Luminant

Mike Blevins
Executive Vice President
& Chief Nuclear Officer
Mike.Blevins@Luminant.com

Luminant Power
P O Box 1002
6322 North FM 56
Glen Rose, TX 76043

T 254 897 5209
C 817 559 9085
F 254 897 6652

CP-200800057
Log # TXX-08008

Ref. # 10CFR50.90

January 10, 2008

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555

SUBJECT: COMANCHE PEAK STEAM ELECTRIC STATION
DOCKET NOS. 50-445 AND 50-446
SUPPLEMENT TO LICENSE AMENDMENT REQUEST (LAR) 07-004
REVISION TO THE OPERATING LICENSE AND TECHNICAL SPECIFICATION 1.0, "USE AND APPLICATION" TO REVISE RATED THERMAL POWER FROM 3458 MWT TO 3612 MWT
(TAC NOS. MD6615 AND MD6616)

REFERENCE: Letter logged TXX-07106 dated August 28, 2007 from Mike Blevins to the NRC submitting License Amendment Request (LAR) 07-004, proposing revisions to the Operating Licenses and to Technical Specifications 1.0, "USE AND APPLICATION" to revise rated thermal power from 3458 MWT to 3612 MWT

Dear Sir or Madam:

Per Reference 1, Luminant Generation Company, LLC (Luminant Power) requested Technical Specification (TS) changes to the Comanche Peak Steam Electric Station, herein referred to as Comanche Peak Nuclear Power Plant (CPNPP), Units 1 and 2 Operating Licenses and to Technical Specifications 1.0, "USE AND APPLICATION" to revise rated thermal power from 3458 MWT to 3612 MWT.

On December 11, 2007, the NRC provided Luminant Power with a request for additional information from the following branches regarding the proposed changes to rated thermal power.

Reactor Systems Branch
Electrical Engineering Branch
Fire Protection Branch
Piping and NDE Branch

The responses to these questions are provided in the attachments to this letter. Attachment 1 provides the basic responses to the Requests for Additional Information (RAI). Enclosure 1 provides supplemental information for NRC Reactor Systems Branch Question 7. Attachments 2 and 3 provide supplemental information for NRC Reactor Systems Branch Question 19. Attachment 4 (Official Use Only- Security Related Information) provides supplemental information for NRC Fire Protection Branch Question 4. Enclosures 2 and 3 provide supplemental information for NRC Electrical Engineering Branch Question 4.

A001

In accordance with 10CFR50.91(b), Luminant Power is providing the State of Texas with a copy of this proposed amendment supplement.

This communication contains the following new or revised commitments which will be completed or incorporated into the CPSES licensing basis as noted:

Number	Commitment	Due Date/Event
3435228	The requested information corresponding to a better-estimate type analysis, e.g., with nominal initial conditions, is scheduled to be provided in a separate letter.	February 29, 2008
3435242	The Unit 2 HELB temperature evaluation is expected to be completed by April 15, 2008.	April 15, 2008

Should you have any questions, please contact Mr. J. D. Seawright at (254) 897-0140.

I state under penalty of perjury that the foregoing is true and correct.

Executed on January 10, 2008.

Sincerely,

Luminant Generation Company LLC

Mike Blevins

By: Fred W. Madden
Director, Oversight & Regulatory Affairs

Attachments -
1. Responses to Requests for Additional Information
2. Revised Table 2.8.5.0-1
3. Revised Section 2.8.5.4.2
4. Supplement for Question 4 from the NRC Fire Protection Branch - [OUO-SRI]

Enclosures -
1. Nuclear Safety Advisory Letter - NASL-94-001
2. Letter from TXU Delivery to Jeff LaMarca (Luminant Power) dated April 24, 2007
3. Circuit Breaker Interrupting Duty Study

c -
E. E. Collins, Region IV
B. K. Singal, NRR
Resident Inspectors, Comanche Peak

Alice Rogers
Environmental & Consumer Safety Section
Texas Department of State Health Services
1100 West 49th Street
Austin, Texas 78756-3189

RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION

COMANCHE PEAK STRETCH POWER UPRATE

REACTOR SYSTEMS BRANCH

Section 2.8.2

NRC Question 1.

The Stretch Power Uprate Licensing Report (SPULR) discusses CPSES's use of the VANTAGE+ fuel design. Describe the content of each unit's current fuel system makeup and that proposed for the first uprated cycle. Provide a summary of the hydraulic and mechanical compatibility features of each type of fuel assembly used in the uprated core.

CPNPP Response:

The fuel system makeup for both Unit's current operating cycles (U1C13 and U2C10) is VANTAGE+ fuel. Key features of VANTAGE+ fuel are ZIRLO™ cladding, midspan grids, and guide/instrument tubes, debris filtering bottom nozzle, protective bottom grid, and pre-oxidized cladding. Intermediate flow mixer grids (IFMs) were introduced to both Unit's fresh fuel starting in U1C12 and U2C10, respectively. The current operating cycles contain a combination of VANTAGE+ fuel with and without IFMs. The hydraulic and mechanical compatibility of co-resident IFM and non-IFM fuel was explicitly evaluated and approved in WCAP-10445-NP-A. The first uprated cycle (U1C14) is expected to contain VANTAGE+ fuel with IFMs, with the possibility of a single VANTAGE+ fuel assembly without IFMs to be used as the center assembly. Cycle specific loading patterns are based on CPNPP requirements and available burned fuel inventory. For example, fuel defects detected in burned assemblies scheduled for reinsertion could be replaced by previously discharged VANTAGE+ fuel without IFMs as part of a redesign.

NRC Question 2.

Summarize how the Stretch Power Uprate (SPU) core design differs, from the current core design, to support the higher energy requirements of the uprated core. Include discussion on integral fuel burnable absorber (IFBA) use, fuel enrichment, burnup, and batch loading.

CPNPP Response:

A core loading pattern and associated 3-D nodal model were prepared to support the uprate safety analysis work. The 3-D nodal model is a post-uprated equilibrium cycle model at the uprate conditions. The loading pattern is consistent with current operating Comanche Peak loading patterns. The IFBA and Wet Annular Burnable Absorber (WABA) loading for the uprate pattern is similar to the current Comanche Peak operating cycles. The main difference due to power uprate is the uprate loading pattern employs higher enriched feed fuel with a larger percentage of higher enriched fuel in the split enrichments. For example, the current U1C13 loading pattern feed batch is a 72/16 assembly split with enrichments of 4.45/4.90 w/o, respectively. The uprate model used a feed batch with a 60/28 assembly split with enrichments of 4.95/4.40 w/o respectively. Batch average and peak discharge burnups are slightly higher than non-uprated loading patterns, but maintain significant margin to burnup limits.

Section 2.8.3

NRC Question 3.

Explain why the pressure drop across the core decreases as a result of the power uprate analysis.

CPNPP Response:

The predicted best estimate (BE) flow rate upon which the pressure drop is based is slightly lower at uprated power conditions. Since pressure drop is proportional to the square of BE flow rate, the newly calculated pressure drop decreases slightly due to the lower BE flow rate.

Section 2.8.4.1

NRC Question 4.

How is the capability of the Control Rod Drive Mechanism (CRDM) cooling system affected by the planned power uprate?

CPNPP Response:

The Comanche Peak stretch power uprate (SPU) was evaluated to determine if it affects the control rod drive mechanism (CRDM) cooling system. Comanche Peak Units 1 and 2 operate at T_{cold}, meaning that the reactor vessel head temperature follows the reactor vessel inlet temperature. Therefore, the reactor vessel inlet temperatures for the SPU and the original parameters were compared to determine if the original parameters are greater than or negligibly lower than the SPU parameters. Either higher or negligibly lower original parameters would indicate that the SPU does not impact the CRDM cooling system.

Table 1 compares the reactor vessel inlet temperatures for the SPU and original parameters. The inlet temperatures are higher for the original parameters. The reduction in the original reactor vessel head temperatures will subsequently reduce the conductive and convective heat loads that the CRDM magnetic jack coil assemblies are subjected to. A reduced heat load on the CRDM assemblies will result in a favorable decrease in the CRDM electrical coil temperatures and a decrease in heat rejected to the containment building.

Table 1: Comparison of Reactor Vessel Inlet Temperatures for Original and SPU Parameters

		Reactor Vessel Inlet Temp. (°F)
Unit 1	Original	559.6
	SPU	558
Unit 2	Original	559.6
	SPU	558

In conclusion, the Comanche Peak Units 1 and 2 SPU will not adversely affect the CRDM cooling system.

NRC Question 5.

How will the scram response times of the CRDMs be affected by the planned power uprate?

CPNPP Response:

The scram response time of 2.7 seconds is discussed in Section 2.2.3 of WCAP-16840-P.

Section 2.8.4.2 (Overpressure Protection)

NRC Question 6.

Provide the results, including transient plots and sequence of events tables, for the loss of external electrical load/turbine trip event performed for CPSES Units 1 and 2, which demonstrate that the overpressure criteria continue to be met for the SPU program when the second, safety-grade reactor trip signal is credited (SRP 5.2.2 II.3.B.iii).

CPNPP Response:

The requested information corresponding to a better-estimate type analysis, e.g., with nominal initial conditions, is scheduled to be provided in a separate letter by the end of February, 2008.

NRC Question 7.

Describe the method (e.g., analyses or calculations) that was used to determine the allowable power levels corresponding to 1, 2, and 3 inoperable main steam safety valves, as specified in Technical Specification 3.7.1.1 and in License Amendment Request (LAR) Table 2.8.4.2-1.

CPNPP Response:

The method for determining the allowable power levels with inoperable main steam safety valves is described in Westinghouse Nuclear Safety Advisory Letter NSAL-94-001, "Operation at Reduced Power Levels with Inoperable MSSVs," dated January 20, 1994 (See Enclosure 1).

NRC Question 8.

This section alludes to CPSES FSAR Section 5.2.2, which states that overpressure protection is provided for the loss of electrical load and/or turbine trip, the uncontrolled rod withdrawal at power, the loss of reactor coolant flow, the loss of normal feedwater, and the loss-of-offsite power to the station auxiliaries. Then it states that, "[t]hese events bound those credible events that could lead to overpressure of the reactor coolant system (RCS) if adequate overpressure protection were not provided." Explain this statement.

CPNPP Response:

The intent of this statement was to identify that the noted events are the only credible events (ANS Condition II events) that have the potential to result in overpressure of the reactor coolant system if adequate overpressure protection were not available. Section 2.8.5 describes the analyses of these events, which demonstrate that the plant's overpressure protection capability is adequate.

NRC Question 9.

Explain how demonstrating compliance with Title 10 of the *CODE of Federal Regulations* (10 CFR), part 50, Appendix A, General Design Criterion (GDC) 15, "Reactor coolant system design," and GDC-31 , "Fracture prevention of reactor coolant pressure boundary," would satisfy the intent of SRP 5.2.2.

CPNPP Response:

See Response to NRC Question 6 above.

Section 2.8.5.0 (Non-LOCA Introduction)

NRC Question 10.

Discuss the differences between steam generators at each CPSES unit and how these differences are accounted for in the safety analyses.

CPNPP Response:

Unit 1 utilizes four Westinghouse Model Δ76 steam generators, which are feedring-type steam generators with a total heat transfer surface area of 76,000 ft^2 each. Unit 2 utilizes four Westinghouse Model D5 steam generators, which are preheater-type steam generators with a total heat transfer surface area of 48,165 ft^2 each. The steam generators are modeled directly in each of the RETRAN-based analyses. Details of the RETRAN steam generator modeling characteristics are provided in WCAP-14882-P-A and Section 2.8.5.0.9 of the licensing report.

NRC Question 11.

Confirm the statement that "none of the non-LOCA transients are limiting with minimum setpoints..." by showing an acceptable departure from nucleate boiling (DNB) reduction resulting from an analyzed decrease in MSSV lift setpoints.

CPNPP Response:

In the non-LOCA transients for which compliance with the minimum DNBR limit is a relevant event acceptance criterion, the Reactor Coolant System (RCS) temperature is influenced by steam relief (secondary-side cooling) through the MSSVs. If the MSSVs were to open earlier in the transient (e.g., due to lower MSSV set pressures), they would release more steam and result in lower RCS temperatures than if they were to open later in the transient (e.g., due to higher MSSV set pressures). Lower RCS temperatures result in higher calculated DNBRs. Therefore, one may conclude that, relative to the DNBR acceptance limit, lower MSSV set pressures are less limiting than higher MSSV set pressures.

NRC Question 12.

Describe how the moderator temperature coefficient is calculated. Confirm that the behavior described in Bullet 3 of Section 2.8.5.0.4 is an analyzed and expected value.

CPNPP Response:

The moderator temperature coefficient (MTC) is calculated using standard Westinghouse core design methods. A 3-D nodal code is used for the MTC calculations. The MTC is calculated over a range of core burnup covering the full range of power operation to verify that the Technical Specification limit is met. This MTC calculation was performed using the post uprate equilibrium cycle model discussed in the response to Question 2 and confirmed that the core design meets the CPNPP Technical Specification limit. The moderator temperature and density coefficient limits identified in Bullet 3 of Section 2.8.5.0.4 are verified on a cycle-specific basis as part of the Reload Safety Evaluation Process.

Section 2.8.5.3 (Loss of Flow)

NRC Question 13.

Identify and explain any changes in the loss of flow sequences that occur (i.e., sequence timing) as a result of the proposed power uprate.

CPNPP Response:

As the applicable reactor trip setpoints and delays remained unchanged, and the flow coastdown characteristics are not affected by the power uprate, the sequence timing for each of the loss of flow events is generally the same as before. However, the timing of the minimum DNBR did change because a greater rod drop time of 2.7 seconds (vs. 2.4 seconds) was applied.

Section 2.8.5.4.1 (RWFS)

NRC Question 14.

How will the increase in fuel duty and power level affect startup transients and the negative reactivity from doppler effects? Will any of the trip setpoint functions be changed (source range neutron flux reactor trip, intermediate range neutron flux reactor trip, power range neutron flux reactor trip (low setting), power range neutron flux reactor trip (high setting), high nuclear flux rate reactor trip)?

CPNPP Response:

The increase in the nominal reactor power level will result in an increase in the Doppler power defect (the integral of the Doppler power coefficient from zero to full power). The maximum reactivity insertion rate is unaffected by the uprate. The Doppler defect and reactivity insertion rate used in the analysis are conservative bounding values and are confirmed on a cycle-by-cycle basis.

The neutron flux setpoints are given as a percent of the nominal reactor power. These will not be changed as a result of the power uprating, although after the neutron flux channels are recalibrated at the increased power, the trip setpoints represent a higher absolute power level. For this event, the neutron flux transient is sufficiently rapid (near prompt-critical) that the variation in the actual neutron flux setpoints are of no importance. Only the reactor trip delay times, which were not changed, are important.

NRC Question 15.

In the Low Power Startup analysis, boron concentration does not appear to have been considered. Explain why?

CPNPP Response:

The analysis takes into account the limiting moderator temperature coefficient (MTC) at hot zero power in the just-critical condition, as allowed by the plant Technical Specifications. The MTC is a function of boron concentration, and is conservative with respect to the just-critical boron concentration in this condition.

NRC Question 16.

In the results, the maximum power level, peak fuel rod temperature, and maximum heat flux was included but the peak reactor temperature and pressure were not. Justify the reason for omitting these results from the analysis.

CPNPP Response:

The core power transient associated with this event is extremely fast (near prompt-critical). The peak heat flux occurs at about 12 seconds, which is approximately 2-3 seconds after the reactor returns to significant power levels. The reactor trip is effective (start of rod motion) at 10.3 seconds. Therefore, the transient time of interest is only about the first 5 seconds after the return to power. This time is too short to result in any change in the reactor core inlet temperature. Although there would be a small increase in the RCS pressure, no credit is taken for this in the DNBR evaluation. Therefore, no transient analysis of the RCS loop is needed, or is performed for this event.

Section 2.8.5.4.2 (RWAP)

NRC Question 17.

In section 2.8.5.4.2.2.2, a conservatively small value of the doppler coefficient is assumed and a conservatively large positive moderator density coefficient and a large negative doppler coefficient are assumed. Provide these values and explain how they were determined.

CPNPP Response:

As indicated in Section 2.8.5.4.2.2.2, both minimum and maximum reactivity feedback conditions are considered. The values for the applied moderator and Doppler reactivity feedback coefficients are presented in Table 2.8.5.0-5 of the licensing report (WCAP-16840-P) and summarized below. These values were determined based on historical knowledge of Comanche Peak and other plants, and are confirmed to be conservative for each fuel cycle during the reload safety evaluation process, which is described in WCAP-9272-P-A.

Core Kinetics Parameters and Reactivity Feedback Coefficients		
Parameter	Beginning of Cycle (Minimum Feedback)	End of Cycle (Maximum Feedback)
MTC, pcm/°F	5.0 (≤ 70% RTP)[1] linearly ramping to 0.0 at 100% RTP)	N/A
Moderator Density Coefficient, $\Delta k/(g/cc)$	N/A	0.50
Doppler Temperature Coefficient, pcm/°F	-0.91	-2.90
Doppler-Only Power Coefficient, pcm/%power (Q = power in %)	-9.55 + 0.035Q	-19.4 + 0.068Q
Note: 1. RTP ≡ Rated Thermal Power		

NRC Question 18.

Explain how rod configurations and power distributions were considered in this analysis.

CPNPP Response:

The rod configuration variety is accounted for by analyzing a broad spectrum of constant reactivity insertion rates at three different power levels (100%, 60%, 10%). The minimum reactivity insertion rate of 1 pcm/second is a typical value, and the maximum reactivity insertion rate of 110 pcm/second bounds that corresponding to the most conservative set of two RCCA banks moving together at maximum speed (confirmed for each reload). Fifteen to twenty intermediate reactivity insertion rates are analyzed to establish the minimum DNBR results as a function of insertion rate.

As only the RETRAN computer code is used, core power distributions are not a direct input to the analysis. However, maximum core power peaking factors are used to define the DNB core limit lines, which provide the basis for the conservative DNBR approximation model applied in the RETRAN analysis.

NRC Question 19.

The SPULR states that two cases for minimum and maximum reactivity feedback were analyzed. The staff was unable to locate the results for the maximum reactivity feedback case. Provide these results.

CPNPP Response:

The requested results are provided in the attached revision to Section 2.8.5.4.2 (Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power). This section was recently revised to address some isolated issues related to the corresponding analysis. As the revised analysis affected results that were presented in Table 2.8.5.0-1, Table 2.8.5.4.2-1, and Table 2.8.5.4.5-1 (Boron Dilution) of the licensing report, revised tables are also provided (See Attachments 2 and 3).

Section 2.8.5.4.3 (Control Rod Misoperation)

NRC Question 20.

Conditions of first-order importance for any time in cycle are initial power level and distribution, initial rod configuration, reactivity addition rate, moderator temperature, fuel temperature, and void reactivity coefficients. Verify that these parameters were taken into consideration when conducting the analyses.

CPNPP Response:

The analyzed reactor (core) power, initial reactor coolant system conditions (i.e., fuel temperature, moderator temperature and reactivity feedback), and initial rod configuration are plant-specific. The transient axial and radial power distributions and reactivity addition rate have been confirmed to be applicable to CPNPP Units 1 and 2. The DNB and peaking factor limit calculations include uncertainty that bound the plant's power level and reactor coolant conditions (i.e., moderator temperature, pressure and flow). The event analysis includes conservative rod configuration and transient rod movement assumptions that are designed to generate limiting radial and axial power conditions and induce the maximum reactivity insertion possible for each accident scenario. Conservative reactivity coefficient values are assumed to be constant for the duration of each transient. Specifically, for a dropped RCCA and dropped RCCA bank event, explicit ranges of moderator temperature coefficient are analyzed that bound the range of cycle-specific parameters applicable to CPNPP Units 1 and 2.

Consistent with the reload safety evaluation methodology employed, these first-order conditions are examined each cycle to ensure that the plant- and cycle-specific conditions are reconfirmed every reload.

NRC Question 21.

Provide supporting results to show that an upper bound of the number of fuel rods experiencing departure from nucleate boiling (DNB) is 5 percent of the total number of fuel rods in the core.

CPNPP Response:

The single rod withdrawal analysis utilized the equilibrium cycle post uprate 3-D nodal model discussed in the response to RAI Question 2. The percentage of rods below the DNBR limit was confirmed by finding the percentage of rods which, when multiplied by the calculational uncertainty, were above the $F\Delta H$ non-statistical limit. For all cases, the percentage of rods in violation of the peaking factor limit in the entire core was always found to be less than or equal to 0.300% for all single rod withdrawals. The 5% limit is confirmed on a cycle specific basis as part of the reload safety evaluation process (WCAP-9272-P-A).

NRC Question 22.

Clarify why DNB calculations were not performed for the rod cluster control assemblies (RCCAs) missing from other banks and how power shape calculations for the RCCA ejection analysis accounts for the previously stated analysis.

CPNPP Response:

During operation within the Limiting Conditions for Operation defined by the plant Technical Specifications (specifically, the rod insertion limits of Technical Specification 3.1.5 and 3.1.6, which also define control rod sequence and overlap), control bank D is allowed to be inserted more deeply into the core than the other control banks (the shutdown banks are required to be fully withdrawn). As such, the largest reactivity effects (and thus, the highest local peaking factors) due to one RCCA being fully withdrawn at high reactor power levels are limited to an RCCA from control bank D. The LR statement about power shape calculations for rods missing from other banks (Section 2.8.5.4.2.3.4, 2 lines at bottom of page 2.8.5-275 and top 3 lines of page 2.8.5-276) being comparable to the RCCA ejection analysis is not relevant to the analysis for Comanche Peak.

Section 2.8.5.4.5 (Boron Dilution)

NRC Question 23.

This section of the SPULR states that for at power, Modes 1 and 2, the dilution accident erodes the shutdown margin made available through reactor trip. For shutdown mode initial conditions, Modes 3, 4, 5, and 6, the dilution accident erodes the shutdown margin inherent in the borated RCS inventory and that which may be provided by control rods (control and shutdown banks) made available through reactor trip. Clarify how, in Modes 1 and 2, the reactor is shut down through a reactor trip (control rods, boron, etc.).

CPNPP Response:

This statement refers to the reactor trip that will occur during the boron dilution event itself in Modes 1 and 2. In these modes of operation, the plant is initially either critical and at 100% power (Mode 1), or critical and being transitioned to 100% power from shutdown (Mode 2). The initial boron concentration is assumed to be a conservative maximum value for the initial concentration at either full or zero power, with the rods at the insertion limits, and no xenon.

When the boron dilution occurs, the addition of positive reactivity results in an increase in core power until either the high neutron flux reactor trip setpoint (Mode 1) or low neutron flux reactor trip setpoint (Mode 2) is reached. The reactor then shuts down due to rod insertion with the minimum required shutdown margin assumed. The critical boron concentration following reactor trip is assumed to correspond to the hot zero power, all rods inserted (minus the most reactive RCCA), no xenon condition. Continued dilution after reactor trip eventually overcomes the shutdown margin and the core will return critical unless the operators intervene. The time it takes the core to return to criticality after reactor trip is calculated in the analysis and confirmed to be greater than 15 minutes.

NRC Question 24.

The Chemical and Volume Control (CVCS) System malfunction analysis was not performed for Mode 6 refueling because a boron dilution event is prevented by administrative control of valves in the possible dilution paths. Clarify whether the 30-minute limit is still obtainable between the time that an alarm annunciates an unplanned moderator dilution and the time that shutdown margin is lost.

CPNPP Response:

CPNPP Technical Specification 3.9.2 requires each valve used to isolate unborated water sources to be secured in the closed position in Mode 6 (refueling), effectively precluding an inadvertent boron dilution event. Therefore, the CVCS malfunction (or the inadvertent boron dilution) transient is not analyzed in Mode 6. The 30 minute time limit is only applicable to the Mode 6 analysis, and thus, is a moot subject.

NRC Question 25.

Explain whether CVCS malfunction analyses accounted for any malfunctions or equipment out-of-service.

CPNPP Response:

The initial conditions for all FSAR Chapter 15 accident analyses, including the CVCS malfunction transients, are assumed to be compliant with the Limiting Conditions for Operation as defined in the plant Technical Specifications. As such, the CVCS malfunction analysis does not account for any pre-existing malfunctions or equipment out of service.

NRC Question 26.

Clarify what, if any, operator actions are credited in the transient sequence addressed by section 2.8.5.4.5.

CPNPP Response:

During normal CVCS operations, the Reactor Coolant System (RCS) mass is "letdown" at a relatively small rate for filtration purposes. After filtration, the mass is directed to the Volume Control Tank (VCT) where it is returned to the RCS via a centrifugal charging pump (CCP) which takes suction from the VCT. During normal operation, this process results in a constant inventory in the RCS and VCT. Inadvertent boron dilution transients are initiated by the addition of unborated water to the VCT, which is eventually pumped into the RCS via the CCP(s).

The Refueling Water Storage Tank (RWST) is required through Technical Specification 3.5.4 to be maintained at a boron concentration high enough to ensure the core is subcritical following a variety of postulated transients and accidents.

The credited operator actions in response to an inadvertent boron dilution event consist of re-aligning the suction of the CCPs from the dilution source (the VCT) to the borated water source (the RWST). The specific operator actions (which are unaffected by the uprate) are the sequential opening of RWST isolation valves (LCV-112D/E) and the closure of VCT isolation valves (LCV-112B/C). TXU topical report RXE-94-001-A (Technical Specification 5.6.5b, Item 12) contains more descriptions of the analysis and the previous NRC reviews.

NRC Question 27.

When running the CVCS malfunction analyses, were the power level, core pressure, and minimum DNBR specifically stated for the input parameters?

CPNPP Response:

Because the CVCS malfunction analyses are initiated from a shutdown condition, initial conditions such as power level and core pressure have little meaning, and the DNBR is not calculated. The important parameters for the CVCS malfunction analyses include the RCS mass (which is dependent on the RCS temperature), the dilution flow rate, the initial boron concentration (required to comply with the Technical Specification limit on shutdown margin) and the boron concentration at which the core could be critical. The RCS temperature used in the analysis, as well as the initial and critical boron concentrations, are dependent on the Mode of operation.

