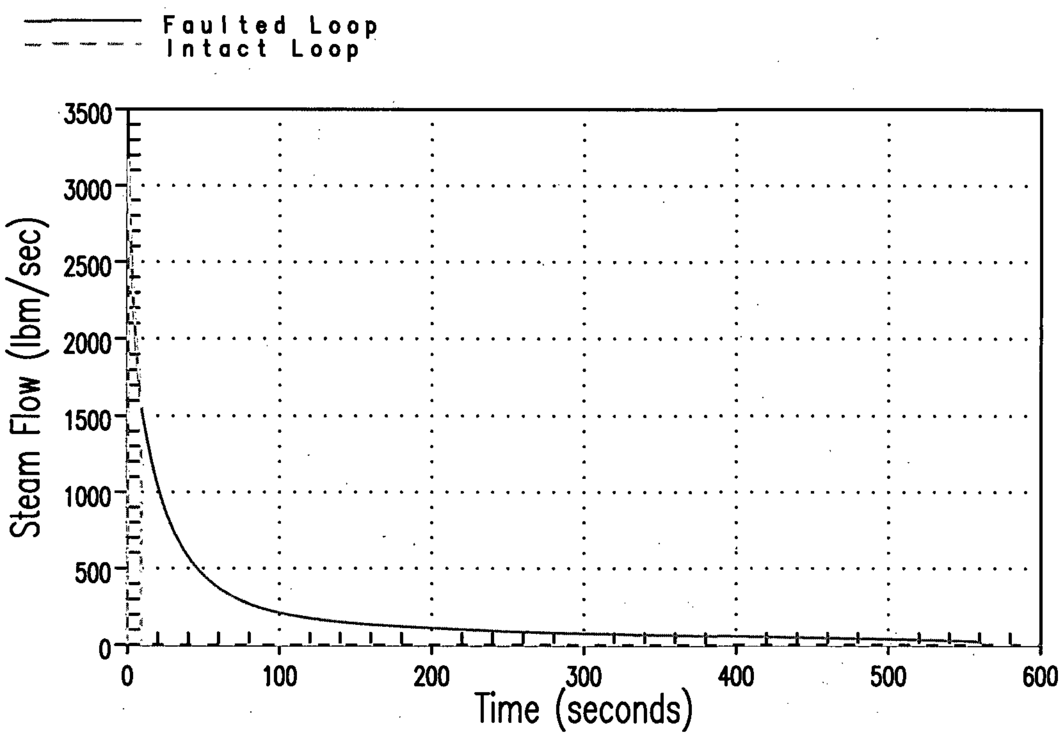
Watts Bar Unit 2 Hot Zero Power Steam Line Break without Offsite Power Available –Reactivity Versus Time



Watts Bar Unit 2 Hot Zero Power Steam Line Break without Offsite Power Available –Core Average Temperature Versus Time



Watts Bar Unit 2 Hot Zero Power Steam Line Break without Offsite Power Available –RCS Pressure Versus Time



Watts Bar Unit 2 Hot Zero Power Steam Line Break without Offsite Power Available –Steam Flow Versus Time

Response to Item A.3

The steamline break case presented in the Watts Bar Unit 2 FSAR models a 1.4 ft^2 double ended rupture (DER) with maximum AFW (2840 gpm) conservatively delivered to the faulted steam generator to exacerbate the cooldown. The break size sensitivity study done for Watts Bar reduced the break size but continued to model the break as a DER with maximum AFW delivered to a single generator. All of the cases with the maximum AFW delivered to one steam generator ultimately reach the accumulator actuation pressure. In a credible break, AFW is assumed to be split evenly between the steam generators. Changing the modeling to a credible break with the AFW evenly distributed to the four steam generators yields a less limiting transient and less of a depressurization. With the break modeled as a credible break, a break size of 0.118 ft^2 will not actuate the accumulators. In this case, there is no return to critical. This is the largest break that does not actuate the accumulators and it is considerably less limiting than the large break case presented in the FSAR.

The Point Beach case that is referenced in the RAI is a 0.116 ft^2 credible break which assumes maximum AFW (1200 gpm) split equally between the two steam generators. Like the Watts Bar case discussed above, the Point Beach case does not actuate the accumulators nor does it return to critical. When the modeling of the breaks is the same, the responses are the same for the two plants.

Also, see the response to Items A.1.2 and A.1.3. A revised analysis has been performed in which the more conservative Watts Bar Unit 1 reactivity model has been applied to Watts Bar Unit 2. This increased the peak heat flux reached in the with offsite power case making the Watts Bar Unit 2 transients comparable to those presented in WCAP-9226-P-A.

Responses to Item A.4 and A.5

The responses to these questions were provided to the NRC in TVA submittal dated 6-27-11

Response to Item A.6

The original version of WCAP-9226 was published in January of 1978. At that time, the proposed DNBR limit using the W-3 correlation was 1.30. As such, all of the DNBR plots in WCAP-9226 show a DNBR limit of 1.30. During the review of WCAP-9226, the DNBR limit for cases where the RCS pressure falls to between 500 and 1000 psia was increased to 1.45 (see NS-NRC-86-3116 – dated 3/25/86). The DNBR limit of 1.45 for RCS pressures between 500 and 1000 psia has been applied for Watts Bar Unit 2 as prescribed by the SER written for WCAP-9226-P-A.

The transient plots in Section 3 of WCAP-9226 show the sensitivity to several parameters relative to the "Reference Case" defined in Section 3.1.1.2 of WCAP-9226 and are not intended to show adherence to the acceptance criteria. The conclusions drawn from these sensitivity studies are detailed in Section 3.1.4 and continue to be applicable today for Watts Bar Unit 2.

Response to the Boron Dilution RAI

The Watts Bar units were originally licensed to Regulatory Guide 1.70, Revision 0 and 1 which required explicit Boron Dilution calculations in Modes 1, 2 and 6. Subsequent revisions to Regulatory Guide 1.70 has added requirements to consider boron dilutions in all six operating modes.

In January of 1985, the NRC issued generic letter 85-05 with the subject: "Inadvertent Boron Dilution Events". Generic Letter 85-05 states that "the consequences are not severe enough to jeopardize the health and safety of the public and do not warrant backfitting requirements for boron dilution events at operating reactors." Generic letter 85-05 also states that "while the NRC will not require operating plant backfits for boron dilution events at this time, the staff would regard an unmitigated boron dilution event as a serious breakdown in the licensee's ability to control its plant, and strongly urges each licensee to assure itself that adequate protection against boron dilution events exists in its plants."

The Watts Bar Unit 2 FSAR contains an explicit Boron Dilution calculation for Modes 1, 2 and 6 consistent with Reg. Guide 1.70, Revisions 0 and 1 and the Watts Bar Unit 1 licensing basis. In excess of the Reg. Guide 1.70 requirements, TVA follows an operating procedure in Modes 4 and 5 that ensures that there will be 15 minutes from the beginning of a dilution until shutdown margin is lost. This procedure conservatively assumes an active mixing volume consistent with Mode 5 conditions and the RCS drained to the mid plane of the nozzles. Curves of the critical boron concentration over the initial boron concentration as a function of RHR flow rate and dilution flow rate are used to adjust the boron concentration to ensure at least 15 minutes are available before shutdown margin is lost. Unit 1 follows this procedure and the intent is to follow the same procedure for Unit 2.

Enclosure 3
TVA Letter Dated July 29, 2011

FSAR mark-ups for SLB transients

conditions at the end of the WCOBRA/TRAC calculations indicate that the transition to long term cooling is underway even before the entire core is quenched.

Based on the ASTRUM Analysis results (Table 15.4-18b), it is concluded that Watts Bar Unit 2 maintains a margin of safety to the limits prescribed by 10 CFR 50.46.

15.4.1.1.7 PLANT OPERATING RANGE

The expected PCT and its uncertainty developed are valid for a range of plant operating conditions. The range of variation of the operating parameters has been accounted for in the uncertainty evaluation. Tables 15.4-19 summarizes the operating ranges as defined for the proposed operating conditions which are supported by the Best-Estimate LBLOCA analysis for Watts Bar Unit 2. Tables 15.4-14 and 15.4-15 summarize the LBLOCA containment data used for calculating containment pressure. If operation is maintained within these ranges, the LBLOCA results developed in this report using WCOBRA/TRAC are considered to be valid. Note that some of these parameters vary over their range during normal operation (accumulator temperature) and other ranges are fixed for a given operational condition (Tavg).

Out of Scope

15.4.1.2 Hydrogen Production and Accumulation

Pursuant to NRC final rule as defined in 10 CFR 50.44 and Regulatory Guide 1.7, the new definition of design-basis LOCA hydrogen release eliminates requirements for hydrogen control systems for mitigation of releases. "All PWRs with ice condenser type containments must have the capability to control combustible gas generated from metal-water reaction involving 75% of the fuel cladding surrounding the active fuel region (excluding the cladding surrounding the plenum volume) so that there is no loss of containment structural integrity. The deliberate ignition systems provided to meet this existing combustible gas source term are capable of safely accommodating even greater amounts of combustible gas associated with even more severe core melt sequences that fail the reactor vessel and involve molten core-concrete interaction. Deliberate ignition systems, if available, generally consume the combustible gas before it reaches concentrations that can be detrimental to containment integrity." On the basis of this definition, no further analysis is required to support events considered to be outside the design basis. Deliberate ignition systems are described in FSAR Section 6.2.5

15.4.2 Major Secondary System Pipe Rupture

15.4.2.1 Major Rupture of a Main Steam Line

15.4.2.1.1 Identification of Causes and Accident Description

No Changes

The steam release arising from a rupture of a main steam line would result 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 a reduction of core shutdown margin.

No Changes

If the most reactive rod cluster control assembly (RCCA) is assumed stuck in its fully withdrawn position after reactor trip, there is an increased possibility that the core will become critical and return to power. A return to power following a steam line rupture is a potential problem mainly because of the high power peaking factors which exist, assuming the most reactive RCCA to be stuck in its fully withdrawn position. The core is ultimately shut down by the boric acid injection delivered by the safety injection system.

The analysis of a main steam line rupture is performed to demonstrate that the following criterion is satisfied:

Assuming a stuck RCCA with or without offsite power and assuming a single failure in the engineered safeguards, the core remains in place and intact. Radiation doses are not expected to exceed the guidelines of 10 CFR 100.

Although DNB and possible clad perforation following a steam pipe rupture are not necessarily unacceptable, the following analysis, in fact, shows that no violation of the DNB design basis occurs for any rupture assuming the most reactive assembly stuck in its fully withdrawn position.

The following functions provide the necessary protection for a steam line rupture:

(1) Safety injection system actuation from any of the following:

(a) Two out of three low pressurizer pressure signals.

