2.5.8 Additional Review Areas (Plant Systems)

2.5.8.1 Circulating Water System

2.5.8.1.1 Introduction

The Circulating Water (CW) System provides a continuous supply of cooling water to the main condenser to remove the heat rejected by the turbine cycle and auxiliary systems. The PBNP review of the CW System focused on changes to the amount of heat absorbed by the system from increased heat rejection from the condenser and other turbine cycle heat exchangers due to the higher EPU power level. The impact of this increased heat on the CW components was evaluated to ensure that the system accomplishes its design functions after implementation of EPU.

Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The non-safety related CW System circulates water from Lake Michigan through the main condensers to condense the steam exhausting from the turbines. The water is discharged back to the lake through discharge flumes. The CW system is a non-seismic piping system whose primary function is to remove heat from the steam cycle via the main condensers. The CW system is described in FSAR Section 10.1, Steam and Power Conversion System.

The dilution and diffusion effects of the circulating water discharge to Lake Michigan are discussed in FSAR Section 2.5, Hydrology. Additional information regarding the release of liquid wastes via the CW System is provided in FSAR Section 11.1, Liquid Waste Management System.

In addition to the licensing bases described in the FSAR, the circulating water system was evaluated for the PBNP License Renewal. System and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

The above SER discusses the circulating water system in Section 2.3.3.12. Aging effects, and the programs credited with managing those effects, are described in Section 3.3.

2.5.8.1.2 Technical Evaluation

Introduction

The Circulating Water System is discussed in the FSAR Section 10.1, Steam and Power Conversion. The circulating water system circulates water from Lake Michigan through the main condensers to condense the steam exhausting from the turbines. The water is discharged back to the lake through discharge flumes. Two circulating water pumps per unit are used to circulate the water. Traveling screens and a screen wash system remove debris from the water. The circulating water system also supplies cooling water to the condensate cooler for maintaining the main generator hot gas temperature.

Approximately 98% of the circulating water pump flow distributes to the tube side of the main condensers to remove the heat rejected by the turbine cycle. This evaluation focuses on the increased amount of rejected heat to be absorbed by the circulating water system and the increased discharge temperature.

Description of Analyses and Evaluations

The circulating water system and its components were evaluated to ensure they are capable of performing their intended function at the EPU operating conditions. The evaluation reviewed the circulating water system to determine whether the existing circulating water system flow rate is capable of removing the increased steam cycle heat rejected at EPU conditions.

The increased heat to the circulating water system from the turbine cycle heat loads at EPU conditions raises the system operating circulating water temperature at the main condenser waterbox outlet. Heat loads during normal plant operation with different cooling water temperatures are used in the heat balance studies for the evaluation.

Other evaluations related to the circulating water system, piping and components are included in the following LR sections:

- Liquid waste effluent discharge to the discharge flumes – LR Section 2.5.6.2, Liquid Waste Management System
- Protection against flooding due to a failure in the Circulating Water System - LR Section 2.5.1.1.3, Circulating Water System (Related to Flooding)
- Heat removal and cooling of the main condenser – LR Section 2.5.5.2, Main Condenser
- Condenser Vacuum System is addressed in LR Section 2.5.3.2, Main Condenser Evacuation System
- Environmental Impact of circulated water returned to Lake Michigan is addressed in LR Appendix D, Supplemental Environmental Report.

Evaluation of the Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

The circulating water system with regards to its Condenser heat removal function is not within the scope of License Renewal as described in NUREG-1839, as no modification or change will be made to the circulation water system. Design pressure and flow rate of the circulation water system will not change with EPU. Under the EPU, there will be a small temperature increase associated with heat load rejection to the condenser. The small temperature increase will not affect the pressure retaining components of the circulating water system. Therefore the pressure retaining capacity of piping, valves, and other water passages in the system are unaffected by EPU. EPU does not add any new components nor does it introduce any new functions for existing components that would change the license renewal evaluations and conclusions with regards to the system heat removal function.

Results

A lake water temperature evaluation concluded that the maximum expected lake water temperature can be assumed to be 76°F or less. To be consistent with the conclusion of the report along with current site data, the EPU heat balance models used 75°F as the circulating water inlet temperature for summer conditions. The resulting increase in the discharge circulating water system temperature at EPU conditions is approximately 4°F.

This small increase in the circulating water system temperature does not have an adverse impact on the existing component design parameters and functions. The circulating water system operating pressures and temperatures at EPU conditions remain bounded by the original design pipe specifications.

The higher circulating water discharge temperatures were also reviewed against the Wisconsin Pollutant Discharge Elimination System (WPDES) permit (WI-0000957-7). It was determined that EPU will not affect the permit, since the permit does not limit maximum discharge temperature, differential temperature across the condenser, or total discharge heat.

All other limitations on discharge to Lake Michigan will be maintained for EPU in accordance with the WPDES permit. EPU does not affect the existing chemical treatment program employed at PBNP.

2.5.8.1.3 Conclusions

PNBP has assessed the circulating water system at EPU conditions. PBNP concludes that the assessment adequately accounts for the effects of the increase in heat loads from the turbine cycle on the circulating water system discharge temperature to Lake Michigan. PBNP concludes that the current circulating water system will be adequate and accounts for the effects of the proposed EPU on the system's capability to remove heat rejected from the turbine cycle and auxiliary heat exchangers. PBNP finds that the current design of the circulating water system will provide a reliable supply of water at EPU conditions to condense the steam exhausted from the low-pressure turbines. PBNP also concludes that the current design of the circulating water system piping and its components will accommodate the higher condenser duty and higher temperatures at EPU conditions. Finally, PBNP concludes that the operation of the circulating water system at the EPU power level is not limited by the current discharge permit (WPDES WI-0000957-7) since the permit does not set maximum discharge temperature, differential temperature across the condenser, or total discharge heat. Therefore, PBNP finds the proposed EPU acceptable with regards to the circulating water system.

2.6 Containment Review Considerations

2.6.1 Primary Containment Functional Design

2.6.1.1 Regulatory Evaluation

The containment encloses the reactor system and is the final barrier against the release of significant amounts of radioactive fission products in the event of an accident.

The PBNP review covered the pressure and temperature conditions in the containment due to a spectrum of postulated loss-of-coolant accidents (LOCAs) and secondary system line-breaks.

The NRC's acceptance criteria for primary containment functional design are based on:

- GDC 16, insofar as it requires that reactor containment be provided to establish an essentially leak-tight barrier against the uncontrolled release of radioactivity to the environment
- GDC 50, insofar as it requires that the containment and its internal components be able to accommodate, without exceeding the design leakage rate and with sufficient margin, the calculated pressure and temperature conditions resulting from any LOCA
- GDC 38, insofar as it requires that the containment heat removal system(s) function to rapidly reduce the containment pressure and temperature following any LOCA and maintain them at acceptably low levels
- GDC 13, insofar as it requires that instrumentation be provided to monitor variables and systems over their anticipated ranges for normal operation and accident conditions
- GDC 64, insofar as it requires that means be provided for monitoring the plant environs for radioactivity that may be released from normal operations and postulated accidents

Specific review criteria are contained in the SRP Section 6.2.1.1.A.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion
(PBNP GDC).

The PBNP specific GDC for the Containment System are as follows:

CRITERION: The containment structure shall be designed (a) to sustain, without undue risk to the health and safety of the public, the initial effects of gross equipment failures, such as a large reactor coolant pipe break, without loss of required integrity, and (b) together with other engineered safety features as may be necessary, to retain for as long as the situation requires, the functional capability of the containment to the extent necessary to avoid undue risk to the health and safety of the public. (PBNP GDC 10)

The reactor containment structure is a horizontally and vertically pre-stressed post tensioned concrete cylinder on top of a reinforced concrete slab and covered by a pre-stressed post tensioned shallow concrete dome.

The design pressure of the containment exceeds the peak pressure occurring as the result of the complete blowdown of the reactor coolant through any rupture of the reactor coolant system up to and including the hypothetical double ended severance of a reactor coolant pipe.

The containment structure and all penetrations are designed to withstand, within design limits, the combined loadings of the design basis accident and safe shutdown earthquake.

All piping systems which penetrate the containment structure are anchored at the penetration.

Penetrations for lines containing high pressure or high temperature fluids (steam, feedwater, and blowdown lines) are designed so that the containment is not breached by a hypothesized pipe rupture. All lines connected to the primary coolant system that penetrate the containment are also anchored in the secondary shield walls (i.e., walls surrounding the steam generators and reactor coolant pumps). These anchors are designed to withstand the thrust, moment, and torque resulting from a hypothesized rupture of the attached pipe.

All isolation valves are supported to withstand, without impairment of valve operability, the combined loadings of the design basis accident and safe shutdown earthquake. The design pressure is not exceeded during any subsequent long term pressure transient determined by the combined effects of heat sources such as residual heat and metal water reaction with minimum operation of the emergency core cooling and the containment air recirculation and spray cooling systems.

CRITERION: The reactor containment structure, including openings and penetrations, and any necessary containment heat removal systems, shall be designed so that the leakage of radioactive materials from the containment structure under conditions of pressure and temperature resulting from the largest credible energy release following a loss of coolant accident, including the calculated energy from metal water or other chemical reactions that could occur as a consequence of failure of any single active component in the emergency core cooling system, will not result in undue risk to the health and safety of the public. (PBNP GDC 49)

In calculating the containment pressure, rupture sizes up to and including a double ended severance of reactor coolant pipe are considered. The pressure and temperature loadings obtained by analyzing various loss of coolant accidents, when combined with operating loads and maximum wind or seismic forces, do not exceed the load carrying capacity of the structure, its access opening, or penetrations.

CRITERION: The selection and use of containment materials shall be in accordance with applicable engineering codes. (PBNP GDC 50)

The selection and use of containment materials comply with the applicable codes and standards.

The concrete containment is not susceptible to a low temperature brittle fracture.

The containment liner is enclosed within the containment and thus is not exposed to the temperature extremes of the environs. The containment ambient temperature during operation is between 50°F and 120°F.

Containment penetrations which can be exposed to the environment are also designed to the NDT + 30°F criterion in accordance with ASME Section III, Subsection B.

Additional details of the Containment System are provided in FSAR Sections 5.1, Containment System Structure, Section 5.4, Containment System Structure, System Design Evaluation, Section 5.5, Containment System Structure, Minimum Operating Conditions, Section 5.6, Containment System Structure, Construction, and Section 14.3.4, Containment Integrity Evaluation.

CRITERION: Where an active heat removal system is needed under accident conditions to prevent exceeding containment design pressure, this system shall perform its required function, assuming failure of any single active component. (PBNP GDC 52)

Adequate heat removal capability for the containment is provided by two separate, engineered safety features systems. These are the containment spray system, whose components are described in FSAR Section 6.4, Containment Spray System, and the containment air recirculation cooling system, whose components operate as described in FSAR Section 6.3.2, Containment Air Recirculation Cooling System (VNCC), System Design and Operation. These systems are of different engineering principles and serve as independent backups for each other.

CRITERION: Instrumentation and controls shall be provided as required to monitor and maintain within prescribed operating ranges essential reactor facility operating variables. (PBNP GDC 12)

Instrumentation and controls are provided to monitor and maintain important reactor parameters (including neutron flux, primary coolant pressure, loop flow rate, coolant temperatures, and control rod positions) within prescribed operating ranges. Other instrumentation and control systems are provided to monitor and maintain, within prescribed operating ranges, the temperatures, pressure, flow, and levels in the reactor coolant system, steam systems, containment, and other auxiliary systems. The quantity and types of instrumentation provided are adequate for safe and orderly operation of all systems and processes over the full operating range of the plant. Detailed discussion of instrumentation and control systems is provided in FSAR Chapter 7, Instrumentation and Control. Post-accident monitoring instrumentation is required to meet the intent of Regulatory Guide 1.97, Revision 2. FSAR Section 7.6.2, Instrumentation Systems, Post Accident Monitoring Instrumentation, discusses the specific plant variables to which this regulatory guide applies and the type and category of each variable.

CRITERION: The facility includes those means necessary to maintain control over the plant gaseous radioactive effluents. Appropriate holdup capacity shall be provided for retention of gaseous effluents, particularly where unfavorable environmental conditions can be expected to require operational limitations upon the release of radioactive effluents to the environment. In all cases, the design for radioactivity control must be justified on the basis of 10 CFR 20 requirements, for both normal operations and for any transient situation that might reasonably be anticipated to occur, and on the basis of 10 CFR 100 dosage level guidelines for potential reactor accidents (PBNP GDC 70).

Radioactive gases are effectively controlled to prevent their unmonitored release to the atmosphere.

The NRC reviewed the PBNP response to NRC IE Bulletin 80-04, Analysis of a PWR Main Steam Line Break with Continued Feedwater Addition. The NRC concluded that the PBNP analysis was acceptable and no further action was required.

Subsequent to the closure of IEB 80-04, PBNP identified a concern that containment design pressure could be exceeded in a postulated main steam line break accident inside containment assuming a single failure of the main feed regulating valve to shut.

In addition to the evaluations described in the FSAR, the containment system was evaluated for the PBNP License Renewal. The evaluations are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

The containment system is evaluated under License Renewal.

2.6.1.2 Technical Evaluation

The evaluation of the design basis analyses for the containment pressure and temperature response to a loss-of-coolant accident (LOCA) or a main steam line break (SLB) event demonstrates that the current design is acceptable to support operation at extended power uprate (EPU) conditions.

2.6.1.2.1 Introduction

The containment integrity analyses are described in FSAR, Section 14.3.4, Containment Integrity Evaluation, (LOCA containment response) and Section 14.2.5.C, Standby Safety Feature Analysis, Containment Response Analysis, (SLB containment response). The analyses are performed to demonstrate the acceptability of the containment heat removal system to mitigate the consequences of a LOCA or SLB inside containment. The analyses documented in the subsections below have been performed at EPU conditions.

Calculation of the containment response following a postulated LOCA or SLB is analyzed by use of the computer code GOTHIC version 7.2a. The GOTHIC Technical Manual (Reference 1) provides a description of the governing equations, constitutive models, and solution methods in the solver. The GOTHIC Qualifications Report (Reference 2) provides a comparison of the solver results with both analytical solutions and experimental data.

The GOTHIC containment modeling for PBNP Units 1 and 2 is consistent with the recent NRC approved Ginna evaluation model (Reference 3). The latest code version is used to take advantage of the diffusion layer model (DLM) heat transfer option. This heat transfer option was approved by the NRC (Reference 3) for use in Ginna containment analyses with the condition that mist be excluded from what was earlier termed as the mist diffusion layer model (MDLM). The GOTHIC containment modeling for PBNP Units 1 and 2 follows the conditions of acceptance placed on Ginna. Ginna and PBNP both have dry containment designs. The differences in GOTHIC code versions are documented in Appendix A of the GOTHIC User Manual Release Notes (Reference 4). Version 7.2a is used consistent with the restrictions identified in Reference 3; none of the user-controlled enhancements added to version 7.2a were implemented in the PBNP Units 1 and 2 containment model. A description of the PBNP units GOTHIC model is provided below.

2.6.1.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The major modeling input parameters and assumptions that are used in the PBNP Units 1 and 2 containment evaluation model for the LOCA and steam line break events are identified in this section. The assumed initial conditions and input assumptions associated with the containment volume, containment fan coolers and containment sprays are listed in Table 2.6.1-1, Containment Response Analysis Parameters. The primary function of the residual heat removal system (RHRS) is to remove heat from the core by way of the ECCS. The recirculation system alignment is outlined in Table 2.6.1-2, LOCA Containment Response Analysis Recirculation System Alignment Parameters. The containment structural heat sink input is provided in Table 2.6.1-3, Containment Structural Heat Sink Input, and the corresponding material properties are listed in Table 2.6.1-4, Material Properties for Containment Structural Heat Sinks.

The following are major assumptions made in the analysis:

- Homogeneous mixing is assumed. The steam-air mixture and the water phases each have uniform properties. More specifically, thermal equilibrium between the air and the steam is assumed. However, this does not imply thermal equilibrium between the steam-air mixture and the water phase.
- Air is taken as an ideal gas, while compressed water and steam tables are employed for water and steam thermodynamic properties.
- For the blowdown portion of the analysis, the discharge flow separates into steam and water phases at the breakpoint. The saturated water phase is at the total containment pressure, while the steam phase is at the partial pressure of the steam in the containment. For the post-blowdown portion of the LOCA analysis, steam and water releases are input separately.
- The saturation temperature at the partial pressure of the steam is used for heat transfer to the heat sinks and the fan coolers.

Noding Structure

The PBNP GOTHIC containment evaluation model for the LOCA and steam line break events consist of one lumped-parameter control volume representing containment. Additional boundary conditions, volumes, flow paths, and components are used to model accumulator nitrogen release and sump recirculation. Injection of accumulator nitrogen during a LOCA event is modeled by a boundary condition. The recirculation system model uses GOTHIC component models for the RHR and component cooling water (CCW) heat exchangers (HXs) and the CCW pumps. Recirculation flow from the sump is modeled using a boundary condition.

Volume Input

GOTHIC requires the volume, height, diameter, and elevation input values for each node. The containment is modeled as a single control volume in the containment model. The minimum free volume of 1,000,000 ft^3 was used.

The containment model contains volumes representing the Service Water System (SW). The SW system volumes are water-solid and assumed to be initially at 74.7 psia and 82°F.

Flow Paths

Flow boundary conditions linked to functions that define the M&E releases model the break flow to the containment. The boundary conditions are connected to the containment control volume via flow paths. The injection spray is modeled as a boundary condition connected to the containment control volume via a flow path.

The flow rates through the flow paths are specified by boundary conditions, so the purpose of the flow path is to direct the flow to the proper control volume. The flow path input is mostly arbitrary. Standard values are used for the area, hydraulic diameter, friction length, and inertia length of the flow path.

Heat Sinks

The heat sinks in the containment are modeled as GOTHIC thermal conductors. The heat sink data is based on conservatively low surface areas and is summarized in Table 2.6.1-3, Primary Containment Functional Design, Containment Structural Heat Sink Input.

A thin air gap is assumed to exist between the steel and concrete for steel-jacketed heat sinks. A gap conductivity of 0.0174 Btu/h-ft-°F is assumed between steel and concrete.

The thermophysical properties for the heat sink materials are summarized in Table 2.6.1-4, Primary Containment Functional Design, Material Properties for Containment Structural Heat Sinks.

Heat and Mass Transfer Correlations

GOTHIC has several heat transfer coefficient options that can be used for containment analyses. For the PBNP GOTHIC model, the direct heat transfer coefficient set is used with the DLM mass transfer correlation for the heat sinks inside containment. This heat transfer methodology was reviewed and approved for use in the Ginna containment design basis accident analyses (Reference 3). The DLM correlation does not require the user to specify a revaporization input value.

The direct heat transfer coefficient set is used for the heat sinks representing floors, ceilings, and walls. The submerged conductors are essentially insulated from the vapor after the pool develops. Insulated surfaces are modeled with no heat loss (0.0 Btu/hr-ft2/°F).

Containment Fan Coolers

The Containment Fan Coolers (CFCs) are modeled in GOTHIC as a cooler/heater component in the containment volume. They are initiated on a high containment pressure signal. The heat removal rate for one CFC is defined by a function in GOTHIC. Multipliers are used to define the amount of operational CFCs. See Table 2.6.1-1, Containment Response Analysis Parameters, and Table 2.6.1-5, Containment Fan Cooler Performance, for the CFC parameters and heat removal capability assumed for the containment response analyses.

Sump Recirculation

The RHR heat exchanger cools the water from the containment sump. The RHR system injects the cooled water into the RCS to cool the core. The RHR heat exchanger is cooled with CCW and service water provides the ultimate heat sink, cooling the CCW heat exchangers.

Mass and Energy Release

The LOCA and SLB mass and energy release methodology generates releases from both sides of the break, and are, therefore, input to the GOTHIC containment model via two flow boundary conditions. The LOCA mass and energy releases are documented in LR Section 2.6.3.1, M&E Release Analysis for Postulated Loss-of-Coolant Accidents. The SLB mass and energy releases are documented in LR Section 2.6.3.2, Mass and Energy Release Analysis for Secondary System Pipe Ruptures. The break mass and enthalpy are linked to the boundary conditions as external functions defined by control variables. During blowdown, the liquid portion of the break flow is released as drops with an assumed diameter of 100 microns (0.00394 inches). This is consistent with the methodology approved for Ginna (Reference 3) and is based on data presented in Reference 5.

The LOCA M&E releases (see LR Section 2.6.3.1, M&E Release Analysis for Postulated Loss Of Coolant Accidents, from the boundary conditions are analyzed for PBNP Units 1 and 2 out to 3600 seconds for the double-ended pump suction break case (the double-ended hot leg M&E releases are only analyzed out to the end of blowdown); that is, the time at which all energy in the primary heat structures and steam generator secondary system is released/depressurized to atmospheric pressure (14.7 psia and 212°F). After 3600 seconds the LOCA M&E release to the containment is assumed to be from steaming of decay heat. The long-term, post 3600 second, mass and energy release calculations are performed through user defined functions by GOTHIC. These input functions are used to incorporate the sump water cooling in the long term and are consistent with the Westinghouse methodology previously approved by the NRC (Reference 6). A flow boundary condition is defined to provide the long-term boil-off M&E release to containment. The mass flow rate and enthalpy of the flow is calculated using GOTHIC control variables.

The ANS Standard 5.1 (Reference 7) decay heat model (+2σ uncertainty) is used to calculate the long-term boil-off from the core. Table 2.6.3.1-4, LOCA M&E Release Analysis Core Decay Heat Fraction, lists the decay heat curve used. All of the decay heat is assumed to produce steam from the recirculated ECCS water. The remainder of the ECCS water is returned to the sump region of the containment control volume. These assumptions are consistent with the long-term LOCA M&E methodology documented in Reference 6.

Containment Spray System

Containment spray is modeled with one boundary condition for the injection phase and two coupled boundary conditions for the recirculation phase. Point Beach has two trains of containment safeguards available, with one spray pump per train. Injection spray is actuated on the “Hi-Hi” containment pressure setpoint. The sprays begin injecting water from the RWST after a delay for pump start-up and diesel start-up, if there is a loss of offsite power. The containment spray flow varies according to containment pressure and can be found in Table 2.6.1-6, Containment Spray Performance. The spray flow rate is modeled in GOTHIC as a control variable. Other containment spray parameters are detailed in Table 2.6.1-1. Spray is assumed to be homogeneous and well-mixed with 100 percent of the flow condensing to droplets.

Accumulator Nitrogen Gas Modeling

The accumulator nitrogen gas release is modeled with a flow boundary condition in the LOCA containment model. The nitrogen release rate was conservatively calculated by maximizing the mass available to be injected. The nitrogen gas release rate was used as input for the GOTHIC function, as a specified rate over a fixed time period. Nitrogen gas is released at a rate of 24.32 lbm/second; beginning at 40.64 seconds (average accumulator tank water volume empty time) and ending at 60.64 seconds.

Acceptance Criteria

The containment response analysis demonstrates the acceptability of the containment heat removal systems to mitigate the consequence of a large LOCA or steam line break inside containment. The impact of LOCA or steam line break mass and energy (M&E) releases on the containment pressure and temperature are addressed to ensure that the containment pressure and temperature remain below their respective design limits. The containment design pressure and temperature for PBNP is 60 psig (74.7 psia) and 286°F respectively.

The systems must also be capable of maintaining the equipment qualification (EQ) parameters to within acceptable limits at the EPU program conditions.

The containment response for design basis LOCA or main steam line break is an American Nuclear Society (ANS) Condition IV event, an infrequent fault. The relevant requirements to satisfy NRC acceptance criteria (Reference 8) are as follows:

- The peak calculated containment pressure should be less than the containment design pressure of 60 psig (74.7 psia).
- The calculated pressure at 24 hours should be less than 50% of the peak calculated value. (This is related to the criteria for containment leakage assumptions as affecting doses at 24 hours. It only applies to the LOCA containment response.)

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

The analysis performed to assess the containment response to the limiting LOCA resulting from operation at EPU conditions does not add any new functions for existing components that would change the license renewal system evaluation boundaries. The analytical results associated with operating at EPU conditions do not add any new or previously unevaluated aging effects that necessitate a change to aging management programs or require a new program as internal and external environments remain within the parameters previously evaluated. Therefore, there is no impact to license renewal scope, aging effects, and aging management programs as a result of EPU activities.

2.6.1.2.3 Containment Response to Loss-of-Coolant Accident

Description of Analyses and Evaluations

The PBNP Units 1 and 2 LOCA containment response analysis considered a spectrum of cases as discussed in Licensing Report (LR) Section 2.6.3.1, M&E Release Analysis for Postulated Loss-of-Coolant Accidents. The cases address break location, and postulated single failure (minimum and maximum safeguards). Only the limiting cases, which address the containment peak pressure case and limiting long-term EQ case, are presented herein. The limiting cases were found to be the double-ended hot leg (DEHL) break case for peak pressure, and the double-ended pump suction (DEPS) break case with minimum safeguards for the long-term EQ. The LOCA pressure and temperature response analyses were performed assuming a loss-of-offsite power and a worst single failure (loss of one emergency diesel generator (EDG) that is, loss of one containment cooling train).

Design Basis Accident

Consistent with the application of single-failure criterion presented in LR Section 2.6.3.1.2.1.2, M&E Release Analysis for Postulated Loss-of-Coolant Accidents, Application of Single-Failure Criterion, an inherent assumption is that offsite power is lost with the pipe rupture for the LOCA event. This results in the actuation of the EDG, powering the two trains of safeguards equipment. Operation of the EDG delays the operation of the safeguards equipment that is required to mitigate the transient. Relative to single failure criterion with respect to a LOCA event, one spray train is considered inoperable, whether due to a EDG failure (minimum safeguards case) or as the limiting single failure in the maximum safeguards case.

The minimum safeguards case was based upon a diesel train failure (loss of one cooling train) i.e., the active heat removal is:

- One containment spray pump in the injection phase
- Two CFCs
- One RHR pump and heat exchanger (HX) (with recirculation sprays)
- One component cooling water pump and one CCW HX
- Service water acting as the ultimate heat sink

The calculation for the DEPS case with minimum safeguards was performed for 2.6 million seconds (approximately 30 days). The DEHL case was terminated soon after the end of the blowdown phase.

Results

The results from the LOCA containment integrity analysis at EPU conditions using GOTHIC version 7.2a are documented in this section. The containment pressure and steam temperature profiles for the DEHL case (peak pressure) are shown in Figures 2.6.1-1, and 2.6.1-2. Table 2.6.1-7, Double-Ended Hot Leg Break Sequence of Events, provides the transient sequence of events for the DEHL transient. The results of the DEPS break case with minimum safeguards (long-term EQ transient) are shown in Figures 2.6.1-3, 2.6.1-5. Table 2.6.1-8, Double-Ended Pump Suction Break Sequence of Events (Minimum Safeguards), presents sequence of events for the DEPS with minimum safeguards transient. Table 2.6.1-9, LOCA Containment Response Results, provides the containment pressure and temperature results relative to peak containment conditions and also at 24 hours for EQ support and the acceptance limits for these parameters.

From the containment response analysis, performed in support of the PBNP Units 1 and 2 EPU, the limiting containment peak pressure and temperature is 70.05 psia and 279.9°F (DEHL transient). The limiting pressure at 24 hours is 23.7 psia (DEPS with minimum safeguards transient). The results of the containment response analysis at EPU conditions are within the bounds of the acceptance criteria outlined in LR Section 2.6.1.2.2, Primary Containment Functional Design, Input Paramters, Assumptions and Acceptance Criteria, and are therefore acceptable.

Refer to LR Section 2.3.1, Environmental Qualification of Electrical Equipment, for impact on the equipment qualification.

The following two subsections outline the sequence of events for the DEHL and DEPS with minimum safeguards transients respectively:

LOCA Containment Response Transient Description: Double Ended Hot Leg Break

This analysis assumes a loss-of-offsite power coincident with a double ended rupture of the RCS piping between the reactor vessel outlet nozzle and the steam generator inlet (i.e., a break in the RCS hot leg).

The postulated RCS break results in a rapid release of mass and energy to the containment with a resulting rapid rise in both the containment pressure and temperature. As the containment pressure rises, the RCS rapidly depressurizes, which results in the generation of compensated pressurizer reactor trip at 0.311 seconds and a low pressurizer pressure SI setpoint at 3.8 seconds. The containment pressure continues to rise rapidly in response to the release of mass and energy until the end of blowdown at 16.8 seconds, with the pressure reaching a value of 70.05 psia at 16.01 seconds. This is the highest peak containment pressure of the three cases analyzed. The highest peak containment temperature of 279.9°F also occurs coincident with the peak pressure. The end of blowdown marks a time when the initial inventory in the RCS has been exhausted and a process of filling the RCS downcomer in preparation for reflood has begun. Since the reflood for a hot leg break is very fast due to the low resistance to steam venting posed by the broken hot leg, the hot leg break mass and energy release transients are terminated shortly after blowdown. Table 2.6.1-7 provides the transient sequence of events for the DEHL transient.

LOCA Containment Response Transient Description: Double Ended Pump Suction Break with Minimum Safeguards

This analysis assumes a loss-of-offsite power coincidence with a double-ended rupture of the RCS piping between the steam generator outlet and the RCS pump inlet (suction). The associated single failure assumption is the failure of a diesel to start, resulting in one train of ECCS and containment safeguards equipment being available. This combination results in a minimum set of safeguards being available. Further, loss of offsite power delays the actuation times of the safeguards equipment due to the required diesel startup time after receipt of the safety injection signal.

The postulated RCS break results in a rapid release of mass and energy to the containment with a resulting rapid rise in both the containment pressure and temperature. As the containment pressure rises, the RCS rapidly depressurizes which results in the generation of a compensated pressurizer pressure reactor trip at 0.418 seconds and a low pressurizer pressure SI setpoint at 4.1 seconds. The containment pressure continues to rise rapidly in response to the release of mass and energy until the end of the blowdown phase at 13.2 seconds, with the containment pressure reaching a value of 67.73 psia at 12.51 seconds.

The end of the blowdown phase marks a time when the initial inventory in the RCS has been exhausted and a slow process of filling the RCS downcomer in preparation for reflood has begun. Since the mass and energy release during this period is low, pressure decreases slightly and then increases in response to the reflood mass and energy release out to a second peak occurring at approximately 70 seconds. The turn around in containment pressure at 60 seconds is a result of the accumulator nitrogen cover gas flow ending at 60.64 seconds, initiation of the sprays at 72.73 seconds, and initiation of the containment fan coolers (CFCs) at 84.24 seconds. Reflood continues at a reduced flooding rate due to the buildup of mass in the RCS core which offsets the downcomer head. This reduction in flooding rate and the continued action of the CFCs and spray leads to a slowly decreasing pressure out to the end of reflood, which occurs at 206.31 seconds.

At this juncture, by design of the Reference 6 model, energy removal from the SG secondaries begins at a high rate, resulting in a rapid rise in containment pressure from the end of reflood out to approximately 781.4 seconds when energy has been removed from the SG in the faulted loop, bringing the SG in the faulted loop secondary pressure down to the containment design pressure of 74.7 psia. At appromiately the same time (772.1 seconds), the peak containment temperature of 279.3°F is reached. The result of the SG secondary energy release is a containment pressure of approximately 66.5 psia, the third major peak for this transient. After this event, the mass and energy released is reduced due to so much energy removal from the SGs having been accomplished and pressure slowly decreases out to the recirculation switchover time of 3,397.73 seconds.

At this time, the ECCS is realigned for recirculation resulting in an increase in the SI temperature due to delivery from the hot sump. At 8000 seconds the injection sprays are terminated which results in a slight increase in pressure until the recirculation sprays are initiated at 9200 seconds. The pressure once again decreases until the recirculation sprays are terminated at 15,600 seconds. After a slight increase in pressure, the containment pressure continues to decrease due to lower decay heat, SG energy release and continued CFC cooling. This trend continues to the end of the transient at 2.6E+06 seconds. Table 2.6.1-8 presents sequence of events for the DEPS with minimum safeguards transient.

2.6.1.2.4 Containment Response to Main Steam Line Break

Description of Analysis

The steam line break containment response analysis uses the mass and energy releases described in Section 2.6.3.2, M&E Release Analysis for Secondary System Pipe Ruptures, with the GOTHIC evaluation model described in LR Section 2.6.1.2.2, Primary Containment Functional Design, Input Paramters, Assumptions and Acceptance Criteria. The variation of initial power level and the postulated single failures are discussed in LR Section 2.6.3.2, M&E Release Anlysis for Secondary Systems, Description of Analyses and Evaluations. For the auxiliary feedwater (AFW) runout protection failure and the feedwater isolation valve (FIV) failure, full containment safeguards of four fan coolers and two containment spray pumps are credited. For the containment safeguards failure cases, one train of safeguards is assumed to fail, with two fan coolers and one containment spray pump operating.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

The analysis performed to assess the containment response to the limiting steam line break resulting from operation at EPU conditions does not add any new functions for existing components that would change the license renewal system evaluation boundaries. The analytical results associated with operating at EPU conditions do not add any new or previously unevaluated aging effects that necessitate a change to aging management programs or require a new program as internal and external environments remain within the parameters previously evaluated. Therefore, there is no impact to license renewal scope, aging effects, and aging management programs as a result of EPU activities.

Results

The containment response to a steam line break was analyzed with GOTHIC for each of the mass and energy release cases from LR Section 2.6.3.2, M&E Release Analysis for Secondary System. The analysis includes the effects of the extended power uprate to 1806 MWt NSSS power, a decrease in the shutdown margin to 2.0%Δk, higher AFW flowrates, and the benefit of the safety-grade feedwater isolation valve being added in each feedline loop. The analysis bounds Unit 1 and Unit 2.

Prior to the EPU analysis, the limiting steam line break containment pressure case was initiated from full power with the FRV on the faulted loop failed open. As explained in Section 2.6.3.2.2.1, M&E Release for Secondary System Pipe Rupture, Introduction, the plant modification to add a safety-grade FIV to each feedline has a significant benefit in reducing the feedwater that enters the faulted steam generator and is released from the steam line break. This plant modification is necessary to accommodate the effects of the EPU, lower shutdown margin and higher AFW flowrates. The limiting containment pressure case for the EPU is a large double-ended rupture steam line break initiated from 30% power with a single failure of the feedwater isolation valve. The peak containment pressure of 58.7 psig occurs at 254 seconds and is below the containment design pressure of 60 psig. The peak containment temperature for this case is 284.4°F (Table 2.6.1-10, MSLB Containment Response Results).

The sequence of events for the containment response portion of this event is provided in Table 2.6.1-11, Sequence of Events for SLB Initiated from 30% Power with FIV Single Failure, for the limiting case with the containment pressure transient shown in Figure 2.6.1-6 and the containment temperature transient shown in Figure 2.6.1-7. Figure 2.6.1-8 and Figure 2.6.1-9 show the containment pressure and temperature transients respectively for the limiting case compared to the limiting case prior to the EPU and the FIV plant modification.

2.6.1.3 Conclusion

PBNP has reviewed the assessment of the containment pressure and temperature transient and concludes that it has adequately accounted for the increase of M&E that would result from the proposed EPU. PBNP further concludes that containment systems will continue to provide sufficient pressure and temperature mitigation capability to ensure that containment integrity is maintained. PBNP also concludes that the containment systems and instrumentation will continue to be adequate for monitoring containment parameters and release of radioactivity during normal and accident conditions and will continue to meet the PBNP current licensing basis requirements with respect to PBNP GDC 10, 12, 49, 50, 52 and 70 following implementation of the proposed EPU. Therefore, PBNP finds the proposed EPU acceptable with respect to containment functional design.

2.6.1.4 References

1. NAI 8907-06, Rev. 16, GOTHIC Containment Analysis Package Technical Manual, Version 7.2a, January 2006

2. NAI-8907-09, Rev. 9, GOTHIC Containment Analysis Package Qualification Report, Version 7.2a, January 2006

3. Docket No. 50-244, Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Amendment No. 97 to Renewed Facility Operating License No. DPR-18 R. E. Ginna Nuclear Power Plant, Nuclear Regulatory Commission, July 11, 2006

4. NAI 8907-02, Rev. 17, GOTHIC Containment Analysis Package User Manual, Version 7.2a, January 2006

5. AICHE Journal Volume 8, #2, Sprays Formed by Flashing Liquid Jets, May 1962

6. WCAP-10325-P-A, (Proprietary), and WCAP-10326-A, (Nonproprietary), Westinghouse LOCA Mass and Energy Release Model for Containment Design March 1979 Version, May 1983

7. ANSI/ANS-5.1 1979, American National Standard for Decay Heat Power in Light Water Reactors, August 29, 1979

8. NUREG-0800, U.S. Nuclear Regulatory Commission Standard Review Plan, Section 6.2.1.1.A, PWR Dry Containments, Including Subatmospheric Containments, Rev. 2, January 2006

Table 2.6.1-1 Containment Response Analysis Parameters

Parameter	Value
Service Water Temperature (°F)	82
RWST Water Temperature (°F)	100
Initial Containment Temperature (°F)	120
Initial Containment Pressure (psig)	2.0
Initial Relative Humidity (%)	20
Net Free Volume (ft^3)	1,000,000
Reactor Containment Fan Coolers (CFCs)	
Total CFCs Available	4
CFCs Available with a Single Failure	
Diesel Failure (LOCA)	2
Containment safeguards Failure (SLB)	2
Containment Hi Pressure Setpoint (psig)	6.0
Delay Time (sec)	
Loss of Offsite Power	84
With Offsite Power	70
Air Flow Rate through Cooler (ft^3/min/CFC)	33,500
Containment Fan Cooler Heat Removal as a Function of Containment Saturation Temperature	See Table 2.6.1-5
Containment Sprays	
Total Containment Spray Pumps Available	2
Containment Spray Pumps Available with a Single Failure	
Diesel Failure (LOCA)	1
Containment safeguards Failure (SLB)	1
Flowrate (gpm)	
Injection Phase (per train)	See Table 2.6.1-6
Flowrate (gpm)	
Recirculation Phase (per train)	900
Containment Hi-Hi Pressure Setpoint (psig)	30.0
Delay Time (sec)	
Loss of Offsite Power	70
With Offsite Power	56
Switchover from injection to recirculation (sec) (includes 1200 second delay)	9200
Containment Spray Termination Time (sec)	15,600

Table 2.6.1-2 LOCA Containment Response Analysis Recirculation System Alignment Parameters

Residual Heat Removal System	
RHR Heat Exchangers	
Maximum number	2
Modeled in analysis[1]	1
Recirculation switchover time with minimum safeguards, sec (after SI setpoint is reached)	3,395
Flow rate, gpm	
Tube side	1,951
Shell side	2,780
Component Cooling Water Heat Exchangers	
Maximum number	2
Modeled in analysis	1
Flow rate, gpm	
Shell side[1]	2,895
Tube side[1] (service water)	2,700
Additional heat loads, MBtu/hr	2.0
Note: 1. Minimum heat removal data representing 1 EDG	

Table 2.6.1-3 Containment Structural Heat Sink Input

GOTHIC Heat Sink Description	Area (ft^2)	Material	Thickness (inches)
Upper Dome	1,610	Paint Type 1*	0.01404
		Carbon Steel	0.2496
		Gap	0.021
		Concrete	36
Middle Dome	5,912	Paint Type 1	0.01404
		Carbon Steel	0.2496
		Gap	0.021
		Concrete	36
Lower Dome	6,432	Paint Type 1	0.01404
		Carbon Steel	0.2496
		Gap	0.021
		Concrete	36
Upper Containment outer wall (above 66')	16,988	Paint Type 1	0.015
		Carbon Steel	0.2496
		Gap	0.021
		Concrete	42
Middle Containment outer wall (21' to 66')	14,844	Paint Type 1	0.015
		Carbon Steel	0.2496
		Gap	0.021
		Concrete	42
Lower Containment outer wall (8' to 21')	4,166	Paint Type 1	0.015
		Carbon Steel	0.2496
		Gap	0.021
		Concrete	42
Rx Cavity: Shield wall/Rx Pit	1,695	Paint Type 2*	0.039
		Concrete	12
Rx Cavity: tunnel walls	260	Paint Type 2	0.039
		Concrete	12
Rx Cavity: Keyway tower/shaft	1,120	Paint Type 2	0.039
		Concrete	12

Table 2.6.1-3 Containment Structural Heat Sink Input

GOTHIC Heat Sink Description	Area (ft^2)	Material	Thickness (inches)
Rx Cavity: Floor slab	353	Paint Type 2	0.015
		Concrete	12
Pzr walls (inside 46'-86')	2,027	Paint Type 2	0.039
		Concrete	15
Pzr floor slab	156	Paint Type 2	0.015
		Concrete	24
		Paint Type 2	0.039
Pzr missile shields	176	Paint Type 2	0.039
		Carbon Steel	0.5
		Gap	0.021
		Concrete	15
		Paint Type 1	0.039
Upper Ctmt interior walls	5,420	Paint Type 2	0.039
		Concrete	15
Upper Ctmt floor/Annular Cmpt ceiling	4,339	Paint Type 2	0.015
		Concrete	4
Annular Cmpt: Interior wall (46' to 66')	5,372	Paint Type 2	0.039
		Concrete	15
Annular Cmpt: Interior wall (21' to 46')	8,263	Paint Type 2	0.039
		Concrete	15
Annular Cmpt: laydown area high wall (21'-66')	585	Paint Type 2	0.039
		Concrete	18
Annular Cmpt 46' floor slab	3,914	Paint Type 2	0.015
		Concrete	4
Annular Cmpt floor/Annular Sump ceiling (21')	4,272	Paint Type 2	0.015
		Concrete	4
Annular Sump: interior walls (8' to 21')	4,487	Paint Type 2	0.039
		Concrete	15
Annular Sump floor slab (8')	4,352	Paint Type 2	0.015
		Concrete	12

Table 2.6.1-3 Containment Structural Heat Sink Input

GOTHIC Heat Sink Description	Area (ft^2)	Material	Thickness (inches)
Loop A: walls	6,691	Paint Type 2	0.039
		Concrete	15
Loop A: floor slab	816	Paint Type 2	0.015
		Concrete	12
Loop A: missile shields	251.1	Paint Type 2	0.015
		Concrete	15
		Paint Type 2	0.039
Loop B: walls	8,087	Paint Type 2	0.039
		Concrete	15
Loop B: floor slab	794	Paint Type 2	0.015
		Concrete	12
Loop B: missile shields	208	Paint Type 2	0.015
		Concrete	15
		Paint Type 2	0.039
Loop B: sub-pzr cmpt walls	286	Paint Type 2	0.039
		Concrete	15
Loop B: sub-pzr cmpt floor	176	Paint Type 2	0.015
		Concrete	24
		Paint Type 2	0.039
Refueling cavity wall	4,691	Stainless Steel	0.1875
		Gap	0.021
		Concrete	18
		Paint Type 2	0.039
Refueling cavity floor/Annular sump ceiling	536	Stainless Steel	0.1875
		Gap	0.021
		Concrete	36
		Paint Type 2	0.039
Misc. steel in reactor cavity compartment	667.36	Paint Type 1	0.0130
		Carbon Steel	1.2630
Misc. steel in the pressurizer compartment	1.08	Paint Type 1	0.0130
		Carbon Steel	0.0050

Table 2.6.1-3 Containment Structural Heat Sink Input

GOTHIC Heat Sink Description	Area (ft^2)	Material	Thickness (inches)
Misc. steel in the upper containment	5,048.27	Paint Type 1	0.0130
		Carbon Steel	0.3770
Misc. steel in the annular compartment	22,507.34	Paint Type 1	0.0130
		Carbon Steel	0.3960
Misc. steel in the annular sump compartment	6,662.86	Paint Type 1	0.0130
		Carbon Steel	0.2300
Misc. steel in the Loop A compartment	3,390.63	Paint Type 1	0.0130
		Carbon Steel	0.3720
Misc. steel in the Loop B compartment	3,390.63	Paint Type 1	0.0130
		Carbon Steel	0.3720
Misc. steel in the dome compartment	20,731.29	Paint Type 1	0.0130
		Carbon Steel	0.1480
Misc. steel in refueling cavity compartment	398.26	Paint Type 1	0.0130
		Carbon Steel	1.4750
1 CFC in upper containment compartment; unpainted copper	7,071.89	Copper	0.0130
1 CFC in upper containment compartment	21.53	Stainless Steel	1.0220
1 CFC in annular compartment	7,075.48	Copper	0.0130
Unpainted stainless steel in Annular Compartment; 1 CFC	24.08	Stainless Steel	0.6700
Polar crane & Rail girder in the upper containment	8,094.46	Paint Type 1	0.0130
		Carbon Steel	0.9060
A RCP in the Loop A compartment	570.49	Paint Type 1	0.0079
		Copper	2.583
B RCP in the Loop B compartment	570.49	Paint Type 1	0.0079
		Copper	2.583
PRT Unpainted SS	509	Stainless Steel	0.6700
* Paint Type 1 is Amercote 66 top coating with a Dimecote 6 primer coating; Paint Type 2 is Phenoline 305 top coating with a Carboline 195 primer coating.			

Table 2.6.1-4 Material Properties for Containment Structural Heat Sinks

Material Type	Density lbm/ft^3	Thermal Conductivity Btu/hr-ft-F	Specific Heat Btu/lbm-F
Concrete	144	0.81	0.2
Stainless Steel	488	9.4	0.123
Carbon Steel	490	26	0.115
Copper (pure)	557.69	231.7	0.092
Gap (air)	0.06	0.0174	0.241
Amercote 66 top coating/Dimecote 6 primer coating (Paint Type 1)	1	0.25	21.7
Phenoline 305 top coating/Carboline 195 primer coating (Paint Type 2)	1	0.187	37.8

Table 2.6.1-5 Containment Fan Cooler Performance

Containment Temperature (°F)	Minimum Heat Removal Rate (Btu/sec) Per Reactor Containment Fan Cooler
100	750
200	5,930
210	6,448
220	6,965
230	7,484
240	8,001
250	8,520
260	9,037.5
270	9,546
280	10,055
290	10,564
300	11,073
330	12,600

Table 2.6.1-6 Containment Spray Performance

Containment Pressure (psig)	1 Pump (gpm)	2 Pumps (gpm)
0	1,324.0	2,665.8
10	1,287.2	2,589.8
20	1,250.3	2,515.6
30	1,206.9	2,431.0
40	1,162.5	2,342.7
50	1,117.0	2,252.4
60	1,070.7	2,160.2

Table 2.6.1-7 Double-Ended Hot Leg Break Sequence of Events

Time (sec)	Event Description
0.0	Break Occurs and Loss of Offsite Power is Assumed
.311	Compensated Pressurizer Pressure for Reactor Trip (1968.7 psia) Reached and Turbine Trip Occurs
3.8	Low-Pressurizer Pressure SI Setpoint (1663 psia) Reached - Feedwater Isolation Signal
4.95	Broken Loop Accumulator Begins Injecting Water
4.99	Intact Loop Accumulator Begins Injecting Water
15.81	Feedwater Isolation Valves Closed
16.01	Peak Temperature Occurs (279.9°F)
16.01	Peak Pressure Occurs (70.05 psia)
16.8	End of Blowdown Phase
50.0	Transient Modeling Terminated

Table 2.6.1-8 Double-Ended Pump Suction Break Sequence of Events (Minimum Safeguards)

Time (sec)	Event Description
0.0	Break Occurs and Loss of Offsite Power is Assumed
.418	Compensated Pressurizer Pressure Reactor Trip (1968.7 psia) Reached and Turbine Trip Occurs
2.73	Containment Spray Actuation Pressure Setpoint (44.7 psia; Analysis Value) Reached
4.1	Low Pressurizer Pressure SI Setpoint (1663 psia) Reached (Safety Injection Begins coincident with Low Pressurizer Pressure SI Setpoint)
5.27	Broken Loop Accumulator Begins Injecting Water
5.37	Intact Loop Accumulator Begins Injecting Water
12.51	Containment Peak Pressure Occurs (67.73 psia)
13.2	End of Blowdown Phase
13.2	Accumulator Mass Adjustment for Refill Period
16.11	Feedwater Isolation Valves Closed
41.1	Pumped Safety Injection Begins (Includes 37 Second Diesel Delay)
39.163	Broken Loop Accumulator Water Injection Ends
42.113	Intact Loop Accumulator Water Injection Ends
72.73	Containment Spray Pump (RWST) Begins
84.24	CFCs Begin Heat Removal (Includes 84 Second Delay)
206.31	End of Reflood for Minimum Safeguards Case
772.1	Containment Peak Temperature Occurs (279.3°F)
781.4	M&E Release Assumption: Broken Loop Steam Generator (SG) Equilibration When the Secondary Temperature is at Saturation (T_{sat}) at Containment Design Pressure of 74.7 psia
975.11	M&E Release Assumption: Broken Loop SG Equilibration at Containment Pressure of 60.7 psia
1109.7	M&E Release Assumption: Intact Loop SG Equilibration When the Secondary Temperature is at Saturation (T_{sat}) at Containment Design Pressure of 74.7 psia
1285.03	M&E Release Assumption: Intact Loop SG Equilibration at Containment Pressure of 54.7 psia
3397.73	Switchover to Recirculation Begins
8000.0	Injection Sprays Terminated

Table 2.6.1-8 Double-Ended Pump Suction Break Sequence of Events (Minimum Safeguards)

Time (sec)	Event Description
9200.0	Recirculation Sprays Initiated (Injection Spray Termination Plus 1200 Second Delay)
15,600.0	Recirculation Spray Terminated
2.6E+6	Transient Modeling Terminated

Table 2.6.1-9 LOCA Containment Response Results

Case	Peak Press. @ Time	Peak Temp. @ Time	Peak Press. (psia) @ 24 hours	Peak Temp. (°F) @ 24 hours
DEHL	70.05 psia @ 16.01 sec	279.9°F @ 16.01 sec	NA	NA
DEPS - Minimum Safeguards	67.73 psia @ 12.51 sec	279.3°F @ 772.1 sec	23.7	156.2
Containment Pressure – Acceptance Limits				
	Peak Pressure	**Pressure @ 24 hours**		
Pressure	74.7 psia	50% of the calculated peak pressure		
Containment Temperature – Acceptance Limits				
	Peak Temperature	**Temperature @ 24 hours**		
Temperature	286°F	Less than EQ profile		

Table 2.6.1-10 MSLB Containment Response Results

Double Ended Rupture at 30% Power	Peak Pressure of 73.4 psia @ 254 sec.	Peak Temperature of 284.4°F @ 244 sec.

Table 2.6.1-11 Sequence of Events for SLB Initiated from 30% Power with FIV Single Failure

Event	Time (sec)
Hi-1 containment pressure setpoint is reached	0.9
Hi-2 containment pressure setpoint is reached	38.5
Fan coolers start	71.0
Containment spray pumps start	94.5
Peak containment temperature occurs	244.2
Peak containment pressure occurs	254.2
Break release stops	610.0

Figure 2.6.1-1 Containment Pressure – Double-Ended Hot Leg Break

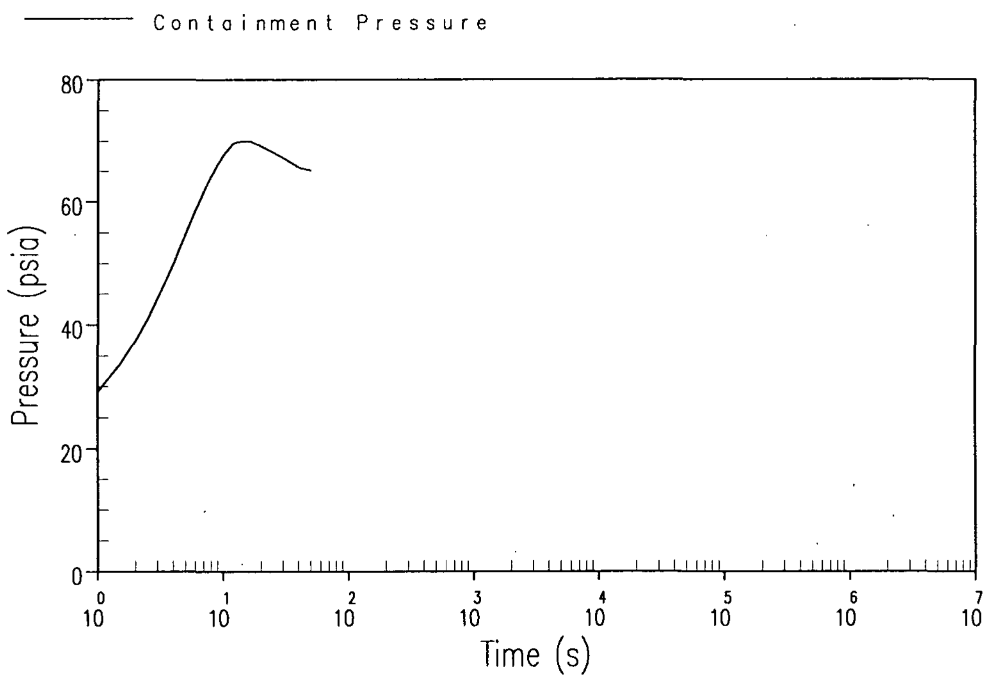


Figure 2.6.1-2 Containment Temperature – Double-Ended Hot Leg Break

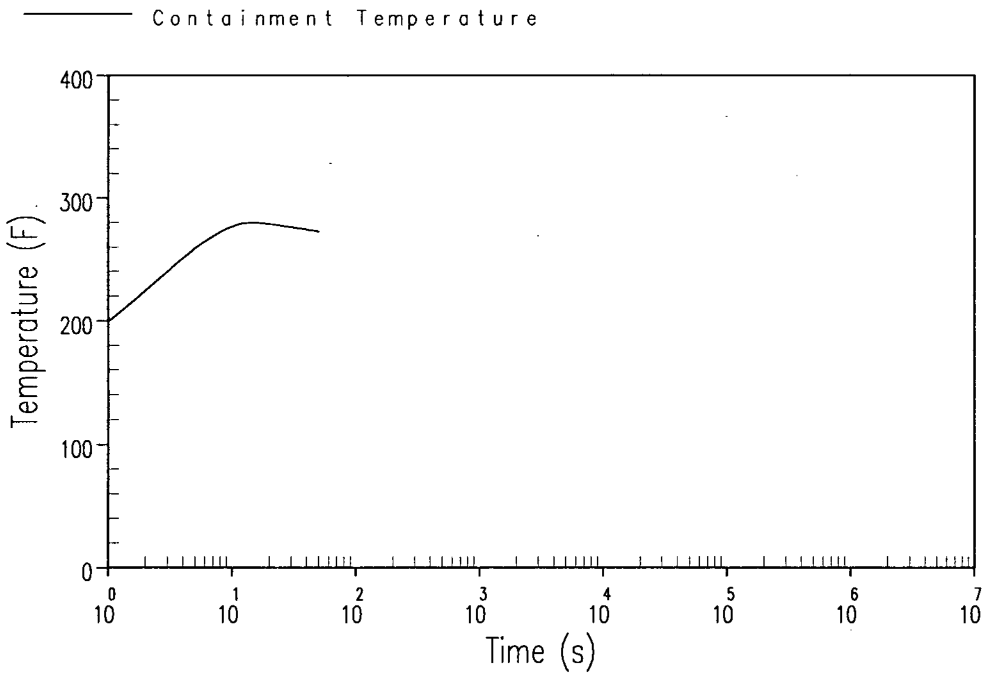


Figure 2.6.1-3
Containment Pressure – Double-Ended Pump Suction Break (Minimum Safeguards)

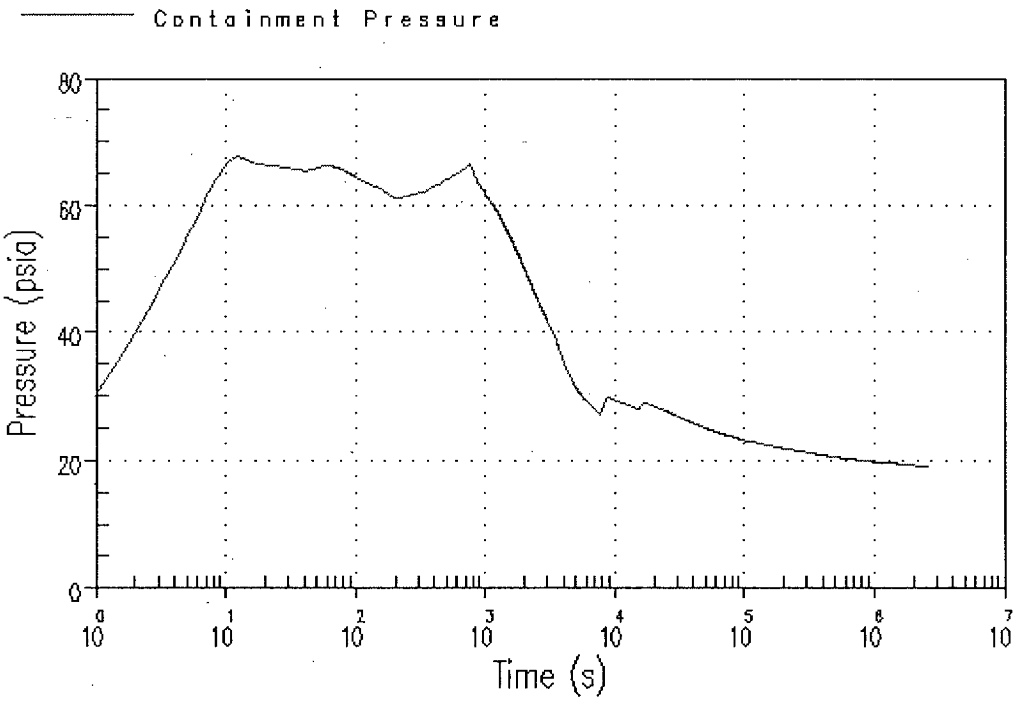


Figure 2.6.1-4
Containment Temperature – Double-Ended Pump Suction Break (Minimum Safeguards)

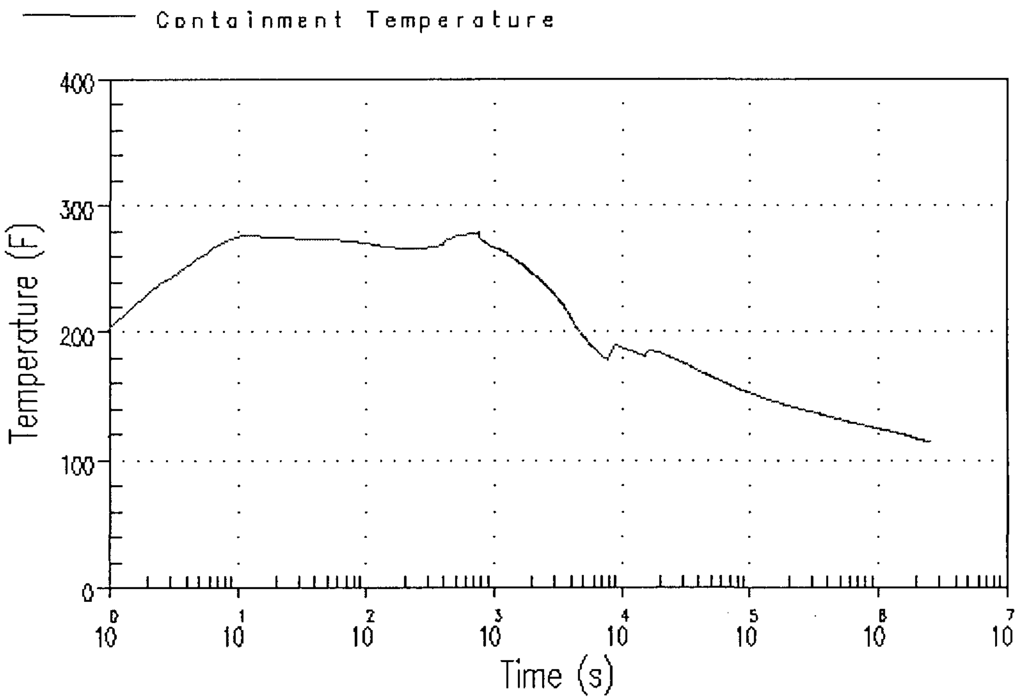


Figure 2.6.1-5
Containment Sump Temperature – Double-Ended Pump Suction Break (Minimum Safeguards)

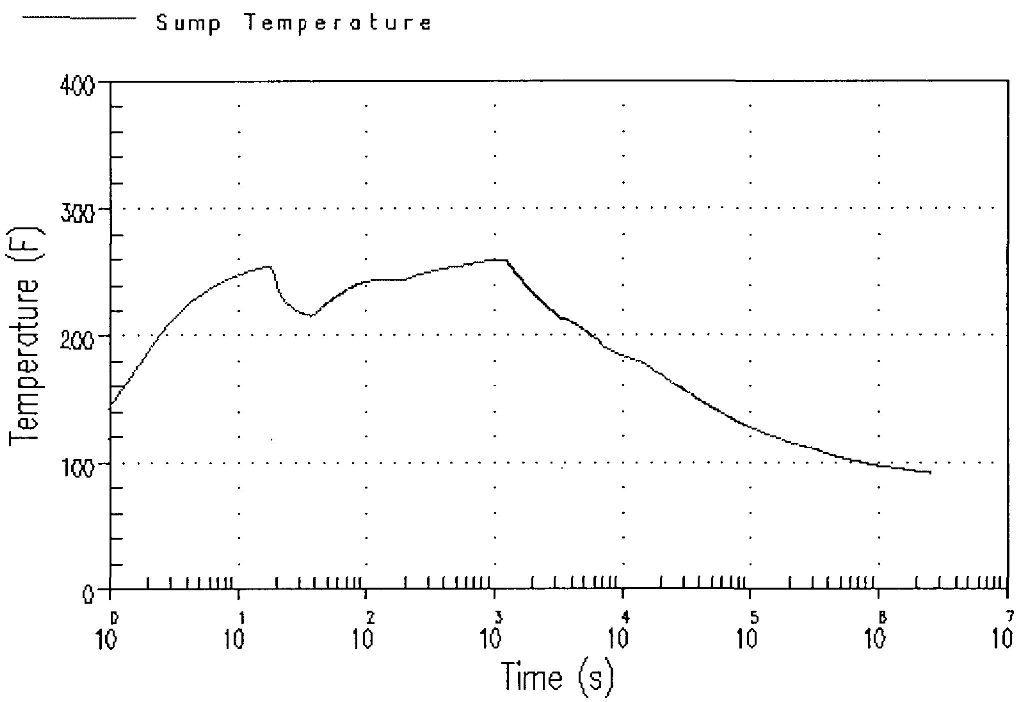


Figure 2.6.1-6
Containment Pressure for Steam Line Break Initiated from 30% Power with a Single Failure of the FIV on the Faulted Loop

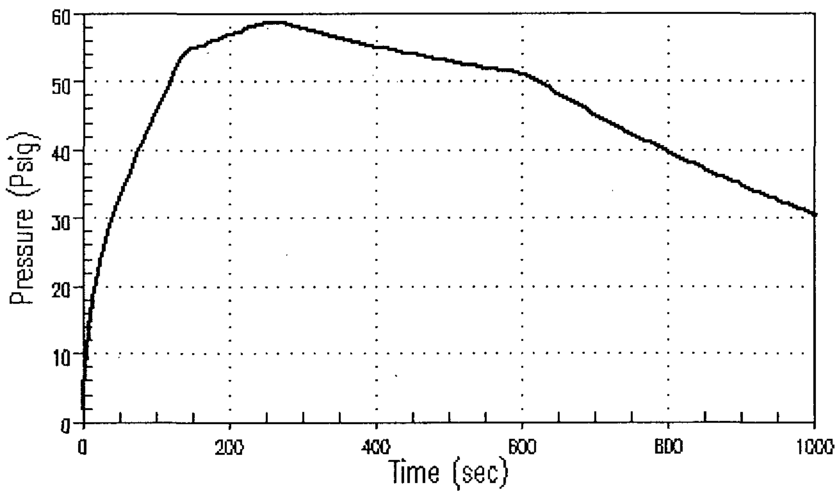


Figure 2.6.1-7
Containment Temperature for Steam Line Break Initiated from 30% Power with a Single Failure of the FIV on the Faulted Loop

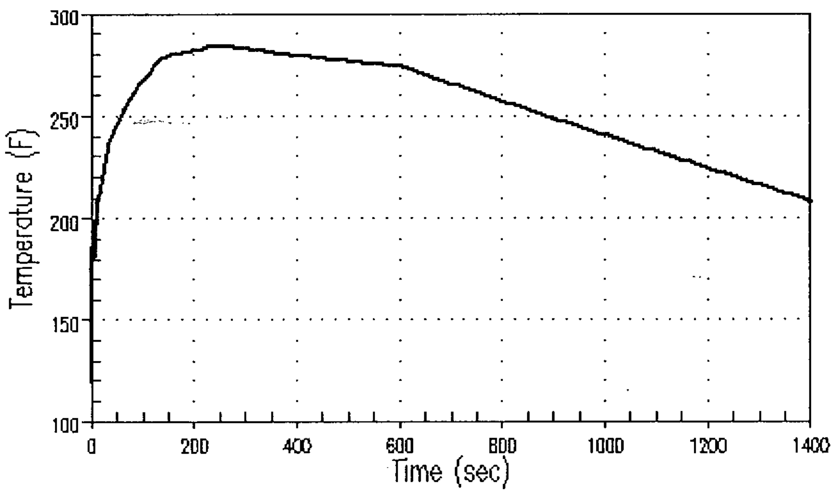


Figure 2.6.1-8
Comparison of Containment Pressure from Limiting EPU Case vs. Previous Analysis

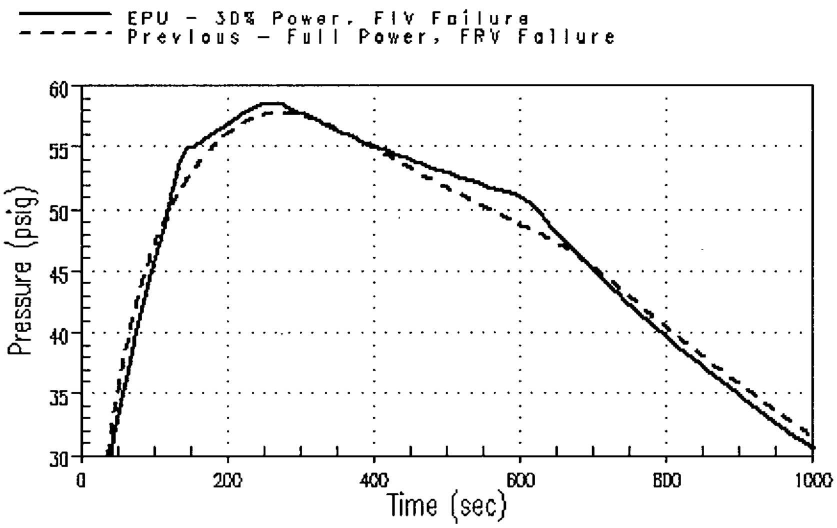
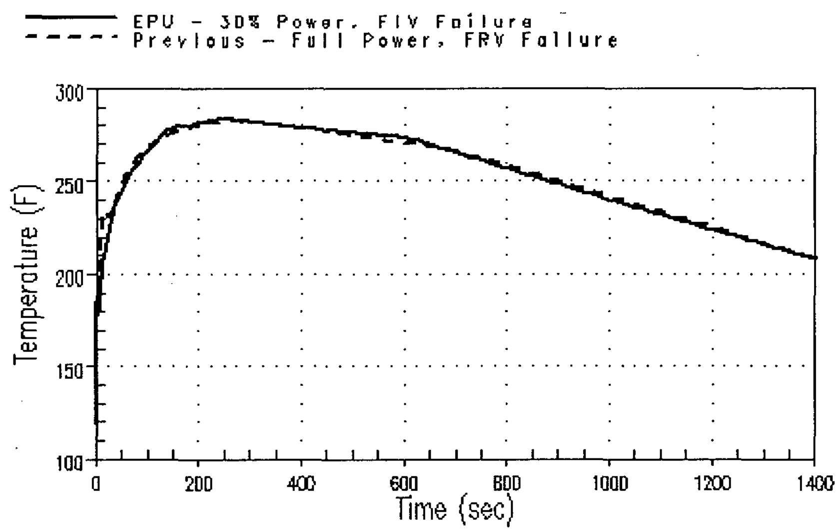


Figure 2.6.1-9
Comparison of Containment Temperature from Limiting Steam Line Break EPU Case vs. Previous Analysis



2.6.2 Subcompartment Analyses

2.6.2.1 Regulatory Evaluation

A subcompartment is defined as any fully or partially enclosed volume within the primary containment that houses high-energy piping and would limit the flow of fluid to the main containment volume in the event of a postulated pipe rupture within the volume. The PBNP review for subcompartment analyses covered the determination of the design differential pressure values for containment subcompartments. The PBNP review focused on the effects of the increase in mass and energy release into the containment due to operation at EPU conditions and the resulting increase in pressurization.

The NRC's acceptance criteria for subcompartment analyses are based on:

- GDC 4, insofar as it requires that structures, systems and components (SSCs) important-to-safety be designed to accommodate the effects of and be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, and that such SSCs be protected against dynamic effects, and
- GDC 50, insofar as it requires that the containment subcompartments be designed with sufficient margin to prevent fracture of the structure due to the calculated pressure differential conditions across the walls of the subcompartments.

Specific review criteria are contained in NRC SRP Section 6.2.1.2.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50 Appendix A GDC-4 and 50 are as follows:

CRITERION: Adequate protection for those engineered safety features, the failures of which could cause an undue risk to the health and safety of the public, shall be provided against dynamic effects and missiles that might result from plant equipment failures. (PBNP GDC 40)

As documented in FSAR Sections 4.1, Reactor Coolant System, Design Basis, 6.1.1, Engineered Safety Features Criteria and 9.0.1, Auxiliary and Emergency Systems, General Design Criteria, analyses were completed for PBNP for the main reactor coolant piping, pressurizer surge line piping, the accumulator injection lines and the residual heat removal suction and discharge lines to demonstrate that the probability of such ruptures is extremely low. NRC approval was received for these analyses, and based on this application of leak-before-break (LBB) methodology, the original design requirement for the facility to accommodate the dynamic effects of the above breaks is no longer applicable.

CRITERION: The reactor containment structure, including openings and penetrations, and any necessary containment heat removal systems, shall be designed so that the leakage of radioactive materials from the containment structure under conditions of pressure and *temperature resulting from the largest credible energy release following a* loss-of-coolant-accident, including the calculated energy from metal-water or other chemical reactions that could occur as a consequence of failure of any single active component in the emergency core cooling system, will not result in undue risk to the health and safety of the public. (PBNP GDC 49)

As documented in FSAR Section 5.1.1.1, Containment System Structure, General Design Criteria, the containment building is designed to withstand pressures resulting from the complete blowdown of reactor coolant through any rupture of the reactor coolant system up to and including the hypothetical double-ended break of a reactor coolant pipe. The reactor containment completely encloses the entire reactor and reactor coolant system and ensures that an acceptable upper limit for leakage of radioactive materials to the environment is not exceeded even if gross failure of the reactor coolant system occurs.

See LR Section 2.1.6, Leak Before Break, for further discussion.

FSAR Section 14.3.4, Evaluation of Containment Internal Structures, discusses containment subcompartment pressurization.

In addition to the evaluations described in the FSAR, PBNP's SSCs have been evaluated for plant license renewal. Plant system and component materials of construction, operating history, and programs used to manage aging effects are documented in Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005. Containment internal structures are included within the scope of license renewal as discussed in SER Section 2.4.1. The passive, long-lived internal structures are subject to existing aging management programs as described in SER Section 3.5.

2.6.2.2 Technical Evaluation

Introduction

The containment subcompartments (i.e., the reactor cavity area, the reactor coolant loop cubicles and the pressurizer cubicle), were evaluated for their structural response to potential increases in mass and energy releases (and associated pressure differentials) resulting from postulated current licensing basis high energy line breaks that are assumed to initiate at EPU operating conditions versus that used for original design.

Description of Analyses and Evaluations

Summary of Design Basis History of PBNP Containment Subcompartments

As noted in historical FSAR Section 14.3.4, Evaluation of Containment Internal Structures, containment internal structures at PBNP such as the reactor coolant loop compartments and the reactor shield wall are designed for the pressure build-up that could occur following a LOCA. The original licensing basis took into consideration that the pressure would build up in these relatively small volumes at a rate faster than the overall containment thus imposing a differential pressure across the walls of the compartments.

Historical FSAR Section 14.3.4, Evaluation of Containment Internal Structures, indicates that the:

- Reactor coolant loop compartments are designed for a pressure differential of 23 psi which represents the maximum calculated differential pressures resulting from an instantaneous double ended rupture of the reactor coolant pipe.
- Maximum differential pressures within the reactor cavity and pipe annulus surrounding the vessel nozzles of 175 psi and 900 psi, respectively, based on a longitudinal split of area equivalent to the cross-sectional area of a reactor coolant pipe, i.e., 4.5 ft^2.

The design and licensing basis requirement for PBNP containment subcompartments to withstand the dynamic effects of large reactor coolant system pipe breaks was deleted from the FSAR upon receipt of NRC Letter (G. E. Lear) to WEPCO dated May 6, 1986, which indicated that LBB technology was approved for PWR reactor coolant line breaks that have extremely low probability of occurrence. The above NRC letter also noted that asymmetric blowdown loads need not be considered for PBNP.

As noted in the Regulatory Evaluation above, the application of NRC approved LBB methodology for pipe breaks within the PBNP containment subcompartments results in no further need to evaluate the following pipe ruptures for EPU:

- Main Reactor Coolant Piping
- Pressurizer Surge Line Piping
- Accumulator Injection Lines
- Residual Heat Removal (RHR) suction and discharge lines

The largest remaining piping connections to the cold leg are 3-inch connections associated with charging and alternate charging connections, and a 6-inch connection on the hot leg (B loop). This 6-inch connection is capped and abandoned, but represents the largest unanalyzed potential double ended break.

Reactor Cavity Area

As a result of NRC approval of the application of LBB methodology at PBNP, and per current licensing basis, subcompartment pressurization need not be addressed for the reactor cavity area.

Reactor Coolant Loop Cubicle/Pressurizer Cubicle

The reactor coolant loop compartment walls are designed to a differential pressure of 23 psi for walls below EL. 46'-0" (Lower Compartment) and 7 psi for walls above EL. 46'-0" (Upper Compartment). The pressurizer cubicle walls are designed to a differential pressure of 23 psi. These design values are based on compartment pressurization resulting from a double ended rupture of a primary coolant line greater than 10 inches in diameter, and at operating conditions associated with original plant license.

The M&E releases at EPU conditions resulting from a 3-inch or 6-inch primary coolant line break (largest break size per current licensing basis), are bounded by the M&E release from a 10-inch

DER primary coolant line break at operating conditions associated with original plant license. Since the differential pressure across the cubicle walls will decrease with the decrease in M&E release into the cubicle, it is concluded that the differential pressure across the cubicle structure at EPU conditions is bounded by the original design basis, and that the design of the structure remains acceptable for EPU conditions.

Results

The differential pressure across the containment subcompartment walls resulting from postulated pipe ruptures at EPU conditions crediting LBB methodology is bounded by the original design basis, and the subcompartment structures remain acceptable for EPU conditions.

2.6.2.3 Conclusion

PBNP has assessed the effects of EPU and the changes in predicted pressurization resulting from the EPU mass and energy releases and concludes that containment SSCs important to safety will continue to be protected from the dynamic effects resulting from pipe breaks and that the subcompartments will continue to have sufficient margins to prevent fracture of the structure due to pressure difference across the walls following implementation of the proposed EPU. Based on this, PBNP concluded that the plant will continue to meet PBNP GDCs 40 and 49 for the proposed EPU. Therefore, PBNP finds the proposed EPU acceptable with respect to subcompartment analysis.

2.6.3 Mass and Energy Release

2.6.3.1 M&E Release Analysis for Postulated Loss-of-Coolant Accidents

2.6.3.1.1 Regulatory Evaluation

The release of high-energy fluid into containment from pipe breaks could challenge the structural integrity of the containment, including sub-compartments and systems within the containment. PBNP's review covered the energy sources that are available for release to the containment and the Mass & Energy (M&E) release rate calculations for the initial blowdown phase of the accident.

The NRC's acceptance criteria for M&E release analyses for postulated loss-of-coolant accidents (LOCAs) are based on:

- GDC 50, insofar as it requires that sufficient conservatism is provided in the M&E release analysis to ensure that containment design margin is maintained
- 10 CFR 50, Appendix K, insofar as it identifies energy sources during a LOCA

Specific review criteria are contained in the SRP, Section 6.2.1.3.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP specific GDC for M&E releases for postulated loss-of-coolant accidents are as follows:

CRITERION: The reactor containment structure, including openings and penetrations, and any necessary containment heat removal systems, shall be designed so that the leakage of radioactive materials from the containment structure under conditions of pressure and temperature resulting from the largest credible energy release following a loss-of-coolant-accident, including the calculated energy from metal-water or other chemical reactions that could occur as a consequence of failure of any single active component in the emergency core cooling system, will not result in undue risk to the health and safety of the public. (PBNP GDC 49)

The evolution of the containment analysis licensing basis is discussed in LR Section 2.6.1.1, Primary Containment Functional Design. For purposes of evaluating the integrity of the containment as a whole and the integrity of structures internal to the containment (sub-compartments), the effects of M&E releases are examined for long-term releases and short-term releases, respectively. The containment functional design requirement is discussed in FSAR Section 5.1, Containment System Structure. The containment integrity evaluation (long-term releases) is described in FSAR Section 14.3.4, Containment Integrity Evaluation. The method of analysis to study pressure transients in cavities and/or compartments inside of the containment resulting from the depressurization of the primary coolant is described in FSAR Appendix A.2 Addendum 2. LR Section 2.6.1, Primary Containment Functional Design, discusses containment LOCA response analysis. LR Section 2.6.2, Subcompartment Analysis, discusses the sub-compartment analysis.

Compliance with 10 CFR 50, Appendix K, with regard to energy sources, is described in FSAR Section 14.3.4, Containment Integrity Evaluation, for the loss-of-coolant accident (LOCA) analyses.

2.6.3.1.2 Technical Evaluation

2.6.3.1.2.1 Long-Term LOCA M&E Releases

The evaluation/generation of the design basis long-term LOCA M&E release data was completed to support the extended power uprate (EPU) program operation.

2.6.3.1.2.1.1 Introduction

The long-term LOCA M&E releases are described in FSAR Section 14.3.4, Containment Integrity Evaluation. The M&E release rates described in this section form the basis of further computations to evaluate the containment response following the postulated LOCA (FSAR Section 14.3.4, Containment Integrity Evaluation) and to ensure that containment design margin is maintained.

The uncontrolled release of pressurized high-temperature reactor coolant, termed a LOCA, will result in the release of steam and water into the containment. This, in turn, will result in increases in the local subcompartment pressures and an increase in the global containment pressure and temperature. Therefore, both long-term and short-term effects on the containment resulting from a postulated LOCA were considered using the conditions for PBNP Units 1 and 2 at EPU.

The long-term LOCA M&E releases analyzed using the Reference 1 methodology for the PBNP Units 1 and 2 EPU were analyzed out to 3600 seconds. The long-term post reflood releases were calculated by the GOTHIC code (References 6 and 7) and were used with the blowdown, reflood and post-reflood transient releases from the Reference 1 methods in the containment integrity analysis (discussed in LR Section 2.6.1, Primary Containment Functional Design). The use of GOTHIC in this context requires approval from the NRC. To demonstrate the acceptability of the containment safeguards systems to mitigate the consequences of a hypothetical large-break LOCA (LBLOCA), the long-term LOCA M&E releases were analyzed to 3600 seconds and used as input to the containment integrity analysis with GOTHIC that continued the long-term LOCA mass and energy release to 30 days. The containment safeguards systems must be capable of limiting the peak containment pressure to less than the design pressure, and limiting the temperature excursion to less than the environmental qualification (EQ) acceptance limits.

The EPU analyses were performed using the Westinghouse LOCA M&E Release Model for Containment Design March 1979 Version, described in WCAP-10325-P-A (Reference 1). The NRC review and approval letters are found in References 1 and 3.

2.6.3.1.2.1.2 Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters and Assumptions

The M&E release analysis is sensitive to the assumed characteristics of various plant systems, in addition to other key modeling assumptions. Where appropriate, bounding inputs are used and instrumentation uncertainties are included. For example, the RCS operating temperatures were chosen to bound the highest average coolant temperature range of all operating cases, and a temperature uncertainty allowance was then added (+6.4°F). The RCS pressure in this analysis is based on a nominal value of 2250 psia, plus an uncertainty allowance (+50 psi). Nominal parameters are used in certain instances. All input parameters are chosen consistent with accepted analysis methodology.

Some of the most critical items are the RCS initial conditions, core decay heat, safety injection flow, and primary and secondary metal mass and steam generator heat release modeling. Specific assumptions concerning each of these items are discussed in the following paragraphs. Tables 2.6.3.1-1, System Parameters Initial Conditions, through Tables 2.6.3.1-3, SI Flow Maximum Safeguards, present key data assumed in the analysis.

A licensed reactor core power of 1800 MWt (increased by 0.6% power measurement uncertainty) was used in the analysis. (As previously noted, RCS operating temperatures were chosen to bound the highest average coolant temperature range.) The use of higher temperatures is conservative because the initial fluid energy is based on coolant temperatures, which are at the maximum levels attained in steady-state operation. Additionally, an allowance to account for instrument error and dead band was reflected in the initial RCS temperature. As previously discussed, the initial RCS pressure in this analysis was based on a nominal value of 2250 psia, plus an allowance that accounted for the measurement uncertainty on pressurizer pressure. The selection of 2300 psia as the limiting pressure is considered to affect blowdown phase results only, since this represents the initial pressure of the RCS. The RCS rapidly depressurizes from this value until the point where it equilibrates with containment pressure.

The rate at which the RCS blows down is initially more severe at the higher RCS pressure. Additionally, the RCS has a higher fluid density at the higher pressure (assuming a constant temperature), and subsequently has a higher RCS mass available for releases. Therefore, 2250 psia plus uncertainty was selected for the initial pressure as the limiting condition for the long-term M&E release calculations.

The selection of the fuel design features for the long-term M&E release calculation is based on the need to conservatively maximize the energy stored in the fuel at the beginning of the postulated accident (that is, to maximize the core-stored energy). The core-stored energy is based on the time in life for maximum fuel densification. The assumptions used to calculate the fuel temperatures for the core-stored energy calculations account for appropriate uncertainties associated with the models in the PAD code (such as calibration of the thermal model, pellet densification model, or cladding creep model). In addition, the fuel temperatures for the core-stored energy calculation account for appropriate uncertainties associated with manufacturing tolerances (such as pellet as-built density). The total uncertainty for fuel temperature calculation is a statistical combination of these effects and is dependent upon fuel type, power level, and burnup. Therefore, the analysis very conservatively accounts for the stored energy in the core.

A uniform steam generator tube plugging (SGTP) level of 0% was modeled. This assumption maximized the reactor coolant volume and fluid release by including the RCS fluid in all steam generator tubes. During the post-blowdown period, the steam generators are active heat sources since significant energy remains in the secondary metal and secondary mass that has the potential to be transferred to the primary side. The 0% tube plugging assumption maximized heat transfer area and, therefore, the transfer of secondary heat across the steam generator tube. Additionally, this assumption reduced the reactor coolant loop resistance, which reduced the ΔP upstream of the break for the pump suction breaks and increased break flow. Therefore, the analysis very conservatively modeled the effects related to SGTP.

The secondary-to-primary heat transfer is maximized by assuming conservative heat transfer coefficients. This conservative energy transfer is ensured by maximizing the initial internal energy of the inventory in the steam generator secondary side. This internal energy is based on full-power operation plus uncertainties.

Following a LBLOCA inside containment, the safety injection system (SIS) operates to reflood the RCS. The first phase of the SIS operation is the passive accumulator injection. Two accumulators are assumed available to inject. When the RCS depressurizes below 834.7 psia, the accumulators begin to inject. The accumulator injection temperature was conservatively modeled high at 120°F. Relative to the active pumped emergency core cooling system (ECCS) operation, the M&E release calculation considered configurations, component failures, and offsite power assumptions to conservatively bound respective alignments. The cases include a minimum safeguards case (one high-head SI (HHSI) pump, and one low-head SI (LHSI) pump, see Tables 2.6.3.1-2, SI Flow Minimum Safeguards, and a maximum safeguards case (two HHSI and two LHSI pumps, see Table 2.6.3.1-3. In addition, a conservative containment backpressure was assumed to bound the GOTHIC calculated results. The assumption of high containment backpressure was shown in Reference 1 to be conservative for the generation of M&E energy releases.

In summary, the following assumptions were employed to ensure that the M&E releases are conservatively calculated, thereby maximizing energy release to containment:

- Maximum expected operating temperature of the RCS (100% full-power operation)
- Allowance for RCS temperature uncertainty (+6.4°F)
- Analyzed core power of 1811 MWt (includes uncertainty)
- Allowance for calorimetric error (0.6% of power)
- Conservative heat transfer coefficients (that is, steam generator primary/secondary heat transfer and RCS metal heat transfer)
- Allowance in core-stored energy for effect of fuel densification

- An allowance for RCS initial pressure uncertainty (+50 psi)
- A total uncertainty for fuel temperature calculation based on a statistical combination of effects and dependent upon fuel type, power level, and burnup
- A maximum containment backpressure equal to design pressure (74.7 psia)
- SGTP level (0% uniform)
  - Maximizes reactor coolant volume and fluid release
  - Maximizes heat transfer area across the steam generator tubes
  - Reduces reactor coolant loop resistance, which reduces the ΔP upstream of the break for the pump suction breaks and increases break flow

Therefore, based on the previously discussed conditions and assumptions, an analysis of PBNP Units 1 and 2 was performed for the release of M&E from the RCS in the event of LOCA.

Application of Single-Failure Criterion

An analysis of the effects of the single-failure criterion has been performed on the M&E release rates for each break analyzed. An inherent assumption in the generation of the M&E release is that offsite power is lost with the pipe rupture. This results in the actuation of the emergency diesel generators (EDGs), required to power the SIS. Operating the EDG delays the operation of the SIS that is required to mitigate the transient. This is not an issue for the double-ended hot leg break (DEHL), which is blowdown limited.

Two cases were analyzed to assess the effects of a single failure. The first case assumed minimum safeguards SI flow based on the postulated single failure of an EDG. This assumption results in the loss of one train of safeguards equipment. Therefore, the remaining ECCS was conservatively modeled as: one HHSI pump and one LHSI pump. The maximum safeguards case was modeled as: two HHSI pumps and two LHSI pumps until the RWST water level is drained down to 60% and then only one HHSI pump and one LHSI pump are modeled for the remainder of the injection phase. The single failure assumption postulated is the failure of one containment spray train. Only a single train of recirculation flow was used for the maximum safeguards case. Typically a maximum safeguards case would include two trains of safety injection and recirculation flow. PBNP plant procedures direct operators to shut down one of the two trains and place it in standby when the RWST water level is drained down to 60% through the remainder of the transient. The analysis of the cases described provides confidence that the effect of credible single failures is bounded.

Decay Heat Model

American Nuclear Society (ANS) Standard 5.1 was used in the LOCA M&E release model for PBNP Units 1 and 2 for the determination of decay heat energy. The NRC approved the use of the ANS Standard 5.1, decay heat model for the calculation of M&E releases to the containment following a LOCA. Table 2.6.3.1-4 lists the decay heat curve used in the PBNP Units 1 and 2 EPU M&E release analysis.

Significant assumptions in the generation of the decay heat curve for use in the LOCA M&E release analysis include the following:

- The decay heat sources considered are fission product decay and heavy element decay of U-239 and Np-239
- The decay heat power from fissioning isotopes other than U-235 is assumed to be identical to that of U-235
- The fission rate is constant over the operating history of maximum power level
- The factor accounting for neutron capture in fission products is taken from Table 10 of the ANS Standard 5.1 (Reference 2)
- The fuel is assumed to be at full power for 10^8 seconds
- The total recoverable energy associated with one fission is assumed to be 200 MeV/fission
- Two sigma uncertainty (two times the standard deviation) is applied to the fission product decay

Acceptance Criteria

The long-term cooling criterion was examined. An LBLOCA is classified as an ANS Condition IV event, an infrequent fault. The relevant requirements to satisfy the acceptance criteria are as follows:

- 10 CFR 50, Appendix A
- 10 CFR 50, Appendix K, Paragraph I.A

To meet these requirements, the following must be addressed:

- Sources of energy
- Break size and location
- Calculation of each phase of the accident

2.6.3.1.2.1.3 Description of Analyses and Evaluations

Description of Analyses

The evaluation model (EM) used for the long-term LOCA M&E release calculations is the 1979 model described in WCAP-10325-P-A (References 1 and 3). This EM has been reviewed and approved by the NRC. The initial approval letter is included with Reference 1. Further approval is provided in Reference 3.

This section presents the long-term LOCA M&E releases generated in support of the PBNP Units 1 and 2 EPU program. These M&E releases were used in the containment integrity analysis and equipment qualification temperature evaluation.

The M&E release rates described in this section form the basis of further computations to evaluate the containment following the postulated accident. Discussed in this section are the long-term LOCA M&E releases for the hypothetical double-ended pump suction (DEPS) rupture with minimum safeguards and DEHL rupture cases. The M&E releases and related analysis information for these cases are shown in Tables 2.6.3.1-5 through 2.6.3.1-13. These cases are used for the long-term containment response analyses in LR Section 2.6.1, Primary Containment Functional Design and Section 2.6.5, Containment Heat Removal.

This section presents an analysis for PBNP Units 1 and 2. Parameters were used from both plants to generate one bounding analysis.

LOCA M&E Release Phases

The containment system receives M&E releases following a postulated rupture in the RCS. These releases continue over a time period, which, for the LOCA M&E analysis, is typically divided into four phases.

Blowdown – the period of time from accident initiation (when the reactor is at steady-state operation) to the time that the RCS and containment reach an equilibrium state.

Refill – the period of time when the lower plenum is being filled by the accumulator and ECCS water. At the end of blowdown, a large amount of water remains in the cold legs, downcomer, and lower plenum. To conservatively consider the refill period for the purpose of containment M&E releases, it is assumed that this water is instantaneously transferred to the lower plenum along with sufficient water to completely fill the lower plenum. This allows an uninterrupted release of M&E to containment. Therefore, the refill period is conservatively neglected in the M&E release calculation.

Reflood – the period of time that begins when water from the lower plenum enters the core and ends when the core is completely quenched.

Post-Reflood (Froth) – the period of time following the reflood phase. At the end of reflood, the core has been recovered with water and the ECCS continues to supply water to the vessel. Depending on the location of the break, the two-phase mixture in the vessel may pass through the steam generator on the broken loop and acquire heat from the stored energy in the secondary system. The methods from Reference 1 are used until 3600 seconds.

Computer Codes

The WCAP-10325-P-A (Reference 1) M&E release evaluation model comprises M&E release versions of the following codes: SATAN VI, WREFLOOD, FROTH, and EPITOME. These codes were used to calculate the long-term LOCA M&E releases for PBNP Units 1 and 2. Reference 1 includes a Safety Evaluation Report (SER) dated February 18, 1987 for the use of these codes.

SATAN VI calculates the blowdown phase, the first portion of the thermal-hydraulic transient following break initiation, including pressure, enthalpy, density, M&E flow rates, and energy transfer between primary and secondary systems as a function of time.

The WREFLOOD code addresses the portion of the LOCA transient where the core reflooding phase occurs after the primary coolant system has depressurized (blowdown) due to the loss of water through the break and when water supplied by the ECCS refills the reactor vessel and cools the core. The most important feature of WREFLOOD is the steam/water mixing model.

The FROTH code models the post-reflood portion of the transient until the time that the secondary side of the intact loop's steam generator has depressurized to the containment design pressure.

EPITOME continues the FROTH post-reflood portion of the transient from the time at which the secondary side equilibrates to the containment design pressure to 3600 seconds. It also compiles a summary of data for the entire transient, including formal instantaneous M&E release tables and M&E balance tables with data at critical times.

Break Size and Location

Generic studies have been performed and documented in Reference 1 with respect to the effect of postulated break size on the LOCA M&E releases. This section presents the M&E releases to the containment subsequent to a hypothetical LOCA. The release rates were calculated to support the EPU program and were calculated for pipe failures at two distinct locations:

1. Hot leg (between vessel and steam generator)

2. Pump suction (between steam generator and pump)

A third possible location is the cold leg (between the reactor coolant pump and the vessel), but the generic studies that have been documented in Reference 1 have shown that the double-ended break in the cold leg is not limiting for peak calculated containment pressure and temperature.

During the reflood phase, these breaks have the following characteristics. For a hot leg break, the vent path resistance is relatively low, which results in a high core flooding rate, and the majority of the fluid which exits the core bypasses the steam generators in venting the containment. The pump suction break combines the effects of the relatively high core flooding rate, as in a hot leg break, and steam generator heat addition, as in the cold leg break. As a result, the pump suction breaks yield the highest energy flow rates during the post-blowdown period. However, relative to breaks at other locations, the core flooding rate (and therefore the rate of fluid leaving the core) is low, because all the core vent paths include the resistance of the reactor coolant pump.

The spectrum of breaks analyzed includes the double-ended hot leg break (DEHL) and double-ended pump suction break (DEPS) with a discharge coefficient of 1.0. Because of the phenomena of reflood as discussed above, the pump suction break location is the worst case for long term containment pressurization. This conclusion is supported by studies presented in Reference 1. Pressure due to the high short-term blowdown release associated with this break location.

M&E Release Data

<u>Blowdown M&E Release Data</u>

The SATAN VI code was used for computing the blowdown transient. Table 2.6.3.1-5 presents the calculated M&E release for the blowdown phase of the DEHL break. For the DEHL break M&E release tables, break path 1 refers to the M&E exiting from the reactor vessel side of the break; break path 2 refers to the M&E release exiting from the steam generator side of the break.

Table 2.6.3.1-8 presents the calculated M&E releases for the blowdown phase of the DEPS break. The blowdown phase of the DEPS break applies to both the minimum safeguards case and the maximum safeguards case. For the pump suction breaks, break path 1 in the M&E release tables refers to the M&E exiting from the steam generator side of the break. Break path 2 refers to the M&E exiting from the pump side of the break.

Reflood M&E Release Data

The WREFLOOD code is used for computing the reflood transient.

Table 2.6.3.1-9 presents the calculated reflood M&E for the pump suction double-ended rupture, minimum safeguards case. The minimum safeguards case data (as opposed to the maximum safeguards case) is presented due to it being the limiting case for the long-term portion of the containment response transient discussed in LR Section 2.6.1, Primary Containment Functional Design.

The transient responses of the principal parameters during reflood are given in Table 2.6.3.1-10 for the double-ended rupture, minimum safeguards case.

Post-Reflood M&E Release Data

The long-term M&E releases account for the transfer of the decay heat and the stored energy in the primary and secondary systems to the containment after the end of reflood. The energy for each source term is acquired at the end of reflood from the Westinghouse M&E release analysis. The rate of energy release is determined by a simplified, RCS model that is coupled to the containment volume. Thus, the flow from the vessel to the containment is dependent on the calculated containment pressure. Table 2.6.3.1-11 presents the calculated post-reflood M&E for the pump suction double-ended rupture minimum safeguards case to 3600 seconds.

Sources of M&E

The sources of mass considered in the LOCA M&E release analysis are given in Table 2.6.3.1-6, and Table 2.6.3.1-12. These sources include the:

- RCS water
- Accumulator water
- Pumped injection (SI)

The energy inventories considered in the LOCA M&E release analysis are given in Table 2.6.3.1-7 and Table 2.6.3.1-13. The energy sources are the following:

- RCS water
- Accumulator water
- Pumped injection (SI)
- Decay heat
- Core-stored energy
- RCS metal (includes steam generator tubes)

- Generator metal (includes transition cone, shell, wrapper, and other internals)
- Steam generator secondary energy (includes fluid mass and steam mass)
- Secondary transfer of energy (feedwater into and steam out of the steam generator secondary: feedwater pump coastdown after the signal to close the flow control valve)

The analysis used the following energy reference points:

- Available energy: 212°F; 14.7 psia (energy available that could be released)
- Total energy content: 32°F; 14.7 psia (total internal energy of the RCS)

The M&E inventories are presented at the following times (in seconds), as appropriate:

	DEHL	DEPS
• Time zero (initial conditions)	0.0	0.0
• End-of-blowdown time	16.8	13.2
• End-of-refill time	16.8	13.2
• End-of-reflood time	N/A	206.31
• Time of broken loop steam generator equilibration to pressure setpoint	N/A	975.11
• Time of intact loop steam generator equilibration to pressure setpoint	N/A	1285.03
• Time of full depressurization (3600 seconds)	N/A	3600.0

The energy release from the metal-water reaction rate is considered as part of the WCAP-10325-P-A (Reference 1) methodology. Based on the way that the energy in the fuel is conservatively released to the vessel fluid, the fuel cladding temperature does not increase to the point where the metal-water reaction is significant. This is in contrast to the 10 CFR 50.46 analyses, which are biased to calculate high fuel rod cladding temperatures and, therefore, a potentially significant metal-water reaction. For the LOCA mass and energy release calculation, the energy created by the metal-water reaction value is small and is not explicitly provided in the energy balance tables. The energy that is determined is part of the mass and energy releases and is therefore already included in the overall mass and energy releases for PBNP Units 1 and 2.

The sequences of events for the LOCA transients are shown in Tables 2.6.3.1-14 and 2.6.3.1-15.

2.6.3.1.2.1.4 M&E Release Analysis for Postulated LOCA Results

The LOCA M&E releases from accident initiation to the end of reflood, where applicable, have been provided for the DEHL and for the DEPS break cases. Post-reflood M&E releases after 3,600 seconds were calculated internally to the containment model.

The M&E release transients for the limiting transients are presented in Tables 2.6.3.1-5 through 2.6.3.1-7 for the DEHL case and Tables 2.6.3.1-8 through 2.6.3.1-13 for the DEPS case with minimum ECCS flows.

The results of this analysis (M&E release rate transients) were used in the containment integrity analysis (see LR Section 2.6.1, Primary Containment Functional Design).

2.6.3.1.2.1.5 M&E Release Analysis for Postulated LOCA Conclusion

The consideration of the various energy sources listed in LR Section 2.6.3.1.2.1.2, M&E Release Analysis for Postulated Loss-of-Coolant Accidents, Input Parameters, Assumptions, and Acceptance Criteria, for the long-term M&E release analysis provides assurance that all available sources of energy have been included in this analysis. By addressing all available sources of energy as well as the limiting break size and location and the specific modeling of each phase of the long-term LOCA transient, the review guidelines presented in SRP, Section 6.2.1.3 have been satisfied.

2.6.3.1.2.2 Short-Term LOCA M&E Releases

An evaluation was conducted to determine the effect of the PBNP Units 1 and 2 EPU program on the short-term LOCA-related M&E releases. PBNP Units 1 and 2 were initially approved for Leak-Before-Break (LBB) via Reference 5. In accordance with the 1987 revision to GDC-4, the dynamic effects of RCS main loop piping breaks and RCS branch line breaks 10 inch diameter and larger have been eliminated from consideration (see LR Section 2.1.6, Leak-Before-Break).

The short-term LOCA-related M&E releases were used as input to the subcompartment analyses (see LR Section 2.6.2, Subcompartment Analyses). These analyses were performed to ensure that the walls of a sub-compartment can maintain their structural integrity during the short pressure pulse (generally less than 3 seconds) accompanying a high-energy line pipe rupture within that sub-compartment. Short-term M&E release calculations are performed to support the steam generator compartments and the pressurizer compartment.

2.6.3.1.2.2.1 Introduction

The containment internal structures are designed for a pressure buildup that could occur following a postulated LOCA. If a LOCA were to occur in these relatively small volumes, the pressure would build up at a faster rate than the overall containment, thus imposing a differential pressure across the walls of the compartments.

Short-term LOCA M&E release calculations are performed to support the steam generator compartments and the pressurizer compartment.

PBNP Units 1 and 2 are licensed in accordance with the 1987 revision to GDC-4. This eliminates the need to consider RCS branch lines 10 inches in diameter and greater for sub-compartment pressurization. The pressurizer surge line was also eliminated for structural design basis in WCAP-15065, Revision 1. The largest remaining break locations that need to be considered are a 6 inch double-ended hot leg break and a 3 inch double-ended cold leg break. The releases associated with these smaller breaks would be considerably lower than the large RCS breaks.

LR Section 2.6.2, Subcompartment Analyses, discusses the short-term evaluation conducted for this program.

2.6.3.1.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters and Assumptions

The short-term LOCA M&E release analysis is sensitive to the assumed characteristics of various plant systems, in addition to other key modeling assumptions. Where appropriate, bounding inputs are used and instrumentation uncertainties are included. For example, the RCS operating temperatures were chosen to bound the temperature range of all operating cases and a temperature uncertainty allowance (-6.4°F) was then included. The RCS pressure in this analysis is based on a nominal value of 2250 psia plus an uncertainty allowance to arrive at a value of 2300 psia. All input parameters are chosen consistent with accepted analysis methodology. Increased power has no impact on the short-term releases because of the duration of the event (that is, ~3.0 seconds). Only reductions in the initial RCS temperature conditions (including uncertainties) would affect the blowdown M&E release rates and thus the results.

Any possible change in the core-stored energy does not adversely affect the normal plant operating parameters, system actuations, accident mitigating capabilities or assumptions important to the short-term LOCA M&E releases. Any change in core-stored energy would have no effect on the releases because of the short duration of the postulated accident.

Therefore, the only effects that need to be addressed are the change in RCS coolant temperatures and the changes in analysis assumptions for RCS coolant pressure.

In summary, the following assumptions were employed to ensure that the 6 inch double-ended hot leg and 3 inch double-ended cold leg break releases were conservatively calculated for the EPU program:

- Minimum RCS vessel outlet temperature of 592.9°F
- Minimum RCS vessel/core inlet temperature of 525.0°F (corresponds to minimum reactor vessel temperature for PTS considerations)
- Allowance for RCS temperature uncertainty of -6.4°F
- Allowance for RCS pressure uncertainty of + 50.0 psi

Acceptance Criteria

A LOCA is classified as an ANS Condition IV event – an infrequent fault. The relevant requirements to satisfy the acceptance criteria are as follows:

The NRC's NUREG-0800, Section 6.2.1.3, M&E Release Analysis for Postulated Loss-of-Coolant Accidents subsection II, Part 3a provides guidance on NRC's expectations for what must be included in a LOCA M&E release calculation, if that calculation is to be acceptable. The Westinghouse M&E models described in WCAP-8264-P-A Rev. 1 (Reference 4) have been found by the NRC to satisfy those expectations.

2.6.3.1.2.2.3 Description of Analysis and Evaluations

Description of Analysis

Short-term releases are linked directly to the critical mass flux, which increases with increasing pressures and decreasing temperatures. The short-term LOCA releases are expected to increase due to changes associated with the current RCS conditions. Short-term blowdown transients are characterized by a peak M&E release rate that occurs during a sub-cooled condition; thus the Zaloudek correlation, which models this condition, is currently used in the short-term LOCA M&E release analyses (Reference 4). This correlation was used to conservatively evaluate the impact of the deviations in the RCS inlet and outlet temperature for the EPU program. Therefore, using lower temperatures maximizes the short-term LOCA M&E releases.

The releases from the 6 inch double-ended hot leg and 3 inch double-ended cold leg breaks evaluated for Point Beach Units 1 and 2 are found in Table 2.6.3.1-16.

Refer to LR Section 2.6.2, Subcompartment Analysis, for the analysis of the line breaks within the containment sub-compartments.

2.6.3.1.2.2.4 Short-Term LOCA M&E Releases Results

In summary, with the elimination of the large RCS breaks, the only break locations that needed to be considered were a 6 inch double-ended hot leg break and a 3 inch double-ended cold leg break. The breaks were evaluated using RCS coolant temperatures and pressures at the PBNP Units 1 and 2 EPU conditions. The results of this evaluation can be found in Table 2.6.3.1-16. The impact of the EPU program on the compartment response is discussed in LR Section 2.6.2, Subcompartment Analysis.

2.6.3.1.2.2.5 Short-Term LOCA M&E Releases Conclusion

The short-term LOCA mass and energy releases have been evaluated to determine the affect of the EPU. The original design basis short-term mass and energy releases remain bounding due to LBB. The decrease in mass and energy releases associated with the smaller breaks more than offsets the potential penalties associated with increased releases associated with the EPU. Additionally, releases have been provided for the smaller breaks at the EPU conditions.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

The analysis performed to assess the containment response to the limiting LOCA resulting from operation at EPU conditions does not add any new functions for existing components that would change the license renewal system evaluation boundaries. The analytical results associated with operating at EPU conditions do not add any new or previously unevaluated aging effects that necessitate changes to aging management programs or require new programs as internal and external environments remain within the parameters previously evaluated. Therefore, there is no impact to license renewal scope, aging effects, and aging management programs as a result of EPU activities.

2.6.3.1.3 Conclusion

PBNP has reviewed the M&E release assessment and concludes that it has adequately addressed the effects of the proposed EPU and appropriately accounts for the sources of energy identified in 10 CFR 50, Appendix K. Based on this, the PBNP staff finds that the M&E release analysis will continue to meet the PBNP Units 1 and 2 current licensing basis with respect to the requirements in PBNP GDC 49 for ensuring that the analysis is conservative. Therefore, PBNP finds the proposed EPU acceptable with respect to M&E release for postulated LOCA.

2.6.3.1.4 References

1. WCAP-10325-P-A, (Proprietary), and WCAP-10326-A, (Nonproprietary), Westinghouse LOCA Mass and Energy Release Model for Containment Design March 1979, May 1983

2. ANSI/ANS-5.1 1975, American National Standard for Decay Heat Power in Light Water Reactors, August 1979

3. NRC to W, Acceptance of Clarifications of Topical Report WCAP-10325, Westinghouse LOCA Mass And Energy Release Model For Containment Design – March 1979 Version, (TAC No. MC7980), October 18, 2005

4. WCAP-8264-P-A, Rev. 1, and WCAP-8312-P-A, Rev. 2, Topical Report Westinghouse Mass and Energy Release Data for Containment Design, August 1975

5. Generic Letter 84-04, Safety Evaluation of Westinghouse Topical Reports Dealing with Elimination of Postulated Pipe Breaks in PWR Primary Main Loops, February 1, 1984

6. NAI-8907-06, Rev. 16, GOTHIC Containment Analysis Package Technical Manual, Version 7.2a, January 2006

7. NAI-8907-09, Rev. 9, GOTHIC Containment Analysis Package Qualification Report, Version 7.2a, January 2006

Table 2.6.3.1-1
System Parameters Initial Conditions

Parameters	Value
Analyzed Core Power (MWt) (includes 0.6% calometric uncertainty)	1811.0
RCS Total Flow Rate (lbm/sec)	18,777.8
Vessel Outlet Temperature(1) (°F)	617.5
Core Inlet Temperature(1) (°F)	549.3
Vessel Average Temperature(1) (°F)	583.4
Initial Steam Generator Steam Pressure (psia)	800.0
Steam Generator Design:	
Unit 1	44F
Unit 2	Δ47
SGTP (%)	0
Initial Steam Generator Secondary Side Mass (lbm)	105,704.5
Assumed Maximum Containment Backpressure (psia)	74.7
Accumulator	
Water volume (ft^3) per accumulator (minimum)(2)	1100.0
N_2 cover gas pressure (psia) (maximum)(3)	834.7
Temperature (°F)	120.0
SI Start Time, (sec) (total time from beginning of event, which includes the maximum delay from reaching the setpoint)	40.8 (DEHL) 41.1 (DEPS)
Auxiliary Feedwater Flow (gpm/steam generator) (Minimum Safeguards)	0
Auxiliary Feedwater Flow (gpm/steam generator) (Maximum Safeguards)	0

Notes:
RCS total flow rate, RCS coolant temperatures, N_2 cover gas pressure, and steam generator secondary side mass include appropriate uncertainty and/or allowance.

1. RCS coolant temperatures include uncertainty of +6.4°F.
2. Does not include accumulator line volume.
3. N_2 cover gas pressure includes uncertainty of +20 psi.

Table 2.6.3.1-2
SI Flow Minimum Safeguards

RCS Pressure (psia)	Total Flow (lbm/sec)
Injection Mode (reflood phase)	
14.7	363.2
34.7	341.2
54.7	316.9
74.7	290.1
94.7	257.6
114.7	214.3
Injection Mode (post-reflood phase)	
74.7	290.1
Recirculation Mode	
14.7	270.9

Table 2.6.3.1-3
SI Flow Maximum Safeguards

RCS Pressure (psia)	Total Flow (lbm/sec)
Injection Mode (reflood phase)	
14.7	800.0
34.7	766.0
54.7	728.0
74.7	686.0
94.7	642.0
114.7	592.0
Injection Mode (post-reflood phase)	
74.7	686.0
Recirculation Mode	
14.7	270.9

Table 2.6.3.1-4
LOCA M&E Release Analysis Core Decay Heat Fraction

Time (sec)	Decay Heat Generation Rate Fraction
10	0.053876
15	0.050401
20	0.048018
40	0.042401
60	0.039244
80	0.037065
100	0.035466
150	0.032724
200	0.030936
400	0.027078
600	0.024931
800	0.023389
1000	0.022156
1500	0.019921
2000	0.018315
4000	0.014781
6000	0.013040
8000	0.012000
10,000	0.011262
15,000	0.010097
20,000	0.009350
40,000	0.007778
60,000	0.006958
80,000	0.006424
100,000	0.006021
150,000	0.005323
200,000	0.004847
400,000	0.003770
600,000	0.003201
800,000	0.002834
1,000,000	0.002580

Table 2.6.3.1-5
DEHL Break Blowdown M&E Release

Time Seconds	Break Path No.1[1] Mass lbm/sec	Break Path No.1[1] Energy Thousand Btu/sec	Break Path No. 2[2] Mass lbm/sec	Break Path No. 2[2] Energy Thousand Btu/sec
0	0	0	0	0
0.00105	43846.1	27887.9	43844.7	27886.1
0.0021	45581.8	28990.5	45315.1	28815.3
0.101	36870.4	23703.6	26076.1	16547.1
0.201	34526.6	22144.8	22945.8	14470.9
0.301	33562	21476.5	20500.8	12755.1
0.401	32156.7	20571.6	19258.5	11788.9
0.502	31510.2	20158.8	18476.4	11131.1
0.601	31265.9	20016.2	17888.3	10625.9
0.701	30564.7	19617.4	17440.1	10231.7
0.801	30263.4	19509.8	17081.8	9914.3
0.902	29745.8	19293.3	16765.8	9639.7
1	28848.3	18828.7	16570.2	9448.4
1.1	27963.2	18376.9	16420.9	9294.4
1.2	27114.4	17952.7	16374.8	9206.7
1.3	26248.2	17518.1	16399.9	9164.4
1.4	25313.3	17030	16464	9148.5
1.5	24276.9	16462.1	16554.9	9151.5
1.6	23233.8	15875.5	16663.2	9168.8
1.7	22229.9	15314	16773.9	9192
1.8	21313.4	14823.9	16878.9	9217
1.9	20449	14388.2	16973	9240.7
2	19488.2	13903.7	17042.3	9255.8
2.1	18661.9	13429.7	17085.9	9260.8
2.2	18094	13035.2	17097.2	9252.4
2.3	17750.7	12707.4	17079.7	9231.6
2.4	17536.3	12436.6	17034.8	9198.9
2.5	17356.4	12197.5	16964.3	9155.1
2.6	17167.9	11976	16868.8	9099.9
2.7	16974.9	11772.4	16746.4	9032.2

Table 2.6.3.1-5
DEHL Break Blowdown M&E Release

Time Seconds	Break Path No.1[1] Mass lbm/sec	Break Path No.1[1] Energy Thousand Btu/sec	Break Path No. 2[2] Mass lbm/sec	Break Path No. 2[2] Energy Thousand Btu/sec
2.8	16845.5	11638.7	16599.7	8953.3
2.9	16736.3	11528.7	16416.6	8856.4
3	16663.7	11433.8	16208.6	8747.5
3.1	16647.1	11357.8	15977.9	8627.6
3.2	16674.8	11299.2	15731.1	8500.1
3.3	16721.6	11248	15445.5	8352.7
3.4	16768	11200.1	15113.9	8181
3.5	16796.2	11146.1	14737.4	7985.6
3.6	16807.1	11090.9	14333.3	7775.8
3.7	16800.7	11033.2	13917.8	7560.7
3.8	16747.1	10965.1	13505.1	7348.2
3.9	16628.6	10879.3	13124.3	7153.8
4	16502.8	10792	12745.7	6961.8
4.2	16249.6	10617.5	11999.7	6584
4.4	16009.3	10433.8	11208.8	6180.2
4.6	15799.7	10256.9	10432.6	5782.9
4.8	15594	10081.1	9719.7	5417.5
5	15369.7	9896.9	9091.4	5096.3
5.2	15147.9	9713.8	8552.6	4821.3
5.4	14909.2	9517.7	8080.8	4580.8
5.6	14680.3	9323	7661.8	4367.5
5.8	11401.5	7905.3	7274.6	4170.3
6	11060.5	7663.1	6893.2	3975.8
6.2	10618.4	7405.7	6516.3	3785
6.4	10190.4	7119.4	6147.5	3601.2
6.6	9794.1	6900.7	5791.7	3427.3
6.8	9369.6	6607.8	5446.4	3261
7	8991.4	6363	5119.3	3105.5
7.2	8648	6154.1	4811.3	2959.6
7.4	8102.8	5858.6	4526.3	2823.7

Table 2.6.3.1-5
DEHL Break Blowdown M&E Release

Time Seconds	Break Path No.1[1] Mass lbm/sec	Break Path No.1[1] Energy Thousand Btu/sec	Break Path No. 2[2] Mass lbm/sec	Break Path No. 2[2] Energy Thousand Btu/sec
7.6	7741.8	5613.8	4267.2	2698.4
7.8	7266.7	5315.8	4051.8	2593.7
8	6775.6	5068.8	3863.1	2495.2
8.2	6249.8	4806.7	3669.4	2387.7
8.4	5743.8	4542.3	3479	2286.5
8.6	5267	4287	3287.2	2191.6
8.8	4804.3	4038.6	3089.7	2099.3
9	4366.7	3800.9	2891.7	2010
9.2	3934.8	3578.4	2698.8	1926.1
9.4	3502.8	3365.7	2512.5	1847.9
9.6	3078.3	3161.7	2333.6	1775.5
9.8	2650.7	2894.8	2161.3	1707.5
10	2390.4	2671.5	1995.8	1642.7
10.2	2238.2	2477.7	1836.5	1579.4
10.2	2237.9	2477.2	1836.1	1579.4
10.4	2117.5	2322.7	1690.6	1522.9
10.6	1964.5	2176.7	1558	1474.6
10.8	1804.6	2052.5	1434	1428.9
11	1660.3	1928.1	1327	1391.5
11.2	1522.3	1800.7	1235.1	1352.4
11.4	1417.2	1696.5	1153.7	1311.8
11.6	1298.7	1567	1081.5	1259.1
11.8	1192.5	1452.2	985.5	1177.5
12	1082.7	1329.1	868.3	1060.9
12.2	947.6	1167.7	682.1	840.3
12.4	825.3	1022.9	535	662
12.6	711	885.2	453	562.9
12.8	92.9	111.8	521.3	649
13	0	0	600.9	747.2
13.2	0	0	667.6	828.2

Table 2.6.3.1-5
DEHL Break Blowdown M&E Release

Time Seconds	Break Path No.1[1] Mass lbm/sec	Break Path No.1[1] Energy Thousand Btu/sec	Break Path No. 2[2] Mass lbm/sec	Break Path No. 2[2] Energy Thousand Btu/sec
13.4	0	0	724.5	894.2
13.6	0	0	775.6	948.2
13.8	0	0	810.8	977.9
14	0	0	822.8	987.8
14.2	0	0	794	961.4
14.4	0	0	694.2	852.3
14.6	0	0	557.2	687.9
14.8	0	0	544.7	675
15	0	0	536.8	664.5
15.2	0	0	454.6	563
15.4	41.7	54.4	358.2	445
15.6	410.4	496.8	309.6	385.6
15.8	387.9	476.4	262.7	327.3
16	300.2	368.6	220.7	276
16.2	0	0	192.6	241.4
16.4	0	0	162.3	203.9
16.6	0	0	66.6	84.2
16.8	0	0	0	0

Notes:
1. Path 1: M&E exiting from the reactor vessel side of the break.
2. Path 2: M&E exiting from the steam generator side of the break.

Table 2.6.3.1-6
DEHL Break Mass Balance

Time (Seconds)		.00	16.80	16.80+ε
		Mass (thousand lbm)		
Initial	In RCS and ACC	414.28	414.28	414.28
Added Mass	Pumped Injection	0	0	0
	Total Added	0	0	0
Total Available		414.28	414.28	414.28
Distribution	Reactor Coolant	273.05	56.69	74.23
	Accumulator	141.24	97.14	79.6
	Total Contents	414.28	153.83	153.83
Effluent	Break Flow	0	260.44	260.44
	ECCS Spill	0	0	0
	Total Effluent	0	260.44	260.44
Total Accountable		414.28	414.27	414.27

Note: +ε is used to indicate that the column represents the bottom of core recovery conditions that occurs instantaneously after blowdown.

Table 2.6.3.1-7
DEHL Break Energy Balance

Time (seconds)		.00	16.80	16.80+ε
		Energy (million Btu)		
Initial Energy	In RCS, ACC, S GEN	428.22	428.22	428.22
Added Energy	Pumped Injection	0	0	0
	Decay Heat	0	3.06	3.06
	Heat from Secondary	0	13.49	13.49
	Total Added	0	16.55	16.55
Total Available		428.22	444.77	444.77
Distribution	Reactor Coolant	160.66	13.78	15.08
	Accumulator	12.73	8.75	7.45
	Core Stored	15.37	6.31	6.31
	Primary Metal	83.49	77.96	77.96
	Secondary Metal	43.12	41.78	41.78
	Steam Generator	112.85	124.94	124.94
	Total Contents	428.22	273.52	273.52
Effluent	Break Flow	0	170.76	170.76
	ECCS Spill	0	0	0
	Total Effluent	0	170.76	170.76
Total Accountable		428.22	444.28	444.28

Note: +ε is used to indicate that the column represents the bottom of core recovery conditions that occurs instantaneously after blowdown.

Table 2.6.3.1-8
DEPS Break Blowdown M&E Release

Time Seconds	Break Path No. 1(1) Mass lbm/sec	Break Path No. 1(1) Energy Thousand Btu/sec	Break Path No. 2 Flow(2) Mass lbm/sec	Break Path No. 2 Flow(2) Energy Thousand Btu/sec
0	0	0	0	0
0.00111	78896.5	42751.6	40705.8	22023.7
0.102	40750.1	22140.7	19865.1	10735.6
0.201	45906.9	25150.7	21789.2	11785.3
0.301	46635.4	25826.9	23266.4	12592.3
0.402	46463.4	26063	23652.3	12807
0.501	44243.9	25145.3	23203.6	12568.9
0.601	44737.3	25735.4	22630.8	12264.7
0.701	44349.8	25781.3	22187.3	12030.6
0.802	43115.9	25299.2	21904.1	11882.1
0.902	41756.9	24720.4	21665.2	11756
1	40471.9	24162	21405.9	11617.1
1.1	39198.5	23590.9	21103.8	11453.8
1.2	37929	23001.8	20769.7	11272.3
1.3	36664.5	22396.3	20403	11072.4
1.4	35366	21754	20011.1	10858.1
1.5	33958.6	21039.2	19624.1	10647.1
1.6	32631.6	20383.6	19324.4	10484
1.7	31570.6	19920	19040.6	10329.9
1.8	30583.8	19521.4	18726.4	10158.9
1.9	29417.3	19025.6	18379.1	9969.6
2	27859.2	18294.9	18026.6	9777.7
2.1	23196.2	15461.8	17662.1	9579.2
2.2	19829.4	13479.5	17292	9377.9
2.3	17362.9	12011.8	16944.7	9189.8
2.4	15416.3	10807.8	16716.9	9067.8
2.5	14152.2	10018.8	16470.7	8935.7
2.6	13381.6	9534.9	15921.4	8637.9
2.7	12822.8	9175.4	15477.7	8398.8
2.8	12324.2	8856.7	15130.4	8213

Table 2.6.3.1-8
DEPS Break Blowdown M&E Release

	Break Path No. 1(1)		Break Path No. 2 Flow(2)	
Time Seconds	Mass lbm/sec	Energy Thousand Btu/sec	Mass lbm/sec	Energy Thousand Btu/sec
2.9	11885.8	8594.7	14893.7	8088.3
3	11469	8363	14677.5	7974.5
3.1	11095.7	8170	14467.2	7863.8
3.2	10742.5	7990.6	14271.1	7761
3.3	10413.2	7825.2	14086.9	7664.9
3.4	10114.7	7680.1	14366.9	7825.4
3.5	9842.7	7549.9	14430	7863.6
3.6	9594.5	7428.3	14395.7	7848.8
3.7	9371.3	7315.9	14410.8	7861.4
3.8	9174.1	7214.3	14377.1	7846.9
3.9	9006.1	7124.1	14306.8	7812
4	8853.6	7034.5	14247.4	7783
4.2	8582.1	6855.8	13996.7	7651.4
4.4	8343.2	6667.2	13609	7445.5
4.6	8134.2	6463	13225.7	7244.7
4.8	7956.8	6252.1	12825.3	7036.5
5	7829.7	6057.1	12395.8	6813
5.2	7702	5861.3	11957.7	6585
5.4	7499.1	5643	11509.3	6351.4
5.6	7250.2	5392.7	11120.9	6134.2
5.8	7051.9	5161.3	10843.4	5945.4
6	6943.2	4978.7	10715.3	5816.4
6.2	7119.1	4982.7	10651.6	5714.9
6.4	7354.4	5068.3	10739.8	5698.8
6.6	7105.5	5075.6	10577.6	5564.3
6.8	6324.6	4766.7	10407	5425.9
7	5843.1	4469.5	10151.3	5252.7
7.2	5627.4	4281.7	9627.3	4941
7.4	5464.1	4132.7	9079	4619
7.6	5303	4003.7	8644.7	4361.8

Table 2.6.3.1-8
DEPS Break Blowdown M&E Release

Time Seconds	Break Path No. 1(1) Mass lbm/sec	Break Path No. 1(1) Energy Thousand Btu/sec	Break Path No. 2 Flow(2) Mass lbm/sec	Break Path No. 2 Flow(2) Energy Thousand Btu/sec
7.8	5125.5	3878.9	8257	4140.2
8	4941.4	3757.7	7871.9	3924.9
8.2	4757.2	3645.4	7483.9	3707.9
8.4	4519.7	3522.7	7036.4	3450
8.6	4266.9	3401.7	6722.2	3250.1
8.8	4040.6	3281.1	6408.9	3048.8
9	3838.9	3170.6	6115	2855.6
9.2	3647.2	3077.4	5842.1	2675.6
9.4	3451.1	2988.7	5581.8	2507
9.6	3254.2	2910.9	5378	2369.7
9.8	3062	2844	5200.5	2249.1
10	2859	2777.7	4950.7	2103.9
10.2	2646.9	2718.2	4671.6	1951.6
10.4	2418.6	2660.8	4385.3	1801.3
10.6	2089.4	2480.9	4055	1636
10.8	1765.2	2172.6	3712.7	1463.5
11	1514.7	1876.1	3494.3	1332.1
11.2	1321.6	1641.7	3341.7	1222.5
11.4	1123.3	1399.4	3161.2	1110.1
11.6	939.5	1172.6	2977.9	1009.4
11.8	783.7	979.6	2683.6	883.2
12	637.9	798.1	2348.3	755.9
12.2	516.9	647.4	2012.5	636.4
12.4	411.6	515.9	1626.1	506.3
12.6	294.4	369.3	1172.1	360
12.8	179.8	225.9	663.5	202

Table 2.6.3.1-8
DEPS Break Blowdown M&E Release

Time Seconds	Break Path No. 1[1] Mass lbm/sec	Break Path No. 1[1] Energy Thousand Btu/sec	Break Path No. 2 Flow[2] Mass lbm/sec	Break Path No. 2 Flow[2] Energy Thousand Btu/sec
13	67.9	85.6	160.8	48.9
13.2	0	0	0	0

Notes:

1. Path 1: M&E exiting from the steam generator side of the break.
2. Path 2: M&E exiting from the broken loop reactor coolant pump side of the break.

Table 2.6.3.1-9
DEPS Break Reflood M&E Release – Minimum SI

Time Seconds	Break Path No. 1[1] Mass lbm/sec	Break Path No. 1[1] Energy Thousand Btu/sec	Break Path No. 2 Flow[2] Mass lbm/sec	Break Path No. 2 Flow[2] Energy Thousand Btu/sec
13.2	0	0	0	0
13.7	0	0	0	0
13.8	0	0	0	0
14	0	0	0	0
14.1	0	0	0	0
14.1	0	0	0	0
14.2	82.3	97.3	0	0
14.3	30.3	35.8	0	0
14.4	20.2	23.9	0	0
14.5	23.5	27.7	0	0
14.6	29.6	35	0	0
14.7	39.3	46.4	0	0
14.8	46.3	54.7	0	0
14.9	53	62.6	0	0
15	59.4	70.2	0	0
15.1	65.5	77.4	0	0
15.2	69.3	81.9	0	0
15.2	70.7	83.6	0	0
15.3	75.2	88.9	0	0
15.4	79.6	94	0	0
15.5	83.7	99	0	0
15.6	87.8	103.7	0	0
15.7	91.7	108.4	0	0
15.8	95.4	112.8	0	0
15.9	99.1	117.1	0	0
16	102.6	121.3	0	0
16.1	106.1	125.4	0	0
16.2	109.4	129.3	0	0
17.2	139	164.3	0	0
18.2	163.5	193.4	0	0

Table 2.6.3.1-9
DEPS Break Reflood M&E Release – Minimum SI

Time Seconds	Break Path No. 1(1) Mass lbm/sec	Break Path No. 1(1) Energy Thousand Btu/sec	Break Path No. 2 Flow(2) Mass lbm/sec	Break Path No. 2 Flow(2) Energy Thousand Btu/sec
18.9	260.5	308.4	2137.9	258.5
19.3	309.7	366.8	2842.2	341.7
20.3	326.7	387	2974.9	365.4
21.3	322.8	382.4	2932.7	361.5
22.3	318.5	377.3	2885.3	357
22.9	316	374.3	2856.2	354.1
23.3	314.2	372.2	2836.6	352.2
24.3	310	367.2	2788	347.5
25.3	305.9	362.3	2740.1	342.7
26.3	302	357.6	2693.3	338.1
27.3	298.2	353.1	2647.8	333.6
27.8	296.3	350.9	2625.6	331.4
28.3	294.5	348.8	2603.6	329.2
29.3	291	344.6	2560.7	324.9
30.3	287.7	340.6	2519.2	320.8
31.3	284.5	336.8	2478.9	316.8
32.3	281.4	333.2	2439.9	312.9
33.3	278.4	329.6	2402.1	309.1
34.3	275.6	326.3	2365.4	305.4
35.3	272.8	323	2329.8	301.9
36.3	270.2	319.9	2295.2	298.4
37.3	267.6	316.8	2261.7	295
38.3	265.2	313.9	2229.1	291.7
39.2	245.5	290.6	1592.7	241.8
39.3	222.9	263.8	923.1	169.9
40.3	189.1	223.6	970	164.2
41.3	197.6	233.7	1225.2	183.2
42.3	192.9	228.2	204.8	80.9
43.3	223.9	264.9	213.9	94.2
44.3	219.4	259.6	212.4	92.3

Table 2.6.3.1-9
DEPS Break Reflood M&E Release – Minimum SI

Time Seconds	Break Path No. 1[1] Mass lbm/sec	Break Path No. 1[1] Energy Thousand Btu/sec	Break Path No. 2 Flow[2] Mass lbm/sec	Break Path No. 2 Flow[2] Energy Thousand Btu/sec
45.3	214.9	254.2	211	90.5
46.3	210.2	248.7	209.5	88.6
47.3	205.8	243.5	208.1	86.8
48.3	201.4	238.3	206.7	85
49.3	197.1	233.1	205.4	83.3
50.3	192.7	227.9	204	81.6
51.3	188.3	222.8	202.7	79.9
52.3	184	217.6	201.3	78.2
53.3	179.7	212.5	200	76.5
53.8	177.5	209.9	199.4	75.7
54.3	175.3	207.4	198.7	74.8
55.3	171.1	202.3	197.4	73.2
56.3	166.8	197.2	196.2	71.6
57.3	162.5	192.2	194.9	70
58.3	158.3	187.2	193.7	68.5
59.3	154.1	182.2	192.5	66.9
60.3	150	177.3	191.3	65.4
61.3	145.9	172.5	190.1	64
62.3	141.8	167.6	189	62.5
63.3	137.8	162.9	187.8	61.1
64.3	133.8	158.2	186.7	59.7
65.3	129.8	153.5	185.7	58.4
66.3	126	148.9	184.6	57.1
67.3	122.2	144.4	183.6	55.8
68.3	118.4	140	182.7	54.6
69.3	114.7	135.6	181.7	53.4
70.3	111.1	131.4	180.8	52.3
71.3	107.6	127.2	179.9	51.1
72.3	104.2	123.1	179.1	50.1
72.6	103.2	121.9	178.8	49.8

Table 2.6.3.1-9
DEPS Break Reflood M&E Release – Minimum SI

Time Seconds	Break Path No. 1(1) Mass lbm/sec	Break Path No. 1(1) Energy Thousand Btu/sec	Break Path No. 2 Flow(2) Mass lbm/sec	Break Path No. 2 Flow(2) Energy Thousand Btu/sec
73.3	101.4	119.9	178.1	48.9
74.3	99.9	118.1	177.3	47.9
76.3	97	114.7	175.6	46
78.3	94.3	111.5	174	44.1
80.3	91.7	108.3	172.4	42.2
82.3	89.2	105.4	171	40.5
84.3	86.8	102.5	169.5	38.8
86.3	84.5	99.9	168.2	37.2
88.3	82.4	97.3	166.9	35.7
90.3	80.4	95	165.7	34.2
92.3	78.5	92.7	164.5	32.8
94.3	76.7	90.6	163.4	31.5
96.3	75	88.7	162.4	30.3
98.3	73.5	86.9	161.4	29.2
98.7	73.2	86.5	161.2	28.9
100.3	72.1	85.2	160.5	28.1
102.3	70.7	83.6	159.6	27.1
104.3	69.5	82.2	158.8	26.1
106.3	68.4	80.8	158.1	25.2
108.3	67.4	79.6	157.4	24.4
110.3	66.4	78.5	156.7	23.7
112.3	65.6	77.5	156.2	23
114.3	64.8	76.5	155.6	22.3
116.3	64.1	75.7	155.1	21.7
118.3	63.4	75	154.6	21.2
120.3	62.9	74.3	154.2	20.7
122.3	62.3	73.7	153.8	20.2
124.3	61.9	73.1	153.5	19.8
126.3	61.5	72.6	153.1	19.4
128.3	61.1	72.2	152.9	19.1

Table 2.6.3.1-9
DEPS Break Reflood M&E Release – Minimum SI

Time Seconds	Break Path No. 1(1) Mass lbm/sec	Break Path No. 1(1) Energy Thousand Btu/sec	Break Path No. 2 Flow(2) Mass lbm/sec	Break Path No. 2 Flow(2) Energy Thousand Btu/sec
130.3	60.8	71.8	152.6	18.8
131.5	60.6	71.6	152.4	18.6
132.3	60.5	71.5	152.3	18.5
134.3	60.3	71.2	152.1	18.2
136.3	60.1	71	151.9	18
138.3	59.9	70.8	151.7	17.8
140.3	59.7	70.6	151.6	17.6
142.3	59.6	70.5	151.4	17.4
144.3	59.5	70.3	151.3	17.2
146.3	59.4	70.3	151.2	17.1
148.3	59.4	70.2	151.1	17
150.3	59.3	70.1	151	16.9
152.3	59.3	70.1	150.9	16.8
154.3	59.3	70.1	150.8	16.7
156.3	59.3	70.1	150.7	16.6
158.3	59.3	70.1	150.7	16.5
160.3	59.3	70.1	150.6	16.5
162.3	59.4	70.1	150.6	16.4
164.3	59.4	70.2	150.5	16.3
166.3	59.4	70.2	150.5	16.3
168.1	59.5	70.3	150.5	16.3
168.3	59.5	70.3	150.5	16.3
170.3	59.5	70.4	150.5	16.2
172.3	59.6	70.4	150.4	16.2
174.3	59.7	70.5	150.4	16.2
176.3	59.8	70.6	150.4	16.2
178.3	59.8	70.7	150.4	16.2
180.3	59.9	70.8	150.4	16.1
182.3	60	70.9	150.4	16.1
184.3	60.1	71	150.4	16.1

Table 2.6.3.1-9
DEPS Break Reflood M&E Release – Minimum SI

Time Seconds	Break Path No. 1[1] Mass lbm/sec	Break Path No. 1[1] Energy Thousand Btu/sec	Break Path No. 2 Flow[2] Mass lbm/sec	Break Path No. 2 Flow[2] Energy Thousand Btu/sec
186.3	60.2	71.1	150.4	16.1
188.3	60.3	71.2	150.4	16.1
190.3	60.4	71.3	150.4	16.1
192.3	60.5	71.5	150.4	16.1
194.3	60.6	71.6	150.4	16.1
196.3	60.7	71.7	150.4	16.2
198.3	60.8	71.8	150.4	16.2
200.3	60.9	71.9	150.4	16.2
202.3	61	72.1	150.4	16.2
204.3	61.1	72.2	150.4	16.2
206.3	61.2	72.3	150.4	16.2

Notes:

1. Path 1: M&E exiting from the steam generator side of the break.
2. Path 2: M&E exiting from the broken loop reactor coolant pump side of the break.

Table 2.6.3.1-10
DEPS - Minimum Safety Injection Principal Parameters During Reflood

Time sec	Temp °F	Flooding Rate in/sec	Carry-over Fraction	Core Height ft	Down-Comer Height ft	Flow Fraction	Total	Injection Accumulator	SI Spill	Enthalpy Btu/lbm
							(Pounds mass per second)			
13.2	151.7	0	0	0	0	0.5	0	0	0	0
14	150.6	24.775	0	0.77	1.48	0	4296.2	4296.2	0	90.1
14.1	150.3	25.757	0	0.98	1.44	0	4284.4	4284.4	0	90.1
14.1	150.1	25.638	0	1.09	1.41	0	4272.8	4272.8	0	90.1
14.5	149.9	3.121	0.148	1.37	2.33	0.372	4218.5	4218.5	0	90.1
15.1	150.1	3.179	0.282	1.49	4.28	0.54	4150	4150	0	90.1
15.2	150.2	3.162	0.296	1.5	4.52	0.547	4144.7	4144.7	0	90.1
15.8	150.4	3.087	0.395	1.61	6.54	0.578	4076.9	4076.9	0	90.1
18.9	151.7	4.426	0.622	2	15.66	0.706	3753.1	3753.1	0	90.1
19.3	151.8	4.888	0.637	2.06	15.81	0.747	3708.2	3708.2	0	90.1
21.3	152.9	4.656	0.685	2.32	15.83	0.745	3539.7	3539.7	0	90.1
22.9	153.8	4.464	0.702	2.51	15.83	0.743	3429.7	3429.7	0	90.1
27.8	157	4.111	0.724	3.01	15.83	0.734	3141.9	3141.9	0	90.1
33.3	160.8	3.87	0.731	3.5	15.83	0.726	2881.6	2881.6	0	90.1
39.2	165.2	3.5	0.734	4	15.83	0.67	2023.2	2023.2	0	90.1
40.3	165.9	2.973	0.724	4.08	15.83	0.649	1311.3	1311.3	0	90.1
41.3	166.6	3.066	0.726	4.14	15.83	0.66	1578.2	1290.8	0	86.08
42.3	167.3	3.137	0.723	4.21	15.81	0.673	289.3	0	0	68
43.3	168.1	3.314	0.731	4.29	15.53	0.681	285.2	0	0	68
46.3	170.5	3.136	0.73	4.51	14.72	0.677	285.9	0	0	68
53.8	177.4	2.715	0.724	5.01	13.02	0.665	287.5	0	0	68
63.3	187	2.214	0.715	5.55	11.47	0.642	289.1	0	0	68
72.6	196.4	1.785	0.704	6	10.53	0.605	290.2	0	0	68
86.3	209.7	1.495	0.697	6.56	9.82	0.599	290.2	0	0	68

Table 2.6.3.1-10
DEPS - Minimum Safety Injection Principal Parameters During Reflood

Time sec	Temp °F	Flooding Rate in/sec	Carry-over Fraction	Core Height ft	Down-Comer Height ft	Flow Fraction	Total	Injection Accumulator	SI Spill	Enthalpy Btu/lbm
							(Pounds mass per second)			
98.7	219.6	1.311	0.692	7	9.57	0.596	290.2	0	0	68
116.3	231	1.155	0.688	7.56	9.62	0.595	290.2	0	0	68
131.5	239.3	1.089	0.688	8	9.88	0.597	290.2	0	0	68
150.3	248.1	1.056	0.691	8.52	10.34	0.601	290.2	0	0	68
168.1	255.4	1.047	0.694	9	10.82	0.604	290.1	0	0	68
180.3	260	1.045	0.698	9.32	11.16	0.607	290.1	0	0	68
188.3	262.8	1.046	0.7	9.53	11.38	0.608	290.1	0	0	68
206.3	268.6	1.049	0.705	10	11.88	0.611	290.1	0	0	68

Table 2.6.3.1-11
DEPS Break Post-Reflood M&E Release – Minimum SI

Time Seconds	Break Path No. 1[1] Mass lbm/sec	Break Path No. 1[1] Energy Thousand Btu/sec	Break Path No. 2 Flow[2] Mass lbm/sec	Break Path No. 2 Flow[2] Energy Thousand Btu/sec
206.4	115.5	146.5	176.3	46.3
211.4	116.2	147.5	177.7	47.3
216.4	115.9	147.1	177.5	47.3
221.4	115.5	146.6	177.4	47.3
226.4	115.2	146.2	177.3	47.3
231.4	114.8	145.7	177.1	47.2
236.4	115.6	146.7	177	46.9
241.4	115.2	146.2	176.9	46.9
246.4	114.9	145.8	176.7	46.9
251.4	114.5	145.3	176.6	46.8
256.4	114.2	144.9	176.5	46.8
261.4	114.9	145.8	176.3	46.5
266.4	114.5	145.3	176.2	46.5
271.4	114.2	144.9	176.1	46.5
276.4	113.8	144.4	176.4	46.4
281.4	113.4	143.9	176.7	46.4
286.4	114.1	144.8	176	46.1
291.4	113.7	144.4	176.4	46.1
296.4	113.4	143.9	176.8	46.1
301.4	113	143.4	177.2	46
306.4	113.7	144.2	176.5	45.7
311.4	113.3	143.8	176.9	45.7
316.4	112.9	143.3	177.3	45.7
321.4	112.5	142.8	177.7	45.7
326.4	112.1	142.3	178	45.6
331.4	112.8	143.1	177.4	45.3
336.4	112.4	142.6	177.8	45.3
341.4	112	142.1	178.2	45.3
346.4	111.6	141.6	178.6	45.3
351.4	112.2	142.4	178	45

Table 2.6.3.1-11
DEPS Break Post-Reflood M&E Release – Minimum SI

Time Seconds	Break Path No. 1[1] Mass lbm/sec	Break Path No. 1[1] Energy Thousand Btu/sec	Break Path No. 2 Flow[2] Mass lbm/sec	Break Path No. 2 Flow[2] Energy Thousand Btu/sec
356.4	111.8	141.8	178.4	45
361.4	111.4	141.3	178.8	45
366.4	111	140.8	179.2	44.9
371.4	111.5	141.5	178.6	44.6
376.4	111.1	141	179	44.6
381.4	110.7	140.5	179.5	44.6
386.4	111.3	141.2	178.9	45.6
391.4	110.8	140.6	179.3	45.6
396.4	110.4	140.1	179.8	45.5
401.4	110	139.6	180.2	45.5
406.4	110.6	140.3	179.6	45.2
411.4	110.2	139.9	179.9	45.2
416.4	109.9	139.4	180.3	45.2
421.4	110.4	140.2	179.7	44.9
426.4	110.1	139.7	180.1	44.8
431.4	109.7	139.2	180.5	44.8
436.4	110.2	139.9	179.9	44.5
441.4	109.8	139.4	180.3	44.5
446.4	109.4	138.9	180.7	44.4
451.4	110	139.6	180.2	44.2
456.4	109.6	139	180.6	44.1
461.4	109.2	138.5	181	44.1
466.4	109.7	139.2	180.5	45
471.4	109.2	138.6	180.9	45
476.4	108.8	138.1	181.4	45
481.4	109.3	138.7	180.9	44.7
486.4	108.8	138.1	181.3	44.7
491.4	109.3	138.7	180.9	44.4
496.4	108.8	138.1	181.3	44.4
501.4	108.4	137.5	181.8	44.4

Table 2.6.3.1-11
DEPS Break Post-Reflood M&E Release – Minimum SI

Time Seconds	Break Path No. 1(1) Mass lbm/sec	Break Path No. 1(1) Energy Thousand Btu/sec	Break Path No. 2 Flow(2) Mass lbm/sec	Break Path No. 2 Flow(2) Energy Thousand Btu/sec
506.4	108.8	138.1	181.4	44.1
511.4	108.3	137.5	181.8	44.1
516.4	108.7	138	181.5	43.8
521.4	108.2	137.3	181.9	43.8
526.4	108.6	137.8	181.6	43.5
531.4	108.1	137.2	182.1	44.7
536.4	108.4	137.6	181.7	44.4
541.4	107.9	136.9	182.3	44.4
546.4	108.2	137.3	182	44.2
551.4	107.7	136.6	182.5	44.2
556.4	107.9	137	182.2	43.9
561.4	107.4	136.3	182.8	43.9
566.4	107.6	136.6	182.5	43.7
571.4	107	135.8	183.1	43.7
576.4	107.2	136.1	182.9	43.5
581.4	107.4	136.3	182.7	43.2
586.4	106.8	135.5	183.4	44.4
591.4	107	135.7	183.2	44.2
596.4	107.1	135.9	183.1	43.9
601.4	107.2	136	183	43.7
606.4	106.5	135.2	183.6	43.8
611.4	106.6	135.3	183.5	43.6
616.4	106.7	135.4	183.5	43.4
621.4	106.7	135.4	183.5	43.2
626.4	106.7	135.4	183.5	44.1
631.4	106.7	135.4	183.5	43.9
636.4	106.6	135.3	183.6	43.8
641.4	106.5	135.2	183.7	43.6
646.4	106.4	135	183.8	43.4
651.4	106.2	134.8	184	43.3

Table 2.6.3.1-11
DEPS Break Post-Reflood M&E Release – Minimum SI

Time Seconds	Break Path No. 1(1) Mass lbm/sec	Break Path No. 1(1) Energy Thousand Btu/sec	Break Path No. 2 Flow(2) Mass lbm/sec	Break Path No. 2 Flow(2) Energy Thousand Btu/sec
656.4	106	134.5	184.2	43.2
661.4	105.7	134.2	184.4	43
666.4	106.1	134.7	184.1	43.8
671.4	105.8	134.2	184.4	43.7
676.4	106	134.5	184.2	43.4
681.4	105.5	133.9	184.6	43.4
686.4	105.6	134	184.5	43.1
691.4	105.6	134.1	184.5	42.9
696.4	105.6	134	184.6	43.8
701.4	105.4	133.7	184.8	43.6
706.4	105.1	133.4	185.1	43.5
711.4	105.3	133.6	184.9	43.2
716.4	105.3	133.6	184.9	43
721.4	105.1	133.4	185.1	42.8
726.4	105.3	133.6	184.9	43.6
731.4	105.1	133.4	185	43.4
736.4	104.8	132.9	185.4	43.3
741.4	105	133.2	185.2	43
746.4	104.7	132.8	185.5	42.8
751.4	104.6	132.8	185.5	42.6
756.4	104.6	132.7	185.6	43.4
761.4	104.4	132.4	185.8	43.2
766.4	104.2	132.2	186	43
771.4	104.3	132.3	185.9	42.7
776.4	104	132	186.2	42.5
781.4	42.5	53.9	247.7	60.3
975	42.5	53.9	247.7	60.3
975.1	49	61.2	241.1	57.5
976.4	49	61.2	241.1	57.6
1285	49	61.2	241.1	57.6

Table 2.6.3.1-11
DEPS Break Post-Reflood M&E Release – Minimum SI

Time Seconds	Break Path No. 1[1] Mass lbm/sec	Break Path No. 1[1] Energy Thousand Btu/sec	Break Path No. 2 Flow[2] Mass lbm/sec	Break Path No. 2 Flow[2] Energy Thousand Btu/sec
1285.1	45.7	52.6	244.4	18.6
3395	36.8	42.4	253.3	20.3
3395.1	36.8	42.4	234.1	40.6
3600	36.2	41.6	234.7	40.7

Notes:

1. Path 1: M&E exiting from the steam generator side of the break.
2. Path 2: M&E exiting from the broken loop reactor coolant pump side of the break.

Table 2.6.3.1-12
DEPS Break Mass Balance Minimum Safeguards

	Time (Seconds)	**.00**	**13.20**	**13.20+ε**	**206.31**	**975.11**	**1285.03**	**3600.00**
		Mass (Thousand lbm)						
Initial Mass	In RCS and Accumulator	414.28	414.28	414.28	414.28	414.28	414.28	414.28
Added Mass	Pumped Injection	0	0	0	47.87	270.92	360.84	1028.61
	Total Added	0	0	0	47.87	270.92	360.84	1028.61
*** **Total Available** ***		414.28	414.28	414.28	462.15	685.2	775.13	1442.89
Distribution	Reactor Coolant	273.05	17.72	42.72	71.05	71.05	71.05	71.05
	Accumulator	141.24	114.79	89.79	0	0	0	0
	Total Contents	414.28	132.51	132.51	71.05	71.05	71.05	71.05
Effluent	Break Flow	0	281.77	281.77	385.11	608.28	698.2	1365.97
	ECCS Spill	0	0	0	0	0	0	0
	Total Effluent	0	281.77	281.77	385.11	608.28	698.2	1365.97
*** **Total Accountable** ***		414.28	414.28	414.28	456.15	679.33	769.25	1437.02

Note: +ε is used to indicate that the column represents the bottom of core recovery conditions which occurs instantaneously after blowdown.

Table 2.6.3.1-13
DEPS Break Energy Balance Minimum Safeguards

	Time (Seconds)	**.00**	**13.20**	**13.20+ε**	**206.31**	**975.11**	**1285.03**	**3600.00**
		Energy (Thousand Btu)						
Initial Energy	In RCS, Accumulators and Steam Generators	428.22	428.22	428.22	428.22	428.22	428.22	428.22
Added Energy	Pumped Injection	0	0	0	3.25	18.42	24.54	74.39
	Decay Heat	0	2.52	2.52	14.6	48.39	59.88	129.65
	Heat from Secondary	0	11.69	11.69	11.69	11.69	11.69	11.69
	Total Added	0	14.21	14.21	29.55	78.51	96.11	215.73
*** **Total Available** ***		428.22	442.43	442.43	457.77	506.73	524.33	643.95
Distribution	Reactor Coolant	160.66	4.96	7.22	19.06	19.06	19.06	19.06
	Accumulator	12.73	10.34	8.09	0	0	0	0
	Core Stored	15.37	9.34	9.34	2.77	2.63	2.53	1.81
	Primary Metal	83.49	79.8	79.8	66.63	40.71	37.31	26.59
	Secondary Metal	43.12	42.85	42.85	40.61	25.18	22.47	15.97
	Steam Generator	112.85	125.81	125.81	117.78	69.29	61.88	43.54
	Total Contents	428.22	273.1	273.1	246.86	156.88	143.26	106.98
Effluent	Break Flow	0	169.02	169.02	206	344.94	370.12	528.3
	ECCS Spill	0	0	0	0	0	0	0
	Total Effluent	0	169.02	169.02	206	344.94	370.12	528.3
*** **Total Accountable** ***		428.22	442.11	442.11	452.86	501.81	513.38	635.27

Note: +ε is used to indicate that the column represents the bottom of core recovery conditions which occurs instantaneously after blowdown.

Table 2.6.3.1-14
Double-Ended Hot Leg Break Sequence of Events

Time (sec)	Event Description
0.0	Break Occurs and Loss-of-Offsite Power Are Assumed
0.311	Compensated Pressurizer Pressure for Reactor Trip (1968.7 psia) Reached and Turbine Trip Occurs
3.8	Low-Pressurizer Pressure SI Setpoint (1663 psia) Reached - Feedwater Isolation Signal
4.95	Broken Loop Accumulator Begins Injecting Water
4.99	Intact Loop Accumulator Begins Injecting Water
15.81	Feedwater Isolation Valves Closed
16.8	End of Blowdown Phase
16.8	Accumulator Mass Adjustment for Refill Period
16.8	Transient Modeling Terminated

Table 2.6.3.1-15
Double-Ended Pump Suction Break - Minimum Safeguards Sequence of Events

Time (sec)	Event Description
0.0	Break Occurs and Loss-of-Offsite Power Are Assumed
0.418	Compensated Pressurizer Pressure Reactor Trip (1968.7 psia) Reached and Turbine Trip Occurs
4.1	Low Pressurizer Pressure SI Setpoint (1663 psia) Reached (Safety Injection Begins coincident with Low Pressurizer Pressure SI Setpoint)
5.27	Broken Loop Accumulator Begins Injecting Water
5.37	Intact Loop Accumulator Begins Injecting Water
13.2	End of Blowdown Phase
13.2	Accumulator Mass Adjustment for Refill Period
16.11	Feedwater Isolation Valves Closed
39.163	Broken Loop Accumulator Water Injection Ends
41.1	Pumped Safety Injection Begins (Includes 37 Second Diesel Delay)
42.113	Intact Loop Accumulator Water Injection Ends
206.31	End of Reflood for Minimum Safeguards Case
781.4	M&E Release Assumption: Broken Loop Steam Generator (SG) Equilibration When the Secondary Temperature is at Saturation (T_{sat}) at Containment Design Pressure of 74.7 psia
975.11	M&E Release Assumption: Broken Loop SG Equilibration at Containment Pressure of 60.7 psia
1109.7	M&E Release Assumption: Intact Loop SG Equilibration When the Secondary Temperature is at Saturation (T_{sat}) at Containment Design Pressure of 74.7 psia
1285.03	M&E Release Assumption: Intact Loop SG Equilibration at Containment Pressure of 54.7 psia
3397.73	Switchover to Recirculation Begins
3600.0	End of Transient

Table 2.6.3.1-16
Short-Term LOCA M&E Releases

Time (sec)	Flow (lbm/sec)	Enthalpy (BTU/lbm)
Double-Ended Hot Leg 6" Break		
0.0	0.0	0.0
0.001	9615.02	598.04
3.0	9615.02	598.04
Double-Ended Cold Leg 3" Break		
0.0	0.0	0.0
0.001	2952.76	510.29
3.0	2952.76	510.29

2.6.3.2 Mass and Energy Release Analysis for Secondary System Pipe Ruptures

2.6.3.2.1 Regulatory Evaluation

PBNP's review covered the energy sources that are available for release to the containment, the mass and energy release rate calculations, and the single-failure analyses performed for steam and feedwater line isolation provisions, which would limit the flow of steam or feedwater to the assumed pipe rupture. The NRC's acceptance criteria for mass and energy release analysis for secondary system pipe ruptures are based on GDC-50, insofar as it requires that the margin of the design of the containment structure reflect consideration of the effects of potential energy sources that have not been included in the determination of peak conditions, the experience and experimental data available for defining accident phenomena and containment response, and the conservatism of the model and the value of input parameters. Specific review criteria are contained in SRP Section 6.2.1.4.

PBNP Current Licensing Basis

As noted in PBNP updated Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

PBNP specific GDC for the adequacy of assumptions regarding energy sources available for release to the containment and the M&E release rate calculations are as follows:

Criterion: The containment structure shall be designed (a) to sustain, without undue risk to the health and safety of the public, the initial effects of gross equipment failures, such as a large reactor coolant pipe break, without loss of required integrity, and (b) together with other engineered safety features as may be necessary, to retain for as long as the situation requires, the functional capability of the containment to the extent necessary to avoid undue risk to the health and safety of the public. (PBNP GDC 10)

The evolution of the containment analysis licensing basis is discussed in LR Section 2.6.1, Primary Containment Functional Design.

System and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 1)

Components associated with mass and energy are included in the License Renewal Program.

2.6.3.2.2 Technical Evaluation

2.6.3.2.2.1 Introduction

Steamline ruptures occurring inside the reactor containment structure may result in significant releases of high-energy fluid to the containment environment, producing elevated containment temperatures and pressures. The magnitude of the releases following a steamline rupture is dependent upon the plant initial operating conditions and the size of the rupture as well as the configuration of the plant steam system and the containment design. There are competing effects and credible single failures in the postulated accident scenario used to determine the worst cases for containment pressure following a steamline break.

The PBNP steamline break and containment response analysis considers a spectrum of cases that varies the initial plant conditions and single failure. The following sections identify the analysis methodology, the selection of cases, the major plant assumptions, and the results of the analysis. Major elements considered in this analysis compared to the current licensing-basis analysis are the modification of main feedwater regulating valves as a back-up to the new feedwater isolation valves, the extended power uprate (EPU), and a reduction in the shutdown margin for the core at the end-of-cycle conditions. Specifics of these changes include the following:

- New feedwater isolation valves (FIV) are being added to each feedline. The FIVs will be the fast-closing (5 second stroke time), safety-grade method of isolating the feedlines when a safety injection (SI) signal is generated. The FIVs are being located immediately outside containment, and are between each SG and the current feedwater regulating valve (FRV) in the loop-specific feedline piping. The maximum unisolable feedline volume is 225 ft^3 between the SG and the FIV.
- The current safety-grade FRVs are being modified with a non-safety grade internal trim and operators. The new FRVs will have a stroke time of 10 seconds, and are maintained in the current location with an unisolable volume of 355 ft^3.
- The changes in the feedwater isolation valves cause a different single failure postulated in the main feedwater system. The current analysis postulates that the faulted loop FRV fails open, with back-up feedline isolation provided by the main feedwater pump discharge valves, with an unisolable volume of 1274 ft^3 to the faulted SG. The EPU analysis postulates the FIV on the faulted loop fails open, with back-up feedline isolation provided by the FRV and bypass valves. The smaller unisolable volume to the FRV presents a much less challenging scenario with less water added to the faulted SG.
- The shutdown margin is being reduced from 3.1%Δk to 2.0%Δk. This is a penalty to the analysis, but can now be accommodated because of the benefit provided by the plant modifications to the main feedwater valves.
- Changes being made to the auxiliary feedwater (AFW) system, have two key impacts on this analysis: 1) the total AFW flowrates are higher than the current analysis, and 2) there is now a different AFW system single failure to be considered that can increase the maximum AFW flowrate.

2.6.3.2.2.2 Input Assumptions, Parameters, and Acceptance Criteria

This subsection summarizes the major input assumptions associated with the main feedwater system, the auxiliary feedwater system, the steam generator, the main steam system, and the RCS.

Main Feedwater System

The rapid depressurization that occurs following a steamline rupture typically results in large amounts of water being added to the steam generators through the main feedwater system. A rapid-closing main feedwater isolation valve (FIV) and feedwater regulating valve (FRV) and bypass valve in each of the main feedwater lines limits this effect. The feedwater addition to the faulted steam generator is maximized to be conservative because it increases the water mass inventory that will be converted to steam and released from the break.

Following the initiation of the steamline break, the feedwater flow increases due to the FRV opening in response to the steam flow/feedwater flow mismatch or the decreasing steam generator water level, as well as due to a lower backpressure on the feedwater pump as a result of the depressurizing steam generator. This maximizes the total mass addition prior to feedwater isolation. The feedwater isolation response time, following the safety injection signal, is assumed to be a total of 7 seconds, accounting for delays associated with signal processing plus FIV stroke time. For the circumstance in which the FIV in the faulted loop is postulated to fail open, the feedwater isolation response time is assumed to be a total of 12 seconds accounting for signal processing plus FRV and bypass valve stroke time.

Following feedwater isolation, as the steam generator pressure decreases, some of the fluid in the feedwater lines downstream of the isolation or regulator and bypass valves may flash to steam if the feedwater temperature exceeds the saturation temperature. This unisolable feedwater line volume (225 ft^3 when the FIV is credited to close and 355 ft^3 when the FRV and bypass valves closure is credited as a back-up when the FIV fails open) is an additional source of fluid that can increase the mass discharged out of the break. The unisolable volume in the feedwater lines is maximized for the faulted loop.

Auxiliary Feedwater

Generally, within the first minute following a steamline break, the auxiliary feedwater (AFW) system is initiated on any one of several protection system signals. AFW to the faulted steam generator will increase the secondary mass available for release to containment and therefore is maximized. Maximum AFW flowrates from both the motor-driven auxiliary feedwater pump as well as the turbine-driven pump are assumed. The AFW is assumed to start at the time a safety injection setpoint is reached, with no electronic or pump start-up delay. Operator action is credited to terminate the AFW flow to the faulted steam generator at 10 minutes after the initiation of the steamline break.

Initial Steam Generator Fluid Inventory

A maximum initial steam generator mass in the faulted loop steam generator has been used in all of the analyzed cases. The use of a high faulted loop initial steam generator mass maximizes the steam generator inventory available for release to containment. The initial level corresponds to 74% narrow range span (NRS) at all power levels. This consists of a nominal level of 64% NRS plus a steam generator water level control uncertainty of 10% NRS.

Unisolable Steamline

The initial steam in the steamline between the break and the steamline non-return check valve is included in the mass and energy released from the break.

Quality of the Break Effluent

The break effluent is assumed to be dry, saturated steam throughout most of the transient. However, when a large double-ended break first occurs, it is expected that there will be a significant quantity of liquid in the break effluent. Entrainment of water in the blowdown discharge is a result of the swell of the steam generator two-phase mixture and flow reversal through the steam separator drains of the steam generator due to the sudden depressurization.

The break quality is input as a function of time and varies depending on the initial power level. Break quality characteristics that bound those presented in WCAP-8822 (Reference 2) were used, as previously approved by the NRC for PBNP in Reference 3.

Reactor Coolant System Assumptions

While the mass and energy released from the break is determined from assumptions that have been discussed above, the rate at which the release occurs is largely controlled by the conditions in the reactor coolant system. The major features of the primary side analysis model are summarized below:

- The analyzed NSSS power is 1816.8 MWt (1806 plus 0.6% calorimetric uncertainty).
- RCS vessel full-power average temperature is 577.0°F plus an uncertainty of 6.4°F.
- Continued operation of the reactor coolant pumps maintains a high heat transfer rate to the steam generators.
- The model includes consideration of the heat that is stored in the RCS metal.
- Reverse heat transfer from the intact steam generator to the RCS is modeled as the temperature in the RCS falls below the steam generator fluid temperature.
- Core residual heat generation is assumed based on the 1979 ANS decay heat plus 2σ model (Reference 4).
- Conservative core reactivity coefficients corresponding to end-of-cycle conditions with the most reactive rod stuck out of the core are assumed. This maximizes the reactivity feedback effects as the RCS cools down as a result of the steamline break.
- All cases have credited a minimum shutdown margin of 2.0%Δk.
- Minimum safety injection flow rates corresponding to the failure of one safety injection train have been assumed for all cases in this analysis. The flow rates are modeled to conservatively minimize the amount of boron delivered to the RCS providing negative reactivity feedback.

- No steam generator tube plugging is assumed to maximize the primary-to-secondary heat transfer rate.

Protection System Actuations

The low steamline pressure setpoint is the first SI signal and is credited to cause:

- reactor trip
- start of AFW pumps
- closure of FIVs after a delay of 7 seconds (addresses electronic delay and valve stroke time)
- closure of back-up FRVs after a delay of 12 seconds (addresses electronic delay and valve stroke time)
- start of SI pumps after a delay of 13 seconds (addresses electronic delay and pump start-up time)

Acceptance Criteria

The main steamline break is classified as an ANS Condition IV event, an infrequent fault. The acceptance criteria associated with the steamline break event resulting in mass and energy releases inside containment is based on an analysis that provides sufficient conservatism to show that the containment design margin is maintained. The specific criteria applicable to this analysis are related to the assumptions regarding power level, stored energy, the break flow, main and auxiliary feedwater flow, steamline and feedwater isolation, and single failure assumptions that have been included in this steamline break mass and energy release analysis as discussed in Reference 2.

2.6.3.2.2.3 Description of Analyses and Evaluations

The Westinghouse steamline break mass and energy release methodology was approved by the Nuclear Regulatory Commission (NRC) (Reference 5) and is documented in WCAP-8822 (Reference 2). WCAP-8822 forms the basis for the assumptions used in the calculation of the mass and energy releases resulting from a steam line rupture. WCAP-8822 uses MARVEL as the mass and energy release system code. This was subsequently replaced by LOFTRAN (Reference 6), which was used in the previous PBNP licensing basis analysis.

Initial Power Level

The power level at which the plant is operating when the steamline break is postulated can cause different competing effects. A single power level cannot be specified as the most limiting. At higher power levels, there is less initial water/steam in the steam generator, which is a benefit. However, at higher power levels there is a greater initial feedwater flow rate, higher feedwater temperature, more decay heat, and there is a greater rate of heat transfer from the primary side, which are all penalties. Therefore, representative power levels of 100.6, 70, 30, and 0% of the uprated full NSSS power conditions have been investigated for PBNP. A calorimetric uncertainty of 0.6% is applied to the initial condition for the full power case.

Break Definitions

All cases consider the largest possible break, a double-ended rupture (DER) immediately downstream of the flow restrictor at the outlet of the steam generator. A DER is defined as a rupture in which the steam pipe is completely severed and the ends of the break fully displace from each other. This break conservatively bounds the plant response to any smaller break size. The effective forward break area is limited by the 1.4 ft^2 cross-sectional area of the flow restrictor. The reverse break area is the cross-sectional area of the pipe, which is 4.3 ft^2.

Single-Failure Assumptions

There are three single failures that are analyzed for this event: an AFW runout protection failure, a feedwater isolation valve failure, and a failure of a safeguards train.

The AFW runout protection failure models the single failure in the AFW system which results in a maximum delivery of AFW to the faulted SG. At PBNP the limiting AFW single failure flow control valve failed open on the faulted generator. The additional AFW delivered to the faulted SG will result in increased mass and energy releases inside containment.

The FIV failure models a failure of the safety-grade fast acting valve isolating feedwater from the faulted loop. The FIV (7-second closure time) in the feedline to the faulted steam generator is assumed to fail open and backup isolation is provided by the slower (12-second closure time) FRV and bypass valve, which are also slightly further away from the steam generator. The increased inventory of unisolable feedwater between the FIV and FRV and bypass valve, plus additional pumped main feedwater until the later closure of the FRV is available to be released to containment through the steamline break.

The safeguards failure is the failure of one containment safeguards train. The main impact is on the containment response analysis (see LR Section 2.6.1, Primary Containment Functional Design) where the active heat removal is reduced by the loss of one train of fan coolers and one containment spray pump. In the mass and energy release analysis, this failure also causes the loss of one train of safety injection. However, there is only one train of safety injection credited for all the PBNP EPU cases.

2.6.3.2.3 Results

Steamline break cases were analyzed varying the initial power level and the assumed single failure. The mass and energy release from the break was calculated using the LOFTRAN code. The analysis included the effects of the extended power uprate to 1806 MWt, a decrease in the shutdown margin to 2.0%Δk, higher AFW flowrates, and the benefit of the safety-grade feedwater isolation valve being added in each feedline loop. The acceptance criteria are met for PBNP Unit 1 and Unit 2.

Prior to the EPU analysis, the limiting steamline break containment pressure case was initiated from full power with the FRV on the faulted loop failed open. The previous analysis modeled feedwater isolation due to the closure of the main feedwater pump discharge valves and the trip of the main feedwater pumps. The large unisolable volume from the main feedwater pump discharge valves to the faulted steam generator contained over 65,000 lbm of water which flashed as the SG depressurized, entered the faulted steam generator and eventually released out the steamline break. The steamline break postulated from a full power initial condition was the most limiting because the main feedwater temperature is the highest and the feedwater flashing occurs the earliest.

For the EPU there is a plant modification to add a safety-grade FIV to each feedline. This becomes the valve that is postulated to fail open as one of the single failures and the FRV and bypass valve become the back-up valves that are credited to close in this accident scenario. Because both the FIV and FRV and bypass valve are on the loop-specific feedline and relatively close to the faulted steam generator, the amount of feedwater that flashes and enters the faulted steam generator is reduced by approximately 50,000 lbm. The flashing phenomenon becomes less important, which is the main reason that a different initial power level is found to be the most limiting case.

The limiting containment pressure case for the EPU (see LR Section 2.6.1.2.4, Containment Response to Main Steam) is a large double-ended rupture steamline break initiated from 30% power with a single failure of the feedwater isolation valve. The sequence of events for this case is given in Table 2.6.3.2-1, Sequence of Events for SLB Initiated from 30% Power with FIV Single Failure, while the mass and energy releases are listed in Table 2.6.3.2-2, SLB Mass/Energy Releases from 30% Power with FIV Single Failure. Figure 2.6.3.2-1 and Figure 2.6.3.2-2 show the break flowrate and break energy release rate, respectively, for the limiting case compared to the limiting case prior to the EPU and the FIV plant modification.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

The analysis performed to assess the containment response (including mass and energy releases) to the limiting Steam Line Break resulting from operation at EPU conditions does not add functions to existing components that would change the license renewal system evaluation boundaries. The analytical results associated with operating at EPU conditions do not add any new or previously unevaluated aging effects that would necessitate a change to aging management programs or require new programs, as internal and external environments remain within the parameters previously evaluated. Therefore, there is no impact on license renewal scope, aging effects, and aging management programs due to EPU.

2.6.3.2.4 Conclusion

PBNP has reviewed the mass and energy release assessment for the postulated secondary system pipe ruptures and finds that the analysis adequately addresses the effects of the proposed EPU. Based on this, PBNP concludes that the analysis (including the effects of new FIVs, the change in shutdown margin, and the changes to the auxiliary feedwater system) meets the PBNP current licensing basis requirements with respect to PBNP GDC 10 for ensuring that the analysis is conservative (i.e., that the analysis includes sufficient margin). Therefore, the PBNP finds the proposed EPU acceptable with respect to mass and energy release for postulated secondary system pipe ruptures.

2.6.3.2.5 References

1. Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

2. WCAP-8822, Mass and Energy Releases Following a Steam Line Rupture, September 1976

3. NRC letter to NMC, Point Beach Nuclear Plant Units 1 and 2 – Issuance of Amendments RE: Change of Containment Maximum Pressure Technical Specification Limit (TAC NOS. MB3870 and MB3871), November 2002

4. ANSI/ANS-5.1-1979, American National Standard for Decay Heat Power in Light Water Reactors, August 1979

5. Letter from NRC, Acceptance for Referencing of Licensing Topical Report WCAP-8821 and WCAP-8859, 'TRANFLO Steam Generator Code Description,' and WCAP-8822 and WCAP-8860, 'Mass and Energy Release Following a Steam Line Rupture,' August 1983

6. WCAP-7907, LOFTRAN Code Description, April 1984

Table 2.6.3.2-1
Sequence of Events for SLB Initiated from 30% Power with FIV Single Failure

Event	Time (sec)
First SI setpoint reached	0.2
AFW starts	0.2
Rod motion starts	2.2
Feedwater isolation	12.2
Steam generator tubes start to uncover	130.4
Faulted loop feedwater flashing starts	144.6
AFW terminated to faulted loop	600.0
Break release stops	610.0

Table 2.6.3.2-2
SLB Mass/Energy Releases from 30% Power with FIV Single Failure

Time (sec)	Break Flowrate (lbm/sec)	Break Enthalpy (BTU/lbm)
0.0	0.0	0.0
0.2	11846.7	1193.2
0.4	11779.9	1193.8
0.6	2710.0	1194.5
1.4	2516.2	1196.6
1.6	2698.8	1124.7
1.8	3250.9	979.5
2.0	4131.9	833.3
2.2	4842.1	753.0
3.4	5578.8	670.5
5.8	4616.0	696.4
7.0	4206.0	710.5
8.4	3611.7	747.4
9.6	3178.3	781.1
10.8	2805.7	815.4
12.2	2437.9	856.5
13.4	2211.3	893.4
15.8	1852.8	968.4
17.0	1702.7	1006.4
18.4	1567.8	1042.1
22.2	1268.3	1140.9
23.6	1143.4	1204.3
27.4	1060.7	1204.1
38.8	892.9	1203.1
46.2	816.7	1202.4
53.8	771.8	1201.9
69.0	736.7	1201.5
130.2	727.0	1201.3
132.2	709.6	1201.0
134.2	673.5	1200.4
136.2	622.9	1199.4
138.0	564.7	1198.1

Table 2.6.3.2-2
SLB Mass/Energy Releases from 30% Power with FIV Single Failure

Time (sec)	Break Flowrate (lbm/sec)	Break Enthalpy (BTU/lbm)
144.8	291.4	1186.8
145.4	277.0	1186.0
145.8	274.2	1185.9
146.6	282.0	1186.5
148.0	308.8	1188.1
148.6	312.5	1188.3
149.4	308.8	1188.0
151.2	290.2	1187.0
153.4	303.9	1187.8
155.6	293.0	1187.1
158.0	301.3	1187.6
160.4	295.0	1187.2
162.6	298.5	1187.4
198.4	282.8	1186.5
211.2	273.9	1185.9
233.6	247.7	1183.9
248.0	218.4	1181.4
274.4	144.0	1173.4
279.2	133.5	1171.9
288.8	120.4	1169.5
294.4	115.0	1168.6
302.4	110.4	1167.8
321.6	106.7	1167.1
600.6	106.6	1167.1
601.2	104.7	1166.7
602.4	96.5	1165.1
603.0	91.2	1163.7
603.4	84.9	1162.6
603.8	80.2	1161.5
605.0	69.0	1158.5
606.2	59.2	1155.7
608.2	40.3	1151.9

Table 2.6.3.2-2
SLB Mass/Energy Releases from 30% Power with FIV Single Failure

Time (sec)	Break Flowrate (lbm/sec)	Break Enthalpy (BTU/lbm)
608.6	36.0	1151.5
608.8	35.0	1151.1
609.0	30.7	1151.0
609.2	30.2	1150.7
609.4	24.9	1150.6
609.6	24.4	1150.4
609.8	0.0	0.0

Figure 2.6.3.2-1
Comparison of Steamline Break Flowrate from Limiting EPU Case vs. Previous Analysis

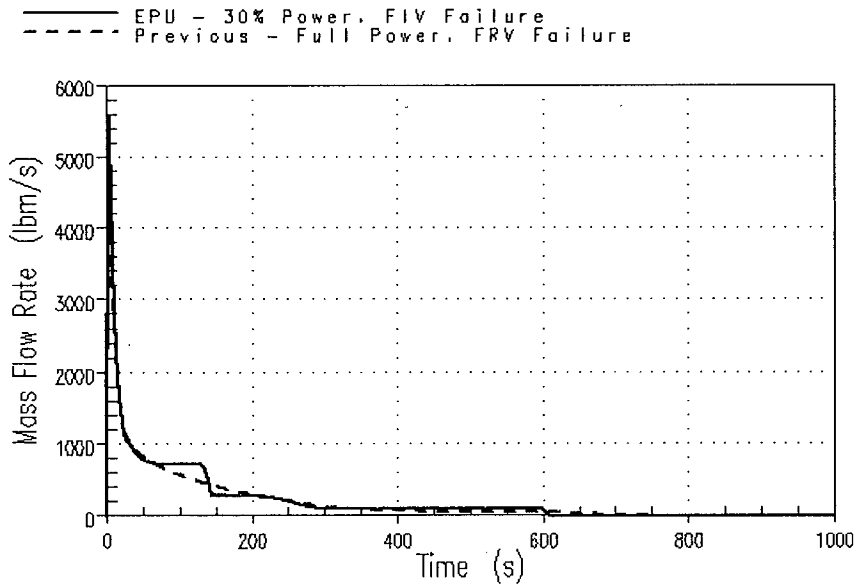
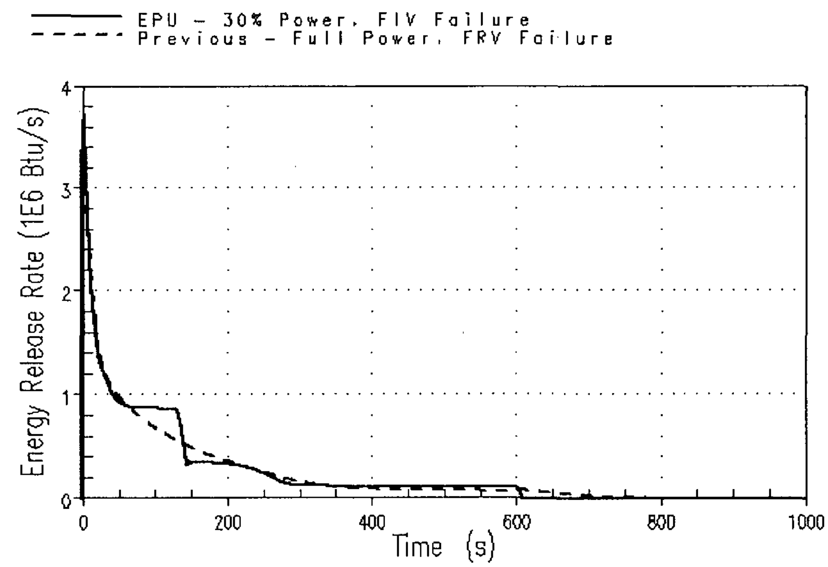


Figure 2.6.3.2-2
Comparison of Steamline Break Energy Release Rate from Limiting EPU Case vs. Previous Analysis



2.6.4 Combustible Gas Control in Containment

2.6.4.1 Regulatory Evaluation

Following a loss-of-coolant accident (LOCA), hydrogen and oxygen may accumulate inside the containment due to chemical reactions between the fuel rod cladding and steam, corrosion of aluminum and other materials, and radiolytic decomposition of water. If excess hydrogen is generated, it may form a combustible mixture in the containment atmosphere. The PBNP review covered:

- The production and accumulation of combustible gases
- The capability to prevent high concentrations of combustible gases in local areas
- The capability to monitor combustible gas concentrations
- The capability to reduce combustible gas concentrations

PBNP's review primarily focused on any impact that the proposed EPU may have on hydrogen release assumptions, and how increases in hydrogen release are mitigated.

The NRC's acceptance criteria for combustible gas control in containment are based on:

- 10 CFR 50.44, insofar as it requires that certain plants be provided with the capability for controlling combustible gas concentrations in the containment atmosphere
- GDC 5, insofar as it requires that SSCs important-to-safety not be shared among nuclear power plants unless it can be shown that sharing will not significantly impair their ability to perform their safety functions
- GDC 41, insofar as it requires that systems be provided to control the concentration of hydrogen or oxygen that may be released into the reactor containment following postulated accidents to ensure that containment integrity is maintained
- GDC 42, insofar as it requires that systems required by GDC 41 be designed to permit periodic inspections
- GDC 43, insofar as it requires that systems required by GDC 41 be designed to permit appropriate periodic testing

Specific review criteria are contained in NRC SRP Section 6.2.5.

PBNP Current Licensing Basis

The Containment Hydrogen Dectectors and Recombiners System (generally referred to as the Post Accident Containment Vent (PCAV)) provides a long-term method of controlling hydrogen accumulation within the containment following a loss-of-coolant accident. The system includes independent sample, exhaust and supply piping connections, and the associated piping and valves to support the system intended functions. Each piping connection is equiped with redundant containment isolation valves located to minimize personnel radiation exposure should valve operation be required. Exhaust piping discharges to either the Primary Auxiliary Building ventilation system (VNPAB) or a hydrogen recombiner (stored offsite).

The NRC eliminated the hydrogen release associated with a design basis loss of coolant accident from 10 CFR 50.44 and the associated requirements that necessitated the hydrogen recombiners and the containment post accident hydrogen vent and purge system. As a result of this regulatory change, the availability of and capability to install hydrogen recombiners has been removed from the PBNP licensing and design basis. In addition, the post accident containment purge system has been removed from the licensing basis. However, the capability to facilitate post accident containment purging is being maintained for beyond design basis accident management.

The capability to monitor post-accident hydrogen concentration in containment is retained, consistent with 10 CFR 50.44(b)(4)(ii), the requirement is contained in the Technical Requirements Manual, but the components necessary to monitor hydrogen no longer need to be classified as safety-related as previously recommended by Regulatory Guide 1.97.

The PBNP Containment Hydrogen Detectors and Recombiners System (PACV) was evaluated for plant license renewal. Systems and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

2.6.4.2 Technical Evaluation

None required.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

The PBNP containment combustible gas control system was evaluated for plant license renewal. This evaluation and conclusions are presented in NRC License Renewal Safety Evaluation Report of the Point Beach Nuclear Plant, Units 1 and 2, NUREG-1839, dated December 2005.

Portions of the containment combustible gas control system were determined to be within the scope of license renewal as discussed in NUREG-1839, Section 2.3.3.16. For those components within the scope of license renewal, the programs to manage the effects of aging were identified and evaluated in NUREG-1839 Section 3.3.2.1.12.

The NRC license renewal evaluations were performed when components of the containment combustible gas control system were included in the PBNP licensing and design basis. With the subsequent change to 10 CFR 50.44 discussed above, and the PBNP license amendment request to eliminate hydrogen monitors from technical specifications dated January 30, 2004 (ML040420424) and approved by the NRC on August 13, 2004 (ML041750666), these system components are being removed from the scope of license renewal, and evaluation for the impact of the proposed EPU on license renewal evaluations is not considered necessary.

2.6.4.3 Results

Not Applicable.

2.6.4.4 Conclusion

PBNP concludes that, based on change to 10 CFR 50.44 and the license amendment approved by the NRC on August 13, 2004, the containment combustible gas control system and its components are no longer part of the PBNP license and design basis. PBNP further concludes that post-LOCA hydrogen generation at the proposed EPU conditions need not be further evaluated. Therefore, PBNP finds the proposed EPU acceptable with respect to combustible gas control in containment.

2.6.4.5 References

1. Letter from NMC to NRC, Application for Technical Specification Improvement to Eliminate Requirements for Hydrogen Recombiners and Hydrogen Monitors Using Consolidated Line Item Improvement Process, dated January 30, 2004 (ML040420424)

2. Letter from NRC to NMC, Point Beach Nuclear Plant, Units 1 and 2, Issuance of Amendments Re: Relocation of Requirements for Hydrogen Monitors (TAC NOS. MC1904 AND MC1905), dated August 13, 2004 (ML041750666)

2.6.5 Containment Heat Removal

2.6.5.1 Regulatory Evaluation

Fan cooler systems, spray systems, and residual heat removal systems are provided to remove heat from the containment atmosphere and/or from the water in the containment sump. The PBNP review in this area focused on (1) the effects of the proposed EPU on the analyses of the available net positive suction head (NPSH) to the containment heat removal system pumps and (2) the analyses of the heat removal capabilities of the spray water system and the fan cooler heat exchangers.

The NRC's acceptance criteria for containment heat removal are based on:

- GDC 38, insofar as it requires that the containment heat removal system be capable of rapidly reducing the containment pressure and temperature following a LOCA and maintaining them at acceptably low levels.

Specific review criteria are contained in the SRP Section 6.2.2 as supplemented by Draft Guide 1107.

PBNP Current Licensing Bases

As noted in PBNP Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP specific GDC for containment heat removal is as follows:

CRITERION: Where an active heat removal system is needed under accident conditions to prevent exceeding containment design pressure, this system shall perform its required function, assuming failure of any single active component. (PBNP GDC 52)

Adequate heat removal capability for the containment is provided by two separate, engineered safety features systems. These are the Containment Spray System and the Containment Air Recirculation Cooling System (VNCC). These systems are of different engineering principles and serve as independent backups for each other.

The containment air recirculation cooling system is designed to recirculate and cool the containment atmosphere in the event of a loss-of-coolant accident and thereby ensure that the containment pressure cannot exceed its design value of 60 psig at 286°F (100% relative humidity). Although the water in the core after a loss-of-coolant accident is quickly subcooled by the safety injection system, the containment air recirculation cooling system is designed on the conservative assumption that the core residual heat is released to the containment as steam.

The primary purpose of the containment spray system is to spray cool water into the containment atmosphere, when appropriate, in the event of a loss-of-coolant accident and thereby ensure that the containment pressure does not exceed the design value of 60 psig at 286°F (100% relative humidity). This protection is afforded for all pipe break sizes up to and including the hypothetical instantaneous circumferential rupture of a reactor coolant pipe. Although the water in the core after a loss-of-coolant accident is quickly subcooled by the safety injection system, the containment spray system design is based on the conservative assumption that the core residual heat is released to the containment as steam.

The following combination of equipment will provide sufficient heat removal capability to maintain the post accident containment pressure below the design value, assuming that the core residual heat is released to the containment as steam.

- One containment spray pump and two of the four containment cooling fans.

The functional performance assumptions for the containment heat removal systems are inputs to the containment accident analyses. The evolution of the containment analysis licensing basis is discussed in LR Section 2.6.1, Primary Containment Functional Design.

The current licensing basis for the containment heat removal systems (VNCC and Containment Spray Systems) is contained in FSAR Section 5.3, Containment Ventilating System, Section 6.1.1, Engineered Safety Features Criteria, Section 6.3, Containment Air Recirculation Cooling System (VNCC), and Section 6.4, Containment Spray System.

License Renewal

In addition to the evaluations described in the FSAR, the PBNP containment heat removal systems were evaluated for plant License Renewal. System and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

With respect to the above SER, the components of the containment heat removal systems that are within the scope of license renewal are identified in SER Section 2.3.2.2, Containment Spray, and Section 2.3.3.9, Containment Ventilation.

2.6.5.2 Technical Evaluation

Introduction

This section discusses the Containment Heat Removal Systems modeled in the Containment Integrity Analysis for a postulated LOCA event (LR Section 2.6.1, Primary Containment Functional Design) in support of EPU operation. The containment heat removal systems modeled comply with the criterion of PBNP GDC 52. The steamline break mass and energy release inside containment event was also analyzed for EPU operation. The containment pressure and temperature response for both a postulated LOCA and a postulated steamline break are analyzed to confirm that the containment design limits are not exceeded. For containment heat removal the steamline break does not represent the limiting case since the energy released from the break is essentially terminated when the main and auxiliary feedwater flow is isolated. The steamline break does not result in long term decay heat addition into the containment.

The purpose of the Containment Integrity LOCA analyses is to demonstrate that the containment, containment structures, and containment cooling safeguards systems are adequate to mitigate the consequences of a hypothetical rupture of a large break reactor coolant system (RCS) pipe.

The effect of LOCA mass and energy releases on the Containment pressure and temperature are addressed to ensure that the containment pressure and temperature remain below the design limits of 60 psig at 286°F under EPU operation. EPU increases the heat available to be released into Containment, and thus, subsequent heat loads on the containment heat removal systems.

Removal of the containment heat following a postulated LOCA event is provided by two engineered safety features systems. These systems are the Containment Spray System, which is described in FSAR Section 6.4, and the Containment Air Recirculation Cooling System (VNCC), which is described in FSAR Section 6.3.

The containment spray system consists of two pumps, one spray additive tank, spray ring headers and nozzles, and associated piping and valves. The pumps and spray additive tank are located in the Auxiliary Building. The pumps take suction directly from the Refueling Water Storage Tank (RWST) during the injection phase. The primary design function of the system is to remove containment heat by spraying borated water into the containment following a LOCA. Heat is removed from the containment atmosphere via heat transfer to the spray droplets. A second function of the system is to remove iodine from the containment atmosphere following a LOCA. A third function of the containment spray system is to provide sufficient sodium hydroxide from the spray additive tank to maintain the required containment sump pH levels. The system is designed to operate in conjunction with the safety injection system during the Injection Phase following a LOCA. During the recirculation phase the system is aligned to take suction from the discharge of the RHR heat exchangers to provide spray flow.The RHR system is discussed in LR Section 2.8.4.4, Residual Heat Removal System. As discussed in LAR 241, Alternative Source Term (ML083450683), the Containment Spray System and the RHR System will be modified to provide throttling capability of the systems in the recirculation phase of the accident. These system changes have been included in the EPU evaluation for containment heat removal capability.

The function of the VNCC system under normal operating conditions is addressed in LR Section 2.7.7, Other Ventilation Systems. The VNCC consists of four fan cooler units, a duct distribution system, and the associated instrumentation and controls. The fan cooler units are located in a missile protected area along the containment wall. Each unit consists of a roughing filter bank, cooling coils, and two fans and motors. One fan and motor are designed for accident conditions following a LOCA. The second fan and motor are designed for normal operation and are not required to operate following a LOCA. Cooling water is provided to the cooling coils by the service water system. Under limiting design basis accident conditions, each fan cooler unit is capable of removing 37.5×10^6 Btu/hr from a saturated air-steam mixture at 286°F, with a flow rate of 33,500 cfm. The design function of the system is to recirculate and cool the containment atmosphere following a LOCA.

Description of Analyses and Evaluations

The Containment Integrity Analysis was performed to demonstrate the ability of the Containment Spray System and the VNCC in conjunction with the Safety Injection System to maintain the containment pressure and temperature within the design limits of 60 psig and 286°F following a LOCA inside Containment under EPU conditions.

Three LOCA cases were analyzed for PBNP. The cases analyzed were the full Double-ended Hot Leg Break (DEHL) case, the full Double-ended Pump Suction Break (DEPS) with minimum safeguards (MINSI), and the DEPS with maximum safeguards (MAXSI). All of the cases assume a loss of offsite power coincident with the break. For the DEHL case and the DEPS MINSI case the limiting single failure is taken to be the loss of one train of the Engineered Safety Features resulting in only one Containment Spray Pump and two Containment Fan Coolers along with one train of the Safety Injection System being available to mitigate the postulated LOCA. For the DEPS MAXSI case the limiting single failure postulated is the loss of one Containment Spray Pump resulting in one Containment Spray Pump, four Containment Fan Coolers along with two trains of Safety Injection in the Injection Phase and one train of Safety Injection in the Recirculation Phase being available to mitigate the postulated LOCA.

The Containment Spray System is modeled in GOTHIC to actuate on a high containment pressure trip of 30 psig (44.7 psia). There is a time delay from the pressure trip until full spray flow of 70 seconds without offsite power available. The spray flow rate during the injection phase is modeled as a function of Containment pressure. The spray flow rate during recirculation phase is 900 gpm per pump. The spray drop diameter is modeled as 1000 microns (0.0394 inches).

The Containment Fan Coolers are modeled in GOTHIC to actuate on a Containment pressure of 6 psig with a delay time of 84 seconds from when the setpoint is reached without offsite power available. The fan cooler heat removal is modeled as a function of the Containment saturation temperature. The air flow rate through each fan cooler is conservatively assumed to be 33,500 ft^3/min.

LR Section 2.6.1, Primary Containment Functional Design, Table 2.6.1-1 provides the key parameters used in the Containment Integrity Analysis relative to the Containment Spray System and the VNCC. LR Section 2.6.1, Primary Containment Functional Design, Table 2.6.1-5 provides the heat removal capability of the Containment Fan Coolers.

Results

The Containment Integrity Analysis demonstrates the ability of the Containment Spray System and the VNCC to maintain the Containment temperature and pressure within the design limits of 286°F and 60 psig following a postulated LOCA. LR Section 2.6.1, Primary Containment Functional Design, Table 2.6.1-9 shows the calculated peak temperature of 279.9°F and the calculated peak pressure of 70.05 psia (55.35 psig) resulting from the full Double-ended Hot Leg Break (DEHL) case. The long term Containment pressure and temperature profile is given by the full Double-ended Pump Suction (DEPS) case with minimum safeguards (MINSI). The pressure at 24 hours for the DEPS cases fall to less than half of the peak pressures for both cases.

Net Positive Suction Head

The effect of EPU on the Containment Spray Pump Net Positive Suction Head Available (NPSHA) analysis has been evaluated. NPSHA for a pump is a function of the pressure of the suction source, the pressure drop in the suction piping, and the vapor pressure of the suction flow. The minimum NPSHA occurs when the pressure of the source and the backpressure of the outlet are minimized, the flow resistance in the suction piping is maximized, and the vapor pressure is maximized. The required NPSH for the Containment Spray Pump ranges from 26 ft. at 1575 gpm to 30 ft. at 1690 gpm.

The containment spray pump takes suction from the refueling water storage tank (RWST) during the injection phase. During the injection phase the pressure at the Containment Spray Pump suction source is calculated based on the RWST level and RWST pressure. The pressure drop in the suction piping is based on maximum flow conditions. The vapor pressure of the suction flow is based on the maximum RWST temperature. The EPU NPSH analysis concludes adequate NPSH for the containment spray pumps during the injection phase is dependent on configuration (number of systems taking suction from the RWST) and RWST water level. Plant operating procedures ensure adequate water levels are maintained in the RWST so that the containment spray pump NPSH requirements are met during the injection phase.

During the recirculation phase the containment spray pump takes suction from the RHR System (the discharge of the RHR Heat Exchangers) which takes suction from the containment sump. The pressure of the suction source during the recirculation phase is determined by the containment sump level and containment pressure and temperature. A minimum sump level and atmospheric sontainment pressure are used. The pressure drop in the suction piping is based on maximum flow conditions. The fluid conditions in the containment sump vary throughout the recirculation phase. Equilibrium conditions between the sump and the atmosphere are the conservative bounding conditions for the ECCS NPSH pump analysis. The equilibrium fluid temperature is taken to be 212°F. The calculated NPSH ratio (NPSHA/NPSHR) for the containment spray pumps during the recirculation is greater than 1, therefore, the EPU NPSH analysis concludes NPSHA for the Containment Spray Pumps during the recirculation phase is adequate for all analyzed cases without crediting containment pressure in excess of normal atmospheric pressure. The NPSHA evaluation takes into account the modifications being implemented to the containment spray system and the RHR system by LAR 241 - Alternative Source Term (ML083450683) which provides throttling capability of the systems during the recirculation phase of the accident. Throttling of the CS flow and the RHR core injection flow ensures adequate net positive suction head is maintained to the running RHR pump, ensuring adequate core injection flow is available at all times, and allowing sufficient time to place recirculation spray in service to meet radiological analyses assumptions associated with implementation of AST.

License Renewal

Portions of the containment spray system and the VNCC are within the scope of License Renewal as identified in the License Renewal Safety Evaluation Report, NUREG-1839, Section 2.3.2.2, Containment Spray and Section 2.3.3.9, Containment Ventilation. Aging Management Programs used to manage the aging effects associated with the containment spray system are addressed in the NUREG-1839, Section 3.2.2.3.3, Containment Spray – Aging Management Evaluation – Table 3.2.2-2. Aging Management Programs used to manage the aging effects associated with the VNCC are addressed in the NUREG-1839, Section 3.3.2.3.9, Containment Ventilation System – Aging Management Evaluation – Table 3.3.2-8. EPU activities are not adding any new components within the existing license renewal system evaluation boundaries nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. Operating at EPU conditions does not add any new or previously unevaluated materials to the containment spray system or VNCC. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified as a result of EPU.

2.6.5.3 Conclusion

PBNP has assessed the effects of EPU on the containment heat removal systems and concludes that the assessment has adequately addressed the effects of the proposed EPU. PBNP finds that the systems will continue to meet the design function of rapidly reducing the containment pressure and temperature following a LOCA, and maintaining them at acceptably low levels and comply with PBNP GDC 52. Therefore, PBNP finds the proposed EPU acceptable with respect to the containment heat removal systems.

2.6.6 Pressure Analysis for Emergency Core Cooling System Performance Capability

2.6.6.1 Regulatory Evaluation

Following a loss-of-coolant accident (LOCA), the emergency core cooling system (ECCS) will supply water to the reactor vessel to reflood the reactor core and thereby cool the core. The core flooding rate will increase with increasing containment pressure. PBNP reviewed analyses of the minimum containment pressure that could exist during the period of time following a LOCA until the core is reflooded to confirm the validity of the containment pressure used in ECCS performance capability studies. PBNP's review included assumptions made regarding heat removal systems, structural heat sinks, and other heat removal processes that have the potential to reduce the pressure.

The NRC's acceptance criteria for the pressure analysis for ECCS performance capability are based on:

- 10 CFR 50.46, insofar as it requires the use of an acceptable emergency core cooling system evaluation model that realistically describes the behavior of the reactor during LOCAs, or an emergency core cooling system evaluation model developed in conformance with 10 CFR 50, Appendix K.

PBNP Current Licensing Basis

FSAR Section 14.3.2, Large Break Loss-of-Coolant Accident Analysis, describes the methodology used to analyze the large break LOCA. The current ECCS containment backpressure analysis for a large break LOCA was performed using the COCO computer code (Reference 1) as sanctioned by the current Large Break LOCA evaluation model (Reference 2). The containment backpressure used in the WCOBRA/TRAC hydraulic calculations was conservatively low and included the effect of all pressure reducing systems and processes.

2.6.6.2 Technical Evaluation

This section discusses the containment backpressure analysis used in the Point Beach Units 1 and 2 large break LOCA analyses.

2.6.6.2.1 Introduction

The system hydraulic transient for a large break LOCA is influenced by the containment pressure transient response to the M&E released from the reactor coolant system (RCS) by the LOCA. In the best estimate ECCS evaluation model using the automated statistical treatment of uncertainty method (ASTRUM) (Reference 3), the containment pressure transient is provided as a boundary condition to the system hydraulic transient. License Amendment Request 258, Incorporate Best Estimate Large Break Loss of Coolant Accident (LOCA) Analyses Using ASTRUM (ML083330160), was submitted to the NRC for approval on November 25, 2008. The containment pressure transient applied is to be conservatively low and includes the effect of the operation of all pressure reducing systems and processes. The COCO computer code (Reference 1) is used to generate the containment pressure response to the M&E release from the break from a reference WCOBRA/TRAC transient. This containment pressure curve is then used to determine an appropriate input to the WCOBRA/TRAC code as sanctioned by the large break LOCA evaluation model (Reference 3).

2.6.6.2.2 Input Parameters, Assumptions, and Acceptance Criteria

2.6.6.2.2.1 Input Parameters and Assumptions

Table 2.6.6-1, Parameters for ECCS Containment Backpressure Analysis, provides the general parameters used in the ECCS containment backpressure boundary condition analysis. Table 2.6.6-2, Containment Fan Cooler Maximum Heat Removal Rate for ECCS Containment Backpressure Analysis, provides the containment fan coolers heat removal rate used in the ECCS containment backpressure boundary condition analysis. Table 2.6.6-3, Structural Heat Sink Data for ECCS Containment Backpressure Analysis, provides the structural heat sink data used in the ECCS containment backpressure boundary condition analysis. Processes were used which ensure that the values and ranges used in the ECCS containment backpressure analyses for a large break LOCA conservatively bound the values and ranges of the plant as-operated for those parameters.

Acceptance Criteria

As specified in 10 CFR 50, Appendix K: The containment backpressure boundary condition analysis is acceptable if the containment pressure used for evaluating the cooling effectiveness during reflood does not exceed a pressure calculated conservatively for this purpose. The calculation should include the effects of operation of all installed pressure reducing systems and processes.

2.6.6.2.3 Description of Analyses and Evaluations

The Containment Backpressure Analysis for a Large Break LOCA was performed using the COCO computer code (Reference 1) as sanctioned by the large break LOCA evaluation model (Reference 3). The application of this code is consistent with Westinghouse Emergency Core Cooling System Evaluation Model Summary, WCAP-8339 Appendix A (Non-Proprietary), June 1974 (Reference 4). These analyses reflect the PBNP specific parameters as discussed in Section 2.6.6.2.2.1, Pressure Analysis for ECCS Performance Capability,Input Parameters and Assumptions. The result of the analyses is discussed in Section 2.6.6.3, Pressure Analysis for ECCS Performance Capability, Results.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

The NRC issued its PBNP License Renewal Safety Evaluation Report (SER), NUREG-1839, in December 2005. The ECCS components whose performance is relied upon to support the inputs, assumptions, and results of the containment backpressure analysis for a large break LOCA are discussed in SER Section 2.3.2, Engineered Safety Features Systems. EPU activities do not impact license renewal scope, aging effects, and aging management programs as described in NUREG-1839. The ECCS performance capability described in this section for the proposed EPU involves analytical techniques and methodology which are unaffected by the proposed EPU, and the results of which remain bounded by the acceptance criteria of

10 CFR 50.46. Therefore, the conclusions reached in NUREG-1839 for the ECCS components and their aging management programs are not impacted by EPU activities associated with these analytical techniques and methodology.

2.6.6.3 Results

Figures 2.6.6-1 and 2.6.6-2 provide plots of the containment pressure curve used as an input into the WCOBRA/TRAC uncertainty runs and the containment pressure curve calculated by the COCO computer code for PBNP Units 1 and 2, respectively. The containment pressure curves used as input to the uncertainty runs for the thermal-hydraulic calculations are at a lower pressure than the containment pressure curves calculated by the COCO computer code for Units 1 and 2. The containment pressure curves used in the Large Break LOCA analyses are considered acceptable.

2.6.6.4 Conclusion

PBNP has reviewed the minimum containment pressure analyses and concludes that the analyses have adequately accounted for plant operation at the EPU power level and were performed using acceptable analytical models. PBNP further concludes that the evaluation has demonstrated that the containment pressure curve used in the large break LOCA analyses are considered acceptable. Based on this, PBNP concludes that the requirements in 10 CFR 50.46 regarding emergency core cooling system performance will continue to be met following implementation of the proposed EPU. Therefore, PBNP finds the analyses acceptable with respect to minimum containment pressure for emergency core cooling system performance.

2.6.6.5 References

1. F. M. Bordelon and E. T. Murphy, Containment Pressure Analysis Code (COCO), WCAP-8327 (Proprietary Version), WCAP-8326 (Non-Proprietary Version), June 1974

2. S. I. Dederer et. al., Application of Best-Estimate Large Break LOCA Methodology to Westinghouse PWRs with Upper Plenum Injection, WCAP-14449-P-A, Revision 0 (Proprietary Version), August 1995

3. M. E. Nissley et. al., Realistic Large-Break LOCA Evaluation Methodology Using the Automated Statistical Treatment of Uncertainty Method (ASTRUM), WCAP-16009-P-A (Proprietary Version), WCAP-16009-NP-A (Non-Proprietary Version), January 2005

4. F. M. Bordelon et. al., Westinghouse Emergency Core Cooling System Evaluation Model Summary, WCAP-8339 Appendix A (Non-Proprietary), June 1974

Table 2.6.6-1
Parameters for ECCS Containment Backpressure Analysis

Parameter	Value
Containment Physical Description	
Maximum Net Free Volume (ft^3)	1,118,250
Containment Initial Conditions	
Minimum Operating Pressure (psia)	14.7
Minimum Operating Temperature (°F)	90
Relevant Temperatures	
Minimum Refueling Water Storage Tank (RWST) Temperature (°F)	32
Minimum Outside Temperature (°F)	-25
Containment Spray System and SI Spill	
Maximum Number of Pumps Operating	2
Maximum Runout Flow Rate (gpm from ALL pumps)	3900
Minimum Initiation Time (sec)	10
Maximum Safety Injection Spill Flow Rate (gpm)	487.4
Containment Fan Coolers	
Maximum Number of Fan Coolers Operating	4
Minimum Post Accident Initiation Time of Fan Coolers (sec)	0

Table 2.6.6-2
Containment Fan Cooler Maximum Heat Removal Rate for ECCS Containment Backpressure Analysis

Containment Temperature (°F)	Heat Removal Rate for One CFC (BTU/sec)
120	3718
160	8893
190	14,953
210	19,425
220	21,558
240	25,539
260	29,047
270	30,725

Table 2.6.6-3
Structural Heat Sink Data for ECCS Containment Backpressure Analysis

Heat Sink	Description	Area (ft^2)	Material*	Thickness (inches)
1	Upper Dome	1883.7	Paint Type 1	0.01404
			Carbon Steel	0.2496
			Gap	0.021
			Concrete	36
2	Middle Dome	6917.0	Paint Type 1	0.01404
			Carbon Steel	0.2496
			Gap	0.021
			Concrete	36
3	Lower Dome	7525.4	Paint Type 1	0.01404
			Carbon Steel	0.2496
			Gap	0.021
			Concrete	36
4	Upper Containment outer wall (above 66')	19876.0	Paint Type 1	0.015
			Carbon Steel	0.2496
			Gap	0.021
			Concrete	42
5	Middle Containment outer wall (21' to 66')	17367.5	Paint Type 1	0.015
			Carbon Steel	0.2496
			Gap	0.021
			Concrete	42
6	Lower Containment outer wall (8' to 21')	4874.2	Paint Type 1	0.015
			Carbon Steel	0.2496
			Gap	0.021
			Concrete	42
7	Rx Cavity: Shield wall/Rx Pit	1983.2	Paint Type 2	0.039
			Concrete	12
8	Rx Cavity: Tunnel walls	304.2	Paint Type 2	0.039
			Concrete	12
9	Rx Cavity: Keyway tower/shaft	1310.4	Paint Type 2	0.039
			Concrete	12
10	Rx Cavity: Floor slab	413.0	Paint Type 2	0.015
			Concrete	12

Table 2.6.6-3
Structural Heat Sink Data for ECCS Containment Backpressure Analysis

Heat Sink	Description	Area (ft^2)	Material*	Thickness (inches)
11	Pzr walls (inside 46'-86')	2371.6	Paint Type 2	0.039
			Concrete	15
12	Pzr floor slab	182.5	Paint Type 2	0.015
			Concrete	24
			Paint Type 2	0.039
13	Pzr missile shields	205.9	Paint Type 2	0.039
			Carbon Steel	0.5
			Gap	0.021
			Concrete	15
			Paint Type 1	0.039
14	Upper Ctmt interior walls	6341.4	Paint Type 2	0.039
			Concrete	15
15	Upper Ctmt flr/Annular Cmpt clng	5076.6	Paint Type 2	0.015
			Concrete	4
16	Annular Cmpt: Interior wall (46' to 66')	6285.2	Paint Type 2	0.039
			Concrete	15
17	Annular Cmpt: Interior wall (21' to 46')	9667.7	Paint Type 2	0.039
			Concrete	15
18	Annular Cmpt: laydown area high wall (21'-66')	684.5	Paint Type 2	0.039
			Concrete	18
19	Annular Cmpt 46' floor slab	4579.4	Paint Type 2	0.015
			Concrete	4
20	Annular Cmpt flr/Annular Sump ceiling (21')	4998.2	Paint Type 2	0.015
			Concrete	4
21	Annular Sump: interior walls (8' to 21')	5249.8	Paint Type 2	0.039
			Concrete	15
22	Annular Sump floor slab (8')	5091.8	Paint Type 2	0.015
			Concrete	12
23	Loop A: walls	7828.5	Paint Type 2	0.039
			Concrete	15
24	Loop A: floor slab	954.7	Paint Type 2	0.015
			Concrete	12

Table 2.6.6-3
Structural Heat Sink Data for ECCS Containment Backpressure Analysis

Heat Sink	Description	Area (ft^2)	Material*	Thickness (inches)
25	Loop A: missile shields	293.8	Paint Type 2	0.015
			Concrete	15
			Paint Type 2	0.039
26	Loop B: walls	9461.8	Paint Type 2	0.039
			Concrete	15
27	Loop B: floor slab	929.0	Paint Type 2	0.015
			Concrete	12
28	Loop B: missile shields	243.4	Paint Type 2	0.015
			Concrete	15
			Paint Type 2	0.039
29	Loop B: sub-pzr cmpt walls	334.6	Paint Type 2	0.039
			Concrete	15
30	Loop B: sub-pzr cmpt floor	205.9	Paint Type 2	0.015
			Concrete	24
			Paint Type 2	0.039
31	Refueling cavity wall	5488.5	Stainless Steel	0.1875
			Gap	0.021
			Concrete	18
			Paint Type 2	0.039
32	Refueling cavity flr/Annular sump clng	627.1	Stainless Steel	0.1875
			Gap	0.021
			Concrete	36
			Paint Type 2	0.039
33	Misc. steel in reactor cavity compartment	780.8	Paint Type 1	0.013
			Carbon Steel	1.263
34	Misc. steel in the pressurizer compartment	1.3	Paint Type 1	0.013
			Carbon Steel	0.005
35	Misc. steel in the upper containment	5906.5	Paint Type 1	0.013
			Carbon Steel	0.377
36	Misc. steel in the annular compartment	26333.6	Paint Type 1	0.013
			Carbon Steel	0.396

Table 2.6.6-3
Structural Heat Sink Data for ECCS Containment Backpressure Analysis

Heat Sink	Description	Area (ft^2)	Material*	Thickness (inches)
37	Misc. steel in the annular sump compartment	7795.5	Paint Type 1	0.013
			Carbon Steel	0.23
38	Misc. steel in the Loop A compartment	3967.0	Paint Type 1	0.013
			Carbon Steel	0.372
39	Misc. steel in the Loop B compartment	3967.0	Paint Type 1	0.013
			Carbon Steel	0.372
40	Misc. steel in the dome compartment	24255.6	Paint Type 1	0.013
			Carbon Steel	0.148
41	Misc. steel in refueling cavity compartment	466.0	Paint Type 1	0.013
			Carbon Steel	1.475
42	1 CFC in upper containment compartment; unpainted copper	8274.1	Copper	0.013
43	1 CFC in upper containment compartment	25.2	Stainless Steel	1.022
44	1 CFC in annular compartment	8278.3	Copper	0.013
45	Unpainted stainless steel in Annular Compartment; 1 CFC	28.2	Stainless Steel	0.67
46	Polar crane & Rail girder in the upper containment	9470.5	Paint Type 1	0.013
			Carbon Steel	0.906
47	A RCP in the Loop A compartment	667.5	Paint Type 1	0.0079
			Copper	2.583
48	B RCP in the Loop B compartment	667.5	Paint Type 1	0.0079
			Copper	2.583
49	PRT Unpainted SS	595.5	Stainless Steel	0.67

*Paint Type 1 is Amercote 66 top coating with a Dimecote 6 primer coating; Paint Type 2 is Phenoline 305 top coating with a Carboline 195 primer coating.

Figure 2.6.6-1 COCO Calculated Containment Backpressure (using mass and energy releases from a reference WCOBRA/TRAC transient) and WCOBRA/TRAC Input Containment Backpressure Versus Time After Break for Unit 1

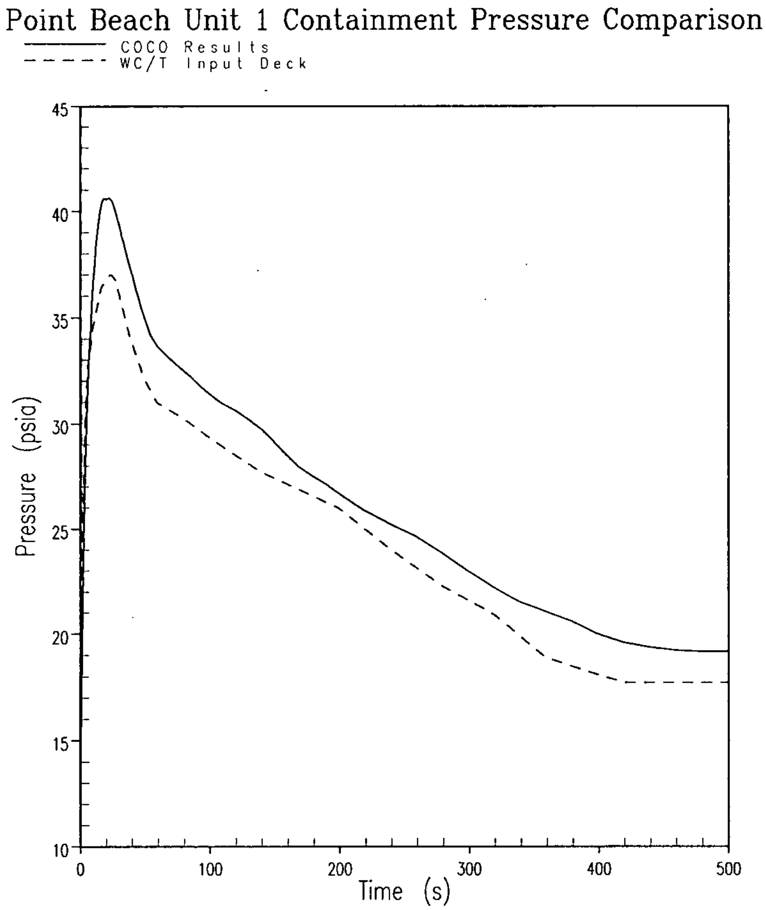
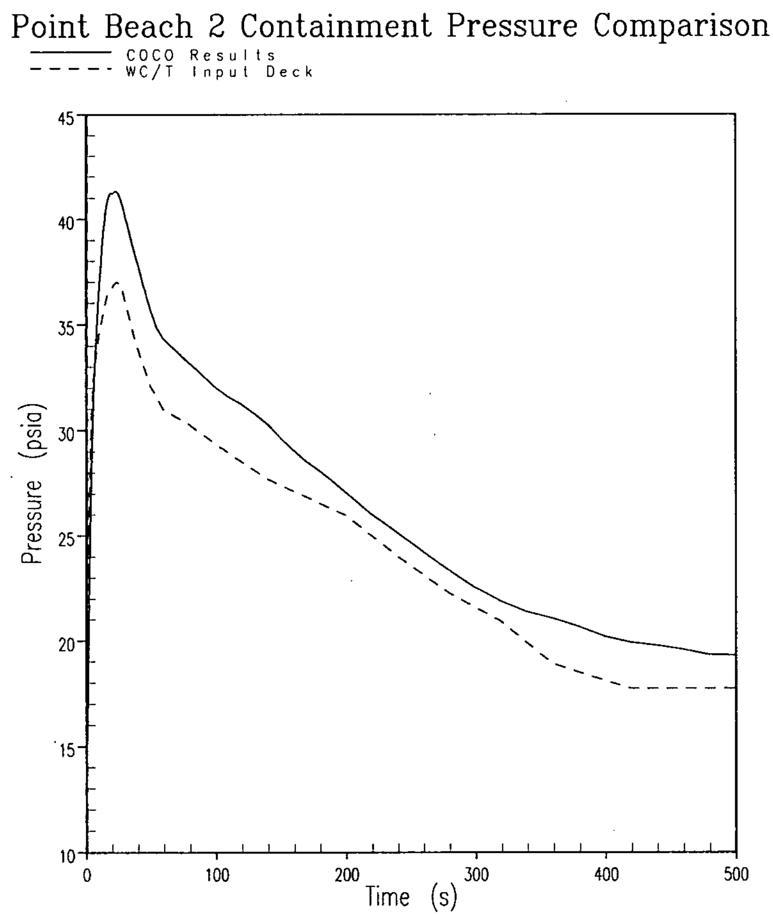


Figure 2.6.6-2 COCO Calculated Containment Backpressure (using mass and energy releases from a reference WCOBRA/TRAC transient) and WCOBRA/TRAC Input Containment Backpressure Versus Time After Break for Unit 2



2.7 Habitability, Filtration, and Ventilation

2.7.1 Control Room Habitability System

2.7.1.1 Regulatory Evaluation

PBNP reviewed the control room habitability system and control building layout and structures to ensure that plant operators are adequately protected from the effects of accidental releases of toxic and radioactive gases. The PBNP review focused on the effects of the proposed EPU on radiation doses, toxic gas concentrations, and estimates of dispersion of airborne contamination.

The NRC's acceptance criteria for the control room habitability system are based on:

- GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with postulated accidents, including the effects of the release of toxic gases.
- GDC-19, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent, to any part of the body, for the duration of the accident.

Specific review criteria are contained in SRP Section 6.4 and other guidance provided in Matrix 7 of RS-001.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50 Appendix A GDC-4 and 19 are as follows:

CRITERION: The facility shall be provided with a control room from which actions to maintain safe operational status of the plant can be controlled. Adequate radiation protections shall be provided to permit continuous occupancy of the control room under any credible post-accident condition or as an alternative, access to other areas of the facility as necessary to shut down and maintain safe control of the facility without excessive radiation exposures of personnel.
(PBNP GDC 11)

PBNP is equipped with a common control room which contains those controls and instrumentation necessary for operation of each unit's reactor and turbine generator under normal and accident conditions. The control room is continuously occupied by operating personnel under all operating conditions.

The control building, which houses the control room envelope (CRE) and the control room HVAC system, is Seismic Class I.

The CRE is a component in the control room habitability system. When the control room HVAC system is running in the emergency mode, the CRE must be capable of limiting the unfiltered in-leakage. Integrity of the CRE barrier is programmatically and procedurally monitored, maintained, and controlled.

The control room HVAC (VNCR) system performs no safety related functions, but was re-classified as augmented quality (AQ) in January 1998. No formal safety classification rules existed when the original VNCR system was designed. This system was upgraded to support the augmented quality function "provide radiation protection to permit continuous occupancy of the control room under any credible post-accident condition without excessive radiation exposure of personnel".

NUREG-0737, Item III.D.3.4, Control Room Habitability Requirements

This post-TMI NUREG required all licensees to submit a letter to the NRC stating whether or not they met the control room habitability criteria of applicable Standard Review Plans (SRPs) for radiation and toxic gas releases. It explicitly separated requirements into the following two categories: (1) licensees who were required to meet the SRP, and had to prove they met the SRP and (2) licensees who were not required to meet the SRP, who were required to "perform the necessary evaluations and identify appropriate modifications". PBNP fell into the latter category. This NUREG also required PBNP to complete an attachment entitled, Information Required for Control Room Habitability Evaluation, for an independent evaluation of the habitability system.

As part of meeting the requirements of this action item, PBNP implemented several modifications: portable lead shielding was staged for placement in front of the south and north control room doors and the east control room viewing window; additional self contained breathing apparatuses (SCBAs) were placed in the control room; and, control room air supply duct radioactive gas detection equipment was installed. NRC acceptance of PBNP actions regarding this action item was provided on August 10, 1982. Supplementing the NRC safety evaluation was a letter from Pacific Northwest Laboratories (PNL), who provided an independent review of the PBNP response. PNL concluded that the control room met the requirements of 10 CFR 50, Appendix A, General Design Criteria 3, 4, 5, and 19. All required modifications were implemented and communicated to the NRC on September 4, 1984.

The only change made to these NUREG-0737, III.D.3.4 related modifications occurred in 1995, when an office area was built adjacent to the north wall of the control room, thereby, providing the necessary shielding in place of the lead shielding. A modification to replace the remaining portable lead shielding with permanent block wall is planned to support the pending License Amendment Request 241 - Alternative Source Term (ML083450683). Following this modification, the NUREG-0737, III.D.3.4 commitment for portable lead shielding will be eliminated.

Continued compliance with the PBNP GDC 11 and NUREG-0737, III.D.3.4, is demonstrated via administrative controls, which establish periodic inspections and maintenance requirements. Changes to designs affecting safety-related structures, systems, or components (SSCs) or SSCs that support safe operation of the plant, are controlled by QA procedures. Design changes are processed in accordance with the design control process. Any planned changes that affect the CRE boundary integrity are required to be identified and appropriate breach control procedures invoked before work orders are authorized.

PBNP Control Room Habitability Program

PBNP has a Control Room Envelope Habitability Program that provides the current programmatic guidance to identify, mitigate or correct degraded or nonconforming conditions the program provides information required to confirm CRE and CRHS meets applicable design and licensing basis requirements, except for the unfiltered in-leakage rate.

In response to GL 2003-01 (Reference 1), PBNP will also comply with the dose limits of 10 CFR 50 Appendix A, General Design Criteria 19 - Dose Limits Using Alternate Source Term Methodology as described in the pending License Amendment Request 241 - Alternative Source Term. Pending LAR 241, AST, when approved by the Commission will implement GDC 19 dose limits. Following approval of LAR 241, a license amendment will be submitted to provide the response to GL 2003-01. An approved surveillance methodology for the control room envelope (and any associated modifications to the envelope) in accordance with the provisions of TSTF-448, that includes unfiltered leakage. Submittal of this license amendment is being tracked as a Regulatory Commitment that is essential to the closure of GL 2003-01.

Hazardous chemical and toxic gas assessment is not part of the licensing basis for PBNP. Reactor shutdown capability would be maintained in the control room due to the design features of the ventilation system. These features include the capability to exhaust smoke from the control room and computer room or from the cable spreading room through a dedicated smoke and heat vent fan.

The current licensing basis for the Control Room Habitability System is contained in FSAR Section 7.1.2, Instrumentation and Control, General Design Criteria, Section 7.5.3, Operating Control Stations, Occupancy, Section 9.8, Control Room Ventilation System (VNCR) and Section 11.6.3, Shielding Systems, System Evaluation, and the pending License Amendment Request 241 - Alternative Source Term (ML083450683). (Reference 3)

In addition to the evaluations described in the FSAR sections listed above, the PBNP control room habitability system was evaluated for plant license renewal. Systems and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 2)

With respect to the above SER, control room ventilation system (VNCR) is addressed in Section 2.3.3.10, Essential Ventilation System. Aging effects, and the programs used to manage the aging effects associated with the control room ventilation system, are discussed in Section 3.3.2.3.10.

2.7.1.2 Technical Evaluation

Introduction

The CRE must be capable of minimizing unfiltered in-leakage when the VNCR is running in emergency mode. The integrity of the CRE allows the VNCR to maintain positive pressure within the CRE during a post-accident condition, in order to prevent infiltration of airborne contaminants.

The VNCR provides HEPA and charcoal filtered air during post-accident conditions, and provides smoke evacuation in the event of fire within the CRE. The VNCR can also be operated in MODE 3 (100% recirculation, with 25% HEPA and Charcoal filtered recirculation air) for smoke removal in the event of a fire.

The VNCR system is a Non-Safety Related, Augmented Quality, constant-volume HVAC system that provides ventilation, heating, cooling, humidification, dehumidification, pressurization, filtration, smoke exhaust and radiological habitability to the Control Room and the Computer Room. Per FSAR Section 9.8, Control Room Ventilation System (VNCR) and 10 CFR 50 Appendix A, General Design Criteria 19, the VNCR provides 4 modes of operation, as follows:

The VNCR modes of operation are described here. MODE 1 is normal operation, MODE 2 is 100% recirculation, MODE 3 is 100% recirculation with 25% filtered return air and MODE 4 is 25% filtered outside air/75% recirculation.

For MODE 1, one of the two normal supply fans is started. The fan start opens the outside air damper to a predetermined throttled position to supply approximately 1000 CFM of make-up air ducted from an intake penthouse located on the roof of the auxiliary building. The make-up air and the return air from the control and computer rooms passes through a roughing filter and cooling units before entering one of the normal recirculation fans.

MODE 2 operation is 100% recirculation of the air and is initiated by a containment isolation/safety injection signal or manually. After implementation of the Alternative Source Term analysis the automatic actuation of MODE 2 by a containment isolation signal will be removed from the control circuits of the affected dampers.

MODE 3 operation employs one of two control room emergency filter fans and a filtration unit which includes a roughing filter, a HEPA filter, and a charcoal filter. This MODE is manually initiated. With dampers in the full open position, a portion (approximately 25%) of the recirculated air is directed through a filter bank and the operating emergency fan back to the suction of the normal recirculation fan. Operation in this mode also closes the outside make-up air damper and de-energizes the washroom exhaust fan.

MODE 4 is similar to MODE 3 except the return air inlet damper to the emergency fans remains closed and the outside air supply damper opens. This allows make-up air to pass through a filter and the emergency fan to the suction of the normal recirculation fan, ensuring a positive pressure is maintained in the control and computer rooms to limit in-leakage. This MODE is currently initiated by a high radiation signal from the control room area monitor, a high radiation signal from the noble gas monitor located in the supply duct to the control room, or manually. After implementation of the Alternative Source Term analysis the automatic actuation of MODE 4 by a radiation monitor signal will be removed from the control circuits of the affected dampers and fans.

A new system MODE of operation, VNCR Accident MODE (MODE 5), is to be implemented by PBNP LAR 241, Alternative Source Term, dated December 8, 2008 (ML083450683) (Reference 3). MODE 5 is required to be operational prior to implementation of the EPU. MODE 5 provides emergency HEPA/charcoal filtered outside air and HEPA/charcoal filtered recirculating air. To create MODE 5 the MODE 4 flow path is modified to include the return air flow path to the emergency fans. This allows a combination of outside air and return air to pass through the emergency HEPA/charcoal filter unit to the suction of the recirculation fan, assuring a positive pressure that will prevent excessive unfiltered in-leakage into the control room ventilation boundary. MODE 5 will be automatically initiated by a containment isolation signal, a high radiation signal from the control room monitor, or a high radiation signal from the noble gas monitor located in the supply duct to the control room. This mode can also be initiated manually from the control room. Operation in MODE 5 is the assumed mode of operation for the control room habitability analyses for the Alternative Source Term analysis.

The VNCR can exhaust smoke from the control room, computer room or cable spreading room through dedicated smoke and heat vent fan W-13C. Interlocking dampers allow smoke and heat removal from one room at a time. The VNCR also has auto-start of standby fan on low flow condition and diesel generator backup power to control room filter fan and recirculation fan. As indicated in the pending License Amendment Request 241 - Alternative Source Term (ML083450683), CREFS fans will auto start upon loss of offsite power.

The CRE is equipped with a fire protection system to assure that fire will not prevent safe shutdown functions or significantly increase the risk of radioactive release to the environment during a postulated fire.

The control room is equipped with a breathing air manifold system connected to a storage reservoir located outside of the room. Breathing apparatus is available to essential control room operators to permit continuous occupancy of the control room under any credible post-accident condition. The control room is also equipped with Self Contained Breathing Apparatus (SCBA).

Description of Analyses and Evaluations

The control room habitability was evaluated to ensure that EPU conditions would not cause any significant changes to essential aspects of habitability, such as building envelope integrity, heating and cooling capacity and the ability of the VNCR to ventilate, remove smoke, filter airborne contaminants and maintain sufficient positive space static pressure under emergency conditions. The evaluations performed are in compliance with PBNP's commitments to NRC Generic Letter 2003-01 (Reference 1).

Operation of the VNCR system in MODE 5 is the assumed mode of operation for the EPU control room habitability analyses. The EPU Control Room dose analysis is presented in LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms, and demonstrates the effectiveness of the VNCR to permit continuous occupation of the Control Room in compliance with PBNP GDC 11 and NRC Generic Letter 2003-01. (Reference 1)

Other evaluations related to the control room habitability system are addressed in the following LR sections:

- Protection against dynamic effects of missiles, pipe whip and discharging fluids – LR Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects; and LR Section 2.5.1.3, Pipe Failures.

Evaluation of Impact on Renewed Plant Operating License Evaluations and Licensing Renewal Programs

In regard to the aging programs and aging influences described in the License Renewal SER NUREG 1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, the engineered safety feature ventilation system was evaluated and it was concluded that this system was within the scope of the License Renewal. On the basis of its review, the NRC staff concluded that the applicant demonstrated that the aging effects associated with the essential ventilation systems (i.e., Control Room Environment (CRE), namely Control Room HVAC (VNCR), Computer Room HVAC (VNCOMP)) components will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation as required by 10 CFR 54.21. Thus, any new aging effects due to EPU requiring management will be managed consistent with the CLB.