Section 2.8.5.4.6

NRC Question 28.

Provide the results of this analysis for cladding oxidation and hydrogen formation.

CPNPP Response:

The RCCA Ejection analysis results for cladding oxidation at the hot spot are:

Condition	Reacted Zirconium (%)
Beginning of Cycle, Hot Full Power	0.62
Beginning of Cycle, Hot Zero Power	0.64
End of Cycle, Hot Full Power	0.56
End of Cycle, Hot Zero Power	1.96

It should be noted that the percent reacted Zirconium is calculated at the hot spot in the ejected rod configuration, which represents a very small portion of the core. Thus the total amount of reacted Zirconium and amount of hydrogen formation is very small on a core average basis, and is negligible compared to the Loss of Coolant Accident.

Section 2.8.5.5

NRC Question 29.

Verify that the RETRAN N-16 model, which provides the CPSES OTN-16 and OPN-16 reactor trips (functionally equivalent to the overtemperature and overpower ΔT (delta temperature) reactor trips of other Westinghouse plants), have been reviewed and approved by the NRC staff, particularly for use in analyses of the RCCA withdrawal at power and RCS depressurization events.

CPNPP Response:

The RETRAN N-16 model was developed by Comanche Peak engineers and originally presented to the NRC in TXU Topical Report RXE-91-001-A (Technical Specification 5.6.5b, Item 7). Included in this topical report are integral comparisons with CPNPP transients. This NRC-approved model was used for many non-LOCA transients, including the RCCA withdrawal at power and RCS depressurization transients. This tested N-16 model was then adapted for the CPNPP model developed in accordance with WCAP-14882-P-A.

NRC Question 30.

For the inadvertent operation of the emergency core coolant system (ECCS) event, show that the operators, following applicable emergency procedures, can open at least three of the four steam generator atmospheric relief valves (ARVs) within 7 minutes and 30 seconds after a safety grade alarm (e.g., the reactor trip or SI signal).

Similarly, show that the operators, following applicable emergency procedures, can secure the ECCS within 13 minutes after a safety grade alarm.

CPNPP Response:

The safety grade alarm (SI signal) is assumed to be initiated concurrent with the inadvertent SI signal. A simulator exercise was performed in accordance with CPNPP validation guidelines to assure that the assumed response times were reasonable. The simulator was set up to replicate many of the conservative assumptions of the FSAR Chapter 15 analyses, including the failure of automatic operation of the pressurizer PORVs, the Steam Dump System, and the automatic operation of the steam generator atmospheric relief valves (ARVs). Verifying the RCS average temperature is trending to 557°F and taking manual control of the RCS average temperature occurred shortly after entry into the emergency procedures well within the assumed 7.5 minutes. Through the continuation of the simulator exercise, the crew was able to step through the procedures and secure ECCS well within the 13 minutes assumed in the analyses (close to 10 minutes). All communication protocols and management expectations for conduct of operations were met during the exercise. These Design Basis Accident response time requirements will be periodically reviewed and, based on simulator observations, re-validated as necessary.

NRC Question 31.

How does the analysis of the inadvertent operation of the ECCS during power operation (LAR Section 2.8.5.5) bound the CVCS malfunction that results in an increase in reactor coolant inventory? (This is not simply a comparison of flow rates.)

CPNPP Response:

The primary reason that a malfunction of the CVCS is bounded by an Inadvertent Operation of the ECCS for Comanche Peak is that the rate of reactor coolant inventory increase is much greater during an Inadvertent ECCS than it is during a CVCS malfunction. Also, in the analysis of the Inadvertent ECCS event, a reactor trip is assumed to occur coincident with the event initiation so as to conservatively minimize the contraction of the reactor coolant, which translates into a more rapid start to the increase in pressurizer water volume as a result of the core decay heat and continued ECCS flow injection. With a delay in the reactor trip, the relatively cold ECCS flow causes a greater cooldown and maximizes the contraction of the reactor coolant, which significantly delays the start to the increase in pressurizer water volume. For a CVCS malfunction event, reactor trip would be delayed and the pressurizer water volume transient would be less severe.

NRC Question 32.

During an inadvertent operation of the ECCS event, fully opening at least three of four ARVs would cool the RCS to temperatures below 557degrees Fahrenheit (°F). How would the operators control the RCS temperature to 557°F?

CPNPP Response:

Shortly after entry into the Emergency Operating Procedures, the reactor operators are instructed to maintain the RCS at the no-load temperature of 557°F. This action would normally occur without operator intervention through operation of the Steam Dump System (based on an average to reference temperature error) or the automatic operation of the atmospheric relief valves (ARVs) (based on a steam pressure error). Both of these systems use valves capable of modulation. However, these automatic functions are not fully safety grade and are not credited in the analyses. In the analysis of the inadvertent ECCS operation transient, with no credit for the automatic operation of the steam dump System and the ARVs, the steam generator pressure would be dependent on the set pressure of the main steam safety valves, resulting in higher steam pressures and correspondingly higher RCS temperatures. Shortly after the start of the event, the reactor operators would cool the RCS to ~557°F using manual control of the ARVs (the ARVs are qualified for manual control only). These actions are modeled in the analysis by fully opening 3 ARVs at 7 minutes 30 seconds into the event. The reactor operators would then control the plant at 557°F manually by modulating the ARVs thereafter.

ELECTRICAL ENGINEERING BRANCH

NRC Question 1.

In Section 2.3.1.2.2 of the SPULR, "Inside Containment," it is stated that at SPU, the containment analysis of design basis accidents (DBAs) demonstrates that the equipment qualification (EQ) for peak temperature remains bounded by the current EQ profile. However, the long-term temperature slightly exceeds the current profile at limited time later in the transient after the peak temperature has been reduced.

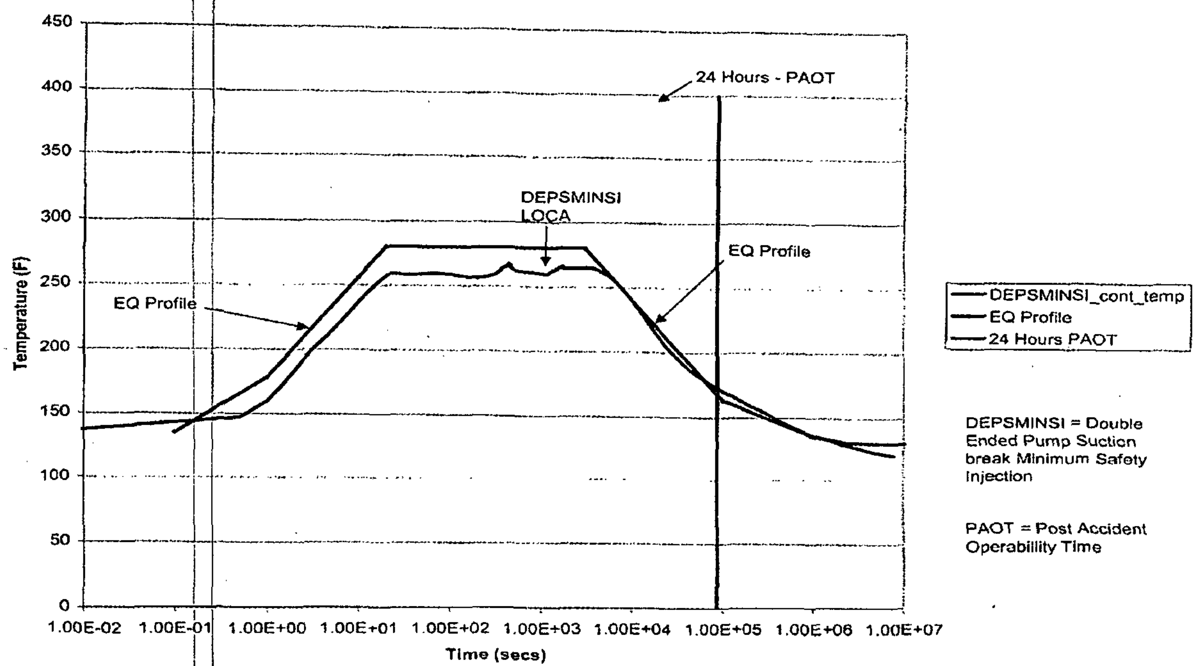
Provide details of the long-term temperature impact and the temperature evaluation done for DBA conditions.

CPNPP Response:

The peak SPU LOCA temperature of 266.1 degrees Fahrenheit (°F) is reached at approximately 446 seconds (DEPSMINSI curve on Figure E 1-1 below). As shown on Figure E 1-1, a new EQ profile has been issued that extends the time duration at 280 °F so that it envelopes the new SPU LOCA curve and specifically the area that had exceeded the old EQ profile. This new EQ profile is being added to the EQ Packages as part of the CPNPP EQ package update using the plant EQ procedure. The PAOT impact is minor, since there is only a 7 °F difference between the SPU LOCA curve (170 °F) and the intersection point of the EQ profile (163 °F) at the 24 hour mark.

Therefore, all EQ equipment inside the containment remains qualified for the SPU LOCA conditions.

Figure E 1-1
CPNPP SPU LOCA Accident vs. EQ Temperature Profile



DEPSMINSI = Double Ended Pump Suction break Minimum Safety Injection

PAOT = Post Accident Operability Time

NRC Question 2.

In Section 2.3.1.2.2 of the SPULR, "Inside Containment," it is stated the following:

> **"Where the increase in radiation exceeds the current EQ limits, additional analysis *will be* [emphasis added] performed to document that the affected components specific dose is bounded by the specific component EQ qualification."**

Provide the results of the additional radiation analysis performed on the affected components.

CPNPP Response:

The SPU radiation zone levels inside containment exceeded the qualification levels for five (5) components (four pressurizer solenoid operated vent valves (two per Unit) and a Unit 1 pressure transmitter) in the electrical EQ program. The location specific analyses performed for the above components demonstrated that the results of the radiation environments at the individual component locations are below the associated qualification levels.

NRC Question 3.

In Section 2.3.1.2.2 of the SPULR, "Outside Containment," it is stated that there is a small temperature increase from existing high energy line break (HELB) temperatures in the main steam and feedwater penetration areas. The licensee further stated the following:

> **"Where the increase in temperature exceeds the current EQ limits, additional analysis *will be* [emphasis added] performed to document that the affected components specific qualification bounds the affect of the temperature increase.**

Provide the results of the additional temperature analysis performed on the affected components.

CPNPP Response:

As described in LR section 2.3.1.2.2, for the Unit 1 HELB small temperature increase, a component specific evaluation determined the equipment is qualified. However, the Unit 2 HELB temperature evaluation is ongoing and is expected to be completed by April 15, 2008.

The EQ review methodology is to compare the actual equipment qualification test reports for duration at peak temperature with respect to the HELB conditions and/or develop a thermal lag analysis if necessary to evaluate equipment qualification temperatures that do not have sufficient margin with respect to the accident condition. Margins for this evaluation use the guidance found in IEEE 323-1974. The EQ packages will be updated to provide this evaluation using the CPNPP EQ Program procedure.

NRC Question 4.

In Section 2.3.2.2.3.1 of the SPULR, it is stated the Electric Reliability Council of Texas (ERCOT), through the transmission service provider evaluated steady-state and stability studies for the impact of the SPU on the reliability of the CPSES 345 kilovolt switchyard.

Provide a copy of the evaluation of steady-state and stability studies carried out by ERCOT.

CPNPP Response:

Comanche Peak requested that ERCOT perform the necessary studies to accept the uprated plant power output level changes of about 49 MW for Unit 1 and 37 MW for Unit 2. A meeting was held with ERCOT and TXU Electric Delivery (TXUED) on December 14, 2006. At this meeting, TXUED and ERCOT stated that an additional steady state study and a stability study would not be required for this small addition of 86 megawatts to the ERCOT grid. They also stated that a short circuit study would be required.

TXU Electric Delivery letter dated April 24, 2007 (Enclosure 2) describes the basis for not performing the additional studies.

TXUED, now called ONCOR, provides an annual analysis update for Comanche Peak's offsite power requirements. The latest analysis is "2007 Assessment of Grid Reliability for Comanche Peak S.E.S.". However, the purpose of this analysis was not intended to address Comanche Peak power uprate.

ONCOR personnel were contacted and are willing to discuss their process that evaluated the Comanche Peak power uprate, if required.

The results of the short circuit study, documented in the Circuit Breaker Interrupting Duty Study dated April 24, 2007 (Enclosure 3), concludes that no switchyard breakers are overdutied due to the proposed megawatt increase at Comanche Peak.

NRC Question 5.

In Section 2.3.3.2.3 of the SPULR, it is stated that the main generator capability curve has been revised based on a Siemens generator uprate study. The licensee further stated that the new uprate main generator nameplate rating will be 1410 megavolts ampere at 0.9 power factor.

Provide the nominal or approximate megawatt generation of the CPSES units before and after the SPU. Provide a copy of the updated main generator capability curve.

CPNPP Response:

The following nominal pre-SPU heat balances (3458 MWth) have been produced by Siemens Power Generation for Comanche Peak Units 1 & 2:

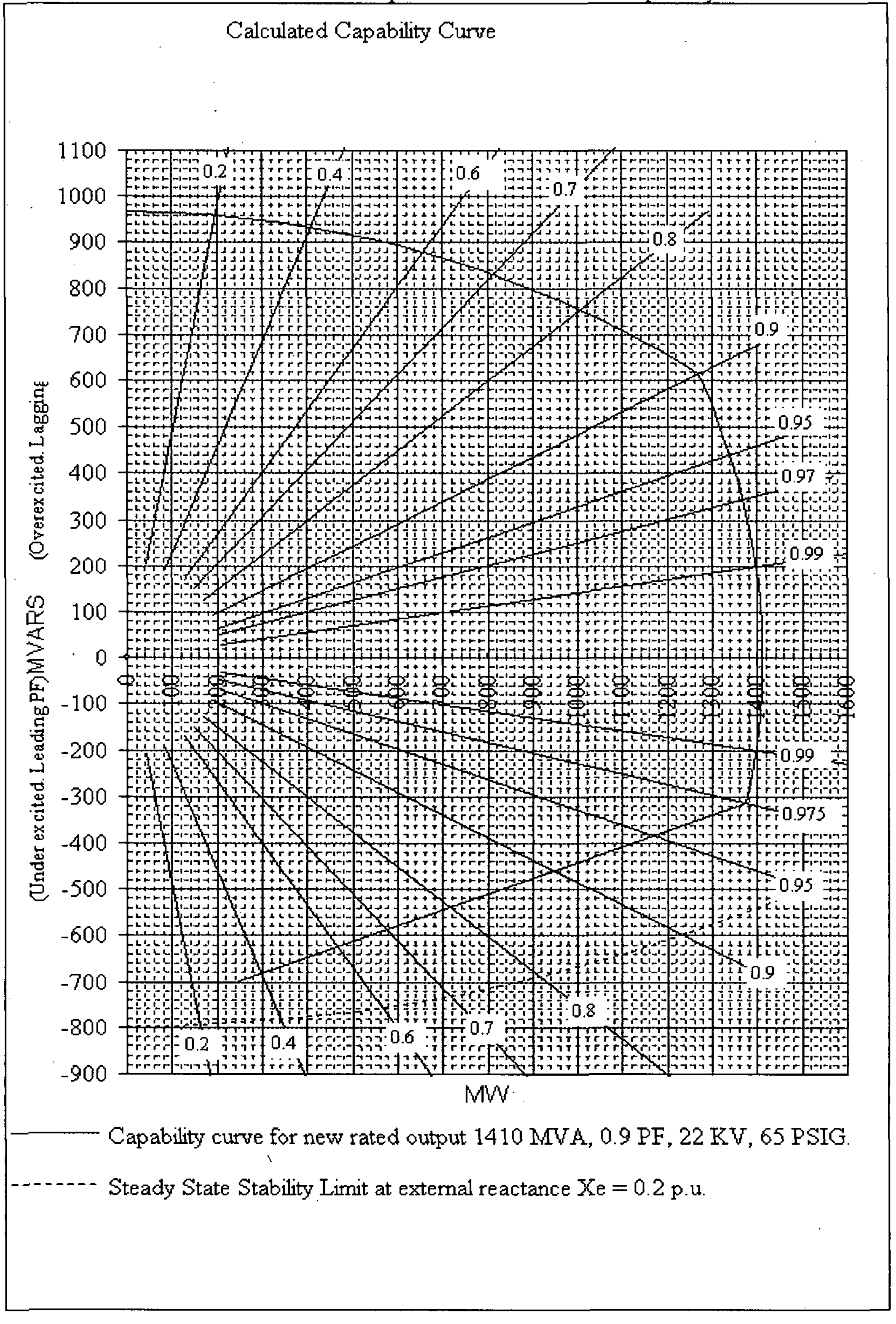
Unit 1:	100% Operating Point	23445-SPC-WB-8496-1	1,206,294 KW
Unit 2:	100% Operating Point	22967-SPC-WB-8497-1	1,208,987 KW

The following nominal SPU heat balances (3612 MWth) have been produced by Siemens Power Generation for Comanche Peak Units 1 & 2:

Unit 1:	New HP 100% Operating Point	11764-S312-10909-01	1,263,055 KW
Unit 2:	New HP 100% Operating Point	11765-S312-10939-01	1,252,995 KW

Also, please find below the Siemens Power Generation updated Main Generator capability curve.

Siemens Power Generation Updated Main Generator Capability Curve



NRC Question 6.

In Section 2.3.3.2.3 of the SPULR, it is stated that its evaluation confirmed that the existing main transformers, with existing administrative limits, are adequate for the SPU.

Provide details of the analysis that was performed to determine the adequacy of the main transformers and the administrative limits of main transformers. Also, provide details of the analysis that was performed to determine the adequacy of the connected iso-phase buses.

CPNPP Response:

The existing Comanche Peak main transformers have a nameplate rating of 650 MVA at 20.9 kV/345 kV. An additional cooler bank had been added to the main transformers several years ago to bring the equivalent thermal rating to 780 MVA.

Two main transformers are connected in parallel resulting in an equivalent thermal rating of 1560 MVA. The transformers have sufficient capacity to remove the heat load due to their losses with margin for the new generator rating of 1410 MVA at 0.9 PF.

Comanche Peak limits transformer primary side voltage to 22.9 kV or less which limits transformer gassing to acceptable levels. Note that this voltage level is about 4% above the generator nameplate of 22 kV and almost 10% above the transformer primary side nameplate of 20.9 kV.

Comanche Peak has decided to replace the main transformers to remove the voltage restriction and add additional margin. The new main transformers will be installed in the fall of 2009 on Unit 2 and the spring of 2010 for Unit 1.

The iso-phase bus original equipment manufacturer, Delta-Unibus, was asked to evaluate and recommend changes for the isolated-phase bus system to operate at the new power levels. Delta-Unibus has completed their evaluation and has recommended that we increase the size of the isolated-phase bus cooling package to accommodate the higher bus ampacity. This cooling package modification will be installed to support the Power Uprate in the fall of 2008 for Unit 1 and the fall of 2009 for Unit 2. The work is controlled through our plant modification procedures and is tracked within the CPNPP Corrective Action Program (SMF-2006-003080).

NRC Question 7.

In Section 2.3.3.2.3 of the SPULR, it is stated that the existing isolated phase bus duct main generator and main transformer tap busses are inadequate to support unit operation at SPU conditions. Modifications will be implemented to support SPU conditions.

Provide details of the modifications and assurance that the modifications will be implemented before operation at SPU.

CPNPP Response:

The isolated phase bus cooling capacity was evaluated by the Original Equipment Manufacturer (OEM) Delta Unibus for adequacy of main generator and main transformer tap busses to support unit operation at SPU conditions. A modification to increase cooling requirements was recommended by the vendor. The modification to the isolated phase bus cooling will replace the entire cooling package with an upgraded cooling package to support Power Uprate. The upgraded cooling package will provide sufficient cooling for main generator and main transformer tap busses to support isolated phase bus operation at SPU conditions. This modification will be implemented prior to Power Uprate of the respective unit.

The work scopes identified for Power Uprate are identified and tracked as modifications within the CPNPP Corrective Action Program (SMF-2006-003080). The work scopes are scheduled for implementation prior to Unit 1 Power Uprate in the fall of 2008 and the Unit 2 Power Uprate in the fall of 2009.

NRC Question 8.

In Section 2.3.2.2.1 of the SPULR, it is stated that the existing protective system relay settings will be adjusted as required to reflect the increase in the load flow in the tie lines connecting the Unit 1 and Unit 2 main transformers to the switchyard.

Provide assurance that the adjustment of above relay settings will be implemented before operation at SPU.

CPNPP Response:

The adjustment of the protective system relay settings is part of the work scope identified and tracked as modifications within the CPNPP Corrective Action Program (SMF-2006-003080). The work scopes are scheduled for implementation prior to the Unit 1 Power Uprate in the fall of 2008 and the Unit 2 Power Uprate in the fall of 2009.

NRC Question 9.

In Section 2.3.3.2.3 of the SPULR, it is stated that its evaluation of the main generator protection confirmed that the main generator total and partial loss of field and negative sequence relays settings are affected by the SPU conditions. The settings for these relays will be adjusted to support the SPU.

Provide assurance that the adjustment of above relay settings will be implemented before operation at SPU.

CPNPP Response:

The adjustment of the relay settings pertaining to the main generator protection is part of the work scope identified and tracked as modifications within the CPNPP Corrective Action Program (SMF-2006-003080). The work scopes are scheduled for implementation prior to the Unit 1 Power Uprate in the fall of 2008 and the Unit 2 Power Uprate in the fall of 2009.

NRC Question 10.

In Section 2.3.3.2.3 of the SPULR, it is stated that the applied protective relaying schemes and setpoints for reactor coolant pumps (RCPs) hot and cold loop motor operation and reactor electrical penetrations are affected as a result of the increase of the brake horsepower of RCP motors to support unit operation at SPU conditions.

Provide assurance that the adjustment of above relay settings will be implemented before operation at SPU.

CPNPP Response:

The change in setpoints for reactor coolant pumps (RCPs) hot and cold loop motor operation will assure that the containment penetration conductors primary and backup protection is not adversely affected by these changes. The adjustment of the relay settings pertaining to the RCPs is part of the work scope identified and tracked as modifications within the CPNPP Corrective Action Program (SMF-2006-003080). The work scopes are scheduled for implementation prior to the Unit 1 Power Uprate in the fall of 2008 and the Unit 2 Power Uprate in the fall of 2009.

FIRE PROTECTION BRANCH

NRC Question 1.

Attachment 1 to Matrix 5 ("Supplemental Fire Protection Review Criteria, Plant Systems"), of NRR RS-001, Revision 0, *Review Standard for Extended Power Uprates*, states that "power uprates typically result in increases in decay heat generation following plant trips. These increases in decay heat usually do not affect the elements of a fire protection program related to (1) administrative controls, (2) fire suppression and detection systems, (3) fire barriers, (4) fire protection responsibilities of plant personnel, and (5) procedures and resources necessary for the repair of systems required to achieve and maintain cold shutdown. In addition, an increase in decay heat will usually not result in an increase in the potential for a radiological release resulting from a fire. However, the licensee's LAR should confirm that these elements are not impacted by the CPSES SPU."

The staff note that SPULR, Section 2.5.1.4 "Fire Protection", specifically addresses only item (1) above. Provide additional information to address items (2) through (5), and a statement confirming no increase in the potential for a radiological release resulting from a fire.

CPNPP Response:

SPU does not affect fire suppression and detection systems (except as noted below in NRC Question #4). No changes to fire barriers, fire protection responsibilities of plant personnel, nor procedures and resources (necessary for the repair of systems required to achieve and maintain cold shutdown) have been made as a result of SPU.

Since no changes are being made to the Fire Protection Program elements - (1) administrative controls, (2) fire suppression and detection systems, (3) fire barriers, (4) fire protection responsibilities of plant personnel, and (5) procedures and resources necessary for the repair of systems required to achieve and maintain cold shutdown, then CPNPP response to a fire shutdown scenario is not changed by the SPU. With consideration for increased decay heat, plant shutdown and cooldown can still be accomplished within the time requirements as stated in the CPNPP Fire Protection Report. Therefore, there is no increase in the potential for a radiological release resulting from a fire.

NRC Question 2.

Attachment 1 to Matrix 5 ("Supplemental Fire Protection Review Criteria, Plant Systems"), of NRR RS-001, Revision 0, *Review Standard for Extended Power Uprates*, states that "...where licensees rely on less than full capability systems for fire events the licensee should provide specific analyses for fire events that demonstrate that (1) fuel integrity is maintained by demonstrating that the fuel design limits are not exceeded and (2) there are no adverse consequences on the reactor pressure vessel integrity or the attached piping. Plants that rely on alternative/dedicated or backup shutdown capability for post-fire safe shutdown should analyze the impact of the power uprate on the alternative/dedicated or backup shutdown capability ..."

The licensee should identify the impact of the SPU on the plant's post-fire safe-shutdown procedures. The staff notes that Section 2.5.1.4.2.2, "Description and Analyses and Evaluations," of the SPULR does not address items (1) and (2) above. Provide additional information addressing items (1) and (2).

CPNPP Response:

The fire safe shutdown analysis and the plant cooldown analysis have been updated for SPU conditions. These analyses demonstrate that the plant can be shutdown and cooled to cold shutdown conditions well within the 72 hour requirement discussed in the CPNPP Fire Protection Report. Since the ability to shutdown and cooldown the plant at SPU conditions with increased decay heat loads is achieved within the required time limits, it is concluded that fuel design limits would not be exceeded and there would be no adverse consequences on the reactor pressure vessel integrity or the attached piping.

NRC Question 3.

SPULR, Section 2.5.1.4.2.2, states that "...time critical tasks are identified in the thermal/hydraulic analysis of the fire safe-shutdown scenario. Operations procedures implement the time critical tasks to:

- **Transfer power-operated relief valve (PORV) control to hot shutdown panel within five minutes**
- **Establish seal return flow within 30 minutes**
- **Start plant cooldown prior to two hours or pressurizer level exceeding 92 percent..."**

Do the above time critical operator actions result from the SPU? Discuss any assumptions, especially those of a potentially non-conservative nature that may have been made in determining that the operator actions can confidently be accomplished within the available time.