(b) Two out of three high containment pressure signals.

(c) Two out of three low steamline pressure signals in any steamline.

(2) The overpower reactor trips (neutron flux and ΔT) and the reactor trip occurring in conjunction with receipt of the safety injection signal.

(3) Redundant isolation of the main feedwater lines: Sustained high feedwater flow would cause additional cooldown. A safety injection signal will rapidly close all feedwater control valves and main feedwater isolation valves, and trip the main feedwater pumps, condensate booster pumps, condensate demineralizer pump, and motor-operated standby feedwater pump if operating.

(4) Trip of the fast acting steam line stop valves (main steam isolation valves) (designed to close in less than 6 seconds) on:

(a) Two out of four high-high containment pressure signals.

(b) Two out of three low steamline pressure signals in any steamline.

(c) Two out of three high negative steamline pressure rate signals in any steamline.

No Changes

Fast-acting isolation valves are provided in each steam line that will fully close within 6 seconds after a steamline isolation signal setpoint is reached. The time delay for actuation of the low steamline pressure safety injection actuation signal, high negative steamline pressure rate signal, high-high containment pressure signal, and manual block of the low steamline pressure safety injection actuation signal must be within 2 seconds after initiation. This, along with the main steam isolation time of approximately 6 seconds,shall not exceed a 8 second total response time for this action in the safety analysis for this event. For breaks downstream of the isolation valves, closure of all valves would completely terminate the blowdown. For any break, in any location, no more than one steam generator would blowdown even if one of the isolation valves fails to close. A description of steam line isolation is included in Chapter 10.

Steam flow is measured by monitoring dynamic head in nozzles located in the throat of the steam generator. The effective throat area of the nozzles is 1.4 square feet, which is considerably less than the main steam pipe and thus the nozzles also serve to limit the maximum steam flow for a break at any location.

Table 15.4-6 lists the equipment required in the recovery from a high energy line rupture. Not all equipment is required for any one particular break, since it will vary depending upon postulated break location and details of initial conditions. Design criteria and methods of protection of safety related equipment from the dynamic effects of postulated piping ruptures are provided in Section 3.6.

15.4.2.1.2 Analysis of Effects and Consequences

Method of Analysis

The analysis of the steam pipe rupture has been performed to determine:

(1) The core heat flux and reactor coolant system temperature and pressure resulting from the cooldown following the steam line break. The LOFTRAN[11] Code has been used.

(2) The thermal and hydraulic behavior of the core following a steam line break. A detailed thermal and hydraulic digital computer code, VIPRE-01[30], has been used to determine if the calculated DNBR occurs for the core conditions computed in Item 1 above.

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

(1) End-of-life shut down margin at no load, equilibrium xenon conditions, and the most reactive RCCA stuck in its fully withdrawn position. Operation of the control rod banks during core burnup is restricted in such a way that addition of positive reactivity in a steam line break accident will not lead to a more adverse condition than the case analyzed.

No Changes

(2) The 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 and pressure has been included. The k_{eff} versus temperature at 1110 psi corresponding to the negative moderator temperature coefficient used is shown in Figure 15.2-40. The effect of power generation in the core on overall reactivity is shown in Figure 15.4-9. The parameters used to determine the radioactivity releases for the steamline break are given in Table 15.5-16.

The core properties associated with the sector nearest the affected steam generator and those associated with the remaining sector were conservatively combined to obtain average core properties for reactivity feedback calculations. Further, it was conservatively assumed that the core power distribution was uniform. These two conditions cause underprediction of the reactivity feedback in the high power region near the stuck rod. To verify the conservatism of this method, the reactivity as well as the power distribution was checked for the statepoints shown on Table 15.4-7. These core analyses considered the Doppler reactivity from the high fuel temperature near the stuck RCCA, moderator feedback from the high water enthalpy near the stuck RCCA, power redistribution and non-uniform core inlet temperature effects. For cases in which steam generation occurs in the high flux regions of the core, the effect of void formation was also included. It was determined that the reactivity employed in the kinetics analysis was always larger than the reactivity calculated including the above local effects for all statepoints. The limiting statepoint is presented in Table 15.4-7. These results verified conservatism, i.e., underproduction of negative reactivity feedback from power generation.

(3) Minimum capability for injection of concentrated boric acid which is bounding for higher boric acid solution corresponding to the most restrictive single failure in the safety injection system. The emergency core cooling system consists of three systems: 1) the passive accumulators (at 1900 ppm), 2) the residual heat removal system, and 3) the safety injection system (at 2000 ppm).

The actual modeling of the safety injection system in LOFTRAN is described in Reference [11] and reflects injection as a function of RCS pressure versus flow including RCP seal injection, excluding centrifugal charging pump miniflow, and with no spilling lines. This injection analysis result is bounded when using the minimum composite pump curve (degraded by 5% of design head) as shown in Figure 6.3-4. This corresponds to the flow delivered by one charging pump and one safety injection pump delivering its full flow to the cold leg header. No credit has been taken for the low concentration borated water, which must be swept from the lines downstream of the RWST prior to the delivery of concentrated boric acid to the reactor coolant loops.

For the cases where offsite power is assumed, the sequence of events in the safety injection system is the following. After the generation of the safety injection signal (appropriate delays for instrumentation, logic, and signal transport included), the appropriate valves begin to operate and the high head safety injection pump starts. In 27 seconds, the valves are assumed to be in their final position and the pump is assumed to be at full speed. The volume containing the low concentration borated water is swept, of course, before the 2000 ppm (which is bounding for higher boric acid concentrations) reaches the core. This delay, described above is inherently included in the modeling.

In cases where offsite power is not available, a 10-second delay is assumed to start the diesels and then begin loading the necessary safety injection equipment sequentially onto them.

This assumption results in additional conservatism in the analysis, which adds the 10 seconds to the 27 seconds assumed for valve alignment in the offsite power available case for a total of 37 seconds.

(4) Design value of the steam generator heat transfer coefficient including allowance for fouling factor.

(5) Since the steam generators are provided with integral flow restrictors with a 1.4 square foot throat area, any rupture with a break area greater than 1.4 square feet, regardless of location would have the same effect on the Nuclear Steam Supply System (NSSS) as the 1.4 square foot break. The following cases have been considered in determining the core power and reactor coolant system transients:

(a) Complete severance of a pipe, with the plant initially at no load conditions, full reactor coolant flow with offsite power available.

(b) Case a above with loss of offsite power. Loss of offsite power results in coolant pump coastdown.

(6) Power peaking factors corresponding to one stuck RCCA and nonuniform core inlet coolant temperatures are determined at 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 control assembly-during the return to power phase following the steam line break.

The limiting statepoint~~s for the two cases are~~ is presented in Table 15.4-7.

Both the cases above assume initial hot shutdown conditions at time zero since this represents the most limiting initial condition. Should the reactor be just critical or operating at power at the time of a steam line break, the reactor will be tripped by the normal 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, the average coolant temperature is higher than at no load and there is appreciable energy stored in the fuel. Thus, the additional stored energy is removed via the cooldown caused by the steam line break before the no load conditions of RCS 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 which assumes no load condition at time zero.

However, since the initial steam generator water inventory is greatest at no load, the magnitude and duration of the RCS cooldown are greater for steam line breaks occurring from no load conditions.

(7) In computing the steam flow during a steam line break, the Moody Curve[9] for fl/D = 0 is used.

(8) A steam generator tube plugging level of ~~10%~~ 0% is assumed.

(9) A thermal design flowrate of 372,400 gpm is used which accounts for ~~the 10% steam generator tube plugging level and~~ instrumentation uncertainty.

Results

The results presented are a conservative indication of the events which would occur assuming a steam line rupture since it is postulated that all of the conditions described above occur simultaneously.

Core Power and RCS Transient

Figures 15.4-11a through 15.4-11c show the RCS transient and core response following a main steam line rupture (complete severance of a pipe) at initial no load condition (Case a). Offsite power is assumed available so that full reactor coolant flow exists. The transient shown assumes an uncontrolled steam release from only one steam generator. Should the core be critical at near zero power when the rupture occurs the initiation of safety injection by low steamline pressure will trip the reactor. Steam release from more than one steam generator will be prevented by automatic trip of the fast acting isolation valves in the steam lines by high-high containment pressure or low steam line pressure signals. Even with the failure of one valve, release is limited by isolation valve closure for the other steam generators while the one generator blows down. The main steamline isolation valves are designed to be fully closed in less than 6 seconds from receipt of a closure signal.

As shown in Figure 15.4-11a the core attains criticality with the RCCAs inserted (with the design shutdown assuming one stuck RCCA) shortly after boron solution at 2000 ppm (which is bounding for higher boric acid concentrations) enters the reactor coolant system. A peak core power less than the nominal full power value is attained.

The calculation assumes the boric acid is mixed with, and diluted by the water flowing in the reactor coolant system prior to entering the reactor core. The concentration after mixing depends upon the relative flow rates in the reactor coolant system and in the safety injection system. The variation of mass flow rate in the reactor coolant system due to water density changes is included in the calculation as is the variation of flow rate in the safety injection system due to changes in the reactor coolant system pressure. The safety injection system flow calculation includes the line losses in the system as well as the pump head curve.

It should be noted that the safety injection accumulators are actuated in Case (a) due to low RCS pressure (Figure 15.4-11b). Once the accumulators actuate, 2400 ppm boron is delivered to the core and the transient is terminated before a significant return to power is achieved. Once the transient is terminated and the plant is stabilized, emergency operating procedures may be followed to recover from the MSLB event.

Figures 15.4-12a through 15.4-12c show the responses of the salient parameters for Case b which corresponds to the case discussed above with additional loss of offsite power at the time the safety injection signal is generated. The injection of borated water is conservatively delayed to 37 seconds based on the assumed 10 second diesel generator delay time plus the 27 seconds associated with the valve lineup for the offsite power available case (Case a). In this case criticality is achieved later and the core power increase is slower than in the similar case with offsite power available. The ability of the emptying steam generator to extract heat from the reactor coolant system is reduced by the decreased flow in the reactor coolant system. For both these cases the peak power remains well below the nominal full power value.

Unlike Case a, Case b does not result in the actuation of the safety injection accumulators. ~~Therefore, due to the fact that less boric acid solution is delivered to the core, Case b results in a more limiting return to power than Case a.~~

It should be noted that following a steam line break only one steam generator blows down completely. Thus, the remaining steam generators are still available for dissipation of decay heat after the initial transient is over. In the case of loss of offsite power this heat is removed to the atmosphere via the steam line safety valves.