Results

The design and operation of the CRE, VNCR, control room fire protection system and control room breathing air system are unaffected by EPU. The proposed EPU has no effect on fire barrier or pressure boundary integrity of the CRE. The proposed EPU has no effect on the ability of the VNCR to provide a controlled environment for the comfort and safety of control room personnel and to support the operability of control room and computer room components under normal and postulated accident conditions. EPU modifications have minimal effect on internal heat gain in the control room or computer room, and they likewise do not affect the ability of the VNCR to maintain normal specified space temperatures, evacuate smoke, activate emergency filtration flow, maintain emergency filtration air flow rates, maintain space static pressure during emergency filtration air flow and meet minimum HEPA and charcoal filtration efficiencies. The proposed EPU will result in minimal increases in combustible loading in the CRE. The EPU will not increase the likelihood of fire or decrease the effectiveness of the fire protection system. The proposed EPU does not alter the accessibility or effectiveness of any part of the breathing air manifold system. VNCR MODE 5 is being added by the Alternative Source Term analysis and is required for implementation of EPU. For a discussion of EPU impact on control room dose, refer to LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms.

2.7.1.3 Conclusions

PBNP has assessed the effects of the proposed EPU on the ability of the control room habitability system to protect plant operators against the effects of accidental releases of radioactive gases. PBNP has adequately accounted for the increase of radioactive gases that would result from the proposed EPU. PBNP further concludes that the control room habitability system will continue to provide the required protection following implementation of the proposed EPU. The EPU dose calculations prepared as part of this assessment use the methodology contained in the Alternative Source Term analysis and, therefore, require the implementation of VNCR MODE 5 for EPU operation. Based on this, and the pending approval of AST LAR 241, PBNP concludes that the control room habitability system will continue to comply with PBNP GDC 11, the dose limits of 10 CFR 50 and Appendix A GDC 19. Therefore, PBNP finds the proposed EPU acceptable with respect to the control room habitability system.

2.7.1.4 References

1 NRC Generic Letter 2003-01: Control Room Habitability, dated June 12, 2003

2 NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005

3 Point Beach Nuclear Plant Units 1 and 2 License Amendment Request 241, Alternative Source Term (ML083450683), submitted December 8, 2008

2.7.2 Engineered Safety Feature Atmosphere Cleanup

2.7.2.1 Regulatory Evaluation

ESF atmosphere cleanup systems are designed for fission product removal in post-accident environments. These systems generally include primary systems (e.g., in-containment recirculation) and secondary systems (e.g., emergency or post-accident air-cleaning systems) for the fuel-handling building, control room, shield building, and areas containing ESF components. For each ESF atmosphere cleanup system, the PBNP review focused on the effects of the proposed EPU on system functional design, environmental design, and provisions to preclude temperatures in the adsorber section from exceeding design limits.

The NRC's acceptance criteria for ESF atmosphere cleanup systems are based on:

- GDC 19, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent, to any part of the body, for the duration of the accident.
- GDC 41, insofar as it requires that systems to control fission products released into the reactor containment be provided to reduce the concentration and quality of fission products released to the environment following postulated accidents.
- GDC 61, insofar as it requires that systems that may contain radioactivity be designed to assure adequate safety under normal and postulated accident conditions.
- GDC 64, insofar as it requires that means be provided for monitoring effluent discharge paths and the plant environs for radioactivity that may be released from normal operations, including anticipated operational occurrences (AOOs), and postulated accidents.

Specific review criteria are contained in SRP Section 6.5.1.

PBNP Current Licensing Bases

As noted in Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predate those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50 Appendix A GDC 19, 41, 61 and 64 are as follows:

CRITERION: The facility shall be provided with a control room from which actions to maintain safe operational status of the plant can be controlled. Adequate radiation protections shall be provided to permit continuous occupancy of the control room under any credible post-accident condition or as an alternative, access to other areas of the facility as necessary to shut down and maintain safe control of the facility without excessive radiation exposures of personnel. (PBNP GDC 11)

CRITERION: Means shall be provided for monitoring the containment atmosphere and the facility effluent discharge paths for radioactivity released from normal operations, from anticipated transients, and from accident conditions. An environmental monitoring program shall be maintained to confirm that radioactivity releases to the environs of the plant have not been excessive. (PBNP GDC 17)

CRITERION: Provisions shall be made in the design of fuel and waste storage facilities such that no undue risk to the health and safety of the public could result from an accidental release of radioactivity. (PBNP GDC 69)

In-Containment Recirculation System

The current radiological analyses and the pending License Amendment Request 241 - Alternative Source Term (AST) (ML083450683) (Reference 2) assume that the air volume in the containment building is mixed by the containment fan coolers to support the iodine removal function performed by the containment spray system.

In-Containment Iodine Removal System

The current radiological analyses assume that the containment spray system operates in the injection phase of the accident to remove iodine from the containment atmosphere. The radiological analyses associated with the pending License Amendment Request 241 - Alternative Source Term (ML083450683) (Reference 2) assume that the containment spray system operates to remove iodine from the containment atmosphere in the injection phase and the recirculation phase of the accident, with a maximum 20 minute interruption for the purposes of aligning the containment spray system for recirculation spray.

The containment spray system delivers a sodium hydroxide solution into the spray stream to remove iodine. The system includes a common sodium hydroxide tank that contains enough sodium hydroxide solution which, upon mixing with the refueling water from the refueling water storage tank during the injection phase, and the borated water contained within the accumulators and primary coolant that collect in the containment sump during the recirculation phase, to maintain the pH within a range of 7.0 to 10.5. This required range is not affected by EPU. A pH of greater than 7.0 assures the iodine removal effectiveness of the containment spray. The maximum pH is based on Equipment Qualification considerations and is set at 10.5.

Control Room

The control room HVAC (VNCR) system performs no safety related functions, but was re-classified as augmented quality (AQ) in January 1998. No formal safety classification rules existed when the original VNCR system was designed. This system was upgraded to support the augmented quality function "provide radiation protection to permit continuous occupancy of the control room under any credible post-accident condition without excessive radiation exposure of personnel."

As described in the pending License Amendment Request 241 - Alternative Source Term (ML083450683) (Reference 2), the current VNCR system is capable of meeting the dose limits of 10 CFR 50 Appendix A General Design Criteria 19 as required by NUREG-0737, Item III.D.3.4 (Reference 3) while taking credit for use of potassium iodide (KI) to reduce the thyroid dose. The proposed AST accident analyses do not credit the use of KI and do not assume the current MODE 4 configuration for accident mitigation. Instead, the VNCR system is assumed to operate with filtered return air in addition to filtered makeup air. This configuration is referred to as

MODE 5 (emergency HEPA/charcoal filtered outside air and HEPA/charcoal filtered return air mode), and is automatically initiated from either a containment isolation signal, or by a high radiation signal from either the control room area monitor RE-101 or the process monitor RE-235, which takes suction from, located in the supply duct to the control room. This MODE 5 operation, which is required to be operational prior to implementation of EPU, will allow a combination of outside air (≤2500 cfm) and return air to pass through the emergency HEPA/charcoal filter unit to the suction of the control room recirculation fan for a total flow rate of 4950 cfm ±10%.

The control room filter assembly (F-16) removes particulates, aerosols, and radioactivity from the control room supply and/or recirculation air during events requiring emergency air filtration. The F-16 filter assembly consists of a roughing, HEPA and charcoal filter, with filter efficiencies of 95% for elemental iodine, 95% for methyl iodine, and 99% for particulate. The F-16 filter assembly is protected from fire effects using a manually actuated water suppression system supplied by the fire water system.

Other Atmospheric Cleanup Systems

Ventilation air from buildings normally containing radioactive materials and equipment is exhausted through HEPA and/or carbon adsorber equipment depending on the potential for significant releases.

The PBNP auxiliary building ventilation (VNPAB) system is non-safety related, and no credit is taken for removal of iodine by the VNPAB system nor is credit taken for isolation of release paths. The radiological analyses associated with the pending License Amendment Request 241, Alternative Source Term (ML083450683) (Reference 2), is based on the VNPAB being manually restored by operator action within 30 minutes following the alignment of RHR to containment sump recirculation mode of operation to ensure that the auxiliary building vent stack is the source of the release associated with the ECCS leakage phase of the event. License Amendment Request 241 identifies that the portions of the VNPAB system credited for AST will be upgraded to augmented quality status. Additionally, NRC 2009-0023, Supplement to License Amendment Request 241 Alternative Source Term (ML090540860) (Reference 4), identifies that the VNPAB system will be added to the scope of the Maintenance Rule (10 CFR 50.65) and the scope of the License Renewal Program (10 CFR 54.37 (b)). Auxiliary building ventilation is provided by supply and exhaust fans that ventilate the area and exhaust to the atmosphere via the auxiliary building vent stack. The VNPAB provides roughing, HEPA and charcoal filtration (normally bypassed) prior to exhausting the air to the auxiliary building vent stack. The auxiliary building vent stack is a monitored release path.

Radiation Monitoring (RM)

The radiation monitoring system monitors radiation levels and fluid activities at various locations throughout the plant. It is designed to provide direct indication and warning of radiation levels in the plant, measure gas releases from the plant vent stacks and initiate isolation and control functions on certain effluent streams.

The containment atmosphere, the auxiliary building vent, the drumming area vent, the condenser air ejector exhaust, and the gas stripper building exhaust are monitored for radioactivity concentration during normal operations, anticipated transients, and accident conditions. High radiation in any of these is indicated and alarmed in the control room.

The current licensing basis for the in-containment recirculation system, the in-containment iodine removal system, the primary auxiliary building ventilation system, and the control room ventilation system is contained in FSAR Section 6.3, Containment Air Recirculation Cooling System, Section 6.4, Containment Spray System, Section 9.5, Primary Auxiliary Building Ventilation, Section 9.8, Control Room Ventilation System, Section 11.2, Gaseous Waste Management System, Section 11.5, Radiation Monitoring System, Section 11.6, Shielding Systems, and Appendix C.1, Purpose of Chemical Addition to Containment Spray.

License Renewal

In addition to the evaluations described in the FSAR sections listed above, the PBNP ESF ventilation systems were evaluated for plant license renewal. Systems and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 1)

Components of the ESF Atmosphere Cleanup Systems are within the scope of License Renewal. Aging effects to all system components are monitored using the aging effects program. There are no modifications or additions to system components as the result of EPU that would introduce any new functions or change the functions of existing components that would affect the license renewal system evaluation boundaries. Thus, no new aging effects requiring management are identified.

2.7.2.2 Technical Evaluation

Containment

The containment spray system and the containment air recirculation cooling system (VNCC) are designed to reduce the concentration of iodine released to the environment following postulated accidents.

The containment spray system sprays cool, borated water into the containment atmosphere in the event of a loss of coolant accident or main steam line break, and thereby ensures that containment pressure does not exceed the design value of 60 psig at 286°F (100% Relative Humidity) and removes iodine from the containment atmosphere. This protection is afforded for all pipe break sizes up to and including the hypothetical, instantaneous, circumferential rupture of a reactor coolant pipe.

The containment air recirculation cooling system (VNCC) removes heat during normal conditions and following a LOCA. The VNCC has four air cooling units. Each air cooling unit consists of the following equipment arranged in the following flow-through sequence: inlet screen, roughing filter (only installed during refueling shutdown), cooling coil, and two separate vane-axial fans (one designed for accident conditions and the other for normal operation). Backdraft dampers in the discharge duct work of the units isolate an inactive unit from the duct distribution system. In addition a backdraft damper is installed on the normal fan discharge to prevent back flow during accident fan operation. Air is drawn through the inlet screen, roughing filter (if installed) and cooling coil, and then supplied to the containment atmosphere through a common discharge header. Cooling water is provided to the cooling coils by the service water system. Under limiting design basis accident conditions, each fan cooler unit is capable of removing 37.5 x 10^6 Btu/hr from a saturated air-steam mixture at 286°F, with a flow rate of 33,500 cfm. The design function of the system is to recirculate and cool the containment atmosphere following a LOCA.

The containment air recirculation cooling (VNCC) system is further discussed in LR Section 2.7.7, Other Ventilation Systems (Containment).

Additional discussion of design basis accident containment atmosphere cleanup is provided in LR Section 2.5.3.1, Fission Product Control Systems and Structures.

EPU does not affect the ability of the Containment Spray System or the VNCC to reduce the concentration of iodine released from the containment to the environment following a postulated accident. The offsite and control room dose analyses, presented in LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms, demonstrate the effectiveness of the containment spray system and the VNCC to minimize the release of radioactivity to the environment following a LOCA.

Control Room

The Control Room HVAC System (VNCR) is a Non-Safety Related, Augmented Quality constant-volume HVAC system that provides ventilation, heating, cooling, humidification, dehumidification, pressurization, filtration, smoke exhaust and radiological habitability to the Control Room and the Computer Room. The VNCR system is discussed in further detail in LR Section 2.7.1, Control Room Habitability System and Section 2.7.3, Control Room Area Ventilation System.

The VNCR is capable of limiting unfiltered air infiltration to the Control Room Envelope (CRE) when the VNCR is running in emergency mode by maintaining a positive pressure in the Control Room thus assuring leakage is out of rather than into the Control Room. The pressure boundary integrity of the CRE is subject to regular, procedural monitoring, testing and maintenance.

The integrity of the CRE allows the Control Room Ventilation System (VNCR) to maintain positive pressure in the control room during a post-accident condition, in order to limit infiltration of airborne contaminants. The VNCR also provides HEPA and charcoal filtered air during post-accident conditions, and provides smoke evacuation in the event of fire within the CRE. The VNCR is designed to meet the dose limits of 10 CFR 50 Appendix A GDC-19.

EPU does not affect the ability of the VNCR to activate emergency filtration flow, maintain emergency filtration air flow rates, maintain space static pressure during emergency filtration air flow and meet minimum HEPA and charcoal filtration efficiencies. A new mode of operation for the VNCR will be implemented as a result of the pending License Amendment Request 241 - Alternative Source Term (ML083450683). This new mode, MODE 5, provides emergency filtered outside air and filtered recirculating air. Operation in MODE 5 is the assumed mode of operation for the control room habitability analyses for Alternative Source Term and EPU evaluations. The EPU Control Room dose analysis is presented in LR Section 2.9.2, Radiological Consequences

Analyses Using Alternative Source Terms, and demonstrates the effectiveness of the VNCR to permit continuous occupation of the Control Room.

Auxiliary Building

The Primary Auxiliary Building Ventilation System (VNPAB) is a non-safety related system. Portions of this system will be upgraded to augmented quality status to support Alternative Source Term requirements.

VNPAB performs the following functions:

- Exhaust and filtration (of exhaust) from rooms potentially containing iodine vapor and/or contaminated particles during normal and accident conditions to limit offsite releases and support auxiliary building habitability.
- Provide a flow path for venting portions of the auxiliary building that are subject to hydrogen line breaks or leaks, in order to maintain hydrogen concentration within allowable limits.
- In support of Alternative Source Term, provide a flow path for post-LOCA ECCS leakage in the auxiliary building to discharge through the auxiliary building ventilation stack.

All auxiliary building exhaust air is filtered through roughing and high efficiency filters for removal of particulates. Areas that have possible contamination from iodine vapor can be exhausted through activated carbon beds in addition to high efficiency filters, if required. The exhausted air from these areas passes through activated carbon filters as required. All air exhausted from these areas is then discharged through the auxiliary building vent stack, which is monitored for radiation. The EPU does not alter the supply or exhaust air flow paths, air flow rates, filtration or existing ability to isolate any portion of the VNPAB. The VNPAB is discussed further in LR Section 2.7.5, Auxiliary and Radwaste Area and Turbine Areas Ventilation System.

Refer to LR Section 2.7.6, ESF Ventilation System, for additional information regarding the ESF ventilation systems.

Spent Fuel Pool Area

Ventilation to the Spent Fuel Pool Area is provided by the drumming area ventilation system (VNDRM) which is a subsystem of the auxiliary building ventilation system. The system serves to control airborne radioactivity in the area by passing the exhaust air through activated carbon beds in addition to high efficiency filters. EPU does not affect the design of the VNDRM system. Refer to LR Section 2.7.4, Spent Fuel Pool Area Ventilation, for additional information regarding spent fuel pool area ventilation.

Radiation Monitoring

The containment atmosphere is continually monitored during normal and transient station operations using the containment particulate and gas monitors. Three high radiation monitors per unit are also installed within the containment. The monitors are used for post-accident monitoring of the containment space conditions. Radioactivity levels contained in the facility effluent discharge paths and in the environs are continually monitored during normal and accident conditions by the station radiation monitoring system and by the radiation protection program for PBNP. The ability of these monitors to perform their function is not affected by the

EPU. Refer to LR Section 2.10.1, Occupational and Public Radiation Doses, for additional discussion.

License Renewal

Components of the ESF Atmosphere Cleanup Systems that are within the scope of License Renewal are described in NUREG-1839, Sections 2.3.2.2, Containment Spray, 2.3.3.9, VNCC, and 2.3.3.10, VNPAB and VNCR. Aging effects, and the programs used to manage the aging effects of these components are discussed in NUREG-1839, Sections 3.2.2.3.3, Containment Spray, 3.3.2.3.9, VNCC, and 3.3.2.3.10, VNPAB and VNCR. There are no modifications or additions to system components as the result of EPU that would introduce any new functions or change the functions of existing components that would affect the license renewal system evaluation boundaries. Operation of the ESF Atmosphere Cleanup Systems at EPU conditions does not add any new types of materials or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

Results

The proposed EPU has no effect on the ability of ESF atmosphere cleanup systems to control the release of radioactivity to the environment within regulatory limits. The offsite and control room dose analyses presented in LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms, demonstrate the effectiveness of the ESF Atmosphere Cleanup Systems to minimize the release of radioactivity to the environment following a LOCA.

2.7.2.3 Conclusions

PBNP has assessed the effects of the proposed EPU on the ESF atmosphere cleanup systems. PBNP accounted for the increase of fission products and changes in expected environmental conditions that would result from the proposed EPU, and PBNP further concludes that the ESF atmosphere cleanup systems will continue to provide adequate fission product removal and radiation monitoring in post-accident environments following implementation of the proposed EPU. Based on this, PBNP concludes that the ESF atmosphere cleanup systems will continue to meet the current licensing basis requirements and comply with PBNP GDC 11, 17 and 69. Therefore, PBNP finds the proposed EPU acceptable with respect to the ESF atmosphere cleanup systems.

2.7.2.4 References

1 NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005

2 Point Beach Nuclear Plant Units 1 and 2 License Amendment Request 241, Alternative Source Term (ML083450683), submitted December 8, 2008

3 NUREG-0737, Clarification of TMI Action Plan Requirements, published November 1980

4 Point Beach Units 1 and 2 - Supplement to License Amendment Request 241 Re: Alternative Source Term, dated February 20, 2009 (ML090540860)

2.7.3 Control Room Area Ventilation System

2.7.3.1 Regulatory Evaluation

The function of the Control Room Ventilation System (VNCR) is to provide a controlled environment for the comfort and safety of control room personnel and to support the operability of control room components during normal operation, Anticipated Operational Occurrences and DBA conditions. The PBNP review of the VNCR focused on the effects that the proposed EPU will have on the functional performance of safety-related portions of the system. The review included the effects of radiation, combustion, and other toxic products; and the expected environmental conditions in areas served by the VNCR.

The NRC's acceptance criteria for the VNCR are based on:

- GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents.
- GDC 19, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent to any part of the body, for the duration of the accident.
- GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents.

Specific review criteria are contained in SRP Section 9.4.1.

PBNP Current Licensing Bases

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP specific GDC for the Control Area Ventilation Systems are as follows:

CRITERION: The facility shall be provided with a control room from which actions to maintain safe operational status of the plant can be controlled. Adequate radiation protections shall be provided to permit continuous occupancy of the control room under any credible post-accident condition or as an alternative, access to other areas of the facility as necessary to shut down and maintain safe control of the facility without excessive radiation exposures of personnel. (PBNP GDC 11)

CRITERION: The facility design shall include those means necessary to maintain control over the plant radioactive effluents, whether gaseous, liquid, or solid. Appropriate holdup capacity shall be provided for retention of gaseous, liquid, or solid effluents, particularly where unfavorable environmental conditions can be expected to require operational limitations upon the release of radioactive effluents to the environment. In all cases, the design for radioactivity control shall be justified (a) on the basis of 10 CFR 20 requirements, for both normal operations and for any transient situation that might reasonably be anticipated to occur and (b) on the basis of 10 CFR 100 dosage level guidelines for potential reactor accidents of exceedingly low probability of occurrence. (PBNP GDC 70)

PBNP is equipped with a common control room which contains those controls and instrumentation necessary for operation of each unit's reactor and turbine generator under normal and accident conditions. The control room is continuously occupied by operating personnel under all operating conditions.

The control building, which houses the control room envelope (CRE) and the control room HVAC system, is Seismic Class I.

The CRE is a passive component in the control room habitability system. When the control room HVAC system is running in the emergency MODE, the CRE must be capable of limiting the unfiltered in-leakage. Integrity of the CRE barrier is programmatically and procedurally monitored, maintained, and controlled.

The control room HVAC (VNCR) system performs no safety related functions, but was re-classified as augmented quality (AQ) in January 1998. No formal safety classification rules existed when the original VNCR system was designed. This system was upgraded to support the augmented quality function "provide radiation protection to permit continuous occupancy of the control room under any credible post-accident condition without excessive radiation exposure of personnel."

NUREG-0737, Item III.D.3.4, Control Room Habitability Requirements

This post-TMI NUREG required all licensees to submit a letter to the NRC stating whether or not they met the control room habitability criteria of applicable Standard Review Plans (SRPs) for radiation and toxic gas releases. It explicitly separated requirements into the following two categories: (1) licensees who were required to meet the SRP, and had to prove they met the SRP and (2) licensees who were not required to meet the SRP, who were required to "perform the necessary evaluations and identify appropriate modifications." PBNP fell into the latter category. This NUREG also required PBNP to complete an attachment entitled, Information Required for Control Room Habitability Evaluation, for an independent evaluation of the habitability system.

As part of meeting the requirements of this action item, PBNP implemented several modifications: portable lead shielding was staged for placement in front of the south and north control room doors and the east control room viewing window; additional self contained breathing apparatuses (SCBAs) were placed in the control room; and, control room air supply duct radioactive gas detection equipment was installed. NRC acceptance of PBNP actions regarding this action item was provided on August 10, 1982. Supplementing the NRC safety evaluation was a letter from Pacific Northwest Laboratories (PNL), who provided an independent review of the PBNP response. PNL concluded that the control room met the requirements of 10 CFR 50, Appendix A, General Design Criteria 3, 4, 5, and 19. All required modifications were implemented and communicated to the NRC on September 4, 1984.

The only change made to these NUREG-0737, III.D.3.4 related modifications occurred in 1995, when an office area was built adjacent to the north wall of the control room, thereby, providing the necessary shielding in place of the lead shielding. A modification to replace the remaining portable lead shielding with permanent block wall is planned to support the pending License Amendment Request 241, Alternative Source Term (ML083450683). Following this modification, the NUREG-0737, III.D.3.4 commitment for portable lead shielding will be eliminated.

Continued compliance with the PBNP GDC 11 and NUREG-0737, III.D.3.4, is demonstrated via administrative controls, which establish periodic inspections and maintenance requirements. Changes to designs affecting safety-related structures, systems, or components (SSCs) or SSCs that support safe operation of the plant, are controlled by QA procedures. Design changes are processed in accordance with the design control process. Any planned changes that affect the CRE boundary integrity are required to be identified and appropriate breach control procedures invoked before work orders are authorized.

In response to GL 2003-01, PBNP will also comply with the dose limits of 10 CFR 50 Appendix A General Design Criteria 19 dose limits using Alternative Source Term methodology as described in the pending License Amendment Request 241 (ML083450683) for implementation of the Alternative Source Term methodology.

Hazardous chemical and toxic gas assessment is not part of the licensing basis for PBNP. Reactor shutdown capability would be maintained in the control room due to the design features of the ventilation system. These features include the capability to exhaust smoke from the control room and computer room, or from the cable spreading room through a dedicated smoke and heat vent fan.

The current licensing basis for the VNCR system is contained in FSAR Section 9.8, Control Room Ventilation System, and the pending PBNP License Amendment Request 241 - Alternative Source Term (ML083450683).

In addition to the evaluations described the FSAR Section listed above, the PBNP control room ventilation system was evaluated for plant license renewal. Systems and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 1.)

With respect to the above SER, control room ventilation system (VNCR) is addressed in Section 2.3.3.10, Essential Ventilation System. Aging effects, and the programs used to manage the aging effects associated with the control room ventilation system, are discussed in Section 3.3.2.3.10.

2.7.3.2 Technical Evaluation

Introduction

The Control Room Ventilation System (VNCR) is designed to provide heating, ventilation, air conditioning, and radiological habitability for the Control Room and Computer Room, which are both within the control room envelope. The control room is maintained at a positive pressure during accident conditions to assure that any leakage is out of (rather than into) the control room. VNCR performs the following functions:

- During normal conditions the system provides outside air ventilation to the control and computer room zones to satisfy personnel fresh air requirements
- During normal conditions the system humidifies/dehumidifies the control and computer room zones to assure equipment operability and maintain operator comfort
- During normal, abnormal and emergency conditions the system provides sufficient control of room temperatures to maintain equipment temperatures within design limits and maintain operator comfort
- During emergency operation the system filters recirculated control room air (or contaminated outside air) to provide a radiologically habitable space to allow continuous operator occupancy
- During emergency operation the system pressurizes the control room to limit unfiltered inleakage to the control room zone
- Following a Halon discharge in the computer room the system isolates the computer room from the control room to prevent Halon-contamination in the control room
- During control or computer room fires the system aligns to vent smoke and heat one room at a time, to prevent cross-contamination of rooms

A normal operating environment of 75° ± 10°F is maintained in the control room. The system equipment is designed to maintain a room temperature of 75° ± 10°F, with outside air temperatures varying from -15°F to 95°F. Instrumentation and associated circuitry in the control room is generally rated for an ambient temperature range of 40°F to 120°F.

For radiological habitability the system is currently capable of operating in four different MODES providing for control room pressurization to limit inleakage, makeup and recirculation through HEPA and charcoal filters to remove contaminates, and recirculation without filtration or makeup. The system is capable of meeting the dose limits of 10 CFR 50 Appendix A GDC-19 as required by NUREG-0737, Item III.D.3.4. The design factors affecting the systems ability to meet the above dose limits include; actuation on a Containment Isolation signal, emergency filtration flow rate of 4950 cfm ± 10%, maintaining a positive pressure $\geq$1/8 in. w.g during MODE 4 operation, and meeting minimum filtration efficiencies specified in the test section for the HEPA and charcoal filters. A new MODE of operation, MODE 5, is to be implemented by LAR 241 - Alternative Source Term (ML083450683).

MODE 1 is normal operation, MODE 2 is 100% recirculation, MODE 3 is 100% recirculation with 25% filtered return air and MODE 4 is 25% filtered outside air / 75% recirculation. MODE 5 (to be implemented by LAR 241, Alternative Source Term) (ML083450683) provides emergency filtered outside air and filtered recirculating air.

For MODE 1, one of the two normal supply fans is started. The fan start opens the outside air damper to a predetermined throttled position to supply approximately 1000 CFM of make-up air ducted from an intake penthouse located on the roof of the auxiliary building. The make-up air and the return air from the control and computer rooms passes through a roughing filter and cooling units before entering one of the normal recirculation fans.

MODE 2 operation is 100% recirculation of the air and is initiated by a containment isolation/safety injection signal or manually. After implementation of LAR 241, Alternative Source Term (ML083450683), the automatic actuation of MODE 2 by a containment isolation signal will be removed from the control circuits of the affected dampers.

MODE 3 operation employs one of two control room emergency filter fans and a filtration unit which includes a roughing filter, a HEPA filter, and a charcoal filter. This MODE is manually initiated. With dampers in the full open position, a portion (approximately 25%) of the recirculated air is directed through a filter bank and the operating emergency fan back to the suction of the normal recirculation fan. Operation in this MODE also closes the outside make-up air damper and de-energizes the washroom exhaust fan.

MODE 4 is similar to MODE 3 except the return air inlet damper to the emergency fans remains closed and the outside air supply damper opens. This allows make-up air to pass through a filter and the emergency fan to the suction of the normal recirculation fan, ensuring a positive pressure is maintained in the control and computer rooms to limit in-leakage. This MODE is currently initiated by a high radiation signal from the control room area monitor, a high radiation signal from the noble gas monitor located in the supply duct to the control room, or manually. After implementation of LAR 241 - Alternative Source Term (ML083450683) the automatic actuation of MODE 4 by a radiation monitor signal will be removed from the control circuits of the affected dampers and fans.

A new MODE of operation, MODE 5, is to be implemented by LAR 241, Alternative Source Term (ML083450683). The VNCR Accident MODE (MODE 5) provides emergency HEPA/charcoal filtered outside air and HEPA/charcoal filtered recirculating air. To create MODE 5, the MODE 4 flow path is modified to include the return air flow path to the emergency fans. This allows a combination of outside air and return air to pass through the emergency HEPA/charcoal filter unit to the suction of the recirculation fan, assuring a positive pressure that will prevent excessive unfiltered in-leakage into the control room ventilation boundary. MODE 5 will be automatically initiated by a containment isolation signal, by a high radiation signal from the control room monitor, or by a high radiation signal from the noble gas monitor located in the supply duct to the control room. This MODE can also be initiated manually from the control room. Operation in MODE 5 is the assumed MODE of operation for the control room habitability analyses for the LAR 241, Alternative Source Term Analysis, Enclosure 3, Section 5.2.

Description of Analyses and Evaluations

The Control Room Ventilation System was evaluated to assure it is capable of performing its intended functions at EPU conditions as follows:

- During normal conditions VNCR operates in MODE 1 to where outside air ventilation to the control and computer room zones provides fresh air to meet personnel requirements. The capability of the system to provide fresh (outside) air is not affected by EPU.
- The capability of the system to humidify/dehumidify the control and computer room zones to assure equipment operability and maintain operator comfort is not affected by EPU.
- Under EPU conditions the temperatures of the areas surrounding the control room do not significantly change. In addition there are minimal increases in heat loads internal to the

control room. Therefore during normal, abnormal and emergency conditions the system will provide sufficient control of room temperatures to maintain equipment temperatures within design limits and maintain operator comfort.

- Under EPU there is no significant increase in either radiation levels or contamination levels that would affect the filtering of recirculated control room air (or contaminated outside air) during the emergency operation of the system. This is addressed in LR Section 2.7.1, Control Room Habitability System.
- During emergency operation the system pressurizes the control room to limit unfiltered inleakage to the control room zone. This is addressed in LR Section 2.7.1, Control Room Habitability System.
- There are no changes under EPU that would prevent the isolation of the computer room from the control room following a Halon discharge in the computer room.
- There are no changes under EPU that would prevent system alignment to vent smoke and heat from one room at a time to prevent the cross-contamination of the control room and computer room during a fire in one of the rooms.

Based on the above, the control room area ventilation system provides an environment in the control room that allows for continuous occupancy under post accident conditions. For the evaluation of radiation protection of control room occupants see LR Section 2.7.1, Control Room Habitability System and Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms. Operation of the VNCR in MODE 5 is the assumed MODE of operation for the EPU control room habitability analyses. PBNP control room habitability under accident conditions meets the requirements of PBNP GDC 11.

The new MODE 5 being implemented by LAR 241, Alternative Source Term (ML083450683), is created by modifying the existing MODE 4 flow path. No physical changes are being made to the ventilation fans. Since no changes to the Control Room Area Ventilation System fans are required to support EPU, there is no increased probability of dynamic effects or missiles from the ventilation fans.

LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms, summarizes the EPU assessment of impact on post-accident dose consequences at the site boundary and at locations on-site that require continuous occupancy, such as the control room. The results of LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms, confirm that after implementation of LAR 241, Alternative Source Term (ML083450683), and the EPU, the plant ventilation systems will continue to maintain control over gaseous radioactive releases and maintain dosage level within guidelines in compliance with PBNP GDC 70. Compliance with PBNP GDC 70 with regards to liquid and solid waste is addressed in LR Section 2.5.6.2, Liquid Waste Management System, and Section 2.5.6.3, Solid Waste Management System.

Results

The design and operation of the VNCR system require no further changes due to EPU following the addition of VNCR MODE 5, which is being implemented by LAR 241, Alternative Source Term (ML083450683). The proposed EPU has minimal effect on the ability of the VNCR to

provide a controlled environment for the comfort and safety of control room personnel and to support the operability of control room and computer room components under normal and postulated conditions. EPU has minimal effect on internal heat gain in the control room or computer room and therefore EPU does not affect the ability of the VNCR to maintain normal specified space temperatures. Likewise the ability of the VNCR system to evacuate smoke, activate emergency filtration flow, maintain emergency filtration air flow rates, maintain space static pressure during emergency filtration air flow and meet minimum HEPA and charcoal filtration efficiencies is not affected by EPU. The ability of the control room area ventilation system to limit the radiation dose to personnel within the Control Room and Computer Room is addressed in
LR Section 2.7.1, Control Room Habitability System, and Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms. LR Sections 2.5.6.1, Gaseous Waste Management System, 2.5.6.2, Liquid Waste Management System and 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms, also confirm PBNP compliance with PBNP GDC 70.

License Renewal

Portions of the control room area ventilation systems are within the scope of License Renewal as identified in the License Renewal Safety Evaluation Report, NUREG-1839, Section 2.3.3.10, Essential Ventilation System. Aging Management Programs used to manage the aging effects associated with the control room area ventilation systems are addressed in the NUREG-1839, Section 3.3.2.3.10, Essential Ventilation System – Aging Management Evaluation. EPU activities are not adding any new components within the existing license renewal system evaluation boundaries nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. Operating at EPU conditions does not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified as a result of EPU.

2.7.3.3 Conclusion

PBNP has assessed the effects of the proposed EPU on the ability of the VNCR system to provide a controlled environment for the comfort and safety of control room personnel and to support the operability of control room components. PBNP concludes that the assessment has adequately accounted for changes to parameters affecting the environmental conditions for control room personnel and equipment under the conditions of the proposed EPU. The EPU dose calculations prepared as part of this assessment use the methodology contained in the LAR 241, Alternative Source Term (ML083450683), analysis. Therefore, approval of LAR 241 and implementation of VNCR MODE 5 are required for EPU operation. Accordingly, PBNP concludes that the control room VNCR system will continue to provide an acceptable control room environment for safe operation of the plant following the implementation of the proposed EPU. PBNP also concludes that the system will continue to suitably control the release of gaseous radioactive effluents to the environment. Based on this, PBNP concludes that the control room ventilation system will continue to meet the requirements of PBNP GDCs 11, 70 and the dose limits of 10 CFR 50, Appendix A GDC 19. Therefore, PBNP finds the proposed EPU acceptable with respect to the VNCR system.

2.7.3.4 References

1. Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

2.7.4 Spent Fuel Pool Area Ventilation System

2.7.4.1 Regulatory Evaluation

The function of the spent fuel pool area ventilation system is to maintain ventilation in the spent fuel pool equipment areas, permit personnel access, and control airborne radioactivity in the area during normal operation, anticipated operational occurrences, and following postulated fuel handling accidents. The PBNP review focused on the effects of the proposed EPU on the functional performance of the safety-related portions of the system.

The NRC's acceptance criteria for the spent fuel pool area ventilation are based on:

- GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents
- GDC 61, insofar as it requires that systems which contain radioactivity be designed with appropriate confinement and containment

Specific review criteria are contained in SRP Section 9.4.2.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predate those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50 Appendix A GDC 60 and 61 are as follows:

CRITERION: The facility design shall include those means necessary to maintain control over the plant radioactive effluents, whether gaseous, liquid, or solid. Appropriate holdup capacity shall be provided for retention of gaseous, liquid, or solid effluents, particularly where unfavorable environmental conditions can be expected to require operational limitations upon the release of radioactive effluents to the environment. In all cases, the design for radioactivity control shall be justified (a) on the basis of 10 CFR 20 requirements, for both normal operations and for any transient situation that might reasonably be anticipated to occur and (b) on the basis of 10 CFR 100 dosage level guidelines for potential reactor accidents of exceedingly low probability of occurrence. (PBNP GDC 70)

CRITERION: Provisions shall be made in the design of fuel and waste storage facilities such that no undue risk to the health and safety of the public could result from an accidental release of radioactivity. (PBNP GDC 69)

The PBNP spent fuel pool area ventilation system is non-safety related, and no credit is taken for removal of iodine by the spent fuel pool ventilation system nor is credit taken for isolation of release paths.

Ventilation air from buildings normally containing radioactive materials and equipment is exhausted through HEPA and/or carbon adsorber equipment depending on the potential for significant releases. Ventilation of the spent fuel pool area is provided by supply and exhaust fans that ventilate the area and exhaust to the atmosphere via the drumming area stack that includes a HEPA filter. The drumming area stack is a monitored release path.

The current licensing basis for the spent fuel pool area ventilation system is contained in FSAR Section 14.2.1, Fuel Handling Accident, and Appendix I, Section 1.5, Plant Ventilation and Filtration Systems, and Section 2.6, Ventilation and Exhaust Systems.

The PBNP ventilation systems were evaluated for plant license renewal. Systems and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

With respect to the above SER, the spent fuel pool area ventilation system, which is part of the drumming area ventilation (VNDRM) system, is addressed in Section 2.3.3.10, Essential Ventilation System. The VNDRM system is not within the scope of license renewal.

2.7.4.2 Technical Evaluation

Introduction

The spent fuel pool area ventilation system is part of the drumming area ventilation system, which is a subsystem of the auxiliary building ventilation system. The primary auxiliary building ventilation system is described in FSAR Section 9.5, Primary Auxiliary Building Ventilation System. The spent fuel pool area ventilation system is addressed in FSAR Section 14.2.1, Fuel Handling Accident, and Appendix I, Sections 1.5, Plant Ventilation and Filtration System, and Appendix I, Section 2.6, Ventilation and Exhaust Systems. The impact of the proposed EPU on the auxiliary building ventilation system is further evaluated in LR Section 2.7.5, Auxiliary and Radwaste Area and Turbine Areas Ventilation Systems, LR Section 2.7.6, Engineered Safety Feature Ventilation System and LR Section 2.7.2, Engineered Safety Feature Atmosphere Cleanup. The spent fuel pool area ventilation system serves to control airborne radioactivity in the spent fuel pool area during normal operating conditions. This is accomplished by directing air from the auxiliary building to both the drumming and spent fuel pool (SFP) areas to limit radiation doses to personnel from drumming operations, or from radioactive vapor emanating from the SFP.

All the exhaust air is filtered through roughing and high efficiency filters for removal of particulates. All air exhausted from these areas is then discharged through the drumming area vent stack, which is monitored for radiation.

The PBNP spent fuel pool area ventilation system is non-safety related, and no credit is taken for removal of iodine by the spent fuel pool ventilation system nor is credit taken for isolation of release paths.

Description of Analyses and Evaluations

The spent fuel pool area ventilation system was evaluated to ensure it is capable of performing its intended functions at EPU conditions. The decay heat loads in the spent fuel pool increase due to the EPU conditions. EPU decay heat loads and pool water temperatures have been evaluated to ensure that the system is capable of maintaining the pool temperature within current design temperature under normal EPU and refueling modes. This evaluation is addressed in LR Section 2.5.4.1, Spent Fuel Pool Cooling and Cleanup System.

The radiological evaluations of the spent fuel pool area ventilation are addressed in the following LR sections:

- Offsite dose consequences of a fuel handling accident – LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms
- Control of the release of radioactive effluents – LR Section 2.10.1, Occupational and Public Radiation Doses

The evaluations in these sections show that the spent fuel pool area ventilation continues to comply with PBNP GDCs 70 and 69.

The design of the spent fuel pool area ventilation system does not change as a result of the implementation of EPU. Airborne radioactivity released from the spent fuel in the pool will continue to be collected, exhausted by the drumming area ventilation system, which is a subsystem of the auxiliary building ventilation system, and released to the atmosphere via the monitored and alarmed drumming area ventilation stack.

License Renewal

The spent fuel pool area ventilation system, which is part of the drumming area ventilation system, is not within the scope of License Renewal as identified in the License Renewal Safety Evaluation Report, NUREG-1839, Section 2.3.3.10, Essential Ventilation System. EPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. There are no changes associated with operation of the spent fuel pool ventilation system at EPU conditions and the EPU does not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

Results

The air temperature in the spent fuel pool area is affected by heat released from the spent fuel pool. Although the decay heat in the spent fuel is greater at EPU conditions, the spent fuel pool water temperature during normal and abnormal EPU operation does not exceed the current values. Therefore, the spent fuel pool area ventilation system will maintain the required air temperature conditions for personnel and equipment during EPU operation. Refer to LR Section 2.5.4.1, Spent Fuel Pool Cooling and Cleanup System.

The design of the spent fuel pool area ventilation system does not change following the implementation of the EPU. Airborne radioactivity released from the spent fuel in the pool will continue to be collected, exhausted by the drumming area ventilation system (VNDRM) which is a subsystem of the auxiliary building ventilation system and released to the atmosphere via the monitored and alarmed drumming area ventilation stack. Therefore, the control of airborne radioactivity in the spent fuel pool area is not affected following implementation of the EPU.

Refer to LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms, and Section 2.10.1, Occupational and Public Radiation Doses.

2.7.4.3 Conclusions

PBNP has assessed the effects of the proposed EPU on the Spent Fuel Pool Area Ventilation System. PBNP has adequately accounted for the effects of the proposed EPU on the system's capability to maintain ventilation in the spent fuel pool equipment areas, permit personnel access, control airborne radioactivity in the area, control release of gaseous radioactive effluents to the environment, and provide appropriate containment. Based on this, PBNP concludes that the Spent Fuel Pool area ventilation will continue to comply with PBNP GDCs 69 and 70. Therefore, PBNP finds the proposed EPU acceptable with respect to the Spent Fuel Pool Area Ventilation System.

2.7.5 Auxiliary and Radwaste Area and Turbine Areas Ventilation Systems

2.7.5.1 Regulatory Evaluation

The function of the auxiliary and radwaste area ventilation system and the turbine area ventilation system is to maintain ambient temperatures in the auxiliary and radwaste equipment and turbine areas, permit personnel access, and control the concentration of airborne radioactive material in these areas during normal operation, during anticipated operational occurrences, and after postulated accidents. The PBNP review focused on the effects of the proposed EPU on the functional performance of the safety-related portions of these systems.

The NRC's acceptance criteria for these systems are based on:

- GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents

Specific review criteria are contained in SRP Sections 9.4.3 and 9.4.4

In order to minimize confusion and to maintain consistency with previous NRC staff evaluations performed on PBNP, the systems reviewed in this section are designated "Nonessential Ventilation Systems" as used in the PBNP License Renewal Safety Evaluation Report, NUREG-1839.

(The ventilation systems important to personnel safety or vital equipment operation are composed primarily of the license renewal grouping called essential ventilation systems. Additional information on the essential ventilation systems is provided in LR Section 2.7.2, Engineered Safety Feature Atmosphere Cleanup and LR Section 2.7.6, Engineered Safety Feature Ventilation System. Other systems are addressed elsewhere as called out in RS-001).

PBNP Current Licensing Bases

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP specific GDC for the auxiliary and radwaste area ventilation system and the turbine area ventilation system is as follows:

CRITERION: The facility design shall include those means necessary to maintain control over the plant radioactive effluents, whether gaseous, liquid, or solid. Appropriate holdup capacity shall be provided for retention of gaseous, liquid, or solid effluents, particularly where unfavorable environmental conditions can be expected to require operational limitations upon the release of radioactive effluents to the environment. In all cases, the design for radioactivity control shall be justified (a) on the basis of 10 CFR 20 requirements, for both normal operations and for any transient situation that might reasonably be anticipated to occur and (b) on the basis of 10 CFR 100 dosage level guidelines for potential reactor accidents of exceedingly low probability of occurrence. (PBNP GDC 70)

The following ventilation systems provide suitable and controlled environments for equipment, personnel access, and control of airborne radioactive material:

Auxiliary Building

The auxiliary building ventilation (VNPAB) includes ventilation air from service building controlled areas and is exhausted through the auxiliary building and the drumming area ventilation (VNDRM) vents.

The auxiliary building vent exhausts air from the service building, chemistry laboratory, general areas of the auxiliary building and cubicles containing radioactive equipment. The chemistry laboratory exhausts to the auxiliary building vent through roughing filters, HEPA filters and carbon adsorbers.

Service building ventilation (VNSBB) and general areas and cubicles of the auxiliary building containing equipment with low potential for iodine releases are exhausted through roughing and HEPA filters.

Areas of the auxiliary building with high potential for iodine releases are routed through roughing and HEPA filters to the auxiliary building vent with an optional route through carbon adsorbers and HEPA filters.

Turbine Building Ventilation (VNTB) System

Units 1 and 2 share a combined turbine building. Outside air is provided at all levels of the building and is exhausted through 19 turbine building roof exhausters evenly spaced along the length of the turbine building roof. Turbine building ventilation is exhausted through roof exhausters with no treatment.

The Electrical Equipment Room Ventilation (VNEERM) system is part of the VNTB system and maintains electrical equipment room temperatures within design limits.

Condenser Air Ejectors

Unit 1 and Unit 2 air ejectors discharge to a delay duct in the turbine building which provides a nominal one hour holdup prior to release via the auxiliary building vent. An optional route is through a carbon adsorber prior to the delay duct. Treatment of main condenser air ejector offgas is addressed in LR Section 2.10.1, Occupational and Public Radiation Doses.

Radioactive Waste Gases

The PBNP specific GDC for the control room ventilation system is as follows:

Releases of cover gas from gas decay tanks are directed to the auxiliary building vent at a controlled rate.

Stripped gas from the Unit 1 and Unit 2 gas strippers is normally routed through the charcoal decay tanks and back to the CVCS volume control tank for each unit. This gas may also be released directly to the auxiliary building vent. An optional route is to pass the charcoal decay tank effluent through cryogenic equipment prior to release. However, no credit for the cryogenic system is taken in calculating radioactive releases.

During normal operation, the Radwaste HVAC (VNRAD) system (in the blowdown evaporator building) draws air from the auxiliary building, and discharges to the auxiliary building primarily through open doors to the spent fuel pool area (although it can also discharge through a duct to the auxiliary building), where it is processed by the VNPAB system.

The PBNP CLB for the auxiliary and radwaste area ventilation system and the turbine area ventilation system is provided in FSAR Section 9.5, Primary Auxiliary Building Ventilation, Section 11.2, Gaseous Waste Management System, and Appendix I, Sections 1.5, Plant Ventilation and Filtration Systems, and 2.6, Ventilation and Exhaust Systems.

In addition to the evaluations described in the FSAR, PBNP's nonessential ventilation system was designated as not being within the scope of License Renewal. The system and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

Portions of the primary auxiliary building ventilation system are within the scope of License Renewal under essential ventilation system. EPU activities are not adding any new components within the existing license renewal system evaluation boundaries nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. Operating at EPU conditions does not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Additional structures and components of the VNPAB system will be added to the scope of License Renewal as a result of the licensing action for LAR 241, Alternative Source Term. No new aging effects requiring management are identified as a result of EPU.

2.7.5.2 Technical Evaluation

Introduction

Primary Auxiliary Building Ventilation (VNPAB)

The primary auxiliary building ventilation system (VNPAB) is a non-safety related system. Portions of this system will be upgraded to augmented quality status to support Alternative Source Term requirements.

VNPAB performs the following functions:

- Exhaust and filtration (of exhaust) from rooms potentially containing iodine vapor and/or contaminated particles during normal and accident conditions to limit offsite releases and support auxiliary building habitability.
- Provide a flow path for venting portions of the auxiliary building that are subject to hydrogen line breaks or leaks, in order to maintain hydrogen concentration within allowable limits.
- In support of Alternative Source Term, provide a flow path for post-LOCA ECCS leakage in the auxiliary building to discharge through the auxiliary building ventilation stack.

The VNPAB has one non-safety related, Non-QA function, which is to maintain the building within its design range of 65°F-85°F. Safety-related equipment in the PAB is not affected by a loss-of-HVAC for up to 24 hours thus indicating that the ability to maintain an 85°F design temperature during normal operation is not critical.

Following NRC staff review and approval of License Amendment Request 241, Alternative Source Term (ML083450683) (Reference 1), PBNP will submit a License Amendment Requirs for a Technical Specification addressing a Limiting Condition for Operation and appropriate Surveillence Requirements for the VNPAB.

Radwaste Area Ventilation (VNRAD)

The VNRAD is a non-safety related, non-QA system that is located in the blowdown evaporator building. It was originally installed to support radwaste modifications (gas strippers) and cool a cryogenic area. During normal operation, the VNRAD system (in the blowdown evaporator building) draws air from the auxiliary building, and discharges to the auxiliary building primarily through open doors to the spent fuel pool area (although it can also discharge through a duct to the auxiliary building), where it is processed by the VNPAB system. Although the VNRAD system is not physically connected to the VNPAB system, the boundary is assumed to be at the suction/discharge points, and at the normally open door (which can be closed to isolate the VNRAD system from the VNPAB system).

Turbine Area Ventilation (VNTB)

The VNTB is a non-safety related, non-QA system that provides ventilation for heat removal during summer and heat to maintain minimum space temperature during winter and plant outages. The VNTB provides once-through ventilation, with air intake louvers on the outside walls and exhaust fans on the roof. The VNTB must maintain general areas in the Turbine Building at or below 115°F.

Description of Analyses and Evaluations

EPU does not change the requirements for filtering the air from rooms within the Primary Auxiliary Building (PAB) that may contain iodine. After filtration, the air is released to the atmosphere via the PAB vent stack which is monitored for radiation. EPU does not alter the supply or exhaust air flow paths, air flow rates, filtration, or ability to isolate any portion of the VNPAB. Refer to LR Section 2.7.2, Engineered Safety Feature Atmosphere Cleanup, for additional information regarding the Engineered Safety Feature Atmosphere Cleanup function of the VNPAB system.

The Auxiliary Feedwater (AFW) System is being redesigned to support PBNP operation at EPU conditions (refer to LR Section 2.5.4.5, Auxiliary Feedwater, for further details). As a result, two new motor-driven auxiliary feedwater pumps will be installed in the primary auxiliary building. The heat generated by the addition of these new AFW pumps and any impact on the primary auxiliary building ventilation system, VNPAB, will be addressed as part of the AFW system modification process.

As described in the pending License Amendment Request 241, Alternative Source Term (ML083450683), the alternative source term analysis takes credit for operation of one containment spray pump in addition to one safety injection pump during post-accident ECCS sump recirculation (additional details are provided in LR Section 2.6.5, Containment Heat Removal). Since the AST LAR must be implemented for EPU, this statement will also be true for operation at EPU conditions. The heat released from the operation of one containment spray pump motor and one safety injection pump motor during sump recirculation is bounded by the existing configuration of one containment spray pump and two safety injection pumps operating during the injection phase. Therefore, operation of a containment spray pump during the recirculation phase will not impose an additional load on the VNPAB system following EPU implementation.

EPU does not change the requirements for maintaining hydrogen concentrations in the primary auxiliary building below allowable limits. Hydrogen concentrations are not expected to increase at EPU because there are no expected changes in the hydrogen system or volume control tank.

EPU does not alter the supply or exhaust air flow paths, air flow rates, filtration, heating load or cooling load of the VNRAD. Refer to LR Section 2.10.1, Occupational and Public Radiation Doses, for additional information and discussion of compliance with PBNP GDC 70.

Temperatures in the turbine building general areas are currently maintained within design limits. As part of the implementation of EPU, the feedwater and condensate pump motors are being replaced, and the new, larger motors will give off more heat than the existing motors. In addition, as discussed in LR Section 2.5.5.4, Condensate and Feedwater, the temperature of the feedwater supplied to the steam generators will increase, resulting in additional heat being transferred to various turbine building areas. Considering the heat load increases from motors and process fluids at higher temperatures, the turbine building temperature is expected to increase by approximately 1°F. Given this small increase, the turbine building ventilation system, VNTB, will continue to maintain the temperatures in the turbine building within the design basis.

Results

Aside from the AFW System redesign, plant changes to support operation at EPU conditions will not affect the ability of the VNPAB, VNRAD or VNTB systems to perform their respective design functions. The impact on the VNPAB temperature due to the addition of two new AFW pumps and motors will be addressed during the AFW system modification process. EPU plant changes will not diminish the capability of the VNPAB, VNRAD or VNTB systems to meet the requirements of PBNP GDC 70.

License Renewal

Portions of the primary auxiliary building ventilation system are within the scope of License Renewal as identified in the License Renewal Safety Evaluation Report, NUREG-1839, Section 2.3.3.10, Essential Ventilation System. Aging Management Programs used to manage the aging effects associated with the primary auxiliary building ventilation systems are addressed in the NUREG-1839, Section 3.3.2.3.10, Essential Ventilation System – Aging Management Evaluation. EPU activities are not adding any new components within the existing license renewal system evaluation boundaries nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. Operating at EPU conditions does not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Additional structures and components of the VNPAB system will be added to the scope of License Renewal as a result of the licensing action for LAR 241, Alternative Source Term. No new aging effects requiring management are identified as a result of EPU. The remaining systems discussed in this LR Section are designated as "Nonessential Ventilations Systems" as used in the PBNP License Renewal Safety Evaluation Report, NUREG-1939.

2.7.5.3 Conclusions

PBNP has assessed the effects of the proposed EPU on the auxiliary and radwaste area ventilation system and the turbine area ventilation system. PBNP concludes that the assessment has adequately accounted for the effects of the proposed EPU on the capability of these systems to maintain ventilation in the auxiliary, radwaste equipment and turbine areas, permit personnel access, control the concentration of airborne radioactive material in these areas, and control release of gaseous radioactive effluents to the environment. Based on this, PBNP concludes that the systems will continue to comply with PBNP GDC 70. Therefore, PBNP finds the proposed EPU acceptable with respect to the auxiliary and radwaste area ventilation system and the turbine area ventilation system.

2.7.5.4 Reference

1. FPL Energy LLC to NRC, Point Beach Nuclear Plant Units 1 and 2, Submittal of License Amendment Request 241, Alternative Source Term, December 2008, (ML083450683)

2.7.6 Engineered Safety Feature Ventilation System

(Note that the environmental control for engineered safety feature components that are located inside containment is covered in LR Section 2.6.5, Containment Heat Removal.)

2.7.6.1 Regulatory Evaluation

The function of the Engineered Safety Feature Ventilation System (ESFVS) is to provide a suitable and controlled environment for ESF components following certain anticipated transients and DBAs. The PBNP review for the ESFVS focused on the effects of the proposed EPU on the functional performance of the safety-related portions of the system. The PBNP review also covered:

- The ability of the ESF equipment in the areas being serviced by the ventilation system to function under degraded ESFVS performance.
- The capability of the ESFVS to circulate sufficient air to prevent accumulation of flammable or explosive gas or fuel-vapor mixtures from components (such as storage batteries and stored fuel).
- The capability of the ESFVS to control airborne particulate material (dust) accumulation.

The NRC's acceptance criteria for the ESFVS are based on:

- GDC 4, insofar as it requires that structures, systems, and components (SSCs) important to safety be designed to accommodate the effects of, and to be compatible with, the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents.
- GDC 17, insofar as it requires onsite and offsite electric power systems be provided to permit functioning of safety-related SSCs important to safety.
- GDC 60, insofar as it requires that the plant design includes means to control the release of radioactive effluents.

Specific review criteria are contained in SRP Section 9.4.5.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50 Appendix A GDC 4, 17 and 60 are as follows:

CRITERION: The facility design shall include those means necessary to maintain control over the plant radioactive effluents, whether gaseous, liquid, or solid. Appropriate holdup capacity shall be provided for retention of gaseous, liquid, or solid effluents, particularly where unfavorable environmental conditions can be expected to require operational limitations upon the release of radioactive effluents to the environment. In all cases, the design for radioactivity control shall be justified (a) on the basis of 10 CFR 20 requirements, for both normal operations and for any transient situation that might reasonably be anticipated to occur and (b) on the basis of 10 CFR 100 dosage level guidelines for potential reactor accidents of exceedingly low probability of occurrence. (PBNP GDC 70)

The following ventilation systems provide suitable and controlled environments for ESF components:

The primary auxiliary building (PAB) battery and electrical equipment room ventilation system (VNBI) maintains the station batteries (D-105 and D-106), inverters, and other safety-related components within established temperature limits, including during plant fires. This system also prevents hydrogen buildup in the battery rooms. The VNBI sub-system is classified as Seismic Class I.

The diesel generator building ventilation (VNDG) system maintains ambient temperatures in the required areas within acceptable limits to support the operation of the emergency diesel generators G03, and G04 during a design basis accident, loss of offsite power, Station Blackout (SBO) events, and some plant fires. G03/G04 draw outside air for combustion rather than room air like the G01/G02 diesel generators. The VNDG system provides combustion and ventilation air to the emergency diesel generator room to maintain the room within operating temperature and pressure limits. The VNDG system is classified as Seismic Class I.

The gas turbine building ventilation (VNGT) system supports the operation of the gas turbine by providing cooling (via air flow) once the gas turbine equipment is in operation. This function is necessary for both Appendix R and Station Blackout (SBO) scenarios.

The primary auxiliary building ventilation (VNPAB) system provides sufficient control of building temperatures during normal, abnormal, and accident conditions to maintain equipment within operational temperature limits. Primary auxiliary building ventilation is provided by supply and exhaust fans that ventilate the area and exhaust to the atmosphere via the auxiliary building vent stack. This system also filters the exhaust from rooms potentially containing iodine vapor, and rooms potentially containing particulates, during normal and accident conditions to limit offsite releases, and support auxiliary building habitability. The VNPAB system filtration assembly consists of roughing, HEPA and charcoal filtration prior to exhausting the air to the auxiliary building vent stack. The auxiliary building vent stack is a monitored release path. The VNPAB system is not required to perform any safety-related functions. No credit is taken in any accident analysis or habitability study for the filtration capability of the system.

The drumming area ventilation (VNDRM) system is similar to the VNPAB system with the exception that the exhaust system has no provision for iodine removal and is discharged via a separate, monitored vent stack.

The auxiliary feedwater pump area ventilation (VNAFW) provides sufficient control of room temperatures for the auxiliary Feedwater pump, vital switchgear, and control building battery rooms D05 and D06. The VNAFW also maintains the hydrogen concentration of the battery rooms within allowable limits.

Battery room ventilation (VNBR) provides sufficient control of the control building battery room environment to maintain the batteries within design temperature limits and the hydrogen concentration within allowable limits.

The cable spreading room ventilation (VNCSR) and the computer room ventilation (VNCOMP) provide heating, ventilation, and air conditioning for their respective areas and associated equipment contained within those areas.

The circulating water pump house ventilation (VNPH) system provides heating and ventilation for its respective area and the associated equipment contained within this area.

The current licensing basis for the engineered safety feature ventilation systems is contained in FSAR Section 8.7.2, System Description and Operation, Section 9.5, Primary Auxiliary Building Ventilation, Appendix I Section 1.5, Plant Ventilation and Filtration Systems, and Appendix I Section 2.6, Ventilation and Exhaust Systems.

In addition to the evaluations described in the FSAR Sections listed above, the PBNP engineered safety feature ventilation systems (VNBI, VNDG, VNGT, VNPAB and VNCSR) were evaluated for plant license renewal. Systems and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

The engineered safety feature ventilation system was evaluated and it was concluded that this system was "in-scope" of the License Renewal. On the basis of its review, the staff concluded that the applicant demonstrated that the aging effects associated with the auxiliary systems (i.e., EFSVS) components will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation as required by 10 CFR 54.21

2.7.6.2 Technical Evaluation

Introduction

The ESFVS function to maintain temperatures within specified limits in areas containing safety-related equipment. Normal ventilation exhausts from potentially contaminated areas are filtered and the discharge is monitored for radiation. Included in the scope of the engineered safety feature ventilation system at PBNP are the following subsystems:

- PAB and Swing Battery and Electrical Equipment Room Ventilation System (VNBI), (described in FSAR Section 8.7)
- Diesel Generator Building Ventilation (VNDG) system
- Gas Turbine Building Ventilation (VNGT) system
- Primary Auxiliary Building Ventilation (VNPAB) System, (described in FSAR Section 9.5)
- Drumming Area Ventilation (VNDRM) System

- Auxiliary Feedwater Pump Area Ventilation (VNAFW) System
- Battery Room Ventilation (VNBR) System
- Cable Spreading Room Ventilation (VNCSR) and the Computer Room Ventilation (VNCOMP) System
- The Circulating Water Pump House Ventilation System (VNPH)

The PAB battery and electrical equipment room ventilation system (VNBI) maintains the station batteries (D105 and D106), inverters, and other safety-related components within established temperature limits. This system also prevents hydrogen buildup in the battery rooms. In addition, a second non-safety related VNBI system provides the same function for the swing chargers and swing battery (D-305) located in the Control Building. The supply airflow to the ventilation equipment is from the turbine building. The air is exhausted from the battery rooms to the turbine building.

The diesel generators have several auxiliary support systems that must function in order to perform its safety related function, including the room ventilation system (VNDG). The two Train A emergency diesel generator sets (G01 and G02) are located in separate rooms in the Seismic Class I section of the turbine building. The two Train B Emergency diesel generator sets are located separate rooms in the Seismic Class I Emergency Diesel Generator Building (DGB, G03 and G04). The diesel generator ventilation system (G01 and G02) within the turbine building ventilates two diesel generators that are housed in adjacent, but separate rooms. Two exhaust fans plus motor-operated and natural draft dampers are provided to meet the performance objectives for each diesel generator room. The exhaust fans, 2 per room, draw outside air through the dampers into the room. The fans exhaust directly into the turbine hall. Operation of the fans is controlled by thermostats.

The diesel generator building ventilation system (VNDG) ventilates two diesel generators (G03 and G04) that are housed in adjacent, but separate rooms. Each generator unit is serviced by a safety-related ventilation system having inlet wall louvers with associated back draft dampers, and each room has a set of two 30/70% capacity exhaust fans drawing outside air across the room and exhaust to the roof. The ventilation system provides sufficient air flow to maintain acceptable temperature operation within each room and prevent the possible buildup of a flammable atmosphere. The switchgear and mechanical room ventilation system consists of a common air handling unit that maintains room temperature to support equipment and personnel operation. Upon failure of the air handling unit, an emergency exhaust air fan provides ventilation. Within the fuel oil day tank and transfer pump room, three exhaust fans maintain continuous air flow to prevent a potential buildup of flammable vapors.

The gas turbine is a small power plant within itself, fully capable of operating independent of the remainder of the plant. Although it has no safety related function, the gas turbine is relied upon to provide backup power during some abnormal situations. This unit is normally used for spinning reserve, station blackout and for peaking purposes. The Gas Turbine Building Ventilation System (VNGT) that supports the gas turbine unit is located within its own structure. The VNGT system provides combustion and ventilation air to the gas turbine and diesel generator areas to maintain the areas within the gas turbine and diesel operational temperature. The VNGT system combustion and ventilation air is sized for maximum rated power output of the existing gas turbine, diesel and the associated electrical equipment in the building. An enclosure fan set consisting of an exhaust fan (installed on one side of the enclosure) which removes potential buildup of flammable vapors and its coincident make up air opening (located on the opposite side of the enclosure) ensure continuous air flow throughout the building enclosure.

The primary auxiliary building ventilation system (VNPAB) is evaluated in LR Section 2.7.5, Auxiliary and Radwaste Area and Turbine Areas Ventilation Systems.

The drumming area ventilation system (VNDRM) is evaluated in LR Section 2.7.4, Spent Fuel Pool Area Ventilation System.

The auxiliary feedwater pump area ventilation system (VNAFW) provides sufficient control of room temperatures during normal, abnormal, and emergency conditions to maintain equipment temperatures in the auxiliary feedwater pump rooms, vital switchgear area, and D05 and D06 battery rooms within design limits. This system provides redundant air handling units to form two parallel trains and recirculate a natural supply of cooled air to the auxiliary feedwater pump rooms, vital switchgear area, and battery rooms. Two battery room fans (one per battery room) exhaust air to the turbine building. Turbine building air is drawn into the auxiliary feedwater pump room to make up for the air being exhausted by the battery room exhaust fans.

The battery room ventilation system (VNBR) provides sufficient control of the control building battery room (D05 and D06) environment during normal, abnormal, and accident conditions to maintain the batteries within design temperature limits, and the hydrogen concentration within allowable limits. The make up airflow to the battery room is provided by the auxiliary feed pump room ventilation system via the vital switchgear area. Air is exhausted from the battery room to the turbine building.

The computer room ventilation (VNCOMP) system is evaluated in LR Section 2.7.3, Control Room Area Ventilation System.

The cable spreading room ventilation (VNCSR) consists of a single system which filters, heats, cools and distributes air to the room. The system draws outside air from the common supply plenum with the turbine building, control and computer room ventilation systems. The air is drawn through a roll-type filter and a series of two heat exchangers. The system delivers air to provide positive pressure within the cable spreading room to assure no in-leakage from adjoining rooms. The cable spreading room shares a common smoke and heat vent removal system with the Control Room and the Computer Room. The ventilation system has 2 modes of operation; normal and emergency. The emergency mode of operation is initiated by a containment isolation signal. In the emergency mode of operation, exhaust air and outside air is shut off and the system continuously recirculates the supply air.

The Circulating Water Pump House Ventilation System (VNPH) which ventilates the circulating water pumphouse and associated valve gallery consists of exhaust fans and air-operated make up air dampers. Exhaust fans provide the proper circulation by discharging room air to the outdoors. Air is made up to the building through wall mounted air-operated dampers. Two exhaust fans are provided in the service water pump area. These exhaust fans draw the air from the service water pump area and exhaust into the pumphouse enclosure. Makeup air to the service water pump area is supplied by natural circulation from the pumphouse. Ventilation for the valve gallery is supplied by two exhaust fans. The fans take suction on the air within the area and discharge it outside. Makeup air supplied from outside by motor-operated dampers.

The control room ventilation (VNCR) system is discussed in LR Section 2.7.1, Control Room Habitability System System and Section 2.7.3, Control Room Area Ventilation System. The spent fuel pool ventilation system is discussed in LR Section 2.7.4, Spent Fuel Pool Area Ventilation System.

Description of Analyses and Evaluations

Changes in heat loads which effect ventilation subsystems in areas served by the ESFVS were evaluated to ensure that the ventilation subsystems are capable of performing their intended functions under EPU conditions. The changes were found to be insignificant to degrade essential system operation, to impact the system's capability to circulate sufficient air to prevent accumulation of flammable or explosive gases, or to impact its ability to control airborne particulate material accumulation.

Other evaluations related to the ESFVS are addressed in the following LR Sections:

- Protection against dynamic effects of missiles, pipe whip and discharging fluids. See LR Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects, and LR Section 2.5.1.3, Pipe Failures
- Electrical equipment qualification. See LR Section 2.3.1, Environmental Qualification of Electrical Equipment
- Onsite and offsite electric power systems, including PBNP GDC-39 requirements. See LR Section 2.3.2, Offsite Power System, and LR Section 2.3.3, AC Onsite Power System
- Potential radioactive releases to the environment. See LR Section 2.10.1, Occupational and Public Radiation Doses

Evaluation of Impact on Renewed Plant Operating License Evaluations and Licensing Renewal Programs

In regard to the aging programs and aging influences described in the License Renewal SER NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, the engineered safety feature ventilation system was evaluated and it was concluded that this system was in scope of the License Renewal. On the basis of its review, the staff concluded that the applicant demonstrated that the aging effects associated with the auxiliary systems (i.e., EFSVS) components will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation as required by 10 CFR 54.21. Thus, any new aging effects due to EPU requiring management will be managed consistent with the CLB.

Results

<u>PAB and Swing Battery, and Inverter (Electrical Equipment) Room Ventilation System (VNBI)</u>

The PAB battery and electrical equipment room heat loads do not change after implementation of the EPU (refer to LR Section 2.3.4, DC Onsite Power System). Since area temperatures and volatile gasses do not increase, no changes will be required to the PAB battery and electrical equipment room ventilation system. Likewise, the heat loads to the swing bus chargers and battery in the Control Building is unaffected by EPU.

Diesel Generator Building Ventilation (VNDG) System

A diesel generator is considered operable when the diesel room temperature is maintained ≤120°F with the diesel operating at full load. The VNDG system is designed to maintain the room temperature at ≤120°F with the diesels operating at their ratings. Changes in diesel loading resulting from EPU related equipment changes or additions, or load sequencing changes may reduce the diesel generator margin; however, the loadings at EPU conditions will not exceed the ratings of the diesels. Consequently, the VNDG system, which supports the diesel generator rooms, is not affected by EPU. Therefore, the ventilation system's ability to provide the required temperature conditions for personnel and equipment is not affected by EPU.

Gas Turbine Building Ventilation (VNGT) System

The gas turbine unit load is not increased after implementation of the EPU (refer to LR Section 2.3.3, AC Onsite Power System). Therefore, the ventilation system's ability to provide the required air flow and temperature conditions for personnel and equipment is not affected by the EPU.

Auxiliary Feedwater Pump Area Ventilation (VNAFW) System

In order to support operation at EPU conditions the auxiliary feedwater (AFW) system is being redesigned, including the addition of two new motor-driven AFW pumps in the primary auxiliary building. The present 250 HP motor-driven AFW pumps will remain in place, but be converted to Standby Steam Generator (SSG) pumps. Refer to LR Section 2.5.4.5, Auxiliary Feedwater for additional details. The present turbine-driven auxiliary feedwater pump has not changed and is not impacted by EPU. Thus, the net impact to the VNAFW system is that no new equipment will be added to the area cooled by the VNAFW system and concurrent operation of the turbine driven auxiliary feedwater pumps and the SSGs is not required. Therefore, the VNAFW system's ability to maintain present area temperature conditions for personnel and equipment is not adversely affected by EPU.

The ventilation for the new motor-driven AFW pumps will be addressed in the modification process for the new pumps.

Battery Room Ventilation (VNBR) System

The battery room (D05 and D06) loads do not change after implementation of the EPU (refer to LR Section 2.3.4, DC Onsite Power System). Since area temperatures and volatile gasses do not increase, no changes will be required to the battery room ventilation system (VNBR).

Cable Spreading Room Ventilation (VNCSR) and the Computer Room Ventilation (VNCOMP) System

The cable spreading room heat load does not increase after implementation of EPU. EPU activities do not add any new components nor do they introduce any new functions for existing components that would change the licensed system evaluation boundaries of the cable spreading envelope. During an emergency, the ventilation system is configured to a full recirculation mode. Therefore, the ventilation system's ability to provide the required temperature conditions for personnel and equipment and the control of airborne particulate material is not impacted by the EPU.

Circulating Water Pump House Ventilation System (VNPH)

The building area of the circulating water pump house building and its temperature do not increase after implementation of the EPU. EPU activities do not add any new components nor introduce any new functions within the circulating water pump house building. EPU does not change system flow or pressure. Circulating water is drawn through the pump house from Lake Michigan, and the circulating water inlet temperature is not changed by EPU. Although the discharge temperature of the circulating water increases approximately 4°F as a result of EPU, circulating water does not return to Lake Michigan through the pump house. Thus, the VNPH system is not affected by the temperature increase of the circulating water discharge. Therefore, the ventilation system's ability to provide the required temperature conditions for personnel and equipment and the control of volatile vapors is not impacted by the EPU.

Summary

The evaluation of the plant equipment changes for the proposed EPU did not identify any need to modify subsystems of the engineered safety feature ventilation system. There are no equipment changes as a result of the EPU that could create a new potentially unmonitored radioactive release path. Thus, following the EPU, PBNP will continue to meet the current licensing basis insofar as it requires that the plant design include means to control the release of radioactive effluents, as reflected in general design criteria PBNP GCD 70. The effects of potential releases to the environment are evaluated in LR Section 2.10.1, Occupational and Public Radiation Doses, and remain within current limits following the EPU.

2.7.6.3 Conclusion

PBNP has assessed the effects of the proposed EPU on the ESFVS. PBNP concludes that the assessment has adequately accounted for the effects of the proposed EPU on the ability of the ESFVS to provide a suitable and controlled environment for ESF components. PBNP further concludes that the ESFVS will continue to assure a suitable environment for the ESF components following implementation of the proposed EPU. PBNP also concludes that the ESFVS will continue to suitably control the release of gaseous radioactive effluents to the environment following implementation of the proposed EPU. Based on this, PBNP concludes that the ESFVS will continue to meet the requirements of PBNP GDC 70. Therefore, PBNP finds the proposed EPU acceptable with respect to the ESFVS.

2.7.7 Other Ventilation Systems (Containment)

2.7.7.1 Regulatory Evaluation

The functions of the containment ventilation system are to provide heat removal from the containment atmosphere, to support the removal of radioactive materials from the containment atmosphere, and to provide containment pressure control under normal and accident conditions. The PBNP review of the containment ventilation system focused on the effects that the proposed EPU will have on the functional performance of system.

The acceptance criteria from 10 CFR 50 Appendix A would apply to the containment ventilation system are based on:

- GDC 4, insofar as it requires that safety-related structures, systems, and components be designed to accommodate the effects of and be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents
- GDC 17, insofar as it requires onsite and offsite electric power systems be provided to permit functioning of safety-related structures, systems, and components
- GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents
- GDC 61, insofar as it requires that systems containing radioactivity be designed with appropriate confinement and containment

PBNP Current Licensing Basis

The containment air recirculation cooling (VNCC) system removes heat from the containment following a loss of coolant accident or main steam line break inside containment to limit containment temperatures and pressures to less than containment design limits.

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50 Appendix A GDC 4, 17, 60 and 61 are as follows:

CRITERION: Engineered safety features shall be provided in the facility to back up the safety provided by the core design, the reactor coolant pressure boundary, and their protection systems. Such engineered safety features shall be designed to cope with any size reactor coolant piping break up to and including the equivalent of a circumferential rupture of any pipe in that boundary, assuming unobstructed discharge from both ends. (PBNP GDC 37)

The VNCC system, as one of two independent systems of essentially equal heat removal capacity, reduces the containment pressure and thereby limiting the driving potential for fission product leakage by cooling the containment atmosphere.

The containment air recirculation cooling system is designed to recirculate and cool the containment atmosphere in the event of a loss-of-coolant accident and thereby ensure that the containment pressure cannot exceed its design value of 60 psig at 286°F (100% relative humidity). Although the water in the core after a loss-of-coolant accident is quickly subcooled by the safety injection system, the containment air recirculation cooling system is designed on the conservative assumption that the core residual heat is released to the containment as steam.

CRITERION: An emergency power source shall be provided and designed with adequate independency, redundancy, capacity, and testability to permit the functioning of the engineered safety features and protection systems required to avoid undue risk to the health and safety of the public. This power source shall provide this capacity assuming a failure of a single active component. (PBNP GDC 39)

Independent alternate power systems are provided with adequate capacity and testability to supply the required engineered safety features and protection systems.

Adequate heat removal capability for the containment is provided by two separate, full capacity, engineered safety features systems. These are the containment spray system and the containment air recirculation cooling system. These systems are of different engineering principles and serve as independent backups for each other.

CRITERION: Provisions shall be made in the design of fuel and waste storage facilities such that no undue risk to the health and safety of the public could result from an accidental release of radioactivity. (PBNP GDC 69)

CRITERION: The facility design shall include those means necessary to maintain control over the plant radioactive effluents, whether gaseous, liquid, or solid. Appropriate holdup capacity shall be provided for retention of gaseous, liquid, or solid effluents, particularly where unfavorable environmental conditions can be expected to require operational limitations upon the release of radioactive effluents to the environment. In all cases, the design for radioactivity control shall be justified (a) on the basis of 10 CFR 20 requirements, for both normal operations and for any transient situation that might reasonably be anticipated to occur and (b) on the basis of 10 CFR 100 dosage level guidelines for potential reactor accidents of exceedingly low probability of occurrence. (PBNP GDC 70)

The VNCC system, as one of two independent systems of essentially equal heat removal capacity, reduces the containment pressure and thereby limiting the driving potential for fission product leakage by cooling the containment atmosphere.

Other Containment Ventilation Functions

The containment ventilating systems are designed to remove the normal heat loss from equipment and piping in the containment during plant operation and to maintain a normal ambient temperature less than 105°F. The containment ventilation systems also provide sufficient air circulation and filtering throughout containment areas to permit safe and continuous access to the reactor containment following reactor shutdown, provide for positive circulation of air across the refueling water surface when necessary to minimize personnel inhalation hazards during shutdown, provide a minimum containment ambient temperature of 50°F during reactor shutdown and provide for purging of the containment vessel to the plant vent for dispersion to the environment.

In order to accomplish these objectives, the following systems are provided:

1. Containment Air Recirculation Cooling System (VNCC)
2. Control Rod Drive Mechanism Cooling System (VNCRD)
3. Reactor Cavity Cooling System (VNRC)
4. Refueling Water Surface Ventilation System (VNRF)
5. Purge Supply and Exhaust System (VNPSE)
6. Containment Cleanup (Charcoal Filter) System (VNCF)
7. Post-Accident Containment Venting System (PACV)
8. Radiation Monitoring System (RM)

Ventilation air from buildings normally containing radioactive materials and equipment is exhausted through HEPA and/or carbon absorber equipment depending on the potential for significant releases. The containment is provided with a containment purge system (VNPSE), an internal cleanup system (VNCF), and a purge vent which exhausts above the containment facade. Purge exhaust is through roughing filters, HEPA filters, and carbon absorbers. The VNCF system is provided with roughing filters, HEPA filters and carbon absorbers. The VNCF system is not necessarily operated prior to each purge, and therefore no credit is taken in the evaluation of releases via containment ventilation.

Pressure buildup in the containment as a result of instrument air leakage is vented continuously via the containment air monitor (RM). This effluent is routed to the containment purge filters prior to release via the purge vent.

The containment ventilation ductwork (except the CRDM cooling system ductwork), fans (except the refueling water surface supply and exhaust fans and the CRDM cooling system fans), filters, coils, and housings within the containment are designed as Seismic Class I structures.

The Post Accident Containment Ventilation sub-system (PACV) is addressed separately in LR Section 2.6.4, Combustible Gas Control in Containment.

Other FSAR sections that address the design features and functions of the containment ventilation system include:

- FSAR Section 5.2, Containment Isolation System, which describes containment isolation features to isolate the containment boundaries in the containment ventilation system post-accident.
- FSAR Section 6.4, Containment Spray System, which describes means of heat removal from the containment atmosphere with containment recirculation fan coolers and the containment spray system under accident conditions.

The current licensing basis for the containment ventilation systems is contained in FSAR Section 5.3, Containment Ventilating System, Section 6.1.1, Engineered Safety Features Criteria, Section 6.3, Containment Air Recirculation Cooling System, Appendix I Section 1.5, Plant Ventilation and Filtration System, and Appendix I Section 2.6, Ventilation and Exhaust Systems.

In addition to the evaluations described in the FSAR sections listed above, the PBNP containment ventilation systems (VNCC and VNPSE) were evaluated for plant license renewal. Systems and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

The containment ventilation system evaluation concluded that subsystems VNCC and VNPSE were within the scope of the License Renewal. On the basis of its review, the NRC staff concluded in the SER that the applicant adequately identified the containment ventilation system components that are within the scope of the license renewal, as required by 10 CFR 54.4(a) and that the applicant adequately identified the containment ventilation system components that are subject to an Aging Management Review, as required by 10 CFR 54.21(a)(1).

2.7.7.2 Technical Evaluation

Introduction

The Containment Ventilation Systems, as described in FSAR Section 5.3.1, Containment Ventilating System, Design Basis, are designed to accomplish the following:

- Remove the normal heat loss from the equipment and piping in the containment during plant operation and maintain a normal ambient temperature below about 105°F.
- Provide sufficient air circulation and filtering throughout all containment areas to permit safe and continuous access to the reactor containment within 2 hours after reactor shutdown assuming defects exist in no more than 1% of the fuel rods.
- Provide for positive circulation of air across the refueling water surface when necessary to minimize personnel inhalation hazards during shutdown.
- Provide a minimum containment ambient temperature of 50°F during reactor shutdown.
- Provide for purging of the containment to the plant vent for dispersion to the environment.
- Provide for depressurization of the containment vessel following an accident. For post-accident operation, refer to LR Section 2.6.5, Containment Heat Removal, for the system evaluation.

In order to accomplish these functions, the following systems are provided:

- Containment Air Recirculation Cooling System (VNCC) - removes heat from the containment following a loss of coolant accident or main steam line break inside the containment to limit containment temperatures and pressures to less than containment design limits (refer to LR Section 2.6.5, Containment Heat Removal).
- The VNCC air recirculating cooling function, during normal operation, is accomplished using three of the four air cooling units (with 2 fans/unit) discharging to a common duct to ensure

adequate distribution of filtered and cooled air throughout the containment. The VNCC system maintains the containment ambient temperature below 105°F.

- Control Rod Drive Mechanism Cooling System (VNCRD) - consists of fans and ductwork that draw air through the control rod drive mechanism shroud and eject it to the main containment atmosphere. The VNCRD system cools the control rod drive mechanisms (CRDMs) during normal operation to maintain the CRDM coils within temperature limits. A 100% redundancy is provided by a standby fan.
- Reactor Cavity Cooling System (VNRC) - provides cooling of ex-core neutron detectors, in-core drives and various structures within equipment limits during normal operations. The VNRC system consists of a plenum, cooling coils, fans, and ductwork, and is arranged to supply cooled air to the annulus between the reactor vessel and the primary shield for cooling the primary shield wall and to the nuclear instrumentation external to the reactor. A 100% redundancy is provided by a standby fan and cooling coils.
- Refueling Water Surface Ventilation System (VNRF) - is used during refueling operations to remove contaminants emanating from the water pool above the fuel elements. This is accomplished by the supply fan drawing air from the containment atmosphere and supplying it above the water surface. This air then mixes with containment air and is exhausted by the refueling surface exhaust fan to the purge exhaust system where it is filtered and discharged to atmosphere. The system is not required to assist in mitigating a fuel handling accident or operate during refueling operations.
- Purge Supply and Exhaust System (VNPSE) - provides ventilation air to containment areas during refueling to permit continuous personnel access, provides a flow path to atmosphere, filtration and monitoring to limit offsite releases during containment purges, forced vents or other releases. The containment purge system is independent of any other system and includes provisions to both supply and exhaust air from the containment during MODES 5 and 6. The supply system includes: outside air connection to roughing filters, heating coils, fans, duct system, supply penetration with one butterfly valve and one blind flange, in series for tight shutoff. The exhaust system includes: an exhaust penetration with one butterfly valve and one blind flange in series, duct system, filter bank with roughing and HEPA filters, and exhaust fans. Both supply and exhaust systems include two fans with isolating dampers so that purging can be performed at half or full flow rate. The purge supply and exhaust system is used to maintain a minimum temperature of 50°F during winter shutdowns. Per Technical Specifications, purging of the containment is prohibited during MODES 1, 2, 3 and 4. Radiation monitors are provided to monitor the releases. Refer to LR Section 2.10.1, Occupational and Public Radiation Doses, for the evaluation of the impact on normal releases and the impact on the radiation monitors set-points.
- Containment Cleanup (Charcoal Filter) System (VNCF) - draws air from the containment general area across a HEPA/charcoal filter and discharges it back into the containment.
- Post-Accident Containment Venting System (PACV) - does not function during normal plant operating conditions. The system was designed to remove hydrogen from the containment following a LOCA. The NRC eliminated the hydrogen release associated with a design basis loss of coolant accident from 10 CFR 50.44 and the associated requirements that

necessitated the hydrogen re-combiners and the post-accident containment hydrogen vent and purge system. As a result, the PACV has been removed from the PBNP licensing basis. However, the PACV is being maintained for beyond-design basis accident management. Refer to LR Section 2.6.4, Combustible Gas Control in Containment, for additional information on the post-accident containment venting system (PACV).

- Radiation Monitoring System (RM) - monitors the containment atmosphere and containment discharge paths for radioactivity released during normal operations, transients, and accident conditions. During normal reactor operation at power, the containment may be continuously vented by use of the containment gaseous and particulate sampling and monitoring penetrations. The containment air sample flow is normally routed back to the containment atmosphere. When the unit is in cold shutdown and the containment purge exhaust fans are operating, the containment air sample returns are normally routed to the containment purge exhaust stack. The flow transmitter output and signals are wired to the plant computer to allow continuous computation of radiation releases. Use of this continuous containment ventilation system precludes the buildup of pressure inside the containment which would normally result from instrument air leak off to various instrumentation and valve operators and during containment atmosphere heat up due to primary system temperature increase. The system is automatically isolated in the event of a containment isolation signal to limit any offsite dose consequences.

The principal components of the containment ventilation systems include filters, fans, dampers, valves, heat exchangers, essential ductwork, containment isolation valves, and piping. The containment ventilation ductwork (except the CRDM cooling system ductwork), fans (except the refueling water surface supply and exhaust fans and CRDM cooling system fans), filters, coils and housings within the containment are designed as Seismic Class I structures.

Description of Analyses and Evaluations

The changes in heat loads for ventilation subsystems in the containment were evaluated to ensure that they are capable of performing their intended functions under EPU conditions.

Other evaluations related to the containment ventilation system are addressed in the following LR Sections:

- Protection against dynamic effects, including PBNP GDC 37 requirements, of missiles, pipe whip and discharging fluids - LR Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects and Section 2.5.1.3, Pipe Failures.
- Electrical equipment qualification - LR Section 2.3.1, Environmental Qualification of Electrical Equipment.
- Onsite and offsite electric power systems, including PBNP GDC 39 requirements – LR Section 2.3.3, AC Onsite Power System and LR Section 2.3.4, DC Onsite Power System.
- Protection against turbine missiles and internal missiles (PBNP GDC 40) is discussed in LR Section 2.5.1.2.1, Internally Generated Missiles and Section 2.5.1.2.2, Turbine Generator.
- Containment post accident heat removal – LR Section 2.6.5, Containment Heat Removal

- Radiological consequences analysis – LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms
- Impact of containment purge related to (PBNP GDC 70) normal operational radwaste effluents and associated doses – LR Section 2.10.1, Occupational and Public Radiation Doses

Evaluation of Impact on Renewed Plant Operating License Evaluations and Licensing Renewal Programs

In regard to the aging programs and aging influences described in the License Renewal SER NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005, the Containment Ventilation System was evaluated and it was concluded that subsystems VNCC and VNPSE were within the scope of the License Renewal. On the basis of its review, the NRC staff concluded in the SER that the applicant adequately identified the containment ventilation system components that are within the scope of the license renewal, as required by 10 CFR 54.4(a) and that the applicant adequately identified the containment ventilation system components that are subject to an Aging Management Review, as required by 10 CFR 54.21(a)(1). Operating at EPU does not add any new or previously unevaluated materials to components of the containment ventilation system. Thus, no new aging effects requiring management are identified as a result of EPU.

Results

The ability of the containment ventilation systems (VNCC, VNCRD, VNRC, and VNCF) to provide the required temperature conditions for personnel and equipment in the containment during normal operating modes was evaluated. Operation at EPU power would cause equipment and piping inside the containment to give off additional heat. This would result in a containment temperature rise of less than 1°F. Normally three containment fan cooling units (CFCUs) are run to maintain the containment temperature air below 105°F. The service water temperature is the dominant factor in controlling containment temperature at both the current and EPU power levels. As the service water temperature rises above 65°F, it may be necessary to run four CFCUs to maintain the containment air temperature below 105°F. At EPU four CFCUs will maintain the containment air temperature below 112.5°F (Technical Specification Bases B 3.6.5) as service water increases beyond 75°F up to 80°F.

VNRF and VNPSE operate during refueling and are not affected by EPU. During reactor shutdown, heating coils throughout the containment maintain a minimum temperature of 50°F. This design capability remains unchanged by the EPU.

Refer to LR Section 2.6.5, Containment Heat Removal, for the ventilation system evaluation following an accident.

Operation of the radiation monitoring system and the purge supply and exhaust system has not been changed due to EPU. Radiation monitors are provided to monitor the release of radioactive effluents.

Thus, the evaluation of the containment ventilation systems (VNCC, VNCRD, VNRC, VNRF, VNCF, VNPSE, PACV and RM) at EPU conditions demonstrates that the PBNP will continue to meet the current licensing basis, insofar as it requires that the plant design include means to control the release of radioactive effluents. This design capability remains unchanged by the EPU. The handling, control, and release of radioactive materials are in compliance with 10 CFR 20 limits, as discussed in LR Section 2.10.1, Occupational and Public Radiation Doses and general design criteria PBNP GDC 70.

The evaluation of the containment ventilation systems (VNCC, VNCRD, VNRC, VNRF, VNCF, VNPSE, PACV and RM) at EPU conditions demonstrates that PBNP will continue to meet the current licensing basis, insofar as it requires that systems containing radioactivity be designed with appropriate confinement and containment during normal operations. Radioactivity levels remain bounded by the current licensing basis. Refer to LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms, for accident conditions. Radioactivity levels contained in the effluent discharge paths to the environs are continually monitored during normal and accident conditions by the station radiation monitoring system and by the radiation protection program for PBNP, as reflected in general design criteria PBNP GDC 69. Refer to LR Section 2.10.1, Occupational and Public Radiation Doses, for Normal Operation.

2.7.7.3 Conclusion

PBNP has reviewed the containment ventilation system with respect to heat removal from the containment atmosphere, radioactive material removal from the containment atmosphere and the impact on containment pressure control under normal and accident conditions. The review focused on the effects of the EPU on the performance of the system. The PBNP assessment of the containment ventilation system has adequately addressed the effects of the proposed EPU on the ability of the containment ventilation systems to provide a suitable and controlled environment for the components within the containment. Based on this, PBNP concludes that the containment ventilation systems will continue to comply with PBNP GDCs 37, 39, 69, and 70. Therefore, PBNP finds the proposed EPU acceptable with respect to the containment ventilation system.

2.8 Reactor Systems

2.8.1 Fuel System Design

2.8.1.1 Regulatory Evaluation

The fuel system consists of arrays of fuel rods, burnable poison rods, spacer grids and springs, end plates, and reactivity control rods. PBNP reviewed the fuel system to ensure that:

- The fuel system is not damaged as a result of normal operation and anticipated operational occurrences
- The fuel system damage is never so severe as to prevent control rod insertion when it is required
- The number of fuel rod failures is not underestimated for postulated accidents
- Coolable geometry is always maintained

PBNP's review covered fuel system damage mechanisms, limiting values for important parameters, and performance of the fuel system during normal operation, anticipated operational occurrences, and postulated accidents. The NRC's acceptance criteria are based on:

- 10 CFR 50.46, insofar as it establishes standards for the calculation of emergency core cooling system performance and acceptance criteria for that calculated performance
- GDC 10, insofar as it requires that the reactor core be designed with appropriate margin to ensure that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences
- GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the emergency core cooling system (ECCS), of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to ensure the capability to cool the core is maintained
- GDC 35, insofar as it requires that a system to provide abundant emergency core cooling be provided to transfer heat from the reactor core following a loss-of-coolant accident (LOCA)

Specific review criteria are contained in the Standard Review Plan (SRP), Section 4.2 and other guidance provided in Matrix 8 of RS-001.

PBNP Current Licensing Basis

10 CFR 50.46 provides the acceptance criteria for loss-of-coolant accident evaluations.

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predate those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50, Appendix A, GDC 10, 27 and 35 are as follows:

CRITERION: The reactor core with its related controls and protection systems shall be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits which have been stipulated and justified. The core and related auxiliary system designs shall provide this integrity under all expected conditions of normal operation with appropriate margins for uncertainties and for specified transient situations which can be anticipated. (PBNP GDC 6)

As stated in FSAR Section 3.1, Reactor, Design Criteria, the core design, together with reliable process and decay heat removal systems, provides for this capability under all expected conditions of normal operation with appropriate margins for uncertainties and anticipated transient situations.

CRITERION: One of the reactivity control systems provided shall be capable of making the core subcritical under any anticipated operating condition (including anticipated operational transients) sufficiently fast to prevent exceeding acceptable fuel damage limits. Shutdown margin should assure subcriticality with the most reactive control rod fully withdrawn. (PBNP GDC 29)

FSAR Section 3.1, Reactor, Design Criteria, also states that the reactor core, together with the reactor control and protection system, is designed so that the minimum allowable DNBR is at least equal to the limits specified for Optimized Fuel Assembly (OFA), upgraded OFA, and 422V+ fuel, and there is no fuel melting during normal operation, including anticipated transients.

The shutdown groups are provided to supplement the control group of RCCAs to make the reactor at least 1% subcritical ($k_{eff} = 0.99$) following a trip from any credible operating condition to the hot, zero power condition assuming the most reactive RCCA remains in the fully withdrawn position.

Sufficient shutdown capability is also provided to maintain the core subcritical for the most severe anticipated cooldown transient associated with a single active failure.

CRITERION: The reactivity control systems provided shall be capable of making the core subcritical under credible accident conditions with appropriate margins for contingencies and limiting any subsequent return to power such that there will be no undue risk to the health and safety of the public. (PBNP GDC 30)

The reactivity control systems provided are capable of making and holding the core subcritical, under accident conditions, in a timely fashion with appropriate margins for contingencies. Any time that the reactor is at power, the quantity of boric acid retained in the boric acid storage tanks and/or the refueling water storage tank (RWST) and ready for injection always exceeds that required for the normal cold shutdown. This quantity also exceeds that required to bring the reactor to hot shutdown and to compensate for subsequent xenon decay.

CRITERION: An emergency core cooling system (ECCS) with the capability for accomplishing adequate emergency core cooling shall be provided. This core cooling system and the core shall be designed to prevent fuel and clad damage that would interface with the emergency core cooling function and to limit the clad metal-water reaction to acceptable amounts for all sizes of breaks in the reactor coolant piping up to the equivalent of a double-ended rupture of the largest pipe. The performance of such emergency core cooling system shall be evaluated conservatively in each area of uncertainty. (PBNP GDC 44)

The performance capability of the ECCS is further discussed in FSAR Section 6.2, Safety Injection System. Adequate emergency core cooling is provided by the safety injection system (which constitutes the emergency core cooling system). The primary purpose of the safety injection system is to automatically deliver cooling water to the reactor core in the event of a loss-of-coolant accident. This limits the fuel clad temperature and thereby ensures that the core will remain intact and in place with its heat transfer geometry preserved.

A review of fuel system design for impact on license renewal evaluations is not necessary since continued applicability of the EPU safety analysis for the 14x14, 422V+ fuel assembly will be evaluated or reanalyzed during the reload safety evaluation process for the reload cycles employing this design.

2.8.1.2 Technical Evaluation

2.8.1.2.1 Fuel System Design Features

The licensing basis for the fuel system design is contained in FSAR Chapter 3.0, Reactor, of the PBNP Updated Final Safety Analysis Report (FSAR). For the EPU, the PBNP fuel design will remain the 14x14, 422V+ fuel assembly design with 0.422-inch diameter rods. The typical features of the PBNP 14x14, 422V+ fuel assembly are as follows:

- 1.25X Integral Fuel Burnable Absorber (IFBA), ZrB_2, loading
- 0.422 inch outside diameter fuel rods
- Up to 8 inch annular axial blanket pellets
- 143.25 inch pellet stack length
- Standard height removable top nozzle (RTN)
- Reduced rod bow (RRB) Alloy 718 top grid
- ZIRLO™ 422V+ mid-grids (low-corrosion ZIRLO™ thin strap)
- High-force Alloy 718 bottom grid
- Debris-filter bottom nozzle (DFBN)
- Oxide coated clad for debris mitigation
- ZIRLO™ instrumentation tubes
- ZIRLO™ fuel rod cladding

The 14x14, 422V+ fuel rod has been sized to accommodate a lead rod burnup of up to 75,000 MWD/MTU. The 14x14, 422V+ fuel assembly is currently designed to accommodate a peak fuel rod average burnup of 62,000 MWD/MTU. 422V+ is currently licensed to 60,000 MWD/MTU by the NRC (Reference 6) with extension to 62,000 MWD/MTU on a cycle-specific basis, as delineated in Reference 1, Appendix R.

2.8.1.2.2 Mechanical Compatibility and Performance

2.8.1.2.2.1 Introduction

The effects of the EPU on the mechanical design are limited to induced changes in the core flow rates and operating temperatures, which have been considered in the supporting calculations. The fuel design analysis that could have been impacted are the fuel assembly lift forces and hold-down force margin. Analyses have been performed to demonstrate that the fuel assembly lift force margin requirement is met for the EPU without any modifications to the current fuel assembly design.

The effects of the EPU on the seismic/LOCA performance of the fuel mechanical design have been analyzed to confirm that all acceptance criteria and regulatory requirements are met. The criteria for the seismic loading design are that fragmentation of the fuel rod must not occur as a result of the seismic loads and the control rod insertability must be maintained. In addition, coolable geometry of the core must be maintained.

The effects of the EPU for a LOCA event are that fragmentation of the fuel rod must not occur as a direct result of the blowdown load, and control rod insertability and coolable geometry must be maintained.

2.8.1.2.2.2 Input Parameters, Assumptions and Acceptance Criteria

In accordance with the WCAP-12488-A process, the various criteria for fuel damage and fuel rod failure, fuel coolability, and nuclear design are screened for impacts based on the known design changes from an established design. Each of the key design changes is then evaluated versus the applicable (screened) criteria. The acceptance criteria evaluated for this design change were:

- Fuel rod clad fretting wear
- LOCA and non-LOCA fuel clad temperatures
- Departure From Nucleate Boiling (DNB)
- Thermal-hydrodynamic stability

The results of the evaluation were included in the notification letter from Westinghouse to the NRC Dated June 6, 2005 (Reference 2).

2.8.1.2.2.3 Description of Analyses and Evaluations

With respect to the mechanical performance of the fuel, the impacts on the fuel of the core flow rates and operating temperatures changes have been analyzed. The fuel design analyses that could be impacted are the fuel assembly lift forces and hold-down force margin. Analyses have been performed to demonstrate that the fuel assembly lift force design requirement is met for the EPU without modifications to the current fuel assembly design. The hold-down force calculation conservatively assumed high burnup fuel assembly growth and hold-down spring relaxation due to irradiation effects. The analysis accounted for the opposing forces that act on the fuel assemblies due to fuel assembly weight, buoyancy, spring force, and lift force.

The results of the combined LOCA and seismic analysis were obtained using the time-history numerical integration technique. The maximum grid impact forces obtained from both transients were combined using the square-root-sum-of-the-squares (SRSS) method. The maximum loads were compared with the allowable grid crush strength. In the grid load analysis, the time-history motions of the barrel at the upper core plate elevation and the upper and lower core plates were applied simultaneously to the reactor core model. The time histories representing the seismic motion and the pipe rupture transients were obtained from the time-history analyses of the reactor vessel and internals finite element model.

2.8.1.2.2.4 Mechanical Compatibility and Performance Results

The mechanical design of the fuel is unchanged for the EPU application. Therefore, there is not a transition core or typical transition core issues such as induced cross flow, flow saturation, etc. Effects of flow rate and temperature changes have been considered for the EPU application.

With respect to the mechanical design of the fuel, the analyses performed confirm that the fuel design is structurally and mechanically acceptable for the EPU. Use of reinserted previously irradiated assemblies is also acceptable for the EPU.

The following acceptance criteria were for the EPU:

- Fuel rod clad fretting wear
  None of the changes in fuel or core parameters impact the fuel cladding fretting wear. The change in flow rate is inconsequential
- LOCA and non-LOCA fuel clad temperatures are reviewed in LR Section 2.8.3, Thermal and Hydraulic Design
- DNB is evaluated in LR Section 2.8.3, Thermal and Hydraulic Design
- Thermal-hydrodynamic stability is discussed in LR Section 2.8.5.6.3, Emergency Core Cooling System and Loss-of-Coolant Accidents

The effects of the EPU with regard to the regulatory bases identified in LR Section 2.8.1.1, Fuel System Design, Regulatory Evaluation, are addressed for the seismic/LOCA LR (Section 2.8.1.2.3, Fuel System Design, Seismic/LOCA) and fuel performance (LR Section 2.8.1.2.4, Fuel System Design, Fuel Rod Performance) portions of the fuel system evaluation.

2.8.1.2.3 Seismic/LOCA

2.8.1.2.3.1 Introduction

The effects of the EPU on the fuel mechanical design are limited to changes in the uprate parameters (LR Section 1.1, Nuclear Steam Supply System Parameters). The new core plate motions and vertical impact loads on the nozzles were used in the seismic/LOCA analysis for EPU project. The acceptance criterion for the mechanical evaluation is that (1) fuel rod fragmentation does not occur, (2) a coolable core geometry is maintained, and (3) control rod insertability is maintained.

A seismic and LOCA evaluation for PBNP was performed at the uprated conditions. The results of the evaluation show that the maximum combined impact forces on the mid grid are below the grid crush limits. The results indicated adequate margin for both fuel rod and thimble tube exists. Fragmentation of the fuel rods and thimble tubes will not occur.

The results of the combined seismic and LOCA analyses indicate that the maximum impact forces are less than the respective allowable grid strengths. The allowable grid strengths are established at the 95% confidence level on the true mean from the distribution of experimentally determined grid crush data at operating temperature. Based on the results of the combined seismic and LOCA loads, the fuel design is structurally acceptable for the EPU and the core coolable geometry requirements are met.

2.8.1.2.3.2 Input Parameters, Assumptions, and Acceptance Criteria

The analysis parameters—the natural frequencies, mode shapes, and span masses of the fuel assembly combined with the structural damping—were used to generate a simplified lumped-mass-spring fuel assembly model. The mid-grid crush strength, stiffness, and damping, the fuel assembly impact stiffness and damping, the number of fuel assemblies, and the gap clearances between fuel-assemblies and at the baffles were used to generate the reactor internal model. The WEGAP computer code was used (Reference 4).

The acceptance criteria for the seismic loading design are that fragmentation of the fuel rod must not occur as a result of the seismic loads, and control rod insertability and coolable geometry must be maintained.

The principal acceptance criteria for a LOCA event are that fragmentation of the fuel rod must not occur as a direct result of the blowdown load, and control rod insertability and coolable geometry must be maintained.

The grid crush strength is established based on analysis of the 95% confidence level on the true mean of the test data at operating temperature.

2.8.1.2.3.3 Description of Analyses and Evaluations

The maximum horizontal input motion congruent with the core principal axis was used to determine dynamic fuel responses. The reactor core was analyzed as a de-coupled system with respect to the two lateral directions. The input forcing function was obtained from a separate reactor pressure vessel and reactor internals system analysis.

Based on appropriate modeling, it has been shown that the assumed mode shapes agree well with the predominant fuel assembly vibration frequencies. With the appropriate analysis parameters, the WEGAP reactor core model was used for analyzing transient loadings. The original methodology as defined in Reference 4 has not changed.

The results of the combined LOCA and Safe Shutdown Earthquake (SSE) analysis were obtained using the time-history numerical integration technique. The maximum grid impact forces obtained from both transients were combined using the square root of the sum of squares (SRSS) method. The maximum loads were compared with the allowable grid crush strength.

In the grid load analysis, the time-history motions of the barrel at the upper core plate elevation and the upper and lower core plates were applied simultaneously to the reactor core model. The time histories representing the SSE motion and the pipe rupture transients were obtained from the time history analyses of the reactor vessel and internals finite element model.

2.8.1.2.3.4 Additional Information

No mixed cores were considered in the seismic/LOCA analysis for EPU project since the fuel mechanical design is not changing.

The licensing basis for fuel structural integrity requires that the loading conditions address seismic loading, LOCA loading, and the combination of LOCA and seismic loading as required by the NRC. The seismic and LOCA analysis of the reactor pressure vessel system was performed for the EPU conditions, including the generation of the core plate seismic motions that were used in the PBNP analysis of 14x14, 422V+ fuel assembly design. The LOCA analysis used LOCA hydraulic forcing functions calculated using the MULTIFLEX computer code, see LR Appendix A, Safety Evaluation Report Compliance, and crediting leak-before-break (LBB) for the reactor coolant loop piping.

Detailed site-specific fuel assembly analyses for PBNP have been performed under EPU conditions in accordance with approved methodologies. These methodologies were approved by NRC in WCAP 9401-P-A (Reference 5), WCAP-9500-A (Reference 4), WCAP-12610-P-A (Reference 6), and WCAP-12488-A (Reference 1). Results from these analyses demonstrate that for the limiting-loading condition (combined seismic and LOCA loading), the fuel assembly structural integrity is maintained and the grid impact loads and component stresses remain below the allowable limits. Therefore, the requirements to maintain a coolable core geometry are met.

2.8.1.2.3.5 Results

The maximum SSE and LOCA results for the 14x14, 422V+ fuel assembly in a homogenous core occur in the Z-direction during SSE loading. The maximum structural grid loads for the 14x14, 422V+ fuel assemblies occurred in the peripheral assemblies in the eleven fuel assembly arrays. The maximum fuel assembly deflection occurred in an assembly array consisting of 13 fuel assemblies in the Z-direction during a seismic loading.

The maximum grid loads obtained from SSE and LOCA loading analyses were combined using the SRSS method. The results of the combined seismic and LOCA analyses indicate that the maximum impact forces for the 14x14, 422V+ design using the two-direction grid characteristics are less than the respective allowable grid strengths. The allowable grid strengths are established at the 95% confidence level on the true mean from the distribution of experimentally determined grid crush data at temperature. Based on the results of the combined SSE and LOCA loads, the 14x14, 422V+ fuel design is structurally acceptable for PBNP at EPU conditions. Core coolable geometry requirements are met.

Fuel assembly displacement is limited by the total accumulated gap clearances, plus elastic grid deformations. Fuel assembly stresses were calculated based on the most limiting case. The stresses for the fuel rods and thimble tubes were calculated based on the maximum lateral displacement, the vertical impact load, and operating condition loads. The stresses of the thimble tube and fuel rod are evaluated with the seismic and LOCA load condition (lateral deflection and vertical impact force) for EPU. The evaluation indicates that adequate margins for both fuel rods and thimble tubes exist, so fragmentation of fuel rods will not occur. The detail analyzed stresses and acceptance criteria are listed in Table 2.8.1-1, Maximum Stresses and Allowable of 14x14, 422V+ Thimble Tube and Fuel Rod. The reactor can be safely shut down under faulted-condition loading. In conclusion, the 14x14, 422V+ assembly design is structurally acceptable under the combined seismic and LOCA loadings for PBNP at EPU conditions.

The grid loads evaluated for the LOCA and seismic events, and combined by the SRSS method identified in SRP Section 4.2, are less than the allowable limit. The stresses in the 14x14, 422V+ PBNP fuel assembly components resulting from seismic and LOCA-induced deflections are within acceptable limits. Therefore, control rod insertion and coolable core geometry is maintained.

This evaluation concluded that the stresses of the fuel rod and thimble tube are structurally acceptable under the combined seismic and LOCA loadings for PBNP at EPU conditions. The reactor can be safely shut down and cooled under the combined faulted-condition loads.

2.8.1.2.4 Fuel Rod Performance

2.8.1.2.4.1 Introduction

Fuel rod performance for PBNP fuel is shown to satisfy the NRC fuel rod design bases on a region-by-region basis. These same bases are applicable to all fuel rod designs, including the Westinghouse 14x14, 422V+ fuel design. The current licensing basis is described in Chapter 3.0, Reactor, of the FSAR and is based on the same methods and models (PAD 4.0) used here. This licensing basis analysis is based on maintaining the current fuel, 14x14, 422V+ fuel, with ZIRLO™ fuel rod cladding and the bounding high-temperature nuclear design bases representing four cycles at EPU conditions (two transition cycles and two equilibrium cycles), developed for the Nuclear Design (see LR Section 2.8.2, Nuclear Design). Compliance with the GDC 10 Specified Acceptable Fuel Design Limits (SAFDL) criteria for reload cycles is confirmed via the approved reload methodology of WCAP-9273-NP-A (Reference 7).

2.8.1.2.4.2 Input Parameters, Assumptions, and Acceptance Criteria

The fuel rod design analysis is performed on a cycle-specific basis. The reference analysis presented here is based on the bounding high-temperature nuclear design cases representing four cycles at EPU conditions (two transition cycles and two equilibrium cycles) developed for the Nuclear Design (see LR Section 2.8.2, Nuclear Design). Both the reference analysis and the cycle-specific analysis consider compliance for all fuel designs in the core. Therefore, there is no impact due to having fuel with more than one type of IFBA loading, and annular blanket lengths simultaneously residing in the core during the transition cycles, since this configuration was explicitly evaluated. The mechanical fuel rod design evaluation for each region incorporates all appropriate design features of the region, including any changes to the fuel rod or pellet geometry from that of previous fuel regions (for example, the presence of annular pellets in axial blankets or changes in IFBA loading). Analysis of integral fuel burnable absorber (IFBA) rods includes geometry changes necessary to model the presence of the burnable absorber, and conservatively models the gas release from the ZrB_2 coating.

The Constant Axial Offset Control (CAOC) methodology will be implemented coincident with the uprate and the first transition of the uprated cycles. The CAOC methodology provides additional analytical margin and is reflected in the reference analysis presented here.

Fuel rod design evaluations for the 14x14, 422V+ fuel were performed using NRC-approved models as stated in WCAP-15063-P-A (Reference 8) and NRC-approved design criteria methods as stated in WCAP-10125-P-A and WCAP-13589-A (References 9 and 10) to demonstrate that all fuel rod design criteria are satisfied.

The fuel rod design criteria given below are verified by evaluating the predicted performance of the limiting fuel rod, defined as the rod that has the minimum margin to the design limit. No single rod is limiting with respect to the design criteria. Generic evaluations alone cannot identify which rods are most likely to be limiting for each criterion, so an exhaustive screening of fuel rod power histories and fuel rods was used to determine the limiting rods. The typical changes in the fuel geometry parameters from the current operating conditions and that of the uprated conditions that are important to the fuel rod design analysis reported in this section are:

- Annular blanket length
- Changing from RAOC to CAOC operating strategy
- IFBA loading

The NRC-approved PAD 4.0 code, with NRC-approved models (Reference 8) for in-reactor behavior, is used to calculate the fuel rod performance over its irradiation history. PAD is the principal design tool for evaluating fuel rod performance. PAD iteratively calculates the interrelated effects of temperature, pressure, clad elastic and plastic behavior, fission gas release, and fuel densification and swelling as a function of time and linear power.

PAD 4.0 is a best-estimate fuel rod performance model, and in most cases the design criterion evaluations are based on a best-estimate plus uncertainties approach. A statistical convolution of individual uncertainties due to design model uncertainties and fabrication dimensional tolerances is used. As-built dimensional uncertainties for some critical inputs, such as fuel pellet diameter, can be used in lieu of the fabrication uncertainties. An evaluation of the clad and structural component oxidation and hydriding was also performed.

The criteria pertinent to the fuel rod design were:

Rod Internal Pressure

The internal pressure of the lead fuel rod in the reactor will be limited to a value below that which could cause the diametral gap to increase due to outward clad creep during steady-state operation, and extensive DNB propagation to occur.

Clad Stress and Strain

The design limit for clad stress is that the volume-averaged effective stress, considering interference due to uniform cylindrical pellet-to-clad contact caused by pellet thermal expansion, pellet swelling, uniform clad creep, and pressure differences between the rod internal pressure and the system coolant pressure, be less than the clad-yield strength for Condition I and II events. While the clad has some capability for accommodating plastic strain, the yield stress has been established as the conservative design limit. The design limit for clad strain during steady-state operation is that the total plastic tensile creep strain due to uniform clad creep and uniform cylindrical fuel pellet expansion associated with fuel swelling and thermal expansion is less than 1% from the unirradiated condition. The design limit for fuel rod clad strain during Condition II events is that the total tensile strain due to uniform cylindrical pellet thermal expansion is less than 1% from the pre-transient value. These limits are consistent with proven practice.

Clad Oxidation and Hydriding

The design criteria related to clad corrosion require that the Zircaloy-4/ZIRLO™ clad metal-oxide interface temperature is maintained below specified limits to prevent a condition of accelerated oxidation, which would lead to clad failure. The calculated clad temperature (metal-oxide interface temperature) will be less than 750°F/780°F, respectively, for Zircaloy-4 and ZIRLO™ clad during steady-state operation. For Condition II transients, the calculated clad temperature will not exceed 800°F/850°F, respectively, for Zircaloy-4 and ZIRLO™ clad.

The best-estimate hydrogen pickup level in Zircaloy-4/ZIRLO™ fuel rod cladding and structural components is less than or equal to the 600 ppm limit, on a volume-averaged basis at End of Life (EOL).

Fuel Temperature

For Condition I and II events, the reactor protection system is designed to ensure that the fuel centerline temperature does not exceed the fuel melt temperature criterion. The intent of this criterion is to avoid a condition of gross fuel melting that can result in severe duty on the clad. The concern is based on the large volume increase associated with the phase change in the fuel, and the potential for loss of clad integrity as a result of molten fuel/clad interaction.

Clad Fatigue

The fuel rod design criterion for clad fatigue requires that, for a given strain range, the number of strain fatigue cycles is less than that required for failure, with factors of safety of 2.0 on the stress amplitude and 20.0 on the number of cycles. This criterion addresses concerns about the cumulative effect of short-term cyclic clad stress and strain resulting from daily load follow operation.

Clad Flattening

The clad flattening criterion prevents fuel rod failures due to long-term creep collapse of the fuel rod clad into axial gaps formed within the fuel stack. Current fuel rod designs employing fuel with improved in-pile stability provide adequate assurance that axial gaps large enough to allow clad flattening will not form within the fuel stack.

Fuel Rod Axial Growth

This criterion ensures that there is sufficient axial space to accommodate the maximum expected fuel rod growth. Fuel rods are designed with adequate clearance between the fuel rod and the top and bottom nozzles to accommodate the differences in the growth of fuel rods and the growth of the fuel assembly skeleton to preclude interference of these members.

Plenum Clad Support

This criterion ensures that the fuel clad in the plenum region of the fuel rod will not collapse during normal operating conditions, nor distort so as to degrade fuel rod performance.

Clad Free-Standing

The clad free-standing criterion requires that the clad is short-term, free-standing at beginning of life (BOL), at power, and during hot hydrostatic testing. This criterion precludes the instantaneous collapse of the clad onto the fuel pellet caused by the pressure differential that exists across the clad wall.

Fuel Rod End Plug Weld Integrity

The fuel rod end plug weld shall maintain its integrity during Condition I and II events and shall not contribute to any additional fuel failures above those already considered for Condition III and IV events. The intent of this criterion is to assure that fuel rod failures will not occur due to the tensile pressure differential loads which can exist across the weld.

These criteria are verified at PBNP EPU-specific operating conditions and fuel rod duties. The continued validity of the limiting power shapes used in this analysis is confirmed for each reload using Constant Axial Offset Control (CAOC) methods.

2.8.1.2.4.3 Description of Analyses and Evaluations

Rod Internal Pressure

The Rod Internal Pressure "no gap reopening" criterion for the PBNP fuel rods has been evaluated at EPU conditions by modeling the gas inventories, gas temperature, and rod internal volumes throughout the life of the limiting rod. The resulting rod internal pressure is compared to the design limit on a case-by-case basis of current operating conditions to EOL. This evaluation showed that the "no gap reopening" criterion is met. Note that rod internal pressure "no gap reopening" is most limiting for the transition cycles, leaving minimal margin, cycle-specific analyses required to address on a reload basis.

The second part of the rod internal pressure design basis precludes extensive DNB propagation and associated fuel failure. The basis for this criterion is that no significant additional fuel failures, due to DNB propagation, will occur in cores that have fuel rods operating with rod internal pressure in excess of system pressure. The design limit for Condition II events is that DNB propagation is not extensive, that is, the process is shown to be self-limiting and the number of additional rods in DNB due to propagation is relatively small. For Condition III/IV events, it is shown that the total number of rods in DNB, including propagation effects, is consistent with the assumptions used in radiological dose calculations for the event under consideration.

Clad Stress and Strain

Clad temperature and irradiation effects on yield strength were considered in the analysis. The clad stress criterion has been shown to meet the design limits with consideration of significant performance model and fabrication uncertainties for ZIRLO™ fuel rod cladding. The transient clad strain limit is met based on the analyses performed for evaluation of the transient clad stress criterion. Steady-state clad strain is met by using a PBNP EPU specific calculation.

Clad Oxidation and Hydriding

The clad surface temperatures were evaluated and the applicable clad surface temperature limits were satisfied. The base metal wastage of the Zircaloy-4, ZIRLO™, grids and guide tubes and fuel rod cladding were shown not to exceed the design limit at EOL.

The hydrogen pickup criterion, which limits the loss of ductility due to hydrogen embrittlement, which occurs upon the formation of zirconium hydride platelets, has been met with the current approved model for the PBNP EPU, as well as the new Integral ZIRLO™ Corrosion Model.

Fuel Temperature

The temperature of the fuel pellets were evaluated by modeling the fuel rod geometry, thermal properties, heat fluxes, and temperature differences in order to calculate fuel surface, average and centerline temperatures of the fuel pellets.

Fuel temperatures have been calculated as a function of local power and burnup. The fuel surface and average temperatures with associated rod internal pressure are provided to transient analysis and LOCA for accident analysis of the 14x14, 422V+ seven-grid fuel design. The fuel centerline temperatures are used to show that fuel melt will not occur. For 14x14, 422V+ design, the local linear power that precludes fuel centerline melting is 22.54 kW/ft.

Clad Fatigue

Clad fatigue for the 14x14, 422V+ seven-grid fuel was evaluated by using a limiting fatigue duty cycle consisting of daily load follow maneuvers. The 14x14, 422V+ fuel rod fatigue evaluation, based on a statistical method which takes into account for all significant performance model and fabrication uncertainties in combination with the ASME Boiler and Pressure Vessel Code required uncertainties addressing the most limiting of the factor of 20 on the number of cycles or a factor of 2 on the stress amplitude, showed that the cumulative fatigue usage factor is less than the design limit of 1.0.

Clad Flattening

The NRC has approved WCAP-13589-A (Reference 10), which provided data to confirm that significant axial gaps in the fuel column due to densification (and therefore clad flattening) will not occur in current Westinghouse fuel designs. The PBNP fuel meets the criteria for applying the Reference 10 methodology and, therefore, clad flattening will not occur.

Fuel Rod Axial Growth

The PBNP EPU fuel rod growth evaluation, based on similar designs, demonstrates that there is adequate margin to the fuel rod growth design limit for the 14x14, 422V+ fuel.

Plenum Clad Support

The helical coil spring used in the 14x14, 422V+ fuel design for the PBNP EPU has been shown to provide enough support to prevent potential clad collapse. Therefore, the plenum clad support criterion is met for the 14x14, 422 V+ fuel.

Clad-Free Standing

Evaluations of the clad-free standing criteria have shown that instantaneous collapse of the PBNP fuel will be precluded for differential pressures in excess of the maximum expected differential pressure across the clad under operating conditions. This generic analysis has been shown to be met for all Westinghouse fuel rod geometries.

Fuel Rod End Plug Weld Integrity

Evaluation of the fuel rod end plug weld integrity criteria has shown that no fuel rod failures shall occur during Condition I and II events or contribute to additional failures during Condition III and IV events.

Fuel rod design evaluations for PBNP were performed using the NRC approved models in Reference 8 to demonstrate that the SRP fuel rod design criteria are satisfied. For the 14x4, 422V+ fuel design, these criteria have been shown to be met.

2.8.1.2.4.4 Additional Information

The requests for additional information applicable to fuel rod performance that were issued to other licensees in prior power uprating submittals are addressed below for the PBNP EPU application.

> "With respect to the impacts of the proposed power uprate on the nuclear, thermal-hydraulic and fuel rod design analyses, please provide a listing of the NRC-approved codes and methodologies used for the design analyses discussed in Section 7.10 of the Attachment III of the submittal and confirm that all parameters and assumptions to be used for analyses described in Sections 7.10 of the Attachment III remain within any code limitations or restrictions."

The fuel rod design code and methodology used for the PBNP EPU analyses was previously approved by the NRC (Reference 8).

2.8.1.2.4.5 Results

Fuel performance evaluations have been completed for EPU transition and equilibrium cycles to demonstrate that the design criteria can be satisfied for all fuel rod types in the core under the planned operating conditions of a power uprating to 1800 MWt. Based on input from core design, the fuel rod design was analyzed with an $F_{\Delta H}{}^{N}$ limit of 1.68 for the uprated 14x14, 422V+ fuel. Any additional changes from the plant operating conditions originally evaluated for the mechanical design of a fuel region will be addressed for all affected fuel regions as part of the reload safety evaluation process when the plant changes are to be implemented.

As expected, the large increase in power will have an impact on the fuel rod design margin, although some of this reduction in design margin is offset by the decision to implement Constant Axial Offset Control (CAOC) and increase the length of annular axial blankets. The rod internal pressure (RIP) criteria, including "no gap reopening" and DNB propagation, clad corrosion, clad stress, steady-state clad strain, clad fatigue, and fuel temperature criteria have all had a loss of margin due to the core power increase. For RIP, analyses were performed to define the power history constraints that will be required to provide sufficient RIP margin at the EPU conditions for the other aforementioned criteria, all fuel rod design limits were satisfied for the reference EPU transition and equilibrium cycles.

Continued compliance with fuel rod design criteria for the uprated 14x14, 422V+ fuel will be confirmed for each reload cycle design.

In summary, all fuel rod design criteria have been evaluated for application of the Westinghouse 14x14, 422V+ fuel assembly design in PBNP at EPU conditions. Based on these evaluations, it is concluded that all fuel rod design criterion can be satisfied for 14x14, 422V+ with ZIRLO™ fuel rod cladding design while appropriately accounting for EPU conditions.

2.8.1.3 Conclusions

PBNP has reviewed the analyses related to the effects of the proposed EPU on the fuel system design of the fuel assemblies, control systems, and reactor core. PBNP concludes that the analyses have adequately accounted for the effects of the proposed EPU on the fuel system and demonstrated that:

- The fuel system will not be damaged as a result of normal operation and anticipated operational occurrences
- The fuel system damage will never be so severe as to prevent control rod insertion when it is required
- The number of fuel rod failures will not be underestimated for postulated accidents
- Coolable geometry will always be maintained

Based on this, is PBNP concludes that the fuel system and associated analyses will continue to meet the PBNP current licensing basis with respect to the requirements of 10 CFR 50.46, PBNP GDC 6, 29, 30 and 44 following implementation of the EPU. Therefore, PBNP finds the proposed EPU acceptable with respect to the fuel system design.

2.8.1.4 References

1. WCAP-12488-A, Davidson, S. L., Westinghouse Fuel Criteria Evaluation Process, October 1994, WCAP-12488-A, Addendum 1-A, Rev. 1, Revisions to Design Criteria, January 2002, and WCAP-12488-A, Addendum 2, Revisions to Design Criteria, April 2002

2. LTR-NRC-05-34, Fuel Criterion Evaluation Process (FCEP) Notification of revision to 14x14, 422 VANTAGE + Design (Proprietary/Non-proprietary), June 6, 2005

3. WEPCO NPL 97-0538 to Document Control Desk (NRC), 14x14, 0.422 OD VANTAGE + (422V+) Fuel Design, Application for Point Beach Units 1 & 2, September 9, 1997

4. WCAP-9500-A, Davidson, S. L., et al., Reference Core Report 17x17 Optimized Fuel Assembly, May 1982

5. WCAP-9401-P-A, Davidson, S. L,. et al, Verification and Testing Analyses of the 17x17 Optimized Fuel Assembly, August 1981

6. WCAP-12610-P-A, Davidson, S. L., et al., VANTAGE+ Fuel Assembly Reference Core Report, April 1995

7. WCAP-9273-NP-A, Davidson, S. L. (Ed.), et al., Westinghouse Reload Safety Evaluation Methodology, July 1985

8. WCAP-15063-P-A, Rev. 1 with Errata (Proprietary), Foster, Sidener, and Slagle, Westinghouse Improved Performance Analysis and Design Model (PAD 4.0), July 2000

9. WCAP-10125-P-A (Proprietary), Davidson, S. L., et al., Extended Burnup Evaluation of Westinghouse Fuel, December 1985 and WCAP-10125-P-A, Addendum 1-A (Proprietary), Slagle, W. H., Revisions to Design Criteria, May 2003

10. WCAP-13589-A, Kersting, P. J., et al., Assessment of Clad Flattening and Densification Power Spike Factor Elimination in Westinghouse Nuclear Fuel, March 1995

Table 2.8.1-1
14x14, 422V+ Thimble Tube and Fuel Rod Maximum and Allowable Stresses

14 422V+ design	Direct or Bending	Allowable	Combined Value	Allowable
Unit	ksi	ksi	ksi	ksi
Thimble Tube	< 9.2	24.35	< 11.4	36.54
Fuel Rod	< 25.1	50.12	< 25.1	75.18

2.8.2 Nuclear Design

2.8.2.1 Regulatory Evaluation

PBNP reviewed the nuclear design of the fuel assemblies, control systems and reactor core for EPU conditions to ensure that fuel design limits will not be exceeded during normal operation and anticipated operational transients, and that the effects of postulated reactivity accidents will not cause significant damage to the reactor coolant pressure boundary or impair the capability to cool the core. The PBNP review covered core power distribution, reactivity coefficients, reactivity control requirements and control provisions, control rod patterns and reactivity worths, criticality, burnup and vessel irradiation.

The NRC's acceptance criteria are based on:

- GDC 10, insofar as it requires that the reactor core be designed with appropriate margin to ensure that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences
- GDC 11, insofar as it requires that the reactor core be designed so that the net effect of the prompt inherent nuclear feedback characteristics tends to compensate for a rapid increase in reactivity
- GDC 12, insofar as it requires that the reactor core be designed to ensure that power oscillations, which can result in conditions exceeding specified acceptable fuel design limits, are not possible or can be reliably and readily detected and suppressed
- GDC 13, insofar as it requires that instrumentation and controls be provided to monitor variables and systems affecting the fission process over anticipated ranges for normal operation, anticipated operational occurrences and accident conditions, and to maintain the variables and systems within prescribed operating ranges
- GDC 20, insofar as it requires that the protection system be designed to automatically initiate the reactivity control systems to ensure that acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences and to automatically initiate operation of systems and components important-to-safety under accident conditions
- GDC 25, insofar as it requires that the protection system be designed to ensure that specified acceptable fuel design limits are not exceeded for any single malfunction of the reactivity control systems
- GDC 26, insofar as it requires that two independent reactivity control systems be provided, with both systems capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes
- GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the emergency core cooling system, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to ensure the capability to cool the core is maintained
- GDC 28, insofar as it requires that the reactivity control systems be designed to ensure that the effects of postulated reactivity accidents can neither result in damage to the reactor

coolant pressure boundary greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to significantly impair the capability to cool the core

Specific review criteria are contained in SRP, Section 4.3 and other guidance provided in Matrix 8 of RS-001.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in the PBNP FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50, Appendix A, GDC 10, 11, 12, 13, 20, 25, 26, 27 and 28 are as follows:

CRITERION: The reactor core with its related controls and protection systems shall be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits which have been stipulated and justified. The core and related auxiliary system designs shall provide this integrity under all expected conditions of normal operation with appropriate margins for uncertainties and for specified transient situations which can be anticipated. (PBNP GDC 6)

CRITERION: The design of the reactor core with its related controls and protection systems shall ensure that power oscillations, the magnitude of which could cause damage in excess of acceptable fuel damage limits, are not possible or can be readily suppressed. (PBNP GDC 7)

CRITERION: Instrumentation and controls shall be provided as required to monitor and maintain within prescribed operating ranges essential reactor facility operating variables. (PBNP GDC 12)

CRITERION: Core protection systems, together with associated equipment, shall be designed to prevent or to suppress conditions that could result in exceeding acceptable fuel damage limits. (PBNP GDC 14)

CRITERION: Two independent reactivity control systems, preferably of different principles, shall be provided. (PBNP GDC 27)

CRITERION: The reactivity control systems provided shall be capable of making the core subcritical under credible accident conditions with appropriate margins for contingencies and limiting any subsequent return to power such that there will be no undue risk to the health and safety of the public. (PBNP GDC 30)

CRITERION: The reactor protection systems shall be capable of protecting against any single malfunction of the reactivity control system, such as unplanned continuous withdrawal (not ejection or dropout) of a control rod, by limiting reactivity transients to avoid exceeding acceptable fuel damage limits. (PBNP GDC 31)

CRITERION: Limits, which include reasonable margin, shall be placed on the maximum reactivity worth of control rods or elements and on rates at which reactivity can be increased to ensure that the potential effects of a sudden or large change of reactivity cannot (a) rupture the reactor coolant pressure boundary or (b) disrupt the core, its support structures, or other vessel internals sufficiently to lose capability of cooling the core. (PBNP GDC 32)

PBNP nuclear design is discussed in FSAR Chapter 3.0, Reactor.

A review of fuel system design for impact on license renewal evaluations is not necessary since continued applicability of the EPU safety analysis for the 422V+ fuel assembly will be evaluated or re-analyzed during the reload safety evaluation process for the reload cycles employing this design. The reload design methodology includes the evaluation of the reload core key safety parameters, which comprise the nuclear design-dependent input to the 10 CFR 50.59 evaluation for each reload cycle.

2.8.2.2 Technical Evaluation

2.8.2.2.1 Introduction

The licensing basis for the reload core nuclear design is defined in FSAR Section 3.3, Reactor, Reload Core Design and Safety Analysis. The purpose of the EPU core analysis is to determine prior to the cycle-specific reload design if the current range of values for the key safety parameters remain applicable for the plant uprating. This will allow the majority of any safety analysis re-evaluations/re-analyses to be completed prior to the cycle specific design analysis. It will also allow future EPU core reload analysis to use the simple verification methodology described in Reference 1.

2.8.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The PBNP EPU core will use the Westinghouse 14X14, 422V+ fuel assembly design. The key features of this design are:

- 0.422 inch outside diameter fuel rods
- Annular axial blanket pellets (up to 8 inches at top and bottom)
- 143.25 inch pellet stack length
- Standard height Removable Top Nozzle (RTN)
- Reduced Rod Bow (RRB) Alloy 718 top grid
- OFA style, 422V+ mid-grids with balanced mixing vane pattern
- High force alloy 718 bottom grid
- ZIRLO™ tube-in-tube guide thimble assembly
- Debris Filter Bottom Nozzle (DFBN)
- Oxide coated clad for debris mitigation
- ZIRLO™ instrumentation tubes
- ZIRLO™ fuel rod clad

This fuel assembly design was previously implemented (starting with Unit 1 Cycle 27 and Unit 2 Cycle 25) to provide margin for future uprates and/or extended burnups. The key features of this assembly design (relative to the older OFA design) that support EPU implementation are:

- A changed fuel stack height within the assembly (increase of 1.85 inches)
- A longer fuel rod (increase of 3.6 inches)
- A longer fuel assembly (increase of 0.040 inches)
- A wider pellet-to-clad gap (increase of 0.25 mils)
- A larger pellet diameter (increase of 0.0215 inches)
- A larger clad diameter (increase of 0.022 inches)

These changes, together with the annular axial blankets, result in a larger rod plenum volume to accommodate fission gas release from the extended burnups and EPU conditions of the 14x14, 422V+ design and the helium release from integral fuel burnable absorbers (IFBA) (see LR Section 2.8.1, Fuel System Design).

The specific values of core safety parameters, e.g., power distributions, peaking factors, rod worths, and reactivity parameters are loading pattern dependent. The variations in loading pattern dependent safety parameters for the EPU cycle are expected to be similar to the cycle-to-cycle variations for past reload cycles.

Limits for radial peaking factor ($F_{\Delta H}$) and axial offset must be reduced to offset the impact of EPU on core thermal hydraulics and fuel rod performance. The nuclear design will be constrained to comply with these limits required as a result of the EPU.

No changes to the nuclear design philosophy or methods are necessary because of the transition to EPU. The reload design methodology described in Reference 1 includes the evaluation of the reload core key safety parameters which comprise the nuclear design-dependent input to the FSAR safety evaluation for each reload cycle. These key safety parameters will be evaluated for each reload cycle. If one or more of the parameters fall outside the bounds assumed in the reference safety analysis, the affected transients will be re-evaluated/re-analyzed using standard methods and the results documented in the reload evaluation for that cycle.

Table 2.8.2-2, Range of Key Safety Parameters, provides the key safety parameter ranges compared to the current limits.

2.8.2.2.3 Description of Analyses and Evaluations

The effects of implementing EPU conditions on the nuclear design bases and methodologies for PBNP are evaluated in this section.

Core designs were developed for several typical EPU reload cycles to model the transition to equilibrium EPU conditions based on a nominal projected energy requirement of 500 EFPD (See Table 2.8.2-1, Core Characteristics of the EPU Scoping Cycles). One core design with an atypically long cycle length was also developed to examine the impact of cycle length and feed batch size variations. These core designs are not intended to represent limiting designs, but were instead developed to determine if enough margin exists between typical parameter values and the corresponding safety analysis limits to allow flexibility in designing actual EPU reload cores. Cycle specific calculations will confirm that the actual values are within the safety analysis limits. The margins for the EPU cycles were compared to values for recent reload cycles to evaluate the continued adequacy of margins between typical safety parameter values and the corresponding limits.

The nuclear design analysis for the EPU cores employed standard analytical models and methods (Reference 1, 2,and 3) that have previously been demonstrated to accurately describe the neutronic behavior of the reactor cores.

The effect of extended burnup on nuclear design parameters has been previously discussed in detail in Reference 5.[1] That discussion is valid for the discharge burnups that are anticipated for the EPU cycles. In accordance with the NRC recommendation made in Reference 5, Westinghouse will continue to monitor predicted versus measured physics parameters for extended burnup applications.

Reactor vessel irradiation is discussed in LR Section 2.2.3, Reactor Pressure Vessel Internals and Core Supports. Control rod patterns have been considered in the calculation of the shutdown margin and control rod worths reported in Table 2.8.2-2.

2.8.2.2.4 Results

As shown in Table 2.8.2-2 the margin to key safety parameter limits is not significantly reduced by the EPU implementation. The key safety parameters evaluated for PBNP as it transitions to EPU show little change from the current design. The variations in these parameters are similar to the normal cycle-to-cycle variations that occur as fuel loading patterns are changed each cycle. Changes to the core power distributions and peaking factors are also within the normal cycle-to-cycle variations expected in core loading patterns. As shown in Table 2.8.2-1, Core Characteristics of the EPU Scoping Cycles, the discharge burnups and assembly requirements have increased, relative to the current design, due to the increase in core power. These will vary cycle-to-cycle based on actual energy requirements. The normal methods of feed enrichment variation and insertion of fresh burnable absorbers will be employed to control peaking factors. Compliance with the peaking factor Technical Specifications can be assured using these standard nuclear design techniques.

EPU implementation will not require changes to the current FSAR nuclear design bases or methodology. There are few changes to the range of key nuclear design parameters currently used in the PBNP safety analysis that will be necessary for EPU implementation.

2.8.2.3 Conclusion

PBNP has reviewed the analyses related to the effect of the proposed EPU on the nuclear design of the fuel assemblies, control systems, and reactor core. PBNP concludes that the analyses have adequately accounted for the effects of the proposed EPU on the nuclear design and have

1. While the 14x14, 422v+ product is capable of being extended to a lead rod burnup of up to 75,000 MWD/MTU, VANTAGE+ is currently licensed to 60,000 MWD/MTU by the NRC (Reference 4) with the extension to 62,000 MWD/MTU on a cycle-specific basis, per Reference 7

demonstrated that the fuel design limits will not be exceeded during normal or anticipated operational transients and that the effects of postulated reactivity accidents will not cause significant damage to the reactor coolant pressure boundary or impair the capability to cool the core. Therefore, based on these analyses, in conjunction with the analyses of the fuel system design, thermal and hydraulic design, and transient and accident analyses, it is concluded that the nuclear design of the fuel assemblies, control systems, and reactor core will continue to meet the PBNP current licensing basis requirements with respect to PBNP GDC 6, 7, 12, 14, 27, 30, 31 and 32. Therefore, PBNP finds the proposed EPU acceptable with respect to the nuclear design.

2.8.2.4 References

1. Davidson, S. L. (Ed.), et al., Westinghouse Reload Safety Evaluation Methodology, WCAP-9273-NP-A, July 1985

2. Nguyen, T. Q., et al., Qualification of the PHOENIX-P/ANC Nuclear Design System for Pressurized Water Reactor Cores, WCAP-11596-P-A, June 1988

3. Liu, Y. S., et al., ANC: A Westinghouse Advanced Nodal Computer Code, WCAP-10965-P-A, September 1986

4. Davidson, S. L. (Ed.), et al., VANTAGE + Fuel Assembly Reference Core Report, WCAP-12610-P-A, April 1995; and WCAP-12610-P-A & CENPD-404-P-A Addendum 1-A, Optimized ZIRLO™, July 2006

5. Davidson, S. L. (Ed.), et al., Extended Burnup Evaluation of Westinghouse Fuel, WCAP-10125-P-A (Proprietary), December 1985

6. Davidson, S. L. (Ed.), et al., Westinghouse Fuel Criteria Evaluation Process, WCAP-12488-A (Proprietary), WCAP-14204-A (Non-Proprietary), October 1994

7. Letter from NRC to WEC, Approval for Increase in Licensing Burnup Limit to 62,000 MWD/MTU (TAC No. MD1486)," May 25, 2006

Table 2.8.2-1
Core Characteristics of the EPU Scoping Cycles

Cycle (See Note 2)	Power Rating (MWth)	Nominal Cycle Length (EFPD)	# Feed Assemblies (See Note 1)	Radial Power Peaking FH	3D Peaking Factor FQ	Maximum MTC @ HZP (pcm/°F)	Peak Rod Burnup (MWD/MTU) (See Note 3)
Unit 2 Current Power	1540	506	37	1.57	1.88	-1.9	60219
N	1800	500	48	1.53	1.92	0.3	58788
N+1	1800	500	49	1.50	1.83	0.3	58672
N+2	1800	500	48	1.51	1.86	0.2	56859
N+3	1800	570	57	1.49	1.87	1.6	55244

1. All feed assemblies use the Westinghouse 14X14, 422V+ fuel assembly design
2. The first EPU cycle (designated as N) was arbitrarily chosen to be Unit 2 for nuclear analysis purposes.
3. The peak rod burnup is best estimate at the nominal cycle length. While the 14x14, 422V+ fuel is capable of being extended to a lead rod burnup of up to 75,000 MWD/MTU, VANTAGE + is currently licensed to 60,000 MWD/MTU by the NRC (Reference 4) with extension to 62,000 MWD/MTU on a cycle-specific basis, per Reference 7.

Table 2.8.2-2
Range of Key Safety Parameters

Safety Parameter	Current Design Values		EPU Analysis Values	
Reactor Core Power (MWt)	1540		1800	
Core Average Coolant Temperature. HFP (°F)	577.1		581	
Coolant System Pressure (psia)	2250		2250	
Most Positive MTC (pcm/°F)	≤ + 5.0 (Power < 70%) ≤ 0.0 (Power ≥ 70%)		≤ + 5.0 (Power < 70%) ≤ 0.0 (Power ≥ 70%)	
Most Positive MDC ($\Delta K/g/cm^3$)	0.43		0.43	
Doppler Temperature Coefficient (pcm/°F)	-2.90 to -0.91		-2.90 to -0.91	
Doppler Only Power Coefficient (pcm/%Power)	(See below)		(See below)	
Least Negative, HFP to HZP	-9.55 to -6.05		-9.55 to -6.05	
Most Negative, HFP to HZP	-19.40 to -12.6		-21.5 to -14.7	
Beta-Effective	0.0043 to 0.0072		0.0043 to 0.0072	
Normal Operation $F^N_{\Delta H}$ (with uncertainties)	1.77		1.68	
Required Shutdown Margin (%$\Delta\rho$)	3.10		2.00	
Normal Operation $F_Q(Z)$	2.60		2.60	
	Fraction of Rod Insertion	Rod Worth (%k)	Fraction of Rod Insertion	Rod Worth (%k)
Trip Reactivity versus Rod Position	0.00	0.000	0.00	0.000
	0.10	0.035	0.10	0.035
	0.20	0.075	0.20	0.075
	0.50	0.150	0.50	0.150
	0.60	0.250	0.60	0.250
	0.80	0.750	0.80	0.750
	0.90	3.000	0.90	3.000
	0.96	4.500	0.96	4.500
	1.00	5.000	1.00	5.000
Rod Ejection	(See Below) BOL	(See Below) EOL	(See Below) BOL	(See Below) EOL
Maximum Ejected Rod Worth (%$\Delta\rho$)	0.79 (HZP)	0.93 (HZP)	0.79 (HZP)	0.93 (HZP)
	0.40 (HFP)	0.42 (HFP)	0.40 (HFP)	0.42 (HFP)

Table 2.8.2-2
Range of Key Safety Parameters

Safety Parameter	Current Design Values		EPU Analysis Values	
Maximum Ejected Rod $F_Q(Z)$	11.0 (HZP)	18.0 (HZP)	11.0 (HZP)	18.0 (HZP)
	4.2 (HFP)	5.69 (HFP)	4.2 (HFP)	5.69 (HFP)
Maximum Burnup at Ejected Rod Hot Spot (MWD/MTU)	31000 (HZP)	48000 (HZP)	31000 (HZP)	48000 (HZP)
	31000 (HFP)	48000 (HFP)	31000 (HFP)	48000 (HFP)

2.8.3 Thermal and Hydraulic Design

2.8.3.1 Regulatory Evaluation

PBNP has reviewed the core thermal and hydraulic design analyses and the reactor coolant system to confirm that the design:

- Has been accomplished using acceptable analytical methods,
- Is equivalent to or a justified extrapolation from proven designs,
- Provides acceptable margins of safety from conditions that would lead to fuel damage during normal reactor operation and anticipated operational occurrences, and
- Is not susceptible to thermal-hydraulic instability.

The PBNP review of the analyses also covered hydraulic loads on the core and reactor coolant system components during normal operation and design basis accident conditions and core thermal-hydraulic stability under normal operation and anticipated transients without scram (ATWS) events.

The NRC's acceptance criteria are based on:

- GDC-10, insofar as it requires that the reactor core be designed with appropriate margin to ensure that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences
- GDC-12, insofar as it requires that the reactor core and associated coolant, control, and protection systems be designed to ensure that power oscillations, which can result in conditions exceeding specified acceptable fuel design limits, are not possible or can reliably and readily be detected and suppressed

Specific review criteria are contained in SRP, Section 4.4 and other guidance provided in Matrix 8 of RS-001.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50, Appendix A, GDC-10 and 12 are as follows:

CRITERION: The reactor core with its related controls and protection systems shall be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits, which have been stipulated and justified. The core and related auxiliary system designs shall provide this integrity under all expected conditions of normal operation with appropriate margins for uncertainties and for specified transient situations, which can be anticipated. (PBNP GDC 6)

CRITERION: The design of the reactor core with its related controls and protection systems shall ensure that power oscillations, the magnitude of which could cause damage in excess of acceptable fuel damage limits, are not possible or can be readily suppressed. (PBNP GDC 7)

PBNP nuclear design is discussed in FSAR Chapter 3.0, Reactor.

A review of thermal and hydraulic design for impact on license renewal evaluations is not necessary since continued applicability of the EPU safety analysis for the 422V+ fuel assembly will be evaluated or re-analyzed during the reload safety evaluation process for the reload cycles employing this design. The reload design methodology includes the evaluation of the reload core key safety parameters which comprise the thermal and hydraulic-dependent input to the safety evaluation for each reload cycle.

2.8.3.2 Technical Evaluation

2.8.3.2.1 Introduction

This section describes the thermal-hydraulic (T-H) analysis performed to support operation of PBNP Units 1 and 2 with cores consisting of 14x14, 422V+ fuel assemblies at EPU conditions.

The current licensing basis for T-H design for PBNP includes the prevention of departure from nucleate boiling (DNB) on the limiting fuel rod with a 95% probability at a 95% confidence level and criteria to ensure fuel cladding integrity, and is documented in FSAR Section 3.2.2, Thermal and Hydraulic Design and Evaluation. The EPU analysis is based on the licensing basis incorporating the increased core power. The analysis addresses the DNB performance, including the effects of fuel rod bow and bypass flow. Also considered in this section is the calculation of fuel temperature/pressure data used in various safety analyses and core stored energy.

2.8.3.2.2 Input Parameters, Assumptions, and Acceptance Criteria

For the purposes of the EPU analysis, bounding fuel-related safety and design parameters have been chosen. These bounding parameters have been used in the safety and design analyses discussed in this section and in other relevant sections of this report.

Table 2.8.3-1, PBNP Thermal-Hydraulic Design Parameters Comparison, lists the thermal-hydraulic parameters for the current design at 1540 MWt as well as for the EPU design at 1800 MWt with the 14x14, 422V+ fuel design. The limiting direction for these parameters is shown in Table 2.8.3-2, Limiting Parameter Direction for DNB.

2.8.3.2.2.1 Design Basis and Methodology

The thermal-hydraulic DNBR analysis of the 14x14 422V+ fuel in PBNP Units 1 & 2 is based on the Revised Thermal Design Procedure (RTDP) (Reference 3) and the WRB-1, DNB correlation (References 4 and 5) using the VIPRE-W subchannel analysis code (Reference 1). See LR Section 2.8.5, Accident and Transient Analysis, for use of the VIPRE and required NRC approval for use. The Standard Thermal Design Procedure methodology (STDP) with the WRB-1 or W-3 DNB correlation is used when RTDP is not applicable. The analyses demonstrate that the 95/95 design basis is met for the core in operation at the maximum analyzed core power of 1800 MWt.

2.8.3.2.2.1.1 Subchannel Analysis Code

The Westinghouse version of the VIPRE-01 (VIPRE) code is used for DNBR calculations. The use of VIPRE for the EPU analysis is in full compliance with the conditions specified in the NRC Safety Evaluation Report (SER) in WCAP-14565-P-A (Reference 1). See Appendix A for code applicability.

2.8.3.2.2.2 DNB Methodology

With the RTDP methodology, uncertainties in plant operating parameters, nuclear and thermal parameters, fuel fabrication parameters, computer codes, and DNB correlation predictions are considered statistically to obtain the overall DNB uncertainty factors. Based on the DNB uncertainty factors, RTDP design limit DNBR values are determined such that there is a 95-percent probability with a 95% confidence level that DNB will not occur on the most limiting fuel rod during normal operation, operational transients, or transient conditions arising from faults of moderate frequency.

The uncertainties included in the overall DNB uncertainty factor are:

- Nuclear enthalpy rise hot channel factor, ($F^N_{\Delta H}$)
- Enthalpy rise engineering hot channel factor, ($F^E_{\Delta H}$)
- Uncertainties in the VIPRE-01 and transient codes
- Vessel coolant flow
- Effective core flow fraction
- Core thermal power
- Coolant temperature
- System pressure

Table 2.8.3-3, Peaking Factor Uncertainties, provides a listing and description of the peaking factor uncertainties. Only the random portion of each plant operating parameter uncertainty is included in the statistical combination for RTDP. Any adverse instrumentation bias is treated either as a direct DNBR penalty or a direct analysis input. Instrumentation uncertainties in core thermal power, RCS flow, pressure and temperature used for the fuel transition and EPU analyses, are listed in Table 2.8.3-4, RTDP Uncertainties and Biases.

In addition to the above considerations for uncertainties, DNBR margin was obtained by performing the safety analyses to DNBR limits higher than the design limit DNBR values. Sufficient DNBR margin was conservatively maintained in the safety analysis DNBR limits to offset the rod bow, plant instrumentation bias and potential future DNBR penalties and to provide flexibility in design and operation of the plant. Table 2.8.3-5, RTDP DNBR Margin Summary(1), provides an illustration of the DNBR margin and penalties applicable at uprated conditions.

The Standard Thermal Design Procedure (STDP) is used for those analyses where RTDP is not applicable. The DNBR limit for STDP is the appropriate DNB correlation limit increased by sufficient margin to offset the applicable DNBR penalties.

2.8.3.2.2.2.1 DNB Correlations and Limits

The WRB-1 DNB correlation is based entirely on rod bundle data and takes credit for the significant improvements in DNB performance due to the mixing vane grid effects. NRC acceptance of a 95/95 correlation limit DNB ratio (DNBR) of $[\ ]^{a,c}$ for the 14x14, 422V+ fuel assemblies is documented in References 1 and 4. The WRB-1 correlation applicability has been documented for the PBNP Units 1 and 2 with 14x14, 422V+ fuel in Reference 5.

For the EPU analysis, the RTDP design limit DNBR values are $[\ ]^{a,c}$ and $[\ ]^{a,c}$ for typical and thimble cells, respectively. After accounting for the plant-specific margin, the Safety Analysis Limit (SAL) DNBR is set to $[\ ]^{a,c}$ for both typical and thimble cells. For events where the temperature instrumentation bias is incorporated directly into the accident initial conditions rather than allocating DNBR margin, the SAL DNBR is $[\ ]^{a,c}$. An additional limit of $[\ ]^{a,c}$ is used for the rod withdrawal at power event to account for a minimum DNBR below $[\ ]^{a,c}$. These SALs are employed in the RTDP DNB analyses.

For events where STDP is used, the DNBR correlation limits are $[\ ]^{a,b,c}$ for WRB-1, W-3 at $1000 \leq P \leq 2300$ psia, and W-3 at $500 \leq P \leq 1000$ psia, respectively.

2.8.3.2.2.2.2 Acceptance Criteria

The reactor core is designed to meet the following limiting thermal and hydraulic criteria:

- There is at least a 95% probability that DNB will not occur on the limiting fuel rods during MODES 1 and 2, operational transients, or any condition of moderate frequency at a 95% confidence level.
- No fuel melting during any anticipated normal operating condition, operational transients, or any conditions of moderate frequency.
- Mode of operation under Conditions I and II events will not lead to thermo-hydrodynamic instabilities.

The ratio of the heat flux causing DNB at a particular core location, as predicted by a DNB correlation, to the actual heat flux at the same core location is the DNBR. Analytical assurance that DNB will not occur is provided by showing the calculated DNBR to be higher than the 95/95 Limit DNBR for all conditions of normal operation, operational transients and transient conditions of moderate frequency. The design limit DNBR is calculated by using the RTDP methodology, which for all operating conditions, assures compliance with the DNBR criteria above.

For use in the DNB safety analyses, the design limit DNBR is conservatively increased to provide DNB margin to offset the effect of rod bow and any other DNB penalties that may occur, and to provide flexibility in design and operation of the plant. This increase in the design limit DNBR to account for various penalties and operational issues is the plant-specific margin retained between the design limit DNBR and the Safety Analysis Limit (SAL) DNBR.

2.8.3.2.3 Description of Analyses and Evaluations

To support the operation at EPU conditions, DNBR reanalysis was required to define new core limits, axial offset limits, and ANS Condition II and IV event (e.g. locked rotor) accident acceptability. With the SAL DNBR set, the core limits, axial offset limits (Reference 2), and dropped rod limits are generated. Based on these limits, the maximum design $F^{N}_{\Delta H}$ limit that can be supported is 1.68. This limit incorporates applicable uncertainties, including a measurement uncertainty of $[\ ]^{a,c}$ percent and is adjusted for the power level using the following equation:(Reference 6)

$$F^{N}_{\Delta H} = 1.68 \times [1 + 0.3(1\text{-}P)]$$

where P is the fraction of full power.

The accident DNB analyses to support the EPU are addressed below.

2.8.3.2.3.1 Loss of Flow

This section supplements the methodology discussed in LR Section 2.8.5.3.1, Loss of Forced Reactor Coolant Flow.

The loss of flow DNBR analysis was performed using RTDP and the 3-D non-LOCA analysis methodology (RAVE) described in Reference 13. See LR Section 2.8.5, Accident and Transient Analysis, for the first use of RAVE and the need for NRC approval of use.

The minimum DNBR calculated for the limiting loss of flow case is greater than the safety analysis DNBR limit, thereby demonstrating compliance to the design criterion for this event.

2.8.3.2.3.2 Locked Rotor

This section supplements the methodology discussed in Section 2.8.5.3.1, Loss of Forced Reactor Coolant Flow.

The locked rotor DNBR analysis was performed using RTDP and the 3-D non-LOCA analysis methodology (RAVE) described in Reference 13. The locked rotor accident is classified as an ANS Condition IV event. To calculate the radiation release as a consequence of this accident, DNB calculations were performed to calculate the number of rods that would experience DNB and be conservatively assumed to fail. The acceptance criterion for this analysis is based on the value used in the radiological analysis, to demonstrate that less than 30% of the fuel rods experience DNB. The analysis confirms that less than 25% of the fuel rods are predicted to be in DNB, thereby meeting the acceptance criterion.

The locked rotor Peak Clad Temperature (PCT) analysis was performed using STDP and the 3-D non-LOCA analysis methodology (RAVE) described in Reference 13. The acceptance criterion for this analysis is that the peak clad temperature is less than 2700°F for the ZIRLO™ fuel. The analysis confirms that the acceptance criterion is met.

2.8.3.2.3.3 Feedwater Malfunction

The feedwater malfunction event is bounded by the hot zero power steamline break analysis (see LR Section 2.8.5.1.2, Steam System Piping Failures Inside and Outside Containment) with respect to the DNB acceptance criterion.

2.8.3.2.3.4 RCCA Drop/Misoperation

This section supplements the methodology discussion of Section 2.8.5.4.3, Control Rod Misoperation, for this non-LOCA event.

The NRC-approved Westinghouse analysis methods in Reference 11 were used for analyzing the RCCA drop event. The Dropped Rod Limit Lines (DRLL) define DNB-based limits on peaking factors as functions of core inlet temperature, core power and pressure. Based on the DRLL and transient statepoints covering a range of reactivity insertion mechanisms, nuclear design calculations determined pre-drop $F^N_{\Delta H}$ values corresponding to the post-drop peaking factors at the SAL DNBR. The maximum pre-drop $F^N_{\Delta H}$ for each reload is specified in the Core Operating Limits Report (COLR). The cycle-specific RCCA drop analysis confirms that allowed pre-drop $F^N_{\Delta H}$ values do not violate the COLR limit, and the DNB design basis is met for power uprate. In addition, the maximum linear heat rate from the RCCA drop analysis is lower than the fuel centerline melt limit. Therefore, the peak fuel centerline melt temperature criterion is also met for this event.

The maximum allowable $F^N_{\Delta H}$ limit for RCCA misalignment was calculated using RTDP methodology. This is the value of $F^N_{\Delta H}$ at normal operating conditions that gives a minimum DNBR equal to the RTDP safety analysis DNBR limit. The acceptability of this limit is determined by nuclear design each cycle.

2.8.3.2.3.5 Steam Line Break Accident

The event description is provided in Section 2.8.5.1.2, Steam System Piping Failures Inside and Outside Containment.

The NRC-approved Westinghouse analysis methods in Reference 14 were used for analyzing the steam line break accident. The DNB analyses of the steamline break events were performed at EPU conditions. Cases were analyzed for both hot zero power and hot full power conditions. For each of these cases, the appropriate methodology was applied.

For the hot full power cases, the RTDP methodology and the WRB-1 correlation was used. The DNB analysis showed that the minimum DNBR values are above the DNBR safety analysis limit, thereby demonstrating that the DNBR design basis was met.

For the hot zero power cases, the mechanistic STDP and the W-3 DNB correlation were applied. The W-3 DNBR correlation limit for this transient is [ ]^{a,b,c} in the pressure range of 500-1000 psia. The DNBR limit is the correlation limit increased to account for any DNB penalties applicable at these conditions. The analysis showed that the minimum DNBR was greater than the DNBR limit, thereby demonstrating that the DNBR design basis was met.

2.8.3.2.3.6 Uncontrolled Rod Cluster Control Assembly Withdrawal from Subcritical

The analysis for the uncontrolled rod cluster control assembly withdrawal from subcritical is based on the STDP methodology since the event was initiated from hot zero power conditions. Results and additional information are contained in Section 2.8.5.4.1, Uncontrolled Rod Assemble Withdrawal from A Subcritical or Low Pump Startup Condition.

The DNB analysis of the rod withdrawal from subcritical accident was performed at EPU conditions. This transient results in a power excursion and a bottom-skewed power shape due to the withdrawal of the rod bank. A conservative accident-specific power shape was applied. Two DNB calculations are required for this accident. The W-3 correlation is applied for fuel assembly spans below the first mixing vane grid. The WRB-1 correlation is applied for spans above the first mixing vane grid. Because of the zero power preconditions of this event, the RTDP methodology is not appropriate and therefore, STDP is applied. For the STDP application, the DNBR limits applied are the correlation limits [ ]^{a,b,c} and [ ]^{a,b,c} for W-3 and WRB-1, respectively, increased by any applicable DNBR penalties. The results of the calculations show that the calculated DNBR values remain above the respective DNBR limits thereby demonstrating that the DNB design basis is met.

2.8.3.2.3.7 Rod Withdrawal at Power

The rod withdrawal at power (RWAP) analysis was performed using RTDP methodology, initiated from nominal, hot full power operating conditions. The temperature instrumentation bias is incorporated directly into the RWAP DNB analysis. Sufficient DNBR margin is retained in this SAL to offset the required DNBR penalties (Table 2.8.3-5, RTDP DNBR Margin Summary[1]). The results show that the minimum DNBR of the limiting case meets the accident-specific SAL of [ ]^{a,c}.

2.8.3.2.3.8 Bypass Flow

Two different bypass flow rates are used in the thermal-hydraulic design analysis. The thermal design bypass flow (TDBF) is the conservatively high core bypass flow used with the thermal design flow (TDF) in power capability analyses that use standard (non-statistical) methods, and is also used to calculate fuel assembly pressure drops. The best estimate bypass flow (BEBF) is the core bypass flow that would be expected using nominal values for dimensions and operating parameters that affect bypass flow without applying uncertainty factors. The BEBF is used in conjunction with the vessel minimum measured flow (MMF) for power capability analyses using the RTDP design procedures. The BEBF is also used to calculate fuel assembly lift forces.

2.8.3.2.3.9 Effects of Fuel Rod Bow on DNBR

Rod bow can occur between mid-grids, reducing the spacing between adjacent fuel rods and reducing the margin to DNB. Rod bow must be accounted for in the DNBR safety analysis of Condition I and Condition II events. Westinghouse has conducted tests to determine the impact of rod bow on DNB performance. The testing and subsequent analyses were documented in WCAP-8691. (Reference 7)

Currently the maximum rod bow penalty for the 422V+ fuel assembly at PBNP uprated conditions is [ ]^{a,c} % DNBR at an assembly average burnup of [ ]^{a,c} MWD/MTU (References 7 and 8). No additional rod bow penalty is required for burnups greater than [ ]^{a,c} MWD/MTU since credit is taken for the effect of $F^N_{\Delta H}$ burndown due to the decrease in fissionable isotopes and the buildup of fission products (Reference 9).

2.8.3.2.4 Fuel Temperatures and Rod Internal Pressures

Fuel temperatures and associated rod internal pressures have been generated using the NRC-approved PAD code (Reference 10). The integral fuel burnable absorber (IFBA) and non-IFBA fuel temperature and/or rod internal pressures were used as initial conditions for LOCA and non-LOCA transients. The linear power limit to preclude fuel centerline melt is determined to be [ ]^{a,c} kW/ft at the analyzed conditions.

In addition to the fuel rod temperatures and rod internal pressures, the core stored energy for the 14x14, 422V+ fuel has been determined for use in containment analysis. Core stored energy is defined as the amount of energy in the fuel rods in the core above the local coolant temperature. The local core stored energy is normalized to the local linear power level.

2.8.3.3 Conclusions

PBNP has reviewed the analyses related to the effects of the proposed EPU on the thermal and hydraulic design of the core and the RCS. PBNP concludes that the analyses have adequately accounted for the effects of the proposed EPU on the thermal and hydraulic design and demonstrated that the design (1) has been accomplished using acceptable analytical methods, (2) is proven design, (3) provides acceptable margins of safety from conditions that would lead to fuel damage during normal reactor operation and anticipated operational occurences, and (4) is not susceptible to thermal hydraulic instability. PBNP further concludes that the analyses have adequately accounted for the effects of the proposed EPU on the hydraulic loads on the core and RCS components. Based on this, PBNP concludes that the thermal and hydraulic design will continue to meet the requirements of PBNP GDC 6 and 7 following implementation of the proposed EPU. Therefore, PBNP finds the proposed EPU acceptable with respect to thermal and hydraulic design.

2.8.3.4 References

1. WCAP-14565-P-A, VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis, October 1999

2. WCAP-8745-P-A, Design Bases for the Thermal Overpower ΔT and Thermal Overtemperature ΔT Trip Functions, September 1986

3. WCAP-11397-P-A, Revised Thermal Design Procedure, April 1989

4. WCAP-8762-P-A, New Westinghouse Correlation WRB-1 for Predicting Critical Heat Flux in Rod Bundles with Mixing Vane Grids, July 1984

5. Letter from WEPCO to NRC, 14x14, 0.422" OD VANTAGE + (422V+) Fuel Design, NPL 97-0538, November 1997

6. WCAP-7308-L-P-A, Evaluation of Nuclear Hot Channel Factor Uncertainties, June 1988

7. WCAP-8691 Revision 1, Fuel Rod Bow Evaluation, July 1979

8. Letter from Westinghouse to NRC, Partial Response to Request Number 1 for Additional Information on WCAP-8691, Revision 1, NS-EPR-2515, October 9, 1981; and Letter from Westinghouse to NRC, Remaining Response to Request Number 1 for Additional Information on WCAP-8691, Revision 1, NS-EPR-2572, March 16, 1982

9. Letter from NRC to Westinghouse, Request for Reduction in Fuel Assembly Burnup Limit for Calculation of Maximum Rod Bow Penalty, June 18, 1986

10. WCAP-15063-P-A Rev. 1 with errata, Westinghouse Improved Performance Analysis and Design Model (PAD 4.0), July 2000, WCAP-12610-P-A, VANTAGE+ Fuel Assembly Reference Core Report, April 1995

11. WCAP-11394-P-A, Methodology for the Analysis of the Dropped Rod Event, January 1990

12. Not used

13. WCAP-16259-P-A, Westinghouse Methodology for Application of 3-D Transient Neutronics to Non-LOCA Accident Analysis, August 2006

14. WCAP-9226-P-A Rev. 1, Reactor Core Response to Excessive Secondary Steam Releases, February 1998

Table 2.8.3-1
PBNP Thermal-Hydraulic Design Parameters Comparison

Thermal-Hydraulic Design Parameters	Current Design Value	EPU Analysis Value
Reactor Core Heat Output, MWt	1540	1800(1)
Reactor Core Heat Output, 10^6 BTU/Hr	5255	6142(1)
Heat Generated in Fuel, %	97.4	97.4
Core Pressure, Nominal, psia	2265	2265
Pressurizer Pressure, Nominal, psia	2250	2250
Radial Power Distribution(2)	1.77[1+0.3(1-P)]	1.68[1+0.3(1-P)]
HFP Nominal Coolant Conditions		
(based on 1800 MWt, TDF, design byp. flow, 2265 psia core pressure; uncertainties and biases not included)		
Vessel Thermal Design Flow Rate (including bypass)		
10^6 lbm/hr	67.44	67.56
GPM	178,000	178,000
Core Flow Rate (excluding Bypass,(3))		
10^6 lbm/hr	63.06	63.17
GPM	166,430	166,430
Core Flow Area, ft^2 (full core of 422V+)	27.1	27.1
Core Inlet Mass Velocity,		
10^6 lbm/hr-ft^2	2.33	2.33
Nominal Vessel/Core Inlet Temperature, °F	544.5	542.9
Vessel Average Temperature, °F	574.0	577.0
Core Average Temperature, °F	577.2	581.0
Vessel Outlet Temperature, °F	603.5	611.1
Core Outlet Temperature, °F	607.3	615.3
Average Temperature Rise in Vessel, °F	59.0	68.2
Average Temperature Rise in Core, °F	62.8	72.4
Heat Transfer		
Active Heat Transfer Surface Area, ft^2	28507	28507
Average Heat Flux, BTU/hr-ft^2	179540	209850(1)
Average Linear Power, kW/ft	5.81	6.80

Table 2.8.3-1
PBNP Thermal-Hydraulic Design Parameters Comparison

Thermal-Hydraulic Design Parameters	Current Design Value	EPU Analysis Value
Peak Linear Power for Normal Operation,[4] kW/ft	15.11	17.67[1]
Peak Linear Power for Prevention of Centerline Melt, kW/ft	22.54	22.54
Pressure Drop Across Core, psi[5]	20.9	25.0

Notes:

1. The proposed power level of 1800 MWt has been used for all thermal-hydraulic design analyses which includes 2.6% of power generated in coolant.
2. $P = \frac{ThermalPower}{RatedThermalPower}$
3. Design bypass flow of [ ]^{a,c} % was used for current and uprate conditions.
4. Based on maximum FQ of [ ]^{a,c}.
5. Current Design Value for core pressure drop is based on [ ]^{a,c} gpm best estimate flow rate. EPU value for core pressure drop is based on [ ]^{a,c} gpm best estimate flow rate.

Table 2.8.3-2
Limiting Parameter Direction for DNB

Parameter	**Limiting Direction for DNB**
$F^{N}\Delta H$ nuclear enthalpy rise hot-channel factor	maximum
Heat generated in fuel (%)	maximum
Reactor core heat output (MWt)	maximum
Average heat flux (BTU/hr-ft^2)	maximum
Nominal vessel/core inlet temperature (°F)	maximum
Core pressure (psia)	minimum
Pressurizer pressure (psia)	minimum
Thermal design flow for non-RTDP analyses (gpm)	minimum
Minimum measured flow for RTDP analyses (gpm)	minimum

Table 2.8.3-3
Peaking Factor Uncertainties

$F_{\Delta H} = F^N_{\Delta H} \times F^E_{\Delta H}$		
where:	$F^N_{\Delta H}$	Nuclear Enthalpy Rise Hot Channel Factor – The ratio of the relative power of the hot rod, which is one of the rods in the hot channel, to the average rod power. The normal operation value of this is given in the plant Technical Specifications or a Core Operating Limit Report (COLR).
	$F^E_{\Delta H}$	Engineering Enthalpy Rise Hot Channel Factor – The nominal enthalpy rise in an isolated hot channel can be calculated by dividing the nominal power into this channel by the core average inlet flow per channel. The engineering enthalpy rise hot channel factor accounts for the effects of flow conditions and fabrication tolerances. It can be written symbolically as:
$F^E_{\Delta H} = f\,(F^E_{\Delta H,1},\ F^E_{\Delta H,2},\ F^E_{\Delta H\ \text{inlet maldist}},\ F^E_{\Delta H\ \text{redist}},\ F^E_{\Delta H\ \text{mixing}})$		
where:	$F^E_{\Delta H,1}$	accounts for rod-to-rod variations in fuel enrichment and weight
	$F^E_{\Delta H,2}$	accounts for variations in fuel rod outer diameter, rod pitch, and bowing
	$F^E_{\Delta H\ \text{inlet maldist}}$	accounts for the non-uniform flow distribution at the core inlet
	$F^E_{\Delta H\ \text{redist}}$	accounts for flow redistribution between adjacent channels due to the different thermal-hydraulic conditions between channels
	$F^E_{\Delta H\ \text{mixing}}$	accounts for thermal diffusion energy exchange between adjacent channels caused by both natural turbulence and forced turbulence due to the mixing vane grids
The value of these factors and the way in which they are combined depends upon the design methodology used, that is, STDP or RTDP. Note that no actual combined effect value is calculated for $F^E_{\Delta H}$. These factors are accounted for in the VIPRE-01 calculations.		

Table 2.8.3-4
RTDP Uncertainties and Biases

Parameter	Uncertainties and Biases Used in EPU Safety Analysis
Power	$[\ ]^{a,c}$ power
Reactor Coolant System Flow	$[\ ]^{a,c}$ flow $[\ ]^{a,c}$ flow (bias)
Pressure	$[\ ]^{a,c}$ $[\ ]^{a,c}$ bias
Inlet Temperature	$[\ ]^{a,c}$ $[\ ]^{a,c}$ (bias)

Table 2.8.3-5
RTDP DNBR Margin Summary[1]

	Current Operation (1540 MWt)		EPU: Core Thermal Limits	
	typ[2]	thm[3]	typ[2]	thm[3]
DNB Correlation	WRB-1		WRB-1	
DNBR Correlation Limit	[ ]a,b,c		[ ]a,b,c	
DNBR Design Limit	[ ]a,c	[ ]a,c	[ ]a,c	[ ]a,c
DNBR SAL	[ ]a,c	[ ]a,c	[ ]a,c	[ ]a,c
DNBR Retained Margin[4]	[ ]a,c	[ ]a,c	[ ]a,c	[ ]a,c
DNBR Credit for operation at 1540 MWt[5]	[ ]a,c	[ ]a,c	[ ]a,c	
Instrumentation Bias Penalty[7]	[ ]a,c	[ ]a,c	[ ]a,c	[ ]a,c
Rod Bow DNBR Penalty	[ ]a,c	[ ]a,c	[ ]a,c	[ ]a,c
Core Bypass Flow Penalty[8]	[ ]a,c	[ ]a,c	[ ]a,c	[ ]a,c
Available DNBR Margin[9]	[ ]a,c	[ ]a,c	[ ]a,c	[ ]a,c
	EPU: Rod Withdrawal at Power		EPU: All Other Transients	
	typ[2]	thm[3]	typ[2]	thm[3]
DNB Correlation	WRB-1		WRB-1	
DNBR Correlation Limit	[ ]a,b,c		[ ]a,b,c	
DNBR Design Limit	[ ]a,c	[ ]a,c	[ ]a,c	[ ]a,c
DNBR SAL	[ ]a,c	[ ]a,c	[ ]a,c	[ ]a,c
DNBR Retained Margin[4]	[ ]a,c	[ ]a,c	[ ]a,c	[ ]a,c
DNBR Credit for operation at 1540 MWt[5]	[ ]a,c		[ ]a,c	
Instrumentation Bias Penalty[7]	[ ]a,c	[ ]a,c	[ ]a,c	[ ]a,c
Rod Bow DNBR Penalty	[ ]a,c	[ ]a,c	[ ]a,c	[ ]a,c
Core Bypass Flow Penalty[8]	[ ]a,c	[ ]a,c	[ ]a,c	[ ]a,c
Available DNBR Margin[9]	[ ]a,c	[ ]a,c	[ ]a,c	[ ]a,c

Table 2.8.3-5

RTDP DNBR Margin Summary[1]

Notes:

1. Hot zero power steam line break is analyzed using the W-3 correlation with STDP. The correlation limit DNBR is [ ]^{a,b,c} in the pressure range of 500 to 1000 psia. Rod withdrawal from subcritical is also analyzed using the W-3 correlation with STDP below the bottom non-mixing vane grid. The correlation limit DNBR is [ ]^{a,b,c} for pressure between 1000 psia and 2300 psia. WRB-1 with STDP is used for rod withdrawal from subcritical above the bottom non-mixing vane grid. The SAL DNBR limits are [ ]^{a,b,c} (for W-3 at 500 psia $\leq$ P $\leq$ 1000 psia), [ ]^{a,b,c} (for W-3 at 1000 psia $\leq$ P $\leq$ 2300 psia), and [ ]^{a,b,c} (WRB-1) to preserve 10% DNBR margin for these analyses.
2. TYP = Typical Cell
3. THM = Thimble Cell
4. Retained DNBR margin is the margin that exists between the SAL and the design limit DNBRs.
5. Current safety analysis for PBNP is based on 1650 MWt. DNBR margin, in addition to that retained between the design limit and safety analysis Limit at 1650 MWt, is realized by operation at 1540 MWt.
6. Different DNBR limits are used because the instrumentation T_{avg} bias is directly incorporated into the OTDT setpoint analysis for the core thermal limits and rod withdrawal at power but must be included in the accident analysis for all other transients.
7. Instrumentation biases for the EPU are [ ]^{a,c}°F and [ ]^{a,c} flow. The corresponding DNBR penalties are [ ]^{a,c} (thm/typ) for the T_{avg} bias, and [ ]^{a,c} (thm/typ) for the flow bias.
8. The T/H safety analyses assume a best estimate core bypass flow fraction of [ ]^{a,c} for RTDP DNBR calculations. The final value of the best estimate core bypass flow fraction is [ ]^{a,c}. A DNBR penalty is calculated based on this bypass flow difference and a conservative DNBR: Flow sensitivity factor that is based on EPU conditions.
9. This table does not account for minimum DNBR values that are greater than the safety analysis limit.

2.8.4 Emergency Systems

2.8.4.1 Functional Design of Control Rod Drive System

2.8.4.1.1 Regulatory Evaluation

The PBNP review covered the functional performance of the control rod drive system to confirm that the system can affect a safe shutdown, respond within acceptable limits during anticipated operational occurrences (AOOs), and prevent or mitigate the consequences of postulated accidents. The review also covered the control rod drive cooling system to ensure that it will continue to meet its design requirements.

The NRC's acceptance criteria are based on:

- GDC 4, insofar as it requires structures, systems, and components important-to-safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents
- GDC 23, insofar as it requires that the protection system be designed to fail into a safe state
- GDC 25, insofar as it requires that the protection system be designed to ensure that specified acceptable fuel design limits are not exceeded for any single malfunction of the reactivity control systems
- GDC 26, insofar as it requires that two independent reactivity control systems be provided, with both systems capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes
- GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the emergency core cooling system, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to ensure the capability to cool the core is maintained
- GDC 28, insofar as it requires that the reactivity control systems be designed to ensure that the effects of postulated reactivity accidents can neither result in damage to the reactor coolant pressure boundary greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to significantly impair the capability to cool the core
- GDC 29, insofar as it requires that the protection and reactivity control systems be designed to ensure an extremely high probability of accomplishing their safety functions in event of anticipated operational occurrences

Specific review criteria are contained in the SRP, Section 4.6.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3.

The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50, Appendix A, GDC-4, 23, 25, 26, 27, 28 and 29 are as follows:

CRITERION: The protection systems shall be designed to fail into a safe state or into a state established as tolerable on a defined basis if conditions such as disconnection of the system, loss of energy (e.g., electrical power, instrument air), or adverse environments (e.g., extreme heat or cold, fire, steam, or water) are experienced. (PBNP GDC 26)

Each reactor protection channel and train is designed on the “de-energize to operate” principle; an open circuit or loss of power causes the respective channel or train to go into its tripped condition (the “preferred failure” direction).

The analog channels for the engineered safety features actuation system, with the exception of containment spray actuation, are designed on the same “de-energize to operate” principle as the reactor protection channels. The high-high containment pressure channels for containment spray actuation are designed as energize-to-operate, to avoid spray operation on inadvertent channel power failures.

Regarding the two ESF actuation trains, the output relays are “energize-to-operate” and require power to actuate ESF equipment. This design prevents inadvertent ESF equipment actuation on power failure of an actuation train (the “preferred failure” direction).

CRITERION: Two independent reactivity control systems, preferably of different principles, shall be provided. (PBNP GDC 27)

Two independent reactivity control systems are provided, one involving rod cluster control assemblies (RCCAs) and the other involving the injection of a soluble poison.

CRITERION: The reactivity control systems provided shall be capable of making the core subcritical under credible accident conditions with appropriate margins for contingencies and limiting any subsequent return to power such that there will be no undue risk to the health and safety of the public. (PBNP GDC 30)

The reactivity control systems provided are capable of making and holding the core subcritical, under accident conditions, in a timely fashion with appropriate margins for contingencies.

Normal reactivity shutdown capability is provided within 2.2 seconds following a trip signal by control rods with soluble neutron absorber (boric acid) injection used to compensate for the long-term xenon decay transient and for plant cooldown.

CRITERION: The reactor protection systems shall be capable of protecting against any single malfunction of the reactivity control system, such as unplanned continuous withdrawal (not ejection or dropout) of a control rod, by limiting reactivity transients to avoid exceeding acceptable fuel damage limits. (PBNP GDC 31)

The reactor protection systems are capable of protecting against any single anticipated malfunction of the reactivity control system by limiting reactivity transients so as to avoid exceeding acceptable fuel damage limits.

Reactor shutdown with rods is completely independent of the normal rod control functions since the trip breakers completely interrupt the power to the latch type rod mechanisms regardless of existing control signals.

CRITERION: Adequate protection for those engineered safety features, the failures of which could cause an undue risk to the health and safety of the public, shall be provided against dynamic effects and missiles that might result from plant equipment failures. (PBNP GDC 40)

This plant-specific GDC is very similar to 10 CFR 50, Appendix A, GDC 4. Under the provisions of that criterion, the dynamic effects associated with postulated pipe ruptures of the RCS may be excluded from the design basis when appropriate analyses approved by the NRC demonstrate that the probability of such ruptures is extremely low. Analyses have been completed for PBNP for the Reactor Coolant Loop piping and the Pressurizer Surge Line (Reference 1 and Reference 3). The NRC has approved the analyses (Reference 2, Reference 4, and Reference 5). As such, the original design features of the facility to accommodate the dynamic effects of a Reactor Coolant pipe or Pressurizer Surge line pipe rupture are no longer applicable

CRITERION: Limits, which include reasonable margin, shall be placed on the maximum reactivity worth of control rods or elements and on rates at which reactivity can be increased to ensure that the potential effects of a sudden or large change of reactivity cannot (a) rupture the reactor coolant pressure boundary or (b) disrupt the core, its support structures, or other vessel internals sufficiently to lose capability of cooling the core. (PBNP GDC 32)

Limits, which include considerable margin, are placed on the maximum reactivity worth of control rods or elements and on rates at which reactivity can be increased to ensure that the potential effects of a sudden or large reactivity change cannot (a) rupture the reactor coolant pressure boundary or (b) disrupt the core, its support structures, or other vessel internals so as to lose capability to cool the core.

The maximum positive reactivity insertion rate assumed in the detailed plant analysis is greater than that for the simultaneous withdrawal of the combination of the two sequential control banks having the greatest combined worth at maximum speed. The resultant reactivity insertion rates are within the capability of the overpower-overtemperature protection circuits to prevent core damage.

No credible mechanical or electrical control system malfunction can cause a rod cluster to be withdrawn at a speed greater than 72 steps per minute (45 inches per minute).

Other FSAR sections that address the design features and functions of the control rod drive system include:

- FSAR Section 3.2.1, Nuclear Design and Evaluation, which provides a description of the design of the control rods and the control rod withdrawal and insertion rate associated with reactor operational load changes
- FSAR Section 3.4, Functional Design of Reactivity Control Systems, which provides a general description of the mechanical design and operation of the control rod drive mechanism

- FSAR Chapter 4, Reactor Coolant System, which provides the design characteristics of the reactor coolant system
- FSAR Section 5.1.2.7, Missile Protection, which provides a description of the structure that is provided over the control rod drive mechanisms to block any missiles generated from fracture of the mechanisms
- FSAR Section 5.3, Containment Ventilation System, which provides a description of the control rod drive mechanism cooling system
- FSAR Section 7.2, Reactor Protection System, which provides a description of the reactor trip system interface with the control rod drive system
- FSAR Section 7.7, Control Systems, which provides a description of the operation of the control rod drive system and the analog rod position indication and digital (demand) position systems
- PBNP Technical Specification 3.1, Reactivity Control Systems, and associated bases which describe the operability requirements for the control rods and control rod position indication system.

In addition to the evaluations described in the FSAR, control rod drive system and the control rod drive mechanism cooling system were evaluated for the PBNP license renewal. System and system component materials of construction, operating history, and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

As a component of the reactor vessel, the control rod drives are discussed in Section 2.3.1.2. The control rod drive cooling system is discussed in Section 2.3.3.9, and the aging management of the control rod drive mechanisms is described in Section 3.0 of the SER.

2.8.4.1.2 Technical Evaluation - Control Rod Drive System

2.8.4.1.2.1 Introduction

The impact of EPU on the control rod drive system results from the temperature effects associated with increasing reactor core thermal power to 1800 MWt with an associated increase in reactor coolant system (RCS) average temperature to a maximum of 577.0°F. The increase in RCS average temperature is expected to increase vessel head temperature to 611.1°F (a 5.6°F increase).

As a result of EPU, there are no physical changes required to the control rod drive system, operating coil stacks, power supplies, solid state electronic control cabinets, or the control rod drive cooling system.

2.8.4.1.2.2 Description of Analyses and Evaluations

The effects of the EPU on the control rod drive system are:

- Increased thermal stresses associated with the structural integrity of the control rod mechanisms associated with the increased reactor coolant system head temperatures, and the increased hydraulic, cyclic, and seismic forces associated with normal, transient, and accident conditions at EPU conditions (see LR Section 2.2.2.4, Control Rod Drive Mechanism and Supports).
- Increased heat load to the control rod drive cooling system resulting from the higher head temperatures. The impact to the rod control cooling system is evaluated in LR Section 2.8.4.1.3 below.

Analyses and evaluations of the impact of EPU on the structural integrity of the control rod drive system during normal, transient, and accident conditions were performed using the EPU conditions listed in LR Section 1.1, Nuclear Steam Supply System Parameters Table 1-1. These analyses and evaluations are discussed in LR Section 2.2.2.4, Control Rod Drive Mechanism, and LR Section 2.2.6, NSSS Design Transients. The results of the analyses and evaluations determined the structural integrity of the control rod drive system remained within acceptable limits at EPU conditions.

2.8.4.1.3 Technical Evaluation - Control Rod Drive Mechanism Cooling System

2.8.4.1.3.1 Introduction

Control rod drive mechanisms (CRDMs) use electro-magnetic coils to position the rod cluster control assemblies (RCCAs) within the reactor core. The insulation and potting materials used in the construction of the coils are subject to thermal aging. In order to reduce the thermal aging, CRDM cooling systems were designed to remove heat supplied by conduction and convection from the reactor head and reactor coolant. These systems are the largest source of containment heat load. PBNP recently modified the CRDM cooling systems to better facilitate reactor disassembly during refueling. The components of this modification are referred to as a head assembly upgrade package (HAUP).

2.8.4.1.3.2 Input Parameters, Assumptions, and Acceptance Criteria

There is an increase in CRDM cooling system heat load associated with the increase in reactor vessel head temperature.

There are no acceptance criteria for CRDM heat load. The total containment heat load from all components is evaluated against the capability of the containment coolers.
(See LR Section 2.6.5, Containment Heat Removal)

There is an increase in CRDM coil temperatures associated with the increase in reactor vessel head temperature. Two thermal analyses using two different head temperatures produced corresponding CRDM coil temperatures. Using these two points, (T_{Head1}, T_{Coil1}) and (T_{Head2}, T_{Coil2}), a linear relationship was established between the head temperature and the

CRDM coil temperature. This linear relationship was used to determine the CRDM coil temperature for the EPU.

The design temperature for the CRDM coils is 392°F (after 15 minutes of stepping with containment air at 120°F).

2.8.4.1.3.3 Description of Analyses and Evaluations

The increase in CRDM heat load is simply the difference between the EPU CRDM heat load and the current CRDM heat load, and is calculated to be 67,980 BTU/hr.

The maximum CRDM coil temperature occurs in the lift coil after a 15 minute stepping transient. Two thermal analyses using two different head temperatures determined the corresponding lift coil temperatures at holding conditions. By assuming a linear relationship between the two analyzed points, the lift coil temperature was extrapolated for the EPU conditions in holding mode. A temperature rise for a 15 minute stepping transient was added to the steady state holding temperature to predict a lift coil temperature of 370°F. This is below the coil design temperature of 392°F.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

Passive elements of the control rod drive system are within the scope of license renewal, and identified aging management programs have been found acceptable in the License Renewal safety evaluation report, NUREG-1839. EPU does not require new functions for existing control rod drive system components that would require revision of the license renewal system evaluation boundaries. The operation of the CRD and CRDM cooling systems at EPU conditions does not result in new or previously unevaluated aging effects that necessitate a change to aging management programs, or require new programs, as internal and external environments remain within the parameters previously evaluated. Therefore, there is no impact on license renewal scope, aging effects, and aging management programs due to EPU activities.

2.8.4.1.3.4 Results

The CRDM cooling evaluation determined the expected additional heat load associated with expected higher reactor head temperatures from the EPU, and demonstrated that the design temperature in the electro-magnetic coils, used to move the control rods, was not exceeded. This calculation has determined that the maximum expected electro-magnetic coil temperature is 370°F. This remains below the electro-magnetic coil design limit of 392°F.

The estimated increase in containment heat load of 67,980 BTU/hr from the CRDM cooling system was evaluated in the evaluation of the containment cooling system described in LR Section 2.7.7, Other Ventilation Systems Containment.

PBNP has reviewed the functional design of the CRD system and the CRDM cooling system for the effects of EPU. Analyses and evaluations, described in LR Section 2.4.2, Plant Operability, and LR Section 2.8.5, Accident and Transient Analyses, have demonstrated that at EPU the rod control system will continue to satisfy the design basis for reactivity control and ensure specified acceptable fuel design limits are not exceeded for single malfunction of the reactivity control systems.

The impact of the EPU on the structural integrity of the CRDMs is discussed in LR Section 2.2.2.4, Control Rod Drive Mechanism. The impact of EPU NSSS transients is discussed in LR Section 2.2.6, NSSS Design Transients. No modifications have been made to the hardware, logic or operation of the system that affect the system's current ability to fail into a safe state.

2.8.4.1.4 Conclusion

PBNP has reviewed the analyses related to the effects of the proposed EPU on the functional design of the CRD system and the CRDM cooling system. PBNP concludes that the evaluation has adequately accounted for the effects of the proposed EPU on the systems and demonstrated that the system's ability to affect a safe shutdown, respond within acceptable limits, and prevent or mitigate the consequences of postulated accidents will be maintained following the implementation of the proposed EPU. PBNP further concludes that the evaluation has demonstrated that there is sufficient cooling to ensure the system's design bases will continue to be followed upon implementation of the proposed EPU. Based on this, PBNP concludes that the CRD system and the CRDM cooling system will continue to meet the current licensing bases with respect to the requirements of PBNP GDC 26, 27, 30, 31, 32 and 40 following implementation of the proposed EPU. Therefore, PBNP finds the proposed EPU acceptable with respect to the functional design of the control rod drive system.

2.8.4.2 Overpressure Protection During Power Operation

2.8.4.2.1 Regulatory Evaluation

Overpressure protection for the reactor coolant pressure boundary during power operation is provided by relief and safety valves and the reactor protection system. The PBNP review covered pressurizer relief and safety valves and the piping from these valves to the quench tank (pressurizer relief tank).

The NRC's acceptance criteria are based on:

- GDC 15, insofar as it requires that the reactor coolant system and associated auxiliary, control, and protection systems be designed with sufficient margin to ensure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operation, including anticipated operational occurrences.
- GDC 31, insofar as it requires that the reactor coolant pressure boundary be designed with sufficient margin to ensure that it behaves in a nonbrittle manner and that the probability of rapidly propagating fracture is minimized.

Specific review criteria are contained in the SRP, Section 5.2.2, and other guidance provided in Matrix 8 of RS-001.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50, Appendix A, GDC-15 and 31 are as follows:

CRITERION: The reactor coolant pressure boundary shall be designed, fabricated, and constructed so as to have an exceedingly low probability of gross rupture or significant uncontrolled leakage throughout its design lifetime. (PBNP GDC 9)

The reactor coolant system, in conjunction with its control and protective provisions, is designed to accommodate the system pressures and temperatures attained under all expected modes of plant operation or anticipated system interactions, and maintain the stresses within applicable code stress limits. Fabrication of the components which constitute the pressure boundary of the reactor coolant system is carried out in accordance with the applicable codes at the time of fabrication.

The system is protected from overpressure by means of pressure relieving devices, as required by Section III of the ASME Boiler and Pressure Vessel Code. The system is also protected from overpressure at low temperatures by the low temperature overpressure protection system.

CRITERION: The reactor coolant pressure boundary shall be capable of accommodating without rupture the static and dynamic loads imposed on any boundary component as a result of an inadvertent and sudden release of energy to the coolant. As a design reference, this sudden release shall be taken as that which would result from a sudden reactivity insertion such as rod ejection (unless prevented by positive mechanical means), rod dropout, or cold water addition. (PBNP GDC 33)

The reactor coolant boundary is shown to be capable of accommodating, without rupture, the static and dynamic loads imposed as a result of a sudden reactivity insertion such as a rod ejection. The operation of the reactor is such that the severity of an ejection accident is inherently limited. Since control rod clusters are primarily used to control load variations and boron dilution is used primarily to compensate for core depletion, only the rod cluster control assemblies in the controlling groups are inserted in the core at power, and at full power these rods are only partially inserted. A rod insertion limit monitor is provided as an administrative aid to the operator to insure that this condition is met.

CRITERION: The reactor coolant pressure boundary shall be designed and operated to reduce to an acceptable level the probability of rapidly propagating type failures. Consideration is given (a) to the provisions for control over service temperature and irradiation effects which may require operational restrictions, (b) to the design and construction of the reactor pressure vessel in accordance with applicable codes, including those which establish requirements for absorption of energy within the elastic strain energy range and for absorption of energy by plastic deformation, and (c) to the design and construction of reactor coolant pressure boundary piping and equipment in accordance with applicable codes. (PBNP GDC 34)

The reactor coolant pressure boundary is designed to reduce to an acceptable level, the probability of a rapidly propagating type failure. All pressure containing components of the reactor coolant system are designed, fabricated, inspected, and tested in conformance with the applicable codes at the time of order placement. Further details are given in FSAR Table 4.1-9, Reactor Coolant System, Code Requirements.

Overpressure protection of the RCPB is further discussed in FSAR Section 4.1, Reactor Coolant System, Design Basis, Section 4.2, RCS System Design and Operation, Section 4.3, Reactor Coolant System, Design Evaluation, Section 4.4, Reactor Coolant System, Tests and Inspections and Section 7.2, Instrumentation and Control, Reactor Protection System.

In addition to the evaluations described in the FSAR, the PBNP reactor coolant pressure boundary overpressure protection components were evaluated for plant license renewal. System and system component materials of construction, operating history, and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2 (NUREG-1839), dated December 2005 (Reference 1)

Overpressure components are included in the scope of license renewal.

2.8.4.2.2 Technical Evaluation

2.8.4.2.2.1 Introduction

The limiting credible event with respect to primary and secondary system overpressurization is the loss of external electrical load/turbine-trip (LOL/TT) event. This section briefly summarizes the LOL/TT analysis performed for PBNP, which demonstrates that the overpressure criteria continue to be met for the proposed extended power uprate (EPU). Details of the LOL/TT analysis performed for PBNP in support of the EPU are given in LR Section 2.8.5.2.1, Loss of External Load, Turbine Trip and Loss of Condenser Vacuum.

The technical evaluations of the RCS and components are described in LR Section 2.2.2, Pressure-Retaining Components and Component Supports. The technical evaluation of the pressurizer safety valves is described in LR Section 2.4.2.2, Pressurizer Control Component Sizing. The technical evaluation of the piping from the safety valves to the pressurizer relief tank (PRT) is described in LR Section 2.5.2, Pressurizer Relief Tank.

Note that overpressure protection during low temperature operation is discussed in LR Section 2.8.4.3, Overpressure Protection During Low Temperature Operation.

2.8.4.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The LOL/TT cases for maximizing the peak RCS and main steam system (MSS) pressures were analyzed using the standard thermal design procedure (STDP). Initial uncertainties on NSSS power, reactor coolant flow and RCS temperature and pressure were applied in the conservative direction to obtain the initial plant conditions for the transient analyses in which overpressurization of the RCS or MSS is the primary concern (for the DNB analysis, the uncertainties associated with power, temperature, pressure, and flow are statistically accounted for in the safety analysis DNBR correlation limit). Further details of the input parameters and assumptions for the LOL/TT analyses at the EPU power are discussed in LR Section 2.8.5.2.1, Loss of External Load, Turbine Trip and Loss of Condenser Vacuum.

For this event, primary and secondary system pressures must remain below 110% of their respective design pressures (an RCS pressure limit of 2748.5 psia and a secondary side pressure limit of 1208.5 psia) at all times during the transient. Demonstrating that the primary and secondary pressure limits are met satisfies the PBNP current licensing basis requirements with respect to the PBNP GDC 9, 33 and GDC 34.

2.8.4.2.2.3 Description of Analyses and Evaluations

For the LOL/TT event, the behavior was analyzed for a complete loss of steam load from full power without a direct reactor trip. A detailed analysis was performed, as described in LR Section 2.8.5.2.1, Loss of External Load, Turbine Trip and Loss of Condenser Vacuum, to determine the plant transient conditions following a total loss of load.

In addition, the allowable power levels with inoperable main steam safety valves have been determined and specified in Technical Specification 3.7.1. This Technical Specification allows PBNP to operate with a reduced number of operable main steam safety valves (MSSVs) at a reduced power level. In order to preclude secondary side overpressurization in the event of a LOL/TT event, the maximum power level allowed for operation with inoperable MSSVs must be below the heat removing capability of the operable MSSVs. Table 3.7.1-1 of the PBNP Technical Specifications defines the maximum allowable power limits corresponding to one or two inoperable MSSVs.

Results

The results of the LOL/TT analysis documented in LR Section 2.8.5.2.1, Loss of External Load, Turbine Trip,and Loss of Condenser Vacuum, demonstrate that the primary and secondary pressure limits are met at the proposed EPU conditions. To meet the applicable secondary side pressure limit, the nominal lift settings of the MSSVs with the two highest setpoints were changed. Table 2.8.4.2-1, Main Steam Safety Valves Lift Settings, provides the nominal lift settings of the MSSVs for the EPU along with the current PBNP Technical Specification Table 3.7.1-2 lift settings. Since the reduced maximum power limits are required for these MSSVs to prevent secondary side overpressurization for the proposed EPU, the PBNP Technical Specification Table 3.7.1-2 will be revised accordingly.

Operation at the EPU conditions will have no impact on the reliability of the reactor protection system or the safety valves, therefore, conclusions with respect to the overpressure protection discussed in the FSAR remain valid.

Table 2.8.4.2-2, Maximum Allowable Power versus Operable Main Steam Safety Valves, provides the maximum allowable power limits in percent rated thermal power (RTP) with inoperable MSSVs for the EPU along with the current PBNP Technical Specification Table 3.7.1-1 lift settings. Since more restrictive setpoints are required to prevent secondary side overpressurization with inoperable MSSVs for the proposed EPU, the PBNP Technical Specification Table 3.7.1-1 will be revised accordingly.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

PBNP has evaluated the impact of the EPU on the conclusions reached in the PBNP license renewal application for the components used to provide overpressure protection. The EPU does not add any new functions for existing components that would change the existing license renewal evaluations. Operation at EPU conditions does not result in any new or previously unevaluated aging effects that necessitate a change to aging management programs or require new programs as internal and external environments remain within the parameters previously evaluated. Therefore, there is no impact to the license renewal scope, aging effects, and aging management programs as approved by the NRC in NUREG-1839 (Reference 1) as a result of EPU activities.

2.8.4.2.3 Conclusions

PBNP has reviewed the analyses related to the effects of the EPU on the overpressure protection capability of the plant during power operation. PBNP concludes that the analyses have:

- Adequately accounted for the effects of the proposed EPU on pressurization events and overpressure protection features
- Demonstrated that the plant will continue to have sufficient pressure relief capacity to ensure that pressure limits are not exceeded

PBNP concludes that the overpressure protection features will continue to provide adequate protection to meet the PBNP current licensing basis requirements with respect to the PBNP GDC 9, 33 and 34 following implementation of the proposed EPU. Since more restrictive maximum allowable power limits are required to prevent secondary side overpressurization with inoperable MSSVs for the proposed EPU, the Technical Specification Table 3.7.1-1 will be revised accordingly. Therefore, PBNP finds the proposed EPU acceptable with respect to overpressure protection during power operation.

2.8.4.2.4 References

1. Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2 (NUREG-1839), dated December 2005

Table 2.8.4.2-1
Main Steam Safety Valves Lift Settings

Valve Number		Lift Setting (psig ±3%)	
Steam Generator			
A	B	Current Technical Specification Setpoint	Proposed EPU Technical Specification Setpoint
MS 2010	MS 2005	1085	1085
MS 2011	MS 2006	1100	1100
MS 2012	MS 2007	1125	1105
MS 2013	MS 2008	1125	1105

Table 2.8.4.2-2
Maximum Allowable Power versus Operable Main Steam Safety Valves

Number of Operable MSSVs per Steam Generator	Current Technical Specification Setpoint (%RTP)	Proposed EPU Technical Specification Setpoint (%RTP)
3	≤49	≤39
2	≤29	≤22

2.8.4.3 Overpressure Protection During Low Temperature Operation

2.8.4.3.1 Regulatory Evaluation

Overpressure protection for the reactor coolant pressure boundary (RCPB) during low temperature operation of the plant is provided by pressure-relieving systems that function during the low temperature operation. The PBNP review covered reactor coolant system (RCS) relief valves with piping to the pressurizer relief tank (quench tank), the charging (make-up) and letdown system, and the residual heat removal (RHR) system, which may be operating when the primary system is water solid.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP specific GDC for Overpressure Protection during Low Temperature Operation are as follows:

CRITERION: The reactor coolant pressure boundary shall be capable of accommodating without rupture the static and dynamic loads imposed on any boundary component as a result of an inadvertent and sudden release of energy to the coolant. As a design reference, this sudden release shall be taken as that which would result from a sudden reactivity insertion such as rod ejection (unless prevented by positive mechanical means), rod dropout, or cold water addition. (PBNP GDC 33)

The reactor coolant boundary is shown to be capable of accommodating, without rupture, the static and dynamic loads imposed as a result of a sudden reactivity insertion such as a rod ejection. The operation of the reactor is such that the severity of an ejection accident is inherently limited. Since control rod clusters are primarily used to control load variations and boron dilution is used primarily to compensate for core depletion, only the rod cluster control assemblies in the controlling groups are inserted in the core at power, and at full power these rods are only partially inserted. A rod insertion limit monitor is provided as an administrative aid to the operator to insure that this condition is met.

CRITERION: The reactor coolant pressure boundary shall be designed and operated to reduce to an acceptable level the probability of rapidly propagating type failures. Consideration is given (a) to the provisions for control over service temperature and irradiation effects which may require operational restrictions, (b) to the design and construction of the reactor pressure vessel in accordance with applicable codes, including those which establish requirements for absorption of energy within the elastic strain energy range and for absorption of energy by plastic deformation, and (c) to the design and construction of reactor coolant pressure boundary piping and equipment in accordance with applicable codes. (PBNP GDC 34)

The PBNP reactor coolant pressure boundary is designed to reduce to an acceptable level the probability of a rapidly propagating type failure. Pressure containing components of the reactor coolant system (RCS) are designed, fabricated, inspected, and tested in conformance with the applicable codes at the time of order placement. Further details are given in FSAR Table 4.1-9.

CRITERION: The reactor coolant pressure boundary shall be designed, fabricated, and constructed so as to have an exceedingly low probability of gross rupture or significant uncontrolled leakage throughout its design lifetime. (PBNP GDC 9)

The RCS in conjunction with its control and protective provisions, is designed to accommodate the system pressures and temperatures attained under all expected modes of plant operation or anticipated system interactions, and maintain the stresses within applicable code stress limits. Fabrication of the components which constitute the pressure boundary of the RCS is carried out in accordance with the applicable codes at the time of fabrication.

The RCS is protected from overpressure at low temperatures by the Low Temperature Overpressure Protection (LTOP) system. The LTOP system is required to provide a diverse means of relieving pressure during operation when the RCS temperature is at or below the LTOP enable temperature as defined in Technical Requirements Manual (TRM) 2.2, Pressure Temperature Limits Report (PTLR).

The PBNP automatic LTOP system that utilizes the two power operated relief valves (PORVs) was originally installed as a result of an NRC request to Westinghouse PWRs in 1976 (Reference 2) to prevent overpressurization events in operating plants. The PBNP LTOP system design was based on a reference mitigating system developed by Westinghouse and Westinghouse Owners Group (WOG) to address the specific NRC concerns. The NRC approved the PBNP overpressure mitigating system on May 20, 1980 (Reference 5).

The PBNP Technical Specification 3.4.12 requires the LTOP system to be operable in MODES 4, 5 and 6 and states the following:

An LTOP system shall be OPERABLE with:

a. A maximum of one Safety Injection (SI) pump capable of injecting into the RCS;

b. Each accumulator isolated, whose pressure is $\geq$ the maximum RCS pressure for the existing RCS cold leg temperature allowed by the P/T limit curves provided in the PTLR, and

c. One of the following pressure relief capabilities:

    1. Two Power-Operated Relief Valves (PORVs) with lift settings within the limits specified in the PTLR, or

    2. The RCS depressurized and an RCS vent path with venting capability equivalent to or greater than a PORV.

Additionally, as required by Generic Letter 88-11, NRC Position on Radiation Embrittlement of Reactor Vessel Materials and Its Impact on Plant Operations (Reference 1), PBNP re-evaluated the effect of neutron radiation on reactor vessel material using the methods described in Regulatory Guide 1.99, Radiation Embrittlement of Reactor Vessel Materials, Revision 2. Based on the pressure-temperature limits resulting from the implementation of Regulatory Guide 1.99, Revision 2, the PBNP LTOP system setpoints were re-evaluated and determined to be unaffected.

In Generic Letter 90-06 (Reference 8), the NRC stated its positions regarding Generic Issues GI-70 (Reference 9) and GI-94 (Reference 10). In GI-70, the NRC recognized that pressurizer PORVs and block valves were provided for plant operational flexibility and for limiting the number of challenges to the safety-related pressurizer safety valves. Therefore, most PWRs had not classified them as safety-related components (except for RCS pressure boundary functions). Following the TMI-2 accident, the NRC concluded that the role of PORVs had changed such that PORVs in many plants were relied upon to perform one or more safety-related functions, including Low Temperature Overpressure Protection. GI-94 addressed the issue of low temperature overpressure protection for light-water reactors. The concern was that major overpressurization of the RCS while at low temperature, if combined with a critical crack in the RPV welds or plate material, could result in a brittle fracture of the pressure vessel. The NRC accepted the PBNP response to GL 90-06 on September 30, 1994. (Reference 6)

On January 27, 1997, the NRC granted PBNP an exemption from 10 CFR 50.60 to permit the use of ASME Code Case N-514 in the determination of the limiting reactor vessel pressure limits in accordance with the requirements of 10 CFR 50, Appendix G. (Reference 7)

Overpressure protection of the RCPB is further discussed in FSAR Section 4.1, Reactor Coolant System, Design Basis, FSAR Section 4.2, RCS System Design and Operation, FSAR Section 4.3, Reactor Coolant System, Design Evaluation, FSAR Section 4.4, Reactor Coolant System, Tests and Inspections, FSAR Section 7.4.2, Low Temperature Overpressure Protection (LTOP), FSAR Section 9.2, Residual Heat Removal (RHR), and FSAR Section 9.3, Chemical and Volume Control System.

In addition to the evaluations described in the FSAR, the PBNP reactor coolant pressure boundary overpressure protection components were evaluated for plant license renewal system and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety evaluation report related to the license renewal of PBNP Units 1 and 2, (NUREG-1839), dated December 2005. (Reference 11)

The LTOP system was evaluated as part of license renewal.

2.8.4.3.2 Technical Evaluation

Existing Design Basis Requirements

Low temperature reactor vessel overpressure protection is provided automatically by the two pressurizer PORVs, as described in FSAR Section 7.4.2, Low Temperature Overpressure Protection, LTOP, with a low pressure setpoint as specified in TRM 2.2. As described in FSAR Section 7.4.2, Low Temperature Overpressure Protection, the LTOP circuitry for low pressure PORV actuation uses multiple pressure sensors, power supplies and logic trains to improve system reliability.

Whenever the RCS cold leg temperature is below the LTOP enable temperature specified in the TRM 2.2, the LTOP system is manually armed. Pressure transients caused by mass injection (MI) or heat injection (HI) are terminated below the limits of 10 CFR 50, Appendix G, as amended by ASME Code Case N-641, by automatic operation of the pressurizer PORVs. The system is designed to protect the RCS pressure boundary from the effects of spurious operations during MODES 4, 5, and 6 when the RCS is in a water solid condition.

Pre-EPU Analyses

The existing automatic LTOP system is designed to mitigate pressure transients that cause a rapid increase in RCS pressure when the RCS is in a water solid condition in MODES 4, 5 and 6. The types of transients evaluated for PBNP (Reference 3) are divided into the following two categories:

- Mass input (MI) transients from injection sources such as charging pumps, safety injection (SI) pumps, or SI accumulators
- Heat input (HI) transients from sources such as steam generators, decay heat or pressurizer heaters

For the automatic LTOP system, the limiting MI transient for PBNP at the pre-EPU conditions is postulated to be due to isolation of the letdown system with continued operation of one SI pump and two charging pumps. Since all but one SI pumps are required to be de-energized prior to enabling the LTOP System, MI due to the start of more than one SI pump is not a credible event for the PBNP LTOP System. The limiting MI transient for PBNP was analyzed at a primary temperature of 70°F and a primary pressure of 150 psig which bounds all RCS conditions when LTOP system is enabled. One reactor coolant pump (RCP) was assumed running for RCS temperatures below 180°F. Both RCPs are assumed running for RCS temperture above 180°F. The analysis assumed water solid conditions. The RHR system was not modeled in the analysis. The analysis assumed 120 gpm of charging flow due to two pump operation. The computer analysis was run for long enough to capture the peak RCS pressure during the limiting MI transient.

For the automatic LTOP system, the most limiting heat addition transient for PNBP at the pre-EPU conditions is the RCS HI transient associated with a 50°F temperature asymmetry between the steam generator (SG) and the primary side water temperatures, This HI transient was analyzed at the pre-EPU conditions.

Based upon the results of the MI and heat addition transients performed for PBNP with the pre-EPU conditions, the MI transient associated with letdown isolation and operation of one SI and two charging pumps represents the limiting condition for the automatic LTOP system operation.

The calculated LTOP system setpoint at the pre-EPU conditions is applicable up to 35.9 Effective Full Power Years (EFPY).

For times when the RCS is de-pressurized and the automatic LTOP system is not available, low pressure protection is provided by a passive system that requires a minimum RCS vent area equivalent to or greater than a PORV.

The maximum RCS pressure calculated for an LTOP event remained below the pressurizer piping limit of 800 psig.

Impact of EPU on LTOP Analyses

The critical parameters for the LTOP system PORV setpoint determination are: (1) the design basis MI and HI transients, (2) RCS volumes, (3) MI flow rates, (4) differential pressures between the reactor vessel and the hot leg pressure transmitter, (5) wide range pressure and temperature uncertainties, (6) pressurizer PORV characteristics, and (7) pressure-temperature limits of 10 CFR 50, Appendix G. Impact of the EPU on these parameters is discussed below.

There are no changes in the design basis MI and HI transients from the current analyses of record for PBNP as a result of the EPU Program.

There are no significant changes to the RCS volumes to PBNP Units 1 and 2 components as part of the EPU Program.

There are no changes to the MI flow rates and differential pressures between the reactor vessel and the hot leg pressure transmitter as a result of the EPU Program. The RCS wide range pressure uncertainty and RCS hot and cold leg temperature uncertainty will not change. In addition, the EPU does not result in any other plant changes (such as, pressurizer PORV characteristics) from the pre-EPU analyses of record.

The existing P-T limits for 36.9 EFPY in Reference 4 are not impacted by the EPU and therefore remain applicable; however, as described in LR Section 2.1.2.2.2, Input Parameters, Assumptions, and Acceptance Criteria, EFPY values have changed from 36.9 to 35.9 EFPY for the EPU.

The only input parameter changes to the LTOP system analysis due to EPU are to the nominal full-power conditions as presented in LR Section 1.1, Nuclear Steam Supply System Parameters. The LTOP system PORV setpoints analyses for both units are performed at reactor shutdown and RCS cold conditions. Therefore, the EPU does not affect the LTOP system PORV setpoint determination.

The acceptance criterion for the LTOP system analysis is that the LTOP system PORV setpoints should prevent the RCS pressure from exceeding the pressure-temperature limits of 10 CFR 50, Appendix G for the design basis MI and HI transients. As for the pre-EPU analyses, the MI transient remains the limiting transient for LTOP system PORV setpoint at EPU conditions.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

The EPU evaluation on the PBNP LTOP system was evaluated for its impact on plant license renewal. System and system component materials of construction, operating history and programs used to manage aging effects as documented in the license renewal safety evaluation report (SER) for the PBNP NUREG-1839, dated December 2005, remain unchanged by the EPU activities associated with the LTOP system.(Reference 11)

With respect to the above SER, the components for which the LTOP system provides a protective function are evaluated within the system that contains them. Aging effects and programs used to manage the aging effects are discussed in Section 3.1, Reactor Coolant

Systems. Since the existing limiting MI and heat addition transients are not affected by the EPU, the peak reactor vessel and RHR system transients presently reported in the FSAR remain valid for the period of extended operation of the plant. Therefore, EPU activities do not impact license renewal scope, aging effects, and aging management programs associated with the LTOP system and the components they protect in the RCS.

2.8.4.3.3 Results

Based on the evaluation, neither the existing limiting MI nor the existing limiting heat addition transients for the PBNP LTOP system are affected by EPU. The pre-EPU LTOP system setpoint analysis which is based on the Reference 3 methodology showed that the LTOP system PORV setpoint associated with the heatup and cooldown curves for PBNP Units 1 and 2 meet the acceptance criterion. It is further concluded that the existing LTOP system setpoint and the enable temperature are not impacted by the EPU, and the existing setpoint and the enable temperature remain applicable for the PBNP EPU. However, the applicability of the LTOP system setpoint and the enable temperature has changed from 36.9 EFPY to 35.9 EFPY. Additionally, the existing requirement for an RCS passive vent area when LTOP is not in service with a depressurized RCS is also unchanged by the EPU.

2.8.4.3.4 Conclusion

PBNP has reviewed the analyses related to the effects of the proposed power uprate on the overpressure protection capability of the plant during low temperature operation. PBNP concludes that:

- The analyses adequately accounted for the effects of the proposed EPU on pressurization events and overpressure protection features, and
- The plant will continue to have sufficient pressure relief capacity to ensure that pressure limits are not exceeded.

Based on this, PBNP concludes that the LTOP system features will continue to provide adequate protection to meet the PBNP current licensing basis requirements with respect to PBNP GDC 9, 33 and 34 following implementation of the proposed power uprate. Therefore, PBNP finds the proposed EPU is acceptable with respect to overpressure protection during low temperature operation.

2.8.4.3.5 References

1. Generic Letter 88-11, NRC Position on Radiation Embrittlement of Reactor Vessel Materials and Its Impact on Plant Operations, July 12, 1988

2. NRC Letter to Westinghouse PWR Utilities, Summary of Meeting Held on November 4, 1976 Concerning Proposed Measures to Prevent Reactor Vessel Overpressurization in Operating Westinghouse (PWR) Facilities, November 17, 1976

3. WCAP-14040-A, Revision 2, Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves, January 1996

4. WCAP-15976-NP, Revision 1, Point Beach Units 1 and 2 Heatup and Cooldown Limit Curves for Normal Operation, March 2008

5. NRC Safety Evaluation Report for Technical Specification Amendment 45/50, Reactor Vessel Over Pressure Mitigating System for Unit 1 and 2, May 20, 1980 (ML021930068)

6. NRC Safety Evaluation Report for Technical Specification Amendment 155/159, Resolution for GL-90-06 and Generic Issue - 94, September 30, 1994

7. NRC to Wisconsin Electric Power, Exemption from Requirements of 10 CFR 50.60, Aceptance Criteria for Fracture Prevention for Light Water Nuclear Power Reactors for Normal Operation - Point Beach Nuclear Plan, Units 1 and 2, January 27, 1997 (ML021970302)

8. Generic Letter 90-06, Resolution of Generic Issues 70, PORV and Block Valve Reliability, and 94, Additional LTOP Protection for PWRs, June 25, 1990

9. Generic Issue 70, PORV and Block Valve Reliability, June 6, 1983

10. Generic Issue 94, Additional Temperature Overpressure Protection for Light Water Reactors, February 1986

11. Safety evaluation report related to the license renewal of PBNP Units 1 and 2, (NUREG-1839), dated December 2005

2.8.4.4 Residual Heat Removal System

2.8.4.4.1 Regulatory Evaluation

The residual heat removal (RHR) system cools down the reactor coolant system following shutdown. The residual heat removal system is a low-pressure system that takes over the shutdown cooling function when the reactor coolant system temperature is reduced. The PBNP review covered the effect of the proposed EPU on the functional capability of the RHR system to cool the reactor coolant system following shutdown and provide decay heat removal.

The NRC's acceptance criteria are based on:

- GDC 4, insofar as it requires that structures, systems, and components important-to-safety be protected against dynamic effects
- GDC 5, insofar as it requires that important-to-safety structures, systems, and components not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions
- GDC 34, which specifies requirements for a residual heat removal system

Specific review criteria are contained in SRP, Section 5.4.7 and other guidance provided in Matrix 8 of RS-001.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50, Appendix A, GDC 4, 5 and 34 are as follows:

CRITERION: Adequate protection for those engineered safety features, the failures of which could cause an undue risk to the health and safety of the public, shall be provided against dynamic effects and missiles that might result from plant equipment failures other than a rupture of the Reactor Coolant System piping. (PBNP GDC 40)

CRITERION: Reactor facilities may share systems or components if it can be shown that such sharing will not result in undue risk to the health and safety of the public. (PBNP GDC 4)

The FSAR does not directly apply PBNP GDC 40 and PBNP GDC 4 to the decay heat removal function of the RHR system.

The current licensing basis for the decay heat removal function of the RHR System is contained in FSAR Section 9.2, Auxiliary Emergency Systems, Residual Heat Removal. During a plant shutdown to cold shutdown conditions, the RHR system performs the non-safety related decay heat removal function for the reactor. To accomplish this alignment, several manual valves must be opened to cross-connect the outlet of the heat exchangers and the discharge of the pumps and to provide a suction path for each of the pumps. After the reactor coolant system temperature and pressure have been reduced to less than or equal to 350°F and less than

400 psig, respectively, residual heat removal is initiated by aligning the pumps to take suction from the "A" hot leg reactor coolant loop and discharge through the heat exchangers into the "B" cold leg reactor coolant loop. If only one pump and one heat exchanger are available, reduction of reactor coolant temperature is accomplished at a lower rate.

In addition to the evaluations described in the FSAR, the PBNP RHR system was evaluated for plant License Renewal. System and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

The RHR system is in scope of license renewal.

2.8.4.4.2 Technical Evaluation

2.8.4.4.2.1 Introduction

The RHR system is described in FSAR Section 9.2, Auxiliary and Emergency Systems, Residual Heat Removal.The system is designed to remove residual and sensible heat from the core and reduce the temperature of the reactor coolant system during the second phase of plant cool down. During the first phase of cool down, the temperature of the reactor coolant system is reduced by transferring heat from the reactor coolant system to the steam and power conversion system.

(Note: The performance of the RHR system during mid-loop operation is discussed in LR Section 2.8.7.1, Loss of Residual Heat Removal at Reduced Inventory.)

2.8.4.4.2.2 Description of Analysis and Evaluations

The EPU increases the residual heat generated in the core during normal cooldown, refueling operations and accident conditions. This provides a higher heat load on the RHR Heat Exchangers (HXs) during cooldown and also during refueling outages. The removal of core decay heat for accident conditions is addressed in LR Section 2.6.5, Containment Heat Removal. The increased heat loads will be transferred to the Component Cooling Water System (CCWS) and ultimately to the Service Water system (SW). Evaluation of the EPU performance of the RHR system in conjunction with the CCW system and SW system with the increased heat loads is addressed in this subsection, LR Section 2.5.4.3, Reactor Auxiliary Cooling Water Systems (Component Cooling Water System), and LR Section 2.5.4.2, Station Component Service Water System.

The EPU affects the plant cooldown time(s) since core power, and therefore, the decay heat increases. The plant cool down calculation was performed at a core power of 1800 MWt to support the EPU (LR Section 1.1, Nuclear Steam Supply System Parameters, Table 1-1). The RCS heat capacity and the other CCW system heat loads were explicitly considered in these analyses. The analysis was performed to demonstrate that the RHR and CCW systems continue to comply with their design basis functional requirements and performance criteria for plant cooldown under the EPU conditions. The two-train system alignment was considered to address the design capability in the FSAR. In addition, a cooldown analysis was performed to support the worst-case scenario for the 10 CFR 50, Appendix R fire hazards and safe shutdown analysis. Also, analysis was performed to demonstrate that existing technical specification cooldown time limits will be achieved at EPU conditions.

The following considerations were applied to these cooldown analyses:

- The CCW and RHR HX data assumes design fouling factors
- The service water temperature of 82°F was assumed
- The CCW system supply temperature is limited to 120°F during cooldown.
- Decay Heat curves bound current fuel cycles

The normal plant cooldown time of 140°F for refueling (MODE 6) or cold shutdown maintenance with both trains of CCW and RHR available (i.e. two RHR pumps and Heat exchangers & two CCW pumps and heat exchangers) increased from 45 hours for the current power rating to 77 hours for the EPU assuming a normal cooldown start time of 4 hours after reactor shutdown. The normal plant cooldown time to cold shutdown (MODE 5 - ≤ 200°F) with both trains of CCW and RHR available increased from 15 hours for the current power rating to 19 hours for the EPU. Since there is no design criterion for normal plant cooldown time, these increases in calculated values, based on design conditions, are acceptable.

The Appendix RSafe Shutdown requires that cold shutdown (MODE 5 - 200°F) be achieved in 72 hours after reactor shutdown. Continued compliance with this time limit was demonstrated at the EPU conditions. The worst case fire scenario trips both Units and results in loss-of-offsite power to both Units, and leaves only one CCW pump available to serve both Units and supply Component Cooloing (CC) water to one CCW heat exchanger and one RHR heat exchanger in each Unit. At EPU conditions, both Units can achieve cold shutdown 66 hours after the reactors shutdown assuming RHR cooldown is initiated in each Unit 48 hours after reactor shutdown. The first phase of plant cooldown must be accomplished with the steam system atmospheric dump valves. For the worst case only one main steam atmospheric dump valve is assumed to be available in each Unit and under natural circulation conditions cooldown to the RHRS cut-in conditions can be achieved in 43 hours. Therefore, continued compliance with the Appendix R cold shutdown requirement within the 72 hour time was demonstrated at EPU conditions with no plant changes required.

Analysis was also performed to demonstrate that continued compliance with all Technical Specification cooldown time limits will be achieved at EPU conditions. The plant Technical Specifications require that the plant be in hot standby (MODE 3) in 6 hours and cold shutdown (MODE 5) in 36 hours with required equipment for power operation out of service. For the worst case scenario, that is, loss of RCPs coupled with the loss of one RHR pump and one CCW pump cold shutdown will be achieved in 19 hours after reactor shutdown if RHR operation is initiated 6 hours after reactor shutdown. Therefore, continued compliance with the Technical Specification cooldown time requirements was demonstrated at the EPU conditions.

The EPU does not impact the design temperature and pressure of the RHR system piping and associated components. Refer to LR Section 2.2.2.1, NSSS Piping, Components and Supports (Class 1), LR Section 2.2.2.2, Balance of Plant Piping, Components, and Supports

(Non Class 1), and LR Section 2.5.1.3, Pipe Failures for the RHR system piping evaluation and the environmental and dynamic effects evaluation relative to meeting the PBNP current licensing basis requirements with respect to GDC 4.

The EPU has no affect on the ability of the RHR system to remove residual heat at reduced reactor coolant system inventory, and therefore, the PBNP will continue to meet the current licensing basis requirements with respect to NRC Generic Letter 88-17, Loss of Decay Heat Removal. Additional discussion of NRC Generic Letter 88-17 is provided in LR Section 2.8.7.1, Loss of Residual Heat Removal at Reduced Inventory.

Evaluation of Impact on Renewal Plant Operating License, Evaluations and License Renewal

EPU activities do not add any new functions for existing components of the RHR system that would change the license renewal system evaluation boundaries. The changes associated with operating the RHR system at EPU conditions do not add any new or previously unevaluated aging effects that necessitate a change to aging management programs or require new programs, as internal and external environments remain within the parameters previously evaluated. Therefore, EPU activities do not impact license renewal scope, aging effects, and aging management programs associated with the RHR system.

2.8.4.4.3 Results

Continued compliance with the RHR system cooldown performance requirements was demonstrated at the EPU conditions with no plant changes being necessary. The EPU cooldown analyses results are as follows:

- The normal plant cooldown time to cold shutdown (MODE 5 - ≤ 200°F) with both trains of RHR and CCW equipment in service will increase from 15 hours to 19 hours. The normal plant cooldown time to 140°F for refueling (MODE 6) or cold shutdown maintenance will increase from 45 hours to 77 hours. Since there are no design criteria for normal plant cooldown times, these increases in calculated values, based on design conditions, are acceptable.
- For the Appendix Rsafe shutdown cooldown scenario, cold shutdown (MODE 5 -≤ 200°F) will continue to be achieved within the 72 hour time limit. The worst case fire scenario trips both Units and results in loss of offsite power to both Units, and leaves only one CCW pump available to serve both Units and supply CCW to one CCW heat exchanger and one RHR heat exchanger in each unit. At EPU conditions, both Units can achieve cold shutdown 66 hours after the reactors shut down, assuming RHR cooldown is initiated in each Unit 48 hours after reactor shutdown.
- Continued compliance with the Technical Specification time limits with respect to achieving hot standby (MODE 3 in 6 hours) and cold shutdown (MODE 5 in 36 hours) was demonstrated at the EPU conditions. With loss of one RHR pump and one CCW pump cold shutdown will be achieved 19 hours after reactor shutdown.

Evaluations described in LR Section 2.2.2.1, NSSS Piping, Components and Supports (Class 1), LR Section 2.2.2.2, Balance of Plant Piping, Components, and Supports (Non Class 1), and

LR Section 2.5.1.3, Pipe Failures, show the response of the RHR system piping to the EPU environmental and dynamics effects remain acceptable relative to meeting the PBNP current licensing basis requirements.

PBNP has a dedicated RHR system for each unit and does not share RHR system components between the two Units.

2.8.4.4.4 Conclusions

PBNP has reviewed the effects of the proposed EPU on the RHR system. PBNP concludes that the effects of the proposed EPU on the system are adequately accounted for and it has been demonstrated that the RHR system will maintain its ability to cool the reactor coolant system following shutdown and provide decay heat removal. Based on this, PBNP concludes that the RHR system will continue to meet PBNP current licensing requirements with respect to PBNP GDC 4 and 40 following implementation of the proposed EPU. Therefore, PBNP finds the proposed EPU acceptable with respect to the RHR system.

2.8.5 Accident and Transient Analyses

2.8.5.0 Non-LOCA Analyses Introduction

This section summarizes the non-loss-of-coolant accident (non-LOCA) transient analyses and evaluations performed to support the extended power uprate (EPU) program for the Point Beach Nuclear Plant (PBNP) Units 1 and 2.

2.8.5.0.1 Fuel Design Mechanical Features

The fuel type currently in use at PBNP Units 1 and 2 is the Westinghouse 14×14, VANTAGE+ fuel design (0.422-inch outer diameter fuel rods) with PERFORMANCE+ features (422V+). The 422V+ fuel rods contain enriched uranium dioxide fuel pellets, mid-enriched annular pellets in axial blankets, and an integral fuel burnable absorber (IFBA) coating on some of the enriched fuel pellets. The fuel rod cladding material is ZIRLO™, as is the material for the mid-grids, guide thimble tubes, and instrumentation tubes. Information on the fuel design is provided in LR Section 2.8.1, Fuel System Design. With respect to the non-LOCA transient analyses, the effects of fuel design mechanical features were accounted for in fuel-related input assumptions such as fuel and cladding dimensions, cladding material, fuel temperatures, and core bypass flow.