CPNPP Response:

These above time critical operator actions were identified previously in the fire safe shutdown analysis for CPNPP. These operator actions are not a result of the SPU. With the conditions of increased decay heat loads due to SPU, these actions have not changed and are still acceptable for safe plant shutdown in the event of a fire accident scenario. Assumptions of time response considered in performing these operator actions do not change as a result of SPU.

NRC Question 4.

Some plants credit aspects of their Fire Protection System for other than fire protection activities, e.g., utilizing the fire water pumps and water supply as backup cooling or inventory for non-primary reactor systems. If the CPSES, Units 1 and 2, credit its fire protection system in this way, the SPULR should identify the specific situations and discuss to what extent, if any, the SPU affects these "non-fire-protection" aspects of the plant Fire Protection System. If the CPSES, Units 1 and 2, do not take such credit, it should also be addressed in the SPULR.

CPNPP Response:

The CPNPP FSAR identifies two event scenarios for which the Fire Protection System (FPS) is utilized for purposes other than fire mitigation. The first scenario involves use of FPS to add inventory to the spent fuel pool(s) (SFP) in the event SFP cooling and make-up from the Reactor Make-up Water System are unavailable. Heat load in the spent fuel pools have increased as a result of the SPU. The analysis at

SPU conditions shows that the time to boiling is still greater than 3 hours which is consistent with the FSAR.

The second scenario type involves the postulation of a crack in the break exclusion area of the main steam line piping outside containment and inside a main steam isolation valve (MSIV) enclosure. For that scenario type, CPNPP is required to assess the consequences of the crack for equipment environmental qualification only. The analysis of that scenario assumes operation of the fire protection sprinkler system in the MSIV enclosure as a means to limit the environmental consequences (temperature and pressure) of the postulated crack. The impact of the SPU is an increase in the mass and energy release in the area. From the analysis, the existing sprinkler system provides acceptable cooling under SPU conditions.

(See Attachment 4 - [OUO-SRI] for additional information)

PIPING AND NDE BRANCH

NRC Question 1.

In section 2.1.5 of the SPULR, an equation for the susceptibility of alloy 600 material is provided for determining the change in susceptibility due to the increase in hot leg temperature. The gas constant, R, is provided as 1.987. The ideal gas constant is typically expressed as 1.103 E-3 kcal/mole-R, or 1.103 cal/mole-°R. Where °R is the Rankine temperature scale. Clarify the units of the gas constant listed in section 2.1.5 and recalculate the value for the change in susceptibility as appropriate.

CPNPP Response:

The units of the gas constant are cal/mole-°K. In the susceptibility equation, $S = A(\phi yk)^4 \exp(-Q/RT)$, the units of temperature are in °R. Taking a differential of the susceptibility equation resulted in $\Delta S/S = (Q/RT^2)\,\Delta T$, which is further shown as $\Delta S/S = (0.08)\,(\Delta T°R)$. Using the 1.103 cal/mole-°R gas constant would result in the following relation $\Delta S/S = (0.14)\,(\Delta T°R)$.

Using this relation the change in susceptibility of Unit 1 would be 17%, while the change in susceptibility of Unit 2 would be 25%. The effect remains the same - that is, there is a negligible increase in susceptibility since the overall failure probability is extremely low.

NRC Question 2.

Discuss the basis for the estimated susceptibility to primary water stress-corrosion cracking (PWSCC) at the Alloy 82/182 weld locations to be ~10^{-11} failure probability as specified in section 2.1.5.2.3 of the SPULR.

CPNPP Response:

The ~10^{-11} failure probability was previously estimated for another utility during an assessment of the plant's Alloy 600 components with respect to PWSCC. The value was determined considering an effective temperature based on the rate equation, $\exp(-Q/RT)$, and the fourth power of the effective stress. The similarities in all pressurized water reactors makes this a relevant probability for all PWRs.

NRC Question 3.

Discuss what is meant by "chemistry changes" in section 2.1.5.2.3 "SCC [Stress Corrosion Cracking] of Austenitic Stainless Steel," as section 2.1.5.2.2 implies there are no changes to the chemistry program, at least in regard to lithium addition.

CPNPP Response:

The "chemistry changes" refer to the decrease of lithium during the fuel cycle that is made to maintain the pH at 7.4.

NRC Question 4.

SPULR, section 2.1.5.2.3, "Description of Analyses and Evaluations," states that the change in the service temperature on thermal aging has been considered. Discuss how the change in the service

temperature on thermal aging has been considered. This section also references WCAP-14575 and states that any potential affect on thermal aging due to the SPU would be contained within the proposed programs of WCAP-14575. Discuss how any potential affect on thermal aging due to the SPU would be contained within the proposed programs of WCAP-14575. Include in the discussion whether those programs have already been implemented or the plan for future implementation.

CPNPP Response:

Thermal aging of cast austenitic stainless steels is dependent on temperature. The maximum potential temperature increase of either CPSES unit is 1.8°F. This increase in temperature is not significant enough to increase the potential for thermal aging, therefore, it is not necessary at this time to implement the programs of WCAP-14575. In addition, while WCAP-14575 is primarily focused on license renewal (beyond the standard 40 year operating license) it remains a good tool for aging management.

NRC Question 5.

Discuss the projected wear rates in the extraction steam piping to the second point heater. Include in the discussion the current wear rates and the changes that may result from implementation of the SPU for both units. Clarify if the piping sections listed in Tables 2.1.8-1 and 2.1.8-2 of the SPULR indicate the largest increases in projected wear rates for the systems in the flow-accelerated corrosion program. If these do not represent the largest increases in wear rate, discuss those with the largest increases in wear rate.

CPNPP Response:

The extraction steam piping to the second point heater is chrome-molybdenum material and is not considered susceptible to FAC.

The lines displayed in Tables 2.1.8.1-1 and 2.1.8-2 of the SPULR represent those that we expect to result in the largest increases in projected wear rates due to SPU conditions. The FAC program model update, which is part of the uprate implementation process, as well as ongoing program monitoring, will confirm the effects of uprate are as expected.

Attachment 2

Question 19
Revised Table 2.8.5.0-1

Table 2.8.5.0-1
Non-LOCA Analysis Limits and Analysis Results

FSAR Section	Event Description	Result Parameter	Analysis Result	
			Analysis Limit	Limiting Case
15.1.1	Decrease in Feedwater Temperature	Minimum DNBR (RTDP, WRB-2)	1.61	1.90
15.1.2	Increase in Feedwater Flow	Minimum DNBR (RTDP, WRB-2) (HFP) Minimum DNBR (non-RTDP, W-3) (HZP)	1.61 (HFP) 1.45 (HZP)	2.10 (HFP) (1) (HZP)
15.1.3	Excessive Increase in Secondary Steam Flow	Minimum DNBR (RTDP, WRB-2)	1.61	> 1.61
15.1.4	Inadvertent Opening of a Steam Generator Relief or Safety Valve	Bounded by Steam Line Break (FSAR Section 15.1.5)	N/A	N/A
15.1.5	Steam System Piping Failure – Zero Power (Core response only)	Minimum DNBR (non-RTDP, W-3) (typical/thimble)	1.45/1.45	3.067/2.861
	Steam System Piping Failure – Full Power (Core response only)	Minimum DNBR (RTDP, WRB-2 correlation) (typical/thimble)	1.61/1.61	2.015/1.963
		Peak Linear Heat Generation (kW/ft)	22.4(2)	21.6
15.2.1	Steam Pressure Regulator Malfunction or Failure that Results in Decreasing Steam Flow	There are no steam pressure regulators at CPSES whose failure or malfunction could cause a steam flow transient (FSAR Section 15.2.1)	N/A	N/A
15.2.2	Loss of External Electrical Load	Bounded by Turbine Trip (FSAR Section 15.2.3)	N/A	N/A
15.2.3	Turbine Trip	Minimum DNBR (RTDP, WRB-2)	1.61	1.98
		Peak RCS Pressure, psia	2,748.2	2,746.0
		Peak MSS Pressure, psia	1,318.2	1,298.4
15.2.4	Inadvertent Closure of Main Steam Isolation Valves	Bounded by Turbine Trip (FSAR Section 15.2.3)	N/A	N/A

Table 2.8.5.0-1 (cont.)
Non-LOCA Analysis Limits and Analysis Results

FSAR Section	Event Description	Result Parameter	Analysis Result	
			Analysis Limit	Limiting Case
15.2.5	Loss of Condenser Vacuum and Other Events Resulting in Turbine Trip	Bounded by Turbine Trip (FSAR Section 15.2.3)	N/A	N/A
15.2.6	Loss of Nonemergency AC Power to the Station Auxiliaries	Maximum pressurizer mixture volume, ft^3	1,800	1,600.4
15.2.7	Loss of Normal Feedwater	Maximum Pressurizer Mixture Volume, ft^3	1,800	1,747.9
15.2.8	Feedwater System Pipe Break	Minimum Margin to Hot Leg Saturation, °F	>0.0	10
15.3.1	Partial Loss of Forced Reactor Coolant Flow	Minimum DNBR (RTDP, WRB-2) (typical/thimble)	1.61/1.61	2.253/2.173
15.3.2	Complete Loss of Forced Reactor Coolant Flow	Minimum DNBR (RTDP, WRB-2) (typical/thimble)	1.61/1.61	1.940/1.901
15.3.3/ 15.3.4	Reactor Coolant Pump Shaft Seizure (Locked Rotor)/Shaft Break	Peak RCS Pressure, psia	2,748.2	2,574.5
		Peak Cladding Temperature, °F	2,700	1,723.6
		Maximum Zirconium-Water Reaction, %	16	0.22
		Maximum Percentage of Rods-in-DNB, %	10	<10
15.4.1	Uncontrolled RCCA Withdrawal from a Subcritical or Low Power Condition	Minimum DNBR Below First Mixing Vane Grid (non-RTDP, W-3 correlation) (typical/thimble)	1.30/1.30	1.824/1.616
		Minimum DNBR Above First Mixing Vane Grid (non-RTDP, WRB-2 correlation) (typical/thimble)	1.17/1.17	2.018/1.997
		Maximum Fuel Centerline Temperature, °F	4,800[(3)]	2,304
15.4.2	Uncontrolled RCCA Withdrawal at Power	Minimum DNBR (RTDP, WRB-2)	1.61	1.613
		Peak MSS Pressure, psia	1,318.2	1,276.7

Table 2.8.5.0-1 (cont.)
Non-LOCA Analysis Limits and Analysis Results

FSAR Section	Event Description	Result Parameter	Analysis Result	
			Analysis Limit	Limiting Case
15.4.3	RCCA Misalignment (Dropped Rod)	Minimum DNBR (RTDP, WRB-2)	1.61	> 1.61
		Peak Linear Heat Generation (kW/ft)	22.4[2]	< 22.4
		Peak Uniform Cladding Strain (%)	1.0	< 1.0
15.4.4	Startup of an Inactive Reactor Coolant Pump at an Incorrect Temperature	No Analysis Performed (See Licensing Report Section 2.8.5.4.4)	N/A	N/A
15.4.5	A Malfunction or Failure of the Flow Controller in a BWR Loop that Results in an Increased Reactor Coolant Flow Rate	This event is not applicable to CPSES.	N/A	N/A
15.4.6	Chemical and Volume Control System (CVCS) Malfunction that Results in a Decrease in the Boron Concentration in the Reactor Coolant (Boron Dilution)	Minimum Time from Alarm to Operator Action to prevent a Complete Loss of Shutdown Margin, Minutes	15	47.6 (Mode 1 manual)
				49.8 (Mode 1 auto)
				52.5 (Mode 2)
				The maximum critical boron concentration is controlled as a function of the plant initial boron concentration to meet a minimum operator action time of 15 minutes. (Modes 3, 4 and 5)

Table 2.8.5.0-1 (cont.)
Non-LOCA Analysis Limits and Analysis Results

FSAR Section	Event Description	Result Parameter	Analysis Result	
			Analysis Limit	Limiting Case
15.4.8	Spectrum of RCCA Ejection Accidents	Maximum Fuel Pellet Average Enthalpy, cal/g	200	114.3 (BOC-HZP)(4) 161.6 (BOC-HFP)(5) 138.9 (EOC-HZP)(6) 157.5 (EOC-HFP)(7)
		Maximum Fuel Melt, %	10(8)	0.00 (BOC-HZP)(4) 0.04 (BOC-HFP)(5) 0.00 (EOC-HZP)(6) 0.23 (EOC-HFP)(7)
		Peak RCS Pressure, psia	Generically addressed in Reference 16	
15.5.1	Inadvertent Operation of the Emergency Core Cooling System During Power Operation	Maximum pressurizer mixture volume, ft^3	1,800	1,780.0
15.5.2	Chemical and Volume Control System Malfunction that Increases Reactor Coolant Inventory	Event is covered by the analyses of the Boron Dilution event (FSAR Section 15.4.6) and the Inadvertent Operation of the Emergency Core Cooling System During Power Operation event (FSAR Section 15.5.1).	N/A	N/A
15.5.3	A Number of BWR Transients	These events are not applicable to CPSES.	N/A	N/A
15.6.1	Inadvertent Opening of a Pressurizer Safety or Relief Valve	Minimum DNBR (RTDP, WRB-2)	1.61	1.9
15.8	ATWS	Peak RCS Pressure, psig	3,200	<3,200

Table 2.8.5.0-1 (cont.)
Non-LOCA Analysis Limits and Analysis Results

FSAR Section	Event Description	Result Parameter	Analysis Result	
			Analysis Limit	Limiting Case

Notes:

1. Bounded by zero power steam system piping failure.
2. Corresponds to a conservative UO_2 fuel melting temperature of 4,700°F.
3. 4,800°F is the fuel melting temperature corresponding to a maximum UO_2 burnup at the hot spot of ~48,276 MWd/MTU.
4. BOC-HZP ≡ Beginning of cycle HZP.
5. BOC-HFP ≡ Beginning of cycle HFP.
6. EOC-HZP ≡ End of cycle HZP.
7. EOC-HFP ≡ End of cycle HFP.
8. BOC and EOC fuel melting temperatures are 4,900 and 4,800°F, respectively. These temperatures correspond to hot spot burnups of approximately 31,034 MWD/MTU (BOC) and 48,276 MWD/MTU (EOC).

Attachment 3

Question 19
Revised Section 2.8.5.4.2

2.8.5.4.2 Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power

2.8.5.4.2.1 Regulatory Evaluation

An uncontrolled rod cluster control assembly (RCCA) bank withdrawal at power can be caused by a malfunction of the rod control system. This bank withdrawal will add positive reactivity to the reactor core, resulting in a power excursion.

The review covered:

- The description of the causes of the anticipated operational occurrence (AOO) and the description of the event itself
- The initial conditions
- The values of reactor parameters used in the analyses
- The analytical methods and computer codes used
- The results of the associated analyses

The acceptance criteria are based on:

- General Design Criterion (GDC)-10, insofar as it requires that the reactor coolant system (RCS) be designed with appropriate margin to ensure that specified acceptable fuel design limits (SAFDLs) are not exceeded during normal operations, including AOOs.
- GDC-20, insofar as it requires that the reactor protection system be designed to initiate automatically the operation of appropriate systems, including the reactivity control systems, to ensure that SAFDLs are not exceeded as a result of AOOs.
- GDC-25, insofar as it requires that the protection system be designed to ensure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems.

Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR) Section 3.1, the GDC used during the licensing of the Comanche Peak Steam Electric Station (CPSES) Units are compared against Title 10, Code of Federal Regulations, Part 50 (10 CFR 50), Appendix A, GDC for Nuclear Power Plants. The adequacy of the CPSES design relative to the GDC is discussed in FSAR Section 3.1.

Specifically, the adequacy of CPSES design relative to:

- GDC-10, Reactor Design, is described in FSAR Section 3.1.2.1.

  The reactor core and associated coolant, control, and protection systems are designed with adequate margins to:

  1. Ensure that fuel damage is not expected during normal core operation and operational transients (Condition I) or any transient conditions arising from occurrences of moderate frequency (Condition II). It is not possible, however, to preclude a very small number of rod failures. These failures are within the capability of the plant cleanup system, and are consistent with plant design bases.

  2. Ensure return of the reactor to a safe state following infrequent incident (Condition III) events with only a small fraction of fuel rods damaged, although sufficient fuel damage might occur to preclude immediate resumption of operation.

  3. Assure that the core is intact with acceptable heat transfer geometry following transients arising from occurrences of limiting faults (Condition IV).

  Note that the term "fuel damage" as used in Item 1 above is defined as penetration of the fission product barrier (i.e., the fuel rod clad). Also note that American National Standards Institute (ANSI) N18.2-1973 expands the definitions of the four conditions enumerated in Items 1 through 3 above.

  FSAR Chapter 4 discusses the design bases and the design evaluation of reactor components. FSAR Chapter 7 provides the details of the control and protections systems instrumentation design and logic. This information supports the FSAR Chapter 15 accident analysis, which shows that acceptable fuel design limits are not exceeded for Condition I and II occurrences.

- GDC-20, Protection System Functions, is described in FSAR Section 3.1.3.1.

  A fully automatic protection system, with appropriate redundant channels, is provided to cope with transients where insufficient time is available for manual corrective action. The design basis for all protection systems is Institute of Electrical and Electronic Engineering (IEEE) Standard 279-1971 and IEEE Standard 379-1972. The reactor protection system automatically initiates a reactor trip when any variable exceeds the normal operating range. Setpoints are designed to provide an envelope of safe operating conditions with adequate margin for uncertainties to ensure that fuel design limits are not exceeded.

  Reactor trip is initiated by removing power to the rod drive mechanisms of all of the full-length RCCAs. This causes the rods to insert by gravity, which rapidly reduces reactor power output. The response and adequacy of the protection system have been verified by analysis of expected transients.

The engineered safety features (ESF) actuation system automatically initiates emergency core cooling, and other safeguards functions, by sensing accident conditions using redundant analog channels measuring diverse variables. Manual actuation of safeguards equipment may be performed where ample time is available for operator action. The ESF actuation system automatically trips the reactor on manual or automatic safety injection signal (SIS) generation.

- GDC-25, Protections System Requirements for Reactivity Control Malfunctions, is described in FSAR Section 3.1.3.6.

  The protection system is designed to limit reactivity transients so that fuel design limits are not exceeded. Reactor shutdown by full-length rod insertion is completely independent of the normal control function, since the trip breakers interrupt power to the rod mechanisms regardless of existing control signals. Therefore, in the postulated accidental withdrawal (assumed to be initiated by a control malfunction), flux, temperature, pressure, level and flow signals would be generated independently. Any of these signals (trip demands) would operate the breakers to trip the reactor.

  FSAR Chapter 15 discusses analyses of the effects of possible malfunctions. These analyses show that for postulated dilution during refueling, startup, or manual or automatic operation at power, the operator has ample time to determine the cause of dilution, terminate the source of dilution, and initiate boration before the shutdown margin is lost. The analyses show that acceptable fuel damage limits are not exceeded even in the event of a single malfunction of either system.

FSAR Section 15.4.2.1 states that uncontrolled RCCA bank withdrawal at power results in an increase in the core heat flux. Since the heat extraction from the steam generator lags behind the core power generation until the steam generator pressure reaches the relief or safety valve setpoint, there is a net increase in the reactor coolant temperature. Unless terminated by manual or automatic action, the power mismatch and resultant coolant temperature rise could eventually result in departure from nucleate boiling (DNB). Therefore, in order to avert damage to the fuel cladding, the reactor protection system is designed to terminate any such transient before the DNB ratio (DNBR) falls below the safety analysis limit value. This event is classified as a Condition II incident as defined by the American Nuclear Society's "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants," ANSI N18.2-1973.

FSAR Section 15.4.2.2 states that the transient is analyzed with the RETRAN Code. It computes pertinent plant variables including temperatures, pressures, and power level.

FSAR Section 15.4.2.3 concludes that the high neutron flux and overtemperature N-16 trip channels provide adequate protection over the entire range of possible reactivity insertion rates; that is, the minimum value of DNBR is always larger than the safety analysis limit value. It is assumed that the high pressurizer water level reactor trip would prevent pressurizer filling. In addition, the positive flux rate and high pressurizer pressure reactor trip functions provide a timely reactor trip to preclude RCS overpressurization in instances where the high neutron flux or overtemperature N-16 trips occur too late to provide the necessary protection.

2.8.5.4.2.2 Technical Evaluation

2.8.5.4.2.2.1 Introduction

An uncontrolled RCCA bank withdrawal at power that causes an increase in core heat flux can result from faulty operator action or a malfunction in the rod control system. Immediately following the initiation of the accident, the steam generator heat removal rate lags behind the core power generation rate until the steam generator pressure reaches the setpoint of the steam generator relief or safety valves. This imbalance between heat removal and heat generation rate causes the reactor coolant temperature to rise. Unless terminated, the power mismatch and resultant coolant temperature rise could eventually result in a violation of the DNBR safety analysis limit and/or fuel centerline melt. Therefore, to avoid core damage, the reactor protection system is designed to automatically terminate any such transient before the DNBR falls below the safety analysis limit value, or the fuel rod linear heat generation rate (kW/ft) limit is exceeded.

The automatic features of the reactor protection system that prevent core damage in an RCCA bank withdrawal incident at power include the following:

- Power range high neutron flux instrumentation actuates a reactor trip on neutron flux if two-out-of-four channels exceed an overpower setpoint.
- Reactor trip actuates if any two-out-of-four channels exceed the high positive neutron flux rate setpoint.
- Reactor trip actuates if any two-out-of-four N-16 channels exceed an overtemperature N-16 setpoint. This setpoint is automatically varied with axial power distribution, coolant average temperature, and coolant average pressure to protect against violating the DNBR safety analysis limit.
- Reactor trip actuates if any two-out-of-four N-16 channels exceed an overpower N-16 setpoint.
- Main steam safety valves (MSSVs) can open for this event and provide an additional heat sink.
- A high pressurizer pressure reactor trip actuated from any two-out-of-four pressure channels which is set at a fixed point. This set pressure is less than the set pressure for the pressurizer safety valves.
- A high pressurizer water level reactor trip actuated from any two-out-of-three channels which is set at a fixed point, when the reactor power is above approximately 10 percent (Permissive 7).

2.8.5.4.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

A number of cases were analyzed assuming a range of reactivity insertion rates for both minimum and maximum reactivity feedback conditions at various power levels. The cases presented below are representative for this event.

For an uncontrolled RCCA bank withdrawal at power accident, the analysis assumed the following conservative assumptions:

- This accident was analyzed with the Revised Thermal Design Procedure (RTDP) (Reference 1). Initial reactor power, RCS pressure, and RCS temperature were assumed to be at their nominal values. Minimum measured flow was modeled. Uncertainties in initial conditions were included in the DNBR safety analysis limit as described in the RTDP.

- For reactivity coefficients, two cases were analyzed.

  - Minimum reactivity feedback; A least negative or positive value of the moderator temperature coefficient of reactivity is assumed corresponding to the beginning of core life. A conservatively small (in absolute magnitude) value of the Doppler coefficient is assumed.

  - Maximum reactivity feedback; A conservatively large positive moderator density coefficient and a large (in absolute magnitude) negative Doppler coefficient are assumed.

- The reactor trip on high neutron flux was assumed to be actuated at a conservative value of 118.0 percent of nominal full power. The N-16 trips included all adverse instrumentation and setpoint errors, while the delays for the trip signal actuation were assumed at their maximum values.

- The RCCA trip insertion characteristic was based on the assumption that the highest-worth RCCA was stuck in its fully withdrawn position.

- A range of reactivity insertion rates was examined. The maximum-positive reactivity insertion rate was greater than that which would be obtained from the simultaneous withdrawal of the two control rod banks having the maximum combined worth at a conservative speed (45 inches/minute, which corresponds to 72 steps/minute).

- To be conservative with respect to DNB, the pressurizer sprays and relief valves were assumed operational since they limit the reactor coolant pressure increase.

- Power levels of 10, 60, and 100 percent of the nuclear steam supply system (NSSS) power of 3,628 MWt were considered.

Based on its frequency of occurrence, the uncontrolled RCCA bank withdrawal at-power accident is considered a Condition II event as defined by the American Nuclear Society's "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants," ANSI N18.2-1973. The following items summarize the main acceptance criteria associated with this event:

- The critical heat flux should not be exceeded. This is met by demonstrating that the minimum DNBR does not go below the safety analysis limit value at any time during the transient.

- Pressure in the RCS and main steam system (MSS) should be maintained below 110 percent of the design pressures.

The protection features presented in Licensing Report (LR) subsection 2.8.5.4.2.2.1 provide mitigation of the uncontrolled RCCA bank withdrawal at-power transient such that the above criteria are satisfied.

Also, a conservative generic evaluation that is applicable to CPSES has shown that the positive flux rate and high pressurizer pressure functions provide a timely reactor trip that precludes RCS overpressurization in instances where the power range high neutron flux or the overtemperature N-16 trip occur too late to provide the necessary protection. This evaluation confirms that the RCS pressure limit is met.

In addition to the criteria mentioned above, an incident of moderate frequency (Condition II event) should not generate a more serious plant condition (Condition III or IV event) without other faults occurring independently. The uncontrolled RCCA bank withdrawal at power event is analyzed only up to the time of reactor trip, as this is the most limiting time with respect to demonstrating that the DNB design basis is satisfied. Provided that primary or secondary overpressurization does not occur in this time frame, the possibility of a boundary failure is not expected. For this Condition II event to propagate to a Condition III event, the pressurizer must become water-solid, water relief through the pressurizer safety valves must occur and cause them to fail open. This is effectively a small break loss of coolant accident, a Condition III event. This Condition II event will not generate a more serious Condition III event since the high pressurizer water level reactor trip would trip the reactor and ensure the pressurizer does not reach a water solid condition. Thus, event propagation is not a concern up to the time of reactor trip. For the time period after reactor trip, the results of the uncontrolled RCCA bank withdrawal at power event, with respect to pressurizer filling, would be bounded by the loss of normal feedwater event discussed in LR Section 2.8.5.2.3

2.8.5.4.2.2.3 Description of Analyses and Evaluations

The purpose of this analysis was to demonstrate the manner in which the protection functions described above actuate for various combinations of reactivity insertion rates and initial conditions. Insertion rate and initial conditions determined which trip function actuated first.