Following blowdown of the faulted steam generator, the plant can be brought to a stabilized hot standby condition through control of auxiliary feedwater flow and safety injection flow as described by plant operating procedures. The operating procedures call for operator action to limit RCS pressure and pressurizer level by terminating safety injection flow, and to control steam generator level and RCS coolant temperature using the auxiliary feedwater system. Any action required of the operator to maintain the plant in a stabilized condition is in a time frame in excess of ten minutes following safety injection actuation.

Margin to Critical Heat Flux

A DNB analysis was performed for the limiting case. The limiting statepoints for the with offsite power case is ~~are~~ presented in Table 15.4-7. It was found that all cases had a minimum DNBR greater than the limit value.

15.4.2.1.3 Conclusions

The analysis shows that the criteria stated earlier in this section are satisfied. In addition, the pressure differential across the steam generator tubes that has been

No Change

calculated for a postulated main feedwater line break is more limiting (i.e., dictates a minimum tube wall thickness) than the pressure differential for a postulated main steam line break. Therefore, steam generator tube rupture is not expected to occur (see Section 4.19.7.6 of Reference [34]).

Although DNB and possible clad perforation following a steam pipe rupture are not necessarily unacceptable and not precluded in the criterion, the above analysis, in fact, shows that no violation of the DNB design basis occurs for any rupture assuming the most reactive RCCA stuck in its fully withdrawn position.

If it is assumed that there is leakage from the reactor coolant system to the secondary system in the steam generators and that offsite power is lost following the steam line break, radioactivity will be released to the atmosphere through the relief or safety valves. Environmental consequences of a postulated steam line break are addressed in Section 15.5.4.

15.4.2.2 Major Rupture of a Main Feedwater Pipe

15.4.2.2.1 Identification of Causes and Accident Description

A major feedwater line rupture is defined as a break in a feedwater pipe large enough to prevent the addition of sufficient feedwater to the steam generators to maintain shell-side fluid inventory in the steam generators. If the break is postulated in a feedline between the check valve and the steam generator, fluid from the steam generator may also be discharged through the break. Further, a break in this location could preclude the subsequent addition of auxiliary feedwater to the affected steam generator. (A break upstream of the feedline check valve would affect the nuclear steam supply system only as a loss of normal feedwater.)

Depending upon the size of the break and the plant operating conditions at the time of the break, the break could cause either a reactor coolant system cooldown (by excessive energy discharge through the break), or a reactor coolant system heatup. Potential reactor coolant system cooldown resulting from a secondary pipe rupture is evaluated in Section 15.4.2.1. Therefore, only the reactor coolant system heatup effects are evaluated for a feedline rupture.

Out of Scope

A feedline rupture reduces the ability to remove heat generated by the core from the reactor coolant system because of the following reasons:

(1) Feedwater to the steam generators is reduced. Since feedwater is subcooled, its loss may cause reactor coolant temperatures to increase prior to reactor trip.

(2) Liquid in the steam generator may be discharged through the break, and would then not be available for decay heat removal after trip.

(3) The break may be large enough to prevent the addition of any main feedwater after trip.

No Change

Table 15.1-2 Summary Of Initial Conditions And Computer Codes Used (Continued) (Page 3 of 4)

FAULTS	COMPUTER CODES UTILIZED	REACTIVITY COEFFICIENTS ASSUMED FOR: MODERATOR TEMPERATURE (Δk/°F)	MODERATOR DENSITY (Δk/gm/cc)	DOPPLER	INITIAL NSSS THERMAL POWER OUTPUT ASSUMED[1] (MWt)
CONDITION IV					
Major Rupture of Pipes Containing Reactor Coolant Up to and Including Double-ended Rupture of the Largest Pipe in the Reactor Coolant System (Loss of Coolant Accident)	WCOBRA/TRAC, HOTSPOT, LOTIC2	--	0.00	Function of fuel temperature.	3475
Major Rupture of a Steam Pipe	LOFTRAN, VIPRE-01,	Function of moderator density; see Section 15.2.13 (Figure 15.2-40)		Note 3	3425 (critical @ 0.0 fraction of nominal [FON]).
Major Rupture of a Main Feedwater Pipe	LOFTRAN	---	0.00	upper[2]	3425
Steam Generator Tube Rupture	LOFTTR2	0 pcm/°F @ 100 RTP	Figure 15.1-7	upper[2]	3427
Single Reactor Coolant Pump Locked Rotor	LOFTRAN, VIPRE-01, FACTRAN	---	0.00	upper[2]	3475
Fuel Handling Accident	NA	NA	NA		3579
Rupture of a Control Rod Drive Mechanism Housing (RCCA Ejection)	TWINKLE, FACTRAN	Refer to Section 15.4.6	---	Least negative Doppler defect, see Table 15.4-12	3411 (HZP 0)

TABLE 15.1-2
(Sheet 4 of 4)

SUMMARY OF INITIAL CONDITIONS AND COMPUTER CODES USED (Cont'd)

FAULTS	COMPUTER CODES UTILIZED	REACTIVITY COEFFICIENTS ASSUMED FOR: MODERATOR TEMPERATURE (Δk/°F)	MODERATOR DENSITY (Δk/gm/cc)	DOPPLER	INITIAL NSSS THERMAL POWER OUTPUT ASSUMED[1, 5,6] (MWt)
CONDITION IV (Cont'd)					
Major Rupture of a Steam Pipe	LOFTRAN, VIPRE-01	Function of moderator density; see Section 15.2.13 (Figure 15.2-40)		Note 3	3475 (critical @ 0.0 fraction of nominal [FON]).
Major Rupture of a Main Feedwater Pipe	LOFTRAN	---	0.0	lower[2]	3475
Steam Generator Tube Rupture	LOFTTR2	0 pcm/°F @ 100 RTP	---	upper[2]	3425
Single Reactor Coolant Pump Locked Rotor	LOFTRAN, VIPRE-01 FACTRAN	---	0.0	upper[2]	3475
Fuel Handling Accident	NA	NA	NA		3579
Rupture of a Control Rod Drive Mechanism Housing (RCCA Ejection)	TWINKLE, FACTRAN	Refer to Section 15.4.6	---	Least negative Doppler defect; see Table 15.4-12	3411 (HZP 0)

[1] The values provided do not include the power uncertainty that is applied either directly (non-RTDP events) or statistically (RTDP events).

[2] Refer to Figure 15.1-5.

[3] ~~Refer to Figure 15.4-9.~~ The integral of the Doppler Power Coefficient is shown in Figure 15.4-9 and a Doppler Temperature Coefficient of -0.000029 Δk/°F was assumed.

[4] LOCA M/E based on Engineering Safety Design Rating (ESDR) of 3650 MWt.

[5] The 14 MWt value is based on a generic calculation for a representative 4-loop design. The Watts Bar specific value is 16.0 MWt. Thus the actual NSSS thermal output can be as high as 3475 MWt with a licensed core power of 3459 MWt.

[6] Although several of these analyses are based upon a core power of 3411 MWt and NSSS power of 3425 MWt, an uprated core power of 3459 MWt and NSSS power of 3475 MWt are also supported via evaluation, based upon a redefinition of the 2% power uncertainty (2% to 0.6%).

Table 15.4-1 Time Sequence Of Events For Condition IV Events (Page 1 of 2)

Accident	Event	Time (Seconds)
Major Reactor Coolant System Pipe Ruptures, Double-Ended Cold Leg Guillotine	See Table 15.4-17	
Major Secondary System Pipe Rupture		
1. Case B		
Complete severence of a pipe, loss of offsite power simultaneous with the break and initiation of safety injection signal	Steam Line Ruptures	0.0
	Low Steam Pressure Setpoint Reached	0.67
	Pressurizer Empties	~~12.0~~ 12.2
	Criticality Attained	~~58.0~~ 38.4
	Boron Reaches Core	~~46.0~~ 46.2
	Accumulators Actuated	N/A
2. Case A		
Complete severence of a pipe, offsite power available	Steam Line Ruptures	0.0
	Low Steam Pressure Setpoint Reached	0.67
	Pressurizer Empties	11.0
	~~Boron Reaches Core~~ Criticality Attained	~~34.0~~ 30.0
	~~Criticality Attained~~ Boron Reaches Core	~~44.0~~ 33.6
	Accumulators Actuated	~~54~~ 54.4
Reactor Coolant Pump Shaft Seizure (Locked Rotor/Broken Shaft)		
All pumps in operation, one shaft seizure without offsite power available	Rotor on one pump seizes	0
Out of Scope	Low flow trip point reached	0.02
	Rods begin to drop	1.22
	Undamaged pumps lose power and begin coasting down	1.22
	Maximum RCS pressure occurs	3.50
	Maximum clad temperature occurs	3.99

No Change

Table 15.4-6 Equipment Required Following A High Energy Line Break (Page 1 of 3)

SHORT TERM (REQUIRED FOR MITIGATION OF ACCIDENT)	HOT STANDBY	REQUIRED FOR COOLDOWN
Reactor trip and safeguards actuation channels including sensors, circuitry, and processing equipment (the protection circuits used to trip the reactor on under- voltage, underfrequency, and turbine trip may be excluded).	Auxiliary feedwater system including pumps, water supply, and system valves and piping (this system must be placed in service to supply water to operable steam generators no later than 10 minutes after the incident).	Steam generator power-operated relief valves (can be manually operated locally) Controls for defeating automatic safety injection actation during a cooldown and depressurization.
Safety injection system including the pumps, the refueling water storage tank, and the systems valves and piping.	Capability for obtaining a reactor coolant systemsample.	Residual heat removal system including pumps, heat exchanger, and system valves and piping necessary to cool and maintain the reactor coolant system in a cold shutdown condition
Diesel generators and emergency power distribution equipment.	Lower compartment cooling fans must be started (a minimum of 2 of 4) 1-1/2 hours to 4 hours after the initiation of HELB.	
Essential raw cooling water system	Ice condenser.	
Containment safeguards cooling equipment.	Air return fan to recirculate air thru ice condenser.	
Main feedwater control valves* (trip closed feature).	Containment spray to maintain hot standby lower compartment temperature.	

No Change

Table 15.4-6 Equipment Required Following A High Energy Line Break (Page 2 of 3)

SHORT TERM (REQUIRED FOR MITIGATION OF ACCIDENT)	HOT STANDBY	REQUIRED FOR COOLDOWN
Bypass feedwater control valves* (trip closed feature).		
Circuits and/or equipment required to trip the main feedwater pumps.*		
Main steam line stop valves* (Main Steam Isolation Valves trip closed feature).		
Main steam line stop valve bypass valves* (trip closed feature).		
Steam generator blowdown isolation valves (automatic closure feature).		
Batteries (Class 1E).		
Control room ventilation.		
Control room equipment must not be damaged to an extent where any equipment will be spuriously actuated or any of the equipment contained elsewhere in this list cannot be operated.		