2.8.5.0.2 Peaking Factors, Kinetics Parameters

Relative to the fuel, the power distribution is characterized by a nuclear enthalpy rise hot channel factor (radial peaking factor, $F^N_{\Delta H}$) of 1.6154 for analyses employing the Revised Thermal Design Procedure (RTDP) (Reference 1), and 1.68 for non-RTDP analyses, and a full-power heat flux hot channel factor (total peaking factor, F_Q) of 2.60. $F^N_{\Delta H}$ is important for transients that are analyzed for departure from nucleate boiling (DNB) concerns (Table 2.8.5.0-1, Non-LOCA Analysis Limits and Analysis Results, identifies which events are analyzed for DNB concerns, as well as the DNB methodology used (RTDP or non-RTDP)). As $F^N_{\Delta H}$ increases with decreasing power level, due to rod insertion, all transients analyzed for DNB concerns are assumed to begin with an $F^N_{\Delta H}$ consistent with the $F^N_{\Delta H}$ defined in the Technical Requirements Manual (TRM) Core Operating Limits Report (COLR) for the assumed nominal power level. The F_Q, for which the limits are specified in the COLR, is important for transients that are analyzed for overpower concerns, e.g., rod cluster control assembly (RCCA) ejection.

The minimum shutdown margin at hot zero power (HZP) conditions, with the most reactive Rod Cluster Control Assembly (RCCA) fully withdrawn, is assumed to be 2.0% Δk/k. This was assumed in the HZP steam line break analysis.

2.8.5.0.3 EPU Program Features

Key features of the EPU program that were considered in the non-LOCA transient analyses are as follows:

- A nuclear steam supply system (NSSS) power level of 1806 MWt (includes a net reactor coolant pump (RCP) heat of 6 MWt)

- 14×14, 422V+ fuel with a fuel rod outer diameter of 0.422 inches
- A nominal, full-power reactor coolant vessel average temperature (T_{avg}) window between 558°F and 577°F was supported. Note that the T_{avg} range from 569°F to 558°F is considered to be for end-of-cycle T_{avg} coastdown operation; a T_{avg} coastdown can be initiated from any T_{avg} within the normal full power T_{avg} range of 569°F to 577°F
- A reactor coolant system (RCS) thermal design flow (TDF) of 178,000 gpm (89,000 gpm/loop) specified in the Technical Specifications, and a minimum measured flow (MMF) of 186,000 gpm (93,000 gpm/loop) as specified in the Core Operating Limits Report
- Westinghouse Model 44F steam generators in Unit 1 and Westinghouse Model Δ47 steam generators in Unit 2, with a maximum steam generator tube plugging (SGTP) level of 10%
- A nominal operating pressurizer pressure of 2250 psia
- A design core bypass flow of 6.5% (non-RTDP analyses) and a statistical core bypass flow of 5.0% (RTDP analyses), conservatively corresponding to having the core thimble plugs removed
- A nominal, full-power main feedwater temperature window between 390°F and 458°F

For most transients that were analyzed for DNB concerns, the RTDP methodology (Reference 1) was employed. With this methodology, nominal values are assumed for the initial RCS conditions of power, temperature, pressure, and flow, and the corresponding uncertainty allowances are accounted for statistically in defining the departure from nucleate boiling ratio (DNBR) safety analysis limit. Note that the nominal RCS flow modeled in RTDP transient analyses is the minimum measured flow of 186,000 gpm. Also note that a +1.4°F temperature bias was applied to the initial reactor coolant vessel average temperature because it was not accounted for statistically in the RTDP DNBR limits.

As discussed in LR Section 2.8.3, Thermal and Hydraulic Design, uncertainties in plant operating parameters, nuclear and thermal parameters, fuel fabrication parameters, computer codes, and DNB correlation predictions were combined statistically to obtain the overall DNB uncertainty factor, which was used to define the design-limit DNBR (1.24 for typical cell and 1.23 for thimble cell). In other words, the design limit DNBR is a DNBR value that is greater than the WRB-1 DNB correlation limit (1.17) by an amount that accounts for the RTDP uncertainties. To provide DNBR margin to offset various penalties such as those due to rod bow and instrument bias, and to provide flexibility in design and operation of the plant, the design limit DNBR was conservatively increased to a value designated as the safety analysis limit DNBR, to which transient-specific DNBR values were compared. The DNBR safety analysis limit for each applicable event is identified in Table 2.8.5.0-1, Non-LOCA Analysis Limits and Analysis Results.

For transient analyses that are not DNB-limited, or for which RTDP is not employed, the initial conditions were obtained by applying the maximum, steady-state uncertainties to the nominal values in the most conservative direction; this is known as Standard Thermal Design Procedure (STDP), or non-RTDP. In these analyses, the RCS flow was assumed to be equal to the TDF, and the following steady-state initial condition uncertainties were applied:

- ± 0.6% NSSS power allowance for calorimetric measurement uncertainty

- ± 6.4°F T_{avg} allowance for deadband and system measurement uncertainties
- ± 50 psi pressurizer pressure allowance for steady-state fluctuations and measurement uncertainties

These uncertainties are conservative with respect to those determined in WCAP-14787 (Reference 21).

2.8.5.0.4 Other Major Analysis Inputs

Table 2.8.5.0-2 summarizes the initial conditions used in the non-LOCA transient analyses. Other major analysis inputs considered in the non-LOCA transient analyses are discussed as follows:

- Four main steam safety valves (MSSVs) per loop were modeled with opening setpoints based on nominal lift settings of at least the following: 1085 psig, 1100 psig, 1105 psig, 1105 psig (see Note below). Each MSSV was modeled with a +3% setpoint tolerance and at least a 5 psi ramp from closed to full-open, which accounts for accumulation. A -3% setpoint tolerance is also supported, but because none of the non-LOCA transients are limiting with minimum setpoints, it has not been explicitly modeled. See Table 2.8.5.0-3, Pressure Relief Models for the RCS (Pressurizer) and MSS, for the MSSV modeling characteristics used in each non-LOCA analysis

  Note: In the analysis of the Loss of External Electrical Load/Turbine Trip event (see Section 2.8.5.2.1), the nominal lift setting of the two MSSVs per loop with the highest lift setting had to be reduced from 1125 psig to 1105 psig to ensure the main steam system (MSS) pressure does not exceed the applicable limit. This requires a revision to Technical Specification Table 3.7.1-2.

- Two pressurizer safety valves (PSVs) were modeled with opening setpoints based on a nominal lift setting of 2485 psig. Setpoint tolerances of +2.5% and -3.0% were considered in the modeling of the PSVs. Additionally, when it was conservative to do so (that is, for peak RCS pressure concerns), the effects of the PSV water-filled loop seals, as discussed in Reference 2, were explicitly modeled. See Table 2.8.5.0-3 for the PSV modeling characteristics used in each non-LOCA analysis
- Consistent with PBNP Technical Specification 3.1.3, for minimum reactivity feedback, a maximum moderator temperature coefficient (MTC) of +5 pcm/°F is applicable at power levels less than or equal to 70%. Above 70% power, the maximum MTC is 0 pcm/°F. For maximum reactivity feedback, a maximum moderator density coefficient (MDC) of 0.43 Δk (g/cc) was assumed
- The fission product contribution to decay heat assumed in the non-LOCA analyses is consistent with the American National Standards Institute/American Nuclear Society standard ANSI/ANS-5.1-1979, for decay heat power in light water reactors (Reference 3), including two standard deviations of uncertainty

2.8.5.0.5 Overtemperature and Overpower ΔT Reactor Trip Setpoints

The overtemperature and overpower ΔT (OTΔT/OPΔT) reactor trip setpoints were recalculated using the methodology described in WCAP-8745-P-A (Reference 4). Conservative core thermal limits, developed using the RTDP methodology (as described in LR Section 2.8.3, Thermal and Hydraulic Design), were used to calculate the OTΔT and OPΔT reactor trip setpoints. The assumed core thermal limits are presented in Figure 2.8.5.0-1. The OTΔT and OPΔT trip setpoints are illustrated in Figure 2.8.5.0-2 and presented in Table 2.8.5.0-4, Parameters Related to Overtemperature ΔT (OTΔT) and Overpower ΔT (OPΔT) Setpoints.

The adequacy of these setpoints was confirmed by showing that the DNB design basis is met in the analyses of those events that credit these functions for accident mitigation. The revised safety analysis setpoints are based upon the assumption that the reference vessel average temperature (T') used in the OTΔT and OPΔT setpoint equations is set to a value less than or equal to 576°F.

The boundaries of operation defined by the OTΔT and OPΔT trips are represented as "protection lines" in Figure 2.8.5.0-2. The protection lines were drawn to include all adverse instrumentation and setpoint errors so that under nominal conditions, a trip would occur well within the area bounded by these lines. These protection lines are based upon the safety analysis limit OTΔT and OPΔT setpoint values, which are the Technical Specification nominal values with allowances for instrumentation errors and acceptable drift between instrument calibrations. The diagram is useful in the fact that the limit imposed by any given DNBR can be represented as a line (T_{avg} versus ΔT). The DNB lines represent the locus of conditions for which the DNBR equals the limit value (1.34 for both typical and thimble cells). All points below and to the left of a DNB line for a given pressure have a DNBR greater than the safety analysis limit DNBR value.

The area of permissible operation (power, temperature, and pressure) is bounded by the combination of the high neutron flux (fixed setpoint) reactor trip, the high- and low-pressurizer pressure reactor trips (fixed setpoints), the OTΔT (variable setpoint) and OPΔT (variable setpoint) reactor trips, and the opening of the MSSVs which limits the maximum RCS average temperature. The adequacy of the OTΔT and OPΔT setpoints was confirmed by demonstrating that the DNB design basis was met for those transients that credit these protection functions.

As a result of the revised OTΔT and OPΔT setpoint equations, the temperature ranges presented below are required for the resistance temperature detector (RTD) instrumentation:

- T_{cold}: 500-650°F (same as current range)
- T_{hot}: 500-650°F (same as current range)
- T_{avg}: 530-630°F(requires a revision from the current range of 520-620°F)
- ΔT: 0-100°F (same as current range)

2.8.5.0.6 RPS and ESFAS Functions Assumed in Analyses

Table 2.8.5.0-5, Summary of RPS and ESFAS Functions Actuated, contains a list of the different reactor protection system (RPS) and engineered safety feature actuation system (ESFAS) functions credited in the non-LOCA transient analyses. The safety analysis setpoints and associated time delays of each function are also presented in Table 2.8.5.0-5, Summary of RPS and ESFAS Functions Actuated.

2.8.5.0.7 RCCA Insertion Characteristics

The negative reactivity insertion following a reactor trip is a function of the acceleration of the RCCAs and the variation in rod worth as a function of rod position. With respect to the non-LOCA transient analyses, the critical parameter is the time from the start of RCCA insertion to when the RCCAs reach the dashpot region, which is located at an insertion point corresponding to approximately 86% of the total RCCA travel distance. For the non-LOCA analyses, the RCCA insertion time from fully withdrawn to dashpot entry was modeled as 2.2 seconds. The assumed negative reactivity insertion following reactor trip is based on having the most reactive RCCA stuck in the fully withdrawn position.

Three figures relating to RCCA drop time and reactivity worth are presented in this report. The RCCA position (fraction of full insertion) versus the time from release is presented in Figure 2.8.5.0-3. The normalized reactivity worth assumed in the safety analyses is shown in Figure 2.8.5.0-4 as a function of rod insertion fraction and in Figure 2.8.5.0-5 as a function of time.

2.8.5.0.8 Reactivity Coefficients

The transient response of the reactor core is dependent on reactivity feedback effects, in particular the MTC and the Doppler Power Coefficient (DPC). Depending upon event-specific characteristics, conservatism dictates the use of either maximum or minimum reactivity coefficient values. Justification for the use of the reactivity coefficient values was treated on an event-specific basis. Table 2.8.5.0-6, Core Kinetics Parameters and Reactivity Feedback Coefficients, presents the core kinetics parameters and reactivity feedback coefficients assumed in the non-LOCA analyses.

The maximum and minimum integrated DPCs assumed in the safety analyses are provided in Figure 2.8.5.0-6. Note that the Hot Zero Power (HZP) steam line break core response analysis used a different DPC, which was based on an RCCA being stuck out of the core (not shown in Figure 2.8.5.0-6).

2.8.5.0.9 Computer Codes Used

Summary descriptions of the principal computer codes used in the non-LOCA transient analyses are provided below. Table 2.8.5.0-7, Summary of Initial Conditions and Computer Codes Used, lists the computer codes used in each of the non-LOCA analyses.

FACTRAN

FACTRAN calculates the transient temperature distribution in a cross-section of a metal-clad UO_2 fuel rod, and the transient heat flux at the surface of the cladding, using as input the nuclear power and the time-dependent coolant parameters of pressure, flow, temperature, and density. The code uses a fuel model with the following features:

- A sufficiently large number of radial space increments to handle fast transients such as an RCCA ejection accident
- Material properties that are functions of temperature
- A sophisticated fuel-to-cladding gap heat transfer calculation
- Calculations to address post-DNB conditions (film boiling heat transfer correlations, Zircaloy-water reaction, and partial melting of the fuel)

The FACTRAN licensing topical report, WCAP-7908 (Reference 5), was approved for use by the NRC via a Safety Evaluation Report (SER) This SER issued for FACTRAN identifies seven conditions of acceptance, which are summarized in Appendix A.2, along with justifications for application to PBNP.

RETRAN

RETRAN is used for studies of transient response of a pressurized water reactor (PWR) system to specified perturbations in process parameters. This code, which is being used for PBNP for the first time, simulates a multi-loop system by a lumped parameter model containing the reactor vessel, hot and cold-leg piping, RCPs, steam generators (tube and shell sides), main steam lines, and the pressurizer. The pressurizer heaters, spray, relief valves, and safety valves can also be modeled. RETRAN includes a point neutron kinetics model and reactivity effects of the moderator, fuel, boron, and control rods. The secondary side of the steam generator uses a detailed nodalization for the thermal transients. The RPS simulated in the code includes reactor trips on high neutron flux, high neutron flux rate, OTΔT, OPΔT, low reactor coolant flow, high- and low-pressurizer pressure, high pressurizer level, and low-low steam generator water level. Control systems are also simulated including rod control and pressurizer pressure control. Parts of the safety injection system (SI), including the accumulators, are also modeled. A conservative approximation of the transient DNBR, based on the core thermal limits, is calculated via RETRAN.

The RETRAN licensing topical report, WCAP-14882 (Reference 7), was approved by the NRC via an SER. This SER issued for RETRAN identifies three conditions of acceptance, which are summarized in Appendix A.3, along with justifications for application to PBNP.

The RETRAN nodalization modeling used in the PBNP analyses is consistent with the Westinghouse plant nodalization model of WCAP-14882, except for the nodalization of the reactor coolant system hot legs. Since the approval of WCAP-14882, the hot leg modeling was enhanced to minimize code instabilities attributed to pressurizer insurge and outsurge. This hot leg model enhancement, which has been applied in other RETRAN analyses performed by Westinghouse, consisted of dividing each hot leg control volume into three equal control volumes. Although it was needed only for the hot leg connected to the pressurizer, all loops were divided in the same manner.

LOFTRAN

Transient response studies of a PWR to specified perturbations in process parameters use the LOFTRAN computer code. This code simulates a multi-loop system by a model containing the reactor vessel, hot and cold-leg piping, steam generators (tube and shell sides), the pressurizer and the pressurizer heaters, spray, relief valves, and safety valves. LOFTRAN also includes a point neutron kinetics model and reactivity effects of the moderator, fuel, boron, and rods. The secondary side of the steam generator uses a homogeneous, saturated mixture for the thermal transients. The code simulates the RPS, which includes reactor trips on high neutron flux, OTΔT and OPΔT, high and low pressurizer pressure, low RCS flow, low-low steam generator water level, and high pressurizer level. Control systems are also simulated including rod control, steam dump, and pressurizer pressure control. The SIS, including the accumulators, is also modeled. LOFTRAN can also approximate the transient value of DNBR based on input from the core thermal safety limits.

The LOFTRAN licensing topical report, WCAP-7907 (Reference 9), was approved by the NRC via an SER . This SER for LOFTRAN identifies one condition of acceptance, which is summarized in Appendix A.4, along with justifications for application to PBNP.

TWINKLE

TWINKLE is a multi-dimensional spatial neutron kinetics code. The code uses an implicit finite-difference method to solve the two-group transient neutron diffusion equations in one, two, and three dimensions. The code uses six delayed neutron groups and contains a detailed multi-region fuel-cladding-coolant heat transfer model for calculating pointwise doppler and moderator feedback effects. The code handles up to 8000 spatial points and performs steady-state initialization. Aside from basic cross-section data and thermal-hydraulic parameters, the code accepts as input basic driving functions such as inlet temperature, pressure, flow, boron concentration, control rod motion, and others. The code provides various outputs, such as channelwise power, axial offset, enthalpy, volumetric surge, pointwise power, and fuel temperatures. It also predicts the kinetic behavior of a reactor for transients that cause a major perturbation in the spatial neutron flux distribution.

The TWINKLE licensing topical report, WCAP-7979 (Reference 10), was approved by the U.S. Atomic Energy Commission (AEC) via an SER . This SER for TWINKLE does not identify any conditions, restrictions, or limitations that need to be addressed for application to PBNP.

Advanced Nodal Code (ANC)

ANC is an advanced nodal code capable of two-dimensional (2-D) and three-dimensional (3-D) neutronics calculations. ANC is the reference model for certain safety analysis calculations, power distributions, peaking factors, critical boron concentrations, control rod worths, reactivity coefficients, etc. In addition, 3-D ANC validates 1-D and 2-D results and provides information about radial (x-y) peaking factors as a function of axial position. It can calculate discrete pin powers from nodal information as well.

The SPNOVA code utilizes the same Westinghouse standard core design methodology with three-dimensional (3-D) nodal expansion methodology for static analysis of cores that is incorporated into the ANC computer program. SPNOVA includes a neutron kinetics capability and uses the Stiffness Confinement Method to solve time dependent equations.

The ANC licensing topical report, WCAP-10965 (Reference 11), was approved by the NRC via an SER . This SER for ANC does not identify any conditions, restrictions, or limitations that need to be addressed for application to PBNP. The SPNOVA licensing topical report, WCAP-12394

(Reference 22), was approved by the NRC via an SER from A.C. Thadani (NRC) to W.J. Johnson (Westinghouse), dated November 26, 1990. The conditions, restrictions, and limitations identified in the SPNOVA SER are generically addressed in WCAP-16259 (Reference 19) for the RAVE methodology. WCAP-16259 was approved by the NRC via an SER from H. N. Berkow (NRC) to J. A. Gresham (Westinghouse), dated September 15, 2005. This SER stipulates a number of conditions and limitations on the use for licensing basis calculations, and these conditions and limitations are summarized in Appendix A.8 along with justification for application to PBNP.

VIPRE

The VIPRE computer program performs thermal-hydraulic calculations. This code, which is being used for PBNP for the first time, calculates coolant density, mass velocity, enthalpy, void fractions, static pressure, and DNBR distributions along flow channels within a reactor core.

The VIPRE licensing topical report, WCAP-14565 (Reference 12), was approved by the NRC via an SER . This SER for VIPRE identifies four conditions of acceptance, which are summarized in Appendix A.5, along with justifications for application to PBNP.

2.8.5.0.10 Classification of Events

Each of the non-LOCA events listed in Table 2.8.5.0-8, Non-LOCA Transients Evaluated or Analyzed[3], is presented in Section 14, Safety Analysis, of the FSAR, except for ATWS. Each non-LOCA event is categorized with respect to its potential consequences. Since 1970, the classification of plant conditions in American Nuclear Society Standard (ANSI) N18.2-1973 (Reference 13) has often been used to facilitate the evaluation of nuclear plant safety and the functional requirements for structures, systems, and components. The plant conditions are divided into four categories in accordance with the anticipated frequencies of occurrence and potential radiological consequences. The four categories (or conditions) are:

- Condition I – Normal Operation
- Condition II – Incidents of Moderate Frequency
- Condition III – Infrequent Events
- Condition IV – Unanticipated Occurrences

The basic principle applied in relating requirements to each of the conditions is that the more probable occurrences must result in little or no risk to the public, and those extreme situations having the potential for greater risk should be those situations least likely to occur. Where applicable, the reactor trip system and/or engineered safety features are assumed in fulfilling this principle. Each condition is described in more detail as follows:

Condition I – Normal Operation

Condition I occurrences are those that are expected frequently or regularly during power operation, refueling, maintenance, or maneuvering of the plant. Condition I occurrences are accommodated with margin between any plant parameter and the value of the parameter that would require either automatic or manual protective action. In this regard, analysis of the event condition is typically based on a conservative set of initial conditions corresponding to the most adverse set of conditions occurring during Condition I operation.

Condition II – Incidents of Moderate Frequency

These events occur with moderate frequency during the life of the plant, any one of which may occur during a calendar year. These events, at worst, result in a reactor trip with the plant being capable of returning to operation after corrective action. Any release of radioactive materials in effluents to unrestricted areas should be in conformance with Title 10 Part 20 of the Code of Federal Regulations (10 CFR 20). A Condition II event, by itself, does not propagate to a more serious incident of the Condition III or Condition IV type without the occurrence of other independent incidents. A single Condition II incident should not cause the loss of any barrier to the escape of radioactive products.

Condition III – Infrequent Events

Condition III events occur very infrequently during the life of the plant, any one of which may occur during the plant's lifetime. Condition III events can be accommodated with the failure of only a small fraction of the fuel rods, although sufficient fuel damage might occur to preclude resumption of operation for a considerable outage time. The release of radioactivity due to Condition III events may exceed the guidelines of 10 CFR 20, but is not sufficient to interrupt or restrict public use of those areas beyond the exclusion area boundary. A Condition III event does not, by itself, generate a Condition IV event or result in a consequential loss of function of the RCS or containment barriers.

Condition IV – Unanticipated Occurrences

Condition IV occurrences are events that are not expected to occur, but are postulated because their consequences have the potential for the release of significant amounts of radioactive material. Condition IV events are the most drastic occurrences that must be designed against, and represent the limiting design cases. Condition IV events should not cause a fission product release to the environment resulting in an undue risk to public health and safety in excess of the guideline values in Title 10 Part 100 of the Code of Federal Regulations (10 CFR 100). A single Condition IV event is not to cause a consequential loss of required functions of systems needed to cope with the event, including those of the RCS and the reactor containment system.

2.8.5.0.11 Events Evaluated or Analyzed

Each of the FSAR transients listed in Table 2.8.5.0-1 were evaluated or analyzed as shown in Table 2.8.5.0-8 in support of the PBNP EPU Program. These transient evaluations and analyses demonstrate that all applicable safety analysis acceptance criteria are satisfied for PBNP. Table 2.8.5.0-1 summarizes the results obtained for each of the non-LOCA transient analyses.

2.8.5.0.12 Analysis Methodology

The transient-specific analysis methodologies that were applied to PBNP have been reviewed and approved by the NRC via transient-specific topical reports (e.g., WCAPs) and/or through the review and approval of plant-specific safety analysis reports. There are five non-LOCA transients analyzed for PBNP that have an approved transient-specific topical report: RCCA drop (dropped rod) (FSAR Section 14.1.3, Rod Cluster Control Assembly Drop), loss of reactor coolant flow and locked rotor (FSAR Section 14.1.8, Loss of Reactor Coolant Flow), steam line break (FSAR Section 14.2.5, Rupture of a Steam Pipe), and RCCA ejection (FSAR Section 14.2.6, Rupture of a Control Rod Mechanism Housing - RCCA Ejection). One additional NRC-approved methodology that was applied to PBNP is the RETRAN modeling methodology for reactor coolant system thick metal mass heat transfer, which was applied in the analyses of the loss of normal feedwater flow (FSAR Section 14.1.10, Loss of Normal Feedwater) and loss of all AC power to the station auxiliaries (FSAR Section 14.1.11, Loss of all AC Power to Station Auxiliaries) events.

Dropped Rod Analysis Methodology

The dropped rod licensing topical report, WCAP-11394 (Reference 14), was approved by the NRC via an SER . The dropped rod SER identifies one condition of acceptance, which is summarized below along with justification for application to PBNP.

1. The Westinghouse analysis, results and comparisons are reactor and cycle specific. No credit is taken for any direct reactor trip due to dropped RCCA(s). Also, the analysis assumes no automatic power reduction features are actuated by the dropped RCCA(s). A further review by the staff (for each cycle) is not necessary, given the utility assertion that the analysis described by Westinghouse has been performed and the required comparisons have been made with favorable results.

   Justification

   For the reference cycle assumed in the PBNP EPU Program, the methodology described in WCAP-11394 was applied and the required comparisons have been made with acceptable results (DNBR limits were not exceeded). Future cycles will be assessed as part of the reload safety evaluation process described in Reference 8.

Loss of Reactor Coolant Flow and Locked Rotor Analysis Methodology

The loss of reactor coolant flow and locked rotor events were analyzed using a methodology in which 3-D transient neutronics were applied. The licensing topical report for this methodology, (RAVE) which is being used for PBNP for the first time, WCAP-16259 (Reference 18), was approved by the NRC via an SER . This SER stipulates a number of conditions and limitations on the use for licensing basis calculations, and these conditions and limitations are summarized in Appendix A.8, along with justification for application to PBNP.

Steam Line Break Methodology

The steam line break licensing topical report, WCAP-9226 Revision 1 (Reference 17), was approved by the NRC via an SER . The steam line break SER identifies two conditions of acceptance, which are summarized below along with justification for application to PBNP.

1. "Only those codes which have been accepted by the NRC should be used for licensing application."

   Justification

   As identified in Table 2.8.5.0-7, the computer codes used in the analysis of the steam line break event are RETRAN, ANC, and VIPRE. Per Section 2.8.5.0.9, these codes have been accepted by the NRC, and therefore this condition of acceptance is satisfied for PBNP.

2. "For the pressure between 500 and 1000 psia, the 95/95 DNBR limit for the W-3 correlation is 1.45."

   Justification

   As shown in Table 2.8.5.0-1, 1.45 was applied as the DNBR limit in the steam line break analysis that used the W-3 DNB correlation. Thus, no further justification is required for PBNP.

RCCA Ejection Methodology

The RCCA ejection licensing topical report, WCAP-7588 Rev. 1-A (Reference 15), was approved by the AEC via an SER . The RCCA ejection SER identifies two conditions of acceptance, which are summarized below along with justification for application to PBNP.

1. "The staff position, as well as that of the reactor vendors over the last several years, has been to limit the average fuel pellet enthalpy at the hot spot following a rod ejection accident to 280 cal/gm. This was based primarily on the results of the SPERT tests which showed that, in general, fuel failure consequences for UO_2 have been insignificant below 300 cal/gm for both irradiated and unirradiated fuel rods as far as rapid fragmentation and dispersal of fuel and cladding into the coolant are concerned. In this report, Westinghouse has decreased their limiting fuel failure criterion from 280 cal/gm (somewhat less than the threshold of significant conversion of the fuel thermal energy to mechanical energy) to 225 cal/gm for unirradiated rods and 200 cal/gm for irradiated rods. Since this is a conservative revision on the side of safety, the staff concludes that it is an acceptable fuel failure criterion."

   Justification

   The maximum fuel pellet enthalpy at the hot spot calculated for each PBNP-specific RCCA ejection case was less than 200 cal/gm. These results satisfy the fuel failure criterion accepted by the NRC staff.

2. "Westinghouse proposes a clad temperature limitation of 2700°F as the temperature above which clad embrittlement may be expected. Although this is several hundred degrees above the maximum clad temperature limitation imposed in the AEC ECCS Interim Acceptance Criteria, this is felt to be adequate in view of the relatively short time at temperature and the highly localized effect of a reactivity transient."

   Justification

   As discussed in Westinghouse letter NS-NRC-89-3466 written to the NRC (Reference 16), the 2700°F clad temperature limit was historically applied by Westinghouse to demonstrate that the core remains in a coolable geometry during an RCCA ejection transient. This limit was never used to demonstrate compliance with fuel failure limits and is no longer used to demonstrate core coolability. The RCCA ejection acceptance criteria applied by Westinghouse to demonstrate long-term core coolability and compliance with applicable offsite dose requirements are identified in LR Section 2.8.5.4.6, Spectrum of Rod Ejection Accidents.

RETRAN Thick Metal Mass Heat Transfer Methodology

The topical report for the RETRAN thick metal mass heat transfer methodology, which is being used for PBNP for the first time, WCAP-14882-S1-P-A (Reference 19), was approved by the NRC via an SER . The SER identifies one condition of acceptance, which is summarized below along with justification for application to PBNP.

1. "The NRC staff review utilized analyses and supporting experimental data supplied by the licensee that are specific to reactor system designs similar to STP, Units 1 and 2. The NRC staff will therefore, require that licensees seeking to apply this methodology for analyses of other nuclear power plants provide supporting justification that use of this methodology is appropriate and conservative for their designs."

   Justification

   With the only exception being that PBNP specific geometric dimensions were used, the same thick metal model described in WCAP-14882-S1-P-A (Reference 19) was incorporated into the RETRAN models used to simulate the loss of normal feedwater flow (FSAR Section 14.1.10) and loss of all AC power to the station auxiliaries (FSAR Section 14.1.11) events. As the Reference 19 thick metal model, which was shown in Reference 19 to be conservative for long-term heatup events such as loss of normal feedwater flow, was applied with plant-specific geometry, use of the Reference 19 methodology is appropriate and conservative for the PBNP design.

2.8.5.0.13 Operator Actions

No operator actions were explicitly credited in the non-LOCA analyses identified in Table 2.8.5.0-1.

2.8.5.0.14 Key Safety Analysis Input Changes

Key safety analysis input changes made in support of the PBNP EPU program are identified in Table 2.8.5.0-9.

2.8.5.0.15 References

1. WCAP-11397-P-A, Revised Thermal Design Procedure, April 1989
2. WCAP-12910 Rev. 1-A, *Pressurizer Safety Valve Set Pressure Shift*, May 1993
3. ANSI/ANS-5.1-1979, American National Standard for Decay Heat Power In Light Water Reactors, August 29, 1979
4. WCAP-8745-P-A, Design Bases for the Thermal Overpower ΔT and Thermal Overtemperature ΔT Trip Functions, September 1986
5. WCAP-7908-A, FACTRAN – A FORTRAN IV *Code for Thermal Transients in a* UO_2 Fuel Rod, December 1989
6. Nuclear Safety Advisory Letter NSAL-07-10, Loss-of-Normal Feedwater/Loss-of-Offsite AC Power Analysis PORV Modeling Assumptions, November 7, 2007
7. WCAP-14882-P-A, RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses, April 1999
8. WCAP-9272-P-A, Westinghouse Reload Safety Evaluation Methodology, July 1985
9. WCAP-7907-P-A, LOFTRAN Code Description," April 1984
10. WCAP-7979-P-A, TWINKLE – A Multi-Dimensional Neutron Kinetics Computer Code, January 1975
11. WCAP-10965-P-A, ANC: A Westinghouse Advanced Nodal Computer Code, September 1986
12. WCAP-14565-P-A, VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis, October 1999
13. ANS N18.2-1973, Nuclear Safety Criteria for the Design of Stationary PWRs, American Nuclear Society
14. WCAP-11394-P-A, Methodology for the Analysis of the Dropped Rod Event," January 1990
15. WCAP-7588 Rev. 1-A, An Evaluation of the Rod Ejection Accident in Westinghouse Pressurized Water Reactors Using Spatial Kinetics Methods," January 1975

16. NS-NRC-89-3466, Letter Westinghouse to NRC, dated October 23, 1989, Use of 2700°F PCT Acceptance Limit in Non-LOCA Accidents

17. WCAP-9226-P-A Revision 1, Reactor Core Response to Excessive Secondary Steam Releases, February 1998

18. WCAP-16259-P-A, Westinghouse Methodology for Application of 3-D Transient Neutronics to Non-LOCA Accident Analysis, August 2006

19. WCAP-14882-S1-P-A, RETRAN-02 Modeling and Qualification For Westinghouse Pressurized Water Reactors Non-LOCA Safety Analyses, Supplement 1 – Thick Metal Mass Heat Transfer Model and NOTRUMP-Based Steam Generator Mass Calculation Method, October 2005

20. Nuclear Safety Advisory Letter NSAL-03-1, Safety Analysis Modeling Loss of Load/Turbine Trip, January 27, 2003

21. WCAP-12394-A, SPNOVA - A Multidimensional Static and Transient Computer Program for PWR Core Analysis, June 1991

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
14.1.1	Uncontrolled Rod Withdrawal from Subcritical	Minimum DNBR Below First Mixing Vane Grid (non-RTDP, W-3 correlation) (typical/thimble)	1.44/1.44	1.954/1.755
		Minimum DNBR Above First Mixing Vane Grid (non-RTDP, WRB-1 correlation) (typical/thimble)	1.30/1.30	2.055/2.055
		Maximum Fuel Centerline Temperature, °F	4800(1)	2166
14.1.2	Uncontrolled Rod Withdrawal at Power	Minimum DNBR (RTDP, WRB-1)	1.337 (Unit 1) 1.337 (Unit 2)	1.337 (Unit 1) 1.344 (Unit 2)
		Peak MSS Pressure, psia	1208.5	1115 (Unit 1) 1114 (Unit 2)
		Peak RCS Pressure, psia	2748.5	2690 (Unit 1) 2692 (Unit 2)
14.1.3	RCCA Drop	Minimum DNBR (RTDP, WRB-1)	1.38	> 1.38
		Peak Linear Heat Generation (kW/ft)	22.54(2)	< 22.54
		Peak Uniform Cladding Strain (%)	1.0	< 1.0
14.1.4	Chemical and Volume Control System Malfunction	Minimum Time to Loss of Shutdown Margin, Minutes	15	17.6 (MODE 1 auto)
			15	15.1 (MODE 1 manual)
			15	18.2 (MODE 2)
			15	$\geq$15 (MODE 5)
			30	32.2 (MODE 6)
14.1.5	Startup of an Inactive Reactor Coolant Loop	No Analysis Performed (See Licensing Report Section 2.8.5.4.4)	N/A	N/A

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
14.1.6	Reduction in Feedwater Enthalpy Incident	(3)	N/A	N/A
14.1.7	Excessive Load Increase Incident	Minimum DNBR (RTDP, WRB-1)	1.34	1.627
14.1.8	Loss of Reactor Coolant Flow	Minimum DNBR (RTDP, WRB-1) (typical/thimble)	1.38/1.38	1.41/1.41
	Locked Rotor	Peak RCS Pressure, psia	3120	2653
		Peak Cladding Temperature, °F	2700	1809.9
		Maximum Zirconium-Water Reaction, %	16	0.4
		Maximum Percentage of Rods-in-DNB, %	30	25
14.1.9	Loss of External Electrical Load	Minimum DNBR (RTDP, WRB-1)	1.34	1.64 (Unit 1) 1.66 (Unit 2)
		Peak RCS Pressure, psia	2748.5	2739.6 (Unit 1) 2741.9 (Unit 2)
		Peak MSS Pressure, psia	1208.5	1205.6 (Unit 1) 1205.0 (Unit 2)
14.1.10	Loss of Normal Feedwater	Maximum pressurizer mixture volume, ft^3	1000	880 (Unit 1) 928 (Unit 2)
14.1.11	Loss of All AC Power to Station Auxiliaries	Maximum Pressurizer Mixture Volume, ft^3	1000	720 (Unit 1) 732 (Unit 2)

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
14.2.5	Rupture of a Steam Pipe – Zero Power (Core response only)	Minimum DNBR (non-RTDP, W-3) (typical/thimble)	1.45/1.45	1.623/1.616 (Unit 1) 1.652/1.650 (Unit 2)
		Peak Linear Heat Generation (kW/ft)	22.54(2)	21.64 (Unit 1) 21.35 (Unit 2)
	Rupture of a Steam Pipe – Full Power (Core response only)	Minimum DNBR Below First Mixing Vane Grid (non-RTDP, W-3 correlation)	1.30	1.411 (Unit 1) 1.428 (Unit 2)
		Minimum DNBR Above First Mixing Vane Grid (non-RTDP, WRB-1 correlation)	1.38	1.644 (Unit 1) 1.654 (Unit 2)
		Peak Linear Heat Generation (kW/ft)	22.54(2)	22.51 (Unit 1) 22.26 (Unit 2)

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
14.2.6	Rupture of a Control Rod Mechanism Housing (RCCA Ejection)	Maximum Fuel Pellet Average Enthalpy, cal/g	200	150.5 (BOC-HZP)(4) 174.1 (BOC-HFP)(5) 161.0 (EOC-HZP)(6) 176.4 (EOC-HFP)(7)
		Maximum Fuel Melt, %	10(8)	0.0 (BOC-HZP)(4) 5.6 (BOC-HFP)(5) 0.0 (EOC-HZP)(6) 9.8 (EOC-HFP)(7)
		Peak RCS Pressure, psia	Generically addressed in Reference 15	
N/A	ATWS	Peak RCS Pressure, psia	3215	3097.4 psia (Unit 1) 3175.1 psia (Unit 2)

Notes:

1. 4800°F is the fuel melting temperature corresponding to a maximum UO_2 burnup at the hot spot of ~48,276 MWd/MTU.
2. Corresponds to a conservative UO_2 fuel melting temperature of 4700°F.
3. Event bounded by excessive load increase incident. See Section 2.8.5.1.1.
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 4900°F and 4800°F, respectively. These temperatures correspond to hot spot burnups of approximately 31,034 MWD/MTU (BOC) and 48,276 MWD/MTU (EOC).
9. The minimum DNBR from the limiting case of the RAVE Loss of Flow analysis is 1.696, which accounts for conservative uncertainty allowances that are required by the RAVE methodology. The minimum DNBR value presented in this table (1.41) accounts for additional conservative allowances for reload flexibility. This additional conservatism was specifically introduced to create a bounding case for the future Point Beach reload cycles.

Table 2.8.5.0-2
Summary of Initial Conditions Used in Non-LOCA Analyses

Parameter	RTDP	Non-RTDP	Notes
NSSS Power (MWt)	1806	1806 * 1.006	1
Nominal Total Net RCP Heat (MWt)	6.0	6.0	1, 2, 3
Maximum Full-Power Vessel T_{avg} (°F)	577	577 ± 6.4	1, 4
Minimum Full-Power Vessel T_{avg} (°F)	558	558 ± 6.4	1, 4
No-Load RCS Temperature (°F)	547.0	547.0	1, 4
Pressurizer Pressure (psia)	2250	2250 ± 50	1
Steam Flow (lbm/hr)	see Note 5	see Note 5	--
Steam Pressure (psia)	see Note 5	see Note 5	--
Full-Power Feedwater Temperature Range (°F)	390 - 458	390 - 458	1
Pressurizer Water Level (% span)	see Note 6	see Note 6	--
Steam Generator Water Level (% NRS)	see Note 7	see Note 7	--

Notes:

1. Section 1.1, NSSS Parameters, of Licensing Report.
2. Total RCP heat input minus RCS thermal losses.
3. A maximum net RCP heat of 8 MWt was conservatively assumed in the non-RTDP analysis of the loss of normal feedwater event.
4. All analyses assumed a programmed no-load T_{avg} of 547°F. For the events initiated from a no-load condition (rod withdrawal from subcritical, steam line break, rod ejection, boron dilution), the use of the no-load T_{avg} as the initial temperature bounds the conditions of startup operations at PBNP with a temperature less than 547°F. This is because the DNBR calculations and the boron dilution calculations would be less limiting at a lower RCS temperature.
5. The nominal steam flow rate and steam pressure are dependent on other nominal conditions.
6. The nominal/programmed pressurizer water level varies linearly from 20% of span at the no-load T_{avg} of 547°F to either 29.9% of span at the minimum full-power T_{avg} of 558°F or 47% of span at full-power T_{avg} values greater than or equal to the maximum full-power T_{avg} of 577°F. The programmed level is constant at the full-power T_{avg} level for T_{avg} values greater than the full-power T_{avg}. An uncertainty of at least ±10% of span was applied when conservative.
7. The programmed steam generator water level modeled in the analyses for both PBNP Units 1 and 2 was a constant 64% narrow range span (NRS) for all power levels; an uncertainty of ±10% NRS was applied when conservative.

Table 2.8.5.0-3
Pressure Relief Models for the RCS (Pressurizer) and MSS

FSAR	Event Description	Pressure Relief Model(1) RCS	Pressure Relief Model(1) MSS
14.1.1	Uncontrolled Rod Withdrawal from Subcritical	5	5
14.1.2	Uncontrolled Rod Withdrawal at Power – Minimum DNBR Case	1A	3A
	Uncontrolled Rod Withdrawal at Power – Peak RCS Pressure Case	2A	3A
14.1.3	RCCA Drop	6	6
14.1.4	Chemical and Volume Control System Malfunction	5	5
14.1.5	Startup of an Inactive Reactor Coolant Loop	Analysis not required.	
14.1.6	Reduction in Feedwater Enthalpy Incident	5	5
14.1.7	Excessive Load Increase Incident	4	4
14.1.8	Loss of Reactor Coolant Flow	1C	7
	Locked Rotor – Rods-in-DNB Case	1C	7
	Locked Rotor – Peak RCS Pressure Case	2A	7
	Locked Rotor – Peak Clad Temperature Case	2A	7
14.1.9	Loss of External Electrical Load – Minimum DNBR Case	1B	3B
	Loss of External Electrical Load – Peak RCS Pressure Case	2A	3B
	Loss of External Electrical Load – Peak MSS Pressure Case	1B	3B
14.1.10	Loss of Normal Feedwater	1C & 2B(2)	3A
14.1.11	Loss of All AC Power to Station Auxiliaries	1C & 2B(2)	3A
14.2.5	Rupture of a Steam Pipe – Zero Power (core response only)	4	4
	Rupture of a Steam Pipe – Full Power (core response only)	4	4
14.2.6	Rupture of a Control Rod Mechanism Housing (RCCA Ejection)	5	5
N/A	ATWS	8	9

Note:
1. The pressure relief models are described on the following pages of this table.
2. Two RCS pressure relief models were considered to address the issue described in NSAL-07-10 (Reference 6).

Table 2.8.5.0-3 continued
Pressure Relief Models for the RCS (Pressurizer) and MSS

Model 1A (Maximum Pressurizer Pressure Relief) The following components were modeled to maximize the RCS pressure relief capability: • Pressurizer Power-Operated Relief Valves (PORVs) – The two pressurizer PORVs were modeled based on a relief rate of 179,000 lbm/hr at 2350 psia. Both PORVs were modeled to begin opening when the pressurizer pressure reached a value of 2350 psia and be full-open at a pressure of 2355 psia. • Pressurizer Sprays – The pressurizer sprays were modeled via a control valve (with a full-open flow area of 0.0716 ft^2) that was set to initially open when the indicated pressurizer pressure exceeded the initial value by 25 psi, and ramping to full-open when the indicated pressurizer pressure exceeded the initial value by 75 psi. • Pressurizer Safety Valves (PSVs) – The two PSVs were modeled with a minimum setpoint of 2425.2 psia, which is 3% below the nominal setpoint of 2485 psig. For each PSV, the full-open area is based on a relief rate of 288,000 lbm/hr at 2575 psia, which is 3% above the nominal setpoint. The effects of the water-filled loop seals were ignored because they would delay the opening of the PSVs. The closing pressure of the PSVs was set to 5% below the opening setpoint (2304.6 psia).
Model 1B (Maximum Pressurizer Pressure Relief) Model 1B is the same as Model 1A except one pressurizer PORV was modeled to actuate on an indicated pressure signal of 2350 psia and the other PORV was modeled to actuate on a PID (proportional-integral-derivative) pressure signal of 100 psia from the nominal reference pressure of 2250 psia.
Model 1C (Maximum Pressurizer Pressure Relief) Model 1C is the same as Model 1B with respect to the pressurizer PORVs and sprays. However, depending on the transient, the PORVs may or may not actuate. For example, although the analysis of the Loss of Reactor Coolant Flow transient showed that the pressurizer pressure does not increase high enough to open the pressurizer PORVs, the Locked Rotor Rods-in-DNB transient analysis showed that the pressurizer PORVs do open. The PSVs were modeled, but do not actuate.
Model 2A (Minimum Pressurizer Pressure Relief) The pressurizer PORVs and pressurizer sprays were assumed to be unavailable. The two PSVs were modeled with a maximum setpoint of 2584.2 psia, which accounts for a 2.5% setpoint tolerance plus a 0.9% set pressure shift associated with the existence of water-filled loop seals (see WCAP-12910 [Reference 2]). A time delay of 0.85-second was modeled to account for the purging of the water in the PSV loop seals. For each PSV, the full-open area is based on a relief rate of 288,000 lbm/hr at 2575 psia, which is 3% above the nominal setpoint. The closing pressure of the PSVs was set to 5 psi below the opening setpoint (2579.2 psia).
Model 2B (Minimum Pressurizer Pressure Relief) Model 2B is the same as Model 2A except the pressurizer sprays were assumed to be available.

Table 2.8.5.0-3 continued
Pressure Relief Models for the RCS (Pressurizer) and MSS

Model 3A (MSS Pressure Relief)

Four MSSVs per loop were modeled with opening setpoints based on the lift settings shown below. For each MSSV, the full-open area is based on a relief rate of 845,000 lbm/hr at 1174 psia, which is 3% above the highest nominal setpoint.

MSSV Bank	Nominal Setpoint	Initial-Open Pressure of the MSSVs*	Full-Open Pressure of the MSSVs**
1	1085 psig	1166.44 psia	1178.73 psia
2	1100 psig	1181.89 psia	1194.35 psia
3	1125 psig	1207.64 psia	1220.39 psia
4	1125 psig	1207.64 psia	1220.39 psia

* Pressure includes +3% for the setpoint tolerance, +34.19 psi for the pressure drop from the inlet connection of the MSSV header to the MSSV, and +14.7 psi to convert to atmospheric pressure.

** Pressure accounts for 1.1% accumulation.

Model 3B (MSS Pressure Relief)

Same as Model 3A, except MSSV banks 3 and 4 have a nominal lift setting of 1105 psig, and 5 psi accumulation was modeled for all MSSVs.

MSSV Bank	Nominal Setpoint	Initial-Open Pressure of the MSSVs	Full-Open Pressure of the MSSVs
1	1085 psig	1166.44 psia	1171.44 psia
2	1100 psig	1181.89 psia	1186.89 psia
3	1105 psig	1187.04 psia	1192.04 psia
4	1105 psig	1187.04 psia	1192.04 psia

Model 4

No specific RCS or MSS pressure relief inputs were modeled. The pressurizer pressure and main steam pressure both decrease during this event. Thus, the pressurizer sprays, pressurizer PORVs, PSVs, and MSSVs are irrelevant.

Model 5

RCS and MSS pressure relief models were not applied because either the computer code(s) used for the analysis of this event did not include pressurizer or steam generator models, or the analysis was a hand calculation that did not involve these plant components. Refer to the accident-specific analysis discussions for additional information.

Model 6

The generic analysis used to address this event assumed that the pressurizer PORVs actuated at 2350 psia with a total maximum relief capacity of 16.65 ft^3/sec. The pressurizer spray valve setpoints assumed were the same as those specified for Model 1, but the total spray capacity was 52.2 lbm/sec. The PSVs and MSSVs were modeled and assumed to be available, but did not actuate.

Table 2.8.5.0-3 continued
Pressure Relief Models for the RCS (Pressurizer) and MSS

Model 7 No specific MSS pressure relief inputs were modeled because the secondary-side pressure transient during the event is non-limiting.			
Model 8 (Pressurizer Pressure Relief for ATWS) Pressurizer Power-Operated Relief Valves (PORVs) – The two pressurizer PORVs were modeled based on a relief rate of 179,000 lbm/hr at 2350 psia. Both PORVs were modeled to begin opening when the pressurizer pressure reached a value of 2350 psia and be full-open at a pressure of 2351 psia. Pressurizer Sprays – The pressurizer sprays were not modeled. Pressurizer Safety Valves (PSVs) – The two PSVs were modeled with an initial opening setpoint of 2500 psia (corresponding to the nominal setpoint of 2485 psig) and a full-open setpoint of 2750 psia (corresponding to 10% accumulation). For each PSV, the full-open relief rate was modeled as 288,000 lbm/hr.			
Model 9 (MSS Pressure Relief for ATWS) Four MSSVs per loop were modeled with opening setpoints based on the lift settings shown below. The relief rates at the full-open pressures for the four MSSVs were modeled as 817,000 lbm/hr, 825,000 lbm/hr, 845,000 lbm/hr, and 845,000 lbm/hr, respectively.			
MSSV Bank	**Nominal Setpoint**	**Initial-Open Pressure of the MSSVs***	**Full-Open Pressure of the MSSVs****
1	1085 psig	1133.9 psia	1138.9 psia
2	1100 psig	1148.9 psia	1153.9 psia
3	1105 psig	1153.9 psia	1158.9 psia
4	1105 psig	1153.9 psia	1158.9 psia
* Pressure includes 34.19 psi for the pressure drop from the inlet connection of the MSSV header to the MSSV and 14.7 psi to convert to atmospheric pressure. ** Pressure accounts for 5 psi accumulation.			

Table 2.8.5.0-4
Parameters Related to Overtemperature ΔT (OTΔT) and Overpower ΔT (OPΔT) Setpoints

OTΔT K_1 (safety analysis value)	1.295
OTΔT K_2	0.016/°F
OTΔT K_3	0.000811/psi
OTΔT f(ΔI) Deadband	-12%ΔI to +6%ΔI
OTΔT f(ΔI) Negative Gain	-2.69%/%ΔI
OTΔT f(ΔI) Positive Gain	+2.00%/%ΔI
T' (OTΔT & OPΔT)	576°F
P' (OTΔT & OPΔT)	2250 psia
OPΔT K_4 (safety analysis value)	1.165
OPΔT K_5	0.0/°F(1)
OPΔT K_6 (for $T_{avg} \geq T'$)	0.00123/°F
OPΔT K_6 (for $T_{avg} < T'$)	0.0/°F
Allowable Full-Power T_{avg} Range	558°F to 577°F
Pressurizer Pressure Range of Applicability for OTΔT and OPΔT	1855 psia to 2425 psia(2)

Note:
1. The K_5 term is zeroed out in the safety analyses.
2. Values correspond to bounding safety analysis limits for the low and high pressurizer pressure reactor trip setpoints.

Table 2.8.5.0-5
Summary of RPS and ESFAS Functions Actuated

FSAR Section	Event Description	RPS or ESFAS Signal(s) Actuated	Analysis Setpoint	Delay (sec)
14.1.1	Uncontrolled Rod Withdrawal from Subcritical	Power-Range High Neutron Flux Reactor Trip (Low Setting)	35%	0.5
14.1.2	Uncontrolled Rod Withdrawal at Power – Minimum DNBR Case	Overtemperature ΔT Reactor Trip	See Table 2.8.5.0-4	5.0[1]
		Power-Range High Neutron Flux Reactor Trip (High Setting)	116%	0.5
	Uncontrolled Rod Withdrawal at Power – Peak RCS Pressure Case	Power-Range High Neutron Flux Reactor Trip (High Setting)	116%	0.5
		High Pressurizer Pressure Reactor Trip	2425 psia	1.0
14.1.3	RCCA Drop	Low Pressurizer Pressure Reactor Trip	See Note 2	2.0
14.1.4	Chemical and Volume Control System Malfunction	Overtemperature ΔT Reactor Trip	See Table 2.8.5.0-4	5.0[1]
14.1.5	Startup of an Inactive Reactor Coolant Loop	N/A	N/A	N/A
14.1.6	Reduction in Feedwater Enthalpy Incident	N/A	N/A	N/A
14.1.7	Excessive Load Increase Incident	N/A	N/A	N/A
14.1.8	Complete Loss of Reactor Coolant Flow – Reference Case	Reactor Coolant Low Flow Reactor Trip	87%	1.0
	Complete Loss of Reactor Coolant Flow – Frequency Decay Case	Reactor Coolant Low Flow Reactor Trip	87%	1.0
	Complete Loss of Reactor Coolant Flow – Undervoltage Case	Reactor Coolant Pump Undervoltage Reactor Trip	See Note	2.5
	Partial Loss of Reactor Coolant Flow	Reactor Coolant Low Flow Reactor Trip	87%	1.0
	Locked Rotor – All Cases	Reactor Coolant Low Flow Reactor Trip	87%	1.0

Table 2.8.5.0-5
Summary of RPS and ESFAS Functions Actuated

FSAR Section	Event Description	RPS or ESFAS Signal(s) Actuated	Analysis Setpoint	Delay (sec)
14.1.9	Loss of External Electrical Load – Minimum DNBR Case	High Pressurizer Pressure Reactor Trip	2418 psia	1.0
	Loss of External Electrical Load – Peak RCS Pressure Case	High Pressurizer Pressure Reactor Trip	2418 psia	1.0
	Loss of External Electrical Load – Peak MSS Pressure Case	High Pressurizer Pressure Reactor Trip	2418 psia	1.0
14.1.10	Loss of Normal Feedwater	Low-Low Steam Generator Water Level Reactor Trip	20% NRS	2.0
		Low-Low Steam Generator Water Level Auxiliary Feedwater (AFW) Pump Start	20% NRS	30.0[4]
14.1.11	Loss of All AC Power to Station Auxiliaries	Low-Low Steam Generator Water Level Reactor Trip	20% NRS	2.0
		Low-Low Steam Generator Water Level Auxiliary Feedwater (AFW) Pump Start	20% NRS	60.0[4]
14.2.5	Steam System Piping Failure – Zero Power (Core response only)	Low Steam Pressure Safety Injection (SI) and Steam Line Isolation Valve Closure	335 psia (lead/lag = 12/2)	2.0
		Steam Line Isolation Valve Closure Delay Following Low Steam Pressure Signal	N/A	7.0
		Feedwater Isolation Valve Closure Delay Following SI Signal	N/A	12.0
		SI Pumps at Full Flow Following SI Signal (with/without offsite power)	N/A	13/28

Table 2.8.5.0-5
Summary of RPS and ESFAS Functions Actuated

FSAR Section	Event Description	RPS or ESFAS Signal(s) Actuated	Analysis Setpoint	Delay (sec)
14.2.5	Steam System Piping Failure – Full Power (Core response only)	Overpower ΔT Reactor Trip	See Table 2.8.5.0-4	6.0
		Reactor Trip due to SI from Low Steam Line Pressure	410 psia (lead/lag = 18/2)	2.0
		Reactor Trip due to SI from High Containment Pressure	6.0 psig	2.0
14.2.6	Rupture of a Control Rod Mechanism Housing (RCCA Ejection)	Power-Range High Neutron Flux Reactor Trip (Low and High Settings)	35% (low setting)	0.5
			118% (high setting)	0.5
N/A	ATWS	ATWS Mitigation System Actuation Circuitry (AMSAC) – Turbine Trip (TT), AFW Pump Start	N/A	30 (TT) 90 (AFW)

Notes:

1. The overtemperature ΔT reactor trip response time was modeled with a first order lag of 3 seconds and a pure delay of 2 seconds. The 3-second lag accounts for delays associated with fluid transport, thermal lag, and RTD (resistance temperature detector) response time. The 2-second delay accounts for delays associated with the protection system electronics, reactor trip breaker opening, and RCCA gripper release.
2. The generic two-loop RCCA drop analysis, which is applicable to PBNP, modeled the low pressurizer pressure reactor trip setpoint as a "convenience trip." The cases that actuated this function assumed dropped rod and control bank worth combinations that were non-limiting with respect to DNB. The fact that the plant-specific low pressurizer pressure reactor trip setpoint (1855 psia) is lower than the value assumed in the generic analysis (1860 psia) does not invalidate the applicability of the generic two-loop RCCA drop analysis to PBNP. Therefore, the low pressurizer pressure reactor trip setpoint value that was used in the generic two-loop RCCA drop analysis (1860 psia) does not represent an analytical limit for this function for PBNP.
3. To bound the loss of flow events initiated by a loss of bus voltage, the reactor coolant low flow reactor trip was conservatively modeled in the Complete Loss of Reactor Coolant Flow reference case. In this reference case, the reactor trip on low flow signal occurs 2.93 seconds into the transient. This case is equivalent to an undervoltage case with a reactor coolant pump power supply undervoltage reactor trip delay of 2.93 seconds. For a Westinghouse designed plant, a typical undervoltage trip delay is 1.5 seconds which has the following typical breakdown.

Table 2.8.5.0-5
Summary of RPS and ESFAS Functions Actuated

FSAR Section	Event Description	RPS or ESFAS Signal(s) Actuated	Analysis Setpoint	Delay (sec)
	Undervoltage trip circuitry including adjustable delay preventing spurious trip	0.95 second		
	EMF decay	0.25 second		
	Trip breaker opening	0.15 second		
	RCCA release time	0.15 second		
	TOTAL DELAY TIME	1.50 seconds		
	To support an increase in the adjustable delay that is used to help prevent spurious undervoltage reactor trips, the Complete Loss of Reactor Coolant Flow reference case was performed without crediting the reactor coolant pump power supply undervoltage reactor trip. Also, note that the reference case analysis conservatively assumes that the pump coastdown begins immediately at time zero, even though a voltage reduction will not cause the pump speed to drop as the EMF decays to the undervoltage setpoint.			
4.	The delay value represents the time of initial AFW flow delivery after the ESFAS setpoint is reached. Following this initial delay, the AFW flow was modeled to increase linearly from 0% to 80% of full flow over the next 30 seconds, and then increase linearly from 80% to 100% of full flow over the subsequent 60 seconds.			

Table 2.8.5.0-6
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] 0.0 (> 70% RTP)	N/A
Moderator Density Coefficient, k/(g/cc)	N/A	0.43
Doppler Temperature Coefficient, pcm/°F	-0.91	-2.90
Doppler-Only Power Coefficient, pcm/%power (Q = power in %)	-9.55 + 0.035Q	-21.5 + 0.068Q
Delayed Neutron Fraction	0.0072 (maximum)	0.0043 (minimum)
Minimum Doppler Power Defect, pcm		
– RCCA Ejection	1000	945 (HFP) 980 (HZP)
– RCCA Withdrawal from Subcritical	1100	N/A
Note: 1. RTP = Rated Thermal Power		

Table 2.8.5.0-7
Summary of Initial Conditions and Computer Codes Used

Event	Computer Codes Used	DNB Correlation	RTDP	Initial Power, %	Vessel Coolant Flow, gpm	Vessel Average Coolant Temp, °F	RCS Pressure, psia
Uncontrolled Rod Withdrawal from Subcritical	TWINKLE FACTRAN VIPRE	W-3(1) WRB-1(2)	No	0 (1800 MWt - Core power)	79,922(3)	547	2200
Uncontrolled Rod Withdrawal at Power – Minimum DNBR Cases	RETRAN VIPRE	WRB-1	Yes	100, 60, 10 (1806 MWt - NSSS power)	186,000	578.4 (100%) 566.4 (60%) 551.4 (10%)	2250
Uncontrolled Rod Withdrawal at Power – Peak RCS Pressure Cases	RETRAN	N/A	No	100.6, 70, 55, 50, 45, 40, 35, 25, 8 (1806 MWt – NSSS power)	178,000	583.4 (100.6%) 574.4 (70%) 569.9 (55%) 568.4 (50%) 566.9 (45%) 565.4 (40%) 563.9 (35%) 560.9 (25%) 555.8 (8%)	2200
RCCA Drop	LOFTRAN(4) ANC VIPRE	WRB-1	Yes	100 (1800 MWt – Core power)	186,000	577.0	2250
Chemical and Volume Control System Malfunction	N/A	N/A	N/A	100 (Mode 1) 5 (Mode 2) 0 (Modes 5 & 6) (1800 MWt – Core power)	N/A	583.4 (Mode 1) 554.9 (Mode 2) 200.0 (Mode 5) 140.0 (Mode 6)	2250 (Mode 1) 2250 (Mode 2) 14.7 (Modes 5 & 6)
Startup of an Inactive Reactor Coolant Loop	See Licensing Report Section 2.8.5.4.4						
Reduction in Feedwater Enthalpy Incident	Bounded by the Excessive Load Increase Incident (see Section 2.8.5.1.1)						
Excessive Load Increase Incident	RETRAN	WRB-1	Yes	100 (1806 MWt – NSSS Power)	186,000	578.4	2250
Loss of Reactor Coolant Flow – All Cases	RETRAN SPNOVA VIPRE(5)	WRB-1	Yes	100 (1806 MWt - NSSS power)	186,000	578.4	2250

Table 2.8.5.0-7
Summary of Initial Conditions and Computer Codes Used

Event	Computer Codes Used	DNB Correlation	RTDP	Initial Power, %	Vessel Coolant Flow, gpm	Vessel Average Coolant Temp, °F	RCS Pressure, psia
Locked Rotor – DNB Case	RETRAN SPNOVA VIPRE[5]	WRB-1	Yes	100 (1806 MWt - NSSS power)	186,000	578.4	2250
Locked Rotor – Peak RCS Pressure Case	RETRAN SPNOVA VIPRE[5]	N/A	No	100.6 (1806 MWt - NSSS power)	178,000	583.4	2300
Loss of External Electrical Load – Minimum DNBR Case	RETRAN	WRB-1	Yes	100 (1806 MWt - NSSS power)	186,000	578.4	2250
Loss of External Electrical Load – Peak RCS Pressure Case	RETRAN	N/A	No	100.6 (1806 MWt - NSSS power)	178,000	577.0 (Unit 1)[6] 583.4 (Unit 2)[6]	2200
Loss of External Electrical Load – Peak MSS Pressure Case	RETRAN	N/A	No	100.6 (1806 MWt - NSSS power)	178,000	583.4	2200
Loss of Normal Feedwater	RETRAN	N/A	No	100.6 (1806 MWt - NSSS power)	178,000	570.6 (Unit 1) 570.6 (Unit 2)	2300 (Unit 1) 2300 (Unit 2)
Loss of All AC Power to Station Auxiliaries	RETRAN	N/A	No	100.6 (1806 MWt - NSSS power)	178,000	570.6 (Unit 1) 570.6 (Unit 2)	2300 (Unit 1) 2200 (Unit 2)
Steam System Piping Failure – Zero Power (Core response only)	RETRAN ANC VIPRE	W-3	No	0 (1806 MWt - NSSS power)	178,000	547.0	2250
Steam System Piping Failure – Full Power (Core response only)	RETRAN ANC VIPRE	WRB-1	Yes	100 (1806 MWt - NSSS power)	186,000	578.4	2250

Table 2.8.5.0-7
Summary of Initial Conditions and Computer Codes Used

Event	Computer Codes Used	DNB Correlation	RTDP	Initial Power, %	Vessel Coolant Flow, gpm	Vessel Average Coolant Temp, °F	RCS Pressure, psia
Rupture of a Control Rod Mechanism Housing (RCCA Ejection)	TWINKLE FACTRAN	N/A	No	102 (HFP) 0 (HZP) (1800 MWt - Core power)	178,000 (HFP) 79,922 [3] (HZP)	583.4 (HFP) 547.0 (HZP)	2200
ATWS	LOFTRAN	N/A	N/A	100 (1806 MWt - NSSS power)	178,000	577.0	2250

Notes:
1. Below the first mixing vane grid.
2. Above the first mixing vane grid.
3. Flow from one loop = 0.449 * TDF.
4. The LOFTRAN portion of the analysis was generic; the DNB evaluation performed with VIPRE utilized the plant-specific values presented.
5. The RETRAN, SPNOVA and VIPRE computer codes were applied in the analyses for these events in a manner consistent with the methodology described in Reference 19. See Appendix A.8, for additional discussion of the application of these codes with the Reference 19 methodology
6. Unit-specific sensitivity studies were performed to address the issue of NSAL-03-1 (Reference 21) related to the initial vessel average coolant temperature applied in analyses of the Loss of Load / Turbine Trip event. For Unit 1, the peak RCS pressure result is slightly more limiting (< 2 psi) when the initial vessel average coolant temperature is at the nominal value of 577°F versus the value of 583.4°F that accounts for uncertainties. In contrast, the Unit 2 peak RCS pressure result is slightly more limiting (< 1 psi) with an initial vessel average coolant temperature of 583.4°F.

Table 2.8.5.0-8

Non-LOCA Transients Evaluated or Analyzed[3]

Event	Report Section	FSAR Section	Notes
Reduction in Feedwater Enthalpy Incident	2.8.5.1.1	14.1.6	2
Excessive Load Increase Incident	2.8.5.1.1	14.1.7	1
Rupture of a Steam Pipe – Zero Power Core Response	2.8.5.1.2	14.2.5	1
Rupture of a Steam Pipe – Full Power Core Response	2.8.5.1.2	14.2.5	1
Loss of External Electrical Load, Turbine Trip, and Loss of Condenser Vacuum	2.8.5.2.1	14.1.9	1
Loss of All AC Power to Station Auxiliaries	2.8.5.2.2	14.1.11	1
Loss of Normal Feedwater	2.8.5.2.3	14.1.10	1
Feedwater System Pipe Break	2.8.5.2.4	N/A	4
Partial Loss of Forced Reactor Coolant Flow	2.8.5.3.1	14.1.8	1
Complete Loss of Forced Reactor Coolant Flow	2.8.5.3.1	14.1.8	1
Locked Rotor/Shaft Break	2.8.5.3.2	14.1.8	1
Uncontrolled Rod Withdrawal from Subcritical	2.8.5.4.1	14.1.1	1
Uncontrolled Rod Withdrawal at Power	2.8.5.4.2	14.1.2	1
RCCA Drop	2.8.5.4.3	14.1.4	1
Startup of an Inactive Reactor Coolant Loop	2.8.5.4.4	14.1.5	2
Chemical and Volume Control System Malfunction (Boron Dilution)	2.8.5.4.5	14.1.4	1
Rupture of a Control Rod Mechanism Housing (RCCA Ejection)	2.8.5.4.6	14.2.6	1
Inadvertent Operation of the Emergency Core Cooling System During Power Operation	2.8.5.5	N/A	4
Inadvertent Opening of a Pressurizer Safety or Relief Valve	2.8.5.6.1	N/A	4
ATWS	2.8.5.7	N/A	1

Notes:

1. Complete analysis
2. Evaluation
3. All analyses and evaluations cover Units 1 and 2
4. Transient is not considered part of the PBNP licensing basis

Table 2.8.5.0-9
Key Safety Analysis Input Changes Made in Support of the PBNP EPU Program

Event	Safety Analysis Input Parameter	New (EPU) Value	Old Value
Uncontrolled Rod Withdrawal at Power	*OTΔT Reactor Trip Setpoint*	*See Table 2.8.5.0-4*	*See Current COLR* and safety analysis K_1 value of 1.255
	OTΔT Reactor Trip Setpoint Delay Time	5 seconds (see Table 2.8.5.0-5)	6 seconds
	Power-Range High Neutron Flux Reactor Trip Setpoint (High Setting)	116%	118%
	High Pressurizer Pressure Reactor Trip Delay Time	1 second	2 seconds
	Lead Time Constant for Lead/Lag Compensator on Measurement of Reactor Vessel T_{avg}	40 seconds	25 seconds
	Lag Time Constant for Lead/Lag Compensator on Measurement of Reactor Vessel T_{avg}	8 seconds	3 seconds
Complete Loss of Reactor Coolant Flow	Reactor Coolant Pump Undervoltage Reactor Trip Delay Time	Not Credited See Note 2	2.5 seconds
Loss of External Electrical Load	High Pressurizer Pressure Reactor Trip Setpoint	2418 psia	2425 psia
	High Pressurizer Pressure Reactor Trip Delay Time	1 second	2 seconds
	Pressurizer Safety Valve Positive Setpoint Tolerance	+2.5%	+3.0%
	Nominal Setpoint for the 3rd and 4th Banks of MSSVs	1105 psig	1125 psig
	MSSV Setpoint Accumulation	5 psi	1.1%

Table 2.8.5.0-9
Key Safety Analysis Input Changes Made in Support of the PBNP EPU Program

Event	Safety Analysis Input Parameter	New (EPU) Value	Old Value
Loss of Normal Feedwater	Low-Low Steam Generator Water Level Reactor Trip/AFW Pump Start Setpoint	20% NRS	17% NRS
	Low-Low Steam Generator Water Level AFW Pump Start Delay Time	30 seconds[(1)]	300 seconds
	Full AFW Flow Rate	275 gpm	200 gpm
	Pressurizer Backup Heater Actuation on Pressurizer Water Level Deviation	Not Modeled	Modeled
	Reactor Coolant System Thick Metal Mass Heat Transfer Model	Credited	Not Credited
Loss of All AC Power to Station Auxiliaries	Low-Low Steam Generator Water Level Reactor Trip/AFW Pump Start Setpoint	20% NRS	17% NRS
	Low-Low Steam Generator Water Level AFW Pump Start Delay Time	60 seconds[(1)]	300 seconds
	Full AFW Flow Rate	275 gpm	200 gpm
	Pressurizer Backup Heater Actuation on Pressurizer Water Level Deviation	Not Modeled	Modeled
	Reactor Coolant System Thick Metal Mass Heat Transfer Model	Credited	Not Credited
Steam System Piping Failure	OTΔT Reactor Trip Setpoint	See Table 2.8.5.0-4	See Current COLR and safety analysis K_4 value of 1.14
	Low Steam Line Pressure Safety Injection Setpoint	410 psia	335 psia
	Lead Time Constant for Lead/Lag Compensator on Measurement of Steam Line Pressure	18 seconds	12 seconds
	Hi-1 Containment Pressure Safety Injection Setpoint (for steam line breaks inside containment at full power)	6.0 psig (Credited)	N/A (Not Credited)

Table 2.8.5.0-9
Key Safety Analysis Input Changes Made in Support of the PBNP EPU Program

Event	Safety Analysis Input Parameter	New (EPU) Value	Old Value
Miscellaneous	Low Pressurizer Pressure Reactor Trip Setpoint	1855 psia	1775 psia
	Reactor Vessel T_{avg} RTD Temperature Range	530-630°F	520-620°F
	Reactor Trip Permissive P-8	45% RTP	60% RTP

Note:

1. This value represents the time of initial AFW flow delivery after the ESFAS setpoint is reached. Following this initial delay, the AFW flow was modeled to increase linearly from 0% to 80% of full flow over the next 30 seconds, and then increase linearly from 80% to 100% of full flow over the subsequent 60 seconds.
2. This reactor trip delay time is not credited in the reference Complete Loss of Reactor Coolant Flow analysis (See Section 2.8.5.3.1).

Figure 2.8.5.0-1 Reactor Core Safety Limits

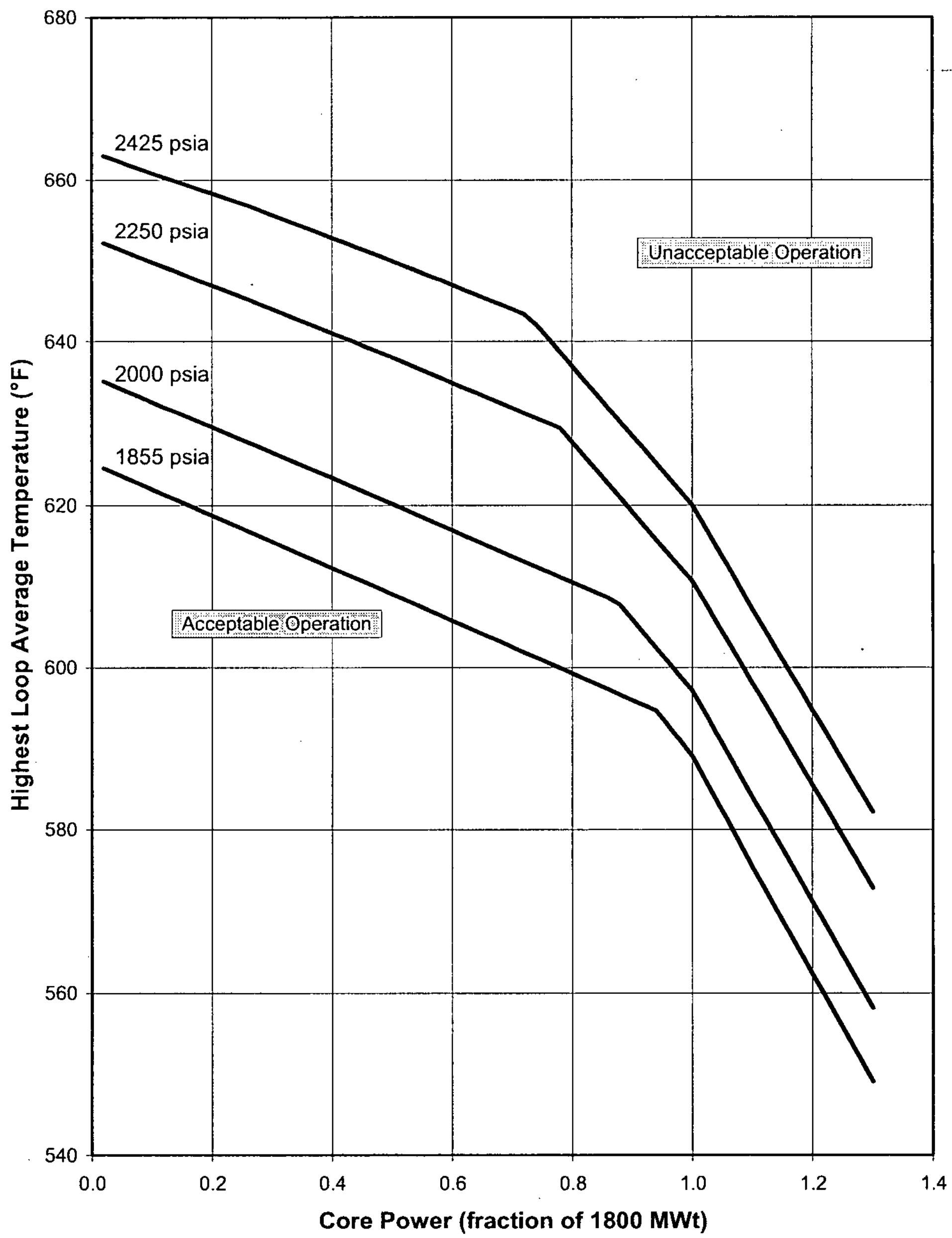


Figure 2.8.5.0-2 Illustration of OTΔT and OPΔT Protection

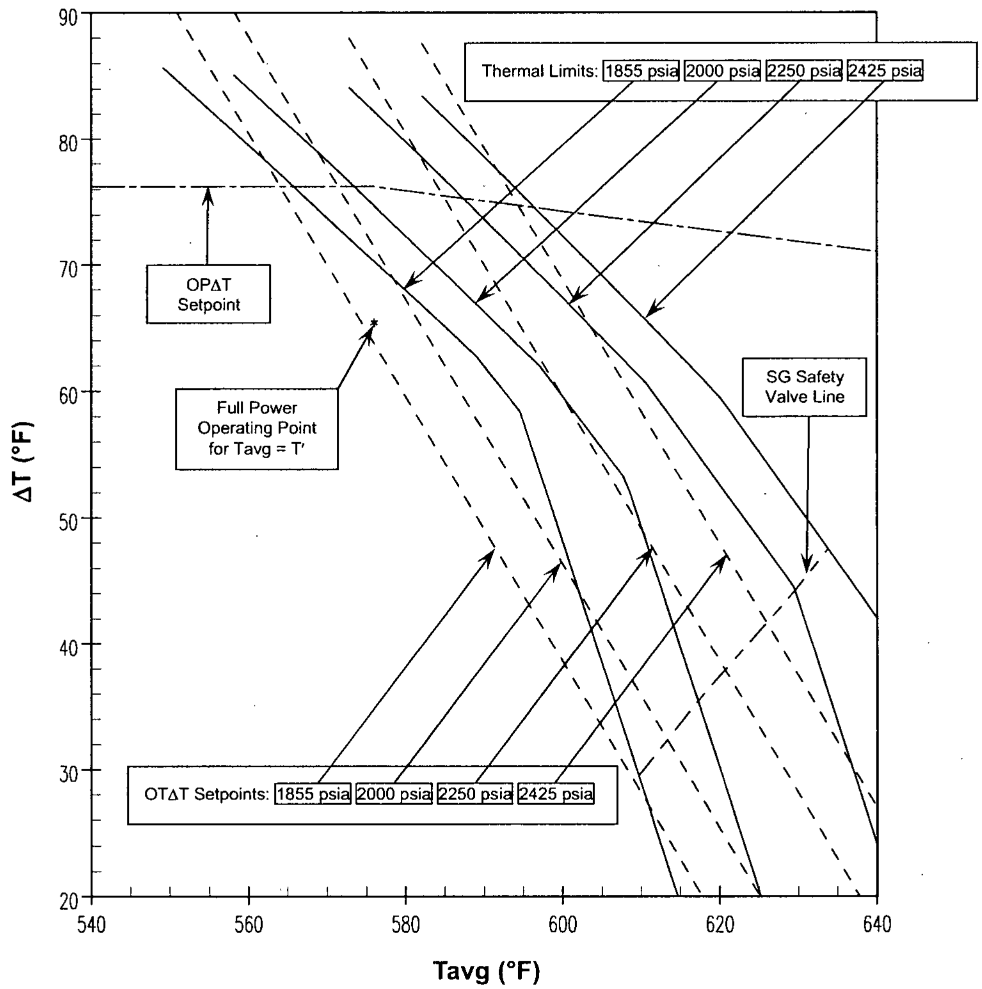


Figure 2.8.5.0-3 Fractional Rod Insertion Versus Time from Release.

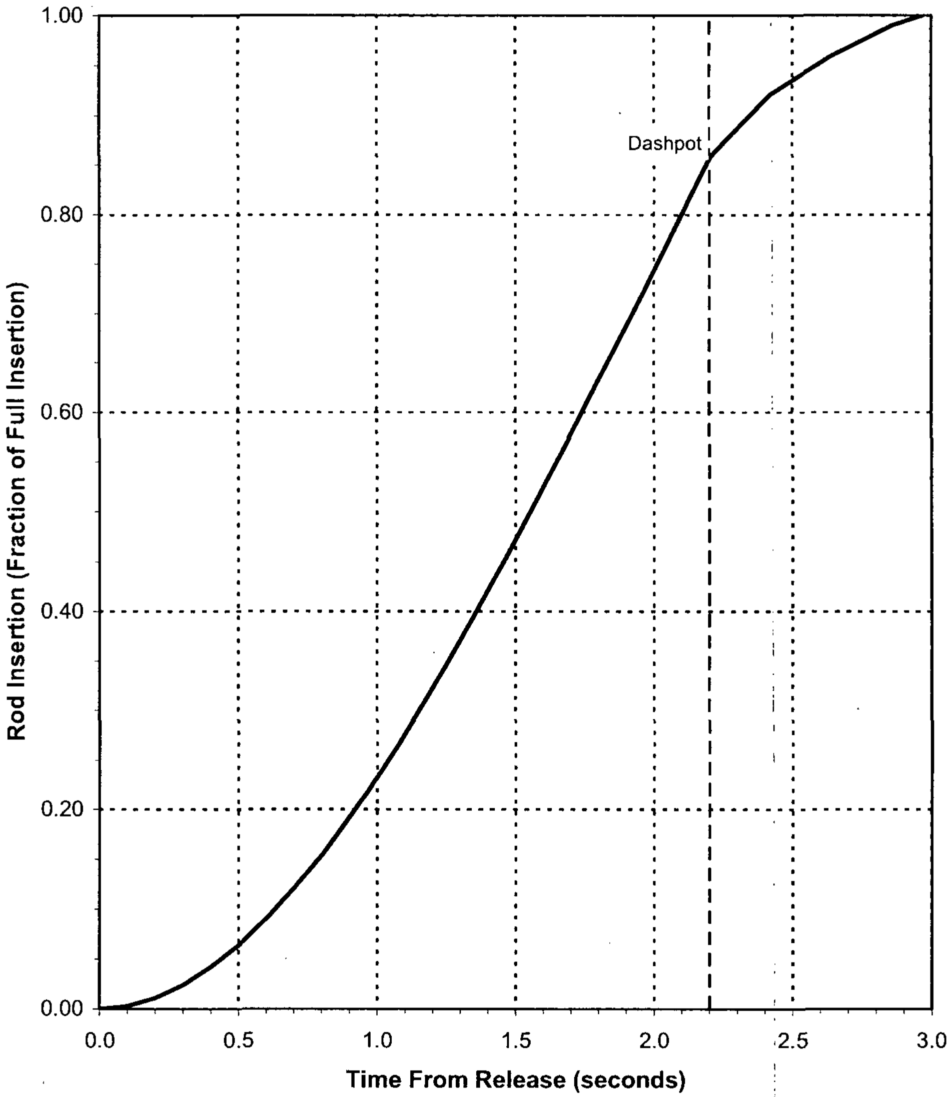


Figure 2.8.5.0-4 Normalized RCCA Reactivity Worth Versus Fractional Rod Insertion

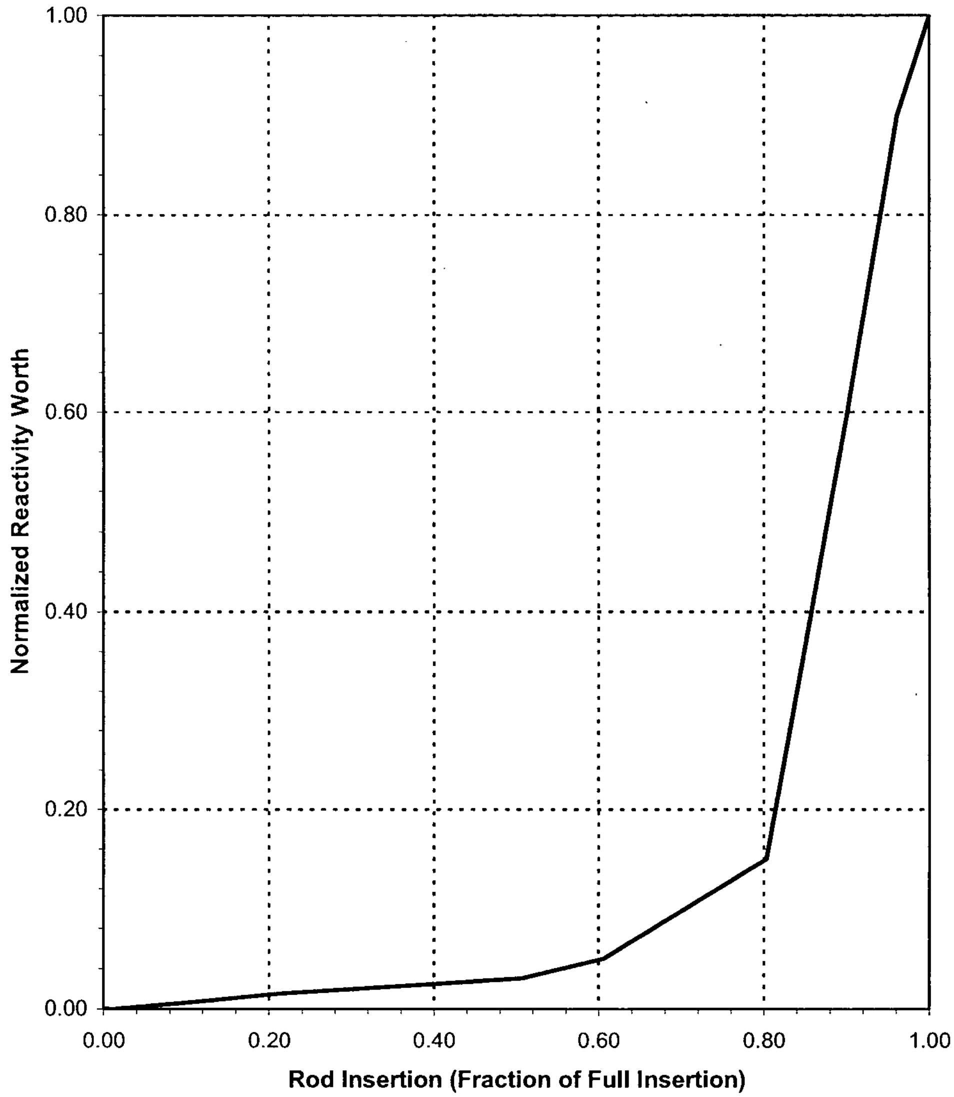


Figure 2.8.5.0-5 Normalized RCCA Reactivity Worth Versus Time from Release

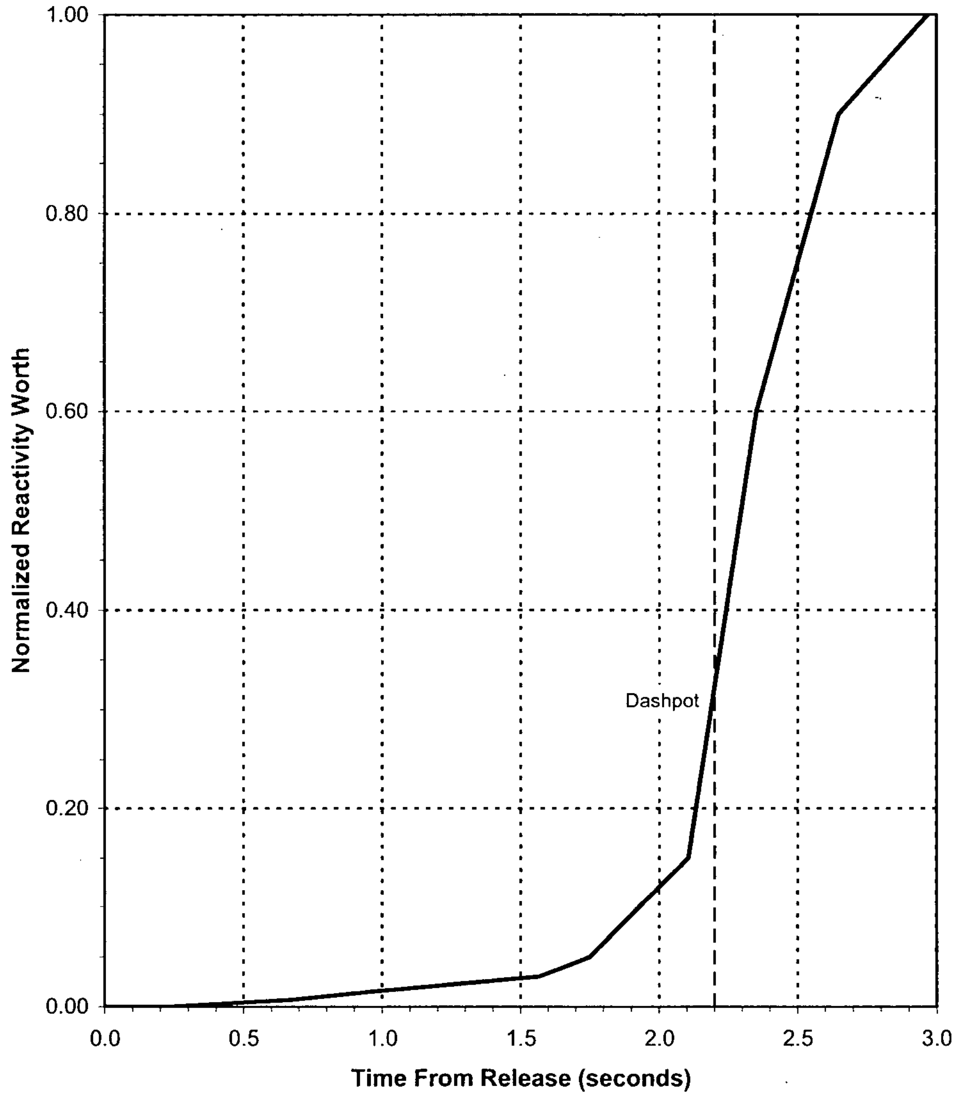
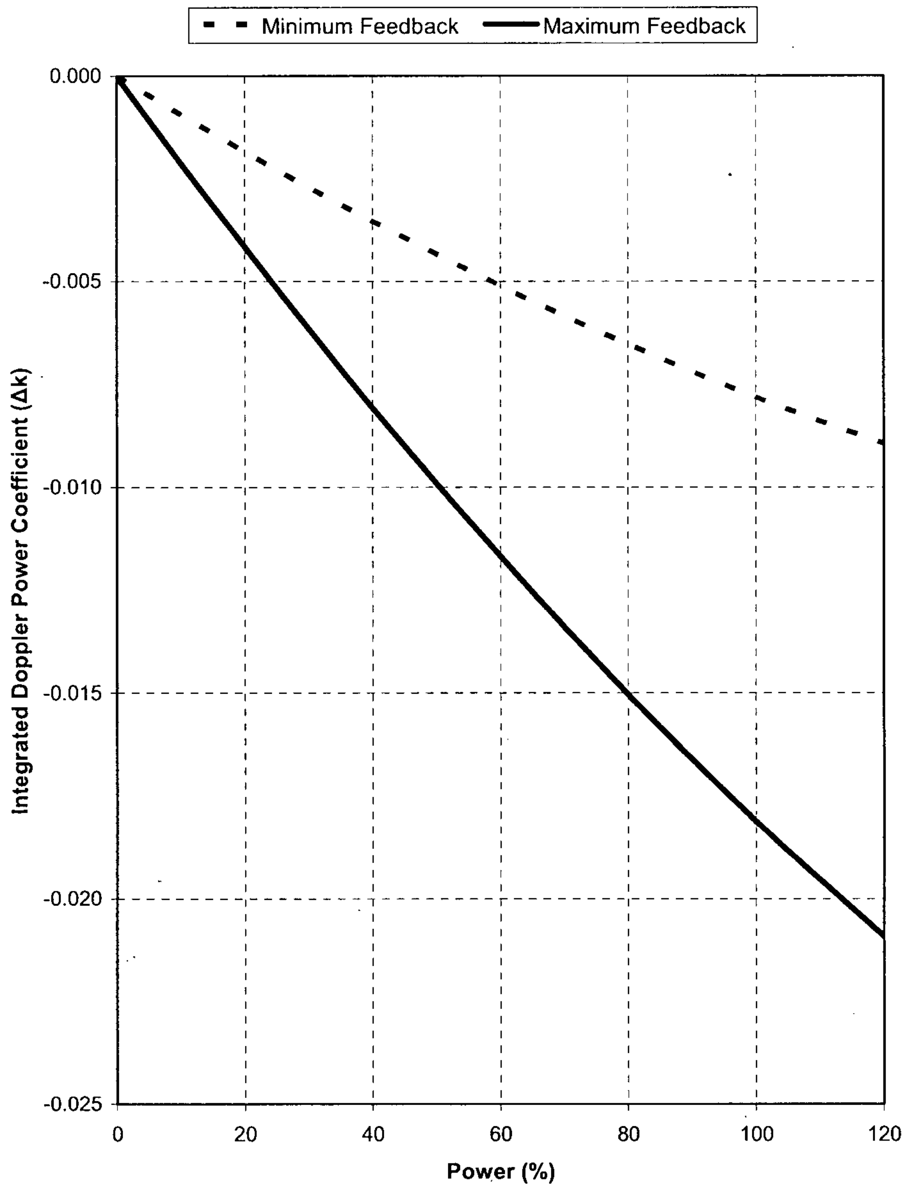


Figure 2.8.5.0-6 Integrated DPC Used in Non-LOCA Transient Analyses



2.8.5.1 Increase in Heat Removal by the Secondary System

2.8.5.1.1 Reduction In Feedwater Enthalpy, Increase In Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of a Steam Generator Relief or Safety Valve

2.8.5.1.1.1 Regulatory Evaluation

Excessive heat removal causes a decrease in moderator temperature that increases core reactivity and can lead to a power level increase and a decrease in shutdown margin. Any unplanned power level increase can result in fuel damage or excessive reactor system pressure. Reactor protection and safety systems are actuated to mitigate the transient. The PBNP review covered:

- The postulated initial core and reactor conditions
- The methods of thermal-hydraulic analyses
- The sequence of events
- The assumed reactions of reactor system components
- The functional and operational characteristics of the reactor protection system
- The operator actions
- The results of the transient analyses

The NRC's acceptance criteria are based on:

- GDC 10, insofar as it requires that the reactor coolant system (RCS) is designed with appropriate margin to ensure that specified acceptable fuel design limits are not exceeded during normal operations including anticipated operational occurrences
- GDC 15, insofar as it requires that the RCS and its associated auxiliary systems are designed with sufficient margin to ensure that the design condition of the reactor coolant pressure boundary is not exceeded during any condition of normal operation
- GDC 20, insofar as it requires that the reactor protection system is designed to automatically initiate the operation of appropriate systems, including the reactivity control systems, to ensure that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including anticipated operational occurrences
- GDC 26, insofar as it requires that a reactivity control system is provided, and is capable of reliably controlling the rate of reactivity changes to ensure that under normal operating conditions, including anticipated operational occurrences, specified acceptable fuel design limits are not exceeded

Specific review criteria are contained in the SRP, Section 15.1.1-4 and other guidance provided in Matrix 8 of RS-001, Revision 0.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Energy Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP specific GDC for excessive heat removal by the secondary system events are as follows:

CRITERION: The reactor core with its related controls and protection systems shall be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits which have been stipulated and justified. The core and related auxiliary system designs shall provide this integrity under all expected conditions of normal operation with appropriate margins for uncertainties and for specified transient situations which can be anticipated. (PBNP GDC 6)

As described in FSAR Section 3.1.2.1, Reactor Core Design, the reactor core, with its related control and protection system, is designed to function throughout its design lifetime without exceeding acceptable fuel damage limits.

Fuel design and nuclear design are further discussed in LR Section 2.8.1 and LR Section 2.8.2, respectively.

CRITERION: Core protection systems, together with associated equipment, shall be designed to prevent or to suppress conditions that could result in exceeding acceptable fuel damage limits. (PBNP GDC 14)

As described in FSAR Section 7.1.2, Instrumentation and Control, General Design Criteria, if the reactor protection system sensors detect conditions which indicate an approach to unsafe operating conditions that require core protection, the system actuates alarms, prevents control rod motion, initiates load runback, and initiates reactor trip by opening the reactor trip breakers.

CRITERION: Two independent reactivity control systems, preferably of different principles, shall be provided. (PBNP GDC 27)

In addition to the reactivity control achieved by the rod cluster control (RCC) described in FSAR Section 3.1, Reactor, Design Basis, reactivity control is provided by the Chemical and Volume Control System (CVCS) which regulates the concentration of boric acid solution neutron absorber in the reactor coolant system. The system is designed to prevent uncontrolled or inadvertent reactivity changes which might cause system parameters to exceed design limits.

CRITERION: The reactivity control system provided shall be capable of making and holding the core subcritical from any hot standby or hot operating condition. (PBNP GDC 28)

The reactivity control systems provided are capable of making and holding the core subcritical from any hot standby or hot operating condition, including conditions resulting from power changes. The rod cluster control assemblies (RCCAs) are divided into two categories comprising control and shutdown groups. The control group, used in combination with chemical shim, provides control of the reactivity changes of the core throughout the life of the core at power conditions. The chemical shim control (CVCS) is normally used to compensate for the more slowly occurring changes in reactivity throughout core life such as those due to fuel depletion, fission product buildup and decay, and load follow.

CRITERION: The reactivity control systems provided shall be capable of making the core subcritical under credible accident conditions with appropriate margins for contingencies and limiting any subsequent return to power such that there will be no undue risk to the health and safety of the public. (PBNP GDC 30)

Normal reactivity shutdown capability is provided by control rods, with boric acid injection from the CVCS system used to compensate for the xenon transients, and for plant cooldown. When the plant is at power, the quantity of boric acid retained in the boric acid tanks and/or the refueling water storage tank (RWST) and ready for injection will always exceed that quantity required for the normal cold shutdown. This quantity will always exceed the quantity of boric acid required to bring the reactor to hot shutdown and to compensate for subsequent xenon decay.

The injection of boric acid is shown to afford backup reactivity shutdown capability, independent of control rod clusters which normally serve this function in the short term situation. Shutdown for long term and reduced temperature conditions can be accomplished with boric acid injection using redundant components.

The reactivity control provided by the CVCS is further discussed in FSAR Section 9.3, Chemical and Volume Control System.

CRITERION: The reactor coolant pressure boundary shall be capable of accommodating without rupture the static and dynamic loads imposed on any boundary component as a result of an inadvertent and sudden release of energy to the coolant. As a design reference, this sudden release shall be taken as that which would result from a sudden reactivity insertion such as rod ejection (unless prevented by positive mechanical means), rod dropout, or cold water addition. (PBNP GDC 33)

The reactor coolant boundary is shown to be capable of accommodating, without rupture, the static and dynamic loads imposed as a result of a sudden reactivity insertion such as a rod ejection. The operation of the reactor is such that the severity of an ejection accident is inherently limited. Since control rod clusters are primarily used to control load variations and boron dilution is used primarily to compensate for core depletion, only the rod cluster control assemblies in the controlling groups are inserted in the core at power, and at full power these rods are only partially inserted. A rod insertion limit monitor is provided as an administrative aid to the operator to insure that this condition is met.

Further analysis of this event is discussed in FSAR Section 14.1.6, Reduction in Feedwater Enthalpy Incident, and Section 14.1.7, Excessive Load Increase Incident.

In addition to the evaluations described in the FSAR, PBNP's systems and components were evaluated for license renewal. Systems and system component materials of construction, operating history, and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 1)

During plant license renewal evaluations, components associated with the control and mitigation of transients that could result in an increase in heat removal by the secondary system were evaluated within the system that contained them.

2.8.5.1.1.2 Technical Evaluation

2.8.5.1.1.2.1 Decrease in Feedwater Temperature

2.8.5.1.1.2.1.1 Introduction

Opening of a low-pressure heater bypass valve causes a reduction in feedwater temperature that increases the thermal load on the primary system. For this event, there is a sudden reduction in feedwater temperature into the steam generators.

At power, the increased subcooling caused by the reduced feedwater temperature creates a greater load demand on the RCS. With the plant at no-load conditions, the addition of cold feedwater may cause a decrease in RCS temperature, and thus a reactivity insertion due to the effects of the negative moderator temperature coefficient. However, since the rate of energy change is reduced as the load and feedwater flow decrease, the no-load transient is less severe than the full-power case.

Depending on the magnitude of the temperature reduction and the operation of the automatic rod control system, the net effect on the RCS can be similar to the effect of increasing secondary steam flow; that is, the reactor will reach a new equilibrium condition at a power level corresponding to the new temperature difference across the secondary-side of the steam generator. For large feedwater temperature reductions, the overpower-overtemperature protection function will prevent a power increase that could lead to a DNBR that is lower than the safety analysis limit value.

2.8.5.1.1.2.1.2 Input Parameters, Assumptions and Acceptance Criteria

The decrease in feedwater temperature event is evaluated to confirm that the Departure from Nucleate Boiling Ratio (DNBR) and fuel centerline temperature design bases are met. The following assumptions are made:

- The evaluations were performed to support an uprated core power of 1800 MWt (nuclear steam supply system (NSSS) power of 1806 MWt).
- A low pressure heater bypass valve opens, resulting in condensate flow splitting between the bypass line and the low pressure heaters; the flow through each path is proportional to the pressure drops.

Based on its frequency of occurrence, the decrease in feedwater temperature event is considered to be 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 (Reference 4). As such, the applicable acceptance criteria for this incident are:

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

- Fuel cladding integrity is maintained by ensuring that the minimum DNBR remains greater than the 95/95 DNBR safety analysis limit in the limiting fuel rods and that the centerline temperature of the fuel rods with the peak linear heat rate (kW/ft) does not exceed the UO_2 melting temperature. Fuel melting is precluded by ensuring that the maximum transient core average thermal power does not exceed a value that would result in exceeding the kW/ft value corresponding to fuel centerline melting at the core hot spot.
- An incident of moderate frequency should not generate a more serious plant condition without other faults occurring independently. Demonstrating that the pressurizer does not become water-solid ensures a more serious plant condition is not generated. Since this event results in a cooldown of the RCS, the reactor coolant experiences a reduction in volume, and therefore pressurizer filling is not a concern.

2.8.5.1.1.2.1.3 Description of Analyses and Evaluation

A decrease in feedwater enthalpy can be caused by an accidental opening of the low pressure feedwater heater bypass valve or a load reduction. Opening the low-pressure feedwater heater bypass valve results in a maximum feedwater temperature reduction of 40°F. It has been determined that the excessive increase in steam flow event (a step-load increase of 10% from full load), which is discussed in LR Section 2.8.5.1.1.2.3, Increase in Steam Flow, is equivalent to a 69°F reduction in the feedwater temperature. Therefore, the consequences of a feedwater temperature reduction of up to 69°F are equivalent to or bounded by the consequences of a 10% load increase from full power.

2.8.5.1.1.2.1.4 Decrease in Feedwater Temperature Results

The reduction in feedwater enthalpy transient was evaluated for PBNP for the EPU program. It has been determined that the decrease in feedwater enthalpy incident is less severe than the excessive load incident (Section 2.8.5.1.1.2.3, Increase in Steam Flow) which assumes a 10% step increase in secondary load. Based on the results presented in that section, the acceptance criteria for this event have been met at EPU conditions.

2.8.5.1.1.2.2 Increase in Feedwater Flow

This event is not part of the PBNP licensing basis.

2.8.5.1.1.2.3 Increase in Steam Flow

2.8.5.1.1.2.3.1 Introduction

An excessive load increase incident (ELI) is defined as a rapid increase in steam flow that causes a power mismatch between the reactor core power and the steam generator load demand. The reactor control system (RCS) is designed to accommodate a 10% step-load increase and/or a 5% per minute ramp-load increase (without a reactor trip) in the range of 15 to 100% of full power. Any loading rate in excess of these values can cause a reactor trip actuated by the reactor protection system. If the load increase exceeds the capability of the reactor control system, the transient would be terminated in sufficient time to prevent the DNB design basis from being violated.

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

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

Regardless of the rate of load increase, the reactor protection system will trip the reactor in time to prevent the DNBR from going below the limit value. Increases in steam load to more than design flow are analyzed as the steam line rupture event in LR Section 2.8.5.1.2, Steam System Piping Failures Inside and Outside Containment.

Protection against an ELI accident, if necessary, is provided by the following reactor protection system signals:

- Overtemperature ΔT (OTΔT)
- Overpower ΔT (OPΔT)
- Power range high neutron flux
- Low pressurizer pressure

2.8.5.1.1.2.3.2 Input Parameters, Assumptions, and Acceptance Criteria

The analysis includes the following conservative assumptions:

- This accident is analyzed with the Revised Thermal Design Procedure (RTDP) (Section 2.8.5.1.1.2.4). Initial reactor power, RCS pressure, and RCS temperature are assumed to be at their nominal values, consistent with steady-state full-power operation
- The PBNP EPU has a vessel average temperature (T_{avg}) range from 558.0°F to 577.0°F. The higher value (including the 1.4°F bias) is used since it is more limiting with respect to minimum DNBR
- The PBNP EPU has a feedwater temperature range from 390.0°F to 458.0°F. The ELI event is not very sensitive to feedwater temperature; however, the higher feedwater temperature is assumed
- Minimum measured flow (MMF) is assumed. Uncertainties in initial conditions are included in the DNBR limit as described in Reference 2
- 0% steam generator tube plugging (SGTP) is assumed; this maximizes primary-to-secondary heat transfer and results in a more severe RCS cooldown transient
- The pressurizer heaters are not credited

- The pressurizer sprays and power operated relief valves (PORVs) are modeled to reduce RCS pressure resulting in a conservative calculation of the margin to the DNBR limit
- Although the high neutron flux, overtemperature ΔT, overpower ΔT, and low pressurizer pressure reactor trips are available to mitigate the ELI event, the analysis conservatively does not credit these trips
- The analysis is performed for a step-load increase of 10% steam flow from 100% of nuclear steam supply system (NSSS) thermal power
- This event is analyzed in both automatic and manual modes of rod control, i.e. no rod motion
- No credit is taken for the heat capacity of the RCS and steam generator metal mass in attenuating the resulting plant cooldown
- The ELI event is analyzed for both the beginning-of-life (BOL) (minimum reactivity feedback) and end-of-life (EOL) (maximum reactivity feedback) conditions. The physics data used for each case are:

  a. Moderator Density Coefficient – a least positive value is assumed with minimum reactivity feedback cases and a most positive value is assumed for maximum reactivity feedback cases

  b. Moderator Temperature Coefficient – a least negative value is assumed for minimum reactivity feedback cases and a most negative value is assumed for maximum reactivity feedback cases

  c. Doppler Power Coefficient – a least negative value is assumed for minimum reactivity feedback cases and a most negative value is assumed for maximum reactivity feedback cases

  d. Delayed Neutron Fraction – a maximum value is assumed for minimum reactivity feedback cases and a minimum value is assumed for maximum reactivity feedback cases

Based on its frequency of occurrence, the ELI accident is considered a Condition II event as defined by the American Nuclear Society (ANS) (Reference 4). The following items summarize the 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 limit value at any time during the transient.
- Pressure in the RCS and main steam systems (MSS) should be maintained below 110% of the design pressures.
- The peak linear heat generation rate (expressed in kW/ft) should not exceed a value that would cause fuel centerline melt.
- An incident of moderate frequency does not generate a more serious plant condition without other faults occurring independently. This criterion is satisfied by verifying that the pressurizer does not fill.

2.8.5.1.1.2.3.3 Description of Analyses and Evaluations

The ELI transient is analyzed using the RETRAN computer code described in WCAP-14882-P-A (Reference 3). The RETRAN code model simulates the reactor coolant system, neutron kinetics, pressurizer, pressurizer relief and safety valves, pressurizer heaters, pressurizer spray, steam generators, feedwater system and main steam safety valves. The code computes pertinent plant variables including steam generator mass, pressurizer water volume, reactor coolant average temperature, reactor coolant system pressure and steam generator pressure.

PBNP Unit 1 has Westinghouse Model 44F steam generators and Unit 2 has Westinghouse Model Δ47 replacement steam generators (RSGs); therefore, a separate ELI analysis was performed for each unit. The ELI analysis considers both minimum and maximum reactivity feedback plant conditions with automatic and manual rod control operation. Thus, eight cases are analyzed for the EPU program.

At BOL, minimum-moderator feedback cases, the core has the least-negative moderator temperature coefficient of reactivity and the least-negative doppler-only power coefficient curve, and, therefore, the least-inherent transient response capability. For the EOL maximum moderator feedback cases, the moderator temperature coefficient of reactivity has its most-negative value and the most-negative doppler-only power coefficient curve. This results in the largest amount of reactivity feedback due to changes in coolant temperature. Normal reactor control systems and engineered safety systems are not required to function.

A 10% step increase in steam demand was assumed and the analysis did not take credit for the operation of the pressurizer heaters.

2.8.5.1.1.2.3.4 Increase in Steam Flow Results

The results of the ELI analysis, assuming a 10% load increase from full power conditions for the EPU program, show that in all cases analyzed, the minimum DNBR remains above the safety analysis limit value and the peak linear heat generation does not exceed the limit value, thus demonstrating that the applicable acceptance criteria for critical heat flux and fuel centerline melt are met. The peak pressurizer water volume remained below the total volume of the pressurizer, demonstrating that this event did not generate a more serious plant condition. Following the initial load increase, the plant reaches a stabilized condition without a reactor trip. With respect to peak pressure, the ELI accident is bounded by the loss-of-electrical-load/turbine-trip analysis. See LR Section 2.8.5.2.1, Loss of External Electrical Load, Turbine Trip and Loss of Condenser Vacuum.

The cases that model minimum reactivity feedback conditions with automatic rod control are the most limiting cases with respect to minimum DNBR. The results are summarized in Table 2.8.5.1.1-1, Excessive Load Increase Summary Results for Unit 1 with Model 44 SGs and Unit 2 with Model Δ47 SGs. The Time Sequence of Events for each case is provided in Table 2.8.5.1.1-2, Time Sequence of Events for the Excessive Load Increase Incident. The transient responses for the four Unit 2 cases, which are representative of the transient in either unit, are shown in Figures 2.8.5.1.1-1 through 2.8.5.1.1-16.

2.8.5.1.1.2.3.5 Conclusions

The analysis performed for the EPU demonstrates that the DNBR does not decrease below the safety analysis limit value at any time during the transient for an ELI incident. Thus, no fuel or clad damage is predicted. The peak core average power (heat flux) remains below the limit of 120% of rated thermal power. The event does not challenge the primary and secondary side pressure limits since the increased heat removal tends to cool the RCS. The peak pressurizer water volume remained below the total volume of the pressurizer, demonstrating that this event did not generate a more serious plant condition. With respect to peak pressure, the ELI accident is bounded by the loss-of-electrical-load/turbine-trip analysis. All applicable acceptance criteria are therefore met.

2.8.5.1.1.2.4 Inadvertent Opening of a Steam Generator Relief or Safety Valve

As described in FSAR Section 14.2.5, Rupture of A Steam Pipe, the cooldown effects and transient results from a credible steam line break (i.e., the inadvertent opening of a steam relief valve) have been shown to be less severe than those for a hypothetical steam line break (i.e., the double-ended rupture). Thus, the credible break case is not explicitly analyzed for PBNP. The limiting steam line break accident has been analyzed as described in Section 2.8.5.1.2, Steam System Piping Failures Inside and Outside Containment, which demonstrates that the DNBR and kW/ft limits are met. Thus, there are no safety concerns for the credible break case.

Evaluation of Impact on Renewal Plant Operating License, Evaluations and License Renewal

EPU activities associated with these analyses do not add any new functions for existing components of the Condensate and Feedwater System (CS) and MS Systems that would change the license renewal system evaluation boundaries. The changes associated with operating the CS and MS systems at EPU conditions do not add any new or previously unevaluated aging effects that necessitate a change to aging management programs or require new programs as internal and external environments remain within the parameters previously evaluated. Therefore, EPU activities associated with these analyses do not impact license renewal scope, aging effects, and aging management programs associated with the CWS and MS systems.

2.8.5.1.1.3 Conclusion

PBNP has reviewed the analyses of the increased heat removal by the secondary system events described above and concludes that the analyses have adequately accounted for plant operation at the proposed EPU power level and were performed using acceptable analytical models. PBNP further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the specified acceptable fuel design limits and the reactor coolant pressure boundary pressure limits will not be exceeded as a result of these events. PBNP concludes that the plant will continue to meet the requirements of PBNP GDCs 6, 14, 27, 28, 30, and 33 following implementation of the proposed EPU. Therefore, PBNP finds the proposed EPU acceptable with respect to the increase in steam flow.

2.8.5.1.1.4 References

1. Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

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

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

4. American Nuclear Society's, Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants, ANSI N18.2 , 1973

Table 2.8.5.1.1-1
Excessive Load Increase Summary Results for Unit 1 with Model 44 SGs and Unit 2 with Model Δ47 SGs

Case	Minimum DNBR/Time (sec)	Core Heat Flux (fon)[1]/Time (sec)
Limits	1.34	1.20
Unit 1 – Model 44 SGs:		
Minimum Reactivity Feedback, Automatic Rod Control	1.62/338.0	1.11/117.0
Minimum Reactivity Feedback, Manual Rod Control	1.92/8.0	1.02/400.0
Maximum Reactivity Feedback, Automatic Rod Control	1.67/64.5	1.11/52.5
Maximum Reactivity Feedback, Manual Rod Control	1.71/76.0	1.09/64.0
Unit 2 – Model Δ47 SGs:		
Minimum Reactivity Feedback, Automatic Rod Control	1.63/300.0	1.12/74.0
Minimum Reactivity Feedback, Manual Rod Control	1.91/7.5	1.02/369.0
Maximum Reactivity Feedback, Automatic Rod Control	1.67/398.0	1.10/79.25
Maximum Reactivity Feedback, Manual Rod Control	1.71/398.0	1.09/80.25
1. fraction of nominal (fon)		

Table 2.8.5.1.1-2
Time Sequence of Events for the Excessive Load Increase Incident

Case	Event	Time of Event (seconds)	
		Unit 1 Model 44 SGs	Unit 2 Model Δ47 RSGs
Beginning of Core Life, Manual Reactor Control	10% step load increase	0	0
	Steady-state conditions reached (approximate)	250	200
Beginning of Core Life, Automatic Reactor Control	10% step load increase	0	0
	Steady-state conditions reached (approximate)	200	200
End of Core Life, Manual Reactor Control	10% step load increase	0	0
	Steady-state conditions reached (approximate)	200	200
End of Core Life, Automatic Reactor Control	10% step load increase	0	0
	Steady-state conditions reached (approximate)	200	200

Figure 2.8.5.1.1-1 Excessive Load Increase, BOL, Manual Rod Control Nuclear Power and Core Heat Flux vs. Time

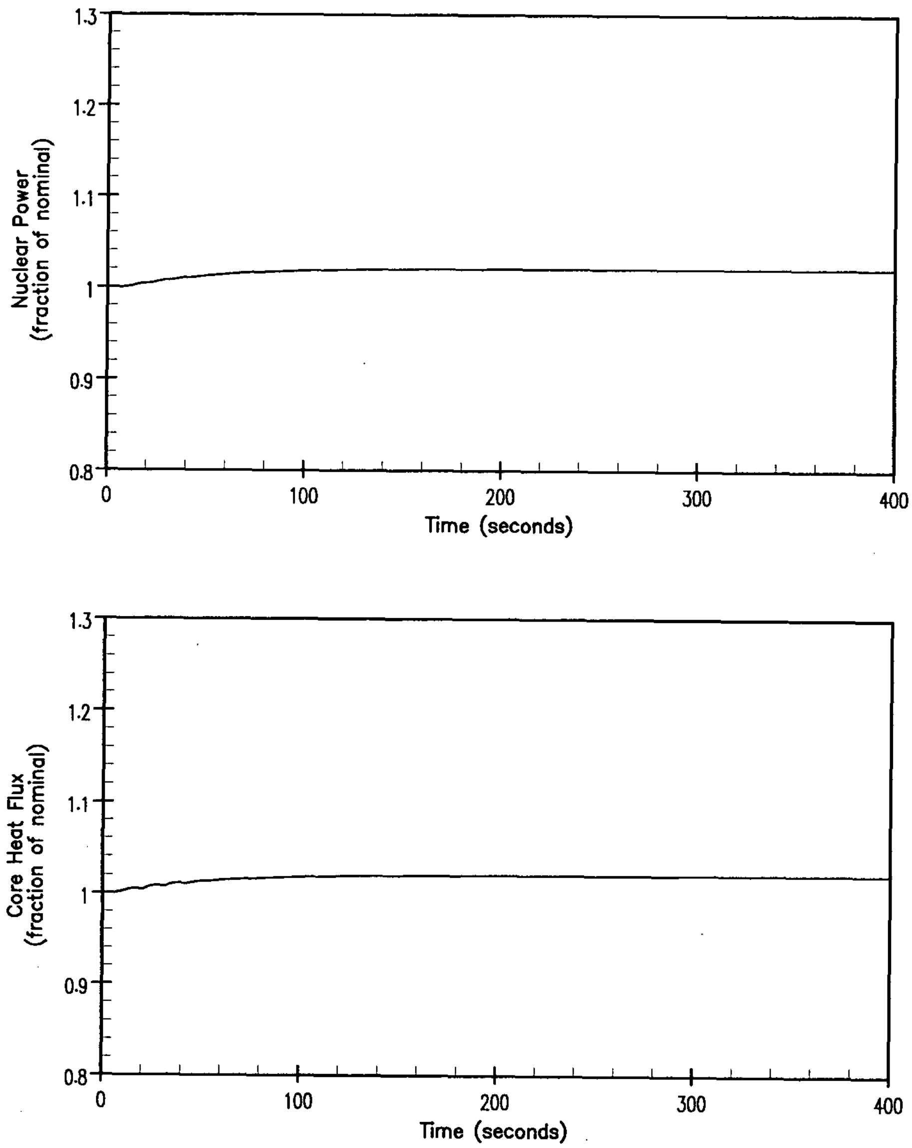


Figure 2.8.5.1.1-2 Excessive Load Increase, BOL, Manual Rod Control Vessel T_{avg} and Vessel Delta-T vs. Time

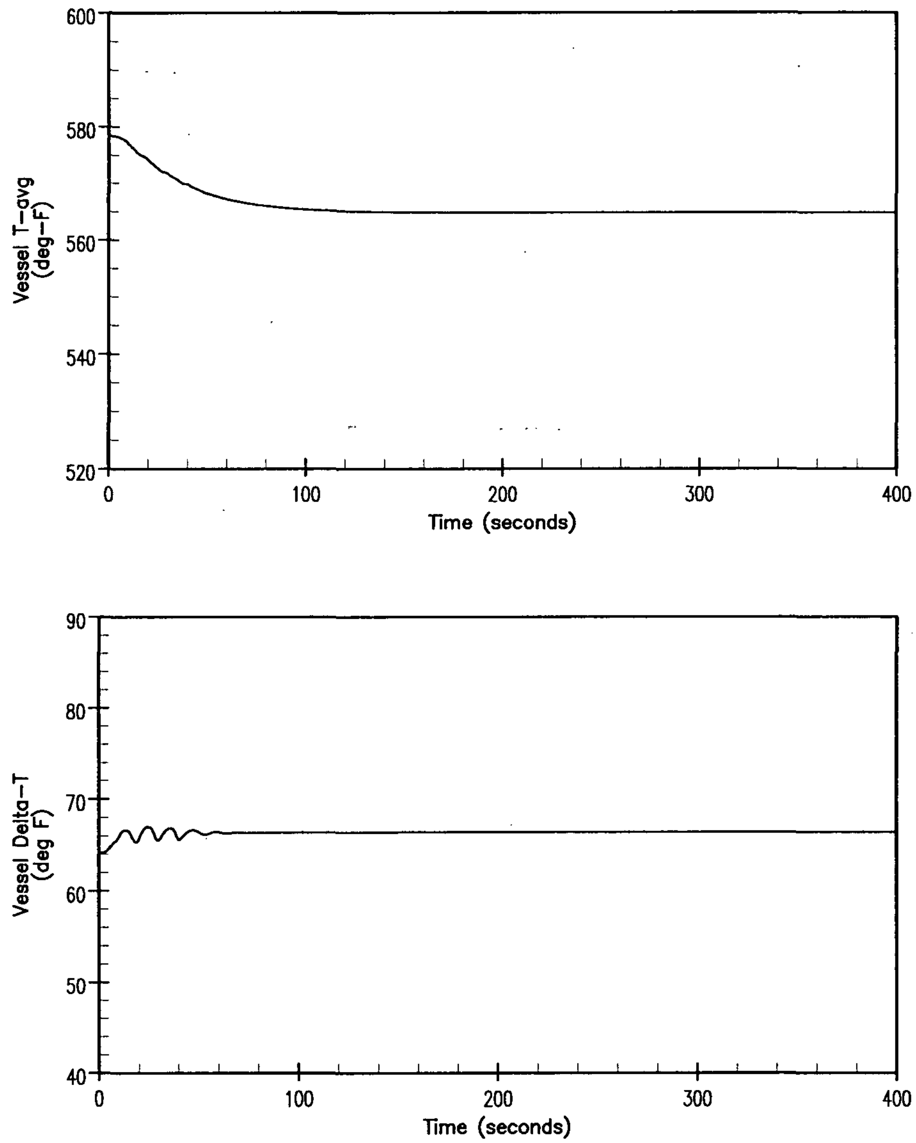


Figure 2.8.5.1.1-3 Excessive Load Increase, BOL, Manual Rod Control Pressurizer Pressure and Pressurizer Water Volume vs. Time

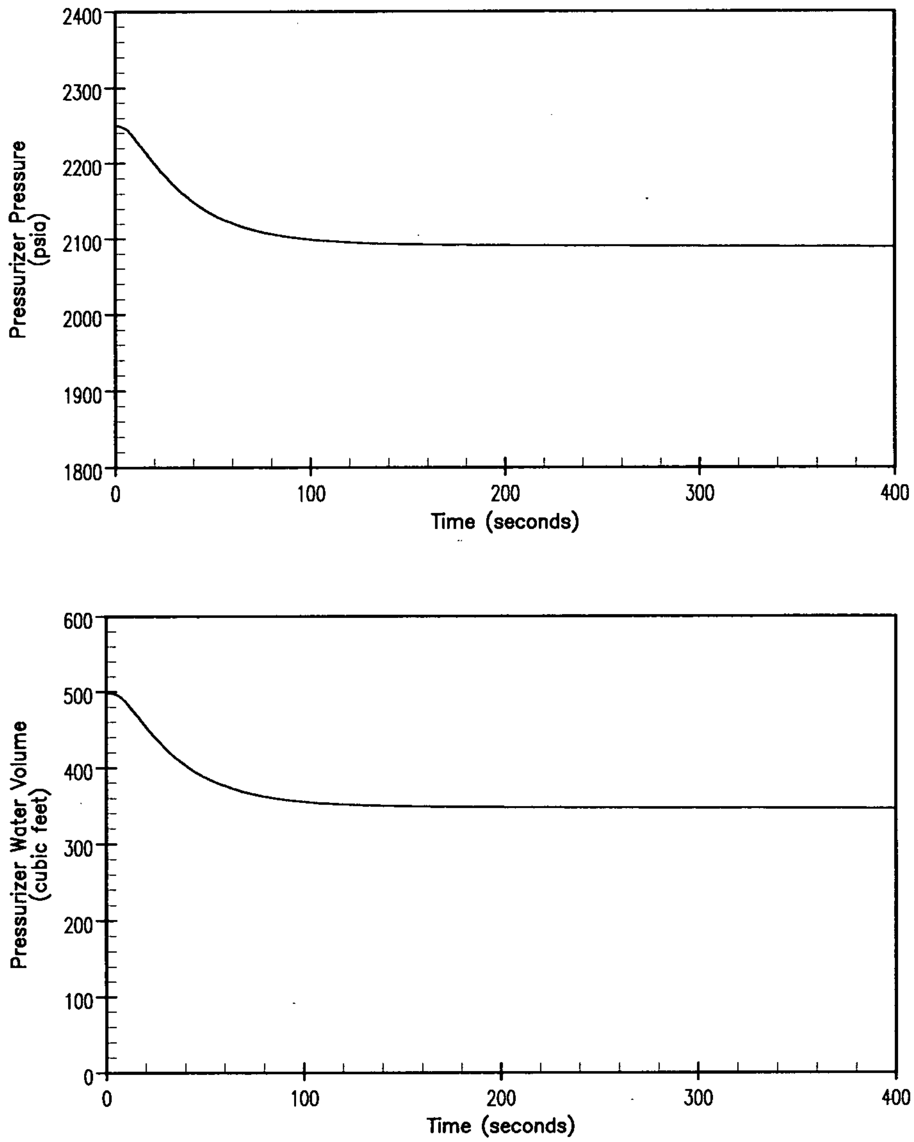


Figure 2.8.5.1.1-4 Excessive Load Increase, BOL, Manual Rod Control Core Reactivity and DNBR vs. Time

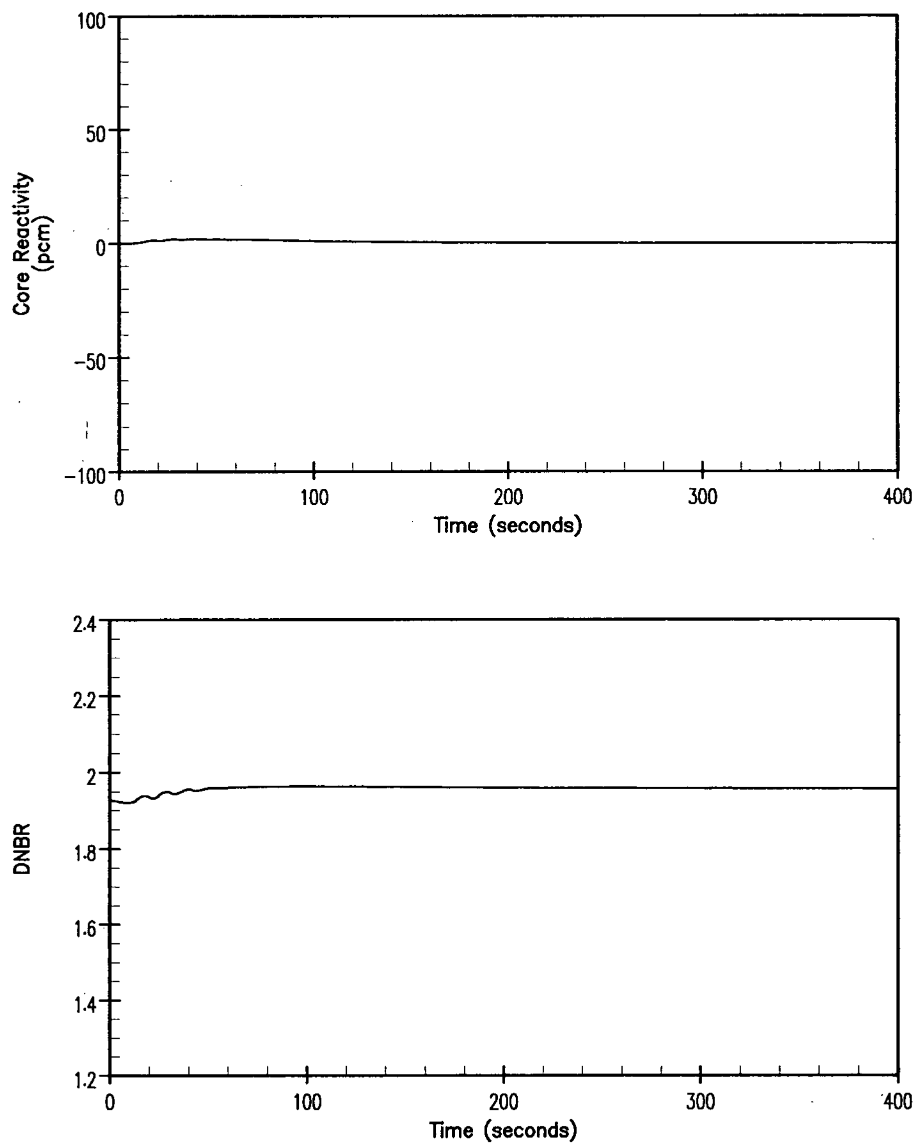
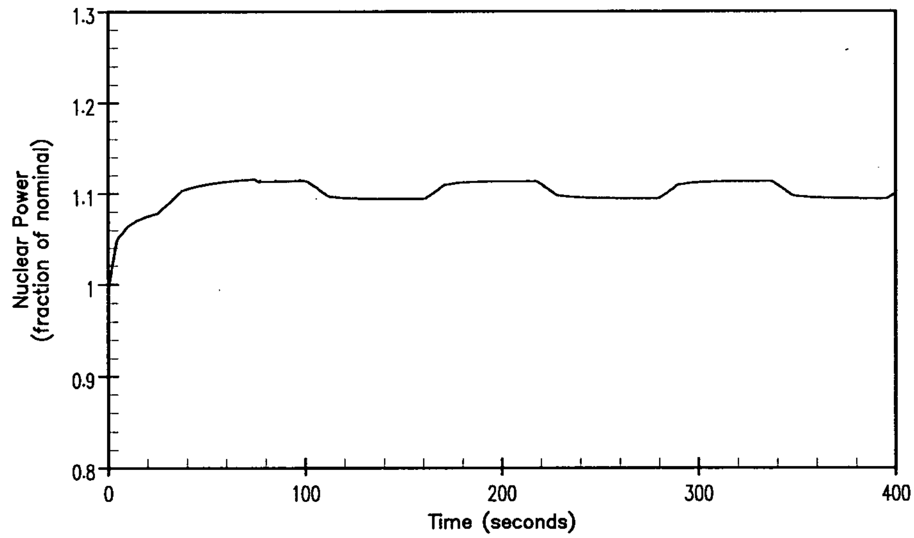


Figure 2.8.5.1.1-5 Excessive Load Increase, BOL, Automatic Rod Control
Nuclear Power and Core Heat Flux vs. Time



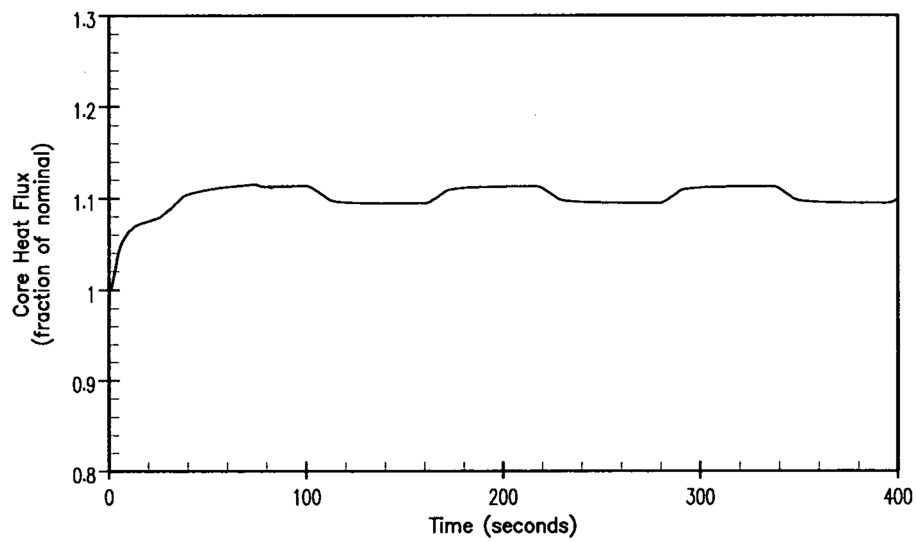
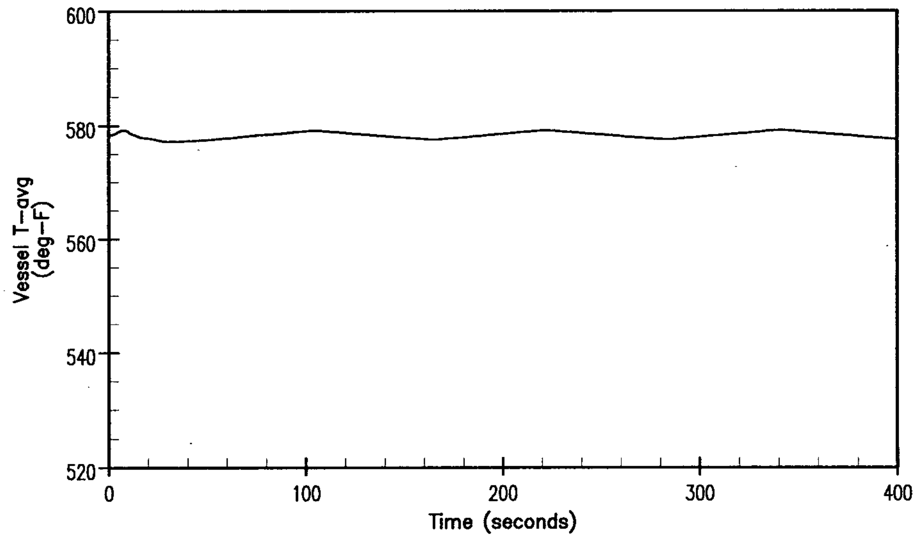


Figure 2.8.5.1.1-6 Excessive Load Increase, BOL, Automatic Rod Control Vessel T_{avg} and Vessel Delta-T vs. Time



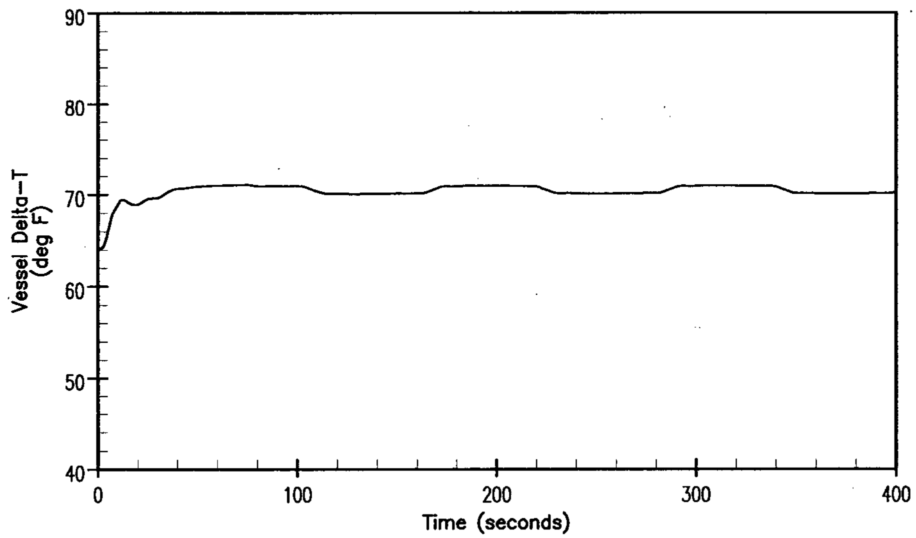
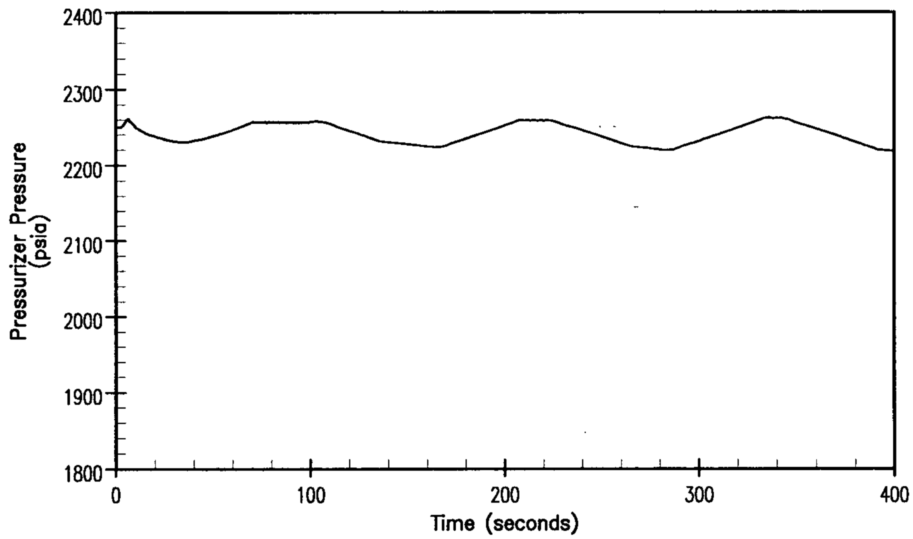


Figure 2.8.5.1.1-7 Excessive Load Increase, BOL, Automatic Rod Control Pressurizer Pressure and Pressurizer Water Volume vs. Time



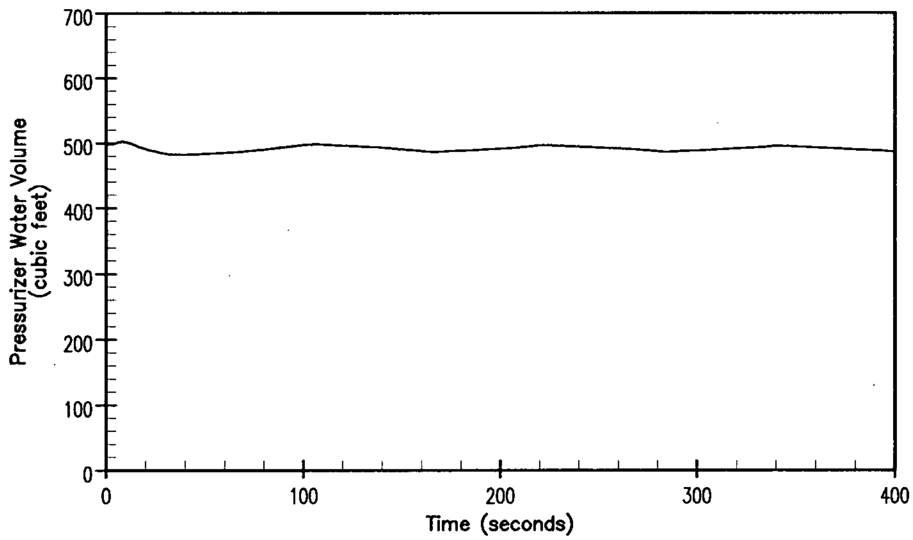
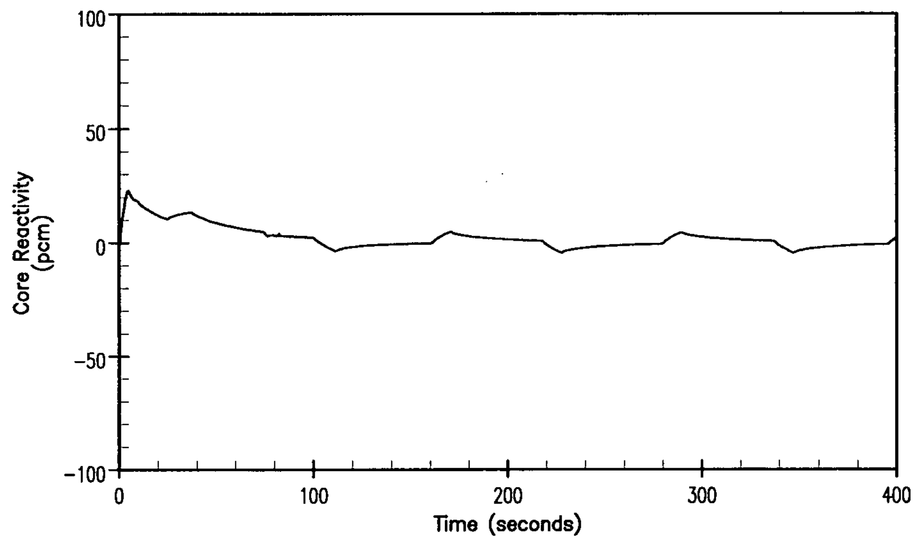


Figure 2.8.5.1.1-8 Excessive Load Increase, BOL, Automatic Rod Control Core Reactivity and DNBR vs. Time



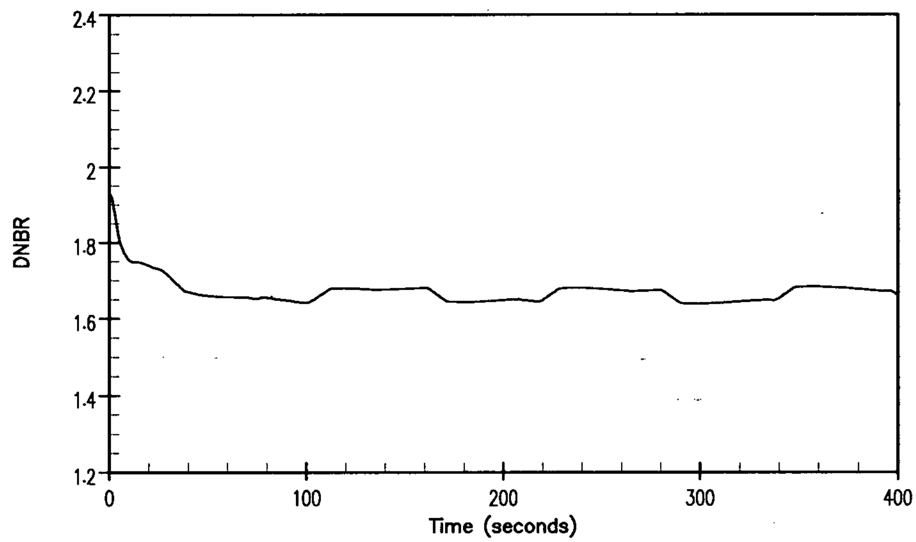
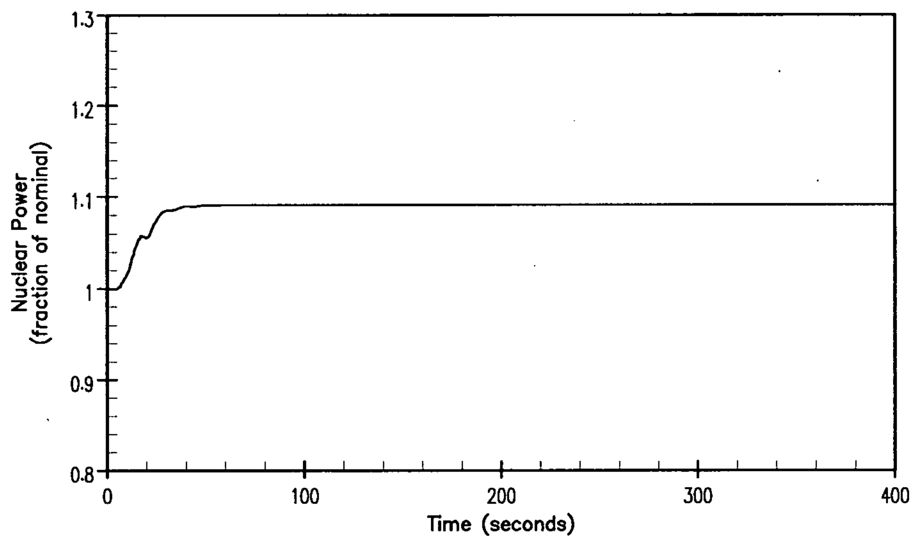


Figure 2.8.5.1.1-9 Excessive Load Increase, EOL, Manual Rod Control Nuclear Power and Core Heat Flux vs. Time



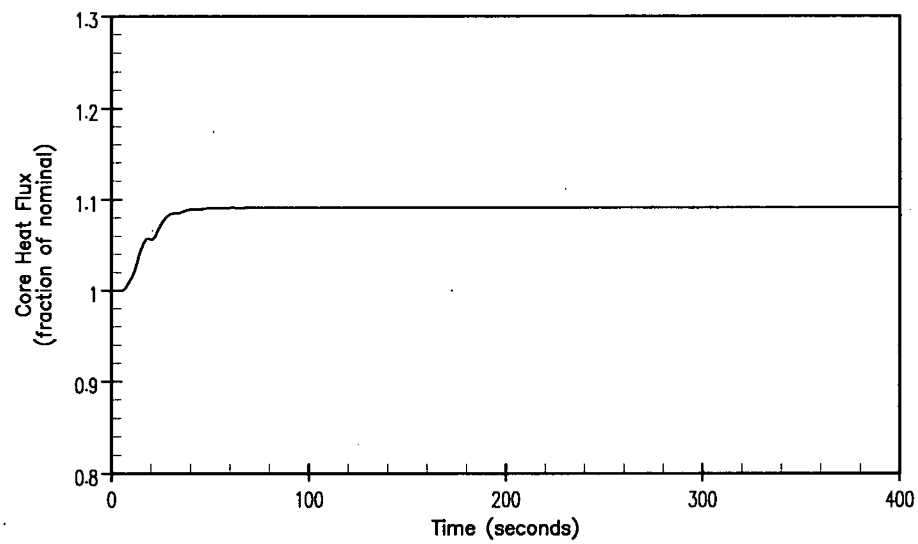
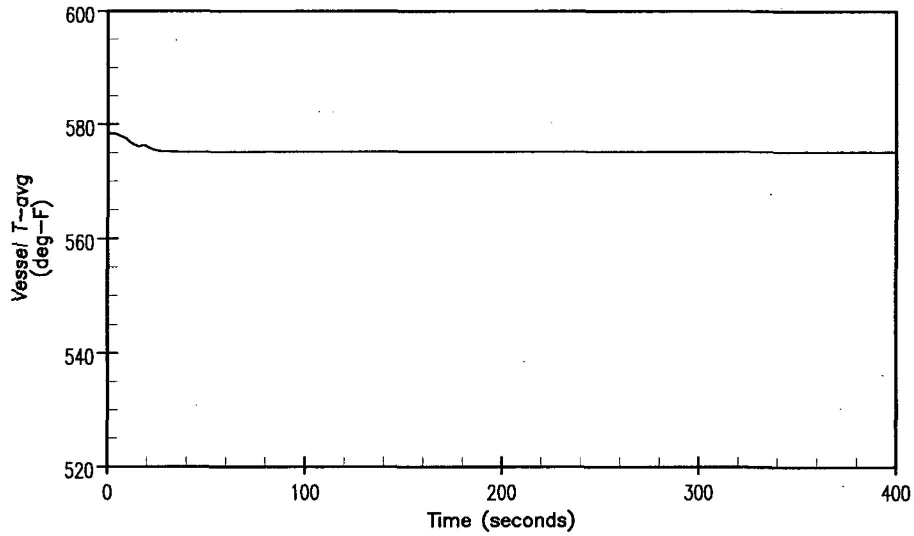


Figure 2.8.5.1.1-10 Excessive Load Increase, EOL, Manual Rod Control Vessel T_{avg} and Vessel Delta-T vs. Time



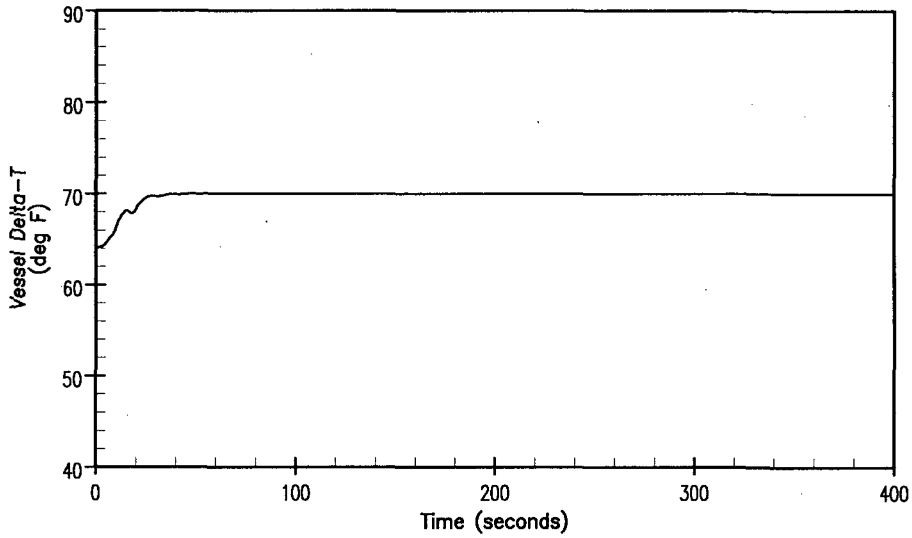


Figure 2.8.5.1.1-11 Excessive Load Increase, EOL, Manual Rod Control Pressurizer Pressure and Pressurizer Water Volume vs. Time

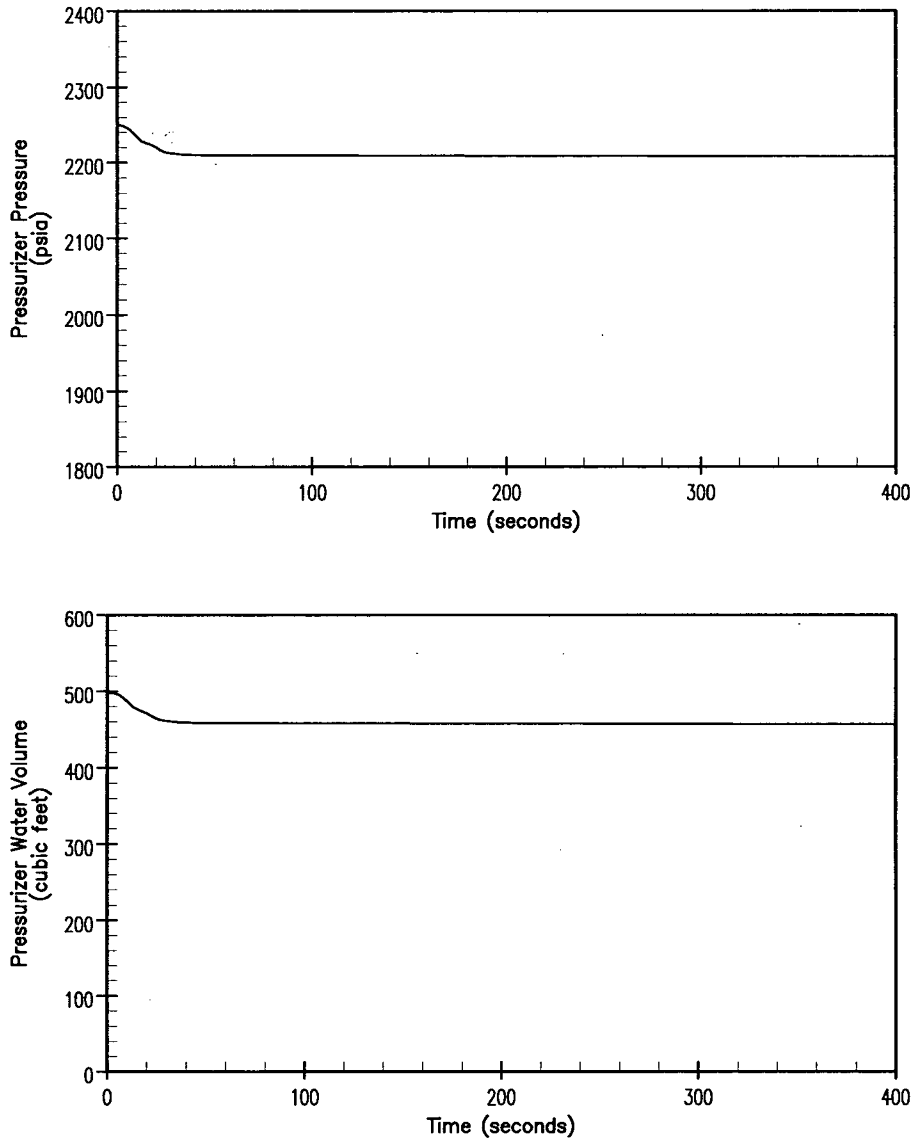


Figure 2.8.5.1.1-12 Excessive Load Increase, EOL, Manual Rod Control Core Reactivity and DNBR vs. Time

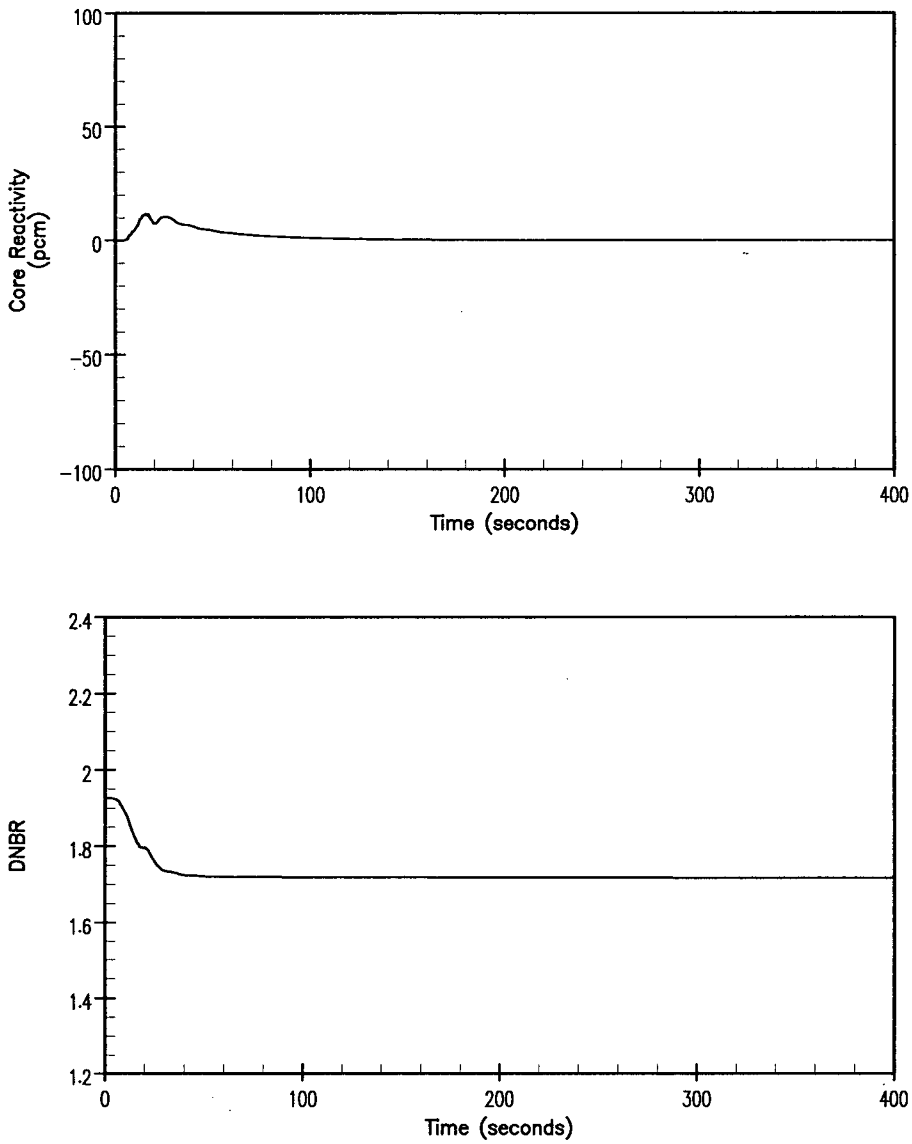


Figure 2.8.5.1.1-13 Excessive Load Increase, EOL, Automatic Rod Control Nuclear Power and Core Heat Flux vs. Time

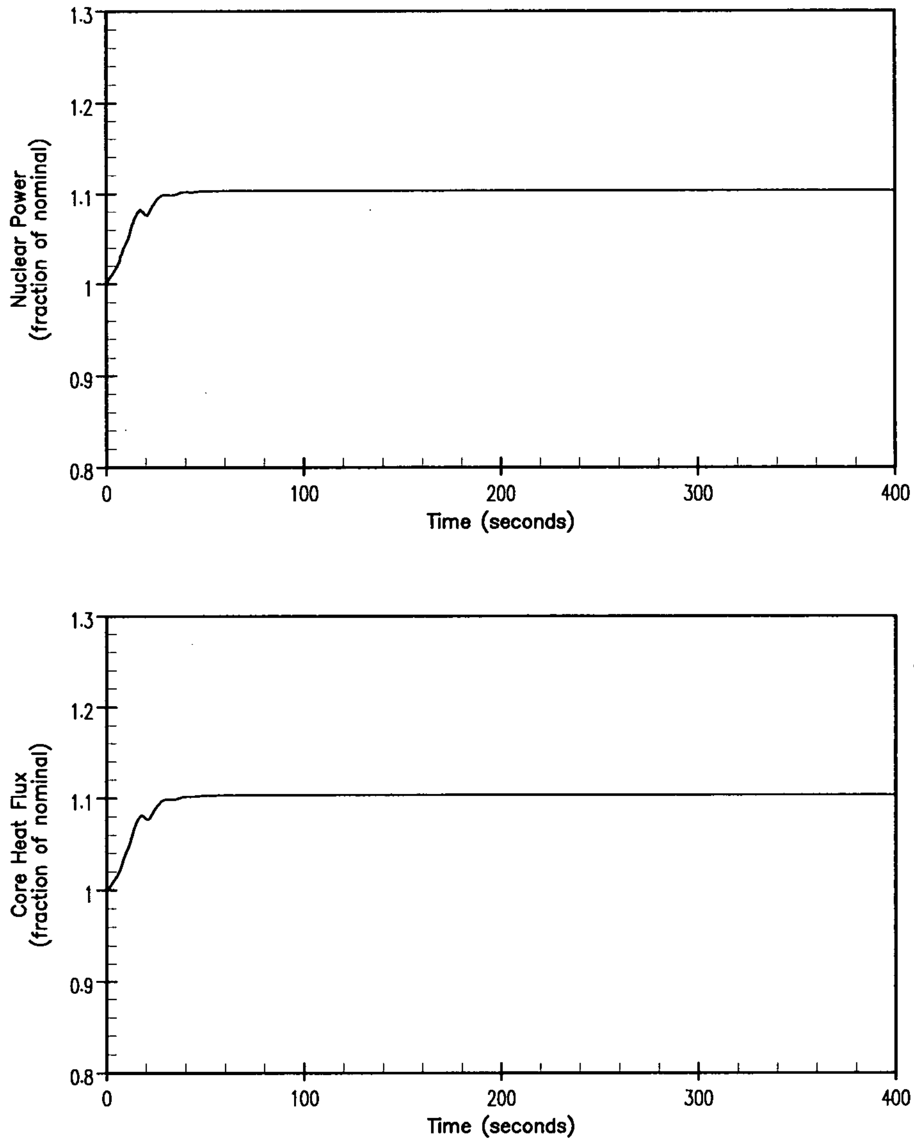
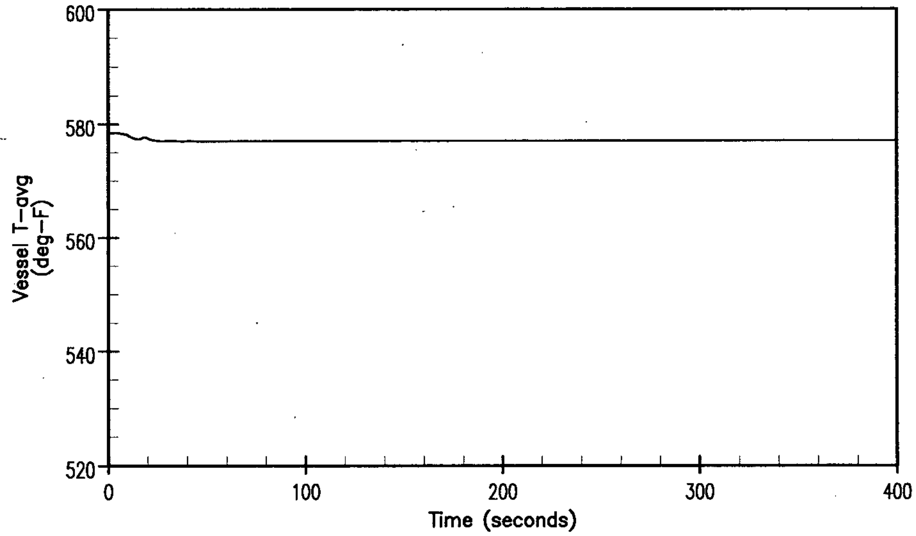


Figure 2.8.5.1.1-14 Excessive Load Increase, EOL, Automatic Rod Control Vessel T_{avg} and Vessel Delta-T vs. Time



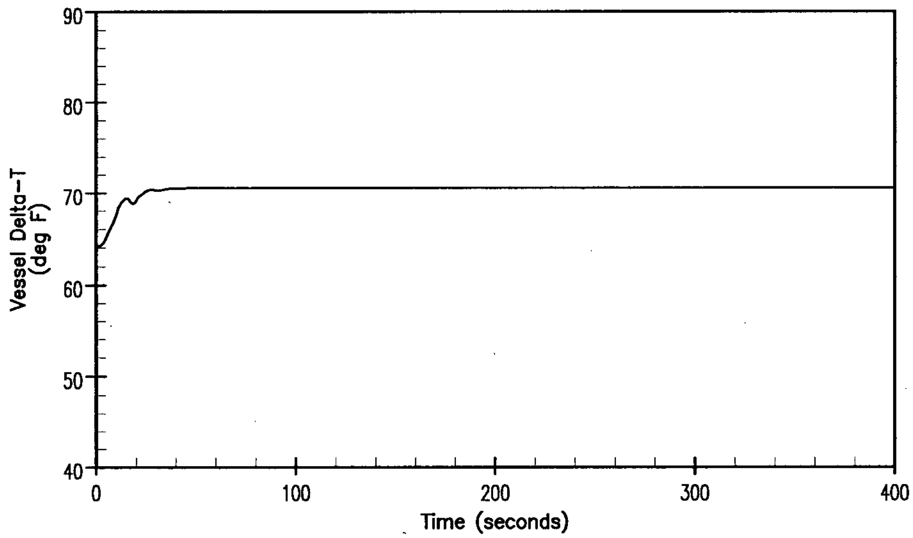
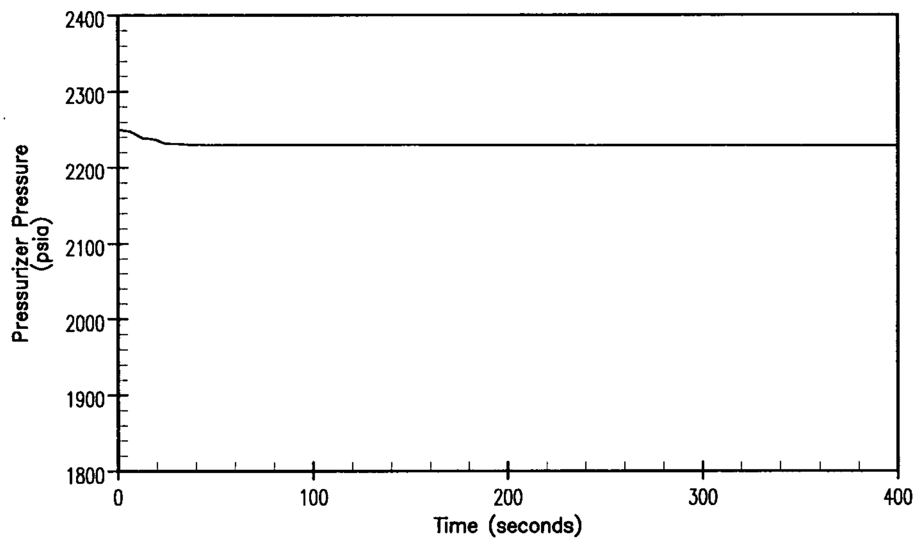


Figure 2.8.5.1.1-15 Excessive Load Increase, EOL, Automatic Rod Control Pressurizer Pressure and Pressurizer Water Volume vs. Time



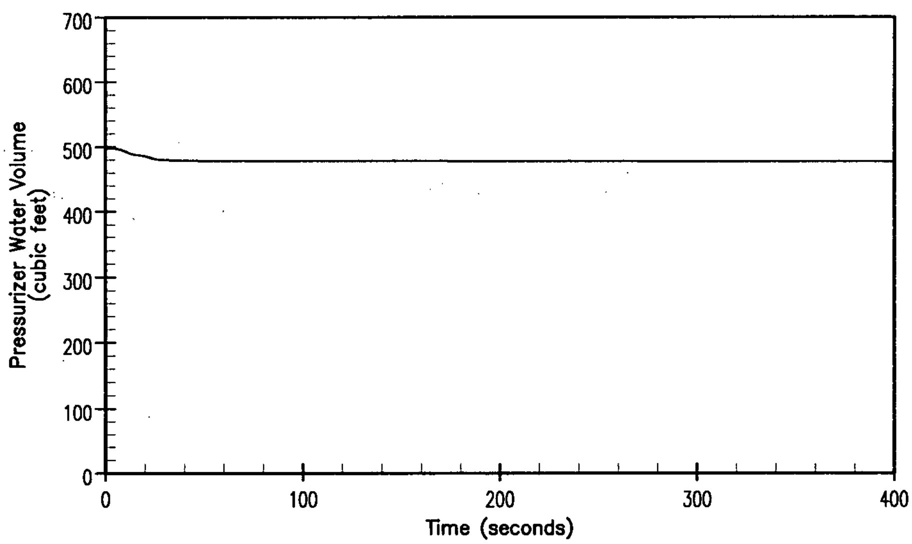
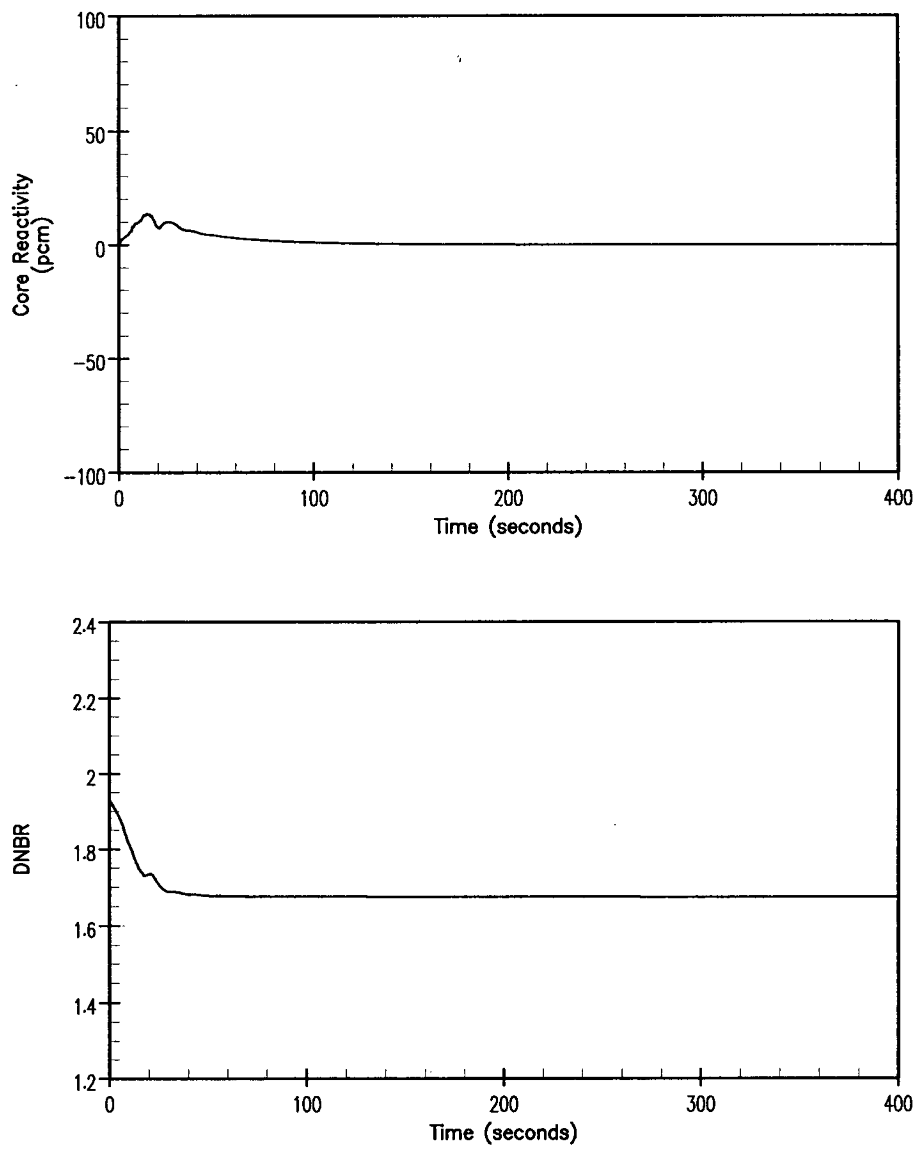


Figure 2.8.5.1.1-16 Excessive Load Increase, EOL, Automatic Rod Control Core Reactivity and DNBR vs. Time



2.8.5.1.2 Steam System Piping Failures Inside and Outside Containment

2.8.5.1.2.1 Regulatory Evaluation

The steam release resulting from a rupture of a main steam pipe will result in an increase in steam flow, a reduction of coolant temperature and pressure, and an increase in core reactivity. The core reactivity increase may cause a power level increase and a decrease in shutdown margin. Reactor protection and safety systems are actuated to mitigate the transient. The PBNP review covered:

- The postulated initial core and reactor conditions
- The methods of thermal and hydraulic analyses
- The sequence of events
- The assumed responses of the reactor coolant and auxiliary systems
- The functional and operational characteristics of the reactor protection system
- The operator actions
- The core power excursion due to power demand created by excessive steam flow
- The variables influencing neutronics
- The results of the transient analyses

The NRC's acceptance criteria are based on:

- GDC 27, insofar as it requires that the reactivity control systems are designed to have a combined capability, in conjunction with poison addition by the emergency core cooling system, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained
- GDC 28, insofar as it requires that the reactivity control systems are designed to assure that the effects of postulated reactivity accidents can neither result in damage to the reactor coolant pressure boundary greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to significantly impair the capability to cool the core
- GDC 31, insofar as it requires that the reactor coolant pressure boundary is designed with sufficient margin to assure that, under specified conditions, it will behave in a non-brittle manner and the probability of a rapidly propagating fracture is minimized
- GDC 35, insofar as it requires the reactor coolant system (RCS) and associated auxiliaries are designed to provide abundant emergency core cooling

Specific review criteria are contained in the SRP, Section 15.1.5, and other guidance provided in Matrix 8 of RS-001, Revision 0.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP specific GDC for steam system piping failures inside and outside containment are as follows:

CRITERION: The reactor coolant pressure boundary shall be designed, fabricated, and constructed so as to have an exceedingly low probability of gross rupture or significant uncontrolled leakage throughout its design lifetime. (PBNP GDC 9)

As described in FSAR Section 4.1, the Reactor Coolant System (RCS), in conjunction with its control and protective provisions, is designed to accommodate the system pressures and temperatures attained under all expected modes of plant operation or anticipated system interactions, and maintain the stresses within applicable code stress limits. Fabrication of the components which constitute the pressure boundary of the RCS is carried out in accordance with the applicable codes at the time of fabrication.

The materials of construction of the pressure boundary of the RCS are protected from corrosion phenomena which might otherwise significantly reduce the system structural integrity during its service lifetime by the use of non-corrosive materials (such as stainless steel) and by the maintenance of proper chemistry control.

System conditions resulting from anticipated transients or malfunctions are monitored and appropriate action is automatically initiated to maintain the required cooling capability and to limit system conditions to a safe level.

The system is protected from overpressure by means of pressure relieving devices, as required by Section III of the ASME Boiler and Pressure Vessel Code. The system is also protected from overpressure at low temperatures by the Low Temperature Overpressure Protection System (LTOP).

CRITERION: The reactivity control systems provided shall be capable of making the core subcritical under credible accident conditions with appropriate margins for contingencies and limiting any subsequent return to power such that there will be no undue risk to the health and safety of the public. (PBNP GDC 30)

As described in FSAR Section 3.1.2.6, Reactivity Holddown Capability, the reactivity control systems provided are capable of making and holding the core subcritical, under accident conditions, in a timely fashion with appropriate margins for contingencies. As described in FSAR Section 6.2, Safety Injection System, for any rupture of a steam pipe and the associated uncontrolled heat removal from the core, the safety injection system adds shutdown reactivity so that with a stuck rod, no off-site power and minimum engineered safety features, there is no consequential damage to the reactor coolant system and the core remains in place and intact. Analysis of the spectrum of steam system piping failures is provided in FSAR Section 14.2.5, Rupture of A Steam Pipe.

CRITERION: Limits, which include reasonable margin, shall be placed on the maximum reactivity worth of control rods or elements and on rates at which reactivity can be increased to ensure that the potential effects of a sudden or large change of reactivity cannot (a) rupture the reactor coolant pressure boundary, or (b) disrupt the core, its support structures, or other vessel internals sufficiently to lose capability of cooling the core. (PBNP GDC 32)

As described in FSAR Section 3.1, Reactor, Design Basis, limits are placed on the maximum reactivity worth of control rods or elements and on rates at which reactivity can be increased to ensure that the potential effects of a sudden or large reactivity change cannot (a) rupture the reactor coolant pressure boundary, or (b) disrupt the core, its support structures, or other vessel internals so as to lose capability to cool the core.

CRITERION: The reactor coolant pressure boundary shall be capable of accommodating without rupture the static and dynamic loads imposed on any boundary component as a result of an inadvertent and sudden release of energy to the coolant. As a design reference, this sudden release shall be taken as that which would result from a sudden reactivity insertion such as rod ejection (unless prevented by positive mechanical means), rod dropout, or cold water addition. (PBNP GDC 33)

The reactor coolant boundary is shown to be capable of accommodating, without rupture, the static and dynamic loads imposed as a result of a sudden reactivity insertion such as a rod ejection. The operation of the reactor is such that the severity of an ejection accident is inherently limited. Since control rod clusters are primarily used to control load variations and boron dilution is used primarily to compensate for core depletion, only the rod cluster control assemblies in the controlling groups are inserted in the core at power, and at full power these rods are only partially inserted. A rod insertion limit monitor is provided as an administrative aid to the operator to insure that this condition is met.

CRITERION: The reactor coolant pressure boundary shall be designed and operated to reduce to an acceptable level the probability of rapidly propagating type failures. Consideration is given (a) to the provisions for control over service temperature and irradiation effects which may require operational restrictions, (b) to the design and construction of the reactor pressure vessel in accordance with applicable codes, including those which establish requirements for absorption of energy within the elastic strain energy range and for absorption of energy by plastic deformation and (c) to the design and construction of reactor coolant pressure boundary piping and equipment in accordance with applicable codes. (PBNP GDC 34)

The reactor coolant pressure boundary is designed to reduce to an acceptable level the probability of a rapidly propagating type failure. The fracture toughness of the materials in the beltline region of the reactor vessel will decrease as a result of fast neutron irradiation induced embrittlement. The decrease in fracture toughness, which is a function of several factors, including accumulated fast neutron fluence, requires a corresponding increase in reference nil ductility temperature

(RT_{NDT}) in order to maintain strength/stress requirements. This change in material properties is factored into the operating procedures such that the reactor coolant system pressure is limited with respect to RCS temperature during plant heatup, cooldown, and normal operation.

CRITERION: An emergency core cooling system with the capability for accomplishing adequate emergency core cooling shall be provided. This core cooling system and the core shall be designed to prevent fuel and clad damage that would interface with the emergency core cooling function and to limit the clad metal-water reaction to acceptable amounts for all sizes of breaks in the reactor coolant piping up to the equivalent of a double-ended rupture of the largest pipe. The performance of such emergency core cooling system shall be evaluated conservatively in each area of uncertainty. (PBNP GDC 44)

Adequate emergency core cooling is provided by the safety injection system (which constitutes the emergency core cooling system) operates in three modes. These modes are delineated as passive accumulator injection, active safety injection and residual heat removal recirculation. The primary purpose of the safety injection system is to automatically deliver cooling water to the reactor core in the event of a loss-of-coolant accident. This limits the fuel clad temperature and thereby ensures that the core will remain intact and in place with its heat transfer geometry preserved.

For any rupture of a steam pipe and the associated uncontrolled heat removal from the core, the safety injection system adds shutdown reactivity so that with a stuck rod, no off-site power and minimum engineered safety features, there is no consequential damage to the reactor coolant system and the core remains in place and intact.

In addition to the evaluations described in the FSAR, the plant systems and components were evaluated for license renewal. Systems and system component materials of construction, operating history, and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005. (Reference 1)

During plant license renewal evaluations, components associated with the control and mitigation of transients that could result in an increase in heat removal by the secondary system were evaluated.

2.8.5.1.2.2 Technical Evaluation

Steam line breaks initiated from either hot full power (HFP) conditions or from hot zero power (HZP) conditions are conservatively chosen to be analyzed to Condition II acceptance criteria. The specific acceptance criteria applied by PBNP for these events are as follows:

- The departure from nucleate boiling ratio (DNBR) should remain above the 95/95 DNBR limit at all times during the transient. In addition, the peak linear heat generation rate (expressed in kW/ft) should not exceed a value which would cause fuel centerline melt. Demonstrating that the DNBR and kW/ft limits are met satisfies the PBNP current licensing basis requirements

- Primary and secondary pressures must remain below 110% of their respective design pressures at all times during the transient. Demonstrating that the primary and secondary pressure limits are met, including allowance made for the worst stuck rod, satisfies the PBNP current licensing basis requirements
- Only the HZP case assumes emergency core cooling system (ECCS) actuation (i.e., safety injection (SI) flow) for mitigation. The analysis performed demonstrates that the SI system has sufficient capacity to mitigate the event. The HFP transient is terminated via a reactor trip. The post-trip portion of the HFP transient is bounded by the HZP case. Thus, demonstrating adequate capacity for the HZP case also demonstrates adequate capacity for the post-reactor trip portion of the HFP transient. The analyses demonstrate that the PBNP current licensing basis requirements are met

The discussion below demonstrates that all applicable acceptance criteria are met for these events at EPU conditions.

2.8.5.1.2.2.1 Steam System Piping Failure at Hot Zero Power

2.8.5.1.2.2.1.1 Introduction

The steam release from a major rupture of a main steam pipe will result in an initial increase in steam flow that decreases during the accident as the steam pressure falls. The energy removal from the RCS causes a reduction of reactor coolant temperature and pressure. In the presence of a negative moderator temperature coefficient (MTC), the cooldown results in a positive reactivity insertion and subsequent reduction in core shutdown margin. If the most-reactive rod cluster control assembly (RCCA) is assumed stuck in its fully withdrawn position after reactor trip, there is an increased possibility that the core will become critical and return to power. A return to power following a steam pipe rupture is a concern primarily because of the high-power peaking factors that would exist assuming the most-reactive RCCA is stuck in its fully withdrawn position. The core is ultimately shut down by boric acid injection delivered by the ECCS (high head safety injection and passive accumulators).

The major rupture of a main steam pipe is the most-limiting cooldown transient. It is analyzed at HZP conditions with no decay heat (decay heat would retard the cooldown, thus reducing the return to power). A detailed discussion of this transient with the most limiting break size is presented below.

The primary design features, which provide protection for steam pipe ruptures are:

- Actuation of the SI system from any of the following:
  - Two-out-of-three pressurizer low-pressure signals
  - Two-out-of-three low-pressure signals in any steam line
  - Two-out-of-three high-containment pressure signals

- If the reactor trip breakers are closed, reactor trip can be actuated from overpower neutron flux, overpower delta-T (OPΔT), or upon actuation of the SI system
- Redundant isolation of the main feedwater lines to prevent sustained high-feedwater flow that will cause additional cooldown. In addition to the normal control action which will close the main feedwater control valves, an SI signal will also rapidly close all feedwater control valves as well as the feedwater isolation valves
- Closure of the fast-acting main steam line isolation valves (MSIVs), on the following:
  - Two-out-of-three high-high containment pressure signals
  - One-out-of-two high-high steam flow signals in a steam line in coincidence with any safety injection signal
  - One-out-of-two high-steam flow signals in a steam line in coincidence with two-out-of-four indications of low-reactor coolant T_{avg} and any SI signal

Each steam line is provided with a main steam isolation valve which isolates flow in the forward direction, and a main steam non-return check valve, which isolates flow in the reverse direction. Thus, even with a single failure of any valve, no more than one steam generator can blow down, no matter where the break is postulated. The unaffected steam generator is still available for dissipation of decay heat after the initial transient is over.

Following blowdown of the faulted steam generator, the unit can be brought to a stabilized hot-standby condition through control of the auxiliary feedwater (AFW) flow and SI flow as described by plant operating procedures. The operating procedures would call for operator action to limit RCS pressure and pressurizer level by terminating SI flow and to control steam generator level and RCS coolant temperature using the auxiliary feedwater system (AFWS).

2.8.5.1.2.2.1.2 Input Parameters, Assumptions, and Acceptance Criteria

The following summarizes the major input parameters and/or assumptions used in the main steam line rupture event:

- End of core life (EOL) shutdown margin (2.0% $\Delta k/k$) is assumed at no-load, equilibrium xenon conditions, and the most reactive control rod assembly is stuck in its fully withdrawn position. Operation of the control rod banks during core burnup is restricted in such a way that addition of positive reactivity in a steam line break accident will not lead to a more adverse condition than the case analyzed
- The negative moderator temperature reactivity coefficient corresponds to the EOL rodded core with the most-reactive control rod in the fully withdrawn position. The core properties associated with the sector nearest the affected steam generator and those associated with the remaining sector were conservatively combined to obtain average core properties for reactivity feedback calculations. To verify the conservatism of this method, the reactivity and power distribution were checked with a detailed ANC core model. These core analyses considered the doppler reactivity feedback from the high fuel temperature near the stuck RCCA, moderator feedback from the high water enthalpy near the stuck RCCA, power redistribution and non-uniform core inlet temperature effects. For cases in which steam

generation occurs in the high flux regions of the core, the effect of void formation was also included. It was determined that the reactivity employed in the RETRAN kinetics analysis was conservative; i.e., under-prediction of negative reactivity feedback from power generation

- Minimum capability for injection of boric acid (2700 ppm) solution is assumed, corresponding to the most restrictive single failure in the SIS. This corresponds to one high-head SI pump delivering its full flow to each cold leg. Although a small return line back to the RWST exists such that the SI piping volume is borated, the analysis conservatively assumes that unborated water must be swept from the SI lines downstream of the RWST isolation valves prior to the delivery of boric acid (2700 ppm) to the reactor coolant loops. The SI pump is assumed to achieve full speed within 13 seconds following receipt of the SI signal for the case in which offsite power is assumed available, and within 28 seconds for the case where offsite power is not available; the additional delay is assumed to model the time delay associated with the start of the diesels and loading of the necessary SI equipment onto them. Note that actual SI flow delivery does not begin until the cold leg pressure falls below the shutoff pressure of the SI pump

- The passive cold leg accumulators provide an additional source of borated water to the core when the RCS pressure decreases below the actuation setpoint. A minimum accumulator boron concentration of 2600 ppm is assumed, with an actuation setpoint of 694.7 psia. A minimum accumulator water temperature of 60°F is assumed.

- To maximize the primary-to-secondary heat transfer rate, zero (0%) steam generator tube plugging is assumed

- The analysis assumes a complete severance of a main steam pipe with the plant initially at no-load conditions. Cases were analyzed for each unit, both with offsite power available (full coolant flow is maintained) and with a loss of offsite power (reactor coolant pumps coast down following the break). Since both the Westinghouse Model 44F (Unit 1) and Model Δ47 (Unit 2) steam generators are equipped with integral flow restrictors with a 1.388 ft^2 throat area, any steam line rupture with a break area greater than this size, regardless of the location, would have the same effect on the reactor as a 1.388 ft^2 break

- Power peaking factors corresponding to one stuck RCCA and non-uniform core inlet coolant temperatures are determined at end of core life (EOL). The coldest core inlet temperature is assumed to occur in the sector with the stuck rod. The power peaking factors account for the effect of the local void in the region of the stuck control assembly during the return-to-power phase following the steam line break. This void, in conjunction with the large negative moderator temperature reactivity coefficient, partially offsets the effect of the stuck assembly. The power peaking factors depend on the core power, operating history, temperature, pressure, and flow

- In computing the steam flow during a steam line rupture, the Moody Curve (Reference 5) for f(L/D) = 0 is used

- Perfect moisture separation in the steam generator is assumed. This assumption leads to conservative results since considerable water would be expected to be discharged from the steam generator. Water entrainment in the steam reduces the steam generator inventory, thereby reducing the magnitude of the temperature decrease (cooldown) in the core

- Main and AFW pumps are assumed to be operating at full capacity when the rupture occurs. This assumption maximizes the cooldown. The main feedwater temperature at no-load conditions is assumed to be 35°F. A conservatively high auxiliary feedwater flow rate of 1200 gpm at a minimum temperature of 35°F is assumed to be delivered to the affected steam generator. Main feedwater is isolated following the SI signal; however, AFW continues for the duration of the transient
- The effect of heat transferred from thick metal in the RCS and the steam generators is not included in the cases analyzed. The heat transferred from these sources would be a net benefit since it would slow the cooldown of the RCS

For the acceptance criteria, see LR Section 2.8.5.1.2.2, Technical Evaluation, above.

2.8.5.1.2.2.1.3 Description of Analyses and Evaluations

A detailed analysis using the RETRAN computer code is performed to determine the plant transient conditions following a main steam line rupture. The code computes pertinent variables, including the core power, RCS temperature and pressure. A detailed core analysis is then performed using the ANC code (Reference 3) to determine if the RETRAN-predicted reactivity feedback model is conservative. Statepoints consisting of nuclear power, RCS loop inlet temperatures, pressure, and core flow are used as input to the detailed thermal and hydraulic digital computer code VIPRE (Reference 4), to determine if the DNBR limit is met for the limiting time in the transient. Details of the RETRAN model are documented in Reference 2. The RETRAN, ANC, and VIPRE computer codes are described in LR Section 2.8.5.0.9, Accident and Transient Analysis, of this report.

2.8.5.1.2.2.1.4 Results

The most limiting main steam line rupture at HZP for each unit is the case in which offsite power is assumed to be available. Since offsite power is assumed available, there is full reactor coolant flow throughout the transient. The sequence of events for these limiting cases is shown in Table 2.8.5.1.2-1, Unit 1: Time Sequence of Events – Steam System Piping Failure at Hot Zero Power, and Table 2.8.5.1.2-2, Unit 2: Time Sequence of Events – Steam System Piping Failure at Hot Zero Power, for Unit 1 and Unit 2, respectively. Figures 2.8.5.1.2-1 through 2.8.5.1.2-6 (Unit 1) and Figures 2.8.5.1.2-7 through 2.8.5.1.2-12 (Unit 2) show the transient results.

As shown in Figures 2.8.5.1.2-4 and 2.8.5.1.2-10, the core attains criticality with the RCCAs inserted (i.e., with the plant shut down assuming one stuck RCCA) before boron solution from the ECCS and accumulators enters the RCS.

The results of the major rupture of a main steam pipe event indicate that the DNB and fuel centerline melt design bases are met. The calculated minimum DNBR is 1.616 (Unit 1) and 1.650 (Unit 2), compared to a limit value of 1.45 (W-3 DNB correlation limit with pressure less than 1000 psia). The calculated peak linear heat generation rate is 21.64 kW/ft (Unit 1) and 21.35 kW/ft (Unit 2), compared to a limit value of 22.54 kW/ft. Primary and secondary pressure limits are not challenged because primary and secondary pressures decrease from their initial values during the transient. Therefore, this event does not adversely affect the core or the RCS, and all applicable acceptance criteria are met.

2.8.5.1.2.2.2 Steam System Piping Failure at Full-Power

2.8.5.1.2.2.2.1 Introduction

This section describes the analysis of a steam system piping failure occurring from at-power initial conditions to demonstrate that core protection is maintained prior to and immediately following reactor trip. The at-power case is currently not analyzed for PBNP but was analyzed for the EPU for completeness.

2.8.5.1.2.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Limiting transient condition statepoints were generated using the Revised Thermal Design Procedure (RTDP) (Reference 6). For RTDP applications, uncertainties on reactor coolant system (RCS) initial conditions (temperature, pressure, power, and flow) are included in the development of the departure from nucleate boiling ratio (DNBR) limit value. When RTDP is not applicable, uncertainties are included in the initial conditions or are conservatively applied to the limiting transient condition in the calculation of the minimum DNBR.

- Initial conditions – The initial core power and RCS pressure are assumed to be at their nominal steady-state, full-power values when generating the transient statepoints (1800 MWt and 2250 psia, respectively). The initial RCS temperature is assumed to be at its nominal steady-state, full-power value plus a 1.4°F bias (see below). Uncertainties are already explicitly included in the DNBR limit calculations
- RCS flow – Minimum measured RCS flow of 93,000 gpm per RCS loop is assumed when generating the transient statepoints and in the DNBR calculations. The flow uncertainty is included in the DNBR limit calculations. The initial loop flows are assumed to be symmetric
- RCS average temperature – The full-power RCS T_{avg} range is from 558.0° to 577.0°F. To ensure that the limiting condition is analyzed, both ends of the T_{avg} window were considered, including a +1.4°F temperature bias
- Feedwater temperature – The main feedwater analytical temperature range is from 390° to 458°F. A nominal feedwater temperature of 458°F is assumed for this event. Sensitivity studies have shown that HFP SLB results are not influenced by the assumed initial feedwater temperature
- Break size – The event is analyzed over a spectrum of break sizes to identify the most limiting overpower condition, which is typically the largest break to produce a reactor trip on overpower delta-T (OPΔT). The Westinghouse Model 44F (Unit 1) and Model Δ47 (Unit 2) steam generators at PBNP have steam exit nozzle flow restrictors that limit the flow area to about 1.388 ft^2. Therefore the analysis conservatively modeled break sizes up to 1.4 ft^2. In addition, the largest break size for which there is no reactor trip is examined to determine if it is more limiting with respect to peak power level

- Reactivity coefficients – The analysis assumed maximum moderator reactivity feedback and minimum Doppler power feedback to maximize the power increase following the break
- Protection system – The protection system features that mitigate the effects of a steam line break are described in LR Section 2.8.5.1.2.2.1 above, steam system piping failure at hot zero power. This analysis only considers the initial phase of the transient from at-power conditions. Protection in this phase of the transient is provided by reactor trip, if necessary (specifically, OPΔT, low steam lne pressure – safety injection, and high containment pressure – safety injection). The fluid conditions at the time of reactor trip for a hot full power case are less severe than the initial conditions for a hot zero power case with respect to the potential for a return to critical. Thus, the post-trip portion of an at-power steam line break is bounded by the hot zero power steam line break analysis. LR Section 2.8.5.1.2.2.1 presents the analysis of the bounding transient following reactor trip, where other protection system features are actuated to mitigate the effects of the steam line break

  Note that since the OPΔT trip function is not qualified for a harsh environment caused by the steam line break, additional work was performed which showed that, although not specifically credited, the Hi-1 containment pressure – safety injection signal would cause reactor trip before OPΔT on all cases in which OPΔT was predicted to provide protection. As such, should OPΔT fail during a harsh steam environment, the core would be protected by the high containment pressure – SI signal

  For breaks outside containment, the OPΔT and low steam line pressure – safety injection protection functions are relied upon to provide the necessary protection to mitigate the event. For breaks inside containment, protection is provided by the high containment pressure – safety injection function. The results of separate containment pressure response analyses showed that the high containment pressure – safety injection signal would be reached before OPΔT on all inside containment break cases. A delayed reactor trip for this event results in more limiting transient results. Based on this, the outside containment breaks, which rely on OPΔT and low steam line pressure – safety injection, are determined to be the most limiting scenario; therefore, it is this scenario that is explicitly modeled. Therefore, the results presented in this section correspond to breaks outside containment

  In order to obtain acceptable results for the steam system piping failure at hot full power analysis for the EPU, protection system setpoint changes are necessary. The low steam line pressure – Safety Injection safety analysis setpoint is changed from 335 psia to 410 psia, and the associated lead/lag dynamic compensation time constants are changed from 12 sec/2 sec to 18 sec/2 sec
- Control systems – The only control system that is assumed to function during a full power-steam line-rupture-core-response event is the main feedwater system. For this event, the feedwater flow is set to match the steam flow

Depending on the size of the break, this event is classified as either a Condition III (infrequent fault) or Condition IV (limiting fault) event. However, the analysis was done to the more conservative Condition II acceptance criteria. The acceptance criteria for this event are consistent with those stated in LR Section 2.8.5.1.2.2; the primary criteria are minimum DNBR and peak linear heat rate (kW/ft)

2.8.5.1.2.2.2.3 Description of Analysis and Evaluations

The analysis of the steam line break at-power for the EPU was performed as follows:

- The RETRAN code (Reference 7) was used to calculate the nuclear power, core heat flux, and RCS temperature and pressure transients resulting from the cooldown following the steam line break.
- The core radial and axial peaking factors were determined using the thermal-hydraulic conditions from RETRAN as input to the nuclear core models. A detailed thermal-hydraulic code, VIPRE (Reference 8), was used to calculate the DNBR for the limiting time during the transient. The DNBR calculations were performed using the WRB-1 DNB correlation and RTDP.

2.8.5.1.2.2.2.4 Steam System Piping Failure at Full-Power Results

The limiting break size from the spectrum of break sizes analyzed is 0.59 ft^2 (Unit 1) and 0.63 ft^2 (Unit 2), with a minimum DNBR of 1.644 (Unit 1) and 1.654 (Unit 2) versus a limit of 1.380, and a peak fuel rod power of 22.51 kW/ft (Unit 1) and 22.26 kW/ft (Unit 2) versus a limit of 22.54 kW/ft. The sequence of events for these limiting cases are shown in Table 2.8.5.1.2-3, Unit 1: Time Sequence of Events – Steam System Piping Failure at Full Power (Core Response – 0.59 ft^2 break), and Table 2.8.5.1.2-4, Unit 2: Time Sequence of Events – Steam System Piping Failure at Full Power (Core Response – 0.63 ft^2 break), for Unit 1 and Unit 2, respectively. Plots for these limiting cases are provided in Figures 2.8.5.1.2-13 through 2.8.5.1.2-16 (Unit 1) and Figures 2.8.5.1.2-17 through 2.8.5.1.2-20 (Unit 2).

The 0.59 ft^2 (Unit 1) and 0.63 ft^2 (Unit 2) break sizes are the most limiting break size with respect to peak core heat flux, minimum DNBR, and peak linear heat generation (kW/ft) for the full-power steam line rupture – core response event.

The DNB design basis and the kW/ft limit are met. Therefore, this event does not adversely affect the core or RCS, and all applicable criteria are met.

The results and conclusions of the analysis performed for the steam system piping failure at full power for the nuclear steam supply system (NSSS) power of 1806 MWt support the implementation of EPU. Furthermore, the results and conclusions of this analysis will be confirmed on a cycle-specific basis as part of the normal reload process.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

EPU activities associated with these analyses do not add any new functions for existing components of the MS System that would change the license renewal system evaluation boundaries. The changes associated with operating the MS System at EPU conditions do not add any new or previously unevaluated aging effects that necessitate a change to aging management programs or require new programs as internal and external environments remain within the parameters previously evaluated. Therefore, EPU activities associated with these analyses do not impact license renewal scope, aging effects, and aging management programs associated with the MS System.

2.8.5.1.2.2.2.5 Conclusion

PBNP has reviewed the analyses of the steam system piping failure events described above and concludes that the analyses have adequately accounted for plant operation at the proposed power level and were performed using acceptable analytical models. PBNP further concludes that the evaluation has demonstrated that the reactor protection and safety systems will continue to ensure that the ability to insert control rods is maintained, the reactor coolant pressure boundary pressure limits will not be exceeded, the reactor coolant pressure boundary will behave in a non-brittle manner, the probability of propagating fracture of the reactor coolant pressure boundary is minimized, and adequate core cooling will be provided. Based on this, PBNP will continue to meet its current licensing basis with respect to the requirements of PBNP GDC 9, 30, 32, 33, 34 and 40 following implementation of the proposed EPU. Therefore, PBNP finds the proposed EPU acceptable with respect to steam system piping failures.