The uncontrolled RCCA bank withdrawal at-power event was analyzed with the RETRAN computer code (Reference 2). The program simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generators, and MSSVs. The code computes pertinent plant variables including temperatures, pressures, power level, and the DNBR (based on a conservative partial derivative approximation of the DNB core limit lines).

2.8.5.4.2.2.4 Results

Figures 2.8.5.4.2-1 through 2.8.5.4.2-3 (Unit 1) and Figures 2.8.5.4.2-16 through 2.8.5.4.2-18 (Unit 2) show the transient response for a rapid uncontrolled RCCA bank withdrawal incident (110 pcm/sec) starting from 100 percent power with minimum reactivity feedback. The neutron flux level in the core rises rapidly while the core heat flux and coolant system temperature lag behind due to the thermal capacity of the fuel and coolant system fluid. Reactor trip on high neutron flux occurs shortly after the start of the accident prior to a significant increase in the heat flux and water temperature with resultant minimum DNB ratios that remain well above the safety analysis limit value throughout the transient.

The transient response for a slow uncontrolled RCCA bank withdrawal (1 pcm/sec) from 100 percent power with minimum feedback is shown in Figures 2.8.5.4.2-4 through 2.8.5.4.2-6 (Unit 1) and Figures 2.8.4.2-19 through 2.8.4.2-21 (Unit 2). With a lower insertion rate the power increase rate is slower, the rate of rise of the average coolant temperature is slower and the system lags and delays become less significant. A reactor trip on overtemperature N-16 occurs after a longer period of time than for a rapid RCCA bank withdrawal. Again, the minimum DNBR remain greater than the safety analysis limit value.

Figures 2.8.5.4.2-7 through 2.8.5.4.2-9 (Unit 1) and Figures 2.8.5.4.2-22 through Figures 2.8.5.4.2-24 for (Unit 2) show the transient response for a rapid uncontrolled RCCA bank withdrawal incident (110 pcm/sec) starting from 100 percent power with maximum reactivity feedback. The transient response for a slow uncontrolled RCCA bank withdrawal (1 pcm/sec) from 100 percent power with maximum feedback is shown in Figures 2.8.5.4.2-10 through 2.8.5.4.2-12 (Unit 1) and Figures 2.8.5.4.2-25 through 2.8.5.4.2-27 (Unit 2). The results are similar to the results of the cases with minimum reactivity feedback, but the maximum reactivity feedback leads to a slower increase in power, resulting in a longer transient.

Figure 2.8.5.4.2-13 (Unit 1) and Figure 2.8.5.4.2-28 (Unit 2) show the minimum DNBR as a function of reactivity insertion rate from 100 percent power for both minimum and maximum reactivity feedback conditions. It can be seen that the high neutron flux and overtemperature N-16 reactor trip functions provided DNB protection over the analyzed range of reactivity insertion rates and the minimum DNBR is never less than the safety analysis limit value.

Figures 2.8.5.4.2-14, 2.8.5.4.2-15 (Unit 1), 2.8.5.4.2-29 and 2.8.5.4.2-30 (Unit 2) show the minimum DNBR as a function of reactivity insertion rate for RCCA bank withdrawal incidents starting at 60- and 10-percent power, respectively. The results are similar to the 100-percent power case. However, as the initial power level is decreased, the range over which the overtemperature N-16 trip is effective is increased.

Calculated sequences of events for two minimum reactivity feedback cases and two maximum reactivity feedback cases are shown in Tables 2.8.5.4.2-1 and 2.8.5.4.2-2, respectively. With the reactor tripped, the plant eventually returns to a stable condition. The plant could subsequently be cooled down further by following normal plant shutdown procedures. The limiting results of the uncontrolled RCCA bank withdrawal at power analysis are shown in Table 2.8.5.4.2-3.

The high neutron flux and overtemperature N-16 reactor trip functions provided adequate protection over the entire range of possible reactivity insertion rates. The results show that the DNB design basis is met and the peak kW/ft is less than the limit. The peak pressures in the RCS and MSS do not exceed 110 percent of their respective design pressures.

Therefore, the results of the analysis show that an uncontrolled RCCA bank withdrawal at-power does not adversely affect the core, the RCS, or the MSS.

2.8.5.4.2.3 Conclusions

This review of the uncontrolled RCCA bank withdrawal at-power event analysis demonstrates that Luminant Power has adequately accounted for the changes in core design required for plant operation at the proposed uprated power level. This analysis was performed using acceptable analytical models. This analysis has also demonstrated that the reactor protection and safety systems will continue to ensure that the specified acceptable fuel design limits are not exceeded. Based on this, it can be concluded that the plant will continue to meet the requirements of GDCs -10, -20, and -25 following implementation of the proposed uprated power level. Therefore, the uprated power level is acceptable with respect to the uncontrolled RCCA bank withdrawal at power event.

2.8.5.4.2.4 References

1. WCAP-11397, "Revised Thermal Design Procedure," April 1989.

2. WCAP-14882, "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," April 1999.

Table 2.8.5.4.2-1 Time Sequence of Events – Uncontrolled RCCA Bank Withdrawal at Power (Minimum Feedback)			
		Time (sec)	
Case	Event	Unit 1	Unit 2
100% Power, Minimum Feedback, Rapid RCCA Bank Withdrawal (110 pcm/sec)	Initiation of Uncontrolled RCCA Bank Withdrawal	0.00	0.00
	Power Range High Neutron Flux – High Setpoint Reached	1.19	1.19
	Reactor Trip (Rod Motion)	1.69	1.69
	Minimum DNBR Occurs	2.52	2.52
100% Power, Minimum Feedback, Slow RCCA Bank Withdrawal (1 pcm/sec)	Initiation of Uncontrolled RCCA Bank Withdrawal	0.00	0.00
	Overtemperature N-16 Setpoint Reached	102.48	98.99
	Reactor Trip (Rod Motion)	104.48	100.99
	Minimum DNBR Occurs	105.00	101.50

Table 2.8.5.4.2-2 Time Sequence of Events – Uncontrolled RCCA Bank Withdrawal at Power (Maximum Feedback)			
		Time (sec)	
Case	Event	Unit 1	Unit 2
100% Power, Maximum Feedback, Rapid RCCA Bank Withdrawal (110 pcm/sec)	Initiation of Uncontrolled RCCA Bank Withdrawal	0.00	0.00
	Power Range High Neutron Flux – High Setpoint Reached	4.13	4.11
	Reactor Trip (Rod Motion)	4.63	4.61
	Minimum DNBR Occurs	4.72	4.70
100% Power, Maximum Feedback, Slow RCCA Bank Withdrawal (1 pcm/sec)	Initiation of Uncontrolled RCCA Bank Withdrawal	0.00	0.00
	Overtemperature N-16 Setpoint Reached	1596.08	1594.60
	Reactor Trip (Rod Motion)	1598.08	1596.60
	Minimum DNBR Occurs	1598.25	1596.63

Table 2.8.5.4.2-3
Uncontrolled RCCA Bank Withdrawal at Power – Limiting Results

	Limiting Value		Safety Analysis Limit	Case
	Unit 1	Unit 2		
Minimum DNBR	1.620	1.613	1.61	60% power, minimum feedback, 6 pcm/sec reactivity insertion rate (Unit 1) 60% power, minimum feedback, 6 pcm/sec reactivity insertion rate (Unit 2)
Peak Core Heat Flux (fon)	1.177	1.176	1.18	100% power, maximum feedback, 32 pcm/sec reactivity insertion rate (Unit 1) 100% power, maximum feedback, 36 pcm/sec reactivity insertion rate (Unit 2)
Peak Secondary System Pressure (psia)	1,276.69	1,276.08	1,318.2	10% power, minimum feedback, 15 pcm/sec reactivity insertion rate (Unit 1) 10% power, minimum feedback, 13 pcm/sec reactivity insertion rate (Unit 2)

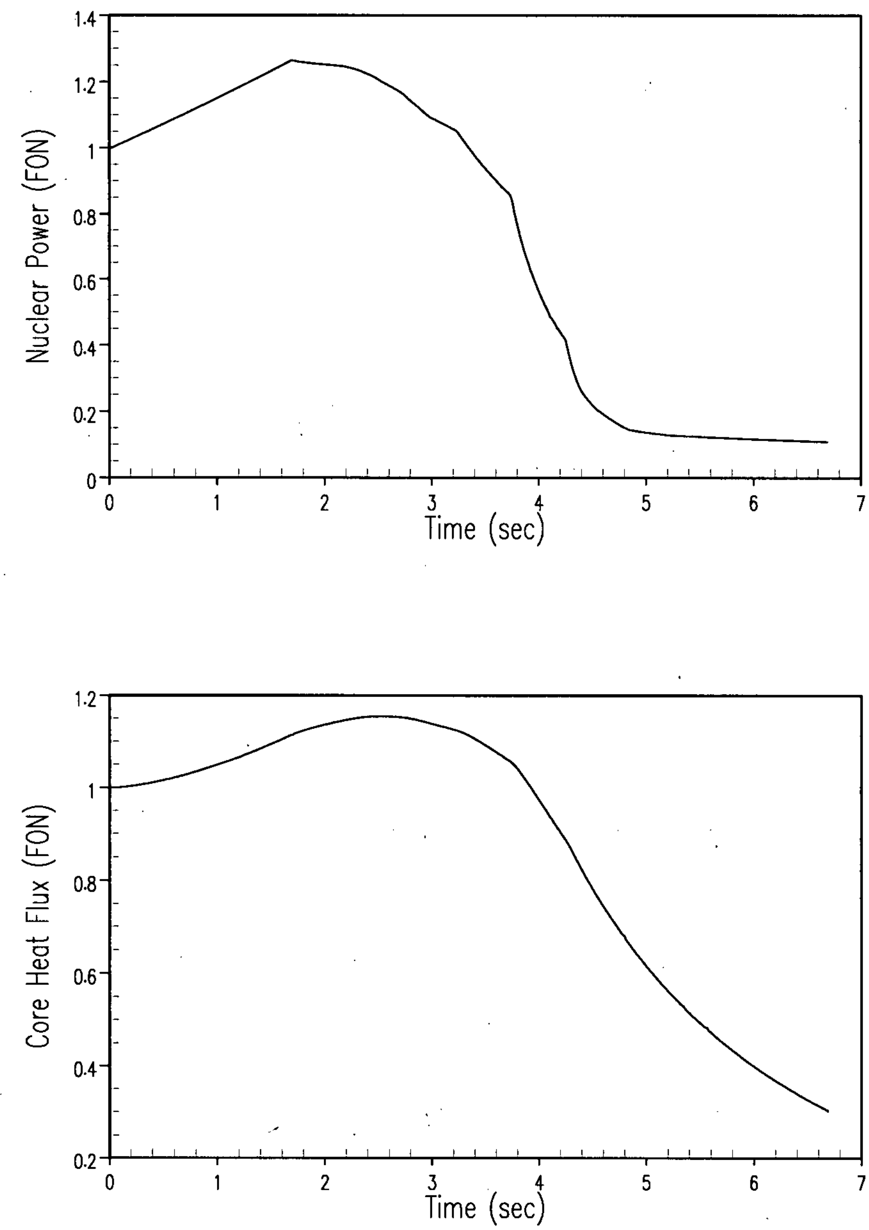
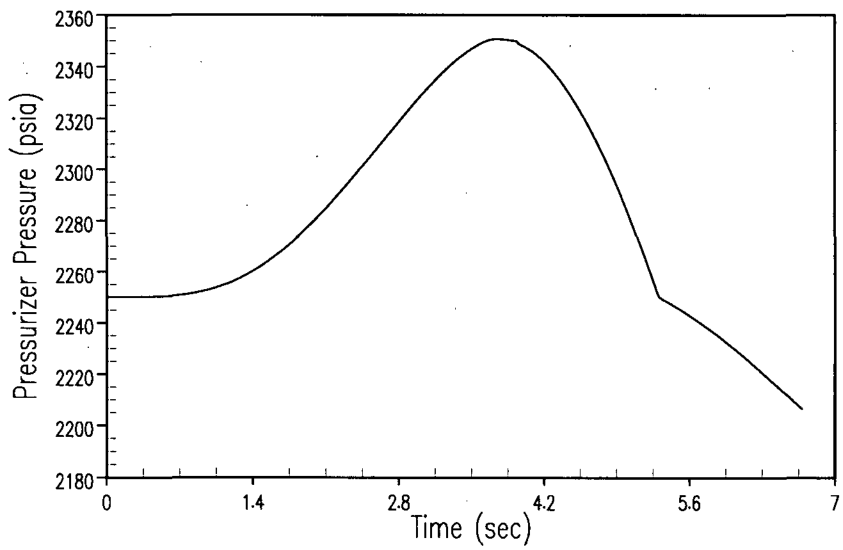


Figure 2.8.5.4.2-1 Bank Withdrawal at Power – Unit 1, Minimum Reactivity Feedback – 100% Power – 110 pcm/sec - Nuclear Power and Core Heat Flux Versus Time



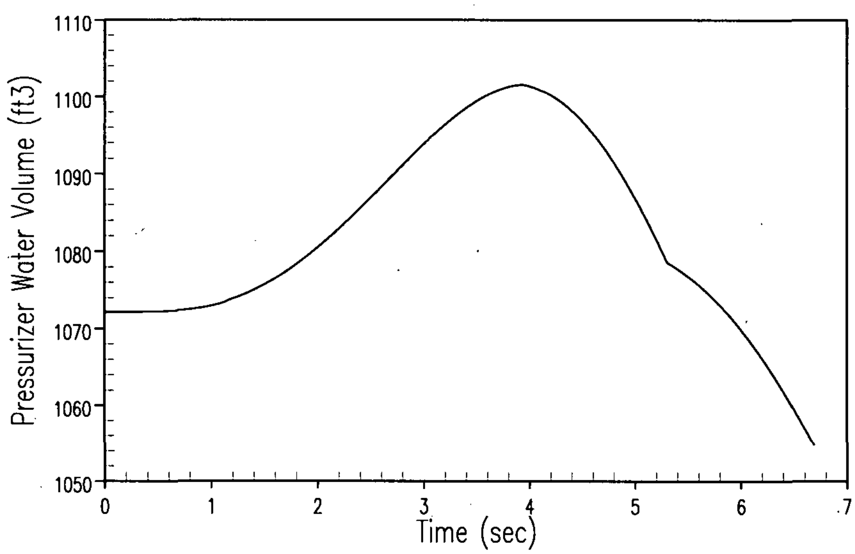
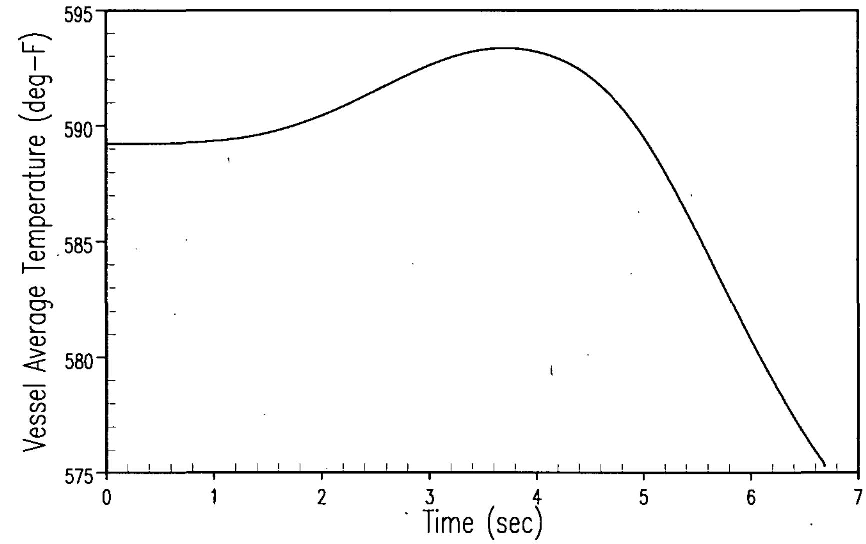


Figure 2.8.5.4.2-2 Bank Withdrawal at Power – Unit 1, Minimum Reactivity Feedback – 100% Power – 110 pcm/sec - Pressurizer Pressure and Water Volume Versus Time



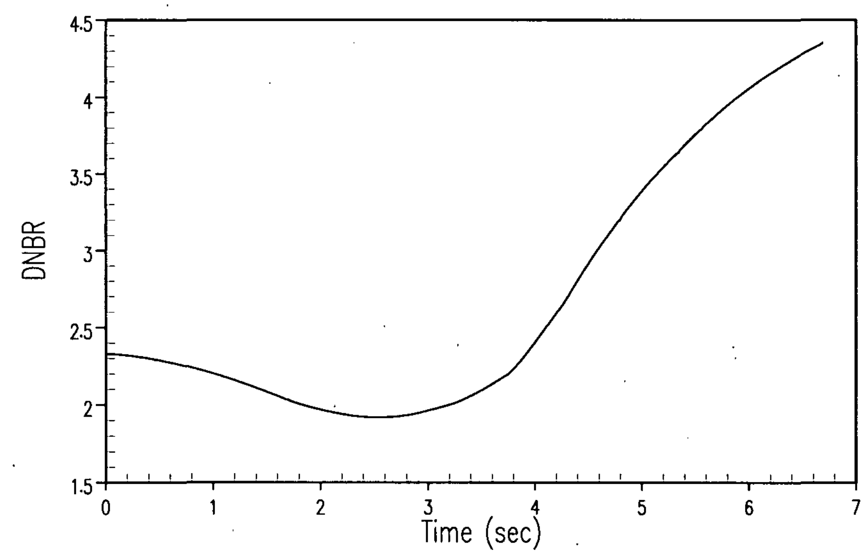


Figure 2.8.5.4.2-3 Bank Withdrawal at Power – Unit 1, Minimum Reactivity Feedback – 100% Power – 110 pcm/sec - Vessel Average Temperature and DNBR Versus Time

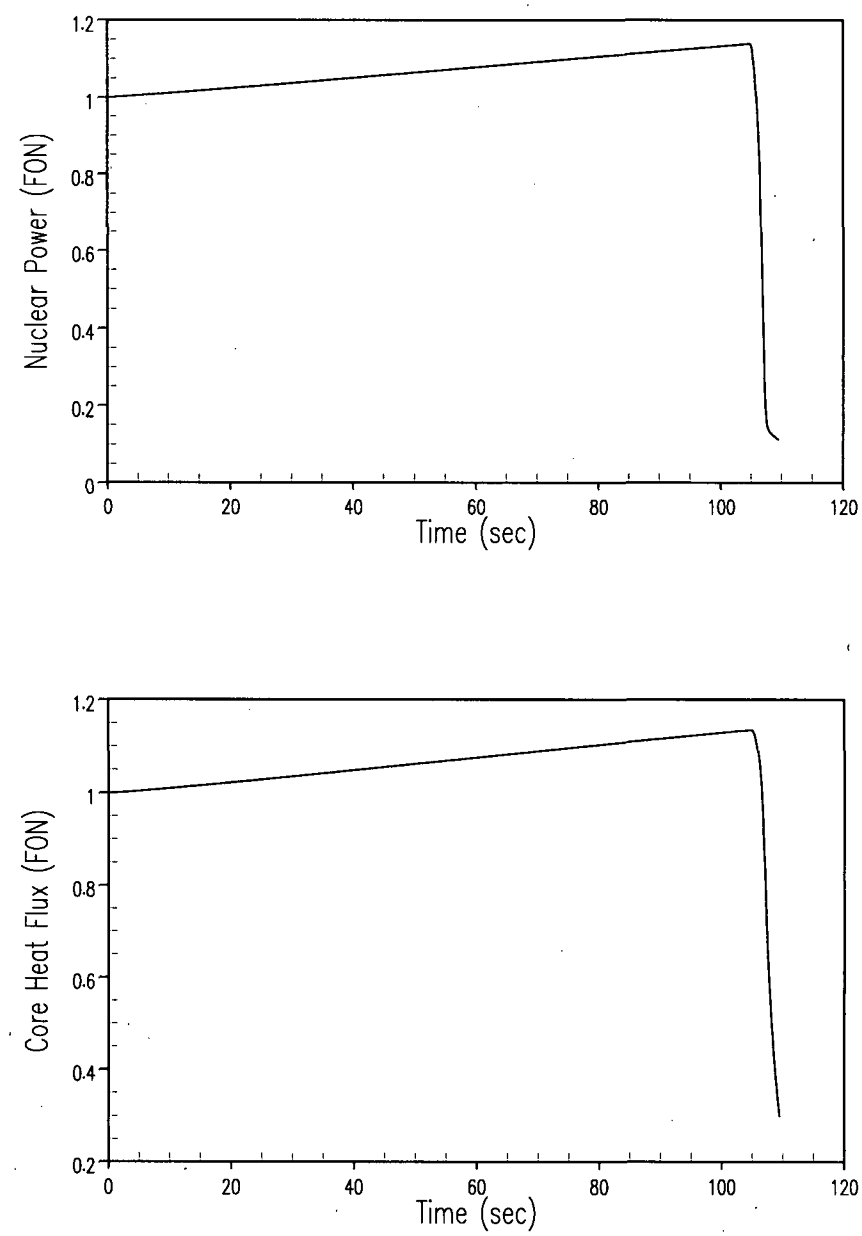
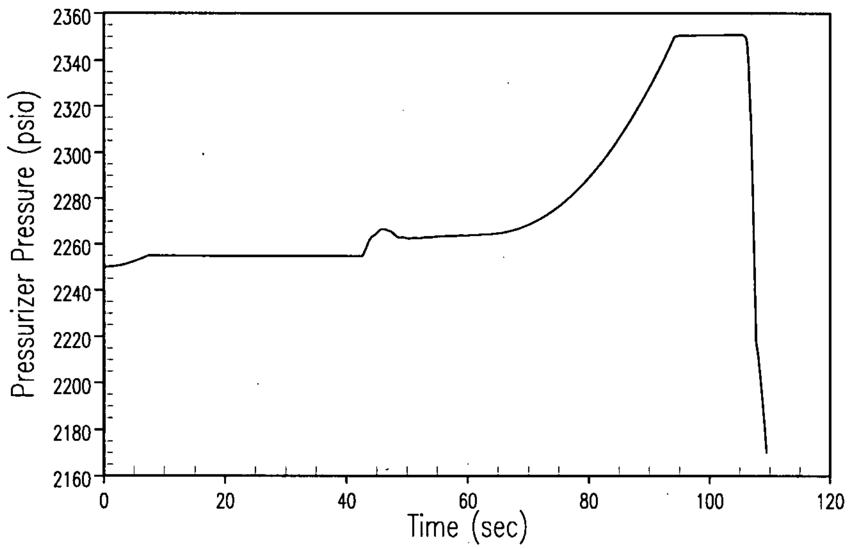


Figure 2.8.5.4.2-4 **Bank Withdrawal at Power – Unit 1, Minimum Reactivity Feedback – 100% Power – 1 pcm/sec - Nuclear Power and Core Heat Flux Versus Time**



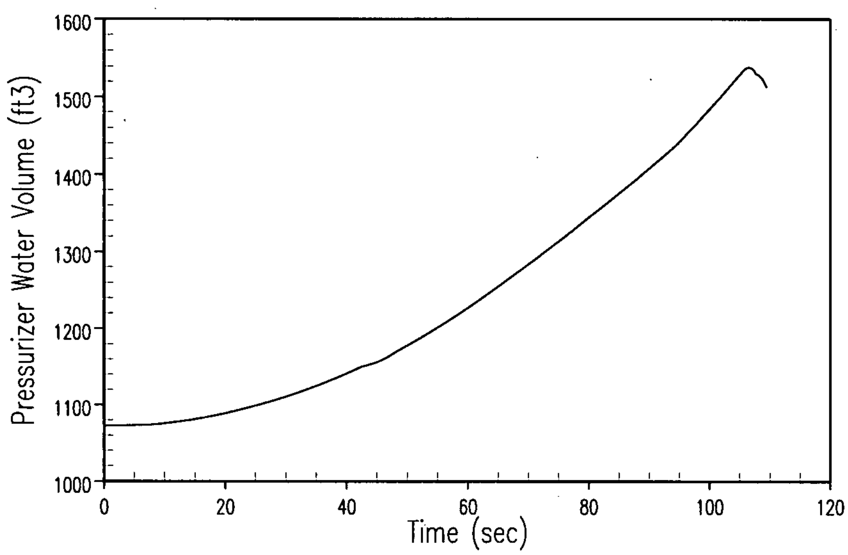


Figure 2.8.5.4.2-5 Bank Withdrawal at Power – Unit 1, Minimum Reactivity Feedback – 100% Power – 1 pcm/sec - Pressurizer Pressure and Water Volume Versus Time