No Change

Table 15.4-6 Equipment Required Following A High Energy Line Break (Page 3 of 3)

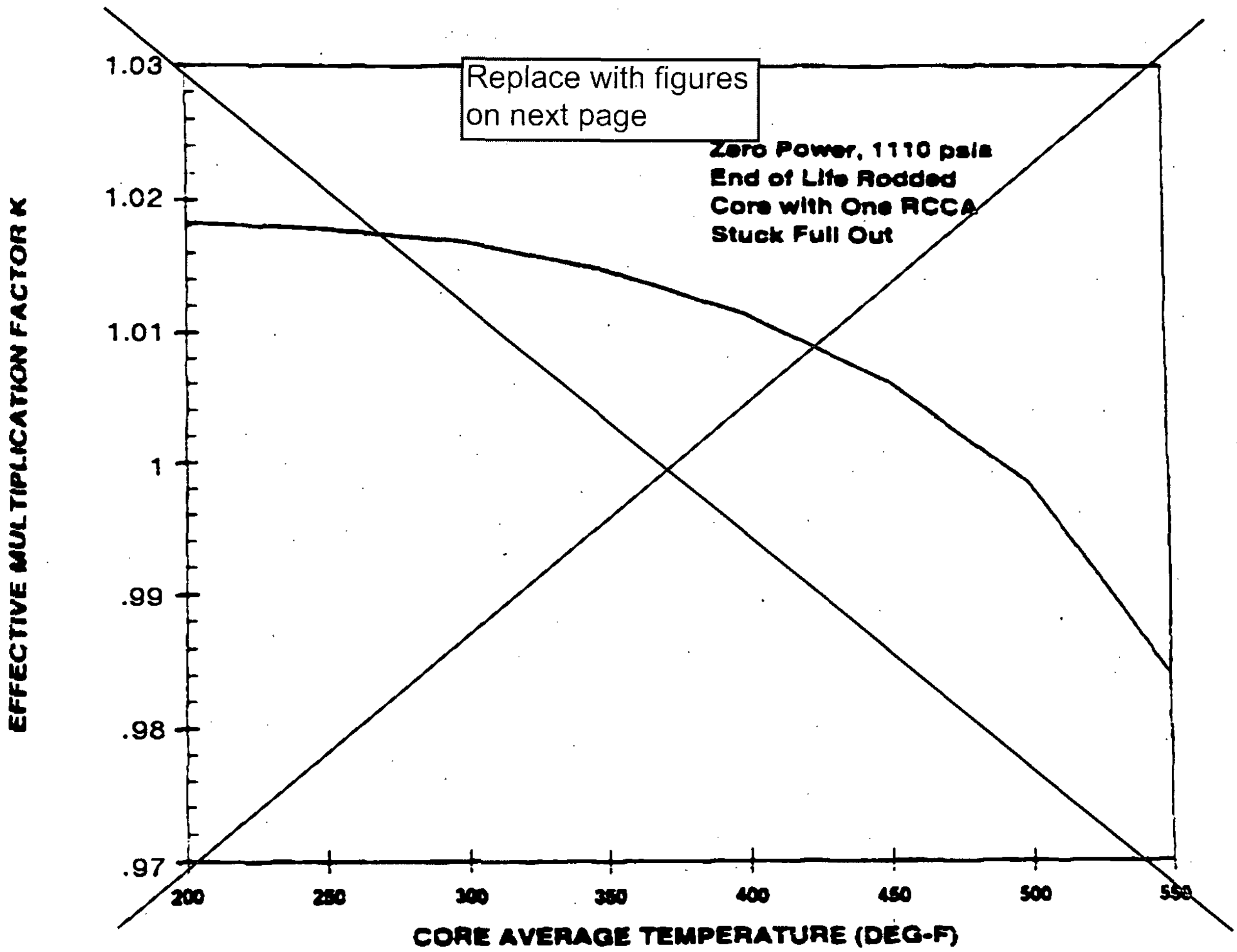
SHORT TERM (REQUIRED FOR MITIGATION OF ACCIDENT)	HOT STANDBY	REQUIRED FOR COOLDOWN
Emergency lighting.		
Post accident monitoring system**		
Wide range Thot or Tcold for each reactor coolant loop.		
Pressurizer water level.		
Wide range reactor coolant system pressure		
Steam line pressure for each steam generator.		
Wide range and narrow range steam generator level for each steam generator.		
Containment pressure		

* Required for steam line, feed line, and steam generator blowdown line break only.

** See Section 7.5 for a discussion of the post accident monitoring system.

Table 15.4-7 Limiting Core Parameters Used In Steam Break DNB Analysis

Reactor vessel inlet temperature (°F)	
Faulted SG Loop	~~398.7~~ 402.9
Intact SG Loops	~~479.5~~ 485.9
RCS pressure (psia)	~~603.22~~ 616.73
RCS flow fraction of nominal (%)	100
Heat flux fraction of nominal (%)	~~1.6~~ 7.9
Reactivity (~~%~~) %ρ	~~0.015~~ 0.105
Density (gm/cc)	~~0.829~~ 0.824
Boron (ppm)	~~16.45~~ 7.85
Time (seconds)	~~57.4~~ 56.8



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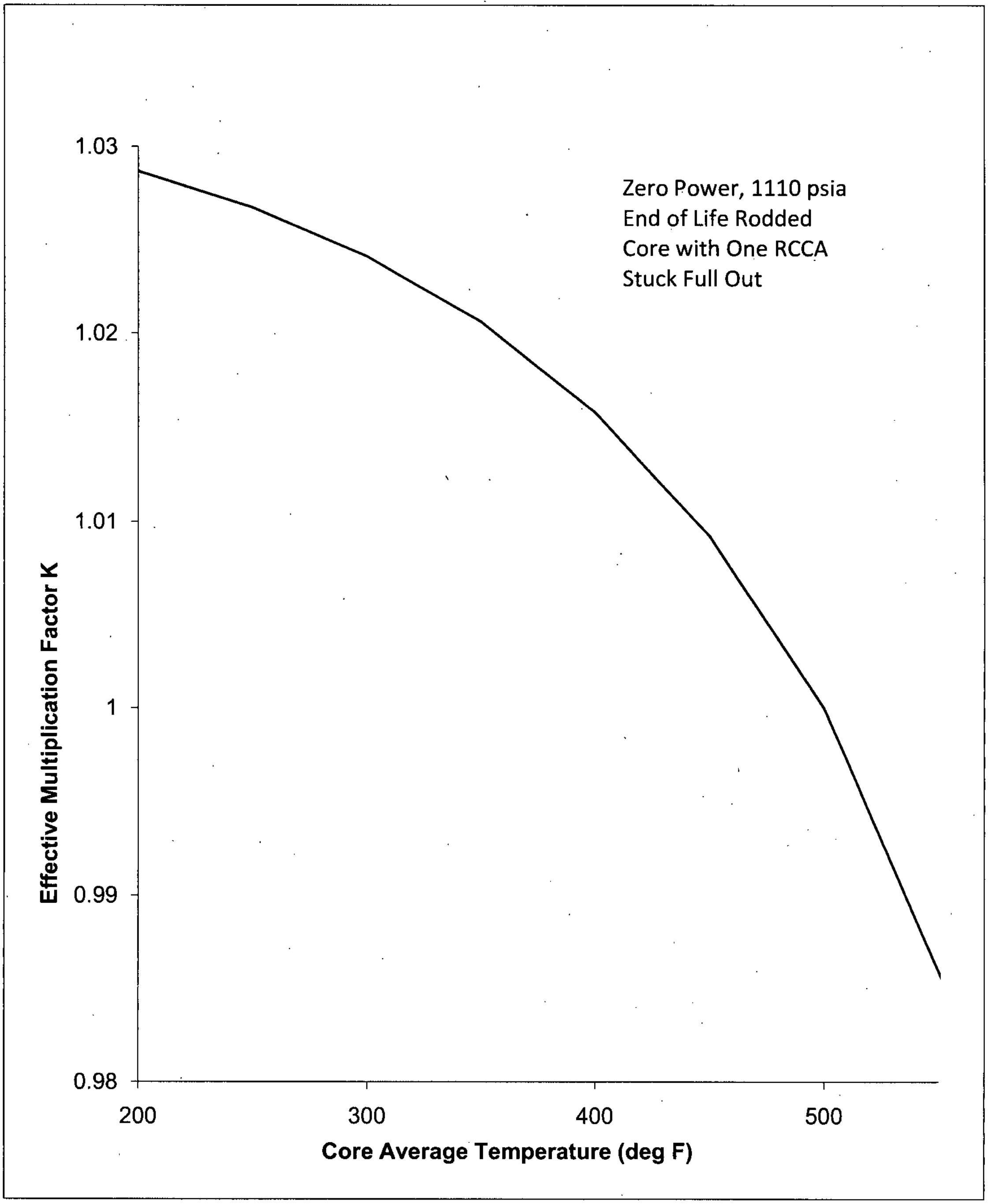
VARIATION OF Keff WITH
CORE AVERAGE TEMPERATURE
FIGURE 15.2-40

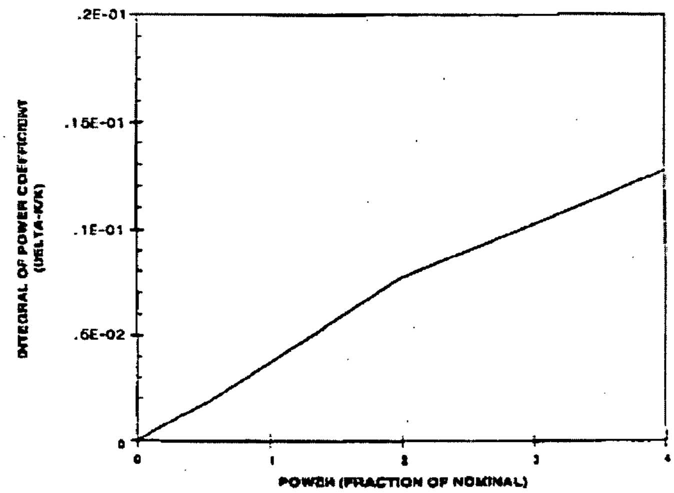


Variation of Keff With

Core Average Temperature

Figure 15.2-40

No Change



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VARIATION OF REACTIVITY WITH POWER AT A CONSTANT CORE AVERAGE TEMPERATURE FIGURE 15.4-9

Figure 15.4-9 Variation of Reactivity with Power at Constant Core Average Temperature