2.8.5.1.2.3 References

1. Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005
2. WCAP-14882-P-A (Proprietary), RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses, Huegel, D. S., et al., April 1999
3. WCAP-10965-P-A (Proprietary), ANC: A Westinghouse Advanced Nodal Computer Code, Davidson, S. L. (Ed.), et al., September 1986
4. WCAP-14565-P-A (Proprietary) and WCAP-15306-NP-A (Non-proprietary), VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis, Sung, Y. X. et al., October 1999
5. Moody, F. J., Transactions of the ASME, Journal of Heat Transfer, Figure 3, page 134, February 1965
6. WCAP-11397-P-A (Proprietary) and WCAP-11397-A (Nonproprietary), Revised Thermal Design Procedure, Friedland, A. J. and Ray, S., April 1989
7. WCAP-14882-P-A (Proprietary), RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses, Huegel, D. S., et al., April 1999
8. WCAP-14565-P-A (Proprietary) and WCAP-15306-NP-A (Nonproprietary), VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis, Sung, Y. X. et al., October 1999

Table 2.8.5.1.2-1
Unit 1: Time Sequence of Events – Steam System Piping Failure at Hot Zero Power

Case	Event	Time (sec)
With Offsite Power Available (Model 44F steam generator)	Main steam line ruptures in loop 1	0.0
	High-high steam line flow setpoint reached in loop 1	0.01
	High-high steam line flow setpoint reached in loop 2	0.23
	Low steam pressure SI setpoint reached in loop 1, steam line isolation logic satisfied in both loops	1.5
	SI actuation occurs	3.5
	Steam line isolation completed in both loops	8.5
	Main feedwater isolation completed in both loops	13.5
	SI pumps achieve full speed	14.5
	SI flow injection begins (cold leg pressure falls below SI pump shutoff pressure)	16.9
	Criticality attained	30.7
	Accumulators begin to inject	91.8
	Peak core heat flux, minimum DNBR occurs	93.8
	Borated water from the SIS reaches the core (> 1 ppm)	94.0

Table 2.8.5.1.2-2
Unit 2: Time Sequence of Events – Steam System Piping Failure at Hot Zero Power

Case	Event	Time (sec)
With Offsite Power Available (Model Δ47 steam generator)	Main steam line ruptures in loop 1	0.0
	High-high steam line flow setpoint reached in loop 1	0.01
	High-high steam line flow setpoint reached in loop 2	0.24
	Low steam pressure SI setpoint reached in loop 1, steam line isolation logic satisfied in both loops	1.4
	SI actuation occurs	3.4
	Steam line isolation completed in both loops	8.4
	Main feedwater isolation completed in both loops	13.4
	SI pumps achieve full speed	14.4
	SI flow injection begins (cold leg pressure falls below SI pump shutoff pressure)	16.2
	Criticality attained	30.2
	Accumulators begin to inject	86.8
	Borated water from the SIS reaches the core (> 1 ppm)	88.7
	Peak core heat flux, minimum DNBR occurs	89.0

Table 2.8.5.1.2-3
Unit 1: Time Sequence of Events – Steam System Piping Failure at Full Power (Core Response – 0.59 ft^2 break)

Event	Time (sec)
Steam Line Ruptures	0.0
Overpower ΔT Reactor Trip Setpoint Reached (both loops)	24.3
Rods Begin to Drop	26.3
Minimum DNBR Occurs (1.644)*	26.5
Peak Core Heat Flux Occurs	26.5
* DNBR safety analysis limit: 1.380	

Table 2.8.5.1.2-4
Unit 2: Time Sequence of Events – Steam System Piping Failure at Full Power
(Core Response – 0.63 ft^2 break)

Event	Time (sec)
Steam Line Ruptures	0.0
Overpower ΔT Reactor Trip Setpoint Reached (both loops)	24.4
Rods Begin to Drop	26.4
Minimum DNBR Occurs (1.654)*	26.7
Peak Core Heat Flux Occurs	26.7
* DNBR safety analysis limit: 1.380	

Figure 2.8.5.1.2-1 Unit 1 Steam System Piping Failure at Hot Zero Power – 1.388 ft^2 Break With Offsite Power Available Nuclear Power and Core Heat Flux vs. Time

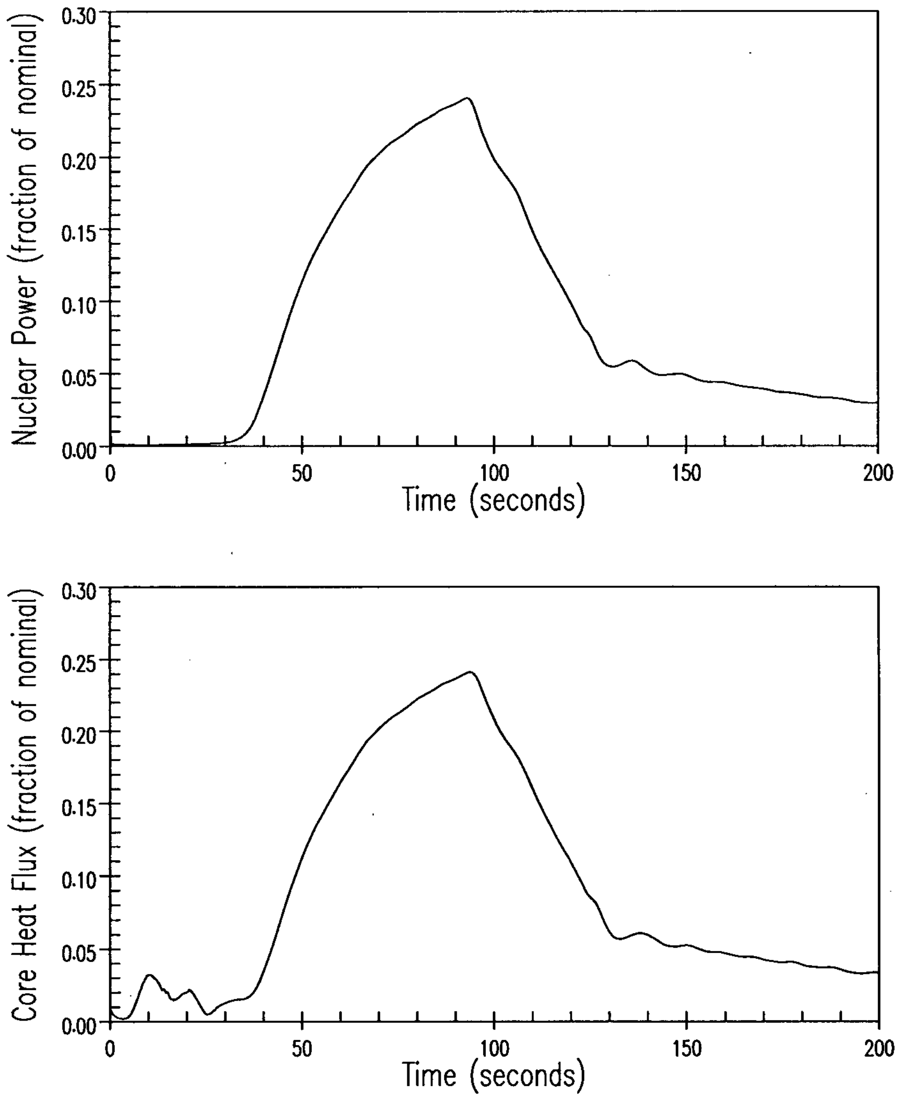
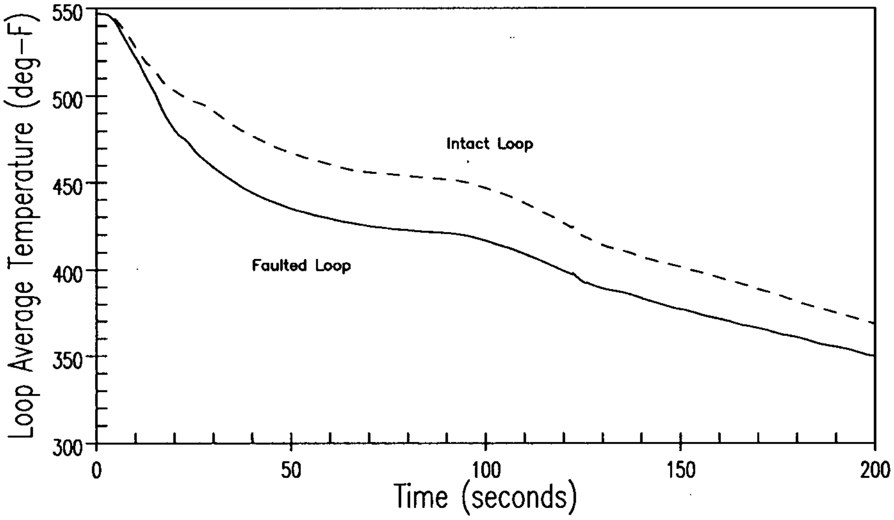


Figure 2.8.5.1.2-2 Unit 1 Steam System Piping Failure at Hot Zero Power – 1.388 ft^2 Break With Offsite Power Available RCS Average and Cold Leg Temperatures vs. Time



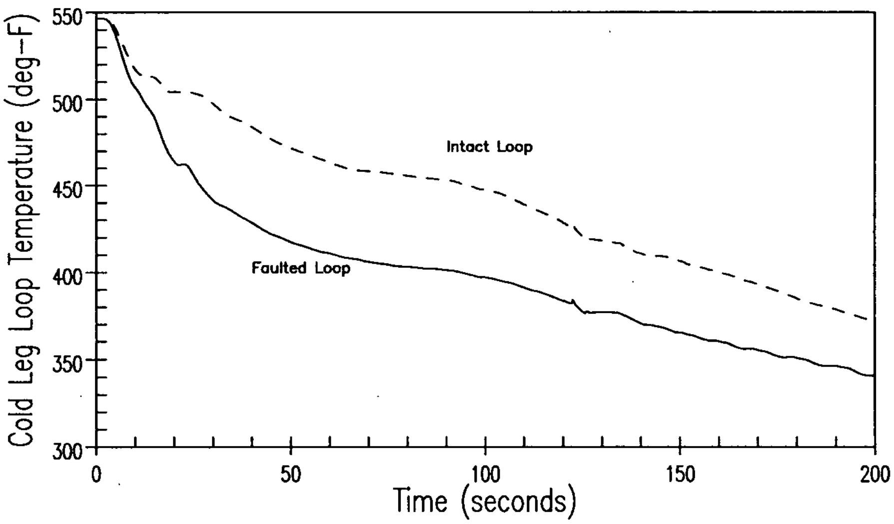


Figure 2.8.5.1.2-3 Unit 1 Steam System Piping Failure at Hot Zero Power – 1.388 ft^2 Break With Offsite Power Available Core Pressure and Pressurizer Water Volume vs. Time

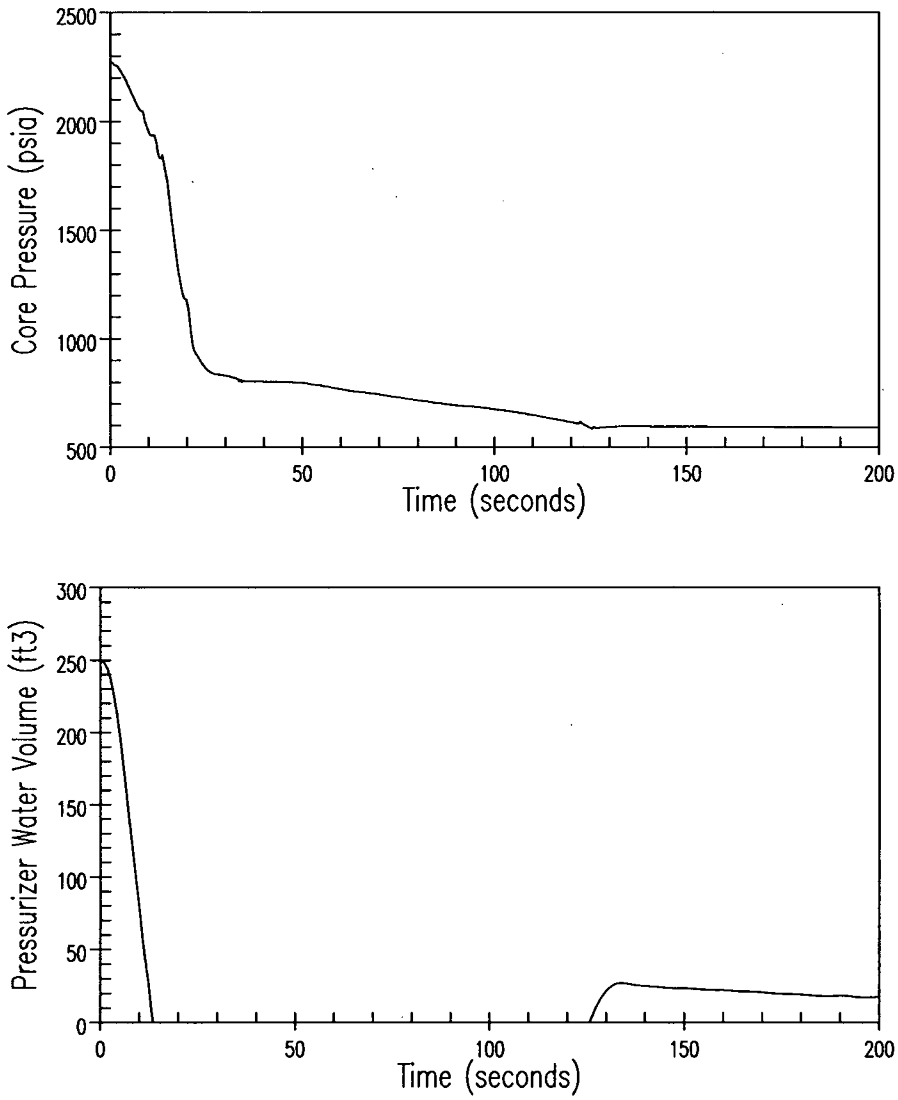


Figure 2.8.5.1.2-4 Unit 1 Steam System Piping Failure at Hot Zero Power – 1.388 ft^2 Break With Offsite Power Available Core Boron Concentration and Reactivity vs. Time

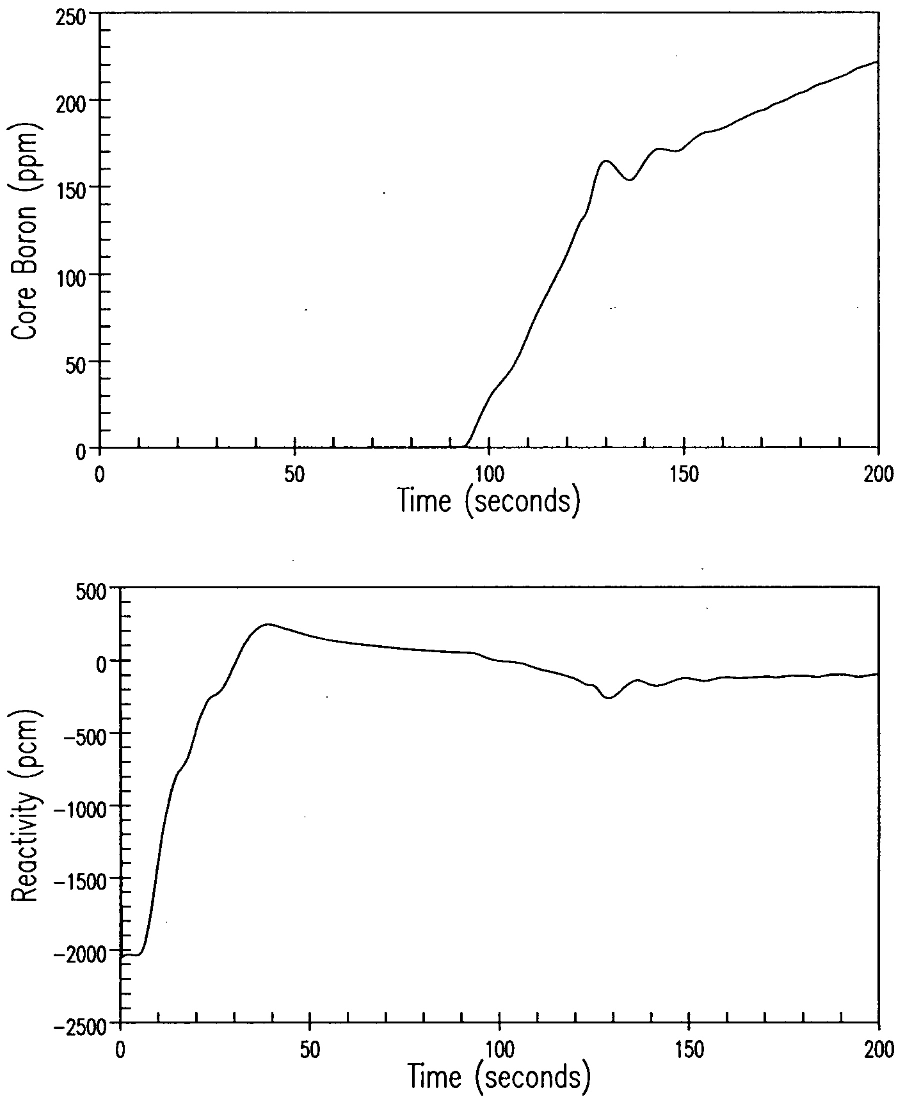


Figure 2.8.5.1.2-5 Unit 1 Steam System Piping Failure at Hot Zero Power – 1.388 ft^2 Break With Offsite Power Available Steam Pressure and Steam Flow vs. Time

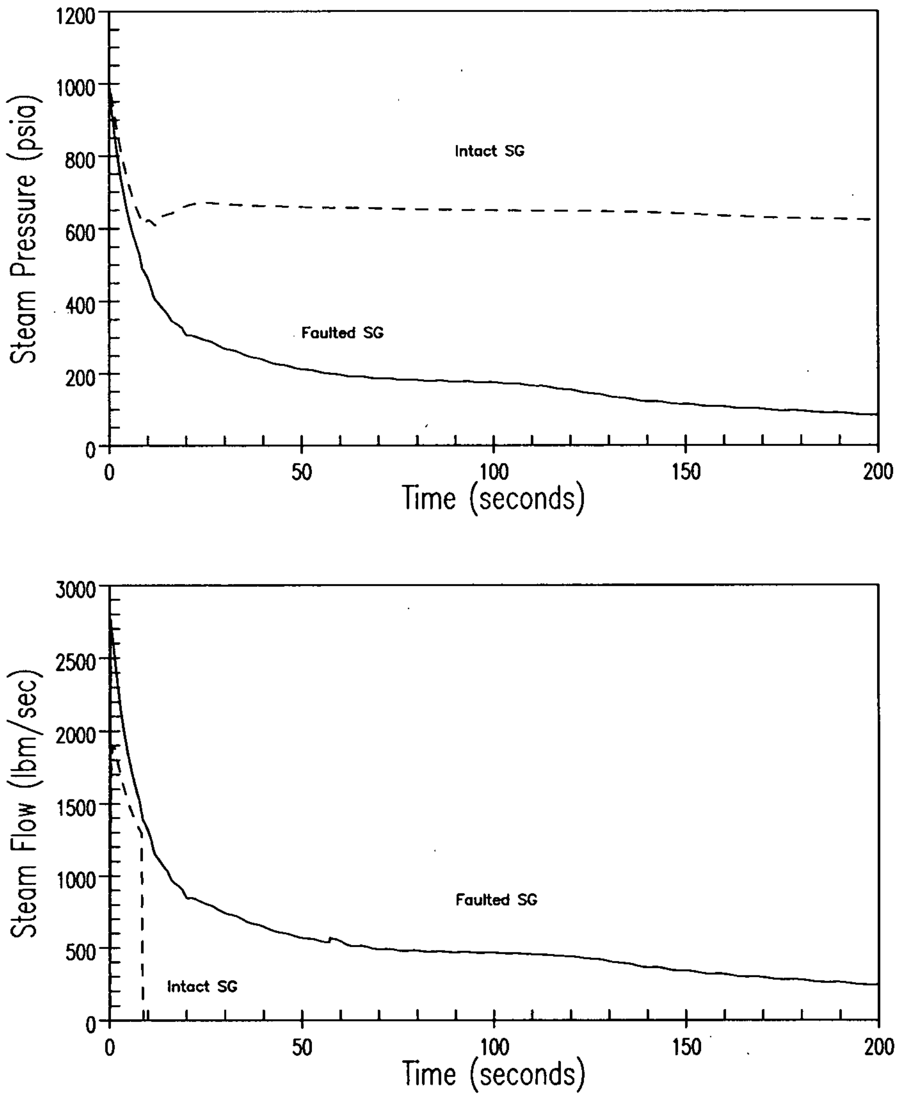


Figure 2.8.5.1.2-6 Unit 1 Steam System Piping Failure at Hot Zero Power – 1.388 ft² Break With Offsite Power Available Feedwater Flow and Core Flow vs. Time

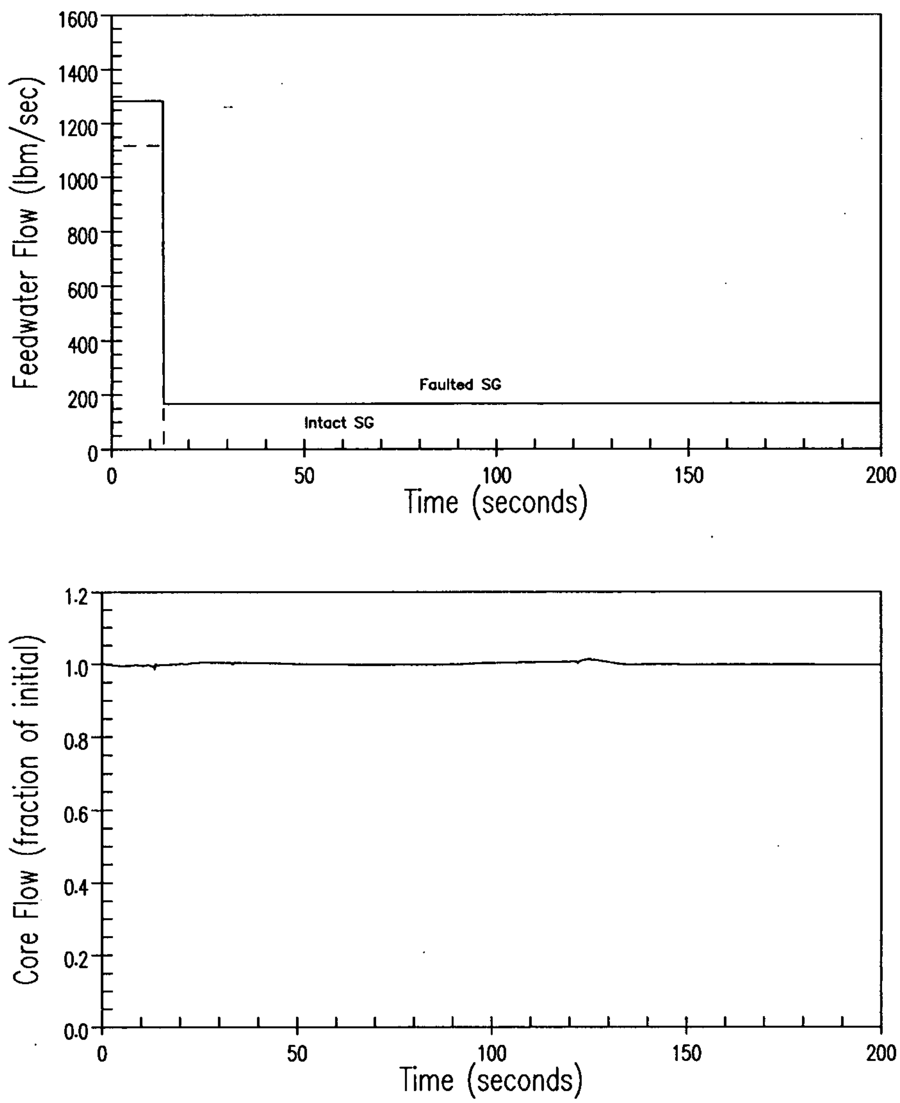


Figure 2.8.5.1.2-7 Unit 2 Steam System Piping Failure at Hot Zero Power – 1.388 ft^2 Break With Offsite Power Available Nuclear Power and Core Heat Flux vs. Time

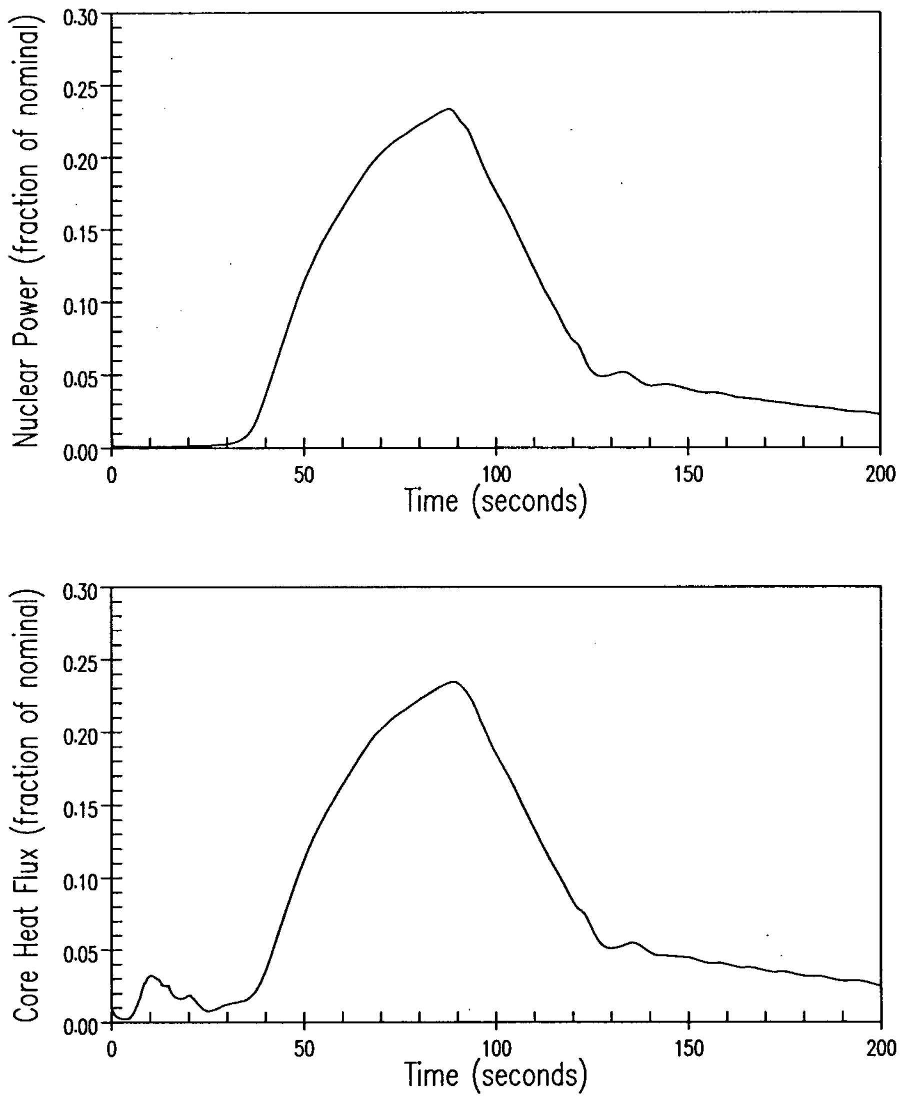


Figure 2.8.5.1.2-8 Unit 2 Steam System Piping Failure at Hot Zero Power – 1.388 ft^2 Break With Offsite Power Available RCS Average and Cold Leg Temperatures vs. Time

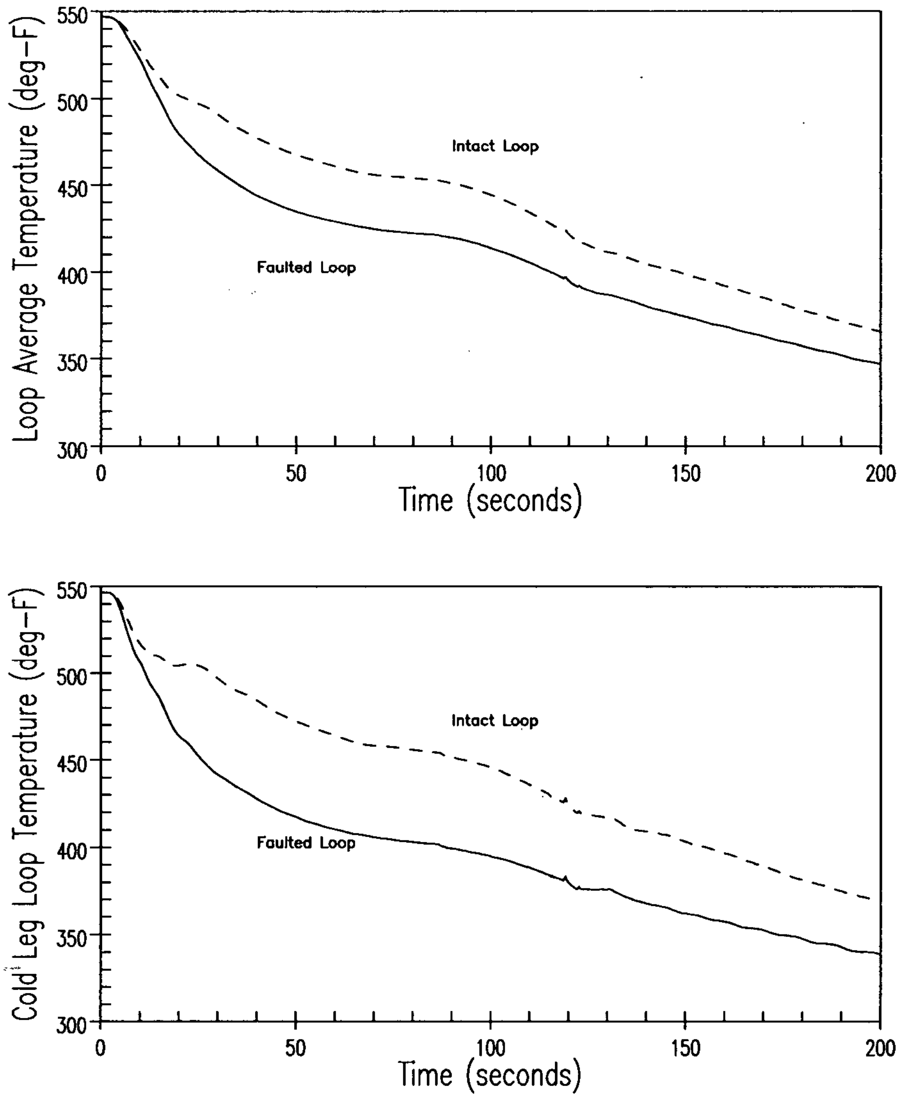
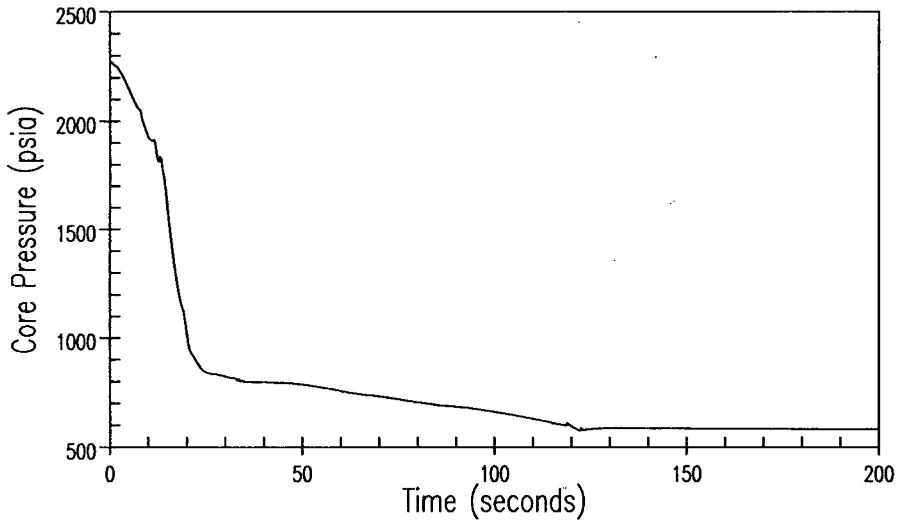


Figure 2.8.5.1.2-9 Unit 2 Steam System Piping Failure at Hot Zero Power – 1.388 ft^2 Break With Offsite Power Available Core Pressure and Pressurizer Water Volume vs. Time



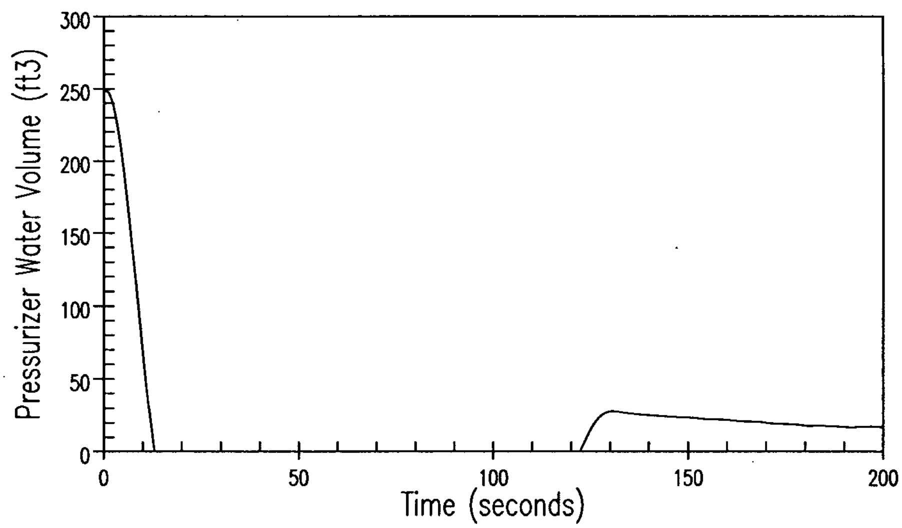
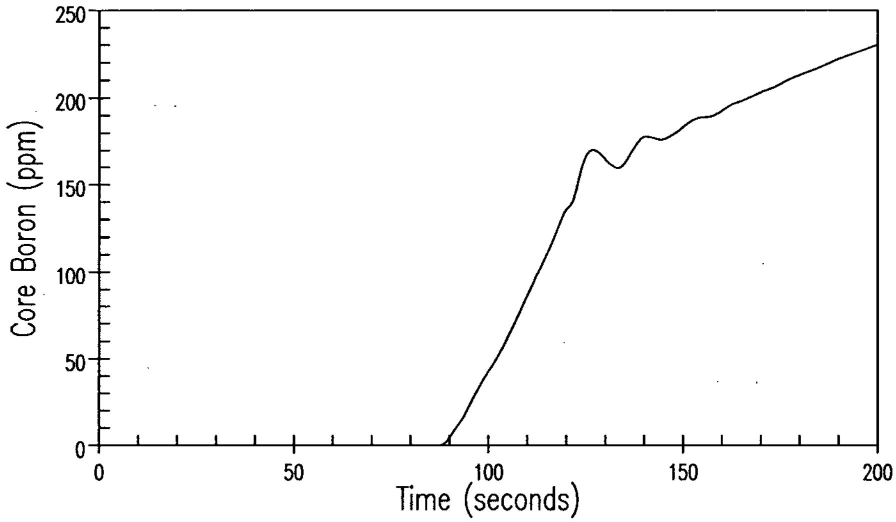


Figure 2.8.5.1.2-10 Unit 2 Steam System Piping Failure at Hot Zero Power – 1.388 ft^2 Break With Offsite Power Available Core Boron Concentration and Reactivity vs. Time



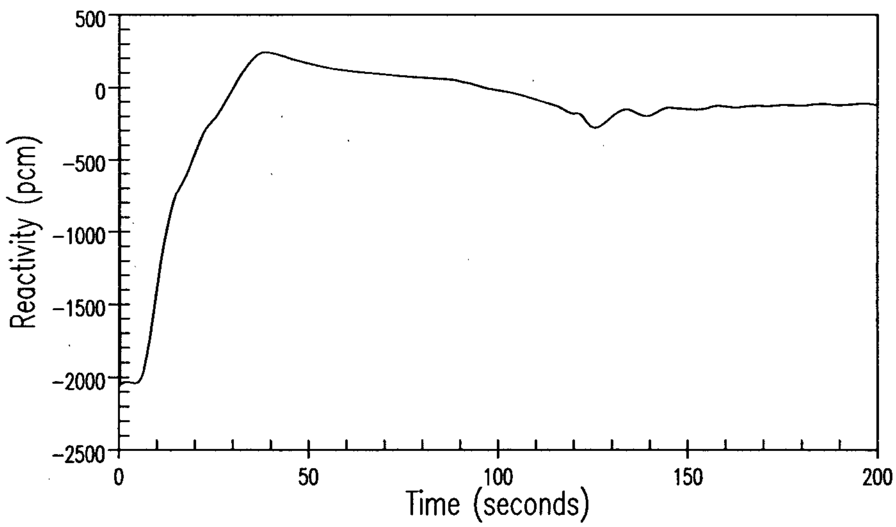


Figure 2.8.5.1.2-11 Unit 2 Steam System Piping Failure at Hot Zero Power – 1.388 ft^2 Break With Offsite Power Available Steam Pressure and Steam Flow vs. Time

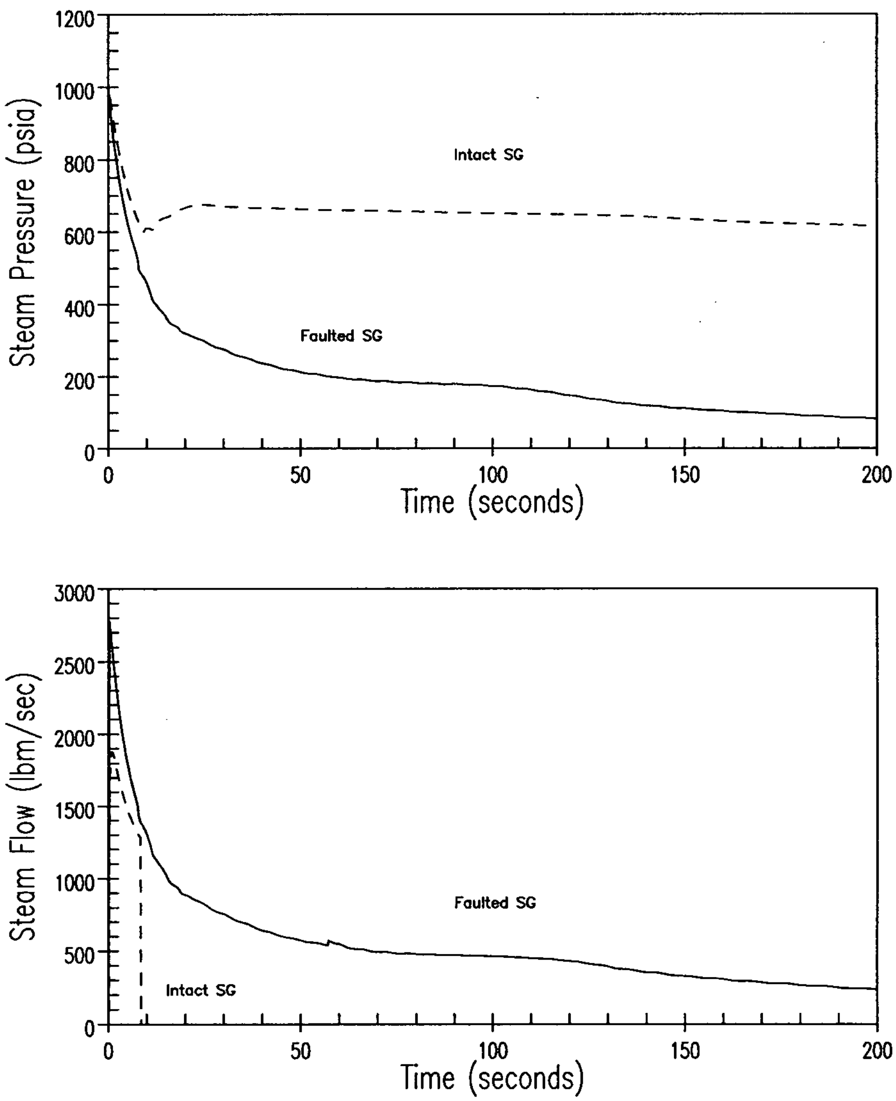
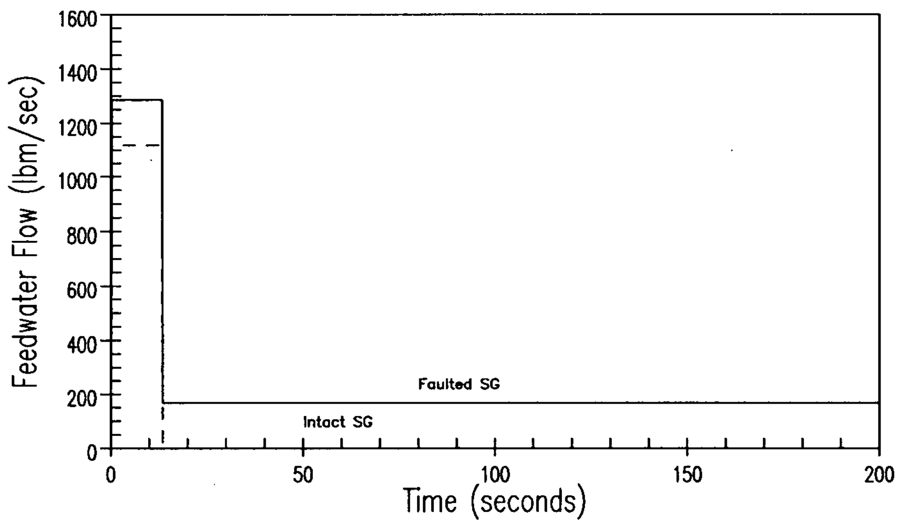


Figure 2.8.5.1.2-12 Unit 2 Steam System Piping Failure at Hot Zero Power – 1.388 ft^2 Break With Offsite Power Available Feedwater Flow and Core Flow vs. Time



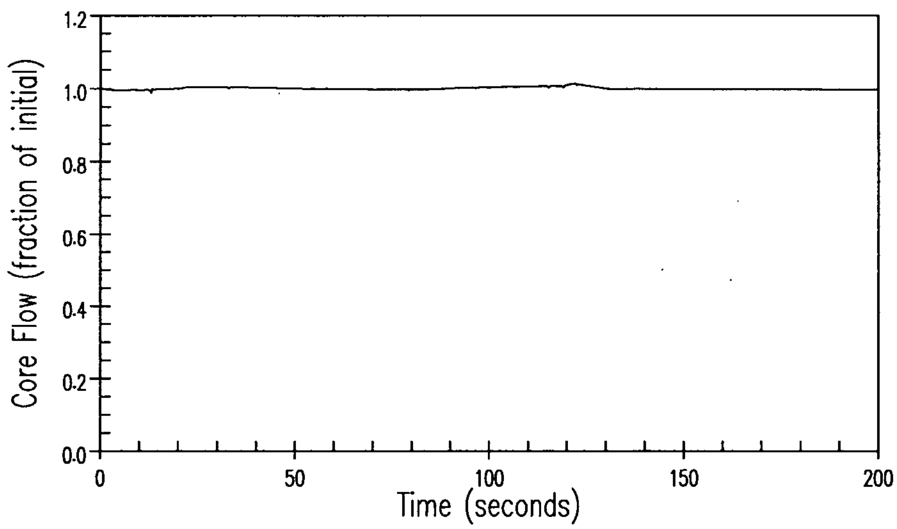


Figure 2.8.5.1.2-13 Unit 1 Steam System Piping Failure at Full Power – 0.59 ft^2 Break Nuclear Power and Core Heat Flux vs. Time

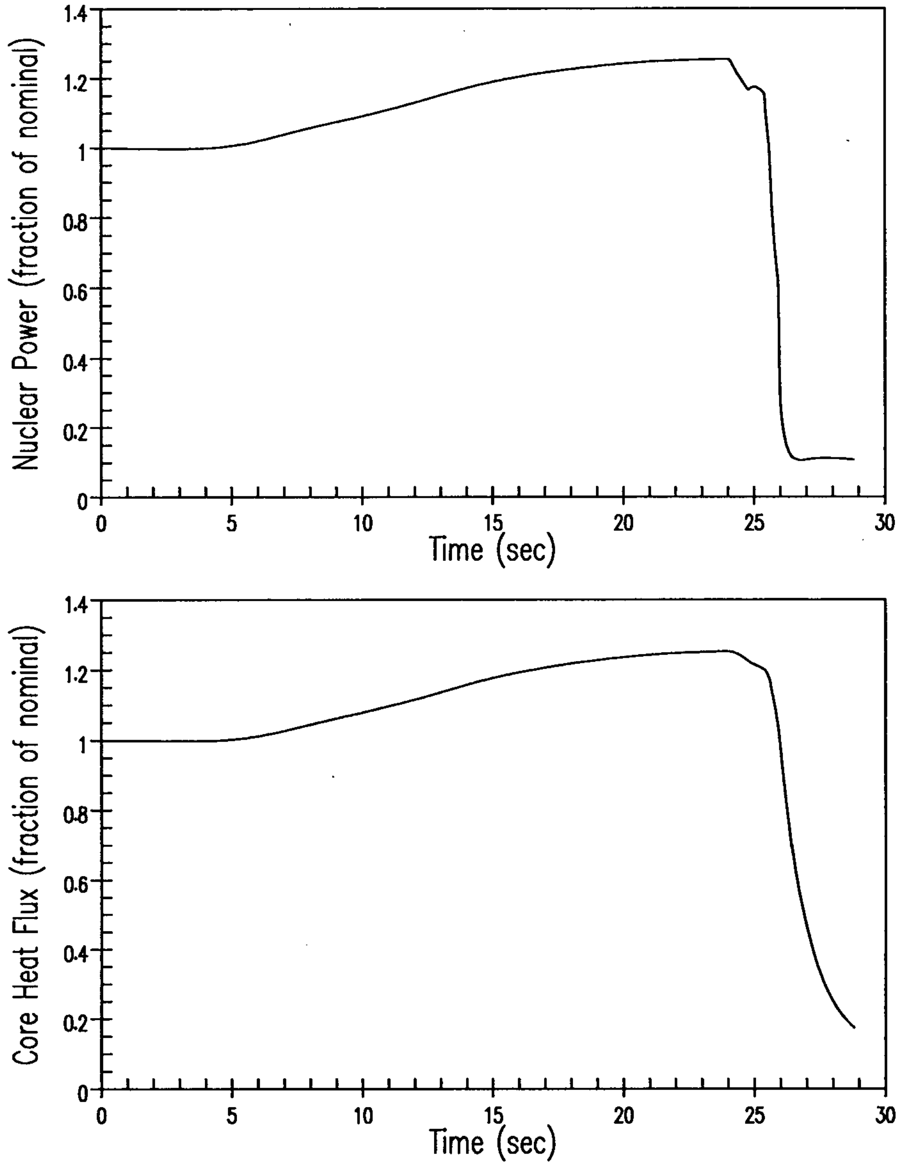


Figure 2.8.5.1.2-14 Unit 1 Steam System Piping Failure at Full Power – 0.59 ft^2 Break Pressurizer Pressure and Pressurizer Water Volume vs. Time

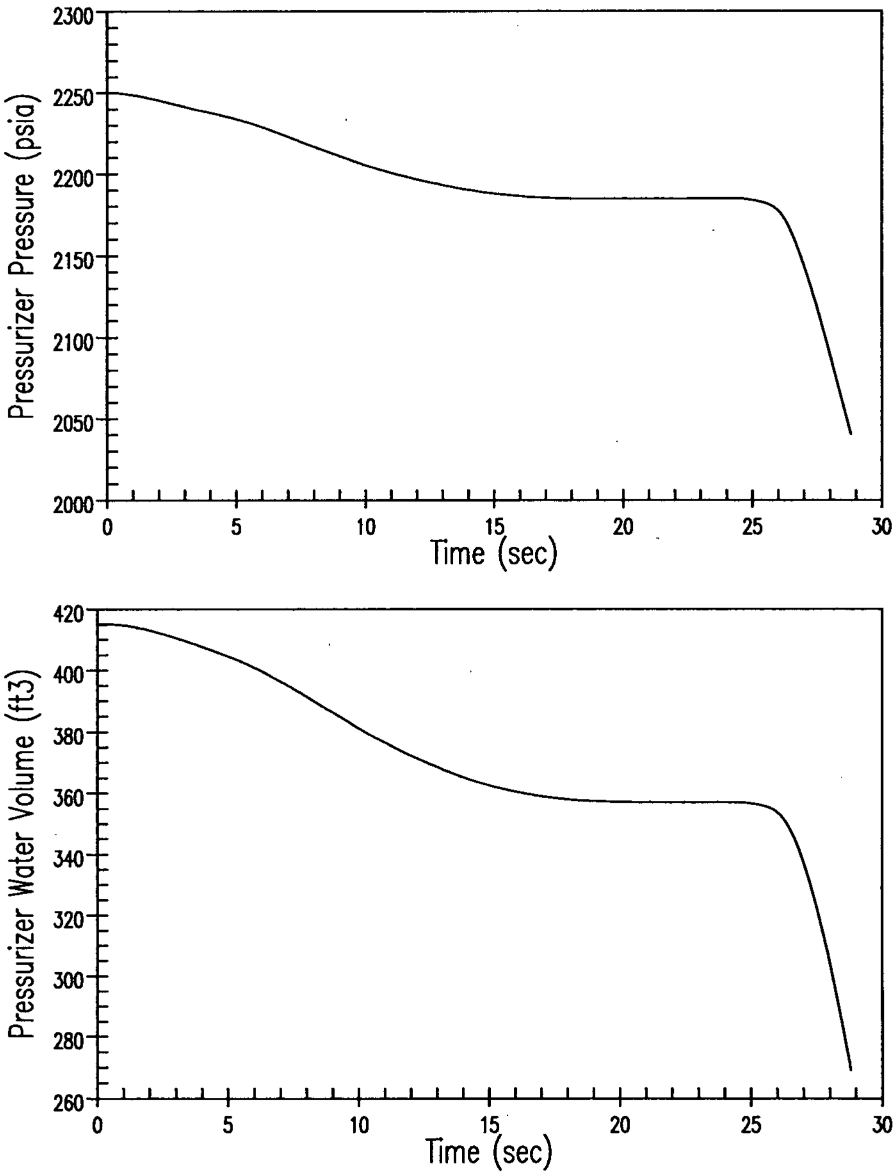


Figure 2.8.5.1.2-15 Unit 1 Steam System Piping Failure at Full Power – 0.59 ft^2 Break Vessel Inlet Temperature vs. Time

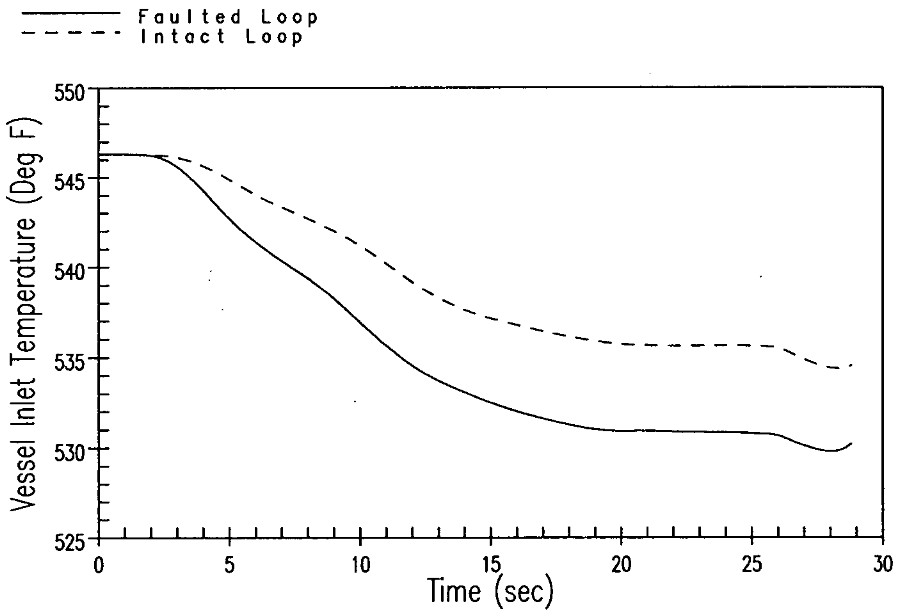


Figure 2.8.5.1.2-16 Unit 1 Steam System Piping Failure at Full Power – 0.59 ft^2 Break Steam Generator Dome Pressure and Steam Generator Outlet Steam Flow Rate vs. Time

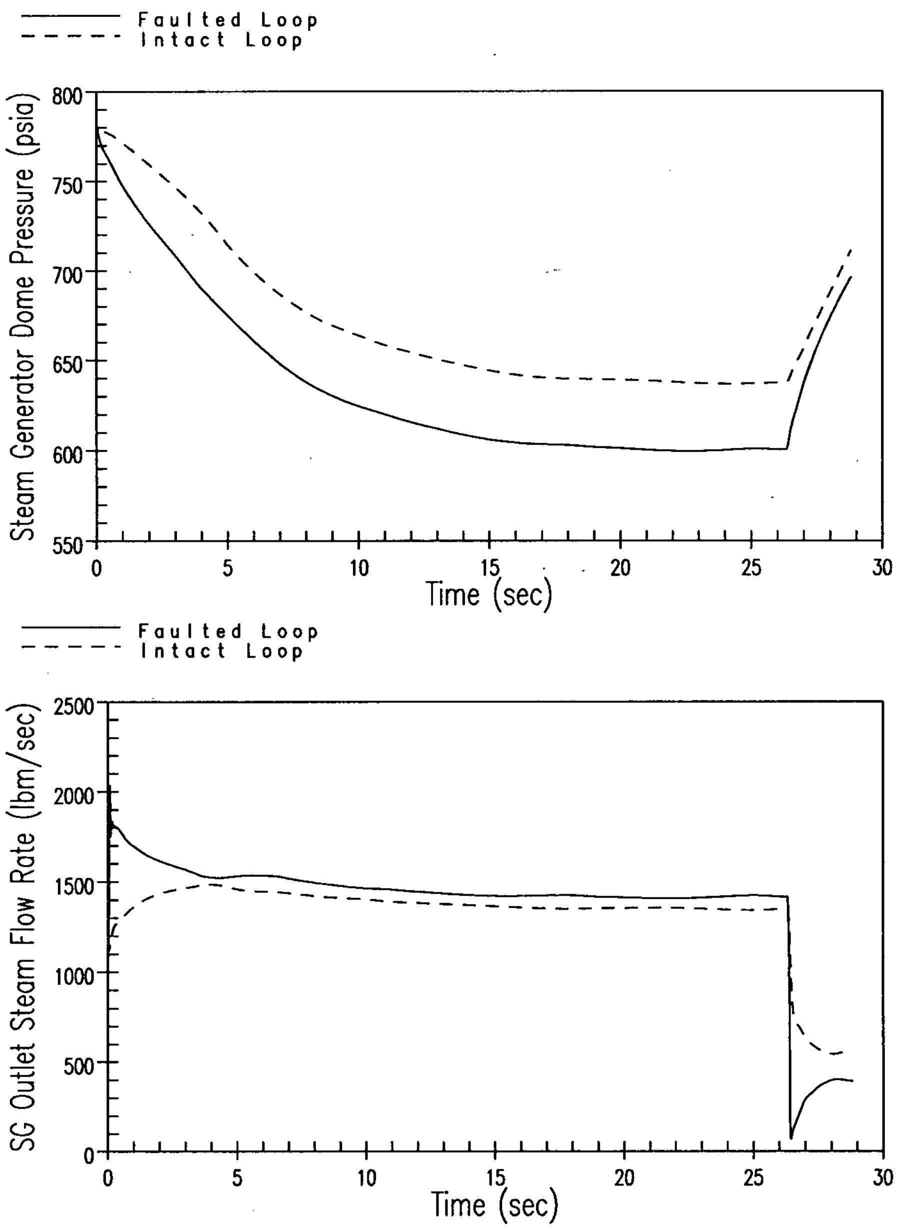
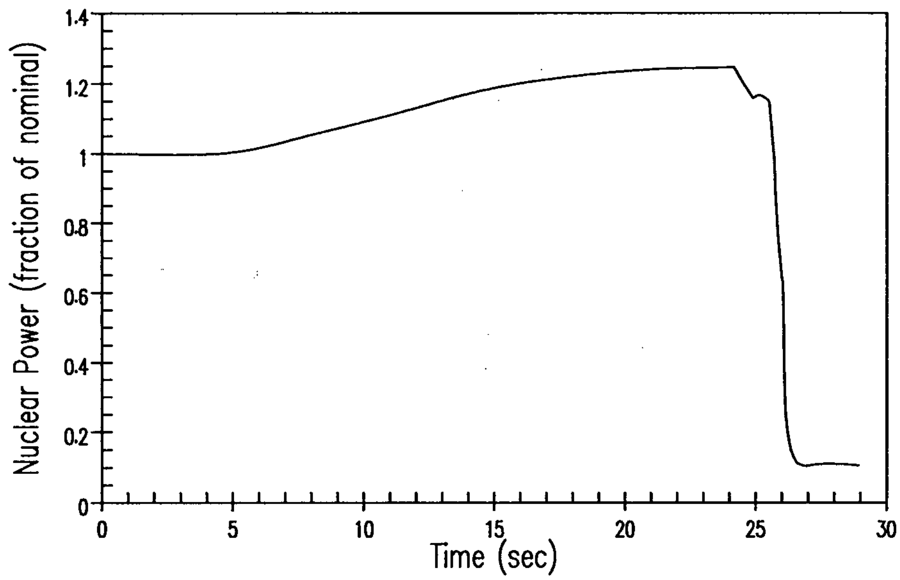


Figure 2.8.5.1.2-17 Unit 2 Steam System Piping Failure at Full Power – 0.63 ft^2 Break Nuclear Power and Core Heat Flux vs. Time



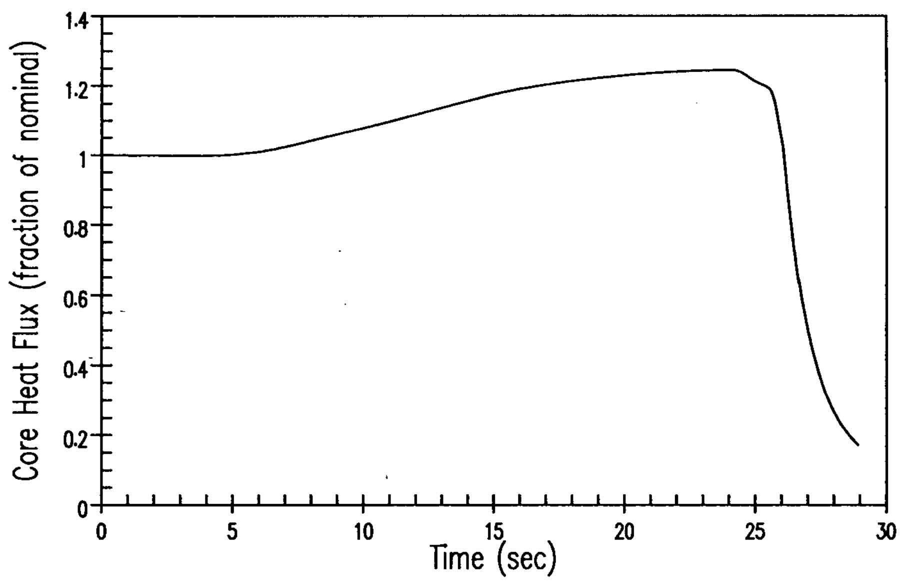


Figure 2.8.5.1.2-18 Unit 2 Steam System Piping Failure at Full Power – 0.63 ft^2 Break Pressurizer Pressure and Pressurizer Water Volume vs. Time

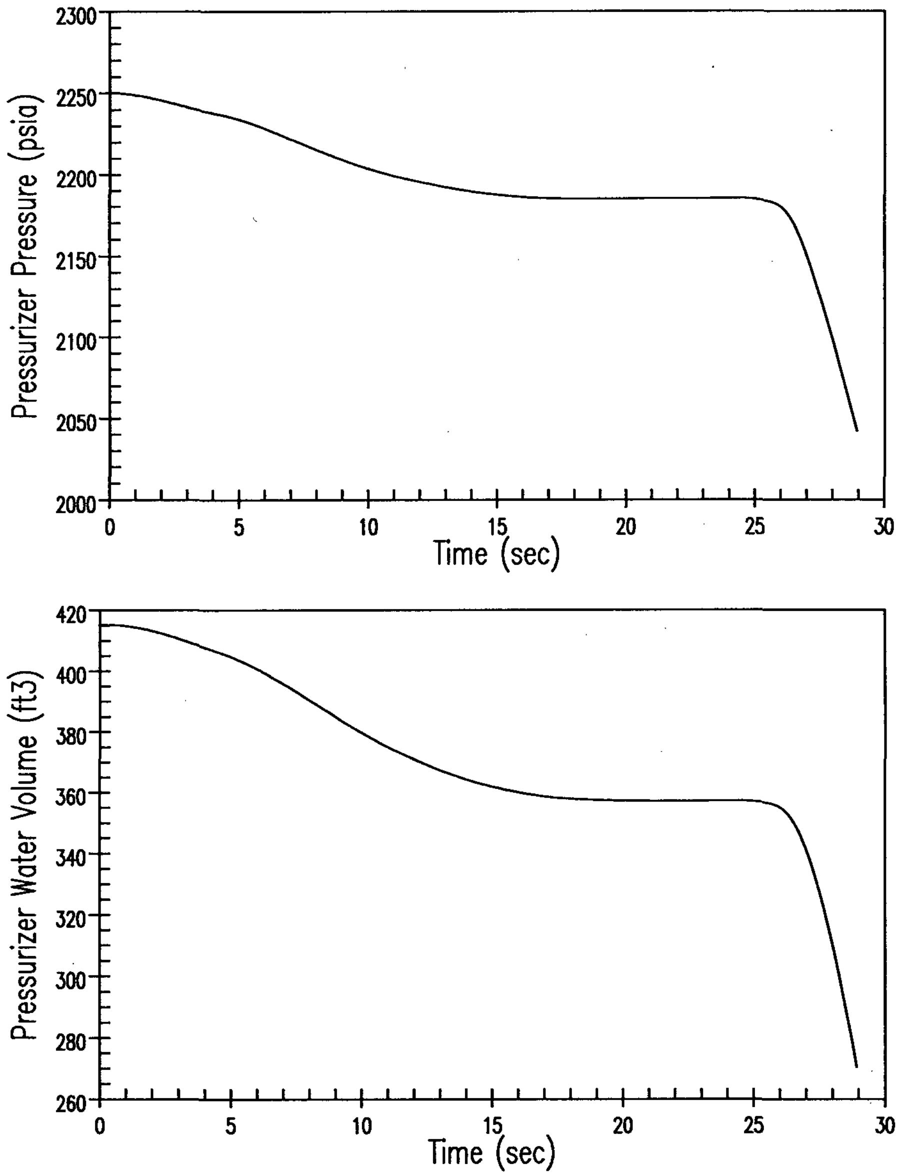


Figure 2.8.5.1.2-19 Unit 2 Steam System Piping Failure at Full Power – 0.63 ft^2 Break Vessel Inlet Temperature vs. Time

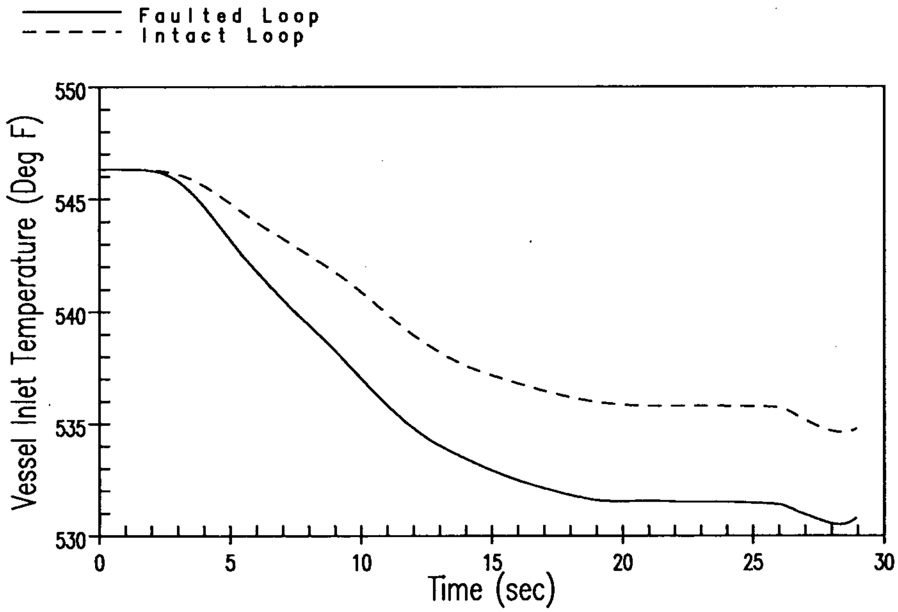
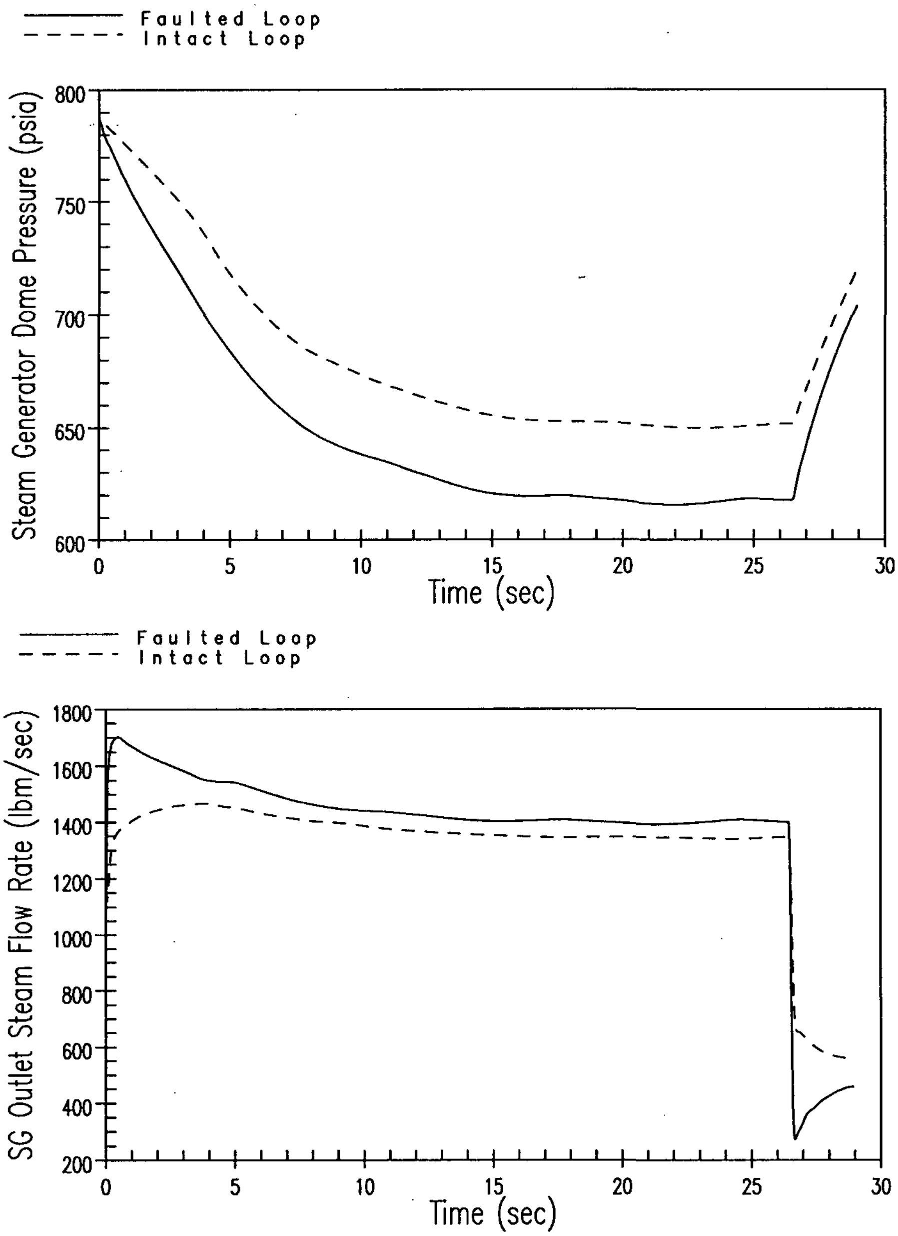


Figure 2.8.5.1.2-20 Unit 2 Steam System Piping Failure at Full Power – 0.63 ft^2 Break Steam Generator Dome Pressure and Steam Generator Outlet Steam Flow Rate vs. Time



2.8.5.2 Decrease in Heat Removal By the Secondary System

2.8.5.2.1 Loss of External Electrical Load, Turbine Trip, and Loss of Condenser Vacuum

2.8.5.2.1.1 Regulatory Evaluation

A number of initiating events can result in unplanned decreases in heat removal by the secondary system. These events result in a sudden reduction in steam flow and, consequently, result in pressurization events. Reactor protection and safety systems are actuated to mitigate the transient.

Loss of external electrical load can cause a sudden heat addition to the reactor coolant system (RCS) resulting in an increase in RCS temperature and pressure and an increase in pressurizer level and affect fuel design parameters and core reactivity. Similar effects to the RCS will be experienced following instantaneous turbine trip or loss of condenser vacuum during power operation.

The PBNP review covered the sequence of events, the analytical models used for analyses, the values of parameters used in the analytical models, and the results of the transient analyses.

The NRC acceptance criteria are based on:

- GDC 10, insofar as it requires that the RCS is designed with appropriate margin to ensure that specified acceptable fuel design limits are not exceeded during normal operations, including anticipated operational occurrences
- GDC 15, insofar as it requires that the RCS and its associated auxiliary systems is designed with sufficient margin to ensure that the design condition of the reactor coolant pressure boundary is not exceeded during any condition of normal operation
- GDC 26, insofar as it requires that a reactivity control system is provided, and is capable of reliably controlling the rate of reactivity changes to ensure that under normal operating conditions, including anticipated operational occurrences, specified acceptable fuel design limits are not exceeded

Specific review criteria are contained in the SRP, Section 15.2.1-5, and other guidance provided in Matrix 8 of RS-001.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50 Appendix A GDC 10, 15 and 26 are as follows:

CRITERION: The reactor core with its related controls and protection systems shall be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits which have been stipulated and justified. The core and related auxiliary system designs shall provide this integrity under all expected conditions of normal operation with appropriate margins for uncertainties and for specified transient situations which can be anticipated. (PBNP GDC 6)

As described in FSAR Section 3.1.2.1, Reactor Core Deisgn, the reactor core with its related control and protection system, is designed to function throughout its design lifetime without exceeding acceptable fuel damage limits.

Fuel design and nuclear design are further discussed in LR Section 2.8.1, Fuel System Design, and LR Section 2.8.2, Nuclear Design.

CRITERION: The reactor coolant pressure boundary shall be designed, fabricated, and constructed so as to have an exceedingly low probability of gross rupture or significant uncontrolled leakage throughout its design lifetime. (PBNP GDC 9)

As described in FSAR Section 4.1, Reactor Coolant System, Design Basis, the reactor coolant system, in conjunction with its control and protective provisions, is designed to accommodate the system pressures and temperatures attained under all expected modes of plant operation or anticipated system interactions, and maintain the stresses within applicable code stress limits.

System conditions resulting from anticipated transients or malfunctions are monitored and appropriate action is automatically initiated to maintain the required cooling capability and to limit system conditions to a safe level. The system is protected from overpressure by means of pressure relieving devices, as required by Section III of the ASME Boiler and Pressure Vessel Code. The system is also protected from overpressure at low temperatures by the low temperature overpressure protection system.

CRITERION: One of the reactivity control systems provided shall be capable of making the core subcritical under any anticipated operating condition (including anticipated operational transients) sufficiently fast to prevent exceeding acceptable fuel damage limits. Shutdown margin should assure subcriticality with the most reactive control rod fully withdrawn. (PBNP GDC 29)

The reactor core, together with the reactor control and protection system, is designed so that the minimum allowable DNBR is at least equal to the limits specified for STD, OFA, upgraded OFA, and 422V+ fuel, and there is no fuel melting during normal operation, including anticipated transients.

The shutdown groups are provided to supplement the control group of RCCAs to make the reactor at least 1% subcritical ($k_{eff} = 0.99$) following a trip from any credible operating condition to the hot, zero power condition assuming the most reactive RCCA remains in the fully withdrawn position.

In addition to the evaluations described in the FSAR, the analyses of events at PBNP that can result in a sudden reduction in steam flow, and hence increase in reactor coolant system pressure, were evaluated for plant License Renewal. System and system component materials of construction, operating history, and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2 (NUREG-1839), dated December 2005 (Reference 1)

The Loss of External Electrical Load, Turbine Trip, and Loss of Condenser Vacuum analyses are not evaluated for license renewal.

2.8.5.2.1.2 Technical Evaluation

2.8.5.2.1.2.1 Introduction

A major load loss on the plant (FSAR Section 14.1.9, Loss of Electrical Load) can result from either a loss-of-external-electrical load or from a turbine trip. A loss-of-external-electrical load can result from an abnormal variation in network frequency or other adverse network operating condition. In either case, offsite power is available for the continued operation of plant components such as the reactor coolant pumps (RCPs). A turbine trip can result from several occurrences, including a loss of condenser vacuum. A loss of condenser vacuum would preclude the use of steam dumps to the condenser. However, since steam dumps are assumed to not be available in the analysis of the loss-of-external-electrical load/turbine trip event, no additional adverse effects would result if the turbine trip were caused by a loss of condenser vacuum. Therefore, the analysis results and conclusions contained in this section apply to a loss-of-external-electrical load, turbine trip and loss of condenser vacuum.

The plant is designed to accept a 50% loss-of-electrical load while operating at full power, or a complete loss of load while operating below 50% power without actuating a reactor trip with all nuclear steam supply system (NSSS) control systems in automatic (see LR Section 2.4.2, Plant Operatibility). A 50% loss-of-electrical load is handled by the steam dump system, the rod control system, and the pressurizer. Should a complete loss of load occur from full power, the reactor protection system will automatically actuate a reactor trip.

The most likely source of a complete loss of load on the NSSS is a trip of the turbine generator. In this case, there is a direct reactor trip signal derived from either the turbine auto-stop oil pressure or a closure of the turbine stop valves, provided the reactor is operating above 50% power. Reactor temperature and pressure do not increase significantly if the steam dump system and pressurizer pressure control system are functioning properly. However, the RCS and main steam system (MSS) pressure-relieving capacities are designed to ensure the safety of the plant without requiring the use of automatic rod control, pressurizer pressure control, and/or steam dump control systems. In this analysis, the behavior of the plant is evaluated for a complete loss-of-steam load from full power without direct reactor trip from a turbine trip in order to demonstrate the adequacy of the pressure-relieving devices and core protection margins.

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

2.8.5.2.1.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Three cases were analyzed for a total loss of load from full-power conditions:

- Minimum Departure from Nucleate Boiling Ratio (DNBR) Case – With automatic pressurizer pressure control and maximum steam generator tube plugging (SGTP)
- Peak MSS Pressure Case – With automatic pressurizer pressure control and minimum SGTP
- Peak RCS Pressure Case – Without automatic pressurizer pressure control and maximum SGTP

For the minimum DNBR case, it must be shown that the calculated DNBR remains above the safety analysis DNBR limit. For the peak RCS and peak MSS pressure cases, it must be shown that the pressures remain below 110% of their respective design pressures.

The key attributes of the analyses are summarized as follows:

Initial Operating Conditions

The minimum DNBR case was analyzed using the revised thermal design procedure (RTDP) (Reference 2). NSSS power and RCS temperature and pressure were assumed to be at their nominal values consistent with steady-state, full-power operation. Minimum measured flow was modeled. Uncertainties in initial conditions were included in the safety analysis DNBR limit as described in Reference 2.

The peak RCS and MSS pressure cases were analyzed using the standard thermal design procedure (STDP). Initial uncertainties on NSSS power, reactor coolant flow and RCS temperature and pressure were applied in the conservative direction to obtain the initial plant conditions for the transient. Both cases modeled thermal design flow.

Reactivity Coefficients

The total loss of load transient was analyzed conservatively with minimum reactivity feedback (beginning of core life). All cases assumed the least-negative doppler power coefficient and a 0 pcm/°F moderator temperature coefficient, which bounds less than full power conditions with a positive moderator temperature coefficient. Minimum reactivity conditions were conservative since reactor power was maintained until the time of reactor trip, which exacerbated the calculated minimum DNBR and maximum RCS and MSS pressures.

Reactor Control

Manual rod control was modeled for all cases. If the reactor had been in automatic rod control, the control rod banks would have driven into the core prior to reactor trip, thereby reducing the severity of the transient.

Pressurizer Spray, PORVs, and Safety Valves

The loss-of-load event was analyzed both with and without pressurizer pressure control. The pressurizer PORVs and sprays were assumed to be operable for the minimum DNBR case to minimize the increase in primary pressure, which was conservative for the DNBR criterion. The pressurizer PORVs and sprays were also assumed to be operable for the peak MSS pressure case to minimize the increase in primary pressure, which delayed reactor trip, resulting in a conservatively high calculated peak secondary side pressure. The peak RCS pressure case was analyzed without pressurizer pressure control to conservatively maximize the RCS pressure increase. In all cases, the MSSVs and PSVs were assumed to be operable.

A total PSV setpoint tolerance of -3%/+2.5% was accounted for in the analysis. For the minimum DNBR case and peak MSS pressure case (pressurizer pressure control cases), the negative tolerance was applied to conservatively reduce the setpoint. For the case analyzed for peak RCS pressure, the positive tolerance was applied to conservatively increase the setpoint pressure; in addition, a +0.9% setpoint shift and a 0.85-second purge time delay were modeled to account for the existence of PSV water-filled loop seals, as described in Reference 4.

Feedwater Flow

Main feedwater flow to the steam generators was assumed to be lost at the time of turbine trip. No credit was taken for auxiliary feedwater flow; however, auxiliary feedwater flow would eventually be initiated and a stabilized plant condition reached in the long term.

Reactor Trip

Only the overtemperature ΔT, high-pressurizer pressure, and overpower ΔT reactor trips were assumed to be operable for the purposes of this analysis. No credit was taken for a reactor trip on high pressurizer level or the direct reactor trip on turbine trip. The minimum DNBR case, peak MSS pressure case and peak RCS pressure case all trip on the high pressurizer pressure signal.

Secondary Side Steam Release

No credit was taken for the operation of the steam dump system or steam generator atmospheric dump valves (ADVs). This assumption maximizes secondary pressure. The MSSV model for all cases includes an allowance of +3% for safety valve setpoint tolerance and an accumulation model that assumes that the safety valves are wide open once the pressure exceeds the setpoint (plus tolerance) by 5 psi.

Single Failures

The limiting single failure is failure of one train of the reactor protection system. The remaining (operable) train trips the reactor. The MSSVs and PSVs are considered passive safety-related components and are assumed not to fail to open on demand.

Steam Generator Conditions

Maximum (10%) steam generator tube plugging is assumed in the minimum DNBR case and peak RCS pressure case since it maximizes the RCS temperature transient following event initiation. However, the peak MSS pressure case is analyzed at zero steam generator tube plugging since this conservatively maximizes the primary-to-secondary heat transfer and maximizes the initial steam generator pressure. This assumption is slightly more limiting with respect to the secondary side pressure transient.

Acceptance Criteria

Based on its frequency of occurrence, the loss-of-external-electrical load/turbine trip accident is considered a Condition II event as defined by the American Nuclear Society. The specific criteria for this accident are as follows:

- Pressures in the reactor coolant and main steam systems are maintained below 110% of their respective design pressures (an RCS pressure limit of 2748.5 psia and an MSS pressure limit of 1208.5 psia)
- Fuel cladding integrity is maintained by demonstrating that the minimum DNBR remains above the 95/95 DNBR limit for PWRs (the applicable safety analysis DNBR limit is 1.34)
- An incident of moderate frequency does not generate a more serious plant condition without other faults occurring independently

  This criterion is satisfied by verifying that the pressurizer does not fill (i.e., total pressurizer water volume remains less than 1000 ft^3)
- An incident of moderate frequency in combination with any single active component failure, or single operator error, is considered an event for which an estimate of the number of potential fuel failures is provided for radiological dose calculations. For such accidents, fuel failure is assumed for all rods for which the DNBR falls below those values cited above for cladding integrity unless it can be shown, based on an acceptable fuel damage model, that fewer failures occur. There is no loss of function of any fission product barrier other than the fuel cladding

  This criterion is satisfied by verifying that DNBR remains above the 95/95 DNBR limit.

2.8.5.2.1.2.3 Description of Analyses and Evaluations

A detailed analysis using the RETRAN (Reference 3) computer code was performed to determine the plant transient conditions following a total loss of load due to turbine trip without a direct reactor trip from turbine trip. The code models the core neutron kinetics, RCS, pressurizer, pressurizer PORVs and sprays, steam generators, MSSVs, and the auxiliary feedwater system. RETRAN computes pertinent variables, including the pressurizer pressure, steam generator pressure, and reactor coolant average temperature. Additional discussion of the RETRAN code is contained in LR Section 2.8.5.0.9, Accident and Transient Analysis, Computer Codes Utilized.

2.8.5.2.1.2.4 Loss of External Electrical Load, Turbine Trip, and Loss of Condenser Vacuum Results

The calculated sequence of events for the three loss-of-external-electrical load/turbine trip cases analyzed for each unit are presented in Table 2.8.5.2.1-1, Time Sequence of Events – Loss of External Electrical Load and/or Turbine Trip. The limiting values for each case from the extended power uprate (EPU) analysis along with a comparison to the previous analysis results are shown in Table 2.8.5.2.1-2, Loss of External Electrical Load and/or Turbine Trip – Results and Comparison to Previous Results. For the minimum DNBR and peak MSS pressure cases, the

EPU analysis results are more limiting than the previous analysis results due to the higher EPU power level. For the peak RCS pressure case, the EPU analysis results are less limiting than the previous analysis results because of the key input changes that were made for the EPU analysis as discussed in the results for Case 3 below.

Case 1: Minimum DNBR Case

The transient response calculated for the total loss-of-load event (minimum DNBR case) is shown in Figures 2.8.5.2.1-1 through 2.8.5.2.1-3 for Unit 1 and Figures 2.8.5.2.1-4 through 2.8.5.2.1-6 for Unit 2.

The reactor was tripped via a high pressurizer pressure signal. The nuclear power slightly increased until the reactor was tripped and the pressurizer PORVs and sprays minimized the primary pressure transient, which was conservative for DNBR. Although the DNBR value decreased below the initial value, it remained well above the safety analysis limit throughout the entire transient. The peak pressurizer water volume remained below the total volume of the pressurizer, demonstrating that this event did not generate a more serious plant condition.

Case 2: Peak MSS Pressure Case

The transient response calculated for the total loss-of-load event (peak MSS pressure case) is shown in Figures 2.8.5.2.1-7 through 2.8.5.2.1-9 for Unit 1 and Figures 2.8.5.2.1-10 through 2.8.5.2.1-12 for Unit 2.

The reactor was tripped via a high pressurizer pressure signal. The nuclear power slightly increased until the reactor was tripped and the pressurizer PORVs and sprays minimized the primary pressure transient, which was conservative to delay reactor trip and exacerbate the peak secondary side pressure. The MSSVs actuated to maintain the secondary side pressure below 110% of the design value. The peak pressurizer water volume remained below the total volume of the pressurizer, demonstrating that this event did not generate a more serious plant condition.

To meet the applicable secondary side pressure limit, the nominal lift settings of the MSSVs with the two highest setpoints were changed. Table 2.8.5.2.1-3, Main Steam Safety Valves Lift Settings, provides the nominal lift settings of the MSSVs for the EPU along with the current PBNP Technical Specification Table 3.7.1-2 setpoints. Since lower lift settings are required for these MSSVs to prevent secondary side overpressurization for the proposed EPU, the PBNP Technical Specification Table 3.7.1-2 will be revised accordingly.

Case 3: Peak RCS Pressure Case

The transient response calculated for the total loss-of-load event (peak RCS pressure case) is shown in Figures 2.8.5.2.1-13 through 2.8.5.2.1-15 for Unit 1 and Figures 2.8.5.2.1-16 through 2.8.5.2.1-18 for Unit 2.

The reactor was tripped via a high pressurizer pressure signal. The nuclear power remained essentially constant at full power until the reactor was tripped. The PSVs actuated and it was confirmed that the primary side pressure was maintained below 110% of the design value. The peak pressurizer water volume remained below the total volume of the pressurizer, demonstrating that this event did not generate a more serious plant condition.

To meet the applicable primary side pressure limit, the positive PSV setpoint tolerance was reduced from the pre-EPU value of +3% to a value of +2.5% for the EPU. Table 2.8.5.2.1-4, Pressurizer Safety Valves Lift Settings, provides the lift setting range for the PSVs for the EPU along with the current PBNP Technical Specification 3.4.10 lift setting range. Since smaller positive setpoint tolerance is required for the PSVs to prevent primary side overpressurization for the proposed EPU, the PBNP Technical Specification 3.4.10 will be revised accordingly. In addition, for the high pressurizer pressure reactor trip function, the safety analysis trip setpoint was reduced from the pre-EPU value of 2425 psia to a value of 2418 psia for the EPU, and the safety analysis signal delay time was reduced from the pre-EPU value of 2.0 seconds to a value of 1.0 second for the EPU.

2.8.5.2.1.3 Results

The results of this analysis showed that the plant design is such that a total loss-of-external-electrical load without a direct reactor trip presents no hazard to the integrity of the RCS or the MSS. The applicable acceptance criteria were met. The minimum DNBR remained greater than the applicable safety analysis limit value and the peak RCS and MSS pressures remained below 110% of their respective design pressures at all times as shown in Table 2.8.5.2.1-2, Loss of External Electrical Load and/or Turbine Trip – Results and Comparison to Previous Results. The protection features adequately mitigated the loss-of-external-electrical load/turbine trip transient such that the above acceptance criteria were satisfied.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

EPU activities associated with these analyses do not add any new functions for existing components that would change the license renewal system evaluation boundaries. The changes associated with operating at EPU conditions do not add any new or previously unevaluated aging effects that necessitate a change to aging management programs or require new programs as internal and external environments remain within the parameters previously evaluated. Therefore, EPU activities associated with these analyses do not impact license renewal scope, aging effects, and aging management programs.

2.8.5.2.1.4 Conclusions

PBNP has reviewed the analyses of the decrease in heat removal events described above and concludes that the analyses have adequately accounted for plant operation at the EPU power level and were performed using acceptable analytical models. PBNP further concludes that the evaluation has demonstrated that the reactor protection and safety systems continue to ensure that the specified acceptable fuel design limits and the reactor coolant pressure boundary and main steam system pressure limits will not be exceeded as a result of these events. Based on this, PBNP concludes that the plant will continue to meet the PBNP current licensing basis requirements with respect to PBNP GDC 6, 9, and 29 following implementation of the proposed EPU. Therefore, PBNP finds the proposed EPU acceptable with respect to loss of external electrical level, turbine trip, and loss of condenser vacuum.

2.8.5.2.1.5 References

1. Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2 (NUREG-1839), dated December 2005

2. WCAP-11397-P-A (Proprietary), WCAP-11397-A (Non-Proprietary), Revised Thermal Design Procedure, April 1989

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

4. WCAP-12910, Rev. 1-A, Pressurizer Safety Valve Set Pressure Shift, May 1993

Table 2.8.5.2.1-1
Time Sequence of Events – Loss of External Electrical Load and/or Turbine Trip

Case	Event	Time (sec) Unit 1	Time (sec) Unit 2
Minimum DNBR Case (auto pressurizer pressure control, RTDP initial conditions)	Loss of Electrical Load/Turbine Trip	0.0	0.0
	High-Pressurizer Pressure Reactor Trip Setpoint Reached	10.9	10.3
	Rods Begin to Drop	11.9	11.3
	Minimum DNBR Occurs	12.4	11.9
Peak MSS Pressure Case (auto pressurizer pressure control, STDP initial conditions)	Loss of Electrical Load/Turbine Trip	0.0	0.0
	High-Pressurizer Pressure Reactor Trip Setpoint Reached	11.8	11.6
	Rods Begin to Drop	12.8	12.6
	Peak Secondary Side Pressure Occurs	17.4	17.2
Peak RCS Pressure Case (no pressurizer pressure control, STDP initial conditions)	Loss of Electrical Load/Turbine Trip	0.0	0.0
	High-Pressurizer Pressure Reactor Trip Setpoint Reached	6.0	5.9
	Rods Begin to Drop	7.0	6.9
	Peak RCS Pressure Occurs	9.2	9.0

Table 2.8.5.2.1-2
Loss of External Electrical Load and/or Turbine Trip – Results and Comparison to Previous Results

Result	EPU Analysis		Previous Analysis		Limit
	Unit 1	Unit 2	Unit 1	Unit 2	
Minimum DNBR	1.64	1.66	1.91	1.91	1.34 (EPU)/1.36 (pre-EPU)
Peak RCS Pressure (psia)	2739.6	2741.9	2745.3	2747.5	2748.5
Peak MSS Pressure (psia)	1205.6	1205.0	1190.7	1190.7	1208.5

Table 2.8.5.2.1-3
Main Steam Safety Valves Lift Settings

Valve Number		Lift Setting (psig ±3%)	
Steam Generator		Proposed EPU Technical Specification Setpoint	Current Technical Specification Setpoint
A	B		
MS 2010	MS 2005	1085	1085
MS 2011	MS 2006	1100	1100
MS 2012	MS 2007	1105	1125
MS 2013	MS 2008	1105	1125

Table 2.8.5.2.1-4
Pressurizer Safety Valves Lift Settings

	Proposed EPU Technical Specification Setpoint	Current Technical Specification Setpoint
Two pressurizer safety valves shall be OPERABLE with lift settings	≥ 2410 psig and ≤ 2547 psig	≥ 2410 psig and ≤ 2560 psig

Figure 2.8.5.2.1-1 Loss of Load/Turbine Trip Minimum DNBR Case – Unit 1 Nuclear Power and Vessel Average Temperature versus Time

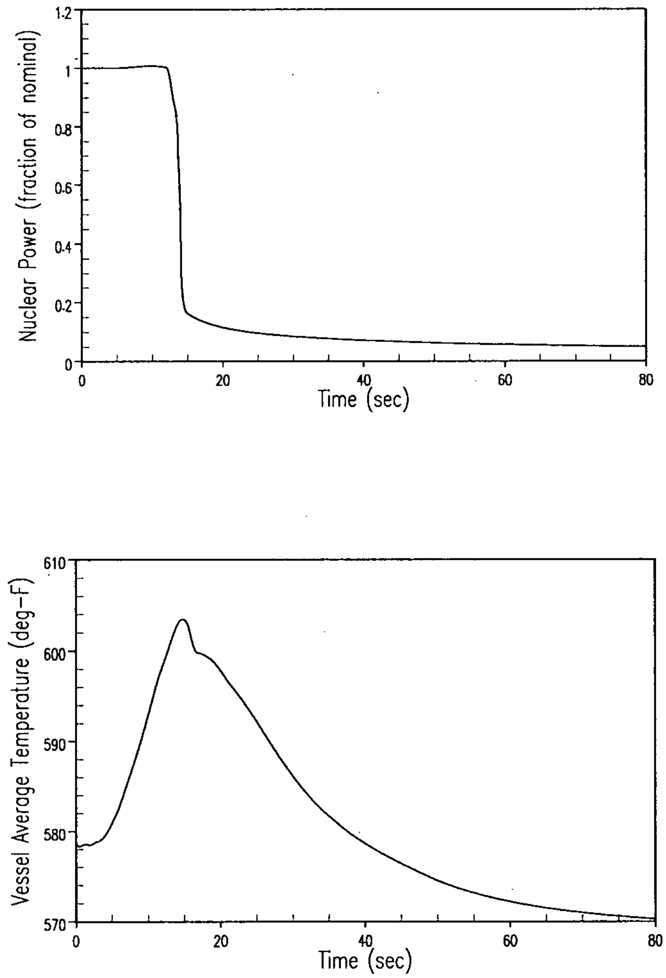
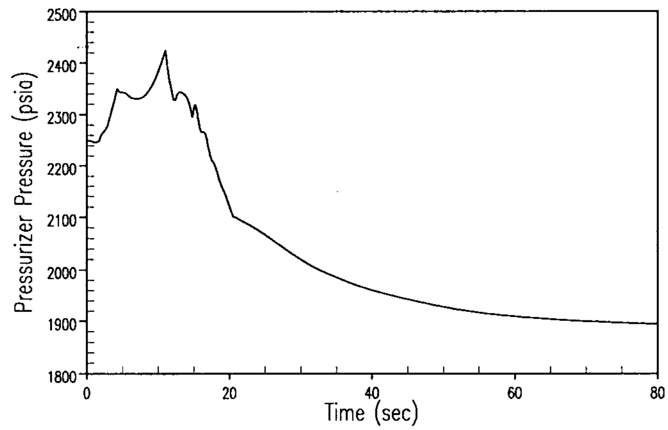


Figure 2.8.5.2.1-2 Loss of Load/Turbine Trip Minimum DNBR Case – Unit 1 Pressurizer Pressure and Pressurizer Water Volume versus Time



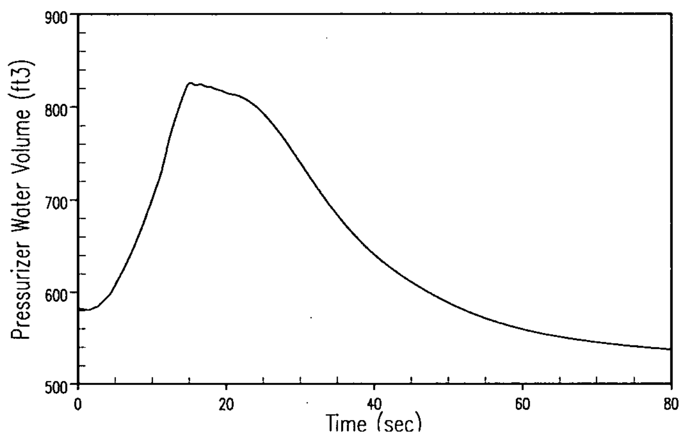
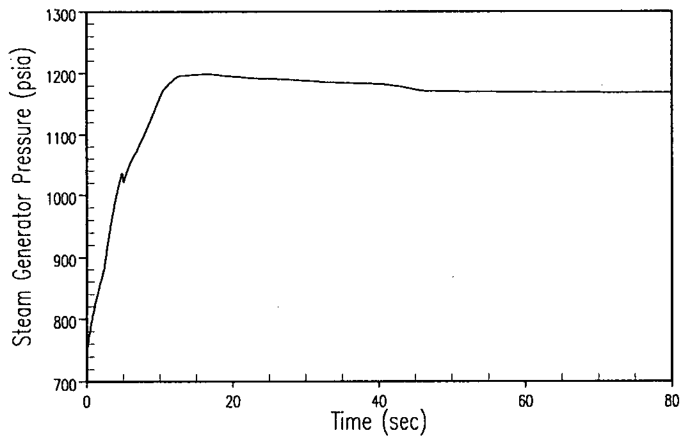


Figure 2.8.5.2.1-3 Loss of Load/Turbine Trip Minimum DNBR Case – Unit 1 Steam Generator Pressure and DNBR versus Time



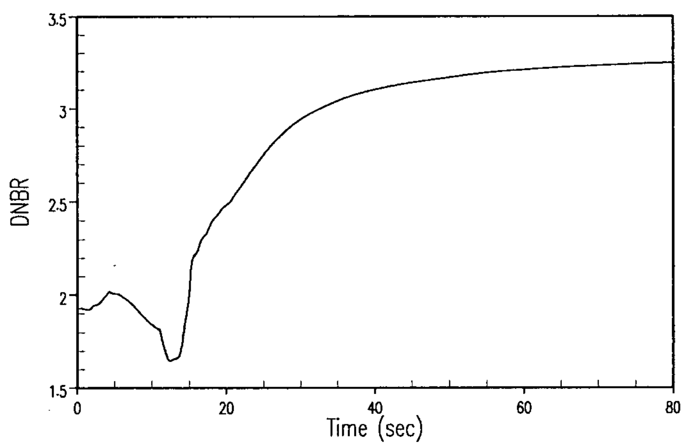


Figure 2.8.5.2.1-4 Loss of Load/Turbine Trip Minimum DNBR Case – Unit 2 Nuclear Power and Vessel Average Temperature versus Time

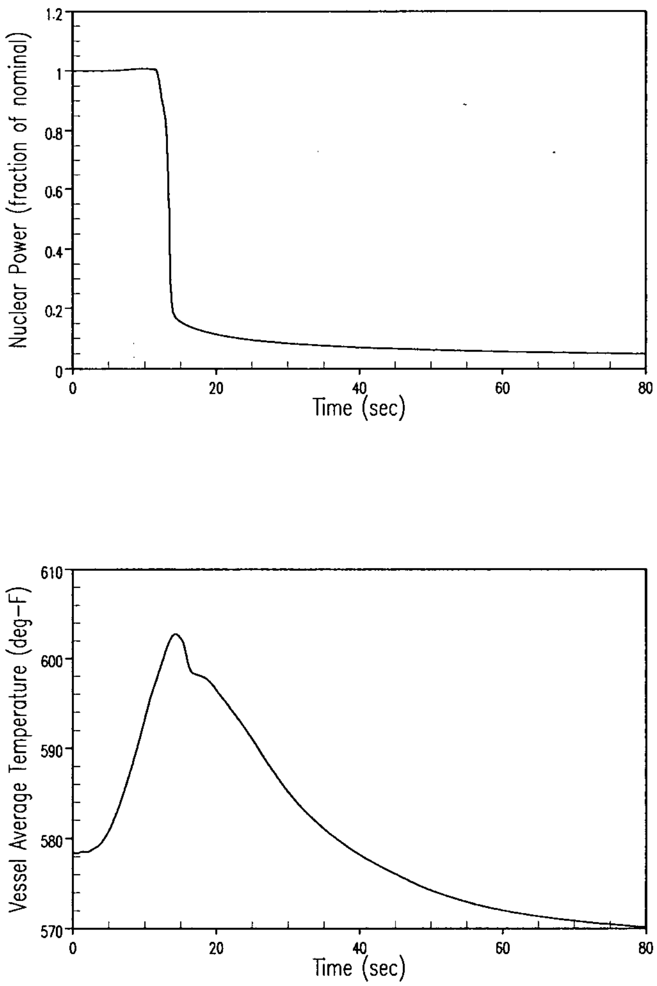
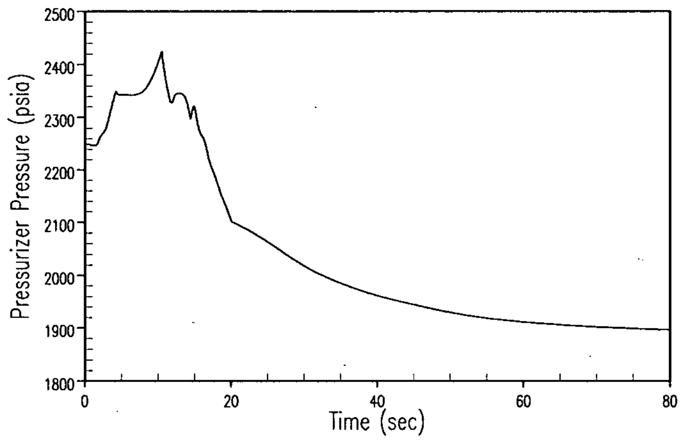


Figure 2.8.5.2.1-5 Loss of Load/Turbine Trip Minimum DNBR Case – Unit 2 Pressurizer Pressure and Pressurizer Water Volume versus Time



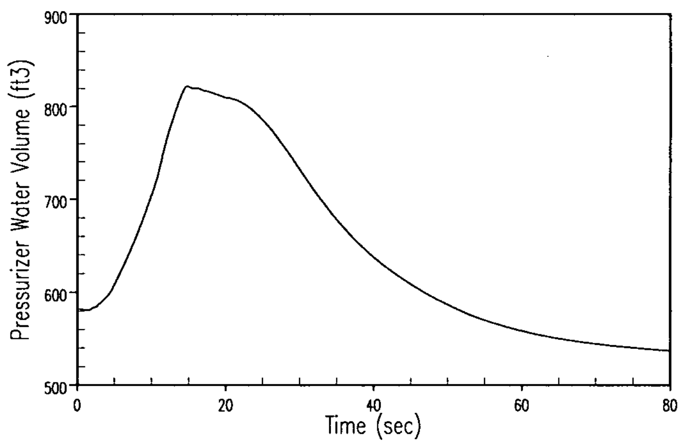
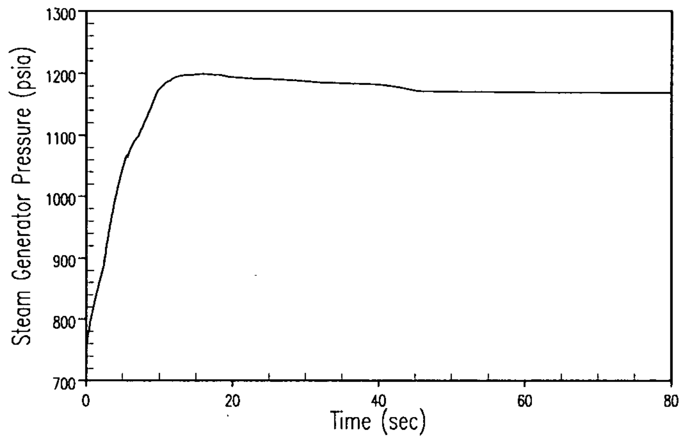


Figure 2.8.5.2.1-6 Loss of Load/Turbine Trip Minimum DNBR Case – Unit 2 Steam Generator Pressure and DNBR versus Time



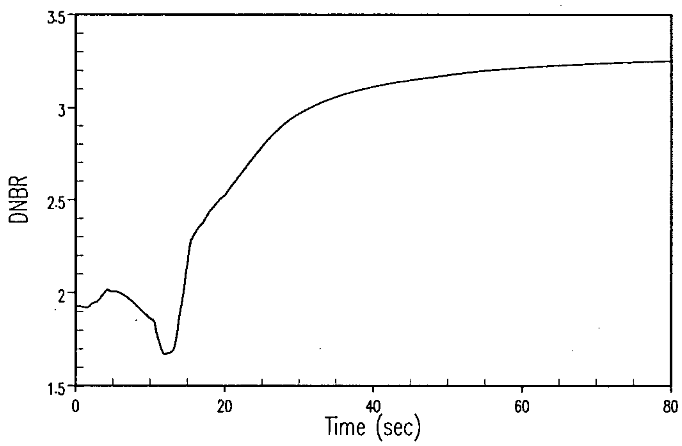
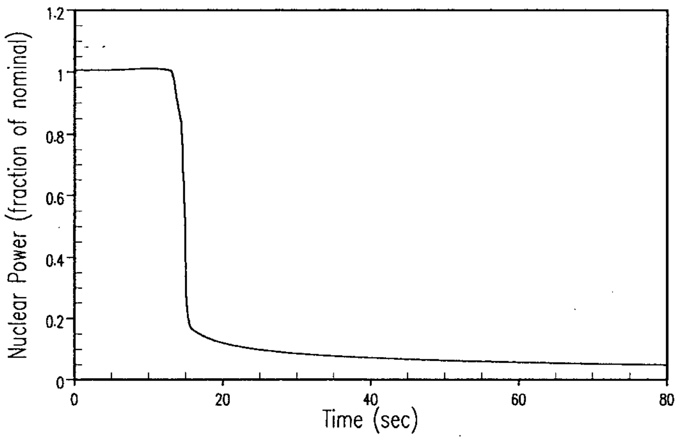


Figure 2.8.5.2.1-7 Loss of Load/Turbine Trip Peak MSS Pressure Case – Unit 1 Nuclear Power and Vessel Average Temperature versus Time



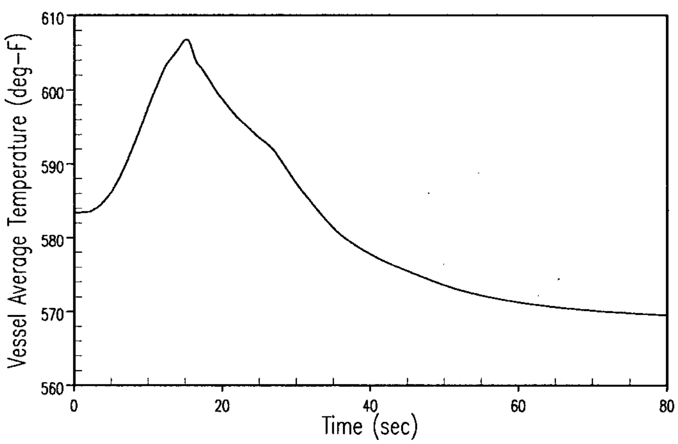
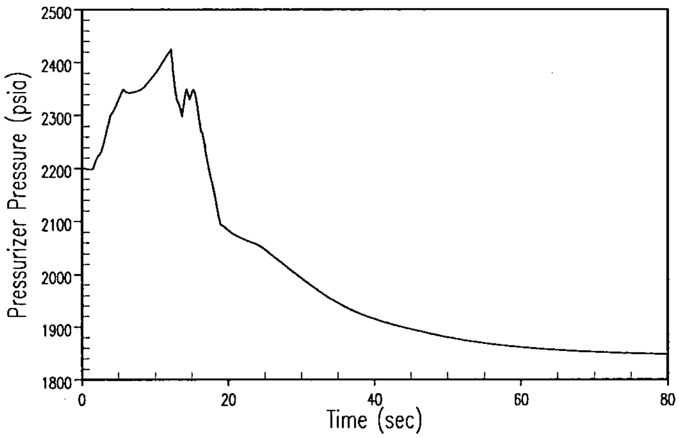


Figure 2.8.5.2.1-8 Loss of Load/Turbine Trip Peak MSS Pressure Case – Unit 1 Pressurizer Pressure and Pressurizer Water Volume versus Time



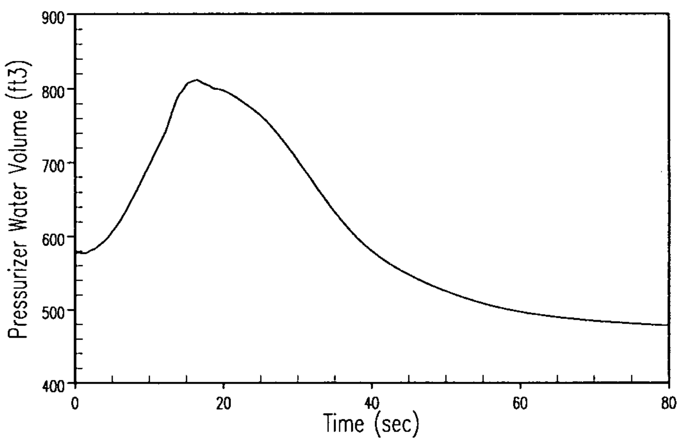


Figure 2.8.5.2.1-9 Loss of Load/Turbine Trip Peak MSS Pressure Case – Unit 1 Steam Generator Pressure versus Time

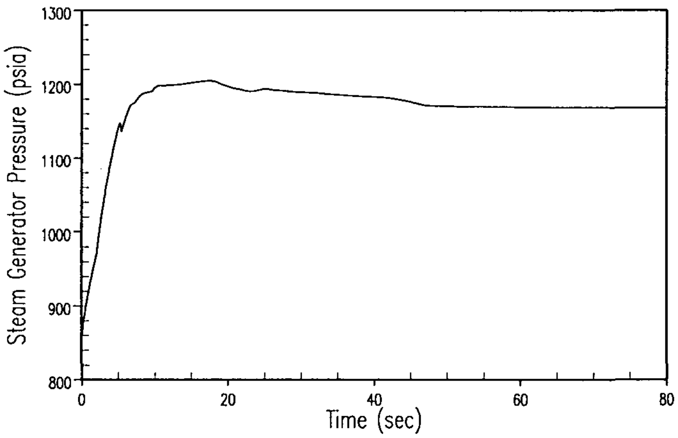


Figure 2.8.5.2.1-10 Loss of Load/Turbine Trip Peak MSS Pressure Case – Unit 2 Nuclear Power and Vessel Average Temperature versus Time

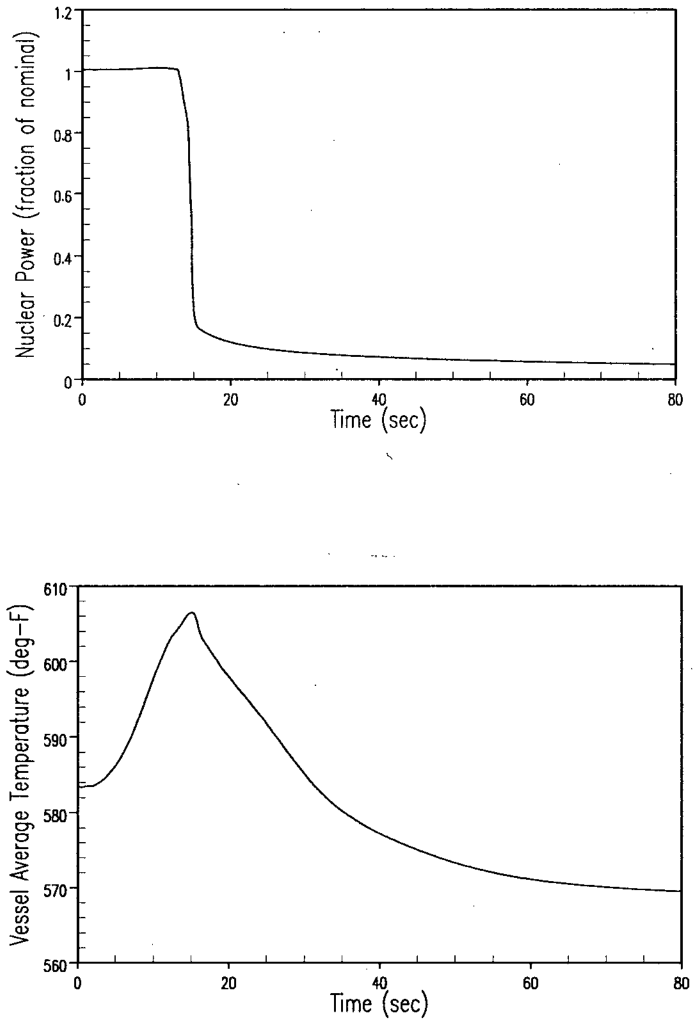


Figure 2.8.5.2.1-11 Loss of Load/Turbine Trip Peak MSS Pressure Case – Unit 2 Pressurizer Pressure and Pressurizer Water Volume versus Time

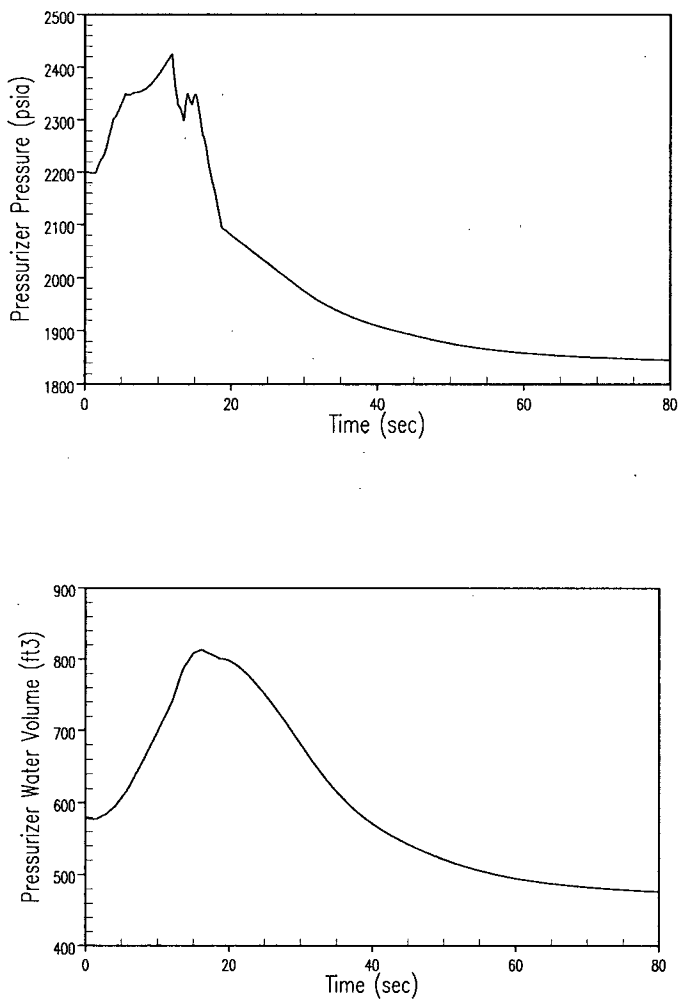


Figure 2.8.5.2.1-12 Loss of Load/Turbine Trip Peak MSS Pressure Case – Unit 2 Steam Generator Pressure versus Time

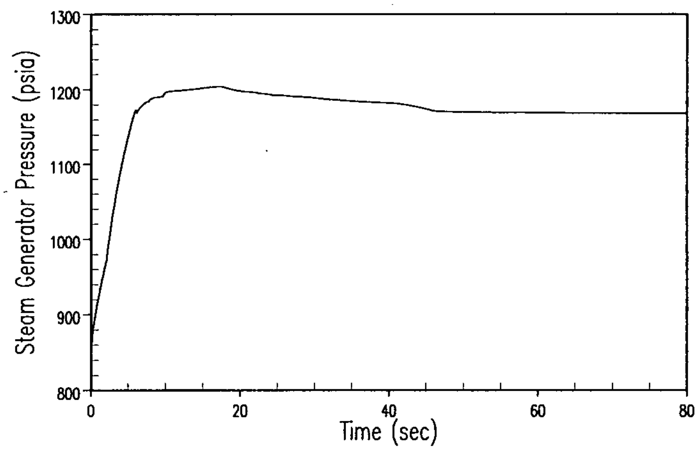
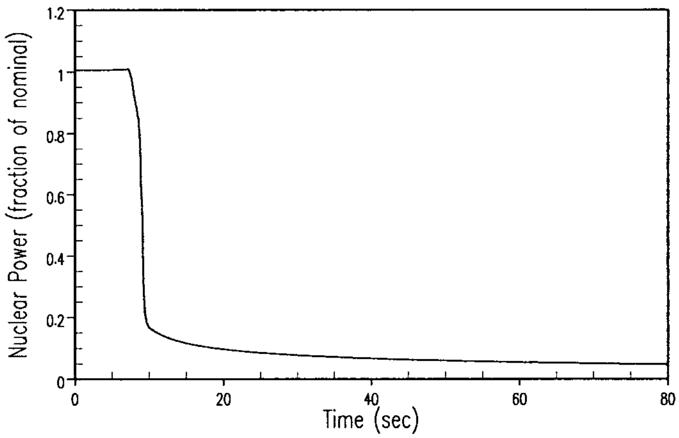


Figure 2.8.5.2.1-13 Loss of Load/Turbine Trip Peak RCS Pressure Case – Unit 1 Nuclear Power and Vessel Average Temperature versus Time



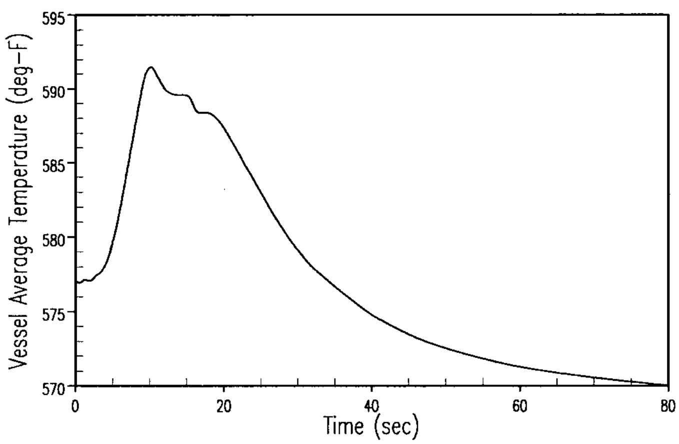
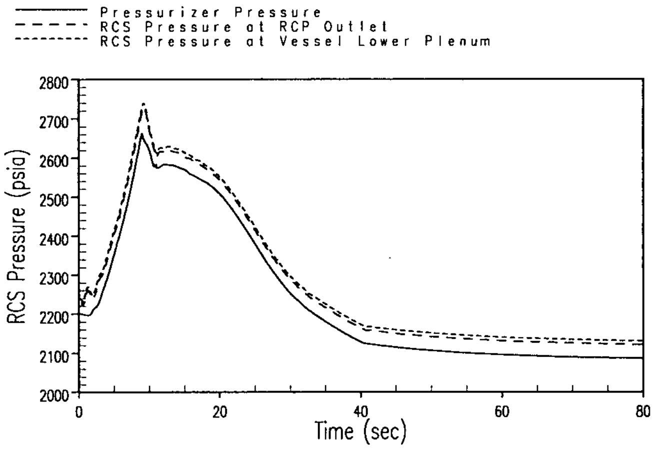


Figure 2.8.5.2.1-14 Loss of Load/Turbine Trip Peak RCS Pressure Case – Unit 1 RCS Pressure and Pressurizer Water Volume versus Time



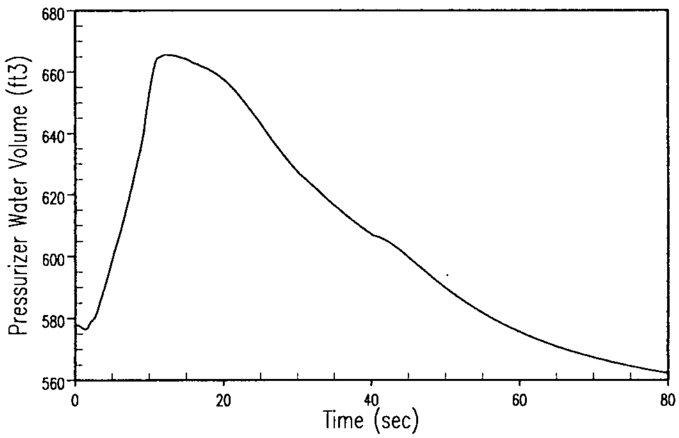


Figure 2.8.5.2.1-15 Loss of Load/Turbine Trip Peak RCS Pressure Case – Unit 1 Steam Generator Pressure versus Time

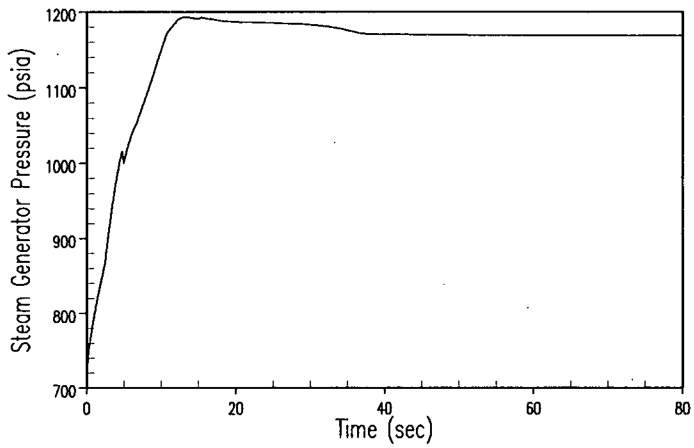
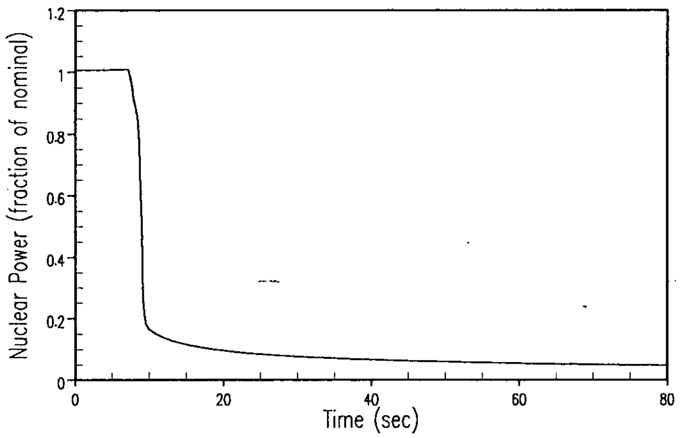


Figure 2.8.5.2.1-16 Loss of Load/Turbine Trip Peak RCS Pressure Case – Unit 2 Nuclear Power and Vessel Average Temperature versus Time



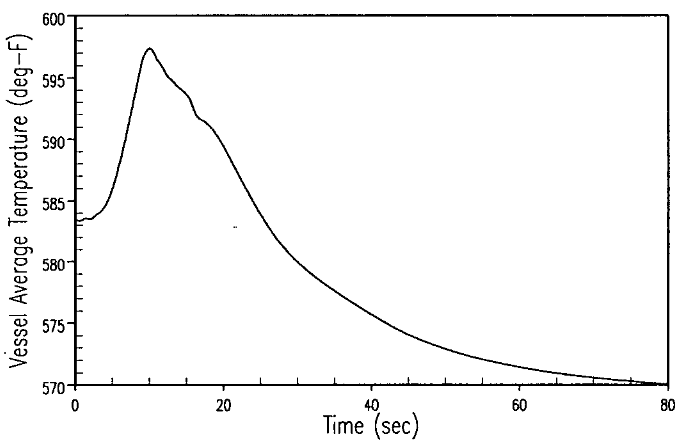
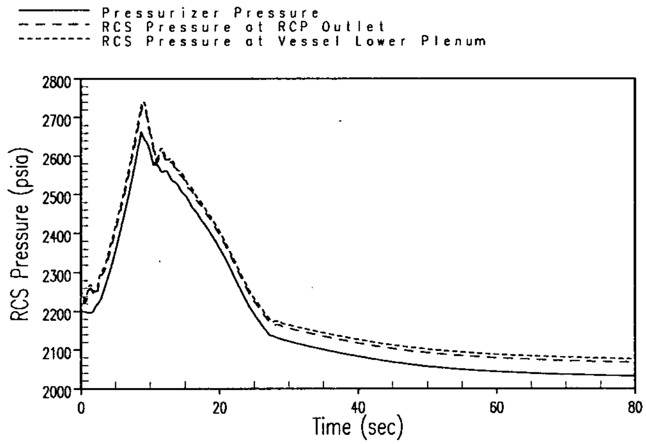


Figure 2.8.5.2.1-17 Loss of Load/Turbine Trip Peak RCS Pressure Case – Unit 2 RCS Pressure and Pressurizer Water Volume versus Time



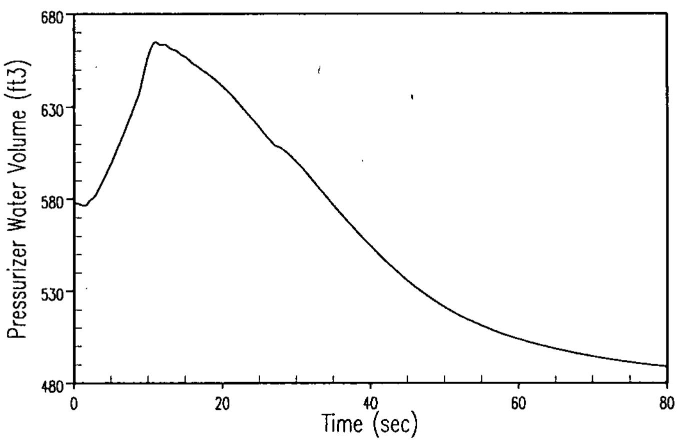
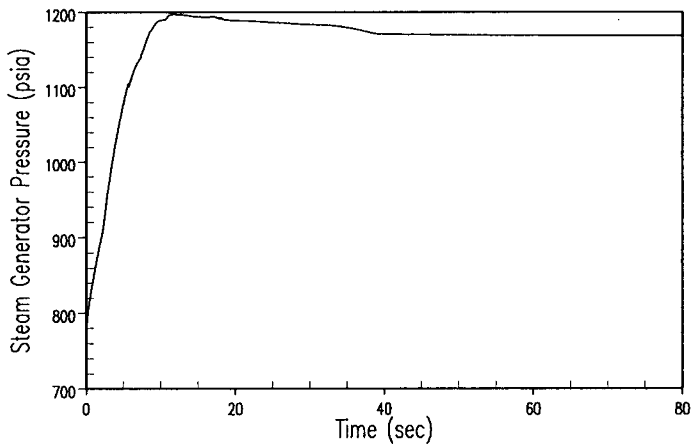


Figure 2.8.5.2.1-18 Loss of Load/Turbine Trip Peak RCS Pressure Case – Unit 2 Steam Generator Pressure versus Time



2.8.5.2.2 Loss of Non-Emergency AC Power to the Station Auxiliaries

2.8.5.2.2.1 Regulatory Evaluation

The loss-of-non-emergency-ac-power event is assumed to result in the loss-of-all power to the station auxiliaries and the simultaneous tripping of all reactor coolant pumps (RCPs). This causes a flow coastdown as well as a decrease in heat removal by the secondary system, a turbine trip, an increase in pressure and temperature of the coolant, and a reactor trip. Reactor protection and safety systems are actuated to mitigate the transient. The PBNP review covered the sequence of events, the analytical models used for analyses, the values of parameters used in the analytic models, and the results of the transient analyses.

The NRC acceptance criteria are based on:

- 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 are not exceeded during normal operations, including anticipated operational occurrences
- GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design condition of the reactor coolant pressure boundary (RCPB) is not exceeded during any condition of normal operation
- GDC 26, insofar as it requires that a reactivity control system be provided and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including anticipated operational occurrences, specified acceptable fuel design limits are not exceeded

Specific review criteria are contained in SRP, Section 15.2.6, and other guidance provided in Matrix 8 of RS-001, Revision 0.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50, Appendix A, GDC 10, 15 and 26 are as follows:

CRITERION: The reactor core with its related controls and protection systems shall be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits which have been stipulated and justified. The core and related auxiliary system designs shall provide this integrity under all expected conditions of normal operation with appropriate margins for uncertainties and for specified transient situations which can be anticipated. (PBNP GDC 6)

As stated in FSAR Section 3.1, Reactor Core Design, the core design, together with reliable process and decay heat removal systems, provides for this capability under all expected conditions of normal operation with appropriate margins for uncertainties and anticipated transient situations, including the effects of the loss of external electric load (FSAR Section 14.1.9, Loss of External Electrical Load).

Further discussion of this design is provided in FSAR Chapter 4, Reactor Coolant System.

CRITERION: The reactor coolant pressure boundary shall be designed, fabricated, and constructed so as to have an exceedingly low probability of gross rupture or significant uncontrolled leakage throughout its design lifetime. (PBNP GDC 9)

As described in FSAR Section 4.1, Reactor Coolant System, Design Basis, the reactor coolant system, in conjunction with its control and protective provisions, is designed to accommodate the system pressures and temperatures attained under all expected modes of plant operation or anticipated system interactions, and maintain the stresses within applicable code stress limits.

System conditions resulting from anticipated transients or malfunctions are monitored and appropriate action is automatically initiated to maintain the required cooling capability and to limit system conditions to a safe level. The system is protected from overpressure by means of pressure relieving devices, as required by Section III of the ASME Boiler and Pressure Vessel Code. The system is also protected from overpressure at low temperatures by the Low Temperature Overpressure Protection System.

CRITERION: One of the reactivity control systems provided shall be capable of making the core subcritical under any anticipated operating condition (including anticipated operational transients) sufficiently fast to prevent exceeding acceptable fuel damage limits. Shutdown margin should assure subcriticality with the most reactive control rod fully withdrawn. (PBNP GDC 29)

The reactor core, together with the reactor control and protection system, is designed so that the minimum allowable DNBR is at least equal to the limits specified for STD, OFA, upgraded OFA, and 422V+ fuel, and there is no fuel melting during normal operation, including anticipated transients.

The shutdown groups are provided to supplement the control group of RCCAs to make the reactor at least 1% subcritical (keff = 0.99) following a trip from any credible operating condition to the hot, zero power condition assuming the most reactive RCCA remains in the fully withdrawn position

CRITERION: The reactivity control systems provided shall be capable of making the core subcritical under credible accident conditions with appropriate margins for contingencies and limiting any subsequent return to power such that there will be no undue risk to the health and safety of the public. (PBNP GDC 30)

Normal reactivity shutdown capability is provided by control rods, with boric acid injection from the Chemical and Volume Control System (CVCS) used to compensate for the xenon transients, and for plant cooldown. When the plant is at power, the quantity of boric acid retained in the boric acid tanks and/or the refueling water storage tank (RWST) and ready for injection will always exceed that quantity required for the normal cold shutdown. This quantity will always exceed the quantity of boric acid required to bring the reactor to hot shutdown and to compensate for subsequent xenon decay.

The injection of boric acid is shown to afford backup reactivity shutdown capability, independent of control rod clusters which normally serve this function in the short term situation. Shutdown for long term and reduced temperature conditions can be accomplished with boric acid injection using redundant components.

The reactivity control provided by the CVCS is further discussed in FSAR Section 9.3, Chemical and Volume Control System.

In addition to the evaluations described in the PBNP FSAR, the analysis of a loss of non-emergency AC power to station auxiliaries event was evaluated for plant license renewal. System and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 1)

The analysis of a loss of non-emergency AC power to station auxiliaries event is part of License Renewal.

2.8.5.2.2.2 Technical Evaluation

Introduction

A complete loss of nonemergency AC power (FSAR Section 14.1.11, Loss of All AC Power to Station Auxiliaries) will result in a loss of power to the plant auxiliaries, i.e., the reactor coolant pumps, main feedwater pumps, condensate pumps, etc. The loss-of-power can be caused by a complete loss of the offsite grid accompanied by a turbine generator trip at the station, or by a loss of the onsite AC distribution system.

A loss of normal feedwater (LONF) with a loss of nonemergency AC power (LOAC) occurring at the time of reactor trip is a more severe event (in terms of peak pressurizer volume) than the loss of nonemergency AC power event in which the reactor trips on low reactor coolant system flow and the reactor coolant pumps coastdown at the beginning of the event. In the LONF with LOAC event, the reactor trip is conservatively delayed until the low-low steam generator water level signal is reached, at which time the RCP coastdown begins. Therefore, the more severe LONF with LOAC event, hereafter referred to as LOAC for simplicity, is addressed in this section. The LONF event without a loss of nonemergency AC power is addressed in LR Section 2.8.5.2.3, Loss of Normal Feedwater Flow.

The events following an LOAC with turbine and reactor trip are described in the sequence listed below:

- Plant vital instruments are supplied by emergency DC power sources
- The atmospheric dump valves (ADVs) can be automatically opened to the atmosphere as the steam system pressure rises following the trip. The condenser is assumed unavailable for steam dump. If the relief capacity of the ADVs is inadequate, the main steam safety valves (MSSVs) can lift to dissipate the sensible heat of the fuel and coolant plus the residual decay heat produced in the reactor
- The ADVs (or MSSVs, if the ADVs are inadequate or unavailable), are used to dissipate the residual decay heat and to maintain the plant at the MODE 3 (hot shutdown) condition as the no-load temperature is approached
- The emergency diesel generators start on the loss of voltage to the engineered safety features buses and begin to supply safeguards loads in the event offsite power is also lost

The following provide the necessary protection following an LOAC:

- The reactor can be tripped on one or more of the following reactor trip signals:
  - Pressurizer-high pressure trip signal if any two-of-three pressure channels exceed a fixed setpoint
  - Pressurizer-high water level trip signal if any two-of-three level channels exceed a fixed setpoint
  - Overtemperature ΔT trip signal if any two-out-of-four ΔT channels exceed an overtemperature ΔT setpoint. This setpoint is automatically varied with axial power imbalance, coolant temperature, and pressurizer pressure to protect against departure from nucleate boiling (DNB)
  - Low-low steam generator water level trip signal if any two-out-of-three level channels in either steam generator is below a fixed setpoint
- One motor-driven auxiliary feedwater (MDAFW) pump is started on any of the following:
  - Low-low water level in two-out-of-three level channels in either steam generator
  - Loss of voltage on both 4.16 kV buses supplying the main feedwater pump motors
  - Safety injection
  - Manual actuation
- One turbine-driven auxiliary feedwater (TDAFW) pump is started on any of the following:
  - Low-low water level in two-out-of-three level channels in either steam generator
  - Loss of voltage on both 4.16 kV buses supplying the main feedwater pump motors
  - Safety Injection
  - Manual actuation
- The main steam safety valves (MSSVs) open to provide an additional heat sink and protection against secondary side overpressure.
- The pressurizer safety valves (PSVs) may open to provide protection against overpressure of the reactor coolant system (RCS).

With the exceptions noted below, the Auxiliary Feedwater (AFW) system is initiated as discussed in the LONF analysis (see LR Section 2.8.5.2.3, Loss of Normal Feedwater Flow). The reactor trip system and AFW system design provide reactor trip and AFW flow following any loss of normal feedwater.

Following the loss of power to the RCPs, heat removal is maintained by natural circulation in the RCS loops. Following the RCP coastdown, the natural circulation capability of the RCS will remove decay heat from the core, aided by the AFW flow in the secondary system. Demonstrating that acceptable results can be obtained for this event proves that the resultant natural circulation flow in the RCS is adequate to remove decay heat from the core.

The first few seconds after a loss of AC power to the RCPs closely resembles the analysis of the complete loss of flow event (see LR Section 2.8.5.3.1, Loss of Forced Reactor Coolant Flow) in that the RCS experiences a rapid flow reduction transient. This aspect of the LOAC event is bounded by the analysis performed for the complete loss of flow event that demonstrates that the DNB design basis is met. The analysis of the LOAC event demonstrates that RCS natural circulation and the AFW system are capable of removing the stored and residual heat, and consequently will prevent RCS or main steam system (MSS) overpressurization and core uncovery. The plant is therefore able to return to a safe condition.

Input Parameters, Assumptions, and Acceptance Criteria

The major inputs and assumptions used in this analysis were identical to those used in the LONF analysis described in LR Section 2.8.5.2.3, Loss of Normal Feedwater Flow, with the exceptions that power is assumed to be lost to the RCPs after rod motion begins and the AFW actuation delay times are different. Details of the modeling differences from the LONF analysis are as follows:

- The loss of non-emergency AC power was assumed to occur soon after the time of reactor trip on low-low steam generator water level. This assumption maximizes the amount of stored energy in the RCS and minimizes the steam generator water inventory at the time of reactor trip, which are conservative with respect to the long-term heatup
- The plant was initially operating at an NSSS power of 100.6% of 1806 MWt, with nominal RCP heat of 6.0 MWt. Assuming nominal RCP heat is conservative because when the RCPs coast down and cease to add heat to the primary coolant, the core decay heat is based on a slightly higher initial core power
- The RCPs were assumed to lose power and coastdown 2 seconds after the beginning of rod motion following the reactor trip signal, and the post-trip heat removal from the core relied upon natural circulation flow in the RCS loops. The 2 second RCP coastdown time delay after reactor trip is a reasonable value that is typically assumed, and is not a critical parameter in the analysis because it is short relative to the overall transient time
- The RCS flow coastdown was based on a momentum balance around each reactor coolant loop (RCL) and across the reactor core. This momentum balance was combined with the continuity equation, a pump momentum balance, the as-built pump characteristics, and conservative estimates of system pressure losses
- It was assumed that one MDAFW or one TDAFW pump was available to supply a minimum flow of 275 gpm split equally to both steam generators. Therefore, loss of either of these pumps could be considered as the worst single failure. The AFW flow was initiated 60 seconds after the low-low SG water level setpoint was reached; from 60 to 90 seconds, the AFW flow rate ramped from 0% to 80% of total flow; from 90 to 150 seconds, the AFW flowrate ramped from 80% to 100% of total flow; beyond 150 seconds, 100% of total flow (275 gpm) was maintained. The initial AFW enthalpy was assumed to be 70.90 Btu/lbm (corresponding to the maximum AFW temperature of 100°F)
- The most limiting LOAC case (with respect to pressurizer filling), which corresponds to the Model Δ47 steam generators of Unit 2, was modeled with a conservative temperature

uncertainty subtracted from the high nominal (window) T_{avg} (i.e., 577.0°F - 6.4°F), a conservative pressure uncertainty subtracted from the nominal value (i.e., 2250 psia - 50 psi), while modeling high (458°F) main feedwater temperature conditions. The most limiting case LOAC case with the Model 44F steam generators of Unit 1 was modeled with a conservative temperature uncertainty subtracted from the high nominal (window) T_{avg} (i.e., 577.0°F - 6.4°F), a conservative pressure uncertainty added to the nominal value (i.e., 2250 psia + 50 psi), while modeling low (390°F) main feedwater temperature conditions. Whereas the most limiting Unit 1 LOAC case was one in which the pressurizer power-operated relief valves (PORVs) were assumed to be inoperable, the most limiting Unit 2 LOAC case was one in which the pressurizer PORVs were assumed to operate as-designed

- Steam generator tube plugging (SGTP) levels of both 0% and 10% were analyzed, with 0% being the most limiting

Based on its frequency of occurrence, the LOAC event was considered a Condition II event as defined by the American Nuclear Society. The following items summarize the acceptance criteria associated with this event:

- Fuel cladding integrity is maintained by ensuring that the minimum DNBR remains above the 95/95 DNBR limit
- Pressure in the RCS and MSS are maintained below 110% of the design pressures
- An incident of moderate frequency does not generate a more serious plant condition without other faults occurring independently

With respect to DNB, the LOAC event is bounded by the loss of flow event reported in LR Section 2.8.5.3.1, Loss of Forced Reactor Coolant Flow. The DNBR consequences of the LOAC event are similar to those of the LONF event (see discussion presented in Section 2.8.5.2.2.2), with the additional effect of a reduction in the core flow rate caused by loss of power to the RCPs. However, the LOAC event is bounded by the complete loss of flow event for which the RCP coastdown is the initiating fault and the reactor trip occurs when the core flow is already degraded.

With respect to overpressurization, the LOAC event is bounded by the loss of load event reported in LR Section 2.8.5.2.1, Loss of External Electrical Load, Turbine Trip, and Loss of Condenser Vacuum, in which assumptions are made to conservatively calculate the RCS and MSS pressure transients. For the LOAC event, turbine trip occurs after reactor trip, whereas for loss of load the turbine trip is the initiating fault. Therefore, the primary/secondary power mismatch and resultant RCS and MSS heatup and pressurization transients are always more severe for loss of load than for LOAC.

The restrictive acceptance criterion, that the pressurizer does not become water solid, has been used for this event. Satisfying this single criterion ensures that the capacity of the AFW system is sufficient for long-term removal of decay heat. It also demonstrates the preclusion of a more serious plant condition and ensures that the pressure criteria and minimum DNBR criterion are satisfied for the long-term.

Description of Analyses and Evaluations

A detailed analysis using the RETRAN (Reference 2) computer code was performed to determine the plant transient following a loss of all AC power. The code described the core neutron kinetics, RCS, including natural circulation, pressurizer, pressurizer PORVs and sprays, steam generators, MSSVs, and the AFW system, and computed pertinent variables, including the pressurizer pressure, pressurizer water level, and reactor coolant average temperature. Additional discussion of the RETRAN code is contained in LR Section 2.8.5.0.9, Accident and Transient Analyses, Computer Codes Utilized.

Credit was taken for a portion of the coolant-to-metal heat transfer that would occur during the long-term primary-side heat-up. A RETRAN thick metal mass heat transfer model was developed for use in the LONF and LOAC event analyses using the RETRAN thick metal mass heat transfer model methodology described in WCAP-14882-S1-P-A (Reference 3). See Section 2.8.5.0.12 for justification of the use of this methodology.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

The system, structures, and components whose performance is relied upon to support the inputs, assumptions, and results of the analyses described in this section for transients resulting in unplanned sudden decreases in heat removal by the secondary system are not being modified by the EPU activities. EPU activities do not add any new functions for existing components associated with these analyses that would change the license renewal evaluation boundaries. Operation of these components at EPU conditions does not introduce any unevaluated aging effects that would necessitate a change to aging management programs or require a new program as internal and external environments remain within the parameters previously evaluated. In addition, the primary and secondary systems performance capability described in this section is for upset conditions which are not the conditions used for license renewal aging evaluations. Therefore, EPU activities associated with loss of non-emergency AC power do not impact license renewal scope, aging effects, and aging management programs.

2.8.5.2.2.3 Results

Figures 2.8.5.2.2-1 through 2.8.5.2.2-6 present transient plots of plant parameters for the limiting LOAC case with the Model 44F steam generators (Unit 1) and Figures 2.8.5.2.2-7 through 2.8.5.2.2-12 present transient plots of plant parameters for the limiting LOAC case with the Model Δ47 steam generators (Unit 2), with the assumptions identified in Section 2.8.5.2.2.2. The calculated sequence of events for this event is listed in Table 2.8.5.2.2-1, Loss of Non-Emergency AC Power to the Plant Auxiliaries Time Sequence of Events. Numerical results of the EPU analysis along with a comparison to the previous analysis results are shown in Table 2.8.5.2.2-2, Loss of Non-Emergency AC Power to the Plant Auxiliaries Results. The most limiting cases are initiated with the average RCS temperature at the high end of the T_{avg} temperature window minus uncertainties.

The first few seconds after the loss of power to the RCPs, the flow transient closely resembled the complete loss of flow incident, where core damage due to rapidly increasing core temperatures was prevented by the reactor trip. After the reactor trip, stored and residual heat had to be removed to prevent damage to the core and the RCS and MSS. The RETRAN code results showed that the natural circulation and AFW flow available was sufficient to provide adequate core decay heat removal following reactor trip and RCP coastdown.

Figures 2.8.5.2.2-4 and 2.8.5.2.2-10 illustrate that the pressurizer did not reach a water solid condition, therefore, no water relief from the pressurizer occurred.

With respect to DNB, the LOAC event is bounded by the complete loss of flow event described in LR Section 2.8.5.3.1, Loss of Forced Reactor Coolant Flow, for which the minimum DNBR was determined to be greater than the safety analysis limit value. Also, with respect to primary and secondary overpressurization, the loss of load event alanysis described in LR Section 2.8.5.2.1, Loss of External Electrical Load, Turbine Trip, and Loss of Condenser Vacuum demonstrates that the primary and secondary pressure limits of 2748.5 psia and 1208.5 psia, respectively, are met.

The results of the analysis showed that the pressurizer did not reach a water solid condition. Therefore, the LOAC event did not adversely affect the core, the RCS, or the MSS.

2.8.5.2.2.4 Conclusions

PBNP has reviewed the analysis of the LOAC event and concludes that the analysis has adequately accounted for plant operation at the power level and was performed using acceptable analytical models (including the use of RETRAN). PBNP further concludes that the evaluation has demonstrated that the reactor protection and safety systems (including the revised auxiliary feedwater assumptions, the use of RETRAN thick metal mass heat transfer model, the revised SG low-low level trip setpoint and the revised pressurizer level program) will continue to ensure that the specified acceptable fuel design limits and the reactor coolant pressure boundary pressure limits will not be exceeded as a result of this event. Based on this, PBNP concludes that the plant will continue to meet the PBNP current licensing basis requirements with respect to PBNP GDC 6, 9, 29 and 30 following implementation of the EPU. Therefore, PBNP finds the EPU acceptable with respect to the LOAC event.

2.8.5.2.2.5 References

1. Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

2. WCAP-14882-P-A, RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses, Huegel, D.S., et al, April 1999

3. WCAP-14882-S1-P-A, RETRAN-02 Modeling and Qualification For Westinghouse Pressurized Water Reactors Non-LOCA Safety Analyses, Supplement 1 - Thick Metal Mass Heat Transfer Model and NOTRUMP-Based Steam Generator Mass Calculation Method, October 2005

Table 2.8.5.2.2-1
Loss of Non-Emergency AC Power to the Plant Auxiliaries Time Sequence of Events

Event	Time (seconds)	
	Unit 1 (Model 44F SGs)	**Unit 2 (Model Δ47 SGs)**
Main Feedwater Flow Stops	20.0	20.0
Low-Low Steam Generator Water Level Reactor Trip Setpoint Reached	63.5	55.0
Rods Begin to Drop	65.5	57.0
RCPs Begin to Coastdown	67.5	59.0
Flow from One AFW Pump is Initiated	123.5	115.0
Long-Term Peak Water Level in Pressurizer Occurs	285.0	776.0
Core Decay Heat Decreases to AFW Heat Removal Capacity	~844	~790

Table 2.8.5.2.2-2
Loss of Non-Emergency AC Power to the Plant Auxiliaries Results

	EPU Analysis	Previous Analysis	Limit
Peak Pressurizer Water Volume from the Limiting Unit 1 Case (ft^3) (Model 44F SGs)	720	887	1000
Peak Pressurizer Water Volume from the Limiting Unit 2 Case (ft^3) (Model Δ47 SGs)	732	915	1000

Figure 2.8.5.2.2-1 Loss of Non-Emergency AC Power to the Plant Auxiliaries Unit 1 (Model 44F SGs) Nuclear Power and Core Average Heat Flux vs. Time

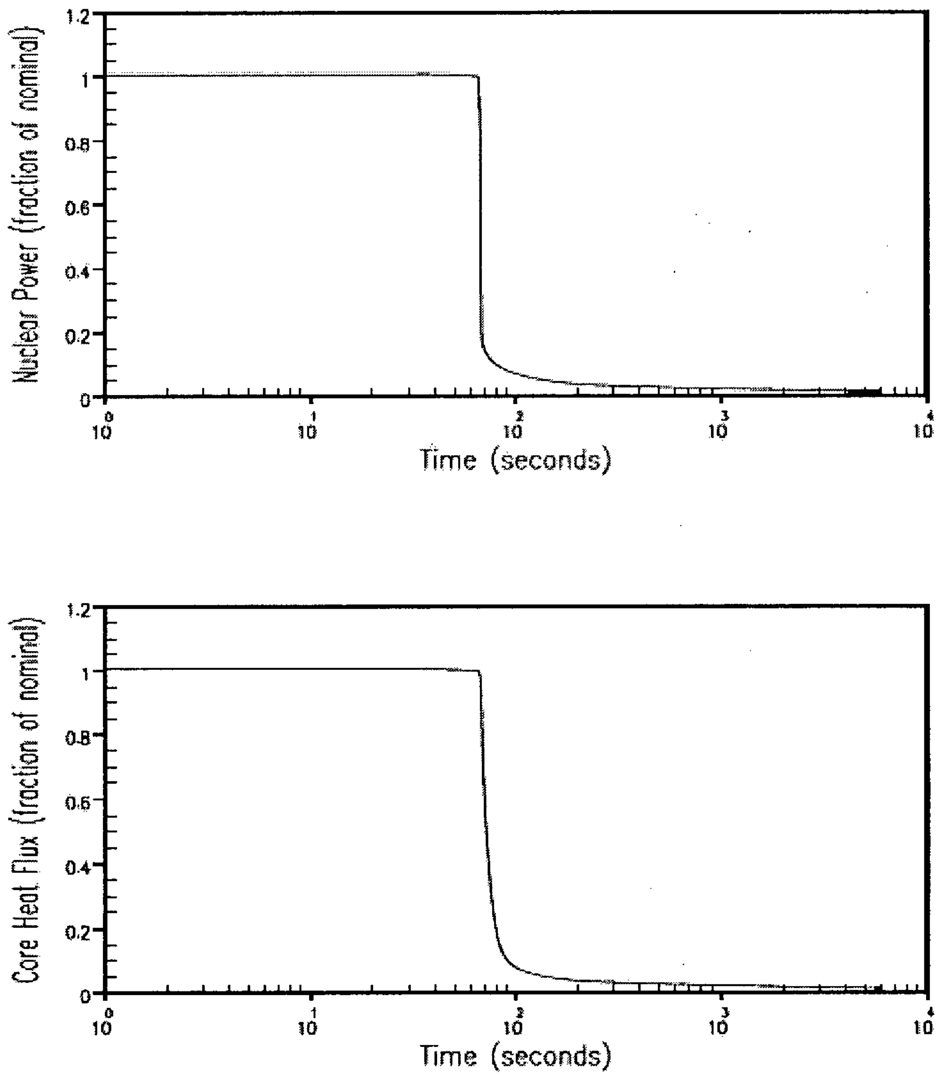


Figure 2.8.5.2.2-2 Loss of Non-Emergency AC Power to the Plant Auxiliaries Unit 1 (Model 44F SGs) Core Reactivity and Reactor Vessel Flow vs. Time

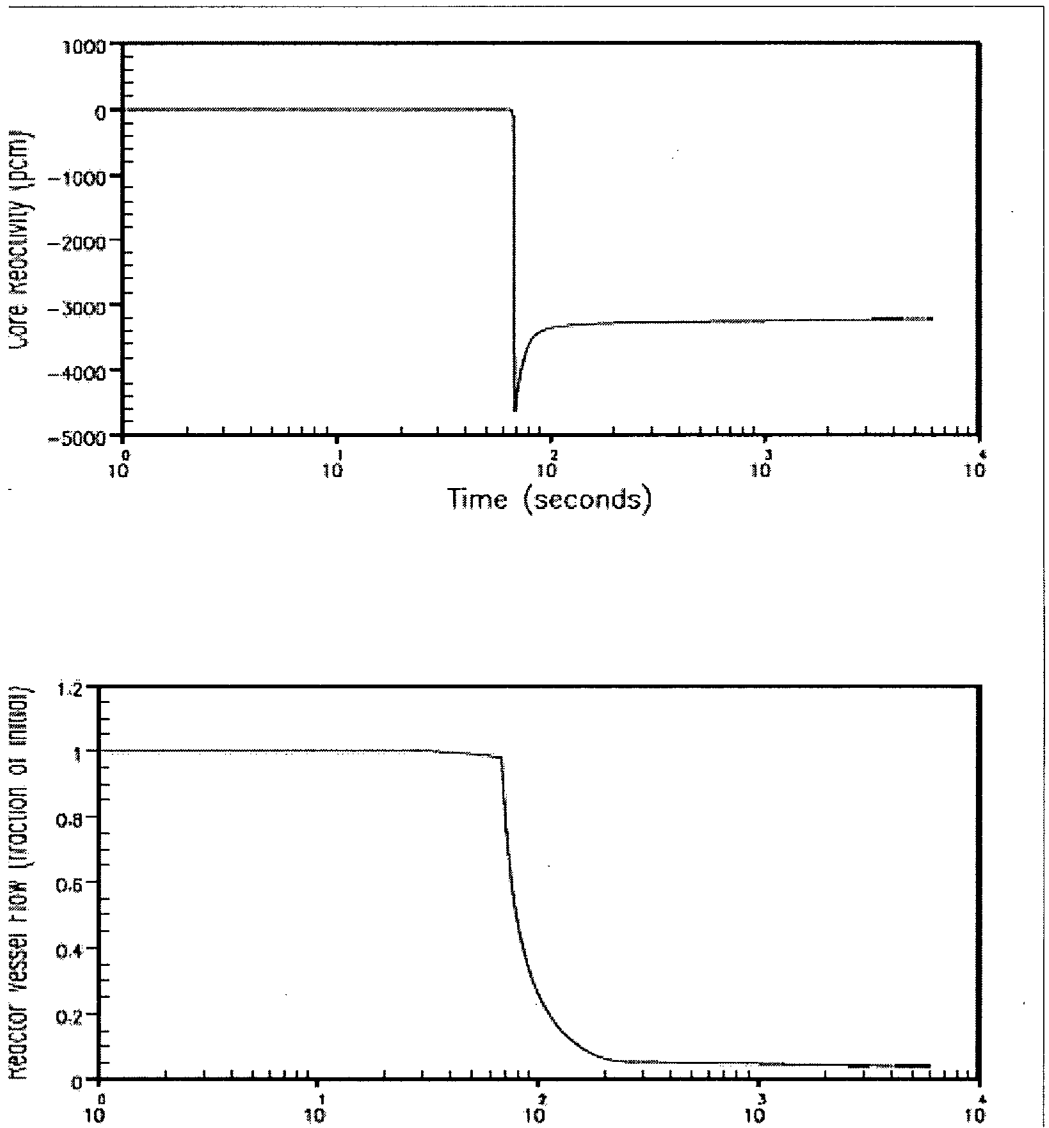


Figure 2.8.5.2.2-3 Loss of Non-Emergency AC Power to the Plant Auxiliaries Unit 1 (Model 44F SGs) Loop T-hot and T-cold vs. Time

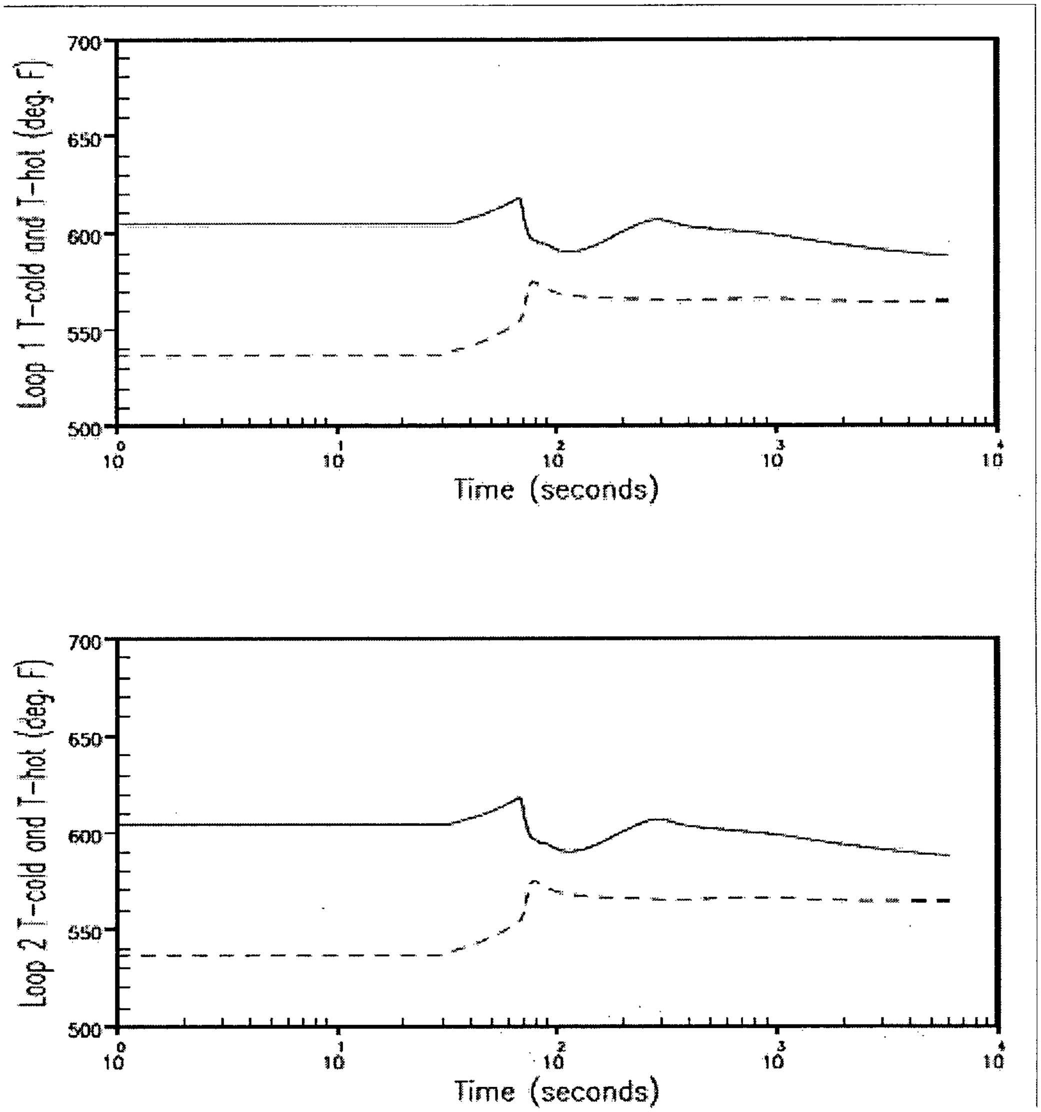


Figure 2.8.5.2.2-4 Loss of Non-Emergency AC Power to the Plant Auxiliaries Unit 1 (Model 44F SGs) Pressurizer Pressure and Water Volume vs. Time

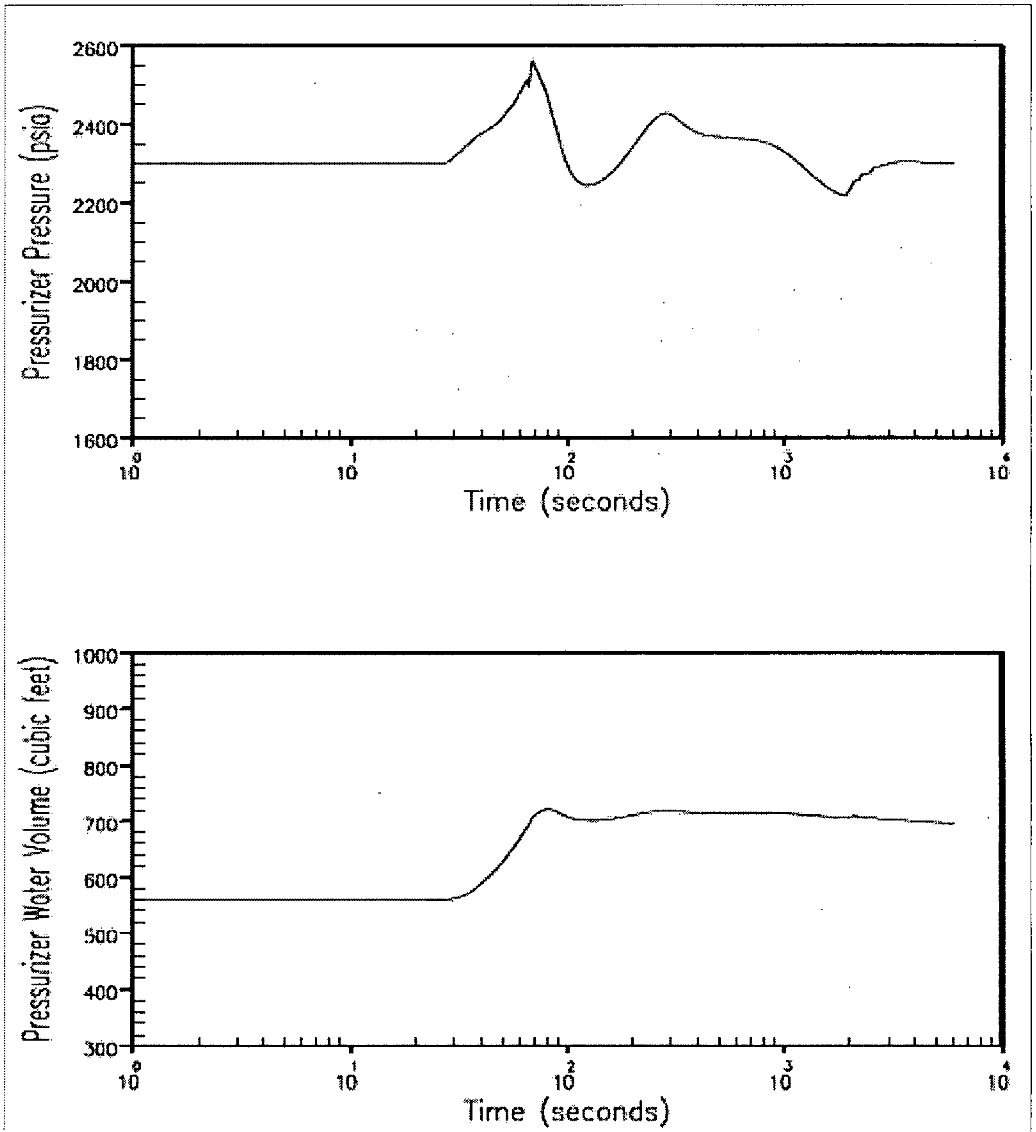
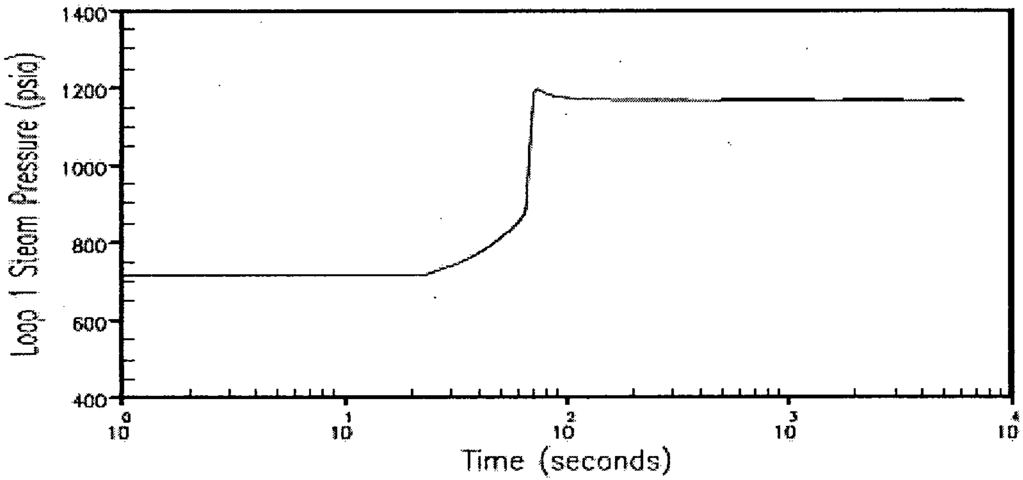


Figure 2.8.5.2.2-5 Loss of Non-Emergency AC Power to the Plant Auxiliaries Unit 1 (Model 44F SGs) Loop Steam Pressure vs. Time



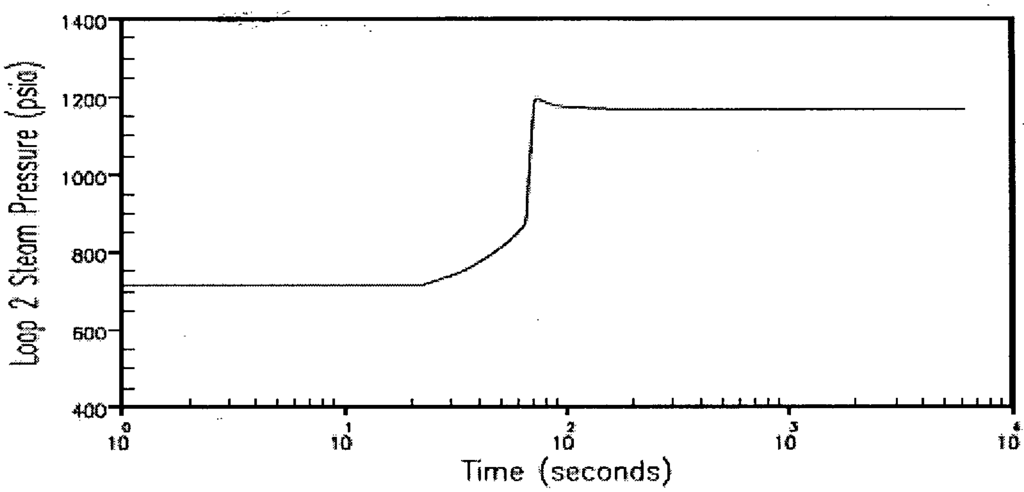


Figure 2.8.5.2.2-6 Loss of Non-Emergency AC Power to the Plant Auxiliaries Unit 1 (Model 44F SGs) Loop Steam Generator Mass Inventory and Steam Generator Level vs. Time

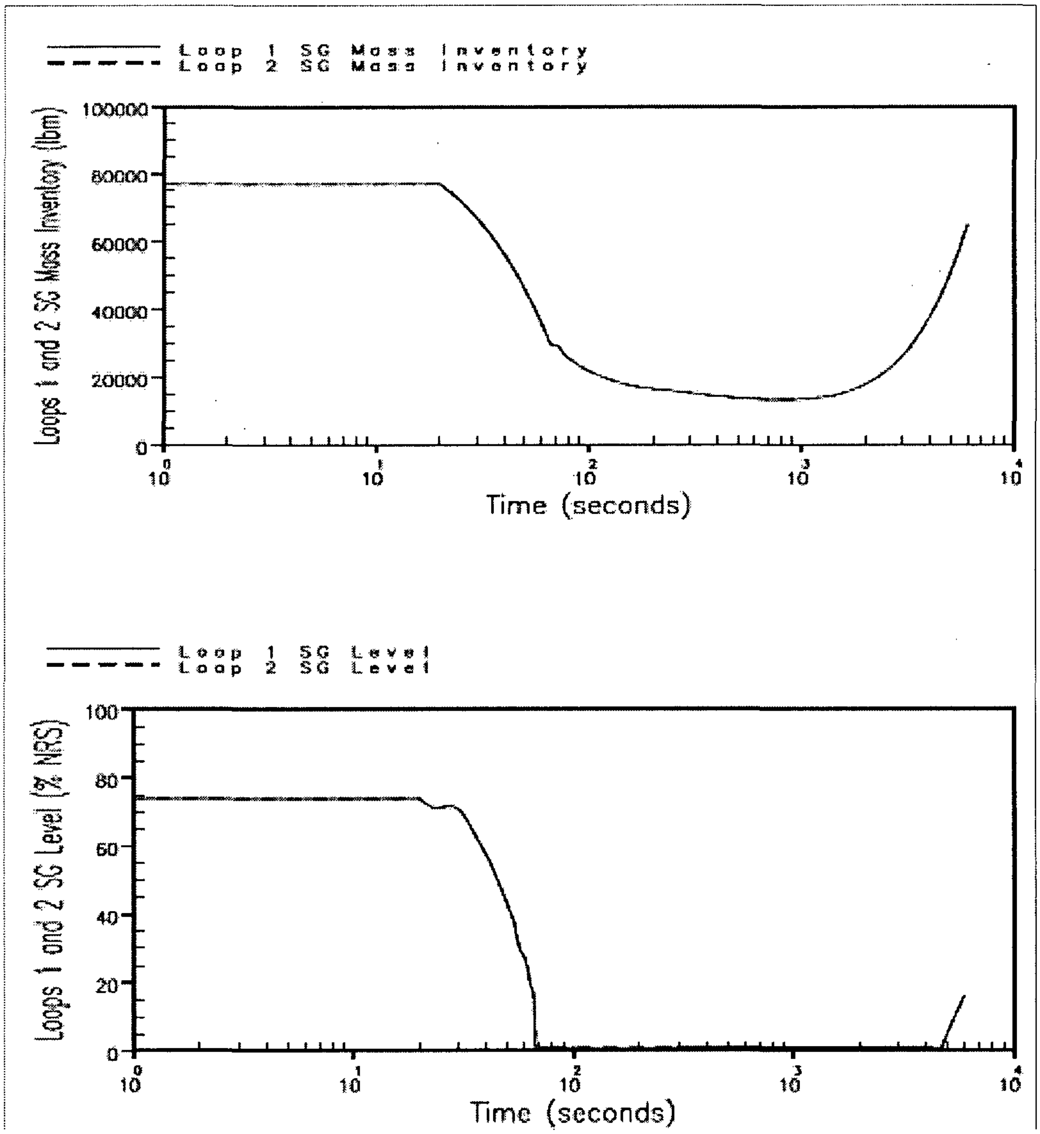
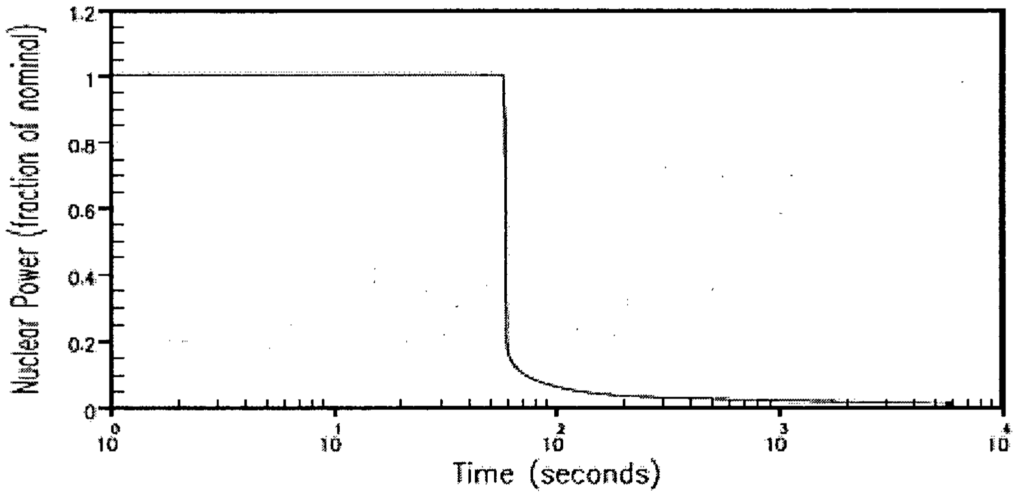


Figure 2.8.5.2.2-7 Loss of Non-Emergency AC Power to the Plant Auxiliaries Unit 2 (Model Δ-47 SGs) Nuclear Power and Core Average Heat Flux vs. Time



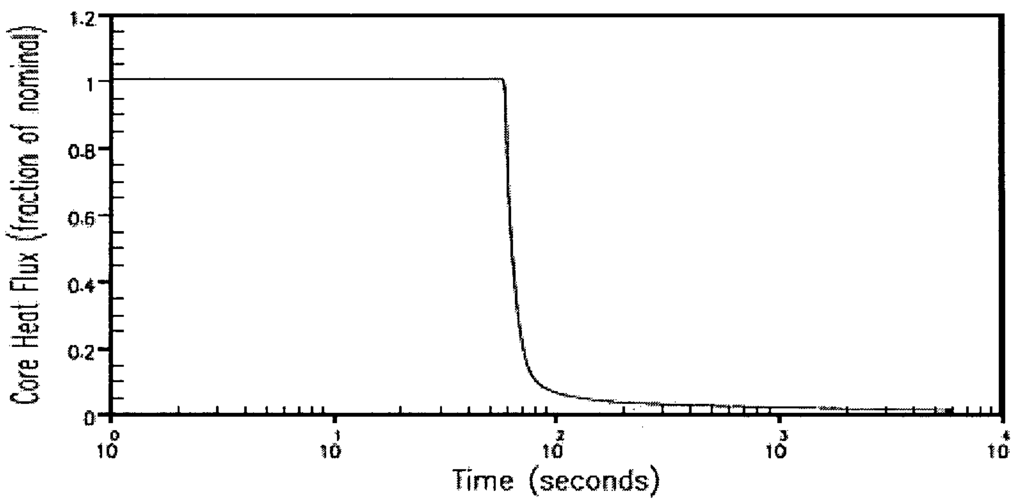


Figure 2.8.5.2.2-8 Loss of Non-Emergency AC Power to the Plant Auxiliaries Unit 2 (Model Δ-47 SGs) Core Reactivity and Reactor Vessel Flow vs. Time

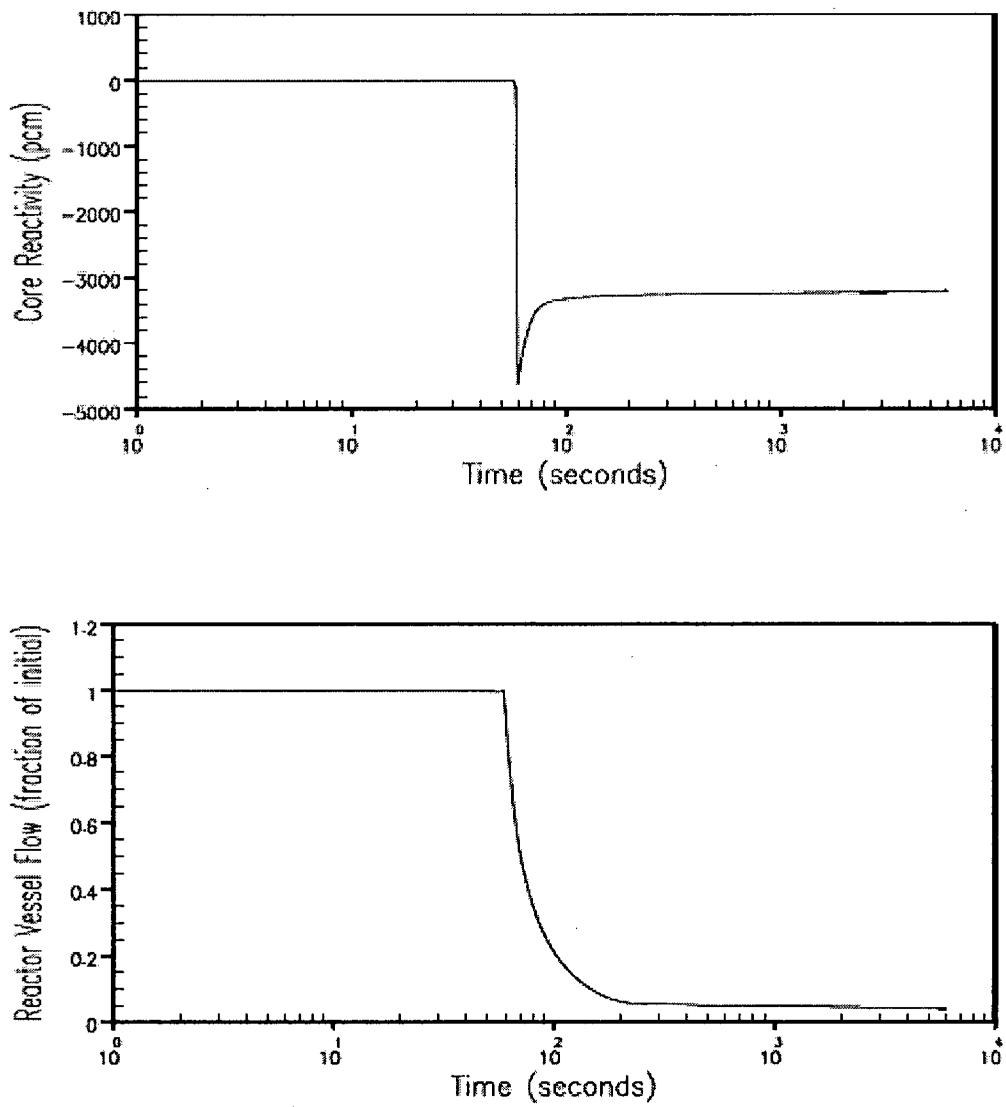


Figure 2.8.5.2.2-9 Loss of Non-Emergency AC Power to the Plant Auxiliaries Unit 2 (Model Δ-47 SGs) Loop T-hot and T-cold vs. Time

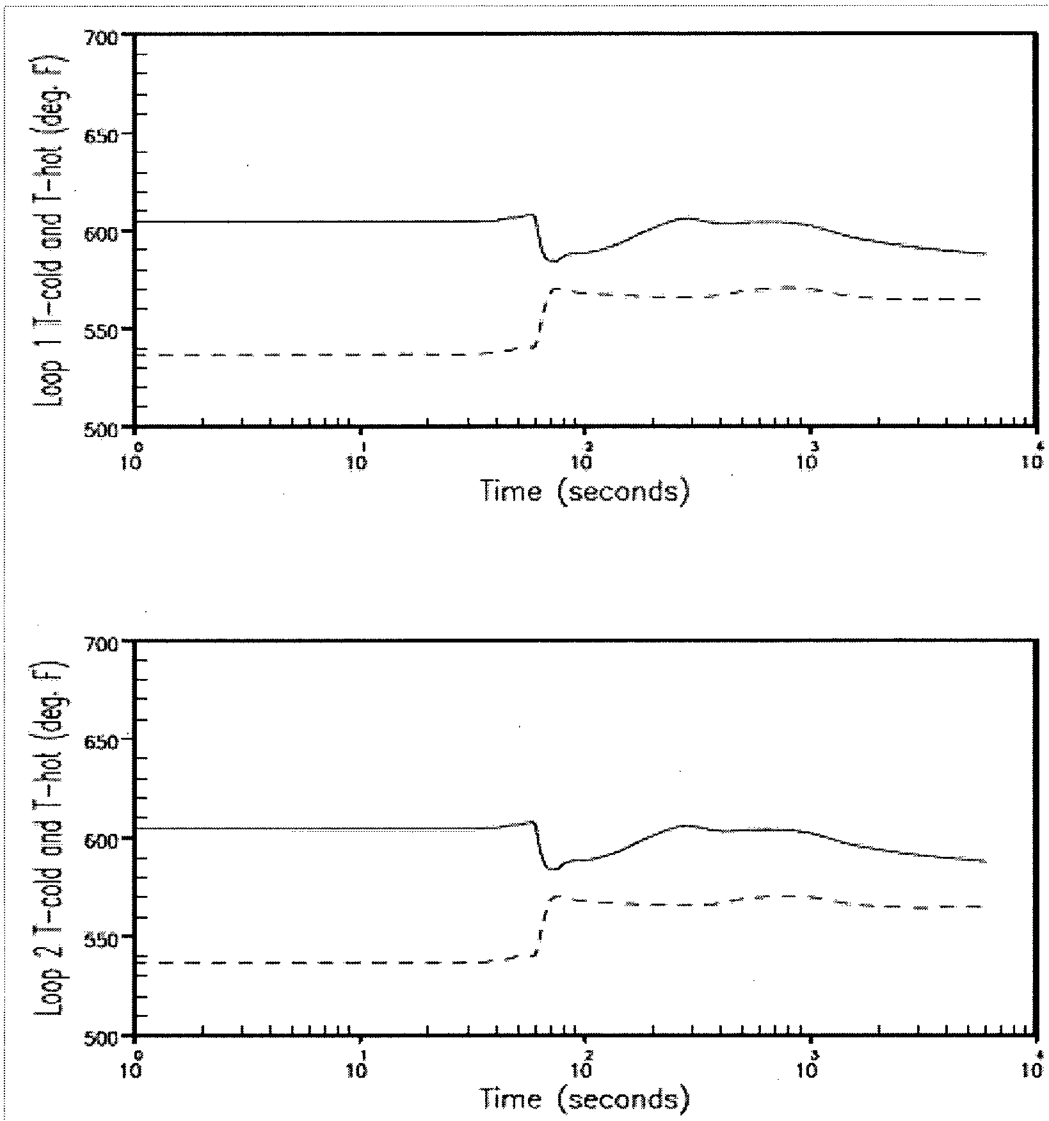
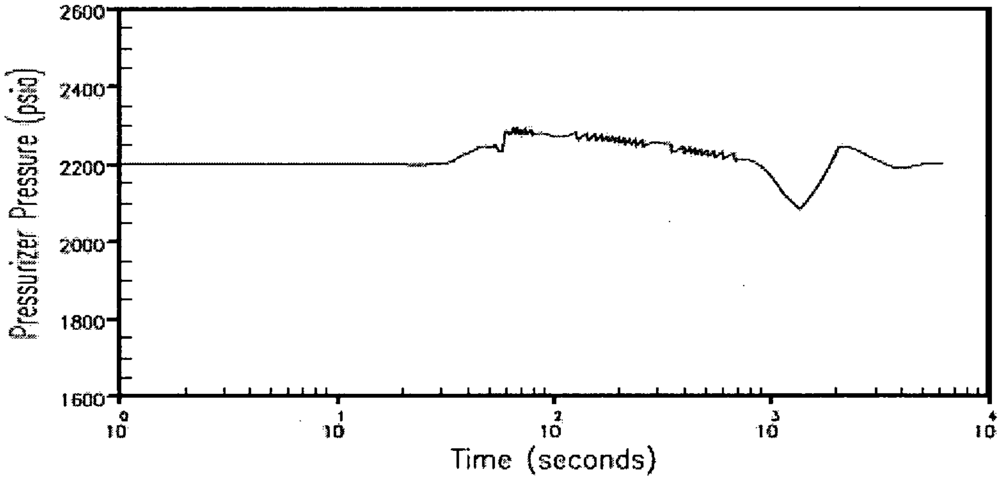


Figure 2.8.5.2.2-10 Loss of Non-Emergency AC Power to the Plant Auxiliaries Unit 2 (Model Δ47 SGs) Pressurizer Pressure and Water Volume vs. Time



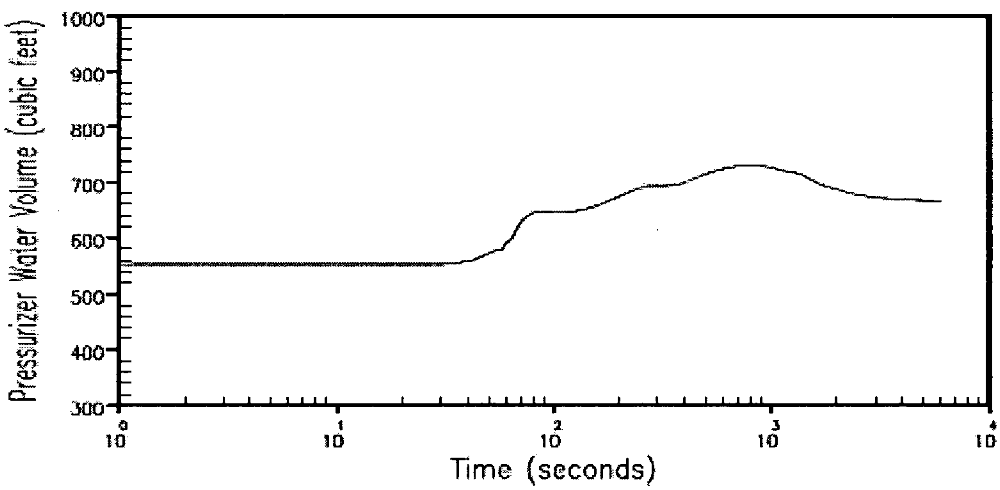


Figure 2.8.5.2.2-11 Loss of Non-Emergency AC Power to the Plant Auxiliaries Unit 2 (Model Δ47 SGs) Loop Steam Pressure vs. Time

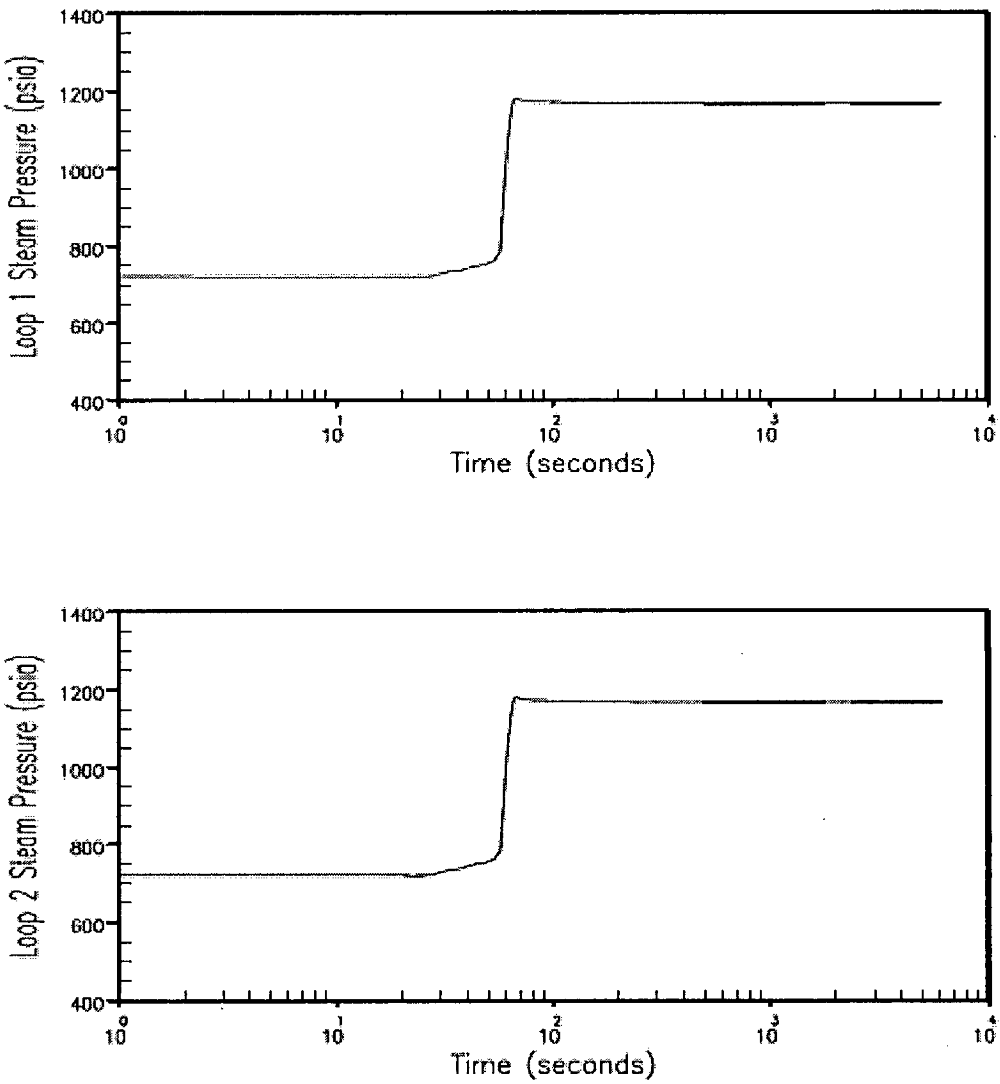
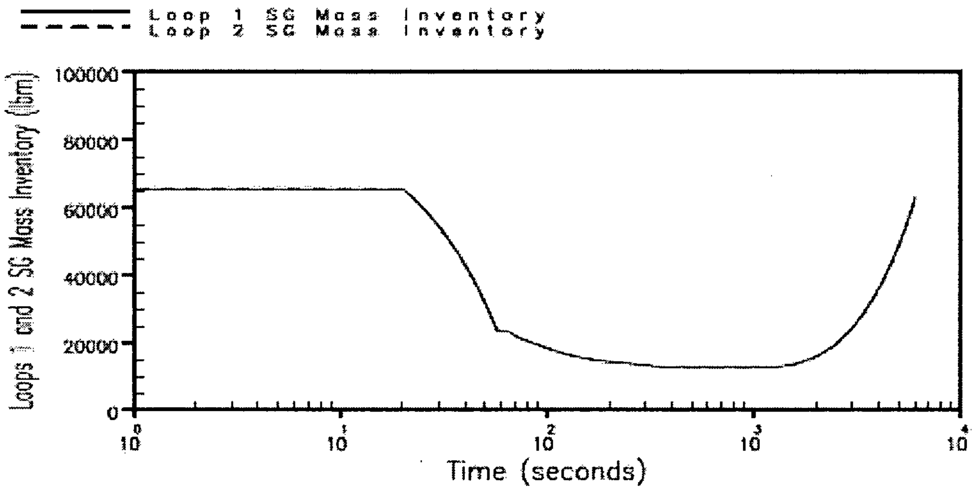
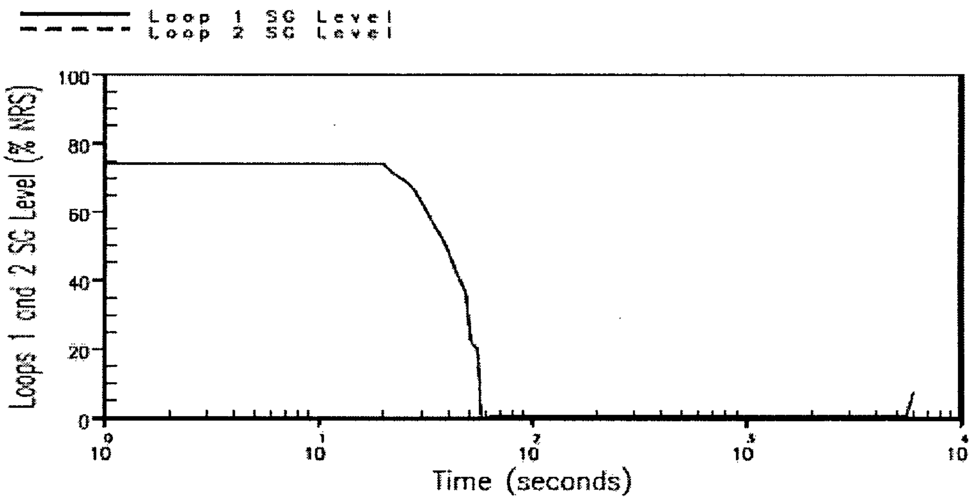


Figure 2.8.5.2.2-12 Loss of Non-Emergency AC Power to the Plant Auxiliaries Unit 2 (Model Δ47 SGs) Loop Steam Generator Mass Inventory and Steam Generator Level vs. Time





2.8.5.2.3 Loss of Normal Feedwater Flow

2.8.5.2.3.1 Regulatory Evaluation

A loss of normal feedwater flow (LONF) could occur from pump failures, valve malfunctions, or a loss of offsite power (LOOP). Loss of feedwater flow results in an increase in reactor coolant temperature and pressure that eventually requires a reactor trip to prevent fuel damage. Decay heat must be transferred from fuel following a LONF. Reactor protection and safety systems are actuated to provide this function and mitigate other aspects of the transient. The PBNP review covered:

- the sequence of events
- the analytical models used for the analyses
- the values of parameters used in the analytical models, and
- the results of the transient analyses

The NRC's acceptance criteria are based on:

- GDC 10, insofar as it requires that the RCS is designed with appropriate margin to ensure that specified acceptable fuel design limits are not exceeded during normal operations, including anticipated operational occurrences
- GDC 15, insofar as it requires that the RCS and its associated auxiliary systems are designed with margin sufficient to ensure that the design condition of the reactor coolant pressure boundary (RCPB) is not exceeded during any condition of normal operation
- GDC 26, insofar as it requires that a reactivity control system is provided and is capable of reliably controlling the rate of reactivity changes to ensure that under normal operating conditions, including anticipated operational occurrences, specified acceptable fuel design limits are not exceeded

Specific review criteria are contained in the SRP, Section 15.2.7, and other guidance provided in Matrix 8 of RS-001, Revision 0.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP, GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50, Appendix A, GDC-10, 15 and 26 are as follows:

CRITERION: The reactor core with its related controls and protection systems shall be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits which have been stipulated and justified. The core and related auxiliary system designs shall provide this integrity under all expected conditions of normal operation with appropriate margins for uncertainties and for specified transient situations which can be anticipated. (PBNP GDC 6)

As stated in FSAR Section 3.1, Reactor, Design Basis, the core design, together with reliable process and decay heat removal systems, provides for this capability under all expected conditions of normal operation with appropriate margins for uncertainties and anticipated transient situations, including the effects of the loss of normal feedwater (FSAR Section 14.1.10, Loss of Normal Feedwater).

Further discussion of this design is provided in FSAR Chapter 4, Reactor Coolant System.

CRITERION: The reactor coolant pressure boundary shall be designed, fabricated, and constructed so as to have an exceedingly low probability of gross rupture or significant uncontrolled leakage throughout its design lifetime. (PBNP GDC 9)

As described in FSAR Section 4.1, Reactor Coolant System, Design Basis, the reactor coolant system, in conjunction with its control and protective provisions, is designed to accommodate the system pressures and temperatures attained under all expected modes of plant operation or anticipated system interactions, and maintain the stresses within applicable code stress limits.

System conditions resulting from anticipated transients or malfunctions are monitored and appropriate action is automatically initiated to maintain the required cooling capability and to limit system conditions to a safe level. The system is protected from overpressure by means of pressure relieving devices, as required by Section III of the ASME Boiler and Pressure Vessel Code. The system is also protected from overpressure at low temperatures by the low temperature overpressure protection system.

CRITERION: One of the reactivity control systems provided shall be capable of making the core subcritical under any anticipated operating condition (including anticipated operational transients) sufficiently fast to prevent exceeding acceptable fuel damage limits. Shutdown margin should assure subcriticality with the most reactive control rod fully withdrawn. (PBNP GDC 29)

The reactor core, together with the reactor control and protection system, is designed so that the minimum allowable DNBR is at least equal to the limits specified for STD, OFA, upgraded OFA, and 422V+ fuel, and there is no fuel melting during normal operation, including anticipated transients.

The shutdown groups are provided to supplement the control group of RCCAs to make the reactor at least 1% subcritical (k_{eff} = 0.99) following a trip from any credible operating condition to the hot, zero power condition assuming the most reactive RCCA remains in the fully withdrawn position.

CRITERION: The reactivity control systems provided shall be capable of making the core subcritical under credible accident conditions with appropriate margins for contingencies and limiting any subsequent return to power such that there will be no undue risk to the health and safety of the public. (PBNP GDC 30)

Normal reactivity shutdown capability is provided by control rods, with boric acid injection from the Chemical and Volume Control System (CVCS) used to compensate for the xenon transients, and for plant cooldown. When the plant is at power, the quantity of boric acid retained in the boric acid tanks and/or the refueling water storage tank (RWST) and ready for injection will always exceed that quantity required for the normal cold shutdown. This quantity will always exceed the quantity of boric acid required to bring the reactor to hot shutdown and to compensate for subsequent xenon decay.

The injection of boric acid is shown to afford backup reactivity shutdown capability, independent of control rod clusters which normally serve this function in the short term situation. Shutdown for long term and reduced temperature conditions can be accomplished with boric acid injection using redundant components.

The reactivity control provided by the CVCS is further discussed in FSAR Section 9.3, Chemical and Volume Control System.

In addition to the evaluations described in the FSAR, the loss of normal feedwater flow analysis was evaluated for plant license renewal. System and system component materials of construction, operating history and programs used to manage aging effects are documented in;

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 1)

The loss of normal feedwater flow analysis is included in License Renewal.

2.8.5.2.3.2 Technical Evaluation

Introduction

A LONF (FSAR Section 14.1.10, Loss of Normal Feedwater) results in a reduction in capability of the secondary system to remove the heat generated in the reactor core. If an alternative supply of feedwater is not supplied, core residual heat following reactor trip would heat the primary system water to the point where water relief from the pressurizer could occur, resulting in a substantial loss of water from the reactor coolant system (RCS). Since the plant is tripped well before the steam generator heat transfer capability is reduced, the primary system variables do not approach a condition that causes a DNBR limit violation.

The LONF that occurs as a result of the loss of AC power is discussed in Section 2.8.5.2.2, Loss of Non-Emergency AC Power to Station.

The following events occur following the reactor trip for the LONF as a result of main feedwater pump failures or valve malfunctions:

- The atmospheric dump valves (ADVs) are automatically opened to the atmosphere as the main steam system pressure rises following a loss of feedwater, steam flow/feedwater flow mismatch coincident with low water level in either steam generator, and turbine trip. The condenser is assumed unavailable for steam dump. If the relief capacity of the ADVs is inadequate, or the ADVs are unavailable, the main steam safety valves (MSSVs) can lift to dissipate the sensible heat of the fuel and coolant plus the residual decay heat produced in the reactor
- As the no-load temperature is approached, the ADVs (or MSSVs, if the ADVs are unavailable), are used to dissipate the residual decay heat and to maintain the plant at the MODE 3 (hot shutdown) condition

The following provide the necessary protection in the event of a LONF:

- The reactor can be tripped on one or more of the following reactor trip signals:
  - Pressurizer-high pressure trip signal if any two-of-three pressure channels exceed a fixed setpoint
  - Pressurizer high water level trip signal if any two-of-three level channels exceed a fixed setpoint
  - Overtemperature ΔT trip signal if any two-out-of-four ΔT channels exceed an overtemperature ΔT setpoint. This setpoint is automatically varied with axial power imbalance, coolant temperature, and pressurizer pressure to protect against DNB
  - Low-low steam generator water level trip signal if any two-out-of-three level channels in either steam generator is below a fixed setpoint
  - Trip of both main feedwater pumps (i.e., opening of both main feedwater pump breakers)
- One motor-driven auxiliary feedwater (MDAFW) pump is started on any of the following:
  - Low-low water level in two-out-of-three level channels in either steam generator
  - Loss of both 4.16kv buses supplying the main feedwater pump motors
  - Safety injection
  - Manual actuation
- One turbine-driven auxiliary feedwater (TDAFW) pump is started on any of the following:
  - Low-low water level in two-out-of-three level channels in either steam generator
  - Loss of both 4.16 kV buses supplying the main feedwater pump motors
  - Safety Injection
  - Manual actuation
- The MSSVs open to provide an additional heat sink and protection against secondary side overpressure
- The pressurizer safety valves (PSVs) may open to provide protection against overpressure of the RCS

The analysis of the LONF event demonstrates that the AFW system is capable of removing the stored and residual heat, and consequently will prevent RCS or main steam system (MSS) overpressurization and core uncovery. The plant is therefore able to return to a safe condition.

Input Parameters, Assumptions, and Acceptance Criteria

The major inputs and assumptions used in the analysis are described as follows:

- The plant was initially operating at an NSSS power of 100.6% of 1806 MWt, with maximum RCP heat of 8.0 MWt. The RCPs were assumed to continuously operate throughout the transient, providing a constant reactor coolant volumetric flow equal to the thermal design flow value. Although not assumed in the analysis, the RCPs could be manually tripped at some later time in the transient to reduce the heat addition to the RCS caused by the operation of the pumps

- Main feedwater temperature conditions at 390°F and 458°F were analyzed
- The direction of conservatism for both the initial reactor vessel average coolant temperature and the pressurizer pressure can vary. As such, cases were considered with the initial temperature and pressure uncertainties applied in each direction. The initial average temperature uncertainty was conservatively assumed to be ±6.4°F. The initial pressurizer pressure uncertainty was conservatively assumed to be ± 50 psi. The most limiting LONF case (with respect to pressurizer filling), for the cases with the Model 44F or Δ47 steam generators, was with the temperature uncertainty subtracted from the high nominal (window) T_{avg} value (i.e., 577°F - 6.4°F), pressure uncertainty added to the nominal value (i.e., 2250 psia + 50 psi), while modeling high (458°F) main feedwater temperature conditions. The most limiting cases were cases in which the pressurizer power-operated relief valves were assumed to be inoperable. Note that there are two peaks in the pressurizer water level for a loss of normal feedwater event. The first peak is a function of the initial conditions and the second peak is an indication of the capability of the AFW system to perform long term heat removal. Thus, the magnitude of the second peak is used to determine the limiting case
- Reactor trip occurred on steam generator low-low water level at 20% of the narrow range span (NRS)
- It was assumed that one Motor-Driven Auxiliary Feedwater (MDAFW) or one Turbine-Driven Auxiliary Feedwater (TDAFW) pump was available to supply a minimum flow of 275 gpm split equally to both steam generators. Therefore, loss of either of these pumps could be considered as the worst single failure. The AFW flow was initiated 30 seconds after the low-low SG water level setpoint was reached; from 30 to 60 seconds, the AFW flowrate ramped from 0% to 80% of total flow; from 60 to 120 seconds, the AFW flowrate ramped from 80% to 100% of total flow; beyond 120 seconds, 100% of total flow (275 gpm) was maintained. The AFW enthalpy was assumed to be 70.90 Btu/lbm (corresponding to the maximum AFW temperature of 100°F)
- The pressurizer sprays were assumed to be operable. The pressurizer PORVs were assumed to be inoperable in the limiting cases. These assumptions maximize the peak pressurizer water volume. If the pressurizer sprays did not operate, the PSVs would prevent the RCS pressure from exceeding the RCS pressure limit during this transient. The pressurizer backup heaters were modeled to not actuate on the high pressurizer level deviation signal. However, the backup heaters were modeled to actuate on low pressurizer pressure. The pressurizer backup heater actuation on a pressurizer high level deviation signal will be removed
- The nominal pressurizer water levels that correspond to the high (577°F) and low (558°F) T_{avg} conditions are 47% and 29.9% of span, respectively. An uncertainty of +10% of span was applied to the initial pressurizer level for all cases
- Secondary system steam relief is achieved through the self-actuated MSSVs. Note that steam relief would normally be provided by the steam generator ADVs or condenser dump

valves for most cases of LONF. However, the condenser dump valves and the ADVs were assumed to be unavailable

- The MSSVs were modeled assuming 3.0% tolerance and 1.1% accumulation
- Core residual heat generation was based on the 1979 version of ANS 5.1 (Reference 2). ANSI/ANS-5.1-1979 is a conservative representation of the decay energy release rates. Long-term operation at the initial power level preceding the trip was assumed
- Steam generator tube plugging (SGTP) levels of both 0% and 10% were analyzed, with 10% being the most limiting

Based on its frequency of occurrence, the LONF event is considered a Condition II event as defined by the American Nuclear Society. The following items summarize the acceptance criteria associated with this event:

- Fuel cladding integrity is maintained by ensuring that the minimum DNBR remains above the 95/95 DNBR limit
- Pressure in the RCS and MSS is maintained below 110% of the design pressures
- An incident of moderate frequency does not generate a more serious plant condition without other faults occurring independently

With respect to overpressurization, the LONF event is bounded by the loss of load event reported in Section 2.8.5.2.1, Loss of External Electrical Load, Turbine Trip, and Loss of Condenser Vacuum, in which assumptions are made to conservatively calculate the RCS and MSS pressure transients. For the LONF event, turbine trip occurs after reactor trip, whereas for loss of load the turbine trip is the initiating fault. Therefore, the primary/secondary power mismatch and resultant RCS and MSS heatup and pressurization transients are always more severe for loss of load than for LONF.

With respect to DNB, the LONF event is also bounded by the loss of load event. Both of these events represent a reduction in the heat removal capability of the secondary system. For the LONF event, the RCS temperature increases gradually as the steam generators boil down to the low-low level trip setpoint, at which time reactor trip occurs, followed by turbine trip. For the loss of load event, the turbine trip is the initiating event, and the loss of heat sink is much more severe. The initial RCS heatup will be much more severe for the loss of load event than for the LONF event, and the loss of load event will always be more severe with respect to the minimum DNBR criterion.

The restrictive acceptance criterion, that the pressurizer does not become water solid, was used for this event. Satisfying this single criterion ensures that the capacity of the AFW system is sufficient for long-term removal of decay heat and reactor coolant pump heat. It also demonstrates the preclusion of a more serious plant condition and ensures that the pressure criteria and minimum DNBR criterion are satisfied for the long-term.

2.8.5.2.3.3 Description of Analyses and Evaluations

A detailed analysis using the RETRAN (Reference 3) computer code was performed to determine the plant transient conditions following a LONF. The code modeled the core neutron kinetics, RCS, pressurizer, pressurizer PORVs and sprays, steam generators, MSSVs, and the AFW system. The code also computed pertinent variables, including the pressurizer pressure, pressurizer water level, steam generator mass, and reactor coolant average temperature. Additional discussion of the RETRAN code is contained in Section 2.8.5.0.9, Computer Codes Used.

Credit was taken for a portion of the coolant-to-metal heat transfer that would occur during the long-term primary-side heat-up. A RETRAN thick metal mass heat transfer model was developed for use in the LONF and LOAC event analyses using the RETRAN thick metal mass heat transfer model methodology described in WCAP-14882-S1-P-A (Reference 4). See LR Section 2.8.5.0.12, Accident and Transient Analysis, for justification of the use of this methodology.

2.8.5.2.3.4 Results

The calculated sequence of events for this event is listed in Table 2.8.5.2.3-1, Sequence of Events. Figures 2.8.5.2.3-1 through 2.8.5.2.3-6 present transient plots of the significant plant parameters for the case with the limiting LONF case with the Model 44F steam generators (Unit 1) and Figures 2.8.5.2.3-7 through 2.8.5.2.3-12 present transient plots of plant parameters for the limiting LONF case with the Model Δ47 steam generators (Unit 2), with the assumptions listed in Section 2.8.5.2.3.2, Technical Evaluation. The analysis demonstrates that 275 gpm of auxiliary feedwater split equally between the two steam generators is adequate to remove decay heat and pump heat such that no pressurizer filling will occur. Numerical results of the EPU analysis along with a comparison to the previous analysis results are shown in Table 2.8.5.2.3-2, Loss of Normal Feedwater Flow Results. The most limiting cases are initiated with the average RCS temperature at the high end of the temperature window minus uncertainties.

Following the reactor and turbine trip from full load, the water level in the steam generators fell due to reduction of the steam generator void fraction and because steam flow through the safety valves continued to dissipate the stored and generated heat. At 30 seconds after the low-low level water level setpoint was reached, the AFW flow automatically started, consequently reducing the rate at which the steam generator water level was decreasing.

The capacity of the AFW pump enabled sufficient heat transfer from each steam generator to dissipate the core residual heat without the pressurizer reaching a water solid condition (as shown in Figure 2.8.5.2.3-4). This precluded any water relief through the RCS pressurizer relief valves or PSVs.

With respect to DNB, the LONF event is bounded by the loss of load event (see LR Section 2.8.5.2.1, Loss of External Electrical Load, Turbine Trip, and Loss of Condenser Vacuum), for which the minimum DNBR was determined to be greater than the safety analysis limit value. Also, with respect to primary and secondary overpressurization, the loss of load event analysis described in Section 2.8.5.2.1, Loss of External Electrical Load, Turbine Trip, and Loss of Condenser Vacuum, demonstrates that the primary and secondary pressure limits of 2748.5 psia and 1208.5 psia are met.

The results of the analysis showed that the pressurizer did not reach a water solid condition. Therefore, the LONF event did not adversely affect the core, the RCS, or the MSS.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

The system, structures, and components whose performance is relied upon to support the inputs, assumptions, and results of the analyses described in this section for transients resulting in unplanned sudden decreases in heat removal by the secondary system are not being modified by the EPU activities. EPU activities do not add any new functions for existing components associated with these analyses that would change the license renewal evaluation boundaries. Operation of these components at EPU conditions does not introduce any unevaluated aging effects that would necessitate a change to aging management programs or require a new program as internal and external environments remain within the parameters previously evaluated. In addition, the primary and secondary systems performance capability described in this section is for upset conditions which are not the conditions used for license renewal aging evaluations. Therefore, EPU activities associated with loss of normal feedwater do not impact license renewal scope, aging effects, and aging management programs.

2.8.5.2.3.5 Conclusions

PBNP has reviewed the analysis of the LONF event and concludes that the analysis has adequately accounted for operation of the plant at the power level and was performed using acceptable analytical models (including the use of RETRAN and the RETRAN thick metal heat transfer model) (Reference 4). PBNP further concludes that the evaluation has demonstrated that the reactor protection and safety systems (including the revised auxiliary feedwater assumptions, the revised SG low-low level trip setpoint and the revised pressurizer level program) will continue to ensure that the specified acceptable fuel design limits and the reactor coolant pressure boundary and main steam system pressure limits will not be exceeded as a result of the LONF. Based on this, PBNP concludes that the plant will continue to meet the PBNP current licensing basis requirements with respect to PBNP, GDC 6, 9, 29 and 30 following implementation of the EPU. Therefore, PBNP finds the EPU acceptable with respect to the LONF event.

2.8.5.2.3.6 References

1. Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

2. ANSI/ANS-5.1-1979, American National Standard for Decay Heat Power in Light Water Reactors, August 1979

3. WCAP-14882-P-A, RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses), Huegel, D.S., et al., April 1999

4. WCAP-14882-S1-P-A, RETRAN-02 Modeling and Qualification For Westinghouse Pressurized Water Reactors Non-LOCA Safety Analyses, Supplement 1 - Thick Metal Mass Heat Transfer Model and NOTRUMP-Based Steam Generator Mass Calculation Method, October 2005

Table 2.8.5.2.3-1
Sequence of Events

Event	Time (seconds)	
	Unit 1 (Model 44F SGs)	Unit 2 (Model Δ47 SGs)
Main Feedwater Flow Stops	20.0	20.0
Low-Low Steam Generator Water Level Reactor Trip Setpoint Reached	56.0	54.4
Rods Begin to Drop	58.0	56.4
Flow from One AFW Pump is Initiated	86.0	84.4
Long-Term Peak Water Level in Pressurizer Occurs	1410	1378
Core Decay Heat Decreases to AFW Heat Removal Capacity	~1414	~1392

Table 2.8.5.2.3-2
Loss of Normal Feedwater Flow Results

	EPU Analysis	Previous Analysis	Limit
Peak Pressurizer Water Volume from the Limiting Unit 1 Case (ft^3) (Model 44F SGs)	880	856	1000
Peak Pressurizer Water Volume from the Limiting Unit 2 Case (ft^3) (Model Δ47 SGs)	928	941	1000

Figure 2.8.5.2.3-1 Loss of Normal Feedwater Flow Unit 1 (Model 44F) Nuclear Power and Core Average Heat Flux vs. Time

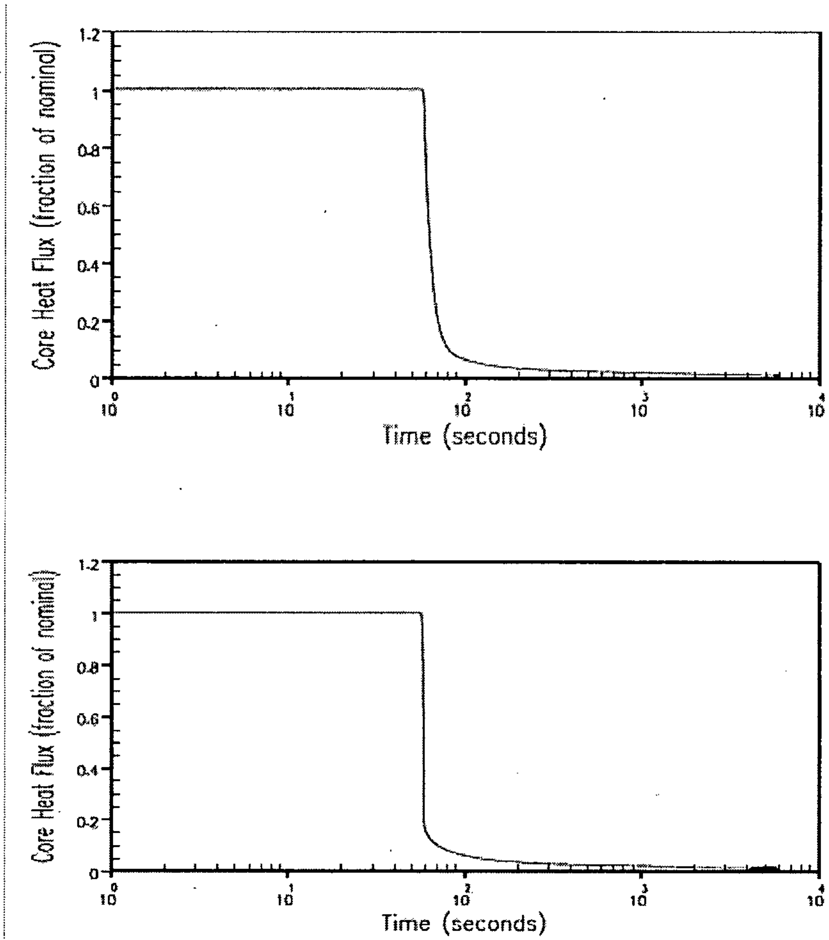


Figure 2.8.5.2.3-2 Loss of Normal Feedwater Flow Unit 1 (Model 44F) Core Reactivity and Reactor Vessel Flow vs. Time

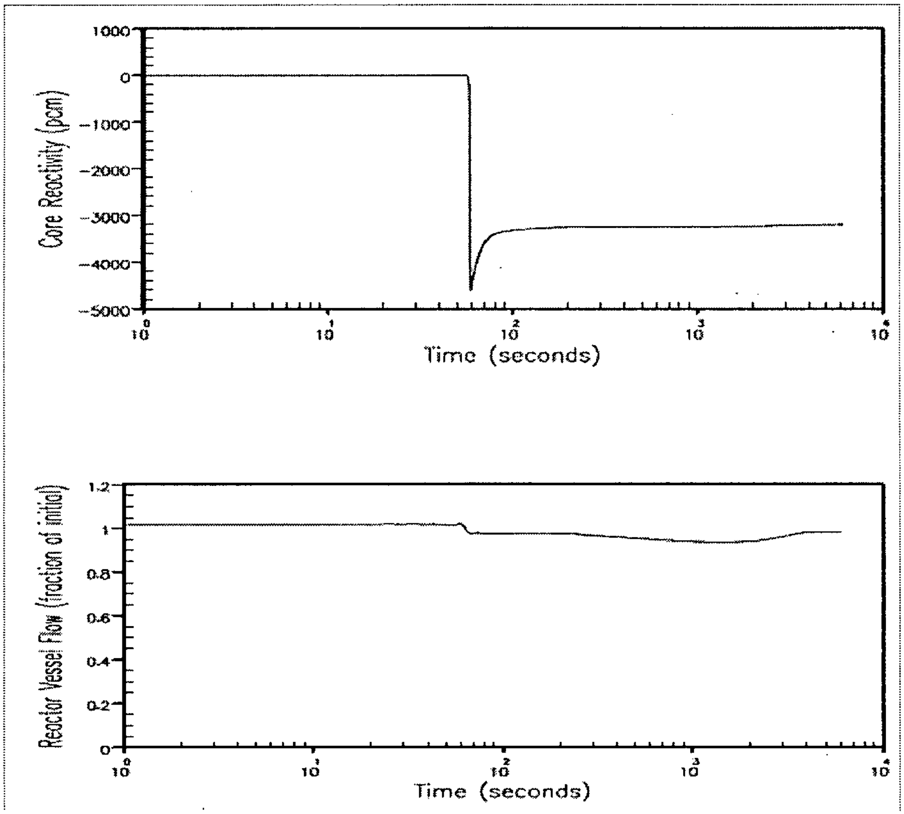


Figure 2.8.5.2.3-3 Loss of Normal Feedwater Flow Unit 1 (Model 44F) Loop T-hot and T-cold vs. Time

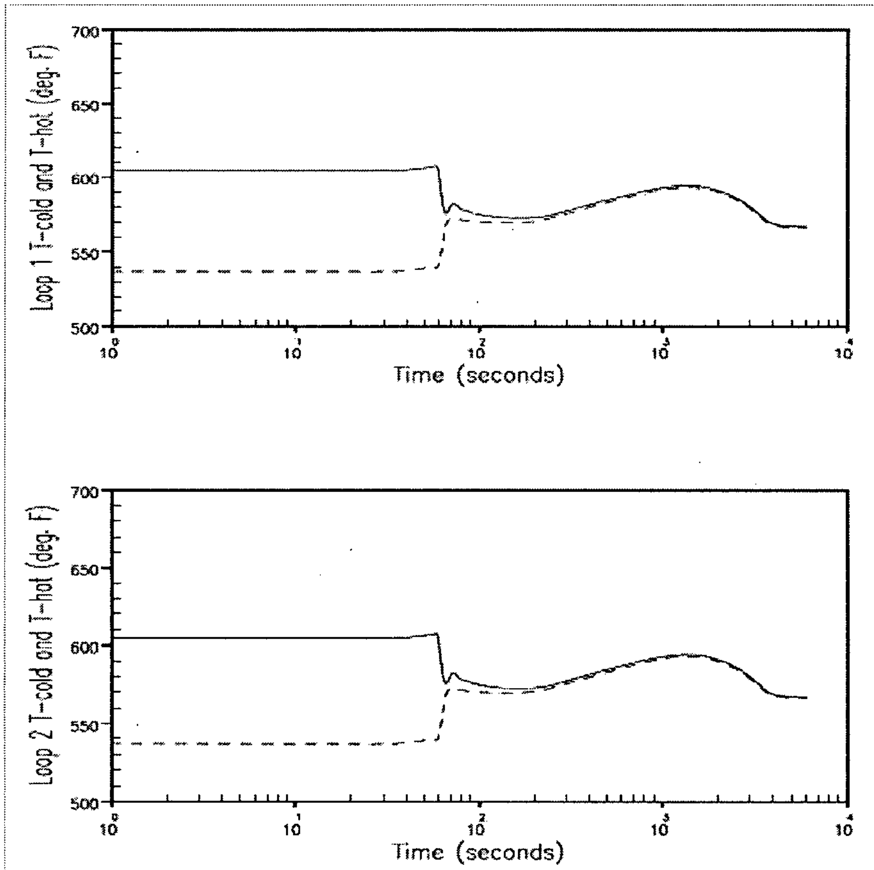


Figure 2.8.5.2.3-4 Loss of Normal Feedwater Flow Unit 1 (Model 44F) Pressurizer Pressure and Water Volume vs. Time

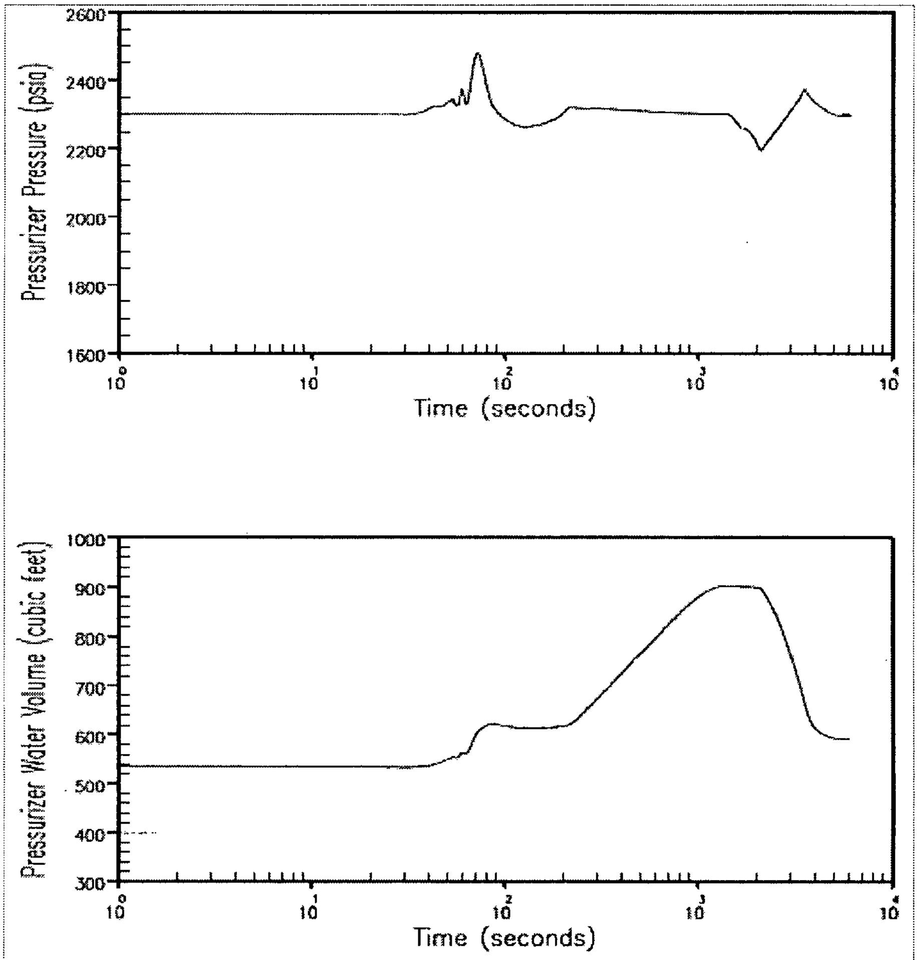


Figure 2.8.5.2.3-5 Loss of Normal Feedwater Flow Unit 1 (Model 44F) Loop Steam Pressure vs. Time

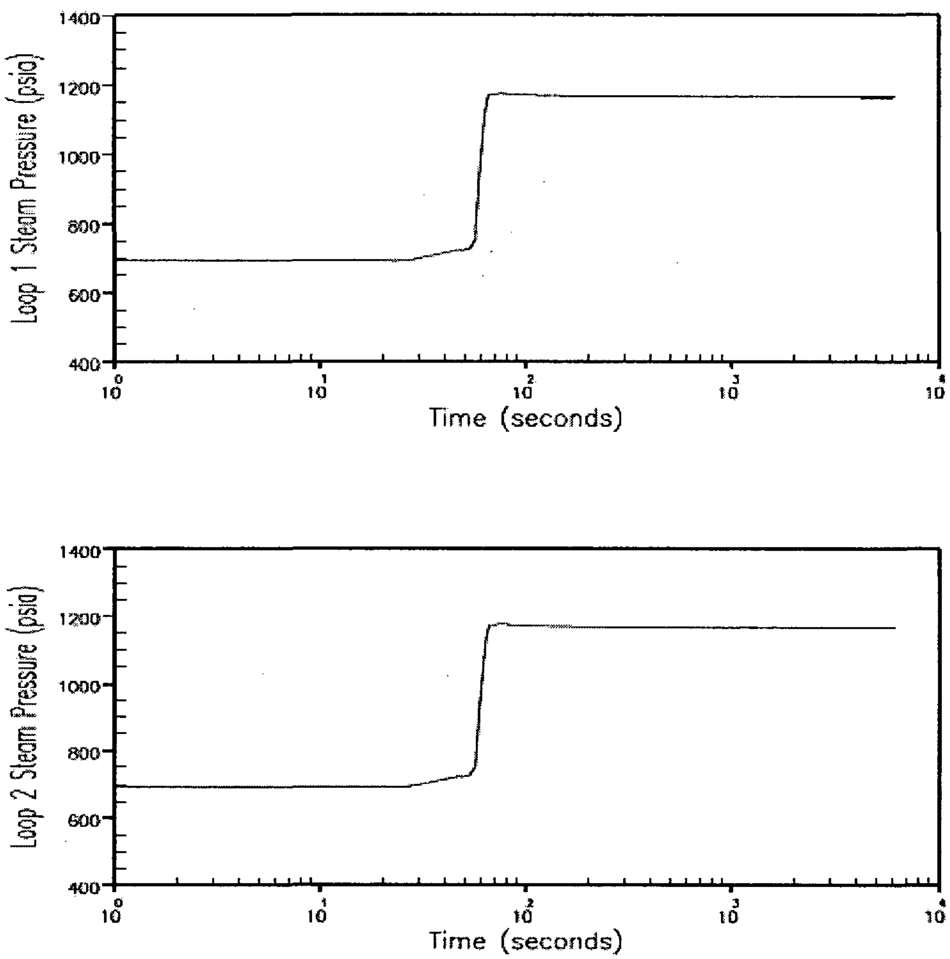
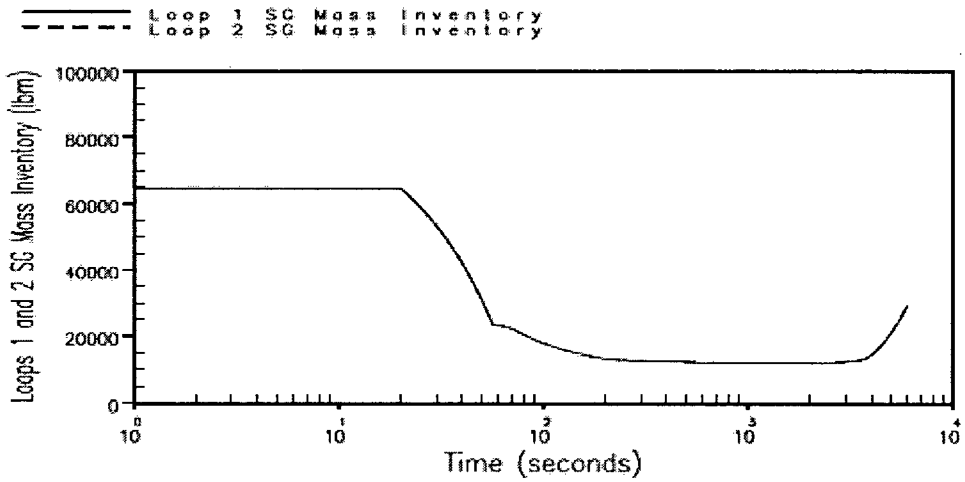


Figure 2.8.5.2.3-6 Loss of Normal Feedwater Flow Unit 1 (Model 44F) Loop Steam Generator Mass Inventory and Steam Generator Level vs. Time



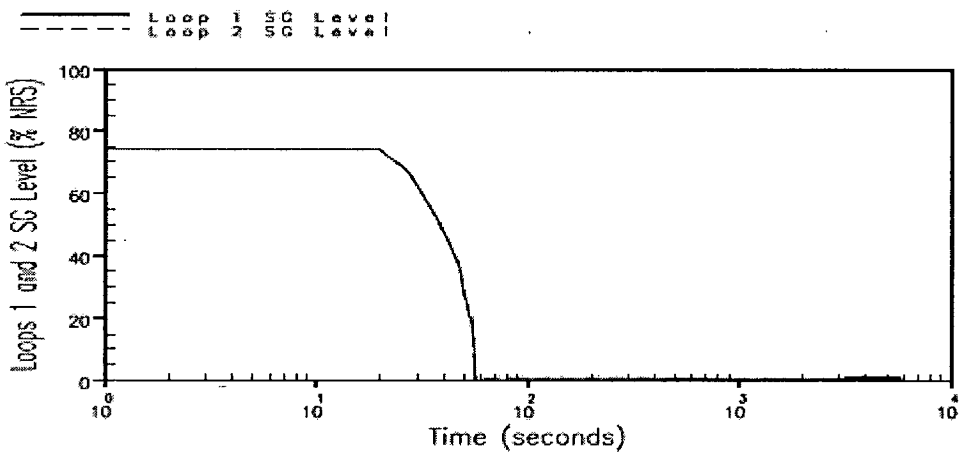


Figure 2.8.5.2.3-7 Loss of Normal Feedwater Flow Unit 2 (Model Δ47) Nuclear Power and Core Average Heat Flux vs. Time

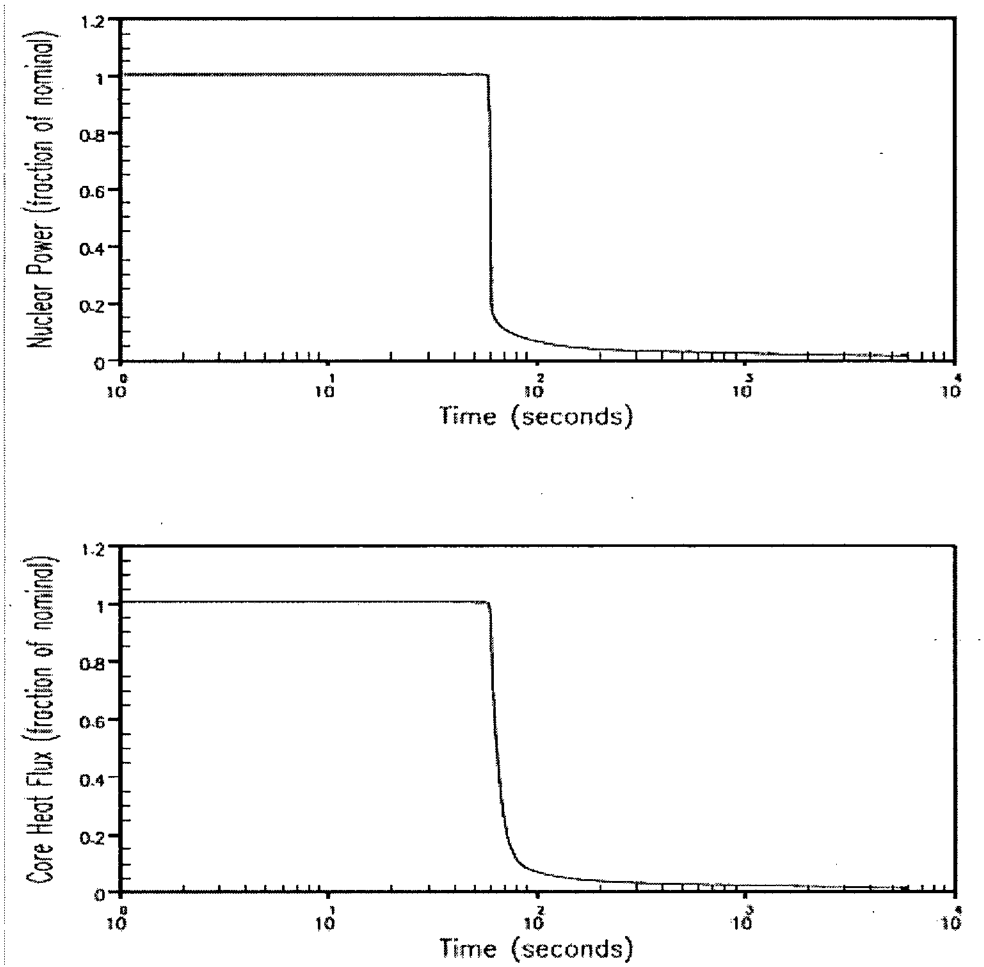


Figure 2.8.5.2.3-8 Loss of Normal Feedwater Flow Unit 2 (Model Δ47) Core Reactivity and Reactor Vessel Flow vs. Time

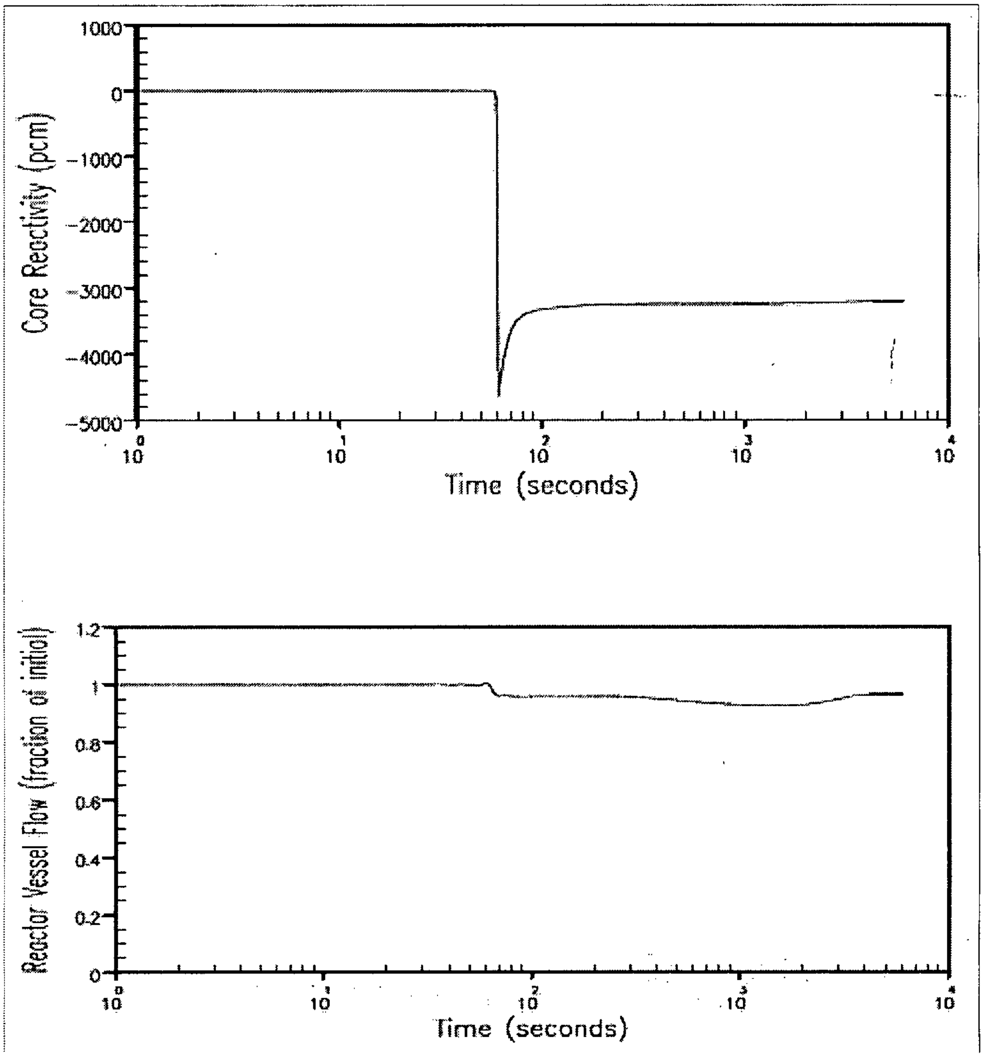


Figure 2.8.5.2.3-9 Loss of Normal Feedwater Flow Unit 2 (Model Δ47) Loop T-hot and T-cold vs. Time

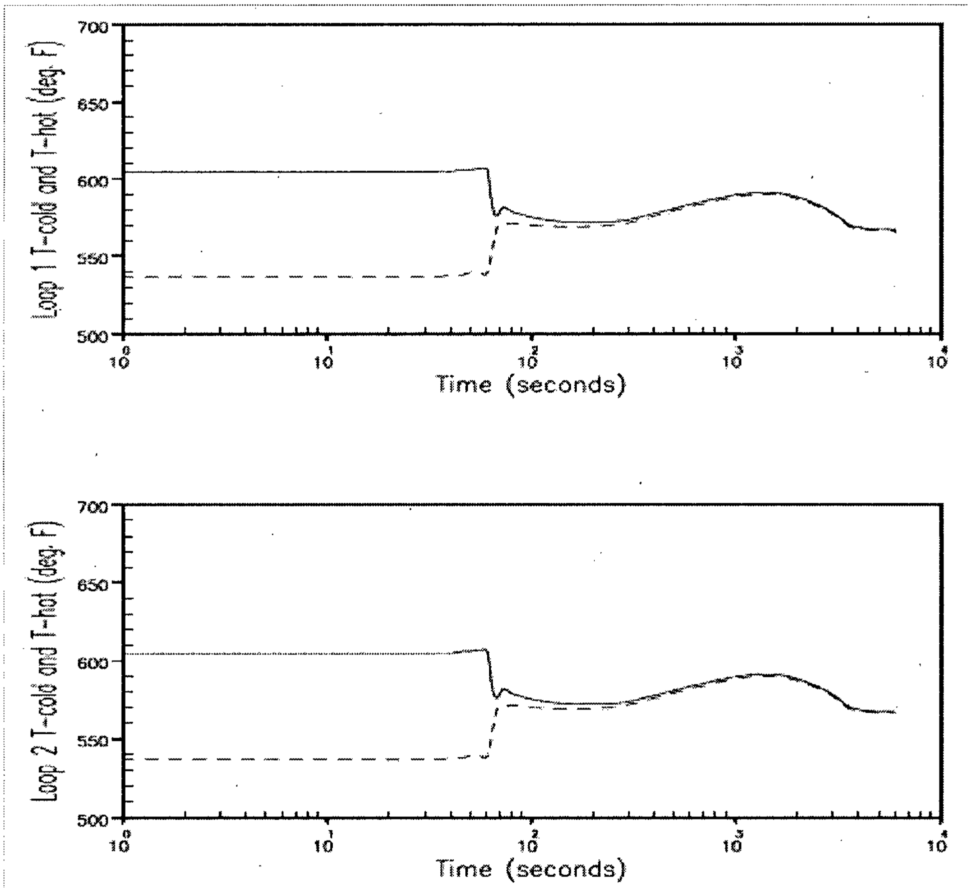


Figure 2.8.5.2.3-10 Loss of Normal Feedwater Flow Unit 2 (Model Δ47) Pressurizer Pressure and Water Volume vs. Time

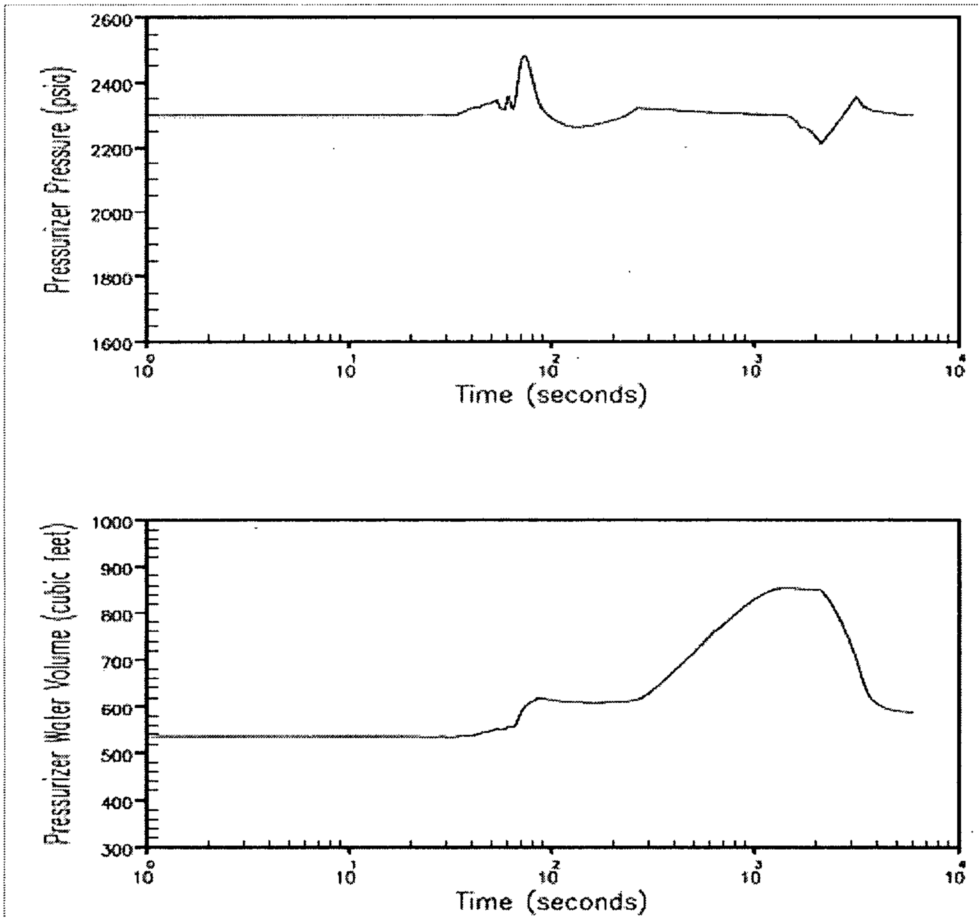


Figure 2.8.5.2.3-11 Loss of Normal Feedwater Flow Unit 2 (Model Δ47) Loop Steam Pressure vs. Time

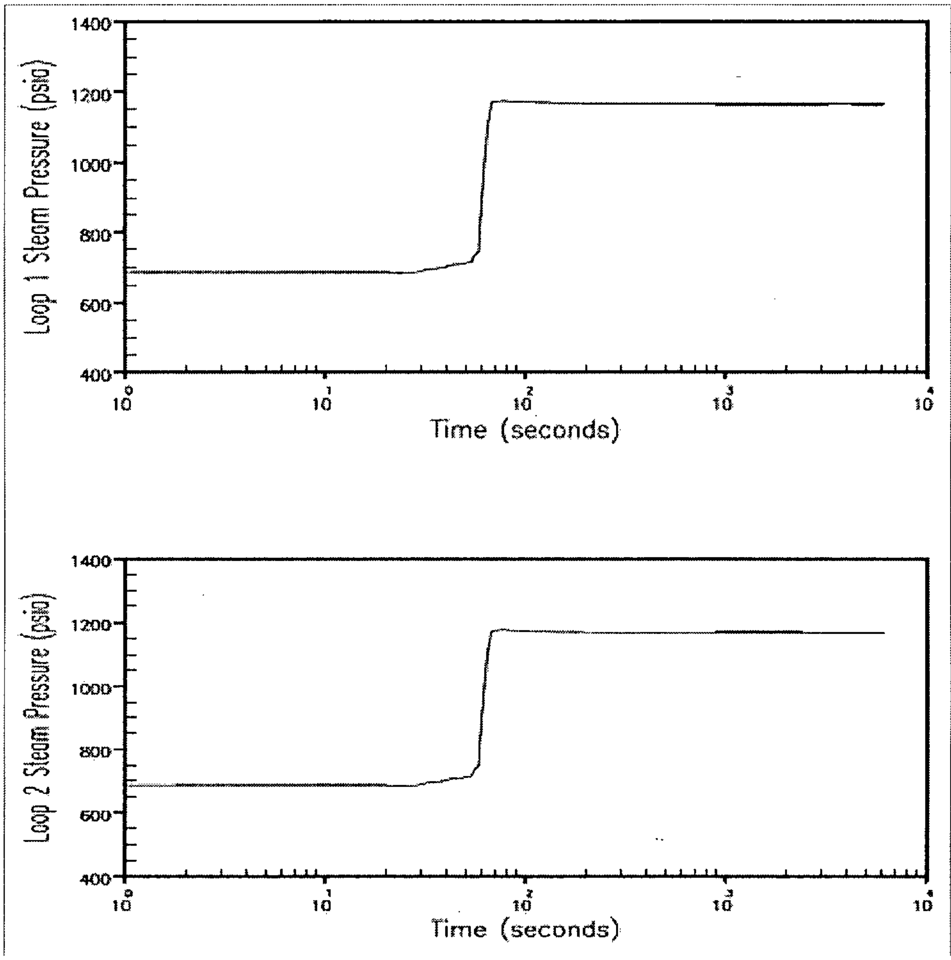
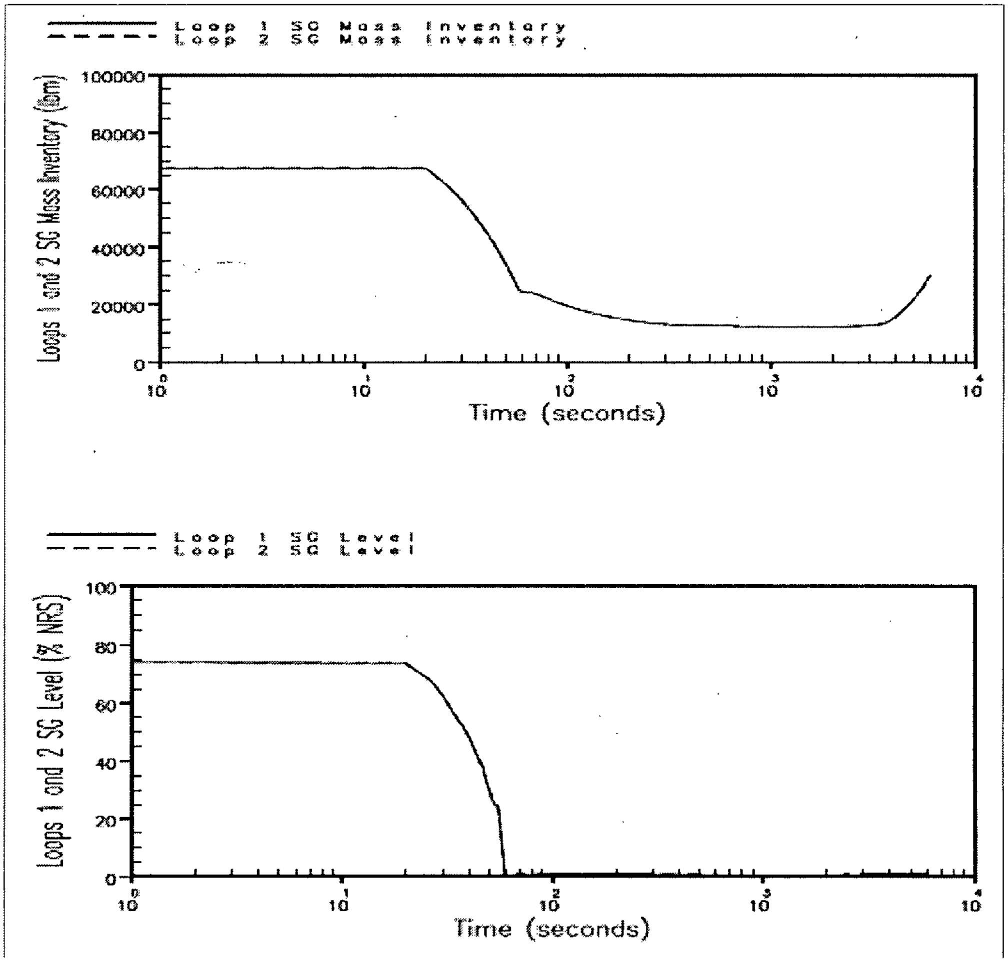


Figure 2.8.5.2.3-12 Loss of Normal Feedwater Flow Unit 2 (Model Δ47) Loop Steam Generator Mass Inventory and Steam Generator Level vs. Time



2.8.5.2.4 Feedwater System Pipe Breaks Inside and Outside Containment

2.8.5.2.4.1 Regulatory Evaluation

Pipe break could cause either a reactor coolant system (RCS) cooldown (by excessive energy discharge through the break) or an RCS heatup (by reducing feedwater flow to the affected RCS). Depending upon the size and location of the break and the plant operating conditions at the time of the break. In either case, reactor protection and safety systems are actuated to mitigate the transient.

The NRC's acceptance criteria are based on:

- GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the emergency core cooling system (ECCS), of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, thus ensuring that core cooling capability is maintained
- GDC 28, insofar as it requires that the reactivity control systems be designed to ensure that the effects of postulated reactivity accidents can neither result in damage to the reactor coolant pressure boundary greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to significantly impair the capability to cool the core
- GDC 31, insofar as it requires that the reactor coolant pressure boundary be designed with sufficient margin to ensure that, under specified conditions, it will behave in a non-brittle manner and the probability of a rapidly propagating fracture is minimized
- GDC 35, insofar as it requires the reactor cooling system and associated auxiliaries be designed to provide abundant emergency core cooling

Specific review criteria are contained in the SRP, Section 15.2.8, and other guidance provided in Matrix 8 of RS-001, Revision 0.

PBNP Current Licensing Basis

Feedwater System pipe breaks are not required to be analyzed per the PBNP current licensing basis.

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP, GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50, Appendix A, GDC 27, 28, 31 and 35 are as follows:

CRITERION: The reactivity control systems provided shall be capable of making the core subcritical under credible accident conditions with appropriate margins for contingencies and limiting any subsequent return to power such that there will be no undue risk to the health and safety of the public. (PBNP GDC 30)

FSAR Section 3.1.2.6, Design Basis, Reactivity Holddown Capability, addresses the reactivity control systems.

CRITERION: Limits, which include reasonable margin, shall be placed on the maximum reactivity worth of control rods or elements and on rates at which reactivity can be increased to ensure that the potential effects of a sudden or large change of reactivity cannot (a) rupture the reactor coolant pressure boundary or (b) disrupt the core, its support structures, or other vessel internals sufficiently to lose capability of cooling the core. (PBNP GDC 32)

FSAR Section 3.1.2.8, Reactor Design Basis, Maximum Reactiity Worth of Control Rods, discusses the maximum reactivity worth of control rods and the reactivity insertion limits.

CRITERION: The reactor coolant pressure boundary shall be capable of accommodating without rupture the static and dynamic loads imposed on any boundary component as a result of an inadvertent and sudden release of energy to the coolant. As a design reference, this sudden release shall be taken as that which would result from a sudden reactivity insertion such as rod ejection (unless prevented by positive mechanical means), rod dropout, or cold water addition. (PBNP GDC 33)

FSAR Section 4.1, Reactor Coolant System, Design Basis, discusses the capability of the reactor coolant pressure boundary.

CRITERION: An emergency core cooling system with the capability for accomplishing adequate emergency core cooling shall be provided. This core cooling system and the core shall be designed to prevent fuel and clad damage that would interface with the emergency core cooling function and to limit the clad metal-water reaction to acceptable amounts for all sizes of breaks in the reactor coolant piping up to the equivalent of a double-ended rupture of the largest pipe. The performance of such emergency core cooling system shall be evaluated conservatively in each area of uncertainty. (PBNP GDC 44)

FSAR Section 6.2, Engineered Safety Features, Safety Injection System, addresses the emergency core cooling system capability.

Mass and Energy (M&E) release analysis for postulated secondary system pipe ruptures is discussed in LR Section 2.6.3.2, M&E Release Analysis for Secondary Systems. Steam system piping failures inside and outside of containment are discussed in LR Section 2.8.5.1.2, Steam System Piping Failure Inside and Outside Containment. Feedwater system pipe breaks inside and outside containment are also addressed in LR Section 2.5.1.3, Pipe Failures.

In addition to the evaluations described in the FSAR, the feedwater system was evaluated for plant license renewal. System and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 1)

The analysis of feedwater system pipe breaks is not within the scope of license renewal.

2.8.5.2.4.2 Technical Evaluation

Not required to be analyzed per the PBNP current licensing basis.

2.8.5.2.4.3 Conclusion

Not required to be analyzed per the PBNP current licensing basis.

2.8.5.2.4.4 References

1. Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

2.8.5.3 Decrease in Reactor Coolant System Flow

2.8.5.3.1 Loss of Forced Reactor Coolant Flow

2.8.5.3.1.1 Regulatory Evaluation

A decrease in reactor coolant flow occurring while the plant is at power could result in a degradation of core heat transfer. An increase in fuel temperature and accompanying fuel damage could then result if specified acceptable fuel design limits are exceeded during the transient. Reactor protection and safety systems are actuated to mitigate the transient. The PBNP review covered:

- The postulated initial core and reactor conditions
- The methods of thermal and hydraulic analyses
- The sequence of events
- The assumed reactions of reactor systems components
- The functional and operational characteristics of the reactor protection system
- The operator actions
- The results of the transient analyses

NRC's acceptance criteria are based on:

- GDC 10, insofar as it requires that the reactor coolant system (RCS) is designed with appropriate margin to ensure that specified acceptable fuel design limits are not exceeded during normal operations, including anticipated operational occurrences
- GDC 15, insofar as it requires that the RCS and its associated auxiliary systems are designed with margin sufficient to ensure that the design condition of the reactor coolant pressure boundary is not exceeded during any condition of normal operation
- GDC 26, insofar as it requires that a reactivity control system is provided, and is capable of reliably controlling the rate of reactivity changes to ensure that under normal operating conditions, including anticipated operational occurrences, specified acceptable fuel design limits are not exceeded

Specific review criteria are contained in the SRP, Section 15.3.1-2 and other guidance provided in Matrix 8 of RS-001, Revision 0.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP, GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP specific GDC for loss of forced reactor coolant flow are as follows:

CRITERION: The reactor core with its related controls and protection systems shall be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits which have been stipulated and justified. The core and related auxiliary system designs shall provide this integrity under all expected conditions of normal operation with appropriate margins for uncertainties and for specified transient situations which can be anticipated. (PBNP GDC 6)

As described in FSAR Section 3.1.2.1, Reactor Core, Design Basis, the reactor core, with its related control and protection system, is designed to function throughout its design lifetime without exceeding acceptable fuel damage limits.

CRITERION: The reactor coolant pressure boundary shall be designed, fabricated, and constructed so as to have an exceedingly low probability of gross rupture or significant uncontrolled leakage throughout its design lifetime. (PBNP GDC 9)

As described in FSAR Section 4.1, Reactor Coolant System, Design Basis, the RCS, in conjunction with its control and protective provisions, is designed to accommodate the system pressures and temperatures attained under all expected modes of plant operation or anticipated system interactions, and maintain the stresses within applicable code stress limits.

System conditions resulting from anticipated transients or malfunctions are monitored and appropriate action is automatically initiated to maintain the required cooling capability and to limit system conditions to a safe level. The system is protected from overpressure by means of pressure relieving devices, as required by Section III of the ASME Boiler and Pressure Vessel Code.

CRITERION: One of the reactivity control systems provided shall be capable of making the core subcritical under any anticipated operating condition (including anticipated operational transients) sufficiently fast to prevent exceeding acceptable fuel damage limits. Shutdown margin should assure subcriticality with the most reactive control rod fully withdrawn. (PBNP GDC 29)

The reactor core, together with the reactor control and protection system, is designed so that the minimum allowable DNBR is at least equal to the limits specified for STD, OFA, upgraded OFA, and 422V+ fuel, and there is no fuel melting during normal operation, including anticipated transients.

The shutdown groups are provided to supplement the control group of RCCAs to make the reactor at least 1% subcritical (k_{eff} = 0.99) following a trip from any credible operating condition to the hot, zero power condition assuming the most reactive RCCA remains in the fully withdrawn position.

The analysis of the loss of coolant flow is discussed in FSAR Section 14.1.8, Loss of Reactor Coolant Flow.

In addition to the evaluations described in the FSAR, the PBNP loss of forced reactor coolant flow analysis was evaluated for plant license renewal. System and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 1)

The loss of forced reactor coolant flow analysis is not within the scope of license renewal.

2.8.5.3.1.2 Technical Evaluation

2.8.5.3.1.2.1 Introduction

A loss of forced coolant flow event (FSAR Section 14.1.8, Core and Coolant Boundary Protection Analysis, Loss of Reactor Coolant Flow) can result from a mechanical or electrical failure in one or more reactor coolant pumps (RCPs) or from a fault in the power supply to these pumps. If the reactor is at power at the time of the event, the immediate effect from the loss of forced coolant flow is a rapid increase in the coolant temperature. This increase in coolant temperature could result in departure from nucleate boiling (DNB), with subsequent fuel damage if the reactor is not promptly tripped.

The following signals provide protection against a complete loss of forced reactor coolant flow incident:

- Low voltage on pump power supply bus
- Pump circuit breaker opening (low frequency on pump power supply bus opens pump circuit breaker)
- Low reactor coolant flow

The reactor trip on low primary coolant loop flow provides protection against loss-of-flow conditions. When the reactor is operating at power levels above the P-8 permissive setpoint, the reactor is tripped when two-out-of-three low flow signals for either reactor coolant loop are below the setpoint. This trip is automatically blocked when three-out-of-four power range channels are below the P-8 permissive setpoint. Between approximately 10% power (P-7 permissive setpoint) and the power level corresponding to the P-8 permissive setpoint, the reactor is tripped when two-out-of-three low coolant flow signals for both reactor coolant loops are below the setpoint. Reactor trip on low reactor coolant flow is blocked below the P-7 permissive setpoint, when three-out-of-four power range channels are below approximately 10% power and two-out-of-two turbine first stage pressure channels are below approximately 10% of full load turbine pressure.

The reactor trip on RCP undervoltage is provided to protect against conditions that can cause a loss of voltage to all RCPs, i.e., loss of offsite power. The undervoltage trip function is blocked below approximately 10% power (P-7 permissive setpoint).

Above the P-8 permissive setpoint, the reactor is tripped when either reactor coolant pump breaker is open. This trip is automatically blocked when three-out-of-four power range channels are below the P-8 permissive setpoint. When two-out-of-four power range channels are above the P-8 permissive setpoint, the trip is automatically reinstated.

A reactor trip from pump breaker is initiated when two-out-of-two undervoltage or one-out-of-one fault relays on the breaker's associated bus are below the trip setpoint. Both reactor coolant pump breakers are tripped when one-out-of-two underfrequency relays on both buses are below the trip setpoint.

2.8.5.3.1.2.2 Input Parameters, Assumptions, and Acceptance Criteria

This event was analyzed using the Revised Thermal Design Procedure (RTDP) (Reference 2). Initial core power was assumed to be at its nominal value consistent with steady-state, full-power operation. RCS pressure and RCS vessel average temperature were assumed to be at their nominal values. Minimum Measured Flow (MMF) was also assumed. Uncertainties in the initial conditions were included in the departure from nucleate boiling ratio (DNBR) limit value as described in the RTDP.

Engineered safety systems (e.g., safety injection) were not required to function. No single active failure in any system or component required for mitigation will adversely affect the consequences of this event.