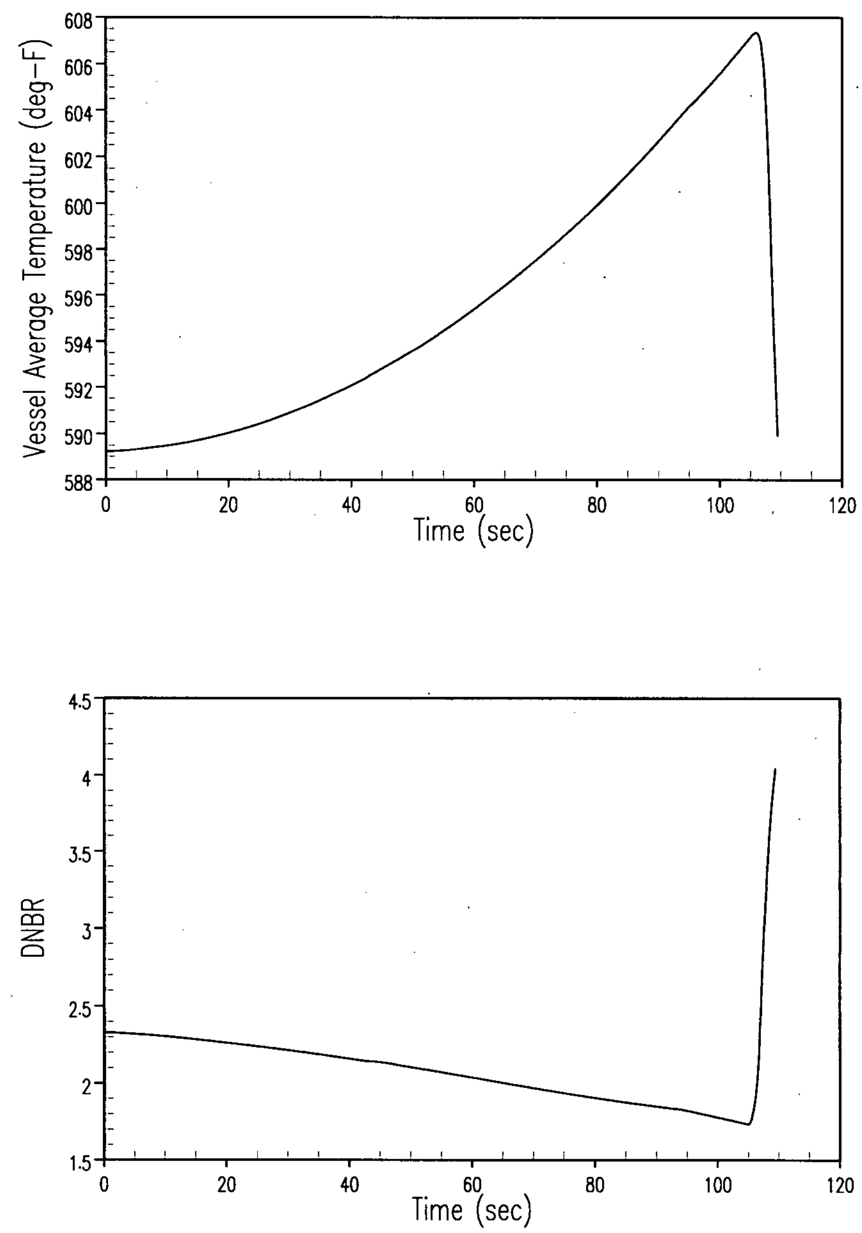


Figure 2.8.5.4.2-6 **Bank Withdrawal at Power – Unit 1, Minimum Reactivity Feedback – 100% Power – 1 pcm/sec - Vessel Average Temperature and DNBR Versus Time**

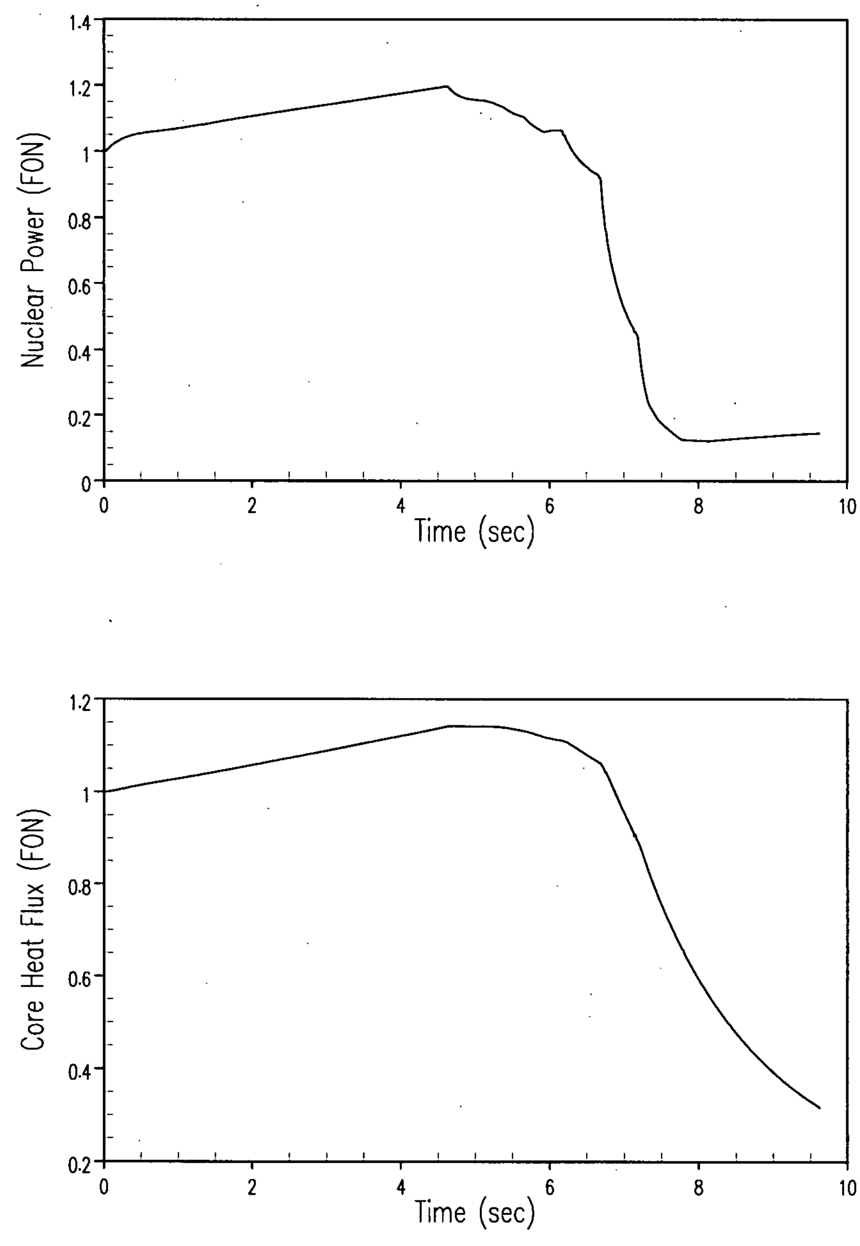
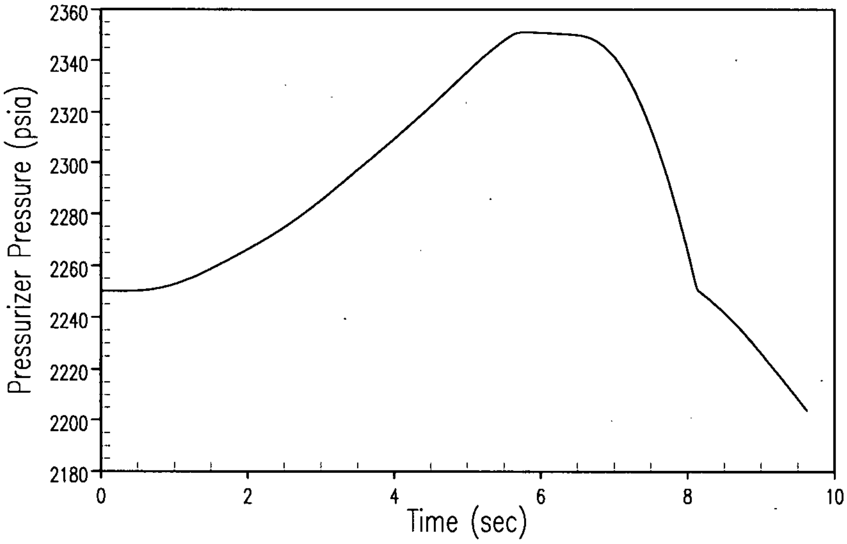


Figure 2.8.5.4.2-7 Bank Withdrawal at Power – Unit 1, Maximum Reactivity Feedback – 100% Power – 110 pcm/sec - Nuclear Power and Core Heat Flux Versus Time



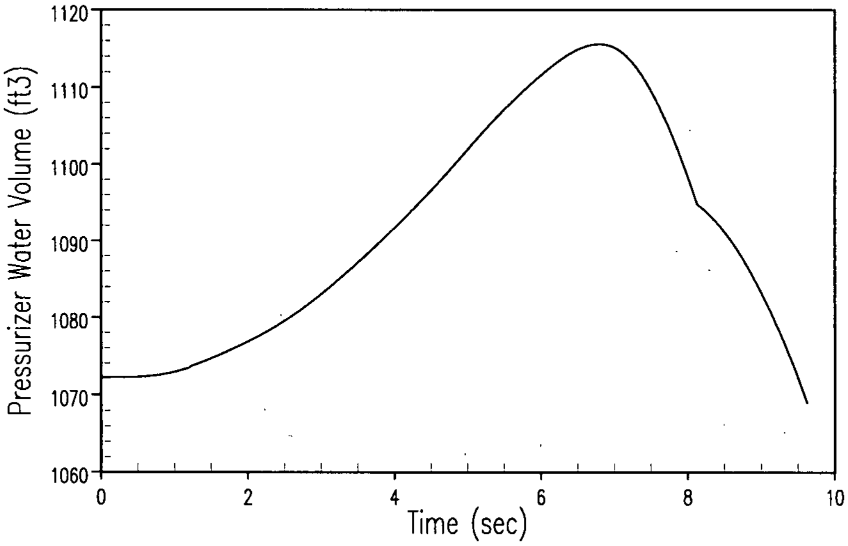


Figure 2.8.5.4.2-8 Bank Withdrawal at Power – Unit 1, Maximum Reactivity Feedback – 100% Power – 110 pcm/sec - Pressurizer Pressure and Water Volume Versus Time

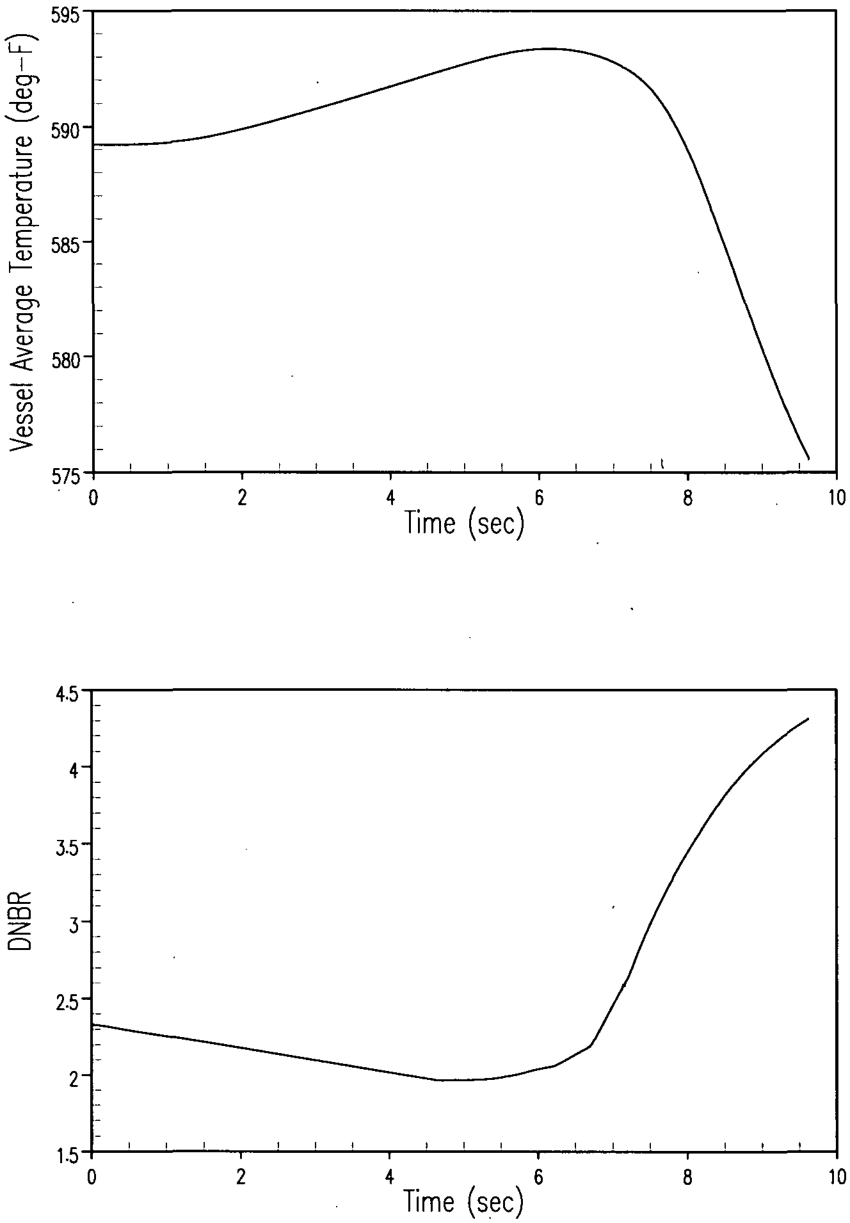
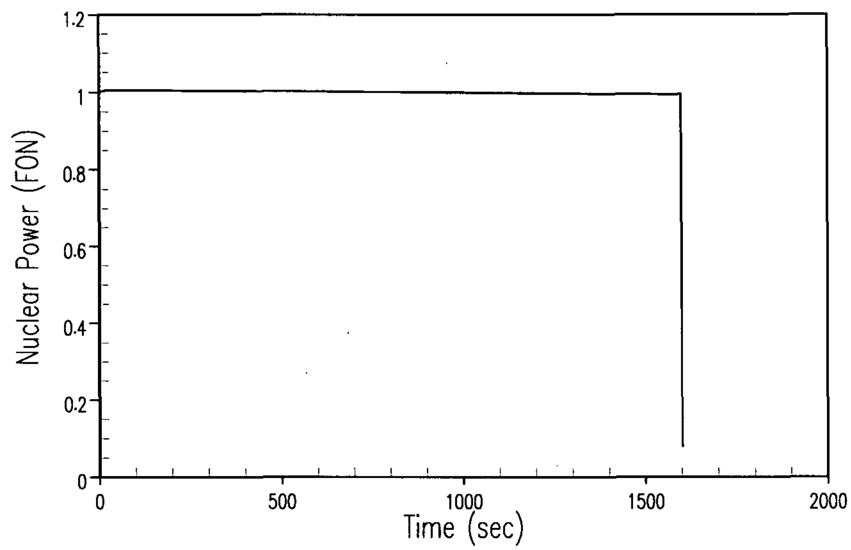


Figure 2.8.5.4.2-9 Bank Withdrawal at Power – Unit 1, Maximum Reactivity Feedback – 100% Power – 110 pcm/sec - Vessel Average Temperature and DNBR Versus Time



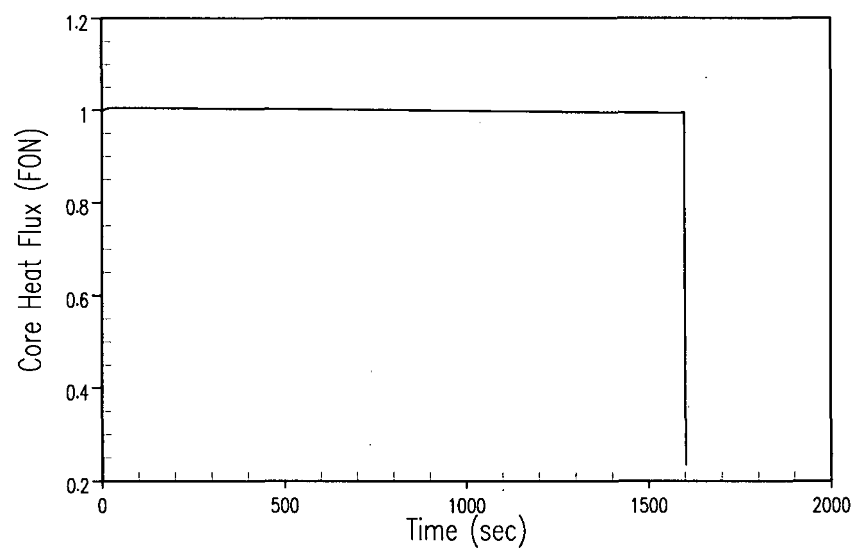
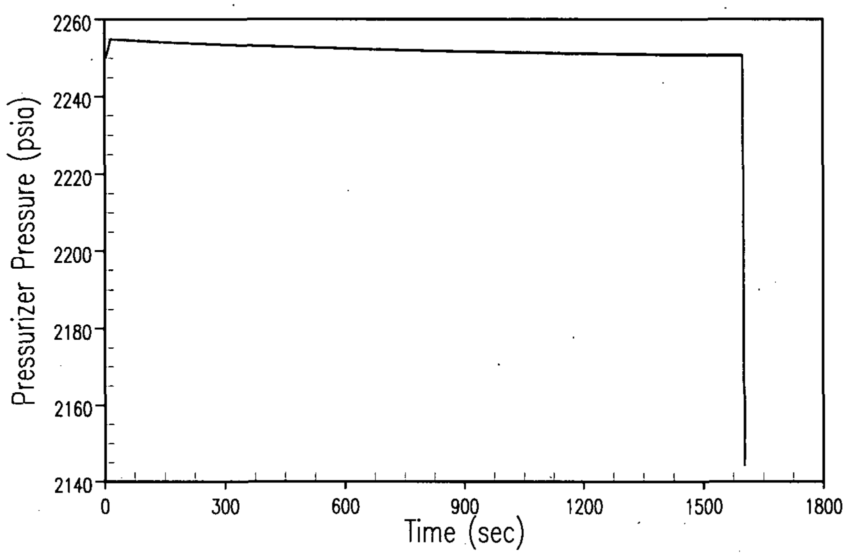


Figure 2.8.5.4.2-10 Bank Withdrawal at Power – Unit 1, Maximum Reactivity Feedback – 100% Power – 1 pcm/sec - Nuclear Power and Core Heat Flux Versus Time



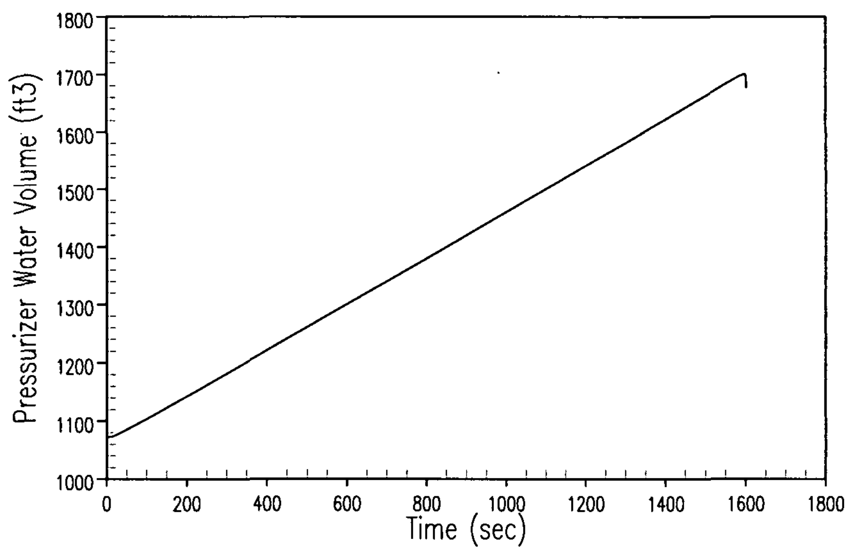


Figure 2.8.5.4.2-11 Bank Withdrawal at Power – Unit 1, Maximum Reactivity Feedback – 100% Power – 1 pcm/sec - Pressurizer Pressure and Water Volume Versus Time

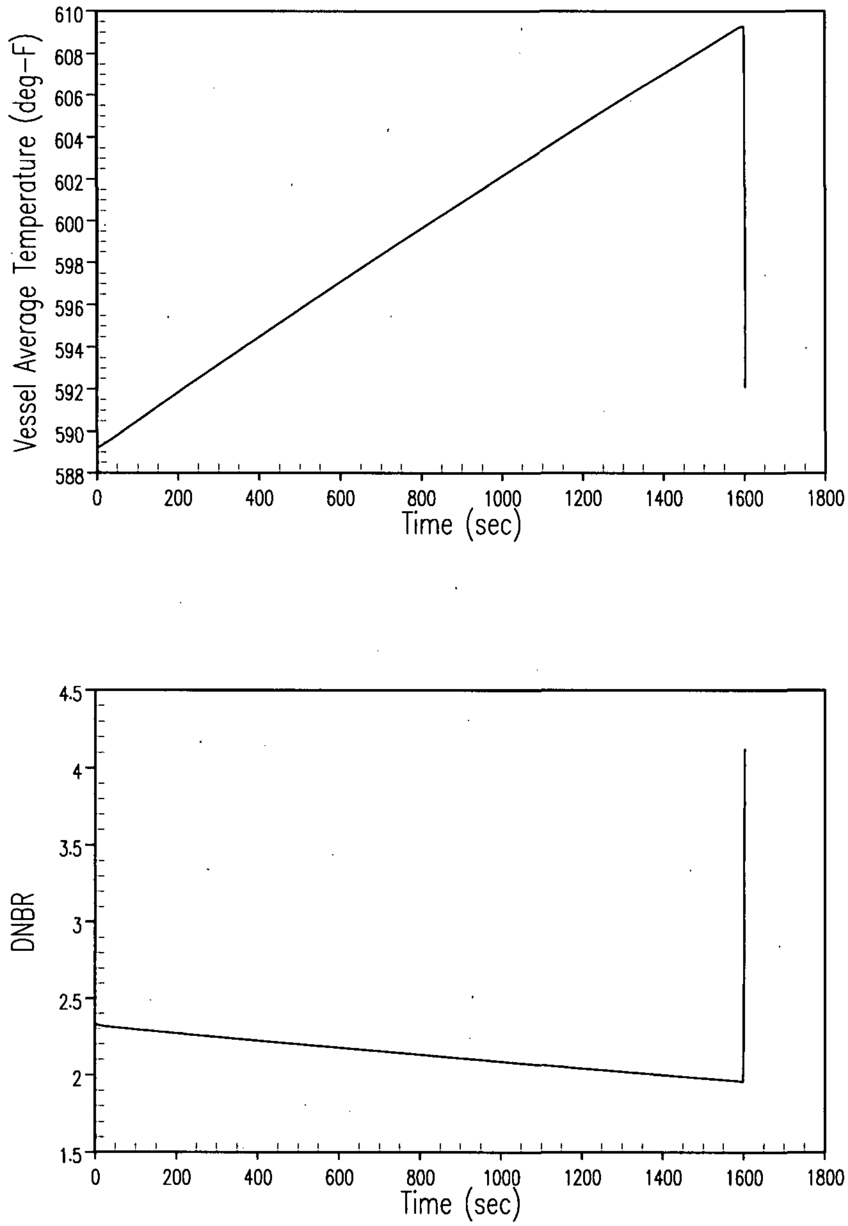


Figure 2.8.5.4.2-12 Bank Withdrawal at Power – Unit 1, Maximum Reactivity Feedback – 100% Power – 1 pcm/sec - Vessel Average Temperature and DNBR Versus Time

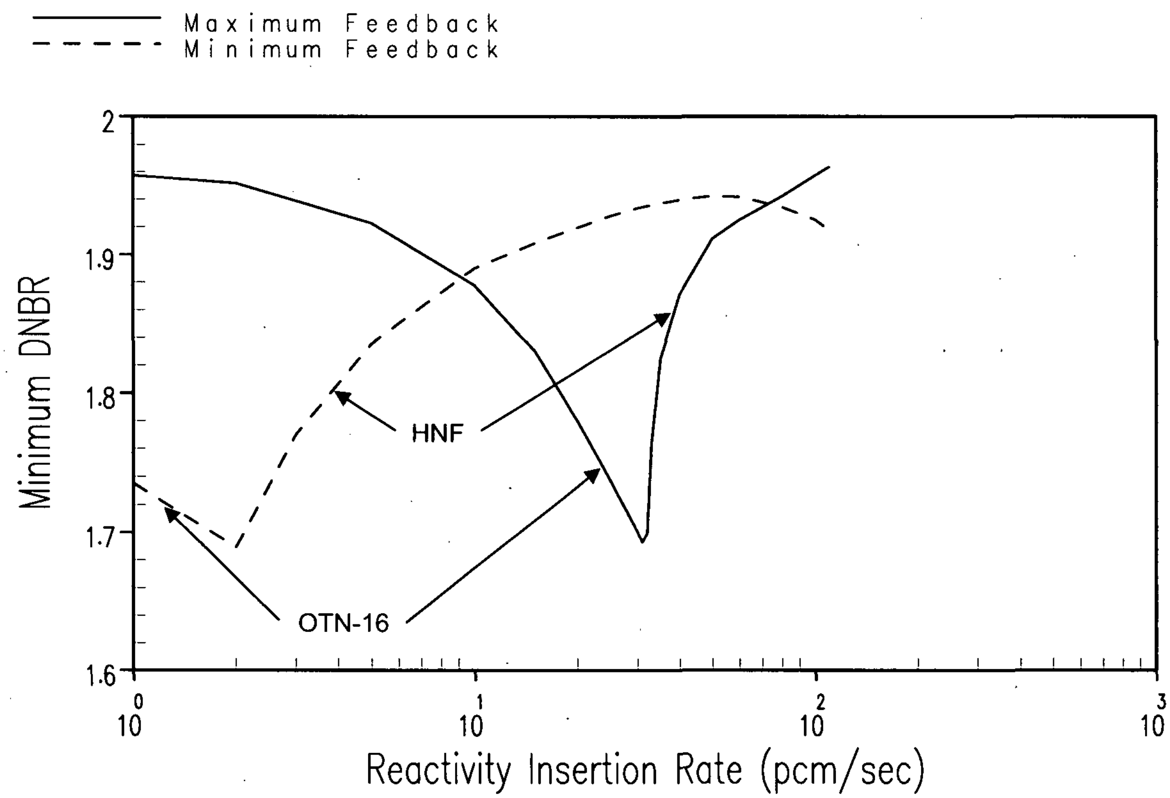


Figure 2.8.5.4.2-13 Bank Withdrawal at Power – Unit 1, 100% Power - Minimum DNBR Versus Reactivity Insertion Rate