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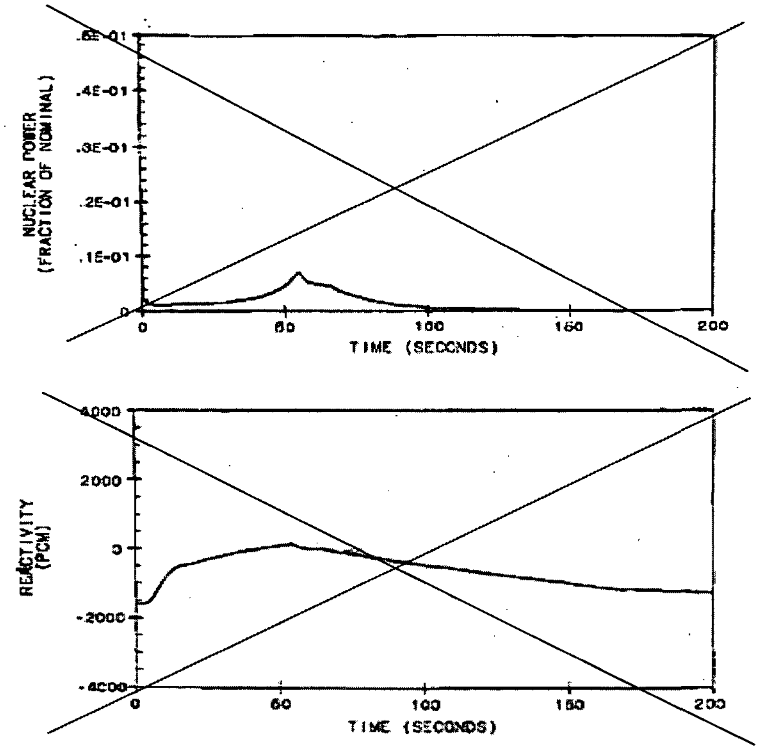

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TRANSIENT RESPONSE TO STEAM LINE BREAK WITH SAFETY INJECTION AND OFFSITE POWER (CASE A)

FIGURE 15.4.11a

Figure 15.4-11a Transient Response to Steam Line Break with Safety Injection and Offsite Power (CASE A)

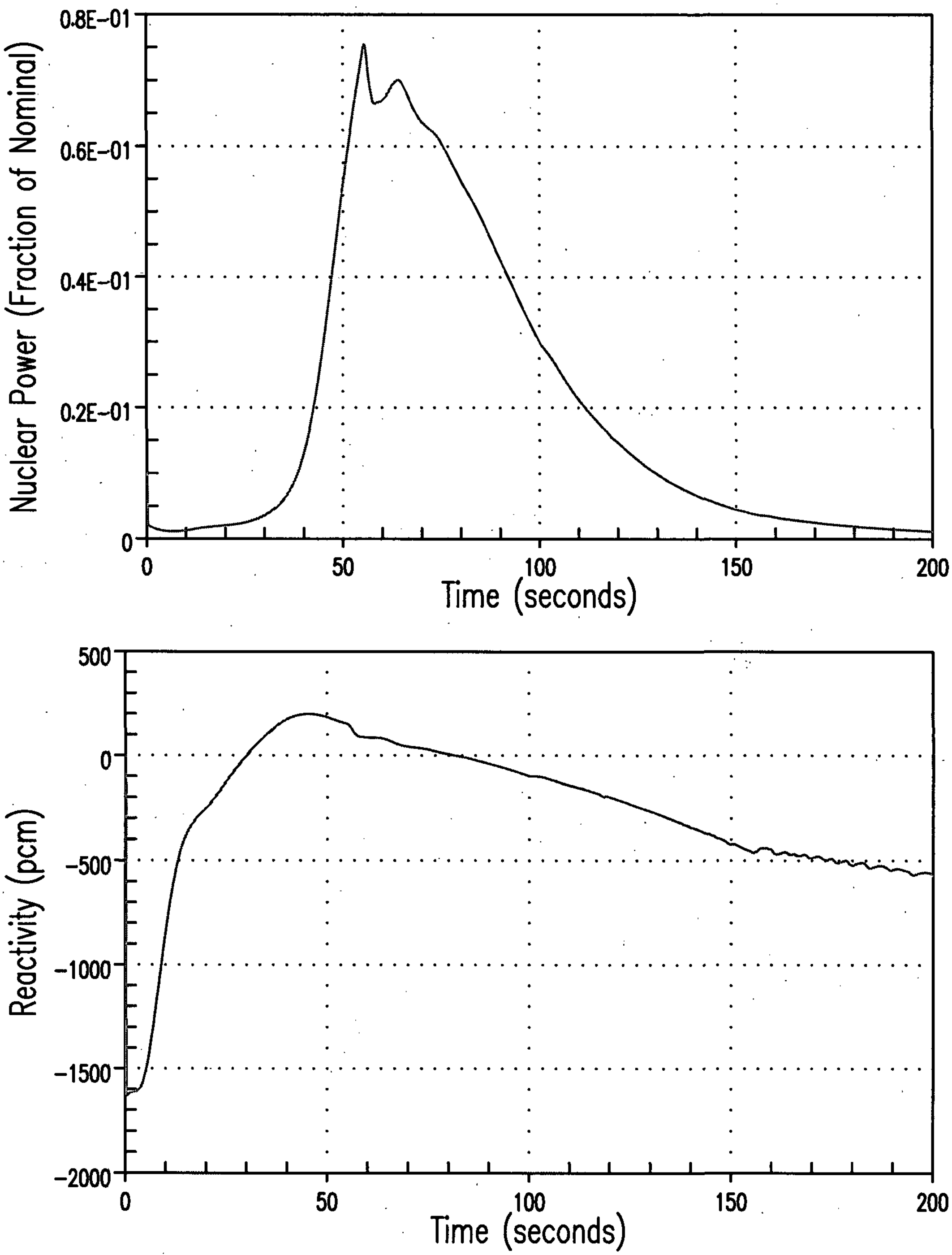

Figure 15.4.11a: Transient Response To Steam Line Break with Safety Injection and Offsite Power (Case A)

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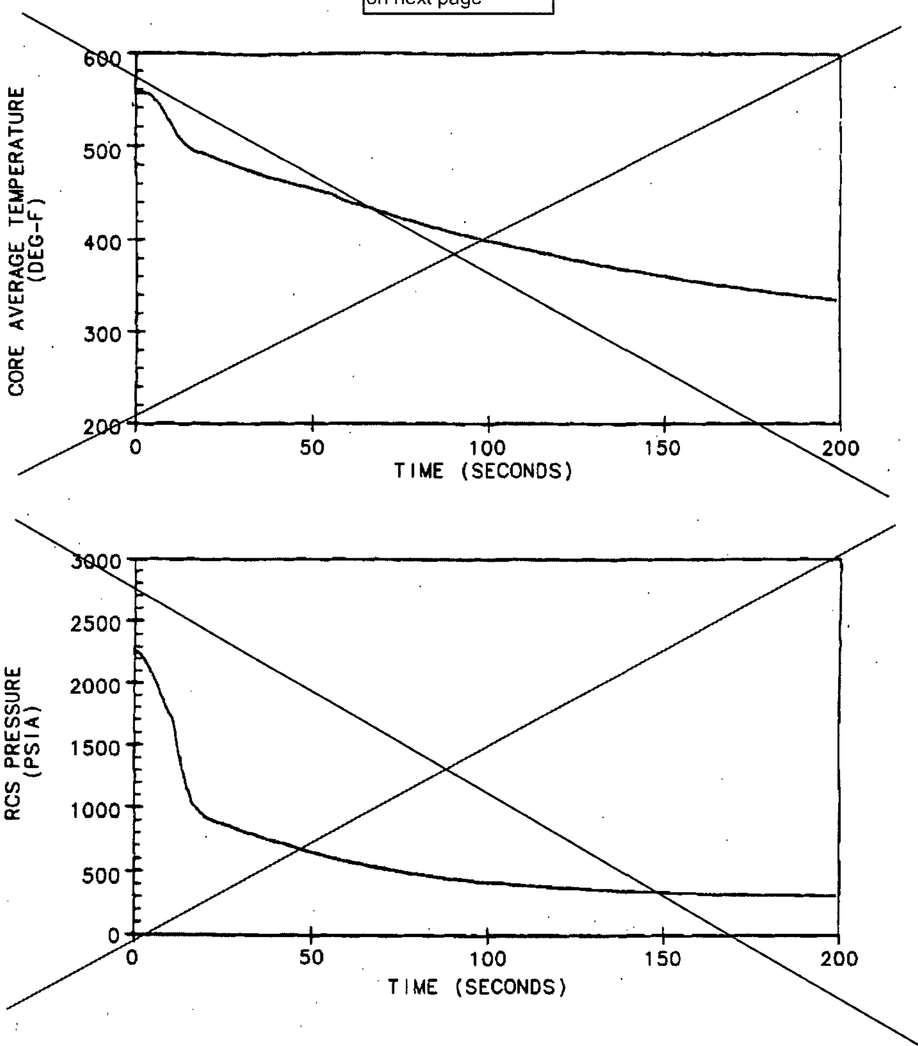

Figure 15.4-11b Transient Response to Steam Line Break with Safety Injection and Offsite Power (CASE A)