Acceptance Criteria

A complete loss of forced reactor coolant flow event is classified by the American Nuclear Society as a Condition III event; however, for conservatism, the event was analyzed to Condition II criteria. The immediate effect from a complete loss of forced reactor coolant flow is a rapid increase in the reactor coolant temperature and subsequent increase in RCS pressure. The specific acceptance criteria for the event are:

- The critical heat flux is not to be exceeded. This criterion is met by demonstrating that the minimum DNBR does not go below the limit value at any time during the transient.
- Pressure in the RCS and MSS is maintained below 110% of their respective design pressures.

2.8.5.3.1.2.3 Description of Analyses and Evaluations

The complete loss of flow transients were analyzed using the Westinghouse advanced 3-D methodology (Reference 5) with three computer codes (also referred to as the RAVE methodology). This is the second application of the advanced 3-D methodology at PBNP. RAVE was first used to determine the percentage of rods in DNB for the locked rotor accident in the pending PBNP License Amendment Request 241, "Alternative Source Term" (ML083450683) submitted December 8, 2008 for NRC review.

The SPNOVA code (References 7 and 8) is used to perform steady-state and transient 3-D core neutronics calculations, using the VIPRE code (Reference 4) to calculate the transient local coolant density and fuel effective temperature (T_{eff}) for the feedback calculations. The SPNOVA code also includes static thermal-hydraulics models for steady-state design calculations. The VIPRE code is used to calculate the local heat flux to the coolant in the RETRAN core model described below. The VIPRE code is also used in a separate hot rod calculation to determine the minimum DNBR versus time.

The RETRAN code is used to calculate the RCS conditions versus time, including the reactor vessel, RCS loops, pressurizer and steam generators. The RETRAN code also models the reactor trips, engineered safety feature functions, and the RCS control functions. The VIPRE code obtains its core inlet conditions (core inlet flow and temperature) and core exit pressure from the RETRAN calculation. The RETRAN model is described in more detail in References 3 and 5.

The loss of flow calculation was performed at Beginning of Cycle (BOC) Hot Full Power (HFP) conditions. The analysis used minimum moderator temperature feedback and maximum doppler feedback. The analysis assumed a maximum value of the delayed neutron fraction. The control rods were initially assumed to be at their fully withdrawn position to minimize the initial rate of reactivity insertion following a reactor trip. A conservative rod position vs. time curve was assumed.

Since the loss of flow event is analyzed using the RTDP (Reference 2), the analysis was performed using nominal HFP conditions for reactor power, RCS average temperature, and pressurizer pressure. The RCS flow rate was set to the MMF. All other RCS initial conditions (pressurizer water volume, steam generator level, etc.) were also set to nominal conditions.

The loss of flow analysis is performed for the following cases:

- pump bus frequency decay (underfrequency) event,
- loss of pump power supply voltage (undervoltage) event,
- partial loss of flow (PLOF) event, and
- reference complete loss of flow (CLOF) case (bounds the undervoltage and partial loss of flow events).

The limiting loss of flow transient is the pump bus frequency decay (underfrequency) event with a 5 Hz/s frequency decay rate which conservatively does not credit the RCP underfrequency trip. The reactor trip occurs on a low flow signal. This underfrequency event is assumed to begin after a one-second null transient. The pumps slow down due to the frequency decay rate of 5 Hz/s. The flow decreases as a response to the slower pump rotation throughout the transient and the reactor trips on a low flow signal. The RCP underfrequency trip is conservatively not credited in the analysis. The low flow reactor trip setpoint of 87% FON is reached at t = 2.76 seconds. Rod motion occurs at 3.76 seconds, assuming a 1 second low flow trip time delay.

The complete loss of flow (undervoltage) event is analyzed for a loss of both RCPs with both reactor coolant loops in operation. The event is bounded by the reference complete loss of flow case presented below.

The partial loss of flow event is analyzed for a loss of one RCP with both reactor coolant loops in operation. The event is bounded by the reference complete loss of flow case presented below

A reference complete loss of flow (CLOF) case is analyzed for a loss of both RCPs with both reactor coolant loops in operation. This case bounds the undervoltage and the PLOF events. This CLOF event is assumed to initiate at 1.0 second and both RCPs start to coastdown. The undervoltage trip is delayed until the low flow reactor trip signal is reached, which occurs at 2.93 seconds into the transient. Rod motion occurs at 3.93 seconds, assuming a 1-second low flow trip time delay. This case is equivalent to an undervoltage event with a 2.93-second reactor trip delay. Since the analysis was performed without crediting the reactor coolant pump power supply undervoltage trip, a longer undervoltage reactor trip delay would be inconsequential in terms of the analysis results. Therefore, the reference CLOF case bounds all undervoltage events regardless of the reactor coolant pump power supply undervoltage trip delay. This reference CLOF case also uses the same low flow reactor trip as the PLOF event.

The VIPRE DNBR calculation was based on the core average power, power distribution, inlet temperature, core inlet flow, and core exit pressure vs. time. The core average power and power distributions were obtained from core feedback calculations, including the time-dependent changes in radial enthalpy rise hot channel factor ($F_{\Delta H}$) and the axial power distributions. The design pin-by-pin radial power distribution, with the peak rod power raised to a value consistent with the limit allowed by the plant Technical Specifications, was used as the initial condition for the DNBR calculations. The reactor coolant conditions obtained from the core feedback calculations include inlet temperature, core inlet flow and core exit pressure vs. time. The results are presented in Section 2.8.5.3.1.3 below.

A P-8 permissive setpoint analysis was also performed at EPU conditions to define the highest steady-state power level at which the reactor can operate with one RCS loop inactive without violating the N-1 core thermal limits. This resulted in a revision of the current Technical Specification value of < 50% to a value of ≤ 38%. Advanced 3-D methods were not required for the P-8 analysis. The P-8 analysis modeled the coastdown of one RCP at ≤ 45% power which demonstrates that the DNBR design basis is satisfied.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Program

EPU activities associated with these analyses do not add any new functions for existing components that would change the license renewal system evaluation boundaries. The changes associated with operating at EPU conditions do not add any new or previously unevaluated aging effects that necessitate a change to aging management programs or require new programs as internal and external environments remain within the parameters previously evaluated. Therefore, EPU activities associated with these analyses do not impact license renewal scope, aging effects, and aging management programs.

2.8.5.3.1.3 Results

The minimum DNBR acceptance criterion was met. Fuel clad damage criteria were not challenged in the loss of forced reactor coolant flow cases since the DNBR criterion was met. The limiting loss of flow event is the pump bus frequency decay (underfrequency) event with a 5 Hz/s frequency decay rate. The transient results for this limiting case are presented in Figures 2.8.5.3.1-1 through 2.8.5.3.1-6. The transient results for the reference complete loss of flow case (bounding both the undervoltage and partial loss of flow cases) are presented in Figures 2.8.5.3.1-7 through 2.8.5.3.1-12. The sequence of events for the limiting frequency decay case, the reference complete loss of flow case, the undervoltagecase and the partial loss of flow case are presented in Table 2.8.5.3.1-1,Time Sequence of Events – Loss of Forced Reactor Coolant Flow.

The analysis performed for the EPU demonstrates that, for the aforementioned loss of flow cases, the DNBR did not decrease below the safety analysis limit value at any time during the transients; thus, no fuel or clad damage is predicted. The peak primary and secondary system pressures remained below their respective limits at all times. The effects of loop-to-loop flow asymmetry due to 10% SGTP imbalance have been considered in these analyses. All applicable acceptance criteria were met.

The protection features presented in LR Section 2.8.5.3.1.2.1, above, provide mitigation for the complete loss of forced reactor coolant flow transients such that the above criteria are satisfied. Furthermore, the results and conclusions of this analysis will be confirmed on a cycle-specific basis as part of the normal reload process (Reference 6).

2.8.5.3.1.4 Conclusions

PBNP has reviewed the analyses of the decrease in reactor coolant-flow event and concludes that the analyses have adequately accounted for plant operations at the uprated power level and were performed using acceptable analytical models. PBNP further concludes that the evaluation has demonstrated that the reactor protection (including the change of P-8) and safety systems will continue to ensure that the specified acceptable fuel design limits (DNB ratio remains above the minimum DNB ratio limit) and the reactor coolant pressure boundary and main steam system pressure limits will not be exceeded as a result of this event. Based on this, PBNP concludes that the plant will continue to meet the PBNP current licensing basis requirements with respect to PBNP GDC 6, 9, and 29 following implementation of the proposed EPU. Therefore, PBNP finds the proposed EPU acceptable with respect to the decrease in reactor coolant flow event.

2.8.5.3.1.5 References

1. Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

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

3. WCAP-14882-P-A, RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses, D. S. Huegel, et al., April 1999

4. WCAP-14565-P-A (Proprietary) and WCAP-15306-NP-A (Non-Proprietary), VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis, Sung, Y. X., et al., October 1999

5. WCAP-16259-P-A (Proprietary) and WCAP-16259-A (Non-Proprietary), Westinghouse Methodology for Application of 3-D Transient Neutronics to Non-LOCA Accident Analysis, Beard, C. L., et al., August 2006

6. WCAP-9272-P-A (Proprietary), Westinghouse Reload Safety Evaluation Methodology, Approved July 1985

7. WCAP-12394-A (Proprietary) and WCAP-12983-A (Nonproprietary), SPNOVA – A Multidimensional Static and Transient Computer Program for PWR Core Analysis, Chao, Y. A., et al.,June 1991

8. Letter from Westinghouse to NRC, Process Improvement to the Westinghouse Neutronics Code System, NTD-NRC-96-4679, March 29, 1996

Table 2.8.5.3.1-1
Time Sequence of Events – Loss of Forced Reactor Coolant Flow

Case	Event	Time (sec)
Underfrequency Event	Transient begins	0.00
	Frequency decay begins and RCPs begin to decelerate	1.00
	Low flow reactor trip setpoint reached	2.76
	Rods begin to drop	3.76
	Minimum DNBR occurs	4.55
Reference Complete Loss of Flow Case (Bounds both undervoltage and partial loss of flow)	Transient begins	0.00
	Both RCPs lose power and begin coasting down	1.00
	RCP undervoltage reactor trip setpoint reached	1.00
	Low flow reactor trip setpoint reached	2.93
	Rods Begin to Drop	3.93
	Minimum DNBR Occurs	4.60

Figure 2.8.5.3.1-1 Loss of Forced Reactor Coolant Flow Flow Nuclear Power vs. Time Underfrequency Event

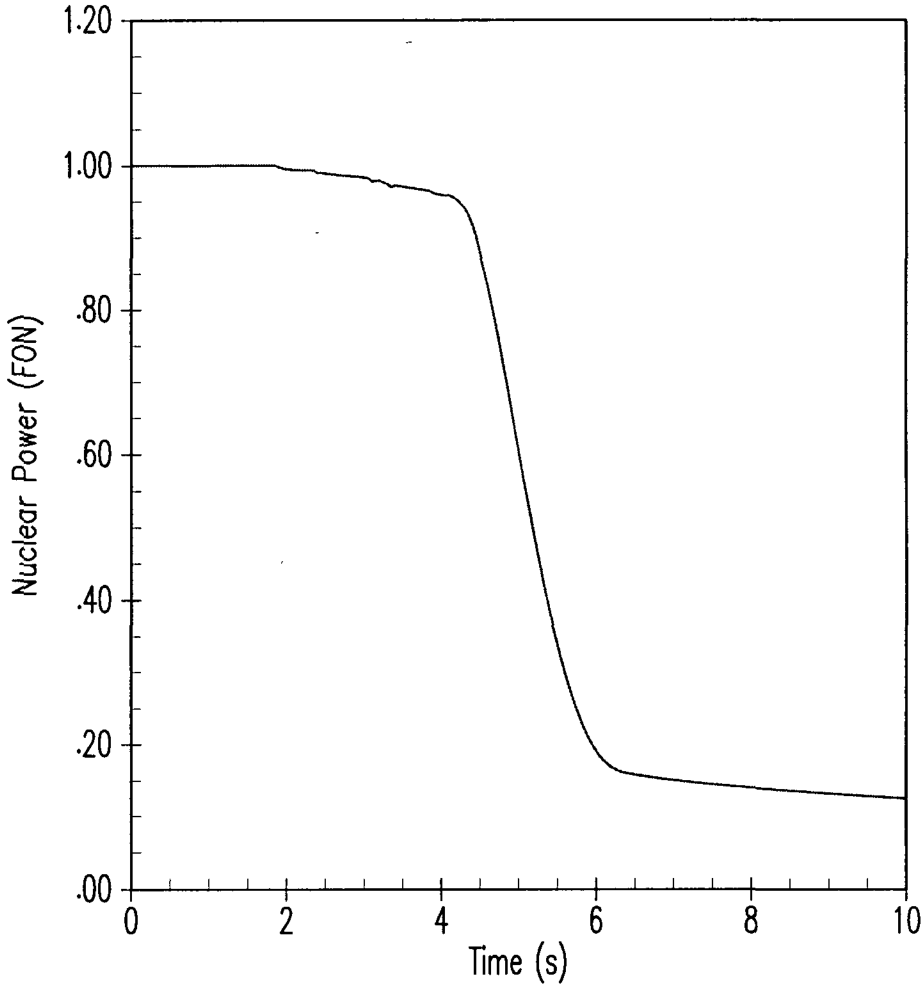


Figure 2.8.5.3.1-2 Loss of Forced Reactor Coolant Flow Loop Flow vs. Time Underfrequency Event

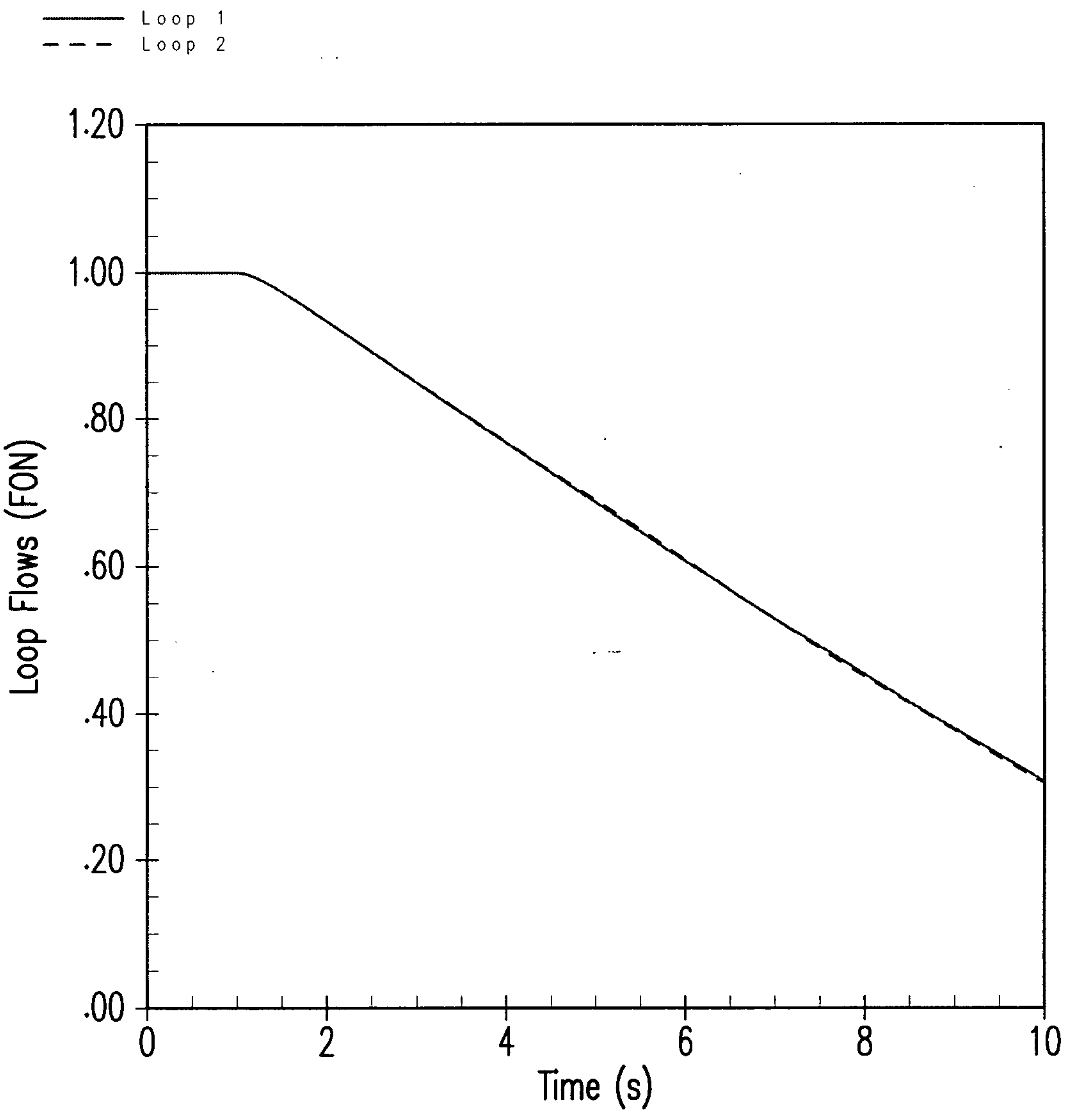


Figure 2.8.5.3.1-3 Loss of Forced Reactor Coolant Flow Core Average Heat Flux vs. Time Underfrequency Event

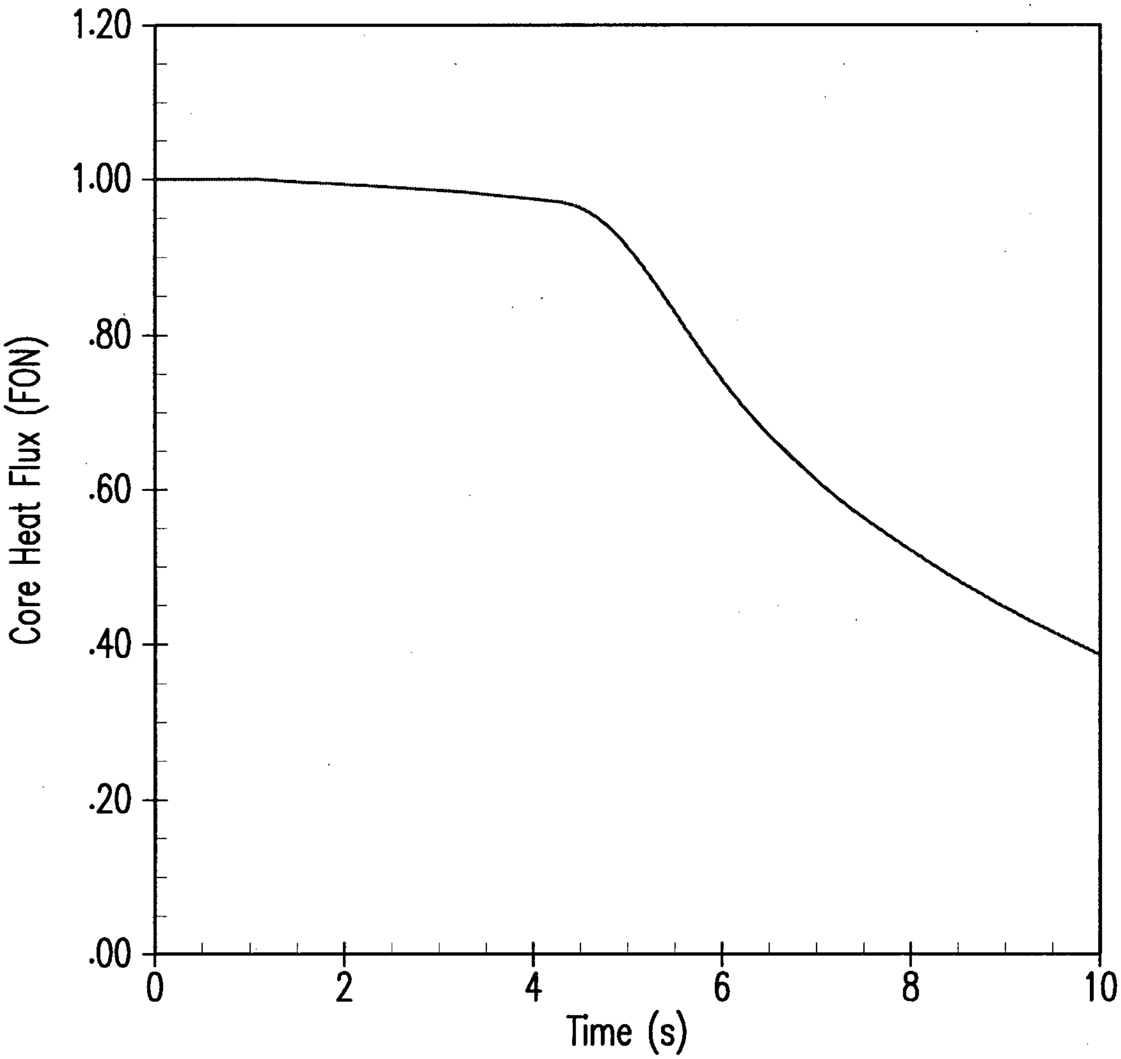


Figure 2.8.5.3.1-4 Loss of Forced Reactor Coolant Flow Hot Channel Heat Flux vs. Time Underfrequency Event

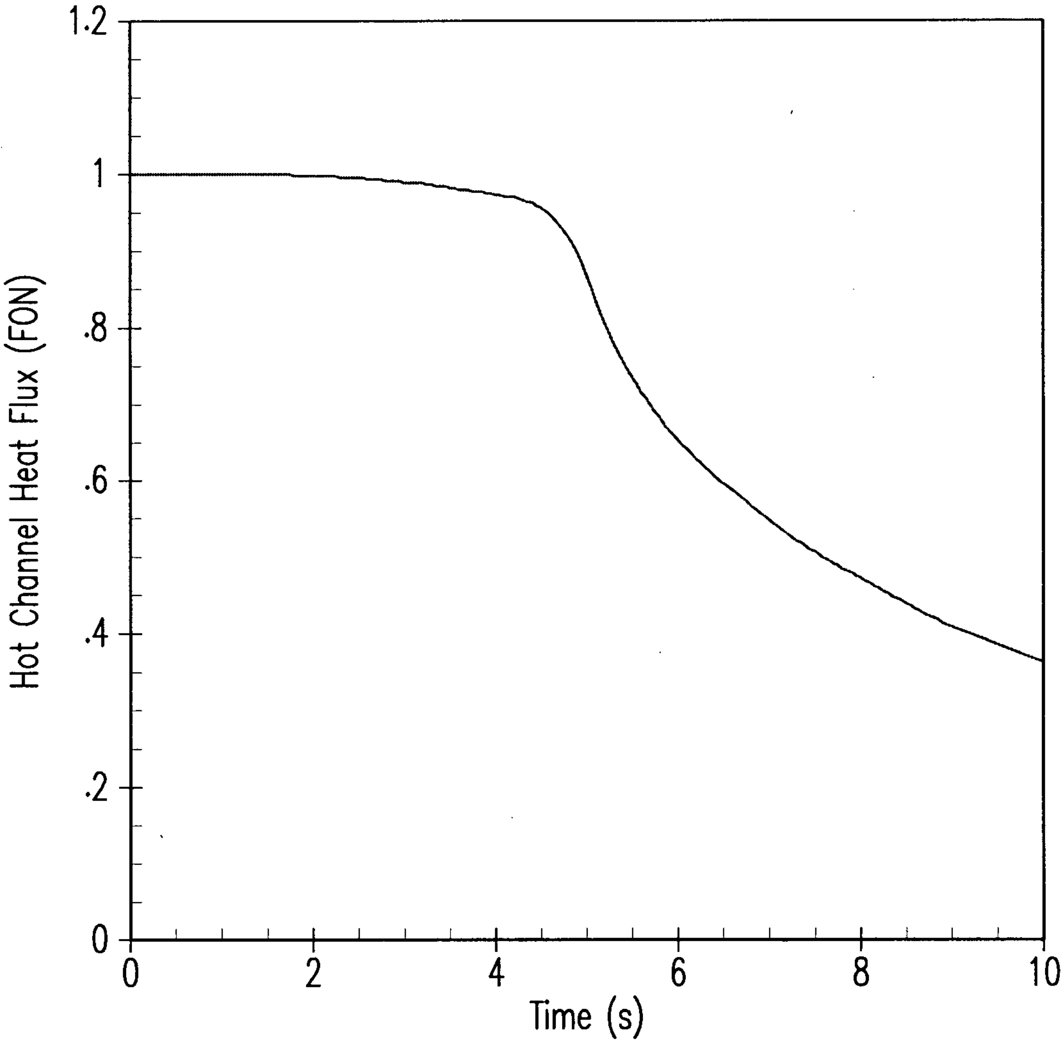


Figure 2.8.5.3.1-5 Loss of Forced Reactor Coolant Flow RCS Pressure vs. Time Underfrequency Event

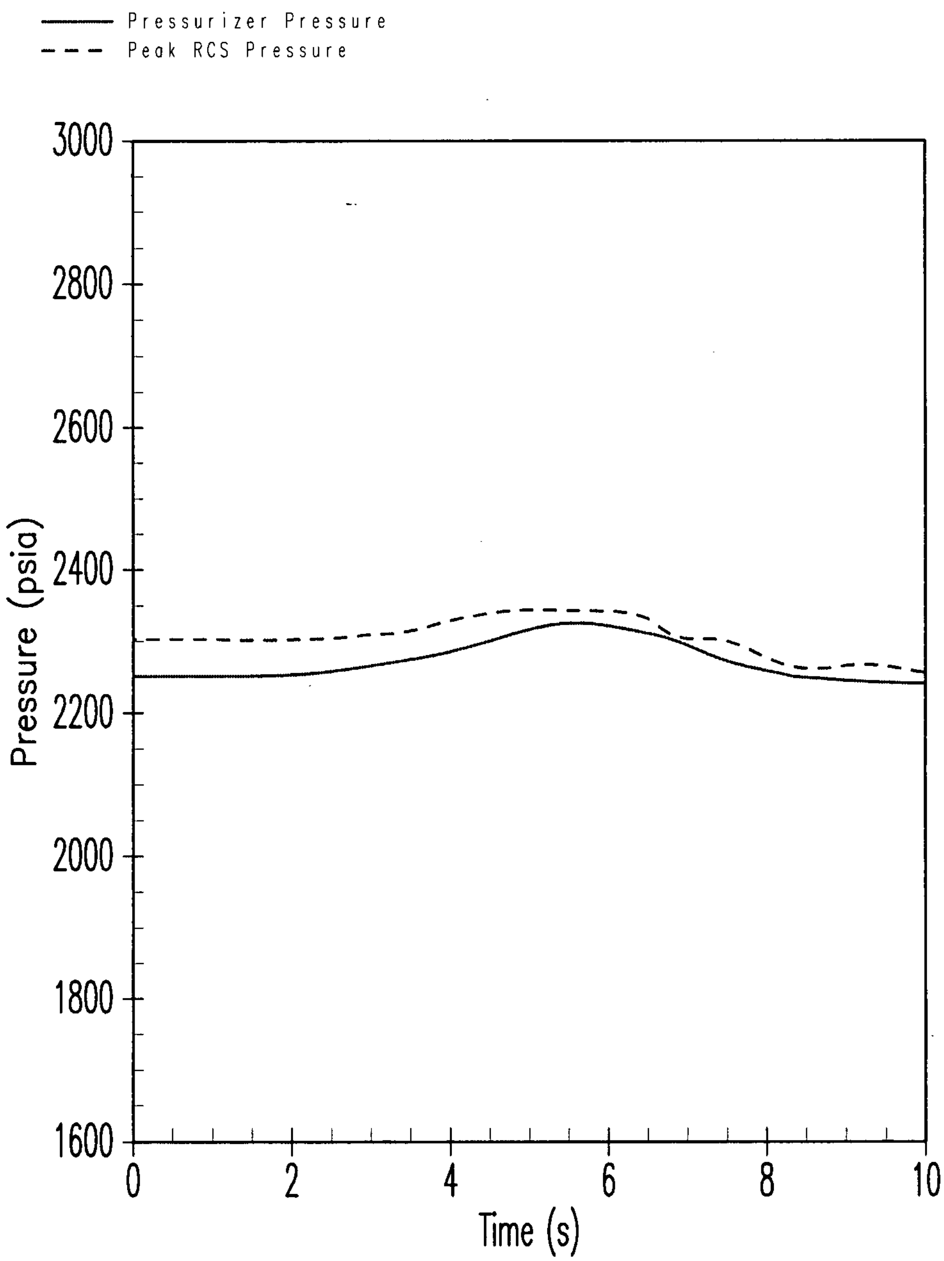


Figure 2.8.5.3.1-6 Loss of Forced Reactor Coolant Flow DNBR vs. Time Underfrequency Event

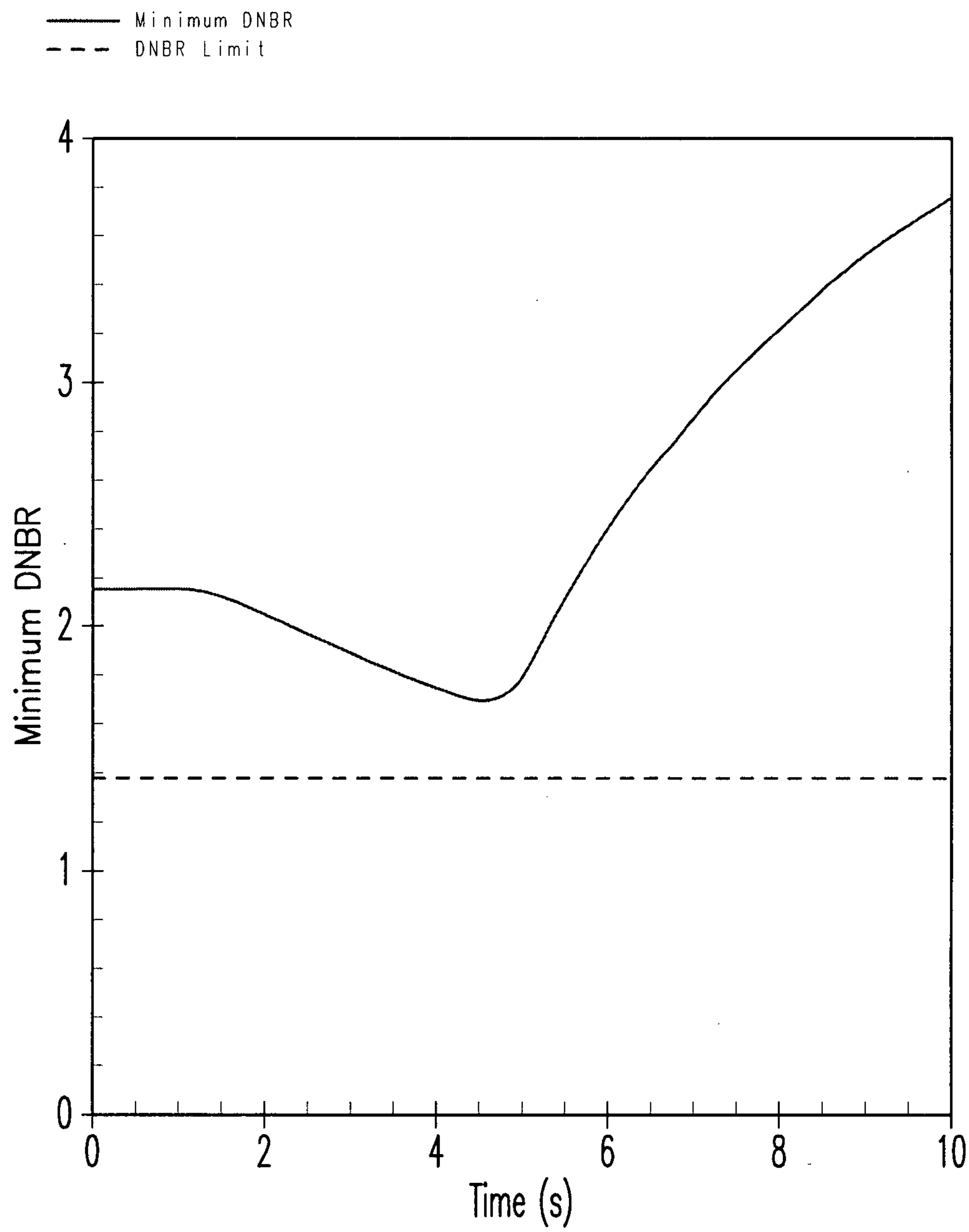


Figure 2.8.5.3.1-7 Loss of Forced Reactor Coolant Flow Nuclear Power vs. Time Reference Complete Loss of Flow Event

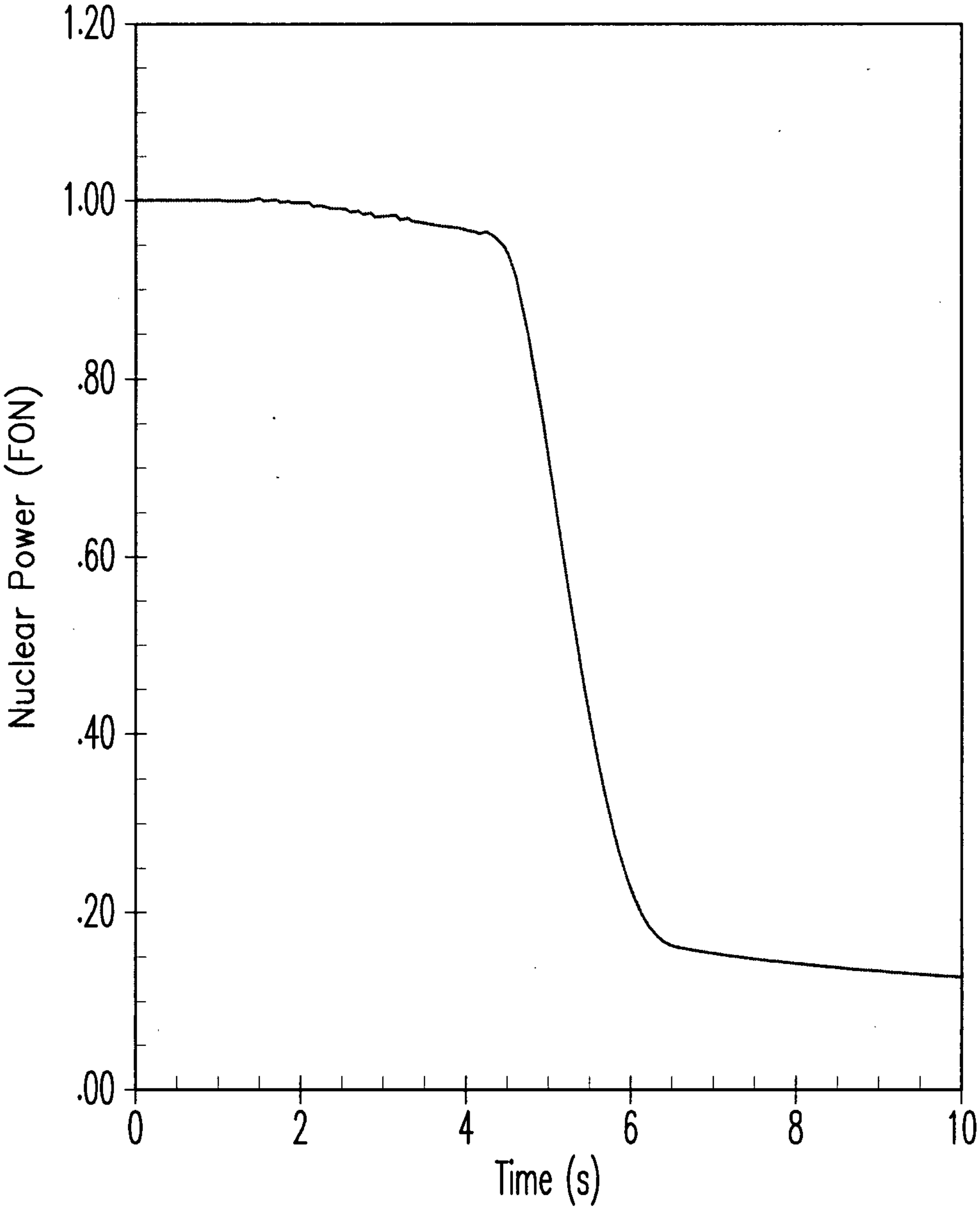


Figure 2.8.5.3.1-8 Loss of Forced Reactor Coolant Flow Loop Flow vs. Time Reference Complete Loss of Flow Event

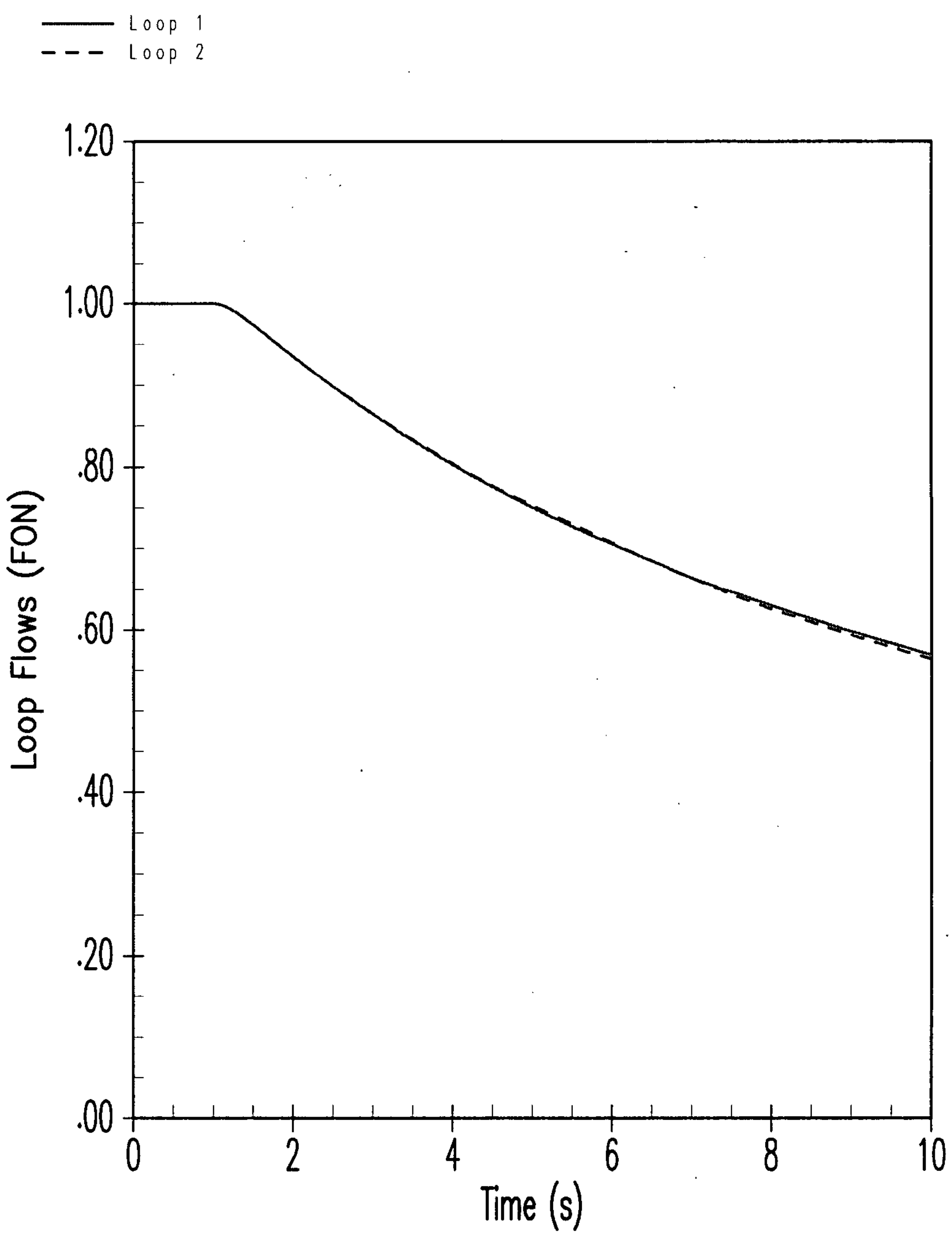


Figure 2.8.5.3.1-9 Loss of Forced Reactor Coolant Flow Core Average Heat Flux vs. Time Reference Comlete Loss of Flow Event

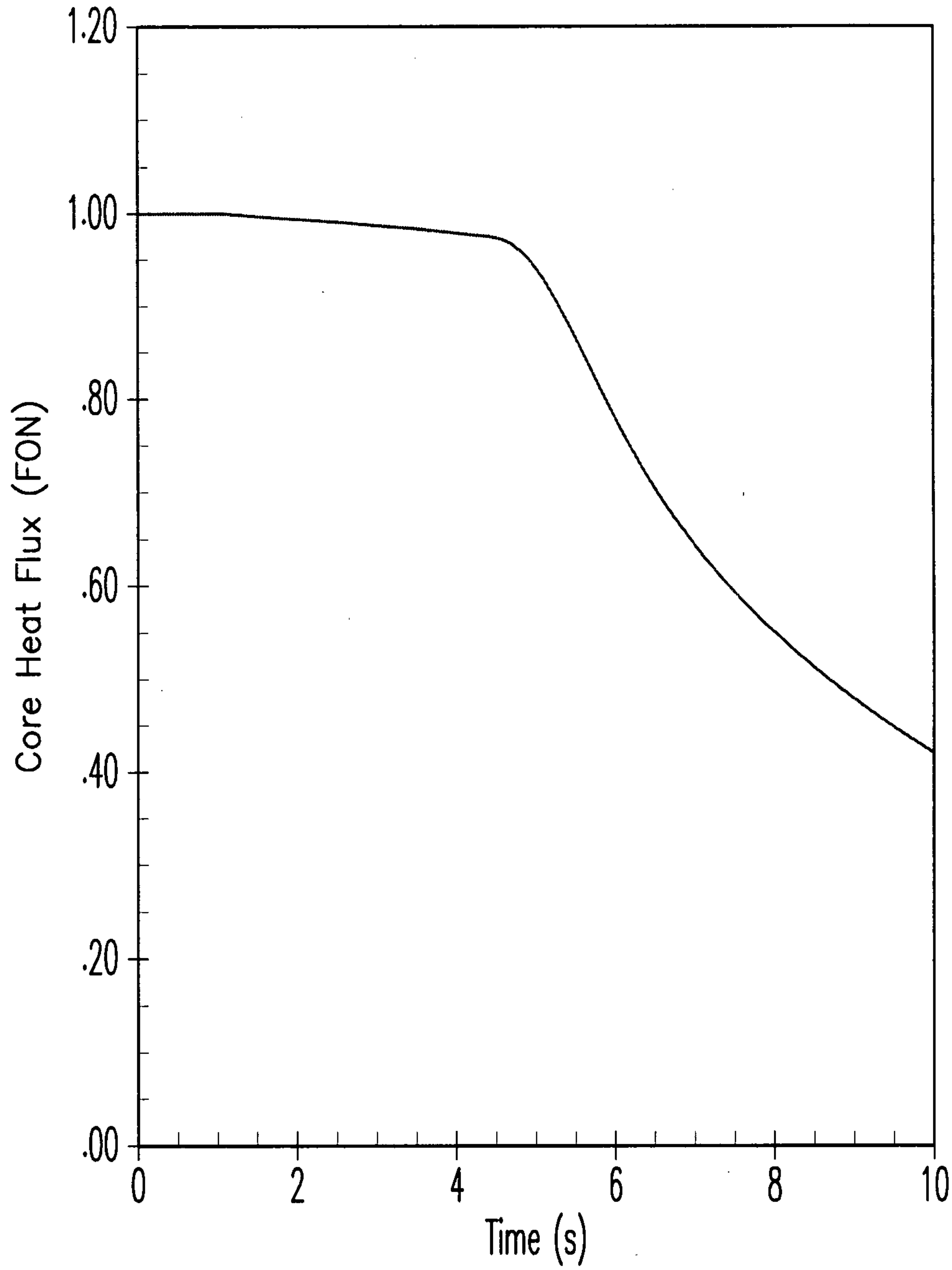


Figure 2.8.5.3.1-10 Loss of Forced Reactor Coolant Flow Hot Channel Heat Flux vs. Time Reference Complete Loss of Flow Event

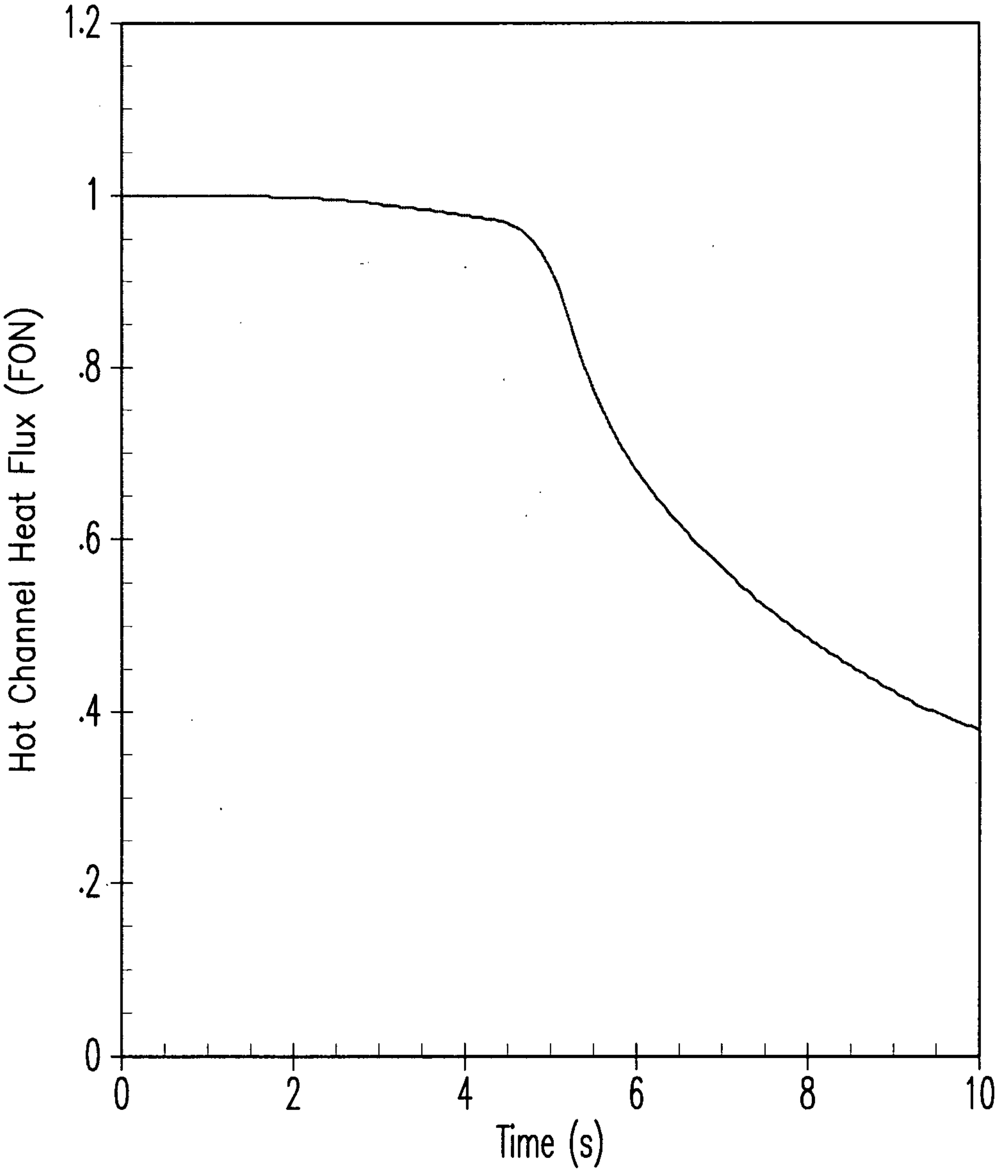


Figure 2.8.5.3.1-11 Loss of Forced Reactor Coolant Flow RCS Pressure vs. Time Reference Complete Loss of Flow Event

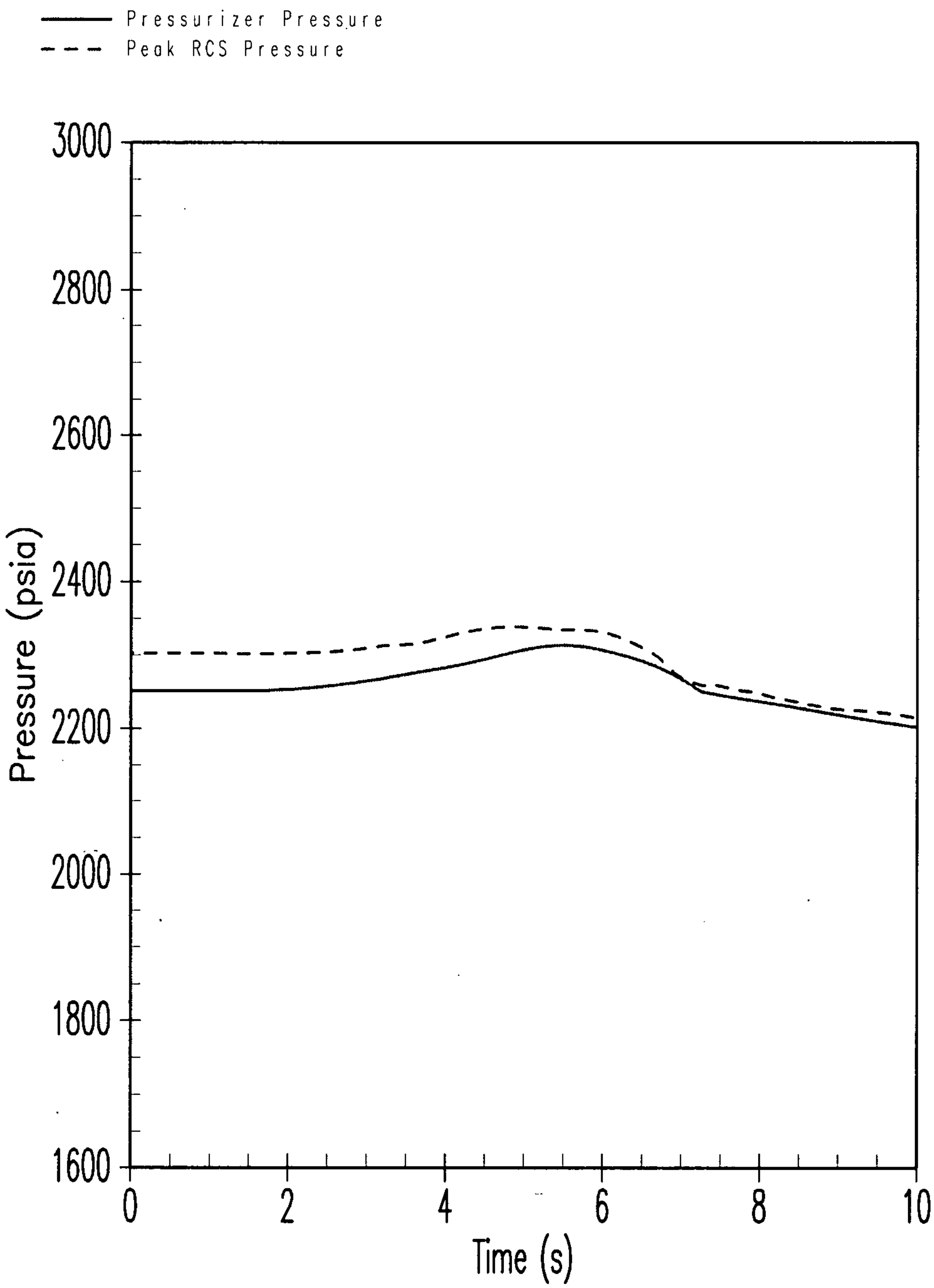
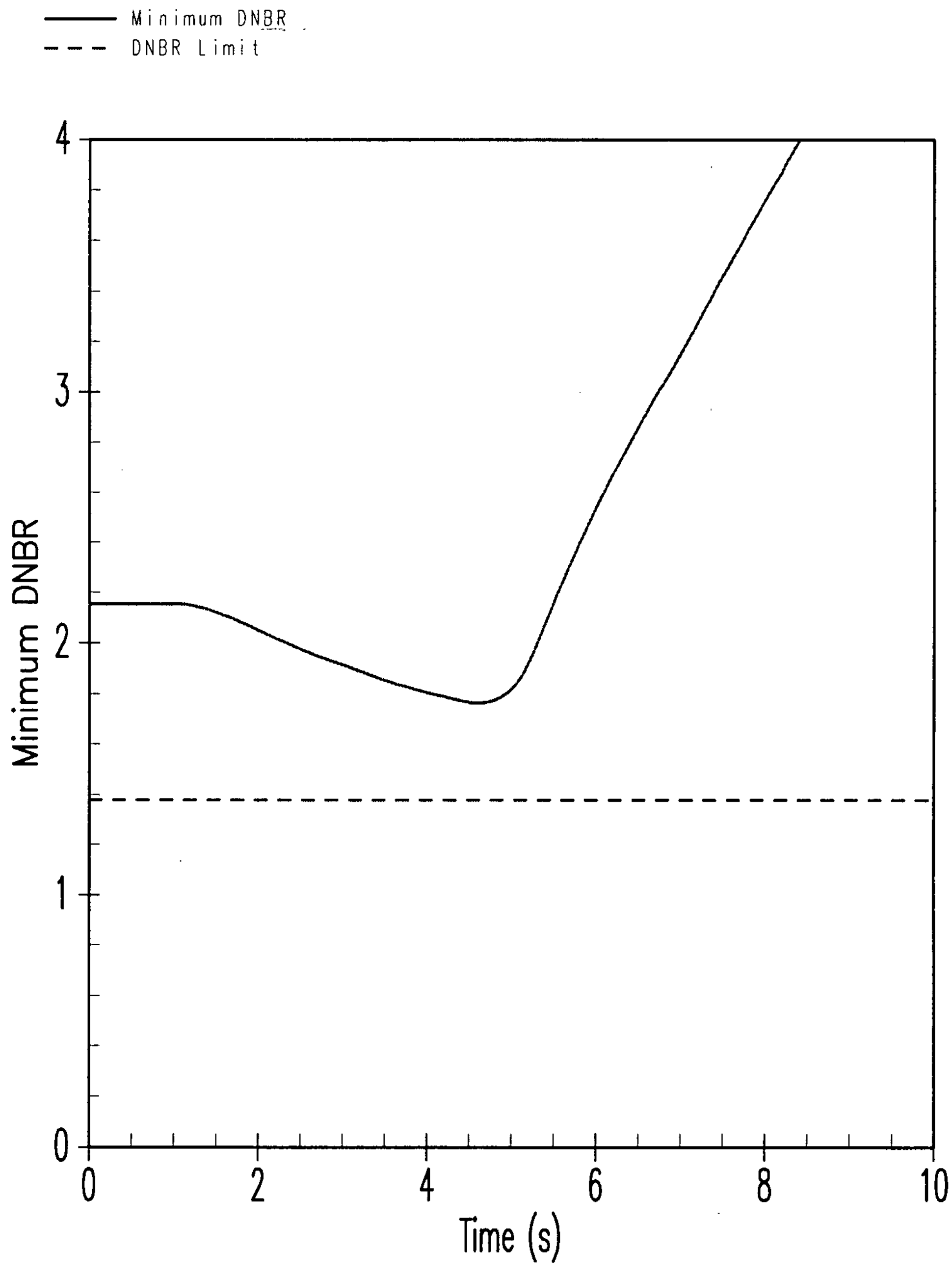


Figure 2.8.5.3.1-12 Loss of Forced Reactor Coolant Flow DNBR vs. Time Reference Complete Loss of Flow Event



2.8.5.3.2 Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break

2.8.5.3.2.1 Regulatory Evaluation

The events postulated are an instantaneous seizure of the rotor or break of the shaft of a reactor coolant pump (RCP). Flow through the affected loop is rapidly reduced, leading to a reactor and turbine trip. The sudden decrease in core coolant flow while the reactor is at power results in a degradation of core heat transfer, which could result in fuel damage. The initial rate of reduction of coolant flow is greater for the rotor seizure event. However, the shaft break event permits a greater reverse flow through the affected loop later during the transient and, therefore, results in a lower core flow rate at that time. In either case, reactor protection and safety systems are actuated to mitigate the transient. The PBNP review covered:

- The postulated initial and long-term core and reactor conditions
- The methods of thermal and hydraulic analyses
- The sequence of events
- The assumed reactions of reactor system components
- The functional and operational characteristics of the reactor protection system
- The operator actions
- The results of the transient analyses

The NRC's acceptance criteria are based on:

- GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained
- GDC 28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to significantly impair the capability to cool the cor and
- GDC 31, insofar as it requires that the RCPB be designed with sufficient margin to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized

Specific review criteria are contained in SRP Section 15.3.3-4 and other guidance provided in Matrix 8 of RS-001.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP, GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50, Appendix A, GDC-27, 28 and 29 are as follows:

CRITERION: The reactivity control systems provided shall be capable of making the core subcritical under credible accident conditions with appropriate margins for contingencies and limiting any subsequent return to power such that there will be no undue risk to the health and safety of the public. (PBNP GDC 30)

FSAR Section 3.1.2.6, Reactivity Holddown Capability, addresses the reactivity control systems.

CRITERION: Limits, which include reasonable margin, shall be placed on the maximum reactivity worth of control rods or elements and on rates at which reactivity can be increased to ensure that the potential effects of a sudden or large change of reactivity cannot (a) rupture the reactor coolant pressure boundary or (b) disrupt the core, its support structures, or other vessel internals sufficiently to lose capability of cooling the core. (PBNP GDC 32)

FSAR Section 3.1.2.8, Maximum reactivity Worth of Control Rods, discusses the maximum reactivity worth of control rods and the reactivity insertion limits.

CRITERION: The reactor coolant pressure boundary shall be designed and operated to reduce to an acceptable level the probability of rapidly propagating type failures. Consideration is given (a) to the provisions for control over service temperature and irradiation effects which may require operational restrictions, (b) to the design and construction of the reactor pressure vessel in accordance with applicable codes, including those which establish requirements for absorption of energy within the elastic strain energy range and for absorption of energy by plastic deformation, and (c) to the design and construction of reactor coolant pressure boundary piping and equipment in accordance with applicable codes. (PBNP GDC 34)

The reactor coolant pressure boundary is designed to reduce to an acceptable level the probability of a rapidly propagating type failure. The reactor coolant system pressure is limited with respect to RCS temperature during plant heatup, cooldown, and normal operation. These limits are determined in accordance with the methods of analysis and the margins of safety of Appendix G of ASME Code Section XI and are included in the PBNP Pressure Temperature Limits Report (PTLR). All pressure containing components of the reactor coolant system are designed, fabricated, inspected, and tested in conformance with the applicable codes at the time of order placement. Further details are given in FSAR Table 4.1-9, Reactor Coolant Systems, Code Requirements.

Additional information is provided in FSAR Section 3.1, Reactor, Design Basis, Section 4.1, Reactor Coolant System, Design Criteria, Section 7.1.2, Instrumentation and Control, General Design Criteria, Section 9.3.1, Chemical and Volume Control, Design Basis, and Section 14.1.8, Loss of Reactor Coolant Flow.

In addition to the evaluations described in the FSAR, the RCP locked rotor/shaft break event analysis was evaluated for plant License Renewal. System and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 1)

The RCP locked rotor/shaft break event analysis is not within the scope of license renewal.

2.8.5.3.2.2 Technical Evaluation

2.8.5.3.2.2.1 Introduction

The event postulated is an instantaneous seizure of a RCP rotor ("locked rotor") as described in FSAR Section 14.1.8, Loss of Reactor Coolant Flow, or the sudden break of the shaft of the RCP. Flow through the affected reactor coolant loop is rapidly reduced, leading to initiation of a reactor trip on a low reactor coolant loop flow signal.

Following initiation of the reactor trip, heat stored in the fuel rods continues to be transferred to the coolant causing the coolant to expand. At the same time, heat transfer to the shell-side of the steam generators is reduced, first because the reduced flow results in a decreased tube-side film coefficient, and then because the reactor coolant in the tubes cools down while the shell-side temperature increases (turbine steam flow is reduced to zero upon plant trip due to turbine trip on reactor trip). The rapid expansion of the coolant in the reactor core, combined with reduced heat transfer in the steam generators, causes an insurge into the pressurizer and a pressure increase throughout the RCS. The insurge into the pressurizer compresses the steam volume, actuates the automatic pressurizer spray system, opens the power-operated relief valves (PORVs), and opens the pressurizer safety valves (PSVs), in that sequence. The PORVs are designed for reliable operation and are expected to function properly during the event.

The consequences of a locked rotor are very similar to those of a pump shaft break. The initial rate of the reduction in coolant flow is slightly greater for the locked rotor event. However, with a broken shaft, the impeller could conceivably be free to spin in the reverse direction. The effect of reverse spinning is to decrease the steady-state core flow when compared to the locked rotor scenarios.

2.8.5.3.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

There were three locked rotor cases analyzed: one to determine the percentage of rods-in-DNB, a second to determine the peak RCS pressure and a third to determine the peak cladding temperature (PCT).

The first case was run to establish the percentage of rods-in-DNB in support of the radiological analysis. One locked rotor and shaft break was assumed with all reactor coolant loops in operation. This case made assumptions designed to maximize the number of rods-in-DNB. Initial core power was assumed to be at its nominal value consistent with steady-state, full-power operation. The reactor coolant system pressure and vessel average temperature were assumed to be at their nominal values. Minimum Measured Flow (MMF) was also assumed. Uncertainties in initial conditions were accounted for in the DNBR limit value as described in the Revised Thermal Design Procedure (RTDP) (Reference 7). The pressure-reducing effects of the PORVs and the automatic pressurizer spray system were modeled in the rods-in-DNB analysis for conservatism.

The second and third cases were performed to evaluate the peak RCS pressure and PCT. As in the rods-in-DNB case, one locked rotor and shaft break was assumed with all reactor coolant loops in operation. These cases made assumptions designed to maximize the RCS pressure and cladding temperature, using the Standard Thermal Design Procedure (STDP). Initial core power, reactor coolant temperature, and pressure include allowances for calibration and instrument errors. Thermal Design Flow (TDF) was also assumed. The pressure-reducing effects of the pressurizer PORVs and automatic pressurizer spray system were not modeled.

Engineered safety systems (e.g., safety injection) are not required to function. No single active failure in any system or component required for mitigation will adversely affect the consequences of this event.

Acceptance Criteria

The RCP locked rotor/shaft break accident is classified by the ANS as a Condition IV event. An RCP locked rotor/shaft break results in a rapid reduction in forced reactor coolant loop flow that increases the reactor coolant temperature and subsequently causes the fuel cladding temperature and RCS pressure to increase. The following items summarize the criteria associated with this event:

- Fuel cladding damage, including melting, due to increased reactor coolant temperatures must be prevented. This is precluded by demonstrating that the maximum cladding temperature at the core hot spot remains below 2700°F, and the zirconium-water reaction at the core hot spot is less than 16% by weight
- Pressures in the RCS and MSS are to be maintained less than that which would cause stresses to exceed the faulted condition stress limits for very low probability events such as locked rotor
- The total percentage of rods-in-DNB is less than that analyzed in the dose analysis. The specific limit for the EPU radiological analysis is 30%

With respect to secondary side overpressurization, this event was bounded by the loss of load/turbine trip event as discussed in LR Section 2.8.5.2.1, Loss of External Electrical Load, Turbine Trip, and Loss of Condenser Vacuum.

2.8.5.3.2.2.3 Description of Analyses and Evaluations

The locked rotor transients were analyzed using the Westinghouse advanced 3-D methodology (Reference 5) with three primary computer codes, linked by an external communication interface (also referred to as the RAVE methodology). This is the second application of the advanced 3-D methodology at PBNP. RAVE was first used to determine the percentage of rods in DNB for the locked rotor accident in the pending PBNP License Amendment Request 241, Alternative Source Term, (ML083450683) submitted December 8, 2008 for NRC review.

The SPNOVA code (References 8 and 9) is used to perform steady-state and transient 3-D core neutronics calculations, using the VIPRE code (Reference 3) to calculate the transient local coolant density and fuel effective temperature (T_{eff}) for the feedback calculations. The SPNOVA code also includes static thermal-hydraulics models for steady-state design calculations. The VIPRE code is used to calculate the local heat flux to the coolant in the RETRAN core model described below. PBNP is requesting NRC approval for the use of SPNOVA (ANC) and VIPRE.

The RETRAN code is used to calculate the RCS conditions versus time, including the reactor vessel, RCS loops, pressurizer and steam generators. The RETRAN code also models the reactor trips, engineered safety feature (ESF) functions, and the RCS control functions. The VIPRE code obtains its core inlet conditions (core inlet flow and temperature) and core exit pressure from the RETRAN calculation. The RETRAN model is described in more detail in References 2 and 5.

The VIPRE code is also used in separate hot rod calculations to determine the minimum DNBR versus time and the peak clad temperatures versus time.

2.8.5.3.2.2.3.1 Rods-in-DNB Analysis

The locked rotor rods-in-DNB calculation was performed at Beginning of Cycle (BOC) Hot Full Power (HFP) conditions. The analysis used minimum moderator temperature feedback, maximum doppler feedback and a maximum value of the delayed neutron fraction. The control rods were initially assumed to be at their fully withdrawn position to minimize the initial rate of reactivity insertion following a reactor trip. A conservative rod position vs. time curve was assumed.

Since the locked rotor rods-in-DNB evaluation is analyzed using the Revised Thermal Design Procedure (RTDP; Reference 7), the analysis was performed using nominal HFP conditions for reactor power, RCS average temperature, and pressurizer pressure. The RCS flow rate was set to the Minimum Measured Flow (MMF). All other RCS initial conditions (pressurizer water volume, steam generator level, etc.) were also set to nominal conditions.

The accident was initiated by causing an immediate halt in the rotational speed of one RCP. A loss of offsite power was conservatively assumed to occur at the time of reactor trip (control rod release), causing the unaffected RCP to lose power and coast down freely. Reactor trip occurs on the low flow reactor trip function at 87% flow with a trip delay time of 1.0 second.

The VIPRE code was used in a separate time-dependent DNBR calculation to determine the number of rods-in-DNB. The DNBR calculation was based on the core average power, power distribution, inlet temperature, core inlet flow, and core exit pressure vs. time. The core average power and power distributions were obtained from the core feedback calculations, including the time-dependent changes in radial enthalpy rise hot channel factor ($F_{\Delta H}$) and the axial power distributions. The design pin-by-pin radial power distribution, with the peak rod power raised to a value consistent with the limit allowed by the plant Technical Specifications, was used as the initial condition for the DNBR calculations. The reactor coolant conditions (inlet temperature, core inlet flow and core exit pressure vs. time) were obtained from the core feedback calculations. The results are presented in Section 2.8.5.3.2.3 below.

2.8.5.3.2.2.3.2 Peak Pressure/Peak Clad Temperature Analyses

The locked rotor peak RCS pressure and PCT calculations were performed at Beginning of Cycle (BOC) Hot Full Power (HFP) conditions. The analyses used minimum moderator temperature feedback and maximum doppler feedback. The analyses assumed a maximum value of the delayed neutron fraction. The control rods were initially assumed to be at their fully withdrawn position to minimize the initial rate of reactivity insertion following a reactor trip. A conservative rod position vs. time curve was assumed.

Since the locked rotor peak RCS pressure and PCT cases are analyzed using the STDP, the analysis was performed using a +0.6% uncertainty in the initial reactor power, a ±6.4°F combined uncertainty and bias in RCS temperature, and a +50 psi uncertainty in pressurizer pressure. The RCS flow rate was set to the Thermal Design Flow (TDF). All other RCS initial conditions, except pressurizer water volume (steam generator level, etc.) were set to nominal conditions.

No credit is taken for the pressure-limiting effects of the pressurizer PORVs, pressurizer spray, steam dump or controlled feedwater flow after plant trip. Although these operations are expected to occur and would result in a lower peak pressure, an additional degree of conservatism is provided by ignoring their effects.

The lift pressure of the pressurizer safety valves is assumed to be 3.4% above the nominal set pressure of 2500 psia, including +0.9% set pressure shift due to the presence of pressurizer safety valve loop seals (Reference 4). The safety valve steam relief capacity is 288,000 lbm/hr per valve.

The accident was initiated by causing an immediate halt in the rotational speed of one RCP. A loss of offsite power was conservatively assumed to occur at the time of reactor trip (control rod release), causing the unaffected RCP to lose power and coast down freely. Reactor trip occurs on the low flow reactor trip function at 87% flow with a trip delay time of 1.0 second.

A separate VIPRE hot rod calculation to determine the peak clad temperature is performed assuming that the hot rod is experiencing DNB throughout the flow transient. The initial hot rod power was increased such that the initial hot spot power was at the plant F_Q limit.

The film boiling coefficient was calculated in the VIPRE code (Reference 3) using the Bishop-Sandberg-Tong film boiling correlation. The fluid properties were evaluated at the film temperature. The program calculated the film coefficient at every time-step based upon the actual heat transfer conditions at the corresponding time step. The nuclear power, system pressure, bulk density, and RCS flow rate as a function of time were based on the core feedback calculations.

The magnitude and time dependence of the heat transfer coefficient between fuel and cladding (gap coefficient) had a pronounced influence on the thermal results. The larger the value of the gap coefficient, the more heat was transferred between the pellet and cladding. Based on investigations on the effect of the gap coefficient upon the maximum cladding temperature during the transient, the gap coefficient was assumed to increase from a steady-state value consistent with initial maximum fuel temperatures to approximately 10,000 Btu/hr-ft^2-°F at the initiation of the transient. Therefore, a large amount of energy stored in the fuel was released to the cladding at the initiation of the transient.

The zirconium-steam reaction can become significant above a cladding temperature of 1800°F. The Baker-Just parabolic rate equation was used to define the rate of zirconium-steam reaction. The effect of the zirconium-steam reaction was included in the calculation of the hot spot cladding temperature transient.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Program

EPU activities associated with these analyses do not add any new functions for existing components that would change the license renewal system evaluation boundaries. The changes associated with operating at EPU conditions do not add any new or previously unevaluated aging effects that necessitate a change to aging management programs or require new programs as internal and external environments remain within the parameters previously evaluated. Therefore, EPU activities associated with these analyses do not impact license renewal scope, aging effects, and aging management programs.

2.8.5.3.2.3 Results

2.8.5.3.2.3.1 Rods-In-DNB Analysis

With respect to the locked rotor rods-in-DNB case, the value of 30% rods-in-DNB used in the dose analysis is supported by the analyses performed. The analysis determined that 25% of the rods would be in DNB as shown in Table 2.8.5.3.2-2, Results for Single RCP Locked Rotor and Comparison to Previous Results. The low reactor coolant flow reactor trip function provided mitigation for a locked rotor transient such that the acceptance criteria were satisfied. The effects of loop-to-loop flow asymmetry due to 10% SGTP imbalance have been considered in this analysis. Furthermore, the results and conclusions of this analysis will be confirmed on a cycle-specific basis as part of the normal reload process, consistent with the approved reload methodology (Reference 6).

2.8.5.3.2.3.2 Peak Pressure/Peak Clad Temperature Analyses

With respect to the peak RCS pressure, peak clad temperature, and zirconium-steam reaction, the analyses demonstrated that all applicable acceptance criteria were met. The calculated sequence of events is presented in Table 2.8.5.3.2-1, Time Sequence of Events – Single RCP Locked Rotor – Peak Pressure Case, Time Sequence of Events - Single RCP Locked Rotor - Peak Pressure Case, for the locked rotor event. Note that RAVE was used for the analysis predicting peak clad temperature and peak RCS pressure. Using this more sophisticated code (three dimensional modeling) has resulted in PCT and peak RCS pressure results at EPU conditions that are lower than at current licensed power levels using earlier analysis techniques. The results of the calculations (peak pressure, peak clad temperature, and zirconium-steam reaction) are summarized in Table 2.8.5.3.2-2, Results for Single RCP Locked Rotor and Comparison to Previous Results. The transient results for the peak pressure/hot spot cases are provided in Figures 2.8.5.3.2-1 through 2.8.5.3.2-6.

The analysis performed for the EPU demonstrated that, for the locked rotor event, the peak clad surface temperature calculated for the hot spot during the worst transient remained considerably less than 2700°F, and the amount of zirconium-water reaction was small. Under such conditions, the core remained in place and intact with no loss of core cooling capability.

The analysis also confirmed that the peak RCS pressure reached during the transient was less than that which would cause stresses to exceed the faulted condition stress limits, and thereby, the integrity of the primary coolant system was demonstrated. With respect to secondary overpressurization, the loss of load event described in LR Section 2.8.5.2.1, Loss of External Electrical Load, Turbine Trip, and Loss of Condenser Vacuum, demonstrates that the secondary pressure limit is met.

The low reactor coolant flow reactor trip function provided mitigation for a locked rotor transient such that the above criteria were satisfied. The effects of loop-to-loop flow asymmetry due to 10% SGTP imbalance have been considered in these analyses. Furthermore, the results and conclusions of this analysis will be confirmed on a cycle-specific basis as part of the normal reload process (Reference 6).

2.8.5.3.2.4 Conclusion

PBNP has reviewed the analyses of the sudden decrease in core coolant flow events and concludes that the analyses have adequately accounted for plant operation at the power level and were performed using acceptable analytical models. PBNP further concludes that the evaluation has demonstrated that the reactor protection and safety systems will continue to ensure that the ability to insert control rods is maintained, the reactor coolant pressure boundary and main steam system pressure limits will not be exceeded, the reactor coolant pressure boundary will behave in a non-brittle manner, the probability of propagating fracture of the reactor coolant pressure boundary is minimized, and adequate core cooling will be provided. Based on this, PBNP concludes that the plant will continue to meet the PBNP current licensing basis requirements with respect to PBNP, GDC 30, 32, and 34 following implementation of the proposed EPU. Therefore, PBNP finds the proposed EPU acceptable with respect to RCP rotor seizure and RCP shaft break.

2.8.5.3.2.5 References

1. Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

2. WCAP-14882-P-A, RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses, D. S. Huegel, et al., April 1999

3. WCAP-14565-P-A (Proprietary) and WCAP-15306-NP-A (Nonproprietary), VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis, Sung, Y. X. et al., October 1999

4. WCAP-12910, Pressurizer Safety Valve Set Pressure Shift, Barrett, G. O., et al., March 1991

5. WCAP-16259-P-A (Proprietary) and WCAP-16259-A (Non-Proprietary), Westinghouse Methodology for Application of 3-D Transient Neutronics to Non-LOCA Accident Analysis, Beard, C. L., et al., August 2006

6. WCAP-9272-P-A (Proprietary), Westinghouse Reload Safety Evaluation Methodology, Approved July 1985

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

8. Chao, Y. A., et al., SPNOVA – A Multidimensional Static and Transient Computer Program for PWR Core Analysis, WCAP-12394-A (Proprietary) and WCAP12983-A (Nonproprietary), June 1991

9. Letter from Westinghouse to NRC, Process Improvement to the Westinghouse Neutronics Code System, NTD-NRC-96-4679, March 29, 1996

Table 2.8.5.3.2-1
Time Sequence of Events – Single RCP Locked Rotor – Peak Pressure Case

Event	Time (sec)
Transient Begins	0.0
Rotor on One Pump Locked or the Shaft Breaks	1.0
Low Flow Reactor Trip Setpoint Reached	1.1
Rods Begin to Drop	2.1
Remaining Pump Loses power and Begins to Coast Down	2.1
Main Steam Isolation on Reactor Trip	2.1
Main Feedwater Isolation on Reactor Trip	2.1
Maximum RCS Pressure Occurs	5.1
*The Maximum Clad Average Temperature (hot rod calculation) occurs at 3.5 seconds.	

Table 2.8.5.3.2-2
Results for Single RCP Locked Rotor and Comparison to Previous Results

Criteria	EPU Analysis	Previous Analysis	Limit
Maximum Clad Temperature at Core Hot Spot, °F	1810	1994	2700
Maximum Zirconium-Water Reaction at Core Hot Spot, wt. %	0.4	0.7	16.0
Maximum RCS Pressure, psia	2653	2873	3120
% of Rods in DNB	25	100	30

Figure 2.8.5.3.2-1 Single RCP Locked Rotor – Peak Pressure Case RCS Pressure vs. Time

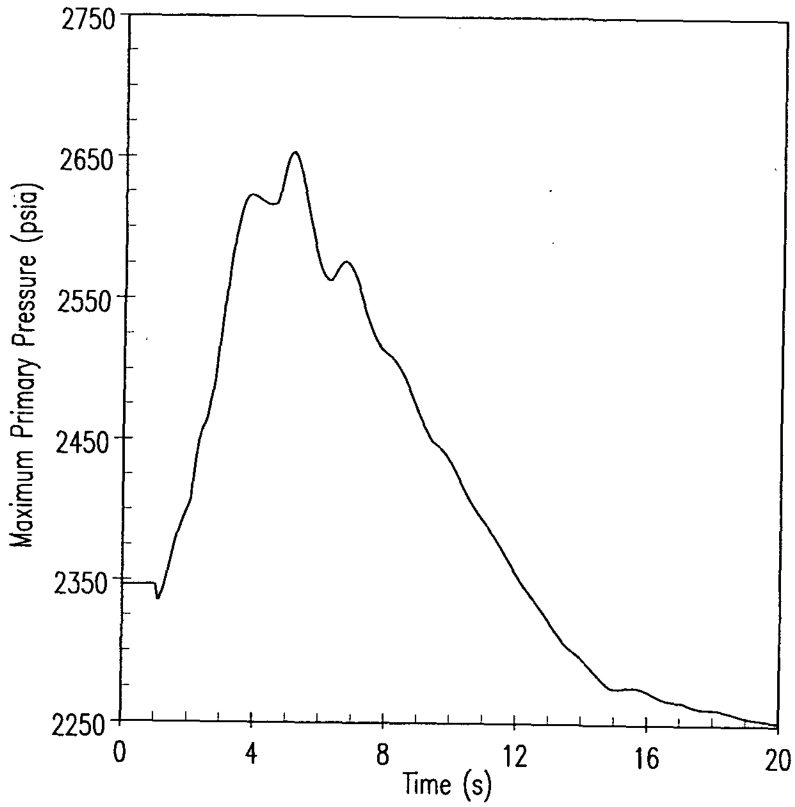


Figure 2.8.5.3.2-2 Single RCP Locked Rotor - – Peak Pressure Case Loop Flow vs. Time

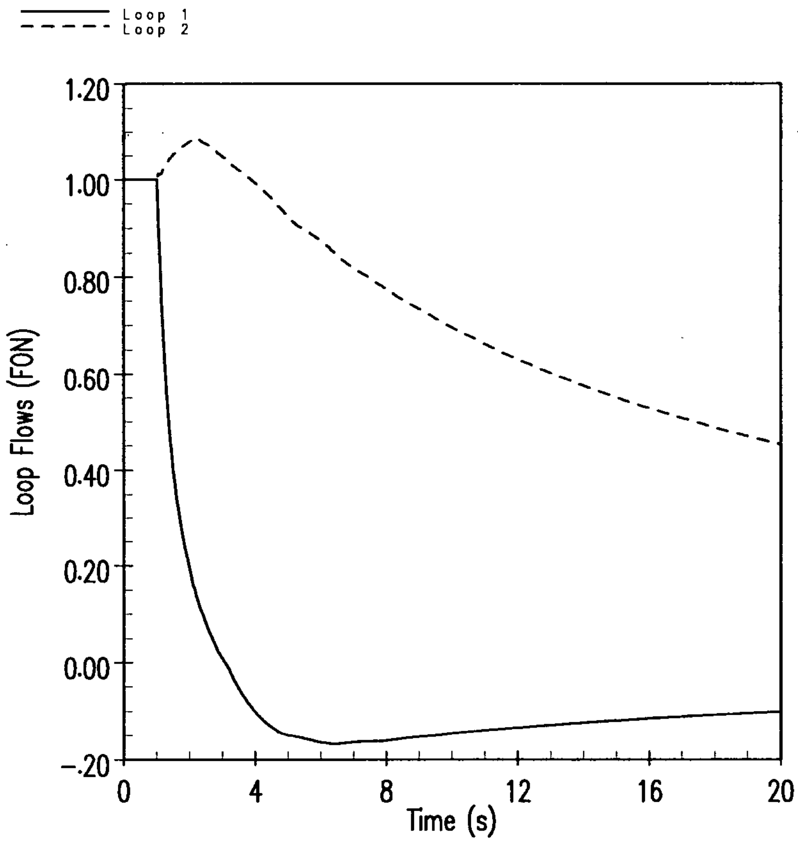


Figure 2.8.5.3.2-3 Single RCP Locked Rotor – Peak Pressure Case Nuclear Power vs. Time

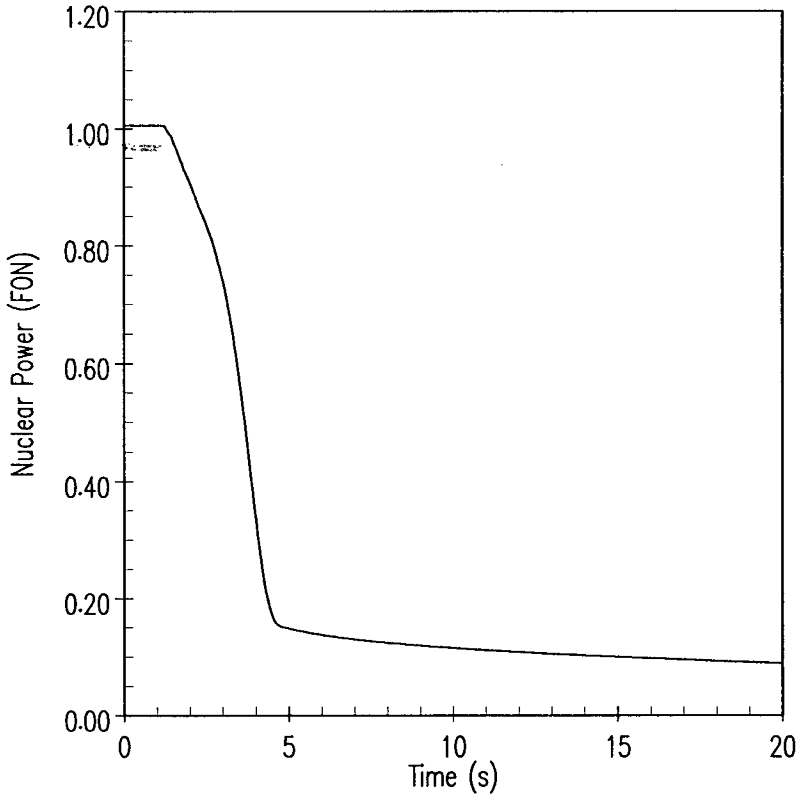


Figure 2.8.5.3.2-4 Single RCP Locked Rotor – Peak Clad Temperature Case Nuclear Power vs. Time

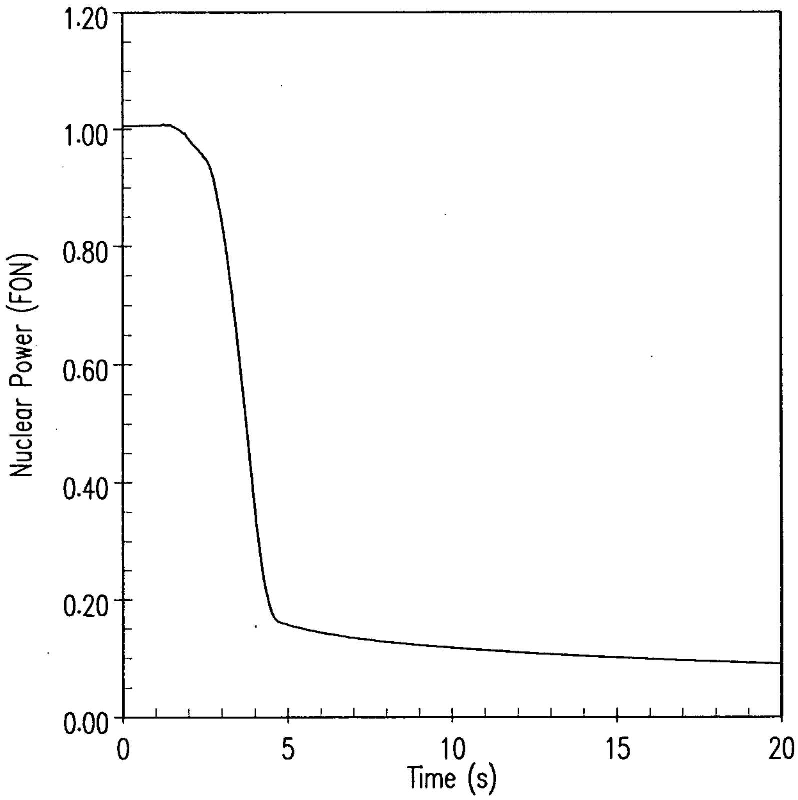


Figure 2.8.5.3.2-5 Single RCP Locked Rotor – Peak Clad Temperature Case Core Average Heat Flux vs. Time

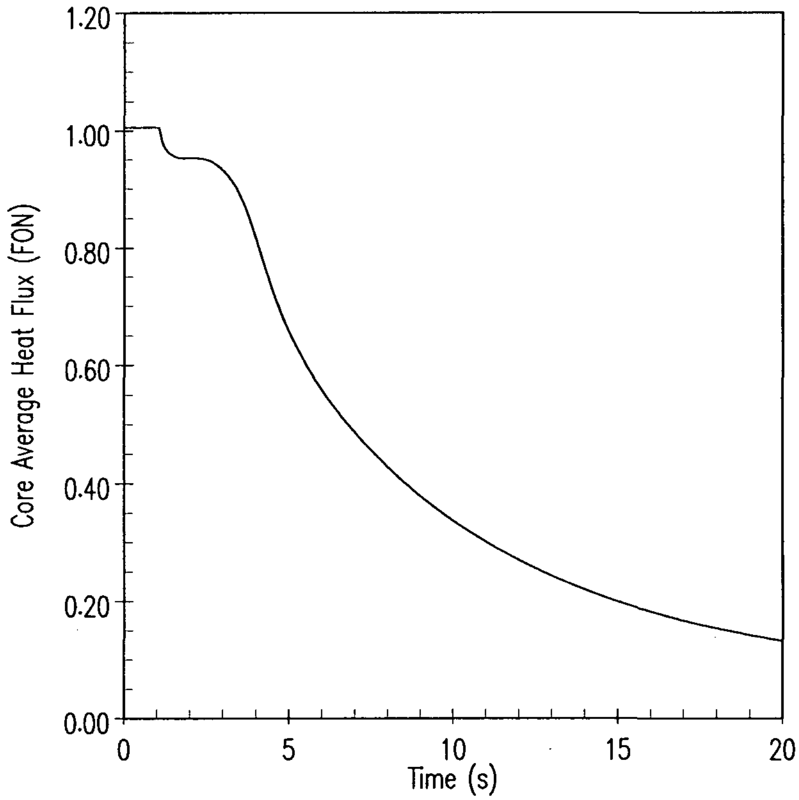
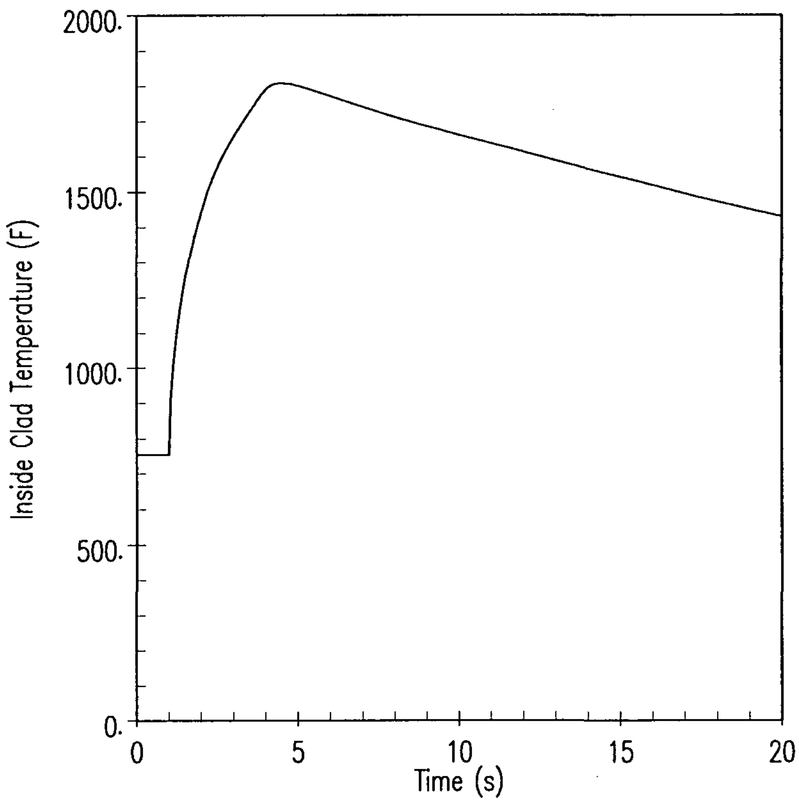


Figure 2.8.5.3.2-6 Single RCP Locked Rotor – Peak Clad Temperature Case Fuel Cladding Temperature vs. Time



2.8.5.4 Reactivity and Power Distribution Anomalies

2.8.5.4.1 Uncontrolled Rod Cluster Control Assembly Withdrawal from a Subcritical or Low-Power Startup Condition

2.8.5.4.1.1 Regulatory Evaluation

An uncontrolled rod control assembly (RCCA) withdrawal from subcritical or low-power startup conditions can be caused by a malfunction of the reactor control or rod control systems. This withdrawal will uncontrollably add positive reactivity to the reactor core, resulting in a power excursion. The PBNP review covered:

- The description of the causes of the transient and the transient itself
- The initial conditions
- The values of reactor parameters used in the analysis
- The analytical methods and computer codes used
- The results of the transient analyses

The NRC's acceptance criteria are based on:

- GDC 10, insofar as it requires that the RCS is designed with appropriate margin to ensure that specified acceptable fuel design limits are not exceeded during normal operations, including anticipated operational occurrences
- GDC 20, insofar as it requires that the reactor protection system is designed to automatically initiate the operation of appropriate systems, including the reactivity control systems, to ensure that specified acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences and
- GDC 25, insofar as it requires that the protection system is designed to ensure that specified acceptable fuel design limits are not exceeded for any single malfunction of the reactivity control systems

Specific review criteria are contained in the SRP, Section 15.4.1 and other guidance provided in Matrix 8 of RS-001, Revision 0.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50, Appendix A, GDC, 10, 20 and 25 are as follows:

CRITERION: The reactor core with its related controls and protection systems shall be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits which have been stipulated and justified. The core and related auxiliary system designs shall provide this integrity under all expected conditions of normal operation with appropriate margins for uncertainties and for specified transient situations which can be anticipated. (PBNP GDC 6)

As described in FSAR Section 3.1.2.1, Reactor Core Design, the reactor core, with its related control and protection system, is designed to function throughout its design lifetime without exceeding acceptable fuel damage limits.

Fuel design and nuclear design are further discussed in LR Section 2.8.1, Fuel System Design and LR Section 2.8.2, Nuclear Design, respectively. The analysis of an uncontrolled RCCA withdrawal from a subcritical condition is discussed in FSAR Section 14.1.1, Uncontrolled Rod Withdrawal from Subcritical. The analysis of an uncontrolled RCCA withdrawal while the reactor is at power is discussed in FSAR Section 14.1.2, Uncontrolled Rod Withdrawal At Power.

CRITERION: Core protection systems, together with associated equipment, shall be designed to prevent or to suppress conditions that could result in exceeding acceptable fuel damage limits. (PBNP GDC 14)

If the reactor protection system sensors detect conditions which indicate an approach to unsafe operating conditions that require core protection, the system actuates alarms, prevents control rod motion, initiates load runback, and initiates reactor trip by opening the reactor trip breakers.

CRITERION: The reactor protection systems shall be capable of protecting against any single malfunction of the reactivity control system, such as unplanned continuous withdrawal (not ejection or dropout) of a control rod, by limiting reactivity transients to avoid exceeding acceptable fuel damage limits. (PBNP GDC 31)

Continuous rod withdrawal accidents from both subcritical and at-power conditions are analyzed plant transients that rely on an automatic reactor trip for core protection. Automatic reactor trip is completely independent of the normal RCCA control functions, since the reactor trip breakers interrupt the power to the control rod drive mechanisms regardless of existing control signals.

The reactor trip system, which provides a protective function to prevent fuel limits from being exceeded, is described in FSAR Section 7.2, Reactor Protection System.

In addition to the evaluations described in the FSAR, the components of the reactivity control and protection system were evaluated for license renewal. Systems and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 1)

Components of the reactivity control and protection systems are within the scope of license renewal.

2.8.5.4.1.2 Technical Evaluation

2.8.5.4.1.2.1 Introduction

An uncontrolled rod cluster control assembly (RCCA) withdrawal incident is defined as an uncontrolled addition of reactivity to the reactor core by withdrawal of rod cluster control assemblies resulting in a power excursion. While the probability of a transient of this type is extremely low, such a transient could be caused by a malfunction of the reactor control rod drive system. This could occur with the reactor either subcritical or at power. The "at power" occurrence is discussed in Section 2.8.5.4.2, Uncontrolled RCCA Withdrawal at Power. The uncontrolled RCCA withdrawal from a subcritical condition is classified as an ANS Condition II event of moderate frequency.

Reactivity is added at a prescribed and controlled rate in bringing the reactor from a shutdown condition to a low power level during startup by RCCA withdrawal or by reducing the core boron concentration. RCCA motion can cause much faster changes in reactivity than can result from changing boron concentration.

The rods are physically prevented from withdrawing in other than their respective banks. Power supplied to the rod banks is controlled such that no more than two banks can be withdrawn at any time. The rod drive mechanism is of the magnetic latch type and the coil actuation is sequenced to provide variable speed rod travel. The maximum reactivity insertion rate is analyzed in the detailed plant analysis assuming the simultaneous withdrawal of the combination of the two rod banks with the maximum combined worth at maximum speed.

The neutron flux response to a continuous reactivity insertion is characterized by a very fast flux increase terminated by the reactivity feedback effect of the negative doppler coefficient. This self-limitation of the initial power increase results from a fast negative fuel temperature feedback (doppler effect) and is of prime importance during a startup transient since it limits the power to an acceptable level prior to protection system action.

Should a continuous RCCA withdrawal be initiated, the transient will be terminated by one of the following automatic protective functions:

- Source range neutron flux reactor trip – actuated when either of two independent source range channels indicates a flux level above a pre-selected, manually adjustable setpoint. This trip function may be manually bypassed when either of the intermediate range neutron flux channels indicates a flux level above the source range cutoff power level. It is automatically reinstated when both intermediate channels indicate a flux level below the source range cutoff power level
- Intermediate range neutron flux reactor trip – actuated when either of two independent intermediate range channels indicates a flux level above a pre-selected, manually adjustable setpoint. This trip function may be manually bypassed when two of the four power range channels are reading above approximately 10% of full power and is automatically reinstated when three of the four channels indicate a power level below this value
- Power range neutron flux reactor trip (low setting) – actuated when two out of the four power range channels indicate a power level above approximately 25% of full power. This trip function may be manually bypassed when two of the four power range channels indicate a power level above approximately 10% of full power. This trip function is automatically reinstated when three of the four channels indicate a power level below 10% power

- Power range neutron flux reactor trip (high setting) – actuated when two out of the four power range channels indicate a power level above a preset setpoint. This trip function is always active in MODES 1 and 2

In addition, control rod stops on high intermediate range flux (one-out-of-two) and high power range flux (one-out-of-four) serve to cease rod withdrawal and prevent the need to actuate the intermediate range flux trip and the power range flux trip, respectively. This analysis credits the power range neutron flux trip (low setting) to initiate the reactor trip.

2.8.5.4.1.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The accident analysis used the Standard Thermal Design Procedure (STDP) methodology since the conditions resulting from the transient are outside the range of applicability of the Revised Thermal Design Procedure (RTDP) methodology. To obtain conservative results for the analysis of the uncontrolled RCCA bank withdrawal from subcritical event, the following input parameters and initial conditions are modeled:

- The magnitude of the nuclear power peak reached during the initial part of the transient, for any given reactivity insertion rate, is strongly dependent on the doppler-only power defect. Therefore, a conservatively low absolute value is used (1100 pcm) to maximize the nuclear power transient
- A most-positive moderator temperature coefficient (+5 pcm/°F) is used since this yields the maximum rate of power increase. The contribution of the moderator reactivity coefficient is negligible during the initial part of the transient because the heat transfer time constant between the fuel and moderator is much longer than the nuclear flux response time constant. However, after the initial neutron flux peak, the succeeding rate of power increase is affected by the moderator reactivity coefficient
- The analysis assumes the reactor to be at hot zero power conditions with a nominal no-load temperature of 547°F. This assumption is more conservative than that of a lower initial system temperature (i.e., shutdown conditions). The higher initial system temperature yields a larger fuel-to-moderator heat transfer coefficient, a larger specific heat of the moderator and fuel, and a less-negative (smaller absolute magnitude) Doppler defect. The less-negative Doppler defect reduces the Doppler feedback effect, thereby increasing the neutron flux peak. The high neutron flux peak combined with a high fuel specific heat and larger heat transfer coefficient yields a larger peak heat flux
- The analysis assumes the initial effective multiplication factor (K_{eff}) to be 1.0 since it maximizes the peak neutron flux and results in the most severe nuclear power transient
- Reactor trip is assumed on power range high neutron flux (low setting). A conservative combination of instrumentation error, setpoint error, delay for trip signal actuation, and delay for control rod assembly release is modeled. The analysis assumes a 10% uncertainty in the power range flux trip setpoint (low setting), raising it from the nominal value of 25% of full power to 35% of full power. A delay time of 0.5 seconds is assumed for trip signal actuation and control rod assembly release. No credit is taken for the source range or intermediate range protection. During the transient, the rise in nuclear power is so rapid that the effect of errors in the trip setpoint on the actual time at which the rods release is negligible. The total

reactor trip reactivity is based on the assumption that the highest worth rod cluster control assembly is stuck in its fully withdrawn position

- The maximum positive reactivity insertion rate assumed is greater than that for the simultaneous withdrawal of the two sequential control banks having the greatest combined worth at the maximum rod withdrawal speed. The assumed reactivity insertion rate is 75 pcm/sec which is based on a rod worth of 100 pcm/inch and a maximum rod speed of 72 steps per minute
- The DNB analysis assumes the most-limiting axial and radial power shapes possible during the fuel cycle associated with having the two highest combined worth banks in their highest worth position
- The analysis assumes the initial power level to be below the power level expected for any shutdown condition (10^{-9} fraction of nominal power). The combination of highest reactivity insertion rate and low initial power produces the highest peak heat flux
- The analysis assumes one of the two Reactor Coolant Pumps to be in operation. This is conservative with respect to the DNB transient
- This accident analysis used the Standard Thermal Design Procedure (STDP) methodology. The use of STDP stipulates that the RCS flow rate will be based on a fraction of the thermal design flow for one reactor coolant pump (RCP) operating and that the RCS pressure is 50 psi below nominal. Since the event is analyzed from hot zero power, the steady-state STDP uncertainties on core power and RCS average temperature are not considered in defining the initial conditions

The uncontrolled rod cluster control assembly bank withdrawal from subcritical event is considered an ANS Condition II event, a fault of moderate frequency, and is analyzed to show that the core and reactor coolant system are not adversely affected by the event. This is demonstrated by showing that the DNB design basis is not violated and subsequently that there is little likelihood of core damage. It must also be shown that the peak hot spot fuel centerline temperature remains within the acceptable limit (4800°F), although for this event, the heat up is relatively non-limiting.

2.8.5.4.1.2.3 Description of Analyses and Evaluations

The analysis of the uncontrolled RCCA bank withdrawal from subcritical conditions is performed in three stages. First, a spatial neutron kinetics computer code, TWINKLE (Reference 2), is used to calculate the core average nuclear power transient, including the various core feedback effects, i.e., doppler and moderator reactivity. FACTRAN computer code (Reference 3) uses the average nuclear power calculated by TWINKLE and performs a fuel rod transient heat transfer calculation to determine the core average heat flux and hot spot fuel temperature transients. The core average heat flux calculated by FACTRAN is used in the VIPRE computer code (Reference 4) for transient DNBR calculations.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

Components of the reactivity control and protection systems that are within the scope of license renewal are electrical and instrumentation and control components that are treated as commodity groups in NUREG-1839. Aging effects and the programs used to manage the aging effects of these components are discussed in NUREG-1839, Section 3.6. There are no modifications or additions to system components as a result of EPU that would introduce any new functions or change the functions of existing components that would affect the license renewal system evaluation boundaries. Operation of the reactivity control and protection systems at EPU conditions does not add any unevaluated aging effects that would necessitate a change to aging management programs or require a new program, as internal and external environments remain within the parameters previously evaluated. Therefore, EPU activities associated with uncontrolled RCCA bank withdrawal do not impact license renewal scope, aging effects, and aging management programs.

2.8.5.4.1.2.4 Results

The analysis shows that all applicable acceptance criteria are met. The minimum DNBR never goes below the safety analysis limit value and the peak fuel centerline temperature is 2166°F. The peak temperatures are well below the minimum temperature where fuel melting would be expected (4800°F).

Figure 2.8.5.4.1-1 shows the nuclear power transient, Figure 2.8.5.4.1-2 shows the core average heat flux transient, and Figure 2.8.5.4.1-3 shows the fuel center line average and surface temperatures at the hot spot.

The time sequence of events for both cases is presented in Table 2.8.5.4.1-1, Time Sequence of Events - Uncontrolled RCCA Bank Withdrawal from a Subcritical Condition.

In the event of an RCCA withdrawal from subcritical conditions, the core and the RCS are not adversely affected since the combination of thermal power and coolant temperature results in a minimum DNBR greater than the safety analysis limit value. Furthermore, since the maximum fuel temperatures predicted to occur during this event are much less than those required for fuel melting to occur, no fuel damage is predicted as a result of this transient. Clad damage is also precluded.

2.8.5.4.1.2.5 Conclusions

PBNP has reviewed the analyses of the uncontrolled RCCA withdrawal from a subcritical or low-power startup condition and concludes that the analyses have adequately accounted for the changes in core design necessary for plant operation at the proposed EPU power level. PBNP also concludes that the analyses were performed using acceptable analytical models. PBNP further concludes that the analyses have 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, PBNP concludes that the plant will continue to meet the PBNP current licensing basis requirements with respect to PBNP, GDC 6, 14, and 31 following implementation of the proposed EPU. Therefore, PBNP finds the proposed EPU acceptable with respect to the uncontrolled RCCA withdrawal from a subcritical or low-power startup condition.

2.8.5.4.1.2.6 References

1. Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

2. TWINKLE – A Multi-dimensional Neutron Kinetics Computer Code, WCAP-7979-P-A, January 1975 (Proprietary) and WCAP-8028-A, January 1975 (Non-Proprietary) Barry, R. F., Jr. and Risher, D. H

3. FACTRAN – A FORTRAN-IV Code for Thermal Transients in UO2 Fuel Rod, WCAP-7908-A, December 1989, Hargrove, H. G

4. WCAP-15306-NP-A, VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis, WCAP-14565-P-A (Proprietary) and (Non-Proprietary), October 1999, Sung, Y. X., et al

Table 2.8.5.4.1-1
Time Sequence of Events - Uncontrolled RCCA Bank Withdrawal from a Subcritical Condition

Event	Time (seconds)
Initiation of uncontrolled rod withdrawal	0.0
Power range high neutron flux low setpoints is reached	10.0
Peak nuclear power occurs	10.11
Rod motion begins	10.48
Peak heat flux occurs (0.3522 Fraction of Nominal)	11.93
Minimum DNBR occurs (1.755)	11.93
Peak average clad temperature occurs (709.0°F)	12.23
Peak average fuel temperature occurs (1850.0°F)	12.43

Figure 2.8.5.4.1-1 Point Beach Nuclear Plant Rod Withdrawal from Subcritical Nuclear Power versus Time

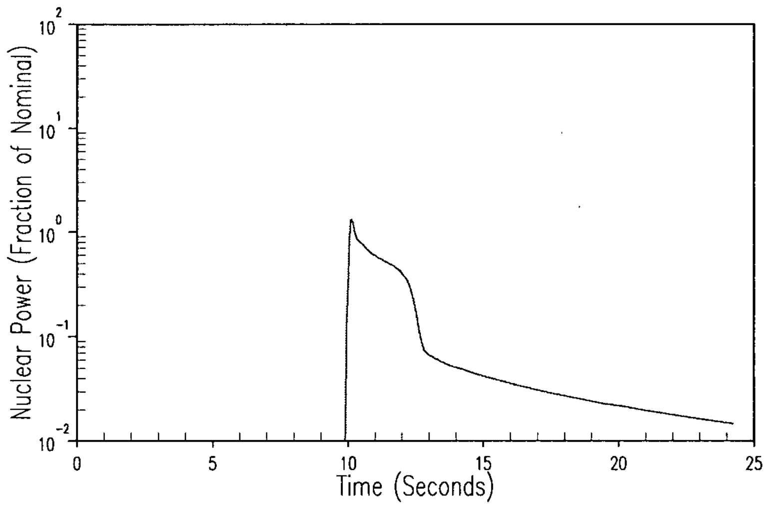


Figure 2.8.5.4.1-2 Point Beach Nuclear Plant Rod Withdrawal from Subcritical Core Average Heat Flux versus Time

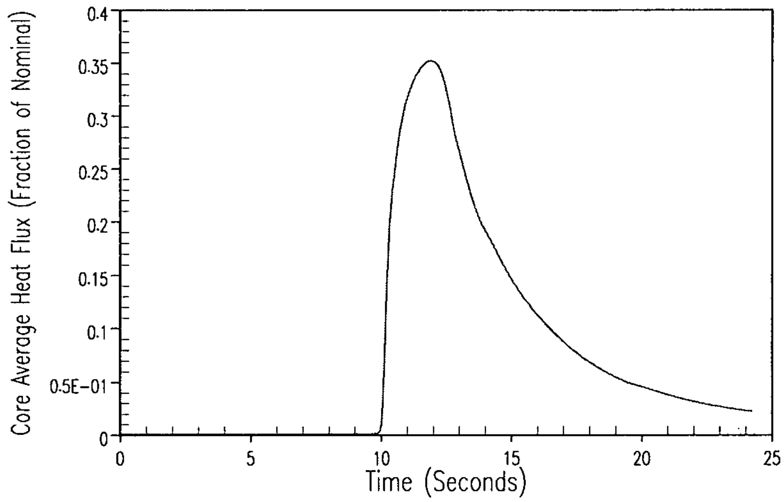
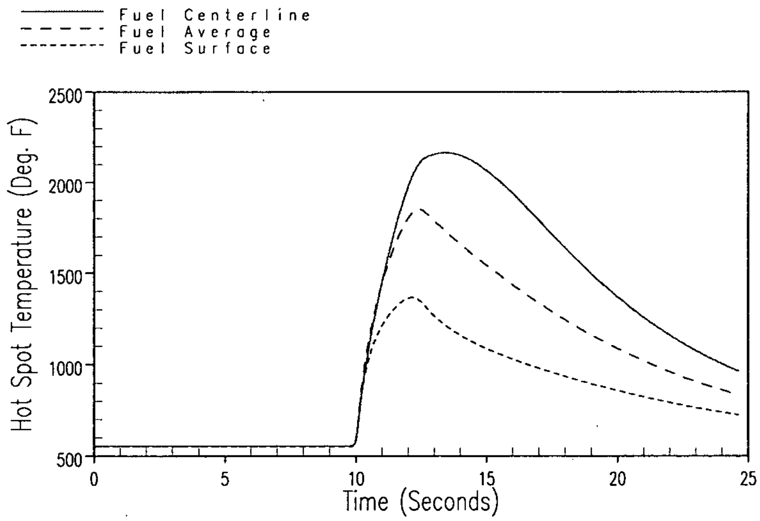


Figure 2.8.5.4.1-3 Point Beach Nuclear Plant Rod Withdrawal from Subcritical Hot Spot Fuel Temperatures versus Time



2.8.5.4.2 Uncontrolled Rod Cluster Control Assembly Withdrawal at Power

2.8.5.4.2.1 Regulatory Evaluation

An uncontrolled rod cluster control assembly (RCCA) withdrawal at power can be caused by a malfunction of the reactor control or rod control systems. This withdrawal will uncontrollably add positive reactivity to the reactor core, resulting in a power excursion. The PBNP review covered:

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

The NRC's acceptance criteria are based on:

- GDC 10, insofar as it requires that the RCS is designed with appropriate margin to ensure that specified acceptable fuel design limits are not exceeded during normal operations, including anticipated operational occurrences
- GDC 20, insofar as it requires that the reactor protection system is designed to automatically initiate the operation of appropriate systems, including the reactivity control systems, to ensure that specified acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences
- GDC 25, insofar as it requires that the protection system is designed to ensure that specified acceptable fuel design limits are not exceeded for any single malfunction of the reactivity control systems

Specific review criteria are contained in SRP Section 15.4.2 and other guidance provided in Matrix 8 of RS-001, Revision 0.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50, Appendix A, GDC 10, 20 and 25 are as follows:

CRITERION: The reactor core with its related controls and protection systems shall be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits which have been stipulated and justified. The core and related auxiliary system designs shall provide this integrity under all expected conditions of normal operation with appropriate margins for uncertainties and for specified transient situations which can be anticipated. (PBNP GDC 6)

As described in FSAR Section 3.1.2.1, Reactor Core Design, the reactor core, with its related control and protection system, is designed to function throughout its design lifetime without exceeding acceptable fuel damage limits.

Fuel design and nuclear design are further discussed in LR Section 2.8.1, Fuel System Design, and LR Section 2.8.2, Nuclear Design, respectively.

CRITERION: Core protection systems, together with associated equipment, shall be designed to prevent or to suppress conditions that could result in exceeding acceptable fuel damage limits. (PBNP GDC 14)

If the reactor protection system sensors detect conditions which indicate an approach to unsafe operating conditions that require core protection, the system actuates alarms, prevents control rod motion, initiates load runback, and initiates reactor trip by opening the reactor trip breakers.

The reactor trip system, which provides a protective function to prevent fuel limits from being exceeded, is described in FSAR Section 7.2, Reactor Protection System.

Fuel design for EPU conditions is evaluated in LR Section 2.8.2, Nuclear Design.

CRITERION: The reactor protection systems shall be capable of protecting against any single malfunction of the reactivity control system, such as unplanned continuous withdrawal (not ejection or dropout) of a control rod, by limiting reactivity transients to avoid exceeding acceptable fuel damage limits. (PBNP GDC 31)

Continuous rod withdrawal accidents from both subcritical and at-power conditions are analyzed plant transients that rely on an automatic reactor trip for core protection. Automatic reactor trip is completely independent of the normal RCCA control functions, since the reactor trip breakers interrupt the power to the control rod drive mechanisms regardless of existing control signals.

Additional information is provided in FSAR Section 3.1, Reactor, Design Basis, and Section 7.0, Instrumentation and Control. Details of the effects of continuous withdrawal of a control rod are described in FSAR Section 14.1.2, Uncontrolled Rod Withdrawal at Power.

In addition to the evaluations described in the FSAR, the components of the reactivity control and protection system were evaluated for License Renewal. Systems and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 1)

Components of the reactivity control and protection systems that are within the scope of license renewal are electrical and instrumentation and control components that are treated as commodity groups in NUREG-1839. (Reference 1)

2.8.5.4.2.2 Technical Evaluation

2.8.5.4.2.2.1 Introduction

An uncontrolled RCCA 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 Departure from Nucleate Boiling Ratio (DNBR) 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 ΔT channels exceed an overtemperature ΔT setpoint. This setpoint is automatically varied with axial power distribution, coolant average temperature, and coolant average pressure to protect against violating the DNBR limit
- Reactor trip actuates if any two out of four ΔT channels exceed an overpower ΔT setpoint. This setpoint is automatically varied with temperature to ensure that the allowable full power rating is not exceeded
- A high pressurizer pressure reactor trip actuates if any two-out-of-three pressure channels exceed a fixed setpoint
- A high pressurizer water level reactor trip actuates if any two-out-of-three level channels exceed a fixed setpoint
- Main steam safety valves (MSSVs) can open for this event and provide an additional heat sink

It should be noted that although additional protection is provided by the overpower ΔT signal, it is not credited in this analysis.

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 DNB analysis assumed the following conservative assumptions:

- This accident was analyzed with the Revised Thermal Design Procedure (RTDP) (Reference 2). Initial reactor power, RCS pressure, and RCS temperature were assumed to be at their nominal values, adjusted to account for any applicable measurement biases, consistent with steady-state full-power operation. Minimum measured flow was modeled. Uncertainties in initial conditions were included in the DNBR limit as described in the RTDP.
- For reactivity coefficients, two cases were analyzed.
  - Minimum reactivity feedback: A moderator temperature coefficient (MTC) as large as +5 pcm/°F and a least-negative doppler-only power coefficient formed the basis for the Beginning-Of-Life (BOL) minimum reactivity feedback assumption
  - Maximum reactivity feedback: A conservatively large, positive moderator density coefficient (corresponding to a large negative MTC) and a most-negative Doppler-only power coefficient formed the basis for the End-Of-Life (EOL) maximum reactivity feedback assumption
- The reactor trip on high neutron flux was assumed to be actuated at a conservative value of 116% of nominal full power. The ΔT 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 from 1 pcm/sec to 100 pcm/sec were 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 (107 pcm/in, which corresponds to 80.25 pcm/sec)
- Power levels of 10, 60, and 100% of the analyzed NSSS power of 1806 MWt were considered
- The entire full power T_{avg} range of 558°F to 577°F is examined

For the Overpressure analysis, the above assumptions still apply with the following differences:

- This accident was analyzed with the Standard Thermal Design Procedure (STDP). Initial reactor power, RCS pressure, and RCS temperature were assumed to be at their nominal values, conservatively adjusted to account for any applicable uncertainties and measurement biases, consistent with steady-state full-power operation. Unlike the RTDP, DNB cases, uncertainties in initial conditions were explicitly modeled in the overpressure cases. Thermal design flow was modeled
- For reactivity coefficients, only minimum reactivity feedback is considered since this maximizes the peak pressure response
- The high pressurizer pressure reactor trip is credited

- Power levels of 8, 25, 35, 40, 45, 50, 55, 70, and 100.6% of the analyzed NSSS power of 1806 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. 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 limit value at any time during the transient.
- Fuel centerline temperatures should not exceed the melting temperature. This is met by ensuring that the peak core average heat flux does not exceed 120% of Rated Thermal Power (RTP)
- Pressure in the RCS and Main Steam system (MS) should be maintained below 110% of the design pressures

The protection features presented in licensing report Section 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.

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 rod withdrawal at-power event was analyzed with the RETRAN computer code (Reference 3). The program simulated the neutron kinetics, RCS, pressurizer, pressurizer relief (DNB cases only) and safety valves, pressurizer spray (DNB cases only), steam generators, and main steam safety valves (MSSVs). The program computed pertinent plant variables including temperatures, pressures, power level, and a conservative DNBR approximation.

Although RETRAN has the capability of conservatively approximating the transient value of the DNBR, a detailed DNB analysis was performed for the limiting cases with the thermal-hydraulic computer code VIPRE (Reference 4). These are first time applications of RETRAN and VIPRE for PBNP.

2.8.5.4.2.2.4 Results

Figures 2.8.5.4.2-1 through 2.8.5.4.2-3 show the transient response for a rapid uncontrolled RCCA bank withdrawal incident (100 pcm/sec) starting from 100% power with minimum feedback for Unit 1. Reactor trip on high neutron flux occurred shortly after the start of the accident. Because of the rapid reactor trip, small changes in T_{avg} and pressure resulted in the margin to the DNBR limit being maintained.

The transient responses for a slow uncontrolled RCCA bank withdrawal (1 pcm/sec) from 100% power with minimum feedback for Unit 1 are shown in Figures 2.8.5.4.2-4 through 2.8.5.4.2-6. Reactor trip on overtemperature ΔT occurred after a longer period of time and the rise in temperature was consequently larger than for a rapid RCCA bank withdrawal. Again, the minimum DNBR was greater than the safety analysis limit value.

Figure 2.8.5.4.2-7 shows the minimum DNBR as a function of reactivity insertion rate from 100% power for both minimum and maximum reactivity feedback conditions for Unit 1. It can be seen that the high neutron flux (HNF) and overtemperature ΔT reactor trip functions provided DNB protection over the range of reactivity insertion rates. The minimum DNBR was never less than the safety analysis limit value.

Figures 2.8.5.4.2-8 and 2.8.5.4.2-9 show the minimum DNBR as a function of reactivity insertion rate for RCCA bank withdrawal incidents starting at 60 and 10% power, respectively, for Unit 1. The results were similar to the 100% power case; however, as the initial power level decreased, the range over which the overtemperature ΔT trip is effective was increased. For the cases that violated the proposed safety analysis DNBR limit value of 1.34 using the conservative RETRAN DNBR approximation model, the DNBR response was recalculated using the detailed thermal-hydraulic computer code VIPRE. The limiting VIPRE-calculated DNBR was 1.337 at 10% power and an insertion rate of 21 pcm/second with minimum reactivity feedback. Therefore, the Safety Analysis Limit (SAL) DNBR was reduced to 1.337 for the RWAP event by assessing and subtracting a 0.23% DNBR penalty from the DNBR margin retained in the SAL DNBR. This is acceptable since sufficient margin existed between the design limit DNBR and SAL DNBR. In all cases, the DNBR remained above the safety analysis limit for Unit 1.

Figures 2.8.5.4.2-10 through 2.8.5.4.2-18 show the transient responses for Unit 2. As was done for Unit 1, the cases that violated the safety analysis DNBR limit value using the conservative RETRAN DNBR approximation model were recalculated using the detailed thermal-hydraulic computer code VIPRE. The limiting VIPRE-calculated DNBR was 1.344 at 10% power and an insertion rate of 21 pcm/second. In all cases, the DNBR remained above the safety analysis limit for Unit 2.

Fuel centerline temperatures are shown not to exceed the melting temperature by ensuring that the peak core average heat flux does not exceed 120% RTP. The maximum calculated core average heat flux for Unit 1 was 115.6% RTP at 100% power and an insertion rate of 5 pcm/second with minimum reactivity feedback. The maximum calculated core average heat flux for Unit 2 was 115.7% RTP at 100% power and an insertion rate of 35 pcm/second with maximum reactivity feedback. In all cases for both units, the core average heat flux does not exceed a level that could result in fuel melt.

The uncontrolled RCCA bank withdrawal at-power accident was also analyzed to ensure that the RCS and MS peak pressures did not exceed 110% of the respective design pressures. For both units, a range of reactivity insertion rates at various power levels were analyzed. It was determined that insertion rates above 68 pcm/second resulted in RCS pressures in excess of 110% of design pressure. Thus, for both units, the maximum permissible insertion rate was conservatively limited to 50 pcm/second. For Unit 1, the peak RCS and MS pressures up to 50 pcm/second are 2690 psia and 1115 psia, respectively. For Unit 2, the peak RCS and MS pressures up to 50 pcm/second are 2692 psia and 1114 psia, respectively. In all cases for both units at an insertion rate of 50 pcm/second or below, the peak RCS and MS pressures do not exceed 110% of the respective design pressures.

A calculated sequence of events for Unit 1, for two cases, is shown in Table 2.8.5.4.2-1,Unit 1 Time Sequence of Events – Uncontrolled RCCA Bank Withdrawal at Power. The calculated sequence of events for Unit 2 is shown in Table 2.8.5.4.2-2,Unit 2 Time Sequence of Events – Uncontrolled RCCA Bank Withdrawal at Power. With the reactor tripped, the plant eventually returned to a stable condition. The plant could subsequently be cooled down further by following normal plant shutdown procedures. Numerical results of the EPU analysis along with a comparison to the previous analysis results are shown in Table 2.8.5.4.2-3,Uncontrolled RCCA Bank Withdrawal at Power – Results and Comparison to Previous Results. In all cases, the EPU analyses are more limiting than the previous analyses.

The high neutron flux and overtemperature ΔT reactor trip functions provided adequate protection over the entire range of possible reactivity insertion rates (i.e., the minimum value of DNBR was always larger than the safety analysis limit value) for both units. The RCS and MS pressures were maintained below 110% of the design pressures for both units. It should be noted that additional cases were performed to conservatively maximize the RCS pressure, which demonstrated that the RCS pressure limit criterion was met. Therefore, the results of the analysis showed that an uncontrolled RCCA withdrawal at-power does not adversely affect the core, the RCS, or the MS and all applicable criteria were met for both units.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

Components of the reactivity control and protection systems that are within the scope of license renewal are electrical and instrumentation and control components that are treated as commodity groups in NUREG-1839 (Reference 1). Aging effects and the programs used to manage the aging effects of these components are discussed in NUREG-1839, Section 3.6. There are no modifications or additions to system components as the result of EPU that would introduce any new functions or change the functions of existing components that would affect the license renewal system evaluation boundaries. Operation of the reactivity control and protection systems at EPU conditions does not add any unevaluated aging effects that would necessitate a change to aging management programs or require new programs as internal and external environments remain within the parameters previously evaluated. Therefore, EPU activities associated with uncontrolled RCCA withdrawal at power do not impact license renewal scope, aging effects and aging management programs.

2.8.5.4.2.3 Conclusions

PBNP has reviewed the analyses of the uncontrolled RCCA withdrawal at-power event and concludes that the analyses have adequately accounted for the changes in core design required for plant operation at the uprated power level. PBNP also concludes that the analyses were performed using acceptable analytical models, including the first time application of RETRAN and VIPRE. PBNP further concludes that the analyses have demonstrated that the reactor protection and safety systems incorporating the changes to the OTΔT setpoint parameters will continue to ensure the specified acceptable fuel design limits are not exceeded. Based on this, PBNP concludes that the plant will continue to meet the requirements of PBNP, GDC 6, 14 and 31 following implementation of the EPU, including the required setpoint changes presented in LR Section 2.8.5.0, Accident and Transient Analysis. Therefore, PBNP finds the EPU acceptable with respect to the uncontrolled RCCA withdrawal at-power.

2.8.5.4.2.4 References

1. Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

2. WCAP-11397-P-A (Proprietary), WCAP-11397-A (Non-Proprietary), Revised Thermal Design Procedure, April 1989

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

4. WCAP-14565-P-A (Proprietary) and WCAP-15306-NP-A (Non-Proprietary), VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis, Sung, Y. X. et al., October 1999

Table 2.8.5.4.2-1
Unit 1 Time Sequence of Events – Uncontrolled RCCA Bank Withdrawal at Power

Case	Event	Time (sec)
100% Power, Minimum Feedback, Rapid RCCA Withdrawal (100 pcm/sec)	Initiation of Uncontrolled RCCA Withdrawal	100.0
	Power Range High Neutron Flux – High Setpoint Reached	101.3
	Rods Begin to Fall	101.8
	Minimum DNBR Occurs	102.0
100% Power, Minimum Feedback, Slow RCCA Withdrawal (1 pcm/sec)	Initiation of Uncontrolled RCCA Withdrawal	100.0
	OTΔT High Setpoint Reached	171.1
	Rods Begin to Fall	173.1
	Minimum DNBR Occurs	173.0

Table 2.8.5.4.2-2
Unit 2 Time Sequence of Events – Uncontrolled RCCA Bank Withdrawal at Power

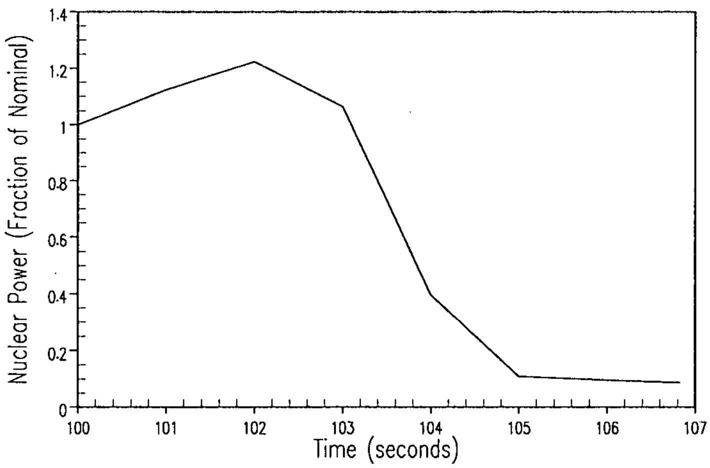
Case	Event	Time (sec)
100% Power, Minimum Feedback, Rapid RCCA Withdrawal (100 pcm/sec)	Initiation of Uncontrolled RCCA Withdrawal	100.0
	Power Range High Neutron Flux – High Setpoint Reached	101.3
	Rods Begin to Fall	101.8
	Minimum DNBR Occurs	102.0
100% Power, Minimum Feedback, Slow RCCA Withdrawal (1 pcm/sec)	Initiation of Uncontrolled RCCA Withdrawal	100.0
	OTΔT Setpoint Reached	171.9
	Rods Begin to Fall	173.9
	Minimum DNBR Occurs	174.0

Table 2.8.5.4.2-3
Uncontrolled RCCA Bank Withdrawal at Power – Results and Comparison to Previous Results

	Limiting EPU Analysis		Limiting Previous Analysis	EPU Limit	
	Unit 1	Unit 2		Unit 1	Unit 2
Minimum DNBR (1)	1.337	1.344	1.527	1.337(2)	
Peak Primary System Pressure, psia(3)	2690(4)	2692(4)	2529(5)	2748.5	
Peak Secondary System Pressure, psia(6)	1115	1114	<1208.5	1208.5	

1. The calculated minimum DNBRs for both units correspond to 10% power and an insertion rate of 21 pcm/second with minimum reactivity feedback.
2. The SAL DNBR was reduced to 1.337 by assessing and subtracting a 0.23% DNBR penalty from the DNBR margin retained in the SAL DNBR. This is justifiable since sufficient margin existed between the design limit DNBR and SAL DNBR.
3. The calculated maximum RCS pressures for both units correspond to 55% power and an insertion rate of 50 pcm/second.
4. The maximum reactivity insertion rate is limited to 50 pcm/second. This is confirmed on a reload specific basis for all cycles in which the EPU conditions exist.
5. The maximum reactivity insertion rate is limited to 47 pcm/second. This is confirmed on a reload specific basis.
6. The calculated maximum MS pressures for Units 1 and 2 correspond to 8% power and insertion rates of 1 pcm/second and 50 pcm/second, respectively.

Figure 2.8.5.4.2-1 Unit 1 Rod Withdrawal at Power Minimum Reactivity Feedback – 100% Power - 100 pcm/sec Nuclear Power and Core Heat Flux vs. Time



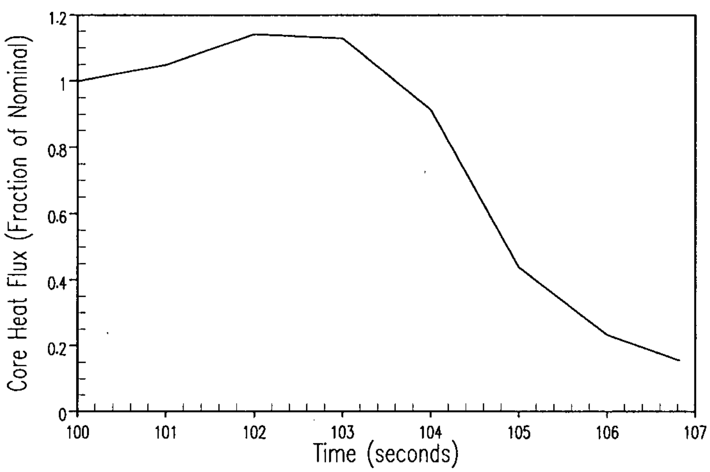
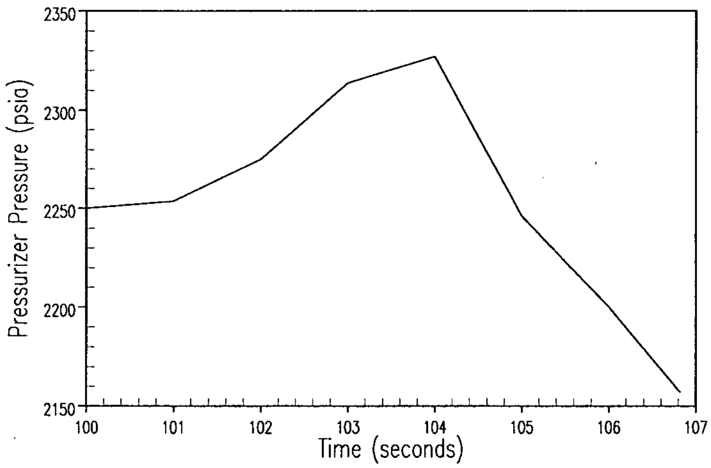


Figure 2.8.5.4.2-2 Unit 1 Rod Withdrawal at Power Minimum Reactivity Feedback – 100% Power - 100 pcm/sec Pressurizer Pressure and Water Volume vs. Time



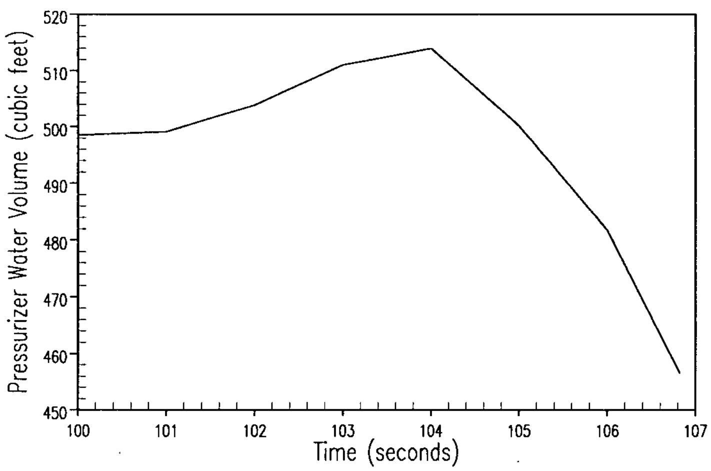


Figure 2.8.5.4.2-3 Unit 1 Rod Withdrawal at Power Minimum Reactivity Feedback – 100% Power - 100 pcm/sec Core Average Temperature and DNBR vs. Time

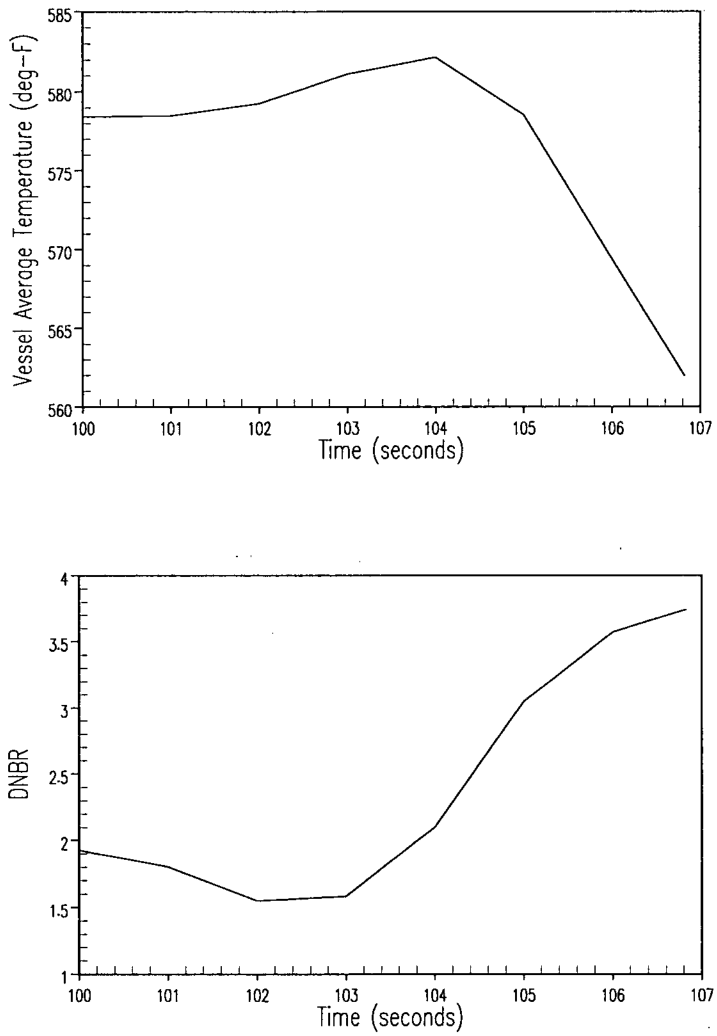


Figure 2.8.5.4.2-4 Unit 1 Rod Withdrawal at Power Minimum Reactivity Feedback – 100% Power - 1 pcm/sec Nuclear Power and Core Heat Flux vs. Time

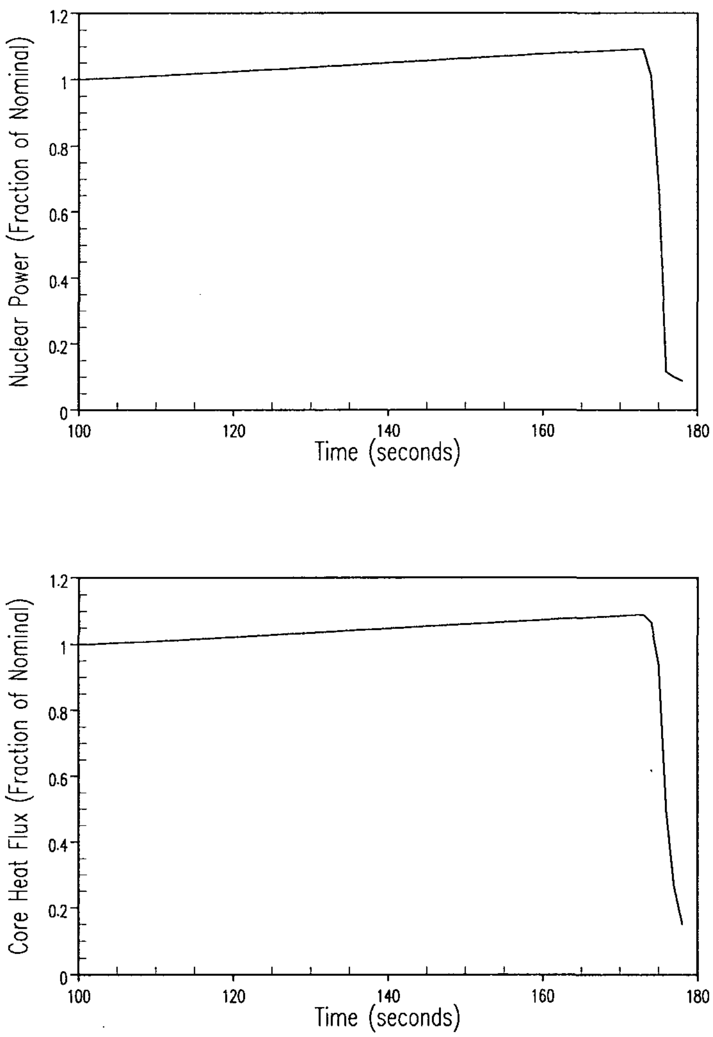
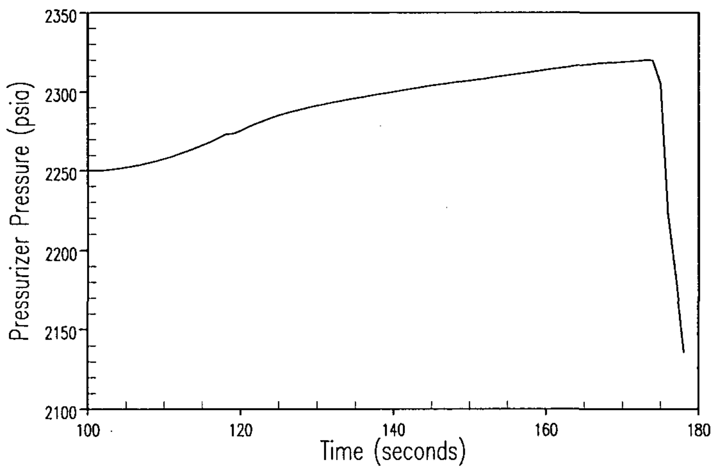


Figure 2.8.5.4.2-5 Unit 1 Rod Withdrawal at Power Minimum Reactivity Feedback – 100% Power - 1 pcm/sec Pressurizer Pressure and Water Volume vs. Time



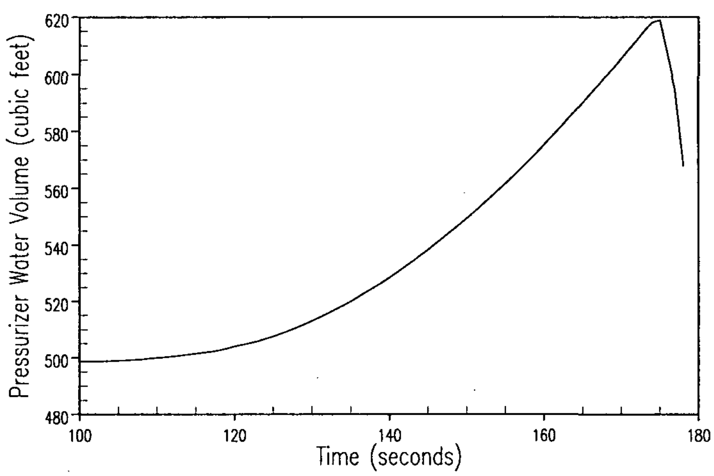


Figure 2.8.5.4.2-6 Unit 1 Rod Withdrawal at Power Minimum Reactivity Feedback – 100% Power - 1 pcm/sec Core Average Temperature and DNBR vs. Time

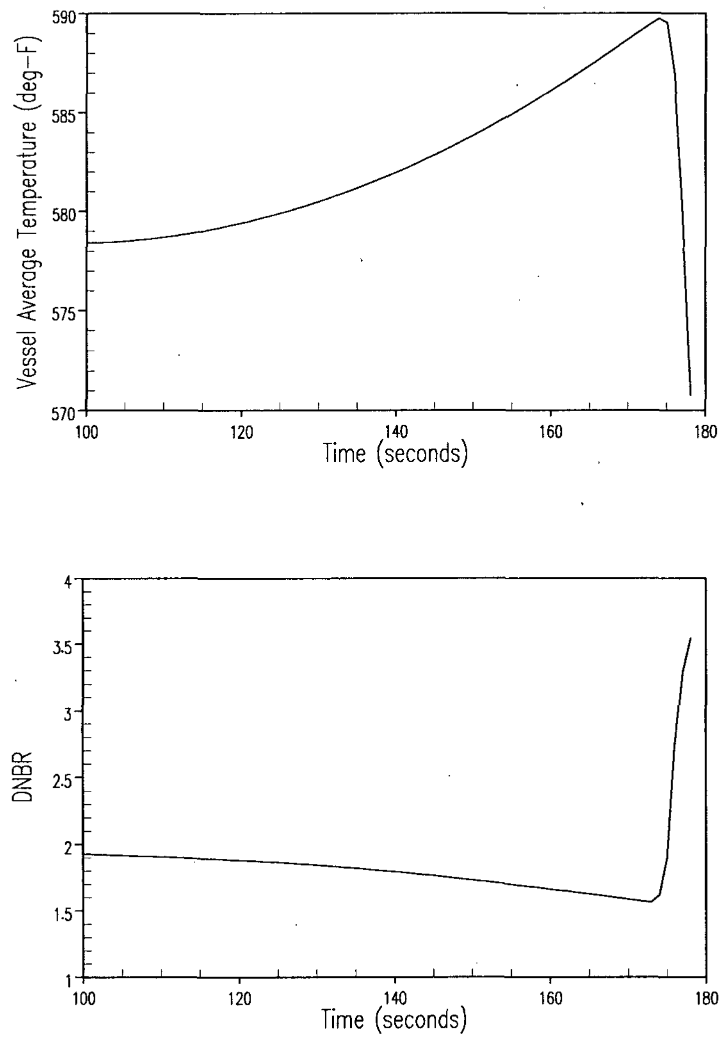


Figure 2.8.5.4.2-7 Unit 1 Rod Withdrawal at Power 100% Power Minimum DNBR vs. Reactivity Insertion Rate

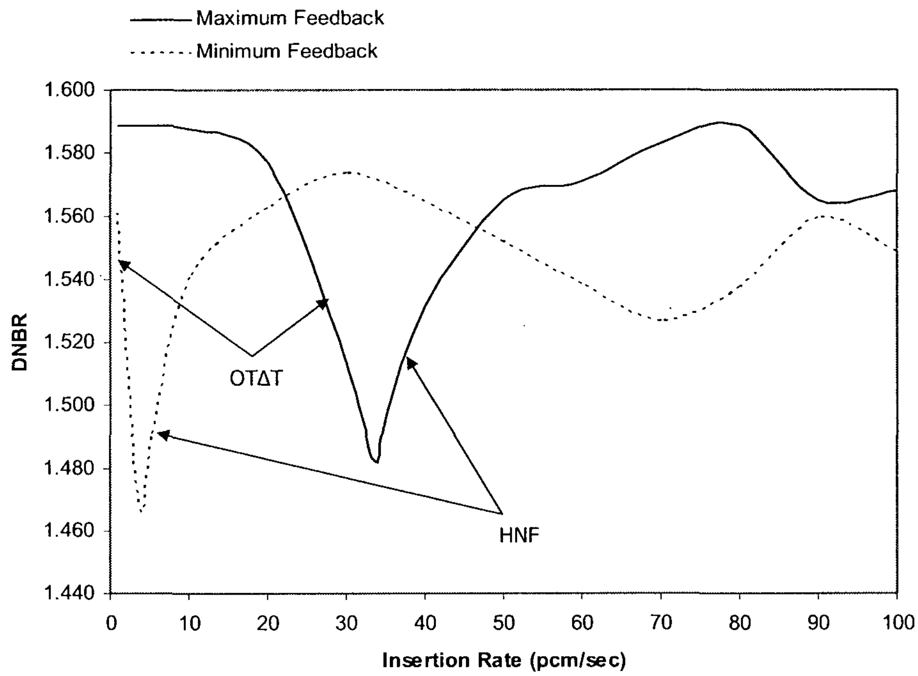


Figure 2.8.5.4.2-8 Unit 1 Rod Withdrawal at Power 60% Power Minimum DNBR vs. Reactivity Insertion Rate

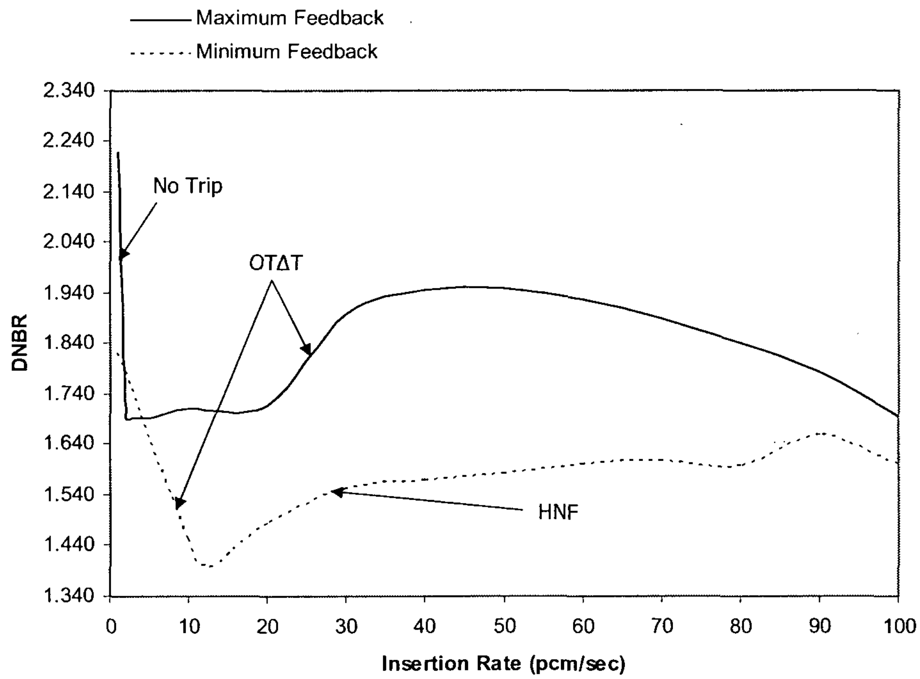
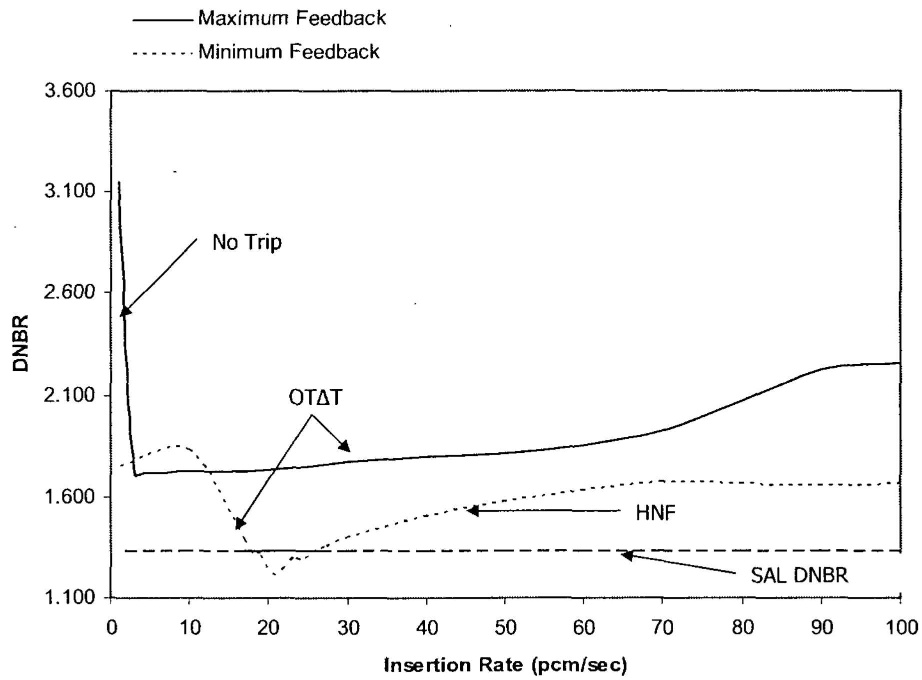


Figure 2.8.5.4.2-9 Unit 1 Rod Withdrawal at Power 10% Power Minimum DNBR vs. Reactivity Insertion Rate



The cases that violate the SAL DNBR limit of 1.337 based upon the RETRAN RW3 DNB model were run with the VIPRE code. The limiting VIPRE-calculated DNBR was 1.337 at an insertion rate of 21 pcm/second.

Figure 2.8.5.4.2-10 Unit 2 Rod Withdrawal at Power Minimum Reactivity Feedback – 100% Power - 100 pcm/sec Nuclear Power and Core Heat Flux vs. Time

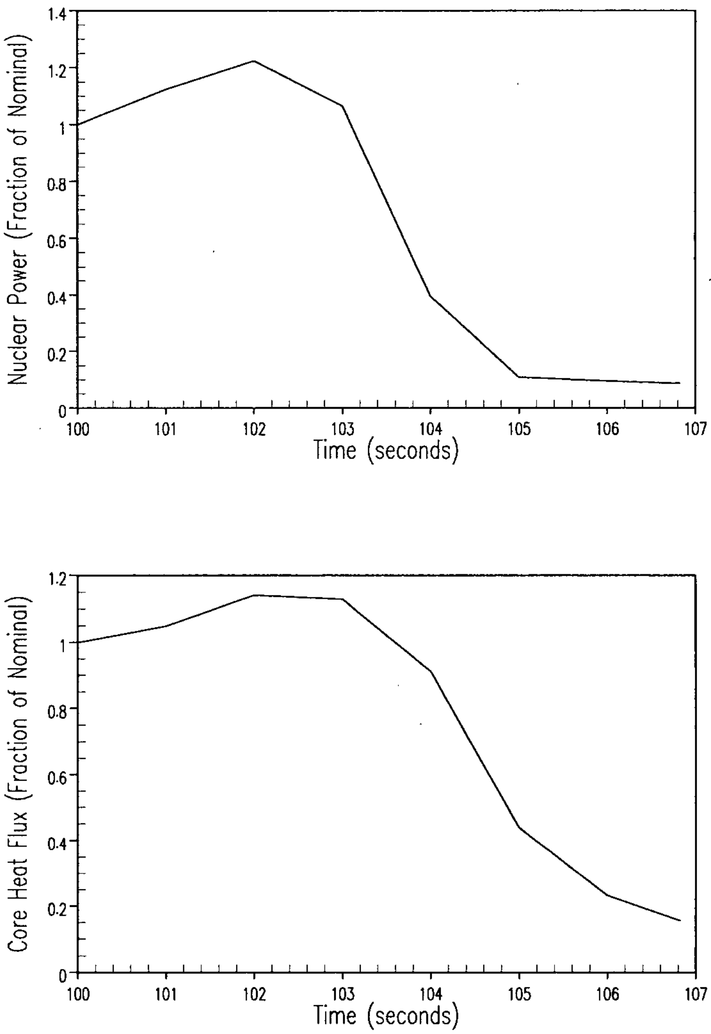
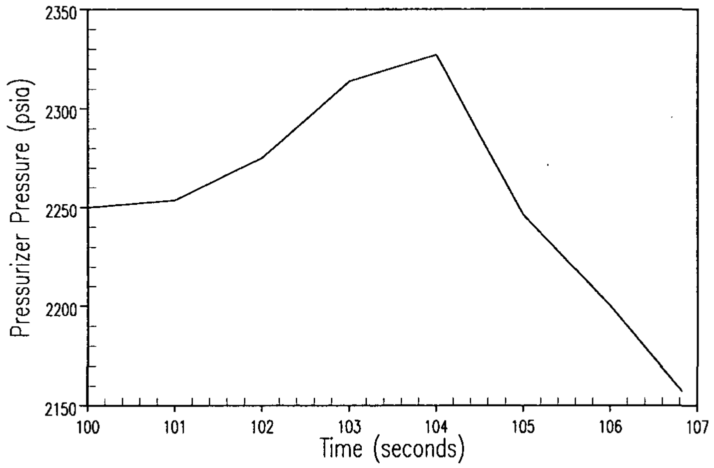


Figure 2.8.5.4.2-11 Unit 2 Rod Withdrawal at Power Minimum Reactivity Feedback – 100% Power - 100 pcm/sec Pressurizer Pressure and Water Volume vs. Time



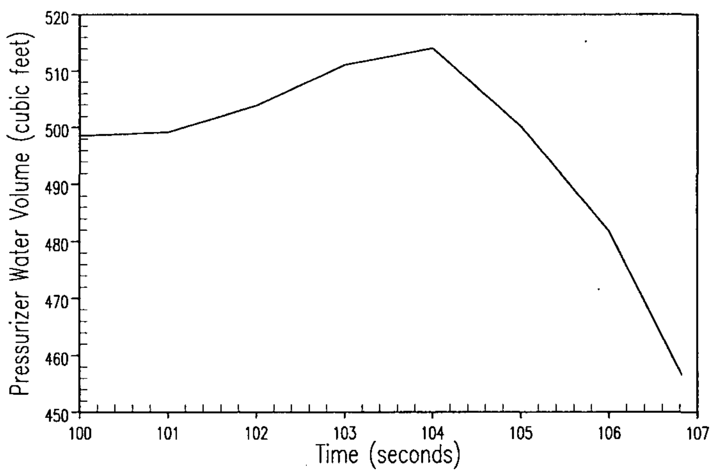


Figure 2.8.5.4.2-12 Unit 2 Rod Withdrawal at Power Minimum Reactivity Feedback – 100% Power - 100 pcm/sec Core Average Temperature and DNBR vs. Time

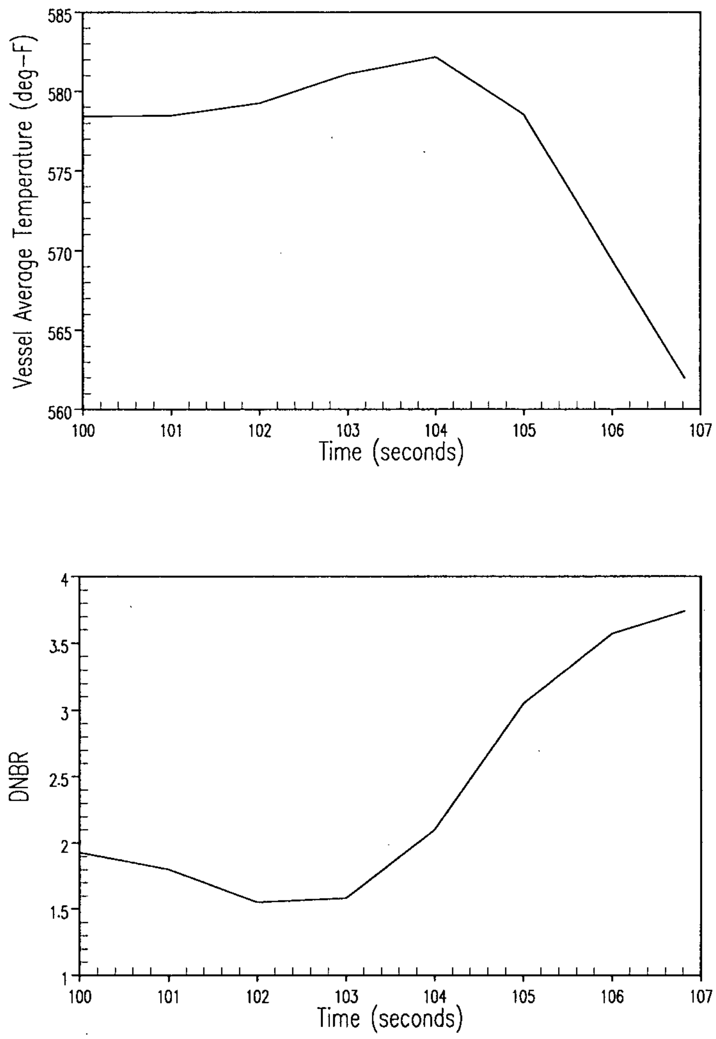
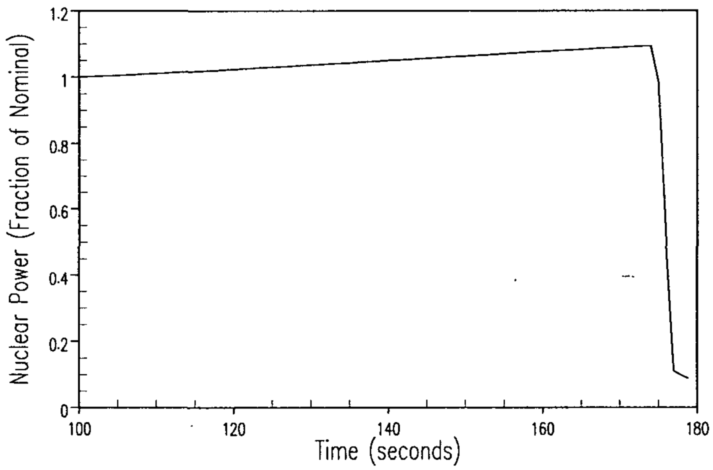


Figure 2.8.5.4.2-13 Unit 2 Rod Withdrawal at Power Minimum Reactivity Feedback – 100% Power - 1 pcm/sec Nuclear Power and Core Heat Flux vs. Time



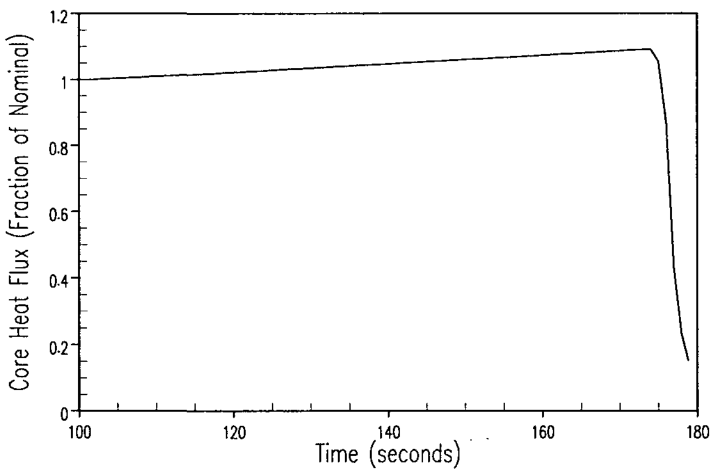
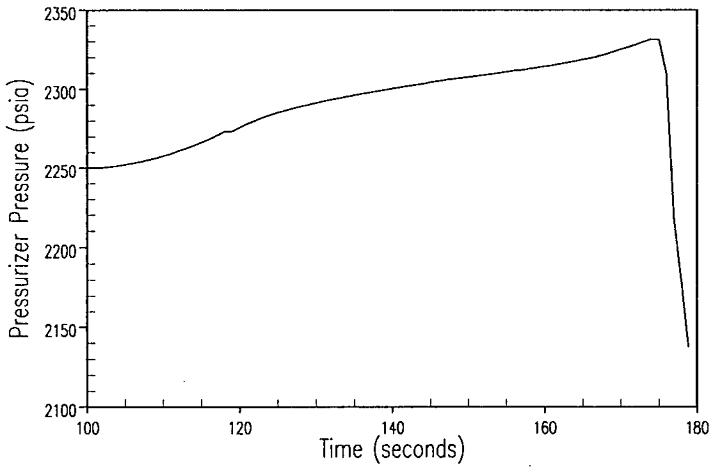


Figure 2.8.5.4.2-14 Unit 2 Rod Withdrawal at Power Minimum Reactivity Feedback – 100% Power - 1 pcm/sec Pressurizer Pressure and Water Volume vs. Time



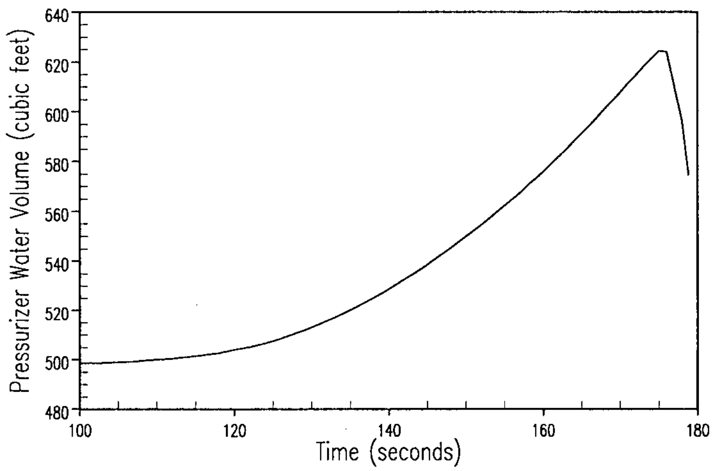
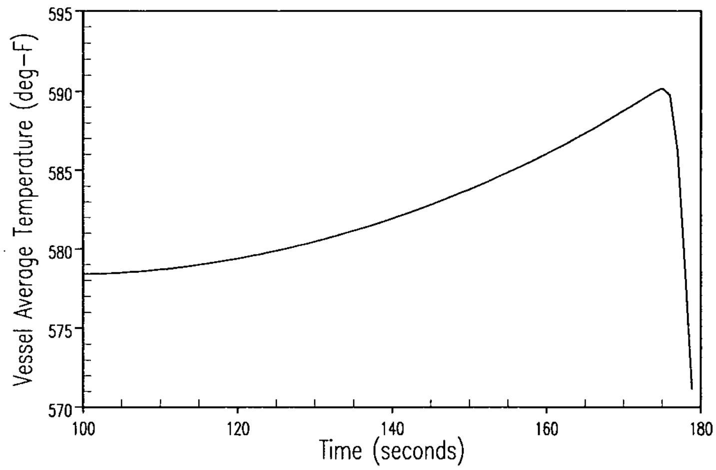


Figure 2.8.5.4.2-15 Unit 2 Rod Withdrawal at Power Minimum Reactivity Feedback – 100% Power - 1 pcm/sec Core Average Temperature and DNBR vs. Time



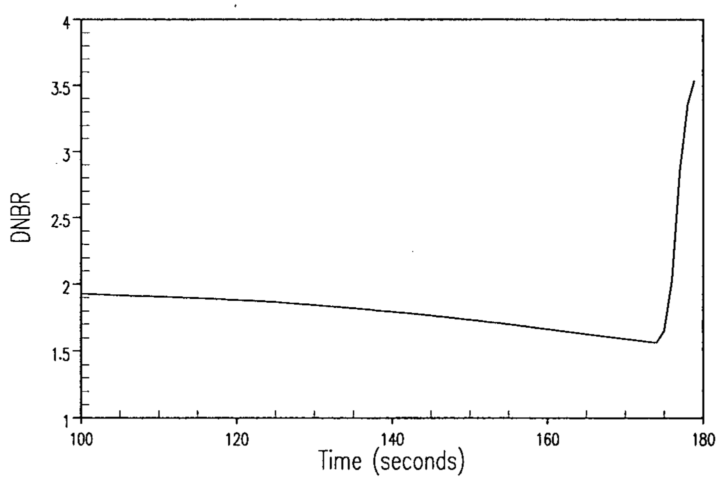


Figure 2.8.5.4.2-16 Unit 2 Rod Withdrawal at Power 100% Power Minimum DNBR vs. Reactivity Insertion Rate

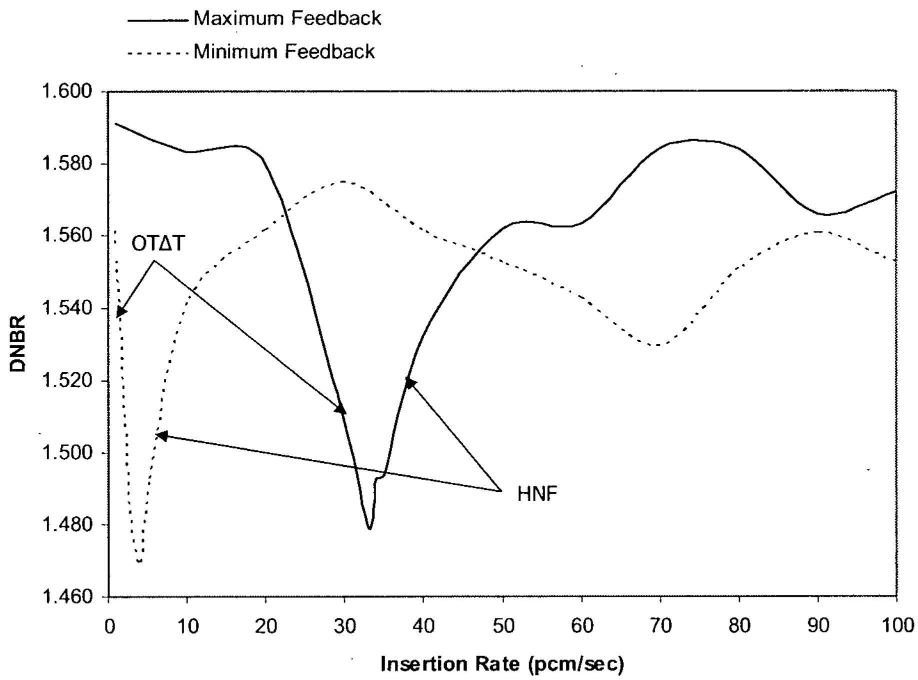


Figure 2.8.5.4.2-17 Unit 2 Rod Withdrawal at Power 60% Power Minimum DNBR vs. Reactivity Insertion Rate

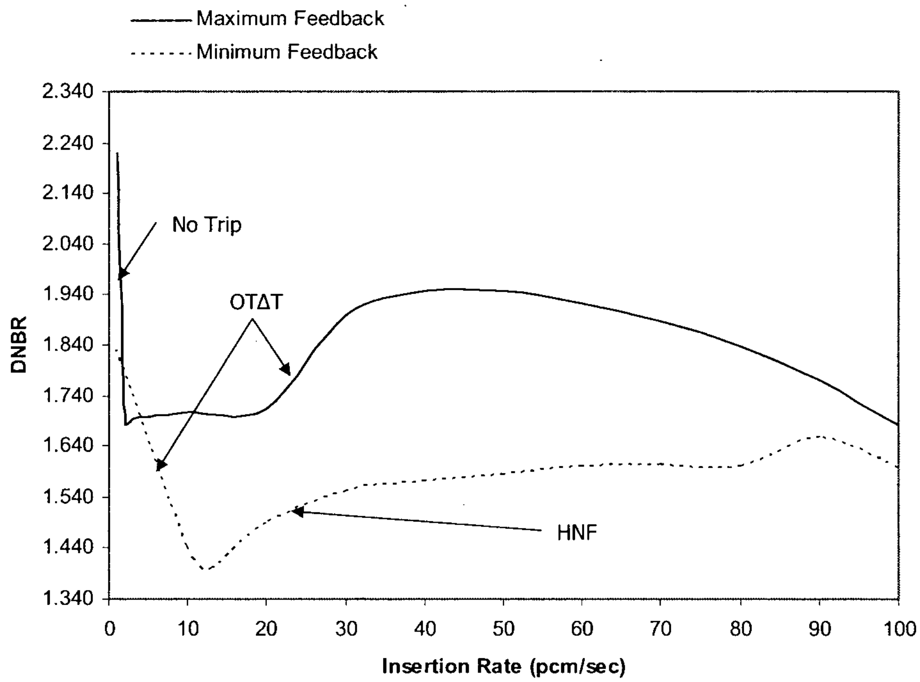
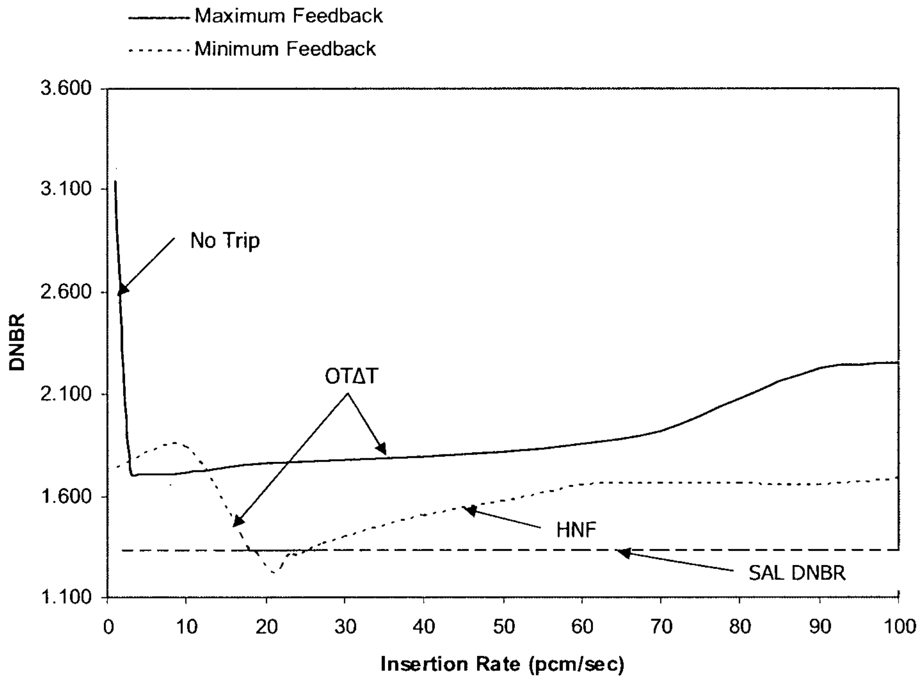


Figure 2.8.5.4.2-18 Unit 2 Rod Withdrawal at Power 10% Power Minimum DNBR vs. Reactivity Insertion Rate



The cases that violate the SAL DNBR limit of 1.337 based upon the RETRAN RW3 DNB model were run with the VIPRE code. The limiting VIPRE-calculated DNBR was 1.344 at an insertion rate of 21 pcm/second.

2.8.5.4.3 Control Rod Misoperation

2.8.5.4.3.1 Regulatory Evaluation

The PBNP review covered the types of control rod misoperations that are assumed to occur, including those caused by a system malfunction or operator error. The review covered:

- The descriptions of rod position, flux, pressure, and temperature indication systems, and those actions initiated by these systems (e.g., turbine runback, rod withdrawal prohibit, rod block) that can mitigate the effects or prevent the occurrence of various misoperations
- The sequence of events
- The analytical model used for analyses
- The important inputs to the calculations
- The results of the analyses

The NRC's acceptance criteria are based on:

- GDC 10, insofar as it requires that the reactor core is designed with appropriate margin to ensure that specified acceptable fuel design limits are not exceeded during any normal operation condition, including the effects of anticipated operational occurrences
- GDC 20, insofar as it requires that the protection system is designed to initiate the reactivity control systems automatically to ensure that acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences and to automatically initiate operation of important-to-safety systems and components under accident conditions
- GDC 25, insofar as it requires that the protection system is designed to ensure that specified acceptable fuel design limits are not exceeded for any single malfunction of the reactivity control systems

Specific review criteria are contained in the SRP Section 15.4.3 and other guidance provided in Matrix 8 of RS-001, Revision 0.

Point Beach Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50, Appendix A, GDC 10, 20 and 25 are as follows:

CRITERION: The reactor core with its related controls and protection systems shall be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits which have been stipulated and justified. The core and related auxiliary system designs shall provide this integrity under all expected conditions of normal operation with appropriate margins for uncertainties and for specified transient situations which can be anticipated. (PBNP GDC 6)

As described in FSAR Section 3.1.2.1, Reactor Core Design, the reactor core, with its related control and protection system, is designed to function throughout its design lifetime without exceeding acceptable fuel damage limits.

Fuel design and nuclear design are futher discussed in LR Section 2.8.1, Fuel System Design, and LR Section 2.8.2, Nuclear Design, respectively.

CRITERION: Core protection systems, together with associated equipment, shall be designed to prevent or to suppress conditions that could result in exceeding acceptable fuel damage limits. (PBNP GDC 14)

If the reactor protection system sensors detect conditions which indicate an approach to unsafe operating conditions that require core protection, the system actuates alarms, prevents control rod motion, initiates load runback, and initiates reactor trip by opening the reactor trip breakers.

The reactor trip system, which provides a protective function to prevent fuel limits from being exceeded, is described in FSAR Section 7.2, Reactor Protection System.

CRITERION: The reactor protection systems shall be capable of protecting against any single malfunction of the reactivity control system, such as unplanned continuous withdrawal (not ejection or dropout) of a control rod, by limiting reactivity transients to avoid exceeding acceptable fuel damage limits. (PBNP GDC 31)

The reactor protection systems are capable of protecting against any single anticipated malfunction of the reactivity control system by limiting reactivity transients so as to avoid exceeding acceptable fuel damage limits.

Reactor shutdown with rods is completely independent of the normal rod control functions since the trip breakers completely interrupt the power to the latch type rod mechanisms regardless of existing control signals.

Details of the effects of continuous withdrawal of a control rod are described in FSAR Section 14.1.1, Uncontrolled Rod Withdrawal from Subcritical, and Section 14.1.2, Uncontrolled Rod Withdrawal at Power. Details of the effects of continuous boron dilution are described in FSAR Section 14.1.4, Chemical and Volume control, System Malfunction.

In addition to the evaluations described in the FSAR, the components of the reactivity control and protection system were evaluated for license renewal. Systems and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 1)

The components of the reactivity control and protection system were evaluated for license renewal.

2.8.5.4.3.2 Technical Evaluation

2.8.5.4.3.2.1 Introduction

The rod cluster control assembly (RCCA) misalignment events include the following:

- One or more dropped RCCAs within the same group
- A dropped RCCA bank
- A statically misaligned RCCA

It should be noted that the rod withdrawal from subcritical and rod withdrawal at Power events are discussed in LR Sections 2.8.5.4.1, Uncontrolled CR Assembly Withdrawal From a Subcritical or Low Power Startup Condition, and 2.8.5.4.2, Rod Withdrawal at Power, respectively.

Each RCCA has a position indicator channel that displays the position of the assembly in a display grouping that is convenient to the operator. Fully inserted RCCAs are also indicated by a rod-at-bottom signal that actuates a control room annunciator. Group demand position is also indicated.

Full-length RCCAs are moved in preselected banks, and the banks are moved in the same preselected sequence. Each control bank of RCCAs is divided into two groups. The rods comprising a group operate in parallel through multiplexing thyristors. The two groups in a bank move sequentially such that the first group is always within one step of the second group in the bank. A definite schedule of actuation (or deactuation of the stationary gripper, movable gripper, and lift coils of a mechanism) is required to withdraw the RCCA attached to the mechanism.

Since the stationary gripper, moveable gripper, and lift coils associated with the four RCCAs of a rod group are driven in parallel, any single failure which would cause rod withdrawal would affect a minimum of one group. Mechanical failures are in the direction of insertion, or immobility.

A dropped RCCA or RCCA bank is detected by one or more of the following:

- Sudden drop in the core power level as seen by the nuclear instrumentation system
- Asymmetric power distribution as seen on out-of-core neutron detectors or core exit thermocouples
- Rod at bottom signal
- Rod deviation alarm
- Rod position indication

Dropping of a full-length RCCA is assumed to be initiated by a single electrical or mechanical failure that causes any number and combination of rods from the same group of a given control bank to drop to the bottom of the core. The resulting negative reactivity insertion causes nuclear power to rapidly decrease. An increase in the hot channel factor can occur due to the skewed power distribution representative of a dropped rod configuration. For this event, it must be shown that the departure from nucleate boiling (DNB) design basis is met for the combination of power, hot channel factor, and other system conditions which exist following a dropped rod.

Misaligned RCCAs are detected by:

- Asymmetric power distribution as seen on out-of-core neutron detectors or core exit thermocouples
- Rod deviation alarm
- Rod position indicators

Per the PBNP Technical Specification Bases, the resolution of each rod position indication channel is 5% of span (11.5 steps). Deviation of any RCCA from its group by 24 steps will not cause power distributions worse than the design limits. The deviation alarm alerts the operator to rod deviation with respect to group demand position in excess of the allowable range. If the rod deviation alarm is not operable, the operator is required to take action as required by the Technical Specifications.

If one or more rod position indication channels is inoperable, detailed instructions are provided to assure the alignment of the associated RCCAs. The operator is also required to take action as required by the Technical Specifications.

2.8.5.4.3.2.2 Input Parameters, Assumptions, and Acceptance Criteria

For evaluation of the dropped rod event, transient system conditions at the limiting point in the transient are calculated. These statepoints are provided for conditions which cover the range of reactivity parameters expected to occur during core life. Nuclear models are used to obtain a hot channel factor consistent with the primary system conditions and reactor power. By combining the primary conditions from the transient and the hot channel factor from the nuclear analysis, an assessment of fuel integrity can be made using standard thermal analysis techniques. The initial conditions for these events are analyzed using the Revised Thermal Design Procedure (RTDP) (Reference 2).

For the statically misaligned RCCA event, steady state calculations are performed to determine the peaking factors resulting from a statically misaligned RCCA. The analysis for this case assumes that the initial reactor power, RCS pressure, and RCS temperature are at nominal values with uncertainties included, and with the increased radial peaking factor associated with the misaligned RCCA.

Based on the frequency of occurrence, the one or more dropped RCCAs from the same group, dropped RCCA bank, and statically misaligned RCCA events are considered Condition II events. The primary acceptance criterion for these events is that the critical heat flux should not be exceeded and that fuel centerline melt is precluded. This is demonstrated by showing that the DNB design basis is met and that the peak kW/ft is below that which would cause fuel centerline melt. An additional criterion cited for RCCA misoperation is that the clad strain limit of 1% is satisfied.

2.8.5.4.3.2.3 Description of Analyses and Evaluations

One or More Dropped RCCAs from the Same Group

The LOFTRAN computer code (Reference 3) calculates transient system responses for the evaluation of a dropped RCCA event. The code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables including temperatures, pressures, and power levels.

Nuclear models are used to obtain a hot channel factor consistent with the primary system conditions (transient system responses) and reactor power. By incorporating the primary conditions from the transient analysis and the hot channel factor from the nuclear analysis, it is shown that the DNB design basis is met using dropped rod limit lines developed with the VIPRE code (Reference 4). The transient response analysis, nuclear peaking factor analysis, and performance of the DNB design basis confirmation are performed in accordance with the approved methodology described in WCAP-11394 (Reference 5).

Dropped RCCA Bank

A dropped RCCA bank results in a symmetric power change in the core. Assumptions made in the methodology for the one or more dropped RCCAs from the same group provide a bounding analysis for the dropped RCCA bank.

Statically Misaligned RCCA

Steady-state power distributions are analyzed using the appropriate nuclear physics computer codes. The peaking factors are then compared to peaking factor limits developed using the VIPRE code, which are based on meeting the DNBR design criterion. The following cases are examined in the analysis assuming the reactor is at full power: the worst rod withdrawn with bank D inserted at the insertion limit, the worst rod dropped with bank D inserted at the insertion limit, and the worst rod dropped with all other rods out. It is assumed that the incident occurs at the time in the cycle with maximum predicted peaking factors. This assures a conservative $F_{\Delta H}$ for the misaligned RCCA configuration.

As required by the SE for PBNP License Amendment 212/217 related to TS 3.1.4 (ML040630436), PBNP has evaluated the RAOC bands for operation at EPU conditions. Although PBNP is requesting implementation of CAOC, the RAOC methodology was also evaluated.

The misaligned rod analysis, which considered the full RAOC operating limits for the EPU, is more conservative than the narrower CAOC operating limits that will be implemented for the EPU. Therefore, the conservatism of the axial shapes in the current misaligned rod analysis remains valid.

Control Rod Drive Mechanisms

It should also be noted that the Control Rod Drive Mechanisms (CRDMs) could affect the misoperation of the control rods. The CRDMs are evaluated in LR Section 2.2.2.4, CRDM and Supports.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

Components of the reactivity control and protection systems that are within the scope of license renewal are electrical and instrumentation and control components that are treated as commodity groups in NUREG-1839 (Reference 1). Aging effects, and the programs used to manage the aging effects of these components are discussed in NUREG-1839, Section 3.6. There are no modifications or additions to system components as a result of the EPU that would introduce any new functions or change the functions of existing components that would affect the license renewal system evaluation boundaries. Operation of the reactivity control and protection systems at EPU conditions does not add any unevaluated aging effects that would necessitate a change to aging management programs or require new programs as internal and external environments remain within the parameters previously evaluated. Therefore, EPU activities associated with control rod misoperation do not impact license renewal scope, aging effects, and aging management programs.

2.8.5.4.3.3 Results

One or More Dropped RCCAs from the Same Group

Single or multiple dropped RCCAs within the same group result in a negative reactivity insertion. The core is not adversely affected during this period since power is decreasing rapidly. Either reactivity feedback or control bank withdrawal will re-establish power. Following a dropped rod event in manual rod control (that is, without control system interaction) the plant will establish a new equilibrium condition. The equilibrium process without control system interaction is monotonic, thus removing power overshoot as a concern, and establishing the automatic rod control mode of operation as the limiting case.

For a dropped RCCA event in the automatic rod control mode, the rod control system detects the drop in power and initiates control bank withdrawal. Power overshoot may occur due to this action by the automatic rod controller, after which the control system will insert the control bank to restore nominal power. Figures 2.8.5.4.3-1 through 2.8.5.4.3-4 show a typical transient response to a dropped RCCA event with the reactor in automatic rod control. In all cases, the minimum DNBR remains above the limit value and the peak fuel centerline temperature remains below a temperature which would result in fuel melt. The Condition II clad strain acceptance criterion is confirmed to be met.

Following plant stabilization, the operator may manually retrieve the RCCA(s) by following approved operating procedures.

Dropped RCCA Bank

A dropped RCCA bank results in a large negative reactivity insertion. The core is not adversely affected during the insertion period since power is decreasing rapidly. The transient will proceed similar to "One or More Dropped RCCAs from the Same Group."

The negative reactivity worth of a dropped RCCA bank is generally larger than that caused by one or more dropped RCCAs from the same group. For this reason the initial power reduction from a dropped RCCA bank (or single RCCA of large worth) is large and the power return due to control rod interaction or reactivity feedback is far less than that seen from one or more dropped RCCAs from the same group. In either instance, the minimum DNBR remains above the limit value and the peak fuel centerline temperature and strain limit are not challenged.

Statically Misaligned RCCA

The most severe RCCA misalignment situations, with respect to DNB at significant power levels, are as follows: (1) one RCCA is fully inserted with either all rods out or bank D at the insertion limit, or (2) where bank D is inserted to the insertion limit and one RCCA is fully withdrawn. Multiple independent alarms, including a bank insertion limit alarm, alert the operator well before the transient approaches the postulated conditions.

The insertion limits in the Technical Specifications may vary from time to time, depending on several limiting criteria. The full-power insertion limits on control bank D are to be above that position which meets the DNBR and peaking factor limits. The full-power insertion limit is usually dictated by other criteria. Detailed results will vary from cycle to cycle depending on fuel arrangements.

For the RCCA misalignment case with one RCCA fully inserted (with either all rods out or bank D at the insertion limit), the DNBR does not fall below the limit value. The analysis for this case assumes that the initial reactor power, RCS pressure, and RCS temperature are at nominal values with uncertainties included, and with the increased radial peaking factor associated with the misaligned RCCA.

Calculations have not been performed specifically for RCCAs missing from other control banks, which are permitted to be either fully or partially inserted at part power conditions. However, it has been determined on a generic basis that the increase in radial peaking factor necessary to reach the DNBR limit at reduced power conditions, is greater than the credible increase in radial peaking factors associated with reduced thermal power levels and deeper permitted control bank insertion. Therefore, the full-power case discussed above with bank D at the insertion limit is more limiting than any credible part power RCCA misalignment scenario involving rods at the insertion limit.

For the RCCA misalignment case with bank D inserted to the full-power insertion limit and one RCCA fully withdrawn, the DNBR does not fall below the limit value. The analysis for this case assumes that the initial reactor power, RCS pressure, and RCS temperature are at nominal values with uncertainties included, and with the increased radial peaking factor associated with the misaligned RCCA.

The DNBR safety analysis limit is not violated for the RCCA misalignment incident. Therefore, there is no reduction in the ability of the primary coolant to remove heat from the fuel rod. The peak fuel temperature corresponds to a linear heat generation rate based on the radial peaking factor penalty associated with the misaligned RCCA and the design axial power distribution. The resulting linear heat generation rate is well below that which would cause fuel melting.

After identifying an RCCA group misalignment condition, the operator must take action as required by the plant Technical Specifications and operating procedures.

2.8.5.4.3.4 Conclusions

PBNP has reviewed the analyses of control rod misoperation events and concludes that the analyses have adequately accounted for the changes in core design required for plant operation at the proposed uprated power level and were performed using acceptable analytical models. PBNP further concludes that the analyses have demonstrated that the reactor protection and safety systems will continue to ensure the specified acceptable fuel design limits will not be exceeded during normal or anticipated operational transients. Based on this, PBNP concludes that the plant will continue to meet the current licensing basis requirements with respect to PBNP, GDC 6, 14 and 31 following implementation of the proposed EPU. Therefore, PBNP finds the proposed EPU acceptable with respect to control rod misoperation events.

2.8.5.4.3.5 References

1. Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

2. WCAP-11397-P-A (Proprietary) and WCAP-11397-A (Nonproprietary), Revised Thermal Design Procedure, April 1989

3. WCAP-7907-P-A (Proprietary) and WCAP-7907-A (Nonproprietary), LOFTRAN Code Description, April 1984

4. WCAP-14565-P-A (Proprietary) and WCAP-15306-NP-A (Nonproprietary), VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis, October 1999

5. WCAP-11394 (Proprietary) and WCAP-11395 (Nonproprietary), Methodology for the Analysis of the Dropped Rod Event, April 1987

6. Safety Evaluation Report Related to Amendment No. 212 to Facility Operating License No. DPR-24 and Amendment No. 217 to Facility Operating License No. DRR-27, dated March 29, 2004

7. WCAP-15432, Conditional Extension of the Rod Misalignment Technical Specification for Point Beach Units 1 and 2, April 2001

Table 2.8.5.4.3-1
Time Sequence of Events – Dropped RCCA without Reactor Trip
500 pcm Bank Worth, 100 pcm Drop Rod Worth, 0 MTC Case

Event	**Time (seconds)**
Initiation of the event	0.0
Dropped RCCA falls to bottom of core	1.0
Control bank withdrawal begins	1.3
Peak core heat flux (power overshoot) occurs (1.15 frac. of nominal)	40.0
Control bank insertion begins	41.0
Return to (near) initial power conditions	~130.0

Table 2.8.5.4.3-2
Time Sequence of Events – Dropped RCCA with Reactor Trip
500 pcm Bank Worth, 700 pcm Drop Rod Worth, 0 MTC Case

Event	**Time (seconds)**
Initiation of the event	0.0
Dropped RCCA falls to bottom of core	1.0
Control bank withdrawal begins	1.3
Reactor trip signal reached	32.7
Rods begin to fall	34.7
Peak core heat flux occurs (prior to reactor trip) (0.59 frac. of nominal)	35.0

Table 2.8.5.4.3-3
Results for RCCA Misalignment

Case	Nuclear Hot Channel Factor $F_{\Delta H}^{N} = F_{\Delta H} + \text{Uncertainty}$	Minimum DNBR (SAL DNBR)
RCCA Misalignment Accident	1.95	> 1.38

Figure 2.8.5.4.3-1 Control Rod Misoperation Nuclear Power versus Time

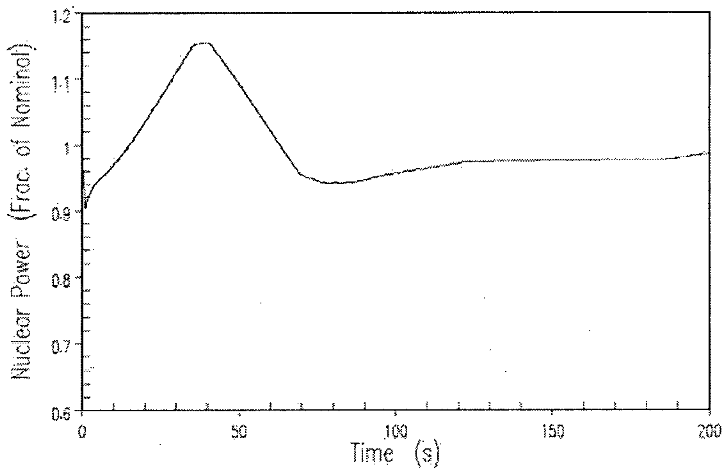


Figure 2.8.5.4.3-2 Control Rod Misoperation Core Heat Flux versus Time

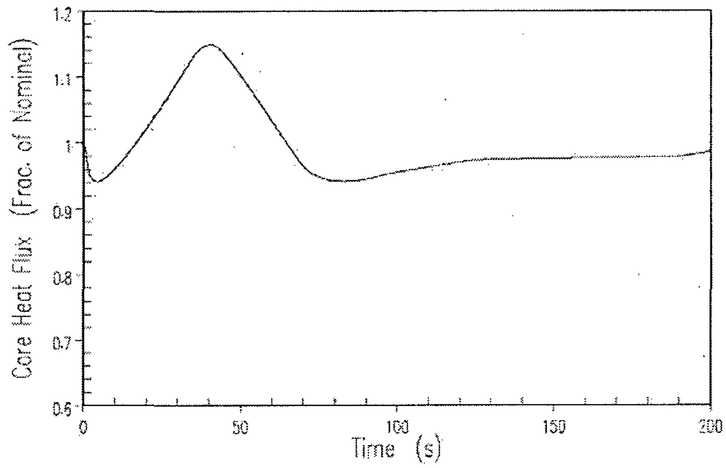


Figure 2.8.5.4.3-3 Control Rod Misoperation Pressurizer Pressure versus Time

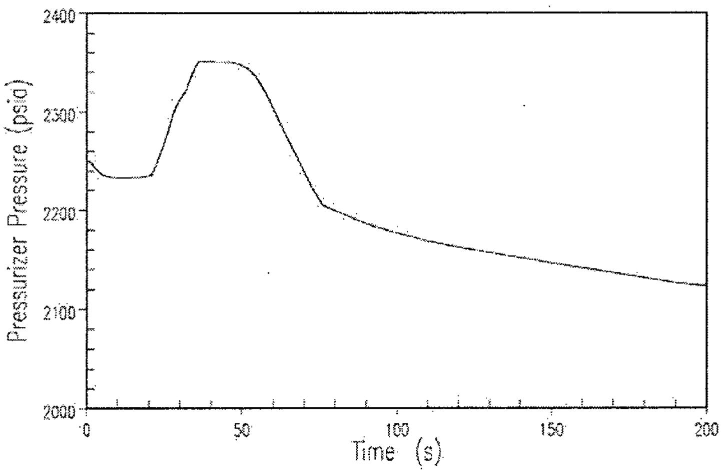
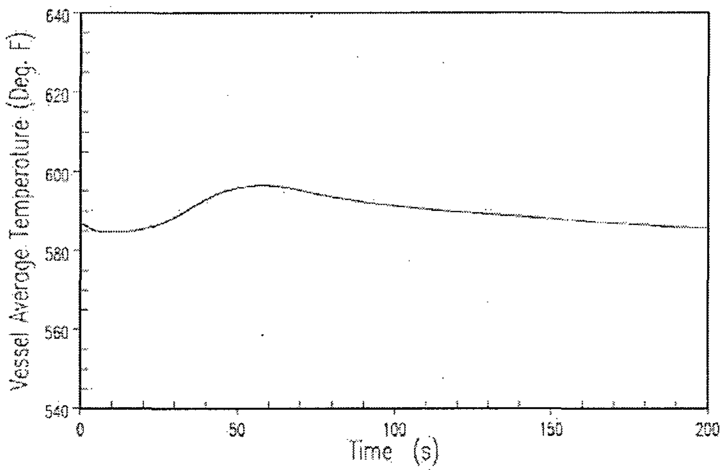


Figure 2.8.5.4.3-4 Control Rod Misoperation Vessel Average Temperature versus Time



2.8.5.4.4 Startup of an Inactive Loop at an Incorrect Temperature

2.8.5.4.4.1 Regulatory Evaluation

A startup of an inactive loop transient can result in either an increased core flow or the introduction of cooler or deborated water into the core. This event causes an increase in core reactivity due to decreased moderator temperature or moderator boron concentration. The PBNP review covered:

- The sequence of events
- The analytical model
- The values of parameters used in the analytical model
- The results of the transient analyses.

The NRC's acceptance criteria are based on:

- GDC 10, insofar as it requires that the reactor coolant system (RCS) is designed with appropriate margin to ensure that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences
- GDC 15, insofar as it requires that the RCS and its associated auxiliary systems are designed with sufficient margin to ensure that the design conditions of the reactor coolant pressure boundary are not exceeded during anticipated operational occurrences
- GDC 20, insofar as it requires that the protection system is designed to automatically initiate the operation of appropriate systems to ensure that specified acceptable fuel design limits are not exceeded as a result of operational occurrences
- GDC 26, insofar as it requires that a reactivity control system is provided and be capable of reliably controlling the rate of reactivity changes to ensure that under normal operating conditions, including anticipated operational occurrences, specified acceptable fuel design limits are not exceeded
- GDC 28, insofar as it requires that the reactivity control systems are designed to ensure that the effects of postulated reactivity accidents can neither result in damage to the reactor coolant pressure boundary greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to significantly impair the capability to cool the core

Specific review criteria are contained in SRP Section 15.4.4-5 and other guidance provided in Matrix 8 of RS-001, Revision 0.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP, GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50, Appendix A, GDC 10, 15, 20. 26 and 28 are as follows:

CRITERION: The reactor core with its related controls and protection systems shall be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits which have been stipulated and justified. The core and related auxiliary system designs shall provide this integrity under all expected conditions of normal operation with appropriate margins for uncertainties and for specified transient situations which can be anticipated. (PBNP GDC 6)

CRITERION: The reactor coolant pressure boundary shall be designed, fabricated, and constructed so as to have an exceedingly low probability of gross rupture or significant uncontrolled leakage throughout its design lifetime. (PBNP GDC 9)

CRITERION: Core protection systems, together with associated equipment, shall be designed to prevent or to suppress conditions that could result in exceeding acceptable fuel damage limits. (PBNP GDC 14)

CRITERION: Two independent reactivity control systems, preferably of different principles, shall be provided. (PBNP GDC 27)

CRITERION: Limits, which include reasonable margin, shall be placed on the maximum reactivity worth of control rods or elements and on rates at which reactivity can be increased to ensure that the potential effects of a sudden or large change of reactivity cannot (a) rupture the reactor coolant pressure boundary or (b) disrupt the core, its support structures, or other vessel internals sufficiently to lose capability of cooling the core. (PBNP GDC 32)

The components of the reactivity control and protection system were evaluated for license renewal. Systems and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- License Renewal Safety Evaluation Report for the Point Beach Nuclear Plant Units 1 and 2 (NUREG-1839), dated December 2005 (Reference 1)

2.8.5.4.4.2 Technical Evaluation

The PBNP Technical Specifications (TS) do not allow the reactor to go critical with only one reactor coolant pump in operation (Reference 2). Therefore, an analysis of this event was determined not to be necessary for 422V+ fuel. The discussion presented in FSAR Section 14.1.5, Startup of An Inactive Reactor Coolant Loop, corresponds to an analysis previously performed assuming a nominal initial power level of 10% and has been retained for historical purposes.

2.8.5.4.4.3 Conclusions

PBNP has reviewed the inactive-loop-startup event and concludes that the plant will continue to meet the requirements of PBNP, GDC 6, 9, 14, 27 and 32 following implementation of the proposed EPU. Therefore, PBNP finds the proposed EPU acceptable with respect to improper startup of an inactive reactor coolant loop at an incorrect temperature.

2.8.5.4.4.4 References

1. Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

2. PBNP Technical Specification 3.4.4 RCS Loops - MODES 1 and 2

2.8.5.4.5 Chemical and Volume Control System Malfunction

2.8.5.4.5.1 Regulatory Evaluation

Unborated water can be added to the reactor coolant system (RCS) via the chemical and volume control system (CVCS). This may happen inadvertently because of operator error or CVCS malfunction and cause an unwanted increase in reactivity and a decrease in shutdown margin. The operator should stop this unplanned dilution before the shutdown margin is eliminated. The PBNP review covered:

- The conditions at the time of the unplanned dilution
- The causes
- The initiating events
- The sequence of events
- The analytical model used for analyses
- The values of parameters used in the analytical model
- The results of the analyses

The NRC's acceptance criteria are based on:

- General Design Criterion (GDC) 10, as it relates to the reactor core and its coolant, control, and protection systems with appropriate design margin to assure that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences
- GDC 15, as it relates to the RCS and its auxiliary, control, and protection systems with sufficient design margin to assure that the design conditions of the reactor coolant pressure boundary (RCPB) are not exceeded during any condition of normal operation, including anticipated operational occurrences
- GDC 26, as it relates to the capability of control rods to reliably control reactivity changes to assure that under conditions of normal operation, including anticipated operational occurrences (AOOs), and with appropriate margin for malfunctions like stuck rods, specified acceptable fuel design limits are not exceeded

Specific review criteria are contained in the SRP, Section 15.4.6, and other guidance provided in Matrix 8 of RS-001, Revision 0.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

Specifically, to the PBNP equivalent GDC for 10 CFR 50, Appendix A, GDC 10, 15, and 26 are as follows:

CRITERION: The reactor core with its related controls and protection systems shall be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits which have been stipulated and justified. The core and related auxiliary system designs shall provide this integrity under all expected conditions of normal operation with appropriate margins for uncertainties and for specified transient situations which can be anticipated. (PBNP GDC 6)

As described in FSAR Section 3.1.2.1, Reactor Core Design, the reactor core, with its related control and protection system, is designed to function throughout its design lifetime without exceeding acceptable fuel damage limits.

Fuel design and nuclear design are further discussed in LR Section 2.8.1, Fuel System Design and LR Section 2.8.2, Nuclear Design, respectively.

CRITERION: The reactor coolant pressure boundary shall be designed, fabricated, and constructed so as to have an exceedingly low probability of gross rupture or significant uncontrolled leakage throughout its design lifetime. (PBNP GDC 9)

As described in FSAR Section 4.1, Reactor Coolant System, Design Basis, the Reactor Coolant System, in conjunction with its control and protective provisions, is designed to accommodate the system pressures and temperatures attained under all expected modes of plant operation or anticipated system interactions, and maintain the stresses within applicable code stress limits.

System conditions resulting from anticipated transients or malfunctions are monitored and appropriate action is automatically initiated to maintain the required cooling capability and to limit system conditions to a safe level. The system is protected from overpressure by means of pressure relieving devices, as required by Section III of the ASME Boiler and Pressure Vessel Code. The system is also protected from overpressure at low temperatures by the Low Temperature Overpressure Protection System.

CRITERION: One of the reactivity control systems provided shall be capable of making the core subcritical under any anticipated operating condition (including anticipated operational transients) sufficiently fast to prevent exceeding acceptable fuel damage limits. Shutdown margin should assure subcriticality with the most reactive control rod fully withdrawn. (PBNP GDC 29)

The reactor core, together with the reactor control and protection system, is designed so that the minimum allowable DNBR is at least equal to the limits specified for STD, OFA, upgraded OFA, and 422V+ fuel, and there is no fuel melting during normal operation, including anticipated transients.

The shutdown groups are provided to supplement the control group of RCCAs to make the reactor at least 1% subcritical ($k_{eff} = 0.99$) following a trip from any credible operating condition to the hot, zero power condition assuming the most reactive RCCA remains in the fully withdrawn position.

CRITERION: The reactivity control systems provided shall be capable of making the core subcritical under credible accident conditions with appropriate margins for contingencies and limiting any subsequent return to power such that there will be no undue risk to the health and safety of the public. (PBNP GDC 30)

Normal reactivity shutdown capability is provided by control rods, with boric acid injection from the CVCS system used to compensate for xenon transients, and for plant cooldown. When the plant is at power, the quantity of boric acid retained in the boric acid tanks and/or the refueling water storage tank (RWST) and ready for injection will always exceed that quantity required for a normal cold shutdown. This quantity will always exceed the quantity of boric acid required to bring the reactor to hot shutdown and to compensate for subsequent xenon decay.

The injection of boric acid is shown to afford backup reactivity shutdown capability, independent of control rod clusters which normally serve this function in the short term situation. Shutdown for long term and reduced temperature conditions can be accomplished with boric acid injection using redundant components.

The reactivity control provided by the CVCS is further discussed in FSAR Section 9.3, Chemical and Volume Control System. The analysis of a CVCS malfunction (boron dilution) event is discussed in FSAR Section 14.1.4, Chemical and Volume Control System Malfunction.

In addition to the evaluations described in the FSAR, the components of the reactivity control and protection system were evaluated for license renewal. Systems and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 1)

Components of the reactivity control and protection systems are within the scope of license renewal.

2.8.5.4.5.1.1 Technical Evaluation

2.8.5.4.5.1.2 Introduction

Positive reactivity can be added to the core with the CVCS by feeding reactor makeup water into the RCS via the reactor makeup control system. Boron dilution is a manual operation. The normal dilution procedures at Point Beach Nuclear Plant (PBNP) call for a limit on the rate and magnitude for any individual dilution, under strict administrative controls. A boric acid blend system is provided to permit the operator to match the boron concentration of reactor coolant makeup water to that existing in the coolant at the time. The CVCS is designed to limit, even under various postulated failure modes, the potential rate of dilution to a value which, after indication through alarms and instrumentation, provides the operator sufficient time to correct the situation in a safe and orderly manner.

2.8.5.4.5.1.3 Input Parameters, Assumptions, and Acceptance Criteria

The most limiting credible source of reactor makeup water to the reactor coolant system is from the reactor makeup water storage tank using the reactor makeup water pumps. Dilution via this pathway can be readily terminated by isolating this source.

The rate of addition of unborated makeup water to the RCS is limited to the capacity of the CVCS charging pumps and FCV-111, Reactor Makeup Water to Boric Acid Blender Flow Control Valve. Normally one charging pump is operating in manual mode and one pump is operating in the automatic mode, responding to pressurizer level changes. The boric acid from the boric acid tank is blended with the reactor makeup water in the blender and the composition is determined by the preset flow rates of boric acid and reactor makeup water on the reactor makeup control system. Two separate operations are required. First, the operator must switch from the automatic makeup mode to the dilute mode. Then the start button must be depressed. Omitting either step would prevent dilution. This makes the possibility of an inadvertent dilution very small.

Information on the status of the reactor coolant makeup is continuously available to the operator. Lights are provided on the control board to indicate the operating condition of pumps in the CVCS. Alarms are actuated to warn the operator if boric acid or demineralized water flow rates deviate from preset values as a result of a system malfunction. An additional alarm is available to warn the operator of a potential dilution condition.

A CVCS malfunction during refueling, cold shutdown, startup, and power operation are considered in this analysis.

A CVCS malfunction is classified as an ANS Condition II event, a fault of moderate frequency. Criteria established for Condition II events are as follows:

- The critical heat flux should not be exceeded. This is met by demonstrating that the minimum DNBR does not go below the limit value at any time during the transient
- Pressures in the RCS and main steam system (MSS) should be maintained below 110% of the design pressures
- Fuel temperature and fuel clad strain limits should not be exceeded. The peak linear heat generation rate should not exceed a value that would cause fuel centerline melt

This event is analyzed to show that there is sufficient time for mitigation of an inadvertent boron dilution prior to the complete loss of shutdown margin. A complete loss of plant shutdown margin results in a return of the core to the critical condition causing an increase in the RCS temperature and heat flux. This could violate the safety analysis limit DNBR value and challenge the fuel and fuel cladding integrity. A complete loss of plant shutdown margin could also result in a return of the core to the critical condition causing an increase in RCS pressure. This could challenge the pressure design limit for the RCS.

If the minimum allowable shutdown margin is shown not to be lost, the condition of the plant at any point in the transient is within the bounds of those calculated for other Condition II transients. By showing that the above criteria are met for those Condition II events, it can be concluded that they are also met for the boron dilution event. Operator action is relied upon to preclude a complete loss of plant shutdown margin.

The specific acceptance criterion applied for these events is that adequate operator action time is available prior to a complete loss of shutdown margin. For CVCS malfunction events in MODES 1, 2 and 5, there must be at least 15 minutes from the time that an alarm or trip setpoint is reached until shutdown margin is lost. For CVCS malfunction events in MODE 6, there must be at least 30 minutes from event initiation until shutdown margin is lost. With shutdown margin maintained, there is no return to criticality and no violation of the 95/95 DNBR limit (PBNP GDC 6 and 29), as well as no violation of the primary and secondary pressures limits (PBNP GDC 9). Furthermore, since a return to criticality is precluded and fuel design limits are not exceeded, the PBNP requirements with respect to PBNP, GDC 30 are met.

2.8.5.4.5.1.4 Description of Analyses and Evaluations

Dilution During MODE 6 (Refueling)

The analysis of the boron dilution event in MODE 6 assumes a maximum dilution flow rate of 121 gpm (two CVCS charging pumps). An active RCS volume of approximately 1884 ft^3 is assumed. The volume is calculated taking into account that the Residual Heat Removal (RHR) system is in operation and therefore the volume associated with the steam generators is not modeled. Also, it is assumed that the RCS is drained to the mid-plane of the reactor vessel nozzles. From the initiation of the event, there are more than 30 minutes available for operator action prior to the complete loss of shutdown margin.

Dilution During MODE 5 (Cold Shutdown)

This analysis was performed to determine the required boron concentration necessary to prevent a complete loss of shutdown margin from an inadvertent boron dilution event with a reduced RCS volume for a duration of 15 minutes.

The analysis used a conservative RCS volume by assuming that the RCS is drained to the mid-plane of the nozzles (1884 ft^3). The RCS volume when drained to the mid-plane of the nozzles is the smallest volume that can result from any allowable scenario while in Cold Shutdown. Mixing of the diluting water (boron free) and the RCS water was assumed to take place in the vessel inlet nozzle which then proceeds in a "wave front fashion" through the rest of the RCS. A maximum RCS temperature of 200°F is assumed and a minimum temperature is assumed for the dilutant. The dilution flow rate is conservatively increased to compensate for the density differences.

These calculations determine what boron concentration is required to ensure that the operator has 15 minutes to identify and terminate the boron dilution prior to a complete loss of shutdown margin. The calculations cover one, two or three charging pumps in operation and RHR flow rates up to approximately 6000 gpm. The results of the analysis are presented in Figure 2.8.5.4.5-1 and in Table 2.8.5.4.5-2, CVCS Malfunction Boron Dilution Event in MODE 5 (Cold Shutdown) Results.

To use Figure 2.8.5.4.5-1 and/or Table 2.8.5.4.5-2, the following steps are followed:

1. Determine the current or minimum intended RHR flow rate

2. Determine the maximum dilution flow rate (based on the number of operable charging pumps).

3. Use Figure 2.8.5.4.5-1 or Table 2.8.5.4.5-2 to find DLF = f(RHR flow rate, dilution flow rate)

4. Determine the Critical Boron Concentration (C_{bc})

5. Calculate the required minimum boron concentration (C_{bi}) – where $C_{bi} = C_{bc}/DLF$

6. Ensure that the RCS boron concentration is $\geq C_{bi}$. An alternate approach is to further limit the maximum possible dilution flow rate.

7. For RHR flow rates greater than 6000 gpm, DLF at 6000 gpm should be used.

Dilution During MODE 2 (Startup)

Prior to refueling, the reactor coolant system is filled with borated water from the refueling water storage tank. Core monitoring is by external BF_3 detectors. Mixing of reactor coolant is accomplished by operation of the reactor coolant pumps. The maximum dilution flow (181.5 gpm or three CVCS charging pumps) is considered. The volume of reactor coolant is approximately 5035 ft^3, which is the volume of the RCS excluding the pressurizer. The volume is calculated taking into account a steam generator tube plugging of 10%. High source level and all reactor trip alarms are effective.

The minimum time required to reduce the reactor coolant boron concentration from 1800 to 1600 ppm, where shutdown margin could be lost with all rods at the insertion limits, is greater than 15 minutes. There is adequate time for operator action due to the high count rate signal, and termination of dilution flow.

Dilution During MODE 1 (At Power)

In this mode, the plant can be operated in either automatic or manual rod control. The analysis assumes a maximum dilution flow rate of 181.5 gpm (three CVCS charging pumps). An active RCS volume of approximately 5035 ft^3 is assumed. The analysis conservatively addresses a full power T_{avg} range of 558°F to 577°F.

With the reactor in automatic rod control, the power and temperature increase from the boron dilution results in insertion of the control rods and a decrease in available shutdown margin. The rod insertion limit alarms (low and low-low settings) alert the operator at least 15 minutes prior to a complete loss of shutdown margin. This is sufficient time to determine the cause of the dilution and isolate the reactor makeup water source before the available shutdown margin is lost.

With the reactor in manual control and no operator action taken to terminate the transient, the power and temperature rise cause the reactor to reach the power range high neutron flux trip setpoint or the overtemperature ΔT trip setpoint, resulting in a reactor trip. The boron dilution transient in this case is essentially equivalent to an uncontrolled RCCA bank withdrawal at power. The maximum reactivity insertion rate for a boron dilution is conservatively 0.9 pcm/sec, which is within the range of insertion rates analyzed for the uncontrolled RCCA bank withdrawal at power. Therefore, the effects of the dilution prior to reactor trip are bounded by the uncontrolled RCCA bank withdrawal at power analysis (LR Section 2.8.5.4.2, Rod Withdrawal at Power). Following reactor trip, there are more than 15 minutes prior to a complete loss of shutdown margin. There is adequate time for the operator to determine the cause of the dilution and isolate the reactor makeup water source before the available shutdown margin is lost.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

Components of the reactivity control and protection systems that are within the scope of license renewal are electrical and instrumentation and control components that are treated as commodity groups in NUREG-1839. Aging effects and the programs used to manage the aging effects of these components are discussed in NUREG-1839, Section 3.6 (Reference 1). There are no modifications or additions to system components as the result of the EPU that would introduce any new functions or change the functions of existing components that would affect the license renewal system evaluation boundaries. Operation of the reactivity control and protection systems at EPU conditions does not add any unevaluated aging effects that would necessitate a change to aging management programs or require new programs, as internal and external environments remain within the parameters previously evaluated. Therefore, EPU activities associated with a CVCS malfunction do not impact license renewal scope, aging effects, and aging management programs.

2.8.5.4.5.2 Results

If an unintentional dilution of boron in the RCS does occur, numerous alarms and indications are available to alert the operator to the condition. The maximum reactivity addition due to the dilution is slow enough to allow the operator sufficient time to determine the cause of the dilution and take corrective action before shutdown margin is lost.

The boron dilution analysis demonstrated that all applicable acceptance criteria are met at EPU conditions. This means that operator action to terminate the dilution flow is within 15 minutes from the time that an alarm or trip setpoint is reached in MODE 1, MODE 2 and MODE 5 and within 30 minutes from event initiation in MODE 6, which precludes a complete loss of shutdown margin. The results of the boron dilution analysis are provided in Table 2.8.5.4.5-1, CVCS Malfunction Boron Dilution Event Results, and Table 2.8.5.4.5-2, CVCS Malfunction Boron Dilution Event in MODE 5 (Cold Shutdown) Results.

2.8.5.4.5.3 Conclusions

PBNP has reviewed the analyses of the decrease in boron concentration in the reactor coolant due to a CVCS malfunction, and concludes that the analyses have adequately accounted for plant operation at the proposed power level and were performed using acceptable analytical models. PBNP further concludes that the analyses have demonstrated that the reactor protection and safety systems will continue to ensure that the specified acceptable fuel design limits and the reactor coolant pressure boundary pressure limits will not be exceeded as a result of this event. Based on this, PBNP concludes that the plant will continue to meet the current licensing basis requirements with respect to PBNP, GDC 6, 9, 29, and 30 following implementation of the proposed EPU. Therefore, PBNP finds the proposed EPU acceptable with respect to the decrease in boron concentration in the reactor coolant due to a CVCS malfunction.

2.8.5.4.5.4 References

1. Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

Table 2.8.5.4.5-1
CVCS Malfunction Boron Dilution Event Results

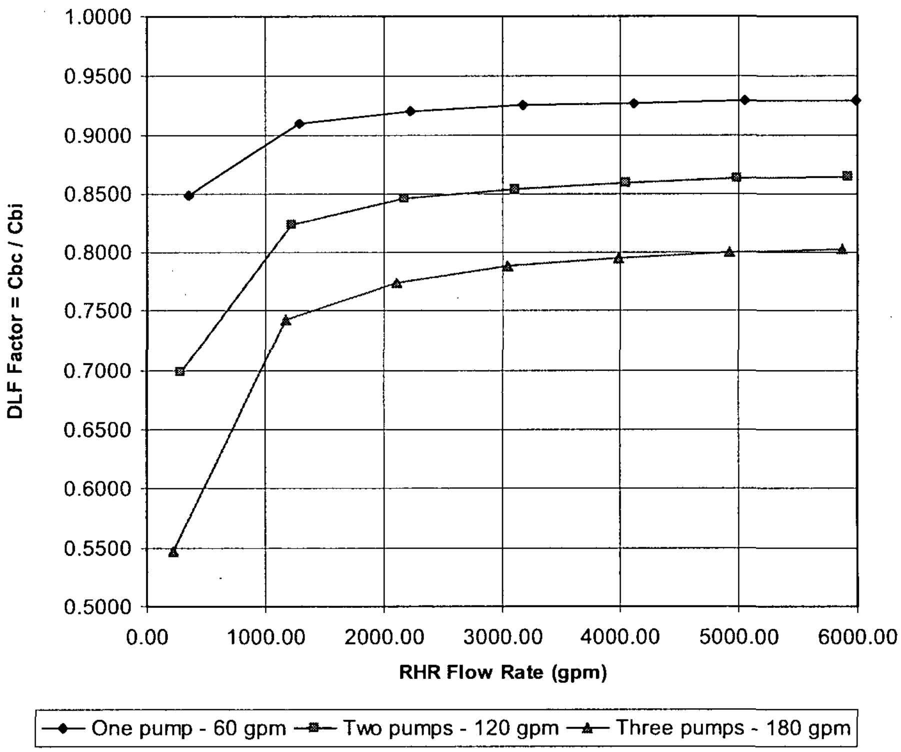
Case *	EPU Analysis (min)	Previous Analysis (min)	Limit (min)
Available Time in MODE 1 – Automatic Rod Control	17.6	19.1	15
Available Time in MODE 1 – Manual Rod Control	15.1	18.2	15
Available Time in MODE 2	18.2	18.3	15
Available Time in MODE 6	31.1	32.6	30

* For each case, the initial boron concentration and the critical boron concentration are verified on a cycle specific basis. The available times provided for MIODES 1 and 2 are from the time that an alarm or trip setpoint is reached to the time of a complete loss of shutdown margin; the time from event initiation to a complete loss of shutdown margin is presented for MODE 6.

Table 2.8.5.4.5-2
CVCS Malfunction Boron Dilution Event in MODE 5 (Cold Shutdown) Results

One Pump - 60 gpm		Two Pumps - 120 gpm		Three pumps - 180 gpm	
RHR Flow (gpm)	DLF	RHR Flow (gpm)	DLF	RHR Flow (gpm)	DLF
360.	0.849	290.	0.698	230.	0.547
1300.	0.910	1230.	0.824	1170.	0.742
2230.	0.920	2170.	0.845	2110.	0.774
3170.	0.925	3110.	0.854	3050.	0.787
4110.	0.927	4050.	0.859	3990.	0.795
5050.	0.929	4990.	0.862	4930.	0.799
5990.	0.930	5930.	0.864	5870.	0.802

Figure 2.8.5.4.5-1 Ratio of the Initial Boron Concentration to the Critical Concentration as a function of RHR Flow Rate (in MODE 5)



2.8.5.4.6 Spectrum of Rod Ejection Accidents

2.8.5.4.6.1 Regulatory Evaluation

Control rod ejection accidents cause a rapid positive reactivity insertion together with an adverse core power distribution, which could lead to localized fuel rod damage. PBNP evaluated the consequences of a control rod ejection accident to determine the potential damage caused to the reactor coolant pressure boundary and to determine whether the fuel damage resulting from such an accident could impair cooling water flow. PBNP's review covered:

- The initial conditions
- The rod patterns and worths, scram worth as a function of time, and reactivity coefficients
- The analytical model
- The core parameters that affect the peak reactor pressure or the probability of fuel rod failure
- The results of the transient analyses

The NRC's acceptance criteria are based on:

- GDC 28, insofar as it requires that the reactivity control systems are designed to assure that the effects of postulated reactivity accidents can neither result in damage to the reactor coolant pressure boundary greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to significantly impair the capability to cool the core.

Specific review criteria are contained in the SRP Section 15.4.8 and other guidance provided in Matrix 8 of RS-001, Revision 0.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP, GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP specific GDC equivalent to the 10 CFR 50, Appendix A, GDC above for the spectrum of Rod Ejection Accidents is as follows:

CRITERION: Limits, which include reasonable margin, shall be placed on the maximum reactivity worth of control rods or elements and on rates at which reactivity can be increased to ensure that the potential effects of a sudden or large change of reactivity cannot (a) rupture the reactor coolant pressure boundary or (b) disrupt the core, its support structures, or other vessel internals sufficiently to lose capability of cooling the core. (PBNP GDC 32)

Additional information is provided in FSAR Section 3.1, Reactor, Design Basis and Section 14.2.6, Rupture of a Control Rod Mechanism Housing – RCCA Ejection.

In addition to the evaluations described in the FSAR, the components of the reactivity control and protection system were evaluated for license renewal. Systems and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 1)

The rod ejection analyses are not in the scope of license renewal.

2.8.5.4.6.2 Technical Evaluation

The criterion applied by Westinghouse to ensure the core remains in a coolable geometry following a rod ejection incident is that the average fuel pellet enthalpy at the hot spot must remain less than 200 cal/g (360 Btu/lbm). The use of the initial conditions presented in Table 2.8.5.4.6-1, Parameters and Results of the Limiting RCCA Ejection Analysis, resulted in conservative calculations of the fuel pellet enthalpy.

Overpressurization of the RCS during a rod ejection event is generically addressed in WCAP-7588, Revision 1-A. (Reference 2)

Another applicable acceptance criterion is that fuel melting must be limited to less than the innermost ten percent of the fuel pellet at the hot spot, even if the average fuel pellet enthalpy at the hot spot is less than the limit of 360 Btu/lbm. Conservative fuel melt temperatures of 4900°F and 4800°F are assumed for the hot spot for the BOL and EOL cases, respectively.

2.8.5.4.6.2.1 Introduction

This accident is defined as a mechanical failure of a control rod drive mechanism pressure housing resulting in the ejection of the rod cluster control assembly (RCCA) and drive shaft. The consequence of this mechanical failure is a rapid positive reactivity insertion together with an adverse core power distribution, possibly leading to localized fuel rod damage. The resultant core thermal power excursion is limited by the doppler reactivity effect of the increased fuel temperature and terminated by reactor trip actuated by high nuclear power signals.

A failure of a control rod mechanism housing sufficient to allow a control rod to be rapidly ejected from the core is not considered credible for the following reasons:

- Each control rod drive mechanism housing is completely assembled and shop-tested at 3105 psig
- Stress levels in the mechanism are not affected by system transients at power, or by the thermal movement of the coolant loops. Moments induced by the design earthquake can be accepted within the allowable primary working stress range specified in the ASME Code, Section III, for Class I components
- The latch mechanism housing and rod travel housing are Grade F316 stainless steel. This material exhibits excellent notch toughness at all temperatures that will be encountered. The joints between the latch mechanism housing and head adapter, and between the latch mechanism housing and rod travel housing, are fabricated with full penetration welds

A significant margin of strength in the elastic range, together with the large energy absorption capability in the plastic range, gives additional assurance that the gross failure of the housing will not occur.

In general, the reactor is operated with the rod cluster control assemblies inserted only far enough to control design neutron flux shape. Reactivity changes caused by the core depletion are compensated by boron changes. Further, the location and grouping of control rod banks are selected during the nuclear design to lessen the severity of a rod cluster control assembly ejection accident. Therefore, should a rod cluster control assembly be ejected from its normal position during full-power operation, minor reactivity excursion, could be expected to occur. The position of all rod cluster control assemblies is continuously indicated in the control room. An alarm will occur if a bank of rod cluster control assemblies approaches its insertion limit or if one control rod assembly deviated from its bank. There are low and low-low level insertion alarm circuits for each control bank. The control rod position monitoring and alarm systems are described in Reference 2.

2.8.5.4.6.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Input parameters for the analysis are conservatively selected on the basis of values calculated for this type of core. The most important parameters are discussed below. Table 2.8.5.4.6-1, Parameters and Results of the Limiting RCCA Ejection Analysis, presents the parameters used in this analysis.

Ejected Rod Worths and Hot Channel Factors (F_Q)

The values for ejected rod worths and hot channel factors are calculated using either three-dimensional static methods or a synthesis of one-dimensional and two-dimensional calculations. Standard nuclear design codes are used in the analysis. No credit is taken for the flux-flattening effects of reactivity feedback. The calculation is performed for the maximum allowed bank insertion at a given power level, as determined by the rod insertion limits. The analysis assumes adverse xenon distributions to provide worst-case results.

Appropriate margins are added to the ejected rod worth and hot channel factors to account for any calculational uncertainties.

Delayed Neutron Fraction, β

The ejected rod accident is sensitive to β if the ejected rod worth is equal to or greater than β_{eff}, as in the zero-power transients. In order to allow for future fuel cycle flexibility, conservative estimates of β of 0.49% at beginning of cycle and 0.43% at end of cycle are used in the analysis.

Reactivity Weighting Factor

The largest temperature rises, and the largest reactivity feedbacks, occur in channels where the power is higher than average. Since the weight of a region is dependent on flux, these regions have high weights. This means that the reactivity feedback is larger than that indicated by a simple single-channel analysis. Physics calculations have been performed for temperature changes with a flat temperature distribution and with a large number of axial and radial temperature distributions. Reactivity changes were compared and effective weighting factors determined. These weighting factors take the form of multipliers which, when applied to single-channel feedbacks, correct them to effective whole-core feedbacks for the appropriate flux shape. In this analysis, a one-dimensional (axial) spatial kinetics method is employed, thus axial weighting is not necessary if the initial condition is made to match the ejected rod configuration. In addition, no weighting is applied to the moderator feedback. A conservative radial weighting factor is applied to the transient fuel temperature to obtain an effective fuel temperature as a function of time accounting for the missing spatial dimension. These weighting factors have also been shown to be conservative compared to three-dimensional analysis.

Moderator and Doppler Coefficient

The critical boron concentrations at the beginning of cycle and end of cycle are adjusted in the nuclear code in order to obtain moderator density coefficient curves which are conservative when compared to the actual design conditions for the plant. As discussed above, no weighting factor is applied to these results. The resulting moderator temperature coefficient is at least +5 pcm/°F at the appropriate zero-power nominal average temperature for the beginning-of-cycle cases.

The doppler reactivity defect is determined as a function of power level using a one-dimensional steady-state computer code with a doppler weighting factor of 1.0. The doppler weighting factor will increase under accident conditions, as discussed above.

Heat Transfer Data

The FACTRAN code (Reference 3), used to determine the hot spot transient, contains standard curves of thermal conductivity versus fuel temperature. During a transient, the peak centerline fuel temperature is independent of the gap conductances during the transient. The cladding temperature is, however, strongly dependent on the gap conductance and is highest for high gap conductances. For conservatism a high gap heat transfer coefficient value of 10,000 Btu/hr-ft^2-°F has been used during transients. This value corresponds to a negligible gap resistance and a further increase would have essentially no effect on the rate of heat transfer.

Coolant Mass Flow Rates

When the core is operating at full power, both coolant pumps will always be operating. For zero power conditions, the system is conservatively assumed to be operating with one pump. The principal effect of operating at reduced flow is to reduce the film boiling heat transfer coefficient. This results in higher peak cladding temperatures, but does not affect the peak centerline fuel temperature. Reduced flow also lowers the critical heat flux. However, since DNB is always assumed at the hot spot, and since the heat flux rises very rapidly during the transient, this produces only second order changes in the cladding and centerline fuel temperatures.

Trip Reactivity Insertion

The trip reactivity insertion is assumed to be 4.0% Δk from hot full power and 2.0% Δk from hot zero power, including the effect of one stuck RCCA. These values are also reduced by the ejected rod. The shutdown reactivity is simulated by dropping a rod of the required worth into the core. The start of rod motion occurs 0.5 seconds after reaching the power range high neutron flux trip setpoint. It is assumed that insertion to dashpot does not occur until 2.2 seconds after the rods begin to fall. The time delay to full insertion, combined with the 0.5 second trip delay, conservatively delays insertion of shutdown reactivity into the core.

Acceptance Criteria

Due to the extremely low probability of a rod cluster control assembly ejection accident, this event is classified as an ANS Condition IV event. As such, some fuel damage could be considered an acceptable consequence.

Comprehensive studies of the threshold of fuel failure and of the threshold of significant conversion of the fuel thermal energy to mechanical energy have been carried out as part of the SPERT project by the Idaho Nuclear Corporation (Reference 6). Extensive tests of UO_2 zirconium-clad fuel rods representative of those present in pressurized water reactor-type cores have demonstrated failure thresholds in the range of 240 to 257 cal/gm. However, other rods of a slightly different design exhibited failure as low as 225 cal/gm. These results differ significantly from the TREAT (Reference 7) results that indicated a failure threshold of 280 cal/gm. Limited results have indicated that this threshold decreased 10% with fuel burnup. The clad failure mechanism appears to be melting for unirradiated (zero burnup) rods and brittle fracture for irradiated rods. The conversion ratio of thermal to mechanical energy is also important. This ratio becomes marginally detectable above 300 cal/gm for unirradiated rods and 200 cal/gm for irradiated rods; catastrophic failure (large fuel dispersal, large pressure rise), even for irradiated rods, did not occur below 300 cal/gm.