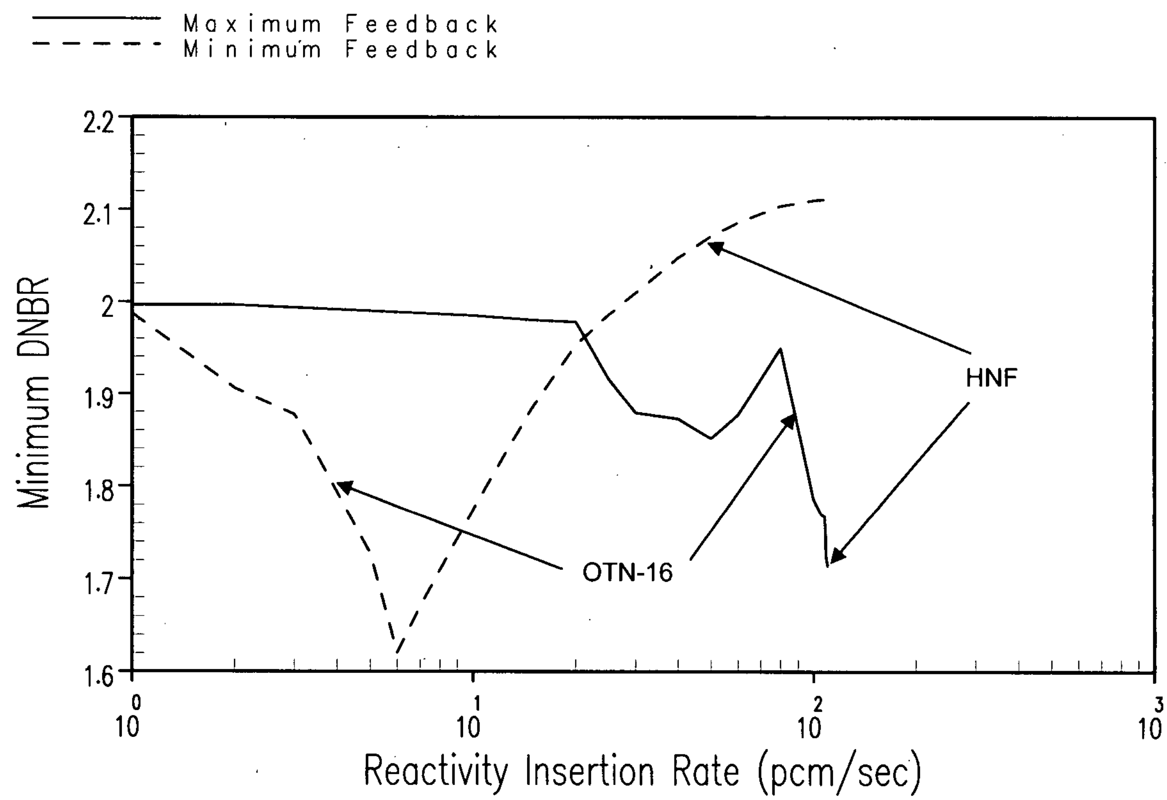


Figure 2.8.5.4.2-14 Bank Withdrawal at Power – Unit 1, 60% Power - Minimum DNBR Versus Reactivity Insertion Rate

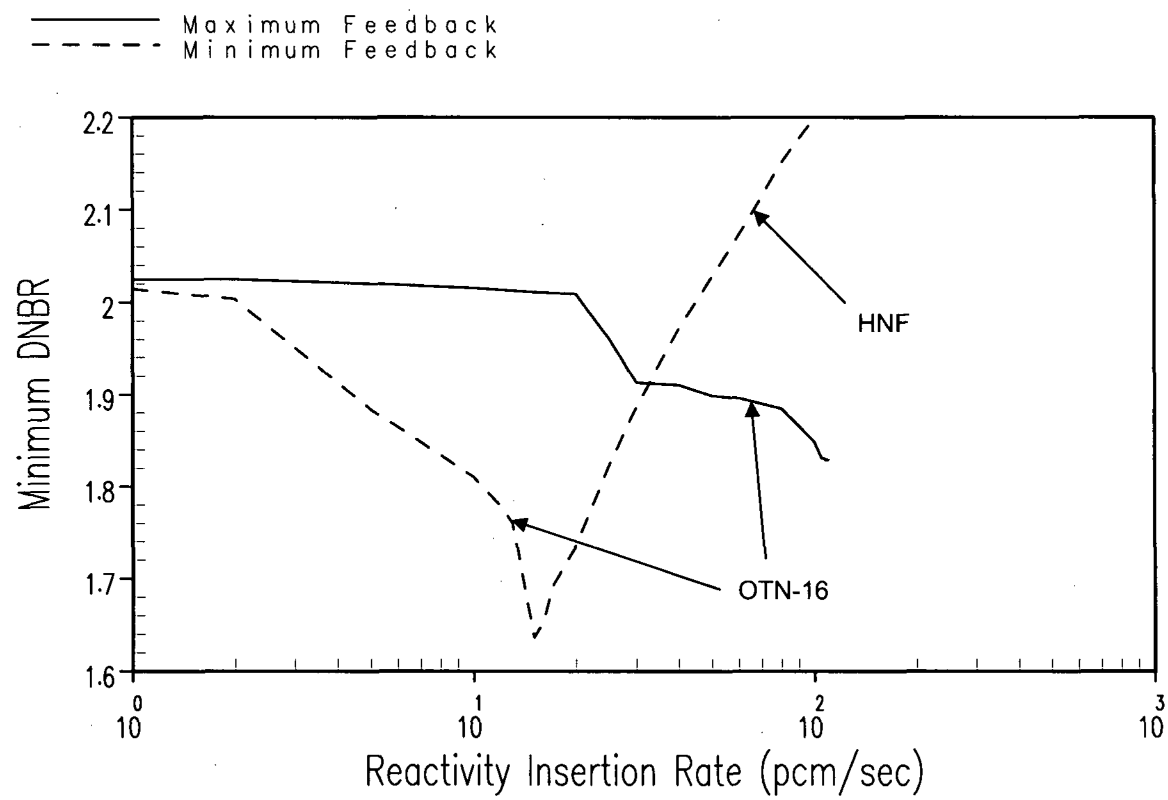


Figure 2.8.5.4.2-15 Bank Withdrawal at Power – Unit 1, 10% Power - Minimum DNBR Versus Reactivity Insertion Rate

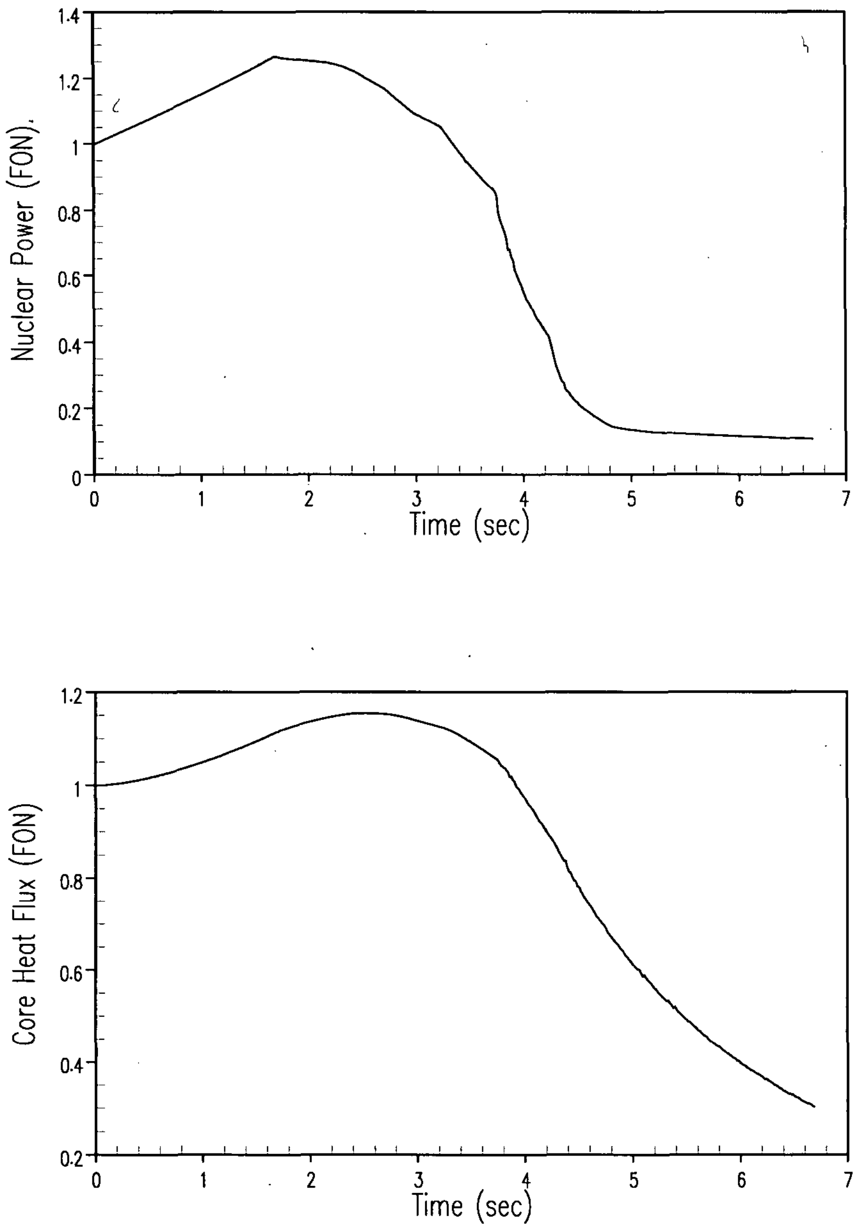


Figure 2.8.5.4.2-16 Bank Withdrawal at Power – Unit 2, Minimum Reactivity Feedback – 100% Power – 110 pcm/sec - Nuclear Power and Core Heat Flux Versus Time

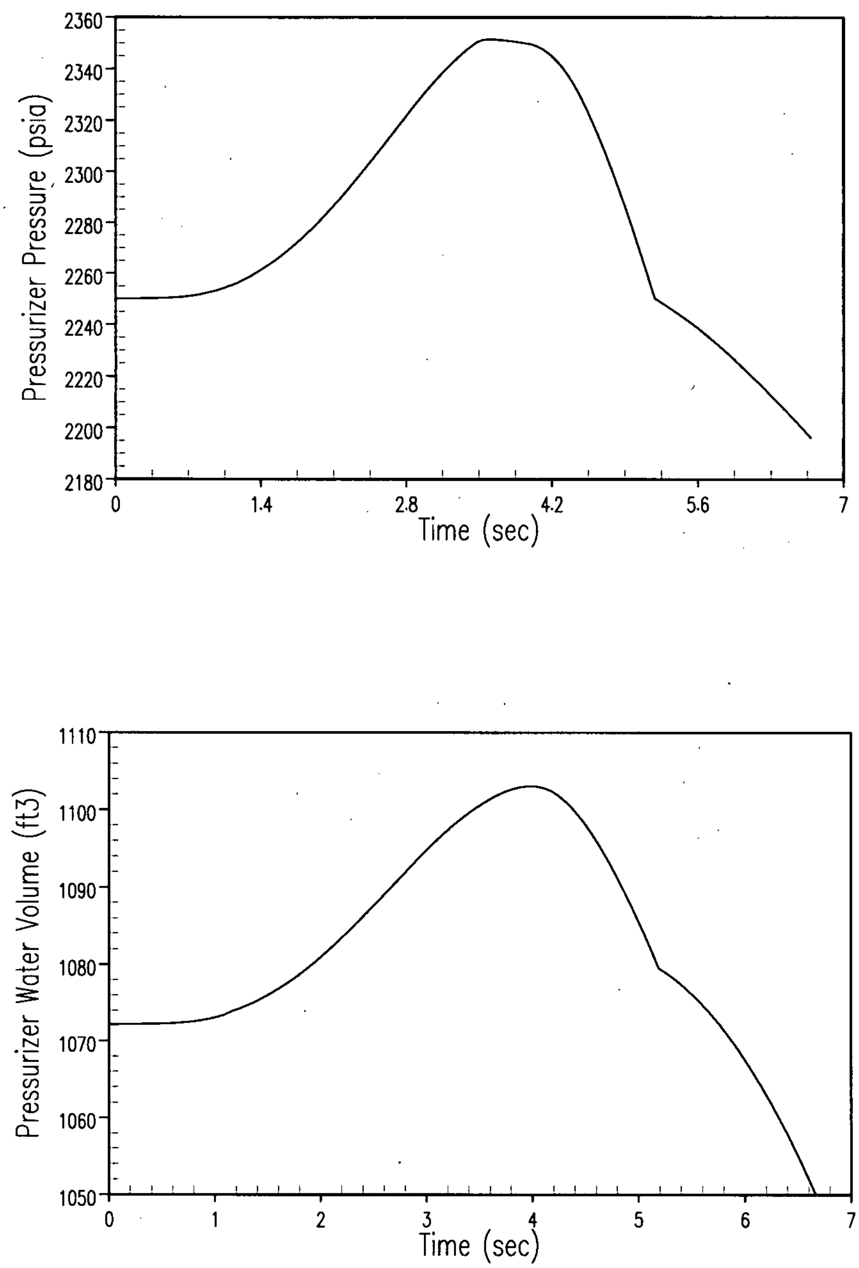


Figure 2.8.5.4.2-17 Bank Withdrawal at Power – Unit 2, Minimum Reactivity Feedback – 100% Power – 110 pcm/sec - Pressurizer Pressure and Water Volume Versus Time

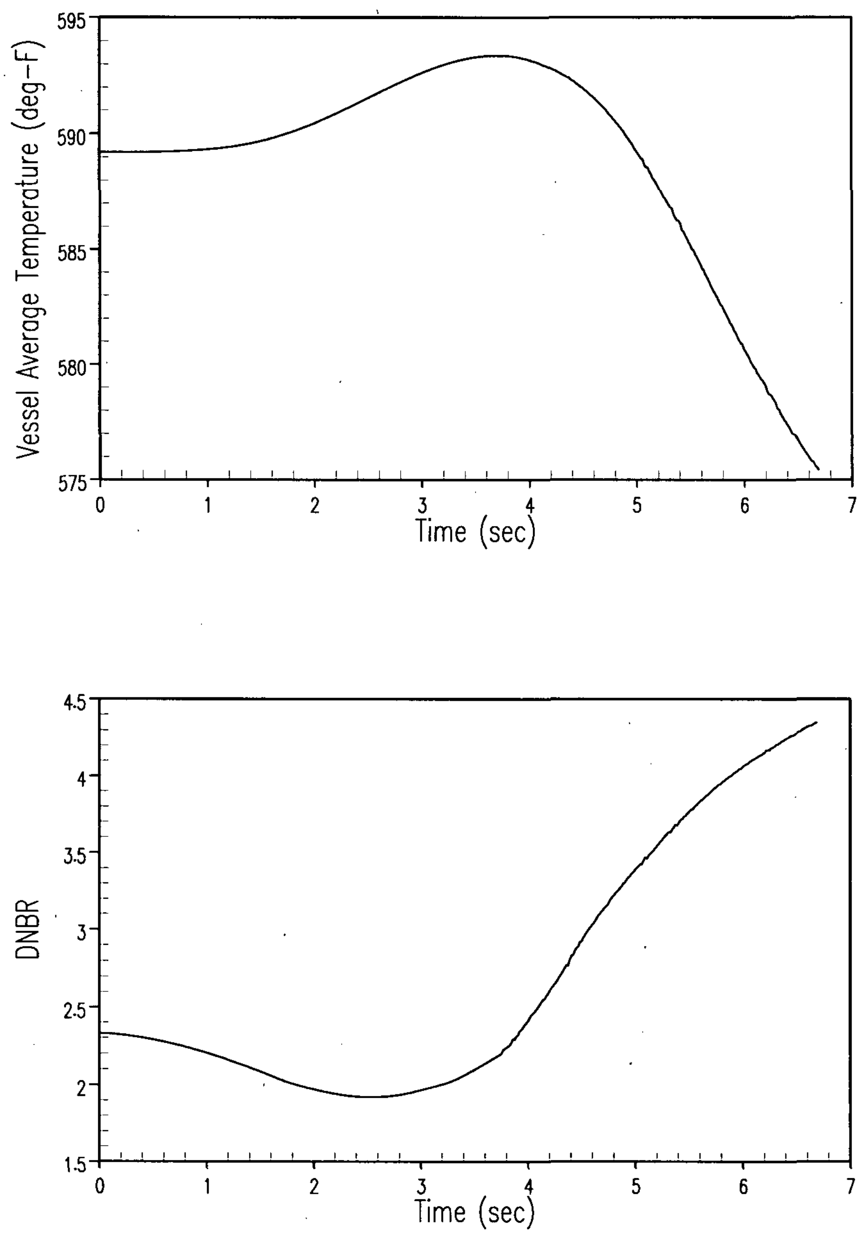


Figure 2.8.5.4.2-18 Bank Withdrawal at Power – Unit 2, Minimum Reactivity Feedback – 100% Power – 110 pcm/sec - Vessel Average Temperature and DNBR Versus Time

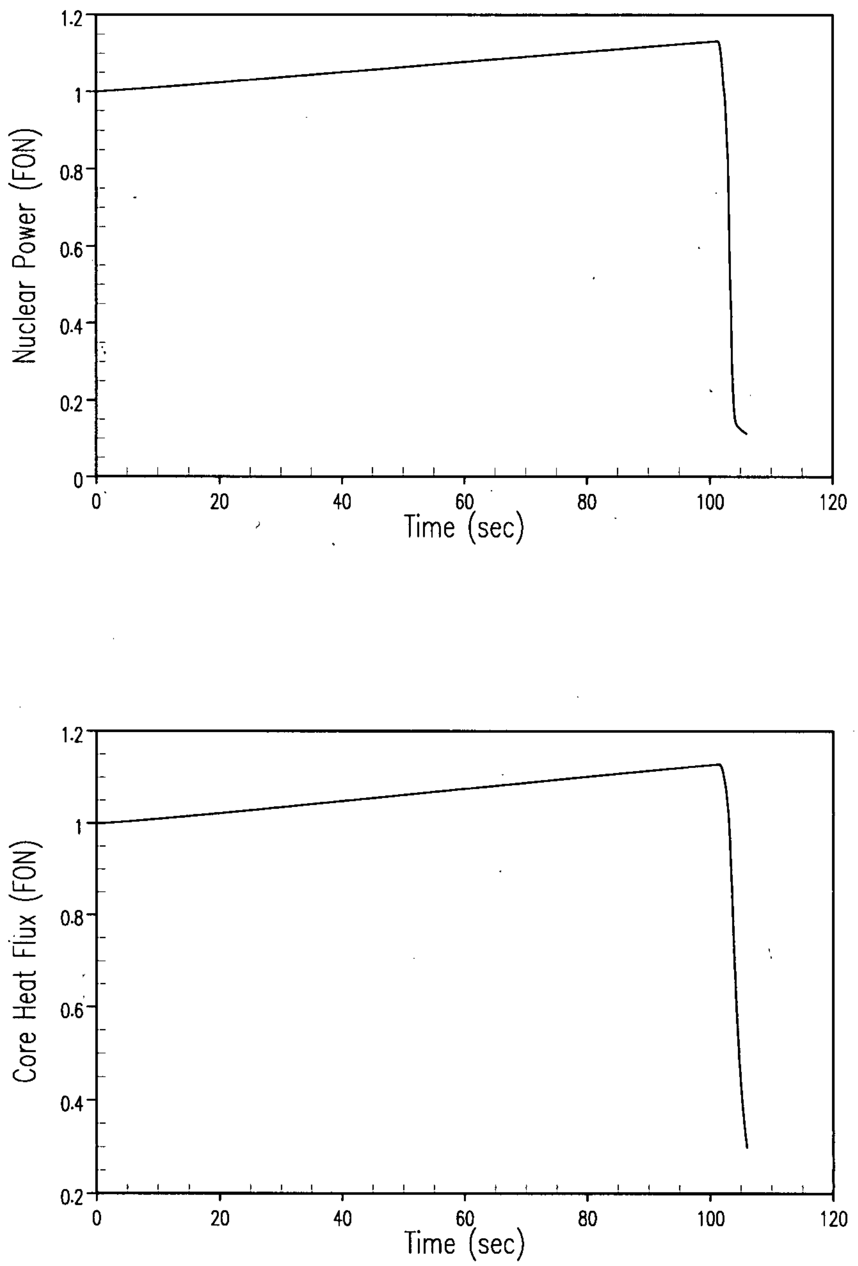


Figure 2.8.5.4.2-19 Bank Withdrawal at Power – Unit 2, Minimum Reactivity Feedback – 100% Power – 1 pcm/sec - Nuclear Power and Core Heat Flux Versus Time

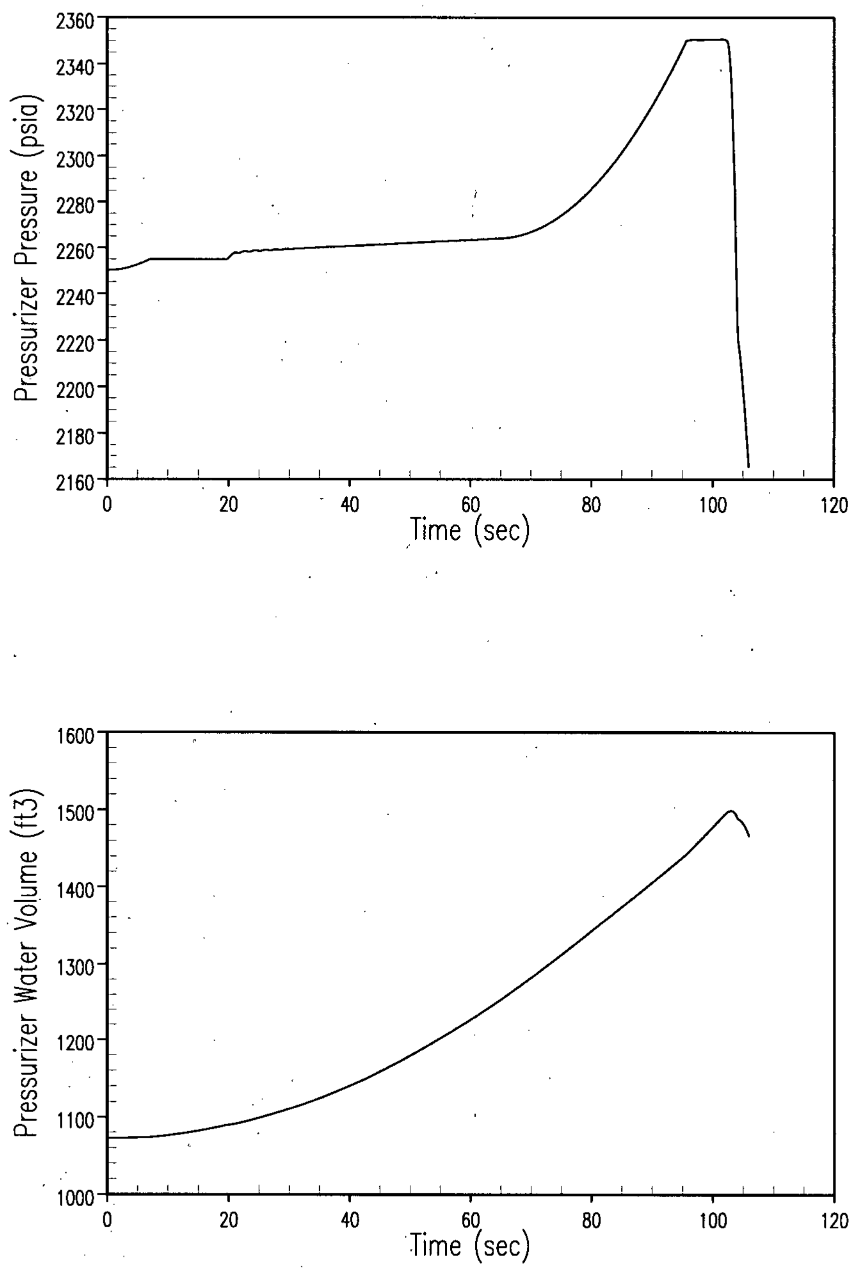
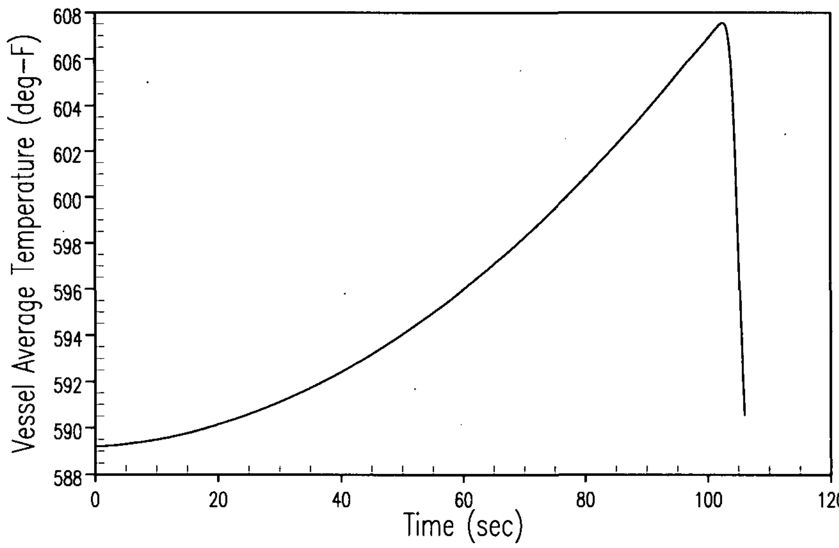


Figure 2.8.5.4.2-20 Bank Withdrawal at Power – Unit 2, Minimum Reactivity Feedback – 100% Power – 1 pcm/sec - Pressurizer Pressure and Water Volume Versus Time