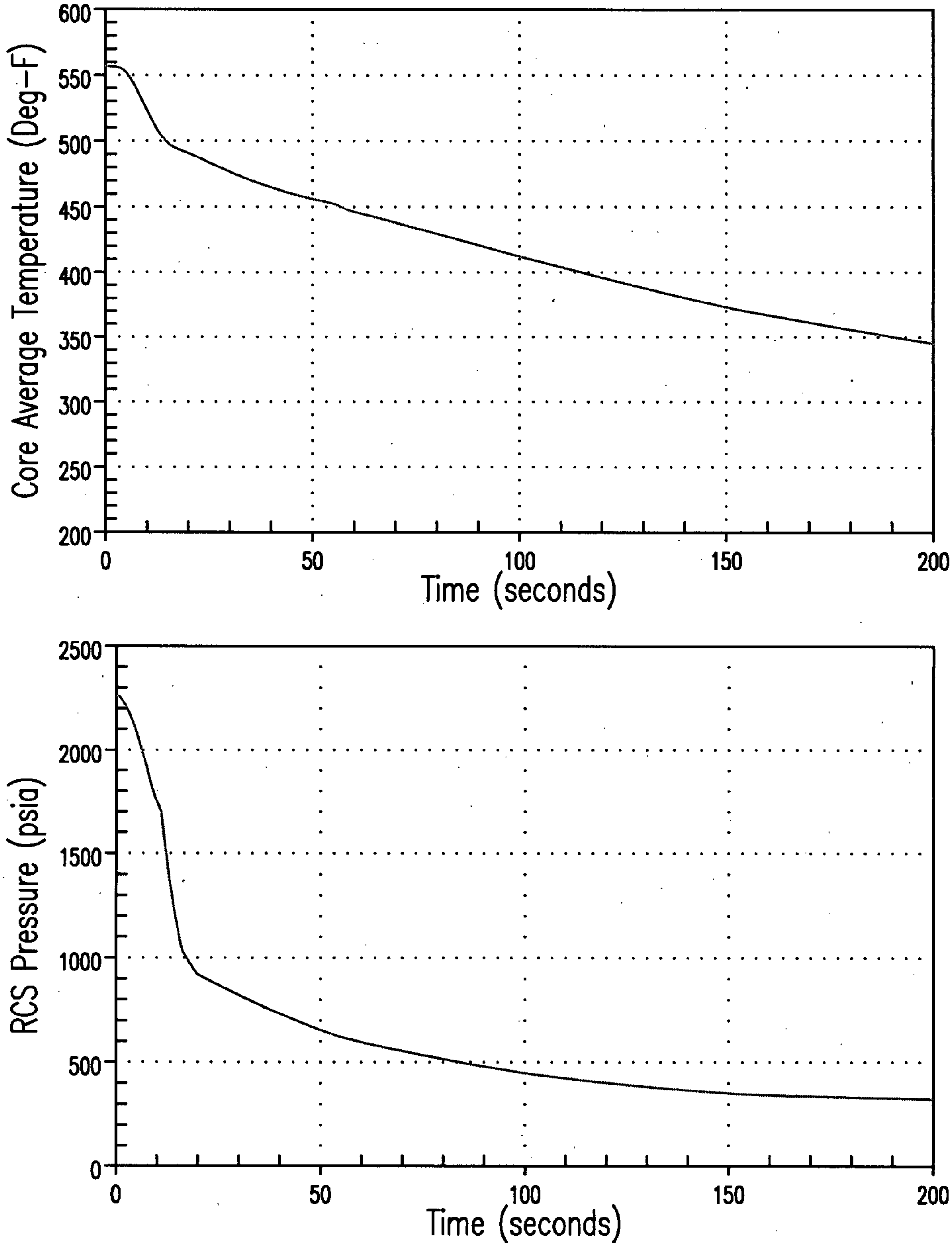

Figure 15.4.11b: Transient Response To Steam Line Break with Safety Injection and Offsite Power (Case A)

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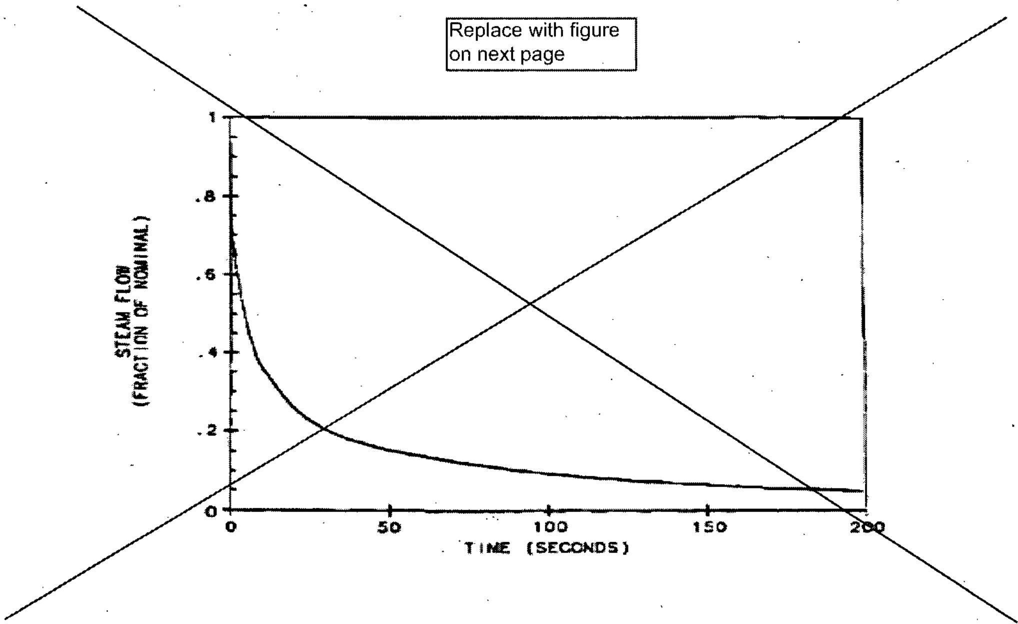

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TRANSIENT RESPONSE TO STEAM LINE BREAK WITH SAFETY INJECTION AND OFFSITE POWER (CASE A)

FIGURE 15.4.11c

Figure 15.4-11c Transient Response to Steam Line Break with Safety Injection and Offsite Power (CASE A)

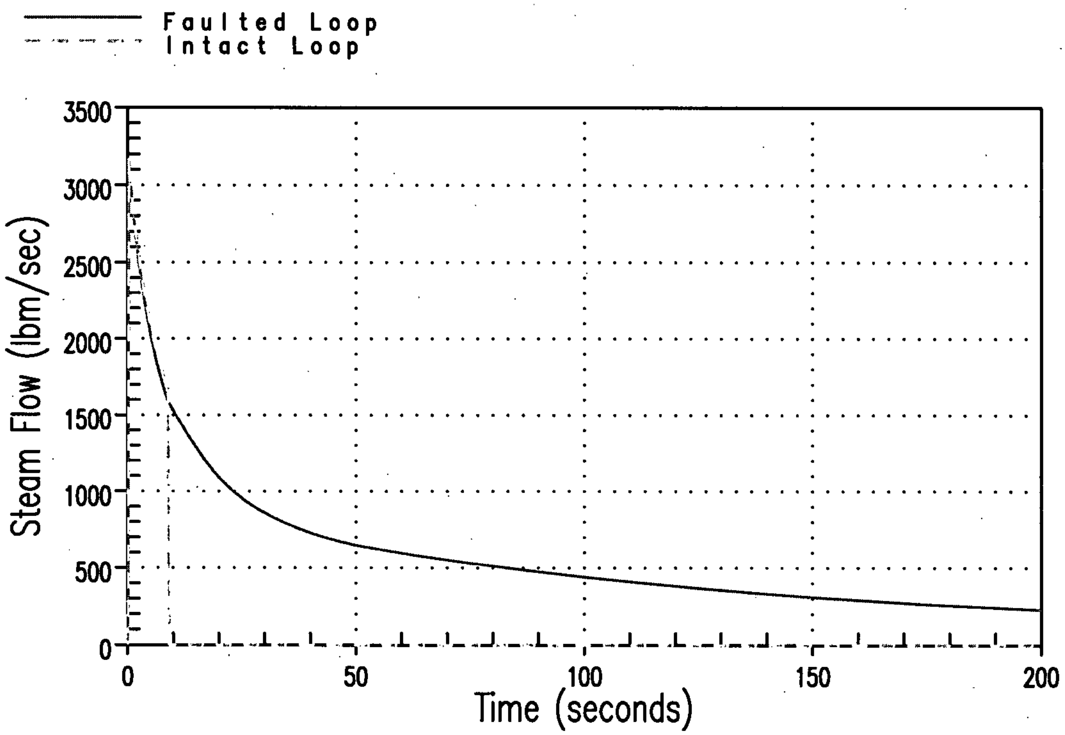

Figure 15.4.11c: Transient Response To Steam Line Break with Safety Injection and Offsite Power (Case A)

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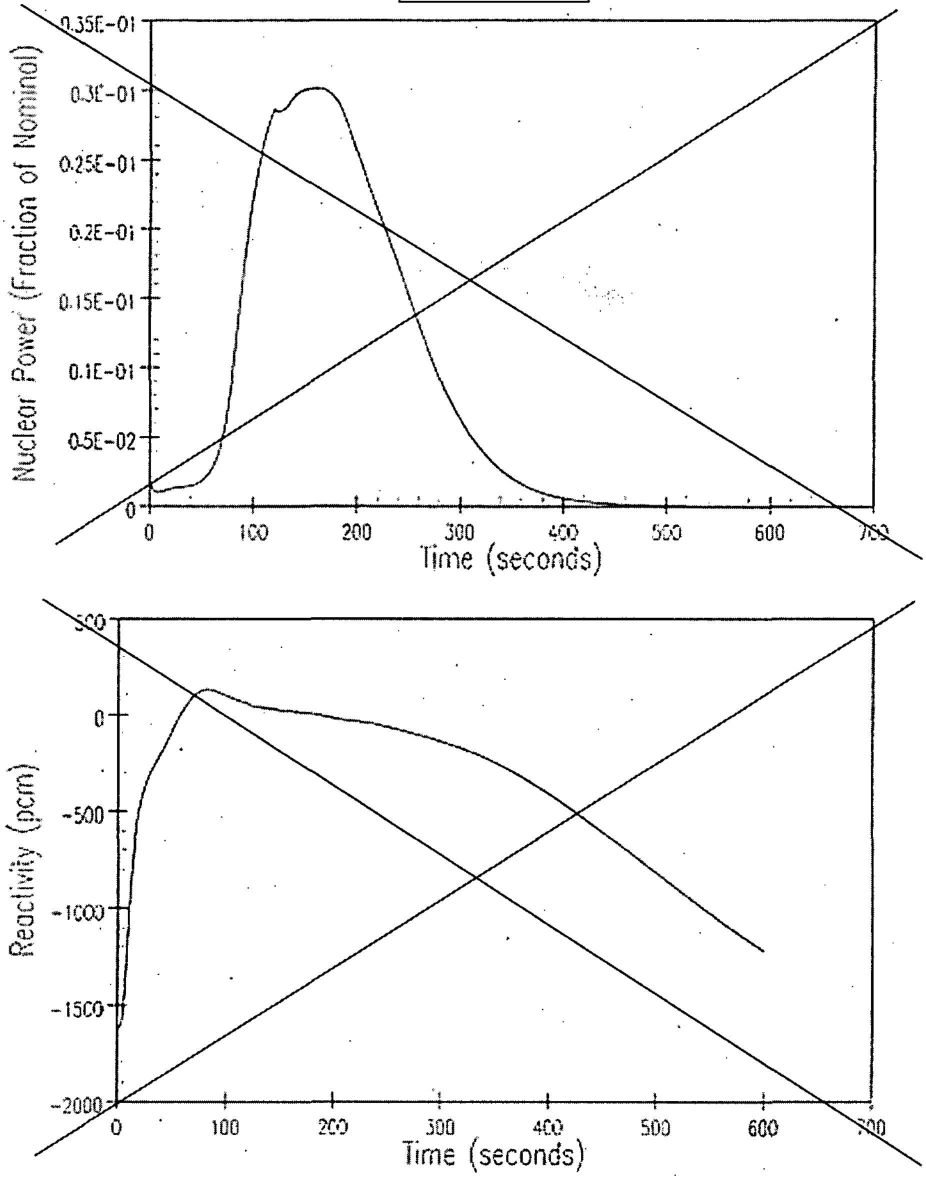