The real physical limits of this accident are that the rod ejection event and any consequential damage to either the core or the reactor coolant system must not prevent long-term core cooling and that the radiological consequences conform to the dose methodology. More-specific and restrictive criteria are applied to ensure fuel dispersal in the coolant, gross lattice distortion or severe shock waves will not occur. In view of the above experimental results, and the conclusions of WCAP-7588, Rev. 1-A (Reference 2) and Reference 8, the limiting criteria are:

- Average fuel pellet enthalpy at the hot spot must be maintained below 225 cal/gm for unirradiated and 200 cal/gm (360 Btu/lbm) for irradiated fuel. For this analysis, the 200 cal/gm (360 Btu/lbm) limit is applied for both unirradiated and irradiated fuel
- Peak reactor coolant pressure must be less than that which could cause RCS stresses to exceed the faulted-condition stress limits (note: the peak pressure aspects of the Rod Ejection transient are addressed generically in Reference 2)
- Fuel melting is limited to less than 10% of the pellet volume at the hot spot even if the average fuel pellet enthalpy is below the 360 Btu/lbm fuel enthalpy limit

2.8.5.4.6.2.3 Description of Analyses and Evaluations

This section describes the models used in the analysis of the rod ejection accident. Only the initial few seconds of the power transient are discussed, since the long term considerations are the same as for a small loss of coolant accident.

The calculation of the RCCA ejection transient is performed in two stages, first an average core channel calculation and then a hot region calculation. The average core calculation uses spatial neutron-kinetics methods to determine the average power generation with time including the various total core feedback effects; i.e., doppler reactivity and moderator reactivity. Enthalpy and temperature transients at the hot spot are then determined by multiplying the average core energy generation by the hot channel factor and performing a fuel rod transient heat transfer calculation. The power distribution calculated without feedback is conservatively assumed to persist throughout the transient. A detailed discussion of the method of analysis can be found in Reference 2.

Average Core

The spatial-kinetics computer code, TWINKLE (Reference 4) is used for the average core transient analysis. This code solves the two-group neutron diffusion theory kinetic equation in one, two or three spatial dimensions (rectangular coordinates) for six delayed neutron groups and up to 8000 spatial points. The computer code includes a detailed multi-region, transient fuel-clad-coolant heat transfer model for calculation of pointwise doppler and moderator feedback effects. This analysis uses the code as a one-dimensional axial kinetics code since it allows a more-realistic representation of the spatial effects of axial moderator feedback and RCCA movement. However, since the radial dimension is missing, it is still necessary to employ very conservative methods (described below) of calculating the ejected rod worth and hot channel factor.

Hot Spot Analysis

In the hot spot analysis, the initial heat flux is equal to the nominal times the design hot channel factor. During the transient, the hot channel factor is linearly increased from the steady-state to the transient value in 0.1 second, the time for full ejection of the rod. The assumption is made that the hot spot before and after ejection are coincident. This is very conservative since the peak after ejection will occur in or adjacent to the assembly with the ejected rod, and prior to ejection the power in this region will necessarily be depressed.

The average core energy addition, calculated as described above, is multiplied by the appropriate hot channel factors. The hot spot analysis uses the detailed fuel and clad transient heat transfer computer code, FACTRAN (Reference 3). This computer code calculates the transient temperature distribution in a cross section of a metal clad UO_2 fuel rod, and the heat flux at the surface of the rod, using the nuclear power versus time and local coolant conditions as input. The zirconium-water reaction is explicitly represented, and all material properties are represented as functions of temperature. A parabolic radial power distribution is assumed within the fuel rod.

FACTRAN uses the Dittus-Boelter or Jens-Lottes correlation to determine the film heat transfer before DNB, and the Bishop-Sandberg-Tong correlation (Reference 5) to determine the film boiling coefficient after DNB. The Bishop-Sandberg-Tong correlation is conservatively used assuming zero bulk fluid quality. The DNB heat flux is not calculated, instead the code is forced into DNB by specifying a conservative DNB heat flux. The gap heat transfer coefficient can be calculated by the code; however, it is adjusted to force the full-power, steady-state temperature distribution to agree with fuel heat transfer design codes.

Reactor Protection

The protection for this accident, as explicitly modeled in the analysis, is provided by the power range high neutron flux trip (high and low settings).

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

Components of the reactivity control and protection systems that are within the scope of license renewal are electrical and instrumentation and control components that are treated as commodity groups in NUREG-1839 (Reference 1). Aging effects and the programs used to manage the aging effects of these components are discussed in NUREG-1839, Section 3.6. There are no modifications or additions to system components as the result of EPU that would introduce any new functions or change the functions of existing components that would affect the license renewal system evaluation boundaries. Operation of the reactivity control and protection systems at EPU conditions does not add any new types of materials or previously unevaluated aging effects that would necessitate a change to aging management programs or require new programs, as internal and external environments remain within the parameters previously evaluated. Therefore, EPU activities associated with rod ejection do not impact license renewal scope, aging effects, and aging management programs.

2.8.5.4.6.3 Results

The results of the analyses performed for the rod ejection event, which cover beginning and end-of-cycle conditions at hot full power and hot zero power, are discussed below.

Beginning of Cycle, Zero Power

The worst ejected rod worth and hot channel factor are conservatively calculated to be 0.79% ΔK and 11.0, respectively. The peak hot spot average fuel pellet enthalpy reached 150.5 cal/gm (270.9 Btu/lbm). The peak fuel centerline temperature never reaches the BOC melt temperature of 4900°F, so no fuel melting is predicted. The EPU analysis used input parameters similar to the existing analysis of record, with the exception of those parameters specifically changed by the EPU. Consistent with expectations, the results of the BOC HZP rod ejection became more severe at the EPU conditions, but still meet the applicable acceptance criteria.

Beginning of Cycle, Full Power

Control bank D is assumed to be inserted to its insertion limit. The worst ejected rod worth and hot channel factor are conservatively calculated to be 0.40% ΔK and 4.2, respectively. The peak hot spot average fuel pellet enthalpy reached 174.1 cal/gm (313.3 Btu/lbm). The peak fuel centerline temperature reached the BOC melt temperature of 4900°F; however, fuel melting remains well below the limiting criterion of 10% of total pellet volume at the hot spot. The BOC HFP case previously modeled an overly conservative isothermal temperature coefficient (ITC). The BOC HFP case analyzed for the EPU incorporated an ITC consistent with full power operation, which more than compensated for the EPU impact.

End of Cycle, Zero Power

The worst ejected rod worth and hot channel factor are conservatively calculated to be 0.93% ΔK and 18.0, respectively. The peak hot spot average fuel pellet enthalpy reached 161.0 cal/gm (289.8 Btu/lbm). The peak fuel centerline temperature never reaches the EOC melt temperature of 4800°F, so no fuel melting is predicted. An increased doppler power defect compensated for much of the EPU impact, resulting in only a small overall impact on the EOC HZP results. Considering the input changes, the results are consistent with expectations.

End of Cycle, Full Power

Control bank D is assumed to be inserted to its insertion limit. The ejected rod worth and hot channel factors are conservatively calculated to be 0.42% ΔK and 5.69 respectively. The peak hot spot average fuel pellet enthalpy reached 176.4 cal/gm (317.6 Btu/lbm). The peak fuel centerline temperature reached melting, conservatively assumed at 4800°F; however, fuel melting remains below the limiting criterion of 10% of the pellet volume at the hot spot. Based solely on the EPU, the EOC HFP results would be expected to be more limiting than the previous analysis. An increase in the doppler power defect served to limit the impact of the EPU to a slight change, as anticipated.

A summary of the parameters used in the rod ejection analyses, and the analyses results, are presented in Table 2.8.5.4.6-1, Parameters and Results of the Limiting RCCA Ejection Analysis. The sequence of events for all four cases are presented in Table 2.8.5.4.6-2, Time Sequence of Events – RCCA Ejection. Figure 2.8.5.4.6-1 shows the transient curves for the BOC HZP case; Figure 2.8.5.4.6-2 shows the transient curves for the EOC HZP case. Figure 2.8.5.4.6-3 shows the transient curves for the BOC HFP case; Figure 2.8.5.4.6-4 shows the transient curves for the EOC HFP case.

Pressure Surge

A detailed calculation of the pressure surge for an ejected rod worth of one dollar at beginning of cycle, hot full power, indicates that the peak pressure does not exceed that which would cause reactor pressure vessel stress to exceed the faulted condition stress limits (Reference 2). Since the severity of the present analysis does not exceed the "worst-case" analysis (Reference 2), the accident for this plant will not result in an excessive pressure rise or further adverse effects to the RCS.

Summary of Results

Despite the conservative assumptions, the analyses indicate that the described fuel and clad limits are not exceeded. It is concluded that there is no danger of sudden fuel dispersal into the coolant. Since the peak pressure does not exceed that which would cause stresses to exceed the faulted condition stress limits, it is concluded that there is no danger of further consequential damage to the RCS. Generic analyses demonstrate that the fission product release as a result of fuel rods entering DNB is limited to less than 10% of the fuel rods in the core.

The results and conclusions of the analyses performed for the rupture of a control rod drive mechanism housing rod cluster control assembly ejection support operation up to the EPU core power of 1800 MWt, plus uncertainties.

2.8.5.4.6.4 Conclusions

PBNP has reviewed the analyses of the rod ejection accident and concludes that the analyses have adequately accounted for plant operation at the proposed power level and were performed using acceptable analytical models. PBNP further concludes that the analyses have demonstrated that appropriate reactor protection and safety systems will prevent postulated reactivity accidents that could result in damage to the reactor coolant pressure boundary greater than limited local yielding, or cause sufficient damage that would significantly impair the capability to cool the core. Based on this, PBNP concludes that the plant will continue to meet the PBNP current licensing basis requirements with respect to PBNP GDC 32 following implementation of the proposed EPU. Therefore, PBNP finds the proposed EPU acceptable with respect to the rod ejection accident.

2.8.5.4.6.5 References

1. Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

2. Risher, D. H., An Evaluation of the Rod Ejection Accident in Westinghouse Pressurized Water Reactors using Special Kinetics Methods, WCAP-7588; Rev. 1-A, January 1975

3. Hargrove, H. G., FACTRAN, A FORTRAN IV Code for Thermal Transients in a UO2 Fuel Rod, WCAP-7908-A, December 1989

4. Barry, R. F., and Risher, D. H., TWINKLE - A Multi-Dimensional Neutron Kinetics Computer Code, WCAP-7979-P-A, January 1975 (Proprietary) and WCAP-8028-A, January 1975 (Non-Proprietary)

5. Bishop, A. A., Sandberg, R. O. and Tong, L. S., Forced Convection Heat Transfer at High Pressure After the Critical Heat Flux, ASME 65-HT-31, August 1965

6. Taxebius, T.G., ed., Annual Report – SPERT Project, October 1968 – September 1969, IN-1370 Idaho Nuclear Corporation, June 1970

7. Liimatainen, R.C. and Testa, F.J., Studies in TREAT of Zircaloy 2-Clad, UO2-Core Simulated Fuel Elements, ANL-7225, p. 177, November 1966

8. Letter from WEC to NRC, Letter Number NS-NRC-89-3466, Use of 2700°F PCT Acceptance Limit in Non-LOCA Accidents, October 23, 1989

Table 2.8.5.4.6-1
Parameters and Results of the Limiting RCCA Ejection Analysis

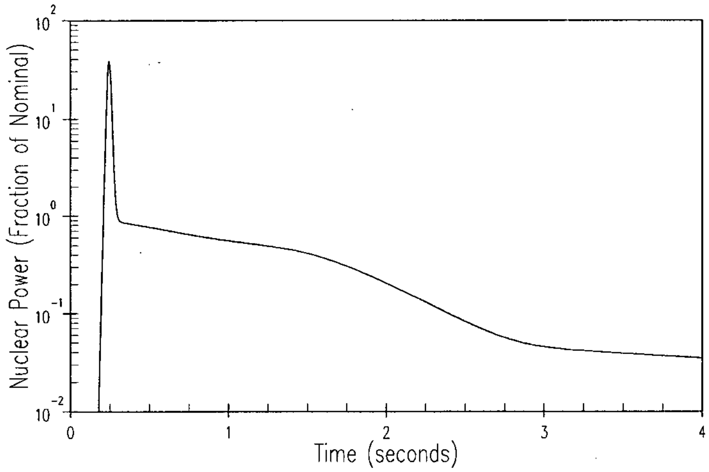
Input Parameters				
	Beginning of Cycle	**Beginning of Cycle**	**End of Cycle**	**End of Cycle**
	Hot Full Power	Hot Zero Power	Hot Full Power	Hot Zero Power
Initial core power level, percent of 1800 MWt	102%	0%	102%	0%
Ejected rod worth, % ΔK	0.40	0.79	0.42	0.93
Delayed neutron fraction, %	0.49	0.49	0.43	0.43
Feedback reactivity weighting	1.139	2.008	1.316	2.704
Trip reactivity, % ΔK	4.0	2.0	4.0	2.0
F_Q before rod ejection	2.60	--	2.60	--
F_Q after rod ejection	4.2	11.0	5.69	18.0
Number of operational RCPs	2	1	2	1

Analysis Results					
	Beginning of Cycle	**Beginning of Cycle**	**End of Cycle**	**End of Cycle**	**Limit**
	Hot Full Power	Hot Zero Power	Hot Full Power	Hot Zero Power	
Max fuel pellet average temperature, °F	3995	3538	4041	3742	NA
Max fuel centerline temperature, °F	>4900	3959	>4800	4075	NA
Max fuel stored energy, cal/g	174.1	150.5	176.4	161.0	200.
Fuel melt at the hot spot, %	5.63	0	9.79	0	10.

Table 2.8.5.4.6-2
Time Sequence of Events – RCCA Ejection

Event	Time (sec)	
	BOC HFP	**EOC HFP**
Initiation of Rod Ejection	0.0	0.0
Power Range High Neutron Flux Setpoint Reached	0.03	0.02
Peak Nuclear Power Occurs	0.13	0.13
Rods Begin to Fall	0.53	0.52
Peak Fuel Average Temperature Occurs	1.90	1.98
Peak Clad Temperature Occurs	2.06	2.11
	BOC HZP	**EOC HZP**
Initiation of Rod Ejection	0.0	0.0
Power Range High Neutron Flux Setpoint Reached	0.20	0.15
Peak Nuclear Power Occurs	0.24	0.18
Rods Begin to Fall	0.70	0.65
Peak Clad Temperature Occurs	2.02	1.50
Peak Fuel Average Temperature Occurs	2.16	1.65

Figure 2.8.5.4.6-1 Rod Ejection – Beginning of Cycle/Hot Zero Power Case



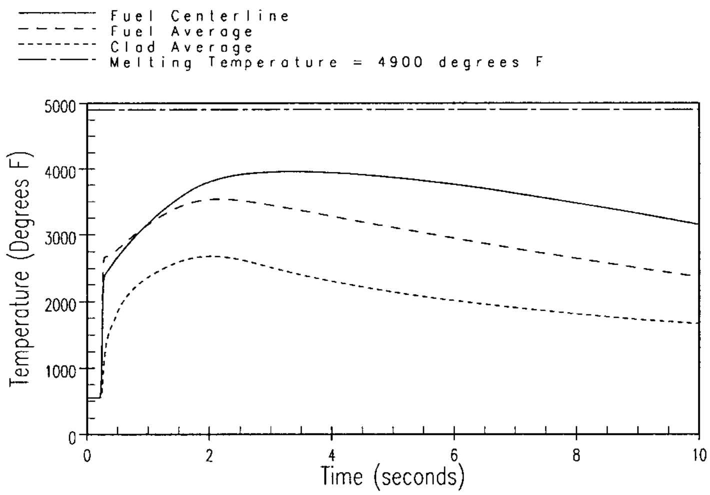
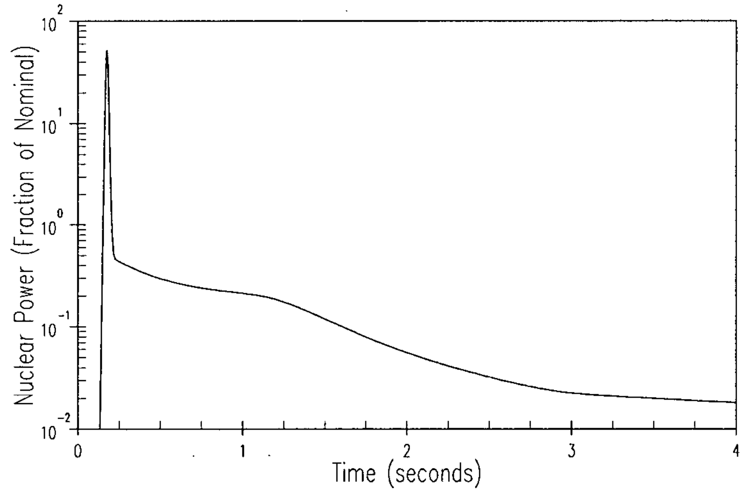


Figure 2.8.5.4.6-2 Rod Ejection – End of Cycle/Hot Zero Power Case



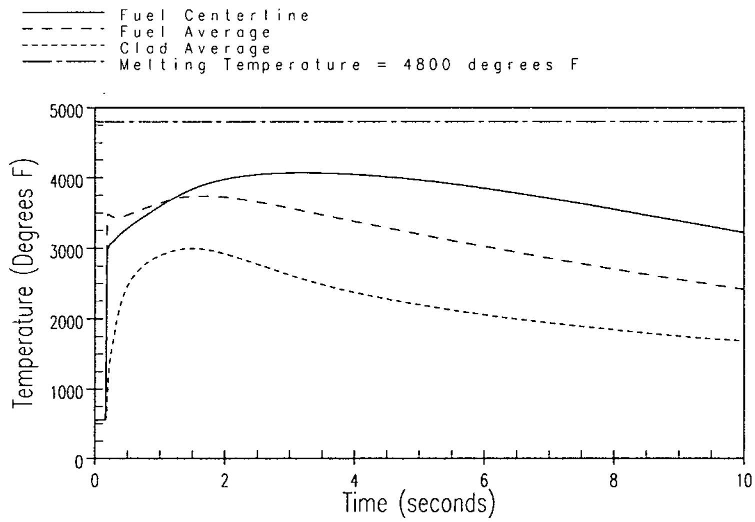
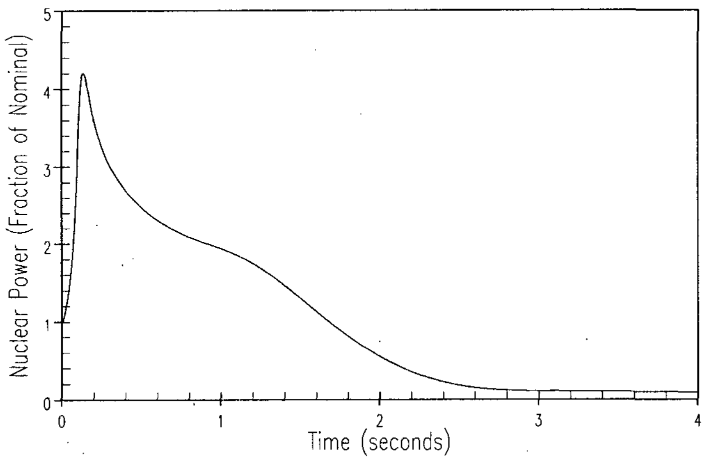


Figure 2.8.5.4.6-3 Rod Ejection – Beginning of Cycle/Hot Full Power Case



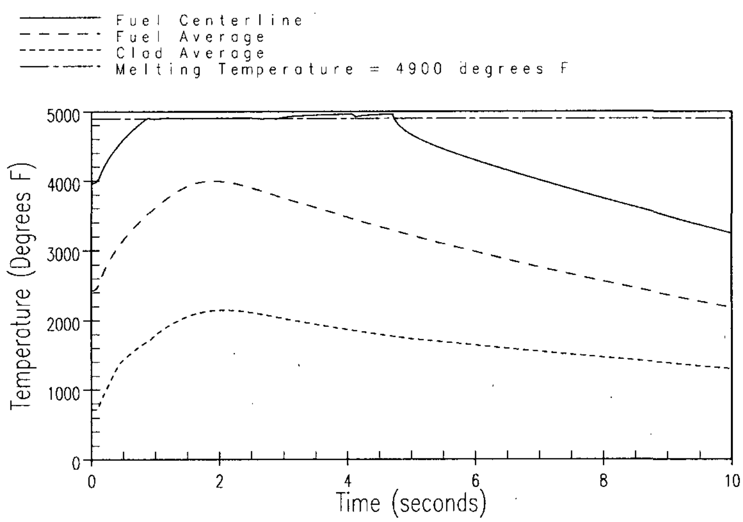
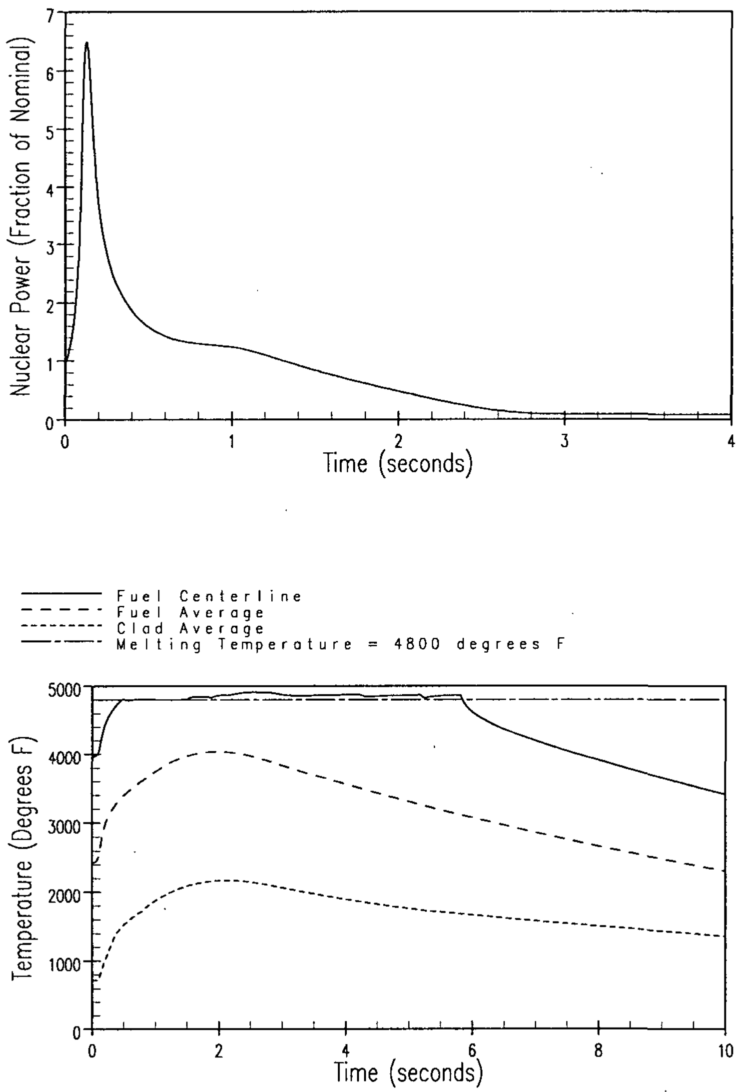


Figure 2.8.5.4.6-4 Rod Ejection – End of Cycle/Hot Full Power Case



2.8.5.5 Inadvertent Operation of Emergency Core Cooling System and Chemical and Volume Control System Malfunction that Increases Reactor Coolant Inventory

2.8.5.5.1 Regulatory Evaluation

Equipment malfunctions, operator errors, and abnormal occurrences could cause unplanned increases in reactor coolant inventory. Depending on the boron concentration and temperature of the injected water and the response of the automatic control systems, a power level increase may result and, without adequate controls, could lead to fuel damage or overpressurization of the reactor coolant system (RCS). Alternatively, a power level decrease and depressurization may result. Reactor protection and safety systems are actuated to mitigate these events. The PBNP review covered the inadvertent actuation of the emergency core cooling system (ECCS) or chemical and volume control system (CVCS) malfunction for purposes of determining if an increase in reactor coolant inventory that could lead to an increase in RCS pressure and pressurizer level could occur.

The NRC's acceptance criteria are based on:

- GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including anticipated operational occurrences
- GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design conditions of the reactor coolant pressure boundary are not exceeded during anticipated operational occurrences
- GDC 26, insofar as it requires that a reactivity control system be provided and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including anticipated operational occurrences, SAFDLs are not exceeded

Specific review criteria are contained in SRP Section 15.5.1-2 and other guidance provided in Matrix 8 of RS-001.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP, GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50, Appendix A, GDC 10, 15 and 26 are as follows:

CRITERION: The reactor core with its related controls and protection systems shall be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits, which have been stipulated and justified. The core and related auxiliary system designs shall provide this integrity under all expected conditions of normal operation with appropriate margins for uncertainties and for specified transient situations which can be anticipated. (PBNP GDC 6)

As described in FSAR Section 3.1.2.1, Reactor Core Design, the reactor core, with its related control and protection system, is designed to function throughout its design lifetime without exceeding acceptable fuel damage limits.

Fuel design and nuclear design are further discussed in LR Section 2.8.1, Fuel System Design, and LR Section 2.8.2, Nuclear Design.

CRITERION: The reactor coolant pressure boundary shall be designed, fabricated, and constructed so as to have an exceedingly low probability of gross rupture or significant uncontrolled leakage throughout its design lifetime. (PBNP GDC 9)

As described in FSAR Section 4.1, Reactor Coolant System, Design Basis, the Reactor Coolant System, in conjunction with its control and protective provisions, is designed to accommodate the system pressures and temperatures attained under all expected modes of plant operation or anticipated system interactions, and maintain the stresses within applicable code stress limits.

System conditions resulting from anticipated transients or malfunctions are monitored and appropriate action is automatically initiated to maintain the required cooling capability and to limit system conditions to a safe level. The system is protected from overpressure by means of pressure relieving devices, as required by Section III of the ASME Boiler and Pressure Vessel Code. The system is also protected from overpressure at low temperatures by the low temperature overpressure protection system.

CRITERION: The reactivity control system provided shall be capable of making and holding the core subcritical from any hot standby or hot operating condition. (PBNP GDC 28)

As described in FSAR Section 9.3, Chemical and Volume Control System, the reactivity control systems provided are capable of making and holding the core subcritical from any hot standby or hot operating condition, including conditions resulting from power changes. The rod cluster control assemblies (RCCAs) are divided into two categories comprising control and shutdown groups. The control group, used in combination with chemical shim, provides control of the reactivity changes of the core throughout the life of the core at power conditions. The chemical shim control (CVCS) is normally used to compensate for the more slowly occurring changes in reactivity throughout core life such as those due to fuel depletion, fission product buildup and decay, and load follow.

CRITERION: The reactivity control systems provided shall be capable of making the core subcritical under credible accident conditions with appropriate margins for contingencies and limiting any subsequent return to power such that there will be no undue risk to the health and safety of the public. (PBNP GDC 30)

As described in FSAR Section 9.3, Chemical and Volume Control, normal reactivity shutdown capability is provided by control rods, with boric acid injection from the CVCS system used to compensate for the xenon transients, and for plant cooldown. When the plant is at power, the quantity of boric acid retained in the boric acid tanks and/or the refueling water storage tank (RWST) and ready for injection will always exceed that quantity required for the normal cold shutdown. This quantity will always exceed the quantity of boric acid required to bring the reactor to hot shutdown and to compensate for subsequent xenon decay.

The injection of boric acid is shown to afford backup reactivity shutdown capability, independent of control rod clusters which normally serve this function in the short term situation. Shutdown for long term and reduced temperature conditions can be accomplished with boric acid injection using redundant components.

ECCS Operation

The emergency core cooling system used at PBNP is the safety injection system (SI). The SI system consists of accumulators, low head injection and high head injection systems. During power operations, the high head safety injection pumps are incapable of delivering flow to the RCS because the pumps' shut-off head is 3400 ft (approximately 1500 psi), which is considerably less than the nominal 2,250 psia operating pressure of the RCS. Therefore, an inadvertent ECCS event which could overpressurize the RCS is not credible for PBNP.

CVCS Malfunction

The CVCS contains three positive displacement charging pumps which can deliver a maximum total flow of 181.5 gpm (60.5 gpm per pump). Normal charging flow is maintained at approximately 46 gpm. In the event that charging flow becomes excessive relative to the RCS inventory make-up requirement, there are alarms to alert the operator to high pressurizer level, high pressurizer pressure, and low volume control tank (CVCS make-up inventory source) level. Reactor trip would occur on high pressurizer pressure or level. The nominal steam volume in the pressurizer is 422 ft^3. The operator would have adequate time and indication to terminate the event. In addition, during normal operation automatic plant protection features, such as Pressurizer Power Operated Relief Valves (PORV) and safety valves, are also available to provide overpressure protection and assist in control of inventory as described in FSAR Section 4.2, RCS System Design and Operation. Low temperature overpressure protection of the reactor coolant pressure boundary (RCPB) is also described in FSAR Section 4.2, RCS System Design and Operation.

2.8.5.5.2 Technical Evaluation

PBNP has evaluated the two potential ECCS and CVCS events that could lead to overpressurization of the RCPB:

- The high pressure SIS pumps remain incapable of delivering water to the RCS at sufficient pressure to cause an overpressure event after EPU, therefore, this event initiator is not applicable, and
- The nominal steam volume in the pressurizer is 422 ft^3 for EPU at the high end of the allowable T_{avg} range as a result of the required change in pressurizer level program (see LR Section 2.4.1, Reactor Protection). It would take several minutes to fill this volume at normal charging flow. The high pressurizer level, high pressurizer pressure and low volume control tank level alarm setpoints are not affected by EPU. The high pressurizer level and high pressurizer pressure reactor trip setpoints are also not affected by EPU. Therefore, the operator would still have adequate time and indication to terminate the event, and automatic plant protection features are adequate. In addition, automatic plant protection features such as PORVs and safety valves would also be available to control inventory and pressure increases. Overpressure protection during normal operation has been evaluated in

LR Section 2.8.4.2, Over Protection During Power Operations, and found to be acceptable. Overpressure protection during low temperature operation has been evaluated in LR Section 2.8.4.3, Over Protection During Low Temperature Operations, and found to be acceptable.

2.8.5.5.3 Conclusions

PBNP has evaluated the inadvertent operation of the ECCS and CVCS malfunction events and concludes that the evaluation has adequately accounted for operation of the plant at the proposed uprated power level. PBNP further concludes that the evaluation has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as the result of these events. Based on this, it is concluded that PBNP will continue to meet its current licensing basis requirements with respect to PBNP, GDCs 6, 9, 28 and 30 following implementation of the proposed EPU. Therefore, PBNP finds the proposed EPU acceptable with respect to the inadvertent operation of ECCS and CVCS events.

2.8.5.6 Decrease in Reactor Coolant Inventory

2.8.5.6.1 Inadvertent Pressurizer Pressure Relief Valve Opening

2.8.5.6.1.1 Regulatory Evaluation

The inadvertent opening of a pressure relief valve results in a reactor coolant inventory decrease and a decrease in reactor coolant system pressure. A reactor trip normally occurs due to low reactor coolant system pressure.

NRC's acceptance criteria are based on:

- GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that specified acceptable fuel design limits are not exceeded during normal operations, including anticipated operational occurrences
- GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operation, including anticipated operational occurrences
- GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under normal operating conditions, including anticipated operational occurrences, specified acceptable fuel design limits are not exceeded

Specific review criteria are contained in SRP, Section 15.6.1, and other guidance provided in Matrix 8 of RS-001.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP, GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50, Appendix A, GDC 10, 15 and 26 are as follows:

CRITERION: The reactor core with its related controls and protection systems shall be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits which have been stipulated and justified. The core and related auxiliary system designs shall provide this integrity under all expected conditions of normal operation with appropriate margins for uncertainties and for specified transient situations which can be anticipated. (PBNP GDC 6)

As described in FSAR Section 3.1.2.1, Reactor Core Design, the reactor core, with its related control and protection system, is designed to function throughout its design lifetime without exceeding acceptable fuel damage limits.

CRITERION: The reactor coolant pressure boundary shall be designed, fabricated, and constructed so as to have an exceedingly low probability of gross rupture or significant uncontrolled leakage throughout its design lifetime. (PBNP GDC 9)

As described in FSAR Section 4.1, Reactor Coolant System, Design Basis, the Reactor Coolant System, in conjunction with its control and protective provisions, is designed to accommodate the system pressures and temperatures attained under all expected modes of plant operation or anticipated system interactions, and maintain the stresses within applicable code stress limits.

CRITERION: The reactivity control system provided shall be capable of making and holding the core subcritical from any hot standby or hot operating condition. (PBNP GDC 28)

The reactivity control systems provided are capable of making and holding the core subcritical from any hot standby or hot operating condition, including conditions resulting from power changes. The rod cluster control assemblies (RCCAs) are divided into two categories comprising control and shutdown groups. The control group, used in combination with chemical shim, provides control of the reactivity changes of the core throughout the life of the core at power conditions. The chemical shim control (CVCS) is normally used to compensate for the more slowly occurring changes in reactivity throughout core life such as those due to fuel depletion, fission product buildup and decay, and load follow.

CRITERION: The reactivity control systems provided shall be capable of making the core subcritical under credible accident conditions with appropriate margins for contingencies and limiting any subsequent return to power such that there will be no undue risk to the health and safety of the public. (PBNP GDC 30)

Normal reactivity shutdown capability is provided by control rods, with boric acid injection from the CVCS system used to compensate for the xenon transients, and for plant cooldown. When the plant is at power, the quantity of boric acid retained in the boric acid tanks and/or the refueling water storage tank (RWST) and ready for injection will always exceed that quantity required for the normal cold shutdown. This quantity will always exceed the quantity of boric acid required to bring the reactor to hot shutdown and to compensate for subsequent xenon decay.

The injection of boric acid is shown to afford backup reactivity shutdown capability, independent of control rod clusters which normally serve this function in the short term situation. Shutdown for long term and reduced temperature conditions can be accomplished with boric acid injection using redundant components.

PBNP has been analyzed for a spectrum of break sizes that bound the size of a stuck-open PORV and block valve. The small break LOCA analysis (FSAR Section 14.3.1, Safety Analysis, Primary System Pipe Ruptures, Small Break Loss-Of-Coolant Accident Analysis) shows the plant to be safe for this postulated event. See LR Section 2.8.5.6.3, Emergency Core Cooling Systems and Loss of Coolant Accidents, for additional information regarding the small break LOCA events.

In addition to the evaluations described in the FSAR, the pressurizer pressure relief valves were evaluated for license renewal. Systems and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 1)

The analysis of an inadvertent opening of a pressurizer pressure relief valve is not within the scope of license renewal.

2.8.5.6.1.2 Technical Evaluation

The inadvertent opening of a pressurizer pressure relief valve is bounded by the PBNP small break LOCA analysis contained in FSAR Section 14.3.1, Safety Analysis, Primary System Pipe rupture, Small Break Loss of coolant Accident Analysis. This event is evaluated for EPU conditions in LR Section 2.8.5.6.3, Emergency Core Cooling Systems and Loss of Coolant Accidents.

2.8.5.6.1.3 Conclusions

The inadvertent opening of a pressurizer pressure relief valve remains bounded by the PBNP small break LOCA analysis. PBNP concludes that the plant will continue to meet the current licensing basis requirements with respect to PBNP, GDCs 6, 9, 28 and 30 following implementation of the proposed EPU. Therefore, PBNP finds the proposed EPU acceptable with respect to the inadvertent opening of a pressurizer pressure relief valve event.

2.8.5.6.1.4 References

1. Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

2.8.5.6.2 Steam Generator Tube Rupture

2.8.5.6.2.1 Regulatory Evaluation

A steam generator tube rupture (SGTR) event causes a direct release of radioactive material contained in the primary coolant to the environment through the ruptured SG tube and main steam safety or atmospheric relief valves. Reactor protection and ESFs are actuated to mitigate the accident and restrict the offsite dose to within the guidelines of 10 CFR 50.67 for the pending NRC approval of PBNP LAR 241 (Reference 3).

The PBNP review covered:

- The postulated initial core and plant conditions
- The method of thermal-hydraulic analysis
- The sequence of events (assuming offsite power either available or unavailable)
- The assumed reactions of reactor system components
- The functional and operational characteristics of the reactor protection system
- The operator actions consistent with the plant's emergency operating procedures
- The results of the accident analysis

The NRC acceptance criteria of the SGTR is focused on the thermal and hydraulic analyses for the SGTR in order to:

- Determine whether 10 CFR 50.67 is satisfied with respect to radiological consequences, which are discussed in LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms, of this safety evaluation and,
- Confirm that the faulted SG does not experience overfill. Preventing SG overfill is necessary in order to prevent the failure of main steam lines.

Specific review criteria are contained in SRP Section 15.6.3 and other guidance provided in Matrix 8 of RS-001, Revision 0.

PBNP Current Licensing Basis

As noted in the Final Safety Analysis Report (FSAR) Section 14.2.4, Steam Generator Tube Rupture, the SGTR accident analysis includes analyses performed to ensure that possible radiological dose consequences are within allowable guidelines. The dose analysis requires thermal-hydraulic calculations be performed to determine the amount of reactor coolant discharged to the ruptured steam generator and the amount of steam released from the steam generators. Operator action to equalize pressure between the ruptured steam generator and the primary system is assumed such that the ruptured steam generator is not overfilled. Analyzed core power level of 1650 MWt , which bounds current power level of 1540 MWt.

- Nominal RCS pressure of 2250 psia
- RCS average temperature range of 557°F to 573.9°F

- Steam Generator Model Δ47 (Unit 2) (bounding)

PBNP has submitted a License Amendment Request (LAR 241, Reference 3) to implement the alternate source term dose calculation methodology. Pending NRC approval, the dose criteria in 10 CFR 50.67 will become the licensing basis for all subsequent radiological consequences analyses. The PBNP review of the SGTR is focused on the thermal-hydraulic analysis for the SGTR used to determine whether 10 CFR 50.67 is satisfied with respect to radiological consequences, which are discussed in LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms and Reference 3.

In addition to the evaluations described in the FSAR, the components associated with the SGTR analysis were evaluated for license renewal. Systems and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

2.8.5.6.2.2 Technical Evaluation

The evaluation of the design basis SGTR event demonstrated that the current design is acceptable to support the EPU operation. (See LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms)

2.8.5.6.2.2.1 Introduction

A steam generator tube rupture (SGTR) thermal-hydraulic analysis for activity release was performed. The analysis was performed using the NSSS design parameters for an uprate to a core power of 1800 MWt.

The major hazard associated with an SGTR event is the potential radiological consequences resulting from the transfer of radioactive reactor coolant to the secondary side of the ruptured steam generator and subsequent release of radioactivity to the atmosphere. The primary thermal-hydraulic parameters which affect the calculation of doses for an SGTR include: (1) the amount of reactor coolant transferred to the secondary side of the ruptured steam generator, and (2) the amount of steam released from the ruptured and intact steam generators to the atmosphere.

The accident analyzed is the double-ended rupture of a single steam generator tube as documented in FSAR Section 14.2.4, Steam Generator Tube Rupture. It is assumed that the primary-to-secondary break flow following an SGTR results in depressurization of the reactor coolant system (RCS), and that reactor trip and safety injection (SI) are automatically initiated on low pressurizer pressure. For the analysis of the break flow, it is assumed that reactor trip and SI actuation occur simultaneously when the pressurizer pressure decreases to the SI actuation setpoint. Loss of offsite power (LOOP) is assumed to occur at reactor trip resulting in the release of steam to the atmosphere via the steam generator safety valves and/or atmospheric dump valves (ADVs). Following reactor trip and SI actuation, it is assumed that the RCS pressure stabilizes at the equilibrium point where the incoming SI flowrate equals the outgoing break flowrate. The equilibrium primary-to-secondary break flow is assumed to persist until 30 minutes after the initiation of the SGTR.

After 30 minutes, it is assumed that steam is released only from the intact steam generator in order to dissipate the core decay heat and to subsequently cool the plant down to the residual heat removal (RHR) system operating conditions. During post-SGTR cooldown, the pressure in the ruptured steam generator is assumed to be decreased by the backfill method in which core decay heat and RCS fluid energy is dissipated by releasing steam from the intact steam generator. This is the preferred approach since it minimizes the radioactivity released to the atmosphere. For the purposes of maximizing calculated steam releases, it is conservatively assumed that the plant cooldown to RHR operating conditions is accomplished within 8 hours after initiation of the SGTR, even though RHR cut-in does not occur until after 8 hours. A primary and secondary side mass and energy balance is used to calculate the steam release from the intact steam generator from 0 to 2 hours, from 2 to 8 hours, and from 8 to 24 hours and then the hourly release rate extrapolated to any RHR cut in time after 24 hours.

A portion of the break flow will flash directly to steam upon entering the secondary side of the ruptured SG. The analysis performed for the uprate incorporates a break flow flashing fraction. Since a transient break flow calculation is not performed, a detailed time dependent flashing fraction that incorporates the expected changes in primary side temperatures can not be calculated. Instead, a conservative calculation of the flashing fraction is performed using the limiting conditions from the break flow calculation. Two time intervals are considered, as in the break flow calculations: pre- and post- reactor trip (SI initiation occurs concurrently with reactor trip). Since the RCS and SG conditions are different before and after the trip, different flashing fractions would be expected.

An evaluation of the margin to SG overfill is contained in Section 2.8.5.6.2.2.5, Evaluation of Margin to Overfill. The impact on the input to the radiological consequences analysis of extending break flow beyond 30 minutes is evaluated in Section 2.8.5.6.2.2.6, Evaluation of Impact of Extending Break Flow Beyond 30 Minutes. The impact of license renewal programs is discussed in Section 2.8.5.6.2.2.7, Evaluation of Impact of Renewed Plant Operating License Evaluations and License Renewal Programs.

2.8.5.6.2.2.2 Licensing Basis Input Parameters, Assumptions, and Acceptance Criteria

A summary of the key SGTR input assumptions used for the evaluation of the power uprate to a core power of 1800 MWt follows:

- Core power level of 1800 MWt
- Nominal RCS pressure of 2250 psia
- RCS average temperature range of 558°F to 577°F
- 0% to 10% steam generator tube plugging (SGTP)
- Steam Generator Models 44F (Unit) and Δ47 (Unit 2)
- Low pressurizer pressure SI actuation setpoint = 1735 psia

- Lowest steam generator safety valve reseat pressure = 930 psia (includes 12.6% main steam system valve (MSSV) blowdown and 3% tolerance)
- SI flowrates include maximum flow from all high-head pumps assuming no spilling

The plant specific secondary-side conditions (e.g., pressure, temperature) address the varying conditions associated with combinations of steam generator model, RCS temperature, and SGTP level. Tube plugging level is assumed to be 0% SGTP to reflect higher steam pressure and temperatures related to the clean steam generator conditions and 10% SGTP to reflect lower steam pressure and temperature at the maximum tube plugging condition.

Acceptance Criteria

The analysis is performed to calculate the mass transfer data for input to the radiological consequences analysis. As such, no acceptance criteria are defined. The results of the analysis are used as input to the radiological consequences analysis presented in Section 2.9.2 , Radiological Consequences Analyses Using Alternative Source Terms, and Reference 3.

2.8.5.6.2.2.3 Description of Licensing Basis Analysis

Method of Analysis

Eight distinct cases were considered for the thermal-hydraulic analysis. The first four cases modeled the Model 44F steam generators at the varying conditions of 0% and 10 % SGTP (and the associated pressures and temperatures on the secondary side), and high and low values for the RCS average temperature. The second four cases modeled the Model Δ47 steam generators at the same varying combinations of tube plugging, and RCS average temperature.

These 8 cases were individually analyzed to determine the primary-to-secondary break flow and steam releases to the atmosphere for the dose analysis between 0 and 30 minutes (break flow termination). The limiting break flow from all of the different calculations along with the limiting steam released to the atmosphere are used in the dose calculation. A single calculation was performed to calculate the long-term steam releases from the intact steam generator for the time intervals 0 to 2 hours, 2 to 8 hours, and 8 to 24 hours and then the hourly release rate extrapolated to any RHR cut in time after 24 hours. The plant cooldown to RHR operating conditions can be accomplished within 30 hours of initiation of a tube rupture.

The break flow flashing fraction is based on the difference between the primary side fluid enthalpy and the saturation enthalpy on the secondary side. Therefore, the highest flashing will be predicted for the case with the highest primary side temperatures. For the flashing fraction calculations it is conservatively assumed that all of the break flow is at the hot leg temperature (the break is assumed to be on the hot leg side of the steam generator). Similarly, a lower secondary side pressure maximizes the difference in the primary and secondary enthalpies, although a lower pressure would have a higher heat of vaporization that would result in less flashing. The highest possible pre-trip flashing fraction based on the range of operating conditions covered by this analysis is for a case with a hot leg temperature of 611.1°F, RCS pressure of the SI setpoint of 1735 psia and initial secondary pressure of 601 psia. All cases consider the same post-trip RCS pressure of 1547 psia and post-trip SG pressure of 930 psia. It is conservatively assumed that the hot leg temperature is not reduced for the 30 minutes in which break flow is calculated. However, the hot leg temperature will need to be less than 600.3°F to ensure subcooling of the RCS fluid. Although it is not modeled, it is assumed that the operators will prevent loss of subcooling. As such, the flashing fraction is calculated assuming saturated conditions in the RCS at 1547 psia.

2.8.5.6.2.2.4 Licensing Basis Analysis Results

The integrated tube rupture break flow, flashed break flow, and integrated atmospheric steam releases for the radiological analysis are summarized in Table 2.8.5.6.2-1, SGTR Thermal-Hydraulic Results for PBNP Units 1 and 2 Radiological Analysis. The maximum primary-to-secondary break flow is independent of the steam generator design and is based on the analysis for 10% tube plugging (lower initial secondary pressure) and 558°F RCS average temperature. The maximum steam release calculation for the initial 30 minutes is based on the results of the case modeling the Model 44F SG, 0% tube plugging (higher initial secondary temperature), and 577°F RCS average temperature. The calculated break flow and steam releases were increased by 10% prior to being tabulated in Table 2.8.5.6.2-1, SGTR Thermal-Hydraulic Results for PBNP Units 1 and 2 Radiological Analysis, for use in the radiological consequences analysis. This conservatism was added to cover plant changes that may impact the SGTR analysis, such that a recalculation of the radiological consequences does not need to be performed for future changes.

The largest contribution to the doses comes from the release of flashed break flow. Flashed break flow after reactor trip and the assumed loss of offsite power (and condenser) contributes more to the calculated doses than that released prior to trip. Therefore, the break flow results are selected to maximize post-trip flashed break flow.

2.8.5.6.2.2.5 Evaluation of Margin to Overfill

The current licensing basis analysis does not require that operators demonstrate the ability to terminate break flow within 30 minutes from the start of the event, and it is recognized that operators may not be able to terminate break flow within 30 minutes for all postulated steam generator tube rupture events. Although, it is considered beyond the licensing basis for PBNP Units 1 and 2, a detailed thermal-hydraulic analysis has been performed to evaluate the potential for ruptured steam generator overfill. The margin to overfill evaluation has been performed to supplement the licensing basis analysis described in the preceding sections which provides input to the radiological analysis of LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms. The margin to overfill evaluation is presented as a supplement to the licensing basis steam generator tube rupture analysis since the licensing basis analysis methodology discussed above does not include consideration of margin to overfill consistent with the historical licensing basis for PBNP Units 1 and 2.

The margin to overfill evaluation was performed using the LOFTTR2 computer code and modeling from WCAP-10698-P-A (Reference 1). The evaluation includes explicit simulation of operator actions leading to break flow termination based on the PBNP Emergency Operating Procedures (EOPs) and simulator studies specific to PBNP Units 1 and 2. The margin to overfill analysis considers the allowable vessel average temperature and steam generator tube plugging ranges consistent with the licensing basis analysis described in the preceding sections.

Consistent with the historical licensing basis for PBNP Units 1 and 2 discussed in the preceding sections, the margin to overfill evaluation does not include consideration of a single failure which is an exception to the WCAP-10698-P-A methodology. Other exceptions to the WCAP-10698-P-A methodology include the use of nominal plant conditions without consideration of uncertainties and reduced conservatism on initial secondary mass. The evaluation included consideration of maximum safety injection and auxiliary feedwater flow rates. The exceptions to the WCAP-10698-P-A methodology provide a "better estimate" margin to overfill analysis consistent with the margin to overfill evaluation approved for D.C. Cook in Reference 2. Since the evaluation is based on the WCAP-10698-P-A methodology, the impact of NSAL-07-11 (Reference 4) was also incorporated into the margin to overfill evaluation.

The margin to overfill evaluation demonstrates that recovery actions can be performed to terminate the primary-to-secondary break flow before overfill of the ruptured steam generator occurs despite the continuation of break flow beyond the 30 minute assumption used in the PBNP Units 1 and 2 licensing basis SGTR analysis discussed in the preceding sections. Note that this margin to overfill evaluation is not intended for inclusion in the SGTR licensing basis of PBNP, but is provided to supplement the licensing basis analyses of Section 2.8.5.6.2.2.1 through Section 2.8.5.6.2.2.4. The operator action times credited in the margin to overfill evaluation are presented in Table 2.8.5.6.2-2, SGTR Operator Action Times for PBNP Units 1 and 2 Supplemental SGTR Evaluations.

The limiting margin to overfill calculation models 10% tube plugging, and 558°F RCS average temperature with the Model 44F steam generator and nominal decay heat. The calculated sequence of events is presented in Table 2.8.5.6.2-3, SGTR Margin to Overfill Sequence of Events for PBNP Units 1 and 2 SGTR Analysis. Figures 2.8.5.6.2-1 and 2.8.5.6.2-2 contain the plant transient pressure response and the primary-to-secondary break flow response to the tube rupture event. Figure 2.8.5.6.2-3 presents the ruptured steam generator water volume as compared to the available steam generator water volume demonstrating that steam generator overfill does not occur.

2.8.5.6.2.2.6 Evaluation of Impact of Extending Break Flow Beyond 30 Minutes

As discussed previously for the margin to overfill evaluation in Section 2.8.5.6.2.2.5, the current licensing basis analysis does not require that operators demonstrate the ability to terminate break flow within 30 minutes from the start of the event. However, as presented in the margin to overfill evaluation, a better estimate analysis modeling operator actions results in a break flow duration greater than 30 minutes. A supplemental thermal hydraulic evaluation was performed using the LOFTTR2 computer code and modeling from WCAP-10698-P-A (Reference 1) consistent with the margin to overfill evaluation of Section 2.8.5.6.2.2.5 to provide thermal hydraulic mass transfer data for input to a radiological consequences analysis. The thermal hydraulic input to dose analysis has been performed to supplement the licensing basis analysis described in Sections 2.8.5.6.2.2.1 through 2.8.5.6.2.2.4, which provides input to the steam generator tube rupture radiological analysis of LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms. The supplemental thermal hydraulic input to dose analysis is presented as a supplement to the licensing basis steam generator tube rupture analysis since the licensing basis analysis does not consider operator actions leading to break flow termination and the supplemental analysis demonstrates break flow termination occurring after the 30 minute break flow termination time used in the licensing basis analysis.

The evaluation includes explicit simulation of operator actions leading to break flow termination based on the PBNP EOPs and simulator studies specific to PBNP Units 1 and 2. The supplemental thermal hydraulic analysis analyzed the most limiting allowable vessel average temperature and steam generator tube plugging consistent with the licensing basis analysis described in Sections 2.8.5.6.2.2.1 through 2.8.5.6.2.2.4. Consistent with the historical licensing basis for PBNP Units 1 and 2 and the margin to overfill evaluation discussed in the preceding sections, the supplemental thermal hydraulic evaluation does not include consideration of a single failure which is an exception to the WCAP-10698-P-A methodology. Other exceptions to the WCAP-10698-P-A methodology include the use of nominal plant conditions without consideration of uncertainties and reduced conservatism on initial secondary mass. The evaluation included consideration of a maximum safety injection flow rate and a minimum auxiliary feedwater flow rate. The exceptions to the WCAP-10698-P-A methodology provide a "better estimate" analysis consistent with the margin to overfill evaluation in Section 2.8.5.6.2.2.5 and the evaluation approved for D.C. Cook in Reference 2.

The limiting supplemental thermal hydraulic calculation models 0% tube plugging and 577°F, RCS average temperature with the Model Δ47 steam generator. The calculated sequence of events is presented in Table 2.8.5.6.2-4, SGTR Supplemental Thermal Hydraulic Analysis Sequence of Events for PBNP Units 1 and 2 SGTR Analysis. Table 2.8.5.6.2-5, SGTR Comparison of Thermal Hydraulic Results for PBNP Units 1 and 2 Radiological Analysis, contains a comparison of the thermal hydraulic mass transfer results for the licensing basis analysis and the supplemental thermal hydraulic analysis. Figures 2.8.5.6.2-4 through 2.8.5.6.2-9 contains plant transient responses to the tube rupture event including primary and secondary pressure, primary-to-secondary break flow, primary-to-secondary flashing fraction, and secondary steam releases.

The supplemental thermal hydraulic analysis demonstrates that despite the continuation of break flow beyond the 30 minute assumption used in the PBNP Units 1 and 2 licensing basis steam generator tube rupture analysis, the thermal hydraulic mass transfers resulting from a better estimate analysis are bounded by those calculated for the licensing basis analysis. Table 2.8.5.6.2-5, SGTR Comparison of Thermal Hydraulic Results for PBNP Units 1 and 2 Radiological Analysis, shows that the supplemental thermal hydraulic analysis results in an approximate increase of 20% in total tube rupture break flow while also resulting in a decrease of approximately 75% in total flashed break flow and 50% in ruptured steam generator steam releases. The intact steam generator steam releases are not significantly different. Flashed break flow has the greatest impact on the steam generator tube rupture radiological consequences analysis since it is modeled as a direct release from the reactor coolant system to the environment with no holdup, dilution, or partitioning in the secondary side of the ruptured steam generator. Note from Table 2.8.5.6.2-4, SGTR Supplemental Thermal Hydraulic Analysis Sequence of Events for PBNP Units 1 and 2 SGTR Analysis, that break flow flashing stops at 1864 seconds, during cooldown using the intact SG. In contrast, the licensing basis analysis maintains a constant flashing fraction for the entire 30 minute break flow duration. As such, the 30 minute licensing basis analysis will provide conservative dose consequences when compared to a better estimate analysis with break flow duration lasting longer than 30 minutes.

This supplemental thermal hydraulic analysis also demonstrates the ability of the AFW system to support the required plant cooldown for break flow termination with a single AFW pump providing 137.5 gpm to each steam generator. Note that when the steam generator is steaming, the required liquid volume to cover the tube bundle does not require the downcomer to be filled up to the level of the top of the tubes. In these cases, water level in the downcomer may be well below the narrow range steam generator span while sufficient froth is maintained in the shell of the steam generator to maintain heat transfer. LOFTTR2 has an internal model which uses steam generator conditions to calculate the volume of water required to maintain full primary-to-secondary heat transfer and compares it to the calculated water volume in the steam generator. If the volume of water in the steam generator falls below the volume required to maintain full heat transfer, the code reduces primary-to-secondary heat transfer proportion to the difference in the volumes. Figure 2.8.5.6.2-10 contains a comparison of the calculated volume required for full primary-to-secondary heat transfer and the intact steam generator volume throughout the transient until break flow termination. For long-term cooldown following termination of primary-to-secondary break flow, there is sufficient auxiliary feedwater flow to refill the intact steam generator and adequately maintain level on narrow range span to support the cooldown to residual heat removal system entry conditions.

2.8.5.6.2.2.7 Evaluation of Impact of Renewed Plant Operating License Evaluations and License Renewal Programs

The evaluation of the SGTR analysis for EPU does not add any new functions for existing components that would change the existing license renewal evaluations. Operation of these systems and components involved in the SGTR analysis at EPU conditions does not introduce any unevaluated aging effects that would necessitate changes to aging management programs or require new programs, as internal and external environments are within the parameters previously evaluated. Therefore, EPU activities associated with the SGTR analysis do not impact license renewal scope, aging effects, and aging management programs

2.8.5.6.2.2.8 Evaluation Results

The SGTR thermal-hydraulic analysis for activity release has been completed in support of the uprating. The most-limiting results of the thermal-hydraulic analysis are provided in Table 2.8.5.6.2-1, SGTR Thermal-Hydraulic Results for PBNP Units 1 and 2 Radiological Analysis. This analysis was used as input to the Radiological Evaluation (LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms, and Reference 3).

The margin to overfill evaluation demonstrates that despite the continuation of break flow beyond the 30 minute termination time assumed in the licensing basis analysis, ruptured steam generator overfill does not occur for PBNP Units 1 and 2.

The supplemental thermal hydraulic input to dose analysis demonstrates that despite the continuation of break flow beyond the 30 minute termination time assumed in the licensing basis analysis, the mass transfer data calculated by the licensing basis analysis is bounding. As such, the radiological consequences of the licensing basis analysis bound the radiological consequences resulting from the better estimate supplemental thermal hydraulic analysis.

These results are valid for a power uprate to a core power of 1800 MWt.

2.8.5.6.2.3 Conclusion

PBNP has reviewed the analysis of the SGTR accident and concludes that the analysis has adequately accounted for operation of the plant at the proposed power level and was performed using acceptable analytical methods. PBNP further concludes that the assumptions used in this analysis are conservative. Therefore, PBNP finds the proposed EPU acceptable with respect to the SGTR event.

2.8.5.6.2.4 References

1. WCAP-10698-P-A, SGTR Analysis Methodology to Determine the Margin to Steam Generator Overfill, August 1987

2. Donald C. Cook Nuclear Plant, Units 1 and 2 – Issuance of Amendments (TAC Nos. MB0739 and MB0740), October 2001, (NRC ADAMS: ML012690136)

3. Point Beach Nuclear Plant Units 1 and 2 Submittal of License Amendment Request 241, Alternative Source Term, December 2008, (NRC ADAMS: ML083450683)

4. NSAL-07-11, Decay Heat Assumption in Steam Generator Tube Rupture Margin-to-Overfill Analysis Methodology, November 2007

Table 2.8.5.6.2-1
SGTR Thermal-Hydraulic Results for PBNP Units 1 and 2 Radiological Analysis

	Time Period	Mass Transfer
Pre-Trip Steam Releases	0 – 220 seconds	1130 lbm/sec/SG
Pre-Trip Tube Rupture Break Flow (Including Flashed Break Flow)	0 – 220 seconds	21,300 lbm
Post-Trip Tube Rupture Break Flow (Including Flashed Break Flow)	220 seconds – 30 minutes	103,200 lbm
Pre-Trip Break Flow Flashed Break Flow (Flashing Fraction = 0.22)	0 – 220 seconds	4690 lbm
Post-Trip Break Flow Flashed Break Flow (Flashing Fraction = 0.13)	220 seconds – 30 minutes	13,420 lbm
Steam Release from Ruptured Steam Generator	220 seconds – 30 minutes	88,100 lbm
Steam Release from Intact Steam Generator	220 seconds – 2 hours	257,700 lbm
Steam Release from Intact Steam Generator	2 – 8 hours	584,000 lbm
Steam Release from Intact Steam Generator	8 – 24 hours	866,000 lbm
Intact SG Steam Release rate	Beyond 24 hours	54,100 lbm/hr

Table 2.8.5.6.2-2
SGTR Operator Action Times for PBNP Units 1 and 2 Supplemental SGTR Evaluations

Action	Time
Operator action time to isolate the ruptured steam generator	6 minutes or LOFTTR2-calculated time to reach 41% narrow range level in the ruptured steam generator, whichever is longer
Operator action time to initiate cooldown following isolation of the ruptured steam generator	17 minutes
Plant response to complete cooldown	LOFTTR2-calculated
Operator action time to initiate depressurization following completion of cooldown	3 minutes
Plant response to complete depressurization	LOFTTR2-calculated
Operator action time to terminate ECCS flow	2 minutes
Break flow termination resulting from primary and secondary pressure equalization	LOFTTR2-calculated

Table 2.8.5.6.2-3
SGTR Margin to Overfill Sequence of Events for PBNP Units 1 and 2 SGTR Analysis

Event	Time (sec)
SGTR occurs	0
Reactor trip (Overtemperature-ΔT)	64
Initiation of AFW	64
Initiation of safety injection	163
Isolation of ruptured steam generator	360
Initiation of cooldown with intact steam generator	1380
Termination of cooldown	1854
Initiation of depressurization	2034
Termination of depressurization	2096
Termination of safety injection	2217
Termination of break flow	2632

Table 2.8.5.6.2-4
SGTR Supplemental Thermal Hydraulic Analysis Sequence of Events for PBNP Units 1 and 2 SGTR Analysis

Event	Time (sec)
SGTR occurs	0
Reactor trip (Overtemperature-ΔT)	77
Initiation of safety injection	202
Initiation of AFW	377
Isolation of ruptured steam generator	804
Initiation of cooldown with intact steam generator	1822
Break flow flashing stops	1968
Termination of cooldown	2442
Initiation of depressurization	2622
Termination of depressurization	2690
Termination of safety injection	2811
Termination of break flow	3144

Table 2.8.5.6.2-5
SGTR Comparison of Thermal Hydraulic Results for PBNP Units 1 and 2 Radiological Analysis

	Licensing Basis Analysis	Supplemental Thermal Hydraulic Analysis
Total Flashed Break Flow	18,110	4,980
Total Break Flow[1]	124,500	155,380
Total Ruptured Steam Generator Steam Releases[2]	88,100	49,320
Total Intact Steam Generator Steam Releases[2]	88,100	96,230

1. Total break flow includes flashed break flow.
2. Total post-trip steam releases until break flow termination.

Figure 2.8.5.6.2-1 SGTR Margin to Overfill Evaluation RCS and Secondary Pressures

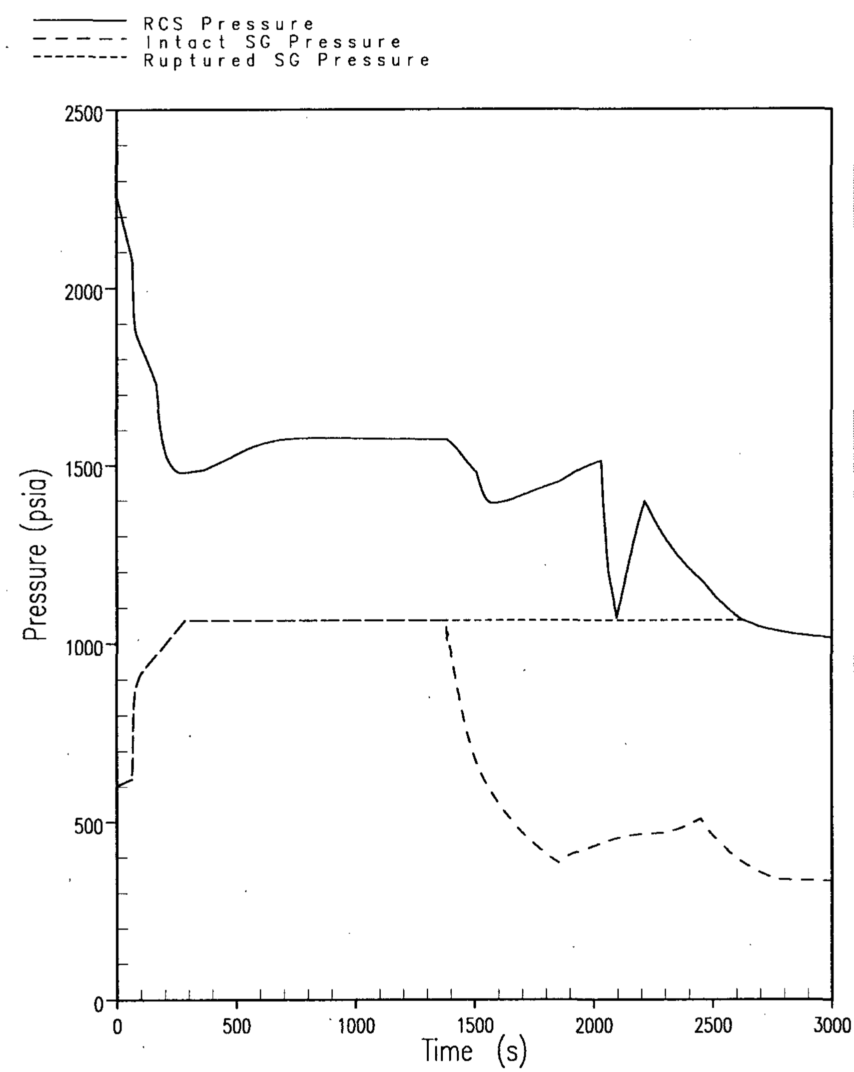


Figure 2.8.5.6.2-2 SGTR Margin to Overfill Evaluation Ruptured SG Break Flow

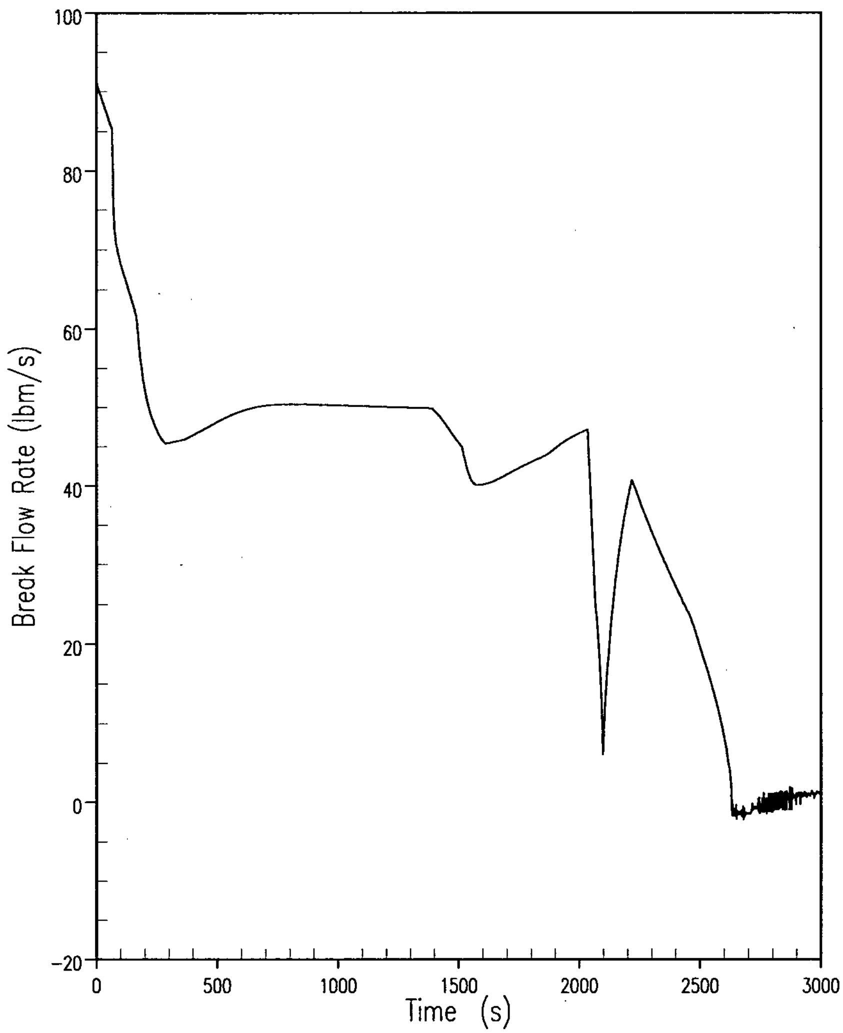


Figure 2.8.5.6.2-3 SGTR Margin to Overfill Evaluation Ruptured SG Water Volume

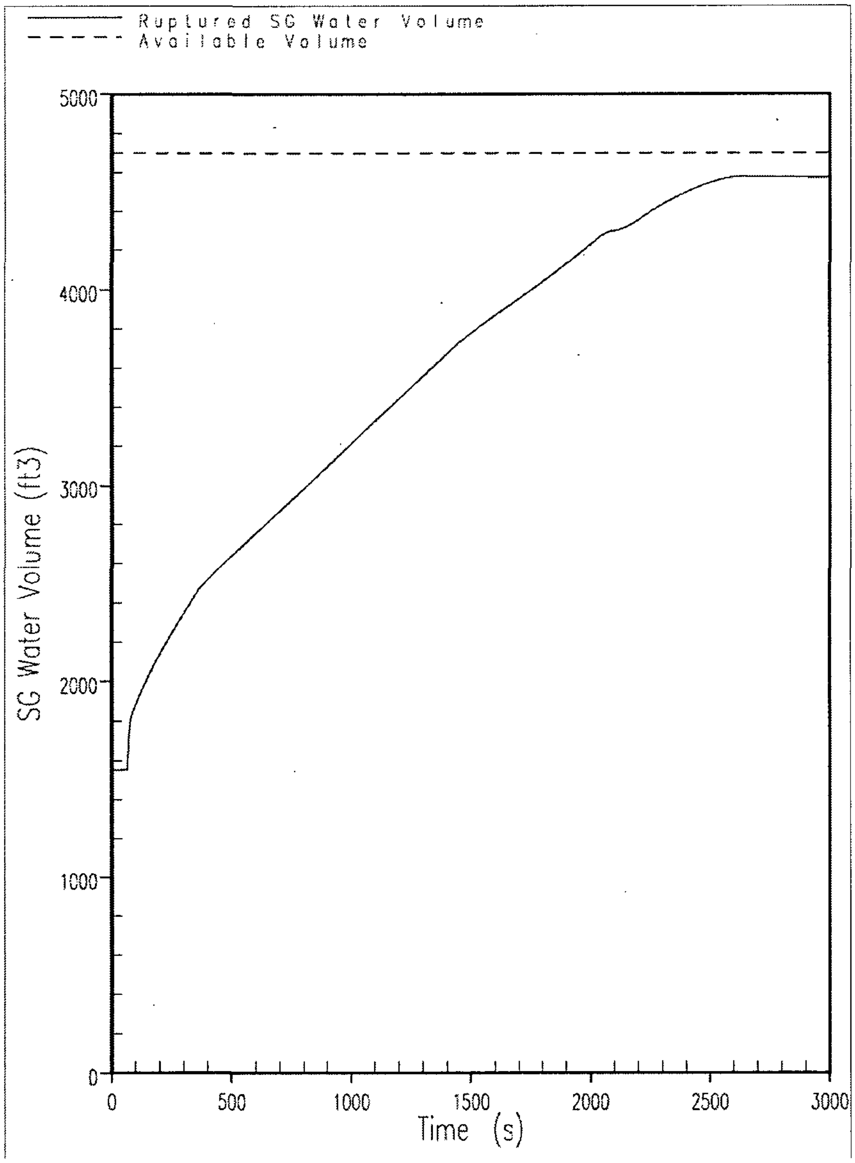


Figure 2.8.5.6.2-4 SGTR Supplemental Thermal Hydraulic Analysis RCS and Secondary Pressures

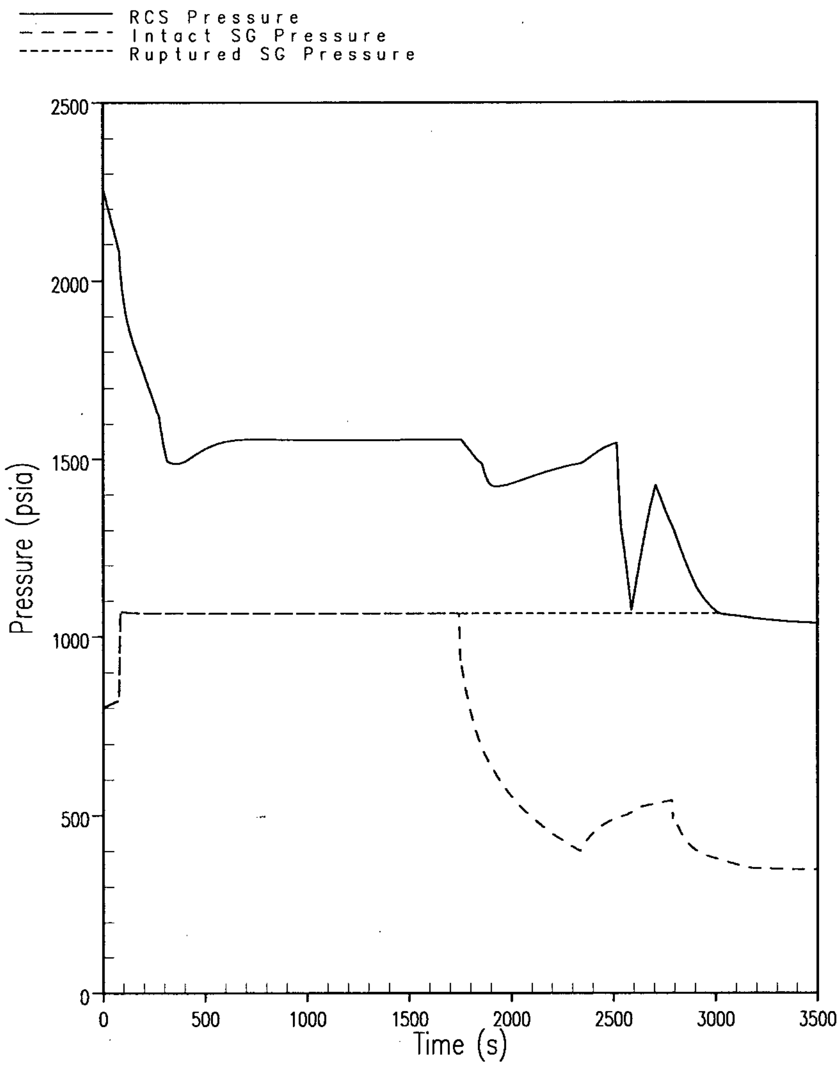


Figure 2.8.5.6.2-5 SGTR Supplemental Thermal Hydraulic Analysis Primary-to-Secondary Break Flow Rate

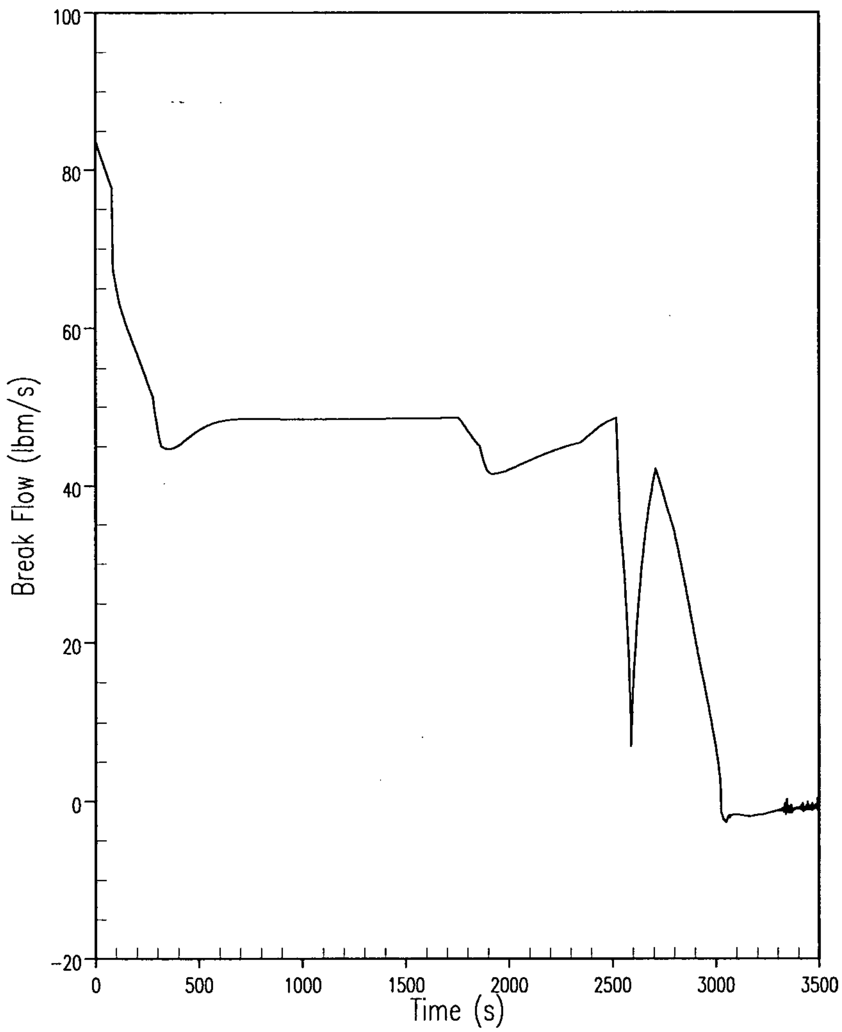


Figure 2.8.5.6.2-6 SGTR Supplemental Thermal Hydraulic Analysis Integrated Primary-to-Secondary Break Flow

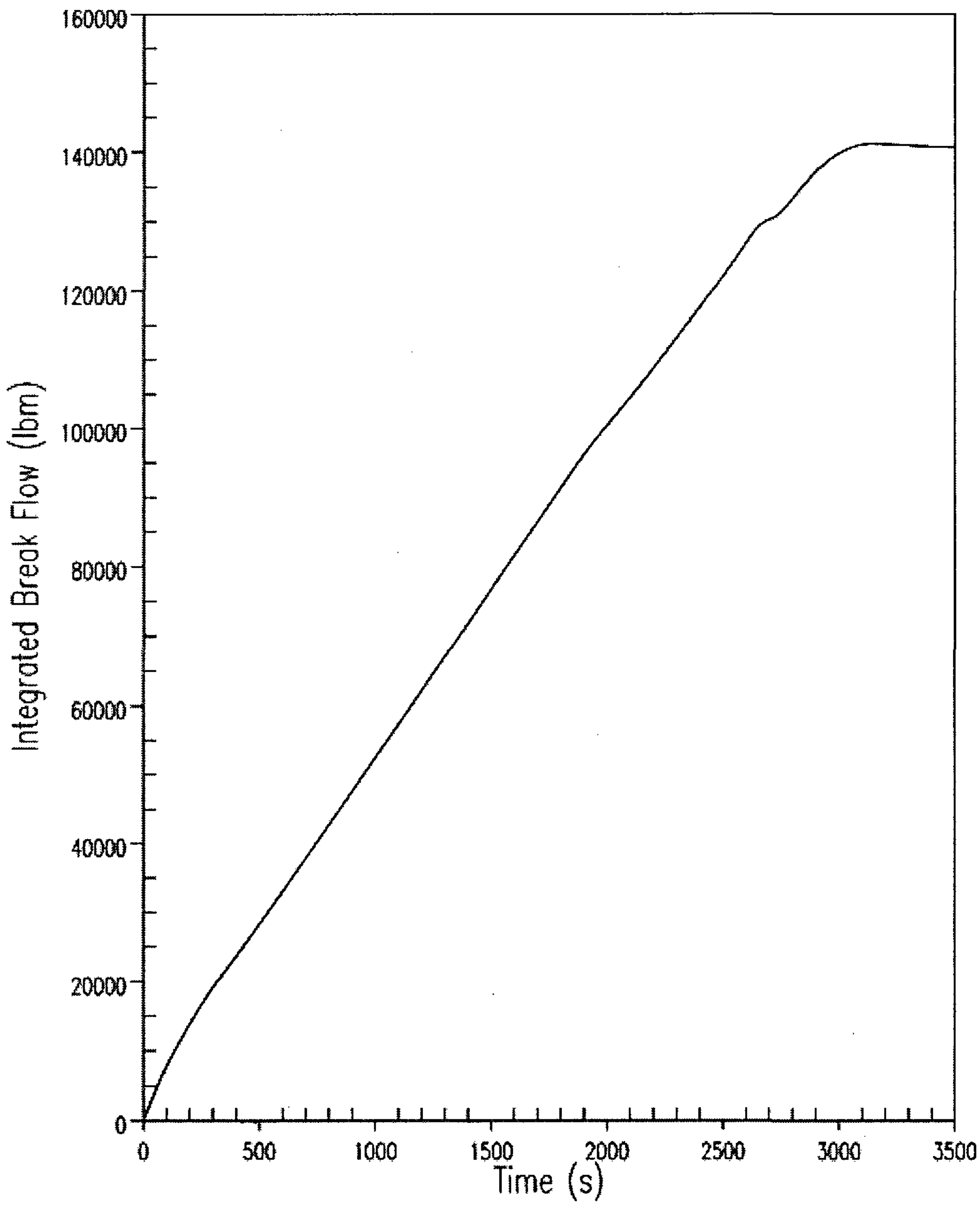


Figure 2.8.5.6.2-7 SGTR Supplemental Thermal Hydraulic Analysis Primary-to-Secondary Break Flow Flashing Fraction

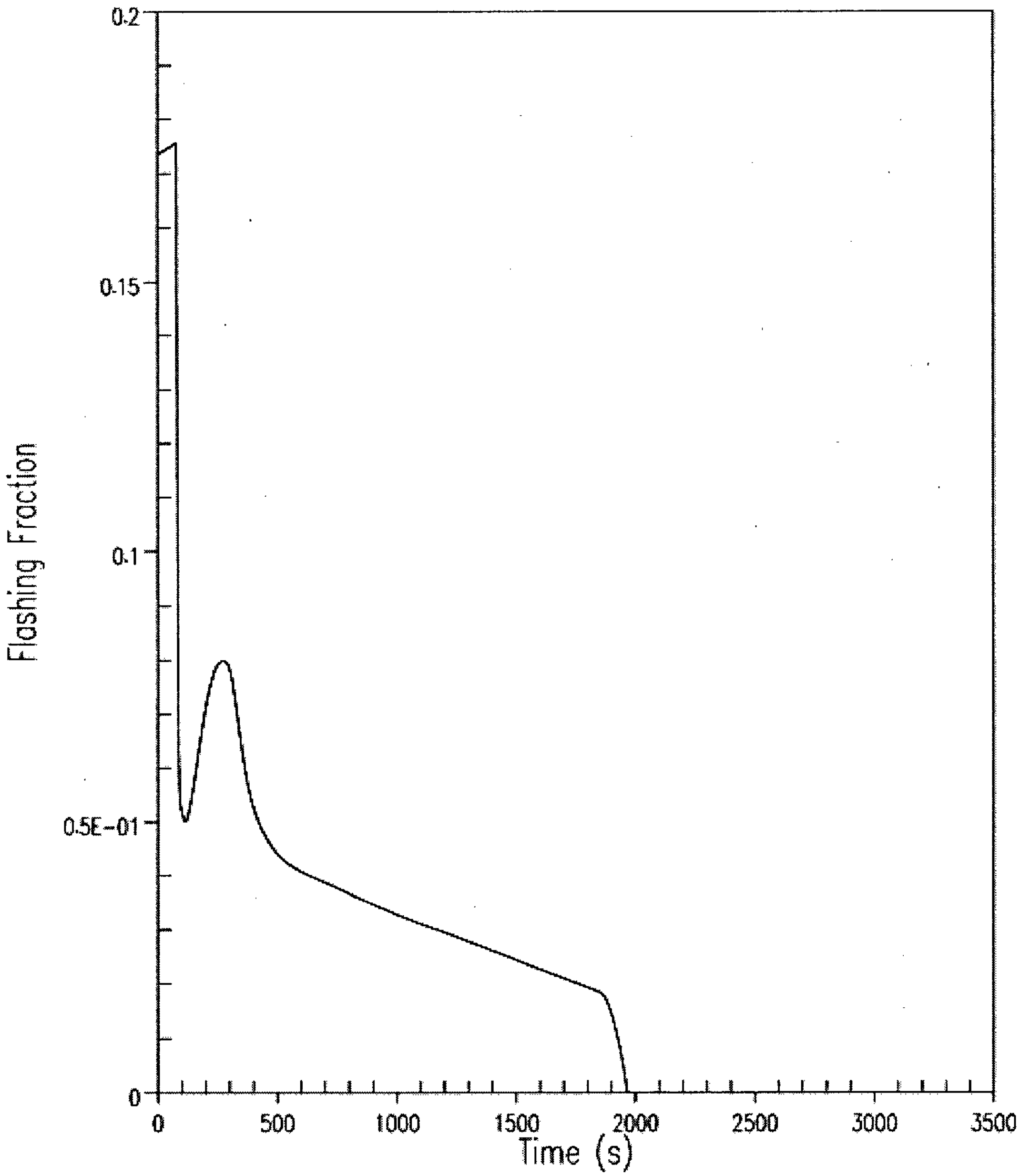


Figure 2.8.5.6.2-8 SGTR Supplemental Thermal Hydraulic Analysis Integrated Primary-to-Secondary Flashed Break Flow

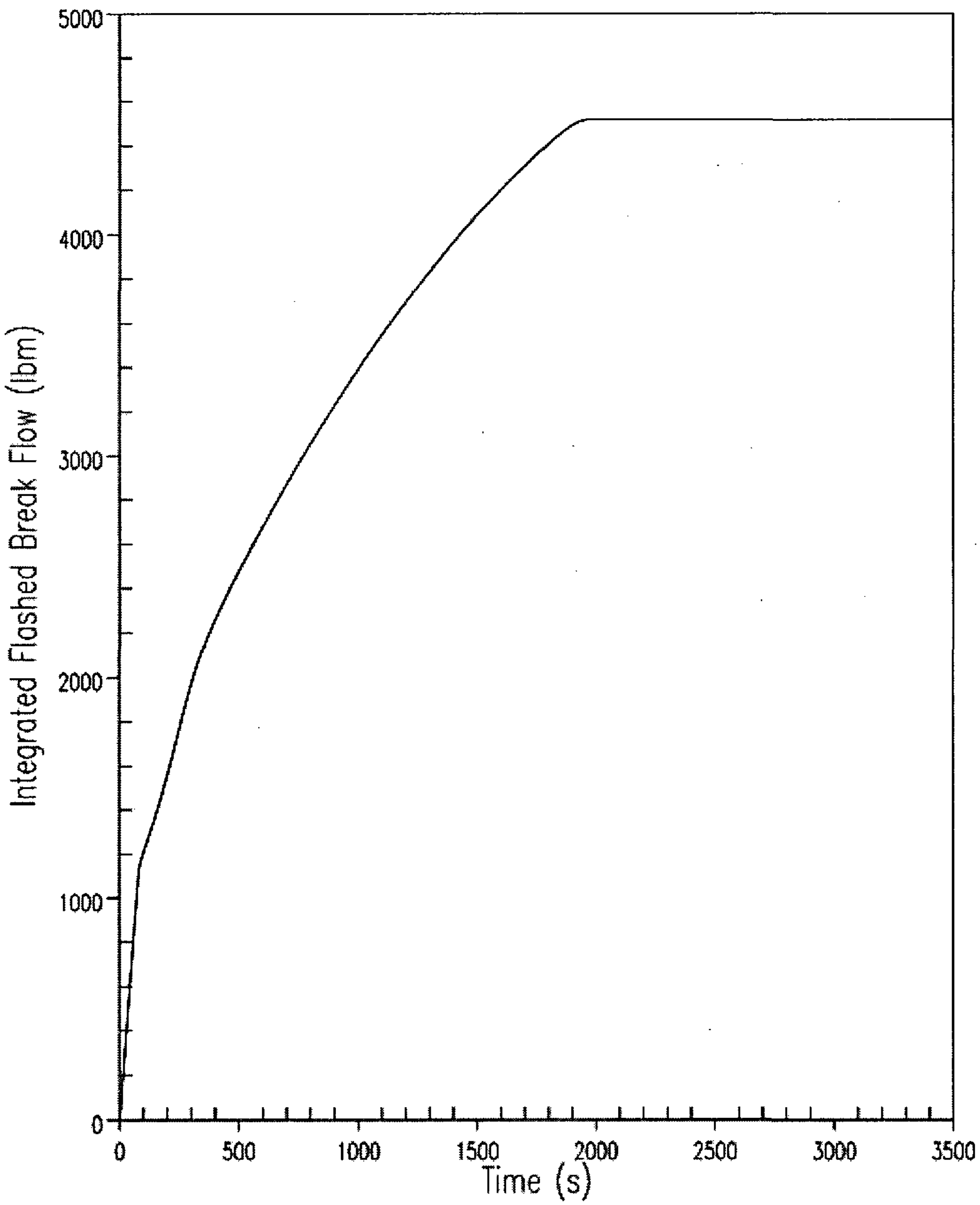


Figure 2.8.5.6.2-9 SGTR Supplemental Thermal Hydraulic Analysis Secondary Mass Release Rates

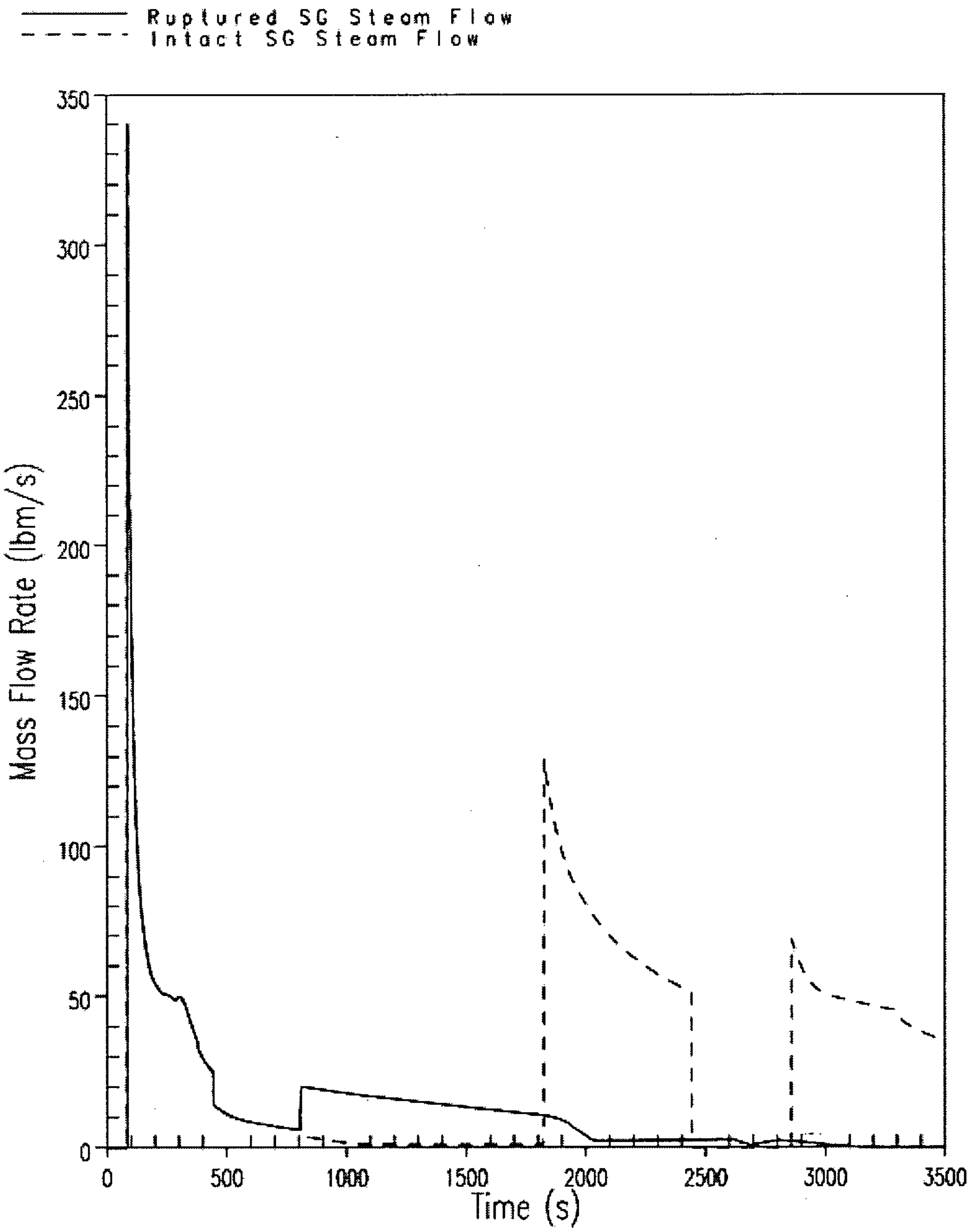
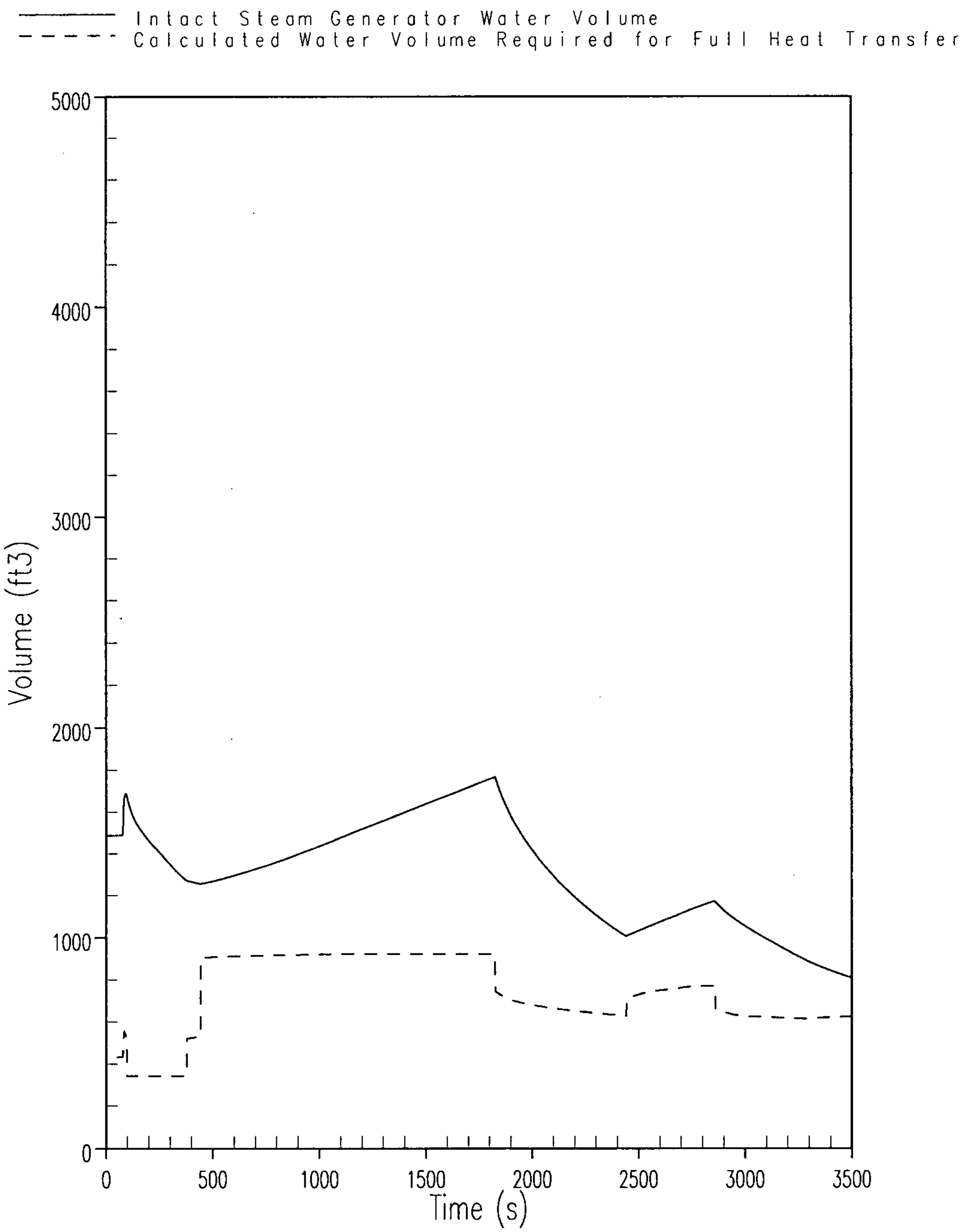


Figure 2.8.5.6.2-10 SGTR Supplemental Thermal Hydraulic Analysis Intact Steam Generator Heat Transfer Water Volume Comparison



2.8.5.6.3 Emergency Core Cooling System and Loss-of-Coolant Accidents

2.8.5.6.3.1 Regulatory Evaluation

Loss of Coolant Accidents (LOCAs) are postulated accidents that would result in the loss of reactor coolant from piping breaks in the reactor coolant pressure boundary at a rate in excess of the capability of the normal reactor coolant makeup system to replenish it. Loss of significant quantities of reactor coolant would prevent heat removal from the reactor core, unless the water is replenished. The reactor protection system (RPS) and emergency core cooling system (ECCS) are provided to mitigate these accidents. The PBNP review covered:

- The determination of break locations and break sizes
- The postulated initial conditions
- The sequence of events
- The analytical model used for analyses, and calculations of the reactor power, pressure, flow, and temperature transients
- The calculations of peak cladding temperature, total oxidation of the cladding, total hydrogen generation, changes in core geometry, and long-term cooling
- The functional and operational characteristics of the RPS and ECCS
- Operator actions

The NRC's acceptance criteria are based on:

- 10 CFR 50.46, insofar as it establishes standards for the calculation of ECCS performance and acceptance criteria for that calculated performance
- 10 CFR 50, Appendix K, insofar as it establishes required and acceptable features of evaluation models for heat removal by the ECCS after the blowdown phase of a LOCA
- GDC 4, insofar as it requires that structures, systems, and components important-to-safety be protected against dynamic effects associated with flow instabilities and loads such as those resulting from water hammer
- GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to ensure the capability to cool the core is maintained
- GDC 35, insofar as it requires that a system to provide abundant emergency core cooling be provided to transfer heat from the reactor core following any LOCA at a rate so that fuel and clad damage that could interfere with continued effective core cooling will be prevented

Specific review criteria are contained in SRP Sections 6.3 and 15.6.5 and other guidance provided in Matrix 8 of RS-001.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP, GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC)

The PBNP equivalent GDC for 10 CFR 50, Appendix A, GDC 4, 27 and 35 are as follows:

CRITERION: Adequate protection for those engineered safety features, the failure of which could cause an undue risk to the health and safety of the public, shall be provided against dynamic effects and missiles that might result from plant equipment failures. (PBNP GDC 40)

As stated in FSAR Section 6.1, Engineered Safety Features, Criteria, this plant-specific General Design Criterion is very similar to 10 CFR 50, Appendix A, GDC 4.

A loss-of-coolant accident or other plant equipment failure might result in dynamic effects. Injection paths leading to unbroken reactor coolant loops are protected against damage as a result of the maximum reactor coolant pipe rupture by layout and structural design considerations. Movement of the injection line, associated with rupture of a reactor coolant loop, is accommodated by line flexibility and by the design of the pipe supports such that no damage outside the loop compartment is possible.

All hangers, stops and anchors are designed in accordance with USAS B31.1, Code for Pressure Piping, and ACI 318, Building Code Requirements for Reinforced Concrete, which provide minimum requirements on material, design and fabrication with ample safety margin for both dead and dynamic loads over the life of the plant.

CRITERION: One of the reactivity control systems provided shall be capable of making the core subcritical under any anticipated operating condition (including anticipated operational transients) sufficiently fast to prevent exceeding acceptable fuel damage limits. Shutdown margin should assure subcriticality with the most reactive control rod fully withdrawn. (PBNP GDC 29)

FSAR Section 3.1, Reactor, Design Basis, also states that the reactor core, together with the reactor control and protection system, is designed so that the minimum allowable DNBR is at least equal to the limits specified for STD, OFA, upgraded OFA, and 422V+ fuel, and there is no fuel melting during normal operation, including anticipated transients.

The shutdown groups are provided to supplement the control group of RCCAs to make the reactor at least 1% subcritical (k_{eff} = 0.99) following a trip from any credible operating condition to the hot, zero power condition assuming the most reactive RCCA remains in the fully withdrawn position.

Sufficient shutdown capability is also provided to maintain the core subcritical for the most severe anticipated cooldown transient associated with a single active failure.

CRITERION: An emergency core cooling system (ECCS) with the capability for accomplishing adequate emergency core cooling shall be provided. This core cooling system and the core shall be designed to prevent fuel and clad damage that would interface with the emergency core cooling function and to limit the clad metal-water reaction to acceptable amounts for all sizes of breaks in the reactor coolant piping up to the equivalent of a double-ended rupture of the largest pipe. The performance of such emergency core cooling system shall be evaluated conservatively in each area of uncertainty. (PBNP GDC 44)

The performance capability of the ECCS is further discussed in FSAR Section 6.2, Engineered Safety Features, Safety Injection System. Adequate emergency core cooling is provided by the safety injection system (which constitutes the emergency core cooling system). The primary purpose of the safety injection system is to automatically deliver cooling water to the reactor core in the event of a loss-of-coolant accident. This limits the fuel clad temperature and thereby ensures that the core will remain intact and in place with its heat transfer geometry preserved.

The PBNP ECCS is capable of meeting the requirements of 10 CFR 50.46 and 10 CFR 50, Appendix K.

As noted in FSAR Section 14.3.2, Safety Analysis, Primary System Pipe Ruptures, Large Break Loss of Coolant Accident Analysis, the current LBLOCA analysis was performed using the Westinghouse LBLOCA WCOBRA/TRAC best-estimate methodology for plants which incorporate upper plenum injection in the safety injection system design. A LOCA evaluation methodology for plants equipped with RHR injection into the upper plenum was submitted to the NRC in 1995. A Request for Additional Information was issued by the NRC consisting of 49 questions regarding the submittal. Westinghouse responded to those questions and has successfully resolved all of the issues. This methodology has been approved by the NRC (Reference 1).

The thermal-hydraulic computer code which was reviewed and approved for the calculation of fluid and thermal conditions in the PWR during a LBLOCA is WCOBRA/TRAC Version MOD7A, Rev. 1 (Reference 2). WCOBRA/TRAC combines two-fluid, three-field, multi-dimensional fluid equations used in the vessel with one-dimensional drift-flux equations used in the loops to allow a complete and detailed simulation of a PWR. Additional detail is provided in FSAR Section 14.3.2.2, Safety Analysis, Primary System Pipe Ruptures, LBLOCA Analytical Model.

The small break loss-of-coolant accident (SBLOCA) analysis described in FSAR Section 14.3.1, Safety Analysis, Primary System Pipe Ruptures, Small Break loss of Coolant Accident Analysis, uses the NOTRUMP and LOCTA-IV (Reference 3 and Reference 4) computer codes. The NOTRUMP computer code is a state-of-the-art one-dimensional general network code consisting of a number of advanced features. Among these features are the calculation of thermal non-equilibrium in all fluid volumes, flow regime-dependent drift flux calculations with counter-current flow limitations, mixture level tracking logic in multiple-stacked fluid nodes, and regime-dependent heat transfer correlations. The NOTRUMP SBLOCA emergency core cooling system (ECCS) evaluation model was developed to determine the RCS response to design basis SBLOCAs and to address the NRC concerns expressed in NUREG-0611, Generic Evaluation of Feedwater Transients and Small Break Loss-of-Coolant Accidents in Westinghouse Designed Operating Plants.

The analysis of record for licensing basis peak cladding temperature (PCT), which includes margin assessments for plant change evaluations and ECCS evaluation model errors, is provided in NRC 2008-0025, ECCS Evaluation Model Changes.

Due to concerns regarding possible boron precipitation in the core after the recirculation phase is established, PBNP has a commitment to establish simultaneous or alternating cold leg and upper plenum injection flow within 14 hours after the occurrence of a LOCA. For most Westinghouse plants, this is referred to as the hot leg injection switchover time. Since PBNP is designed with upper plenum injection capability instead of hot leg injection, this term is not quite accurate, but is used to remain consistent with the industry. The intent of the hot leg injection switchover time requirement is to flush boron precipitate out of the core to prevent flow blockages that may inhibit post-LOCA cooling. The requirement to establish simultaneous or alternating upper plenum injection and cold leg injection is incorporated into the emergency operating procedures.

2.8.5.6.3.2 Technical Evaluation – LBLOCA

This section discusses the Large Break Best Estimate LOCA (LB BELOCA) analysis to support the proposed EPU for PBNP Units 1 and 2.

2.8.5.6.3.2.1 Introduction

In PBNP Units 1 and 2 License Amendment Request (LAR) 258, Incorporate Best Estimate Large Break Loss Of Coolant Accident (LOCA) Analyses Using ASTRUM, (Reference 6) which was submitted to the NRC November 25, 2008, PBNP submitted the LB BELOCA analysis using the Westinghouse Automated Statistical Treatment of Uncertainties Method (ASTRUM) methodology. The LB BELOCA ASTRUM methodology is described in Reference 5 for a major rupture of the reactor coolant pressure boundary (RCPB). A major rupture (large break) is defined as a breach in the RCPB with a total cross sectional area equal to or greater than 1.0 ft^2.

2.8.5.6.3.2.2 Input Parameters, Assumptions, and Acceptance Criteria

All input assumptions for the proposed EPU are provided in LAR 258, Incorporate Best Estimate Large Break Loss Of Coolant Accident (LOCA) Analyses Using ASTRUM, (Reference 6), which was submitted to the NRC November 25, 2008. The analyses input assumptions for the pending LAR 258 are applicable and appropriate for the proposed EPU.

2.8.5.6.3.2.3 Description of Analyses and Evaluations

The LB BELOCA analysis has been performed for PBNP Units 1 and 2 using the latest best-estimate methodology ASTRUM as documented in LAR 258, Incorporate Best Estimate Large Break Loss Of Coolant Accident (LOCA) Analyses Using ASTRUM, (Reference 6).

2.8.5.6.3.2.4 Results

The LB BELOCA analyses have been performed for PBNP Units 1 and 2 using the ASTRUM methodology as documented in LAR 258, Incorporate Best Estimate Large Break Loss Of Coolant Accident (LOCA) Analyses Using ASTRUM, (Reference 6). The results of the analyses demonstrate that the LB BELOCA acceptance criteria presented in 10 CFR 50.46 have been met for each unit.

Evaluation of Impact of Renewed Plant Operating License Evaluations and License Renewal Programs

The NRC issued PBNP license renewal safety evaluation report (SE), NUREG-1839 (Reference 27). The plant systems and components whose performance is relied upon to support the inputs, assumptions and results of the LOCA analyses are discussed in SER Section 3.2, Aging Management of Engineered Safety Features. EPU activities do not add any new functions for existing plant components relied upon to mitigate the effects of postulated LOCA events that would change the license renewal evaluation boundaries. Operation of these systems and components at EPU conditions does not introduce any unevaluated aging effects that would necessitate a change to aging management programs or require new programs as internal and external environments are within the parameters previously evaluated. The system and component performance capability in response to postulated LOCA events described in this section for the proposed EPU involves analytical techniques and methodology, which are unaffected by the proposed EPU, and the results of which remain bounded by the acceptance criteria of 10 CFR 50.46. Therefore, EPU activities associated with LBLOCA events do not impact license renewal scope, aging effects, and aging management programs.

2.8.5.6.3.3 Technical Evaluation – SBLOCA

2.8.5.6.3.3.1 Introduction

The small-break loss-of-coolant accident (SBLOCA) analysis is described in FSAR Section 14.3.1, Small Break Loss of Coolant Accident Analysis. A LOCA is defined as a rupture of the reactor coolant system (RCS) piping or any line connected to the system. The SBLOCA includes all postulated pipe ruptures with a total cross-sectional area less than 1.0 ft^2. The SBLOCAs analyzed in this section are for those breaks beyond the makeup capability of a single charging pump resulting in the actuation of the emergency core cooling system (ECCS). The analysis was performed to demonstrate conformance with the 10 CFR 50.46 requirements for the conditions associated with the Extended Power Uprate (EPU).

2.8.5.6.3.3.2 Input Parameters, Assumptions, and Acceptance Criteria

Key input parameters are summarized in Table 2.8.5.6.3-1, Input Assumptions and Initial Conditions, through Table 2.8.5.6.3-5, Low Head Safety Injection (LHSI) Flows vs. Pressure, Minimum Safeguards, (Upper Plenum Injection). PBNP and Westinghouse Electric Company LLC, used a process which ensured that SBLOCA analysis input values are representative of the as-operated plant values for those parameters. Furthermore, the SBLOCA analysis is based on PBNP specific models.

The acceptance criteria for the SBLOCA analysis are specified in 10 CFR 50.46, as follows:

1. The calculated maximum fuel element cladding temperature shall not exceed 2200°F.

2. The calculated total oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation.

3. The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam shall not exceed 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react.

4. Calculated changes in core geometry shall be such that the core remains amenable to cooling.

5. After any calculated successful initial operation of the ECCS, the calculated core temperature shall be maintained at an acceptably low value and decay heat shall be removed for the extended period of time required by the long-lived radioactivity remaining in the core. (Note that this criterion is not addressed as part of the short-term SBLOCA analysis. Please refer to LR Section 2.8.5.6.3.4, Post-LOCA Subcriticality and Long-Term Cooling.)

2.8.5.6.3.3.3 Description of Analyses and Evaluations

The SBLOCA analysis was performed for the EPU using the 1985 Westinghouse SBLOCA Evaluation Model with NOTRUMP (NOTRUMP-EM) (References 7 through 9), including NRC approved changes to the methodology (References 10 and 11). Westinghouse obtained generic NRC approval of the NOTRUMP computer code's modeling capabilities and solution techniques (Reference 7) and the use of the NOTRUMP computer code for licensing applications (Reference 8) in 1985. NRC approval of additional modeling details (Reference 9), such as limiting break location was obtained in 1986. The NOTRUMP-EM was later revised (Reference 10) and granted generic NRC approval for an improved condensation model and related changes in safety injection modeling assumptions for safety injection to the RCS cold legs. The NRC generically approved updates to the NOTRUMP-EM to include the ability to model annular fuel pellets (Reference 11) in the fuel rod heat-up calculations. The SBLOCA analysis was performed using the above mentioned methodology at EPU conditions to generate the results presented herein. The methodology employed consists of first calculating the system thermal hydraulic response to the SBLOCA event using the NOTRUMP code. These results are then analyzed for their effect on the hot rod heat up using the SBLOCTA code to demonstrate that the peak cladding temperature, cladding oxidation and hydrogen generation are below their limiting values as defined by 10 CFR 50.46 (Reference 13).

For the PBNP EPU SBLOCA analysis, a spectrum of cold leg breaks (1.5, 2, 3, 4, and 6 inch) as well as an accumulator line break of 8.75 inch has been analyzed which resulted in the 3 inch diameter cold leg break to be limiting. As a result of SBLOCA analysis submittals for various EPU and RSG programs, the NRC recently challenged Westinghouse on the coarseness of the standard NOTRUMP-EM break spectrum (i.e., 1.5, 2, 3, 4, and 6 inch). The Westinghouse position on the NOTRUMP-EM break spectrum was sent to the NRC (Reference 12) and included a proposed approach for future NOTRUMP-EM analyses. In any future applications of the NOTRUMP-EM, if any integer break size PCT is approximately equal to or greater than 1700°F, or if the PCT results are close to or greater than the corresponding LBLOCA PCT results, the analysis includes a refined break spectrum to assure 10 CFR 50.46 compliance. The results presented herein do not show PCTs approximately equal to or greater than 1700°F. Also, enough margin exists between the SBLOCA PCT and the LBLOCA PCT to justify not including a refined break spectrum in this analysis.

2.8.5.6.3.3.4 Results

Table 2.8.5.6.3-6, NOTRUMP Transient Results for Unit 1, through Table 2.8.5.6.3-9, BOL Rod Heatup Results for Unit 2, provide the NOTRUMP and SBLOCTA results for the SBLOCA analysis. The peak cladding temperatures are 1049°F and 1103°F and the maximum local transient oxidation values are 0.01% and 0.02% for Units 1 and 2, respectively. The total local oxidation (pre-transient plus transient oxidation) will remain below the 10 CFR 50.46 limit of 17% at all times in the life of the fuel. The core-wide hydrogen generation remains well below the 10 CFR 50.46 acceptance limit of 1%, and the core geometry remains amenable to cooling. The transient results for the limiting cases are provided in Figures 2.8.5.6.3-1 to 2.8.5.6.3-10.

Evaluation of Impact of Renewed Plant Operating License Evaluations and License Renewal Programs

The NRC issued PBNP license renewal safety evaluation report (SE), NUREG-1839, in December 2005 (Reference 27). The plant systems and components whose performance is relied upon to support the inputs, assumptions and results of the SBLOCA analyses are discussed in SER Section 3.2, Aging Management of Engineered Safety Features. EPU activities do not add any new functions for existing plant components relied upon to mitigate the effects of postulated SBLOCA events that would change the license renewal evaluation boundaries. Operation of these systems and components at EPU conditions does not introduce any unevaluated aging effects that would necessitate a change to aging management programs or require new programs as internal and external environments are within the parameters previously evaluated. The system and component performance capability in response to postulated LOCA events described in this section for the proposed EPU involves analytical techniques and methodology which are unaffected by the proposed EPU, and the results of which remain bounded by the acceptance criteria of 10 CFR 50.46. Therefore, EPU activities associated with SBLOCA events do not impact license renewal scope, aging effects, and aging management programs.

2.8.5.6.3.4 Post-LOCA Subcriticality and Long-Term Cooling

2.8.5.6.3.4.1 Introduction

Subcriticality

In support of the PBNP EPU, post-LOCA subcriticality sump boron calculations were performed. The methodology used to demonstrate PBNP compliance with the requirements of 10 CFR 50.46 Paragraph (b) is documented in WCAP-8339 (Reference 18). Reference 18 states that the core will remain subcritical post-LOCA by borated water from the various injected emergency core cooling system (ECCS) water sources. Post-LOCA sump boron calculations demonstrate that the core will remain subcritical upon entering and during the sump recirculation phase of ECCS injection. Containment sump boron concentration calculations were used to develop a core reactivity limit that was confirmed as part of the Westinghouse Reload Safety Evaluation Methodology (Reference 19).

Long-term Cooling

In support of EPU, a post-LOCA long-term cooling analysis was performed. There are two aspects to a long-term cooling analysis – preventing boric acid precipitation and maintaining long-term decay heat removal. This analysis satisfies the requirements of 10 CFR 50.46 Paragraph (b), Item (4) and 10 CFR 50.46, Paragraph (b), Item (5).

(4) Coolable Geometry. Calculated changes in core geometry shall be such that the core remains amenable to cooling.

(5) Long-term Cooling. After any calculated successful initial operation of the ECCS, the calculated core temperature shall be maintained at an acceptably low value and decay heat shall be removed for the extended period of time required by the long-lived radioactivity remaining in the core.

The injection and sump recirculation ECCS modes are described in FSAR Section 6.2, Safety Injection System (SI).

2.8.5.6.3.4.2 Technical Evaluation

Input Parameters, Assumptions, and Acceptance Criteria

Subcriticality

The input parameters and assumptions used in the sump boron calculations are given in Table 2.8.5.6.3-10, PBNP Units 1 and 2 Power Uprate Program Input Parameters. It is noted that a Tech Spec change to the accumulator and refueling water storage tank (RWST) minimum boron concentration is being made. The accumulator minimum boron concentration is being increased from 2600 ppm to 2700 ppm and the RWST minimum boron concentration is being increased from 2700 ppm to 2800 ppm.

The sump boron concentration calculational model is based on the following assumptions:

- The calculation of the sump mixed mean boron concentration assumes minimum mass and minimum boron concentrations for significant boron sources and maximum mass and minimum boron concentration for significant dilution sources
- Boron is mixed uniformly in the sump. The post-LOCA sump inventory is made up of constituents that are equally likely to return to the containment sump; that is, selective holdup in containment is neglected
- The sump mixed mean boron concentration is calculated as a function of the pre-trip RCS conditions

There are no specific acceptance criteria when calculating the post-LOCA sump boron concentration. The resulting sump boron concentration, which is calculated as a function of the pre-LOCA RCS boron concentration, is reviewed for each cycle-specific core design to confirm that adequate boron exists to maintain subcriticality in the long-term post-LOCA.

Long-term Cooling

The major inputs to the boric acid precipitation calculation include core power assumptions, assumptions for boron concentrations, and water volume/masses assumptions for significant contributors to the containment sump. The input parameters used in the PBNP power uprate boric acid precipitation calculations are given in Table 2.8.5.6.3-11, PBNP Post-LOCA Long-Term Cooling Analysis Input Parameters.

The boric acid precipitation calculation model is based on the following assumptions and meets NRC guidance as presented in Reference 14 and is consistent with the interim methodology reported in Reference 15. Additional detailed input assumptions are given with the description of each analysis in the results section.

- The boric acid concentration in the core region was computed over time with consideration of the effect of core voiding on liquid mixing volume. For the LBLOCA case, core voiding is calculated using the time-varied mixing volume and boil-off rate derived from a modified PBNP Units 1 and 2 WCOBRA/TRAC LBLOCA thermal-hydraulic (T/H) analysis. For the SBLOCA case, core voiding is calculated using the time-varied mixing volume and boil-off rate derived from a modified PBNP Units 1 and 2 NOTRUMP SBLOCA T/H analysis
- The core mixing volume used in the calculations considered the potential negative effects of loop pressure drop
- The boric acid concentration limit is the experimentally determined boric acid solubility limit as reported in Reference 16 and summarized in Table 2.8.5.6.3-12, Boric Acid Solution Solubility Limit, and Figure 2.8.5.6.3-12. For large breaks, the effect of containment or RCS pressure above atmospheric pressure is not credited and the boric acid solubility limit at 218°F (boiling point of saturated boric acid solution at atmospheric conditions) is assumed. For breaks where RCS depressurization is not complete or breaks where the RCS might be at elevated pressures at return to simultaneous injection, the solubility limit associated with the saturation temperature of water at the associated elevated pressure is not credited
- The liquid mixing volume used in the calculation includes 50% of the lower plenum as justified in Reference 17
- For SBLOCA scenarios, the analysis does not assume a specific start time for cooldown/depressurization emergency procedures. For the purpose of defining expected scenarios, it is anticipated that operators begin cooldown/depressurization within one hour of the initiation of the event
- The effect of containment sump pH additives on increasing the boric acid solubility limit is not credited
- The boric acid concentration of the makeup containment sump water during recirculation is a calculated sump mixed mean boron concentration. The calculation of the sump mixed mean boron concentration assumes maximum mass and maximum boron concentrations for significant boron sources, and minimum mass and maximum boron concentrations for significant dilution sources

- ECCS flow and enthalpy changes that may occur during the switchover from injection mode to sump recirculation are not part of the long-term cooling analysis, but were considered in the SBLOCA analysis
- NRC requirements pertaining to the decay heat generation rate for both boric acid accumulation and decay heat removal (1971 ANS Standard for an infinite operating time with 20 percent uncertainty) was considered when performing the boric acid precipitation calculations. The assumed core power includes a multiplier to address instrument uncertainty as identified by Section 1.A of 10 CFR 50, Appendix K
- ECCS recirculation flows are evaluated by comparing minimum safety injection pump flows to the flows necessary to dilute the core and replace core boiloff, thus keeping the core quenched

The acceptance criteria for the long-term cooling analysis are demonstrated by the ability to keep the core cool after a LOCA and by calculating a boric acid precipitation time with methods, plant design assumptions, and operating parameters that are consistent with the interim methodology reported in Reference 15. The FSAR and Emergency Operating Procedures (EOPs) will be revised, as needed, to support the latest time to restore simultaneous injection.

Description of Analyses and Evaluations

Subcriticality

With respect to post-LOCA criticality, a post-LOCA subcriticality boron limit curve was developed for the power uprate plant conditions. Provided that the cycle-specific maximum critical boron concentration remains below the post-LOCA sump boron concentration limit curve (for all rods out, no Xenon, 68–212°F), the core will remain subcritical post-LOCA, and the only heat generation will be that due to the remaining long-lived radioactivity. This criterion will be evaluated on a cycle-to-cycle basis in accordance with the reload evaluation methodology (Reference 19).

Long-term Cooling

PBNP Units 1 and 2 EPU Long -Term Cooling Boric Acid Precipitation Control Plan

PBNP Units 1 and 2 are an upper plenum injection (UPI) design (i.e., the low head residual heat removal (RHR) pump delivers flow directly to the upper plenum, while the high head safety injection (SI) pump injects into the reactor coolant system (RCS) cold legs). For breaks large enough to depressurize the RCS below the RHR shut-off head (135 psia) prior to the transfer to recirculation, simultaneous hot (UPI) and cold side injection will occur during the injection phase. The transfer to the recirculation phase can occur as early as 20 minutes following a LBLOCA when the refueling water storage tank (RWST) has been drained to a level of ≤34%. In preparation for the transfer to recirculation, RHR pump suction valve alignments are performed to ensure that there is no interruption in RHR pump UPI flow during the transfer. Upon completing the RHR pump transfer to recirculation, flow from the SI pump is terminated in accordance with EOP-1.3. The RHR pump initially delivers full flow to the upper plenum and the containment spray pump continues to draw from the RWST until the level in the tank reaches ≤12.5%, approximately one hour after the event. At this point, the containment spray (CS) pump is aligned for recirculation. In this mode of operation, the CS pump takes suction from the RHR pump discharge thereby reducing RHR flow to the reactor vessel to 500 gpm (AST LAR 241). The CS pump will operate for three hours after it is restarted in recirculation mode (1 hour, 20 minutes into transient). The SI pump also takes suction from the RHR pump discharge during recirculation, but cannot be used while the CS pump is operating in recirculation. Because of this constraint, the earliest time that simultaneous RHR and SI recirculation can occur is approximately 4 hours, 20 minutes after the start of the transient. The LBLOCA boric acid precipitation control analysis calculates the latest time after the termination of cold leg SI that flow must be restarted in the recirculation phase to restore simultaneous injection to flush the reactor vessel of high concentration boric acid solution.

For smaller breaks that do not depressurize the RCS below the RHR cut-in pressure prior to the transfer to recirculation, only cold leg SI will occur during the injection phase. The high head SI transfer to recirculation (EOP-1.4) is accomplished by first aligning the high head SI pump suction to the discharge of the RHR pump whose suction is aligned to the RWST. When RWST level reaches $\leq$ 34%, the RHR pump suction is aligned to the containment sump in the same manner as for the large break described previously. The CS pump is used to draw the RWST down to $\leq$ 12.5% level in order to add the NaOH buffer to adjust the containment sump pH. The SBLOCA boric acid precipitation control analysis calculates the latest time after the event that the RCS must be depressurized below the RHR cut-in pressure in order to establish upper plenum injection to flush the reactor vessel of high concentration boric acid solution.

Three categories of LOCA break sizes were considered for the boric acid precipitation evaluation: (1) large breaks (greater than approximately 5" in diameter) where the RCS pressure rapidly decreases to the UPI initiation pressure (135 psia) with no operator action, (2) small breaks (between approximately 1.2" and 5" in diameter) where RCS pressure decreases but stabilizes above the UPI initiation pressure, and (3) very small breaks (approximately 1.2" in diameter and smaller) where high head SI refills the RCS and natural circulation is established.

For large breaks in the cold leg, boric acid precipitation was found to not occur since the RCS will depressurize quickly and upper plenum injection will provide flushing flow through the core.

For large breaks in the hot leg, the boric acid concentration in the reactor vessel will only begin to increase with the termination of high head SI to the cold legs, which can occur as early as 20 minutes after the event. Analysis performed using the WCOBRA/TRAC thermal-hydraulic computer code demonstrates that the flow rates and distribution in the reactor vessel will prevent boric acid from concentrating during the first 20 minutes. Calculations for a LBLOCA scenario show that the boric acid solution will approach the solubility limit for atmospheric pressure conditions at 4 hours, 30 minutes after the termination of high head SI to the cold legs. For the EPU, EOP-1.3, Transfer to Sump Recirculation – Low Head Injection, will be revised to instruct operators to re-establish cold leg SI (i.e., simultaneous injection) no later than 4 hours, 30 minutes after the termination of SI in the cold leg (4 hours, 50 minutes after the start of the transient). With this action, boric acid precipitation will be prevented.

For small breaks in the cold leg, RCS pressure will stabilize above the low head RHR cut-in pressure and the boric acid concentration in the reactor vessel will increase until upper plenum injection is established. Emergency Operating Procedure ES-1.2, Post-LOCA Cooldown and Depressurization directs the operators in this scenario to depressurize the RCS using the condenser steam dump, steam generator power atmospheric dump valves, or pressurizer power operated relief valve(s). Calculations for depressurization after a SBLOCA scenario show that the boric acid solution will not approach the solubility limit until approximately 7 hours after the break. When the RCS is depressurized through operator action to below 135 psia, the low head RHR pump flow to the upper plenum will provide immediate core flushing flow. Operational experience, simulator training, and NOTRUMP SBLOCA cooldown/depressurization analyses indicate that operators will depressurize the RCS to less than 135 psia before 7 hours after the break. Results from the SBLOCA boric acid precipitation control analysis demonstrate that, if upper plenum low head RHR is established within 7 hours after the break, boric acid precipitation is precluded even for sudden RCS depressurization to atmospheric pressure.

For small breaks in the hot leg, RCS pressure will again stabilize above the low head RHR cut-in pressure. The boric acid concentration in the reactor vessel will not increase until the cold leg high head SI is terminated. Operators are again directed to depressurize the RCS, and maintain upper plenum injection using the RHR pumps on recirculation and terminate the high head SI as necessary. Once high head SI to the cold leg is terminated, this scenario is bounded by the large hot leg break scenario where cold leg SI (i.e., simultaneous injection) will be re-established no later than 4 hours, 30 minutes after termination.

For very small hot leg or cold leg breaks (less than approximately 1.2" in diameter) the RCS remains pressurized such that natural circulation will not be lost, or if lost, will be re-established. Emergency Operating Procedure (EOP) actions will cooldown and depressurize the RCS under controlled conditions with eventual realignment to normal RHR shutdown cooling. Natural circulation or normal RHR shutdown cooling will dilute any build-up of boric acid in the core.

A summary of the PBNP Units 1 and 2 EPU long-term cooling post-LOCA boric acid control strategy for various size breaks is shown in Table 2.8.5.6.3-13, Post-LOCA Boric Acid Precipitation Analysis Logic for 2-Loop UPI Plant, and Figure 2.8.5.6.3-13.

To summarize the procedural requirements related to preventing boric acid precipitation:

1. During a LOCA when high head SI flow to the cold leg is terminated upon entering sump recirculation, high head SI flow to the cold leg will be re-established within 4 hours and 30 minutes after initial termination.

2. During a SBLOCA, the RCS will be depressurized to less than the upper plenum low head RHR shut-off head within 7 hours after the break occurs.

3. During a SBLOCA when RCS depressurization to the upper plenum low head RHR shut-off head does not occur without operator action, operators will take action to initiate a plant cooldown and depressurization at the maximum Technical Specification allowed cooldown rate within one hour after the break occurs.

These procedural requirements will be captured in emergency operating procedures or background documents and will be incorporated into the operator training program.

Evaluation of Impact of Renewed Plant Operating License Evaluations and License Renewal Programs

The NRC issued the PBNP license renewal safety evaluation report (SE), NUREG-1839, in December 2005 (Reference 27). The plant systems and components whose performance is relied upon to support the inputs, assumptions and results of the Post-LOCA analyses are discussed in SER Section 3.2, Aging Management of Engineered Safety Features. EPU activities do not add any new functions for existing plant components relied upon to mitigate the effects of Post-LOCA events that would change the license renewal evaluation boundaries. Operation of these systems and components at EPU conditions does not introduce any unevaluated aging effects that would necessitate a change to aging management programs or require new programs as internal and external environments are within the parameters previously evaluated. Therefore, EPU activities associated with Post-LOCA events do not impact license renewal scope, aging effects, and aging management programs.

Results

Subcriticality

A post-LOCA subcriticality boron limit curve was developed for the Power Uprate plant conditions. The PBNP Power Uprate Post-LOCA subcriticality boron limit curve is shown in Figure 2.8.5.6.3-11, PBNP Power Uprate Post-LOCA Subcriticality Boron Limit Curve. Technical Specification changes for the EPU are outlined in Table 2.8.5.6.3-10, PBNP Units 1 and 2 Power Uprate Program Input Parameters. The Technical Specification changes include an increase of the minimum boron concentration requirement of the RWST and accumulators to 2800 ppm and 2700 ppm, respectively.

Long-term Cooling

LBLOCA Boric Acid Precipitation Control Analysis

A LBLOCA boric acid precipitation control analysis was performed to address the limiting LBLOCA scenario. That is, breaks in the hot leg where the boric acid concentration in the reactor vessel will begin to increase with the termination of high head SI to the cold legs.

The analysis was based on calculations that used a time-varied mixing volume and boil-off rate derived from a modified PBNP Units 1 and 2 WCOBRA/TRAC LBLOCA reactor coolant system thermal-hydraulic analysis. The modifications to the PBNP Units 1 and 2 WCOBRA/TRAC model were as follows:

- Appendix K decay heat was used (1971 ANS, Infinite Operation + 20%)
- A hot leg break was modeled (the limiting large break scenario for concentrating boric acid)
- Emergency core cooling system (ECCS) flows representative of long-term ECCS performance including sump recirculation were modeled
- The transient was extended to beyond switchover to sump recirculation

The use of the WCOBRA/TRAC thermal-hydraulic analysis has the following advantages:

a. Appropriate capturing of system effects on core mixture level and core void fractions

b. Appropriate capturing of upper plenum low head RHR effects such as counter-current flow limitation and entrainment/de-entrainment on core mixture level and core void fractions

c. Direct source for mixing volume and boil-off rate

d. Consistency with assumptions used in 10 CFR 50.46 PCT calculations

Items a) and b) above satisfy the NRC request to consider void fraction and system effects in the calculation of the reactor vessel mixing volume (Reference 14, Item 1 and Item 2).

The significant assumptions in the large break boric acid precipitation calculations are as follows:

1. The reactor vessel mixing volume is limited to the region from the bottom of the active fuel to the bottom elevation of the hot legs plus 50% of the lower plenum (justified in Reference 17) volume (the region from the bottom of the active fuel to the bottom of the reactor vessel). Hot leg volume or barrel/baffle/former region volumes are not included.

2. Core boil-off rates are obtained in part from the PBNP Units 1 and 2 WCOBRA/TRAC thermal-hydraulic analysis. The core boil-off rate used in the calculations is given in Figure 2.8.5.6.3-16.

3. Time-based liquid mixing volume is extracted from the PBNP Units 1 and 2 WCOBRA/TRAC thermal-hydraulic analysis. The core and upper plenum average voiding assumed in the analysis is given in Figure 2.8.5.6.3-14. The associated mixing volume used in the calculations is given in Figure 2.8.5.6.3-15.

4. The calculations were based on a reactor vessel pressure of 14.7 psia.

5. An atmospheric boric acid solution solubility limit of 29.27 wt% is assumed. This represents the solubility limit at the atmospheric boiling point of a boric acid and water solution (Reference 16). No credit was taken for containment overpressure. No credit was taken for the increased boric acid solution solubility limit due to the presence of containment sump pH additives.

6. Appendix K decay Heat (1971 ANS, Infinite Operation + 20%) was used in all calculations.

Item 5 above satisfies the NRC request to justify the boric acid precipitation limit (Reference 14, Item #3). Item 6 above satisfies the NRC request to use 10 CFR 50 Appendix K decay heat (Reference 14, Item #4).

The results of the large break boric acid precipitation calculations are shown in Figure 2.8.5.6.3-16. As seen in Figure 2.8.5.6.3-16, for large hot leg breaks with no cold leg high head SI during an extended period in sump recirculation, boric acid precipitation will be prevented if cold leg high head SI (i.e., simultaneous injection) is re-established 4 hours, 30 minutes after the termination of SI to the cold leg. This conclusion is based on a calculated minimum time to terminate SI to the cold leg of 20 minutes after the break. Figure 2.8.5.6.3-16 also shows core boil-off, SI dilution flow, and the rate of dilution in the core region if dilution flow is initiated at 4 hours, 30 minutes after the earliest expected termination of cold leg safety injection.

SBLOCA Boric Acid Precipitation Control Analysis

A SBLOCA boric acid precipitation control analysis was performed to address the limiting SBLOCA scenario. That is, breaks in the cold leg where the RCS pressure will stabilize above the upper plenum low head RHR cut-in pressure and the core region boric acid concentration will begin to increase prior to RHR injection. This analysis provides the time available to depressurize the RCS to below 120 psia through operator action prior to reaching the boric acid solution solubility limit. Once the RCS is below 120 psia, the upper plenum RHR will have initiated and will provide core flushing flow. The boric acid solution solubility limit is based on atmospheric conditions to account for an inadvertent, sudden RCS depressurization.

The results of the small break boric acid precipitation calculations are shown in Figure 2.8.5.6.3-20. As seen in Figure 2.8.5.6.3-20, for small breaks where delayed RCS depressurization would occur, the boric acid solution will not approach the solubility limit until approximately 7 hours after the break. If the RCS is depressurized through operator action to below 120 psia, upper plenum injection using the low head RHR pump will provide core flushing flow. Cooldown/depressurization calculations show that operators could depressurize the RCS to less than the RHR cut-in pressure long before 7 hours. Figure 2.8.5.6.3-20 also shows core boil-off, SI dilution flow, and the rate of dilution of core region if dilution flow is initiated at 7 hours after the break.

Small Break Post-LOCA Cooldown Analysis

A range of break sizes were studied to identify the smallest cold leg break for PBNP Units 1 and 2 that would result in the loss of natural circulation and thus a situation that could lead to boric acid precipitation. The small break Post-LOCA cooldown analysis used the following assumptions:

1. Appendix K analysis assumptions consistent with those used for design basis SBLOCA analysis.

2. Operator action to start plant cooldown per EOP ES-1.2 commences at 3600 seconds (1 hour) into the transient using 1 power operated relief valve per steam generator. The cooldown rate is limited to a maximum of 100°F/hr.

The SBLOCA boric acid precipitation control analysis was based on calculations that used a time-varied mixing volume and core boil-off extracted from an extended PBNP Units 1 and 2 NOTRUMP thermal-hydraulic analysis. A 5-inch break was selected since the PBNP Units 1 and 2 EPU NOTRUMP thermal-hydraulic analysis showed that this break size or greater will depressurize the RCS to RHR cut-in pressure without operator actions prior to reaching the boric acid atmospheric solubility limit. The RCS pressure versus time for a 5-inch break is given in Figure 2.8.5.6.3-17. The modeling features of the NOTRUMP runs were as follows:

- Appendix K decay heat (1971 ANS, Infinite Operation + 20%).
- Cold leg break (the limiting small break scenario for boric acid buildup).
- High head SI sump recirculation flows were modeled.
- Low head RHR flows were not modeled.
- The transient was extended to beyond switchover to sump recirculation.

The use of the PBNP Units 1 and 2 NOTRUMP thermal-hydraulic analysis has the following advantages:

a. Appropriate capturing of system effects on core mixture level and core void fractions (credited only to bottom of hot leg).

b. Direct source for mixing volume and core boiloff rates.

c. Consistency with assumptions used in 10 CFR 50.46 PCT calculations.

Item (a) above satisfies the NRC request to consider void fractions and system effects in the calculation of core mixing volume (Reference 14, Item 1 and Item 2).

The significant assumptions used in the SBLOCA boric acid precipitation calculations are as follows:

1. Time-based liquid mixing volume and core boiloff rates are extracted from the PBNP Units 1 and 2 NOTRUMP thermal-hydraulic analysis. The core and upper plenum average voiding assumed in the analysis is given in Figure 2.8.5.6.3-18. The associated mixing volume used in the calculations is given in Figure 2.8.5.6.3-19.

2. Core region boric acid concentrations are calculated assuming an RCS pressure of 120 psia.

3. The core region mixing volume is limited to the region from the bottom of the active fuel to the bottom elevation of the hot legs plus 50% of the lower plenum (justified in Reference 17) volume (the region from the bottom of the active fuel to the bottom of the reactor vessel). Hot leg volume or barrel/baffle/former region volumes are not included.

4. An atmospheric boric acid solution solubility limit of 29.27 wt% is assumed. This represents solubility limit at the atmospheric boiling point of a boric acid and water solution (Reference 16). No credit was taken for containment overpressure. No credit was taken for the increased boric acid solution solubility limit due to the presence of containment sump pH additives.

5. Appendix K decay heat (1971 ANS, Infinite Operation + 20%) was used in all calculations.

Item 4 above satisfies the NRC request to justify the boric acid precipitation limit (Reference 14, Item 3). Item 5 above satisfies the NRC request to use 10 CFR 50 Appendix K decay heat (Reference 14, Item 4).

A range of break sizes were studied to identify the smallest cold leg break size that would result in the loss of natural circulation and result in a situation that could potentially lead to inadvertent boric acid precipitation.

Based on the results of these studies, it was determined that breaks approximately 1.2-inch equivalent diameter and less will maintain (or restore) natural circulation, whereas larger breaks will not. It is possible that during the cooldown process these larger breaks could potentially regain natural circulation at some point. There will be some break size where this does not occur. For PBNP Units 1 and 2, this phenomenon occurs for approximately a 1.2-inch equivalent diameter break. Figures 2.8.5.6.3-21 and 2.8.5.6.3-22 show the broken loop hot leg and cold leg liquid flow for the 0.9-inch and 1.2-inch breaks, respectively. The pressurizer pressure and broken loop hot leg mixture temperature for these same breaks is shown in Figure 2.8.5.6.3-23 and Figure 2.8.5.6.3-24, respectively, and the inner vessel mixture level is shown in Figure 2.8.5.6.3-25 and Figure 2.8.5.6.3-26, respectively.

The 1.2-inch break demonstrates the cooldown aspects for breaks where natural circulation is lost and not regained. This break size establishes the maximum time available to cool down and depressurize the RCS to the UPI cut-in pressure. This analysis shows that the operators will be capable of depressurizing the RCS to the UPI cut-in pressure within approximately 7 hours after the break occurs. This assumes the cooldown begins within 1 hour after the break occurs.

2.8.5.6.3.4.3 Conclusions

Subcriticality

Cycle-specific reload safety evaluations will ensure that the core will remain subcritical post-LOCA, thus ensuring that the combined reactivity control systems capability is maintained.

Long-term Cooling

For breaks large enough to quickly depressurize the RCS below the RHR shut-off head without operator action, the limiting boric acid precipitation scenario is a break in the RCS hot leg. The PBNP power uprate post-LOCA boric acid precipitation calculations used conservative methodology to calculate the appropriate time to restore to cold leg injection once it is terminated for this scenario. Restored SI flow to the cold leg at 4 hours, 30 minutes after termination provides effective core dilution thus precluding boric acid precipitation in the core.

For smaller breaks that do not quickly depressurize the RCS below the RHR shut-off head without operator action, the limiting boric acid precipitation scenario is a break in the RCS cold leg. The PBNP power uprate post-LOCA boric acid precipitation calculations used conservative methodology to calculate the time the operators have to depressurize the RCS below the RHR cut-in pressure before boric acid precipitation levels are reached. RHR flow to the upper plenum prior to 7 hours provides effective core dilution thus precluding boric acid precipitation in the core for this scenario.

These calculations address the requirements of 10 CFR 50.46(b)(4) coolable geometry and 10 CFR 50.46(b)(5) long-term cooling. The long-term cooling analyses for the power uprate show that no changes to the PBNP ECCS are required.

2.8.5.6.3.5 Technical Evaluation - LOCA Forces

2.8.5.6.3.5.1 Introduction

The analysis of the LOCA hydraulic forces generates the hydraulic forcing functions that act on reactor coolant system (RCS) components as a result of a postulated LOCA. The current licensing basis, with respect to the LOCA hydraulic forces, is a combination of MULTIFLEX 1.0 and 3.0 analyses performed for the large branch line breaks performed in support of the Replacement Steam Generators (RSGs) and pwer uprate, and MULTIFLEX 3.0 analyses performed for baffle-former-barrel bolt distributions including fuel qualification, and alnayses.

The most recent qualification of the vessel internals and fuel was performed using an advanced beam model version of MULTIFLEX 3.0 (Reference 20), in accordance with methodology approved by the NRC in WCAP-15029-P-A (Reference 21). This same version of the MULTIFLEX code was used in the LOCA hydraulic forces analysis for the PBNP EPU.

2.8.5.6.3.5.2 Input Parameters

To conservatively calculate LOCA hydraulic forces for PBNP, the following operating conditions, presented in LR Section 1.1, Nuclear Steam Supply System Parameters and LR Section 2.2.6, NSSS Design Transients, were determined in establishing the limiting temperatures and pressures:

- Initial RCS conditions associated with a minimum thermal design flow of 89,000 gpm per loop
- A nominal RCS hot full power (HFP) T_{avg} range of 558.0°F to 577.0°F. This provides an RCS T_{cold} range of 523.1° to 542.9°F.(consistent with a nuclear steam supply system (NSSS) power of 1806 MWt)
- An RCS temperature uncertainty of ±6.4°F
- A feedwater temperature range of 390.0°F to 458.0°F
- A nominal RCS pressure of 2250 psia
- A pressurizer pressure uncertainty of ±50 psi

Based on these conditions, the LOCA forces were generated at a minimum T_{cold} of 516.7°F, including uncertainty, and a pressurizer pressure of 2300 psia, including uncertainty.

2.8.5.6.3.5.3 Assumptions

The NRC allows main coolant piping breaks to be "...excluded from the design basis when analyses reviewed and approved by the Commission demonstrate that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping." This exemption is generally referred to as leak-before-break (LBB). The analyses presented in WCAP-15107, WCAP-15065 and WCAP-15105 (References 24 through 26) are technical justification for eliminating primary loop pipe ruptures from the design basis. Thus, the primary loop piping breaks did not need to be considered when generating PBNP LOCA hydraulic forces. Therefore, the next limiting RCS break sizes are the smaller auxiliary (or branch) lines connected to the RCS. The smaller branch line breaks analyzed for hydraulic forces are the 3 inch charging line in the cold leg and the 6 inch capped nozzle line connection to the hot leg.

2.8.5.6.3.5.4 Acceptance Criteria

LOCA hydraulic forces were provided as input to structural qualification analyses and, as such, had no independent regulatory acceptance criteria. The structural analyses performed using these forcing functions were performed to demonstrate compliance with PBNP, GDC 40 which is very simialr to 10 CFR 50, Appendix A, GDC-4.

2.8.5.6.3.5.5 Description of Analyses and Evaluations

LOCA forces were generated with a focus on the component of interest: loop piping, reactor vessel internals, or steam generator using the advanced beam model version of MULTIFLEX 3.0 (Reference 20), assuming a conservative break opening time of 1 millisecond.

The improved modeling results in lower, more realistic, but still conservative, hydraulic forces on the core barrel.

The MULTIFLEX computer code calculated the thermal-hydraulic transient within the RCS and considered subcooled, transition, and early two-phase (saturated) blowdown regimes. The code used the method of characteristics to solve the conservation laws, assuming one-dimensional (1-D) flow and a homogeneous liquid-vapor mixture. The RCS was divided into sub-regions in which each subregion was regarded as an equivalent pipe. A complex network of these equivalent pipes was used to represent the entire primary RCS.

For the reactor pressure vessel (RPV) and specific vessel internal components, the MULTIFLEX code generated the LOCA thermal-hydraulic transient that was input to the LATFORC and FORCE2 post-processing codes WCAP-8708-P-A (Reference 22). These codes, in turn, were used to calculate the actual forces on the various components.

These forcing functions for horizontal and vertical LOCA hydraulic forces, combined with seismic, thermal, and system shaking loads, were used in the structural evaluations to determine the resultant mechanical loads on the vessel and vessel internals.

The loop forces analysis used the THRUST post-processing code to generate the X, Y and Z directional component forces during a LOCA blowdown from the RCS pressure, density, and mass flux calculated by the MULTIFLEX code. The THRUST code is described and documented in WCAP-8252 (Reference 23).

Steam generator hydraulic transient time-history data were extracted directly from the MULTIFLEX output and evaluated against the steam generator data. Similarly, hydraulic transient time-history data used in qualification of some reactor vessel internal components, such as baffle bolts or RCCA guide tubes, were also extracted directly from the MULTIFLEX output.

2.8.5.6.3.5.6 Results

For the EPU, all relevant LOCA hydraulic forces analyses were performed directly at the analyzed NSSS power level of 1806 MWt, using models specific to the PBNP NSSS design. These analyses included the reactor vessel internals, loop piping, and steam generator. The results of the analyses were then used as input to the structural analyses for component qualification.

Evaluation of Impact of Renewed Plant Operating License Evaluations and License Renewal Programs

The NRC issued its PBNP license renewal safety evaluation report (SE), NUREG-1839, in December 2005 (Reference 27). EPU activities associated with LOCA forces analyses do not add any new functions for existing plant components relied upon to mitigate the effects of LOCA events that would change the license renewal evaluation boundaries. Operation of these systems and components at EPU conditions does not introduce any unevaluated aging effects that would necessitate a change to aging management programs or require new programs as internal and external environments are within the parameters previously evaluated. Therefore, EPU activities associated with LOCA forces analyses do not impact license renewal scope, aging effects, and aging management programs.

2.8.5.6.3.6 Conclusions

PBNP has reviewed the analyses of the LOCA events and the ECCS. PBNP concludes that the analyses have adequately accounted for operation of the plant at the proposed power level and that the analyses were performed using acceptable analytical models. PBNP further concludes that the reactor protection system and the ECCS will continue to ensure that the peak cladding temperature, total oxidation of the cladding, total hydrogen generation, and changes in core geometry, and long-term cooling will remain within acceptable limits. PBNP concludes that the plant will continue to meet the requirements of PBNP, GDCs 40, 29, 44, 30 and 10 CFR 50.46 following implementation of the proposed EPU. Therefore, PBNP finds the proposed EPU acceptable with respect to the LOCA

2.8.5.6.3.7 References

1. Letter, USNRC to Westinghouse, Acceptance for Referencing of the Topical Report WCAP-14449(P), Application of Best Estimate Large Break LOCA Methodology to Westinghouse PWRs With Upper Plenum Injection, (TAC No. M94035), May 21, 1999

2. Bajorek, S. M., et al., 1998, Westinghouse Code Qualification Document for Best Estimate Loss of Coolant Accident Analysis, WCAP 12945-P-A (Proprietary), Volume I, Revision 2, and Volumes II-V, Revision 1, and WCAP-14747 (Non-Proprietary)

3. Lee, N., et. Al., Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code, WCAP-10054-P-A (Proprietary) and WCAP-10081-A (Non-Proprietary), August 1985

4. Bordelon, F. M., et. Al., LOCTA-IV Program: Loss-of-Coolant Transient Analysis, WCAP-8301 (Proprietary), WCAP-8305 (Non-Proprietary) June 1974

5. M. E. Nissley et. al., Realistic Large-Break LOCA Evaluation Methodology Using the Automated Statistical Treatment of Uncertainty Method (ASTRUM), WCAP-16009-P-A (Proprietary Version), WCAP-16009-NP-A (Non-Proprietary Version), January 2005

6. PBNP LAR 258, Incorporate Best Estimate Large Break Loss Of Coolant Accident (LOCA) Analyses Using ASTRUM, dated November 25, 2008

7. WCAP-10079-P-A, NOTRUMP – A Nodal Transient Small Break and General Network Code, Meyer, P. E., August 1985

8. WCAP-10054-P-A, Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code, Lee, N., et al., August 1985

9. WCAP-11145-P-A, Westinghouse Small Break LOCA ECCS Evaluation Model Generic Study with the NOTRUMP Code, Rupprecht, S. D., et al., October 1986

10. WCAP-10054-P-A, Addendum 2, Revision 1, Addendum to the Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code: Safety Injection into the Broken Loop and COSI Condensation Model, Thompson, C. M., et al., July 1997

11. WCAP-14710-P-A, 1-D Heat Conduction Model for Annular Fuel Pellets, Shimeck, D. J., May 1998

12. LTR-NRC-06-44, Transmittal of LTR-NRC-06-44 NP-Attachment, 'Response to NRC Request for Additional Information on the Analyzed Break Spectrum for the Small Break Loss of Coolant Accident (SBLOCA) NOTRUMP Evaluation Model (NOTRUMP EM), Revision 1,' (Non-Proprietary), Gresham, J. A., July 2006

13. 10 CFR 50.46, Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Nuclear Power Reactors

14. NRC letter dated November 23, 2005, Clarification of NRC Letter Dated August 1, 2005, Suspension of NRC Approval for Use of Westinghouse Topical Report CENPD-254-P, Post-LOCA Long-Term Cooling Model, Due to Discovery of Non-Conservative Modeling Assumptions During Calculations Audit (TAC NO. MB1365)," (ML052930272)

15. Letter dated October 3, 2006 from Office of Nuclear Reactor Regulation, NRC to Division of Policy and Rulemaking, Office of Nuclear Reactor Regulation, NRC, Summary Of August 23, 2006 Meeting with the Pressurized Water Reactor Owners Group (PWROG) to Discuss the Status of Program to Establish Consistent Criteria For Post Loss-Of-Coolant (LOCA) Calculations, (ML062690017)

16. P. Cohen, Water Coolant Technology of Power Reactors, Chapter 6, Chemical Shim Control and pH Effect, ANS-USEC Monograph, 1980 (Originally published in 1969)

17. W3FI-2005-0007, Supplement to Amendment Request NPF-38-249, Extended Power Uprate, Waterford Steam Electric Station, Unit 3, February 5, 2005

18. WCAP-8339, Westinghouse Emergency Core Cooling System Evaluation Model - Summary, June 1974

19. WCAP-9272-P-A, Westinghouse Reload Safety Evaluation Methodology, July 1985

20. WCAP-9735, Rev. 2, (Proprietary), and WCAP-9736, Rev. 1, (Nonproprietary), MULTIFLEX 3.0 A FORTRAN-IV Computer Program for Analyzing Thermal-Hydraulic-Structural System Dynamics Advanced Beam Model, K. Takeuchi, et al., February 1998

21. WCAP-15029-P-A (Proprietary) and WCAP-15030-NP-A (Nonproprietary), Westinghouse Methodology for Evaluating the Acceptability of Baffle-Former-Barrel Bolting Distributions Under Faulted Load Conditions, R. E. Schwirian, et al., January 1999

22. WCAP-8708-P-A (Proprietary) and WCAP-8709-A (Nonproprietary), MULTIFLEX A FORTRAN-IV Computer Program for Analyzing Thermal-Hydraulic-Structure System Dynamics, K. Takeuchi, et al., September 1977

23. WCAP-8252 (Nonproprietary), Rev. 1, Documentation of Selected Westinghouse Structural Analysis Computer Codes, K. M. Vashi, May 1977

24. WCAP-15107 (Proprietary) and WCAP-15108 (Nonproprietary), Technical Justification for Eliminating Accumulator Rupture as the Structural Design Basis for Point Beach Units 1 and 2 Nuclear Plants, October 1998

25. WCAP-15065 (Proprietary) and WCAP-15066 (Nonproprietary), Technical Justification for Eliminating Pressurizer Surge Line Rupture as the Structural Design Basis for Point Beach Units 1 and 2 Nuclear Plants, August 1998

26. WCAP-15105 (Proprietary) and WCAP-15106 (Nonproprietary), Technical Justification for Eliminating Residual Heat Removal (RHR) Rupture as the Structural Design Basis for Point Beach Units 1 and 2 Nuclear Plants, October 1998

27. Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

Table 2.8.5.6.3-1

Input Assumptions and Initial Conditions

A. Core Parameters	
100% Core Power Level	1800 MWt
Calorimetric Uncertainty	0.6%
Analyzed Core Power	1811 MWt
Fuel Type	14x14, 422V+ with ZIRLO™
Total Core Peaking Factor, F_Q	2.6
Channel Enthalpy Rise Factor, F_H	1.68
Axial Offset	13%
K(z) Limit	Flat K(z) =1.0
B. Reactor Coolant System	
Thermal Design Flow	89,000 gpm/loop
Nominal Vessel Average Temperature Range	558.0–577.0°F
Pressurizer Pressure	2250 psia
Pressurizer Pressure Uncertainty	50 psi
C. Reactor Protection System	
Reactor Trip Setpoint	1663 psia
Reactor Trip Signal Processing Time (Includes Rod Drop Time)	4.2 seconds
D. Auxiliary Feedwater System	
Maximum AFW Temperature	100°F
Minimum AFW Flow Rate	(1)
Initiation Signal	(1)
AFW Delivery Delay Time	(1)
E. Steam Generators	
Steam Generator Tube Plugging	10%
MFW Isolation Signal	Safety Injection (2)
MFW Isolation Delay Time	2.0 seconds
MFW Flow Coastdown Time	5.0 seconds
Feedwater Temperature	390–458°F
Steam Generator Safety Valve Flow Rates	Table 2.8.5.6.3-2

Table 2.8.5.6.3-1

Input Assumptions and Initial Conditions

F. Safety Injection	
Limiting Single Failure	One Emergency Diesel Generator
Maximum SI Water Temperature	100°F
Low-Low Pressurizer Pressure Signal	1663 psia
SI Delay Time	28 seconds (3)
Safety Injection Flow Rates	Tables 2.8.5.6.3-3 to 2.8.5.6.3-5
G. Accumulators	
Water/Gas Temperature	120°F
Initial Accumulator Water Volume	1118 ft (3)
Minimum Cover Gas Pressure	695 psia
H. RWST Draindown Input	
Maximum Containment Spray Flow	1950 gpm per pump (2 pumps)
Minimum Usable RWST Volume	164,624 gal
Maximum Delay Time for Switchover to Cold Leg Recirculation	0 sec
Minimum SI Flow Rate After Switchover	Tables 2.8.5.6.3-3 and 2.8.5.6.3-4(2)
Maximum SI Water Temperature After Switchover to Cold Leg Recirculation	210°F

1. Since asymmetric AFW flow is not modeled in the standard NOTRUMP evaluation model the conservative assumption of no AFW flow is made.
2. No LHSI modeled during recirculation; demonstrated in analysis to be conservative approach.
3. Analysis was performed at 23 seconds, but was qualitatively analyzed at 28 seconds.

Table 2.8.5.6.3-2
Steam Generator Safety Valve Flows Per Steam Generator

MSSV	Set Pressure (psig)	Uncertainty (%)	Accumulation (%)	Rated Flow at Full Open Pressure (lbm/hr)
1	1085	3	3	817000
2	1100	3	3	825000
3	1105	3	3	845000
4	1105	3	3	845000

Table 2.8.5.6.3-3
High Head Safety Injection (HHSI) Flows vs. Pressure, Minimum Safeguards, Spill to RCS Pressure (Breaks < 8.75 in. diameter)

Pressure (psia)	Spilled Flow (gpm)	Injected Flow (gpm)
14.7	476.28	437.25
114.7	459.63	421.96
214.7	442.55	406.28
314.7	423.26	388.57
414.7	403.46	370.38
514.7	382.64	351.26
614.7	360.20	330.65
714.7	336.93	309.27
814.7	312.31	286.65
914.7	286.57	263.00
1014.7	256.12	234.99
1114.7	222.25	203.84
1214.7	182.54	167.26
1314.7	132.66	121.18
1364.7	97.98	88.96

Table 2.8.5.6.3-4
High Head Safety Injection (HHSI) Flows vs. Pressure, Minimum Safeguards, Spill to 0 psig Containment Pressure (Breaks 8.75 in. diameter)

Pressure (psia)	Spilled Flow (gpm)	Injected Flow (gpm)
14.7	514.67	473.86
114.7	526.66	445.05
214.7	538.99	414.91
314.7	550.88	382.19
414.7	563.29	347.47
514.7	576.34	310.34
614.7	590.22	270.18
714.7	604.92	225.56
814.7	621.01	174.94
914.7	639.47	115.55
934.7	643.56	102.05

Table 2.8.5.6.3-5
Low Head Safety Injection (LHSI) Flows vs. Pressure, Minimum Safeguards, (Upper Plenum Injection)

Pressure (psia)	Injecting Flow (lbm/sec)
14.7	235.2
24.7	224.8
34.7	214.2
44.7	202.8
54.7	190.8
64.7	178.3
74.7	164.9
84.7	150.7
94.7	133.3
104.7	113.9
114.7	90.9
134.7	0.0

Table 2.8.5.6.3-6
NOTRUMP Transient Results for Unit 1

Event (sec)	1.5-Inch	2-Inch	3-Inch	4-Inch	6-Inch	8.75-Inch
Transient Initiated	0	0	0	0	0	0
Reactor Trip Signal	153.7	76.1	31.3	19	8.5	8.7
Safety Injection Signal	153.7	76.1	31.3	19	8.5	8.7
Safety Injection Begins(1)	176.7	99.1	54.3	42	31.5	31.7
Loop Seal Clearing Occurs(2)	1037	590	230	125	28	27
Top of Core Uncovered	4115	1130	442	433	N/A(3)	N/A(3)
Accumulator Injection Begins	N/A	3697	690	385	156	154
Top of Core Recovered	5649	2256	1142	450	N/A(3)	N/A(3)
RWST Low Level	2320	2269	2173	2133	1956	1880

1. Safety Injection is assumed to begin 23.0 s after the Safety Injection Signal.
2. Loop seal clearing is assumed to occur when the steam flow through the broken loop, loop seal is sustained above 1 lbm/s. Only the broken loop is allowed to clear for break sizes less than 6-inches in diameter. For the 6- and 8.75-inch breaks, the broken loop, loop seal clears prior to the intact loop.
3. There is no core uncovery for the 6-inch and 8.75-inch breaks.

Table 2.8.5.6.3-7
NOTRUMP Transient Results for Unit 2

Event (sec)	1.5-Inch	2-Inch	3-Inch	4-Inch	6-Inch	8.75-Inch
Transient Initiated	0	0	0	0	0	0
Reactor Trip Signal	150.6	75.5	31	11.8	8.4	8.5
Safety Injection Signal	150.6	75.5	31	11.8	8.4	8.5
Safety Injection Begins[1]	173.6	98.5	54	34.8	31.4	31.5
Loop Seal Clearing Occurs[2]	1083	553	237	129	28	28
Top of Core Uncovered	4258	1175	335	355	N/A[3]	N/A[3]
Accumulator Injection Begins	N/A	3705	685	366	164	158
Top of Core Recovered	5654	2288	1183	490	N/A[3]	N/A[3]
RWST Low Level	2320	2270	2173	2131	1957	1883

1. Safety Injection is assumed to begin 23.0 s after the Safety Injection Signal.
2. Loop seal clearing is assumed to occur when the steam flow through the broken loop, loop seal is sustained above 1 lbm/s. Only the broken loop is allowed to clear for break sizes less than 6-inches in diameter. For the 6- and 8.75-inch breaks, the broken loop, loop seal clears prior to the intact loop.
3. There is no core uncovery in the 8.75-inch break and only minimal uncovery observed in the 6-inch break.

Table 2.8.5.6.3-8
Beginning of Life (BOL) Rod Heatup Results for Unit 1

Results	1.5-Inch	2-Inch	3-Inch	4-Inch	6-Inch	8.75-Inch
PCT, °F	678	958	1049	532	N/A[2]	N/A[2]
PCT Time, sec	4887	1516	769	445		
PCT Elevation, ft	11.75	10.75	10.75	11.75		
Burst Time[1], sec	N/A	N/A	N/A	N/A		
Burst Elevation[1], ft						
Maximum ZrO_2, %	0	0.01	0.01	0		
Maximum ZrO_2 Elevation, ft	11.75	10.75	10.75	11.75		
Average ZrO_2, %	0	0	0	0		

1. Neither the hot rod nor the hot assembly average rod burst during the SBLOCTA calculations.
2. The core either does not uncover or only uncovers for a very short time; therefore, SBLOCTA calculations are not warranted for the 6- and 8.75-inch breaks.

Table 2.8.5.6.3-9
BOL Rod Heatup Results for Unit 2

Results	1.5-Inch	2-Inch	3-Inch	4-Inch	6-Inch	8.75-Inch
PCT, °F	669	955	1103	803	N/A[2]	N/A[2]
PCT Time, sec	4943	1530	758	442		
PCT Elevation, ft	11.75	10.75	10.75	11		
Burst Time[1], sec	N/A	N/A	N/A	N/A		
Burst Elevation[1], ft						
Maximum ZrO_2, %	0	0.01	0.02	0		
Maximum ZrO_2 Elevation, ft	11.75	10.75	10.75	11		
Average ZrO_2, %	0	0	0	0		

1. Neither the hot rod nor the hot assembly average rod burst during the SBLOCTA calculations.
2. The core either does not uncover or only uncovers for a very short time; therefore, SBLOCTA calculations are not warranted for the 6- and 8.75-inch breaks.

Table 2.8.5.6.3-10
PBNP Units 1 and 2 Power Uprate Program Input Parameters

Parameter	Current Value	Power Uprate Value
RWST Boron Concentration, Minimum (ppm)	2700	2800
Accumulator Boron Concentration, Minimum (ppm)	2600	2700

Table 2.8.5.6.3-11
PBNP Post-LOCA Long-Term Cooling Analysis Input Parameters

Parameter	Power Uprate Value
Analyzed Core Power (MWt)	1811
Analyzed Core Power Uncertainty (percent)	0.6 (included in analyzed power, above)
Decay Heat Standard	1971 ANS, Infinite Operation, plus 20% (10 CFR50 Appendix K)
H_3BO_3 Solubility Limit (weight percent)	See Table 2.8.5.6.3-12
RWST Boron Concentration, Maximum (ppm)	3200
RWST Volume, Maximum (gallons)	289,504
RWST Temperature, Minimum (°F)	40
Accumulator Boron Concentration, Maximum (ppm)	3100
Accumulator Liquid Volume, Minimum (gallons)	7989
Accumulator Tank Temperature, Maximum (°F)	120

Table 2.8.5.6.3-12
Boric Acid Solution Solubility Limit

Temperature, °F	Pressure, psia	Solubility g H_3BO_3/100 g of Solution in H_2O
P = Atmospheric Pressure		
32	14.7	2.70
41	14.7	3.14
50	14.7	3.51
59	14.7	4.17
68	14.7	4.65
77	14.7	5.43
86	14.7	6.34
95	14.7	7.19
104	14.7	8.17
113	14.7	9.32
122	14.7	10.23
131	14.7	11.54
140	14.7	12.97
149	14.7	14.42
158	14.7	15.75
167	14.7	17.41
176	14.7	19.06
185	14.7	21.01
194	14.7	23.27
203	14.7	25.22
212	14.7	27.53
217.9	14.7	29.27
P = P_{SAT}		
226.0	19.3	31.47
242.8	26.3	36.69
260.1	35.5	42.34
277.3	47.1	48.81
289.9	57.5	54.79

Table 2.8.5.6.3-12
Boric Acid Solution Solubility Limit

Temperature, °F	Pressure, psia	Solubility g H_3BO_3/100 g of Solution in H_2O
304.7	71.9	62.22
318.9	88.3	70.67
339.8 = Congruent Melting of H_3BO_3		

Table 2.8.5.6.3-13
Post-LOCA Boric Acid Precipitation Analysis Logic for 2-Loop UPI Plant

<table>
<tr><th colspan="2">APPROXIMATE DEG BREAK SIZE</th><th colspan="4">POST-LOCA BORIC ACID PRECIPITATION ANALYSIS LOGIC FOR 2-LOOP UPI PLANT</th></tr>
<tr><th>FT²</th><th>IN</th><th>SCENARIO</th><th>NATURAL CIRCULATION</th><th>OPERATOR ACTION CREDIT FOR DEPRESSURIZATION</th><th>BORIC ACID PRECIPITATION ANALYSIS</th></tr>
<tr><td></td><td></td><td><u>LARGE BREAKS</u>
Large breaks will rapidly depressurize to containment pressure. Dependent on RHR flow during sump recirculation to maintain core cooling.</td><td rowspan="2">Natural circulation lost.</td><td>No operator action credited. Depressurization to containment pressure will occur rapidly.</td><td>Analyzed at atmospheric conditions using 14.7 psia boric acid buildup calculation with dilution flows confirmed for 14.7 psia at RCS backpressure.</td></tr>
<tr><td>0.136</td><td>5.0</td><td rowspan="3"><u>SMALL BREAKS</u>
Small breaks are limited by the ability to depressurize before upper plenum injection (UPI) is initiated. This criterion is controlled by the ability of the relief valves to effectively remove enough mass and energy to keep the core cool while depressurizing to below the RHR cut-in pressure. Dependent on high head SI to initially keep core cool. Dependent on RHR flow to maintain effective long term cooling.</td><td rowspan="4">Operator action credited in order to depressurize RCS before the boric acid solubility limit is reached. Depressurization of RCS to below RHR cut-in pressure is accomplished using condenser steam dumps, steam generator PORVs, or pressurizer PORVs. The system will eventually reach RHR cut-in pressure and simultaneous injection will begin.</td><td>If RHR cut-in pressure is reached before restoration of cold leg HHSI time, 120 psia boric acid buildup calculation applies. Otherwise, credit higher boric acid solubility limit. If core sub-cooling conditions reached, boric acid precipitation is not a concern.</td></tr>
<tr><td>0.008</td><td>1.2</td><td>Natural circulation, if lost, will be restored before boric acid solubility limit is reached.</td><td>Subcooled conditions reached prior to depressurization to below RHR cut-in pressure. Boric acid precipitation not a concern.</td></tr>
<tr><td>0.004</td><td>0.9</td><td rowspan="2">Natural circulation is never lost and is sufficient in keeping the core diluted.</td><td rowspan="2">Natural circulation is sufficient to keep the core cool and prevent boric acid buildup within the core. Boric acid precipitation not a concern.</td></tr>
<tr><td>0.001</td><td>0.375</td><td><u>LEAKS</u>
Charging system has make-up capacity. Not a LOCA.</td></tr>
</table>

Figure 2.8.5.6.3-1 Point Beach Unit 1: 3-Inch Break Pressurizer Pressure

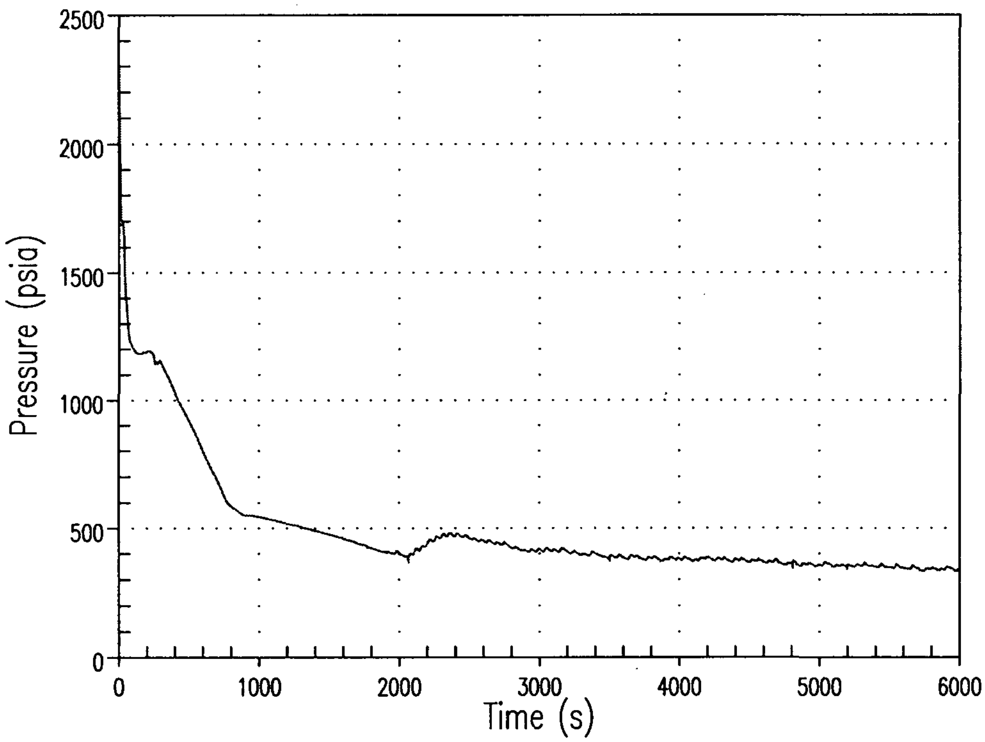


Figure 2.8.5.6.3-2 Point Beach Unit 2: 3-Inch Break Pressurizer Pressure

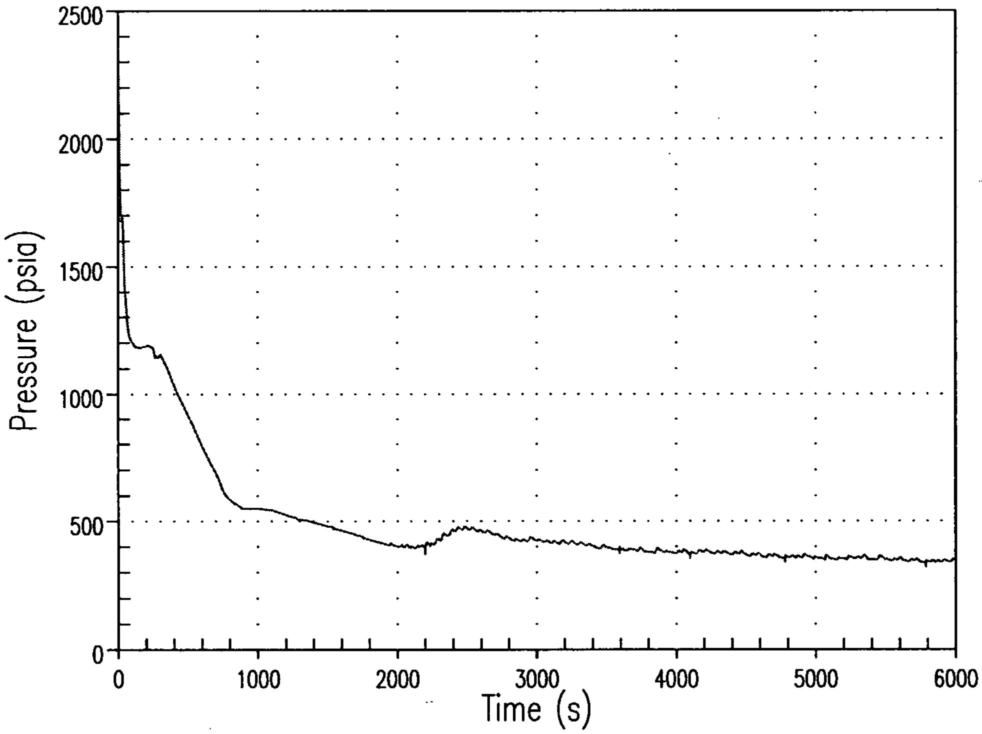


Figure 2.8.5.6.3-3 Point Beach Unit 1: 3-Inch Break Core Mixture Level

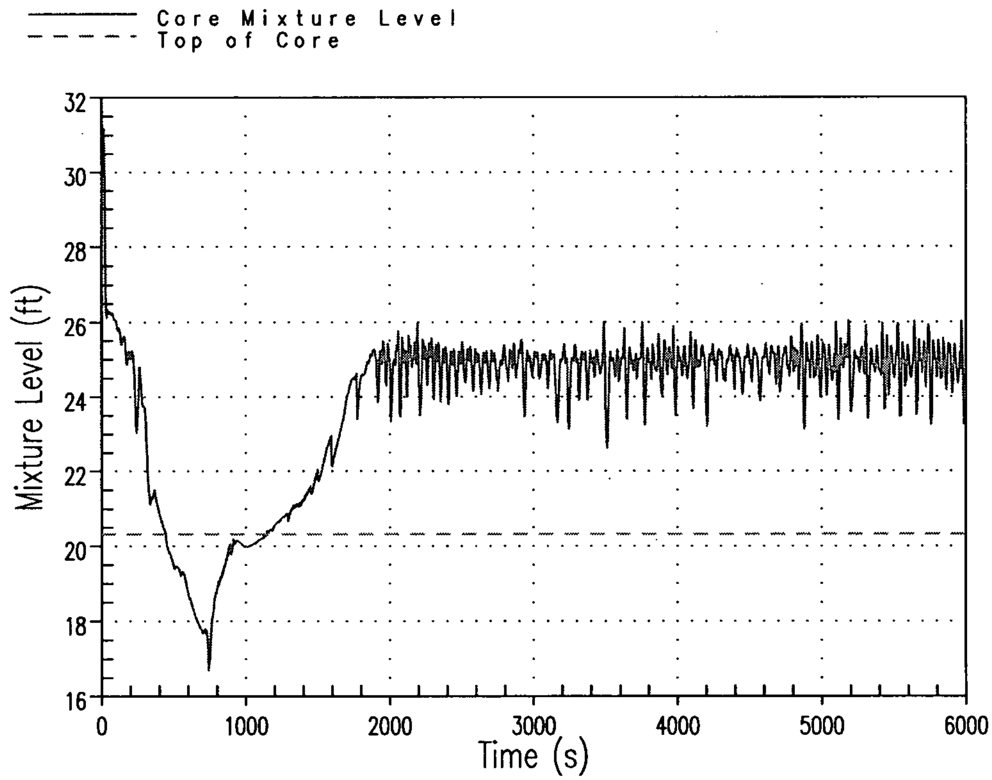


Figure 2.8.5.6.3-4 Point Beach Unit 2: 3-Inch Break Core Mixture Level

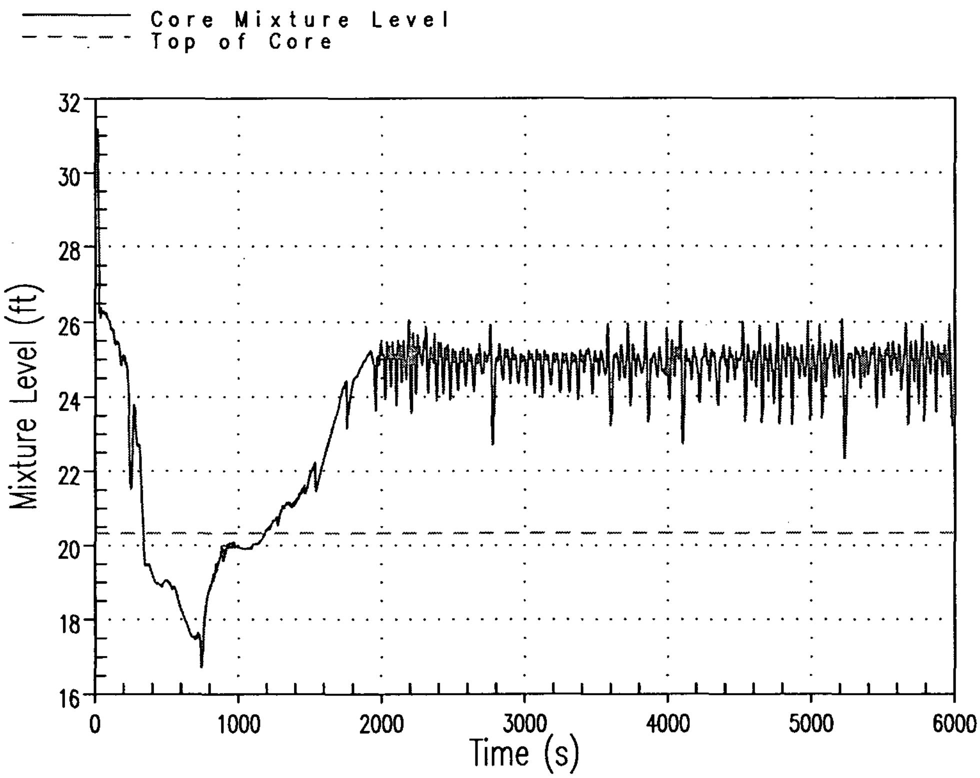


Figure 2.8.5.6.3-5 Point Beach Unit 1: 3-Inch Break Broken Loop and Intact Loop Pumped SI Flow Rate

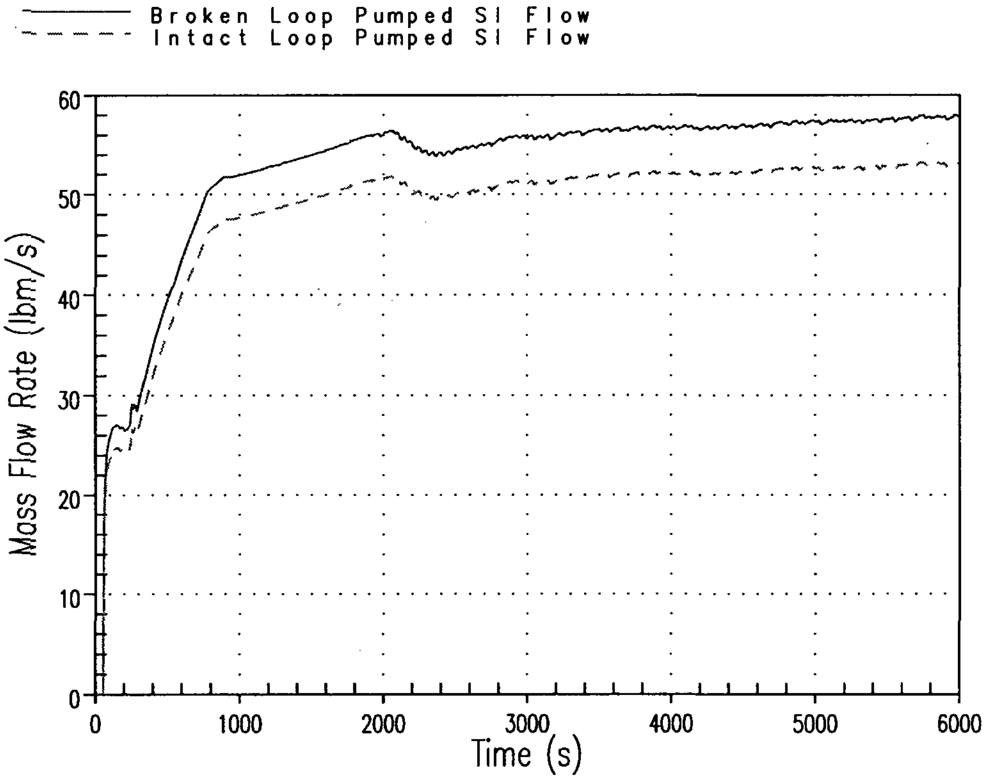


Figure 2.8.5.6.3-6 Point Beach Unit 2: 3-Inch Break Broken Loop and Intact Loop Pumped SI Flow Rate

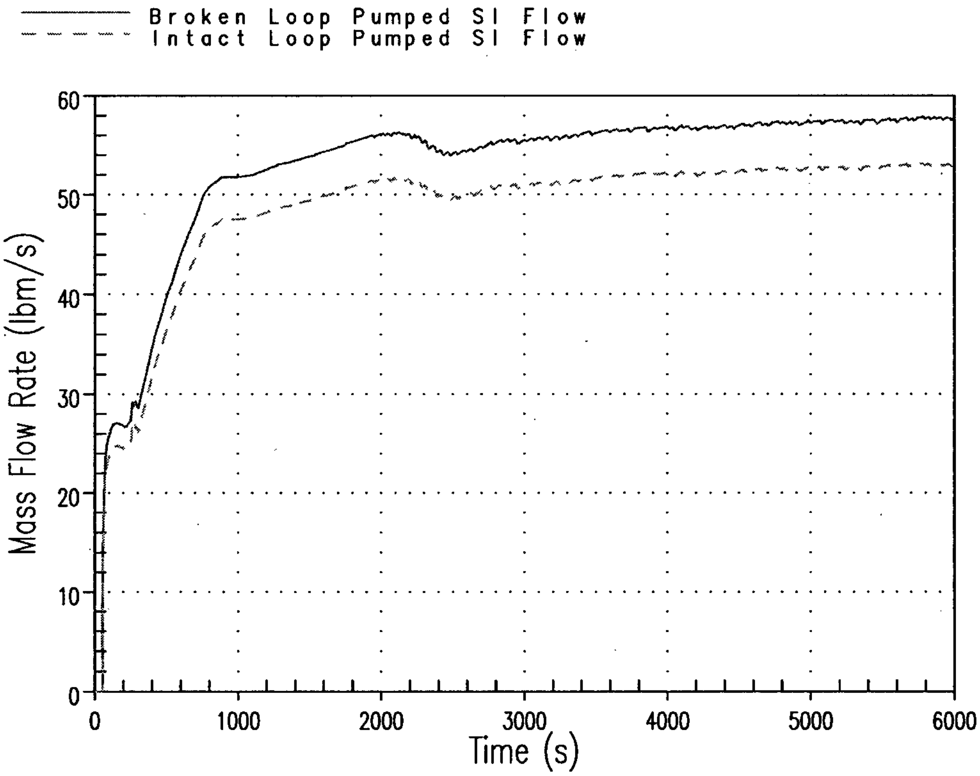


Figure 2.8.5.6.3-7 Point Beach Unit 1: 3-Inch Break Peak Cladding Temperature at PCT Elevation

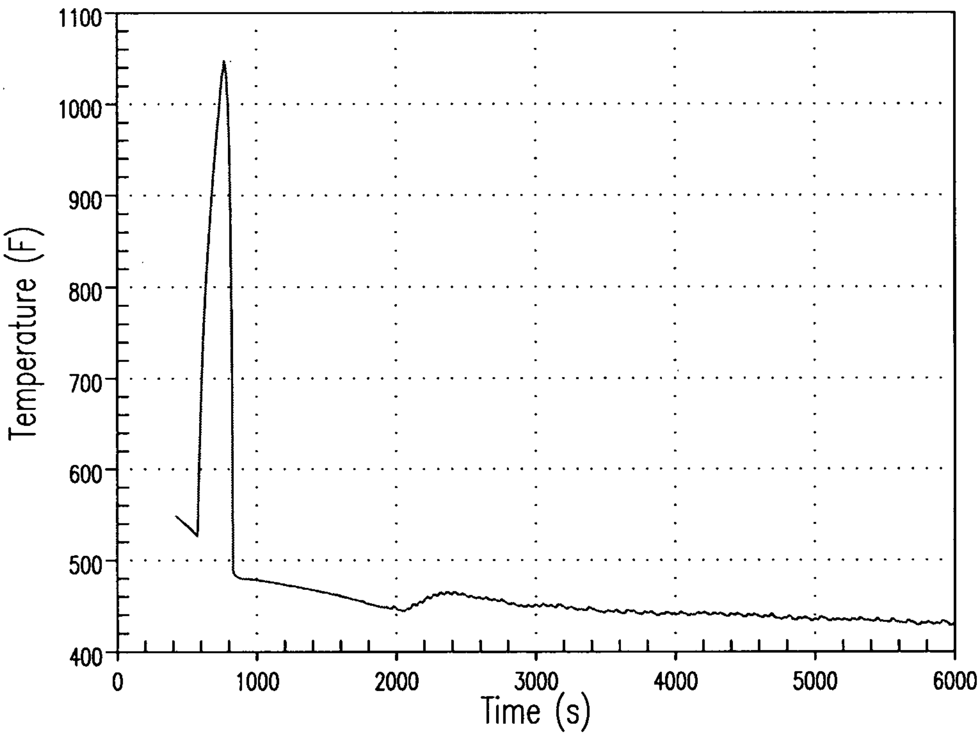


Figure 2.8.5.6.3-8 Point Beach Unit 2: 3-Inch Break Peak Cladding Temperature at PCT Elevation

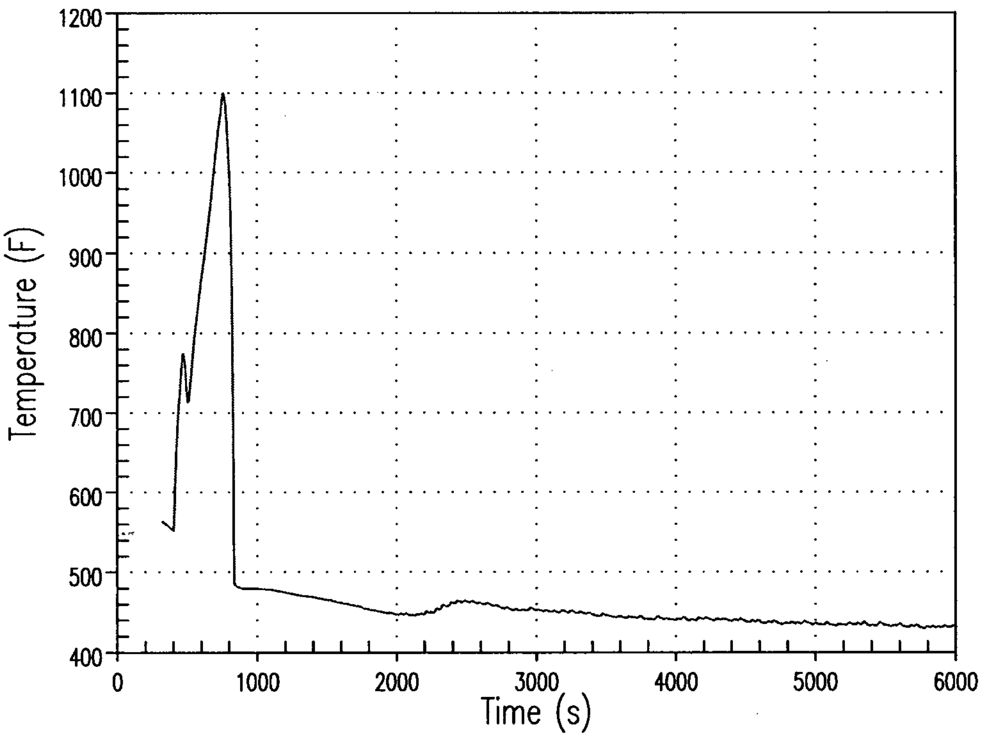


Figure 2.8.5.6.3-9 Point Beach Unit 1: 3-Inch Break Core Exit Vapor Flow

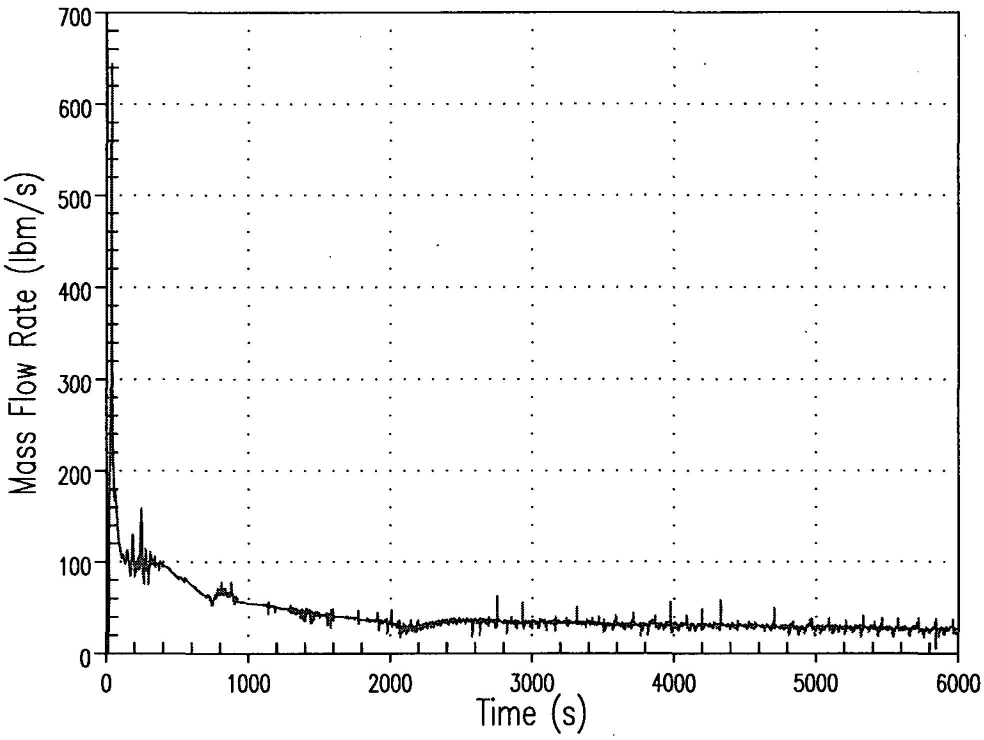


Figure 2.8.5.6.3-10 Point Beach Unit 2: 3-Inch Break Core Exit Vapor Flow

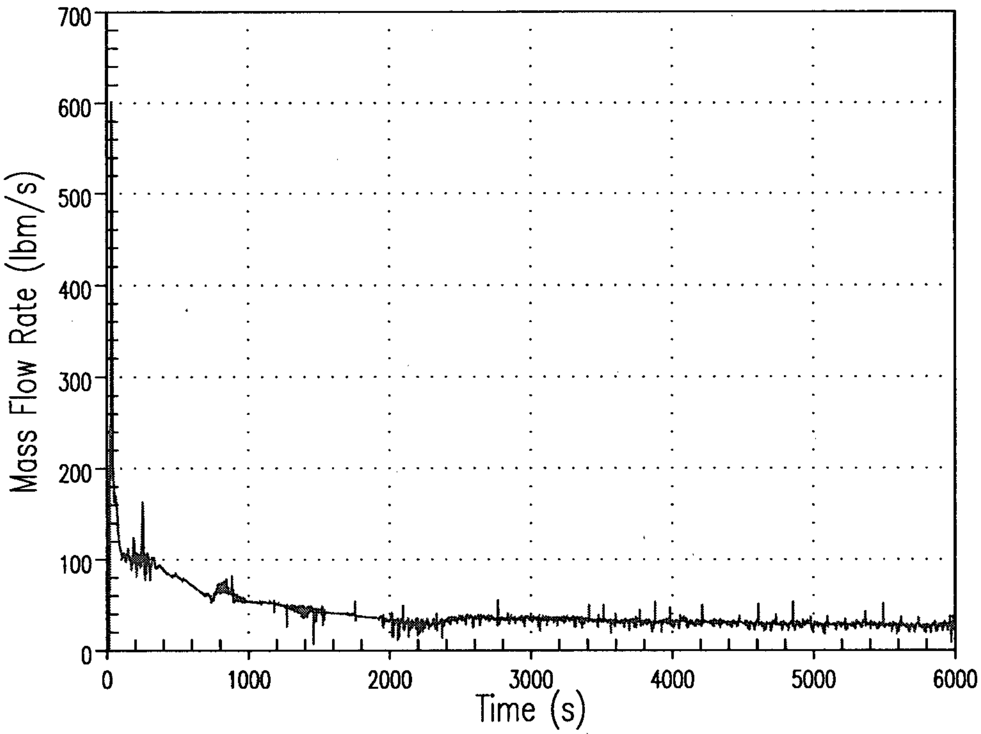
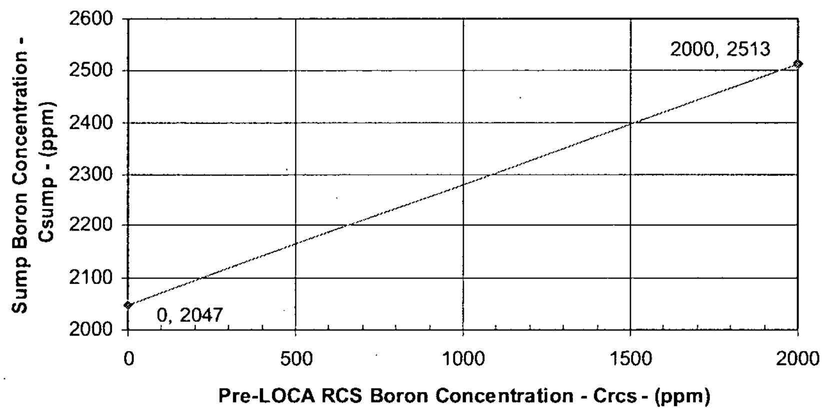


Figure 2.8.5.6.3-11 PBNP Power Uprate Post-LOCA Subcriticality Boron Limit Curve



Csump = 0.2331 x Crcs + 2047

Figure 2.8.5.6.3-12 Boric Acid Solubility Limit

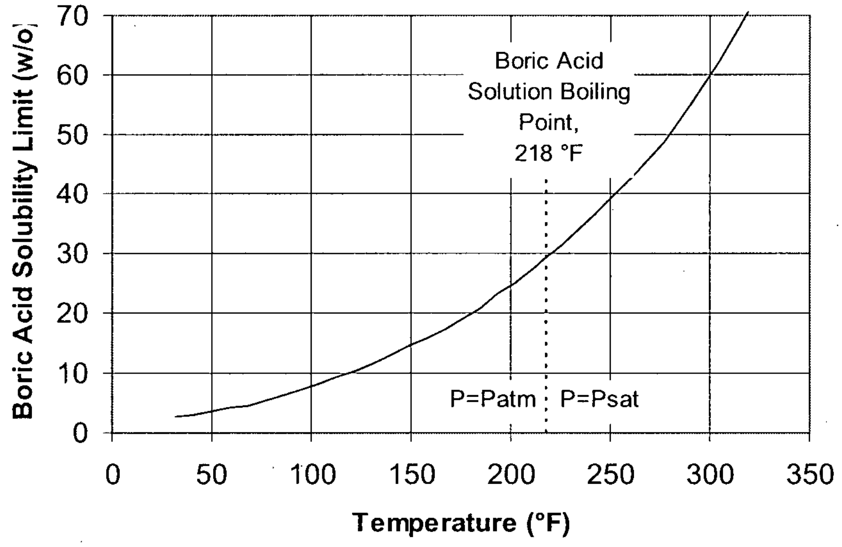


Figure 2.8.5.6.3-13 Post-LOCA Boric Acid Precipitation Control Plan for 2-Loop UPI Plants

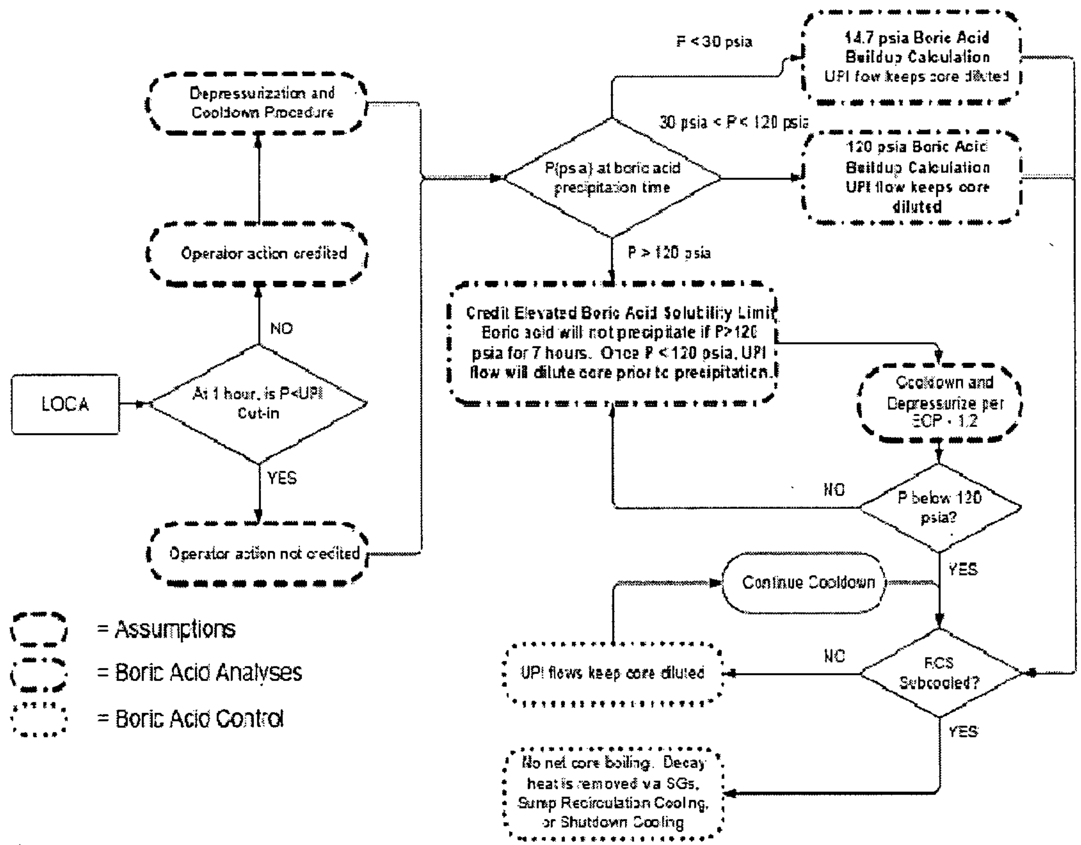


Figure 2.8.5.6.3-14 LBLOCA Boric Acid Concentration Analysis - Core/Upper Plenum Average Void Fraction versus Time

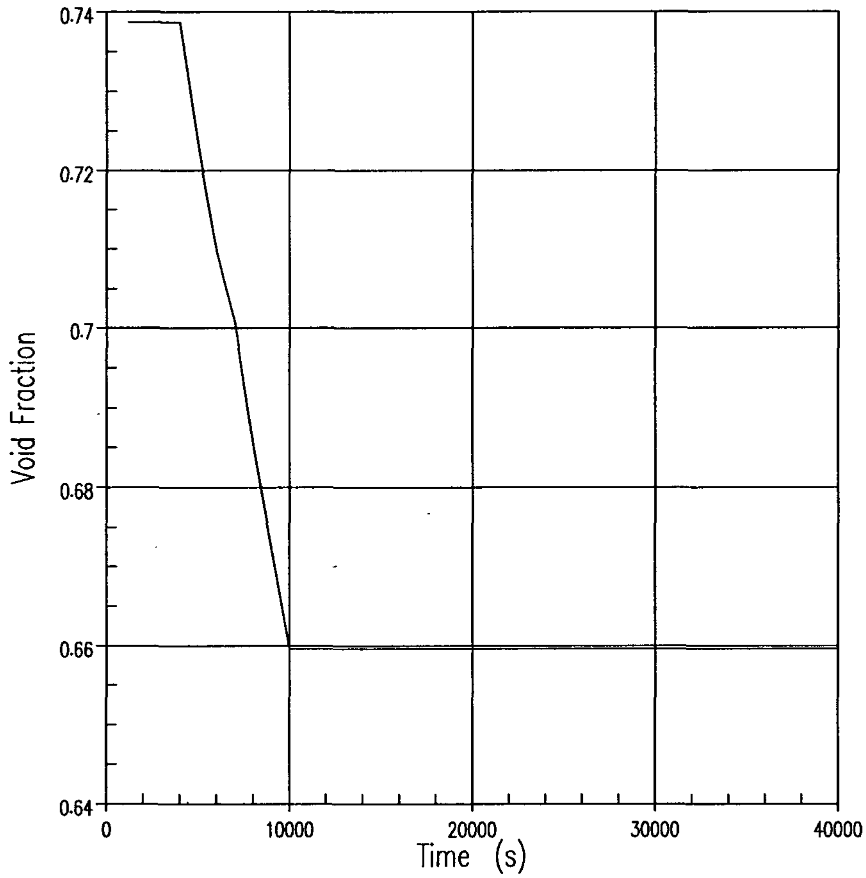


Figure 2.8.5.6.3-15 LBLOCA Boric Acid Concentration Analysis - Mixing Volume versus Time

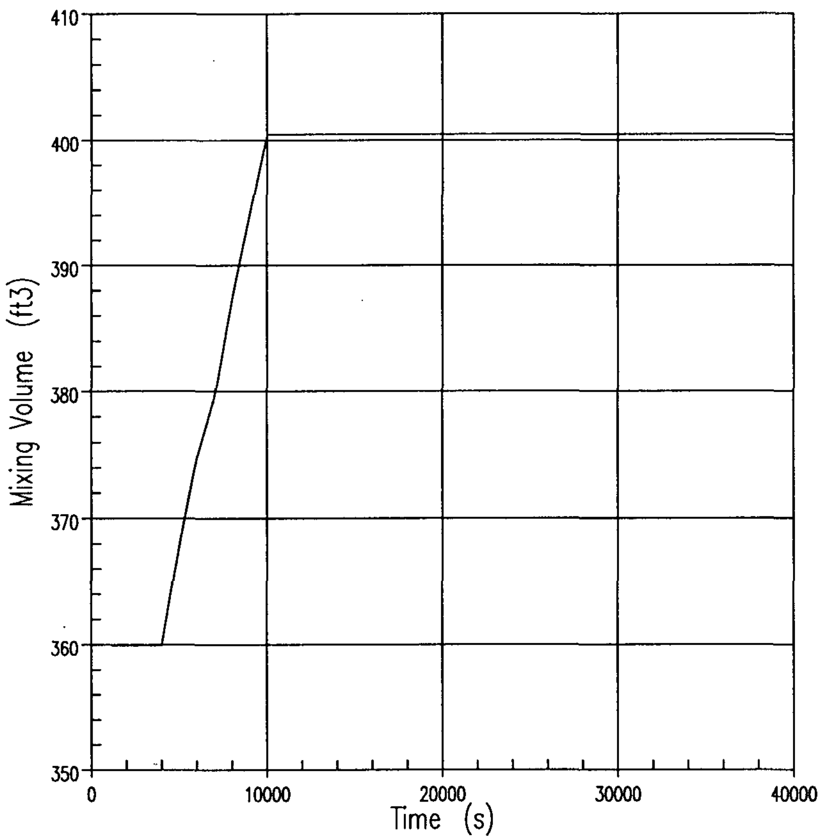


Figure 2.8.5.6.3-16 LBLOCA Boric Acid Concentration Analysis - Vessel Boric Acid Concentration/Boiloff and Dilution Flow versus Time

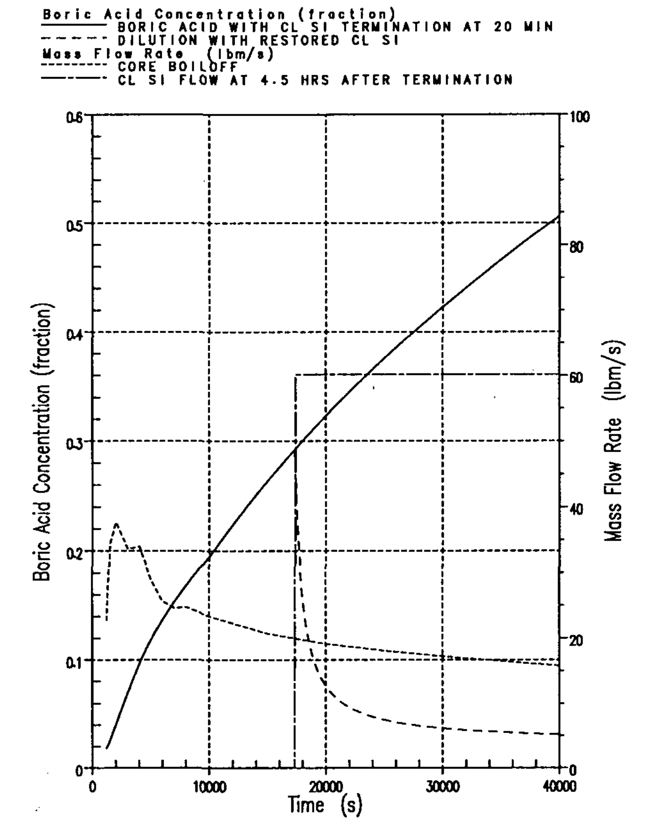


Figure 2.8.5.6.3-17 SBLOCA - 5-inch Break RCS Depressurization Without Operator Actions

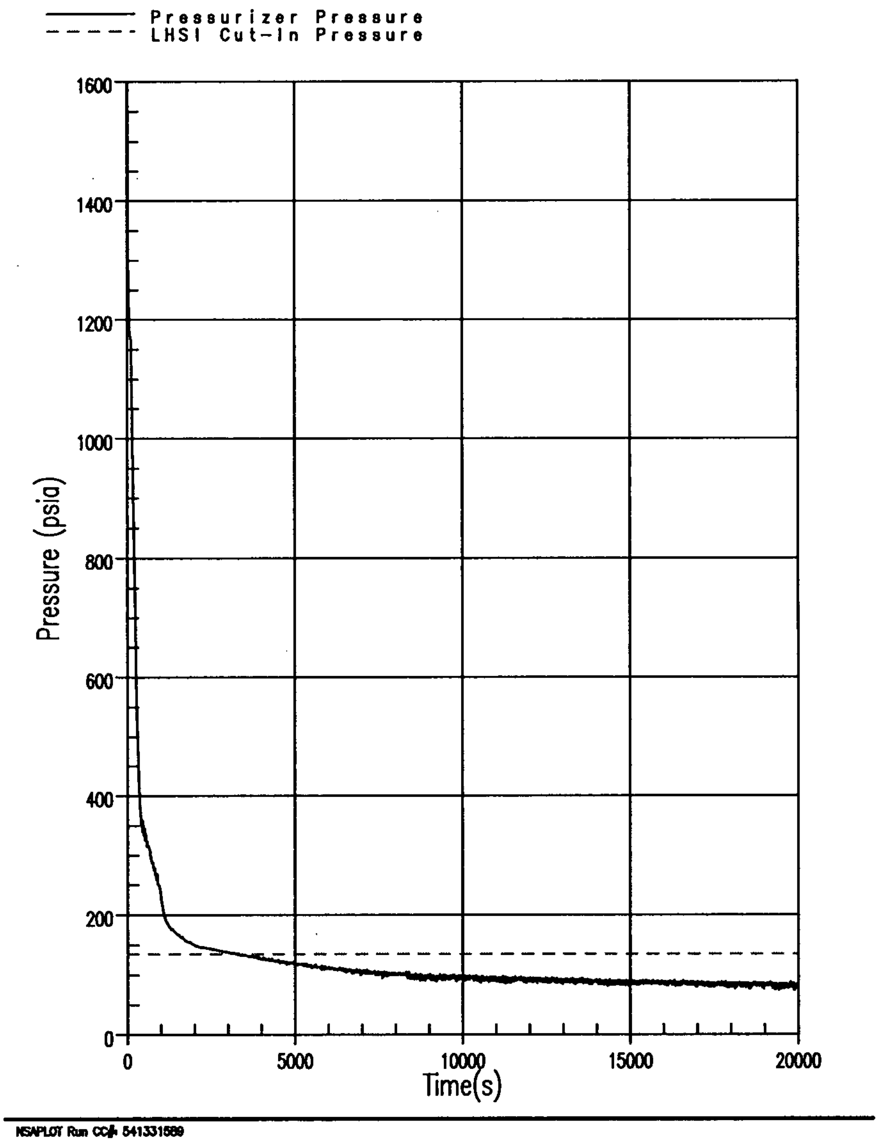


Figure 2.8.5.6.3-18 SBLOCA Boric Acid Concentration Analysis - Core/Upper Plenum Average Void Fraction versus Time

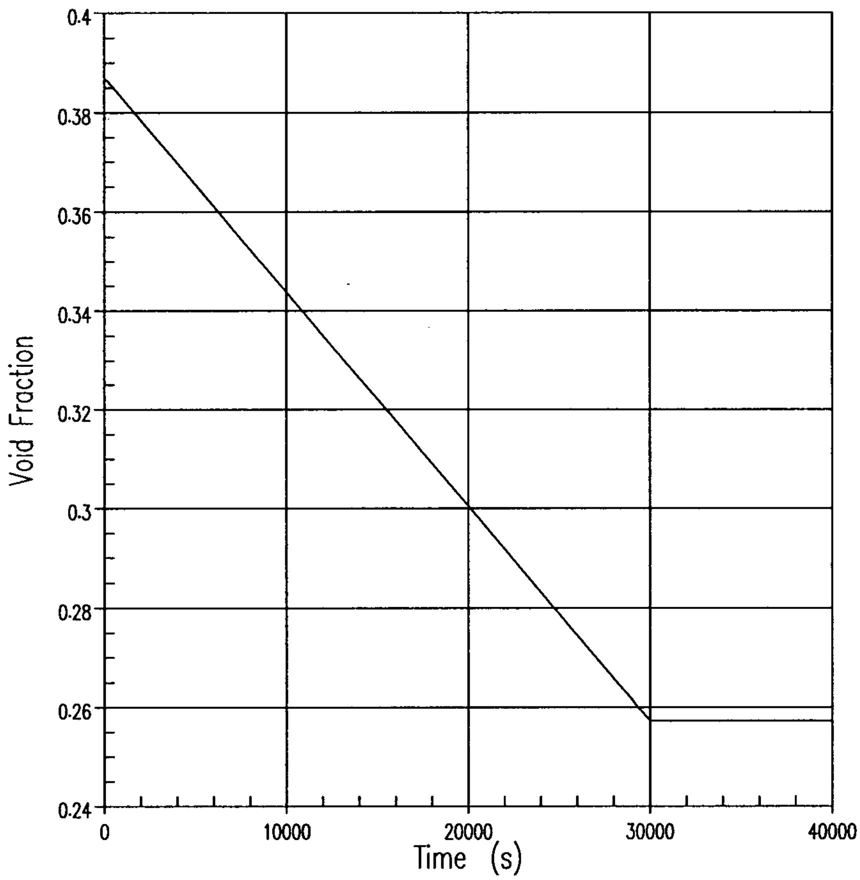


Figure 2.8.5.6.3-19 SBLOCA Boric Acid Concentration Analysis - Mixing Volume versus Time

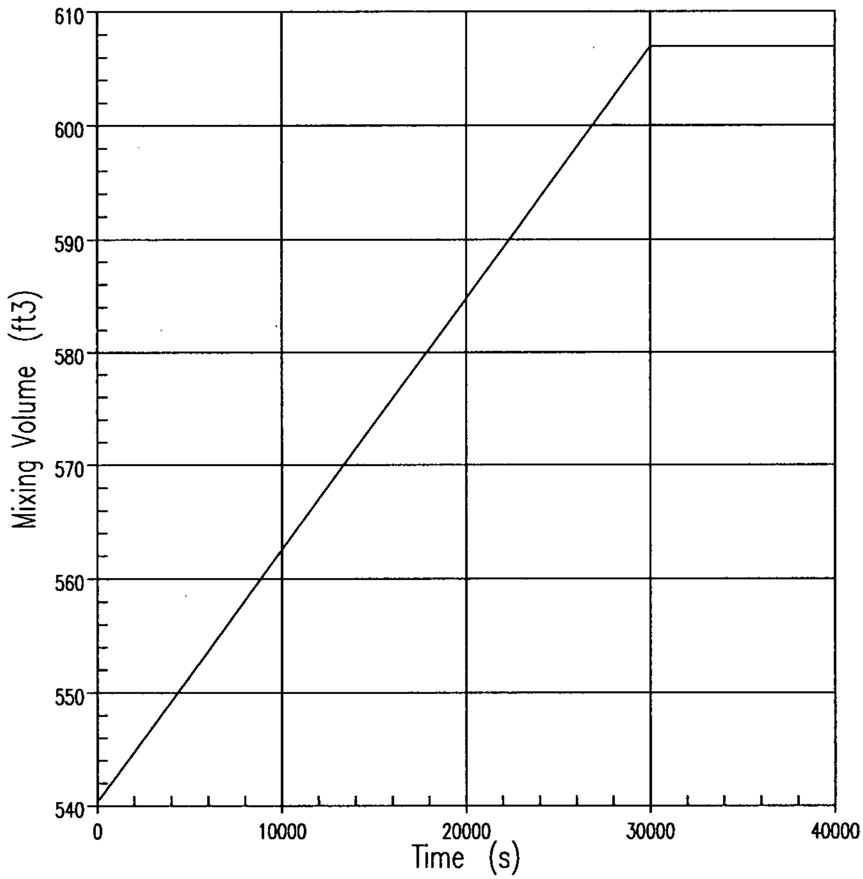


Figure 2.8.5.6.3-20 SBLOCA Boric Acid Concentration Analysis - Vessel Boric Acid Concentration/Boiloff and Dilution Flow versus Time

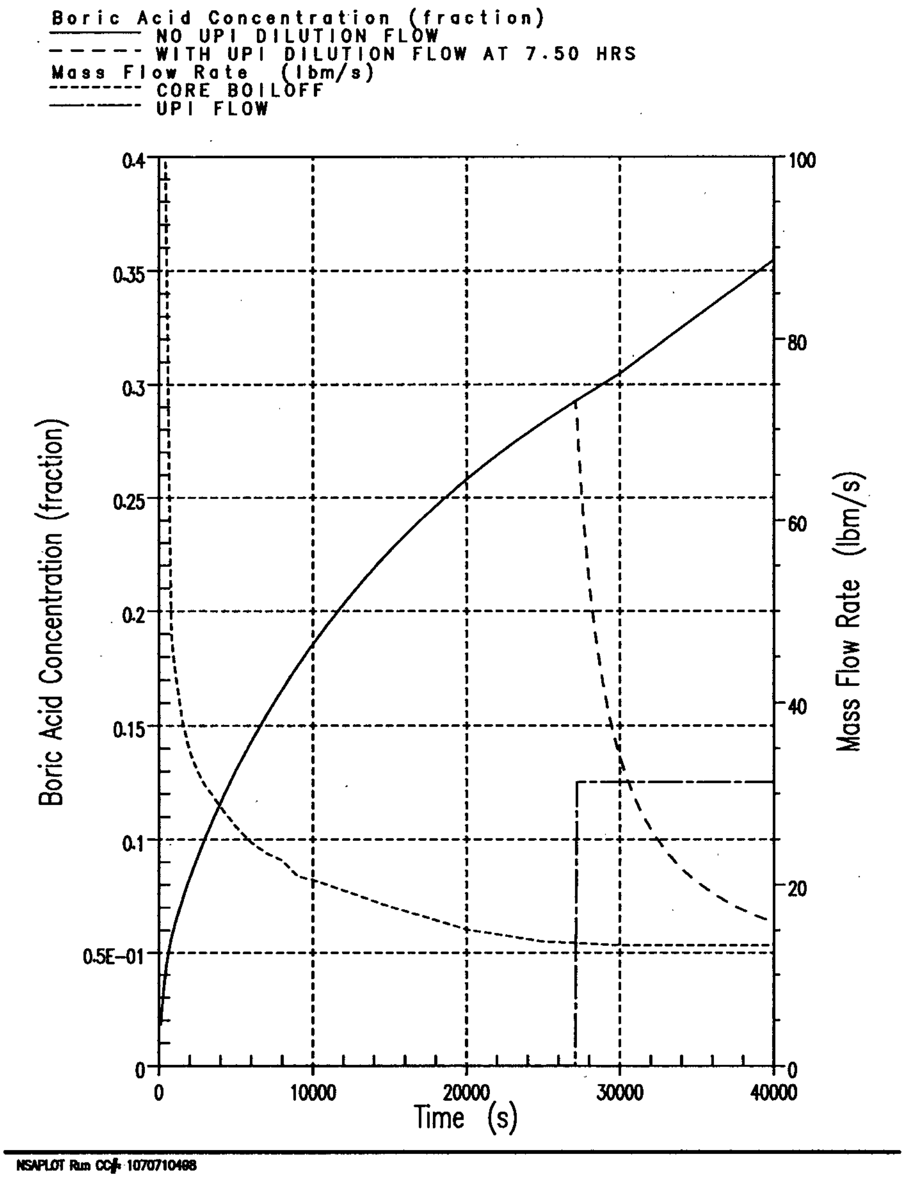


Figure 2.8.5.6.3-21 0.9-Inch Break Broken Loop Hot Leg and Cold Leg Liquid Flow

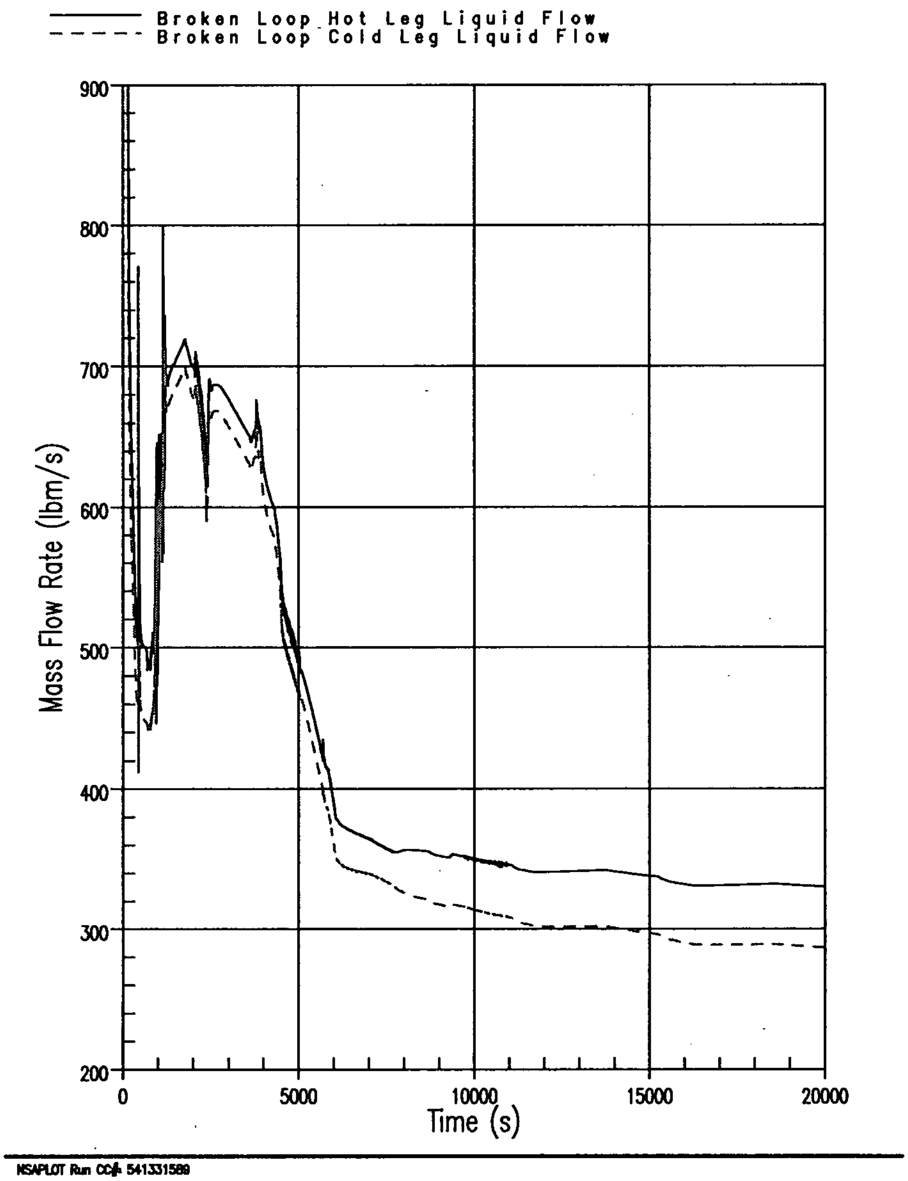


Figure 2.8.5.6.3-22 1.2-Inch Break Broken Loop Hot Leg and Cold Leg Liquid Flow

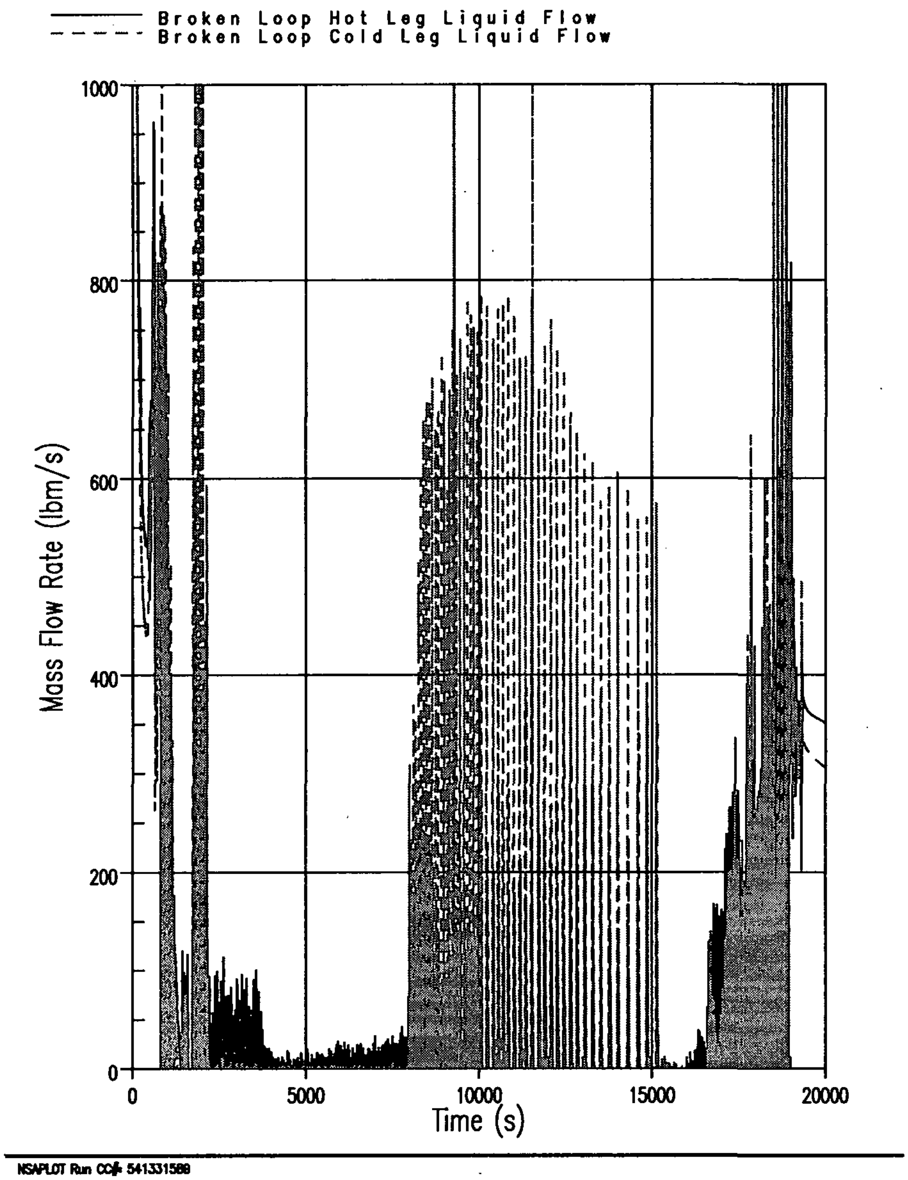


Figure 2.8.5.6.3-23 0.9-Inch Break Pressurizer Pressure and Broken Loop Hot Leg Mixture Temperature

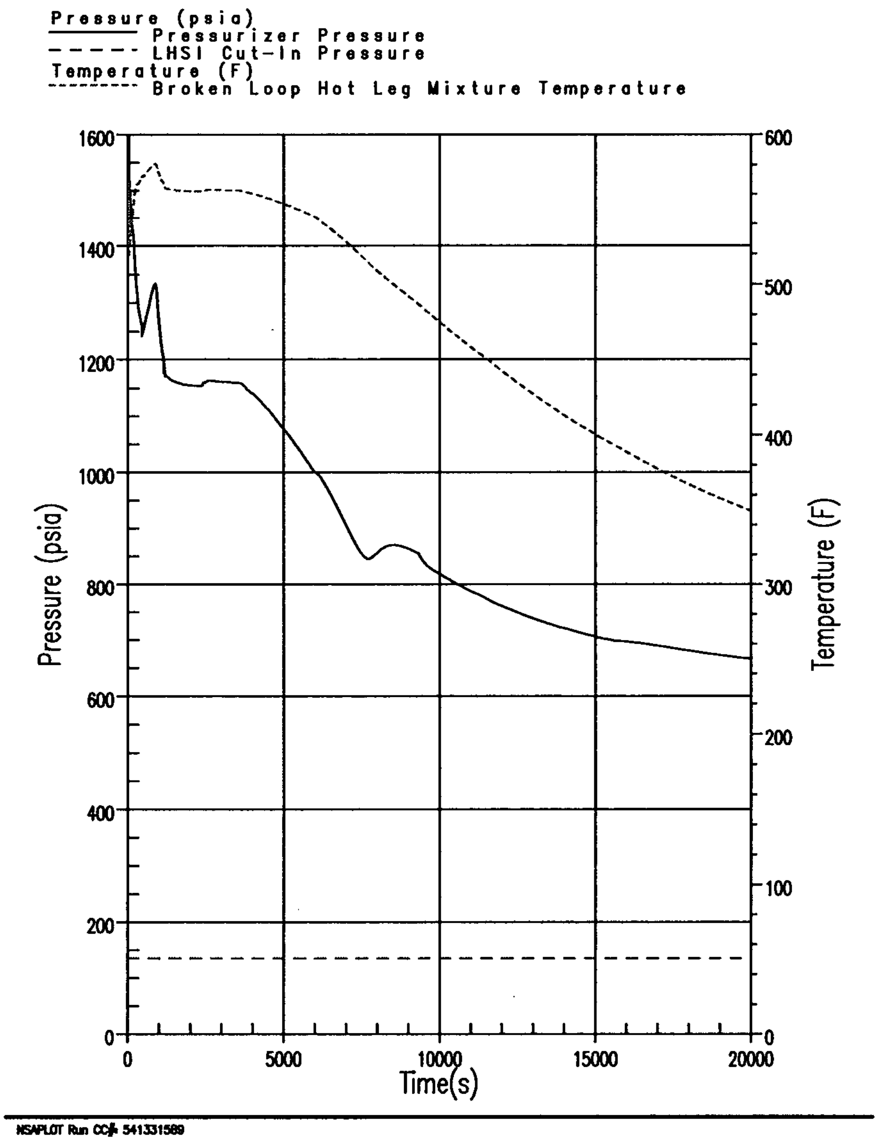


Figure 2.8.5.6.3-24 1.2-Inch Break Pressurizer Pressure and Broken Loop Hot Leg Mixture Temperature

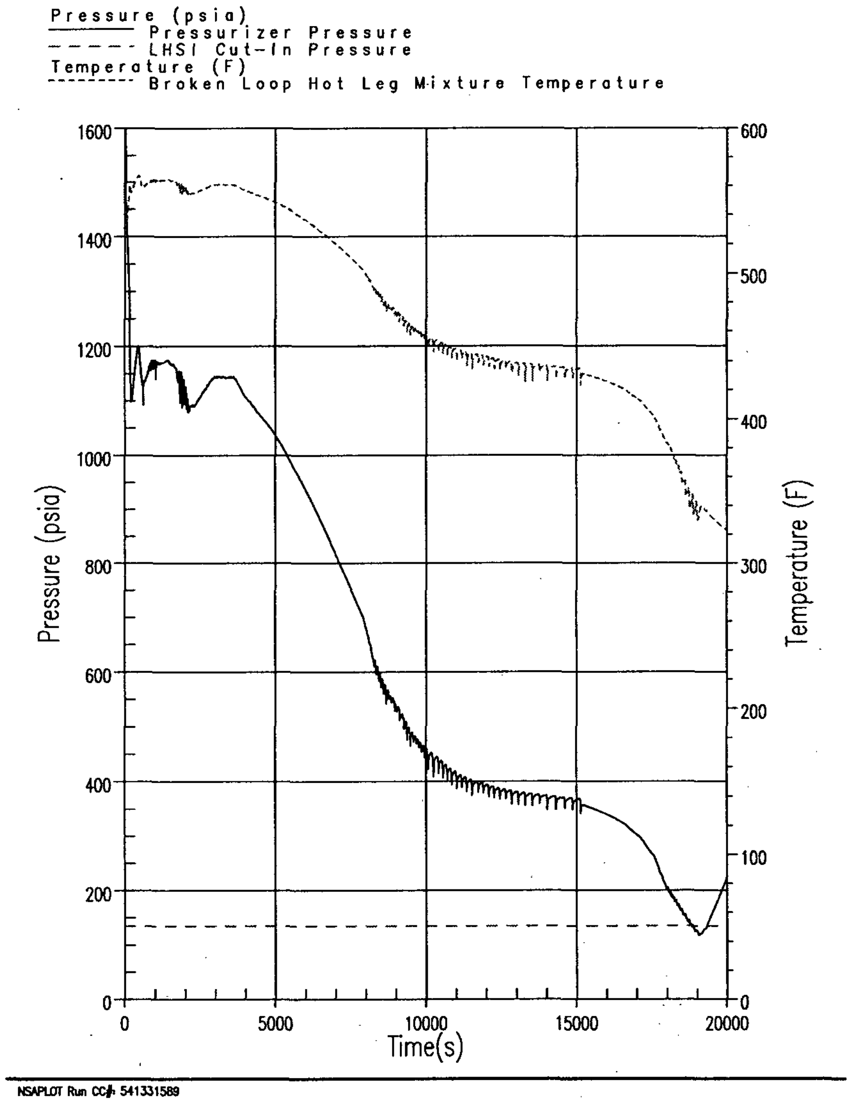


Figure 2.8.5.6.3-25 0.9-Inch Break Inner Vessel Mixture Level

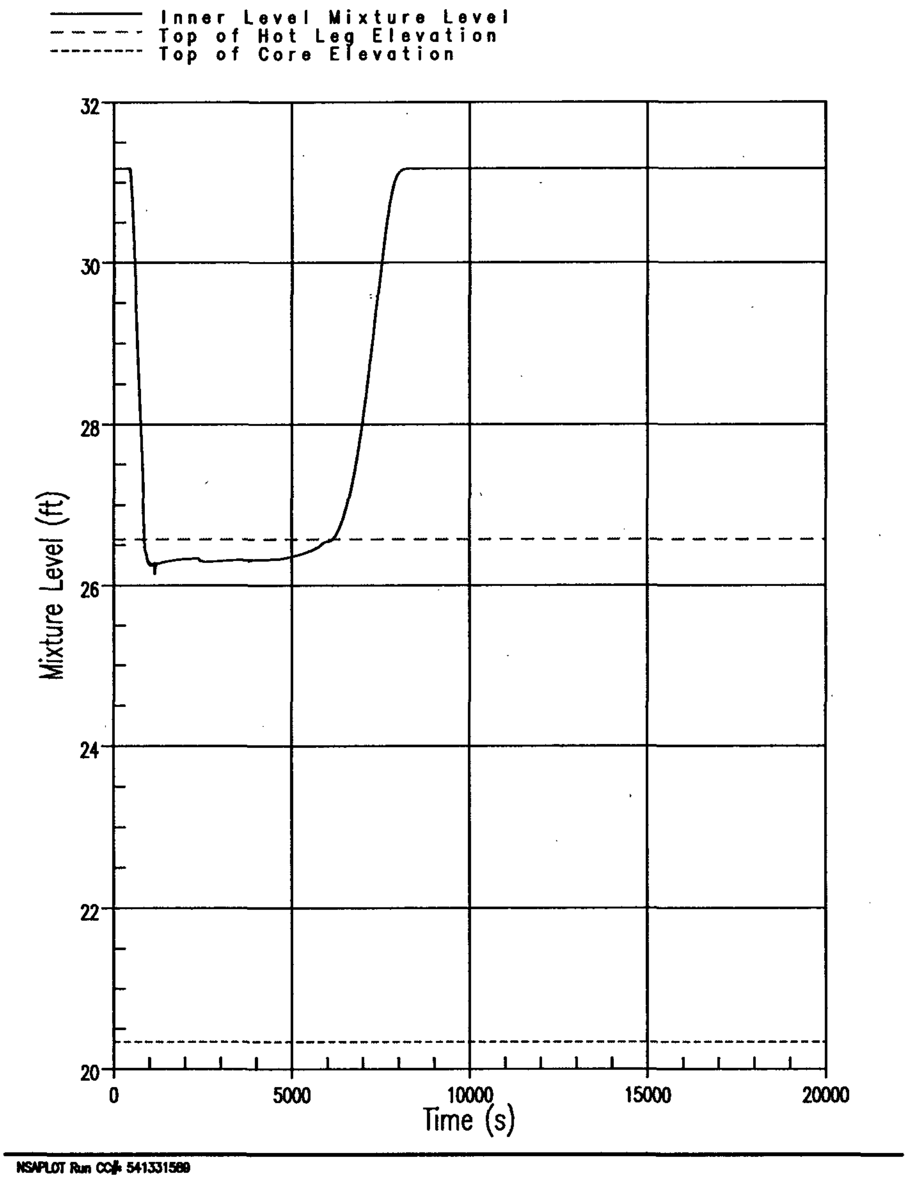
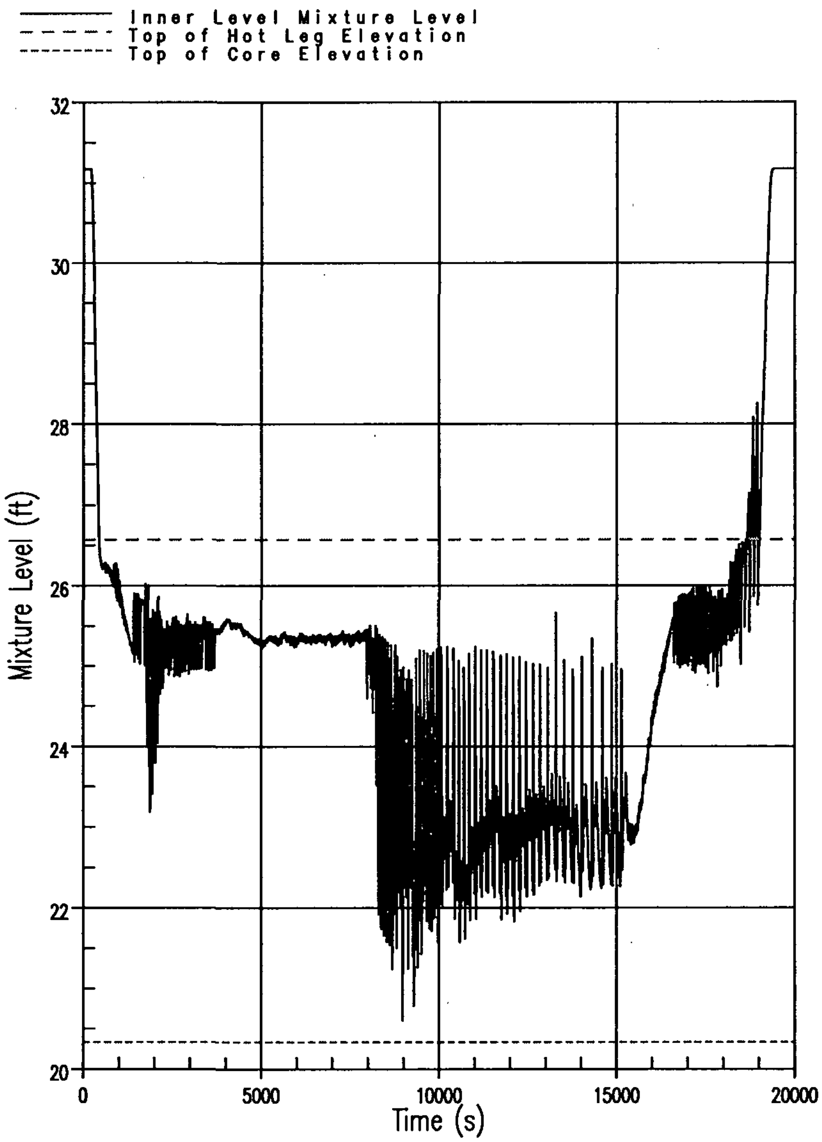


Figure 2.8.5.6.3-26 1.2-Inch Break Inner Vessel Mixture Level



NSAPLOT Run CC# 541331589

2.8.5.7 Anticipated Transients Without Scram

2.8.5.7.1 Regulatory Evaluation

Anticipated transients without scram (ATWS) are defined as an anticipated operational occurrence followed by the failure of the reactor trip portion of the protection system specified in GDC-20. For a Westinghouse PWR design, 10 CFR 50.62(c)(1) requires that each pressurized water reactor (PWR) must have equipment that is diverse from the reactor trip system to automatically initiate the auxiliary (or emergency) feedwater system and initiate a turbine trip under conditions indicative of an ATWS. This equipment must perform its function in a reliable manner and be independent of the existing reactor trip system.