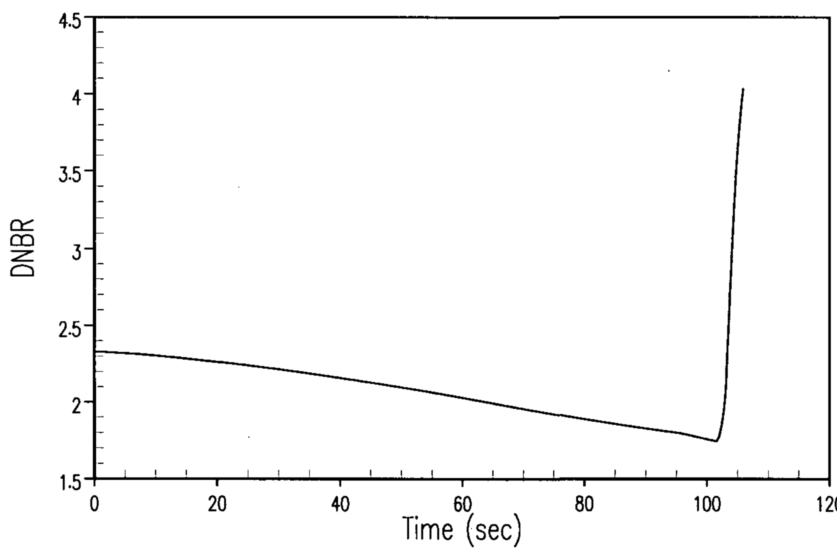


Figure 2.8.5.4.2-21 Bank Withdrawal at Power – Unit 2, Minimum Reactivity Feedback – 100% Power – 1 pcm/sec - Vessel Average Temperature and DNBR Versus Time

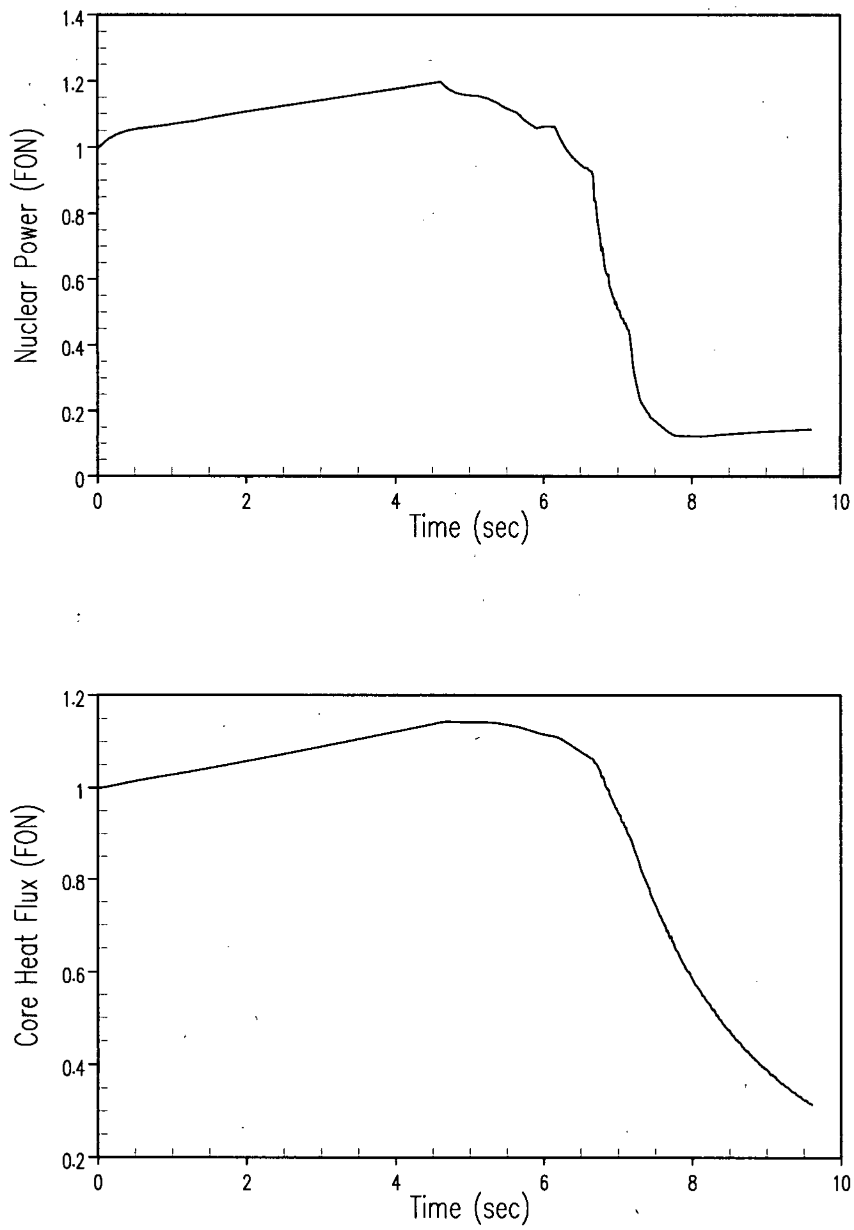


Figure 2.8.5.4.2-22 Bank Withdrawal at Power – Unit 2, Maximum Reactivity Feedback – 100% Power – 110 pcm/sec - Nuclear Power and Core Heat Flux Versus Time

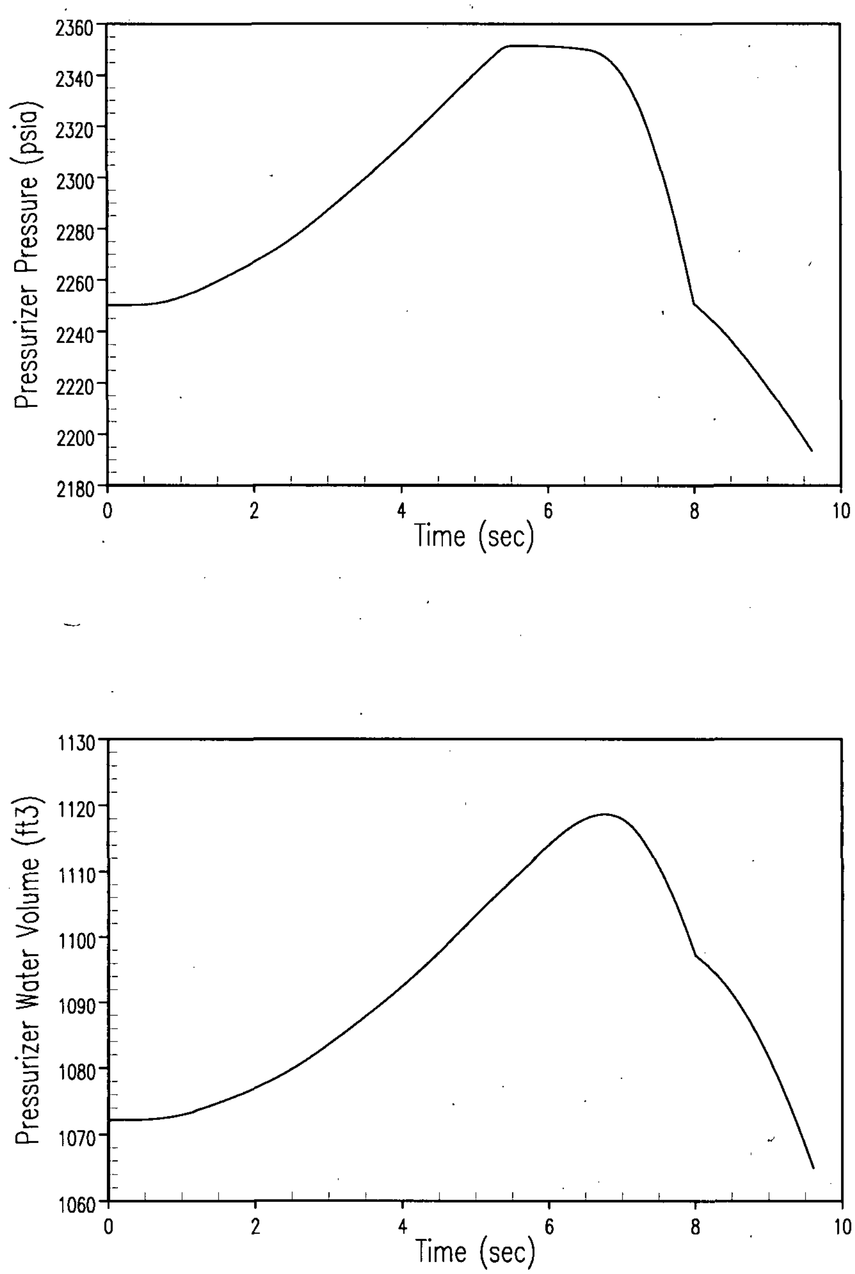


Figure 2.8.5.4.2-23 Bank Withdrawal at Power – Unit 2, Maximum Reactivity Feedback – 100% Power – 110 pcm/sec - Pressurizer Pressure and Water Volume Versus Time

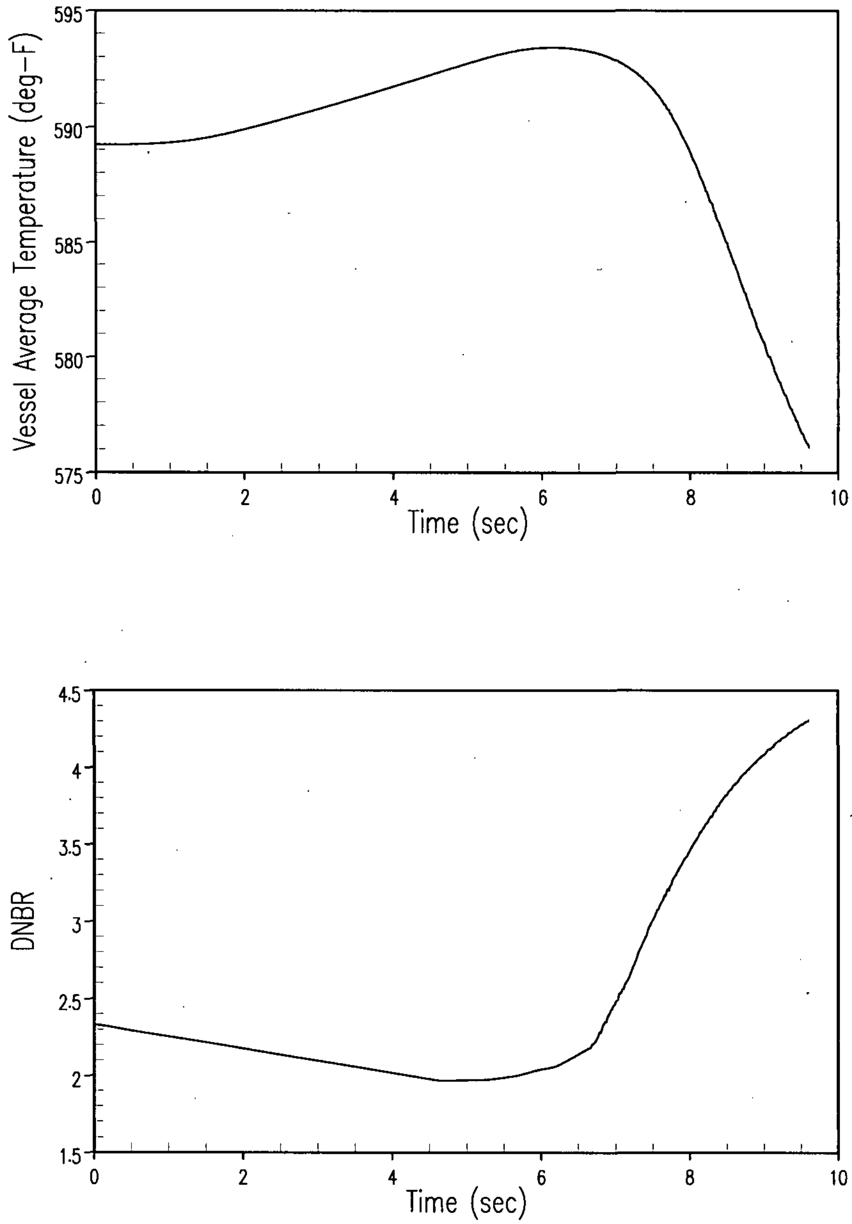


Figure 2.8.5.4.2-24 Bank Withdrawal at Power – Unit 2, Maximum Reactivity Feedback – 100% Power – 110 pcm/sec - Vessel Average Temperature and DNBR Versus Time

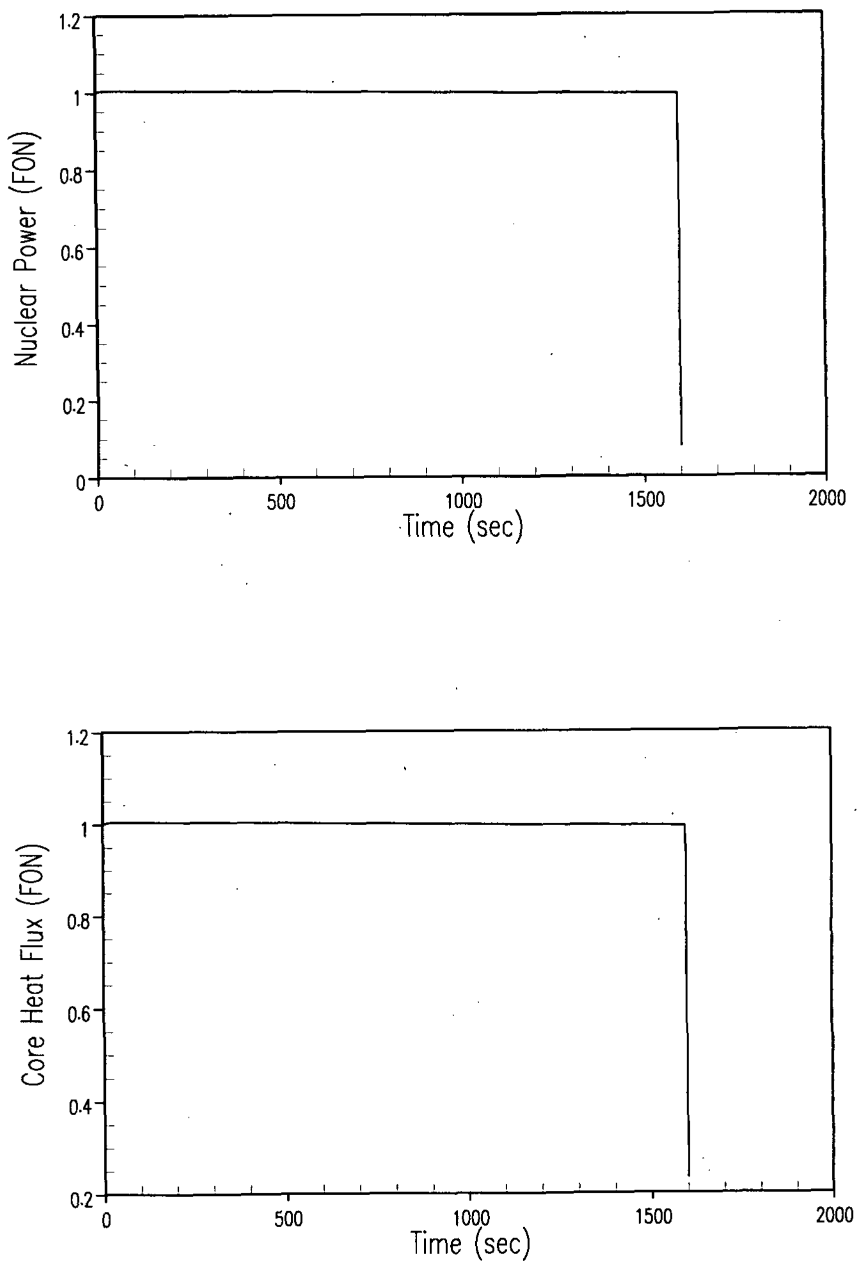
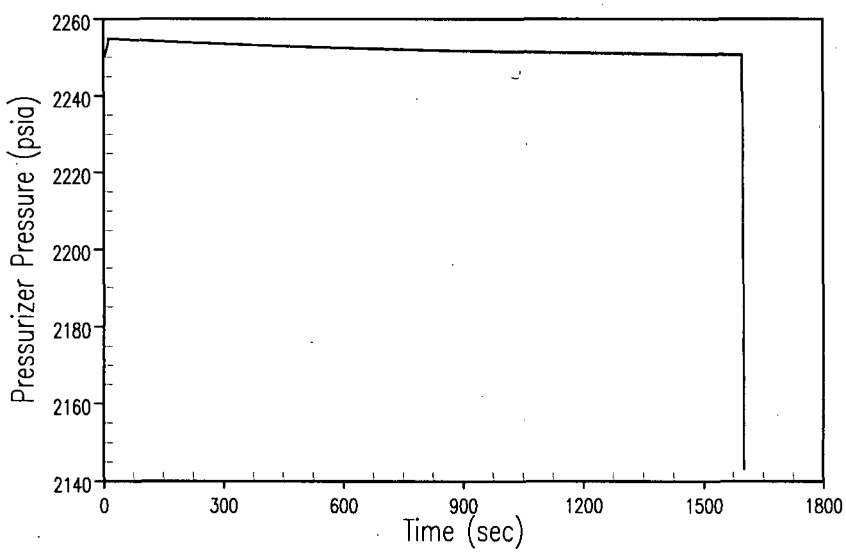


Figure 2.8.5.4.2-25 Bank Withdrawal at Power – Unit 2, Maximum Reactivity Feedback – 100% Power – 1 pcm/sec - Nuclear Power and Core Heat Flux Versus Time



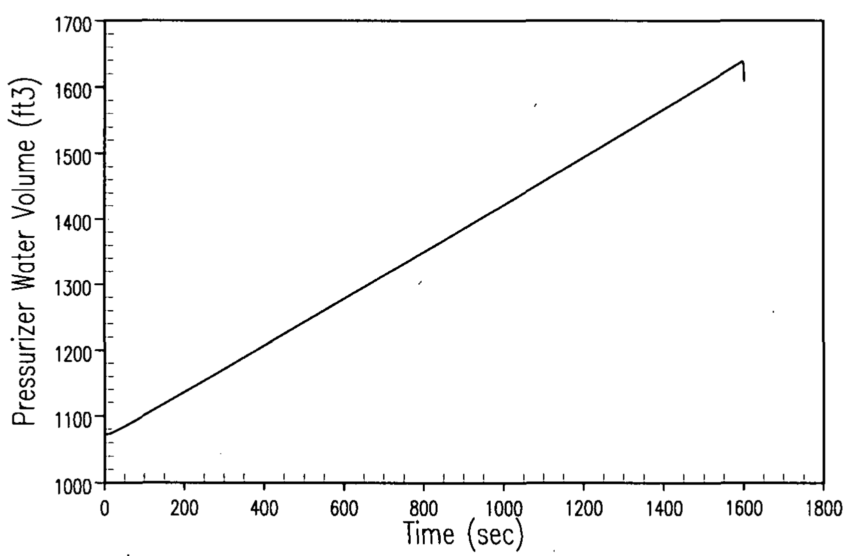


Figure 2.8.5.4.2-26 Bank Withdrawal at Power – Unit 2, Maximum Reactivity Feedback – 100% Power – 1 pcm/sec - Pressurizer Pressure and Water Volume Versus Time

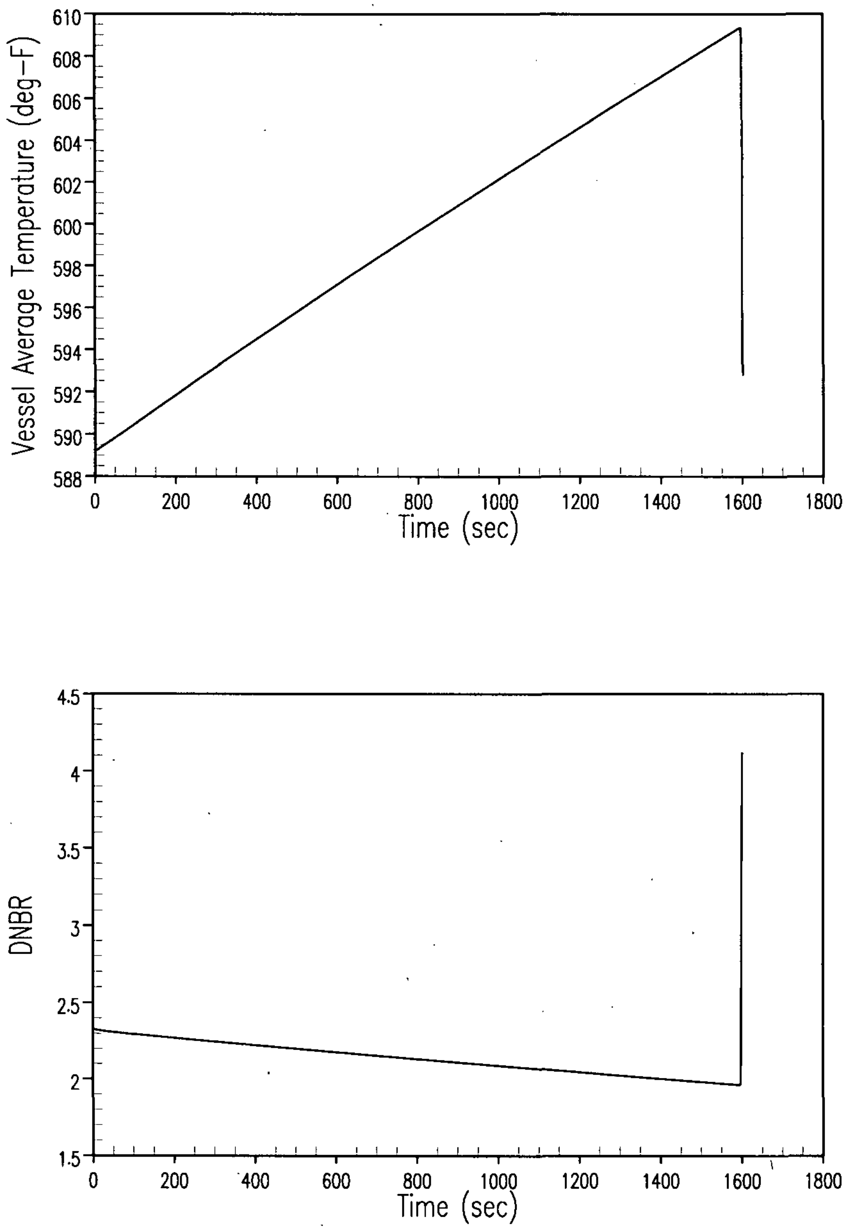


Figure 2.8.5.4.2-27 Bank Withdrawal at Power – Unit 2, Maximum Reactivity Feedback – 100% Power – 1 pcm/sec - Vessel Average Temperature and DNBR Versus Time

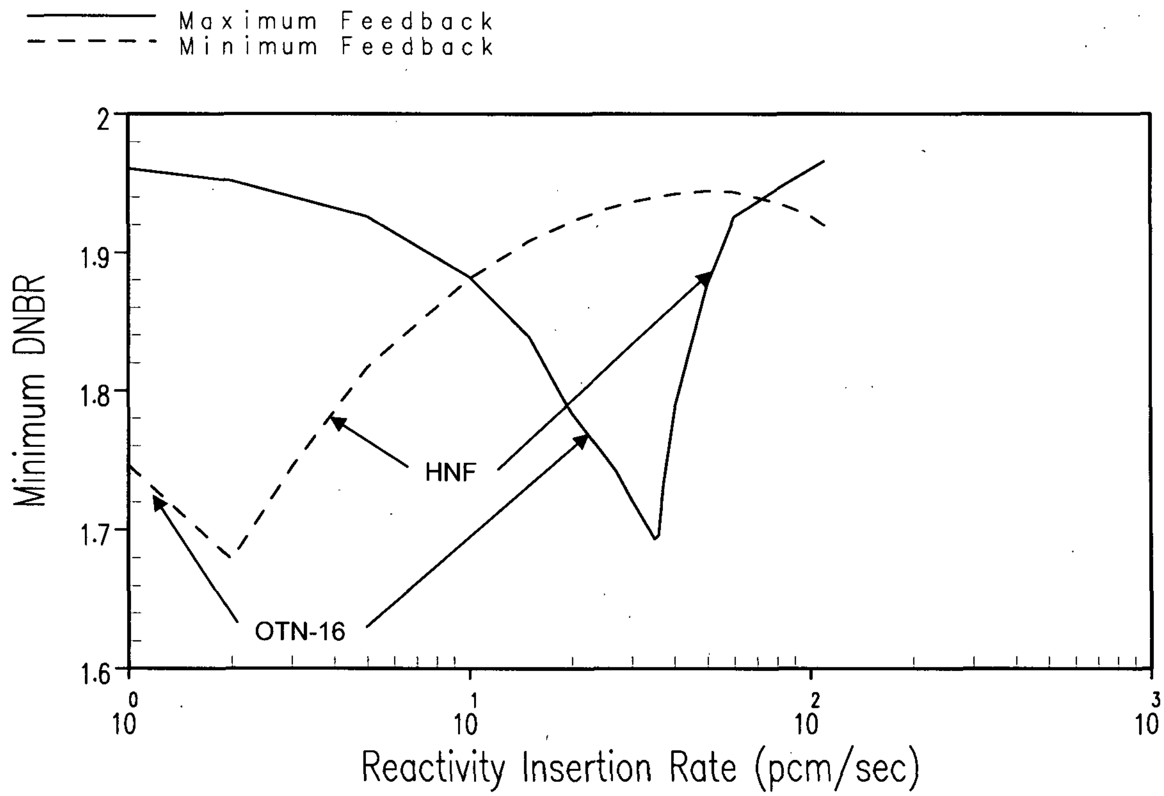


Figure 2.8.5.4.2-28 Bank Withdrawal at Power – Unit 2, 100% Power - Minimum DNBR Versus Reactivity Insertion Rate