**Figure 15.4-12a Transient Response to Steam Line Break without Offsite Power
Nuclear Power and Reactivity Versus Time**

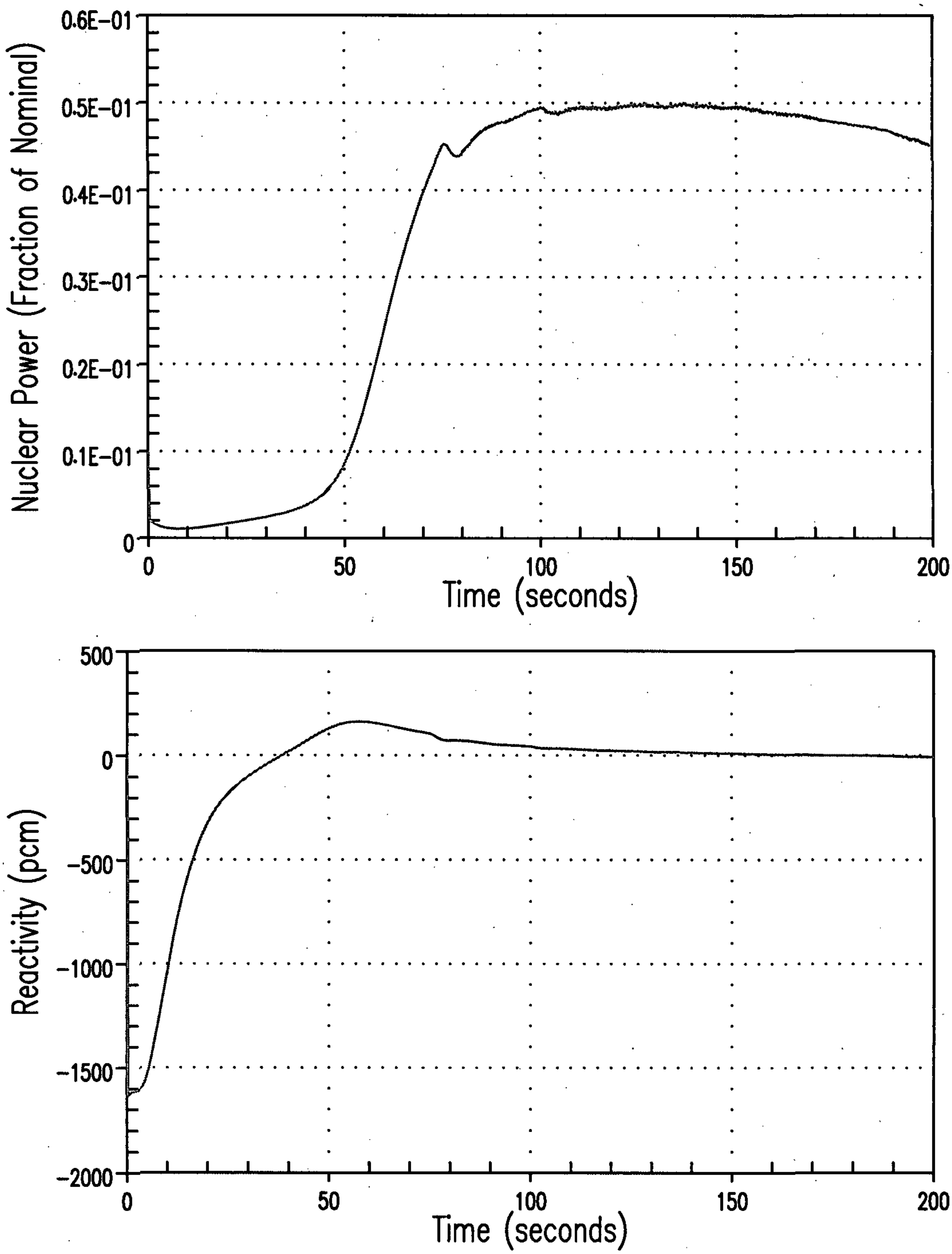

Figure 15.4-12a Transient Response to Steam Line Break without Offsite Power Nuclear Power and Reactivity Versus Time

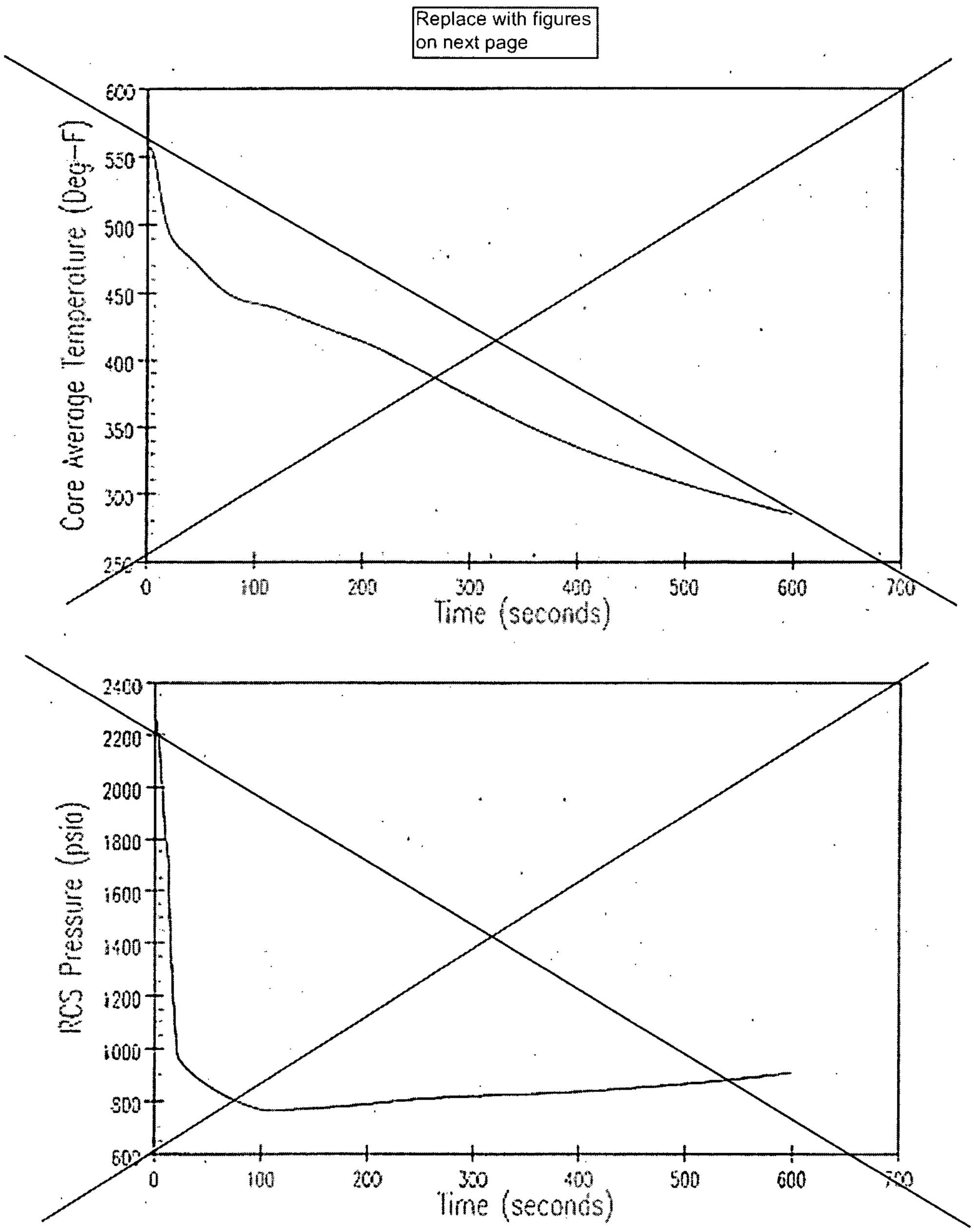

Figure 15.4-12b Transient Response to Steam Line Break without Offsite Power Core Average Temperature and RCS Pressure Versus Time

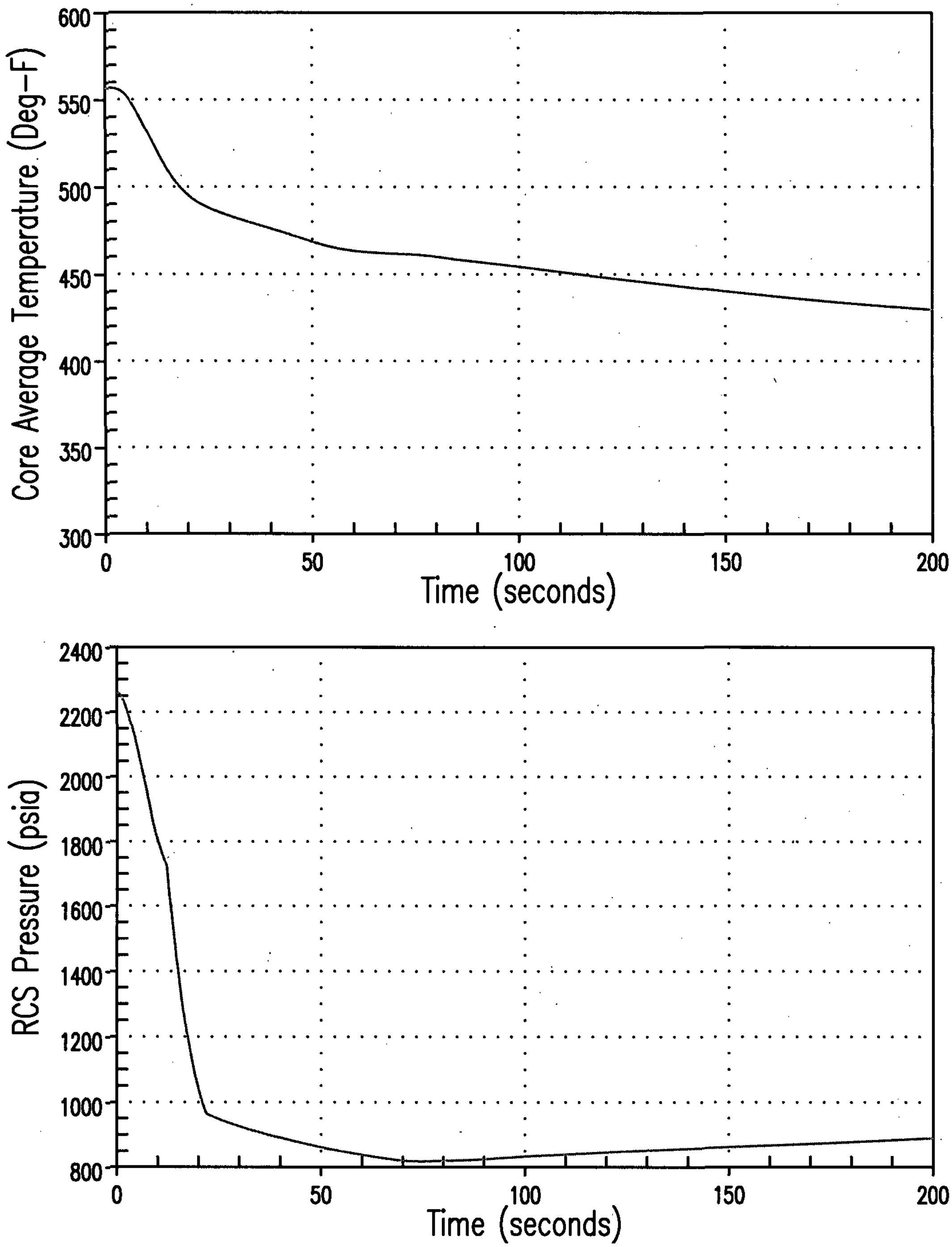

Figure 15.4-12b Transient Response to Steam Line Break without Offsite Power Core Average Temperature and RCS Pressure Versus Time