The PBNP review was conducted to ensure that:

- The above requirement was met, and
- That the setpoints for the ATWS mitigating system actuation circuitry (AMSAC) remained valid for the EPU

In addition, for plants where a diverse scram system is not specifically required by 10 CFR 50.62, PBNP verified that the consequences of an ATWS were acceptable. The acceptance criterion is that the peak primary system pressure should not exceed the ASME Boiler and Pressure Vessel Code (B&PV), Service Level C limit of 3200 psig. The peak ATWS pressure is primarily a function of the moderator temperature coefficient (MTC) and the primary system relief capacity. PBNP reviewed:

- The limiting event determination
- The sequence of events
- The analytical model and its applicability
- The values of parameters used in the analytical model
- The results of the analyses

PBNP reviewed the justification of the applicability of generic vendor analyses to its plant and the operating conditions for the EPU.

PBNP Current Licensing Basis

PBNP is not required to install a diverse scram system. 10 CFR 50.62(c)(1), requires the incorporation of a diverse (from the reactor trip system) actuation of the auxiliary feedwater system and turbine trip for Westinghouse-designed plants. The installation of the NRC-approved AMSAC design, which is described in FSAR Section 7.4.1, Instrumentation and Control, other Actuation Systems - AMSAC, satisfies this rule. The bases for this rule and the AMSAC design are supported by Section 5.0 of WCAP-10858-P-A, Rev. 1, AMSAC Generic Design Package (Reference 9).

As part of the NRC review of the measurement uncertainty recovery (MUR) uprate, PBNP used a generic analysis for a 3-loop PWR to support the 1.4% MUR power uprate. Using the same methodology as the loss-of-external-load ATWS, another analysis determined that the peak pressure for the loss of feedwater ATWS would not exceed 2789 psia. Both analyses concluded that the peak pressure would not exceed the limit of 3200 psig (References 3 and 7).

There are no changes to the methods or acceptance criteria applied for ATWS in support of the EPU. The analysis of the ATWS event is described in FSAR Section 7.4.1, Instrumentation and Control, Other Actuation Systems - AMSAC.

In addition to the evaluations described in the FSAR, the PBNP ATWS analysis was evaluated for plant license renewal. System and system component materials of construction, operating history, and programs used to manage aging effects are documented in

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 10)

The ATWS analysis is not within the scope of license renewal.

2.8.5.7.2 Technical Evaluation

2.8.5.7.2.1 Introduction

10 CFR 50.62(c)(1) (Reference 1), requires the incorporation of a diverse (from the reactor trip system) actuation of the AFW system and turbine trip for Westinghouse-designed plants. The installation of the NRC-approved AMSAC satisfies this final rule. The basis for this rule and the AMSAC design are supported by Westinghouse generic analyses documented in NS-TMA-2182 (Reference 3). These analyses were performed based on guidelines published in NUREG-0460 (Reference 4).

NS-TMA-2182 (Reference 3) also references WCAP-8330 (Reference 5) and subsequent related documents, which formed the initial Westinghouse submittal to the NRC for ATWS, and which were based on the guidelines set forth in WASH-1270 (Reference 6). For operation at EPU conditions, the Westinghouse generic ATWS analyses (Reference 3) were evaluated for their continued applicability.

NS-TMA-2182 (Reference 3) describes the methods used in the analysis and provides reference analyses for two-loop, three-loop, and four-loop plant designs with several different steam generator models available in plants at that time. The reference analysis results demonstrated that the Westinghouse plant designs would satisfy the criteria in NUREG-0460 (Reference 4).

The failure of the reactor scram is presumed to be a common mode failure of the control rods to insert into the core. The assumption of this common mode failure is beyond the requirement to address a single failure in the typical FSAR transient analyses. In addition, the methodology of NS-TMA-2182 (Reference 3) uses control-grade equipment to mitigate consequences of the event, and uses nominal system performance characteristics in the evaluation of the event.

2.8.5.7.2.2 *Input Parameters, Assumptions, and Acceptance Criteria*

The original primary input to the loss of normal feedwater (LONF) ATWS analysis for the EPU was the reference two-loop Model 44 SG ATWS model and analysis documented in NS-TMA-2182 (Reference 3). The following analysis assumptions were used:

- The nominal and initial conditions are updated to reflect Point Beach Units 1 and 2 with an analyzed NSSS power of 1806 MWt
- Consistent with the analysis basis for the final ATWS Rule (NS-TMA-2182):
  - Thermal design flow (TDF) is assumed
  - No uncertainties are applied to the initial power, RCS average temperature or RCS pressure (Reference 8)
  - Zero percent steam generator tube plugging (SGTP) is assumed. Zero percent SGTP is more limiting (i.e., results in a higher peak RCS pressure) for ATWS events
  - Control rod insertion was not assumed
  - The AMSAC actuation setpoint is not directly assumed in the ATWS analyses. The analyses model turbine trip and actuation of the AFW system, as a result of an AMSAC signal, not the AMSAC signal itself. This is consistent with the generic analysis. A 30-second turbine trip delay and a 90-second delay for initiating AFW following the AMSAC signal are assumed
  - Steam dump flow was modeled to be 40% of nominal full-load steam capacity. This bounds a lower plant-specific value at EPU conditions
- An AFW flow range of 400-800 gpm was assumed. A value of 800 gpm is consistent with that assumed in generic ATWS analyses (Reference 3). A higher flow at EPU conditions would be less limiting (i.e. results in a lower peak RCS pressure) for the ATWS event
- The ATWS evaluation for the EPU assumed a PBNP-specific MTC of -8 pcm/°F that bounds 95% of the cycle. This value is consistent with that assumed in generic ATWS analyses (Reference 3)
- The Unit 1 steam generator data was revised to incorporate the current steam generator parameters and heat transfer characteristics of the Model 44F and the Unit 2 steam generator data was revised to incorporate the current steam generator parameters and heat transfer characteristics of the Model Δ47 replacement steam generators

2.8.5.7.2.3 Description of Analyses and Evaluations

An analysis was performed to assess the effect of the EPU on the reference two-loop Model 44, SG LONF ATWS analysis documented in NS-TMA-2182 (Reference 3). The analysis included revision of the reference two-loop Model 44, SG ATWS model to reflect the plant conditions at an analyzed NSSS power level of 1806 MWt. The Unit 1 steam generator data was revised to incorporate the current steam generator parameters and heat transfer characteristics of the Model 44F and the Unit 2 steam generator data was revised to incorporate the current steam generator parameters and heat transfer characteristics of the Model Δ47 steam generators. The LOFTRAN computer code was used to perform the PBNP ATWS analysis for the EPU, consistent with the analysis basis for the final ATWS Rule.

2.8.5.7.2.4 ATWS Results

The results of the ATWS analysis for PBNP with an NSSS power of 1806 MWt, provided in Table 2.8.5.7-1, Comparison of Peak RCS Pressure, show that the peak RCS pressure obtained for Unit 1 with Model 44F SGs and Unit 2 with Model Δ47 RSGs, 3097 psia and 3175 psia, respectively, did not exceed the B&PV Code, Service Level C stress limit criterion of 3215 psia (3200 psig). As such, the analytical basis for the final ATWS Rule continued to be met for operation of PBNP at an NSSS power of 1806 MWt. The updated EPU analysis places no restrictions on the existing AMSAC setpoint.

Time sequence of events is provided in Table 2.8.5.7-2, Time Sequence of Events Loss of Normal Feedwater ATWS, for both PBNP Units 1 and 2. Transient plots for the PBNP EPU ATWS are provided in Figures 2.8.5.7-1 through 2.8.5.7-8.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

Systems and system components associated with the ATWS analysis that are within the scope of license renewal are identified along with their aging effects requiring management, and applicable aging management programs in the PBNP license renewal application. The acceptability of these aging management programs is documented in the license renewal safety evaluation, NUREG-1839 (Reference 10).

The EPU does not add any new functions for existing components that would change the existing license renewal evaluations. Operation of these systems and components at EPU conditions does not introduce any unevaluated aging effects that would necessitate changes to aging management programs or require new programs, as internal and external environments are within the parameters previously evaluated. Therefore, EPU activities associated with ATWS analyses do not impact license renewal scope, aging effects, and aging management programs.

2.8.5.7.3 Conclusions

PBNP has reviewed the information related to ATWS and concludes that it has adequately accounted for the effects of the EPU on ATWS. PBNP concludes that the evaluation has demonstrated that the AMSAC continues to meet the requirements of 10 CFR 50.62 following implementation of the EPU. The evaluation has shown that the plant is not required by 10 CFR 50.62 to have a diverse scram system. Additionally, the evaluation has demonstrated, as explained above, that the peak primary system pressure following an ATWS event remains below the acceptance limit of 3200 psig. Therefore, PBNP finds the EPU acceptable with respect to ATWS.

2.8.5.7.4 References

1. 10 CFR 50.62, Requirements for Reduction of Risk from ATWS Events for Light Water-Cooled Nuclear Power Plants

2. ASME Boiler and Pressure Vessel Code, The American Society of Mechanical Engineers

3. NS-TMA-2182, Anticipated Transients Without Scram for Westinghouse Plants, December 1979

4. NUREG-0460, Anticipated Transients Without Scram for Light Water Reactors, April 1978

5. WCAP-8330, Westinghouse Anticipated Transients Without Trip Analysis, August 1974

6. NRC Report WASH-1270, Technical Report on Anticipated Transients Without Scram for Water Cooled Power Reactors, September 1973

7. NRC SER 2002-0010, Point Beach Nuclear Plant, Units 1 and 2 – Issuance of Amendments Re: Measurement Uncertainty Recapture Power Uprate, dated November 29, 2002

8. Letter from Division of Systems Safety Office of Nuclear Reactor Regulation to Nuclear Safety Department of Westinghouse Electric Company, February 15, 1979

9. WCAP-10858-P-A, Rev. 1, AMSAC Generic Design Package, July 1987

10. Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

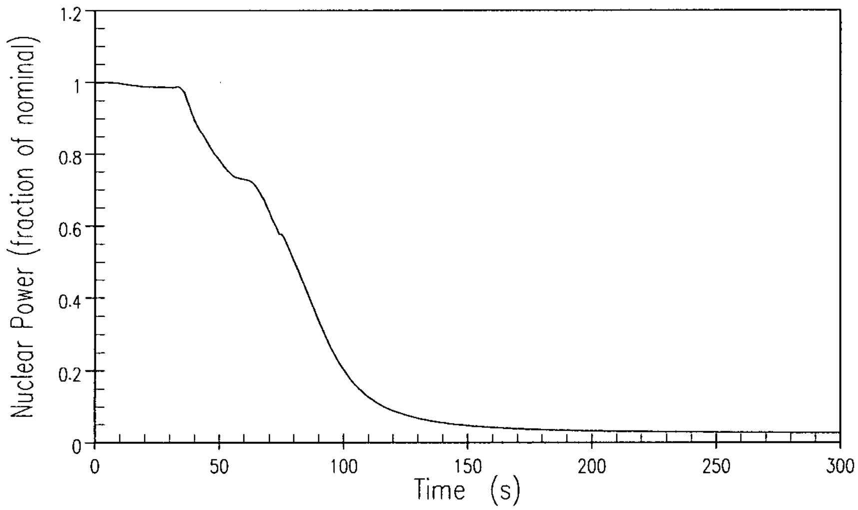
Table 2.8.5.7-1
Comparison of Peak RCS Pressure

Event	Peak RCS Pressure, psia	
	PBNP Unit 1 with Model 44F SG EPU	**PBNP Unit 2 with Model Δ47 RSG EPU**
Loss of Normal Feedwater ATWS RCS pressure limit of 3215 psia	3097.4	3175.1

Table 2.8.5.7-2
Time Sequence of Events Loss of Normal Feedwater ATWS

Event	Time (sec)	
	PBNP Unit 1 with Model 44F SG	**PBNP Unit 2 with Model Δ47 RSG**
Loss of FW flow initiated	0.0	0.0
Turbine trip occurs	30.0	30.0
AFW initiated	90.0	90.0
Peak RCS Pressure (3097 psia for Unit 1 and 3175 psia for Unit 2) reached [versus RCS pressure limit of 3215 psia]	92.0	90.0

Figure 2.8.5.7-1 PBNP Unit 1 with Model 44F SGs LONF ATWS Nuclear Power and Core Heat Flux versus Time



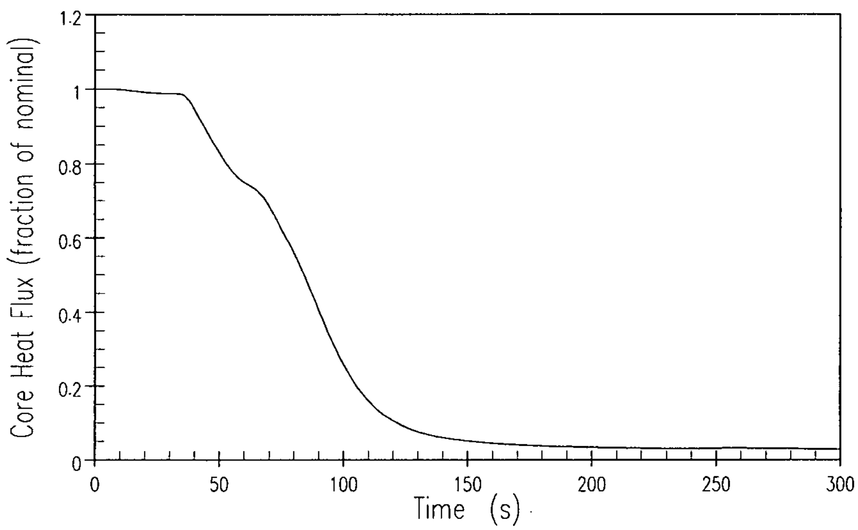
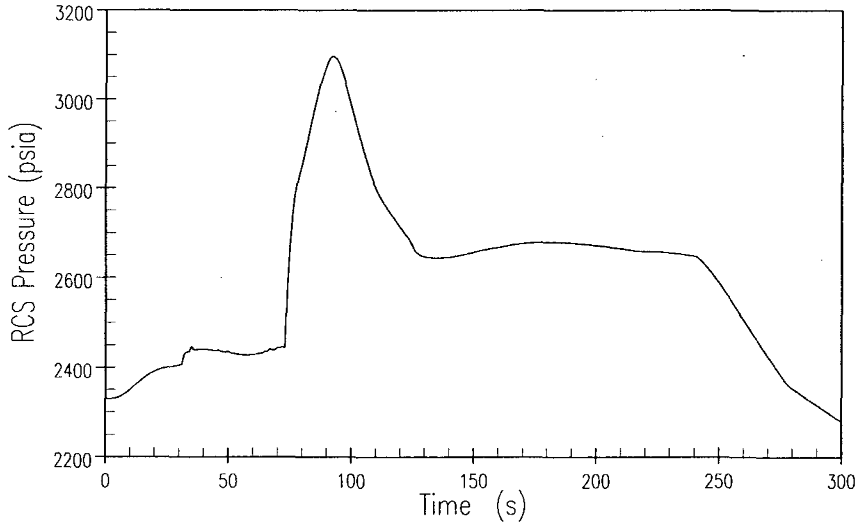


Figure 2.8.5.7-2 PBNP Unit 1 with Model 44F SGs LONF ATWS RCS Pressure and Pressurizer Water Volume versus Time



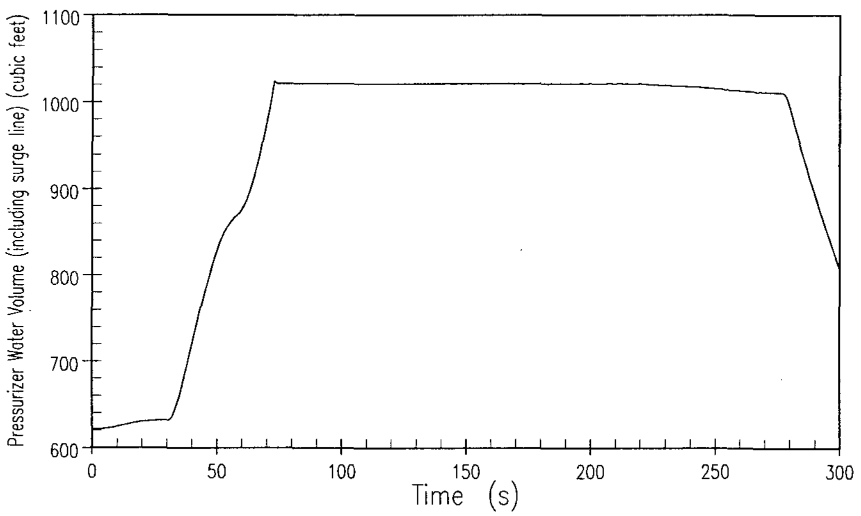
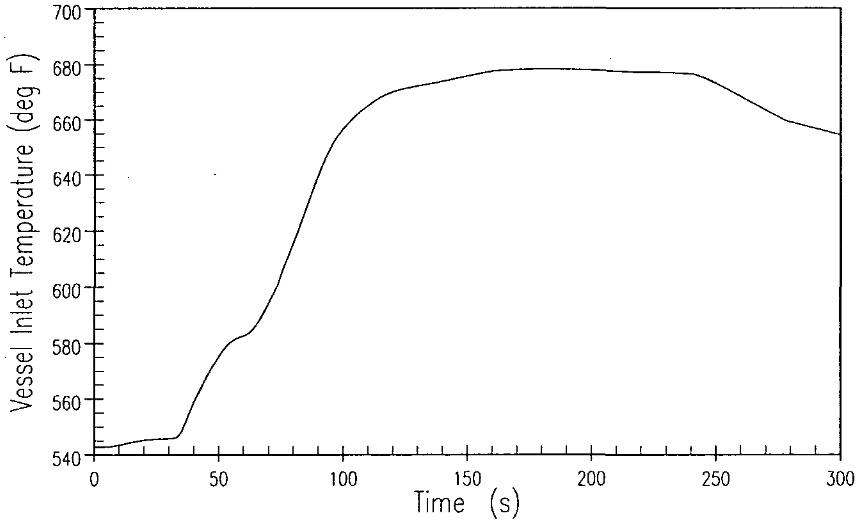


Figure 2.8.5.7-3 PBNP Unit 1 with Model 44F SGs LONF ATWS Vessel Inlet Temperature and RCS Flow versus Time



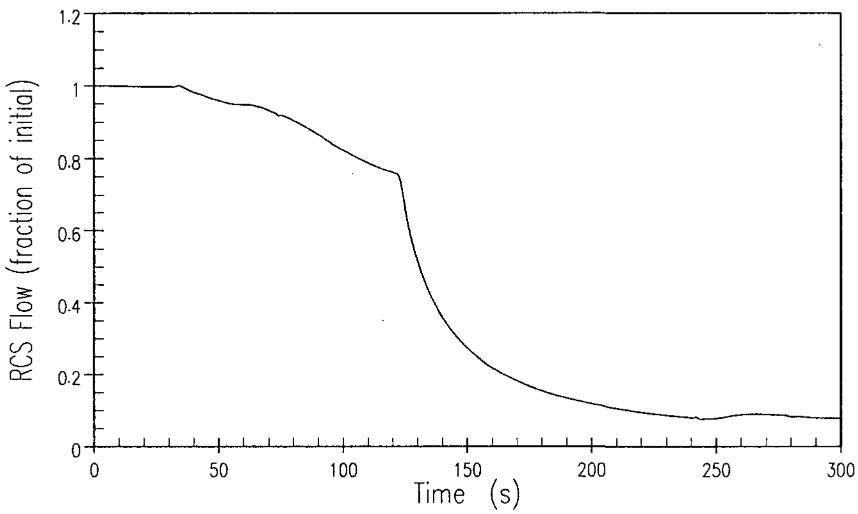
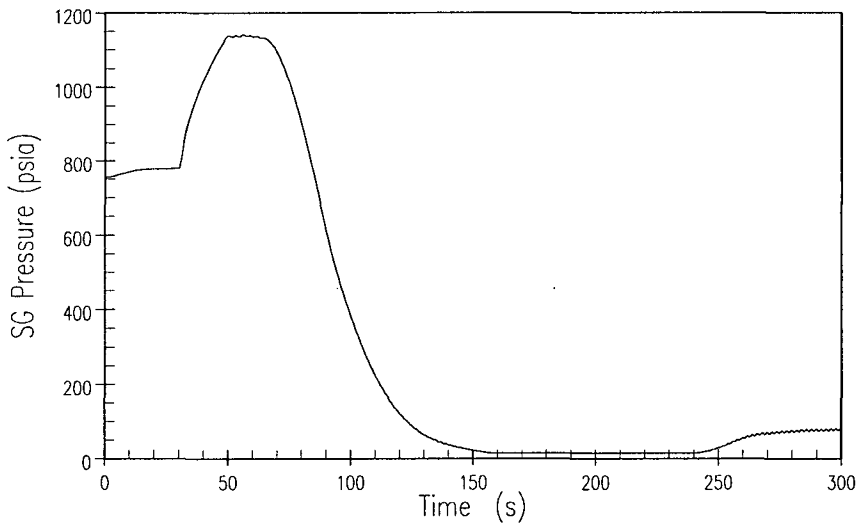


Figure 2.8.5.7-4 PBNP Unit 1 with Model 44F SGs LONF ATWS SG Pressure and SG Mass versus Time



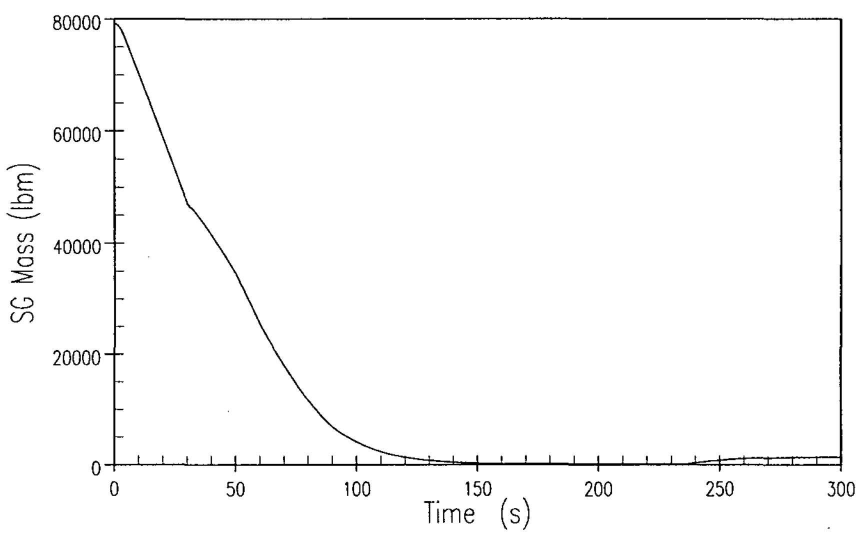
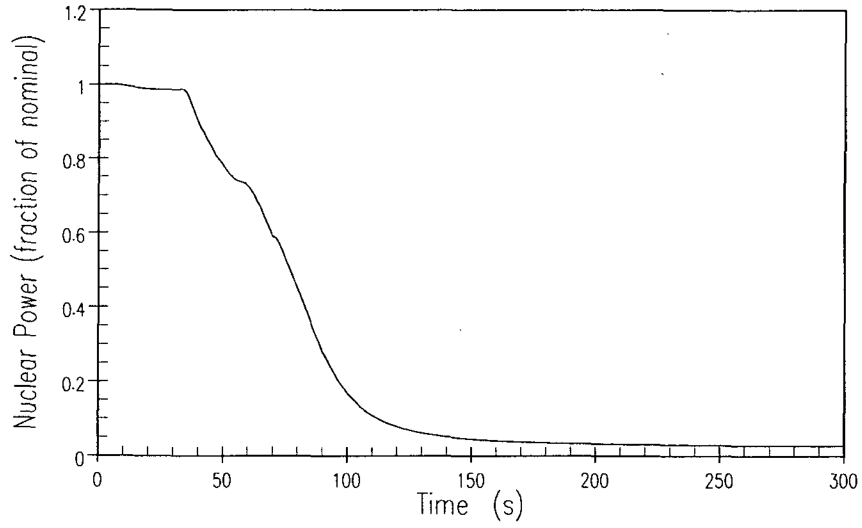


Figure 2.8.5.7-5 PBNP Unit 2 with Model Δ47 RSG LONF ATWS Nuclear Power and Core Heat Flux versus Time



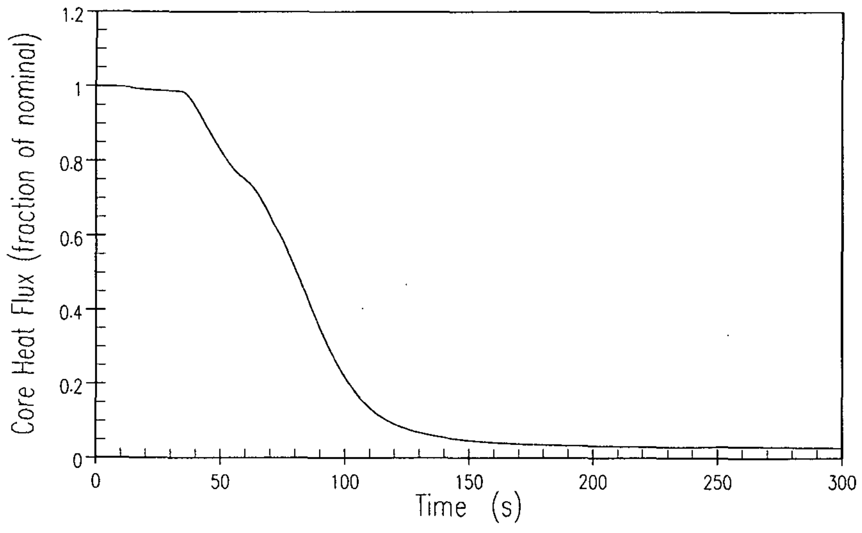
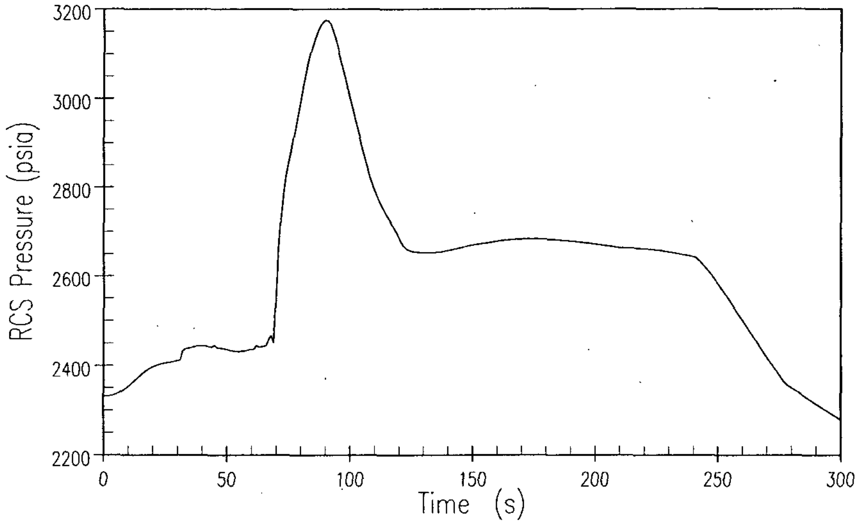


Figure 2.8.5.7-6 PBNP Unit 2 with Model Δ47 RSG LONF ATWS RCS Pressure and Pressurizer Water Volume versus Time



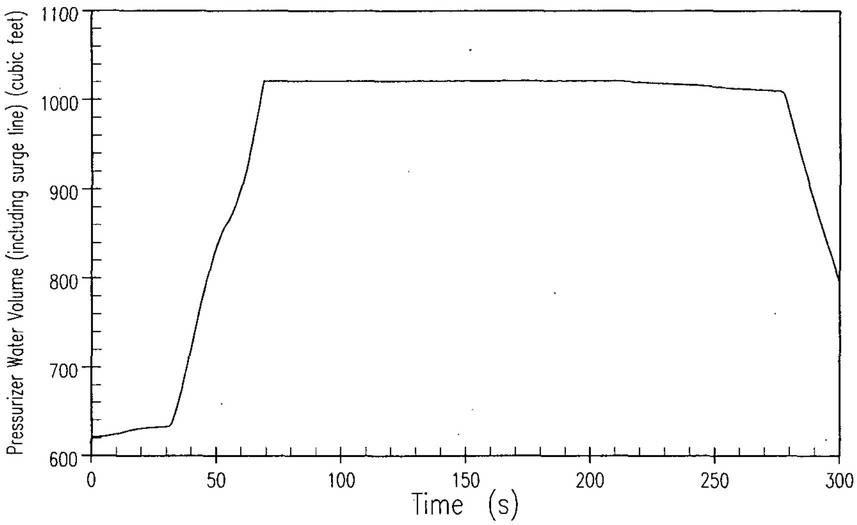
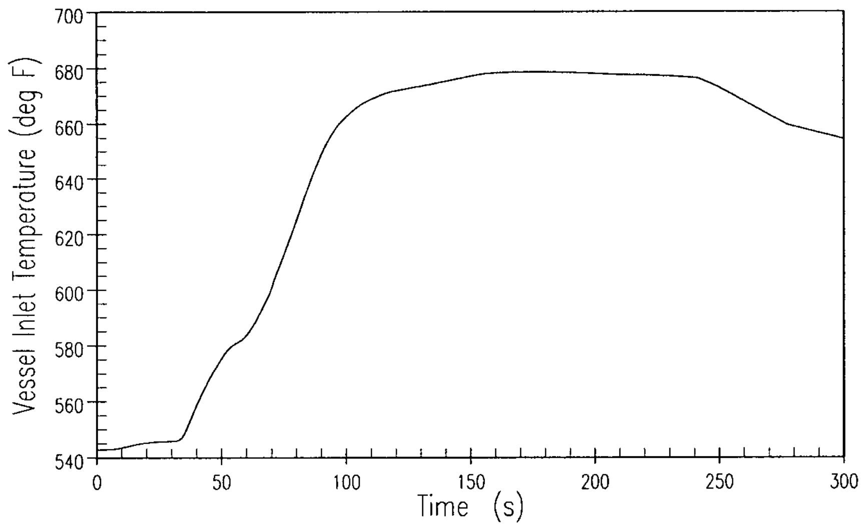


Figure 2.8.5.7-7 PBNP Unit 2 with Model Δ47 RSG LONF ATWS Vessel Inlet Temperature and RCS Flow versus Time



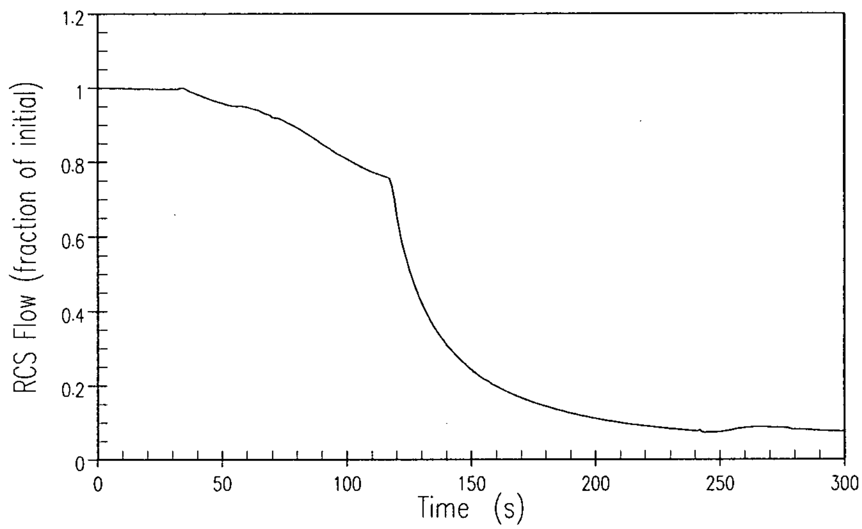
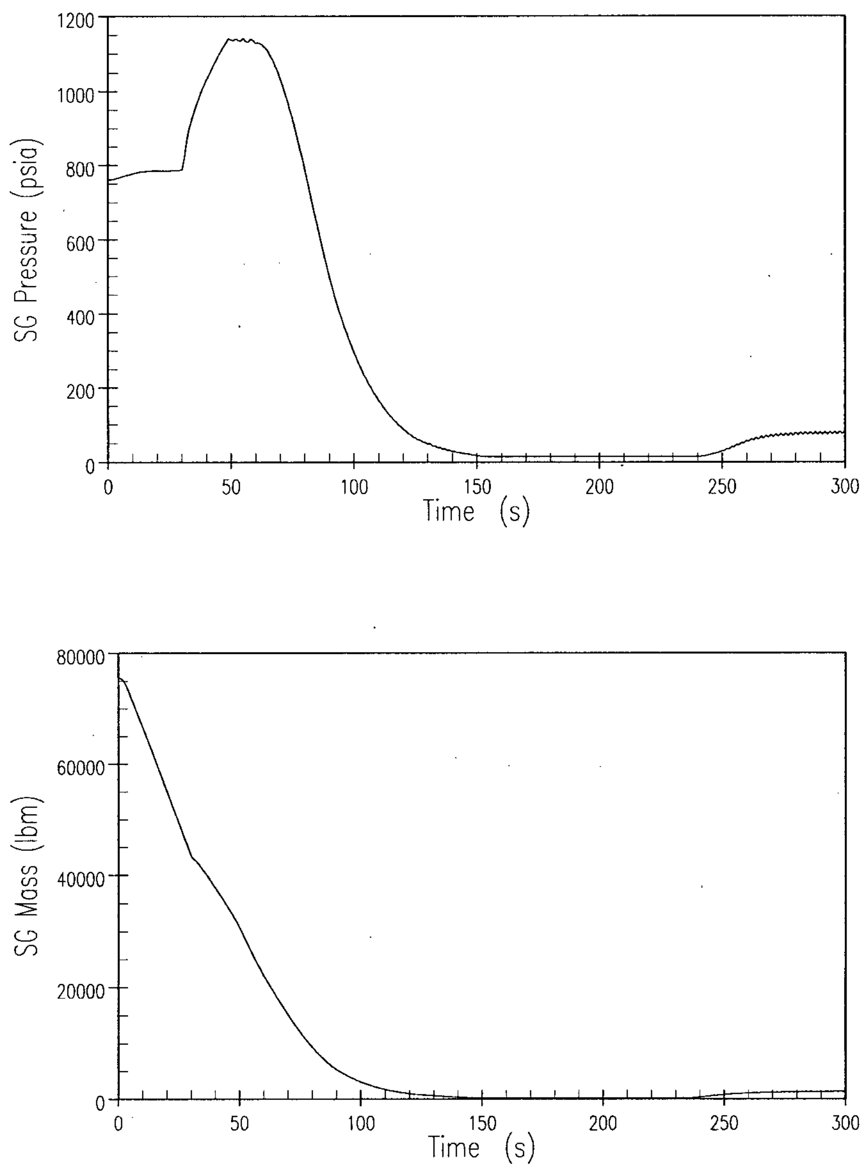


Figure 2.8.5.7-8 PBNP Unit 2 with Model Δ47 RSG LONF ATWS SG Pressure and SG Mass versus Time



2.8.6 Fuel Storage

2.8.6.1 New Fuel Storage

2.8.6.1.1 Regulatory Evaluation

Nuclear reactor plants include facilities for the storage of new fuel. The quantity of new fuel to be stored varies from plant to plant, depending upon the specific design of the plant and the individual refueling needs. The PBNP review covered the ability of the storage facilities to maintain the new fuel in a subcritical array during all credible storage conditions. The review focused on the effect of changes in fuel design on the analyses for the new fuel storage facilities. The NRC's acceptance criteria are based on GDC 62, insofar as it requires the prevention of criticality in fuel storage systems by physical systems or processes, preferably utilizing geometrically safe configurations. Specific review criteria are contained in SRP Section 9.1.1.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP, GDC relative to the Atomic Energy Commission proposed GDC is discussed in the FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50, Appendix A, GDC 62 is as follows:

CRITERION: Criticality in the new and spent fuel storage pits shall be prevented by physical systems or processes. Such means as geometrically safe configurations shall be emphasized over procedural controls. (PBNP GDC 66)

The new fuel storage area has accommodations as defined in FSAR Table 9.4-1, Fuel Handling Data, and is designed so that it is impossible to insert assemblies in locations other than storage locations in the new fuel racks. Administrative controls are used to ensure that fuel stored in the new fuel storage racks complies with the requirements of the criticality analyses described in FSAR Section 9.4.2, Fuel Handling System, System Design and Operation, including the use of a 3 out of 4 checkerboard arrangement when required. The fuel in the new fuel storage vault is stored vertically and in an array with sufficient center-to-center distance between assemblies to assure $k_{eff} < 0.95$ as described in PBNP Technical Specifications 4.3.1.

In addition to the evaluations described in the FSAR, the new fuel storage system was evaluated for license renewal. System and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 1)

With respect to the above SER, the new fuel storage system is addressed in Section 2.3.3.13, Fuel Handling System. The concrete supporting structure for the new fuel pool and storage racks is discussed in SER Section 2.4.6, Primary Auxiliary Building Structure. Aging effects, and the programs used to manage the aging effects associated with new fuel storage are discussed in Section 3.3 of the SER.

PBNP has been granted an exemption from the requirements of 10 CFR 70.24 concerning criticality monitors (Reference 2).

2.8.6.1.2 Technical Evaluation

PBNP has reviewed the potential effects of the EPU, and this review has identified the following: (1) There are no fuel design changes implemented in support of the EPU that affect this evaluation, (2) there is no increase in the Technical Specification maximum allowed fuel enrichment (5.0 w/o U-235) for the EPU, and (3) there are no modifications to the New Fuel Storage Vault for the EPU. Therefore, PBNP concludes that the analysis of record for the new fuel storage vault remains valid for the EPU. Therefore, no additional analysis is required.

2.8.6.1.2.1 Evaluation of Impact on Renewed Plant Operating License Evaluations an License Renewal Programs

The PBNP new fuel storage is within the scope of license renewal as identified in Sections 2.4.6 and 3.5.2.3.7 of Reference 3. EPU activities are not changing the fuel design, nor changing the maximum fuel enrichment, nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. The EPU conditions do not add any new or previously unevaluated aging effects that would necessitate changes to aging management programs or require new programs, as internal and external environments remain within the parameters previously evaluated. Therefore, EPU activities associated with new fuel storage do not impact license renewal scope, aging effects, and aging management programs.

2.8.6.1.2.2 Results

PBNP has reviewed the potential effects of the EPU, and this review has identified the following: (1) There are no fuel design changes implemented in support of the EPU that impact this assessment, (2) there is no increase in the Technical Specification maximum allowed fuel enrichment (5.0 w/o U-235) for the EPU, (3) there are no modifications to the new fuel storage vault for the EPU, and (4) no new aging effects requiring management exist. Therefore, PBNP concludes that the analysis of record for the new fuel storage vault remains valid for the EPU.

2.8.6.1.3 Conclusion

PBNP has reviewed whether there are any potential effects from the EPU for PBNP on the analyses of record for the new fuel storage facility, and concludes that no additional analyses are required. The new fuel storage facilities will continue to meet the requirements of PBNP, GDC 66 following implementation of the proposed EPU. Therefore, PBNP finds the proposed EPU acceptable with respect to new fuel storage.

2.8.6.1.4 References

1. Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

2. Letter, NRC to WE, Point Beach Nuclear Plant, Unit Nos. 1 and 2 - Issuance of Exemption from the Requirements of 10 CFR 70 (TAC NOS. M98973 AND M98974), October 6, 1997

3. V. Rodriguez, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, NUREG-1839, December 2005

2.8.6.2 Fuel Storage

2.8.6.2.1 Regulatory Evaluation

Nuclear reactor plants include storage facilities for the wet storage of spent fuel assemblies. The safety function of the spent fuel pool and storage racks is to maintain the spent fuel assemblies in a safe and subcritical array during all credible storage conditions and to provide a safe means of loading the assemblies into shipping casks. The PBNP review covered the effect of the proposed EPU on the criticality analysis (e.g., reactivity of the spent fuel storage array and boraflex degradation or neutron poison efficacy). The NRC's acceptance criteria are based on:

- GDC 4, insofar as it requires that structures, systems, and components important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents
- GDC 62, insofar as it requires that criticality in the fuel storage systems be prevented by physical systems or processes, preferably by use of geometrically safe configurations

Specific review criteria are contained in SRP Section 9.1.1.

PBNP Current Licensing Basis

PBNP has submitted License Amendment Request (LAR) 247, Spent Fuel Pool Storage Criticality Control (Reference 1), to the NRC for approval. This request proposes changes to the PBNP Technical Specifications to incorporate the results of a new spent fuel pool criticality analysis. The new criticality analysis determines the acceptable fuel storage configurations in the spent fuel pool (SFP) storage racks with credit for burnup, integral fuel burnable absorber (IFBA), Plutonium-241 decay, and soluble boron, where applicable. The effect of the proposed EPU on the criticality analysis has been analyzed for both current licensing basis and the proposed LAR 247 amendment case and is presented in the LR Section 2.8.6.2.2, Technical Evaluation.

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP, GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The equivalent PBNP GDC for 10 CFR 50, Appendix A, GDC 4 and 62 are as follows:

CRITERION: Adequate protection for those engineered safety features, the failures of which could cause an undue risk to the health and safety of the public, shall be provided against dynamic effects and missiles that might result from plant equipment failures other than a rupture of the reactor coolant system piping.

An original design basis for protection of equipment against the dynamic effects of a rupture of the reactor coolant system piping is no longer applicable. (PBNP GDC 40)

CRITERION: Criticality in the new and spent fuel storage pits shall be prevented by physical systems or processes. Such means as geometrically safe configurations shall be emphasized over procedural controls. (PBNP GDC 66)

The spent fuel storage pool has accommodations as defined in FSAR Table 9.4-1, Fuel Handling Data. It is possible to insert assemblies in areas of the pool other than the spent fuel storage racks. A criticality analysis was performed for a misplaced 4.6 w/o fresh assembly adjacent to a storage rack module containing a 9x9 array of 4.6 w/o fresh fuel assemblies with no intervening rack poison. The analysis shows the spent fuel pool K_{eff} limit of 0.95 is met by maintaining at least 700 ppm boron in the spent fuel pool. The 700 ppm boron concentration is well within the 2100 ppm minimum boron concentration required in the spent fuel pool by Technical Specification 3.7.11.

Administrative controls ensure that fuel stored in the spent fuel pool meets the requirements of Technical Specifications and the criticality analysis discussed above.

The spent fuel storage pool is shared by each unit. It is constructed of reinforced concrete and is Class I Seismic design.

Calculations have been performed which demonstrate that tornado generated winds will not remove any critical amount of water from the spent fuel pool. Any water removed in this way will leave adequate coverage to maintain cooling of the stored fuel elements.

No special design features had been made for the spent fuel pool as far as turbine missiles were concerned because it had been believed that the worst low-trajectory missile could not have sufficient translational kinetic energy to reach the spent fuel pool. However, model tests initiated by Westinghouse contradicted this theory in the case of a turbine overspeed. Therefore, a completely independent turbine speed detection and valve trip initiation system for the turbine generators of PBNP Units 1 and 2 was provided to minimize the likelihood of a turbine generator unit overspeeding above the design speed. FSAR Section 14.1.12, Uncontrolled Rod Withdrawal at Power, gives more insight into this event.

Until approval of License Amendment Request 247, the Boraflex Monitoring Program manages aging effects for the Boraflex material in the spent fuel racks. This program addresses the concerns described in NRC GL 96-04.

PBNP has been granted an exemption from the requirements of 10 CFR 70.24 concerning criticality monitors (Reference 2).

The spent fuel storage pool is further described in the FSAR Sections 9.4, Fuel Handling System, 15.2.5, Boraflex Monitoring Program, 15.4.5, Neutron Absorber, Appendix A.5, Seismic Design Analysis, and Appendix A.6, Shared Systems Analysis.

The spent fuel pool cooling and cleanup system is addressed in LR Section 2.5.4.1, Spent Fuel Pooling Cooling and Cleanup.

In addition to the evaluations described in the FSAR, the spent fuel storage system was evaluated for license renewal. System and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 4)

With respect to the above SER, the spent fuel storage system is addressed in Section 2.3.3.13, Fuel Handling System. The concrete supporting structure for the new fuel pool and storage racks is discussed in SER Section 2.4.6, Primary Auxiliary Building Structure. Aging effects, and the programs used to manage the aging effects associated with spent fuel storage are discussed in Section 3.3 of the SER. The Boraflex Monitoring Program is described in Sections 3.0.3.2.5 and 4.6.1.

2.8.6.2.2 Technical Evaluation

2.8.6.2.2.1 Introduction

The purpose of this section is to describe the review of potential effects of the EPU for PBNP on the current analysis of record for the spent fuel pool. This review consists of two components: (1) review the potential effects of the EPU relative to the current licensing basis, and (2) review the potential effects of the EPU relative to the spent fuel pool criticality safety analysis proposed in Licensing Amendment Request 247 (Reference 3). There are no physical changes being made to the spent fuel pool or storage racks due to the EPU. The effects of the EPU on the spent fuel pool cooling system are evaluated in LR Section 2.5.4.1, Spent Fuel Pool Cooling and Cleanup. There is no effect on the Boraflex Monitoring Program.

2.8.6.2.2.2 Evaluation of EPU Effects on Current Licensing Basis

PBNP has reviewed the potential effects of the EPU for PBNP on the current licensing basis, and this review has identified the following: (1) there are no fuel design changes implemented in support of the EPU that impact this assessment, (2) there is no increase in the Technical Specification maximum allowed fuel enrichment (5.0 w/o U-235) for the EPU, and (3) there are no modifications to the spent fuel pool for the EPU. Therefore, PBNP concludes that the current analysis of record for the spent fuel pool remains valid for the EPU.

2.8.6.2.2.3 Evaluation of EPU Effects on Criticality Safety of LAR 247

A spent fuel pool criticality safety analysis is proposed in Licensing Amendment Request 247 (Reference 3) to take reactivity credit for assembly burnup, integral fuel burnable absorber (IFBA), Pu-241 decay and soluble boron. The analysis utilizes input parameters that are appropriate for the proposed EPU of PBNP

This analysis is described in detail in Reference 3.

Many of these input parameters are consistent with the current licensing basis. However, inputs parameters affected by the PBNP EPU, such as core operating temperatures and power levels, are considered appropriately. A complete list of the input parameters and assumptions utilized in the spent fuel pool criticality safety analysis is included in the technical report (Reference 3).

The boron dilution analysis for PBNP Units 1 and 2 determined that 10 hours would be required to dilute the SFP from the minimum allowed TS boron concentration of 2100 parts per million, (ppm) in Specification 3.7.11, Fuel Storage Pool Boron Concentration, to a concentration less than the criticality safety analysis determined minimum concentration of 664 ppm. This time duration demonstrates that sufficient time is available for operators to recognize and terminate an inadvertent dilution event.

In summary, the analysis provided in Reference 3 outlines the limits on soluble boron concentration, enrichment, burnup, IFBA content and decay times of the fuel that ensure that there is a 95% probability at a 95% confidence level that the K_{eff} of the PBNP spent fuel pool will remain less than 1.0 with full density unborated water present, and less than 0.95 for all normal conditions with credit for soluble boron present in the water. This analysis explicitly considers the effects of the EPU on core operation, and the subsequent effects on spent fuel storage. Therefore, PBNP concludes that the criticality safety analysis of LAR 247 for the spent fuel pool is valid for the EPU for PBNP.

2.8.6.2.2.4 Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

The PBNP spent fuel pool storage is within the scope of license renewal as identified in Sections 2.3.3.3, 2.4.6, 3.3.2.3.4 and 3.5.2.3.7 of Reference 4. EPU activities are not changing the fuel design, nor increasing the fuel enrichment, nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. The EPU conditions do not add any new or previously unevaluated aging effects that would necessitate changes to aging management programs or require new programs as internal and external environments remain within the parameters previously evaluated. Therefore, EPU activities associated with spent fuel storage do not impact license renewal scope, aging effects, and aging management programs.

2.8.6.2.2.5 Results

PBNP has reviewed the potential effects of the EPU for fuel storage, and this review has concluded the following:(1) the current analysis of record for the spent fuel pool remains valid for EPU, (2) the criticality safety analysis of LAR 247 for the spent fuel pool is also valid for the EPU, and (3) no new aging effects requiring management exist.

2.8.6.2.3 Conclusion

PBNP has reviewed whether there are any potential effects from the EPU on the current licensing basis for spent fuel rack criticality safety, and concludes that no additional analyses are required. Additionally, PBNP concludes that the effects of the proposed EPU on the analyses of LAR 247 have been accounted for by explicit consideration of EPU core operating conditions and the results of this analysis are also acceptable. PBNP concludes that the spent fuel pool design will continue to ensure an acceptable degree of subcriticality following implementation of the proposed EPU. Based on this, PBNP concludes that the spent fuel storage facilities will continue to meet the requirements of PBNP GDC 40 and 66 following implementation of the proposed EPU. Therefore, PBNP finds the proposed EPU acceptable with respect to spent fuel storage.

2.8.6.2.4 References

1. PBNP License Amendment Request (LAR) 247, Spent Fuel Storage Criticality Control (ML082240685), dated July 24, 2008

2. Letter, NRC to WE, Point Beach Nuclear Plant, Unit Nos. 1 and 2 - Issuance of Exemption from the Requirements of 10 CFR 70 (TAC NOS. M98973 AND M98974), October 6, 1997

3. M. Anness, Point Beach Units 1 and 2 Spent Fuel Pool Criticality Safety Analysis, WCAP-16541-NP, Revision 2, June 2008

4. NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, December 2005

2.8.7 Additional Reactor Systems

2.8.7.1 Loss of Residual Heat Removal at Reduced Inventory

2.8.7.1.1 Regulatory Evaluation

NRC Generic Letter (GL) 88-17, Loss of Decay Heat Removal (Reference 1), identified actions to be taken to preclude loss of decay heat removal (DHR) during nonpower operations. These actions included operator training and the development of procedures and hardware modifications as necessary to prevent the loss of DHR during reduced reactor coolant inventory operations, to mitigate accidents before they progress to core damage, and to control radioactive material if a core damage accident should occur. Procedures and administrative controls were required that cover reduced inventory operations and ensure that both hot legs are not blocked by nozzle dams unless a vent path is provided that is large enough to prevent pressurization and loss of water from the reactor vessel. Instrumentation was required to provide continuous core exit temperature and reactor water level indication. Sufficient equipment was required to be maintained in an operable or available status so as to mitigate the loss of the DHR cooling or loss of reactor coolant system (RCS) inventory should such an event occur during mid-loop or reduced inventory conditions.

PBNP Current Licensing Basis

There are no specific NRC acceptance criteria within NRC regulations for operations at mid-loop or reduced inventory conditions. However, the NRC requested all holders of operating licenses to respond to eight recommended expeditious actions and six programmed enhancements identified in GL 88-17. The PBNP responses to these actions are contained in:

GL-88-17 response

- Expeditious Action Item 1: PBNP provided training related to the Diablo Canyon event prior to entering reduced inventory operation
- Expeditious Action Item 2: PBNP implemented procedures and administrative controls that reasonably ensure that containment closure will be achieved prior to the time at which core uncovery could result from a loss of decay heat removal coupled with an inability to initiate alternate cooling or addition of water to the RCS inventory. Containment closure will be able to be accomplished within 30 minutes. This is procedurally accomplished (OP 4F Reactor Coolant System Reduced Inventory Requirements) prior to the time to boil (TTB). These procedures used in NUMARC 91-06, Guidelines for Industry Actions to Address Shutdown Management, as guidance
- Expeditious Action Item 3: PBNP confirmed that at least two independent, continuous temperature indications that are representative of the core exit conditions were available whenever the RCS is in a mid-loop condition and the reactor vessel head is located on top of the reactor vessel
- Expeditious Action Item 4: PBNP confirmed that one independent, continuous RCS water level indication was available whenever the RCS is in a reduced inventory condition

- Expeditious Action Item 5: PBNP implemented procedures and administrative controls that generally avoid operations that deliberately or knowingly lead to perturbations to the RCS and/or systems that are necessary to maintain the RCS in a stable and controlled condition while the RCS is in a reduced inventory condition
- Expeditious Action Item 6: PBNP confirmed that at least two available or operable means of adding inventory to the RCS that are in addition to pumps that are a part of the normal decay heat removal systems
- Expeditious Action Item 7: PBNP implemented procedures and administrative controls that reasonably ensure that all hot legs are not blocked simultaneously by nozzle dams unless a vent path is provided that is large enough to prevent pressurization of the upper plenum of the reactor vessel
- Expeditious Action Item 8 was not applicable to PBNP
- Programmed Enhancement Item 1:

  a. PBNP confirmed that one independent, continuous RCS water level indication was available whenever the RCS is in a reduced inventory condition. A second independent, continuous RCS water level indication was later installed as previously committed. In addition, a permanent sight glass was proposed but not implemented. Instead, a magnetic level indicator was installed to replace the existing tygon tube that was in use at the time

  b. PBNP confirmed that at least two independent, continuous temperature indications that are representative of the core exit conditions were available whenever the RCS is in a mid-loop condition and the reactor vessel head is located on top of the reactor vessel

  c. PBNP confirmed the capability of continuously monitoring decay heat removal (DHR) system performance whenever a DHR system was being used for cooling the RCS

  d. PBNP confirmed the availability of visible and audible indications of abnormal conditions in temperature and DHR system performance. A RCS low level alarm indication in the control room was installed concurrent with the second level system described above

- Programmed Enhancement Item 2: PBNP developed and implemented procedures that cover reduced inventory operation and that provide an adequate basis for entry into a reduced inventory condition
- Programmed Enhancement Item 3: PBNP confirmed that reliable equipment for RCS cooling and avoiding loss of RCS cooling was available and functional. PBNP developed and implemented procedures to maintain sufficient equipment operable or available to mitigate loss of DHR or RCS inventory. PBNP also confirmed that adequate equipment for personnel communications was available to support activities related to the RCS or systems necessary to maintain the RCS in a stable and controlled condition
- Programmed Enhancement Item 4: PBNP confirmed that WCAP-11916 "Loss of RHRS Cooling While the RCS is Partially Filled," Revision 0 provided the analytical background for

the procedures, instrumentation installation and response, and equipment/NSSS interactions and response

- Programmed Enhancement Item 5: PBNP stated that it did not have a Technical Specification on minimum RHR system flow rate and did not have an autoclosure interlock.
- Programmed Enhancement Item 6: PBNP stated that activities to reasonably minimize the likelihood of loss of DHR would be administratively controlled.

NRC comments on response to GL 88-17

- A detailed list of personnel receiving training on reduced inventory should include maintenance personnel.
- If quick closure of the equipment hatch is contemplated to meet containment closure, the number of bolts required should be verified.
- A detailed discussion on reactor vessel level indication provided specific recommendations on the use, accuracy and limitations on use of the diverse types of level indication.
- Concerning the provision of the means of adding inventory to the RCS, the NRC provided flow path suggestions (hot leg injection for cold leg opening) and venting capability verification calculation requirements.

WEPCO response to NRC comments

- A training needs analysis was conducted to identify the appropriate and most effective personnel to train in the awareness of reduced RCS inventory considerations.
- There are no plans to remove the equipment hatch during periods of reduced inventory.
- The three methods of level indication were discussed.
- Operating procedures were cited indicating the use of hot leg injection if there was a cold leg opening. Calculations were performed to verify the effectiveness of RCS openings for venting.

On August 26, 1991, WEPCO provided a response to the Inspection Report 266/90014 and 301/90014 observation, that there may not be sufficient independence between the redundant reactor vessel water level instruments used during reduced inventory operations. Plant procedures were subsequently changed to assure appropriate controls over variable and reference vent paths to reactor vessel level instrumentation. This issue was formally closed by the NRC in Inspection Report 50-266/95004(DRP) and 50-301/95004(DRP).

The decay heat removal function of the RHR system is described in FSAR Section 9.2, Residual Heat Removal.

In addition to the evaluations described above, the system components associated with the control or mitigation of a loss of decay heat removal capability during non-power operations were evaluated for license renewal. Systems and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report (SER) Related to the License Renewal of Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 5)

2.8.7.1.2 Technical Evaluation

2.8.7.1.2.1 Introduction

The purpose of the loss of residual heat removal (RHR) at mid-loop evaluation was to determine the time to saturation, boil-off rate, minimum makeup rate to match boil-off, and time to reach 200°F following the loss of RHR at mid-loop conditions. Operation at reduced inventory (RCS level 3 feet or more below the flange), including at mid-loop conditions, is described in PBNP Operating Procedure, OP 4D, Draining the Reactor Cavity and Reactor Coolant System Reduced Inventory Requirements. This procedure includes intial conditions that provide for establishing an appropriate vent path, such as an open pressurizer manway. Administarive controls will be established for limitations on time after shutdown for acceptability of this vent path.

2.8.7.1.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters

The input parameters for the evaluation are given in Table 2.8.7.1-1, Input Parameters for Loss of RHR at Mid-loop Evaluation.

Assumptions

The assumptions are summarized in Table 2.8.7.1-2, Assumptions for Loss of RHR at Mid-loop Evaluation.

Acceptance Criteria for Loss of RHR at Mid-Loop Evaluation

While there are no specific regulations in place, NRC GL 88-17 describes certain requirements for operation at reduced inventory conditions (RCS level three feet below the flange or lower). For PBNP, reduced inventory is defined as less than 55% on level indicators LI-447 and LI-447A. A level of 55% is approximately 3 feet below the reactor vessel flange. Apart from specific equipment requirements in GL 88-17, (e.g., independent core exit temperature indications or diverse/independent means for adding inventory), procedures must be in place for recovery from a loss of RHR event.

The acceptance criteria for the loss of RHR at mid-loop includes maintaining core cooling and protecting the reactor core until RHR can be returned to service. If RHR flow cannot be rapidly restored, the operator starts trending core exit thermocouple temperatures and initiates contingency actions while trying to return RHR to service. This evaluation provides time estimates to reach saturation conditions. The analytical bases for this evaluation can be found in WCAP-11916, Loss of RHRS Cooling While the RCS Is Partially Filled (Reference 2).

2.8.7.1.3 Description of Analyses and Evaluations

As a result of the EPU, the decay heat at a given time after shutdown increases, approximately proportional to the change in the power level due to the EPU. This, in turn, reduces the time to boiling and the time to core uncovery following a postulated loss of RHR cooling. Analyses have been performed to determine the time to reach 200°F, the time to reach saturation, and makeup and boil-off rates for a loss of RHR at mid-loop conditions. The PBNP response (Reference 4) relating to Generic Letter 88-17 has been reviewed to identify information that may be affected by the EPU.

2.8.7.1.4 Results

The results for time to 200°F, time to saturation, boil-off rate and make-up rate for a loss of RHR at mid-loop conditions as a result of the EPU are provided in Table 2.8.7.1-3, Loss of RHR at Mid-loop (EPU) Results. VPNPD-89-061 (Reference 4) requires that preferred flow paths and equipment be available with power to the appropriate components prior to draindown. This provides the means for adding inventory to the RCS in the event of loss of RHR cooling. Generic Letter 88-17 requires at least two means of adding inventory to the RCS must be available. In the event RHR is not available, one safety injection pump, and one charging pump with suction from the RWST, refueling water circ pump with suction from the RWST, or one spent fuel pool pump will be available to provide the necessary makeup to match the boil-off rate. See Table 2.8.7.1-3 for required makeup rates vs. time after shutdown. Table 2.8.7.1-4, Loss of RHR at Mid-loop Results (1540 Mwt), provides results at current power. Administrative controls will be established to provide that sufficient time will have passed since shutdown such that the pump capacity to match the boil-off rate is available.

No issues remain with the existing instrumentation that has been provided to monitor the RCS level and RHR performance during mid-loop operation and no additional instrumentation is required for monitoring mid-loop operation at the EPU conditions.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

Point Beach systems were evaluated for plant license renewal. System and system component materials of construction, operating history and programs used to manage aging effects are documented in, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG 1839), dated December 2005 (Reference 5). Systems and components associated with the issues identified in GL 88-17 for mid-loop operation are addressed in their respective sections of the license renewal SER. These systems and components are subject to the programs used to manage aging effects. EPU activities do not add any new functions for existing plant components relied upon to mitigate the effects of loss of RHR at reduced inventory that would change the license renewal evaluation boundaries. Operation of these systems and components at EPU conditions does not introduce any unevaluated aging effects that would necessitate a change to aging management programs or require new programs as internal and external environments are within the parameters previously evaluated. Therefore, EPU activities associated with loss of RHR at reduced inventory do not impact license renewal scope, aging effects, and aging management programs.

2.8.7.1.5 Conclusion

PBNP has reviewed the assessment of the effects of the EPU on the loss of RHR while operating at RCS reduced inventory conditions and concludes that it has adequately identified the changes required for the EPU to ensure PBNP Units 1 and 2 maintain the ability to operate with the RCS in a reduced inventory condition and to mitigate the consequences of a loss of RHR at Midloop. PBNP further concludes systems, components, and administrative controls meet the acceptance criteria of GL 88-17. Operator response to loss of RHR at reduced inventory is consistent with generic Westinghouse Owners Group (WOG) guidance, which is independent of the licensed reactor thermal power. Therefore, PBNP finds the EPU acceptable with respect to operation at reduced RCS inventory conditions.

2.8.7.1.6 References

1. NRC Generic Letter 88-17, Loss of Decay Heat Removal, October 17, 1988

2. WCAP-11916, Loss of RHRS Cooling While the RCS Is Partially Filled, July 1988

3. WOG Abnormal Response Guideline and Background Information, ARG-1, Loss of RHR While Operating at Mid-Loop Conditions, Rev. 1, issued via WOG-96-093, June 6, 1996

4. WEPCO to USNRC, Response to Generic Letter 88-17, Loss of Decay Heat Removal, Point Beach Nuclear Plants, Units 1 and 2, February 2, 1989

5. Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

Table 2.8.7.1-1
Input Parameters for Loss of RHR at Mid-loop Evaluation

Name	Units	Values	Comment
Power Level	MWt	1800	Nominal value
Time After Shutdown	Hours	48, 100, 168, 240, 300, 416.6, 555.5, 833.3	Consistent with previous calculations
RCS Temperatures	°F	100°F, 140°F	Consistent with previous calculations
422V+ Fuel Mass	Lbm	120,047	UO_2 mass
Cladding Mass	Lbm	27,429	Zirc/ZIRLO™ mass
Heatup Volume	Ft^3	636.8	Water in core, upper plenum, portion of the hot legs

Table 2.8.7.1-2
Assumptions for Loss of RHR at Mid-loop Evaluation

Number	Assumption
1	The evaluation does not give credit for the increase in time to saturation due to heatup of the RV metal mass (excluding the fuel and cladding mass listed in Table 2.8.7.1-1) nor the benefit of cooling due to generation of steam.
2	The initial level in the RCS was assumed to be at mid-loop for the determination of the heatup volume. For reduced inventory operations, it is expected the initial level will be higher per plant procedure OP-4D.
3	Two different initial RCS and steam generator temperatures are assumed for this analysis: 100°F and 140°F. These temperatures are considered typical for the RCS and conservative (high) for the secondary.
4	The decay heat is based on the American Nuclear Society (ANS) ANS-5.1-1979 decay heat standard, including + 2-sigma uncertainty and a conservative Gmax (for fission product absorption). The values are expected to be conservatively high by 10 to 20%.

Table 2.8.7.1-3
Loss of RHR at Mid-loop (EPU) Results

Shutdown Time (hrs)	Time to Saturation (min)		Time to 200°F		BoiloffRate (lbm/s)	Makeup Rate (gpm)[1,2]
	100°F	140°F	100°F	140°F		
48	10.3	6.6	9.2	5.5	8.9	64.3
100	13.3	8.5	11.8	7.0	6.9	50.1
168	16.4	10.4	14.6	8.7	5.6	40.6
240	19.0	12.1	17.0	10.1	4.8	35.0
300	20.8	13.2	18.6	11.0	4.4	32.0
416.6	24.2	15.4	21.6	12.8	3.8	27.5
555.5	27.5	17.5	24.5	14.6	3.3	24.2
833.3	32.0	20.4	28.6	17.0	2.9	20.8

1. Makeup Rate = Boiloff Rate converted to gallons per minute (gpm)
2. A Makeup Rate of 60.5 gpm (the capacity of one charging pump) equates to the Boiloff Rate at 59 hours after shutdown.

Table 2.8.7.1-4
Loss of RHR at Mid-loop Results (1540 Mwt)

Shutdown Time (hrs)	Time to Saturation (min)		Time to 200°F		Boiloff Rate (lbm/s)	Makeup Rate (gpm)[3]
	100°F	140°F	100°F	140°F		
48	12.0	7.7	10.7	6.4	7.6	55.0
100	15.4	9.8	13.8	8.2	5.9	42.9
168	19.1	12.1	17.0	10.1	4.8	34.8
240	22.1	14.1	19.8	11.7	4.1	30.0
300	24.2	15.4	21.6	12.9	3.8	27.4
416.6	28.2	18.0	25.2	15.0	3.3	23.5
555.5	32.1	20.4	28.6	17.0	2.9	20.7
833.3	37.4	23.8	33.4	19.8	2.4	17.8

3. Makeup Rate = Boiloff Rate converted to gallons per minute (gpm)

2.8.7.2 Natural Circulation Cooldown

2.8.7.2.1 Regulatory Evaluation

The ability for a nuclear power plant to cooldown via natural circulation cooling became an explicit issue for all plants following the Three Mile Island event. For the PBNP EPU, a calculation is performed that conveys the natural circulation cooldown capability of PBNP Units 1 & 2.

On March 28 and 29, 1985 Diablo Canyon Unit 1 performed a series of tests to confirm the ability of the plant to cooldown under natural circulation conditions and to demonstrate adequate boron mixing for safe shutdown scenarios. Working in conjunction with the Nuclear Regulatory Commission and Brookhaven National Laboratories per Reference 1, Diablo Canyon Unit 1 was able to adequately demonstrate said capabilities.

From the gathered data and results of the test performed at Diablo Canyon Unit 1 the Westinghouse Owner's Group developed empirical correlations to predict loop ΔT's and natural circulation mass flow rates for use in predicting plant behavior during these conditions.

The following are used to show acceptable natural circulation cooldown behavior.

- The natural circulation ΔTs and temperatures should be reasonable (e.g., bounded by full-power conditions). This helps to avoid any concerns with thermal stresses and also helps to ensure adequate reactor coolant system (RCS) subcooling.
- The Steam Generator (SG) Atmospheric Dump Valves (ADVs) should be capable of cooling down the plant to residual heat removal system (RHR) cut-in conditions within a reasonable time. Allowing for 4 hours at hot standby and an emergency operating procedure (EOP) maximum cooldown rate of 25°F/hour for natural circulation (Reference 5), the time frame for RHR cut-in should be on the order of 12 to 14 hours.
- Compare the hydraulic flow coefficients with those of Diablo Canyon.

Procedural guidance (Reference 5) follows the Westinghouse Owners Group Emergency Response Guidelines (WOG ERGs) and maintains sufficient shutdown margin (SDM). Further, the procedures specify the maximum RCS cooldown rate, appropriate wait times, upper head vessel cooling (as a function of fan status), and monitoring to ensure adequate subcooling is maintained.

PBNP Current Licensing Basis

The layout of the reactor coolant system (RCS) assures the natural circulation capability following a loss of flow to permit plant cooldown without overheating the core.

On June 11, 1980, St. Lucie Unit 1 experienced a natural circulation cooldown event which resulted in the formation of a steam bubble in the upper head region of the reactor vessel. Consequently, the NRC Generic Letter No. 81-21 dated May 5, 1981 was sent to all PWR licensees. Per that letter the licensees were asked to provide an assessment of the ability of their facility's procedures and training' program to properly manage similar events. This assessment included:

1. A demonstration (e.g., analysis and/or test) that controlled natural circulation cooldown from operating conditions to cold shutdown conditions, conducted in accordance with plant procedures, does not result in reactor vessel voiding.

2. Verification that supplies of condensate grade auxiliary feedwater are sufficient to support the cooldown method and

3. A description of the training program and the revisions to the emergency procedures.

Reference 4 describes the NRC Safety Evaluation Report (SER) for the PBNP response to Generic Letter (GL) 81-21. The SER concluded that there is sufficient condensate storage water to cool down on natural circulation if control rod shroud (CRDM) fans are available and that means are available to obtain condensate supplies if necessary.

The SER also states that upon acceptable implementation of the NRC-approved Westinghouse Owners Group Emergency Response Guidelines with appropriate plant specific modifications, the PBNP procedures will be adequate to perform a safe natural circulation cooldown. Procedural guidance (Reference 5) follows the Westinghouse Owners Group Emergency Response Guidelines (WOG ERGs) and maintains sufficient shutdown margin (SDM). Further, the procedures specify the maximum RCS cooldown rate, wait times, and RCS pressure and temperature limits (as a function of control rod shroud fan status).

Changes associated with natural circulation cooldown operation for the EPU condition do not add any new or previously unevaluated materials to the systems or components associated with natural circulation cooldown operation. Component internal and external environments remain within the parameters previously evaluated. Therefore, the proposed EPU has no impact on the previous License Renewal evaluations.

2.8.7.2.2 Technical Evaluation

2.8.7.2.2.1 Introduction

The purpose of the natural circulation cooldown evaluation is to show that the plant, at the EPU condition, exhibits expected natural circulation behavior, similar to that previously calculated for PBNP. A comparison is made to hydraulic parameters measured at other plants in the industry and related to PBNP Units 1 and 2 conditions. In addition, the evaluation will demonstrate the ability to cool down the plant on natural circulation to RHR cut-in conditions (P_{RCS} < 385 psig and T_{hot}< 350°F).

2.8.7.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The input parameters for the evaluation are given in Table 2.8.7.2-1, Input Parameters for Natural Circulation Cooldown Evaluation. The assumptions are summarized in

Table 2.8.7.2-2, List of Significant Assumptions. While there are no formal acceptance criteria for this evaluation, the guidelines used are listed in LR Section 2.8.7.2.1, Regulatory Evaluation.

2.8.7.2.2.3 Description of Analyses and Evaluations

To evaluate the natural circulation capability for the PBNP EPU, the equations from the WOG ERG methodology (Reference 2) are used to estimate flow rates and core delta temperatures using core and system hydraulic flow coefficients. These equations are evaluated for uprated decay heat assumptions to ensure the plant can sufficiently maintain temperature at hot shutdown conditions from the time of reactor trip followed by 4 hours at hot standby, and from 4 hours at hot standby followed by cooldown to RHR cut-in conditions.

In addition, the ADV capacities are estimated as a function of steam generator secondary saturation pressure that is correlated with primary system temperature. After four hours at hot standby conditions, the plant is assumed to begin the cool down to the RHR cut-in conditions at the maximum Emergency Operating Procedure (EOP) rate (25°F/hour per Reference 5).

The hydraulic flow coefficients for both Units of the PBNP are compared with those of Diablo Canyon in Table 2.8.7.2-3, Diablo Canyon vs. PBNP Unit 1 and 2 Hydraulic Flow Coefficients (HFC) for Normal Flow Conditions. The evaluated loop delta temperatures, natural circulation mass flow rates, and associated decay heats, are shown in Table 2.8.7.2-4, Natural Circulation Cooldown Results for 10% SGTP.

Table 2.8.7.2-6, Comparison with Test Performed at Similar 2-Loop Plant, compares the calculated values for PBNP against a test performed for a similar 2-loop plant. The nominal flow percentage is in good agreement with that of the performed test. However, the loop ΔT indicates an approximate 7°F difference. This is attributed to the difference in the test conditions versus the calculation. At the time of the initial test, the rated thermal power of the 2-loop station was 1311 MWt. The EPU power level will be 1800 MWt + 0.6% uncertainties. The ΔT value for PBNP displayed in Table 2.8.7.2-6, Comparison with Test Performed at Similar 2-Loop Plant, represents the calculated value at 1800 MWt. The 2-loop test was performed at 1311 MWt. Correcting the PBNP calculated ΔT of 32.44 °F for power scaling results in a difference of approximately 0.8°F. The power scaling correction adjusts the value of the loop ΔT in conjunction with the proportional relationship between reactor thermal power for use in comparison to previously performed test programs of representative Westinghouse plants.

2.8.7.2.2.4 Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal

The NRC issued its Point Beach License Renewal Safety Evaluation Report (SER), NUREG-1839, in December 2005 (Reference 6). EPU activities do not add any new functions for existing plant components that would change the license renewal evaluation boundaries. Operation of these systems and components at EPU conditions does not introduce any unevaluated aging effects that would necessitate a change to aging management programs or require new programs, as internal and external environments are within the parameters previously evaluated. Therefore, EPU activities associated with natural circulation cooldown do not impact license renewal scope, aging effects, and aging management programs.

2.8.7.2.3 Results

Table 2.8.7.2-3, Diablo Canyon vs. PBNP Unit 1 and 2 Hydraulic Flow Coefficients (HFC) for Normal Flow Conditions, relates the magnitudes of core, vessel, and loop hydraulic flow coefficients of the PBNP Units 1 & 2 to Diablo Canyon Unit 1. The comparison of the hydraulic flow coefficients with Diablo Canyon was performed at 0% steam generator tube plugging (SGTP) as this was the representative condition of the plant configuration for the natural circulation test. As shown from Table 2.8.7.2-3, Diablo Canyon vs. PBNP Unit 1 and 2 Hydraulic Flow Coefficients (HFC) for Normal Flow Conditions, the hydraulic flow coefficients are less than those for Diablo Canyon. This comparison shows that natural circulation flow can be initiated. From Table 2.8.7.2-3, it is shown PBNP Unit 1 has a greater total hydraulic flow coefficient than Unit 2. For the purposes of the natural circulation (NC) cooldown evaluation the values for Unit 1 are bounding for Unit 2. Magnitudes of NC flow and loop ΔTs are shown in Table 2.8.7.2-4, Natural Circulation Cooldown Results for 10% SGTP. Table 2.8.7.2-5, Natural Circulation Heat Transfer Capability Post Reactor Trip, shows that the design capacity of two SG ADVs and the heat transfer capacity across the SG primary side tubes from NC flow are capable of removing the uprated decay heat associated with 10 seconds after reactor trip. In summary the RCS primary and secondary steam supply system are capable of adequately removing reactor decay heat magnitudes as high as 6% RTP (10 seconds post trip).

The natural circulation flow rates listed in Table 2.8.7.2-4, Natural Circulation Cooldown Results for 10% SGTP, show expected behavior associated with a decreasing value of decay heat. At hour 5 the flow rate increases due to initiation of the NC cooldown, and then decreases with decay heat and RCS temperature as expected.

The loop ΔT results listed in Table 2.8.7.2-4, Natural Circulation Cooldown Results for 10% SGTP, show expected behavior as well – the loop ΔTs decrease with decay heat while holding RCS temperature fairly constant during the hot standby period. The exception to the expected behavior is that the second hour loop ΔT is greater than the first hour. This discrepancy in expected behavior is due to the assumption of the initial loop ΔT (1st hour) of 50°F. Once the cooldown is initiated, the loop ΔTs begin increasing slightly as RCS flow decreases. Adequate condensate for the entire cooldown is provided by the condensate storage tank and the service water system.

The establishment of natural circulation cooldown conditions is expected to take several loop transits after the reactor coolant pumps (RCPs) have tripped. The decay heat will be approximately 3% at this time (~3.5 minutes post trip). This time approximates the minimum time required for establishing natural circulation cooling following a trip of the RCPs and co-incident reactor trip. The values in Table 2.8.7.2-5, Natural Circulation Heat Transfer Capability Post Reactor Trip, demonstrate that NC cooling capability is adequate to remove decay heat as high as ~6% Reactor Thermal Power (RTP) which is the approximate RTP associated with 10 seconds post trip. This ensures that NC cooling is capable of removing adequate decay heat associated with the earliest possible time of initiation. The parameters which demonstrate NC cooling capability were evaluated at a decay heat fraction of 1.5%. Thus, the conditions for the evaluation at the hot standby period will be bounded by using the values calculated at the 1.5% decay heat value.

2.8.7.2.4 Conclusion

For the following reasons, the PBNP EPU analyzed at 1811 (core power + uncertainties) MWt will not adversely impact the natural circulation cooldown capability of the plant.

- Acceptable results are found for NC cooling during the hot standby period for realistic residual heat rates as high as 6% of uprated RTP. The maximum expected hot leg temperature calculated from PCWG for this case is 615.3°F, which is bounding for the entire cooldown. (LR Section 1.1, Nuclear Steam Supply System Parameters, Table 1-1)
- The calculated loop delta temperatures follow expected trends
- The ADVs at the EPU conditions are adequate to achieve cooldown to the RHR entry point in a reasonable time period. RHR cut-in conditions can be achieved in ~13 hours. The ADVs are sufficient to achieve the maximum allowable cooldown rate for the entirety of the cooldown as specified in Reference 4

PBNP has reviewed the assessment of the effects of the proposed EPU on the systems required for natural circulation cooldown and concludes that the evaluation has adequately accounted for the effects of changes in plant conditions on the design of those systems. PBNP concludes that the systems can be used to perform a natural circulation cooldown following a trip from full power to RHR cut-in conditions. Therefore, PBNP finds the proposed EPU acceptable with respect to the systems used for natural circulation cooldown.

2.8.7.2.5 Natural Circulation Cooldown References

1. Technical Evaluation Report for Diablo Canyon Natural Circulation, Boron Mixing, and Cooldown Test, J.H. Jo, K.R. Perkins, and N. Cavlina, Brookhaven National Laboratory Technical Report A-3843, December 23, 1986

2. Westinghouse Owners Group Emergency Response Guidelines, Revision 1C, Executive Volume, dated September 30, 1999

3. NSAC-176L, Safety Assessment of PWR Risks During Shutdown Operations, EPRI Outage Risk Assessment and Management (ORAM) Program (prepared by Westinghouse), Final Report August 1992

4. NPC-37913, NRC Safety Evaluation for Point Beach Units 1 and 2 regarding, Generic Letter 81-21, Natural Circulation Cooldown, dated 11/3/1983

5. Point Beach Nuclear Plant Emergency Operating Procedure, Natural Circulation Cooldown, EOP-0.2 Unit 1 Revision 26 including Figure 1 "RCS P/T Limits with One Control Rod Shroud Fan and Figure 2 "RCS P/T Limits with No Control Rod Shroud Fans

6. Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

Table 2.8.7.2-1
Input Parameters for Natural Circulation Cooldown Evaluation

Name	Units	Value	Comment
Analyzed Power Level	MWt	1800	0.6% uncertainty included in analysis
Steam Generator Tube Plugging (SGTP)	Percent	0 & 10	Evaluated Value
Core Inlet Temperature	°F	547	No Load Temperature (transient start condition)
Maximum Cooldown Rate	°F/hr	25	*Point Beach EOP ES-0.2, Natural Circulation Cooldown
* The cooldown rate specified in EOP ES-0.2 for PBNP Units 1 & 2 is 25°F for both.			

Table 2.8.7.2-2
List of Significant Assumptions

1	There are no major plant systems that will prohibit natural circulation flow capabilities.
2	The RCS is intact and both SGs are capable of relieving steam to atmosphere via the SG ADVs.
3	Decay heat rates are based on ANS-5.1-1979, including 2-sigma uncertainty. Values for the decay heat power fraction of full power (P/P_0) are taken from Reference 3.
4	This analysis assumes 4 hours is allowed to elapse from the time of reactor trip to the time of natural circulation cooldown initiation. This allows adequate time for accident mitigation and boration. Additionally normal charging flow availability is assumed.
5	This analysis assumes cooldown and depressurization occur as depicted in Figure 1 of Reference 5 ("RCS P/T Limits With One Control Shroud Fan"). This ensures no additional time is needed for depressurization.

Table 2.8.7.2-3
Diablo Canyon vs. PBNP Unit 1 and 2 Hydraulic Flow Coefficients (HFC) for Normal Flow Conditions

Hydraulic Flow Coefficients			
	Diablo Canyon ft/(gpm)^2	**PBNP Unit 1 ft/(gpm)^2**	**PBNP Unit 2 ft/(gpm)^2**
Reactor Core and Internals	1.290 E-8	2.609E-09	2.609E-09
Reactor Nozzles	3.61 E-9	2.834E-09	2.834E-09
Reactor Coolant Loop Piping	2.09 E-9	2.300E-09	2.300E-09
Steam Generator	1.12 E-8	1.130E-08	9.237E-09
RCP	5.719E-08	5.719E-08	5.719E-08
Total HFC (HFC_{tot}) w/RCP	8.70E-08	7.624E-08	7.417E-08
Total HFC (HFC_{tot}) wo/RCP	2.980E-08	1.904E-08	1.698 E-08

Table 2.8.7.2-4
Natural Circulation Cooldown Results for 10% SGTP

Time (Hours- Post Trip)	Power (%)	Decay Heat (MWt)	Total Flow Rate (lbm/hr)	Loop ΔT (°F)
1	1.4619	26.3148	2.539E+06	26.11
2	1.2344	22.2187	2.062E+06	27.63
3	1.1181	20.1250	2.033E+06	25.33
4	1.0422	18.7602	1.929E+06	24.95
5	0.9870	17.7657	2.199E+06	21.89
6	0.9440	16.9924	2.156E+06	22.33
7	0.9092	16.3649	2.177E+06	22.64
8	0.8800	15.8400	2.081E+06	22.92
9	0.8551	15.3911	2.046E+06	23.18
10	0.8334	15.0003	2.012E+06	23.42
11	0.8142	14.6554	1.979E+06	23.65
12	0.7971	14.3474	1.945E+06	23.88
13	0.7817	14.0698	1.911E+06	24.12

Table 2.8.7.2-5
Natural Circulation Heat Transfer Capability Post Reactor Trip

Decay Heat Power (Btu/hr) at 10 Seconds Post Trip	Energy Removal of 2 ADVs (Btu/hr) at 1 Hour(1)	Heat Transfer Capacity from Primary to Secondary (Btu/hr) at 1 Hour(1)
377,800,000	606,551,070	384,793,294
(1) These heat transfer values are less than those expected at 10 seconds into the transient; however, they demonstrate that the plant is capable of removing decay heat and maintaining hot standby conditions at 10 seconds post reactor trip using Natural Circulation Cooling.		

Table 2.8.7.2-6
Comparison with Test Performed at Similar 2-Loop Plant

	2-Loop Test	Point Beach
Percent Power (%)	1.97	1.97
Loop ΔT(°F)	25.5	32.44(26.26 scaled for power differences)
Percent of Nominal Flow (%)	4.0	4.03

2.9 Source Terms and Radiological Consequences Analyses

2.9.1 Source Terms for Radwaste Systems Analyses

These source terms are developed for use in assessing the effects of the EPU on the release of liquid and gaseous effluents, during normal plant operation.

2.9.1.1 Regulatory Evaluation

PBNP reviewed the radioactive source term associated with EPU to ensure the adequacy of the sources of radioactivity used by PBNP as input to calculations to verify that the radioactive waste management systems have adequate capacity for the treatment of radioactive liquid and gaseous wastes. PBNP's review included the parameters used to determine

- The concentration of each radionuclide in the reactor coolant,
- The fraction of fission product activity released to the reactor coolant,
- Concentrations of all radionuclides other than fission products in the reactor coolant,
- Leakage rates and associated fluid activity of all potentially radioactive water and steam systems, and
- Potential sources of radioactive materials in effluents that are not considered in FSAR, related to liquid waste management systems and gaseous waste management systems.

The NRC's acceptance criteria for source terms are based on

- 10 CFR 20, insofar as it establishes requirements for radioactivity in liquid and gaseous effluents released to unrestricted areas;
- 10 CFR 50, Appendix I, insofar as it establishes numerical guides for design objectives and limiting conditions for operation to meet the "as low as is reasonably achievable" criterion.
- GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents.

Specific review criteria are contained in NRC SRP Section 11.1.

PBNP Current Licensing Basis

10 CFR 20, Standards for Protection Against Radiation, is discussed in FSAR Chapter 11, Waste Management System. As discussed in this FSAR chapter, radioactive disposal facilities are designed so that discharge of radioactive effluents to the environment and offsite shipments of radioactive material are in accordance with applicable regulations, including 10 CFR 20. In addition, the concentration of tritium released to the environment is also controlled within the limits of 10 CFR 20, as discussed in FSAR Section 9.3.3, System Evaluation.

10 CFR 50, Appendix I, As Low As Is Reasonably Achievable (ALARA) Guidelines, is discussed in FSAR Appendix I. Implementation of the overall requirements of 10 CFR 50, Appendix I, as to the utilization of radwaste treatment equipment to ensure that radioactive discharges are as low as is reasonably achievable (ALARA), is required by in Technical Specification (TS) 5.5.4, Radioactive Effluent Controls Program, and TS 5.5.1, Offsite Dose Calculation Manual.

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP specific GDC for the Radwaste Systems radiological analyses are as follows:

CRITERION: The facility design shall include those means necessary to maintain control over the plant radioactive effluents, whether gaseous, liquid, or solid. Appropriate holdup capacity shall be provided for retention of gaseous, liquid, or solid effluents, particularly where unfavorable environmental conditions can be expected to require operational limitations upon the release of radioactive effluents to the environment. In all cases, the design for radioactivity control shall be justified (a) on the basis of 10 CFR 20 requirements, for both normal operations and for any transient situation that might reasonably be anticipated to occur and (b) on the basis of 10 CFR 100 dosage level guidelines for potential reactor accidents of exceedingly low probability of occurrence. (PBNP GDC 70)

Radioactive gases are effectively reduced to prevent their unmonitored release to the atmosphere. Gases are discharged intermittently at a controlled rate from the gas decay tanks through the monitored plant vent when required by plant inventory. A controlled release of gaseous waste from the waste disposal system requires that at least two valves be manually opened, one of which is normally locked shut. In addition, a discharge control valve is provided, which will trip shut on an effluent high radioactivity signal, thereby preventing an unanticipated release. Additional safety margin is provided by the use of ASME III, Class C materials and construction standards on significant components containing radioactive gases and USAS-B31.1 Section 1 piping and valves throughout the system.

A controlled release of liquid waste from the waste disposal system requires that at least two valves be manually opened, of which one of these valves is normally locked shut. In addition, a discharge control valve is provided which is designed to trip shut on an effluent high radioactivity signal from the discharge radiation monitor, thus preventing a release in excess of calculated amounts.

Radioactive fluids entering the waste disposal system are processed or collected in tanks until determination of subsequent treatment can be made. They are sampled and analyzed to determine the quantity of radioactivity, with an isotopic breakdown if necessary. Liquid wastes are processed as required and then released under controlled conditions. The system design and operation are directed toward minimizing releases to unrestricted areas. Discharge streams are appropriately monitored and safety features are incorporated to preclude releases in excess of the limits of 10 CFR 20.

In addition to the evaluations described in the FSAR, PBNP's structures, systems and components (SSCs) have been evaluated for plant license renewal. Plant system and component materials of construction, operating history, and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 3)

Radiological source terms are not in the scope of License Renewal.

2.9.1.1.1 Radiation Sources for Extended Power Uprate

Summary

Radiation source terms are used as input to several radiological consequence analyses that are required in support of the PBNP Extended Power Uprate (EPU). In this section, an evaluation is provided that updates the required radiation sources based on an analyzed core power level of 1811 MWt with additional margins added to account for fuel cycle design variability from cycle to cycle. The results of this evaluation are summarized in Section 2.9.1.1.1.2, Results of the Radiation Source Calculations.

2.9.1.1.1.1 Description of the Evaluation of the Radiation Sources

The source term information for use in the radiological consequence analyses described later in this section was generated using the ORIGEN-S and FIPCO-V (Reference 1 and Reference 2) computer codes. The ORIGEN-S code is a versatile point depletion and radioactive decay computer code for use in simulating nuclear fuel cycles and calculating the nuclide compositions and characteristics of materials contained therein. The ORIGEN-S code is an industry standard code based on the latest industry experimental data. The FIPCO-V computer code calculates the build-up of fission product activities in plant systems and components including the reactor coolant system, chemical and volume control system demineralizer resins, and volume control tank liquid and vapor phases. The time-dependent inventory of the core fission products calculated by ORIGEN-S is used as input to the FIPCO-V evaluations

Calculations for radiation sources were performed for four EPU fuel management cycles including two transition and two equilibrium fuel cycle designs. All of these EPU radiological source calculations are based on an analyzed core power level of 1811 MWt. Since, for future operation, similar fuel cycle designs are intended to be implemented in both PBNP Units 1 and 2, the approach for source term determination described in this section coupled with additional multiplication factors to allow for conservatism and fuel cycle variability allows the calculated radiological source terms to be applied to radiological dose and shielding analyses for both units.

The ORIGEN-S code was used to model the EPU fuel management for the transition and equilibrium fuel cycles to determine the core inventory at cycle end-of-life using the parameters of power, loading, burnup, and enrichment for each fuel region. An evaluation of these four sets of sources was performed to identify the core inventory which would be most conservative with respect to dose analysis. This evaluation identified one of the transition cycle data sets as the most conservative. This transition cycle core inventory was then increased by an additional factor of 1.04 for each nuclide, which is intended to allow the dose analysis based on the inventory to accommodate potential future variations in cycle-to-cycle enrichment, cycle burnup, and loading. This approach to the calculation of the core inventory provides a degree of conservatism while maintaining a consistent data set as a function of decay time following reactor shutdown.

Additional radiological source calculations were performed for the reactor coolant system (RCS), volume control tank (VCT), and gas decay tank (GDT) for EPU fuel management for the transition and equilibrium fuel cycles. In these calculations, no purging of the VCT is assumed through the cycle. These source terms are used for a number of applications including plant shielding assessments.

For these radiological inventories, additional conservatism was introduced by maximizing the sources on an individual isotope basis rather than on the most limiting dose consequence basis as was done with core sources. Using the equilibrium cycle as the baseline, an isotope by isotope comparison was made with the results calculated for each of the three transition cycle designs. This comparison indicated that, with the exception of Ag-110m, a multiplier of 1.08 applied to the equilibrium cycle data set would result in a set of isotopic sources that bound all of the fuel cycle designs analyzed. In the case of Ag-110m, the appropriate multiplier was determined to be 1.12. Therefore, the final results provided in Table 2.9.1-2, Reactor Coolant System Activities, Table 2.9.1-3, Volume Control Tank (VCT) Radiation Sources, and Table 2.9.1-4, Gas Decay Tank (GDT) Radiation Sources, include these multiplication factors.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Program

The radiological source term is not within the scope of license renewal since it is an analytical product of the operational performance of plant systems and components in conjunction with regulatory limits that have been imposed on radiological releases. No changes in those applicable regulatory limits are proposed for plant operation at EPU conditions which would change license renewal boundaries. Systems and components, the performance of which affect the source term, are discussed in their respective system sections in NUREG-1839.

2.9.1.1.1.2 Results of the Radiation Source Calculations

Results of the radiation source calculations for the Point Beach EPU are provided in Table 2.9.1-1, Point Beach Unit 2 EPU Core Activity Inventories (With 1.04 Multiplier), Table 2.9.1-2, Reactor Coolant System Activities, Table 2.9.1-3, Volume Control Tank (VCT) Radiation Sources, and Table 2.9.1-4, Gas Decay Tank (GDT) Radiation Sources.

In Table 2.9.1-1, the total core inventory of nuclides includes those nuclides that are those commonly used in the Alternative Source Term. The isotopic inventories are provided at reactor shutdown as well as for decay times of 65 and 100 hours.

The calculated RCS coolant specific activities are presented in Table 2.9.1-2. The basis assumes no purging of the VCT and 1% fuel defects. Table 2.9.1-3 lists the VCT inventory assuming no purging. Table 2.9.1-4 presents the activities for the GDT, assuming no purging of the VCT during the cycle and assuming a maximum RCS letdown rate to degas the RCS by repeated purges of the VCT at end of cycle.

2.9.1.1.1.3 Conclusions

PBNP has reviewed the radioactive source term associated with the proposed EPU and concludes that the proposed parameters and resultant composition and quantity of radionuclides are appropriate for the evaluation of the radioactive waste management systems. PBNP further concludes that the proposed radioactive source term meets the requirements of 10 CFR 20, 10 CFR 50, Appendix I, and PBNP GDC 70. Therefore, PBNP finds the proposed EPU acceptable with respect to source terms.

2.9.1.1.1.4 References

1. ORNL/TM-2005/39, Version 5, Volume II, Book 1, Section F7, ORIGEN-S: Scale System Module to Calculate Fuel Depletion, Actinide Transmutation, Fission Product Buildup and Decay, and Associated Radiation Source Terms, I. C. Gauld, O. W Hermann, and R. M. Westfall, Oak Ridge National Laboratory, Nuclear Science and Technology Division, April 2005

2. WCAP-7949, FIPCO-V, A Computer Code for Calculating the Distribution of Fission Products in Reactor Systems, J. Sejvar and M. Simon, August 1972

3. Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

Table 2.9.1-1
Point Beach Unit 2 EPU Core Activity Inventories (With 1.04 Multiplier)

Nuclide	Total Core Activity, Ci		
	Shutdown	65 Hrs	100 Hrs
GROUP 1 - Noble Gases			
Kr-85	6.15E+05	6.14E+05	6.14E+05
Kr-85M	1.36E+07	5.92E+02	2.62E+00
Kr-87	2.68E+07	1.13E-08	5.82E-17
Kr-88	3.60E+07	4.65E+00	9.04E-04
Xe-131M	5.55E+05	5.47E+05	5.37E+05
Xe-133	1.02E+08	8.41E+07	7.09E+07
Xe-133M	3.21E+06	2.00E+06	1.33E+06
Xe-134M	1.49E+06	0.00E+00	0.00E+00
Xe-135	2.17E+07	1.75E+06	1.36E+05
Xe-135M	2.20E+07	1.73E+04	4.30E+02
Xe-138	9.05E+07	0.00E+00	0.00E+00
GROUP 2 – Halogens			
Br-83	6.28E+06	4.83E-02	1.96E-06
Br-84	1.14E+07	0.00E+00	0.00E+00
Br-85	1.35E+07	0.00E+00	0.00E+00
I-129	1.46E+00	1.46E+00	1.46E+00
I-130	1.05E+06	2.77E+04	3.89E+03
I-131	5.10E+07	4.15E+07	3.68E+07
I-132	7.47E+07	4.23E+07	3.10E+07
I-133	1.06E+08	1.25E+07	3.88E+06
I-134	1.19E+08	0.00E+00	0.00E+00
I-135	1.01E+08	1.06E+05	2.63E+03
GROUP 3 - Alkali (Rb/Cs)			
Rb-86	9.95E+04	9.00E+04	8.52E+04
Cs-134	9.52E+06	9.50E+06	9.49E+06
Cs-136	2.14E+06	1.86E+06	1.72E+06
Cs-137	6.27E+06	6.27E+06	6.27E+06
Cs-138	9.89E+07	0.00E+00	0.00E+00

Table 2.9.1-1
Point Beach Unit 2 EPU Core Activity Inventories (With 1.04 Multiplier)

Nuclide	Total Core Activity, Ci		
	Shutdown	65 Hrs	100 Hrs
GROUP 4 - Tellurium			
Te-127	4.54E+06	3.37E+06	2.76E+06
Te-127M	7.48E+05	7.46E+05	7.43E+05
Te-129	1.33E+07	1.53E+06	1.49E+06
Te-129M	2.52E+06	2.39E+06	2.32E+06
Te-131M	9.95E+06	2.22E+06	9.90E+05
Te-132	7.30E+07	4.10E+07	3.01E+07
Sb-127	4.63E+06	2.88E+06	2.22E+06
Sb-129	1.42E+07	5.15E+02	2.07E+00
GROUP 5 - Barium/Strontium			
Sr-89	5.03E+07	4.85E+07	4.75E+07
Sr-90	4.80E+06	4.80E+06	4.80E+06
Sr-91	6.30E+07	5.56E+05	4.34E+04
Sr-92	6.73E+07	4.07E+00	5.24E-04
Ba-139	9.42E+07	1.41E-06	4.73E-14
Ba-140	9.05E+07	7.81E+07	7.21E+07
GROUP 6 - Noble Metals			
Ru-103	7.79E+07	7.42E+07	7.24E+07
Ru-105	5.42E+07	2.19E+03	9.26E+00
Ru-106	2.54E+07	2.53E+07	2.52E+07
Rh-105	5.08E+07	1.64E+07	8.27E+06
Tc-99M	8.47E+07	4.71E+07	3.26E+07
Mo-99	9.62E+07	4.86E+07	3.36E+07
GROUP 7 - Lanthanides			
Y-90	5.01E+06	4.90E+06	4.87E+06
Y-91	6.56E+07	6.39E+07	6.29E+07
Y-92	6.82E+07	8.44E+02	9.00E-01
Y-93	7.67E+07	8.98E+05	8.12E+04
Nb-95	8.87E+07	8.86E+07	8.85E+07
Zr-95	8.76E+07	8.51E+07	8.38E+07

Table 2.9.1-1
Point Beach Unit 2 EPU Core Activity Inventories (With 1.04 Multiplier)

Nuclide	Total Core Activity, Ci		
	Shutdown	65 Hrs	100 Hrs
Zr-97	8.80E+07	6.12E+06	1.45E+06
La-140	9.69E+07	8.75E+07	8.18E+07
La-141	8.52E+07	9.45E+02	1.93E+00
La-142	8.25E+07	1.20E-05	1.37E-12
Pr-143	7.75E+07	7.31E+07	6.89E+07
Nd-147	3.33E+07	2.81E+07	2.56E+07
Am-241	6.16E+03	6.22E+03	6.26E+03
Cm-242	1.70E+06	1.70E+06	1.68E+06
Cm-244	1.58E+05	1.58E+05	1.58E+05
GROUP 8 - Cerium Group			
Ce-141	8.52E+07	8.08E+07	7.84E+07
Ce-143	8.03E+07	2.06E+07	9.89E+06
Ce-144	6.72E+07	6.67E+07	6.65E+07
Pu-238	1.33E+05	1.34E+05	1.34E+05
Pu-239	1.45E+04	1.46E+04	1.46E+04
Pu-240	2.25E+04	2.25E+04	2.25E+04
Pu-241	5.73E+06	5.73E+06	5.73E+06
Np-239	9.65E+08	4.38E+08	2.85E+08

Table 2.9.1-2
Reactor Coolant System Activities

Activation Products		**Nonvolatile Fission Products**	
	uCi/gm		uCi/gm
Cr-51	5.40E-03	Y-92	1.25E-03
Mn-54	1.60E-03	Y-93	4.23E-04
Fe-55	2.10E-03	Zr-95	6.68E-04
Fe-59	5.10E-04	Nb-95	6.65E-04
Co-58	1.40E-02	Mo-99	8.50E-01
Co-60	1.30E-03	Tc99m	7.83E-01
		Ru103	5.64E-04
Gaseous Fission Products		Rh-103m	5.64E-04
		Ru-106	1.79E-04
	uCi/gm	Rh-106	1.79E-04
Kr-83m	5.30E-01	Ag-110m	1.07E-03
Kr-85	1.05E+01	Te-125m	3.85E-04
Kr-85m	2.17E+00	I-127[a]	8.57E-11
Kr-87	1.44E+00	Te-127	1.17E-02
Kr-88	4.01E+00	Te127m	3.35E-03
Kr-89	1.15E-01	Te-129	1.28E-02
Xe-131m	3.23E+00	Te129m	1.13E-02
Xe-133	2.91E+02	I-129	5.02E-08
Xe-133m	5.23E+00	I-130	2.16E-02
Xe-135	9.25E+00	I-131	2.82E+00
Xe135m	5.96E-01	Te-131	1.45E-02
Xe-137	2.20E-01	Te-131m	3.38E-02
Xe-138	7.94E-01	I-132	3.17E+00
		Te-132	3.15E-01
Nonvolatile Fission Products		I-133	4.90E+00
		Te-134	3.76E-02
	uCi/gm	I-134	7.46E-01
Br-83	1.12E-01	Cs-134	2.46E+00
Br-84	5.81E-02	I-135	2.81E+00
Br-85	6.87E-03	Cs-136	2.57E+00

Table 2.9.1-2
Reactor Coolant System Activities

Rb-86	2.72E-02	Cs-137	2.09E+00
Rb-88	4.97E+00	Ba-137m	1.98E+00
Rb-89	2.31E-01	Cs-138	1.21E+00
Sr-89	4.57E-03	Ba-140	4.26E-03
Sr-90	2.15E-04	La-140	1.40E-03
Sr-92	1.44E-03	Ce-141	6.39E-04
Y-90	5.96E-05	Ce-143	5.69E-04
Sr-91	6.66E-03	Pr-143	6.32E-04
Y-91	5.88E-04	Ce-144	4.88E-04
Y-91m	3.56E-03	Pr-144	4.88E-04
(a) Gram of I-127 per gram of coolant.			

Table 2.9.1-3
Volume Control Tank (VCT) Radiation Sources

Nuclide	VCT Vapor Inventory (Ci)	VCT Liquid Inventory (Ci)	VCT Total Inventory (Ci)
Kr-83m	1.18E+01	3.66E-01	1.21E+01
Kr-85m	7.05E+01	2.70E+00	7.32E+01
Kr-85	8.74E+02	2.90E+01	9.03E+02
Kr-87	1.95E+01	7.46E-01	2.02E+01
Kr-88	9.84E+01	3.78E+00	1.02E+02
Kr-89	7.89E-02	3.02E-03	8.19E-02
Xe-131m	1.51E+02	8.85E+00	1.60E+02
Xe-133m	2.49E+02	1.36E+01	2.62E+02
Xe-133	1.38E+04	7.84E+02	1.46E+04
Xe-135m	3.17E+01	1.64E+00	3.33E+01
Xe-135	3.85E+02	1.82E+01	4.03E+02
Xe-137	1.81E-01	1.02E-02	1.91E-01
Xe-138	2.30E+00	1.30E-01	2.43E+00
I-127(a)		2.38E-05	2.38E-05
I-129		1.39E-08	1.39E-08
I-130		6.00E-03	6.00E-03
I-131		7.82E-01	7.82E-01
I-132		8.81E-01	8.81E-01
I-133		1.36E+00	1.36E+00
I-134		2.07E-01	2.07E-01
I-135		7.80E-01	7.80E-01
(a) Grams of I-127.			

Table 2.9.1-4
Gas Decay Tank (GDT) Radiation Sources

Isotope	Inventory (Ci)
Kr-83m	1.34E+01
Kr-85	3.35E+03
Kr-85m	1.19E+02
Kr-87	1.95E+01
Kr-88	1.52E+02
Kr-89	7.89E-02
Xe-131m	4.92E+02
Xe-133	4.23E+04
Xe-133m	6.89E+02
Xe-135	7.18E+02
Xe-135m	3.17E+01
Xe-137	1.81E-01
Xe-138	2.30E+00
I-131	2.53E-02
I-133	3.35E-02
I-135	1.46E-02
TOTAL	4.79E+04

2.9.2 Radiological Consequences Analyses Using Alternative Source Terms

2.9.2.1 Regulatory Evaluation

The NRC's acceptance criteria for radiological consequences analyses using an alternate source term are based on:

- 10 CFR 50.67, insofar as it sets standards for radiological consequences of a postulated accident, and
- GDC 19, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem TEDE, as defined in 10 CFR 50.2, for the duration of the accident.

Specific review criteria are contained in SRP Section 15.0.1.

2.9.2.2 Technical Evaluation

In PBNP Units 1 and 2 License Amendment Request (LAR) 241, Alternative Source Term, (Reference 1) which was submitted to the NRC on December 8, 2008, PBNP performed Design Basis Accident (DBA) radiological consequences analyses using the guidance in Regulatory Guide 1.183, Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors. The radiological consequences analyses included the Main Steam Line Break (MSLB), Locked-Rotor Accident (LR), Control Rod Drive Ejection Accident (CRDE), Steam Generator Tube Rupture (SGTR), Loss of Coolant Accident (LOCA), Fuel Handling Accident (FHA) and Reactor Vessel Head Drop (RVHD). PBNP's analysis for each accident considered:

- The sequence of events; and
- Models, assumptions, and values of parameter inputs used for the calculation of the total effective dose equivalent (TEDE).

2.9.2.2.1 Input Parameters and Assumptions

All input assumptions for the proposed EPU are provided in LAR 241 Alternative Source Term (Reference 1) which was submitted to the NRC December 8, 2008. The analyses input assumptions for LAR 241 are applicable and appropriate for the proposed EPU.

2.9.2.2.2 Summary of Dose Consequences

A summary of the radiological dose results for the EPU is provided in LAR 241 (Reference 1).

2.9.2.3 Conclusion

PBNP has reviewed the various design basis accident (DBA) analyses performed in support of the proposed EPU for their potential radiological consequences and concludes that the analyses adequately account for the effects of the proposed EPU. PBNP further concludes that the plant site and the dose-mitigating engineered safety features (ESFs) remain acceptable with respect to the radiological consequences of postulated DBAs since the calculated total effective dose equivalent (TEDE) at the exclusion area boundary (EAB), at the low population zone (LPZ) outer boundary, and in the control room meet the exposure guideline values specified in 10 CFR 50.67 and GDC 19, as well as applicable acceptance criteria denoted in SRP 15.0.1. Therefore, based upon the above and with the approval and implementation of the Alternative Source Term LAR 241, PBNP finds the proposed EPU acceptable with respect to the radiological consequences of DBAs.

2.9.2.4 References

1. Point Beach Nuclear Plant Units 1 and 2 License Amendment Request 241, Alternative Source Term (ML083450683), submitted December 8, 2008

2.9.10.1 Radiological Consequences of Accidental Waste Gas Releases

2.9.10.1.1 Regulatory Evaluation

Analyses are performed to determine the radiological consequences of accidental waste gas releases.

The Nuclear Regulatory Commission (NRC) acceptance criteria for the radiological consequences of the accidental waste gas release are based on:

- General Design Criterion (GDC) 19, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the Control Room under accident conditions without personnel receiving radiation exposure in excess of 5 rem whole body, or its equivalent to any part of the body, for the duration of the accident.
- 10 CFR Part 100, insofar as it establishes requirements for assuring that offsite radiological doses from postulated accidents will be acceptably low.

Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in the FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50 Appendix A GDC 19 is as follows:

CRITERION: The facility shall be provided with a control room from which actions to maintain safe operational status of the plant can be controlled. Adequate radiation protections shall be provided to permit continuous occupancy of the control room under any credible post-accident condition or as an alternative, access to other areas of the facility as necessary to shut down and maintain safe control of the facility without excessive radiation exposures of personnel. (PBNP GDC 11)

PBNP is equipped with a common control room which contains those controls and instrumentation necessary for operation of each unit's reactor and turbine generator under normal and accident conditions. The control room is continuously occupied by the operating personnel under all operating conditions.

The control building, which houses the control room envelope (CRE) and the control room HVAC system, is seismic Class I.

FSAR Section 11.2.5, Accidental Release, Waste Gas, addresses the radiological consequences of the waste gas releases resulting from the rupture of a gas decay tank, volume control tank or charcoal decay tank. The radiological consequences of a number of design basis accidents were reanalyzed using the alternative source term (AST) methodology from Regulatory Guide (RG) 1.183 (Reference 1) and the results were submitted for NRC review and approval (Reference 2). Consistent with Issue 11 of NRC Regulatory Issue summary (RIS) 2006-04 (Reference 3) the events resulting in accidental waste gas releases were excluded from the

Reference 2 full-scope implementation of AST and continue to use the existing analyses, source term methodology and 10 CFR 100 acceptance criteria.

2.9.10.1.2 Technical Evaluation

Description of Event

Three different waste gas release events are considered:

1. A gas decay tank (GDT) is assumed to fail, releasing the stored activity instantaneously to the environment. Activity released from the failed tank is released to the outside atmosphere through the Primary Auxiliary Building (PAB) vent stack.

2. The volume control tank (VCT) is assumed to fail, releasing the stored noble gas activity and a portion of the iodine in the tank instantaneously to the environment. In addition, it is assumed that the letdown flow to the VCT continues for a period of time and that the noble gas activity and a fraction of the iodine activity in the letdown flow are released to the environment. Activity from the failed VCT is released to the outside atmosphere through the PAB vent stack.

3. A charcoal decay tank (CDT) is assumed to fail. A rupture is assumed to occur in one of the three connected CDTs or their associated piping resulting in the release of a portion of the activity stored on the charcoal in the tanks. The activity is assumed to be released instantaneously from the failed system and the release is to the outside atmosphere through the PAB vent stack.

Acceptance Criteria

The offsite dose acceptance criteria for a failure of a component in the waste processing system is 0.5 rem whole body or its equivalent per NRC Branch Technical Position ETSB 11-5 (Reference 10) attached to SRP 11.3, Revision 2 (Reference 11). ETSB 11-5 does not define an acceptance criterion for the offsite thyroid dose, and as such, a conservatively low limit of 1.5 rem is assumed. SRP 6.4 (Reference 12) interprets the dose acceptance criteria of GDC 19 for the control room as 5.0 rem whole body and 30 rem for thyroid and skin doses.

Analysis Assumptions and Parameters

The radiological consequences of these three events have been recalculated at the analyzed core power of 1810.8 MWt. The calculations were performed using the RADTRAD code (Reference 4) Version 3.03, with calculation models consistent with those presented in RG 1.195 (Reference 5).

Common Analysis Inputs and Assumptions:

The doses are determined at the exclusion area boundary (EAB) and at the low population zone (LPZ) outer boundary for the assumed release interval. The calculation of doses for the control room (CR) personnel is extended beyond the time when the releases are terminated to provide a 30-day dose for the operators.

Dose conversion factors (DCFs) used are provided in Table 2.9.10.1-1, Dose Conversion Factors. This data includes the thyroid DCFs from Table 2.1 of Federal Guidance Report 11 (Reference 6), the whole-body DCFs from Table III.1 of Federal Guidance Report 12 (Reference 7), and the beta-skin DCFs from DOE/EH-0070 (Reference 8). The Reference 8 beta-skin DCFs are used for the control room dose calculations since Issue 8 of RIS 2001-19 (Reference 9) points out that the Reference 7 beta-skin DCFs are based on beta and photon emissions, while Reference 8 tabulates the beta- and photon-skin DCFs separately. Although RADTRAD Version 3.03 does not explicitly calculate the control room beta-skin dose, this dose can still be calculated using RADTRAD as follows. In order to calculate the beta-skin dose, the beta-skin DCFs are input as whole body DCFs and the resulting calculated dose is multiplied by the control room geometry correction factor. This geometry correction factor is the only difference between the control room whole body and beta-skin dose equations provided in RG 1.195.

The breathing rates and the atmospheric dispersion factors used in the offsite radiological calculations are provided in Table 2.9.10.1-2, Breathing Rates and Atmospheric Dispersion Factors. Parameters used in the control room personnel dose calculations are provided in Table 2.9.10.1-3, Control Room Parameters. These parameters include the normal operation flowrates, post-accident operation flowrates, control room volume, filter efficiencies, and control room operator occupancy factors.

It is assumed that the control room heating, ventilation, and air conditioning (HVAC) system is initially operating in normal mode. The activity level in the intake duct causes a high radiation signal almost immediately. In addition, the activity entering the control room would result in the area monitor inside the control room also reaching its high alarm setpoint within the first few seconds. It is assumed that control room HVAC accident mode is entered one minute after event initiation. Control room operation in accident mode is described in Table 2.9.10.1-3, Control Room Parameters, and is consistent with the new control room accident mode discussed in PBNP license amendment request (LAR) 241 (Reference 2). It is noted that the isolation of the control room does not prevent any additional activity from entering the control room, since all of the activity was assumed to be released prior to isolation. However, the emergency mode of operation does have a higher rate of air intake than does the normal operating mode. This results in a more rapid purging of activity from the control room.

<u>Gas Decay Tank Rupture (GDT) Analysis Inputs and Assumptions:</u>

The assumptions and inputs to this analysis are itemized in Table 2.9.10.1-4, Inputs/Assumptions Used for Gas Decay Tank Rupture Dose Analysis.

The calculation of the GDT inventory is discussed in LR Section 2.9.1, Source Terms for Radwaste Systems Analysis. The RCS activity that is contained in the VCT is not released to the GDT until the end of the cycle. The GDT is then purged during a 24-hour cycle. Only noble gases are modeled in the source term. Transfer of iodine activity to the gas decay tank is assumed to be insignificant. No credit is taken for isolation of the release path.

<u>Volume Control Tank Rupture Analysis Inputs and Assumptions:</u>

The assumptions and inputs to this analysis are itemized in Table 2.9.10.1-5, Inputs/Assumptions Used for Volume Control Tank Rupture Dose Analysis.

The calculation of the volume control tank inventory is discussed in LR Section 2.9.1, Source Terms for Radwaste Systems Analysis. The reactor coolant system (RCS) activity based on operation at the Technical Specification limits for equilibrium operation is provided in Table 2.9.10.1-6, RCS Coolant Concentrations. The Table 2.9.10.1-6, RCS Coolant Concentrations, iodine activity corresponds to operation at 0.5 μCi/gm Dose Equivalent (DE) I-131. The Table 2.9.10.1-6, RCS Coolant Concentrations, noble gas activity corresponds to operation at 520 μCi/gm DE Xe-133. The coolant activities in Table 2.9.10.1-6, RCS Coolant Concentrations, are based on a core power of 1800 MWt increased to 1810.8 MWt to cover 0.6% calorimetric uncertainty. Credit is taken for the demineralizer in the letdown line reducing the coolant iodine concentration by a factor of 10. Thus, the iodine concentration in the letdown flow that is released as a result of the accident is 10% of the primary coolant activity. The flow through the letdown line is assumed to be isolated within 30 minutes. It is conservatively assumed that all activity released to the environment is released instantaneously (modeled as a 10-second release). This assumption is also applied to the activity releases associated with the thirty minutes of letdown flow (i.e., the activity in the thirty minutes of letdown flow is all released at time-zero). While credit is taken for isolation of the letdown line at thirty minutes into the event, no credit is taken for isolation or filtration of the release path to the environment. 10% of the iodine activity released from the VCT and the letdown line is assumed to become airborne.

Charcoal Decay Tank Rupture Analysis Inputs and Assumptions:

The assumptions and inputs specific to this analysis are itemized in Table 2.9.10.1-7, Inputs/Assumptions Used for Charcoal Decay Tank Rupture Dose Analysis.

It is assumed that the primary coolant noble gas activity for both PBNP Unit 1 and Unit 2 is based on operation with no gas stripping so the primary coolant activity is at its maximum. It is then assumed that both units have gas stripping initiated combined with a conservatively high letdown flow rate. The stripped gases are directed to the shared charcoal decay tanks.

In addition to the initial inventory of activity in the primary coolant, noble gas activity continues to enter the primary coolant system and this activity is also available to be stripped from the letdown flow and delivered to the charcoal decay tanks. Noble gas production rates (Table 2.9.10.1-8, RCS Noble Gas Production Rates) are calculated based on the equilibrium activity in the primary coolant presented in Table 2.9.10.1-6, RCS Coolant Concentrations.

It is assumed that the tank failure occurs when the maximum releasable inventory (based on Dose Equivalent Xe-133) is obtained in the charcoal decay tanks. The releasable inventory is assumed to be 80% of the stored krypton activity and 10% of the stored xenon activity consistent with the analysis currently reported in the FSAR. The difference in the release fractions for krypton and xenon activity on the charcoal reflects the fact that the krypton, because of its smaller atomic mass, passes through the charcoal matrix more readily than the larger xenon atoms. The buildup of activity on the charcoal is as shown in Table 2.9.10.1-9, Dose Equivalent Xe-133 Available for Release from the Charcoal Decay Tanks.

The gas stripped from the letdown flow and directed to the charcoal decay tanks is primarily hydrogen with trace amounts of krypton and xenon. While the hydrogen will pass through the charcoal beds with no significant delay, krypton and xenon are delayed by a process of capture and release during transit through the charcoal beds. It is conservatively assumed that there is no charcoal bed break-through of either kryptons or xenons prior to the time that the maximum inventory is calculated.

Only noble gases are modeled in the source term. Any iodine entering the charcoal decay tanks is assumed to be retained on the charcoal in the event of a depressurization event.

No credit is taken for isolation of the release path.

2.9.10.1.3 Results

The radiological consequences of the gas decay tank rupture, volume control tank rupture, and charcoal decay tank rupture are provided in Table 2.9.10.1-10, Summary of Calculated Doses for GDT, VCT and CDT Ruptures. The acceptance criteria discussed in Section 2.9.10.1.2 of this report are met.

2.9.10.1.4 Conclusions

PBNP has reanalyzed the radiological consequences of waste gas releases to account for the effects of the proposed EPU. PBNP has reviewed the results of the analysis and determined that the radiological consequences of a postulated gas decay tank rupture, volume control tank rupture, or charcoal decay tank rupture are acceptable, since the calculated whole-body doses at the EAB and the LPZ outer boundary are substantially below the exposure guideline values in 10 CFR 100.11 and meet the dose requirements of the current PBNP licensing basis. It is also demonstrated that the Control Room dose meets the dose requirements of GDC 19. Therefore, PBNP finds the proposed EPU acceptable with respect to the radiological consequences of accidental waste gas releases.

2.9.10.1.5 References

1. Regulatory Guide 1.183, Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors, July 2000

2. Point Beach Nuclear Plant Units 1 and 2 License Amendment Request 241, Alternative Source Term Implementation (ML083450683)

3. NRC Regulatory Issue Summary 2006-04, Experience with Implementation of Alternative Source Terms, March 7, 2006

4. NUREG/CR-6604, RADTRAD: A Simplified Model for RADionuclide Transport and Removal And Dose Estimation, December 1997, and Supplements 1 and 2 dated June 1999 and October 2002, respectively

5. Regulatory Guide 1.195, Methods and Assumptions for Evaluating Radiological Consequences of Design Basis Accidents at Light-Water Nuclear Power Reactors, May 2003

6. K. F. Eckerman et al, Limiting Values of Radionuclide Intake and Air Concentration and Dose Conversion Factors for Inhalation, Submersion, and Ingestion, Federal Guidance Report No. 11, Environmental Protection Agency, September 1988

7. K. F. Eckerman and J. C. Ryman, External Exposure to Radionuclides in Air, Water, and Soil, Federal Guidance Report No. 12, Environmental Protection Agency, September 1993

8. DOE/EH-0070, External Dose-Rate Conversion Factors for Calculation of Dose to the Public, July 1988

9. NRC Regulatory Issue Summary 2001-19: *Deficiencies in the Documentation of Design* Basis Radiological Analyses Submitted in Conjunction with License Amendment Requests, October 2001

10. NRC Branch Technical Position ETSB 11-5, Postulated Radioactive Releases Due to A Waste Gas System Leak or Failure, 7/81. (This document is attached to Reference 11)

11. NUREG-0800, Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants, Section 11.3, Revision 2, Gaseous Waste Management System, July 1981

12. NUREG-0800, Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants, Section 6.4, Revision 3, Control Room Habitability System, March 2007

Table 2.9.10.1-1
Dose Conversion Factors

Isotope	Federal Guidance Report 11 (Reference 6), Table 2.1, Thyroid (Sv/Bq)	Federal Guidance Report 12 (Reference 7), Table III.1, Whole Body ($Sv \cdot m^3/Bq \cdot sec$)	DOE/EH-0070 (Reference 8), Beta-Skin ($Sv \cdot m^3/Bq \cdot sec$)
I-131	2.92E-7	1.82E-14	8.66E-15
I-132	1.74E-9	1.12E-13	3.02E-14
I-133	4.86E-8	2.94E-14	2.44E-14
I-134	2.88E-10	1.30E-13	3.87E-14
I-135	8.46E-9	7.98E-14	2.16E-14
Kr-85m	N/A	7.48E-15	1.38E-14
Kr-85	N/A	1.19E-16	1.35E-14
Kr-87	N/A	4.12E-14	9.08E-14
Kr-88	N/A	1.02E-13	2.13E-14
Xe-131m	N/A	3.89E-16	4.07E-15
Xe-133m	N/A	1.37E-15	8.46E-15
Xe-133	N/A	1.56E-15	2.85E-15
Xe-135m	N/A	2.04E-14	5.85E-15
Xe-135	N/A	1.19E-14	1.75E-14
Xe-138	N/A	5.77E-14	3.99E-14

Table 2.9.10.1-2
Breathing Rates and Atmospheric Dispersion Factors

Location	Breathing Rates (m^3/sec)	Atmospheric Dispersion Factors (sec/m^3)
Exclusion Area Boundary	3.5E-4	5.0E-4
Low Population Zone	3.5E-4	3.0E-5
Control Room	3.5E-4	1.8E-3

Table 2.9.10.1-3
Control Room Parameters

Volume	65,243 ft^3
Control Room Unfiltered In-Leakage	300 cfm$^{(1)}$
Normal Ventilation Flow Rates	
Filtered Makeup Flow Rate	0.0 cfm
Filtered Recirculation Flow Rate	0.0 cfm
Unfiltered Makeup Flow Rate	2000 cfm
Unfiltered Recirculation Flow Rate	(Not modeled - no impact on analyses)
Accident Mode Flow Rates	
Filtered Makeup Flow Rate	2500 cfm
Filtered Recirculation Flow Rate	1955 cfm
Unfiltered Makeup Flow Rate	0.0 cfm
Unfiltered Recirculation Flow Rate	(Not modeled - no impact on analyses)
Filter Efficiencies	
Elemental Iodine	95%
Organic (Methyl) Iodine	95%
Particulate	99%
CR Radiation Monitor Setpoint	1.0E-5 μCi/cc of Xe-133
CR Radiation Monitor Location	Control Building Roof
CR Area Monitor Setpoint	2 mrem/hr
CR Area Monitor Location	Wall in the Center of Control Room
Delay to Switch CR HVAC from Normal Operation to Post Accident Operation after receiving an isolation signal	60 seconds
Occupancy Factors	
0 - 24 hours	1.0
1 - 4 days	0.6
4 - 30 days	0.4

Note:

1. The unfiltered inleakage is conservatively assumed to apply only during the release of activity. After the activity release is complete, continued modeling of unfiltered inleakage becomes a nonconservatism.

Table 2.9.10.1-4
Inputs/Assumptions Used for Gas Decay Tank Rupture Dose Analysis

Core Power Level (100.6%)	1810.8 MWt
Noble Gas Activity in the Gas Decay Tank	Ci
Kr-85m	1.19E+2
Kr-85	3.35E+3
Kr-87	1.95E+1
Kr-88	1.52E+2
Xe-131m	4.92E+2
Xe-133m	6.89E+2
Xe-133	4.23E+4
Xe-135m	3.17E+1
Xe-135	7.18E+2
Xe-138	2.30E+0
Isolation of release	No isolation assumed
Time to release all activity	10 seconds (almost instantaneous)

Table 2.9.10.1-5
Inputs/Assumptions Used for Volume Control Tank Rupture Dose Analysis

Core Power Level (100.6%)	1810.8 MWt
Noble Gas Activity in the Volume Control Tank	Ci
Kr-85m	7.32E+1
Kr-85	9.03E+2
Kr-87	2.02E+1
Kr-88	1.02E+2
Xe-131m	1.60E+2
Xe-133m	2.62E+2
Xe-133	1.46E+4
Xe-135m	3.33E+1
Xe-135	4.03E+2
Xe-138	2.43E+0
Iodine Activity in the Volume Control Tank	Ci
I-131	7.82E-1
I-132	8.81E-1
I-133	1.36E+0
I-134	2.07E-1
I-135	7.80E-1
Primary Coolant Activity	See Table 2.9.10.1-6
Letdown Flow Rate	132 gpm
Letdown Gas Stripping	NA
Letdown Demineralizer Decontamination Factor for Iodine	10
Time to Isolate Letdown Line After Accident	30 minutes
Iodine Airborne Fraction	0.1
Time to Release All Activity	10 seconds (almost instantaneous)
Filter Efficiency	No filtration assumed
Isolation of Release	No isolation assumed

Table 2.9.10.1-6
RCS Coolant Concentrations

Isotope	Activity (μCi/gm)
I-131	3.77E-1
I-132	4.24E-1
I-133	6.55E-1
I-134	9.97E-2
I-135	3.76E-1
Kr-85m	1.58E+0
Kr-85	7.63E+0
Kr-87	1.05E+0
Kr-88	2.92E+0
Xe-131m	2.35E+0
Xe-133m	3.80E+0
Xe-133	2.12E+2
Xe-135m	4.33E-1
Xe-135	6.72E+0
Xe-138	5.77E-1

Table 2.9.10.1-7
Inputs/Assumptions Used for Charcoal Decay Tank Rupture Dose Analysis

Core Power Level (100.6%)	1810.8 MWt
Mass of Primary Coolant (per unit)	1.06E8 grams
Letdown Flow Rate (per unit)	132 gpm
Primary Coolant Initial Activity Before Start of Gas Stripping of Letdown Flow	See Table 2.9.10.1-6
Noble Gas Activity in the Volume Control Tank	See Table 2.9.10.1-5
Noble Gas Production Rates in Primary Coolant	See Table 2.9.10.1-8
Mass of Charcoal in the Decay Tanks	3000 lb
Calculated Dose Equivalent Xe-133 Available for Release from the Charcoal Decay Tanks	See Table 2.9.10.1-9
Time to Release All Activity	10 seconds (almost instantaneous)
Filter Efficiency	No filtration assumed
Isolation of Release	No isolation assumed

Table 2.9.10.1-8
RCS Noble Gas Production Rates

Isotope	Production Rate (Ci/min)
Kr-85m	1.24E+0
Kr-85	4.21E-4
Kr-87	2.39E+0
Kr-88	3.36E+0
Xe-131m	3.30E-2
Xe-133m	2.93E-1
Xe-133	6.81E+0
Xe-135m	7.18E+0
Xe-135	2.84E+0
Xe-138	6.22E+0

Table 2.9.10.1-9
Dose Equivalent Xe-133 Available for Release from the Charcoal Decay Tanks

Time (hr)	From Initial RCS Inventory (Ci)	From Ongoing Release from Fuel (Ci)	Total Inventory (Ci)
4	1.8065E+4	1.1287E+4	2.9352E+4
8	1.3479E+4	2.0323E+4	3.3802E+4
24	7.2361E+3	2.7661E+4	3.4897E+4
48	6.0224E+3	2.8879E+4	3.4902E+4
96	4.6257E+3	3.0278E+4	3.4903E+4
250	2.0936E+3	3.2812E+4	3.4905E+4
450	8.3672E+2	3.4069E+4	3.4906E+4
550	5.7174E+2	3.4335E+4	3.4906E+4
650	4.1869E+2	3.4488E+4	3.4906E+4
720	3.5186E+2	3.4555E+4	3.4907E+4

Table 2.9.10.1-10
Summary of Calculated Doses for GDT, VCT and CDT Ruptures

	Whole Body Dose (rem)	Thyroid Dose (rem)	Beta-Skin Dose (rem)
Gas Decay Tank (GDT) Rupture			
EAB	0.2	NA	NA
LPZ	0.02	NA	NA
CR	0.03	NA	1.2
Volume Control Tank (VCT) Rupture			
EAB	0.1	0.04	NA
LPZ	0.006	0.003	NA
CR	0.02	0.07	0.6
Charcoal Decay Tank (CDT) Rupture			
EAB	0.2	NA	NA
LPZ	0.01	NA	NA
CR	0.02	NA	0.6
Acceptance Criteria			
EAB	0.5	1.5	NA
LPZ	0.5	1.5	NA
CR	5.0	30	30

2.10 Health Physics

2.10.1 Occupational and Public Radiation Doses

2.10.1.1 Regulatory Evaluation

PBNP conducted its review to ascertain the overall effects the proposed EPU will have on both occupational and public radiation doses and to determine that PBNP has taken the necessary steps to ensure that any dose increases will be maintained as low as is reasonably achievable (ALARA). The PBNP review included an evaluation of any increases in radiation sources and how this may affect plant area dose rates, plant radiation zones and plant area accessibility. PBNP evaluated how personnel doses needed to access plant vital areas following an accident are affected. PBNP considered the effects of the proposed EPU on plant effluent levels and any effect this increase may have on radiation doses at the site boundary.

The NRC's acceptance criteria for occupational and public radiation doses are based on:

- 10 CFR 20
- General Design Criterion (GDC) 19

Specific review criteria used by NRC are contained in the Standard Review Plan (SRP) Sections 12.2, 12.3, 12.4, and 12.5, and other guidance provided in Matrix 10 of RS-001.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

Criterion: Means shall be provided for monitoring the containment atmosphere and the facility effluent discharge paths for radioactivity released from normal operations, from anticipated transients, and from accident conditions. An environmental monitoring program shall be maintained to confirm that radioactivity releases to the environs of the plant have not been excessive. (PBNP GDC 17)

Criterion: Adequate shielding for radiation protection shall be provided in the design of spent fuel and waste storage facilities. (PBNP GDC 68)

Criterion: The facility design shall include those means necessary to maintain control over the plant radioactive effluents, whether gaseous, liquid, or solid. Appropriate holdup capacity shall be provided for retention of gaseous, liquid, or solid effluents, particularly where unfavorable environmental conditions can be expected to require operational limitations upon the release of radioactive effluents to the environment. In all cases, the design for radioactivity control shall be justified (a) on the basis of 10 CFR 20 requirements, for both normal operations and for any transient situation that might reasonably be anticipated to occur and (b) on the basis of

10 CFR 100 dosage level guidelines for potential reactor accidents of exceedingly low probability of occurrence. (PBNP GDC 70)

LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms, summarizes the EPU assessment of impact on post-accident dose consequences at the site boundary and at locations on-site that require continuous occupancy, such as the control room. The referenced section also addresses PBNP's compliance with the NRC 10 CFR 50 Appendix A GDC 19 dose criteria for the control room using the Alternative Source Term methodology.

PBNP's current licensing basis with respect to radiation protection of plant personnel and the public includes the following:

1. Normal Operation Radiation Levels and Shielding Adequacy

   As discussed in FSAR Section 11.6, Shielding Systems, PBNP is designed for operation at the maximum calculated thermal power and to limit the radiation levels during normal operation at the site boundary to below those levels allowed for continuous non-occupational exposure. Per FSAR Section 11.4, Radiation Protection Program, accessibility of the plant is facilitated by plant shielding and radiation monitoring and is controlled by procedures which take into account the requirements of 10 CFR 20. Plant shielding design and procedural controls ensure that operator exposure is maintained below the levels allowed for occupational exposure set by 10 CFR 20.

2. Radiation Monitoring Setpoints

   As discussed in FSAR Section 11.5, Radiation Monitoring Program, the radiation monitors installed at PBNP can be classified into three categories: (1) area monitors, (2) process and effluent monitors, (3) system-level particulate iodine and noble gas (SPING) monitors. Area monitors provide direct indication of area radiation dose rates in various parts of the plant. The process and effluent monitors provide an indication of increasing radiation levels in various fluid and effluent streams. The SPING monitors measure particulate, iodine and noble gas discharges from the plant. This provides an indication of potential airborne activity in areas surrounding the plant.

   Post-accident monitoring is provided in accordance with Regulatory Guide 1.97, Revision 2, requirements to give notice of significant radiation levels in plant areas or in environmental releases from the plant. The high alarm, alert alarm and trend alarm setpoints for the radiation monitors are based on meeting the above objectives.

3. Post Accident Vital Area Accessibility

   As discussed in FSAR Section 11.6.3, Shielding Systems, System Evaluation, in response to NUREG 0737, Item II.B.2, a plant radiation shielding design review of vital areas was conducted in order to ensure adequate personnel protection while accessing vital areas following a Loss-of-Coolant Accident (LOCA).

Wisconsin Electric Power Company (WEPCO) letter to NRC dated December 31, 1979, Implementation of NUREG 0578, PBNP Units 1 and 2 (Reference 2), submitted the results of the PBNP review for implementation of NUREG 0578, TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendations, Item 2.1.6.b, Design Review of Plant Shielding of Spaces for Post-Accident Operations.

The summary report included with the above letter identifies the contaminated systems, defines post LOCA accessibility/occupancy requirements, and provides a design review of plant shielding of spaces determined to require access for post-accident operations. Mission doses were developed for target areas which were deemed to require post-LOCA access. The above review considered piping carrying post accident recirculation fluid (RHR, SI and CS) as the primary source of radiation at these target areas as well as along the access route. All dose levels were estimated at one hour following the accident. The basis for this assumption was that recirculating sump fluid was considered the primary source for the high post-LOCA radiation levels, and the recirculation mode was not initiated until 1-hour post-LOCA. The summary report identified the period prior to T=1 hr as Phase A, and concluded that no accessibility problems would exist in the plant during this phase. Operator dose per access (included accumulated dose at the target as well as along the access route) was developed based on expected occupancy times, and conservative, non-mechanistic source terms as required by NUREG 0578. The report provided a summary of operator exposure while accessing vital areas (called target areas) and dose rates in corridors/access routes at one hour after the event. It recognized that there were several potential problem areas where 10 CFR 50 Appendix A, GDC-19 limits could be exceeded, and suggested the use of various dose reduction alternatives. A commitment to make future shielding modifications, as needed, was documented in the above report.

Follow-up correspondence between WEPCO and NRC dated September 14, 1981 (Reference 3), and April 26, 1982 (Reference 4), both entitled, Response to NUREG-0737 Update to Schedule Requirements and Implementation Status, indicate that ultimately, only three areas were identified as needing additional shielding, the Unit 1B32 MCC (South wing PAB 8'), the Unit 2B32 MCC (North wing PAB 8') and the C59 panel (PAB central area 26'). The shielding assessments for the MCCs and the C59 panel were based on NUREG-0737 source terms in recirculating fluid; i.e., 50% core halogens and 1% core remainders, which was a departure from the plants original design bases that included 100% of the core noble gas activity in addition to the 50% core halogens and 1% core remainder. NRC's acceptance of the PBNP NUREG 0737(Reference 5) Item II.B.2.2 submittal is documented in NRC letter to WEPCO, dated November 3, 1983, Plant Shielding Modifications for Vital Area Access, PBNP Units 1 and 2 (Reference 6).

Changes in regulatory requirements since 1979, specifically in 10 CFR 50.44, resulted in the elimination of the requirement for combustible gas control for pressurized water reactors without ice condensers. Consequently, PBNP requirements that necessitated the hydrogen recombiners and the containment post-accident hydrogen vent and purge system are no longer required. As a result of this regulatory change, the availability of and capability to install hydrogen recombiners and the associated vital area access requirements have been removed from the PBNP licensing and design basis. (See LR Section 2.6.4, Combustible

Gas Control in Containment, for detail). See LR Section 2.10.2, Post Accident Sample System, for details of the removal of the post-accident sample system vital access requirements.

Further information regarding the PBNP vital access review is provided in LR Section 2.10.1.2, Post-Accident Vital Area Accessibility.

4. Normal Operation Radioactive Effluents and Annual Dose to the Public

   Implementation of the overall requirements of 10 CFR 50, Appendix I, (as to the utilization of radwaste treatment equipment to ensure that radioactive discharges are as low as is reasonably achievable (ALARA)), and of 40 CFR 190 (as to releases of radioactivity and to radiation from uranium fuel cycle sources), are contained in Technical Specification 5.5.4, Radioactive Effluent Controls Program and Technical Specification 5.5.1, Offsite Dose Calculation Manual.

   The PBNP liquid waste management system is discussed in FSAR Section 11.1, Liquid Waste Management System, the PBNP gaseous waste management system is discussed in FSAR Section 11.2, Gaseous Waste Management System, and the PBNP solid waste management system is discussed in FSAR Section 11.3, Solid Waste Management System. These systems are further discussed in LR Sections 2.5.6.1, Gaseous Waste Management, 2.5.6.2, Liquid Waste Management, and 2.5.6.3, Solid Waste Management. Conformity with the design objectives of 10 CFR 50, Appendix I is also discussed in FSAR Appendix I, 10 CFR 50, Appendix I Evaluation of Radioactive Releases from PBNP.

5. Ensuring that Occupational and Public Radiation Exposures are ALARA

   In Amendment 1 to PBNP operating license DPR-24 dated November 17, 1970 (Reference 1), the PBNP volunteered to effect such changes in its equipment and/or operations as will reduce radiation exposures and releases of radioactive materials to unrestricted areas as far below limits specified in 20.106 of 10 CFR Part 20 as the state of the art in the reduction of such emissions will allow. The specific yearly whole body dose at the site boundary in this amendment would be 0.24 R/yr. This compares with the 10 CFR 20 limits of 0.5 R/yr.

   As discussed in FSAR Section 11.4, Radiation Protection Program, the Radiation Protection Program at PBNP maintains occupational radiation exposure as low as is reasonably achievable (ALARA), consistent with plant construction, maintenance, and operational requirements, and within the applicable regulations. Regulatory Guide 8.8 (Reference 7) is used as a basis for developing the ALARA and radiation protection programs to ensure that doses to personnel will be maintained within the limits of 10 CFR 20.

   FSAR Appendix I.1, 10 CFR 50, Appendix I Evaluation of Radioactive Releases from PBNP, discusses implementation of the overall requirements of 10 CFR 50, Appendix I to ensure that radioactive discharges and public exposure are ALARA. These requirements are contained in Technical Specification requirements for the Radioactive Effluent Controls Program and the Offsite Dose Calculation Manual.

In addition to the evaluations described in the FSAR, the PBNP SSCs have been evaluated for plant license renewal. Plant system and component materials of construction, operating history, and programs used to manage aging effects are documented in Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 8). Section 2.5 of the SER discusses radiation monitoring system components within the scope of license renewal.

2.10.1.2 Technical Evaluation

The technical evaluation is presented in five subsections as listed below:

- Normal Operation Radiation Levels and Shielding Adequacy
- Radiation Monitoring Setpoints
- Post-accident Vital Area Accessibility
- Normal Operation Radioactive Effluents and Annual Dose to the Public
- Ensuring that Occupational and Public Radiation Exposures are ALARA

Normal Operation Radiation Levels And Shielding Adequacy

Introduction

Cubicle wall thickness is specified not only for structural and separation requirements, but also to provide radiation shielding in support of radiological equipment qualification, and to reduce operator exposure during all modes of plant operation, including maintenance and accidents.

Conservative estimates of the radiation sources in plant systems and personnel access requirements form the bases of normal operation plant shielding and radiation zoning. These radiation source terms are primarily derived from conservative estimates of the reactor core and reactor coolant (also called primary coolant) isotopic activity inventory, and are referred to as design basis source terms.

The expected radiation source terms in the coolant are more realistic than design and are usually based on industry experience for normal plant operations scaled to reflect plant-specific parameters. Expected source terms are less than those allowable by the plant Technical Specifications and are usually significantly less than the design basis source terms.

The impact of the EPU on the normal operation dose rates and the adequacy of existing shielding is evaluated to ensure safe operation within applicable regulatory limits. The assessment is broken into two parts, the impact of the EPU on (1) plant radiation levels during normal operation, and (2) adequacy of existing shielding for normal plant operation.

The shielding design basis for PBNP is summarized in FSAR Section 11.6, Shielding Systems, which indicates that the original plant shielding design was based on operation at the maximum calculated thermal power and 1 percent fuel defects. Per the Tables in FSAR Section 11.6, Shielding Systems, the original licensed core power level used for shielding determination was

1518.5 MWt and the fuel cycle length was one year. PBNP design documents provided by Westinghouse indicate that plant shielding was actually based on a core power level of 1520 MWt. A proposed 10.5% power uprate with an 18 month cycle was evaluated in 2002 but not implemented. The analyses supporting the proposed uprate were used to support a Margin Uncertainty Recapture (MUR) uprate (Reference 9). PBNP is currently operating at a core power level of 1540 MWt and an 18-month fuel cycle. The impact of the increase in core power level/fuel cycle length from original design on plant radiation levels is monitored, and operator exposure controlled, by the PBNP Radiation Protection Program. The original design calculations supporting plant shielding remain adequate for current plant operations.

The EPU analysis is conservatively based on an analyzed core power level of 1810.8 MWt (includes 0.6% uncertainty) and an 18-month fuel cycle. An increase of fuel cycle length will increase the inventory of long-lived isotopes compared to the original licensing basis core and reactor coolant. The activity inventory of a few isotopes that are produced primarily by neutron activation of stable or long-lived fission products will also increase due to longer accumulation time.

The EPU results in an increase of the nuclear fission rate, and consequently, an increase of neutron flux and the fission product generation rate. This leads to an increase of the fission product inventory in the core and spent fuel and an increase of neutron and gamma flux leaking out of the reactor vessel.

The increase in the neutron flux results in an increase of neutron activation products in the reactor coolant system, control rod assemblies, reactor internals, and in the reactor pressure vessel. The increase in the core inventory of fission products and actinides due to the EPU will also increase the activity concentrations in the reactor coolant due to fuel defects.

In the event that PBNP experiences primary-to-secondary leakage, the activity concentrations in the secondary system will also increase due to primary-to-secondary leakage in the steam generators. The radiation source in the downstream systems will undergo a corresponding increase. This increase in the radioactivity levels, and the associated increase in the radiation source strength, results in an increase of radiation levels in the Containment Building, Primary Auxiliary Building, Turbine Building, and other locations, including offsite, that are subject to direct shine from radiation sources contained in these buildings.

Description of Analyses and Evaluations

The EPU evaluation utilizes scaling techniques to determine the impact of the EPU on plant radiation levels. This evaluation takes credit for conservatism in existing shielding analyses and the site Radiation Protection Program to demonstrate adequacy of current plant shielding to support compliance with the operator exposure limits of 10 CFR 20.

1. Normal Operation Radiation Levels

   For the same facility configuration, the dose rate at a given location is directly proportional to the neutron/gamma flux leaking out of the source region or the volumetric gamma source strength in the source region. The impact of increasing the reactor power from the current licensed level of 1540 MWt to the conservatively analyzed core power level of 1810.8 MWt on the neutron flux and gamma flux in and around the core, fission product and actinide activity inventory in the core and spent fuels, N-16 source in the reactor coolant, neutron activation source in the vicinity of the reactor core, and fission/corrosion products activity in the reactor coolant and downstream systems, was examined, and the increase quantified. This flux or activity increase factor for a given radiation source was determined to be the EPU scaling factor for the estimated dose rate due to that source.

The EPU assessment with regard to normal operation radiation levels is divided into four areas:

a. Areas near the Reactor Vessel

   During normal operation, the radiation source in the reactor core is made up of neutron and gamma fluxes that are approximately proportional to the core power level. The radiation sources during shutdown are the gamma fluxes in the core and the activation activities in the reactor internals, pressure vessel, and primary system piping walls, which also vary approximately in proportion to the reactor power.

   The radiation dose rate near the reactor vessel is determined by the leakage flux from the reactor vessel. Therefore, an uprate from the current licensed core power of 1540 MWt to an analyzed core power of 1810.8 MWt is estimated to increase the normal operation radiation levels in areas near the reactor vessel by a factor of approximately 1.176 (i.e., 1810.8/1540).

b. In-Containment Areas Adjacent to the Reactor Coolant System

   During normal operation, the major radiation source in the reactor coolant system components located within containment is N-16. With the core power increase from 1540 MWt to the analyzed core power of 1810.8 MWt, the fast neutron flux is estimated to increase by approximately 17.6%. The coolant residence time in the core and the transit time are not expected to change significantly due to the uprate. Therefore, the EPU scaling factor for the areas subjected to the N-16 source is 1.176.

   The deposited corrosion product activity depends on the reactor coolant chemistry and the cobalt impurity in reactor coolant system and steam generator components. Since the water chemistry remains approximately the same, and the EPU will increase the neutron flux by approximately 17.6%, the corrosion product activity deposits and the associated shutdown dose rate are also estimated to increase by approximately 17.6%.

c. Areas near Irradiated Fuels and Other Irradiated Objects

   These areas include the refueling canal, spent fuel pool, in-core instrumentation drive assembly area, and other areas housing neutron irradiated materials. The radiation source is the gamma rays from the fission products and activation products, which are determined by the fission rate, neutron flux level, and the irradiation time.

Since both the fission products and the activation products are estimated to increase by approximately 17.6 % for a core power increase from 1540 MWt to the analyzed core power level of 1810.8 MWt, the EPU scaling factor for the areas subjected to irradiated fuels and other irradiated sources is 1.176.

d. Areas Outside Containment where the Radiation Source is derived from the Primary Coolant Activity

   In most areas outside the reactor containment, the radiation sources are either the primary coolant itself or down-stream sources originating from the primary coolant activity. Following the EPU, both the fission products and the activated corrosion products in the primary coolant, and thus the down-stream sources, are estimated to increase by approximately 17.6% for a core power increase from 1540 MWt to the analyzed power level of 1810.8 MWt. The EPU scaling factor for the areas outside containment where the radiation source is derived from the primary coolant activity is 1.176.

2. Plant Shielding Adequacy

Shielding is used to reduce radiation dose rates in various parts of the station to acceptable levels consistent with operational and maintenance requirements and to maintain the dose rates at the site boundary to below those allowed for continuous non-occupational exposure.

The EPU evaluation takes into consideration that the occupancy requirements are not affected by the EPU. Similarly, the layout/configuration of systems containing radioactivity are unchanged by the EPU. Consequently, the EPU evaluation focused on determining an EPU scaling factor based on the design basis fission and corrosion product activity concentrations in the reactor coolant used in the original plant shielding design versus the corresponding EPU design basis reactor coolant activity concentrations presented in Table 2.10.1-1, PBNP EPU Design Reactor Coolant Activity Concentrations @ 1810.8 MWt[a], which reflects an analyzed core power level of 1810.8 MWt, an 18-month fuel cycle length, and 1% fuel defects. As noted earlier, FSAR Section 11.6, Shielding Systems, conservatively states that plant shielding is based on a core power level of 1518.5 MWt with a 1-year fuel cycle length and 1% fuel defects vs PBNP design documents associated with the original license provided by Westinghouse that indicate that plant shielding design was actually based on a core power level of 1520 MWt.

The source terms at the analyzed power are compared to the source terms used in the original shielding design to evaluate the adequacy of the shielding design. The EPU evaluation takes into consideration (a) the conservative analytical techniques used to establish plant shielding design, (b) the Technical Specification limits on the reactor coolant activity concentrations, and (c) the station's Radiation Protection Program that minimizes the radiation exposure to plant personnel.

a. Reactor Primary Shield

FSAR Section 11.6.2, Shielding Systems, System Design and Operation, discusses the primary shield which consists of a reinforced concrete structure that surrounds the reactor vessel. The primary function of the primary shield is to attenuate the neutron and gamma fluxes leaking out of the reactor vessel. Fuel cycle length has insignificant impact on the maximum dose rates around the reactor vessel which are based on the neutron and gamma flux during power operation.

PBNP reviewed the fluence calculations and confirmed that the original design calculations remain bounding for EPU conditions. With continued use of low leakage fuel management following the EPU, the existing primary shielding remains adequate, and the estimated dose rates adjacent to the reactor vessel/primary wall remain within original design.

b. Reactor Secondary Shields

FSAR Section 11.6.2, Shielding Systems, System Design and Operation, discusses the secondary shield and containment structure surrounding the reactor coolant loops and the primary shield. The primary function of these secondary shields is to attenuate the N-16 source, which emits high-energy gammas. These shields were designed to limit the full-power dose rate outside the Containment Building to less than 1 mrem/hr. The N-16 source is estimated to increase by approximately 19% compared to original design. The N-16 activity level is not impacted by fuel cycle length. The impact of the estimated 19% increase in source terms is bounded by the conservative analytical techniques typically used to establish plant shielding design (such as ignoring the shadow shielding effect of the neighboring sources, rounding up the calculated shield thickness to a higher whole number, etc.). The current reactor coolant loop shielding and containment structure is determined to be adequate for safe operation following the EPU.

c. Fuel Transfer Shield

FSAR Section 11.6.2, Shielding Systems, discuss the fuel handling shielding which provides protection during all phases of removal and storage of spent fuel and control rods. The fuel transfer shielding is designed to alleviate radiation from spent fuel and control rods during transfer and storage, such that radiation levels at the Refueling Cavity water surface and in the Primary Auxiliary Building are less than 2.5 mrem/hr and 1 mrem/hr, respectively.

With the analyzed core power increase from 1520 to 1810.8 MWt, the gamma source from the irradiated fuel is estimated to increase by approximately 19%. The 18-month fuel cycle will also increase the inventory of long-lived isotopes in the irradiated fuel. However, this is not a concern as the estimated maximum dose rates near the refueling canal and the spent fuel pool are dominated by the shorter half-life isotopes in the freshly discharged spent fuel assemblies. The impact of the estimated 19%

increase in source terms used in the EPU analysis versus the original shielding analysis is bounded by the conservative analytical techniques discussed earlier in item b, which were used to establish plant shielding design. Consequently, the current spent fuel shielding is determined adequate for safe operation following the EPU.

d. All Other Shielding Outside Containment

FSAR Section 11.6.2, Shielding Systems, System Design and Operation, discusses the shielding provided outside the containment where the radiation sources are either the reactor coolant itself or down-stream sources originating from coolant activity. A review was performed of the EPU design primary coolant source terms (fission and activation products) versus the original design basis primary coolant source terms. It is noted that the analyzed design primary coolant source term used for the EPU reflects a core power level of 1810.8 MWt, operation with an 18-month fuel cycle, 1% fuel defects, a coolant inventory multiplier of 1.12 for Ag-110m and 1.08 for all other fission products to account for cycle variations, and more advanced fuel burnup modeling/libraries as compared to the computer codes used in the original analyses that addressed a core power level of 1520 MWt and a one-year fuel cycle length.

The EPU assessment concluded that the estimated increase in the dose rate for shielded configurations based on the design EPU reactor coolant versus the pre-uprate coolant is compensated by the plant Technical Specifications that will limit the EPU reactor coolant, degassed reactor coolant, and reactor coolant noble gas source terms and associated dose rates to less than the original design basis values. It is therefor, concluded that the shielding design based on the original design basis primary coolant activity remains acceptable for the EPU condition.

Results

The normal operation radiation levels in most of the plant areas are estimated to increase by approximately 17.6%, i.e., the percentage increase between the current licensed power level of 1540 MWt, and the conservatively analyzed core power level of 1810.8 MWt used for the EPU assessment. The exposure to plant personnel and to the offsite public is also estimated to increase by the same percentage.

The increase in radiation levels will not affect radiation zoning or shielding requirements in the various areas of the plant. This is because the increase is offset by the:

1. Conservative analytical techniques typically used to establish shielding requirements.
2. Conservatism in the original design basis reactor coolant source terms used to establish the radiation zones.
3. Technical Specification 3.4.16 which limits the reactor coolant concentrations to levels significantly below the original design basis source terms.

As indicated in FSAR Section 11.4, Radiation Protection Program, individual worker exposures will be maintained within the regulatory limits of 10 CFR 20 for occupational exposure by the site Radiation Protection Program that controls access to radiation areas. In addition, the Offsite Dose Calculation Manual required by TS 5.5.1, ensures that the radiation levels at the site boundary due to direct shine from radiation sources in the plant will be maintained within the regulatory limits of 10 CFR 20 and 40 CFR 190 for continuous non-occupational exposure.

The EPU assessment also demonstrates compliance with GDC-19 with regard to radiation protection, insofar that actions can be taken in the Control Room to operate the nuclear power unit safely during normal operation.

Radiation Monitoring Setpoints

Introduction

As discussed in FSAR Section 11.5, Radiation Monitoring Program, the radiation monitors installed at PBNP can be classified into three categories: (1) area monitors, (2) process and effluent monitors, (3) system-level particulate iodine and noble gas (SPING) monitors. PBNP is equipped with Containment High-Range Radiation Monitors.

Area monitors are included as a radiation protection feature and provide direct indication of area radiation dose rates in various parts of the plant to support control of radiation exposure of plant personnel. Process and effluent radiation monitors provide radioactivity monitoring in gaseous or liquid process streams, or effluent release points to unrestricted areas to detect system leakage and support control of radiation exposure of both plant personnel and the public. The SPING monitors are used to sample and monitor the airborne materials in the exhaust gas of Unit 1 and 2 containment purge exhaust stacks, auxiliary building exhaust stack, and radwaste packaging area exhaust stack. The Containment High-Range Radiation Monitors give notice of potentially significant radioactive releases from the plant. The high alarm and alert setpoints for the radiation monitors are based on meeting the above objectives.

The function of area monitor alarm setpoints is to provide an early warning of changing radiological conditions in a specified area. The function of alarm setpoints for process/effluent monitors is to indicate leakage or malfunction of equipment, or a potential for an activity release that may exceed the release limit. The high alarm setpoint of selected effluent monitors will also initiate interlocks that terminate activity release to the environment. The function of the post-accident radiation monitors is to give notice of significant radiation levels within plant areas or in environmental releases from the plant.

The bases of the radiation monitor setpoints are intended to give notice of releases approaching the limits of 10 CFR 20, a multiple of the background, or a high value indicating an unusual event (such as leakage or malfunction of systems), that leads to a sudden increase of the activity level in the area of the monitored stream. In some cases, the setpoint values are based on background levels/process fluids source terms that reflect plant operating data and are reviewed frequently and adjusted as required. In all of the above cases, the radiation monitor setpoint bases, and the methods of setpoint determination, remain valid following the EPU.

In some cases, a setpoint value may be based on calculated background levels/process fluid source terms. The EPU will increase the activity level of radioactive isotopes in most streams/components and the associated radiation levels by approximately the percentage of the uprate. However, the relative isotopic compositions in the process and effluent streams are not expected to change due to the EPU. Consequently, the existing setpoint is conservative for EPU operation. The impact of the increase in background level due to the EPU on monitor sensitivity is expected to be addressed by the periodic monitor calibration/settings check which are performed per existing plant procedure.

Description of Analyses and Evaluations

The alarm setpoints for the area monitors are set at dose rates that would signal unusual radiation conditions at the monitored areas. The alarm setpoints for the process monitors are usually set at two times the steady-state monitor reading to indicate an increase of radioactive concentrations of the monitored streams. The alarm setpoints for the effluent monitors and SPING monitors are chosen to ensure that releases would result in concentrations at unrestricted areas that are within the Technical Specification limits for the radiological effluents. The liquid effluent monitor default maximum setpoints are calculated based on the effluent concentration limits specified in 10 CFR 20, Appendix B, Table 2, Column 2, the relative nuclide mixes based on the average isotopic distribution for 1985-1991 liquid effluent releases, the maximum discharge flow rate, and the minimum circulation water flow rate. The gaseous effluent monitor default maximum setpoints are calculated based on the effluent concentration limits specified in 10 CFR 20, Appendix B, Table 2, Column 1, the relative nuclide mixes based on the average noble gas isotopic distribution for 1985-1991 releases, and the highest annual average atmospheric dispersion factor at the site boundary. The high alarm setpoints for the Containment High-Range Area Monitors are set at 100 R/hr to alarm the plant operators of a significant release of core activity inventory into the containment, indicating a high degree of severity of an accident. In all of the above cases, the radiation monitor setpoint bases, and the setpoint values, remain valid following the EPU.

Results

Impact of EPU on radiation monitor setpoints is minimal.

Post Accident Vital Area Accessibility

Introduction

In accordance with NUREG-0737, II.B.2, vital areas are those areas within the station that will or may require access/occupancy to support accident mitigation following a loss-of-coolant accident (LOCA). In accordance with the above regulatory document, all vital areas and access routes to vital areas must be designed such that operator exposure while performing vital access functions remain within regulatory limits.

This section focuses on areas that may require short-term, one-time, or infrequent access following a LOCA. Onsite locations that require continuous occupancy and a demonstration of 30-day habitability are addressed in LR Section 2.9, Source Terms and Radiological Consequences Analyses.

The original licensing basis vital area access review is discussed earlier in Section 2.10.1.1, Item No. 3. As noted in LR Section 2.6.4, Combustible Gas Control in Containment, and LR

Section 2.10.2, Post Accident Sample System, vital area access is no longer required to the hydrogen recombiners and post-accident sampling system.

As part of the EPU evaluation, a review was performed of the Emergency Operating Procedures (EOPs) to identify vital area access requirements applicable for EPU operations. It was determined that almost all of the vital area access requirements identified in the original licensing basis are either:

- not required to be evaluated since they are completed during Phase A of the LOCA, (i.e., prior to the sump water recirculation phase of the accident), and thus do not pose a radiation hazard to the operator, or
- not required steps, but enhancements, which may be undertaken only if the environment is considered acceptable by Radiation Protection (RP) personnel.

The above evaluation determined that only one vital area access requirement remained following the EPU; i.e., access to the C59 panel to manually isolate spray additive tank discharge valves. The review also determined that the task duration at the C59 panel is 10 minutes versus the original licensing basis task duration of 20 minutes.

Note that included in this EPU LAR is the elimination of PBNP's current requirement to draw and analyze post-accident samples of reactor coolant, containment sump water, and containment atmosphere within 3 hours following a large break LOCA. As a result of the above change in requirement, the Unit 1 and Unit 2 sample rooms are removed from the list of vital areas. Justification for elimination of this requirement is presented in LR Section 2.10.2, Post Accident Sample System, which invokes WCAP-14986-A, Westinghouse Owners Group Post Accident Sampling System Requirements: A Technical Basis (Reference 10), and the associated NRC approval of the topical report. Required licensee actions identified in Sections 4.1 and 5 of the NRC SE for WCAP-14986-A have been completed with the exception of the implementation of the incorporation of the WCAP-14696 Core Damage Assessment Guideline into procedures. This last item is included as a commitment in Attachment 4 of this EPU LAR. The plant will remain capable of performing sampling activities; however, following the NRC approval of the elimination of the 3-hour sampling requirement with the EPU amendment, these two areas will no longer be considered vital areas that require access for accident mitigation and safe shutdown. Rather, access will be deferred to when it is considered habitable by PBNP RP staff.

In addition, and as noted in the PBNP Alternative Source Term LAR No. 241, (ML083450683)(Reference 12), PBNP has updated its post-accident dose assessments associated with the site boundary and on-site locations that require continuous occupancy, such as the Control Room, to reflect Alternative Source Terms (AST) as outlined in 10 CFR 50.67, SRP 15.0.1 and Regulatory Guide 1.183. However, the EPU assessment for post-LOCA vital area access continues to be based on TID-14844 Source Terms. This approach is acceptable for Vital Area Access assessments based on the AST benchmarking study reported in NRC SECY-98-154, Results of the Revised (NUREG-1465) Source Term Rebaselining for Operating Reactors, June 30, 1998 (Reference 11), Results of the Revised Source Term Rebaselining for Operating Reactors, which concluded that results of analyses based on TID-14844 would be more limiting earlier on in the event, after which time the AST results would be more limiting.

Areas designated as vital for purposes of accident mitigation usually require access within the first week when the original TID-14844 source terms are more limiting.

As noted in the PBNP Alternative Source Term LAR 241 (ML083450683) as a part of the modifications associated with implementation of AST at PBNP, the control room emergency filtration fans will be automatically loaded onto their respective emergency diesel generator following a loss-of coolant accident coincident with a loss of offsite power. The requirement to rearm these circuits using the local pushbuttons at their respective motor control centers in the primary auxiliary is being eliminated. Also included with the PBNP AST LAR 241 is the potential need to manually close the NaOH discharge line AOVs in the event of loss of instrument air. This new activity is performed prior to aligning containment spray for the recirculation spray mode. At the time access is needed (i.e., within an hour of the accident), the components carrying recirculation fluids are the Low Head Safety Injection (LHSI) and the Residual Heat Removal (RHR) lines. Based on a review of the considerable distance and available shielding between the LHSI / RHR lines and the NaOH discharge line AOVs (including the access path to the AOVs), it is concluded that the dose rates near the AOVs (including the access path) due to the above radiation sources is negligible. Therefore, operator exposure during this mission is deemed to be negligible.

Description of Analyses and Evaluations

The original licensing basis source terms used to develop vital area access dose estimates for PBNP were based on a power level of 1518.5 MWt, a 12-month fuel cycle length and a containment sump water volume of 317,166 gallons.

The proposed EPU core power level is 1800 MWt. Radiological safety analyses supporting the EPU are performed at a reactor power level of 1810.8 MWt (i.e., the core power level of 1800 MWt with a 0.6% margin for power uncertainty) and an 18-month fuel cycle. It is noted that the EPU design core activity includes an additional 4% margin to account for variability in future fuel cycle design. The containment sump water volume applicable to the EPU application is 243,000 gallons.

EPU will typically increase the activity level in the core by the percentage of the uprate. The radiation source terms in equipment/structures containing post-accident fluids, and the corresponding environmental radiation levels, will increase proportionately to the uprate. In addition, factors that impact the equilibrium core inventory (and consequently the estimated radiation environment), are fuel enrichment and burnup.

The methodology used in the EPU evaluation is to demonstrate, using scaling techniques, compliance with the operator exposure dose limits of 5 rem provided in NUREG-0737, II.B.2.

The impact of the EPU on the post-LOCA gamma radiation dose rates used to determine operator exposure during vital area access is evaluated by comparing the gamma source terms, based on the original core inventory used to develop the post-LOCA dose rates, to the gamma source terms, based on the EPU core inventory. This approach takes into consideration that: (a) the post-LOCA operator mission requirements, including the task description and required time for access is not impacted by the EPU, and (b) EPU does not impact the operation and layout/arrangement of plant radioactive systems. As discussed earlier, the task duration at the

C59 panel has been re-evaluated and is determined by plant operations to be 10 minutes versus the original licensing basis task duration of 20 minutes.

Theoretically, following the EPU, the post-LOCA environmental gamma dose rates and the operator dose per identified mission should increase by approximately 19% (1810.8 MWt/1518.5 MWt). However, because the EPU analyzed core reflects: (a) operation with an 18-month fuel cycle, (b) more advanced fuel burnup modeling/libraries than used in the original analyses, and (c) a 4% margin to account for variability in future fuel cycle designs, the calculated EPU scaling factor values will deviate from the core power ratio.

The EPU assessment is essentially a two-step process. The first develops a bounding EPU dose rate scaling factor versus time, and the second multiplies the personnel dose/dose rates at target areas identified in the licensing basis by the bounding EPU scaling factor(s).

The pre-EPU and the EPU core inventories are used to develop the post-LOCA gamma energy release rates (Mev/sec) per energy group vs. time for the post accident sources addressed in the licensing basis, i.e., sump water following a depressurized LOCA. Source terms are based on guidance provided in NUREG 0737.

For the unshielded case, the factor impact on post-accident integrated gamma dose rates is estimated by ratioing the gamma energy release rates weighted by the flux to dose rate conversion factors, as a function of time, for the core power level analyzed for the EPU, to the corresponding weighted source terms based on the original licensing basis core. To address the fact that the vital access locations are outside containment and sump fluid is contained in equipment/piping, the unshielded values include the shielding effect of a pipe wall thickness associated with a standard small bore pipe or a standard large bore pipe. This ensures that the results will not be skewed by photons at low energies especially those less than 25 kev which will be substantially attenuated by any piping sources or self-attenuation.

To evaluate the factor impact of EPU on post-LOCA gamma doses (versus time) in areas that are shielded, the original as well as EPU source terms discussed above were weighted by the concrete reduction factors for each energy group. The concrete reduction factors for 1', 2', and 3' of concrete were used to provide a basis for comparison of the post-LOCA spectrum hardness with respect to time, for lightly shielded and heavily shielded cases.

Since the EPU gamma dose rate scaling factors for the sump fluid vary with time, as well as shielding, to cover all types of analysis models/assessments, the maximum dose rate scaling factor developed from the above assessments was used to estimate the impact of the EPU on the operator dose while accessing the C59 panel.

In summary, the scaling factors used are as follows:

- An EPU dose rate scaling factor of 1.4
- A scaling factor of 1.3 to reflect a change in the sump water volume between that used in the original licensing basis (317,166 gallons) versus the sump volume applicable to the EPU condition (243,000 gallons)

- A scaling factor of 0.5 on the operator dose accumulated at the C59 panel (not applicable to the dose accumulated during ingress/egress) to address the reduction in stay time from 20 minutes to 10 minutes.

Results

The calculated dose to an operator performing vital tasks at the C59 panel is 3 rem thus demonstrating continued compliance with the regulatory limit of 5 rem whole body listed in NUREG-0737, II.B.2.

Normal Operation Radwaste Effluents and Annual Dose to the Public

Introduction

Liquid and gaseous effluents released to the environment during normal plant operations contain small quantities of radioactive materials.

Liquid, gaseous, and solid radwaste systems are designed such that the plant is capable of maintaining normal operation offsite gaseous and liquid releases and doses within regulatory limits. The actual performance and operation of installed equipment, as well as reporting of actual offsite releases and doses, is controlled by the requirements of the Offsite Dose Calculation Manual (ODCM) in accordance with TS 5.51.

There are no specific regulatory limits associated with generation of solid radwaste other than those associated with transportation. However, onsite storage of solid radwaste may result in increased public exposure at the site boundary which is controlled by federal regulations.

EPU will increase the activity level of radioactive isotopes in the reactor and secondary coolant and steam. Due to leakage or process operations, fractions of these fluids are transported to the liquid and gaseous radwaste systems where they are stored/processed prior to discharge. As the activity levels in the coolants and steam are increased, the activity level of radwaste inputs, and subsequent environmental releases, are proportionately increased.

Description of Analyses and Evaluations

The methodology used in the EPU evaluation is to demonstrate, using scaling techniques, compliance with the annual dose limits to an individual in an unrestricted area set by 10 CFR 20, 10 CFR 50, Appendix I and 40 CFR 190 resulting from radioactive gaseous and liquid effluents released to the environment following the EPU. Limits on dose to the public resulting from normal operation are addressed in 10 CFR 20, 10 CFR 50 Appendix I, as well as 40 CFR 190. 10 CFR 50 Appendix I (which is based on the concept of "As Low As Reasonably Achievable") is the most limiting. 10 CFR 20 has a release rate criteria that does not exist in 10 CFR 50 Appendix I. The ODCM controls actual performance and operation of installed equipment and releases, thus maintaining compliance with that aspect of 10 CFR 20. If the projected increase in offsite doses due to radioactive gaseous and liquid effluents either approach or exceed 10 CFR 50, Appendix I guidelines, then the methodology in the ODCM is used to determine compliance with 40 CFR 190. Per Section 4.4 of the ODCM, compliance with the provisions of Appendix I to 10 CFR 50 is adequate demonstration of conformance to the standards set forth in 40 CFR 190 regarding the dose commitment to individuals from the uranium fuel cycle. Per the ODCM, *for 40 CFR 190 compliance, quarterly dose calculations shall include exposures from* effluent pathways and direct radiation contributions from the reactor units and from any outside storage tanks.

There are no changes as a result of the EPU to existing radioactive waste systems (gaseous and liquid) design, plant operating procedures or waste inputs as defined by NUREG-0017, Revision 1. Therefore, a comparison of releases can be made based on current versus EPU inventories/radioactivity concentrations in the reactor coolant and secondary coolant/steam. As a result, the impact of the EPU on radwaste releases and Appendix I doses can be estimated using scaling techniques.

Scaling techniques based on NUREG-0017, Revision 1 (Reference 13) methodology were used to assess the impact of the EPU on radioactive gaseous and liquid effluents at PBNP Units 1 and 2. Use of the adjustment factors presented in NUREG-0017, Revision 1 allows development of coolant activity scaling factors to address the EPU.

The EPU analysis used the core power operating history during the years 2002 to 2006 for both PBNP units, the reported gaseous and liquid effluent and dose data during that period, and NUREG-0017, Revision 1, equations and assumptions and conservative methodology to estimate the impact of operation at the analyzed EPU core power level. The results were then compared to the comparable data from current operation on radioactive gaseous and liquid effluents and the consequent normal operation offsite doses.

For the current condition, the evaluation used offsite doses based on an average 5-year set of organ and whole body doses calculated from effluent reports for the years 2002 through 2006. In 2002, the licensed core power at PBNP Units 1 and 2 was 1518.5 MWt versus 1540 MWt for 2003-2006 resulting from implementation of the MUR power uprate. For purposes of this analysis, the annual capacity factor/availability factor in 2002 was reduced to reflect operation at the 1540 MWt power level.

At the end of 2007, the method for processing liquid waste was changed from the use of an evaporator to the use of the Advanced Liquid Processing System (ALPS) which is a demineralizer based system. The impact of this change in the processing system is included in the EPU assessment as a separate scaling factor for the whole body and organ doses associated with liquid radwaste effluents.

For the EPU condition, the system parameters used in the EPU analysis reflected the flow rates and coolant masses at an NSSS power level of 1806 MWt and a analyzed core power level of 1811 MWt. This is consistent with the guidance provided in NUREG-0017 which requires that the core power level used in the analysis reflect a margin for power uncertainty.

The maximum potential percentage increase in coolant activity levels due to the EPU, for each chemical group identified in NUREG-0017, was estimated using the methodology and equations found in NUREG-0017, Revision 1, and a comparison of the change in power level and in plant reactor coolant system parameters (such as reactor coolant mass, steam generator liquid mass, steam flow rate, reactor coolant letdown flow rate, flow rate to the cation demineralizer, letdown flow rate for boron control, steam generator blowdown flow rate, or steam generator moisture carryover) for both current and EPU conditions. To estimate an upper bound impact on offsite doses, the highest factor found for representative isotopes in any chemical group (including corrosion products) in either unit, pertinent to the release pathway was applied to the average doses previously determined as representative of operation at current conditions. This approach was used to estimate the maximum potential increase in effluent doses due to the EPU and to demonstrate that the estimated offsite doses following the EPU, although increased, will remain below the regulatory limits.

The impact of the EPU on solid radwaste generation was qualitatively addressed based on NUREG-0017, Revision 1, methodology, engineering judgment and the understanding of radwaste and affected plant system operation on the generation of solid radwaste.

The analysis concluded the following:

1. Expected Reactor Coolant Source Terms

   Based on a comparison of current versus EPU input parameters, and the methodology outlined in NUREG-0017, Revision 1, the maximum expected increase in the reactor coolant source is approximately 17.6% for noble gases, I-131, and for other long half-life activity. The change is primarily due to the increase in effective core power level 1811 MWt /1540 MWt (pre-uprate licensed power level) between current and EPU conditions.

2. Liquid Effluents

   Bases on the 2002 to 2006 data, there is a maximum 17.6% increase in the radioactivity content of the liquid releases since input activities are based on long-term reactor coolant activity that is proportional to the core power uprate percentage increase, and on waste volumes that are essentially independent of power level within the applicability range of NUREG-0017. In addition, tritium releases in liquid effluents are assumed to increase approximately 17.6% (corresponding to the effective core power uprate percentage) since the analysis is based on changes in an existing facility's power rating without changing its mode of operation. Thus a 17.6% increase is applied to the whole body dose. Regarding the organ dose, the I-133 in the steam generator liquid increased by 19.1%. This increase factor is conservatively applied to the organ dose.

   To address the potential impact of the change in the method of processing liquid radwaste implemented at the end of the year 2007, from the use of an evaporator to the use of the ALPS (a demineralizer based system), a review was performed of the monthly whole body and organ dose estimates to the public in the year 2008 due to liquid effluents from PBNP. The pre-EPU whole body and organ doses estimates established using the 2002 through 2006 data were compared to that developed for the year 2008. This comparison showed that there was minimal impact on the whole body dose due to tritium being the controlling isotope. The 2008 organ doses which reflect ALPS operation for the whole year showed an increase from the values established using the 2002 to 2006 data; however, the EPU impact is well within the limits of Appendix I.

3. Gaseous Effluents

   For all noble gases, there will be a bounding maximum 17.6% increase of radioactivity content in effluent releases due to the effective core power uprate percentage increase and a very slight decrease in primary coolant mass. Gaseous releases of isotopes with long half lives such as Kr-85 will increase by approximately the percentage of power increase (~17.6%). Gaseous isotopes with shorter half-lives will have increases slightly more than the effective percentage increase in power level up to a bounding value of 18.1%.

Tritium releases in the gaseous effluents increase in proportion to their increased production (17.6%), which is directly related to core power and is allocated in this analysis in the same ratio as current releases.

The impact of the EPU on iodine releases is approximated by the effective core power level increase with the calculated increase in the reactor coolant and secondary coolant I-131 concentration of 17.6% and 35.7%, respectively. The 35.7% would have been used as the limiting increase in thyroid doses due to iodine releases, but tritium is the controlling organ dose isotope at PBNP and limits thyroid dose increases to 17.6%.

For particulates, the methodology of NUREG-0017, Revision 1, specifies the release rate per year per unit per building ventilation system. This is not dependent on power level within the range of applicability. Particulates released via the Turbine Building due to leakage of main steam and air ejector exhaust are generally considered to be a small fraction of total particulate releases. Therefore, minimal change would be expected for the EPU operations. However, a conservative approach is dictated by the fact that the annual effluent release reports do not delineate the source of particulates or iodines released. In addition, at PBNP, tritium is included in the category with iodines and particulates (radionuclides with half-lives greater than 8 days).

On the secondary side, moisture carryover is a major factor in determining the non-volatile activity in the steam. The multiplier (~13.3) applicable to the particulates (cesium) released via the Turbine Building due to main steam leaks and air ejector exhaust is higher than the percentage of the EPU (primarily due to a conservatively estimated 11.3-fold increase in moisture carryover due to the EPU, coupled with a 17.6% increase in coolant concentration). However the contribution of iodines or the particulates to the iodine and particulate category was insignificant compared to the dose contribution from tritium. Therefore, the scaling factor for the entire particulate and iodine category was conservatively estimated at 17.6% for all organs.

4. Estimated Impact on Effluent Doses - Compliance with 10 CFR 50 Appendix I

   Table 2.10.1-2,Dose Comparisons shows that, based on operating history, the maximum estimated dose due to liquid and gaseous radwaste effluents following the EPU is significantly below the 10 CFR 50, Appendix I limits.

5. Solid Radioactive Waste

   The volume of solid waste would not be expected to increase proportionally because the EPU neither appreciably impacts installed equipment performance, nor does it require drastic changes in system operation or maintenance. Only minor, if any, changes in waste generation volume are expected. However, it is estimated that the activity levels for most of the solid waste would increase proportionately to the increase in long half-life coolant activity bounded by the 17.6% maximum increase.

However, it is estimated that as a result of the EPU, the activity levels for most of the solid waste would increase proportionately to the increase in long half-life coolant activity bounded by the 17.6% maximum increase. Taking into consideration the average capacity factor during the 5-year evaluation period of 0.855, and conservatively assuming a capacity factor of 1.0 following the EPU, the total long-lived activity contained in the waste following EPU is estimated to be bounded by approximately 20.6% (that is, 17.6%/0.855) over that currently stored on site.

In the long term, the direct shine dose due to radwaste stored onsite could be conservatively estimated to increase by approximately 20.6% as: (a) current waste decays and its contribution decreases, (b) the radwaste is routinely moved offsite for disposal, (c) waste generated post-uprate enters into storage and (d) plant capacity factor approaches the target value of 1.0.

As the impact on direct shine doses is cumulative of wastes generated from both units over the plants' lifetime and stored onsite, procedures and controls in the ODCM monitor and control this component of the offsite dose and would limit, through administrative and storage controls, the offsite dose to ensure compliance with the 40 CFR 190 direct shine dose limits.

6. Impact of EPU on Direct Shine

   As noted in the PBNP Annual Radioactive Effluent Reports, "the operation of the plant has had no effect on the ambient gamma radiation", thus the annual direct shine dose during the pre-EPU 5-year period evaluated was negligible. For the EPU, the direct shine dose due to plant operation would increase by the increase percentage of the power level, (17.6%), however, as discussed above, the direct shine contribution due to accumulation of stored solid radwaste, could increase by approximately 20.6%. A bounding scaling factor of 20.6% would not change the estimated EPU direct shine dose which would remain negligible.

7. Compliance with 40 CFR 190

   The discussion below regarding compliance with 40 CFR 190 is provided for completeness even though, per the ODCM, "*compliance with the provisions of Appendix I to 10 CFR 50 is adequate demonstration of conformance to the standards set forth in 40 CFR 190 regarding the dose commitment to individuals from the uranium fuel cycle.*"

   The 40 CFR 190 whole body dose limit of 25 mrem to any member of the public includes (a) contributions from direct radiation (including skyshine) from contained radioactive sources within the facility, (b) the whole body dose from liquid release pathways, and (c) the whole body dose to an individual via airborne pathways.

Taking into consideration the estimated annual EPU whole body dose of 9.76E-03 mrem due to gaseous and liquid effluent releases (6.095E-04 mrem/yr and 9.155E-03 mrem/yr, respectively), and the negligible direct shine dose contribution, it is concluded that the 40 CFR 190 whole body dose limit of 25 mrem/yr will not be exceeded by the EPU.

Results

PBNP is required to meet the requirements of 40 CFR 190, 10 CFR 20 and 10 CFR 50, Appendix I. 10 CFR 50 Appendix I is the most limiting.

10 CFR 20 has a release rate criteria that is not contained in 10 CFR 50 Appendix I, but the ODCM controls actual performance and operation of installed equipment and releases, thus maintaining compliance with that aspect of 10 CFR 20.

If the normal operation doses due to radioactive gaseous and liquid effluents either approach or exceed 10 CFR 50, Appendix I guidelines, the ODCM will ensure compliance with 40 CFR 190.

The EPU has no significant impact on the annual radwaste effluent doses This analysis demonstrates that the estimated doses following EPU will remain a small percentage of allowable Appendix I doses; see Table 2.10.1-2. Therefore, it is concluded that following EPU, the liquid and gaseous radwaste effluent treatment systems, in conjunction with the procedures and controls provided by the ODCM, will remain capable of maintaining normal operation offsite doses within the regulatory requirements and the criteria of Amendment 1 to the PBNP Operating License as discussed in the current licensing basis above.

Ensuring that Occupational and Public Radiation Exposures Are ALARA

Introduction

As discussed in FSAR Section 11.4, Radiation Protection Program, it is to a Radiation Protection Program must be implemented that meets the requirements of 10 CFR 20 and ensures that the occupational radiation exposures at PBNP are kept ALARA.

Implementation of the overall requirements of 10 CFR 50, Appendix I relative to utilization of radwaste treatment equipment to ensure that radioactive discharges and public exposure are ALARA is formalized via controls imposed by the ODCM.

Description of Analyses and Evaluations

As required in FSAR Section 11.4, Radiation Protection Program, ALARA procedures currently in place govern all activities in restricted areas at PBNP. Management commitment to the policy is reflected in the design of the plant, and the plant operation and maintenance procedures. Design features credited to support the PBNP commitment to ALARA operator exposures include shielding, which is provided to reduce levels of radiation; ventilation, which is arranged to control the flow of potentially contaminated air; an installed radiation monitoring system, which is used to measure levels of radiation in potentially occupied areas and measure airborne radioactivity throughout the plant; and respiratory protective equipment, which is used as prescribed by the Radiation Protection Program.

Compliance with the requirements of the ODCM ensures that radioactive discharges and public exposure are ALARA.

The EPU assessments documented in this section demonstrate that the dose limits imposed by regulatory requirements are met following the EPU. The EPU does not impact the effectiveness of the design features credited to support PBNP commitment to ALARA operator and public exposures. The intent of the ALARA procedures remain unchanged, specifically, (a) meet the allowable limits on operator and public exposure and (b) keep operator and public exposure at a minimum.

Results

It is concluded that no additional steps are necessary to ensure that dose increases are maintained ALARA.

Evaluation of Impact of Renewal Plant Operating License Evaluations and License Renewal Programs

The EPU assessment of impact on normal plant radiation levels including shielding adequacy, radiation monitoring setpoints, post-accident vital area accessibility, and normal operation radwaste effluents does not impact the list of components that fall within the scope of license renewal. No new components are being added to the scope of license renewal. Consequently, the EPU evaluation discussed in this section has no effect on the PBNP License Renewal.

2.10.1.3 Conclusions

PBNP has assessed the effects of the proposed EPU on radiation source terms and plant radiation levels. In addition, PBNP has addressed the effects of the EPU on the associated impact on shielding adequacy, radiation monitoring setpoints, post-accident vital area accessibility, and normal operation radwaste effluents. PBNP concludes that no additional steps are required to ensure that any increases in radiation doses will be maintained as low as reasonably achievable. PBNP further concludes that the proposed EPU meets the requirements of 10 CFR Part 20, 10 CFR Part 50, Appendix I, 40 CFR 190, and GDC-19. Therefore, PBNP finds the proposed EPU acceptable with respect to radiation protection and ensuring that occupational and public radiation exposures will be maintained as low as reasonably achievable.

2.10.1.4 References

1. Atomic Energy Commission to Wisconsin Electric Power Company/Wisconsin Michigan Power Company, Change No. 1 to License No. DPR-24, dated November 17, 1970

2. Wisconsin Power Electric Power Company (WEPCO) letter to NRC, Implementation of NUREG 0578, PBNP Units 1 and 2, dated December 31, 1979

3. WEPCO to NRC, Response to NUREG-0737 Update to Schedule Requirements and Implementation Status, dated September 14, 1981

4. Response to NUREG-0737 Update to Schedule Requirements and Implementation Status, dated April 26, 1982

5. NUREG-0737 Clarification of TMI Action Plan Requirements, dated November 1980

6. NRC letter to WEPCO, Plant Shielding Modifications for Vital Area Access, PBNP Units 1 and 2, dated November 3, 1983

7. Regulatory Guide 8.8, Information Relevant to Ensuring that Occupational Radiation Exposures at Nuclear Power Stations Will be as Low as is Reasonably Achievable, dated June 1978

8. NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005

9. NRC to NMC LLC, Point Beach Nuclear Plant, Units 1 and 2 - Issuance of Amendments Re: Measurement Uncertainty Recapture Power Uprate, dated November 29, 2002 (ML023370133)

10. WCAP-14986-A, Westinghouse Owners Group Post Accident Sampling System Requirements: A Technical Basis, dated August 2000

11. NRC SECY-98-154, Results of the Revised (NUREG-1465) Source Term Rebaselining for Operating Reactors, dated June 30, 1998

12. Point Beach Nuclear Plant Units 1 and 2, Submittal of License Amendment Request 241, Alternative Source Term, December 2008, (ML083450683)

13. NUREG-0017, Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Pressurized Water Reactors (PWR-GALE Code). Revision 1, dated April 1985

Table 2.10.1-1
PBNP EPU Design Reactor Coolant Activity Concentrations @ 1810.8 MWt[a]

Nuclide	Primary Coolant Activity Conc. (μCi/g)	Nuclide	Primary Coolant Activity Conc. (μCi/g)	Nuclide	Primary Coolant Activity Conc. (μCi/g)
Kr-83m	5.30E-01	Rb-86	2.72E-02	Te-129	1.28E-02
Kr-85m	2.17E+00	Rb-88	4.97E+00	Te-131m	3.38E-02
Kr-85	1.05E+01	Rb-89	2.31E-01	Te-131	1.45E-02
Kr-87	1.44E+00	Sr-89	4.57E-03	Te-132	3.15E-01
Kr-88	4.01E+00	Sr-90	2.15E-04	Te-134	3.76E-02
Kr-89	1.15E-01	Sr-91	6.66E-03	Cs-134	2.46E+00
Xe-131m	3.23E+00	Sr-92	1.44E-03	Cs-136	2.57E+00
Xe-133m	5.23E+00	Y-90	5.96E-05	Cs-137	2.09E+00
Xe-133	2.91E+02	Y-91m	3.56E-03	Cs-138	1.21E+00
Xe-135m	5.96E-01	Y-91	5.88E-04	Ba-137m	1.98E+00
Xe-135	9.25E+00	Y-92	1.25E-03	Ba-140	4.26E-03
Xe-137	2.20E-01	Y-93	4.23E-04	La-140	1.40E-03
Xe-138	7.94E-01	Zr-95	6.68E-04	Ce-141	6.39E-04
		Nb-95	6.65E-04	Ce-143	5.69E-04
Br-83	1.12E-01	Mo-99	8.50E-01	Ce-144	4.88E-04
Br-84	5.81E-02	Tc-99m	7.83E-01	Pr-143	6.32E-04
Br-85	6.87E-03	Ru-103	5.64E-04	Pr-144	4.88E-04
I-127[b]	8.57E-11	Ru-106	1.79E-04		
I-129	5.02E-08	Rh-103m	5.64E-04	Cr 51	5.40E-03
I-130	2.16E-02	Rh-106	1.79E-04	Mn 54	1.60E-03
I-131	2.82E+00	Ag-110m	1.07E-03	Fe 55	2.10E-03
I-132	3.17E+00	Te-125m	3.85E-04	Fe 59	5.10E-04
I-133	4.90E+00	Te-127m	3.35E-03	Co 58	1.40E-02
I-134	7.46E-01	Te-127	1.17E-02	Co 60	1.30E-03
I-135	2.81E+00	Te-129m	1.13E-02		

a. Calculated with a core inventory variation multiplier of 1.12 for Ag-110m and 1.08 for all other fission products

b. gram I-127 per gram of coolant

Table 2.10.1-2
Dose Comparisons

Type of Dose	Appendix I Design Objectives (2 units)	Base Case 100% Capacity Pre-EPU case	Scaled Doses EPU Case	Percentage of Appendix I Design Objectives - EPU
Liquid Effluents				
Dose to total body from all pathways	6 mrem/yr	7.79E-03 mrem/yr	9.2E-03 mrem/yr	0.15%
Dose to any organ from all pathways	20 mrem/yr	8.15E-03 mrem/yr	1.6E-02 mrem/yr	0.08%
Gaseous Effluents				
Gamma Dose in Air	20 mrad/yr	5.34E-04 mrad/yr	6.3E-04 mrad/yr	3.1E-03%
Beta Dose in Air	40 mrad/yr	3.10E-04 mrad/yr	3.7E-04 mrad/yr	9.1E-04%
Dose to total body of an individual	10 mrem/yr	5.17E-04 mrem/yr	6.1E-04 mrem/yr	6.1E-03%
Dose to skin of an individual	30 mrem/yr	9.23E-04 mrem/yr	1.1E-03 mrem/yr	3.6E-03%
Radioiodines and Particulates Released to the Atmosphere				
Dose to any organ from all pathways	30 mrem/yr	3.12E-02 mrem/yr	3.7E-02 mrem/yr	0.12%

1. Based on 2002 to 2006 operation.
2. The method of processing liquid radwaste from the previous use of an evaporator to the current use of a demineralizer based system. This change was implemented at the end of the year 2007 and was reflected in the 2008 dose information for liquid effluents.

2.10.2 *Additional Review Areas (Health Physics)*

The purpose of this LR section is to propose a reduction in the NUREG-0737, Clarification of TMI Action Plan Requirements, Item II.B.3, Post Accident Sampling Capability (Reference 4), requirement for the PBNP Post Accident Sampling System (PASS). The 3-hour sample time requirement to draw and analyze post-accident samples of reactor coolant, containment sump water, and containment atmosphere following a large break LOCA. would be eliminated. Only the 3-hour combined sample and analysis time requirement is affected. The PBNP post-accident sampling system capability will remain unchanged, the associated radiation exposure limits (5 rem whole body or 75 rem to the extremities) will not change, and the PBNP Regulatory Guide (RG) 1.97 compliance will not change. No changes are proposed to TS 5.5.3, Post Accident Sampling. FPL Energy Point Beach is seeking approval of a change in methodology to use the following two WCAPs. This LAR provides for the elimination of the 3 hour requirement to sample and analyze a post accident sample as described in WCAP 14986-A, Westinghouse Owners Group Post Accident Sampling System Requirements: A Technical Basis (Reference 1). The implementation of the licensee required actions of WCAP 14986-A have been completed. As part of the implementation PBNP will also adopt the core damage assessment guidance (CDAG) described in WCAP 14696-A Revision 1, Westinghouse Owners Group Core Damage Assessment Guidance (Reference 2).

This change will result in the Unit 1 and Unit 2 sample rooms no longer being classified as radiological vital areas for required post LOCA personnel access (see LR Section 2.10.1.2, Occupational and Public Radiation Doses, Technical Evaluation).

2.10.2.1 Post Accident Sampling System

2.10.2.1.1 Introduction

Following the TMI-2 event, NUREG-0737, Item II.B.3, Post Accident Sampling Capability, was issued by the NRC. The NUREG specified required actions to be taken by licensees to prevent the recurrence of an event of this type. One of the requirements was that plants have the capability of obtaining and analyzing post-accident samples of the reactor coolant and containment atmosphere within specified times, without causing a radiation exposure to any individual that exceeds 5 rem to the whole body or 75 rem to the extremities. Detailed criteria for the PASS are specified in Section II.B.3 of NUREG-0737 including the onsite radiological and chemical analysis capability to provide, within a three-hour time frame, quantification of the following:

a. *Certain radionuclides in the reactor coolant and containment atmosphere*

b. Hydrogen levels in the containment atmosphere

c. Dissolved gases (e.g., hydrogen), chloride, and boron concentration of liquids

On March 17, 1982, the NRC issued Generic Letter (GL) 82-05, Post-TMI Requirements (Reference 5), in which the NRC requested that licensees establish a firm schedule for implementing post-accident sampling. On November 1, 1983, the NRC issued GL 83-37, NUREG-0737 Technical Specifications (Reference 9), which provided guidance on how to address post-accident sampling in the technical specifications of pressurized-water reactors (PWRs), In GL 83-37, the NRC indicated that all licensees should establish, implement, and maintain an administrative program that would include training of personnel, procedures for sampling and analyses, and provisions for sampling and analysis equipment. Licensees could elect to reference this program in the administrative controls section of the Technical Specifications and include its detailed description in the plant operation manuals. However, the elements contained Item II.B.3 of NUREG-0737 were imposed as requirements for the majority of operating plants through license conditions or by orders.

Regulatory Guide 1.97 (Rev. 2), Instrumentation for Light Water Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident (Reference 3), described acceptable means for licensees to comply with the Commission's regulations (Criteria 13, 19 and 64 of Appendix A to 10 CFR Part 50) to provide instrumentation to monitor plant variables and systems during and following an accident. Regulatory Guide 1.97 included a list of variables to be monitored which included the samples specified in NUREG-0737 and the following additional samples:

- pH in the RCS
- Boron, pH, chlorides, and radionuclides in the containment sump

Since these criteria for PASS have been issued, the NRC has performed generic evaluations which are discussed below.

In the mid 1980s, the NRC reviewed regulatory requirements that may have marginal importance to risk. One of the issues reviewed was the NUREG-0737 criteria for PASS. The conclusion reported in NUREG/CR-4330, Review of Light Water Reactor Regulatory Requirements (dated May 1987) (Reference 10), was that several of the PASS criteria could be relaxed without impacting safety; however, the NRC did not take action to modify the PASS criteria based upon the conclusions of the report.

In 1993, during its review of licensing issues pertaining to evolutionary and advanced light water reactors, the NRC evaluated requirements for PASS specified in 10 CFR 50.34(f)(2)(viii). The NRC recommended to the Commission in SECY-93-087, Policy, Technical, and Licensing Issues Pertaining to Evolutionary and Advanced Light-water Reactor (AWLR) Designs, (dated April 2, 1993) (Reference 11), that: (1) elimination of hydrogen analysis of containment atmosphere samples is appropriate, given that safety-grade hydrogen monitoring instrumentation will be installed; (2) relaxation of dissolved gas (including dissolved hydrogen) sampling time to 24 hours is appropriate; (3) elimination of the mandatory requirement for chloride samples is appropriate; (4) relaxation of the boron sampling time to 8 hours after an accident is appropriate; and (5) relaxation of the sampling time for radionuclides (used to determine the degree of core damage) to 24 hours is appropriate.

The NRC considered the conclusions (and the basis for the conclusions) from these generic evaluations as part of its review of WCAP-14986-A Westinghouse Owners Group Post Accident Sampling System Requirements: A Technical Basis (Reference 1). By letter dated October 27, 1998 (OG-98-108), the Westinghouse Owners Group (WOG) submitted Topical Report WCAP-14986-P, Revision 1, Post Accident Sampling System Requirements: A Technical

Basis, for NRC staff's review to eliminate requirements on the post accident sampling system (PASS) for Westinghouse nuclear power plants. The WOG supplemented its application with letters dated April 28, 1999 (OG-99-041) (Reference 14), and April 10, 2000 (OG-00-025), that (1) provided responses to a request for additional information, and (2) revised the topical report, respectively.

The NRC concluded that WCAP-14986-A provided a basis to eliminate the PASS as a required system for sampling the 15 parameters that are listed in Section 4 of the NRC safety evaluation report (SE) to WCAP 14986-A (dated June 14, 2000). In doing this, the NRC also identified licensee required actions (LRAs), in Section 4.1 of the SE, that must be fulfilled by a licensee of a Westinghouse plants that would eliminate PASS in accordance with WCAP-14986-A and the SE.

In eliminating PASS, the NRC stated that licensees did not have to incorporate the core damage assessment methodology (CDAM) in WCAP-14696, Westinghouse Owners Group Core Damage Assessment Guidance, into their procedures, but they would need to assess the impact of elimination of PASS on their existing CDAM. The NRC approved WCAP-14696-A on September 2, 1999 (Reference 2). PBNP will implement the CDAM described in WCAP-14696 prior to operation at EPU conditions. This will be a new CDAM methodology for PBNP. PBNP will implement the CDAM in the Emergency Plan Implementing Procedures and the associated training of the appropriate emergency planning staff.

As stated in the NRC SE, the NRC concluded, based upon the justification provided in WCAP-14986-A, that there is reasonable assurance that the health and safety of the public will not be endangered by operation of Westinghouse plants without PASS. Therefore, it is acceptable to eliminate PASS from the licensing basis for Westinghouse plants. Technical Specification Task Force (TSTF) 366, Elimination of Requirements for a Post Accident Sampling System (PASS) was issued for removal of the PASS in October, 2000. PBNP is not requesting approval for the elimination of the PASS at this time nor is it changing TS 5.5.3, Post Accident Sampling. However, the 3-hour combined sample and analysis time requirement is proposed to be eliminated via change to the method of evaluation of core damage.

PBNP Current Licensing Basis

The PBNP Post Accident Sampling System (PASS) is described in FSAR Section 9.11, Sampling System. PBNP uses a single sample system per unit to obtain reactor coolant samples during normal operations, during plant cooldown when system pressure is low and the residual heat removal loop is in operation, and during post-accident conditions.

Presented below is a brief summary of the more significant letters and safety evaluations that reflect the current licensing basis relative to TMI Action Plan Item II.B.3 Post Accident Sampling Capability.

The NRC issued NUREG-0737 in November 1980. On March 17, 1982, the NRC issued Generic Letter (GL) 82-05, Post-TMI Requirements, in which the NRC requested that licensees establish a firm schedule for implementing post-accident sampling. On June 30, 1982, the NRC transmitted to PBNP criteria and clarification for NUREG-0737 Item II.B.3, Post Accident Sampling Capability. PBNP provided its initial response in a letter dated September 30, 1982. The NRC transmitted the safety evaluation (SE) related to the PASS for PBNP Units 1 and 2 on December 22, 1982. In the SE, the NRC had determined that 8 of the 11 criteria for the PASS had been fully met and 3 of the 11 criteria had been partially met. PBNP provided additional information to resolve the open items by letters dated February 21, June 3 and July 12, 1983. On November 3 1983, the NRC stated that it considered NUREG-0737 Item II.B.3 to be complete for PBNP Units 1 and 2.

On November 1, 1983, the NRC issued GL 83-37, Technical Specifications, which provided guidance on how to address post-accident sampling in the Technical Specifications. By letter dated February 29, 1984, as modified June 7, 1984, PBNP responded to GL 83-37 by submitting license amendment requests for PBNP Units 1 and 2 that addressed post-accident sampling and other TMI Action Plan items. The NRC approved the PBNP post accident sampling Technical Specifications on July 18, 1985.. The NRC approval was contingent upon a licensee commitment to provide additional program descriptions in its next request for Technical Specification changes.

The current Post Accident Sampling TS 5.5.3 reflects the conversion of the original 1985 Technical Specification to improved Technical Specification (ITS) via License amendment 201/206. As discussed above, PBNP is not requesting elimination of this Technical Specification in accordance with TSTF 366 as part of this license amendment request.

The post accident core damage assessment (CDA) is currently made using the methodology described in Westinghouse Owners Group, Post Accident Core Damage Assessment Methodology, Revision 2, November 1984.

Regulatory Guide (RG) 1.97 Rev. 2, Instrumentation for Light Water Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident (Reference 3), described acceptable means for licensees to comply with the Commission's regulations (Criteria 13, 19 and 64 of Appendix A to 10 CFR 50) to provide instrumentation to monitor plant variables and systems during and following an accident. Regulatory Guide 1.97 included a list of variables to be monitored which included the samples specified in NUREG-0737 and the following additional samples:

- pH in the RCS
- Boron, pH, chlorides, and radionuclides in the containment sump

As stated in FSAR Section 7.6.2.3, Post Accident Monitoring Instrumentation, System Evaluation, the post-accident monitoring instrumentation meets the intent of RG 1.97, Revision 2 (Reference 3). The original response to Generic Letter 82-33 (Reference 12) on RG 1.97 implementation dated September 1, 1983 (Reference 13) identified specific exceptions taken to the regulatory guidance, including the justification for those exceptions. FSAR Table 7.6-1, Instrumentation Systems, Primary Coolant and Sump Grab Samples, reflects the current list of post-accident monitoring variables. FSAR Table 7.6-1, Instrumentation Systems, Primary Coolant and Sump Grab Samples, reflects PBNP's continued sampling for pH in the RCS and boron, pH, chlorides, and radionuclides in the containment sump.

2.10.2.1.2 Technical Evaluation

This licensing report section proposes to eliminate the 3-hour combined sampling and analysis time requirement to draw and analyze post-accident samples of reactor coolant, containment sump water, and containment atmosphere within 3-hours following a large break LOCA. Only the 3-hour sampling and analysis time requirement is affected. PBNP post-accident sampling system capabilities will remain unchanged, the associated radiation exposure limits (5 rem whole body or 75 rem to the extremities) will not change. Compliance with PBNP RG 1.97 Rev. 2, will not change. This proposed change does not request the removal of PASS from PBNP Technical Specification 5.5.3.

The result of this change allows the Unit 1 and Unit 2 sample rooms to be deleted from the list of radiological vital areas required for post-LOCA personnel access.

Justification for elimination of the 3-hour time requirement is based on WCAP-14986-A, Westinghouse Owners Group Post Accident Sampling System Requirements: A Technical Basis, and the associated NRC approval of the topical report.

As stated above, the PBNP current licensing basis for core damage assessment is based on a sample analysis using the WOG Post Accident Core Damage Assessment Methodology Revision 2, dated November 1984. With the approval of this amendment, PBNP will implement WCAP 14696-A Revision 1, Westinghouse Owners Group Core Damage Assessment Guidance, which was approved by the NRC on September 2, 1999 (Reference 2), for use as a methodology change by Westinghouse plants. This proposed change in method of evaluation for CDA will be implemented prior to uprating PBNP Unit 1 or Unit 2 as a part of implementation of the proposed amendment.

An evaluation of the proposed change has been performed in accordance with 10 CFR 50.54(q). The conclusion has been reached that implementation of the revised CDA should increase the effectiveness of the emergency response organization as stated in the NRC safety evaluation for WCAP 14696-A, Revision 1.

As stated in WCAP-14986-A, Revision 2, and reiterated in Section 4.1, Licensee Required Actions, of the NRC Safety Evaluation Related to Topical Report WCAP-14986, Revision 1, Westinghouse Owners Group Post Accident Sampling System Requirements (TAC No. MA4176) dated June 14, 2000, plants intending to eliminate PASS from their licensing basis must confirm that the technical justification for deletion of PASS also leads to the conclusion that the effectiveness of the plant emergency response is not decreased as a result of PASS elimination. In addition, in order to facilitate long-term recovery planning, a conceptual method to obtain samples of reactor coolant liquid, containment sump liquid and containment atmosphere following a core damage accident should be identified. With the approval of this amendment, PBNP will comply with Section 4.1, Licensee Required Actions, specified in NRC, Safety Evaluation Related to Topical Report WCAP-14986, Revision 1, Westinghouse Owners Group Post Accident Sampling System Requirements (TAC No. MA4176), dated June 14, 2000. The licensee required actions are:

1. Establish a capability for classifying fuel damage events at the alert level threshold.
2. Develop contingency plans for obtaining and analyzing highly radioactive samples of reactor coolant, containment sump, and containment atmosphere.

3. Determine that no decrease in the effectiveness of the emergency plan will result from the change in PASS.

4. Maintain offsite capability to monitor radioactive iodines.

This change will be implemented prior to uprating Point Beach Unit 1 or Unit 2 as a part of the PBNP EPU license amendment.

A 10 CFR 50.54 (q) evaluation was complemented and determined that the changes in PASS and the implementation of the revised CDA will increase the effectiveness of the emergency response organization

PBNP has the capability for classifying fuel damage events at the Alert level threshold (EPIP 1.2, Emergency Classification). In the Fission Product Barrier Reference Table for LOSS or POTENTIAL LOSS of Barriers, Item 2, Primary Coolant Activity Level, the threshold for the ALERT level is coolant activity greater than 300 microcuries per gram of I-131 equivalent. This capability uses the normal sampling system (which includes the PASS), as well as dose rate correlations of letdown line failed fuel radiation monitor and containment radiation monitoring. PBNP maintains offsite capability to monitor radioactive iodines.

PBNP Technical Specification 5.5.3, Post Accident Sampling, is not affected by this proposed change. PBNP will remain capable of performing post-accident sampling activities. However, following approval of the elimination of the 3-hour sampling and analysis time requirement for PASS, the Unit 1 and Unit 2 sample rooms will no longer be considered radiological vital areas that require access for accident mitigation and safe shutdown. The 3-hour samples will no longer be required to mitigate a large break LOCA. The capability to take and analyze samples at a later time, post-LOCA, is being maintained as an option to support core damage assessment for emergency preparedness, if desired, and if radiation conditions allow.

2.10.2.2 Conclusions

Based on the justification provided in WCAP-14986-A, Westinghouse Owners Group Post Accident Sampling System Requirements: A Technical Basis, and the associated NRC approval of the topical report, the proposed 3-hour sampling and analysis time requirement to draw and analyze post-accident samples of reactor coolant, containment sump water and containment atmosphere within 3-hours following a large break LOCA is requested to be eliminated. Only the 3-hour sampling and analysis time requirement is affected. PBNP post-accident sampling system capability will remain unchanged, the associated radiation exposure limits (5 rem whole body or 75 rem to the extremities) will not change, the PBNP RG 1.97 compliance will not change, and PBNP does not propose the removal of PASS from PBNP Technical Specifications 5.5.3.

This change allows the elimination of the Unit 1 and Unit 2 sample rooms from the list of radiological vital areas for post-LOCA personnel access. The plant will remain capable of performing sampling activities; however, following approval to eliminate the combined 3-hour sampling and analysis requirement, these two areas will no longer be considered radiological vital areas that require access for accident mitigation and safe shutdown.

2.10.2.3 References

1. WCAP-14986-A, Westinghouse Owners Group Post Accident Sampling System Requirements: A Technical Basis, Revision 2

2. WCAP-14696-A, Westinghouse Owners Group Damage Assessment Guidance, Revision 1

3. Regulatory Guide (RG) 1.97 Revision 2, Instrumentation for Light Water Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

4. NUREG-0737 Item II.B.3, Post Accident Sampling Capability, November 1980

5. Generic Letter (GL) 82-05, Post-TMI Requirements, March 17, 1982

6. NRC to WEPCo, Criteria and Clarification for NUREG-0737 Item II.B.3, Post Accident Sampling System, June 30, 1982

7. WEPCo to NRC, NUREG-0737 Item II.B.3, Post Accident Sampling Capablity, September 30, 1982

8. NRC to WEPCo, Post Accident Sampling System (NUREG-0737 Item II.B.3), November 3 1983

9. Generic Letter 83-37, NUREG-0737 Technical Specifications, November 1, 1983

10. NUREG/CR-4330, Review of Light Water Reactor Regulatory Requirements, May 1987

11. SECY-93-087, Policy, Technical, and Licensing Issues Pertaining to Evolutionary and Advanced Light-water Reactor (AWLR) Designs, dated April 2, 1993

12. Generic Letter 82-33, Supplement 1 to NUREG-0737 - Emergency Response Capabilities, dated December 1982

13. WEPCo to NRC, Implementation of Regulatory Guide 1.97 for Emergency Response Capability, Point Beach Nuclear Plant Units 1 and 2, dated September 3, 1981

14. Westinghouse Owners Group to NRC (OG-99-041), Transmittal of responses to NRC Comments from the March 25,1999 Post Accident Sampling System Meeting, dated April 28, 1999

2.11 Human Performance

2.11.1 Human Factors

2.11.1.1 Regulatory Evaluation

The area of human factors deals with programs, procedures, training, and plant design features related to operator performance during normal and accident conditions. The PBNP staff's human factors evaluation was conducted to ensure that operator performance is not adversely affected as a result of system changes made to implement the proposed EPU. PBNP's review covered changes to operator actions, human-system interfaces, and procedures and training needed for the proposed EPU. The acceptance criteria for human factors are based on General Design Criterion 19, 10 CFR 50.120, 10 CFR Part 55, and the guidance in Generic Letter (GL) 82-33 (NUREG 0737). Specific review criteria are contained in SRP Sections 13.2.1, 13.2.2, 13.5.2.1 and 18.0.

PBNP Current Licensing Basis

As noted in PBNP updated Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP Station predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

- PBNP GDC 11, Control Room, is described in FSAR Section 7.1.2, Instrumentation and Control, General Design Criteria

  The facility shall be provided with a control room from which actions to maintain safe operational status of the plant can be controlled. Adequate radiation protection shall be provided to permit continuous occupancy of the control room under any credible post-accident condition or as an alternative, access to other areas of the facility as necessary to shut down and maintain safe control of the facility without excessive radiation exposures of personnel. (PBNP GDC 11)

  PBNP is equipped with a common control which contains those controls and instrumentation necessary for operation of each unit's reactor and turbine generator under normal and accident conditions. The control room is continuously occupied under all operating and accident conditions, except for the special case of a control room fire forcing evacuation and alternate shutdown from outside the control room. No other accident is required to be assumed during a control room evacuation due to fire.

  Sufficient shielding, distance, and containment integrity are provided to assure that control room personnel shall not be subjected to a dose greater than 5 rem whole body, or its equivalent to any part of the body, under postulated accident conditions. This dose limit includes control room occupancy, ingress, and egress for the duration of the accident.

  The control room ventilation system design normally combines outside makeup air with a large percentage of recirculated air. The radiation monitoring system monitors control room air for radiation, and automatically places the ventilation system in emergency mode if a high radiation condition occurs. Refer to FSAR Section 9.8, Control Room Ventilation System (VNCR), for further discussion of control ventilation system performance capability and FSAR Section 11.6.3, Shielding Systems, System Evaluation, for further discussion of control room habitability.

- Staff qualifications for positions within the scope of 10 CFR 50.120 are delineated in PBNP Technical Specification 5.3.
- Licensed operators are qualified to the requirements of 10 CFR 55 as described in FSAR Section 12.3, Training. A continuing training program for licensed operators and senior operators is implemented under the direction of the Training Manager which meets or exceeds the requirements and recommendations of Section 5.5 of ANSI N18.1-1971 and 10 CFR 55. The present continuing training program is described in PBNP training program documents and procedures.
- The PBNP plant procedure program is discussed in FSAR Section 12.4, Written Procedures. This section identifies the activities that must be conducted by procedures and instructions and provides an appropriate method to develop and approve these procedures and instructions. PBNP Technical Specification 5.4 states that written procedures be established, implemented, and maintained for the emergency operating procedures required to implement the requirements of NUREG-0737 (Reference 1)and NUREG-0737, Supplement 1, as stated in Generic Letter 82-33 (Reference 2). FSAR Section 1.4, Quality Assurance Program, and the Quality Assurance Topical Report FPL-1 discuss the Quality Assurance Program that applies to approvals and changes to these procedures.
- In addition to the above FSAR sections, human performance and human factors related elements for the operating control stations are discussed in FSAR Section 7.5.1, Operating Control Stations Layout, Information Display and Recording. The PBNP plant process computer including the Safety Parameter Display System (SPDS) is described in FSAR Section 7.5.1.4, Operating Control Stations, Plant Process Computer System.

2.11.1.2 Technical Evaluation

Introduction

Human Factors Engineering and Human Performance initiatives are foundational characteristics that help ensure that the plant operators can effectively and safely operate the facility as well as mitigate emergency conditions. When initiating a plant change, the modification process prompts completion of a Human Factors review checklist for changes that may impact the Control Room layout (alarms, indication, appearance or performance). These reviews are performed following the requirements identified in PBNP DG-G01, Human Factors Design Document. In addition, plant operations staff has been represented and participated in EPU planning and modification development studies. To ensure changes associated with EPU do not introduce any unanticipated consequences, a review of the effects of those changes on Human Performance was performed.

Description of Analysis and Evaluations

The NRC has developed a standard set of questions for the review of the human factors area. PBNP has addressed these questions. The following are the NRC staff's questions and the PBNP responses.

1. *Changes in Emergency and Abnormal Operating Procedures*

Describe how the proposed EPU will change the plant emergency and abnormal operating procedures.

Response

The existing Emergency and Abnormal Operating *procedure sets will continue to provide* adequate guidance to cover the spectrum of anticipated events. The following procedure changes are intended to enhance operator response times and to incorporate physical plant changes resulting from EPU. In addition to the more significant items listed below, minor changes (typically setpoints) have been identified for several Emergency, Abnormal and other Operating procedures.

Changes in Emergency and Abnormal Operating Procedures:

The existing PBNP emergency operating procedures provide adequate guidance to cover the spectrum of anticipated plant events. The EPU will result in changes to the emergency and abnormal procedures to address changes in setpoints, alarm response setpoints and physical plant changes as a result of the EPU.

- Procedure changes are required to continue containment spray during containment sump recirculation following a LOCA. The changes required to support implementation of AST are addressed in the LAR 241, (ML083450683).
- Procedure changes are required for the Auxiliary Feedwater System, which is being modified from a shared system to a unitized system. The original shared AFW pumps will be used as Shared Standby Steam Generator (SSG) pumps to be used for startup and shutdown and beyond design basis events. The system configuration changes are addressed in LR Section 2.5.4.5, Auxiliary Feedwater.

The changes to emergency and abnormal procedures as a result of the EPU do not significantly impact operator actions and mitigation strategies. The changes will be appropriately proceduralized and the operators will receive appropriate classroom and/or simulator training for implementation.

Conclusion

The anticipated changes to the PBNP emergency operating and contingency action procedures do not alter basic mitigation strategies and will be adequately implemented by the normal procedure change process.

2. **Changes to Operator Actions Sensitive to Power Uprate**

Describe any new operator actions needed as a result of the proposed EPU. Describe changes to any current operator actions related to emergency or abnormal operating procedures that will occur as a result of the proposed EPU.

Identify and describe operator actions that will involve additional response time or will have reduced time available. The response should address any operator workarounds that might affect existing response times. Identify any operator actions that are being automated or being changed from automatic to manual as a result of the power uprate. Provide justification for the acceptability of these changes.

Response

Any new operator actions or changes in current operator actions needed as a result of the proposed EPU will be addressed in accordance with plant procedure FP-OP-CTC-0,1 Control of Time Critical Operator Actions, and the list of time critical operator actions provided in Attachment E of OM 4.3.2, EOP/AOP Verification/Validation Process, will be revised. Any newly installed instruments, or components required to support the EPU will be implemented in accordance with approved plant procedures and processes. DG-G01, Human Factors Design Document, provides guidance so that control room modifications conform to the human factors criteria established during the Control Room Design Review (CRDR) Project performed at PBNP. The DG-G01 procedure is based on NUREG-0700, Guidelines for Control Room Design Reviews (Reference 3), and incorporates guidelines specific to PBNP. These processes ensure that each change is fully reviewed and approved by station and operations personnel prior to implementation.

Changes to operator actions sensitive to power uprate include the following:

a. The time allowed for initiation of simultaneous RHR upper plenum injection and SI cold leg recirculation to minimize boron precipitation for large LOCA will be changed from 14 hours to 4 hours and 30 minutes as identified in LR Section 2.8.5.6.3.4, Post-LOCA Subcriticality and Long-Term Cooling.

b. Eliminated the operator time allowed for AFW pump suction supply swapover from the normal Condensate Storage Tank suction source to the Safety Related Service Water suction source, which will be an automatic swapover function based on low-low AFW pump suction pressure as identified in LR Section 2.5.4.5, Auxiliary Feedwater.

c. Eliminated the operator action time to manually align shared AFW pumps to the affected unit.

d. Implementing the operator action times allowed after a Steam Generator Tube Rupture as identified in LR Section 2.8.5.6.2, Steam Generator Tube Rupture.

Conclusion

The changes in Operator actions related to EPU are not significant, and established change processes will provide an adequate implementation strategy. The changes do not significantly impact normal Operator actions or off-normal event mitigation strategies. The changes will be appropriately proceduralized and the Operators will receive formal classroom and simulator training for their implementation as required by the Systematic Approach to Training Process outlined in FP-SAT-60, Systematic Approach to Training (SAT) Process Overview.