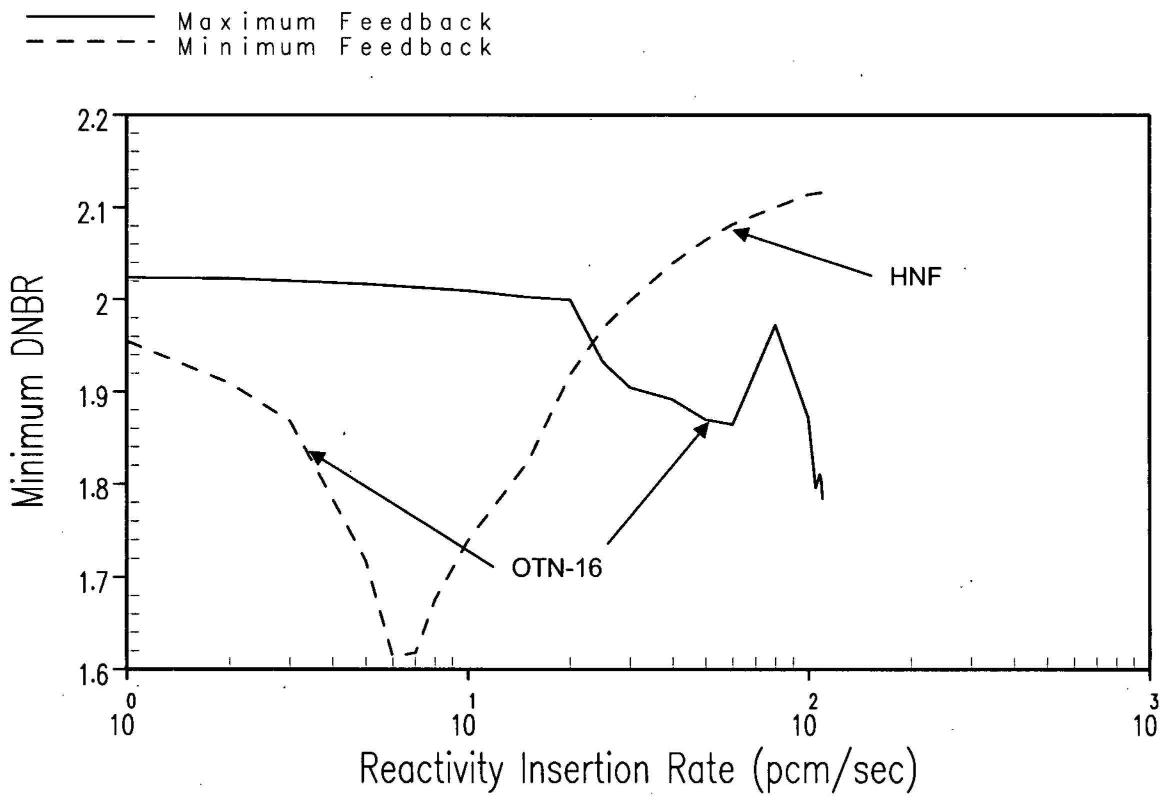


Figure 2.8.5.4.2-29 Bank Withdrawal at Power – Unit 2, 60% Power - Minimum DNBR Versus Reactivity Insertion Rate

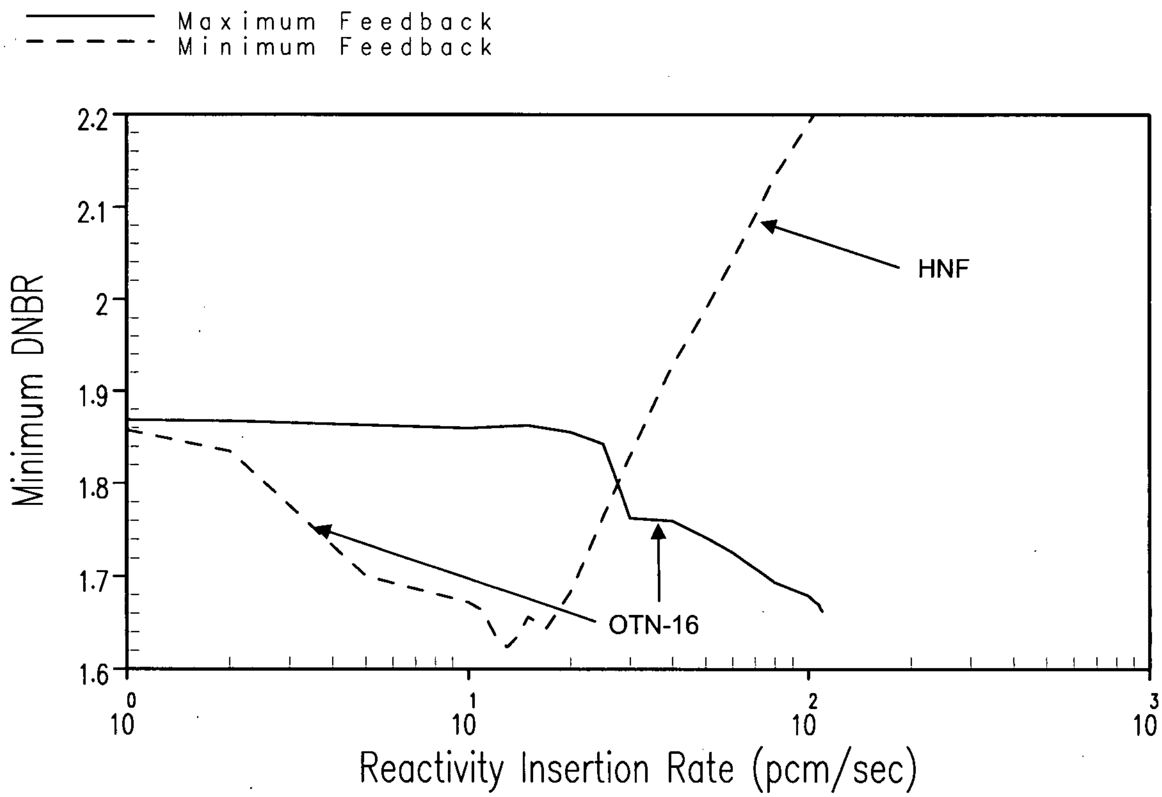


Figure 2.8.5.4.2-30 Bank Withdrawal at Power – Unit 2, 10% Power - Minimum DNBR Versus Reactivity Insertion Rate

Table 2.8.5.4.5-1
CVCS Malfunction Boron Dilution Event Results

Operating Mode	Available Operator Action Time (minutes)	Limit (minutes)
Mode 1 – Manual Rod Control	Unit 1: 54.0 Unit 2: 47.6	15
Mode 1 – Automatic Rod Control	Unit 1: 56.5 Unit 2: 49.8	15
Mode 2	Unit 1: 59.5 Unit 2: 52.5	15
Mode 3	The maximum critical boron concentration is controlled as a function of the plant initial boron concentration to meet a minimum operator action time of 15 minutes	15
Mode 4		15
Mode 5 – Drained		15
Mode 5 – Filled		15
Mode 6	N/A(1)	

Note:
1. No analysis is presented for Mode 6 operation since boron dilution during refueling is precluded by the Technical Specifications requirements.

ESBU

Westinghouse
Energy
Systems
Business
Unit

NUCLEAR SAFETY ADVISORY LETTER

151954

THIS IS A NOTIFICATION OF A RECENTLY IDENTIFIED POTENTIAL SAFETY ISSUE PERTAINING TO BASIC COMPONENTS SUPPLIED BY WESTINGHOUSE. THIS INFORMATION IS BEING PROVIDED TO YOU SO THAT A REVIEW OF THIS ISSUE CAN BE CONDUCTED BY YOU TO DETERMINE IF ANY ACTION IS REQUIRED.

P. O. Box 355, Pittsburgh, PA 15230-0355.

Subject: Operation at Reduced Power Levels with Inoperable MSSVs	**Number:** NSAL-94-001
Basic Component: Loss of Load/Turbine Trip Analysis for Plant Licensing Basis	**Date:** 01/20/94
Plants: See Enclosed List	

Substantial Safety Hazard or Failure to Comply Pursuant to 10 CFR 21.21(a)	Yes ☐	No ☒
Transfer of Information Pursuant to 10 CFR 21.21(b)	Yes ☐	
Advisory Information Pursuant to 10 CFR 21.21(c)(2)	Yes ☐	

SUMMARY

Westinghouse has identified a potential safety issue regarding plant operation within Technical Specification Table 3.7-1. This issue does not represent a substantial safety hazard for your plant pursuant to 10 CFR 21. However, this issue does represent a condition which may impact your plant's licensing basis.

Table 3.7-1 allows plants to operate with a reduced number of operable MSSVs at a reduced power level, as determined by the high neutron flux trip setpoint. The FSAR loss of load/turbine trip (LOL/TT) analysis from full power bounds the case where all MSSVs are operable. The FSAR (LOL/TT) event may not be bounding for the allowable operating configurations of Table 3.7-1 since the high neutron flux trip setpoint, which is identified in Table 3.7-1 for a corresponding number of inoperable MSSVs, may not be low enough to preclude a secondary side overpressurization condition. As a result, the basis for Table 3.7-1 may not be sufficient to preclude overpressurization of the secondary side of the steam generator.

Therefore, it is recommended that you review the enclosed information to determine the applicability of this issue to your plant. The enclosed information contains a more detailed description of the issue and identifies solutions that you may wish to pursue to address this issue. These solutions include, but are not limited to, a re-evaluation of the LOL/TT analysis and/or a change to Technical Specification Table 3.7-1.

Additional information, if required, may be obtained from the originator. Telephone 412-374-6460.

Originator: J.W. Fasnacht
J.W. Fasnacht
Strategic Licensing Issues

H. A. Sepp, Manager
Strategic Licensing Issues

Plants Affected

D. C. Cook 1 & 2
J. M. Farley 1 & 2
Byron 1 & 2
Braidwood 1 & 2
V. C. Summer 1
Zion 1 & 2
Shearon Harris 1
W. B. McGuire 1 & 2
Catawba 1 & 2
Beaver Valley 1 & 2
Turkey Point 3 & 4
Vogtle 1 & 2
Indian Point 2 & 3
Seabrook 1
Millstone 3
Diablo Canyon 1 & 2
Wolf Creek
Callaway 1
Comanche Peak 1 & 2
South Texas 1 & 2
Sequoyah 1 & 2
North Anna 1 & 2
Watts Bar 1 & 2
Sizewell B
Kori 1, 2, 3 & 4
Yonggwang 1 & 2
Salem 1 & 2

Issue Description

Westinghouse has identified a deficiency in the basis for Technical Specification 3.7.1.1. This Technical Specification allows the plant to operate at a reduced power level with a reduced number of operable Main Steam Safety Valves (MSSVs). The deficiency is in the assumption that the maximum allowable initial power level is a linear function of the available MSSV relief capacity. The linear function is identified in the Bases Section for Technical Specification 3/4.7.1.1 and is provided as follows:

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

SP	=	Reduced reactor trip setpoint in % of RATED THERMAL POWER
V	=	Maximum number of inoperable safety valves per steam line
X	=	Total relieving capacity of all safety valves per steam line in lbm/hour
Y	=	Maximum relieving capacity of any one safety valve in lbm/hour
(109)	=	Power range neutron flux-high trip setpoint for all loops in operation

Under certain conditions and with typical safety analysis assumptions, a Loss of Load/Turbine Trip transient from part-power conditions may result in overpressurization of the main steam system when operating in accordance with this Technical Specification. The following discussion describes the issue in more detail and provides recommended alternatives for addressing the issue.

Technical Evaluation

The Loss of Load/Turbine Trip (LOL/TT) event is analyzed in the FSAR to show that core protection margins are maintained (DNBR), the RCS will not overpressurize, and the main steam system will not overpressurize. The analysis assumes an immediate loss of steam relieving capability through the turbine and coincident loss of all main feedwater. No credit is taken for the direct reactor trip on turbine trip, since this trip would not be actuated for the case of a loss of steam load. Rather, the transient is terminated by a reactor trip on high pressurizer pressure, overtemperature ΔT, or low steam generator water level. Secondary side overpressure protection is provided by actuation of the Main Steam Safety Valves (MSSVs), which are designed to relieve at least full power nominal steam flow. The analysis verifies that the MSSV capacity is sufficient to prevent secondary side pressure from exceeding 110 percent of the design pressure.

The FSAR only analyzes the LOL/TT transient from the full power initial condition, with cases examining the effects of assuming primary side pressure control and different reactivity feedback conditions. With fully operational MSSVs, it can be demonstrated that overpressure protection is provided for all initial power levels. However, for most plants, Technical Specification 3.7.1.1 allows operation with a reduced number of operable MSSVs at a reduced power level as determined by resetting the power range high neutron flux setpoint. This Technical Specification is not based on a detailed analysis, but rather on the assumption that the maximum allowable initial power level is a linear function of the available MSSV relief capacity. Recently, it has been determined that this assumption is not valid.

The problem is that if main feedwater is lost, a reactor trip is necessary to prevent secondary side overpressurization for all postulated core conditions. At high initial power levels a reactor trip is actuated early in the transient as a result of either high pressurizer pressure or overtemperature ΔT. The reactor trip terminates the transient and the MSSVs maintain steam pressure below 110% of the design value.

At lower initial power levels a reactor trip may not be actuated early in the transient. An overtemperature ΔT trip isn't generated since the core thermal margins are increased at lower power levels. A high pressurizer pressure trip isn't generated if the primary pressure control systems function normally. This results in a longer time during which primary heat is transferred to the secondary side. The reactor eventually trips on low steam generator water level, but this may not occur before steam pressure exceeds 110% of the design value if one or more MSSVs are inoperable in accordance with the Technical Specification.

Due to the wide variety of plant design features that are important to the LOL/TT analysis, it is difficult to perform a generic evaluation to show that the issue does not apply to certain plants. The following key parameters have a significant effect on the secondary side pressure transient:

- MSSV relief capacity
- Moderator Temperature Coefficient (MTC)
- Margin between the MSSV set pressures (including tolerance) and the overpressure limit
- Low-low steam generator water level reactor trip setpoint

Safety Significance

The Technical Specifications for most plants allow operation at a reduced power level with inoperable MSSVs. From a licensing basis perspective, this condition may result in secondary side overpressurization in the event of a LOL/TT transient. The licensing basis for anticipated operational occurrences (ANS Condition II events) typically requires that the secondary side pressure remain below 110% of the design value.

Westinghouse has determined that this issue does not represent a substantial safety hazard. There are several mitigating factors which provide assurance that there is no loss of safety function to the extent that there is a major reduction in the degree of protection provided to the public health and safety. These include, but are not limited to, the following:

1. Adequate overpressure protection is provided at all power levels if all of the MSSVs are operable.

2. If a reactor trip does not occur but main feedwater flow is maintained, operation in accordance with the Technical Specification Table 3.7-1 will not result in an overpressure condition.

3. In any LOL/TT transient, the atmospheric steam dump valves and/or condenser steam dump valves actuate to relieve energy from the steam generators prior to the opening of the MSSVs, and continue to relieve steam if the MSSVs do open. Since it is not a safety-grade function, steam dump is not assumed to operate in the safety analysis; however, in reality it is the first line of defense in protecting the secondary system against overpressurization. It is very improbable that all these components would be inoperable coincident with inoperable MSSVs.

4. Even near the beginning of core life with a positive or zero MTC, the primary coolant heatup resulting from the transient would tend to drive the MTC negative, which would reduce the core power and heat input to the coolant. This would result in a lower required MSSV capacity to prevent secondary overpressurization. The safety analysis does not credit the reduction of MTC during the transient.

NRC Awareness / Reportability

Westinghouse has not notified the NRC of this issue, based upon the determination that it does not represent a substantial safety hazard pursuant to 10 CFR 21. However, Westinghouse will send a copy of this letter to the NRC since this issue impacts information contained in NUREG-1431, "Standard Technical Specifications, Westinghouse Plants".

Recommendations

To address this issue, the following actions may be considered:

(1) Modify Technical Specification 3.7.1.1 (or equivalent) and the associated basis such that the maximum power level allowed for operation with inoperable MSSVs is below the heat removing capability of the operable MSSVs. A conservative way to do this is to set the power range high neutron flux setpoint to this power level, thus ensuring that the actual power level cannot exceed

this value. To calculate this setpoint, the governing equation is the relationship $q = m\ \Delta h$, where q is the heat input from the primary side, m is the steam flow rate and Δh is the heat of vaporization at the steam relief pressure (assuming no subcooled feedwater). Thus, an algorithm for use in defining the revised Technical Specification table setpoint values would be:

$$\text{Hi}\ \phi = (100/Q)\ \frac{(w_s h_{fg} N)}{K}$$

where:

Hi ϕ = Safety Analysis power range high neutron flux setpoint, percent

Q = Nominal NSSS power rating of the plant (including reactor coolant pump heat), Mwt

K = Conversion factor, 947.82 $\frac{\text{(Btu/sec)}}{\text{Mwt}}$

w_s = Minimum total steam flow rate capability of the operable MSSVs on any one steam generator at the highest MSSV opening pressure including tolerance and accumulation, as appropriate, in lb/sec. For example, if the maximum number of inoperable MSSVs on any one steam generator is one, then w_s should be a summation of the capacity of the operable MSSVs at the highest operable MSSV operating pressure, excluding the highest capacity MSSV. If the maximum number of inoperable MSSVs per steam generator is three then w_s should be a summation of the capacity of the operable MSSVs at the highest operable MSSV operating pressure, excluding the three highest capacity MSSVs.

h_{fg} = heat of vaporization for steam at the highest MSSV opening pressure including tolerance and accumulation, as appropriate, Btu/lbm

N = Number of loops in plant

The values calculated from this algorithm must then be adjusted lower for use in Technical Specification 3.7.1.1 to account for instrument and channel uncertainties (typically 9% power). The maximum plant operating power level would then be lower than the reactor protection system setpoint by an appropriate operating margin.

It should be noted that the use of this equation will resolve the issue identified in this letter by enabling you to re-calculate your Technical Specification 3.7.1.1 setpoints without further modifications to the structure of the Technical Specification. The re-calculated setpoints are likely to be lower than those currently allowed by the Technical Specification. However, you should be aware of at least two conservatisms with the equation. You may wish to review these conservatisms to evaluate the use of the equation relative to your plant specific operating objectives. It is possible to relax some of these conservatisms for use in the Technical Specification. However, relaxation of the conservatisms are likely to result in more significant changes to the structure of the Technical Specification.

First, the above equation (and the existing Technical Specification 3.7.1.1) is conservative since it is based on the maximum number of inoperable MSSVs per loop. For example, a representative four loop plant, in accordance with the current Technical Specification, should reduce the neutron flux setpoint to 87% if it has up to one inoperable MSSV on each loop. This means that the plant should use this setpoint whether there are one, two, three or four inoperable MSSVs, as long as there is only one inoperable MSSV per loop. Thus, the existing Technical Specification and the above equation are conservative and bounding. However, any relaxation of this conservatism must be interpreted with care. The reason is that the steam generators must be protected from an overpressurization condition during a loss of load transient. There are several events that could lead to a loss of load, including the inadvertent closure of one or all MSIVs. The affected steam generator must have a sufficient number of operable MSSVs to protect it from an overpressurization condition, if the MSIV (or MSIVs) was inadvertently closed.

Another conservatism in the above equation (and the existing Technical Specification 3.7.1.1) is in w_S, which is the minimum total steam flow rate capability of the operable MSSVs on any one steam generator. This value is conservative since it assumes that if one or more MSSVs are inoperable per loop, the inoperable MSSVs are the largest capacity MSSVs, regardless of whether the largest capacity MSSVs or the smaller capacity MSSVs are inoperable. The assumption has been made so that the above equation is consistent with the current structure of Technical Specification 3.7.1.1.

(2) As an alternative, plant-specific LOL/TT analyses could be performed to maximize the allowable power level for a given number of inoperable MSSVs. Depending on key specific plant parameters, these analyses may be able to justify the continued validity of the current Technical Specification.

(3) Consider modifying, as required, the Bases Section for Technical Specification 3/4.7.1.1 so that it is consistent with the plant safety analysis. The safety analysis criterion for preventing overpressurization of the secondary side is that the pressure does not exceed 110% of the design pressure for anticipated transients. However, in reviewing several plant technical specifications,

it was noted that the bases for some plants state that the safety valves insure that the secondary system pressure will be limited to within 105 or even 100% of design pressure. This is not consistent with the safety analysis basis and should be revised to indicate 110%.

TXU Electric Delivery

TXU Electric Delivery
2233-B Mountain Creek Pkwy
Dallas, TX 75211-6716
Tel: 214 743 6845
Fax: 972 263 6710
jlewis5 @txued.com

Jacob L. Lewis
Transmission Services Consultant
Transmission Services

April 24,2007

Jeffrey J. LaMarca
W Generation Company LP
Comanche Peak, E17
P.O. Box 1002
Glen Rose, Texas 76043

Subject: Steady-State and Stability Studies

Re: ERCOT Generation Interconnection Request No. 09INR0015

Dear: Mr. LaMarca:

TXU Generation Company LP submitted Generation Interconnection Request No. GIR 09INR2006 to ERCOT for the following increase in generation capability at Comanche Peak Steam Electric Station (CPSES): Unit #1: 49 MW summer (49 MW winter) by Fall 2008; and Unit #2: 37 MW summer (37 MW winter) by Fall 2009 connected to the TXUED 345 kV transmission system in Somervell County.

In 2002 TXU Electric Delivery Company (TXUED) Transmission Planning performed both steady-state and stability studies of the Comanche Peak area transmission system. These studies included detailed analyses of (1) thermal limits of the transmission system, and (2) stability based limitations of Comanche Peak, DeCordova and Wolf Hollow generation during both normal transmission system operating conditions and major transmission circuit outages.

Since these studies were performed there have been no generation additions to the Comanche Peak area. In 2003 the Comanche Switch-Red Creek-Morgan Creek 345 kV transmission circuit was completed. This transmission circuit addition benefits the Comanche Peak area generation from both a system thermal and stability perspective. In addition, the Johnson Switch-Venus 345 kV circuit and the DeCordova-Everman 345 kV circuit were upgraded in 2006 providing additional thermal getaway capacity for CPSES. Also, based on a recent review of the ERCOT SSWG base cases, transmission circuit line capacities were sufficient to handle the proposed increase in generation capability at CPSES.

Based on the forgoing analysis, TXUED Transmission Planning will not perform additional steady-state or stability studies for the referenced Generation Interconnection Request.

Sincerely,

CIRCUIT BREAKER INTERRUPTING DUTY STUDY

FOR

GENERATION INTERCONNECTION REQUEST No. 09INR0015

TXU Power
(Comanche Peak Generation Station)
Somervell County
Total plant upgrade approximately 86 MW

Prepared by
System Protection Section
Transmission Engineering & Operations
TXU Electric Delivery

April 3,2007
Revised April 24,2007

CIRCUIT BREAKER INTERRUPTING DUTY STUDY

GENERATION INTERCONNECTION REQUEST No. 09INR0015
Comanche Peak 345 kV

Introduction

The GIR 09INR0015 is for the replacement of the main power transformers and the upgrade of the turbine-generators associated with units one and two at Comanche Peak Generating Station. Per the information provided for this study there will be two paralleled main power transformers per unit as is currently the case. Each transformer will be rated 345-22 kV and 781 MVA and each generating unit will be rated 1410 MVA at 22 kV and 0.9 PF.

This study is intended to address only circuit breaker interrupting duties and not the impact that the proposed facilities might have on protective relay systems, grounding systems, circuit breaker continuous ratings, etc.

Base System Short Circuit Model

The transmission system was modeled in the Aspen OneLiner Complete 2010 Case (10-26-06).OLR case modified to reflect major system changes planned up to the year 2010 summer peak that might significantly affect 345 kV fault currents in the study area. This modified file is named CP-Complete 2010 Case (04-02-07).OLR.

Modeling of Proposed Facility

The proposed facility was modeled to upgrade the two steam turbine generators and replace the main power transformers associated with each unit. The following modifications were made to the previously described base system to represent the proposed facility changes:

1) The two steam turbine generators were upgraded with new Siemens components with a saturated sub-transient reactance of 0.02092 p.u. @ 100 MVA.
2) Two paralleled transformers 345 kV grounded wye – 22 kV delta steam generator step-up transformers rated 781 MVA with a positive and zero sequence impedance of 13.7% (+/- 5%) at 781 MVA, which were modeled at -5% for an equivalent impedance of j 0.01666 p.u. @ 100 MVA.

Circuit Breakers Studied

Initial studies were conducted to determine the approximate area of the system significantly impacted by the proposed facilities. From these initial first pass studies, it was determined that the following existing circuit breakers should be studied more closely to determine the effects of the proposed facility and related system changes:

Location	*System No.*	*New Rating (%)*	*Rated RMS KA*	***DUTY** -- RMS* **Amperes (before)**	*DUTY -- RMS* **Amperes (after)**
Comanche Peak 345 kV	8000	98.1	50	46,749	49,047
Comanche Peak 345 kV	8010	98.0	50	46,736	48,983
Comanche Peak 345 kV	8020	98.1	50	46,748	49,047
Comanche Peak 345 kV	8030	98.0	50	46,735	48,983
Comanche Peak 345 kV	8080	99.5	50	48,243	49,751
Comanche Peak 345 kV	7970	88.2	50	46,116	44,101
Comanche Peak 345 kV	7980	69.7	63.2	46,096	44,080
Comanche Peak 345 kV	8040	92.0	50	44,415	45,995
Comanche Peak 345 kV	8050	91.1	50	43,976	45,533
Comanche Peak 345 kV	8060	85.2	50	40,986	42,679
Comanche Peak 345 kV	8070	88.2	50	42,219	44,076
Comanche Peak 345 kV	8090	76.6	63	46,794	48,276

CIRCUIT BREAKER INTERRUPTING DUTY STUDY
GENERATION INTERCONNECTION REQUEST No. 09INR0015
Comanche Peak 345 kV

Conclusions

Based on this study, none of the studied breakers in the Comanche Peak switchyard or in the vicinity of Comanche Peak are expected to be overdutied due to the proposed changes.