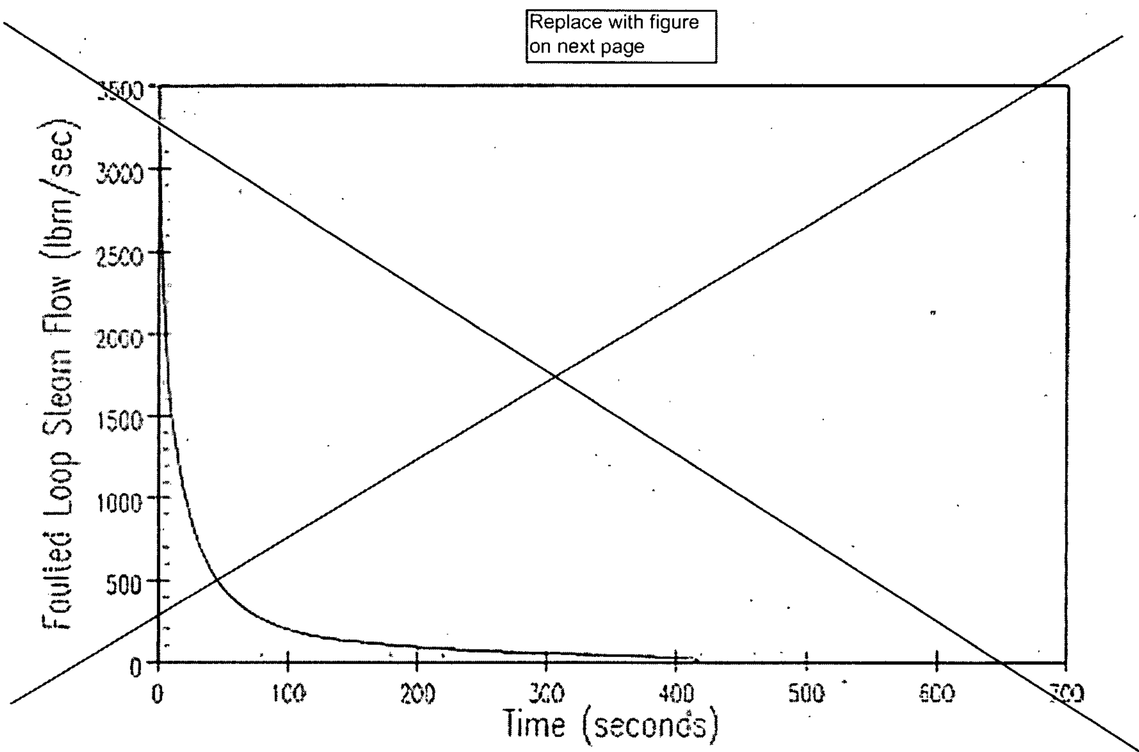

Figure 15.4-12c Transient Response to Steam Line Break without Offsite Power Faulted Loop Steam Flow Versus Time

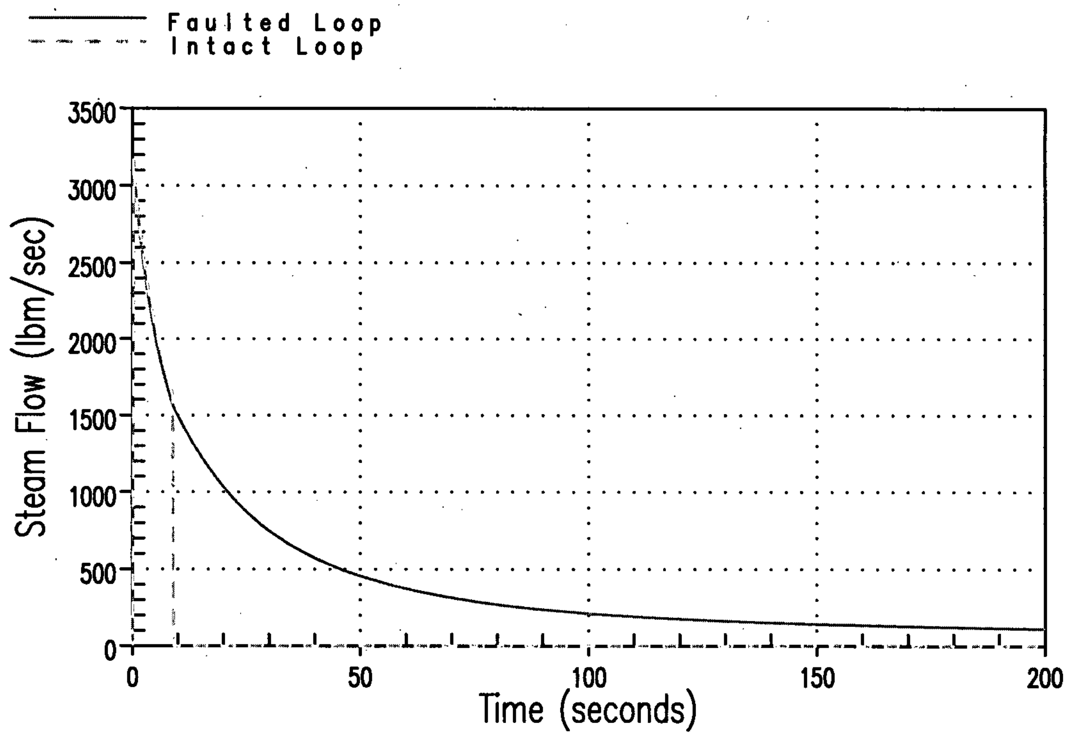

Figure 15.4-12c Transient Response to Steam Line Break without Offsite Power Faulted Loop Steam Flow Versus Time

Behavior of the WBN Unit 2 Incore Instrument Thimble Assemblies (IITAs) Against Mechanical Wear Resulting from Flow-Induced Vibration (FIV)

EMCB RAI 1

The work performed to demonstrate the acceptable behavior of the WBN Unit 2 incore instrument thimble assemblies (IITAs) against mechanical wear resulting from flow-induced vibration is based on a comparative analysis. With respect to the use of the comparative method for evaluating the vibratory response of a referenced nuclear plant's in-core instrument assemblies and the WBN Unit 2 IITAs, provide a justification that demonstrates that the comparative method is acceptable for use in the analysis of the WBN Unit 2 IITAs. This justification should include, but not be limited to, citation of regulatory precedents involving the use of the comparative method and the results of any benchmarking performed against other methods of analysis involving vibratory excitation resulting from parallel flow across structures similar to the IITAs.

EMCB RAI 2

As stated in EMCB RAI 1, the comparative analysis performed for the WBN Unit 2 IITAs to determine whether the IITAs exhibit satisfactory vibration amplitudes resulting from parallel flow between the IITAs and the supporting structures and is based on using the comparative method to contrast the calculated amplitudes for the WBN Unit 2 and the referenced plant in-core instrumentation. During an audit at the Westinghouse offices on July 14, 2011, the NRC staff reviewed the documentation of the vibration analysis performed for the WBN Unit 2 IITAs, which indicated that the acceptance criterion used to justify the satisfactory behavior of the WBN Unit 2 IITAs is based on the vibration amplitudes resulting from the WBN Unit 2 IITA analysis being less than 105 percent of the vibration amplitudes calculated for the referenced plant in-core instrumentation. However, no justification was provided for why the referenced plant vibration amplitudes are acceptable. Therefore, provide a technical justification that demonstrates how the referenced plant calculated vibration amplitudes of the in-core instrumentation provide reasonable assurance that unsatisfactory mechanical wear of these components due to flow-induced vibration will not occur. Additionally, provide justification that shows that the calculated peak vibration amplitude for the WBN Unit 2 IITAs is acceptable from a quantitative standpoint. This justification should compare the calculated value to the dimensional details and structural design of the IITAs to demonstrate that vibratory motion of the IITAs would not result in unacceptable mechanical wear.

Response

Westinghouse is not crediting the referenced analysis to demonstrate pressure boundary integrity of the IITAs.

The IITA are composed of five Vanadium detectors and one thermocouple, each enclosed in their own Stainless Steel sheath. These six items are then enclosed within the final outer sheath.

The final outer sheath is subject to flow induced vibration that may result in mechanical wear just like a flux thimble in plants with movable incore detectors (MID), however, unlike the plants that use a MID system, the IITA outer sheath is not the primary pressure boundary. The primary pressure boundary of the IITA consists of two parts. First is at the Swagelok fitting which seals the outer sheath to the seal table stud. This portion of the outer sheath is not subject to mechanical wear since it is a rigid connection. The second part of the pressure boundary is

Behavior of the WBN Unit 2 Incore Instrument Thimble Assemblies (IITAs) Against Mechanical Wear Resulting from Flow-Induced Vibration (FIV)

the header region of the IITA. This region is hermetically sealed and will only be in contact with water if there is a failure of the outer sheath. See **Figure 1** below for more detail.

Given this design, a complete failure of the outer sheath due to mechanical wear will not result in a pressure boundary breach because the primary pressure boundaries are not in the core and are not subject to mechanical wear. If a failure of the outer sheath occurs, then a failure of the instrument itself may occur and will be seen within BEACON. Information regarding the operation of the plant with a reduced number of self powered detectors can be found in WCAP 12472-P-A Addendum 1-A.

Please see the response to item 376 provided in Reference 6 for further information.

Figure 1
Pressure Boundary Region of IITA