3. Changes to Control Room Controls, Displays and Alarms

Describe any changes the proposed EPU will have on the operator interfaces for control room controls, displays, and alarms. For example, what zone markings (e.g. normal, marginal and out-of-tolerance ranges) on meters will change? What set points will change? How will the operators know of the change? Describe any controls, displays, alarms that will be upgraded from analog to digital instruments as a result of the proposed EPU and how operators will be tested to determine they could use the instruments reliably.

Response

Changes resulting from the proposed EPU on operator interfaces for control room controls, displays, setpoints, and alarms will be implemented in accordance with approved plant procedures and processes such as the modification process and DG-G01, Human Factors Design Document. These processes ensure that training affected or augmented by the EPU is addressed, including how operators will be tested to determine they could use the instruments reliably.

Changes to Control Room controls and displays will not be extensive and will generally include calibration and or rescaling loops for identified instrumentation. New fast acting feedwater isolation valves and a unitized Auxiliary Feedwater system are being implemented for the EPU and will require installation of controls, indication, and Alarms within the Control Room. Control Room changes are also required to continue containment spray following ECCS transfer to the containment sump following a LOCA. The changes required to support implementation of LAR 241. There will also be changes to several control board and computer alarms and limited changes to plant control systems.

Below is a summary of the changes identified (refer to LR Section 2.4.1, Reactor Protection, Safety Features Actuation, and Control Systems, Section 2.4.2, Plant Operability, and Section 2.5.4.5, Auxiliary Feedwater for additional details):

a. The following instrument loops are affected by the EPU (indicator banding, calibration range, and or scaling):

   - Units 1 and 2 Main Steam flow (calibration range, scaling, replace indicator scale plates)
   - Units 1 and 2 HP turbine gland steam supply pressure (calibration range and scaling)
   - Units 1 and 2 HP Turbine first stage pressure (calibration range, scaling, and replace indicator scale plates) including the following interlocks:
     - Permissive P2 – Auto-Rod withdrawal stop at low power
     - Permissive P5 – Steam Dump Interlocks
     - Permissive P7 – Block various trips at power
     - Permissive P20 – AMSAC (Anticipated Transient Without Scram (ATWS) mitigation system actuation circuitry (AMSAC))
     - Feedwater Control input
   - Units 1 and 2 Fifth Point Heater pressure (calibration range and scaling)
   - Units 1 and 2 Preseparator tank pressure (calibration range and scaling)
   - Units 1 and 2 Third Point Heater pressure (calibration range and scaling)
   - Units 1 and 2 Second Point Heater pressure (calibration range and scaling)
   - Units 1 and 2 LP Turbine Crossover pressure (calibration range and scaling)
   - Units 1 and 2 Main Feedwater flow (calibration range, scaling, replace indicator scale plates)
   - Units 1 and 2 Main Feedwater Pump suction flow (calibration range, scaling, replace indicator scale plates)
   - Units 1 and 2 Heater Drain pump discharge flow (calibration range, scaling, replace indicator scale plates)
   - Unit 1 and 2 Auxiliary feedwater (AFW) flow (control valve settings, setpoint)

b. Alarm response procedures (Unit 1 and 2) will require revision as a result of setpoint changes:

- Feedwater pump low feedwater pump suction pressure, trip main feedwater pump
- Condensate Storage Tank low level setpoint, annunciator
- Condenser low vacuum setpoint, annunciator
- Feedwater Isolation Valve trouble
- Auxiliary Feedwater low flow
- Generator high and low hydrogen pressure setpoints, annnunciator

c. Plant computer setpoints will be changed for the following parameters:

- RCS Overtemperature ΔT (OTΔT) Reactor Trip
- RCS Overpower ΔT (OPΔT) Reactor Trip
- Steam Generator Narrow Range Water Level Low-Low Reactor Trip
- Steam Line Isolation High-High Steam Flow
- Steam Line Isolation High Steam Flow
- RCS T_{avg}
- Pressurizer level
- Turbine first stage pressure
- Main feedwater flow
- Main steam flow
- Auxiliary feedwater flow
- Condensate Storage tank levels
- Other various alarm changes
- axial offset controls displays [Currently Revised Axial Offset Controls (RAOC) changing to constant axial offset control (CAOC)]

d. Changes to controls and control systems:

- Turbine first stage pressure
- Control rod speed program (T_{avg} Program and Power Mismatch Circuits)
- Pressurizer level program
- RCS T_{avg} program
- P-8 Permissive Change – Block Single Primary Loop Loss of Flow Trip
- P-9 Permissive Change – Block Reactor Trip Following Turbine Trip

e. Auxiliary Feedwater system

The AFW system will be modified from a shared system to a unitized system with shared standby/startup pumps. This modification will implement changes to the Control Room to modify both existing and new controls on both the benchboard and vertical boards. Also, significant circuit changes will be made for both the existing and new control circuits for the AFW pumps, valves and instrumentation, as identified in LR Section 2.5.4.5, Auxiliary Feedwater. Specific details for these changes will be identified and addressed during the development of the AFW system modification.

BOP Instrumentation and Controls Results

The changes to ranges and/or setpoints for BOP instruments will not change instrument or instrument loop functions. As a result of the EPU, there are no changes to the PBNP GDC 12 current licensing basis that the quantity and types of process instrumentation provided ensures safe and orderly operation of the plant nor will the changes affect separation, redundancy or diversity of the instrumentation and controls discussed above.

Plant Computer

The plant computer (also referred to as the plant process computer system) is described in FSAR Section 7.5.1.4, Operating Control Systems, Plant Process Computer Systems. Plant process computer system inputs that are affected by instrumentation scaling changes will be modified during the implementation phase of the EPU. However, the plant computer safety assessment functions as described in FSAR Section 7.5.1.4a, Operating Control Systems, Plant Process Computer Systems, including SPDS, and 7.5.1.4.b, Operating Control Systems, Plant Process Computer Systems, will not change as result of the EPU.

Conclusion

The operators will be provided detailed training related to the above EPU modifications and resulting control board and procedure changes. Operators are provided station modification review packages as well as classroom and simulator training where appropriate. The initial plant startup of the uprated plant will be implemented as an Infrequently Performed Test/Evolution (IPTE) and will be controlled by the Power Ascension Testing Plan described in LR Section 2.12.1, Approach to EPU Power Level and Testing.

4. **Changes on the Safety Parameter Display System**

Describe any changes to the safety parameter display system resulting from the proposed EPU. How will the operators know of the changes?

Response

No significant safety parameter display system changes are anticipated as a result of EPU, critical safety function status trees will be reviewed and revised as necessary for related changes to setpoints and decision points.

Changes identified for the safety parameter display system will be captured through the normal procedure revision process, modification process, and operator training on plant modifications.

Conclusion

These minor changes will be addressed by the normal processes with Operations involvement in the modification process, procedure change reviews and operator training program modification training.

5. **Changes to the Operator Training Program and the Control Room Simulator**

Describe any changes to the operator training program and the plant referenced control room simulator resulting from the proposed EPU, and provide the implementation schedule for making the changes.

Response:

The existing Licensed/Non-Licensed Operator training programs ensure that adequate training is provided for significant plant modifications prior to implementation. Training will focus on Technical Specification changes, procedure changes, EPU modifications, and power ascension testing. Training will be initiated during the training cycle associated with the EPU modifications prior to implementation. Prior to this time, Licensed/Non-Licensed Operator Training will focus on a general overview of the uprate modifications and then training on specific topics such as the new HP turbine and other topics. Comprehensive training of the entire modification scope will be performed and will include classroom and simulator training and testing on the EPU modifications. The operators will be able to demonstrate understanding of the integrated plant response on the simulator. Just In Time (JIT) startup training will be provided to the Operators during the refueling outage prior to the EPU plant initial startup. This JIT training will also cover the power ascension startup testing plan both in classroom and on the simulator, as necessary.

Plant uprate modifications will be reviewed to determine impact on the simulator. Changes to the simulator modeling will be made to a separate simulator load, on a schedule established to meet the operator training program requirements. The simulator load for current plant configuration will remain unchanged and available for operator training. Status of the simulator configuration will be controlled through the established training process. The Control Board hardware changes, addition of the Main Feed Isolation Valves and associated indications and replacement of indications with revised scaling, will also be scheduled to accommodate the training program requirements.

Additionally, some operators will be involved in the continuing modification review process, providing operational input and gaining knowledge of the required plant changes. Changes, especially to the normal, emergency, and abnormal operating procedures as well as other offnormal procedures, will be reviewed and validated. These activities will help provide a solid foundation for operator understanding and interaction during the formal EPU training sessions.

Conclusion:

EPU results in a significant number of plant modifications which will generate changes to Technical Specifications, operations, maintenance, and testing procedures, as well as training simulator and training lesson plans. Training for implementation of the EPU modifications will be accomplished in accordance with the PBNP Training Program

Results

The results of the EPU Human Factors review show that changes to plant procedures, when prepared in accordance with the current procedure change control process, will not alter the basic mitigation strategies with which the operators are familiar. Changes associated with instrument scaling and setpoints, if any, will not introduce a level of complexity that would lead to misunderstanding the parameter. Operator training will provide effective reinforcement of procedure and plant physical changes as well as build proficiency with the required operator action changes.

2.11.1.3 Conclusion

PBNP has assessed the changes to operator actions, human-system interfaces, procedures, and training required for the proposed EPU and concludes that the effects of the proposed EPU on the available time for operator actions are appropriately accounted for. PBNP further concludes that appropriate actions are taken to ensure that operator performance is not adversely affected by the proposed EPU. PBNP will continue to meet the current licensing requirements of PBNP GDC 11 following implementation of the proposed EPU. Therefore, PBNP finds the proposed EPU acceptable with respect to the human factors aspects of the required system changes.

2.11.1.4 References

1. NUREG-0737, Clarification of TMI Action Plan Requirements, November 1980
2. NRC Generic Letter 82-33, Supplement 1 to NUREG-0737 - Emergency Response Capabilities, dated December 17, 1982
3. NUREG-0700, Human System Interface Design Review Guidelines, March 2002

2.12 Power Ascension and Testing Plan

2.12.1 Approach to EPU Power Level and Test Plan

2.12.1.1 Regulatory Evaluation

The purpose of the EPU test program is to demonstrate that SSCs will perform satisfactorily in service at the proposed EPU power level. The test program also provides additional assurance that the plant will continue to operate in accordance with design criteria at EPU conditions. The review included an evaluation of:

- plans for the initial approach to the proposed maximum licensed thermal power level, including verification of adequate plant performance,
- transient testing necessary to demonstrate that plant equipment will perform satisfactorily at the proposed increased maximum licensed thermal power level, and
- the test program's conformance with applicable regulations.

The NRC's acceptance criteria for the proposed EPU test program are based on 10 CFR 50, Appendix B, Criterion XI, which requires establishment of a test program to demonstrate that SSCs will perform satisfactorily in service. Specific review criteria are contained in SRP Section 14.2.1.

Current PBNP Licensing Basis

The initial startup test program at the PBNP is described in FSAR Chapter 13, Objectives and Scope. FSAR Table 13.2-1, Preoperational Tests, lists the initial plant startup tests performed to place equipment in service.

After the operating characteristics of the reactor and plant had been verified by initial verification and low power tests, a program of power escalation in successive stages was undertaken to bring the plant to its full rated power level. Both reactor and plant operational characteristics were closely examined at each stage and the relevance of the safeguards analysis was verified before escalation to the next programmed level was effected. Based upon data obtained from low power tests, the first escalation was to approximately 40% reactor thermal power. The data at each level was analyzed to determine what indications would be when reactor thermal power was at the next escalation level. Succeeding levels were at approximately 70% and 100% core thermal power.

Reactor physics measurements were made to determine the magnitudes of the power coefficient of reactivity, of xenon reactivity effects, of Rod Cluster Control (RCC) control group differential worth and of relative power distribution in the core as functions of power level and RCC control group position.

Concurrent determinations of primary and secondary heat balances were made to ensure that the several indications of plant power level were consistent and to provide bases for calibration of the power range nuclear channels. The ability of the reactor control and protection system to respond effectively to signals from plant primary and secondary instrumentation under a variety of conditions encountered in normal operations was verified.

At prescribed power levels the response characteristics of the reactor coolant and steam systems to dynamic stimuli were evaluated. The responses of system components were measured for 10% loss of load and recovery, 50% loss of load and recovery, turbine trip, loss of flow and trip of a single RCC unit.

A series of load follow tests were performed at selected power level escalation steps and after rated power level had been achieved. The results of these tests gave actual reactor and plant behavior under operating conditions and were used to verify predicted load follow capabilities.

Adequacy of radiation shielding was verified by gamma and neutron radiation surveys inside the containment and throughout plant buildings and yard areas.

The sequence of tests, measurements and intervening operations were prescribed in the power escalation procedures together with specific details relating to the conduct of the several tests and measurements. The measurements and test operations during power escalation were similar to normal plant operations.

Detailed information on the above power ascension testing is provided in the summaries submitted to AEC, March 1971 for Unit 1, and the two submittals for Unit 2, September 1972 and October 1973 covering the testing at the 20 and 100% power levels, respectively. Because testing of the two units was similar, this report primarily refers to Unit 1 power ascension and testing.

The current licensed reactor power level for PBNP is 1540 MWt. The 1.4% Measurement Uncertainty Recapture (MUR) increase from the original licensed power level was approved by NRC in the Safety Evaluation dated November 29, 2002. Testing at the 1540 MWt reactor power level was completed; the approach to the 1540 MWt power level was undertaken carefully, with calorimetric measurements used to install the revised ΔT and nuclear instrumentation reactor protection setpoints. Plant operating conditions were verified acceptable and in accordance with predicted analyses and design documentation.

2.12.1.2 Technical Evaluation

2.12.1.2.1 Introduction

PBNP is currently proposing an Extended Power Uprate (EPU) to increase core thermal power to 1800 MWt. This uprate involves changes to the plant configuration to accommodate the higher reactor power limit as well as the larger steam and feedwater flows commensurate with the power increase. As a result of these changes, testing is required to ensure that the plant can be operated safely in its uprated condition.

2.12.1.2.2 Background

The proposed EPU at PBNP will result in the reactor operating at a new core thermal power of 1800 MWt. The current licensed core thermal power is 1540 MWt. PBNP has significant operating experience at its current operating condition. PBNP is a Westinghouse two-loop design, and power levels close to the proposed EPU level have been successfully achieved by similar Westinghouse two-loop design plants, such as Kewaunee and Ginna, with no adverse affects.

In a PWR, the largest change in system operating parameters occurs in the secondary side where mass flow is increased commensurate with the uprate. Minor changes also occur in primary side temperatures to provide additional heat transfer in the steam generators. At PBNP, the main steam and condensate/feedwater flows will increase by more than 20%. The full power main steam operating pressure will be slightly less than for current operation, however, reactor coolant operating average temperature, T_{avg} will be increased to 576°F.

In order to accommodate this new thermal power, changes in plant operating parameters have to occur. However, it has been found that the fundamental operating characteristics of an uprated plant remain consistent with the operating characteristics prior to the uprate, and also consistent with other similar units that have been uprated. This means that pre-uprate plant operating experience and industry operating experience provide insight to the viability of a plant uprate. This operating experience will be incorporated into the detailed test plan and controlling procedures.

Several plant modifications are required to support power operation at the proposed uprated core thermal power. Post-modification testing of these modifications will be performed to ensure proper installation. Additionally, system surveillance tests will be performed as required to verify that the modifications meet applicable performance criteria. Integrated plant analyses were performed to define the performance criteria of the various plant modifications necessary to accommodate the uprated power. The results of these analyses, coupled with the evaluation of plant data acquired during power ascension, are used, in part, in lieu of large transient testing to verify that the plant systems are capable of performing safely in the uprated condition.

The EPU testing program will also draw on the results of the original startup and test program and applicable industry experience as a means of ensuring safe operation at the new core thermal power level. Comparisons will be made between recent operating data and the data that will be gathered during the uprate testing to ensure that the results are reasonable. Additionally, PBNP has years of operating experience at the current licensed power level such that system interactions are well known. Ginna and Kewaunee have uprated to a core thermal power levels that are similar to the PBNP EPU power level (1800 MWt) and have operated successfully at the new power level. PBNP has established communication with Ginna and Kewaunee in order to benefit from their power uprate experience.

In addition to Kewaunee and Ginna, PBNP has benefited from industry operating experience in power uprate implementation from several industry sources, including INPO. The PBNP test plan is based on industry operating experience pertaining to power uprate and has used this experience in the formulation of expected system interactions, design of EPU modifications, determination of control system settings and setpoints, and development of post-modification and power ascension test plans. For example, PBNP has learned lessons from the industry regarding vibration and vibration monitoring, iso-phase bus duct cooling and air flow, turbine controls, feed/condensate/drain system flows and pressure drops, feedwater heater performance and reactor control system setpoints.

In summary, the proposed EPU testing program is comprised of a mixture of power ascension monitoring, post-modification testing and analytical evaluation and transient testing, to ensure that the plant can operate safely at its new uprated core thermal power. The following sections describe the proposed PBNP Power Ascension Testing Program and demonstrate that the proposed testing program contains all of the necessary elements to assure safe operation at the uprated power level.

2.12.1.2.3 Proposed Power Ascension Test Plan

2.12.1.2.3.1 General Discussion

The development of the power uprate test program is based on a review of similar test programs performed at other plants and the outputs of various system and integrated plant analyses performed in support of the EPU. Additionally, FSAR Chapter 13, Section 13.4, Initial Testing in the Operating Reactor, describes the test methodology used during the original power ascension was also reviewed. This review was augmented by a review of the actual original power ascension test summaries, in addition to the MUR test documentation.

Prior to the commencement of power ascension testing, the EPU Test Program will require the completion of numerous activities, which include:

- Review and revision of applicable plant operating procedures, administrative procedures, and surveillance test procedures, calibration procedures, chemical and radiological procedures, and other similar procedures.
- Review and revision of computer software programs as required to support the power uprate test program and the new EPU power level.
- Incorporation of applicable plant instrumentation setpoint changes and recalibration of instrumentation as required.
- Implementation and successful post-modification testing of all required plant modifications.
- Review of Temporary Modification logs and Operable but Degraded or Nonconforming conditions to assure there is no impact on the ability of the affected equipment to support uprate, and that uprate will not have an adverse impact on an existing plant condition.

Additionally, commitments which are the result of the EPU License Amendment Request, the NRC EPU Safety Evaluation (SE), and other actions associated with the PBNP EPU implementation, will be verified as being complete, included in the Power Ascension Testing Program, or evaluated as not impacting power ascension.

The EPU Power Ascension Test Program will be developed to verify the following:

- Plant systems and equipment affected by EPU are operating within design limits
- Nuclear fuel thermal limits are maintained within expected margins and the core is operating as designed
- Steam generator water level control is stable with adequate control margin to allow for anticipated transients
- Reactor control systems are stable and capable of maintaining reactor parameters within acceptable limits
- Moisture Separator Reheater (MSR) and feedwater heater drains and level control are stable

- System radiation levels are acceptable and stable
- General area and local environmental conditions are acceptable

The EPU test program consists of a combination of normal startup and surveillance testing, post-modification testing, and power ascension testing deemed necessary to support acceptance of the proposed EPU. The following system and equipment testing has been evaluated for inclusion into the EPU test plan and test program:

- Initial startup testing identified in FSAR Table 13.2 -1, Preoperational Testing (See Table 2.12-1, PBNP Extended Power Uprate Power Ascension Test Plan, and Table 2.12-2, EPU Test Plan and Comparison of Proposed EPU Tests to Original Startup Tests, for EPU planned testing)
- Pre-modification baseline testing
  - Turbine performance test (high-pressure turbine replacement)
  - Piping vibration monitoring (balance of plant)
  - Monitoring of plant parameters
- Post-modification testing (as required and controlled by the design change process). See LR Section 1.0, Introduction to the Point Beach Nuclear Plant Units 1 and 2 Extended Power Uprate Licensing Report for list of Plant Modifications
- Power ascension testing
  - Monitoring of plant parameters
  - Piping vibration monitoring (balance of plant)

Plant modifications will be implemented at PBNP in order to achieve and support the EPU rated power: they are controlled by administrative procedures which provide configuration control, installation instructions, and testing requirements. Post modification testing verifies satisfactory performance of the modification in accordance with the design documentation. The performance of post-modification testing is addressed by existing programmatic controls within the design modification process. Functional and operational post modification testing will be performed for each modification to verify satisfactory installation and performance.

2.12.1.2.3.2 EPU Power Ascension Test Plan and Test Plateaus

Performance in accordance with expectations based upon analyses and operating experience of similar equipment will be established. Acceptance criteria will be established for each plant parameter determined to be included in the "monitored parameter list." See Table 2.12-1, PBNP Extended Power Uprate Power Ascension Test Plan, for an overview of the planned power escalation testing. Industry operating experience as well as consultation with PBNP engineering personnel and industry experts at vendors with significant power uprate testing experience will be used in the selection process.

During the EPU startup, power will be increased in a slow and deliberate manner, stopping at pre-determined power levels for steady-state data gathering and formal parameter evaluation.

These pre-determined power levels are referred to as Test Plateaus. The typical post-refueling power plateaus will be used until the current (1540 MWt) full power condition is attained at approximately 85% of the EPU power level (1800 MWt). Above this power level, smaller intervals between test plateaus will be established, with a concurrent higher frequency of data acquisition. The summary of the Power Ascension Test Plan is provided in Table 2.12-1, PBNP Extended Power Uprate Power Ascension Test Plan.

Prior to exceeding the current licensed core thermal power of 1540 MWt, the steady-state data gathered at the pre-determined power plateaus, and transient data gathered during the specified transient tests at lower power, as well as observations of the slow, but dynamic power increases between the power plateaus, will allow verification of the performance of the EPU modifications. In particular, by comparison of the plant data with pre-determined acceptance criteria, the test plan will provide assurance that unintended interactions between the various modifications have not occurred such that integrated plant performance is adversely affected.

Once at approximately 85% of EPU power, (1540 MWt), power will be slowly and deliberately increased through 5 additional Test Plateaus, each differing by approximately 3% of the EPU rated thermal power. Both dynamic performance during the ascension and steady-state performance for each Test Plateau will be monitored, documented and evaluated against pre-determined acceptance criteria.

Following each increase in power level, test data will be evaluated against its performance acceptance criteria (i.e., design predictions or limits). If the test data satisfies the acceptance criteria then system and component performance will be considered to have complied with their design requirements.

In addition to the steady-state parameter data gathered and evaluated at each Test Plateau, the dynamic parameter response data gathered during the ascension between test plateaus will also be thoroughly reviewed. Of major concern is the overall stability of the plant, and potential chagnes in transient responses that may arise due to the EPU modifications to the secondary systems.

Hydraulic interactions between the new condensate and new feedwater pumps, and modified feed regulating valves, as well as the impact of the higher main feed flow and the associated increased piping pressure loss will be evaluated. Individual control systems such as steam generator level control and moisture separator and feedwater heater drain level control will be optimized for the new conditions as required. It is anticipated that the proposed tests will adequately identify unanticipated adverse system interactions and allow them to be corrected in a timely fashion prior to full power operation at the uprated conditions.

Table 2.12-1, PBNP Extended Power Uprate Power Ascension Test Plan, provides a summary of the Power Ascension Test Plan. Table 2.12-2, EPU Test Plan and Comparison of Proposed EPU Tests to Original Startup Tests, provides a summary of the original startup testing, and a brief comparison with the proposed power ascension test plan. Further, Table 2.12-2, EPU Test Plan and Comparison of Proposed EPU Tests to Original Startup Tests, provides justification for not repeating several of the original tests during the proposed EPU test plan.

2.12.1.2.3.3 Acceptance Criteria

The acceptance criteria for the PBNP power ascension test program will be established as discussed in Regulatory Guide 1.68.

Level 1 acceptance criteria are values for process parameters assigned in the design of the plant that are safety significant. If a Level 1 criterion is not satisfied, the power ascension will be stopped and the plant will be placed in a condition that is safe based upon prior testing. The power escalation test procedure and Technical Specifications will provide direction for actions to be taken to assure the plant is safe and stable. Resolution of the issue that resulted in not meeting the Level 1 criterion must be resolved by equipment changes or through engineering evaluation, as appropriate. Following resolution, the applicable test portion must be repeated to verify that the Level 1 requirement is satisfied. A description of the problem must be included in the report documenting successful completion of the test.

Level 2 acceptance criteria are values that relate to plant functions or parameters that are not safety significant. If Level 2 criteria are not met, the Power Ascension Test Plan may continue. Investigation of the issue that resulted in not meeting the Level 2 criterion may continue in parallel with the power escalation. These investigations would be handled by existing plant processes and procedures.

For the PBNP Power Ascension Test Plan specific Level 1 and 2 acceptance criteria will be established and incorporated into the Power Ascension Test Procedure, (See Attachment 4, Item 24).

2.12.1.2.3.4 Vibration Monitoring

A Piping and Equipment Vibration Monitoring Program, including plant walkdowns and monitoring of plant equipment, will be established to ensure that steady state flow induced piping vibrations following EPU implementation are not detrimental to the plant, piping, pipe supports or connected equipment.

Observed piping vibrations will be evaluated to ensure that damage will not result. The predominant way of assessing these vibrations is to monitor the piping during the plant heat up and power ascension. The methodology to be used for monitoring and evaluating this vibration will be in accordance with ASME OM-S/G-2003.

The scope of the Piping and Equipment Vibration Monitoring Program includes any accessible lines that will experience an increase in their process flow rates. Any branch lines attached to these lines (experiencing increased process flows) will also be monitored as experience has shown that branch lines are susceptible to vibration-induced damage. The scope of the Piping and Equipment Vibration Monitoring Program includes the following systems:

- Main, and Reheat Steam (outside of containment)
- Steam Generator Blowdown
- Feedwater System (outside of containment)
- Condensate System

- Feedwater Heater Vents Relief and Miscellaneous Drains
- Feedwater Heater Drains
- Extraction Steam [and TG Gland Seal and Exhaust]
- Turbine Plant Miscellaneous Drains

The main steam and feedwater piping inside containment is not readily accessible for performing vibration monitoring during power ascension. This piping inside containment is not considered to be a target area for the following reasons:

- The main steam and feedwater piping is well supported and seismically designed.
- The piping is large diameter, not overly flexible, with large diameter bends and few elbows.
- There are no long cantilever branch lines or branch lines with heavy unsupported valves.
- There is no history of vibration problems in these lines at PBNP.
- Operating experience from other 2-loop Westinghouse-designed stations for EPU licensed power levels and which have similar piping and support designs has not identified a history of vibration problems with these lines.
- Review of operating experience at recent EPU stations has not identified significant vibration in these systems inside containment which would have been a safety or failure concern.

Reactor Coolant System piping (RCS) is not included in the scope of this vibration monitoring program as the system does not experience a significant change in flow due to uprate even though there may be minor RCS mass and volumetric flow changes depending on location due to density distribution changes.

The following equipment monitoring will be included:

- Feedwater and Condensate Pumps
- Feedwater and Condensate Motors
- Heater Drain Pumps
- Main Turbine Generator

The program scope will also include any lines or equipment within the monitored systems that have been modified or otherwise identified through the PBNP action report system as having already experienced vibration issues.

The piping and equipment within the scope of the vibration monitoring program will be observed at several different plant operating conditions. The first observations will be conducted prior to the shutdown in which the EPU will be implemented. Data from these observations will be used to develop a list of priorities for observation during the subsequent power escalation.

Subsequent observations will take place at each EPU Test Plateau, as described in Section 2.12.1.2.3.1 above. By comparing the observed pipe vibrations/displacements at various power levels with previously established acceptance Criteria, potentially adverse pipe vibrations will be identified, evaluated and resolved prior to failure.

2.12.1.2.4 Comparison of Proposed EPU Test Programs to the Initial Plant Test Program

The following table (Table 2.12-2, EPU Test Plan and Comparison of Proposed EPU Tests to Original Startup Tests) provides a comparison of the original plant startup testing, as listed in FSAR Section 13.4, Initial Testing in the Operating Reactor, to the proposed Power Ascension Test Program. The table lists all tests performed during original power ascension regardless of power level at which they were performed. Included in the table are descriptions of the original test, listings of the original power level at which the test was performed, whether the test will be replicated as part of the Power Ascension Test Program, and the justification for why it is not performed (if it is not performed). Note that Table 2.12-1, PBNP Extended Power Uprate Power Ascension Test Plan provides more detail on specific data acquisition test plateaus.

2.12.1.2.5 Transient Analytical Methodology

Initiating Events are defined in ANSI N18.2 -1973, Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants. The conditions are:

- Condition I - Normal operation
- Condition II - Incidents of moderate frequency
- Condition III - Infrequent incidents
- Condition IV - Limiting faults

Condition I Initiating Events

Analyses and evaluations have been performed for the Condition I operating transients to assess the aggregate impact of the equipment modifications and setpoint changes for EPU conditions. These analyses and evaluations used the same principal computer code (i.e., LOFTRAN) that has been used in control system analyses for PBNP at current power conditions. The LOFTRAN computer code is described in WCAP-7907 P-A (LOFTRAN Code Description, April 1984) (Reference 1). The code has been approved by the NRC and has been used for many years for accident evaluations for Safety Analysis Reports, and for control system performance and equipment sizing studies.

LOFTRAN has been used in the analysis of Condition I initiating events on PBNP as well as on other Westinghouse designed nuclear power plants. The NRC Safety Evaluation (SE) included in WCAP-7907-P-A describes the LOFTRAN verification process performed by Westinghouse for transients including reactor trip from 100% power, 100% load reduction, and step load changes. The verification process consisted of comparison of LOFTRAN results to actual plant data and to other similar thermal-hydraulic programs. The LOFTRAN verification process also included analysis of a R. E. Ginna steam generator tube rupture (SGTR) event, where comparison of the LOFTRAN results to available plant data demonstrated the ability of LOFTRAN to analyze the SGTR event.

The NRC SER included in WCAP-7907-P-A concludes that the data comparisons and the results comparisons provided by Westinghouse demonstrate the ability of LOFTRAN to analyze the types of events for which it has been used in licensing safety analysis. In conjunction with its extensive use for many years, it has been used in evaluation of Condition I operating transients at many Westinghouse designed nuclear power plants including other similar Westinghouse designed 2-loop nuclear power plants currently operating at approximately 1775 MWt NSSS power.

The LOFTRAN computer code was used to analyze the following Condition I initiating events and Condition II turbine trip transient at PBNP at EPU conditions:

- Step load increase of 10% of full power from 90% to 100% power
- Step load decrease of 10% of full power from 100% to 90% power
- Large load reduction of 50% of full power from 100% power
- Turbine trip without reactor trip initiated from P-9 setpoint, (of uprated full power)
- Turbine trip from 100% power

Based on these limiting analyses run with LOFTRAN, the ramp load increase and decrease of 5% of full power per minute between 15% to 100% power was evaluated as being acceptable at the EPU conditions.

The LOFTRAN analysis inputs and models were updated as appropriate to incorporate the applicable EPU equipment modifications and setpoint changes as well as the EPU operating conditions. The analyses results showed that the plant responses to Condition I initiating events satisfied acceptance criteria and that the NSSS control system responses were stable. Furthermore, plant responses to Condition I initiating events were shown to have acceptable margins to reactor trip and engineered safety features actuation. The results of the analyses performed for Condition I initiating events at EPU conditions are reported in LR Section 2.4.2, Plant Operability. The plant responses to Condition I initiating events at EPU conditions are consistent with their characteristic responses based on operational and analytical experience on PBNP at the current power conditions as well as operational and analytical experience on other similar Westinghouse designed 2-loop nuclear power plants (Ginna and Kewaunee) currently operating at approximately the same NSSS power.

Condition II, III, and IV Initiating Events

Analyses and evaluations have been performed for the Condition II, III, and IV operating transients to assess the aggregate impact of the equipment modifications and setpoint changes for EPU conditions. Analysis inputs and models were updated as appropriate to incorporate the EPU equipment modifications and setpoint changes as well as the EPU operating conditions. These analyses results showed that the plant responses to Condition II, III, and IV initiating events satisfied acceptance criteria. The results of the analyses performed for Condition II, III, and IV initiating events at EPU conditions are reported in LR Section 2.8.5, Accident and Transient Analyses.

The dynamic plant responses to Condition II, III, and IV initiating events at EPU conditions with the EPU equipment modifications and setpoint changes are consistent with their characteristic responses based on operational and analytical experience at other similar Westinghouse designed 2-loop nuclear power plants (Kewaunee and Ginna) currently operating at approximately the same core thermal power.

Natural Circulation

Natural circulation capability for the PBNP EPU is evaluated using the Westinghouse Owners Group (WOG) Emergency Response Guidelines (ERG) methodology. This method is used to estimate flow rates and core delta temperatures using core hydraulic resistance coefficients.

2.12.1.2.6 Justification for Exception to Transient Testing

PBNP has reviewed the recommendations of draft Standard Review Plan (SRP) for the EPU testing programs. As a result of this review, and a review of the original PBNP startup test program and recommendations from the NSSS and BOP vendors, PBNP concludes that no large load transient tests need to be performed as part of the EPU test program. This section discusses the justification for not performing the large transient tests.

Justification for Exception - General

PBNP is being modified to allow for operation at the process conditions associated with 1800 MWt core power level. The LOFTRAN computer code was used to evaluate plant response to Condition I and II initiating events at EPU conditions. The LOFTRAN computer code has been verified with respect to plant data and has been approved by the NRC for use in licensee safety analysis. The LOFTRAN verification process included comparison with plant data for transients including reactor trip from 100% power, 100% load reduction, and step load changes. The LOFTRAN verification process also included comparison with plant data for a steam generator tube rupture (SGTR) event that occurred at Ginna, where the comparison of the LOFTRAN results to available plant data demonstrated the ability of LOFTRAN to analyze the SGTR event. The code has been used by Westinghouse for accident evaluations for Safety Analysis Reports and for control system performance and equipment sizing studies. The application of the LOFTRAN computer code to PBNP considers any limitations included in NRC approval of the code along with plant-specific operating parameters and system configurations.

The LOFTRAN computer code has been used for PBNP for many years at the original and current power levels. In addition to its use on PBNP, it has also been used in evaluation of Condition I and II operating transients at many Westinghouse designed nuclear power plants including other similar Westinghouse designed 2-loop nuclear power plants. This use of LOFTRAN for analysis in a wide variety of different Westinghouse plants for various types of transients - both licensing/design basis analyses and for plant problem troubleshooting - has shown that this computer code can acceptably be used to predict the plant response, thereby negating the need to perform plant transient testing to validate the predicted code responses to large plant transients.

The LOFTRAN analysis inputs and models were updated as appropriate to incorporate EPU-related changes to parameter and setpoint values. Bounding inputs for design parameters were used as described in LR Section 1.1, Nuclear Steam Supply System Parameters. Analyses and evaluations were then performed for the NSSS control systems at EPU conditions. The NSSS control systems include the reactor (rod) control system, reactor coolant temperature (T_{avg}) control system, pressurizer level control system, pressurizer pressure control system, steam generator level control system, and steam dump control system. NSSS control systems setpoints are being revised as required to support EPU operations. Control systems including the rod control and T_{avg} control system, pressurizer and level control system will have setpoints changed as described in LR Section 2.4.1, Reactor Protection, Safety Features Actuation, and Control Systems.

NSSS control systems analyses were performed at EPU conditions for the following design basis Condition I operating transients and the Condition II turbine trip transient to demonstrate acceptable stability and setpoints:

1. 10% step load increase from 90% to 100% of uprated full power
2. 10% step load decrease from 100% to 90% of uprate full power
3. 50% load reduction from 100% of uprated full power
4. Turbine trip without reactor trip from P-9 setpoint (of uprated full power)
5. Turbine trip followed by a reactor trip from 100% of uprated full power

The NSSS control systems analyses assessed the aggregate impact of the applicable equipment modifications and setpoint changes at EPU conditions. The analyses results demonstrate that plant response to operations transients is acceptable, NSSS control systems responses are stable, and margins to reactor trip and engineered safety feature actuations are acceptable. Specifically, the performance of the rod control system and the steam dump control system is acceptable during both steady-state and transient operating conditions. The results also show that sufficient operating margins exist to reactor trip and engineered safety feature (ESF) actuation set points at EPU conditions with the NSSS control systems in the automatic mode. The NSSS control systems' pressure control components (i.e., pressurizer power operated relief valves, pressurizer spray valves, pressurizer heaters, and condenser steam dump valves) satisfy sizing requirements at EPU conditions and are acceptable for the analyzed transients.

These results are consistent with experience on several similar Westinghouse-designed, 2-loop nuclear power plants that use the LOFTRAN computer code for analysis of Condition I and II initiating events and operate at approximately the same NSSS power level as for PBNP at EPU conditions.

Other process parameter changes being made to accommodate the power increase are within the design capability of the related systems, or necessary upgrades are being installed. Therefore, no new thermal-hydraulic phenomena are introduced by either the physical modifications or the changes in operating conditions. Furthermore, the results of the analyses indicate that no new system dependencies or interactions are being introduced by the changes.

As discussed above, the aggregate impact of the EPU equipment modifications and setpoint changes on the dynamic plant response of PBNP for Condition I and II initiating events at EPU conditions was assessed through analyses and evaluations. These analyses and evaluations used the LOFTRAN computer code, which has been verified and approved by the NRC. The extent of the aggregate impact of the EPU equipment modifications and setpoint changes on dynamic plant response is such that it can be adequately addressed through analyses and evaluations. It is accepted practice to use analyses and evaluations to assess the aggregate impact of these types of equipment modifications and setpoint changes on PBNP as well as on other Westinghouse designed nuclear power plants.

Therefore, performing the load transient tests identified above would not confirm any new or significant aspect of performance not already demonstrated through analysis, by previous operating experience or routinely through plant operations. The following provides a description of the load transient tests and justification for exception.

Justification for Exception - Specific

Electrical Load Loss and Load Swings

The net electrical load loss from below Permissive P-9 Setpoint and the load reduction of 50% load at high power are tests to demonstrate that the control systems act together to prevent a reactor trip and also prevent the opening of the main steam safety valves (MSSVs). In particular, the test demonstrates that the rod control, steam dump and pressurizer pressure and level control systems act together to control the NSSS response to within design limits and the reactor trip setpoints. An analysis of a 50% load reduction from 100% EPU power was performed using the LOFTRAN code as described in LR Section 2.4.2, Plant Operability. This analysis demonstrates that the PBNP response to a 50% load reduction will not cause a reactor trip and will not cause MSSVs to open. An analysis of a loss of load from the Permissive P-9 setpoint was also performed at EPU conditions to demonstrate that the PBNP response to step load decrease from below the P-9 setpoint will not cause a reactor trip and will not cause the pressurizer power operated relief valves (PORVs) to open.

There are no major hardware modifications planned for NSSS components as part of the EPU that would affect the plant transient response. Since the NSSS control system functional design and hardware are not impacted and the analyzed 50% load reduction Condition I operating transients show acceptable stability, setpoints, and margin to reactor trip and ESF actuation, the NSSS control systems are acceptable for operation at full power EPU conditions. Analysis of the 50% load reduction provides a bounding justification for not performing 10% load swings either as step or ramp changes. A reactor trip, or the potential for a reactor trip, from high power level results in an unnecessary plant transient and the risk associated with such a transient, while small, should not be incurred. Based on this analysis and the avoided risk of an unnecessary plant transient, a loss of load from below the P-9 setpoint and a 50% load reduction from 100% EPU power to verify proper operation of the plant and automatic control systems is not required in the PBNP EPU Power Ascension Test Plan. Further, load step power changes and load ramp testing is not necessary and will not be performed for EPU conditions.

Manual Turbine Trip from 100% Power Test

The manual turbine trip from 100% power is a test to demonstrate that the control systems act together to maintain NSSS parameters within design limits post-trip and to demonstrate MSSVs do not open. In particular, the test demonstrates that the rod control, steam dump and pressurizer pressure and level control systems act together to control the NSSS response to within design limits and prevent opening of MSSVs. An analysis of a turbine trip from 100% EPU power was performed using the LOFTRAN code as described in LR Section 2.4.2, Plant Operability. This analysis demonstrates that the PBNP plant response to a turbine trip at full power EPU conditions results in acceptable response of pressurizer level and pressure, and MSSVs do not open.

There are no major hardware modifications planned for NSSS components as part of the EPU that would affect the plant transient response. Since the NSSS control system functional design and hardware are not impacted and the analyzed turbine trip from 100% EPU power Condition II operating transient shows acceptable stability, setpoints, and margin to ESF actuation, the NSSS control systems are acceptable for operation at full power EPU conditions. A reactor trip, or the potential for a reactor trip, from high power level results in an unnecessary plant transient and the risk associated with such a transient, while small, should not be incurred. Based on this analysis and the avoided risk of an unnecessary plant transient, a manual turbine trip from 100% EPU power to verify proper operation of the plant and automatic control systems is not required in the PBNP EPU Power Ascension Test Plan.

Natural Circulation Test

The purpose of the natural circulation test is to demonstrate the capability of natural circulation to remove core decay heat while maintaining NSSS parameters within design limits. The test was performed as part of original startup testing at 2% power and demonstrated that natural circulation flows were adequate to remove heat and maintain NSSS parameters in an acceptable range.

To evaluate the natural circulation capability for the PBNP EPU, the Westinghouse Owners Group (WOG) Emergency Response Guidelines (ERG) methodology is used to estimate flow rates and core delta temperatures using core hydraulic resistance coefficients. These equations are evaluated for several decay heat assumptions (1, 2, 3, and 4%) over a range of temperature conditions. This analysis of natural circulation cooldown to residual heat removal (RHR) cut-in conditions is described in more detail in LR Section 2.8.7.2, Natural Circulation Cooldown.

In addition, the atmospheric dump valve (ADV) capacities are estimated as function of steam generator secondary pressure that is correlated with primary system saturated temperature. After 4 hours at hot standby conditions, the plant is assumed to cool down to the RHR cut-in conditions at the maximum Emergency Operating Procedure (EOP) rate (25°F/hour).

There is close agreement between the hydraulic resistance coefficients for the Diablo Canyon and PBNP plants at the uprated conditions and the loop flow ratios are in good agreement. The calculated loop delta temperatures show the same trends and slightly higher scaled values compared to the FSAR reported measured values. The natural circulation flow rate shows expected behavior - decreases as the decay heat decreases at a constant temperature and a decrease with temperature at a constant value of decay heat. The loop delta temperature shows expected behavior - decreases as the decay heat decreases at a constant core average temperature and increases as the core average temperature decreases at a constant value of decay heat.

For the following reasons, the PBNP EPU will not adversely impact the natural circulation cooldown capability of the plant:

- No major hardware modifications to NSSS components that could affect loop flow resistance or steam generator heat transfer are part of the EPU scope.

- Acceptable results are found for natural circulation cooling during the hot standby period for realistic residual heat rates as high as 3% of 1811 MWt. The core outlet temperatures calculated for this case (604.5°F) are bounded by those specified for full power operation for the high Tavg cases (611.8°F) (PCWG Cases 3 and 4, LR Section 1.1, Nuclear Steam Supply System Parameters, Table 1-1).
- The calculated loop delta temperatures are scaled and compared to the FSAR measured values. The scaled, calculated values show the same trends as the original measurements and are slightly larger than measured, due to several conservative assumptions in the calculations. One of the conservative assumptions is that the hydraulic resistance for the reactor coolant pump (RCP) is based upon a locked-rotor K value.
- The atmospheric dump valves (ADVs) at the uprated conditions are adequate to achieve cooldown to the RHR entry point in an acceptable time period. RHR cut-in conditions can be achieved in approximately 14 hours at the maximum rate specified in Emergency Operating Procedures, which includes 4 hours in hot standby conditions.

2.12.1.3 Conclusions

PBNP has reviewed the EPU test program, including plans for the initial approach to the proposed maximum licensed thermal power level and the test program's conformance with applicable regulations. PBNP concludes that the proposed EPU test program provides adequate assurance that the plant will operate in accordance with design criteria and that SSCs affected by the proposed EPU, or modified to support the proposed EPU, will perform satisfactorily in service. Further, PBNP finds that there is reasonable assurance that the EPU testing program satisfies the requirements of 10 CFR 50, Appendix B, Criterion XI. Therefore, PBNP finds the proposed EPU test program acceptable.

2.12.1.4 References

1. WCAP-7907 P-A (LOFTRAN Code Description), dated April 1984

Table 2.12-1
PBNP Extended Power Uprate Power Ascension Test Plan

Test/Modification	Test Description	Prior To Startup	Rated Thermal Power, % of 1800 MWt (Allowance +0%, -5%)																		(Allowance +0%, -1%)				
			0	5	10	15	20	25	30	35	40	45	50	55	60	65	70	75	80	85	88	91	94	97	100
Nuclear Steam Supply System Data Record	Data Collection		X				X		X				X					X		X	X	X	X	X	X
Balance of Plant Data Record	Data Collection		X				X		X				X					X		X	X	X	X	X	X
Transient Data Record	Data Collection						X		X				X					X		X	X	X	X	X	X
Nuclear Design Check Tests	Low Power Physics Testing (Item 32 Table 2.12-2)			X																					
Power Distribution Monitoring	Performing Core Flux Maps								X				X					X					X		
Core Power Determination	Plant Calorimetric (Item 34 Table 2.12-2)																			X			X	X	X
RCS Flow Measurement	Verification of RCS Flow (Item 1 Table 2.12-2)																						X		
Leading Edge Flow Meter Calibration Checks	Verification of Calibration of LEFM																			X			X	X	X
Vibration Monitoring	Monitor vibration in Plant Piping and Rotating Equipment		X																	X	X	X	X	X	X
Plant Radiation Surveys	Verify Expected Dose Rates																			X					X

Table 2.12-1
PBNP Extended Power Uprate Power Ascension Test Plan

Test/Modification	Test Description	Prior To Startup	Rated Thermal Power, % of 1800 MWt (Allowance +0%, -5%)																		(Allowance +0%, -1%)				
			0	5	10	15	20	25	30	35	40	45	50	55	60	65	70	75	80	85	88	91	94	97	100
Plant Temperature Surveys	Verify Expected Temperatures																			X					X
Moisture Carryover Test	Verification MCO 0.25 percent																								X

Note:
1. The 85% plateau corresponds to the current licensed power level, (1540 MWt, approximately 85.6% of EPU power).

Table 2.12-2
EPU Test Plan and Comparison of Proposed EPU Tests to Original Startup Tests

Item No.	Test Description FSAR Table 13.2-1	Test Plan For EPU (yes/no)	Initial Startup Test Objective	EPU Test Basis The scope of EPU planned testing is described in this column
1	Reactor Coolant System	Yes	To verify that all instrumentation and control functions of the system were operating properly and that system flows were correct.	The power uprate has no adverse affect on this system and does not invalidate the test as originally performed. Specifically, the flow rate though the reactor coolant system will change by only a negligible amount as a result of EPU. System instrumentation will be checked out as part of the plant surveillance program required for startup. Measurement of reactor power will be performed a power levels identified in Table 2.12-1. At the 94% plateau, the reactor power measurement will be used as input to the determination of RCS flow. The test is performed routinely to satisfy Tech Spec Surveillance Requirements.
2	Component Cooling	No	To verify component cooling flow to components served by the system and proper operations of valves, instrumentation and alarms associated with the system.	The component cooling system has been assessed and determined to be adequate to support uprate. However, selected component cooling parameters will be monitored during escalation to power.
3	Residual Heat Removal System Test	No	To verify proper operation of valves, instrumentation and alarms associated with the system and the ability of the system to cool the plant from 350°F to 140°F in 20 hours.	RHR system capabilities are adequate for the power uprate condition and that the power uprate has no adverse affect on this system. There are no modifications planned to the RHR system for EPU. Therefore, this test is not required to be performed at the uprated power conditions. Additionally, the operability of this system is verified by regular surveillance testing.

Table 2.12-2
EPU Test Plan and Comparison of Proposed EPU Tests to Original Startup Tests

Item No.	Test Description FSAR Table 13.2-1	Test Plan For EPU (yes/no)	Initial Startup Test Objective	EPU Test Basis The scope of EPU planned testing is described in this column
4	Spent Fuel Pool Cooling	No	To verify proper operation of valves, instrumentation and alarms associated with the system and proper flow paths for cooling.	No modifications have been performed on Spent Fuel Pool Cooling, therefore, this test is not required to be performed at the uprated power conditions. Spent fuel pool conditions are routinely monitored during plant operation.
5	Chemical and Volume Control System	No	To verify that the system performed the following functions: maintain reactor coolant system water inventory, borate and dilute the reactor coolant system, supply reactor coolant pump seal water, maintain primary water chemistry within acceptable limits.	This test was performed during Hot Functional Testing, prior to fuel load. No modifications were made to this system, and there will be only small changes in the reactor coolant system parameters. Therefore, this test is not required to be performed at the uprated power conditions. However, selected parameters will be monitored during the power ascension testing.
6	Sampling System	No	To verify that a specified quantity of representative fluid and gases could be obtained safely at design conditions from each sampling point.	This test was performed during Hot Functional Testing, prior to fuel load. Primary and Secondary samples will be taken and analyzed at full power as a matter of normal plant operations.
7	Waste Disposal System	No	To demonstrate that the system was capable of processing all radioactive liquids, gases and solids associated with plant operation.	The waste disposal system is not impacted by power uprate. Therefore, this test is not required to be performed at the uprated power conditions.

Table 2.12-2
EPU Test Plan and Comparison of Proposed EPU Tests to Original Startup Tests

Item No.	Test Description FSAR Table 13.2-1	Test Plan For EPU (yes/no)	Initial Startup Test Objective	EPU Test Basis The scope of EPU planned testing is described in this column
8	Safety Injection Test	No	To verify proper response of the system to actuating signals in regards to pump, valve, instrumentation and alarms associated with system.	The power uprate has no adverse affect on this system and does not invalidate the test as originally performed. Further, operability of the SI system is verified by standard surveillance testing. Therefore, this test is not required to be performed at the uprated power conditions.
9	Fuel Handling	No	To demonstrate that the system was capable of handling fuel in all circumstances which would occur from receipt of fuel to return of fuel in a safe and orderly manner.	The fuel handling system is not impacted by power uprate. Therefore, this test is not required to be performed at the uprated power conditions. Note that the fuel handling system is used extensively during refueling activities and is inherently undergoing thorough testing.
10	Reactor Protection System	No	To verify the reactor tripping circuitry by operationally checking the analog system tripping and the A and B logic trains.	The power uprate has no adverse affect on this system and does not invalidate the test as originally performed. Therefore, this test is not required to be performed at the uprated power conditions. Specifically, the logic of the Reactor Trip System will not be changed as a part of this EPU and the test does not need to be repeated since the initial testing had satisfactory results. New reactor trip setpoints for EPU will be verified by instrument calibration tests. Additionally, the operation of these systems is verified by regular surveillance testing.

Table 2.12-2
EPU Test Plan and Comparison of Proposed EPU Tests to Original Startup Tests

Item No.	Test Description FSAR Table 13.2-1	Test Plan For EPU (yes/no)	Initial Startup Test Objective	EPU Test Basis The scope of EPU planned testing is described in this column
11	Rod Control System	No	To verify the rod control system satisfactorily performed the required stepping operations for each individual rod under both cold and hot shutdown conditions and to determine the rod drop time for each full length RCCA, and to check out the part-length rod drive system.	The power uprate has no adverse affect on this system and does not invalidate the test as originally performed. Therefore, this test is not required to be performed at the uprated power conditions. Specifically, the parameters of concern for this test are not altered by EPU, and the rod control system has performed its intended function during all phases of plant operation. The operation of these systems is verified by regular surveillance testing.
12	Rod Position Indication System Test	No	To verify the rod position indication system satisfactorily performed the required indication and control for each individual rod under hot shutdown conditions.	The rod position indication system is not impacted by power uprate. Therefore, this test is not required to be performed at the uprated power conditions. The operation of this system is inherently tested during refueling and regular physics testing.
13	Feedwater Control System	No	To demonstrate that the steam generator water level could be controlled in the manual and the automatic mode of operation and to ensure that all alarms and trips were functioning properly.	The feedwater system and controls will be modified to support power uprate. Proper operation of controls will be verified through post-modification testing. Selected system parameters will be monitored during power escalation. Finally, the planned load swing tests will dynamically test the FW control system. See Section 2.12.1.2.3.
14	Steam Dump Control System	No	To verify proper settings of the steam dump control system and the capability of the steam dump system to reduce the transient conditions imposed as a result of a load cutback or rejection up to 50% without a reactor trip.	No changes to the steam dump valves or setpoints are being made for EPU conditions. The system will not be dynamically tested via large load rejection testing; see Section 2.12.1.2.6 where justification is provided for not performing the 50% load rejection test.

Table 2.12-2
EPU Test Plan and Comparison of Proposed EPU Tests to Original Startup Tests

Item No.	Test Description FSAR Table 13.2-1	Test Plan For EPU (yes/no)	Initial Startup Test Objective	EPU Test Basis The scope of EPU planned testing is described in this column
15	Nuclear Instrumentation Test	No	To verify the proper operation of the Nuclear Instrumentation System.	The power uprate has no adverse affect on this system and does not invalidate the test as originally performed. Therefore, this test is not required to be performed at the uprated power conditions. Specifically, this test provided a functional demonstration of the system only. Additionally, the operation of these systems is verified by regular surveillance testing.
16	Radiation Monitoring System Operational Test	No	To verify that all channels were operable and alarm and recording functions were responding properly.	The power uprate has no adverse affect on this system and does not invalidate the test as originally performed. Therefore, this test is not required to be performed at the uprated power conditions. Additionally, the operation of these systems is verified by regular surveillance testing.
17	In-Core Instrumentation System	No	To perform checkout and demonstration of the in-core thermocouple system and the in-core flux mapping system.	The power uprate has no adverse affect on the system and does not invalidate the test as originally performed. The In-Core Detector System is used during normal plant operation and has proven itself to be reliable. Therefore, these tests are not required to be performed at the uprated power conditions. Specifically, the in-core instrumentation and thermocouple readouts are not adversely impacted by the uprate, and the operation of these systems is verified by regular surveillance testing.

Table 2.12-2
EPU Test Plan and Comparison of Proposed EPU Tests to Original Startup Tests

Item No.	Test Description FSAR Table 13.2-1	Test Plan For EPU (yes/no)	Initial Startup Test Objective	EPU Test Basis The scope of EPU planned testing is described in this column
18	Service Water System	No	To verify that the system would supply the required water flow through all equipment supplied with service water and that all instrumentation and controls functioned as designed.	The service water system has been assessed and determined to be adequate to support uprate. It is noted however, that selected service water parameters will be monitored during escalation to power.
19	Fire Protection System	No	To verify proper operation of the system and to check all automatic functions.	The power uprate has no adverse affect on this system and does not invalidate the test as originally performed. Therefore, this test is not required to be performed at the uprated power conditions.
20	Circulating Water System	No	To verify proper operation of pumps, valves and control circuitry; proper priming of the system, and proper flow through the condensers and the condensate cooler.	The circulating water system was assessed and found to be adequate to support uprate. Therefore, this test is not required to be performed at the uprated power conditions. Selected system parameters will be monitored during power escalation.

Table 2.12-2
EPU Test Plan and Comparison of Proposed EPU Tests to Original Startup Tests

Item No.	Test Description FSAR Table 13.2-1	Test Plan For EPU (yes/no)	Initial Startup Test Objective	EPU Test Basis The scope of EPU planned testing is described in this column
21	Instrument and Service Air System	No	To verify: a. the proper operation of all compressors to design specifications, b. the manual and automatic operation of controls at design setpoints, c. design air dryer cycle time and moisture content of discharge air, d. proper air pressure to each instrument and equipment served by the system.	Modifications to the air systems as a result of EPU modifications will be performed as part of the post modification testing. There are no required additional tests to support plant uprate. Therefore, this test is not required to be performed at the uprated power conditions.
22	Reactor Containment Air Circulating System	No	To verify the proper operation of: a. all fans, filters, heating and cooling coils, b. automatic and manual controls to maintain containment atmosphere within design specifications, c. proper operation of recirculation fans and coolers on a safety injection signal, d. purge valve isolation, e. all interlocks and alarms.	The power uprate has no adverse affect on the system and does not invalidate the test as originally performed. The system is adequate to handle the slight increase in containment heat load. Therefore, this test is not required to be performed at the uprated power conditions. Note however, that selected system parameters will be monitored during power escalation.

Table 2.12-2
EPU Test Plan and Comparison of Proposed EPU Tests to Original Startup Tests

Item No.	Test Description FSAR Table 13.2-1	Test Plan For EPU (yes/no)	Initial Startup Test Objective	EPU Test Basis The scope of EPU planned testing is described in this column
23	Feedwater and Condensate System	No	To verify pump, valve, and control operability and set-points. Functional testing was performed when a steam supply was available.	The feedwater system and condensate systems will be modified to support power uprate. New equipment (Condensate and FW pumps, FW heaters) performance will be monitored and system adequacy will be verified through post-modification testing. Further, selected system parameters will be monitored during power escalation.
24	Control Room Ventilation System	No	To demonstrate the control room ventilation system could perform its designed function during normal plant operations and during postaccident plant conditions by checking out each mode of operation.	The EPU did not modify the ventilation system and the testing/balancing that was performed during startup is still valid; therefore, testing of the ventilation system will not be performed. Monitoring of general area temperatures, particularly those areas where new equipment is installed, will be performed as part of the power ascension test procedure to confirm that the ventilation system continues to perform its intended function.
25	Emergency Diesel Generator Test This test verified the air capacity needed to crank the engines for 45 seconds. It also verified that the diesel could be placed on line within 10 seconds.	No	To assure that the emergency diesel-generators were installed in accordance with the design specifications and operated as described in the functional description to satisfactorily accept the safeguard system load upon failure of the normal power supply.	The power uprate has no adverse affect on this system and does not invalidate the test as originally performed. Therefore, this test is not required to be performed at the uprated power conditions. Specifically, the diesel start time, load time, and capacity were validated by this test. These requirements do not change as a result of the power uprate. Additionally, the operation of these systems is verified by regular surveillance testing.

Table 2.12-2
EPU Test Plan and Comparison of Proposed EPU Tests to Original Startup Tests

Item No.	Test Description FSAR Table 13.2-1	Test Plan For EPU (yes/no)	Initial Startup Test Objective	EPU Test Basis The scope of EPU planned testing is described in this column
26	Switchgear System	No	To verify that the electrical, auxiliary, and safeguard systems were installed and operated in accordance with accepted electrical standard and design and thereby provided reliable power to auxiliaries required during any normal or emergency mode of plant operation.	No modifications to plant switchgear were required to support power uprate. Therefore, this test is not required to be performed at the uprated power conditions.
27	Primary System Safety Valves Tests	No	To ascertain the popping and reseat pressure settings of the valves and establish that zero leakage conditions existed across the seating face.	The power uprate has no adverse affect on safety valves and does not invalidate the test as originally performed. The Main Steam Safety Valve setpoints are being revised and the valve setpoint will be tested as part of the modification implementation. In addition new FW Isolation Valves are being installed and will be tested as part of the post-mod test. Safety Valves are routinely tested as required by the ASME Code but not during power ascension testing.
28	Reactor Containment High Pressure Test and Leakage Test	No	To verify the structural integrity and leak tightness of containment.	This test is performed at intervals directed by Technical Specifications. This test does not have to be performed for uprate because the EPU did not modify the containment structure or penetrations in any way.
29	Cold Hydrostatic Tests	No	To verify the structural integrity and leak tightness of the particular system.	Hydrostatic testing of modified systems will be performed during the post modification testing as required PBNP station requirements. No specific EPU power ascension testing is therefore required.

Table 2.12-2
EPU Test Plan and Comparison of Proposed EPU Tests to Original Startup Tests

Item No.	Test Description FSAR Table 13.2-1	Test Plan For EPU (yes/no)	Initial Startup Test Objective	EPU Test Basis The scope of EPU planned testing is described in this column
30	RCC Unit Drop Tests	No	To measure the drop times of all RCC units from loss of coil voltage to dashpot entry at cold and hot conditions with full flow. Selected rods will be dropped at no flow conditions.	No modifications for the control rod system are required for EPU; therefore this test is not required to be re-performed at the EPU condition. Rod drop testing is performed as part of normal low power physics testing during refueling activities.
31	Thermocouple/RTD Inter-calibration This procedure was used to determine the isothermal corrections for reactor coolant resistance temperature detectors and in-core thermocouples.	No	To verify RTD calibration data and to determine in-place isothermal correction constants for all core exit thermocouples.	The EPU will marginally raise the reactor coolant temperature. This testing and cross- calibration is performed as part of normal reactor start-up.
	Nuclear Design Check Tests	Yes	To verify that the nuclear design predictions for endpoint boron concentrations, isothermal temperature coefficients, RCC bank differential and integral worths and power distributions are valid.	Nuclear checks are performed as directed by the Core Operating License Report following each refueling outage. Other core parameters are verified to be in specification before exceeding 50% power as required by Technical Specifications.

Table 2.12-2
EPU Test Plan and Comparison of Proposed EPU Tests to Original Startup Tests

Item No.	Test Description FSAR Table 13.2-1	Test Plan For EPU (yes/no)	Initial Startup Test Objective	EPU Test Basis The scope of EPU planned testing is described in this column
33	Plant Trip	No	To verify reactor control performance control and steam dump performance.	This test was originally performed at 30% and 100% power. The power uprate does not invalidate the test as originally performed. Therefore, this test is not required to be performed at the uprated power conditions. See Section 2.12.1.2.6 for additional justification for not performing this test.
34	Plant Calormetric and Power Range Instrumentation Calibration	Yes	During static and/or transient conditions at approximately 40%, 70%, 90% and 100%. To calibrate power range channels such that total core thermal output is indicated and that the detectors indicated the relationship between incore and excore axial offsets and quadrant tilts.	Nuclear instrumentation calibration is performed at various power levels as part of normal reactor start-up. The flow confirmation test is not impacted by EPU, but a calorimetric flow test will be performed at 85% and 100% EPU power.
35	Load Swing and Load Reduction Test	No	a. ±10% at approximately 25%, 60% and 100% of rated power b. Load reduction of approximately 50% from 55% and 100% power level c. Ramp load increase and decrease between 40% and 90% at the rate of 5%/minute.	This test was originally performed at several power levels to verify the adequacy of various plant systems to respond to load swings. See Section 2.12.1.2.6 for justification for not performing the load reduction and ramp transient tests.

Table 2.12-2
EPU Test Plan and Comparison of Proposed EPU Tests to Original Startup Tests

Item No.	Test Description FSAR Table 13.2-1	Test Plan For EPU (yes/no)	Initial Startup Test Objective	EPU Test Basis The scope of EPU planned testing is described in this column
36	Dynamic RCC Drop Test	No	To verify automatic detection of dropped rod by bottom and power range detector indication for selected rods. A minimum of one drop be accompanied with turbine runback and automatic rod withdrawal stop.	The dropped rod recovery procedure was proven adequate and in subsequent testing, the turbine runback controller performed as designed. This system has been fully tested and found to be satisfactory and the EPU will not affect this system so testing again is not necessary.
37	Static RCC Insertion and Drop Tests	No	To verify that a single RCC unit when misaligned with the control bank can be detected by individual rod position indication or by incore instrumentation if required. To determine the effect of a single full inserted RCC unit on core reactivity and core power distribution.	The dropped rod recovery procedure was proven adequate and in subsequent testing, the turbine runback controller performed as designed. This system has been fully tested and found to be satisfactory and the EPU will not affect this system so testing again is not necessary.
38	Radiation Shielding Effectiveness Test	Yes	a. 10-8 - 10-7 amps b. 1 - 3% c. 30 - 40% d. 100% Measure neutron and gamma shielding effectiveness in the containment.	Radiation shielding measurements performed at lower power levels are not invalidated by EPU. However, plant surveys, including radiation shielding measurements will be performed at the power levels shown in Table 2.12-1, and survey maps updated as necessary.

2.13 Risk Evaluation

2.13.1 Risk Evaluation of EPU

2.13.1.1 Regulatory Evaluation

PBNP conducted a risk evaluation to (1) demonstrate that the risks associated with the proposed EPU are acceptable and (2) determine if "special circumstances" are created by the proposed EPU. As described in Appendix D of SRP Chapter 19 (Reference 1), special circumstances are present if any issue would potentially rebut the presumption of adequate protection provided by the licensee to meet the deterministic requirements and regulations. The PBNP review covered the impact of the proposed EPU on core damage frequency (CDF) and large early release frequency (LERF) for the plant due to changes in the risks associated with internal events, external events, and shutdown operations. In addition, the PBNP review covered the quality of the risk analyses used to support the application for the proposed EPU. This included a review of PBNP's actions to address issues or weaknesses that may have been raised in previous NRC staff reviews of PBNP's individual plant examinations (IPEs) and individual plant examinations of external events (IPEEE), or by an industry peer review.

The NRC's risk acceptability guidelines are contained in Regulatory Guide 1.174 (Reference 2). Specific review guidance is contained in Matrix 13 of RS-001 and its attachments.

2.13.1.2 PBNP Current Licensing Basis

The PBNP Level 1 and Level 2 PRA models were developed initially for the individual plant examination (IPE) and individual plant examination for external events (IPEEE) in response to Nuclear Regulatory Commission (NRC) Generic Letter 88-20. The IPE was completed and submitted for NRC review in June 1993. The IPEEE was submitted in June 1995. The NRC review of the IPE was completed in January 1995 and in September 1999 for the IPEEE.

Since the original IPE, the PBNP internal events PRA model has undergone several model revisions to incorporate improvements in modeling techniques and to maintain consistency with the as-built, as-operated plant.

The first revision to the models extended the time period considered for failure data through December 31, 1993. In addition to the failure data update, several hardware-related changes were added to the model. These hardware-related changes include:

- Added alternate shutdown buses B08 and B09
- Instrument bus static transfer switches
- Full-flow test lines added to ECCS
- Initial SI suction changed from BAST to RWST
- Removed the need for operator action to throttle AFW on loss of air since the valves were now left throttled.

As a result of these changes, the internal events core damage frequency (CDF) changed from 1.15E-04 per year in the IPE model to 9.74E-05 per year. LERF was not calculated in the Revision 1 model. The Revision 1 model results applied to both units.

Revision 2 of the PBNP model extended the time period considered for failure data through June 30, 1996. This revision also changed the post-trip success criteria for service water from two to three pumps required. Also, two new diesel-generators, G03 and G04, along with their associated electrical buses were added. CDF for the Revision 2 internal events model was 5.77E-05 per year. LERF was not calculated for the Revision 2 model. The Revision 2 model results applied to both units.

Revision 3 of the PBNP PRA was completed October 2001 and included plant-specific failure data through December 31, 1999. This revision was the first to explicitly calculate LERF. Also, separate, complete models were developed for Units 1 and 2 and numerous electrical feed lineups were added to the fault tree logic. Minor updates were made to several system models and the human reliability analysis (HRA) was updated for auxiliary feedwater (AFW) related operator actions. CDF for the Revision 3 internal events model was 4.39E-05 per year and LERF was 1.18E-05 per year. The Revision 3 model results applied to both units. A draft of the Revision 3 model was used for the Westinghouse Owners Group (WOG) peer review in June 2001.

After completion of the Revision 3 PRA model, numerous minor revisions were made. These minor model revisions were generally needed to reflect implementation of plant modifications or procedure changes that occurred. In March 2008, Revision 4 of the PRA model was completed and incorporated all of the minor model changes made after completion of Revision 3. Also, plant-specific failure data and initiating event data were updated to reflect experience through 2005. CDF for the Revision 4 internal events model was 3.7E-05 per year for Unit 1 and 4.4E-05 per year for Unit 2. LERF was 3.3E-06 per year for Unit 1 and 3.3E-06 per year for Unit 2.

From external events analysis developed for the IPEEE, seismic events were determined to contribute 1.3E-05 to 1.4E-05 per year to CDF and internal fires a core damage frequency of 5.1E-05 per year to the PBNP risk profile. Other external events were found to add a probabilistically insignificant risk to the plant. The internal flooding analysis and seismic PRA have not been updated since the original IPE and IPEEE submittals.

The fire analysis has been updated once since the IPEEE submittal. This update was done in 1998 and consisted of developing new conditional core damage probabilities using the 1996 version of the internal events model. The changes were made to reflect the installation of two additional diesel generators and relocation of the B-train 4160 VAC switchgear to the EDG building. After completion of these modifications, fire risk was reanalyzed with the resulting CDF determined to be 1.2E-05 per year.

Since the 1998 fire risk update, an evaluation was developed to assess the highest risk significant scenarios and add those scenarios to the on-line risk monitoring program. The methods used to identify the top risk significant fire scenarios are based upon state of the art techniques identified in NUREG/CR-6850, EPRI/NRC-RES Fire PRA Methodology for Nuclear Power Facilities. However, these recent evaluations are not meant to be a full Fire PRA, but only a relative risk screening to identify the top risk scenarios to be monitored for configuration risk management. The evaluations are adequate to identify the top scenarios which contribute to fire risk and are only used for relative risk ranking associated with on-line risk monitoring. Since a screening methodology is used, the results should not be considered as absolute PRA risk levels and should not be compared to other detailed PRA values for other initiators.

2.13.1.3 Technical Evaluation

Purpose:

An increase in allowable reactor core power from 1540 MWt to 1800 MWt (1806 MWt NSSS power) is planned for each unit at the PBNP. Installation of modifications needed to support this extended power uprate (EPU) is planned no later than the Spring 2010 (Unit 1) and Spring 2011 (Unit 2) refueling outages. The purpose of this report is to identify and evaluate the impacts of the EPU on plant risk as reflected in the PBNP probabilistic risk assessment (PRA).

PRA Scope:

PBNP has an at-power PRA model that includes:

- Internal events
- Internal floods
- External floods
- High winds and other external events
- Seismic events
- Fire events (FIVE screening and limited fire PRA only)
- Level 2 analyses
- Large early release frequency (LERF) analyses
- Configuration risk management (CRM) models

PRA Model Description:

The PBNP internal events PRA model uses standard small event tree/large linked fault tree methodology. Event trees are developed for each unique class of identified internal initiating events and top logic is developed to link these functional failures to system-level failure criteria. Fault trees modeling component and human failure events are developed for each of the systems identified in the top logic.

Seismic risk for PBNP was evaluated using a seismic Probabilistic Safety Assessment (SPSA) as part of the IPEEE. In the quantification of the SPSA, the seismic hazard, fragility and systems analyses were combined to estimate the performance of the plant following a seismic event. The quantification was performed in two steps. First, the plant logic model was quantified to establish cutsets for the seismic hazard quantification. Input to the plant logic model includes: component seismic fragility data, random (non-seismic) failure rates, the rate of operator error and the seismic systems cutsets. In the second step of the quantification, the plant logic model was integrated with the mean seismic hazard curve for the site to determine the frequency of core damage. Considering the full range of ground motions, a fragility curve for the plant is generated. The plant level fragility incorporates features of the plant required to mitigate a seismically-induced accident including the structural integrity of safety-related components, systems and buildings designed to survive a seismic event, system safeguards, redundancy in plant safety systems, and operator intervention.

The internal fires analysis for PBNP initially was developed during the IPEEE using the EPRI Fire-Induced Vulnerability Examination (FIVE) Methodology. Since the IPEEE and the fire PRA update in 1998, a screening analysis was developed in 2006 to facilitate assessing on-line configuration risk.

Development of the PBNP PRA is documented in a series of notebooks. Each of these notebooks was reviewed to identify potential updates that may be required to these documents or the associated PRA models as a result of the EPU project. This evaluation specifically addressed changes required solely due to the power uprate.

PRA Model Review

The first step taken to evaluate potential impacts of the EPU project on the PBNP PRA was to identify hardware modifications, setpoint changes, and procedure changes that may be implemented as part of the EPU project and that may have an impact on the PRA models. One of the principal inputs reviewed was the "PBNP Nuclear Plant Extended Power Uprate Feasibility Study Results and Recommendations" (Reference 3). Other documents reviewed include various technical reports addressing grid reliability impacts, turbine overspeed analyses, etc. After identifying the EPU related changes that could impact plant risk, a determination of the quality and technical adequacy of the PBNP PRA to support risk significance was performed.

Next, a detailed, section-by-section, review of each of the PRA notebooks was performed to identify where the PRA models or documentation could be impacted by the EPU. The review resulted in one of the following four dispositions:

a. Potential PRA change or modification required that could have a noticeable impact on numerical risk results

b. PRA documentation update desirable or necessary, however, the change will have no numerical impact on results

c. Minor numerical perturbation, negligible impact on numerical results, no PRA documentation changes required; and

d. No PRA impact

Where the review identified the potential for a noticeable impact on the overall numeric results, an evaluation of the potential impact is performed. The overall quantitative impact for EPU-related impacts is documented in PRA Results below.

Quality of PRA

In June 2001, the Westinghouse Owners Group performed a Peer Review of the PBNP PRA model using a draft of Revision 3.0. The peer review final report was issued in November 2002. The PBNP PRA received a grade of full 3 for technical elements Initiating Events, Accident Sequence Evaluation, System Analysis, Dependencies, and Maintenance and Update. A grade of contingent 3 was assigned to technical elements Data Analysis, Human Reliability Analysis, Structural Response, Quantification, and Containment Performance. Technical element Thermal Hydraulic Analysis received a grade of 2. In general, the review team concluded that the PBNP PRA could be used effectively to support applications involving risk significance determinations supported by deterministic analyses once the items noted in the report are addressed. Since the completion of the peer review, all A-level and 19 of the 30 B-level peer review Facts and Observations (F&O's) have been addressed. In subsection Resolved F&Os below, all resolved A-level and B-level F&Os are delineated along with a summary of how they were resolved. Subsection *Unresolved* F&Os details the unresolved B-level F&Os and provides an evaluation of how the issues raised in these F&Os could impact the EPU PRA evaluation.

Resolved F&Os

Below is described each A-level and B-level WOG peer review F&O along with how each has been resolved.

Initiating Events IE-03 Level of Significance: B

Peer Review Observation: The calculation for LOSP frequency uses EPRI-TR-1000158 to determine the IE frequency. Events that do not apply to PBNP are eliminated. "Applicable events" are used to calculate an IE frequency which is then used as a prior. Only 3 dual unit LOSP events in a total of 449 site years are found applicable to PBNP. The resultant prior is 7E-3/yr for LOSP, which is also the updated mean. This calculation essentially assumes a complete single unit LOSP can not occur at PBNP because of the operating configuration of the switchyard and the way power is shared by Unit 1 and Unit 2. The 7E-3 for dual unit LOSP is caused by grid related and weather instabilities. The 7E-3 value is about 3-10 times less than that used in other plant PRAs. No engineering justification is provided why PBNP is so much better than the average. The following observations were made about the calculation process:

1. Single-unit LOSPs at multi-unit sites are assigned to the transient without power conversion system (PCS) available initiators, based on historical evidence that loss of station transformer X-03 has not resulted in trip of the affected unit (due to the availability of AC power from the unaffected unit). These events are then eliminated from the "LOSP" data base. This may be a non-conservative assumption in that other types of single-unit LOSPs (whether at multi-unit or single-unit sites) may induce plant responses different from those from a transient without PCS available, possibly constituting a different category of initiator, distinct from both the transient without PCS available and LOSP that affect both units.

2. Because of the operating configuration of the switchyard, the assumption was made that no single event in the switchyard could fail all OSP to a single unit, or to both units. Further, making this assumption essentially says that no single event or series of events in the

switchyard can fail all OSP to both units. Given the strange things that can occur in a switchyard, this may be optimistic, or at least should have more studies to back up this claim.

3. The process of eliminating dual unit events is not well documented. The results are low compared to other plants. When most plants use the EPRI data base for a similar calculation, they have 10-20 events that are applicable to their plant. PBNP only had 3, and, given the process and criteria used for screening, should have had 2 [the Turkey Point Hurricane event can be eliminated for PBNP]. Thus, the number of events excluded was surprising, with little back-up documentation. Plants that use the EPRI data base typically derive a LOSP Frequency of about 1E-2 for grid centered and 1E-2 for weather centered.

4. The accounting of site years was suspect. Most plants were counted as contributing 12 site years, even though there were long periods of time between 1988 and 1999 that the plants were shut down. Notice that Sequoyah and DC Cook are assigned the full 12 site years, even though they were shut down for long outages during these years.

5. In tabulating "unit-years" for dual-unit LOSP, single-unit LOSP events at multi-unit sites (3 events) were doubled (to 6 events) for consistency with frequency denominator (unit-years). While this preserved frequency mean values, it essentially "creates data" if used in a Bayesian update process.

6. For dual unit sites, the status of the other unit was ignored. For example, the Beaver Valley event of 10/93, was a dual unit LOSP, but Unit 2 was in refueling, so it did not count as a LOSP for Unit 2. This event is classified as a single unit LOSP, but should be a dual unit LOSP. Another example is the Indian Point 2/3 event from 3/91. Unit 2 was in refueling, Unit 3 was at power. A single event in the Buchanan switchyard caused both plants to lose the main source of OSP. Because they were owned by different companies, it is not counted as a dual unit event.

7. Removing so many events from the data base and then using it as a prior does not seem correct. If the data base is pared to reflect only those events that are directly applicable to PBNP, then the resulting "generic" frequency should be used for the plant-specific case. The use of Bayesian update however does not affect the result.

Resolution: A revised LOOP frequency was developed for both single and dual unit events using essentially all of the EPRI data. Any grid or weather event at a single unit site was counted as a "site" LOOP event. Single unit LOOP events are still considered trip without PCS events for four primary reasons: (1) Service water, instrument air, Aux Feedwater and 125 VDC are all shared between the two units. (2) A fast bus transfer at the 13.8 KV level will occur if the unit X03 transformer fails. (3) 4 KV electrical systems have inter-unit crossties. (4) Any one of four EDGs or the gas turbine can provide sufficient AC power.

These changes were included in a recent update to the initiating events analysis.

Initiating Events IE-07 Level of Significance: B

Peer Review Observation: In regards to the Steam Line Break IE frequency calculation: The IE frequency for SLB Outside Containment is 0.012. This is reasonably high compared to most PWRs. The PB plant specific data is 1 event in 8.74 years, which contributes to the high IE frequency. The 1 event was a feedwater heater blowout.

Resolution: The heater shell failure event on Unit 1 was re-classified as a trip with PCS rather than a SLB because it was low pressure steam and it was isolated immediately by the turbine trip. The SLB frequency used now is the industry average value.

Initiating Events IE-09 Level of Significance: B

Peer Review Observation: (The scope of this observation goes beyond Initiating Events.) As this is a work in progress, independent review has been performed only within the PBNP PSA group to date. Some degree of independent review appears to be prescribed in ESG 5.1, "PRA Maintenance and Update Guideline," via PBF-0026a.

Resolution: All PRA notebooks that were in draft form for the Peer Review have been reviewed and approved.

Accident Sequence Evaluation AS-01 Level of Significance: B

Peer Review Observation: There does not appear to be, within the accident sequences, a systematic search for spatial/environmental dependencies that may arise from initiating or subsequent events, such as a LOCA causing debris clogging of ECCS suction and subsequent loss of long-term recirculation, or a steamline break causing habitability problems which would impair operator ability to perform local actions.

Resolution: The System Walkdown Notebook, PSA 4.14, from the original IPE PRA model, was not reviewed by the Peer Reviewers. This notebook contains an evaluation of spatial inter-system dependencies. The ECCS suction strainer plugging probability is included in the PRA model along with a common mode failure. The actual values used is a generic issue that will be addressed with the rest of the industry. However, the sump strainer plugging probability is unlikely to affect overall results at PBNP due to the low importance of LOCA events.

Thermal Hydraullic Analysis TH-03 Level of Significance: B

Peer Review Observation: The PBNP ATWS model is based primarily on analyses from WCAP-8404, which was prepared in the early 1970s. The Event Tree Notebook discussion (Section 3.14.4) of success criteria for Primary Pressure Relief (PR) for the ATWS model indicates that success requires opening and reclosing of both pressurizer safety valves, but that opening of the PORVs is not required. This modeling of PR ignores the effects of reactivity feedback on peak RCS pressure during ATWS. The generic ATWS analyses, such as those in WCAP-8404, assume a moderator temperature coefficient (and related reactivity coefficients) representative of what was believed to bound the reactivity feedback for some large fraction of the cycle (e.g., an MTC value selected to provide a 95% confidence that the actual value would not be less negative for 95% of a cycle). But from a PRA perspective, the small fraction of the cycle during which pressure relief would be inadequate cannot be dismissed, and must be factored into the model, in this case probably in the PR logic. This is the approach used in later

ATWS evaluations considering ATWS risk, e.g., WCAP-11992, and also the current WOG ATWS program.

Resolution: PR node logic was developed to include generic values for Unfavorable Exposure Time. The ATWS event tree was revised to more closely match the WCAP-11992 and WCAP-15831-P models.

Thermal Hydraulic Analysis TH-06 Level of Significance: A

Peer Review Observation: Condensate Storage Capacity: The PBNP PSA assumes an available CST volume of 40,000 gallons. The minimum Tech Spec requirement for CST inventory is 13,000 gal. A study in 1988, based on 1986-1987 shift logs indicated that 90% of the time, the volume was greater than 40,000 gallons. The two CSTs are combined, so the study found that 90% of the time, there was more than 80,000 gallons in the two CSTs. The sequence timing, HEP's, and AFW performance are based on the 40,000 gallon per CST value. There are several concerns with these assumptions.

1. The 40,000 gallon number is based on the way the plant operated in 1986-87. Recent data should be used.

2. The 13,000 gallon TS limit could have a very limiting effect on system modeling -- (a) CST depletion would occur in 1 hour -- large effect on HEP's for CST refill, (b) cooldown to 400°F in SBO would not be possible -- would necessitate changes in assumptions for SBO event tree. If the CST is at 13,000 for 10% of the time, the effect may be so important that it would require modeling as a separate case.

3. Under conditions of a single unit trip, the affected unit would have 80,000 gallons available, so the CST refill would not be necessary until 10 hours, rather than 4 hours-- lowering the HEP.

4. The number 1 cutset (today) at 1.1E-5 [the total CDF of some plants] involves failure to replenish the CST. It involves a combined HEP of 2E-5. Any changes in the assumptions and basis for the HEP could have significant effect on CDF.

Resolution: An update to the event tree notebook was issued 01/30/2004. In that update, under the description of the Station Blackout Event Tree, the following documentation is provided on CST level:

> "The water volumes in each CST can vary from the Technical Specification minimum value of 13,000 gallons to more than 40,000 gallons if full. Based on plant process computer data from November 2001 through October 2002, the CSTs were at a level of 16 feet or greater 99% of the time when only one unit was operating and a level of 17 feet or greater 99% of the time when both units were operating. In addition, during times when both units were operating, the CSTs were at a level of 16 feet or greater 99.9% of the time. MAAP runs for station blackout success criteria demonstrated that an initial level of 16 feet in the CST, which corresponds to a usable volume of 35,500 gallons is a sufficient inventory to remove decay heat and accomplish a cooldown using the turbine driven AFW pump during the first hour after the event begins."

Modular Accident Analysis Program (MAAP) runs used to document success criteria for the PRA used the 16 foot initial water level for the CST. Thermal hydraulic success in preventing core damage and timing for the human reliability analysis for critical scenarios were all based on having this initial value. This satisfies the intent of this action item and allows closure of the Level A WOG PRA Peer Review finding.

Thermal Hydraulic Analysis TH-07 Level of Significance: B

Peer Review Observation: SG Dryout Time: SG dry-out time for all human error probabilities (HEP)'s is assumed to be 30 minutes. The operator diagnosis and action time is estimated at 25 minutes, leaving a 5-minute window for uncertainty. The success criteria analysis (Section 4 of ET Notebook) shows SG dryout times ranging from 25 minutes to 51 minutes, depending on RCP status and reactor trip parameter. From these calculations, a blanket time of 30 minutes is used for all SG dryout times. The following items should be considered with respect to this timing:

1. If the sequence under consideration fulfilled the 25-minute dryout conditions, the time window for diagnosis disappears. If the sequence fulfills the 51-minute conditions, the time window for diagnosis increases by a factor of 5. This could swing the HEP.

2. There are new SG's at PBNP since this calculation. The volume of water in the secondary (for dryout timing) should be checked.

3. The calculation was done using a 120% ANSI decay heat curve.

Resolution: Plant specific MAAP analyses were performed to evaluate the timing for various scenarios where resumption of SG feed was credited.

Thermal Hydraulic Analysis TH-08 Level of Significance: B

Peer Review Observation: Feed and Bleed Criteria: The feed and bleed criteria of 1 SI pump and 1 PORV at 30 minutes is based on WCAP-9914. The runs in the WCAP were interpreted by citing the case with configuration closest to PBNP and using engineering judgment to justify it's applicability to PBNP (example - the WCAP study used a relief ratio of 177 lbm/hr-MWth, whereas PBNP is 138 lbm/hr-MWth. But, the WCAP used an ANSI decay heat curve 25% higher than best estimate - so, it was judged that the 25% margin in decay heat counteracted the 28% deficiency in relief capacity - thus making the case applicable to PBNP). It would be better to use plant-specific analysis for feed and bleed criteria, which are important to the PRA results, rather than adapting generic analyses.

Resolution: Plant specific MAAP analyses were performed to evaluate the timing for various scenarios where feed and bleed were credited.

Thermal Hydraulic Analysis TH-11 Level of Significance: B

Peer Review Observation: There is an overall generally conservative tone to the accident sequence success criteria documentation (Event Tree Notebook, PRA 3.0). While this approach may have been adequate for response to NRC Generic Letter 88-20, more realistic modeling of plant risk and contributors is needed to support risk-informed plant licensing applications.

Resolution: Plant specific MAAP analyses were performed to verify system success criteria in the event trees.

<u>Thermal Hydraulic Analysis TH-12 Level of Significance: A</u>

Peer Review Observation: There is insufficient guidance and documentation in the PRA to allow a thorough review of the bases for success criteria, and a lack of information regarding how decisions were made to select the type of analytical basis (e.g., FSAR, PBNP-specific calc other than FSAR, generic 2-loop plant analysis, other plant analysis) to be used to support the various success criteria. The documentation of accident sequence success criteria in the Event Tree Notebook (PRA 3.0) does not adequately demonstrate the reasonableness of the success criteria or provide sufficient traceability to supporting analyses. Draft 14 of the ASME PRA Standard (the version currently available) was consulted for specific guidance regarding elements that should be included in success criteria documentation for a PRA capable of supporting risk-informed applications. At least the following criteria from that reference should be met:

a. Document each of the success criteria and the supporting engineering bases, references, and important assumptions for success criteria and the supporting engineering calculations performed in support of the PRA

b. Identify conservative, optimistic, or simplifying assumptions or conditions

c. Provide specific justification, based on results of evaluation or quantification, for use of conservative, optimistic, or simplifying assumptions or conditions

d. Provide the basis for the success criteria development process and the supporting engineering calculations

e. Document uses of and rationale for expert judgment.

f. Document the definition of core damage used in the PRA including the bases for any selected parameter value used in the definition (e.g., peak cladding temperature or reactor vessel level.

g. Document the definition of large early release used in the PRA including identification of those parameters used as the basis for defining containment failure or bypass

h. Document calculations (generic and plant-specific) or other references used to establish success criteria, and identification of cases for which they are used

i. Identify computer codes or other methods used to establish plant-specific success criteria

j. Document the limitations (e.g., potential conservatisms or limitations that could challenge the applicability of computer models in certain cases) of the calculations or codes

k. Identify important assumptions used in establishing success criteria

l. Provide a summary of success criteria for the available mitigating systems and human actions for each accident initiating group modeled in the PRA

m. Document the basis for establishing the time available for human actions

n. Describe processes used to define success criteria for grouped initiating events or accident sequences

As has been noted in other observations for the TH element, the PBNP PRA success criteria documentation is weak in most of the above areas.

Resolution: In an update to the Event Tree notebook, success criteria for unique success branches in the PRA model event trees were verified using MAAP, which is a best-estimate thermal hydraulics and severe accident computer code with a PBNP specific plant model. More than 85 runs were performed (85 base runs plus numerous sensitivity runs) in this effort. Success criteria were referenced back to specific MAAP runs for future reference.

In the Top Event Success Criteria section, the following discussion was added on the desirability of having plant-specific thermal hydraulic basis for success criteria:

> "The original IPE PRA model for PBNP used system success criteria developed largely from the FSAR and other design-basis sources. For some criteria, PBNP specific calculations, generic PWR calculations, or other plant calculations were referenced. Because this is less than desirable for a best estimate PRA model, the current PRA model system success criteria have been validated for each event tree success branch and for many event tree failure branches using the Modular Accident Analysis Program version 4 (MAAP4) code and a PBNP specific parameter file. These MAAP runs also provided timing information used in the development of human error probabilities. Specific MAAP runs used for success criteria are referenced in Sections 3 and 4 of this notebook where appropriate. The MAAP analyses are documented in the PBNP MAAP run database."

This satisfies the intent of this action item and allows closure of the Level A WOG PRA Peer Review finding.

<u>System Analysis SY-12 Level of Significance: B</u>

Peer Review Observation: In the Success Criteria discussion (Section 4.0) of the Event Tree Notebook (PRA 3.0), on page 153, there is a note that "PBNP has "smart" MOVs on the discharge of the motor-driven [AFW] pumps that attempt to diagnose which unit is having the accident and direct flow to that unit. The "smart" function of the MOVs was not modeled in the PBNP PRA." The valves discussed are valves 0-AF-04020 from pump 0-P-038B to the Unit 2B steam generator, 0-AF-04021 from pump 0-P-038B to the Unit 1B steam generator, 0-AF-04022 from pump 0-P-038A to the Unit 2A steam generator, and 0-AF-04023 from pump 0P-038A to the Unit 1A steam generator.

Per the FMEA in the AFW System Notebook (PRA 5.9), failure open of the valve from either pump to the opposite unit when flow is required on the current unit is considered to fail flow to the current unit from that pump. The AFW fault tree logic (e.g., fault tree page AFM, 25, logic for

Block 17) includes logic, for example, to fail flow from the pump P-38A discharge if valve 0-AF-4022 fails open.

It appears that a similar failure could exist if MOV 0-AF-4022 received a false or spurious signal to open. Similarly, false signals to the other valves noted above could adversely affect flow to the other steam generators.

Resolution: A spurious open failure mode for these valves was added to the AFW model.

Human Reliability Analysis HR-01 Level of Significance: B

Peer Review Observation: Guidance for the performance of the HRA is not consolidated. The recently published EPRI HRA technique is used for analysis of the post-initiator human errors for the AFW system. This technique is also planned to be used for the post-initiator human errors for the other systems. At this time, however, these human actions are documented and quantified in the IPE HRA Notebook.

In the original PRA work, it appears that each fault tree analyst included human interactions (HI)s as needed. For the dependent HEP evaluation, the HEP analyst tried to distinguish which HEP was first in a series of actions, which was dominant, and which would have dependencies with others. This led to a series of "HEP-multipliers" to correct for dependencies.

In the new work, (for AFW-related events only as of the date of the peer review) a process has been identified whereby the HRA analyst identifies which events can be combined and subsumed. This streamlines the dependent HEP process. In some other cases, when dependent HIs are identified ahead of time, the cognitive error is modeled in the fault tree separately from the execution error.

The two techniques are fairly similar; however, the HRA is difficult to review. The only HRA analyses for post-initiator human actions which can be reviewed that represent how all of the post-initiator actions will eventually be reviewed are those for AFW.

Analysis of the pre-initiator human actions will eventually use the new EPRI methodology; but, at present, it is documented in the IPE HRA Notebook.

Resolution: A description of the process used was included in the HRA notebook when all HEPs were updated in a recent revision. Post-initiator HEPs were quantified using the EPRI HRA Calculator software.

Human Reliability Analysis HR-02 Level of Significance: A

Peer Review Observation: References for time available to perform the action are often non-existent. Phrases such as "assumed to be 30 minutes" are used. Similarly, there are no references to plant personnel input for time required to complete an action (phrases like "assumed to be 30 minutes" are used without justification).

Resolution: Recent revisions to the human reliability analysis (HRA) notebooks document a completely revised human reliability analysis for the PBNP PRA model. A part of this revision was to provide a basis for the time available to perform operator actions using the Modular Accident Analysis Program (MAAP), which is a best-estimate thermal hydraulics and severe accident computer code with a PBNP specific plant model.

This major revision to the HRA for PBNP, with available times traceable back to specific MAAP runs satisfies the intent of this action item and allows closure of the Level A WOG PRA Peer Review finding.

Structural Response ST-01 Level of Significance: B

Peer Review Observation: The ISLOCA fault tree analysis attempts to model the pressure retaining capability of a pipe beyond its design basis. There are some concerns with the analysis:

1. The fault tree logic for ISLOCA does not appear to be correct. The fault tree models valve failure combinations that can lead to conditions of pipe overpressure. It appears that the fault tree then attempts to combine these with events for (a) operator action to isolate the leak, (b) a split fraction for the break location being outside containment and (c) a split fraction for the conditional probability of pipe failure upon overpressure. The logic in the tree is not correct for the application of these conditioning factors.

2. The justification for the 10% split fraction for being outside containment is not provided.

3. The justification for the capability of the operator to prevent the ISLOCA by isolation is not provided.

4. The basis of the probability for the split fraction for conditional pipe failure is not provided. The use of failure rate models is not explained. Beta factors for common cause failure of valves are not referenced.

5. A single split fraction value (4.6E-4) for conditional probability of pipe failure is used for all pipe sections. There should be different values for different size pipes and different pressure ratings. Some of the values from NUREG/CR-5102 range to 2E-3. These are not represented in the analysis.

6. The basis (and definition) of the elementary failure probabilities is not defined. Leak is not distinguished from rupture.

Resolution: The ISLOCA fault tree was corrected to only credit operator action to isolate the leak where procedurally directed and where the MO valve has been sized to close against the expected DP. Piping failure probabilities from NUREG/CR-5102 were used and references for all data used were provided.

Initiating Events QU-01 Level of Significance: B

Peer Review Observation: Guidance for the model quantification process should be provided. A quantification process notebook should be developed. The notebook should define the steps required to reproduce the quantification results, and provide guidance for future updates. The notebook should include identification of software requirements, required inputs, and a step by step procedure for updating and quantifying the model (e.g., model quantification, application of post processor or recovery files). Specific guidance for selection of truncation values and any other key inputs should be provided. Other items to include in the guidance include:

- how the one-top CDF model is constructed (guidance);
- how any technical adjustments are made to the top of the FT or in the systems below (beyond what is documented in the system and event tree notebooks) to allow quantification;
- any special logic introduced to model sequences (flags, etc.);
- supporting files (such as RECOVERY, .BED, .PRM, etc.),
- summary input/output files;
- results summary files and conclusions;
- computer run parameters;
- type of computer and operating system, list and version of executable codes used;
- limitations of the code;
- References to supporting model notebooks (ET, system, HRA, data) etc.

Other post quantification steps required to validate the results should also be identified, such as a systematic search for dependent human actions, and a process to verify convergence of the CDF and LERF for the selected cutset truncation frequency. A set of key model results to be reviewed should also be identified as part of a standard post quantification review; e.g., event importances, initiator summaries, dominant cutsets.

Resolution: A quantification notebook was created that includes descriptions of the model, the quantification process, importance results for initiators and systems, discussions of asymmetries and convergence. Summary cutset files for CDF and LERF and importance listings of basic events are also included.

<u>Quantification QU-02 Level of Significance: B</u>

Peer Review Observation: Discussion with the PBNP PRA staff, and documentation in Section 5 of the 1993 PSA Report, indicate that sensitivity quantifications have been performed in the past to search for scenarios that may be underestimated due to multiple, potentially dependent, human actions being credited on the scenario. But there is no procedure in place to insure that this search for dependent HEPs will be performed after each update of the PSA. The results of this search should also be documented.

Resolution: A detailed description of the process used to search out dependent human actions was included in the HRA notebook.

<u>Quantification QU-03 Level of Significance: B</u>

Peer Review Observation: As with several other technical sub-elements in the quantification area, it was difficult to grade the current update of the PBNP PSA because it is a work in progress, and the PRA staff had not completed the final quantification or prepared a results summary.

The grading criteria for Subelement QU-13 requires that asymmetries in quantitative modeling be explained and examined to provide application users the necessary understanding regarding why such asymmetries are present in the model. This level of documentation was not found in previously documented results summaries for the PBNP PSA.

Resolution: A description of two prominent unit-to-unit asymmetries involving the loss of D01 initiating event and Unit 1 Train A electrical power was provided in the quantification notebook. This will be helpful in interpreting Safety Monitor results.

<u>Quantification QU-05 Level of Significance: B</u>

Peer Review Observation: At the time of this review, the quantification results were in a preliminary stage and the documentation/summary of results was not drafted. This vintage of the model had no documented evidence that the cutset truncation value was low enough to guarantee convergence of the CDF result to a stable value. No tier two documents were available documenting CDF convergence for previous model quantifications.

Resolution: A convergence study was performed for CDF and LERF with graphical results included in the quantification notebook.

<u>Quantification QU-06 Level of Significance: B</u>

Peer Review Observation: At present there is no formal analysis which addresses plant specific uncertainty or sensitivity issues for the current model. The PRA staff has a list of sensitivity cases to be executed when the model is completed. Other potential candidates for evaluation include: cases where success criteria analyses predict only small margins for success in terms of the number of trains required, or limited time available for operator actions.

Resolution: A parametric uncertainty analysis was performed for the quantified model to produce an estimate of the upper 95% and lower 5% confidence bounds for CDF.

<u>Quantification QU-08 Level of Significance: B</u>

Peer Review Observation: An update of the PRA had been performed, just prior to the Peer Review, so a thorough review by the PRA group of the final sequences had not yet been completed, nor had a summary report been prepared. A summary of contribution to CDF by initiating events was available, as was a listing of cutsets, and summary information regarding risk-important systems and operator actions.

A summary report should be prepared for the PRA, to provide a high level of confidence that all risk significant sequences are realistically modeled and sufficiently understood.

The Peer Review supplemental guidance (draft subtier criteria) states that, for a grade 3 classification for this sub-element, the following need to be addressed:

- The accident sequence results by sequence, sequence types, and total should be reviewed and compared to similar plants to assure reasonableness and to identify any exceptions.
- A detailed description of the Top 10 to 100 accident cutsets should be provided because they are important in ensuring that the model results are well understood and that modeling assumption impacts are likewise well known.

- Similarly, the dominant accident sequences or functional failure groups should also be discussed. These functional failure groups should be based on a scheme similar to that identified by NEI in NEI 91-04, Appendix B.

A review of non-dominant cutsets should also be performed to ensure that undesired conservatisms or un-addressed dependencies are not buried in the model. This is particularly important with respect to use of the Safety Monitor, in which concurrent unavailabilities of several components can result in once non-dominant cutsets becoming dominant.

Resolution: A discussion of dominant cutsets is provided in the quantification notebook. Overall results were compared to similar plants. The comparison showed that the PBNP results are not dissimilar to the PRA results for other Westinghouse plants.

Quantification QU-09 Level of Significance: B

Peer Review Observation: In quantification of the V-sequence (ISLOCA) frequency and any other cutsets whose frequency is proportional to X^N where X is a failure rate and N is a number of independent events in the cutset having the same failure rate, the mean frequency is not equal to the Nth power of the mean failure rate. For N=2 and the case where X is lognormally distributed,

$$\langle X^2 \rangle = M^2 + V,$$

where M is the mean failure rate and V is the variance of the lognormal distribution. The problem is more complicated with N>2. When dealing with the V-sequence the failure rates are very low and the variance is very high such that the variance term dominates. When this is taken into account the mean V-sequence frequency can easily be an order of magnitude greater than the result obtained using a mean point estimate (M^2). It is not clear that this has been taken into account in the V-sequence quantification.

Resolution: A corrected ISLOCA fault tree was quantified and a parametric uncertainty study was performed. The results showed the mean ISLOCA frequency from the uncertainty study to be within 5% of the mean produced by simple quantification of the fault tree.

Maintenance and Update MU-03 Level of Significance: B

Peer Review Observation: Guide ESG 5.1 specifies a fixed PRA update schedule (3 years) and also indicates (Section 4.1.4) that as plant changes are identified, they are to be reviewed for PRA impact. PRA impacts are determined by a PRA analyst and categorized as no impact, minor impact (change at next regular update), or immediate change (significant impact on the model and applications). Criteria for determining impact and disposition are intended to be in accordance with guidance in EPRI TR-105396, "PSA Applications Guide" (August 1995).

1. The guide implies but does not specify that change forms should be evaluated and dispositioned in a timely manner. If a backlog of changes existed, potentially important items could go unaddressed for a while.

2. The guide does not address the potential for cumulative impacts of minor impact changes during the period between regular PRA updates. It is possible that a number of individually minor impact changes that are awaiting implementation could have a cumulative significant impact on an application.

Resolution: All work for this F&O is now complete. The procedure for PRA model maintenance and update used at the time of the Peer Review was replaced by Procedure FP-PE-PRA-02. This procedure directs that pending changes to the PRA model are to be documented using the Action Request (AR) process for tracking and resolution. Issues are evaluated as they are entered as to the need for an immediate change. Those that could have a significant impact on PRA model results for applications are to be documented using the Corrective Action Program (CAP) AR process. Those issues that are judged to have minor or no impact on PRA model results for applications are entered into the non-CAP AR process. Using this method, a determination of significance must be made as soon as the issue enters the process and no time lag occurs.

Unresolved F&Os

Below is described each B-level WOG peer review F&O that remains unresolved. Also provided for each unresolved F&O is an assessment of how the issue raised in each could affect risk for post-EPU conditions. Resolution of all open F&Os is being tracked by site.

Thermal Hydraulic Analysis TH-05 Level of Significance: B

Peer Review Observation: Room Cooling: The need for room cooling is based on a 1990 Station Blackout study. The results of the study were confirmed by an actual test in March 1990, when the cooling to several electrical rooms was shut-off for 2 hours. There are concerns about the application of this analysis to the PRA:

1. The SBO study assumed component heat loads representative of SBO. The PRA is interested in heat loads under normal operating conditions. The PRA analysis to account for the effect of different heat loads is engineering judgment.

2. The SBO analysis often only extended to 2 or 4 hours, which are the coping times for SBO. Few analyses were continued to the full PRA mission time of 24 hours.

3. The SBO analysis is based on a proprietary Tenera code called HEATSINK. No information was available in the documentation to indicate how HEATSINK compares to GOTHIC or some other commonly accepted code.

4. The electrical configuration was changed when the 2 diesel generators were installed. The applicability of the old analysis to the new room configuration is not formally evaluated.

5. The SBO study data for the inverter rooms shows the temperature reaches 119°F after 2 hours, increasing to 146°F at 24 hours. The PRA dismissed HVAC requirements based on the heat-up for the first 2 hours and assumed with no justification that opening of doors and placement of fans would maintain the rooms below 120°F.

6. The outside air temperature during the HVAC test was 34°F. Possible results when the outside air temperature was 85°F were not evaluated.

Assessment for EPU: The issues delineated above have been partially resolved and are related to the applicability of analyses used to justify the need for room cooling in the PRA models.

Extensive and detailed computer modeling of room temperature response to a loss of HVAC was performed for four main rooms of concern: Vital Switchgear Room, Aux Feedwater Pump Room, Cable Spreading Room, and Control Room. The only room of these four that requires an operator action to prevent overheating of sensitive equipment is the CSR. Loss of ventilation flow in the CSR is annunciated in the Control Room. A computer run verified that the procedurally directed operator actions would be effective in eliminating this overheating concern.

A fifth area of some concern is the Primary Aux Building battery charger and instrument inverter rooms. These rooms have redundant cooling fans and coils. High temperature in these rooms is annunciated in the Control Room and is mitigated by opening the doors to these small rooms. Given the low probability of ventilation system failure combined with a failure of operator response action, building these failures into the instrument system logic will have little effect on overall system failure probability and it can be deferred until the system model is updated.

For the EPU project, the heat loads that will increase will be AFW pump motors and MFW pump motors. The increased heat loads have been evaluated for the EPU and it has been determined that no new needs for room cooling exist. The adequacy of the evaluations used for the current PRA models, as discussed above, is not related to plant configurations that will change as result of increased power levels. Therefore, it is concluded that the issues raised in F&O TH-05 will not affect the results of the EPU risk evaluation.

Thermal Hydraulic Analysis TH-10 Level of Significance: B

Peer Review Observation: A number of analyses that were originally performed to justify success criteria for other plant PRAs have been applied to the PBNP PRA (as discussed in the Event Tree Notebook), without adequate justification for their applicability to PBNP. Examples include:

1. In Section 4.0 (Success Criteria), for event ACX (accumulator injection), a discussion is provided justifying success for small LOCA with only one accumulator injecting following cooldown and depressurization in response to an inadequate core cooling (ICC) condition. The basis for the justification starts with an analysis performed for the 4-loop Wolf Creek plant using the TREAT code. Various plant parameters are used to "scale" the results to PBNP to reach the conclusion that success would also be achieved for PBNP. There are several potential areas of concern with this assessment. First, it is not clear, and not discussed, that a TREAT code prediction of plant response for Wolf Creek is directly scalable to PBNP. Second, the procedural guidance referenced is CSP-C.1, which is normally triggered by core exit thermocouple temperature of 1200°F - which in many PRAs is the assigned core damage condition; the steps in question are sufficiently far into the procedure that they would likely not be addressed for a relatively long time. There is no information provided to determine whether the referenced analysis accounts for this, and how it would apply to PBNP.

2. In Section 7.1 (Uncoupling of Core Melt and Containment Failure), a discussion is provided justifying the separation between core damage and containment failure models (i.e., the absence of containment systems from the Level 1 event trees). As the basis for the justification, reference is made to "an internal letter from Fauske and Associates LLC (FAI) to Westinghouse based on MAAP runs with the ZION parameter file." No discussion is provided to demonstrate that an analysis performed with the Zion plant parameter file is applicable to

PBNP. It might be that the referenced internal Westinghouse memo provides this basis, but the memo is not included in the reference list or as an attachment to the notebook.

3. There are references in Section 8.0 of the Event Tree Notebook that suggest that other applications of analyses originally performed for other non-2-loop plants have been used in the PBNP PRA, e.g., Farley plant TREAT analysis.

Assessment for EPU: Other plant references are no longer needed since plant-specific TH analyses were performed. These references need to be eliminated from PRA 3.0 Event Tree/Top Logic Notebook, especially from Section 4. Because these references are no longer relied upon, this can be resolved by a documentation change only. Therefore, it is concluded that the issues raised in F&O TH-10 will not affect the results of the EPU risk evaluation

System Analysis SY-10 Level of Significance: B

Peer Review Observation: Each revised system notebook includes a listing of success criteria, but the bases for the success criteria are not provided. For example:

a. In the Service Water Notebook (PRA 5.13), success criteria are stated as 3 or 4 pumps start and run, depending on whether or not non-essential loads are isolated; but the source analysis is not referenced.

b. In the Auxiliary Feedwater System Notebook (PRA 5.9), the System Description section notes that the operator must be prepared to establish an alternative source of water to the pump suction should the condensate storage tanks become depleted, and that service water and fire water are modeled in the PSA as alternative sources. But the listing of success criteria does not mention the need for operator action to align backup sources, and doesn't address timing of depletion of CST.

The lack of clarity in stating the success criteria makes it difficult to determine whether they are conservative or realistic. The general tone of the success criteria discussions in the System Notebooks and Event Tree Notebook leads to the feeling that the success criteria are conservative. Additional PRA realism might be attained through a documented thorough evaluation of the system success criteria, to establish where use of design basis criteria is realistic and also to establish if and where more realistic criteria might be established.

Assessment for EPU: A plant specific basis for system success criteria now exists and is documented in Section 4.0 of the Event Tree Notebook. The latest models make use of the latest success criteria evaluations but not all references have been updated. Since the PRA models use the latest success criteria; updating of documentation can be completed at a later date. Therefore, it is concluded that the issues raised in F&O SY-10 will not affect the results of the EPU risk evaluation

Data Analysis DA-03 Level of Significance: B

Peer Review Observation: There is very little guidance for and documentation of the process for determining the common cause groups. Guidance for the common cause failure (CCF) group identification is needed. The Data Analysis Notebook (as of 6/19/01) focuses more on the quantification of the CCF events. The documentation does not clearly define which groups were modeled. Section 3.1.3 (page 14 of 74) provides a list of CCF groups that "were considered", but a slightly different list of potential component groups is provided several pages later. Also, there is no discussion of how to model possible asymmetric groups (e.g., two different diesel groups). Without additional guidance or documentation, it is difficult to reproduce the CCF grouping portion of the analysis.

Assessment for EPU: The common cause groups in the current PRA were selected by two PRA analysts working together, so there is consistency across the systems. The issue remaining is to document the method used. Therefore, it is concluded that the issues raised in F&O DA-03 will not affect the results of the EPU risk evaluation.

<u>Data Analysis DA-05 Level of Significance: B</u>

Peer Review Observation: There is a lack of documentation for the development of CCF groups, particularly those CCF groups that are not "standard." Specific examples include:

- Component Cooling Water Pumps: The current model includes no CCF contribution for the failure to run of the normally operating and standby pumps.
- Service Water Pumps: For this group of six pumps, CCF failures (start and run) are only considered for the standby pumps. There is no justification for de-coupling the running and standby pumps or for excluding potential CCF contributions for the running pumps. Also, the global CCF failure event (all six pumps fail to run), does not include the probability of pumps two through 5 failing (the probability of these events must be included in the global event, or the intermediate events should be modeled. If less than six of the pumps are considered to be included in the CCF group, the INEEL parameters for the reduced group size should be used in the quantification).
- The basis for the instrument air CCF unavailabilities should be reviewed due to the importance of this event to the current CDF quantification. A single event modeling failure of all four compressors to start and run is currently in the model. The event is based on "generic" CCF parameters (i.e., not specific to compressors). Also, the intermediate CCF events do not appear to be modeled (i.e., failure of 2 of 4, failure of 3 of 4) but the global failure term for failure of all four appears to include only the probability of all 4 failing. This is non-conservative.

Assessment for EPU: A justification for the service water pump common cause groupings was added to PRA 5.13, Service Water System Notebook. A section justifying common cause groups still needs to be added to system notebooks for PRA 5.2 (4160 VAC), PRA 5.4 (EDG), PRA 5.5 (Y (120 VAC)), PRA 5.6 (125 VDC), and PRA 5.7 (Accumulators).

The common cause failure groups for CCW pumps and Instrument Air compressors will be defined when the system model notebooks are upgraded. Since neither of these systems will have success criteria impacted by the EPU, and since instrument air is a low-risk-significant system, resolution of this issue is assessed as having no impact to the EPU. Also, for the electrical and accumulators notebooks, this is a documentation change only. Therefore, it is concluded that the issues raised in F&O DA-05 will not affect the results of the EPU risk evaluation.

Data Analysis DA-06 Level of Significance: B

Peer Review Observation: Common cause failure to start and run is modeled for two groups of diesel generators. Diesels G-01 and G-02 are modeled in one group, and diesels G-03 and G-04 are modeled in the other. There is no CCF event representing failure of three or four of these diesels. The two sets of diesels do have clear differences (e.g., different manufacturers, different locations and cooling systems) but may also have features in common (fuel oil supply, maintenance crews). The current model provides no justification for excluding common cause events involving failure of three or more diesels.

Assessment for EPU: The diesels are of different generations and have enough different components to allow excluding the two pairs as a group of four. The fuel oil systems, which are identical, are modeled separately and have a common cause group of four. This explanation just needs to be documented. Therefore, it is concluded that the issues raised in F&O DA-06 will not affect the results of the EPU risk evaluation.

Human Reliability Analysis HR-04 Level of Significance: B

Peer Review Observation: There is no guidance for inclusion of miscalibration errors in the fault tree models. Consequently, the entire plant model includes no miscalibration events. (As a note, guidance for inclusion of restoration errors is provided and there are restoration errors in the model).

Assessment for EPU: A study was performed in 2005 to systematically search for miscalibration events for instrumentation that needed to be included in the PRA model. This study identified three miscalibration events that should be included. A sensitivity study performed on these three events for MSPI showed that they will not significantly affect results of the PRA. Therefore, it is concluded that the issues raised in F&O HR-04 will not affect the results of the EPU risk evaluation.

Human Reliability Analysis HR-05 Level of Significance: B

Peer Review Observation: All pre-initiator HEPs are assigned a failure rate of 1E-3 or 5E-3. These are developed by assigning a basic HEP for the first failure and a single independent error for checking/verification. While the PRA staff indicates that this reflects how restoration activities are carried out at PBNP, the reviewers believe that there are very likely opportunities to take credit for other restoration "recovery" factors such as walkdowns. The pre-initiator human error event probabilities for the PBNP PRA appear to be somewhat higher than what is typically seen in other PRAs.

Assessment for EPU: Based on some preliminary Type A HEPs developed, plant specific values are not likely to change much from the screening value now used. Restoration human errors currently in the model each contribute less than 1% to the total CDF. A sensitivity study performed for MSPI showed these HEPs contribute little to overall results. Therefore, it is concluded that the issues raised in F&O HR-05 will not affect the results of the EPU risk evaluation.

Quantification QU-10 Level of Significance: B

Peer Review Observation: The initiating event frequency for loss of instrument air is dominated by common cause failure of all four air compressors (i.e., basic event IA--K---CM--ALL4). This is the leading CCF contributor to core damage (based on the CDF quantification available the week of the review). In the course of reviewing the dominant cutsets, it was determined that the quantification of this event for the initiating event analysis was calculated incorrectly. Common cause failure of all four compressors to run was calculated as the product of the hourly failure rate, the MGL parameters (Beta, Gamma and Delta) and a mission or exposure time of 24 hours.

The exposure time for the initiating event calculation should have been 8760 (i.e., number of hours per year). It is recognized that using 8760 in the IE calculation would yield an initiating event frequency of about 0.1 per year, which is clearly too high a value based on plant and industry experience. But reducing the exposure time to 24 is not a valid method for correcting for this over estimation, since the resulting cutsets do not represent an annual frequency.

Assessment for EPU: The PBNP PRA staff has determined that the current method of calculating CCF for the compressors appears to be correct but that the method used needs to be documented. Therefore, it is concluded that the issues raised in F&O QU-10 will not affect the results of the EPU risk evaluation.

Containment Performance L2-04 Level of Significance: B

Peer Review Observation: Equipment Survivability: There was no evidence of a search (as part of either the Level 1 or Level 2 analysis) for equipment which was credited in but not qualified to operate in a post core melt environment. The two likely candidates are the fan coolers and the PORVs. Page 303 of 320 of the IPE bases the success criterion of only needing one fan cooler unit to protect the containment from overpressure on an un-referenced MAAP run, so it was not possible for the peer reviewers to review this.

In addition, no evaluation was available to indicate that the CFCU's can continue to perform in the post-core damage environments for up to 48 hours (the Level 2 mission time). The Level 2 concludes that the containment will fail from over pressure at 48 hours or longer, if no containment heat removal is available. The effect of prolonged high containment temperature on the containment failure pressure or the CFCU operability is not considered. These two effects could combine to lead to containment failure for sequences with postulated operability of CFCU.

Assessment for EPU: This evaluation was included in the System Walkdown Notebook, PSA 4.14, from the original IPE for systems located outside of containment. The Containment Walkdown Notebook, PSA 4.16, also from the original IPE, did not address equipment survivability post-accident. These two notebooks were not reviewed by the Peer Review team. Survivability of equipment located inside containment still needs to be justified. However, the dominant contributions to LERF for the PBNP come from steam generator tube rupture sequences, a direct bypass of the containment boundary. Since no equipment inside containment is significant to mitigating SGTR sequences, it is concluded that the issues raised in F&O L2-04 will not affect the results of the EPU risk evaluation.

Containment Performance L2-06 Level of Significance: B

Peer Review Observation: The PBNP LERF is defined as (a) all SGTR sequences, (b) all ISLOCA, c) all core damage sequences with containment isolation failure. No other contributions were included. Core melt early and core melt late are not distinguished.

The PBNP LERF does not address Emergency Action Levels (EAL). The LERF includes all SGTR core damage sequences, regardless of the time of release. This is conservative.

The LERF is derived by a top logic fault tree. There is an inconsistency between the core damage top logic model and the LERF top logic model with respect to treatment of induced SG tube ruptures during steam and feed line breaks. In the Level 1 CD model, these pre-core-damage induced tube ruptures are treated like SGTR. However, in the LERF model, they are ignored, whereas all SGTR initiated core damage is considered LERF. Post-core-melt-induced tube rupture is not typically addressed in LERF, but there is no precedent to exclude pre-core-melt induced tube ruptures from LERF.

Assessment for EPU: The PBNP PRA model used for the EPU evaluation has recently been updated and consistently addresses LERF. As discussed in the F&O, post-core melt, induced SGTR is not typically included in LERF. Large secondary line breaks are only small contributors to overall risk so any additional contribution to LERF from secondary line break-induced SGTRs would be minimal. Therefore, it is concluded that the issues raised in F&O L2-06 will not affect the results of the EPU risk evaluation.

Overall Assessment of PBNP PRA Quality

Based on a review of the steps taken to resolve the A-level and B-level F&Os and the assessment of the unresolved F&Os presented above, it is concluded that the PBNP PRA quality and technical adequacy are adequate to support the risk review of the EPU. Note that new thermal hydraulic analyses were performed at EPU conditions using the MAAP code to confirm operator timing and system success criteria for the EPU PRA evaluation.

The extended power uprate is not a risk informed application in that deterministic calculations are used to prove acceptability. This risk evaluation is provided for information purposes and insights.

Assumptions for EPU Assessment

The following assumptions were used in the review of the PRA:

1. Unless stated otherwise, actuation setpoint changes, if any, will have no impact on accident sequence timing

2. Procedures will be revised to reflect new flow requirements and power levels as needed

3. Instruments that are replaced or re-scaled will have similar displays to the original instruments and no change to the HRA will be required to address such instrumentation changes

4. Modifications to the electrical grid needed to support the post-EPU power output from the PBNP units will be completed prior to EPU

EPU-Related Modifications Considered

Significant modifications to both PBNP units will be required to implement the EPU. This assessment evaluates the change in core damage frequency (CDF) and large early release frequency (LERF) that can be expected as a result of proposed modifications to the PBNP Nuclear Plant (PBNP) for implementation of the EPU. Modifications considered in this review include:

1. Higher capacity main feedwater (MFW) pumps and motors and feedwater regulating valve trim.

2. Replacement of all feedwater heaters

3. Addition of fast-acting feedwater isolation valves

4. Replacement of MFW minimum flow bypass lines and control systems

5. Replacement of normal and emergency heater drain valves, reheater drain valves, and heater drain tank dump valves (19 valves on each unit)

6. Replacement of gravity drain piping associated with feedwater heaters 5A, 5B, 4A, 4B, and heater drain tank.

7. Modification of main steam and feedwater piping supports to accommodate increased loads

8. Improve isolated phase bus duct cooling system

9. Replace main transformers

10. Install a new main generator output 19kV circuit breaker on each unit

11. Modification or replacement of portions of balance-of-plant (BOP) instrumentation

12. Installation of additional heater drain tank level control systems

13. Upgrade disks on main steam isolation valves

14. Replace high-pressure turbine steam path and associated inlet piping and upgrade control valves

15. Rewind main generator

16. Modification of steam generator moisture separators

17. Increase the minimum required volume in the condensate storage tank (CST)

The following changes are being installed to ensure adequate AFW flow for design-basis accidents after the planned extended power uprate (EPU) and to improve the availability and reliability of secondary cooling. Modifications include installation of two new motor-driven AFW pumps (MDAFPs) and conversion of the existing MDAFPs for use as standby steam generator (SSG) pumps. The AFW system design changes planned include the following:

- The 250 horsepower (hp) MDAFPs along with their associated piping and components will be converted to SSG pumps. This system will be manually actuated and used during startup and shutdown operation, as well as serve as a backup to the AFW system.
- The new 350 hp pumps along with associated valves and piping needed to provide flow to steam generators will be installed. These new pumps will be powered from 4160 VAC buses instead of 480 VAC buses and one pump will be dedicated to each unit.
- AFW system configuration will be changed so that each MDAFP pump is normally aligned and capable of providing flow to both steam generators in its associated unit
- Flow control valves will be provided for each steam generator to automatically limit flow from the new 350 hp MDAFPs, so that pump failure due to high flow-induced cavitation can be prevented without operator action.
- The new MDAFPs will not require external cooling for motors or bearings
- Fire separation between the MDAFPs and TDAFPs will be increased
- AFW pump suction will be automatically aligned to service water on CST suction line low pressure, thereby eliminating the need for operator action to provide a long-term source of steam generator makeup
- The SSG pumps will be capable of providing flow to any of the four steam generators at PBNP.
- The SSG pumps will be manually initiated.
- Power for the SSG pumps will be from sources capable of being supplied from an onsite power source. This will require operator action, including the operators ensuring that powering the SSG loads will not overload the selected onsite source.

Technical Evaluation of EPU Impacts to PBNP PRA Internal Events

This section describes evaluation of the potential effects of the EPU to the overall risk for PBNP as evaluated by the PRA. Each of the issues identified as having the potential for a numerical impact on the PRA is evaluated to determine the expected effect. After that, then all the identified impacts are included in the PBNP PRA models and combined effects quantified to determine the risk change expected as a result of the EPU. The results of the quantification are then used to identify potential plant improvements that could offset any increase in risk resulting from the EPU.

Risk evaluation conclusions and insights are provided for each discussion topic.

Internal Initiating Events

The PBNP internal events PRA included loss of coolant accident (LOCA), steam generator tube rupture (SGTR), loss of offsite power (LOOP), secondary line break, and transient initiators. For internal event initiators, the underlying contributors to these initiating events are reviewed to determine the potential effects of the EPU on the initiating event frequencies. The results of these evaluations are summarized in the sub-sections that follow.

Loss of Coolant Accident (LOCA)

These frequencies (all sizes) are determined by the potential for passive pipe failures. The EPU does not involve changes to the reactor coolant system or interfacing system piping. Therefore, the LOCA pipe failure frequency values are not affected by the EPU.

A LOCA can also occur as a result of a reactor coolant system (RCS) pressure excursion that results in a stuck open pressurizer power operated relief valve (PORV) or safety relief valve (SRV). The PBNP PRA estimates the probability that a PORV or SRV opens based on the number of transients that have actually occurred at the plant and no events of an inadvertent opening of a PORV or SRV. An update to the PRA transient analysis shows that no appreciable change in the post-trip pressure response is expected. Although the analyses do show a more rapid pressure response for post-EPU conditions, these results are for plant response following a loss of offsite power when pressurizer sprays and RCPs would be unavailable. Availability of pressurizer sprays would be expected to mitigate post-trip pressure increases. Even for loss of offsite power events, the analyses show only a change in timing for pressure changes, but no overall change in pressure response. Non-LOCA design basis accident analyses show that a loss of load event could result in a pressure transient that could challenge pressurizer PORVs or SRVs. Best-estimate analyses show no significant change in post-trip RCS pressure response. Since the total frequency of small and medium LOCAs includes the frequency of stuck open relief valves, the frequency of small and medium LOCAs will be increased.

The frequency of a small LOCA caused by a transient-induced pressure excursion was calculated in the initiating events analysis to be 2.2E-05 per year. This frequency is based on the number of PORVs (2), the frequency of transients (0.46 events per year), the probability of challenging a PORV given a transient (8.1E-03), and the probability that a PORV fails to reseat (3E-03). Of these parameters, the frequency of transients and the probability of challenging a PORV could be affected by the EPU. Although no specific data have been identified, it will be assumed that the transient frequency will increase by 20%. Although the best estimate evaluations show no significant change in post-trip pressure response, the design basis analyses show a significant change in post-trip pressure response. Because the design basis analyses show that a loss of load event could result in a pressure transient that could challenge pressurizer PORVs or SRVs, a significant increase in probability of PORV challenge will be used to provide a bounding estimate of any risk change. This EPU analysis will assume that the probability of challenging a PORV will increase by 300%. These changes would cause the frequency of a transient-induced small LOCA to increase to 7.9E-05 per year. Therefore, the increase in small LOCA frequency would be:

(7.9E-05 per year) - (2.2E-05 per year) = 5.7E-05 per year.

This is added to the base value for small LOCA of 3.2E-03 per year to give a revised estimate for post-EPU small LOCA frequency of:

(3.2E-03 per year) + (5.7E-05 per year) = 3.3E-03 per year.

The frequency of a medium LOCA caused by a transient-induced pressure excursion was calculated in the initiating events analysis to be 7.4E-05 per year. This frequency is based on the number of SRVs (2), the frequency of transients (0.46 events per year), the probability of challenging a SRV given a transient (8.1E-03), and the probability that a SRV fails to reseat (1E-02). Of these parameters, the frequency of transients and the probability of challenging a SRV could be affected by the EPU. Although no specific data have been identified, it will be assumed that the transient frequency will increase by 20%. Because the design basis analyses show that a loss of load event could result in a pressure transient that could challenge pressurizer PORVs or SRVs, a significant increase in probability of SRV challenge will be used to provide a bounding estimate of any risk change. This analysis will assume that the probability of challenging a SRV will increase by 300%. These changes would cause the frequency of a transient-induced medium LOCA to increase to 2.7E-04 per year. Therefore, the increase in medium LOCA frequency would be:

(2.7E-04 per year) - (7.4E-05 per year) = 1.9E-04 per year.

This is added to the base value for medium LOCA of 1.1E-04 per year to give a revised estimate for post-EPU medium LOCA frequency of:

(1.1E-04 per year) + (1.9E-04 per year) = 3.0E-04 per year.

The frequency of large and excessive LOCAs is not dependent on transient frequency or pressure response. Therefore, it is concluded that the only changes to LOCA frequency expected as a result of the EPU are for small and medium LOCAs with the estimated changes are shown below

Basic Event	**Event Description**	**Base Value**	**Percent Increase**	**Updated Value**
INIT-S2	Initiating Event Small LOCA	3.20E-03	3%	3.30E-03
INIT-S1	Initiating Event Medium LOCA	1.10E-04	170%	3.00E-04

Steam Generator Tube Rupture (SGTR)

The frequency of SGTR is independent of power level. Although the EPU will result in increased steam flow and minor changes in primary and secondary side temperatures and pressures, none of these changes are significant. Therefore, it is concluded that no change in SGTR frequency is expected as a result of the EPU.

Loss of Offsite Power (LOOP)

An analysis by the system operator of the impact of the PBNP EPU on the reliability of the 345 kV transmission grid was performed. Several modifications to offsite switching stations will be required prior to completion of the EPU. Assuming that these grid-related upgrades are completed, the system study indicates that the thermal, voltage, and stability performance are not degraded by the EPU. Offsite power is addressed in LR Section 2.3.2, Offsite Power System.

As part of the EPU, a new main generator output circuit breaker will be installed on each unit for use when a generator trip is required. The new breakers will allow the existing 345kV breakers, F52-122(142), to remain closed to feed auxiliary power to the plant's AC auxiliary system via the Unit Auxiliary Transformer (UAT, 1(2)-X02) after the generator trip. The A01 and A02 buses will remain powered from the 345kV system for any plant transients other than a loss of X-01 or X-02 or a failure of the new generator output breaker. This change will greatly improve the performance for the safety related 4160V buses after a unit trip since the balance of plant large motor load will not automatically transfer to the 1(2)-X04 transformer feed causing a significant voltage drop.

The LOOP frequency at PBNP is calculated by considering LOOP events that have occurred throughout the industry and performing a Bayesian update to determine the frequency. Although the installation of generator output breakers will improve performance of the in-plant electrical power systems, the method used to determine LOOP frequency will not change and no new failure modes related to loss of offsite power have been identified. Therefore, it is concluded that no changes to the frequency of LOOP will be expected as a result of the EPU.

<u>Steam Line/Feed Line Break</u>

The frequency of secondary line breaks calculation considers failures due to pipe breaks and steam and feed valve failure. Secondary line breaks are also divided into breaks of steam or feedwater lines inside containment and breaks of steam lines outside containment.

The frequency of secondary pipe breaks is based on the values which are independent of power level. However, studies summarized in Reference 3 indicated that parts of the secondary systems that could be considered wear areas in the FAC program may require replacement earlier for post-EPU power levels than for current power levels. Therefore, secondary line break frequency will be increased. Because no specific areas or failure mechanisms were identified in the study, judgment is used to estimate the magnitude of the increase expected.

Basic Event	Event Description	Base Value	Percent Increase	Updated Value
INIT-TSB	Initiating Event Steam Line Break Outside Containment	1.00E-02	20%	1.2E-02
INIT-TFB	Initiating Event Steam /Feed Break Inside Containment	4.40E-03	20%	5.3E-03

<u>Transients</u>

An assessment of each transient initiating event is performed to determine if the frequency of any transient initiating event could be impacted by any component or system changes.

<u>Transients With the Power Conversion System</u>

This category consists of all transients which cause a reactor trip but do not significantly affect operation or use of the power conversion system (PCS) or necessary safety systems. By definition, offsite power is also assumed to be initially available. The PCS consists of the main feedwater, condensate, turbine bypass systems, and the condenser. For all initiators in this category, the PCS, with at least one condensate pump, is available or can be restored for decay heat removal if auxiliary feedwater is not available.

The frequency for transients with the power conversion system is developed using PBNP-specific operating history. New, fail as-is Main Feedwater Isolation Valves (MFIVs) are being installed, but this is not expected to significantly affect the probability of loss of normal feedwater. Although no other planned changes were identified that would have a direct impact on transient frequency, the plant will be operating with new secondary side equipment and with parameters that are new to the operators. Therefore, the frequency for transients with the power conversion will be increased. Judgment is used to estimate the magnitude of the increase expected.

Basic Event	Event Description	Base Value	Percent Increase	Updated Value
INIT-T3	Initiating Event Transient with PCS	0.71	20%	0.85

Transients Without the Power Conversion System

This category consists of transients which involve significant failure of the PCS but do not affect safety systems. In such a case, the PCS is not available for decay heat removal.

The frequency for transients without the power conversion system is developed using PBNP-specific operating history. Although no planned changes were identified that would have a direct impact on transient frequency, the plant will be operating with new secondary side equipment and with parameters that are new to the operators. In addition, the new fast-acting MFIVs add a new potential failure that could cause a loss of the PCS. That is, a common-cause failure of the new valves to transfer closed would result in a transient without the PCS. Therefore, the frequency for transients without the power conversion will be increased. Because no specific areas or failure mechanisms, other than common cause failure of the MFIVs, were identified in the study, judgment is used to estimate the magnitude of the increase expected.

Basic Event	Event Description	Base Value	Percent Increase	Updated Value
INIT-T2	Initiating Event Transient without PCS	0.19	20%	0.23

Loss of Service Water

This event results from a total loss of the service water system. Loss of the service water system will result in a loss of cooling to safety related and secondary plant systems. Although service water heat loads will increase as a result of the EPU, the system will continue to provide the required heat removal capability at EPU conditions and in postulated accident scenarios. The analyses presented in Reference 3 indicate that no modifications to the service water system are required as a result of the EPU. The loss of service water frequency for the PBNP PRA is determined using a fault tree model so should any future system changes be required, they would be reflected in the fault tree model, and, thus the loss of service water initiating event frequency. However, since no system changes are required for the service water system, it is concluded that no changes to the loss of service water initiating event frequency will be expected as a result of the EPU.

Loss of Component Cooling Water (CCW)

This initiating event includes a total loss of the component cooling water system and considers the possibility of loss of both component cooling water pumps, combinations of component failures, or rupture in the component cooling water system. Although CCW heat loads will increase as a result of the EPU, the system will continue to provide the required heat removal capability at EPU conditions and in postulated accident scenarios. The analyses presented in Reference 3 indicate that no modifications to the CCW system are required as a result of the EPU and that the CCW system is adequately sized to support required accident heat removal needs. The loss of CCW frequency for the PBNP PRA is determined using a fault tree model so should any future system changes be required, they would be reflected in the fault tree model, and, thus the loss of CCW initiating event frequency. However, since no system changes are required for the CCW system, it is concluded that no changes to the loss of CCW initiating event frequency will be expected as a result of the EPU.

Loss of 125 VDC Bus D01

The loss of 125 volt DC Bus D01 event trees apply to those events resulting in the extended loss of 125 volt DC power from Bus D01 buses followed by reactor trip. The resulting transient is similar to the transient with or without power conversion system available except that a number of components could be disabled or may not automatically start due to the bus failure.

Other than some minor instrumentation and control modifications and moving the AFW pump motor power from the 480 VAC to the 4160 VAC power, there are no changes to the 125VDC system. These load changes are considered negligible. The loss of Bus D01 frequency for the PBNP PRA is determined using a fault tree model so should any future system changes be required, they would be reflected in the fault tree model, and, thus the loss of 125 VDC Bus D01 initiating event frequency. However, since no system changes are required for the 125 VDC system, it is concluded that no changes to the loss of 125 VDC Bus D01 initiating event frequency will be expected as a result of the EPU.

Loss of 125 VDC Bus D02

For the same reasons discussed above for the Loss of 125 VDC Bus D01, it is concluded that no changes to the loss of 125 VDC Bus D02 initiating event frequency will be expected as a result of the EPU.

Loss of Instrument Air

This event tree models the total loss of instrument air at PBNP. There are no substantive changes to the instrument air system as a result of the EPU. Addition of the fast-acting MFIVs, while requiring instrument air, would not impact the failure modes for a loss of instrument air. The loss of instrument air frequency for the PBNP PRA is determined using a fault tree model so should any future system changes be required, they would be reflected in the fault tree model, and, thus the loss of instrument air initiating event frequency. However, since no system changes are required for the instrument air system, it is concluded that no changes to the loss of instrument air initiating event frequency will be expected as a result of the EPU.

Station Blackout (SBO)

The frequency for a SBO is not calculated as a separate, individual event. Rather, the SBO frequency is determined through the quantification process using initiating events discussed above and system logic models to estimate the probability of losing all AC power. Any changes to system logic required as a result of the EPU are discussed in the section that follow and will be included as necessary in the quantification process. Therefore, no changes are needed to address the SBO frequency for the EPU.

Anticipated Transient Without Scram (ATWS)

Similar to the discussion for SBO, ATWS frequency is not calculated directly but is determined through the overall quantification process. Therefore, no changes are needed to address the ATWS frequency for the EPU.

Internal Events Accident Sequence Analysis and Event Trees

This section describes the assessment of how the EPU could affect the event tree analysis for the PBNP PRA. An event tree analysis is done for each initiating event category discussed above. The event trees are constructed by identifying front line safety systems and operator actions that either respond to the initiating events or mitigate failures of other frontline systems. The event tree models are delineated to lead to safe states, transfers to other trees, or core damage states.

The success criteria for frontline systems and operator actions identified in the event trees are developed as part of the event tree analysis and used as input to the systems analyses and human reliability analysis (HRA).

In the subsections that follow, the potential for the EPU to affect the accident sequence and event tree analysis for each event tree is evaluated and discussed.

Large LOCA

The Large LOCA event tree model requires low-pressure injection and recirculation. Although the power levels will be higher, the analyses presented in Reference 3 indicate no changes in success criteria or timing information. Therefore, no changes to the Large LOCA event tree analysis will be expected as a result of the EPU.

Medium LOCA

The Medium LOCA event tree model includes high-pressure injection as the primary means to maintain RCS inventory control. Following success of high-pressure injection, long-term cooling through ECCS recirculation is needed. Should high-pressure injection fail, the medium LOCA event tree models rapid RCS depressurization to effect low-pressure injection. RCS depressurization is performed by using steam generator cooling to remove the latent heat from the RCS. Although some minor changes in timing of the cues and required actions for RCS depressurization would be expected, the effect of these changes is evaluated under the HRA for the specific actions modeled. The analyses indicate that no changes in the overall success criteria would occur. Therefore, no changes to the Medium LOCA event tree analysis will be expected as a result of the EPU.

Small LOCA

The Small LOCA event tree model includes high-pressure injection as the primary means to maintain RCS inventory control. Following success of high-pressure injection, long-term cooling using AFW is evaluated. Should AFW fail, primary bleed and feed is modeled for decay heat removal. Should high-pressure injection fail, the small LOCA event tree models rapid RCS depressurization to effect low-pressure injection. RCS depressurization is performed by using steam generator cooling to remove the latent heat from the RCS. Although some minor changes in timing of the cues and required actions for RCS depressurization would be expected, the effect of these changes would be evaluated under the HRA for the specific actions modeled. The analyses indicate that no changes in the overall success criteria for injection, depressurization, and recirculation would occur. Changes in the timing of actions to initiate feed and bleed cooling would be expected as a result of the higher decay heat levels expected after the EPU. The analyses indicate only changes in the overall timing for bleed and feed cooling, not changes in the equipment required. The effect of the timing changes is evaluated under the HRA for the specific actions modeled. Therefore, no changes to the Small LOCA event tree analysis will be expected as a result of the EPU.

Steam Generator Tube Rupture

The accident progression in the SGTR event tree model includes high-pressure injection to maintain RCS inventory followed by operator action to isolate the faulted steam generator and depressurize the RCS to stop the loss of primary coolant. Actions to isolate the steam generator are modeled for two situations, isolation and depressurization before overfill of the steam generator and depressurization after overfill of the steam generator. Timing for overfill was modeled as 60 minutes. Given the higher flow of the AFW pumps and the higher decay heat levels, the time to overfill could be significantly different after the EPU. However, any change in timing is reflected in the HRA for the specific actions modeled. Therefore, no changes to the SGTR event tree analysis will be expected as a result of the EPU.

Interfacing Systems LOCA

The ISLOCA event tree model assumes that core damage occurs following the ISLOCA initiating event. Therefore, no changes to the ISLOCA event tree analysis will be expected as a result of the EPU.

Excessive LOCA

The excessive LOCA event tree model assumes that core damage occurs following the initiating event. Therefore, no changes to the excessive LOCA event tree analysis will be expected as a result of the EPU.

Transient with Power Conversion System (T3)

The transient with power conversion systems event tree model includes secondary heat removal with either AFW or main feedwater. Should secondary cooling fail, primary bleed and feed is modeled for decay heat removal. Although the flow required from AFW is higher as a result of the EPU, installation of the new AFW pumps will allow one pump to provide adequate flow. The EPU will result in changes in steam generator mass and decay heat levels so the time available to initiate bleed and feed cooling will be shorter. The analyses indicate only changes in the overall timing for bleed and feed cooling, not changes in the equipment directly required for accident mitigation. However, cooling for feedwater and condensate pump seals and oil coolers will now be provided by condensate, so service water will not be required as a support system for MFW. The effect of the timing changes is evaluated under the HRA for the specific actions modeled. Therefore, no changes to the transient with power conversion event tree analysis will be expected as a result of the EPU.

Transient without Power Conversion System

The transient without power conversion systems event tree model includes secondary heat removal with AFW. Should AFW fail, primary bleed and feed is modeled for decay heat removal. Although the flow required from AFW is higher, installation of the new AFW pumps will allow one pump to provide adequate flow. The EPU will result in changes in steam generator mass and decay heat levels so the time available to initiate bleed and feed cooling will be shorter. The analyses indicate only changes in the overall timing for bleed and feed cooling, not changes in the equipment required. The effect of the timing changes is evaluated under the HRA for the specific actions modeled. Therefore, no changes to the transient without power conversion event tree analysis will be expected as a result of the EPU.

Steamline Break Outside Containment

The steamline break outside containment event tree models actions needed to prevent pressurized thermal shock (PTS), prevent an induced SGTR, and maintain decay heat removal. Actions and systems needed to prevent or mitigate PTS and an induced SGTR are not related to parameters that will be affected by the EPU. Mitigation of induced SGTR accident sequences progress similarly to SGTR accident sequences that follow random SGTR events. As discussed above, no changes in the accident sequence analysis for random SGTR events resulted from the EPU so no change to the accident sequence analysis for induced SGTR sequences is needed. For induced SGTRs following steamline break events, the accident sequence modeled in the event tree is simplified to delete non-significant sequences. Secondary heat removal considers AFW. Should AFW fail, primary bleed and feed is modeled for decay heat removal. Although the flow required from AFW is higher as a result of the EPU, installation of the new MDAFW pumps will allow one pump to provide adequate flow. The EPU will result in changes in steam generator mass and decay heat levels so the time available to initiate bleed and feed cooling will be shorter. The analyses indicate only changes in the overall timing for bleed and feed cooling, not changes in the equipment required. The effect of the timing changes is evaluated under the HRA for the specific actions modeled. Therefore, no changes to the steamline break outside containment event tree analysis will be expected as a result of the EPU.

Steamline Break Inside Containment

The steamline break inside containment event tree models actions needed to prevent pressurized thermal shock (PTS), prevent an induced SGTR, and maintain decay heat removal. Actions and systems needed to prevent or mitigate PTS and an induced SGTR are not related to parameters that will be affected by the EPU. Mitigation of induced SGTR accident sequences progress similarly to SGTR accident sequences that follow random SGTR events. As discussed above, no changes in the accident sequence analysis for random SGTR events resulted from the EPU so; no change to the accident sequence analysis for induced SGTR sequences is needed.

For induced SGTRs following steamline break events, the accident sequence modeled in the event tree is simplified to delete non-significant sequences. Secondary heat removal considers AFW. Should AFW fail, primary bleed and feed is modeled for decay heat removal. Although the flow required from AFW is higher as a result of the EPU, installation of the new MDAFW pumps will allow one pump to provide adequate flow. The EPU will result in changes in steam generator mass and decay heat levels so the time available to initiate bleed and feed cooling will be shorter. The analyses indicate only changes in the overall timing for bleed and feed cooling, not changes in the equipment required. The effect of the timing changes is evaluated under the HRA for the specific actions modeled. Therefore, no changes to the steamline break inside containment event tree analysis will be expected as a result of the EPU.

Loss of Offsite Power (LOOP)

The LOOP event tree model includes systems needed to maintain RCP seal cooling, so that a seal LOCA is prevented, and provide emergency AC power for plant systems. Preventing a RCP seal LOCA is independent of plant thermal power and, therefore, is not impacted by the EPU. Emergency AC power can be provided by the emergency diesel generators (EDGs) or the gas turbine generator. The analyses presented in Reference 3 show that the capacity of EDGs is adequate for the small increase in load caused by the new motor-driven AFW pumps. Decay heat removal can be provided by either AFW or bleed and feed cooling. Although the flow required from AFW is higher as a result of the EPU, installation of the new motor-driven AFW pumps will allow one pump to provide adequate flow. The EPU will result in changes in steam generator mass and decay heat levels so the time available to initiate bleed and feed cooling will be shorter. The analyses indicate only changes in the overall timing for bleed and feed cooling, not changes in the equipment required. The effect of the timing changes is evaluated under the HRA for the specific actions modeled. Therefore, no changes to the LOOP event tree analysis will be expected as a result of the EPU.

Station Blackout (SBO)

The SBO event tree models the potential for an RCP seal LOCA, recovery of AC power to plant systems, maintaining control of plant systems needed to remove decay heat and mitigate any loss of coolant. The probability of an RCP seal LOCA is independent of reactor power and, therefore, is not impacted by the EPU. The probability of recovery of AC power is also independent of reactor power and is not affected by the EPU. Control of plant systems is dependent on DC battery capacity which is independent of core thermal power and is not affected by the EPU. Decay heat removal can be provided by either AFW or bleed and feed cooling. Although the flow required from AFW is higher, installation of the new motor-driven AFW pumps will allow one pump to provide adequate flow. The EPU will result in changes in steam generator mass and decay heat levels so the time available to initiate bleed and feed cooling will be shorter. The analyses indicate only changes in the overall timing for bleed and feed cooling, not changes in the equipment required. The effect of the timing changes would be evaluated under the HRA for the specific actions modeled. Therefore, no changes to the SBO event tree analysis will be expected as a result of the EPU.

ATWS

The ATWS event tree analysis is based on the methods for a low reactivity core, i.e., a core with a peak moderator temperature coefficient (MTC) of less than +3.5 pcm/°F. Analyses have been performed to confirm the plant response to ATWS and show no change to the success criteria used for the ATWS event tree. That is, the AFW success criteria will remain 400 gpm to 800 gpm for AFW flow. Following the EPU, the core will still be considered a low reactivity core so no changes to the systems or actions considered in the ATWS model is expected. Therefore, no changes to the ATWS event tree analysis will be expected as a result of the EPU.

Loss of Component Cooling Water

The loss of CCW event tree considers establishing seal injection from CVCS to prevent a RCP seal LOCA and AFW to provide decay heat removal. RCP seal cooling requirements are independent of reactor power and, therefore, unaffected by the EPU. Decay heat removal using AFW will require higher flows after the EPU, however, installation of the new motor-driven AFW pumps will allow one pump to provide adequate flow. Therefore, no changes to the loss of CCW event tree analysis will be expected as a result of the EPU.

Loss of a 125 VDC Bus

The loss of a 125 VDC bus event tree analyses includes two event trees, one for a loss of Bus D01 and one for a loss of Bus D02. Both event trees are identical in structure, but two trees are used to consider the equipment affected by each bus loss. The 125 VDC event tree models include secondary heat removal with either AFW or main feedwater. Should secondary cooling fail, primary bleed and feed is modeled for decay heat removal. Although the flow required from AFW is higher, installation of the new motor-driven AFW pumps will allow one pump to provide adequate flow. The EPU will result in changes in steam generator mass and decay heat levels so the time available to initiate bleed and feed cooling will be shorter. The analyses indicate only changes in the overall timing for bleed and feed cooling, not changes in the equipment required. The effect of the timing changes would be evaluated under the HRA for the specific actions modeled. Therefore, no changes to the Loss of a 125 VDC Bus event tree analysis will be expected as a result of the EPU.

Loss of Instrument Air

The loss of instrument air event tree analyses considers actions to control charging flow to maintain RCS inventory control, potential challenge to pressurizer PORVs, and decay heat removal using AFW. Because of the loss of instrument air, bleed and feed cooling is not available. The operator actions needed to control charging flow are independent of power level. The probability of a PORV demand following a loss of instrument air is taken to be 0.5. This value is considered bounding for post-EPU conditions. Although the flow required from AFW is higher for post-EPU conditions, installation of the new motor-driven AFW pumps will allow one pump to provide adequate flow. Therefore, no changes to the Loss Instrument Air event tree analysis will be expected as a result of the EPU.

Loss of Service Water

The loss of service water event tree considers establishing seal injection from CVCS to prevent a RCP seal LOCA and AFW to provide decay heat removal. RCP seal cooling requirements are independent of reactor power and, therefore, unaffected by the EPU. Decay heat removal using AFW will require higher flows after the EPU, however, installation of the new motor-driven AFW pumps will allow one pump to provide adequate flow. Decay heat removal using the MFW system is not credited because of the direct dependence of MFW and condensate on service water. Although modifications will remove the direct dependence of the MFW and condensate systems on service water, instrument air will still be required to support operating valves needed to allow the MFW system provide makeup to the steam generators and to bleed steam to the condenser. Because the instrument air system is completely dependent on service water, MFW will not be credited after a loss of service water event. Therefore, no changes to the loss of service water event tree analysis will be expected as a result of the EPU.

Data Analysis

The EPU will require that motor-driven AFW, MFW, and Condensate pumps be replaced with higher capacity pumps. However, there is no reason to presume that the failure rates or maintenance unavailability for the new pumps will be either higher or lower than the existing pumps. Installation of the new MFIVs will require additional data collection in the future, but initially will use data developed for other air-operated valves at PBNP. Therefore, no changes to the data analysis will be expected as a result of the EPU.

Systems Analysis

This section describes the assessment of how the EPU could affect each of the system analyses performed for the PBNP PRA. In the subsections that follow, the potential for the EPU to affect each of the system analyses is evaluated and discussed.

<u>13.8 kV Electric Power</u>

The 13.8 kV system is modeled as providing power from offsite to the various plant AC buses. No changes to the 13.8 kV power buses are planned as a result of the EPU and no changes to the system success criteria were identified. Therefore, no changes to the 13.8 kV system models will be expected as a result of the EPU.

<u>4160 VAC Electric Power</u>

The 4160 VAC system is modeled as providing power to the safety and non-safety 4160 VAC buses on each unit. Although the EPU will result in the new motor-driven AFW pumps being powered from 4160 VAC, that change is considered in the AFW system analysis.

As part of the EPU, a new 19kV main generator output circuit breaker will be installed on each unit for use when a generator trip is required. The new breakers will allow the existing 345kV breakers, F52-122(142), to remain closed to feed auxiliary power to the plant's AC auxiliary system via the Unit Auxiliary Transformer (UAT, 1(2)-X02) after the generator trip. The A01 and A02 buses will remain powered from the 345kV system for any plant transients other than a loss of X-01 or X-02 or a failure of the new generator output breaker. This change will greatly improve the performance for the safety related 4160V buses after a unit trip since the balance of plant large motor load will not automatically transfer to the 1(2)-X04 transformer feed causing a significant voltage drop.

To model installation of the new main generator output circuit breakers, the following assumptions will be made:

1. When quantifying the Unit 1 model, it will be assumed that the Unit 2 main generator is operating and supplying power to transformer 2X02. This assumption is conservative because it allows including an additional power supply to 2X02 in all cases. However, the main generator would not be available for cases when both Unit 1 and Unit 2 are off line.

2. When quantifying the Unit 2 model, it will be assumed that the Unit 1 main generator is operating and supplying power to transformer 1X02. This assumption is conservative because it allows including an additional power supply to 1X02 in all cases. However, the main generator would not be available for cases when both Unit 1 and Unit 2 are off line.

3. The new main generator output circuit breakers will be provided with redundant trip coils with one being powered from D-05 and the other powered from D-06. Since either trip coil can successfully trip the breaker and because no models currently are developed for buses D-05 and D-06, it will be assumed that the probability of a loss of both trains of DC is small enough to be neglected and DC power to the new circuit breakers is not included in the models.

No other changes to the electric power system that affect the 4160 VAC models are planned as a result of the EPU.

<u>480 VAC Electric Power</u>

The 480 VAC system is modeled as providing power to the safety and non-safety 480 VAC buses on each unit. Although the EPU will result in the new motor-driven AFW pumps being powered from 4160 VAC instead of 480 VAC, that change will be considered in the AFW system analysis. No other changes to the 480 VAC power buses are planned as a result of the EPU and no changes to the system success criteria were identified. Therefore, no changes to the 480 VAC system models will be expected as a result of the EPU.

<u>Emergency Diesel Generators (EDGs)</u>

The EDGs are modeled as providing backup power to the safeguards 4160 VAC buses in the event of a loss of normal, offsite power. No changes to the EDGs or associated systems are planned as a result of the EPU and no changes to the system success criteria were identified. Therefore, no changes to the EDG system models will be expected as a result of the EPU.

<u>Y-System Electric Power</u>

The Y-system is modeled as providing 120 VAC power to various safety-related instrument racks. No changes to the 120 VAC instrument power system are planned as a result of the EPU and no changes to the system success criteria were identified. Therefore, no changes to the Y-system electric power models will be expected as a result of the EPU.

<u>125 VDC Electric Power</u>

The 125 VDC system is modeled as providing DC power to the safety and non-safety 125 VDC buses on each unit. The EPU will result in the new motor-driven AFW pumps being powered from 4160 VAC instead of 480 VAC. As a result, control power for the AFW pump breakers will

be provided from a different DC source. However, that change will be considered in the AFW system analysis. No other changes to the 125 VDC system buses are planned as a result of the EPU and no changes to the system success criteria were identified. Therefore, no changes to the 125 VDC system models will be expected as a result of the EPU.

Accumulators

The accumulators are modeled as providing water from pressurized tanks to the RCS in the event that RCS pressure drops below that of the accumulators. No changes to the accumulator system are planned as a result of the EPU and no changes to the system success criteria were identified. Therefore, no changes to the accumulator system models will be expected as a result of the EPU.

Safety Injection (SI)/Residual Heat Removal (RHR)

The SI and RHR systems are considered within one analysis. Both systems are modeled as providing RCS injection after a SI signal. The RHR system is used to provide cooling to water drawn from the containment sump and to provide a suction source to the SI and containment spray pumps during the recirculation phase. Although heat loads will increase as a result of the EPU, no changes to either the SI or RHR systems are planned as a result of the EPU and no changes to the system success criteria were identified. Therefore, no changes to the SI or RHR system models will be expected as a result of the EPU.

Auxiliary Feedwater

The AFW system model includes the AFW system as well as the main steam safety valves (MSSVs) and atmospheric dump valves (ADVs) as a means of decay heat removal through the steam generators. As a result of the EPU, new motor-driven AFW pumps will be installed with higher-capacity pumps (275 gpm) that are powered from 4160 VAC instead of 480 VAC. Because of the higher capacity of the new motor-driven AFW pumps, the number of pumps needed for system success will not change. Analyses show that the new, larger AFW pumps do not require room cooling for operation. No other changes in AFW pump support systems were indicated in Reference 3. Also, the analyses of Reference 3 show that the MSSVs and ADVs are adequately sized for post-EPU conditions. The Technical Specification minimum required volume for the condensate storage tanks (CST) will be increased from 13,000 gallons to 15,410 gallons to ensure a one-hour hot standby capability. The new required volume is still much less than the 45,000 gallon tank capacity and the normal volume in the CSTs is typically maintained near capacity. Considering these conditions, the change in CST volume requirements would not result in a change in risk. Additionally, a new feature to provide AFW pump suction source automatic switchover from the CST to the safety-related SW supply will be incorporated into the design. Therefore, only changes to AFW pump power and configuration must be considered.

Containment Spray

The containment spray system is modeled as providing a means to limit containment pressure that is diverse from the containment recirculation fan coolers and as a method to limit release of radioactive iodine. Only minor changes related to implementation of the alternate source term (AST) methodology would affect the containment spray system. Operation of the containment spray system is not credited in the current PRA models. No changes to the containment spray system are planned as a result of the EPU that would affect the system success criteria were identified. Therefore, no changes to the containment spray system models will be expected as a result of the EPU.

Containment Air Recirculation Cooling System

The containment air recirculation cooling system is modeled as providing a means to limit containment pressure that is diverse from the containment spray system. No changes to the containment air recirculation cooling system are planned as a result of the EPU and no changes to the system success criteria were identified. Therefore, no changes to the containment air recirculation cooling system models will be expected as a result of the EPU.

Containment Isolation System

The containment isolation system models the actions and systems needed to ensure that the containment remains a functional barrier to fission product release. Although the new MFIVs could be included in the containment isolation model, they are conservatively neglected from the containment isolation evaluation. Crediting the new MFIVs would add an additional means to isolate the feedwater system from the steam generators and containment thereby decreasing the probability of failing to isolate the associated path. Isolation of feedwater is only of concern for secondary line breaks inside containment or for SGTRs. For SGTR events, the release path is not through the feedwater system but out the steam generator relief valves so the MFIVs would provide no reduction in release frequency. The MFIVs are not technically considered containment isolation valves as the containment isolation function is performed by the FW check valves with the steam generator boundary providing the primary barrier. Credit for isolation by the MFIVs would only be needed for sequences where the steam generator secondary side is faulted and the associated FW check valve fails to provide its isolation function. Sequences with these failures are considered negligible contributors to release frequency. For other events, the steam generator boundary remains a functional boundary to fission product release. No other changes affecting containment isolation are planned as a result of the EPU and no changes to the system success criteria were identified. Therefore, no changes to the containment isolation system models will be expected as a result of the EPU.

Service Water

The service water system is modeled as providing cooling water to essential safeguards systems and various plant loads. Although heat loads will increase as a result of the EPU, no changes to the service water system are planned as a result of the EPU and no changes to the system success criteria were identified. Therefore, no changes to the service water system models will be expected as a result of the EPU.

Component Cooling Water

The CCW system serves as an intermediate system between the primary systems and the service water system thereby reducing the probability of leakage of radioactive reactor coolant to the service water system. Although heat loads will increase as a result of the EPU, no changes to the CCW system are planned as a result of the EPU (Reference 3) and no changes to the system success criteria were identified. Therefore, no changes to the CCW system models will be expected as a result of the EPU.

Reactor Protection System (RPS)/Engineered Safety Features Actuation System (ESFAS)

The RPS system is modeled as providing the signals and actions needed to open the reactor trip breakers in response to indications of an approach to unsafe operating conditions. The ESFAS system is modeled as monitoring plant conditions and initiating operation of equipment needed to mitigate or prevent damage to the reactor core or reactor coolant system or to ensure containment integrity. Although various setpoints for the RPS or ESFAS systems may change as a result of the EPU, no actuation signals are being added or deleted. The RPS and ESFAS system models only consider failure of the signal itself, not the actual setpoint. Therefore, no changes to the RPS or ESFAS system models will be expected as a result of the EPU.

ATWS Mitigation System Actuation Circuitry (AMSAC)

The AMSAC is modeled as providing a backup to the reactor protection system to automatically trip the turbine and initiate auxiliary feedwater flow. Although various setpoints and instruments that provide input to AMSAC may change as a result of the EPU, any additional instruments will replace existing instruments and any setpoint changes will be for existing setpoints. No new actuation signals for AMSAC are planned with one possible exception. An input from the new MFIVs to AMSAC may be added, however, specific signals to AMSAC are not considered within the AMSAC model. The AMSAC system model only considers failure of the signal itself, not the actual setpoint or input. Therefore, no changes to the AMSAC system model will be expected as a result of the EPU.

RCP Seal Injection

RCP seal injection is modeled to maintain integrity of RCP seals. Seal injection is redundant and diverse from thermal barrier cooling provided by CCW. No changes to the charging system and no changes to the requirements for seal injection are planned as a result of the EPU and no changes to the system success criteria were identified. Therefore, no changes to the RCP seal injection models will be expected as a result of the EPU.

Core Uncovery Probability

The probability of uncovering the core is used in SBO analyses. This probability is dependent on RCP seal LOCA size, how long power was lost, and whether or not the RCS has been sufficiently cooled down. None of these conditions are dependent on reactor power. Therefore, no changes to the RCP core uncovery models will be expected as a result of the EPU.

RCS Cooldown and Depressurization

RCS cooldown and depressurization is modeled for SGTR events and secondary line breaks inside containment. The model considers equipment and actions needed to allow RHR cooling to provide decay heat removal. Although heat loads will increase as a result of the EPU, no changes to pressure control systems or RHR are planned as a result of the EPU and no changes to the system success criteria were identified. Any changes in the timing available for operator actions will be addressed as part of the HRA. Therefore, no changes to the RCS cooldown and depressurization models will be expected as a result of the EPU.

Emergency Boration

Emergency boration is modeled for ATWS events and includes flow from 1 of 3 charging pumps along with emergency boration. No changes to the charging or boration systems and no changes to the requirements for boration are planned as a result of the EPU and no changes to the system success criteria were identified. Although shutdown boron concentrations will change as a result of the EPU, these changes will be procedurally controlled and will not affect the requirements of the emergency boration systems as related to ATWS mitigation. Therefore, no changes to the emergency boration models will be expected as a result of the EPU.

Main Feedwater

The MFW system model includes the MFW system as well as the MSSVs and ADVs as a means of decay heat removal through the steam generators. As a result of the EPU, the MFW and condensate pumps will be replaced with higher-capacity pumps in order to provide the higher flows required for power operation. The higher flow of the new pumps is not required for decay heat removal. Analyses show that the new, larger MFW pumps do not require room cooling for operation. The requirement for service water cooling to support operation of the MFW and condensate pumps has been removed. No other changes in MFW or condensate pump support systems were indicated in Reference 3. Also, the analyses of Reference 3 show that the MSSVs and ADVs are adequately sized for post-EPU conditions. Installation of the new MFIVs adds a new potential failure mode that could prevent supplying MFW to the steam generators. The MFIVs must be added to the MFW fault tree models.

The MFIVs require air and DC power to operate and will fail as-is on a loss of air or power. Air is supplied from a safety-related accumulator tank. MFW is modeled as a method of secondary cooling only for transient events with power conversion system available. MFW is not credited for LOCA events or secondary line break events. For events where MFW is credited, no signal to close the valves would have been generated. Therefore, the only failure mode considered for the MFIVs in the MFW model is transferring closed.

A generic common-cause factor of 0.2 will be assumed to apply to the failure mode of the valves. Although a spurious signal could result in closing the valves, the use of the conservatively high common cause factor is assumed to bound any failure caused by a spurious signal.

The new basic events for MFIV failure to remain open use existing failure data for air-operated valves transferring closed from the PBNP PRA for the failure probability and a 24-hour mission time. The random failure rate is 1.609E-06. For a 24-hour mission time, the failure probability will be 3.86E-05. With a common cause factor of 0.2, the common cause failure probability will be 7.72E-06. These values were added to the associated basic event data file.

The changes account for the impact of the new MFIVs on using MFW as a means to remove decay heat through the steam generators. No other changes to the MFW system models for decay heat removal are needed to address the EPU.

Main Steam and Feedwater Isolation

Main steam isolation is modeled for SGTR and secondary line break events. Isolation of feedwater is not included in the current PBNP PRA models. As discussed in Reference 3, the new MFIVs are needed to maintain containment pressure within the 60 psig design-basis pressure following a secondary line break inside containment. The total extra energy that would be released without these new valves would result in only a small pressure increase relative to the containment ultimate pressure rating. Since the PRA models use the ultimate failure pressure for containment, neglecting the new MFIVs in the PRA models will have negligible effect. Other changes involve minor modifications to valve trim and do not affect the overall function of the system or the PRA models. Therefore, no changes to main steam or feedwater isolation models will be expected as a result of the EPU.

Fire Protection Refill of Condensate Storage Tanks (CSTs)

For a loss of service water, the fire protection system is modeled for providing bearing cooling for the turbine-driven AFW pump and make-up to the CSTs. No changes to the fire protection system, turbine-driven AFW pump, or CSTs are planned as a result of the EPU and no changes to the system success criteria were identified. Therefore, no changes to the models for providing fire protection water to AFW will be expected as a result of the EPU.

Reduce and Stabilize RCS Pressure

Operator actions to reduce and stabilize RCS pressure are modeled for SGTR events so that RCS pressure is reduced before steam generator overfill. Although decay heat will increase following the EPU, the analyses of Reference 3 show that the ADVs are adequately sized for post-EPU conditions. No changes impacting the function of the pressurizer or related pressure control systems, ADVs, etc., are planned as a result of the EPU and no changes to the system success criteria were identified. Any changes in time available for operator action will be addressed as part of the HRA. Therefore, no changes to the models for RCS depressurization will be expected as a result of the EPU.

RCS Feed and Bleed

Feed and bleed cooling is modeled for decay heat removal when secondary heat removal is not adequate. The analyses indicate only changes in the overall timing for bleed and feed cooling, not changes in the equipment required. The effect of the timing changes is evaluated under the HRA for the specific actions modeled. Therefore, no changes to the models for RCS bleed and feed cooling will be expected as a result of the EPU.

Reactor Power Level < 40%

Reactor power level is considered for ATWS events since an ATWS from an initial power level less than 40% power is less severe than an ATWS event from higher power levels. There is no evidence that the relative power levels for operation of PBNP after the EPU will be different than before the EPU. Therefore, no changes to the models for relative reactor power level will be expected as a result of the EPU.

Primary Pressure Relief

Primary pressure relief is modeled for ATWS events as preventing exceeding the pressure capability of the RCS. No changes to the pressurizer PORVs or SRVs are planned as a result of the EPU. Furthermore, the reactor will still be considered a low-reactivity core after the EPU, and since the unfavorable exposure time (UET) split fractions are developed from generic ATWS analyses, no changes to the PRA models are identified.

Power Recovery

Recovery of offsite power is modeled for SBO sequences. Although the power output of PBNP will increase as a result of the EPU, the power recovery models use generic, historical data to calculate the probability of power recovery. Changes to the grid will be made to accommodate the increased power output. Since reliability of the grid will be unaffected by the EPU and since recovery is based on historical data, there is no reason to presume that the probability of offsite power recovery will be impacted by the EPU. Therefore, no changes to power recovery are expected as a result of the EPU.

Instrument Air

The instrument air system is a support system for various other systems. No changes to the instrument air systems are planned as a result of the EPU other than the addition of the new MFIVs as a new load. The MFIVs will also have an accumulator as a source. No changes to the system success criteria were identified. Therefore, no changes to the instrument air system models will be expected as a result of the EPU.

Relief Valve Closure

ECCS system relief valve closure following RCS depressurization after an ISLOCA is modeled using generic data. Since no changes to the ECCS system relief valves are planned as a result of the EPU, no changes to relief valve closure models will be expected as a result of the EPU.

Fuel Oil

The fuel oil system is modeled as providing a long-term fuel source to the EDGs given the limited supply available in the EDG day tanks. Although the diesel loadings will increase slightly, these changes are minor in comparison to the total loading of the EDGs and the capacity of the fuel oil system. No changes to the fuel oil system are planned as a result of the EPU and no changes to the system success criteria were identified. Therefore, no changes to the fuel oil system models will be expected as a result of the EPU.

Heating Ventilation and Air Conditioning (HVAC)

Two potential changes to the HVAC models have been identified as a result of the EPU. These changes, increased heat loading from the AFW pump motors and increased heat loading from the MFW pump motors, have been evaluated as not requiring any new HVAC. Therefore, no changes to the HVAC system models will be expected as a result of the EPU.

Human Reliability Analysis

This section describes the assessment of how the EPU could affect the HRA performed for the PBNP PRA. Over 100 unique post-initiator operator actions are developed for the PBNP PRA. The vast majority of these events are not impacted by the EPU. In the subsections that follow, operator actions that were evaluated as having the potential to be significantly impacted by the EPU are discussed.

125-HEP-1B32D302 Operator Fails To Align Bus 1B-32 To D-302

The HEP for this action is developed based on the time to core damage following a station blackout with a 480 gpm per pump RCP seal LOCA. The MAAP analyses supporting success criteria have been updated for EPU and show a time window of 98 minutes from initiating event to core damage for the case supporting development of this HEP.

The HEP for this event is quantified with the EPRI HRA Calculator using the CBDTM/THERP method. Reducing the System Time Window from 120 minutes (used in the current analyses) to 98 minutes indicates that a minimum of high dependence should be assigned for recovery actions. The dependence level for all recovery actions was changed from medium to high.

Making this change in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Base Value	Percent Increase	Updated Value
125-HEP-1B32D302	Operator Fails To Align Bus 1B-32 To D-302	1.40E-02	429%	7.40E-02

125-HEP-1B49D301 Operator Failure To Align 1B49 To D301

The HEP for this action is developed based on the time to core damage following a station blackout with a 480 gpm per pump RCP seal LOCA. The MAAP analyses supporting success criteria have been updated for EPU and show a time window of 98 minutes from initiating event to core damage for the case supporting development of this HEP.

The HEP for this event is quantified with the EPRI HRA Calculator using the CBDTM/THERP method. Reducing the System Time Window from 120 minutes (used in the current analyses) to 98 minutes indicates that a minimum of high dependence should be assigned for recovery actions. The dependence level for all recovery actions was changed from medium to high.

Making this change in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Base Value	Percent Increase	Updated Value
125-HEP-1B49D301	Operator Failure To Align 1B49 To D301	1.40E-02	429%	7.40E-02

125-HEP-2B39D301 Operator Failure To Align 2B-39 To D-301

The HEP for this action is developed based on the time to core damage following a station blackout with a 480 gpm per pump RCP seal LOCA. The MAAP analyses supporting success criteria have been updated for EPU and show a time window of 98 minutes from initiating event to core damage for the case supporting development of this HEP.

The HEP for this event is quantified with the EPRI HRA Calculator using the CBDTM/THERP method. Reducing the System Time Window from 120 minutes (used in the current analyses) to 98 minutes indicates that a minimum of high dependence should be assigned for recovery actions. The dependence level for all recovery actions was changed from medium to high.

Making this change in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Base Value	Percent Increase	Updated Value
125-HEP-2B39D301	Operator Failure To Align 2B-39 TO D-301	1.40E-02	429%	7.40E-02

125-HEP-2B42D302 Operator Fails To Align 2B42 To D-302

The HEP for this action is developed based on the time to core damage following a station blackout with a 480 gpm per pump RCP seal LOCA. The MAAP analyses supporting success criteria have been updated for EPU and show a time window of 98 minutes from initiating event to core damage for the case supporting development of this HEP.

The HEP for this event is quantified with the EPRI HRA Calculator using the CBDTM/THERP method. Reducing the System Time Window from 120 minutes (used in the current analyses) to 98 minutes indicates that a minimum of high dependence should be assigned for recovery actions. The dependence level for all recovery actions was changed from medium to high.

Making this change in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Base Value	Percent Increase	Updated Value
125-HEP-2B42D302	Operator Fails To Align 2B42 To D-302	1.40E-02	429%	7.40E-02

125-HEP-B81-D302 Operator Fails To Align Bus B-81 To D-302

The HEP for this action is developed based on the time to core damage following a station blackout with a 480 gpm per pump RCP seal LOCA. The MAAP analyses supporting success criteria have been updated for EPU and show a time window of 98 minutes from initiating event to core damage for the case supporting development of this HEP.

The HEP for this event is quantified with the EPRI HRA Calculator using the CBDTM/THERP method. Reducing the System Time Window from 120 minutes (used in the current analyses) to 98 minutes indicates that a minimum of high dependence should be assigned for recovery actions. The dependence level for all recovery actions was changed from medium to high.

Making this change in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Base Value	Percent Increase	Updated Value
125-HEP-B81-D302	Operator Fails To Align Bus B-81 To D-302	1.40E-02	429%	7.40E-02

125-HEP--D04-D28 Operator Fails To Transfer Pwr From D04 To D28

The HEP for this action is developed based on the time to core damage following a station blackout with a 480 gpm per pump RCP seal LOCA. The MAAP analyses supporting success criteria have been updated for EPU and show a time window of 98 minutes from initiating event to core damage for the case supporting development of this HEP.

The HEP for this event is quantified with the EPRI HRA Calculator using the CBDTM/THERP method. Reducing the System Time Window from 120 minutes (used in the current analyses) to 98 minutes indicates that a minimum of high dependence should be assigned for recovery actions. The dependence level for all recovery actions was changed from medium to high. Making this change in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Base Value	Percent Increase	Updated Value
125-HEP--D04-D28	Operator Fails To Transfer Pwr From D04 To D28	1.40E-02	429%	7.40E-02

125-HEP--D04-D40 Operator Fails To Transfer Pwr From D-04 To D-40

The HEP for this action is developed based on the time to core damage following a station blackout with a 480 gpm per pump RCP seal LOCA. The MAAP analyses supporting success criteria have been updated for EPU and show a time window of 98 minutes from initiating event to core damage for the case supporting development of this HEP.

The HEP for this event is quantified with the EPRI HRA Calculator using the CBDTM/THERP method. Reducing the System Time Window from 120 minutes (used in the current analyses) to 98 minutes indicates that a minimum of high dependence should be assigned for recovery actions. The dependence level for all recovery actions was changed from medium to high. Making this change in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Base Value	Percent Increase	Updated Value
125-HEP--D04-D40	Operator Fails To Transfer Pwr From D04 To D40	1.40E-02	429%	7.40E-02

125-HEP-D05--D01 Operator Failure To Align D-05 To D-01

The HEP for this action is developed based on the time to core damage following a station blackout with a 480 gpm per pump RCP seal LOCA. The MAAP analyses supporting success criteria have been updated for EPU and show a time window of 98 minutes from initiating event to core damage for the case supporting development of this HEP.

The HEP for this event is quantified with the EPRI HRA Calculator using the CBDTM/THERP method. Reducing the System Time Window from 120 minutes (used in the current analyses) to 98 minutes indicates that a minimum of high dependence should be assigned for recovery actions. The dependence level for all recovery actions was changed from medium to high.

Making this change in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Base Value	Percent Increase	Updated Value
125-HEP-D05--D01	Operator Failure To Align D-05 To D-01	1.40E-02	429%	7.40E-02

125-HEP-D06--D02 Operator Failure To Align D-06 To D-02

The HEP for this action is developed based on the time to core damage following a station blackout with a 480 gpm per pump RCP seal LOCA. The MAAP analyses supporting success criteria have been updated for EPU and show a time window of 98 minutes from initiating event to core damage for the case supporting development of this HEP.

The HEP for this event is quantified with the EPRI HRA Calculator using the CBDTM/THERP method. Reducing the System Time Window from 120 minutes (used in the current analyses) to 98 minutes indicates that a minimum of high dependence should be assigned for recovery actions. The dependence level for all recovery actions was changed from medium to high. Making this change in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Base Value	Percent Increase	Updated Value
125-HEP-D06--D02	Operator Failure To Align D-06 To D-02	1.40E-02	429%	7.40E-02

125-HEP-D105-D03 Operator Failure To Align D-105 To D-03

The HEP for this action is developed based on the time to core damage following a station blackout with a 480 gpm per pump RCP seal LOCA. The MAAP analyses supporting success criteria have been updated for EPU and show a time window of 98 minutes from initiating event to core damage for the case supporting development of this HEP.

The HEP for this event is quantified with the EPRI HRA Calculator using the CBDTM/THERP method. Reducing the System Time Window from 120 minutes (used in the current analyses) to 98 minutes indicates that a minimum of high dependence should be assigned for recovery actions. The dependence level for all recovery actions was changed from medium to high. Making this change in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Base Value	Percent Increase	Updated Value
125-HEP-D105-D03	Operator Failure To Align D-105 To D-03	1.40E-02	429%	7.40E-02

125-HEP-D106-D04 Operator Failure To Align D-106 To D-04

The HEP for this action is developed based on the time to core damage following a station blackout with a 480 gpm per pump RCP seal LOCA. The MAAP analyses supporting success criteria have been updated for EPU and show a time window of 98 minutes from initiating event to core damage for the case supporting development of this HEP.

The HEP for this event is quantified with the EPRI HRA Calculator using the CBDTM/THERP method. Reducing the System Time Window from 120 minutes (used in the current analyses) to 98 minutes indicates that a minimum of high dependence should be assigned for recovery actions. The dependence level for all recovery actions was changed from medium to high. Making this change in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Base Value	Percent Increase	Updated Value
125-HEP-D106-D04	Operator Failure To Align D-106 To D-04	1.40E-02	429%	7.40E-02

125-HEP-D14-D40 Failure Of Operator To Align D-14 To Bus D-40

The HEP for this action is developed based on the time to core damage following a station blackout with a 480 gpm per pump RCP seal LOCA. The MAAP analyses supporting success criteria have been updated for EPU and show a time window of 98 minutes from initiating event to core damage for the case supporting development of this HEP.

The HEP for this event is quantified with the EPRI HRA Calculator using the CBDTM/THERP method. Reducing the System Time Window from 120 minutes (used in the current analyses) to 98 minutes indicates that a minimum of high dependence should be assigned for recovery actions. The dependence level for all recovery actions was changed from medium to high. Making this change in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Base Value	Percent Increase	Updated Value
125-HEP-D14-D40	Failure Of Operator To Align D-14 To Bus D-40	1.40E-02	429%	7.40E-02

125-HEP-D28-D40 Failure Of Operator To Align D-28 To Bus D-40

The HEP for this action is developed based on the time to core damage following a station blackout with a 480 gpm per pump RCP seal LOCA. The MAAP analyses supporting success criteria have been updated for EPU and show a time window of 98 minutes from initiating event to core damage for the case supporting development of this HEP.

The HEP for this event is quantified with the EPRI HRA Calculator using the CBDTM/THERP method. Reducing the System Time Window from 120 minutes (used in the current analyses) to 98 minutes indicates that a minimum of high dependence should be assigned for recovery actions. The dependence level for all recovery actions was changed from medium to high.

Making this change in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Base Value	Percent Increase	Updated Value
125-HEP-D28-D40	Failure Of Operator To Align D-28 To Bus D-40	1.40E-02	429%	7.40E-02

125-HEP-D305-D01 Operator Fails To Align D-305 To Bus D-01

The HEP for this action is developed based on the time to core damage following a station blackout with a 480 gpm per pump RCP seal LOCA. The MAAP analyses supporting success criteria have been updated for EPU and show a time window of 98 minutes from initiating event to core damage for the case supporting development of this HEP.

The HEP for this event is quantified with the EPRI HRA Calculator using the CBDTM/THERP method. Reducing the System Time Window from 120 minutes (used in the current analyses) to 98 minutes indicates that a minimum of high dependence should be assigned for recovery actions. The dependence level for all recovery actions was changed from medium to high. Making this change in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Base Value	Percent Increase	Updated Value
125-HEP-D305-D01	Operator Fails To Align D-305 To Bus D-01	1.40E-02	429%	7.40E-02

125-HEP-D305-D02 Operator Fails To Align D-305 To Bus D-02

The HEP for this action is developed based on the time to core damage following a station blackout with a 480 gpm per pump RCP seal LOCA. The MAAP analyses supporting success criteria have been updated for EPU and show a time window of 98 minutes from initiating event to core damage for the case supporting development of this HEP.

The HEP for this event is quantified with the EPRI HRA Calculator using the CBDTM/THERP method. Reducing the System Time Window from 120 minutes (used in the current analyses) to 98 minutes indicates that a minimum of high dependence should be assigned for recovery actions. The dependence level for all recovery actions was changed from medium to high. Making this change in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Base Value	Percent Increase	Updated Value
125-HEP-D305-D02	Operator Fails To Align D-305 To Bus D-02	1.40E-02	429%	7.40E-02

125-HEP-D305-D03 Operator Fails To Align D-305 To Bus D-03

The HEP for this action is developed based on the time to core damage following a station blackout with a 480 gpm per pump RCP seal LOCA. The MAAP analyses supporting success criteria have been updated for EPU and show a time window of 98 minutes from initiating event to core damage for the case supporting development of this HEP.

The HEP for this event is quantified with the EPRI HRA Calculator using the CBDTM/THERP method. Reducing the System Time Window from 120 minutes (used in the current analyses) to 98 minutes indicates that a minimum of high dependence should be assigned for recovery actions. The dependence level for all recovery actions was changed from medium to high. Making this change in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Base Value	Percent Increase	Updated Value
125-HEP-D305-D03	Operator Fails To Align D-305 To Bus D-03	1.40E-02	429%	7.40E-02

125-HEP-D305-D04 Operator Fails To Align D-305 To Bus D-04

The HEP for this action is developed based on the time to core damage following a station blackout with a 480 gpm per pump RCP seal LOCA. The MAAP analyses supporting success criteria have been updated for EPU and show a time window of 98 minutes from initiating event to core damage for the case supporting development of this HEP.

The HEP for this event is quantified with the EPRI HRA Calculator using the CBDTM/THERP method. Reducing the System Time Window from 120 minutes (used in the current analyses) to 98 minutes indicates that a minimum of high dependence should be assigned for recovery actions. The dependence level for all recovery actions was changed from medium to high. Making this change in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Base Value	Percent Increase	Updated Value
125-HEP-D305-D04	Operator Fails To Align D-305 To Bus D-04	1.40E-02	429%	7.40E-02

125-HEP--D49-D51 Operator Fails To Transfer Pwr From D-49 To D-51

The HEP for this action is developed based on the time to core damage following a station blackout with a 480 gpm per pump RCP seal LOCA. The MAAP analyses supporting success criteria have been updated for EPU and show a time window of 98 minutes from initiating event to core damage for the case supporting development of this HEP.

The HEP for this event is quantified with the EPRI HRA Calculator using the CBDTM/THERP method. Reducing the System Time Window from 120 minutes (used in the current analyses) to 98 minutes indicates that a minimum of high dependence should be assigned for recovery actions. The dependence level for all recovery actions was changed from medium to high.

Making this change in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Base Value	Percent Increase	Updated Value
125-HEP--D49-D51	Operator Fails To Transfer Pwr From D-49 To D-51	1.40E-02	429%	7.40E-02

125-HEP--D49-D52 Operator Fails To Transfer Pwr From D-49 To D-52

The HEP for this action is developed based on the time to core damage following a station blackout with a 480 gpm per pump RCP seal LOCA. The MAAP analyses supporting success criteria have been updated for EPU and show a time window of 98 minutes from initiating event to core damage for the case supporting development of this HEP.

The HEP for this event is quantified with the EPRI HRA Calculator using the CBDTM/THERP method. Reducing the System Time Window from 120 minutes (used in the current analyses) to 98 minutes indicates that a minimum of high dependence should be assigned for recovery actions. The dependence level for all recovery actions was changed from medium to high. Making this change in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Base Value	Percent Increase	Updated Value
125-HEP--D49-D52	Operator Fails To Transfer Pwr From D-49 To D-52	1.40E-02	429%	7.40E-02

125-HEP--D49-D53 Operator Fails To Transfer Power From D-49 To D-53

The HEP for this action is developed based on the time to core damage following a station blackout with a 480 gpm per pump RCP seal LOCA. The MAAP analyses supporting success criteria have been updated for EPU and show a time window of 98 minutes from initiating event to core damage for the case supporting development of this HEP.

The HEP for this event is quantified with the EPRI HRA Calculator using the CBDTM/THERP method. Reducing the System Time Window from 120 minutes (used in the current analyses) to 98 minutes indicates that a minimum of high dependence should be assigned for recovery actions. The dependence level for all recovery actions was changed from medium to high.

Making this change in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Base Value	Percent Increase	Updated Value
125-HEP--D49-D53	Operator Fails To Transfer Power From D-49 To D-53	1.40E-02	429%	7.40E-02

125-HEP--D50-D51 Operator Fails To Transfer Pwr From D-50 To D-51

The HEP for this action is developed based on the time to core damage following a station blackout with a 480 gpm per pump RCP seal LOCA. The MAAP analyses supporting success criteria have been updated for EPU and show a time window of 98 minutes from initiating event to core damage for the case supporting development of this HEP.

The HEP for this event is quantified with the EPRI HRA Calculator using the CBDTM/THERP method. Reducing the System Time Window from 120 minutes (used in the current analyses) to 98 minutes indicates that a minimum of high dependence should be assigned for recovery actions. The dependence level for all recovery actions was changed from medium to high. Making this change in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Base Value	Percent Increase	Updated Value
125-HEP--D50-D51	Operator Fails To Transfer Pwr From D-50 To D-51	1.40E-02	429%	7.40E-02

125-HEP--D50-D52 Operator Fails To Transfer Pwr From D-50 To D-52

The HEP for this action is developed based on the time to core damage following a station blackout with a 480 gpm per pump RCP seal LOCA. The MAAP analyses supporting success criteria have been updated for EPU and show a time window of 98 minutes from initiating event to core damage for the case supporting development of this HEP.

The HEP for this event is quantified with the EPRI HRA Calculator using the CBDTM/THERP method. Reducing the System Time Window from 120 minutes (used in the current analyses) to 98 minutes indicates that a minimum of high dependence should be assigned for recovery actions. The dependence level for all recovery actions was changed from medium to high. Making this change in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Base Value	Percent Increase	Updated Value
125-HEP--D50-D52	Operator Fails To Transfer Pwr From D-50 To D-52	1.40E-02	429%	7.40E-02

125-HEP--D50-D53 Operator Fails To Transfer Power From D-50 To D-53

The HEP for this action is developed based on the time to core damage following a station blackout with a 480 gpm per pump RCP seal LOCA. The MAAP analyses supporting success criteria have been updated for EPU and show a time window of 98 minutes from initiating event to core damage for the case supporting development of this HEP.

The HEP for this event is quantified with the EPRI HRA Calculator using the CBDTM/THERP method. Reducing the System Time Window from 120 minutes (used in the current analyses) to 98 minutes indicates that a minimum of high dependence should be assigned for recovery actions. The dependence level for all recovery actions was changed from medium to high.

Making this change in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Base Value	Percent Increase	Updated Value
125-HEP--D50-D53	Operator Fails To Transfer Power From D-50 To D-53	1.40E-02	429%	7.40E-02

125-HEP-EOP10-08 Failure To Restore 125V DC After Loss Of Voltage And Recovery Of AC Power

The HEP for this action is developed based on the time to core damage following a station blackout with a 480 gpm per pump RCP seal LOCA. The MAAP analyses supporting success criteria have been updated for EPU and show a time window of 98 minutes from initiating event to core damage for the case supporting development of this HEP.

The HEP for this event is quantified with the EPRI HRA Calculator using the CBDTM/THERP method. Reducing the System Time Window from 120 minutes (used in the current analyses) to 98 minutes indicates that a minimum of high dependence should be assigned for recovery actions. The dependence level for all recovery actions was changed from medium to high. Making this change in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Base Value	Percent Increase	Updated Value
125-HEP-EOP10-08	Failure To Restore 125V DC After Loss Of Voltage And Recovery Of AC Power	2.10E-03	567%	1.40E-02

138-HEP-STARTG05 Start Gas Turbine And Close Bus Tie Breakers

The HEP for this action is developed based on the time to core damage following a station blackout with a 480 gpm per pump RCP seal LOCA. The MAAP analyses supporting success criteria have been updated for EPU and show a time window of 98 minutes from initiating event to core damage for the case supporting development of this HEP.

The HEP for this event is quantified with the EPRI HRA Calculator using the CBDTM/THERP method. The base analysis for this event used a 90-minute System Time Window which was based on a time of 120 minutes before core damage reduced by the 30 minutes needed to restore DC power systems after this action. In the original analysis, a minimum level of low dependence for recovery actions was suggested but the analysis used an increased dependence level of Medium. Reducing the System Time Window from 90 minutes (used in the current analyses) to 68 minutes indicates that a minimum of medium dependence should be assigned for recovery actions. Consistent with the original analyses, the recommended dependence level will be increased by one level to high. Making this change in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Base Value	Percent Increase	Updated Value
138-HEP-STARTG05	Start Gas Turbine And Close Bus Tie Breakers	2.60E-02	211%	8.10E-02

AF--HEP-START1TD Failure Of Op. To Manually Start TDP-1P29

The HEP for this action is developed based on the time to reach bleed and feed initiation criteria after a transient event. The MAAP analyses supporting success criteria have been updated for EPU and show a time window of 35 minutes from initiating event to reaching bleed and feed criteria for the case supporting development of this HEP.

The HEP for this event is quantified with the EPRI HRA Calculator using the CBDTM/THERP method. The base analysis for this event used a 56-minute System Time Window. In the original analysis, a minimum level of low dependence for recovery actions was suggested but the analysis used an increased dependence level of Medium. Reducing the System Time Window from 56 minutes (used in the current analyses) to 35 minutes indicates that a minimum of medium dependence should be assigned for recovery actions. Consistent with the original analyses, the recommended dependence level will be increased by one level to high. Making this change in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Base Value	Percent Increase	Updated Value
AF--HEP-START1TD	Failure Of Op. To Manually Start TDP-1P29	3.90E-04	154%	9.90E-04

AF--HEP-START2TD Failure Of Op. To Manually Start TDP-2P29

The HEP for this action is developed based on the time to reach bleed and feed initiation criteria after a transient event. The MAAP analyses supporting success criteria have been updated for EPU and show a time window of 35 minutes from initiating event to reaching bleed and feed criteria for the case supporting development of this HEP.

The HEP for this event is quantified with the EPRI HRA Calculator using the CBDTM/THERP method. The base analysis for this event used a 56-minute System Time Window. In the original analysis, a minimum level of low dependence for recovery actions was suggested but the analysis used an increased dependence level of Medium. Reducing the System Time Window from 56 minutes (used in the current analyses) to 35 minutes indicates that a minimum of medium dependence should be assigned for recovery actions. Consistent with the original analyses, the recommended dependence level will be increased by one level to high.

Making this change in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Base Value	Percent Increase	Updated Value
AF--HEP-START2TD	Failure Of Op. To Manually Start TDP-2P29	3.90E-04	154%	9.90E-04

AF--HEP-START-MD Failure To Manually Start MDP After Auto Fails

The HEP for this action is developed based on the time to reach bleed and feed initiation criteria after a transient event. The MAAP analyses supporting success criteria have been updated for EPU and show a time window of 35 minutes from initiating event to reaching bleed and feed criteria for the case supporting development of this HEP.

The HEP for this event is quantified with the EPRI HRA Calculator using the CBDTM/THERP method. The base analysis for this event used a 56-minute System Time Window. In the original analysis, a minimum level of low dependence for recovery actions was suggested but the analysis used an increased dependence level of Medium. Reducing the System Time Window from 56 minutes (used in the current analyses) to 35 minutes indicates that a minimum of medium dependence should be assigned for recovery actions. Consistent with the original analyses, the recommended dependence level will be increased by one level to high. Making this change in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Base Value	Percent Increase	Updated Value
AF--HEP-START-MD	Failure To Manually Start MDP After Auto Fails	3.90E-04	154%	9.90E-04

HEP-IA--AOP5B-74 Operator Fails To Isolate IA Header Rupture

The HEP for this action is developed based on the time to reach bleed and feed initiation criteria after a transient event. The MAAP analyses supporting success criteria have been updated for EPU and show a time window of 35 minutes from initiating event to reaching bleed and feed criteria for the case supporting development of this HEP.

In the original analysis of the actions to isolate a failed instrument air header, it was assumed required to isolate the leak before the header depressurized and that 26 minutes were required for the header to depressurize. Twenty six minutes were required to perform this action. Therefore, with the reduced time available to initiate bleed and feed, inadequate time would be available to perform this action after the EPU. Therefore, this action will be set to guaranteed failure.

Basic Event	Event Description	Base Value	Percent Increase	Updated Value
HEP-IA--AOP5B-74	Operator Fails To Isolate IA Header Rupture	0.092	N/A	Failed

HEP-IA--FO-04748 Operator Fails To Reopen 3047 or 3048

The HEP for this action is developed based on the time to reach bleed and feed initiation criteria after a transient event. The MAAP analyses supporting success criteria have been updated for EPU and show a time window of 35 minutes from initiating event to reaching bleed and feed criteria for the case supporting development of this HEP.

The HEP for this event is quantified with the EPRI HRA Calculator using the CBDTM/THERP method. Reducing the System Time Window from 56 minutes (used in the current analyses) to 35 minutes indicates that a minimum of high dependence should be assigned for recovery actions. The dependence level for all recovery actions was changed from medium to high. Making this change in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Base Value	Percent Increase	Updated Value
HEP-IA--FO-04748	Operator Fails To Reopen 3047 or 3048	1.50E-03	33%	2.00E-03

HEP-IA--FO-START Failure To Start IA or SA Comp After LOOP

The HEP for this action is developed based on the time to initiate bleed and feed cooling. In the original analysis, 56 minutes were available before conditions would indicate the need for bleed and feed cooling. As discussed above, the time to initiate bleed and feed cooling is expected to be 35 minutes after the EPU.

The HEP for this event is quantified with the EPRI HRA Calculator using the CBDTM/THERP method, however, timing was not explicitly considered. That is, the delay time, median response time, and manipulation times were set to zero. The stress level for execution was taken to be high in the current analysis and medium dependence was used to assess dependence for recovery of execution actions. Use of high stress would result in the highest HEP calculated using the CBDTM/THERP methodology. Because the time available to complete these actions would be significantly reduced, dependence will be increased one level for recovery of execution steps. Making this change in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Base Value	Percent Increase	Updated Value
HEP-IA--FO-START	Operator Fails To Start IA or SA Comp After LOOP	4.50E-03	82%	8.20E-03

HEP-MFW-CSPH1-06 Failure to Restore Main Feedwater to SG after SI Signal has Occurred

The HEP for this action is developed based on the time to reach bleed and feed initiation criteria after a transient event. The MAAP analyses supporting success criteria have been updated for EPU and show a time window of 35 minutes from initiating event to reaching bleed and feed criteria for the case supporting development of this HEP.

The HEP for this event is quantified with the EPRI HRA Calculator using the CBDTM/THERP method. The base analysis for this event used a 56-minute System Time Window. In the original analysis, a minimum level of low dependence for recovery actions was suggested but the analysis used an increased dependence level of Medium. Reducing the System Time Window from 56 minutes (used in the current analyses) to 35 minutes indicates that a minimum of high dependence should be assigned for recovery actions. Consistent with the original analyses, the recommended dependence level will be increased by one level to complete. Making this change in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Base Value	Percent Increase	Updated Value
HEP-MFW-CSPH1-06	Failure to Restore Main Feedwater to SG after SI Signal has Occurred	1.70E-02	1370%	2.50E-01

HEP-MFW-EOP01-06 Failure to Align Main Feedwater to the Steam Generators - No SI Present

The HEP for this action is developed based on the time to reach bleed and feed initiation criteria after a transient event. The MAAP analyses supporting success criteria have been updated for EPU and show a time window of 35 minutes from initiating event to reaching bleed and feed criteria for the case supporting development of this HEP.

The HEP for this event is quantified with the EPRI HRA Calculator using the CBDTM/THERP method. The base analysis for this event used a 56-minute System Time Window. In the original analysis, a minimum level of low dependence for recovery actions was suggested but the analysis used an increased dependence level of Medium. Reducing the System Time Window from 56 minutes (used in the current analyses) to 35 minutes indicates that a minimum of medium dependence should be assigned for recovery actions. Consistent with the original analyses, the recommended dependence level will be increased by one level to high. Making this change in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Base Value	Percent Increase	Updated Value
HEP-MFW-EOP01-06	Failure to Align Main Feedwater to the Steam Generators - No SI Present	7.40E-04	89%	1.40E-03

HEP-ODC-EOP-3-21 Operator Fails To Cooldown and Depressurize the Intact SG in One Hr Following a SGTR

The HEP for this action is developed based on a MAAP run with the current, 200 gpm AFW pumps that shows 60 minutes are available to initiate this action to prevent steam generator overfill. For pre-EPU conditions, the MAAP analyses show that steam generator level at 60 minutes would be 45.5 feet. For post-EPU conditions, updated MAAP analyses show that steam generator level of 45.5 feet would be reached at 36 minutes

The HEP for this event is quantified with the EPRI HRA Calculator using the CBDTM/THERP method. The level of complexity PSF was taken to be simple and the stress level for execution was taken to be low in the current analysis. Since the time window available to perform this action would be significantly reduced after the EPU, it will be assumed that the stress level for execution will increase from low to moderate. Making this change in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Base Value	Percent Increase	Updated Value
HEP-ODC-EOP-3-21	HEP-ODC-EOP-3-21 Operator Fails To Cooldown and Depressurize the Intact SG in One Hr Following a SGTR	1.30E-02	100%	2.60E-02

Impact of EPU on External Events and Level 2

Turbine Missile Generation

Turbine-generated missiles were screened from the consideration in the PBNP PRA because they were considered probabilistically insignificant contributors to overall risk. Given the increased power levels of the EPU, however, a reevaluation of turbine-generated missiles was performed. Based on the evaluations presented in LR Section 2.5.1.2.1, Internally Generated Missiles, it is concluded that the risk from turbine-generated and other missiles is not changed as a result of the EPU.

Seismic Events

PBNP is designed to withstand the effects of unusual natural phenomena including earthquakes. The plant was designed to withstand a design basis event (DBE) earthquake (also known as a safe shutdown earthquake [SSE]) with a PGA of 0.12g (12% of gravity). The PGA for the operating basis earthquake (OBE) is one-half of the SSE value. The seismic core damage frequency was calculated as part of the IPEEE to be in the range of 1.3E-05 per year (using the 1993 Lawrence Livermore National Laboratory seismic hazard curves) to 1.4E-05 per year (using the 1989 EPRI seismic hazard curves). The frequency of large fission product releases resulting from seismic events were determined to be less than 10% of seismic CDF. The vast majority of this risk was caused by seismic sequences with a concurrent failure of cable trays or a loss electrical power. Since the seismic capacity of cable trays and equipment related to providing offsite power to PBNP is not being affected by the EPU (see LR Section 2.2.5, Seismic and Dynamic Qualification of Mechanical and Electrical Equipment), it is concluded that seismic risk is not impacted by the EPU.

Internal Fire Events

An evaluation of the risk from internal fires was performed for the PBNP as part of the IPEEE. The fire risk evaluation used the EPRI Fire-induced Vulnerability Examination (FIVE) methodology and estimated a fire-induced CDF of 5.1E-05 per year. Fire risk was dominated by fires in the gas turbine building. Gas turbine building fires contributed to 40% of fire risk. The initial IPEEE fire analysis did not consider the new diesel generators that have been installed, modification of the AFW pump control system so that non-vital switchgear room fires do not prevent automatic start of the pumps, revision to the control room fire procedure, and relocation of control room smoke detectors to allow earlier fire identification.

The fire analysis has been updated in 1998. The update included developing new conditional core damage probabilities using the 1996 version of the internal events model and consideration of the two additional diesel generators and relocation of the B-train 4160 VAC switchgear to the EDG building. After completion of these modifications, fire risk was reanalyzed with the resulting CDF determined to be 1.2E-05 per year. This is the model that is used to assess risk changes resulting from the EPU.

For the EPU-related modifications, most will have only a minor impact on fire risk. For example, larger AFW or MFW pump motors would have a minor impact on fire ignition frequency and the addition of new cabling could increase the fire loading of areas where the cabling is installed. The total impact of such changes, however, is considered to be negligible to overall fire risk. Installation of the new MFIVs would add a new failure mode to the main feedwater system. Since feedwater was not credited in fire scenarios, the installation of the new MFIVs will cause no change on fire risk.

The effectiveness of operator actions credited in the fire analysis could be reduced because of reduced time available to perform the actions. Of the operator actions considered in the IPEEE fire analysis, all but two are either guaranteed failure or zero probability. The two events that are evaluated with a finite probability are starting an AFW pump given that automatic start failed and supplying SW to the AFW pumps after depletion of CSTs. Supplying SW to the AFW pumps after depletion of the CSTs will be automated. In addition, the new Motor-Driven AFW pumps are being installed in a different fire area than the Turbine-Driven pumps. Based on these changes, the overall fire risk is reduced. Since only minor changes in fire ignition frequency and fire loading will occur as a result of the EPU, it is concluded that overall fire risk is reduced by the EPU changes (see LR Section 2.5.1.4, Fire Protection).

High Winds, Floods, and Other External Events

Seismic and internal fires were analyzed as part of the IPEEE. For other external events, PBNP used the progressive screening approach as described in NUREG-1407 to evaluate high winds, floods, transportation, and nearby facility accidents. PBNP analyzed tornadoes and external floods further using quantitative bounding and PRA evaluations. Historical data was used for determining straight wind, tornado, and external flood frequencies. Some site-specific data were used for the analyses of aircraft crashes, land transportation accidents, and nearby facility events. No formal PRA or bounding analysis was performed for transportation and nearby facility accidents. These events were screened out due to their low frequency of occurrence. No changes being implemented as part of the EPU will affect any of the high winds, floods (see LR Section 2.5.1.1, Flood Protection and LR Section 2.5.1.1.3, Circulating Water System) or other external events analyzed for the PBNP. Therefore, it is concluded that no change in risk from any of the other external events is expected as a result of the EPU.

Level 2 Analysis

The PBNP PRA model quantifies LERF as part of the overall quantification process. The LERF model is developed following the approach given in NUREG/CR-6595 for PWRs with a large dry containment. The simplified Level 2 evaluation calculates the LERF considering the CDF sequences. The LERF results show the status of equipment considered important for continued containment integrity and the accident scenario involved. This equipment includes containment isolation valves and containment heat removal systems with important accident scenarios being steam generator tube ruptures (random or induced) and interfacing system LOCAs. Because CDF and LERF are both solved as part of the overall quantification process, any model changes that affect CDF are also quantified in the LERF model.

Shutdown Risk

A quantitative shutdown risk model is not maintained for PBNP. Therefore, a quantitative assessment of risk cannot be performed. For shutdown modes, a defense-in-depth risk management scheme is used and shutdown safety assessments are performed deterministically following the guidelines in NUMARC 91-06. Implementation of the shutdown safety assessments is done procedurally using checklists. One of the considerations in the checklists is the time to the onset of boiling following a loss of shutdown cooling. While the time to boiling will be decreased given the higher decay heat levels post-EPU, the existing procedures will effectively consider the shorter times when the curves used to determine boiling are revised. No other changes related to the EPU will affect any layer of defense considered in the shutdown safety assessments. Therefore, it is concluded that the EPU will have no significant impact on shutdown risk.

PRA Results

The PBNP PRA internal events models were quantified after incorporating the changes for both EPU and the AFW System upgrades described above. The results are shown below and contrasted with the results from the current base model for each unit.

Results Without Risk Reduction Modifications						
	Unit 1			Unit 2		
	Base Model	Post-EPU with AFW Mods	Change	Base Model	Post-EPU with AFW Mods	Change
CDF (per year)	3.7E-05	5.6E-05	1.9E-05	4.4E-05	6.4E-05	2.0E-05
LERF (per year)	3.3E-06	4.5E-06	1.2E-06	3.3E-06	4.5E-06	1.2E-06

Note that the changes in both CDF and LERF due to the EPU with AFW Modifications alone fall into the Region I acceptance guidelines of RG 1.174 (Reference 2). Refer to Figure 3 and Figure 4 of Regulatory Guide 1.174 for Acceptance Guidelines. However, as described below in, Planned Risk Reduction Strategies, several risk-reduction modifications have been identified and are committed to be installed in conjunction with EPU. These modifications will result in a reduction of both the CDF and the LERF for both PBNP Units.

The table below compares the risk results from the current base PRA model to the results with EPU including the AFW and Risk-Reduction modifications:

Results With Risk Reduction Modifications (includes modification described below)						
	Unit 1			Unit 2		
	Base Model	Post-EPU with AFW and Risk-Reduction Mods	Change	Base Model	Post-EPU with AFW and Risk-Reduction Mods	Change
CDF (per year)	3.7E-05	3.5E-05	-2.0E-06	4.4E-05	3.7E-05	-7.0E-06
LERF (per year)	3.3E-06	2.2E-06	-1.1E-06	3.3E-06	2.2E-06	-1.1E-06

Inclusion of the changes expected to result from the EPU show that plant risk increases after just the EPU even with the AFW system modifications. The increase occurs for two reasons. The most significant of the two is that the higher power levels result in shorter times available for operator actions credited with mitigating risk. The second is the potential for pressurizer overfill after a loss of normal feedwater or AC power to result in a small LOCA.

LERF is dominated by SGTR events both before and after the EPU and AFW system modifications. The increase in LERF for this analysis is caused by the increase in probability for operator action failures related to initiating cooldown and depressurization following a SGTR. The increased probability of operator action failure is caused by the decrease in available time to perform the actions. The decreased time availability was assumed to lead to increased stress levels for performing the actions. The most significant action to LERF is the action to restore air to containment following a safety injection signal. This action is needed to allow operation of pressurizer PORVs and auxiliary spray valves which allow depressurization of the RCS. As discussed above, the risk to PBNP from turbine missiles, seismic events, internal fires, high winds, and other external events is expected to be affected only negligibly by the EPU project.

Planned Risk Mitigation Strategies

Since the EPU is estimated to result in a risk increase to the PBNP, it is appropriate to consider strategies that could be used to mitigate that increased risk. By using the results of the analysis described above as well as insights gained from knowledge of PBNP design and operation, the strategies shown in the following sections were identified and their potential effect on risk reduction modeled and quantified. Because the specific, detailed plant design modifications cannot be identified at this point in the evaluation, bounding assumptions and modeling techniques were used.

AFW Pump Min-Flow Requirements

Following a loss of instrument air, the mini-recirc valves on the AFW pumps fail closed. Instrument air is lost as a result of losing service water and the mini-recirc valves are required to open to prevent excessive pump temperatures during low flow conditions. The TDAFP mini-recirculation valves are currently provided with an air accumulator that provides for two hours of operation following a loss of air. The new MDAFP mini-recirculation valves are planned to be provided with a backup nitrogen supply that provides for four hours of operation following a loss of instrument air. After depletion of the backup supplies, operator action is needed to gag open the mini-recirc valves to ensure pump protection. Failure of this operator action is assumed to lead to pump failure.

Potential strategies to ensure AFW min-flow after a loss of air include:

- Install a significantly larger backup pneumatic or compressed gas supply to the mini-recirc valves for both TDAFPs and MDAFPs. A larger air supply could eliminate the need to manually gag open the mini-recirc valves. A larger capacity supply would be added to the new MDAFP mini-recirc valves and a new nitrogen supply would be added to the TDAFP backup air supply. This approach would ensure that the additional supply will allow for over 24-hours of operation in the event of a loss of instrument air, thereby eliminating the operator action to gag open the mini-recirculation valves as a failure mode.
- Install recirculation valves that fail open on loss of air and provide backup pneumatic supply that will last until the required AFW flow has been reduced to the point that the remaining forward flow is greater than the decay heat requirements, assuming no operator action.
- For the new MDAFW pumps, install fail open/fail as-is discharge control valves and fail closed recirculation valves. The system can then be designed to prevent pump failure assuming high steam generator pressure. Total pump flow will increase to the Steam Generators, however the flow rate will be within pump capabilities and amperage draw will be below the breaker trip setpoint, motor damage curves, and cable damage curves as applicable.
- For the new MDAFW pump systems, install AC powered recirculation valves.

The above options will be reviewed and the best strategy or combination of strategies will be incorporated into each AFW pump system. The final option chosen will be equivalent to or exceed the risk reduction, resulting from elimination of operator actions, in the PRA evaluation for EPU.

The results of this risk evaluation are shown below and compared to the risk results from the Post-EPU model with the AFW system upgrade.

	Unit 1			**Unit 2**		
	Post-EPU with AFW Mods		**Change**	**Post-EPU with AFW Mods**	**With Modification to Eliminate Operator Actions for AFW**	**Change**
CDF (per year)	5.6E-05	4.5E-05	- 1.1E-05	6.4E-05	5.3E-05	- 1.1E-05
LERF (per year)	4.5E-06	4.5E-06	None	4.5E-06	4.5E-06	None

As can be seen, steps taken to provide additional air supplies to the AFW pump mini-recirculation valves (or other modification to eliminate operator action) result in a significant reduction in CDF compared to the Post-EPU with AFW Mods CDF. The modification results in no reduction in LERF, however, because LERF risk is dominated by SGTR events with failure to depressurize the RCS. Depressurization failure is caused by failures related to a lack of air to valves inside of containment. Since this modification does not improve availability of air to containment, other modifications will be needed to reduce LERF.

Install Self-Cooled Air Compressor

Instrument and service air compressors at PBNP require service water cooling. Consequently, following a loss of service water, the dominant contributor to risk, instrument air is not available. Since availability of instrument air affects operation of AFW, bleed and feed cooling, and RCS depressurization, removing the dependence of instrument air on service water would result in a reduction of risk.

Various alternatives exist for installation of self-cooled compressors. For example, an additional compressor that is aligned for automatic operation could be installed. Another option would be to replace one or more of the existing compressors with self-cooled compressors. An evaluation of options to provide instrument air will be performed as part of the modification process. However, the final modification will provide, at a minimum, an air compressor independent of service water cooling. Implementing any of the strategies would be expected to result in a similar reduction to plant risk.

The results are shown below and contrasted with the results from the Post-EPU model with AFW system upgrades for each unit.

	Unit 1			**Unit 2**		
	Post-EPU with AFW Mods	**Add Self-Cooled Air Compressor**	**Change**	**Post-EPU with AFW Mods**	**Add Self-Cooled Air Compressor**	**Change**
CDF (per year)	5.6E-05	4.1E-05	- 1.5E-05	6.4E-05	4.2E-05	- 2.2E-05
LERF (per year)	4.5E-06	4.5E-06	None	4.5E-06	4.5E-06	None

As can be seen, provision of self cooled air compressors result in a significant reduction in CDF when compared to the PRA model for Post-EPU with AFW Mods CDF of 5.6E-05 and 6.4E-05 for Units 1 and 2, respectively. LERF does not change.

Provide Backup Air Supply for Pressurizer Auxiliary Spray Valve CV-296

Following a safety injection signal, the containment isolation valves in the instrument air line to containment close. The current plant configuration does not provide any backup air supply to pressurizer PORVs or auxiliary spray valves. As a result, after a safety injection signal, the operators must reopen instrument air valves IA-3047 and IA-3048 to supply air to containment, when bleed and feed cooling or RCS depressurization is required. Loss of instrument air also impacts operation of the AFW pumps, as discussed above, so the need for bleed and feed cooling is more likely after a loss of instrument air.

The strategy planned is to provide a backup compressed gas supply only to the pressurizer auxiliary spray valve, CV-296. Auxiliary spray is a method of reducing RCS pressure that is redundant to the PORVs. Installation of a backup air supply to the auxiliary spray valve, CV-296, could be accomplished, for example, by installing nitrogen bottles to supply the valve while at the same time providing an isolation of the new supply from the containment instrument air header. A backup compressed gas supply to CV-296 would greatly minimize the importance to LERF of operator action to reopen a containment supply instrument air valve.

The PBNP PRA internal events models were quantified after incorporating the changes described above. The results are shown below and contrasted with the results from the Post-EPU model with AFW system upgrades for each unit.

	Unit 1			Unit 2		
	Post-EPU with AFW Mods	Provide Backup Gas Supply to Pzr Aux Spray Valve	Change	Post-EPU with AFW Mods	Provide Backup Gas Supply to Pzr Aux Spray Valve	Change
CDF (per year)	5.6E-05	5.4E-05	-2.0E-06	6.4E-05	6.1E-05	-3.0E-06
LERF (per year)	4.5E-06	2.2E-06	- 2.3E-06	4.5E-06	2.2E-06	- 2.3E-06

As can be seen, steps taken to provide, inside containment, an additional compressed gas supply to CV-296 could result in a significant reduction in LERF based on a comparison to results from both the current base model and the model as changed for the EPU evaluation. A slight reduction in CDF is also seen, when compared to the results from the model as changed for the EPU.

Combined Effects

The PBNP PRA internal events models were quantified after incorporating the changes described above for the EPU including AFW System upgrades plus the three risk-reduction modifications (i.e., eliminate operator actions for the AFW pump mini-recirc valves, installation of a self-cooled air compressor, and backup compressed gas supply to the pressurizer auxiliary spray valves). The results are shown below and contrasted with the results from the current base model for each unit.

	Unit 1			Unit 2		
	Base Model	Post-EPU with AFW and Risk Reduction Mods	Change	Base Model	Post-EPU with AFW and Risk Reduction Mods	Change
CDF (per year)	3.7E-05	3.5E-05	- 2.0E-06	4.4E-05	3.7E-05	- 7.0E-06
LERF (per year)	3.3E-06	2.2E-06	- 1.1E-06	3.3E-06	2.2E-06	- 1.1E-06

These results show that planned risk-reduction changes to plant configuration can reduce overall risk (both CDF and LERF), even with the significant power increase expected from the EPU.

In summary, in order to reduce the overall CDF and LERF values following implementation of the EPU, the following plant modifications are committed to be installed in conjunction with EPU and AFW System upgrades:

- Eliminate the reliance on local manual action to gag the Motor-Driven and Turbine-Driven AFW pump mini-recirculation valves open to prevent pump damage.
- Install an automatic, self-cooled (i.e., air-cooled) air compressor to supply Instrument Air independent of Service Water cooling.
- Provide a backup compressed gas supply for the Pressurizer Auxiliary Spray Valve CV-296 inside containment on each Unit.

2.13.1.4 Conclusion

PBNP reviewed the risk implications associated with implementation of the proposed EPU and concludes that the potential impacts associated with the implementation of the proposed EPU are adequately modeled. Based on the results of this modeling, certain plant modifications are committed to be installed to address the risk increase of the EPU itself. These modifications include installation of a modification to eliminate the reliance on local manual action to gag the Motor-Driven and Turbine-Driven AFW pump mini-recirculation valves open to prevent pump damage, installation of automatic self-cooled (i.e., air-cooled) air compressors to supply Instrument Air independent of Service Water cooling, and installation of backup air supplies to the pressurizer auxiliary spray valve inside containment on each Unit. With installation of these modifications in conjunction with implementation of the EPU (including the AFW System upgrades), the CDF and LERF of PBNP are both reduced from the current levels. PBNP further concludes that the results of the risk analysis indicate that the risks associated with the proposed EPU are acceptable and do not create the "special circumstances" described in Appendix D of SRP Chapter 19. Therefore, PBNP finds the risk implications of the proposed EPU acceptable.

2.13.1.5 References

1. U.S. Nuclear Regulatory Commission, Use of Probabilistic Risk Assessment in Plant-Specific, Risk-Informed Decisionmaking: General Guidance, NUREG-0800, Standard Review Plan Chapter 19.0, Revision 1, December 2002

2. NRC Regulatory Guide 1.174, An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis, Rev. 1, November 2002

3. Letter, PBNP to FPL - RE: Point Beach Nuclear Plant Extended Power Uprate Feasibility Study Results and Recommendations (Including Attachments), April 2, 2007

Appendix A(I)

Safety Evaluation Report Compliance

A.1 Safety Evaluation Report Compliance Introduction

This Appendix is a summary of NRC-approved codes and methods used in LR section 2.8.5, Accident and Transient Analyses, for the PBNP Extended Power Uprate. The appendix addresses compliance with the limitations, restrictions, and conditions specified in the approving safety evaluation of the applicable codes and methods (RS-001 Section 2.1 Matrix 8 Note 7).

Table A.1-1 presents an overview of the Safety Evaluation Reports (SER) by codes and methods. For each SER, the applicable report subsections and appendix subsections are listed.

Table A.1-1: Safety Evaluation Report Compliance Summary

No.	Subject	Topical Report (Reference) / Date of NRC Acceptance	Code(s)	Limitation, Restriction, Condition	Report Section	Appendix Section
1.	Non-LOCA Thermal Transients	WCAP-7908-A (Reference A.1-1) / September 30, 1986	FACTRAN	Yes	2.8.5.4.1 2.8.5.4.6	A.2
2.	Non-LOCA Safety Analysis	WCAP-14882-P-A (Reference A.1-2) / February 11, 1999	RETRAN	Yes	2.8.5.1.1 2.8.5.1.2 2.8.5.2.1 2.8.5.2.2 2.8.5.2.3 2.8.5.4.2	A.3
3.	Non-LOCA Safety Analysis	WCAP-7907-P-A (Reference A.1-3) / July 29, 1983	LOFTRAN	Yes	2.8.5.4.3 2.8.5.7	A.4
4.	Non-LOCA Safety Analysis	WCAP-16259-P-A (Reference A.1-14) / September 15, 2005	RETRAN SPNOVA VIPRE (RAVE)	Yes	2.8.5.3.1 2.8.5.3.2	Appendix A.8 and Appendix A(II)
5.	Neutron Kinetics	WCAP-7979-P-A (Reference A.1-4) / July 29, 1974	TWINKLE	None for Non-LOCA Transient Analysis	2.8.5.4.1 2.8.5.4.6	Not Applicable
6.	Multi-dimensional Neutronics	WCAP-10965-P-A (Reference A.1-5 / June 23, 1986)	ANC	None for Non-LOCA Transient Analysis	2.8.5.1.2 2.8.5.4.3	Not Applicable
7.	Non-LOCA Thermal / Hydraulics	WCAP-14565-P-A (Reference A.1-6 / January 19, 1999)	VIPRE	Yes	2.8.5.4.1 2.8.5.4.3	A.5
8.	Steam Generator Tube Rupture	WCAP-10698-P-A (Reference A.1-15/ March 30, 1987	LOFTTR2	None for Steam Generator Tube Rupture	2.8.5.6.2	Not Applicable

Table A.1-1: Safety Evaluation Report Compliance Summary						
No.	**Subject**	**Topical Report (Reference) / Date of NRC Acceptance**	**Code(s)**	**Limitation, Restriction, Condition**	**Report Section**	**Appendix Section**
9.	App K SBLOCA	WCAP-10079-P-A, WCAP-10054-P-A (with addenda), WCAP-11145, WCAP-14710 (References A.1-7 through A.1-11 / May 23, 1985)	NOTRUMP	Yes	2.8.5.6.3.3	A.6
10.	LOCA Hydraulic Forces	WCAP-8708-P-A (Reference A.1-12 / June 17, 1977, WCAP-9735 Rev. 2 (Reference A.1-13)	MULTIFLEX 3.0	Yes	2.8.5.6.3.5	A.7

References

A.1-1 WCAP-7908-A, "FACTRAN – A FORTRAN IV Code for Thermal Transients in a UO_2 Fuel Rod," H. G. Hargrove, December 1989.

A.1-2 WCAP-14882-P-A, "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," D. S. Huegel, et al., April 1999.

A.1-3 WCAP-7907-P-A, "LOFTRAN Code Description," T. W. T. Burnett, et al., April 1984.

A.1-4 WCAP-7979-P-A, "TWINKLE – A Multi-Dimensional Neutron Kinetics Computer Code," D. H. Risher, Jr. and R. F. Barry, January 1975.

A.1-5 WCAP-10965-P-A, "ANC: A Westinghouse Advanced Nodal Computer Code," Y. S. Liu, et al., September 1986.

A.1-6 WCAP-14565-P-A, "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis," Y. X. Sung, et al., October 1999.

A.1-7 WCAP-10079-P-A and WCAP-10080-A, "NOTRUMP - A Nodal Transient Small Break and General Network Code," Meyer, P. E., August 1985.

A.1-8 WCAP-10054-P-A, "Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code," N. Lee, et al., August 1985.

A.1-9 WCAP-10054-P-A, Addendum 2, Revision 1, "Addendum to the Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code: Safety Injection into the Broken Loop and COSI Condensation Model," C. M. Thompson, et al., July 1997.

A.1-10 WCAP-11145-P-A, "Westinghouse Small Break LOCA ECCS Evaluation Model Generic Study with the NOTRUMP Code," S. D. Rupprecht, et al., 1986.

A.1-11 WCAP-14710-P-A, "1-D Heat Conduction Model for Annular Fuel Pellets," D. J. Shimeck, May 1998.

A.1-12 WCAP-8708-P-A and WCAP-8709-A, "MULTIFLEX A FORTRAN-IV Computer Program for Analyzing Thermal-Hydraulic-Structure System Dynamics," K. Takeuchi, et al., September 1977.

A.1-13 WCAP-9735, Rev. 2 and WCAP-9736, Rev. 1, "MULTIFLEX 3.0 A FORTRAN IV Computer Program for Analyzing Thermal-Hydraulic-Structural System Dynamics Advanced Beam Model," K. Takeuchi, et al., February 1998.

A.1-14 WCAP-16259-P-A and WCAP-16259-NP-A, "Westinghouse Methodology for Application of 3-D Transient Neutronics to Non-LOCA Accident Analysis," C. L. Beard, et al., August 2006.

A.1-15 WCAP-10698-P-A and WCAP-10750-A, "SGTR Analysis Methodology to Determine the Margin to Steam Generator Overfill," R. N. Lewis, et al., August 1987.

A.2 FACTRAN for Non-LOCA Thermal Transients

Table A.2-1: FACTRAN for Non-LOCA Thermal Transients

Limitations, Restrictions, and Conditions
1. ***"The fuel volume-averaged temperature or surface temperature can be chosen at a desired value which includes conservatisms reviewed and approved by the NRC."*** **Justification** The FACTRAN code was used in the analyses of the following transients for PBNP: Uncontrolled Rod Withdrawal from Subcritical (FSAR Section 14.1.1, Uncontrolled Rod Withdrawal From Subcritical) and RCCA Ejection (FSAR Section 14.2.6, Rupture of a Control Rod Mechanism Housing RCCA Ejection). Initial fuel temperatures used as FACTRAN input in the RCCA Ejection analysis were calculated using the NRC-approved PAD 4.0 computer code, as described in WCAP-15063-P-A (Reference A.2-1). As indicated in WCAP-15063-P-A, the NRC has approved the method of determining uncertainties for PAD 4.0 fuel temperatures.
2. ***"Table 2 presents the guidelines used to select initial temperatures."*** **Justification** In summary, Table 2 of the SER specifies that the initial fuel temperatures assumed in the FACTRAN analyses of the following transients should be "High" and include uncertainties: loss of flow, locked rotor, and rod ejection. As discussed above, fuel temperatures were used as input to the FACTRAN code in the RCCA ejection analysis for PBNP. The assumed fuel temperatures, which were calculated using the PAD 4.0 computer code (Reference A.2-1), include uncertainties and are conservatively high. FACTRAN was not used in the loss of flow and locked rotor analyses.
3. ***"The gap heat transfer coefficient may be held at the initial constant value or can be varied as a function of time as specified in the input."*** **Justification** The gap heat transfer coefficients applied in the FACTRAN analyses are consistent with SER Table 2. For the rod withdrawal from subcritical transient, the gap heat transfer coefficient is kept at a conservative constant value throughout the transient; a high constant value is assumed to maximize the peak heat flux (for DNB concerns) and a low constant value is assumed to maximize fuel temperatures. For the RCCA ejection transient, the initial gap heat transfer coefficient is based on the predicted initial fuel surface temperature, and is ramped rapidly to a very high value at the beginning of the transient to simulate clad collapse onto the fuel pellet.
4. ***"…the Bishop-Sandberg-Tong correlation is sufficiently conservative and can be used in the FACTRAN code. It should be cautioned that since these correlations are applicable for local conditions only, it is necessary to use input to the FACTRAN code which reflects the local conditions. If the input values reflecting average conditions are used, there must be sufficient conservatism in the input values to make the overall method conservative."*** **Justification** Local conditions related to temperature, heat flux, peaking factors and channel information were input to FACTRAN for each transient analyzed for PBNP {Uncontrolled rod withdrawal from subcritical (FSAR Section 14.1.1, Uncontrolled Rod Withdrawal from Subcritical) and RCCA ejection (FSAR Section 14.2.6, Rupture of a Control Rod Mechanism Housing RCCA Ejection)}. Therefore, additional justification is not required.
5. ***"The fuel rod is divided into a number of concentric rings. The maximum number of rings used to represent the fuel is 10. Based on our audit calculations we require that the minimum of 6 should be used in the analyses."***

Table A.2-1: FACTRAN for Non-LOCA Thermal Transients

Limitations, Restrictions, and Conditions	
	Justification At least 6 concentric rings were assumed in FACTRAN for each transient analyzed for PBNP (Uncontrolled rod withdrawal from subcritical (FSAR Section 14.1.1, Uncontrolled Rod Withdrawal from Subcritical) and RCCA ejection (FSAR Section 14.2.6, Rupture of a Control Rod Mechanism Housing RCCA Ejection).
6.	***"Although time-independent mechanical behavior (e.g., thermal expansion, elastic deformation) of the cladding are considered in FACTRAN, time-dependent mechanical behavior (e.g., plastic deformation) is not considered in the code. ...for those events in which the FACTRAN code is applied (see Table 1), significant time-dependent deformation of the cladding is not expected to occur due to the short duration of these events or low cladding temperatures involved (where DNBR Limits apply), or the gap heat transfer coefficient is adjusted to a high value to simulate clad collapse onto the fuel pellet."*** **Justification** The two transients that were analyzed with FACTRAN for PBNP (Uncontrolled rod withdrawal from subcritical (FSAR Section 14.1.1, Uncontrolled Rod Withdrawal from Subcritical) and RCCA ejection (FSAR Section 14.2.6, Rupture of a Control Rod Mechanism Housing RCCA Ejection) are included in the list of transients provided in Table 1 of the SER; each of these transients is of short duration. For the Uncontrolled rod withdrawal from subcritical transient, relatively low cladding temperatures are involved, and the gap heat transfer coefficient is kept constant throughout the transient. For the RCCA ejection transient, a high gap heat transfer coefficient is applied to simulate clad collapse onto the fuel pellet. The gap heat transfer coefficients applied in the FACTRAN analyses are consistent with SER Table 2.
7.	***"The one group diffusion theory model in the FACTRAN code slightly overestimates at beginning of life (BOL) and underestimates at end of life (EOL) the magnitude of flux depression in the fuel when compared to the LASER code predictions for the same fuel enrichment. The LASER code uses transport theory. There is a difference of about 3 percent in the flux depression calculated using these two codes. When [T(centerline) – T(Surface)] is on the order of 3000°F, which can occur at the hot spot, the difference between the two codes will give an error of 100°F. When the fuel surface temperature is fixed, this will result in a 100°F lower prediction of the centerline temperature in FACTRAN. We have indicated this apparent nonconservatism to Westinghouse. In the letter NS-TMA-2026, dated January 12, 1979, Westinghouse proposed to incorporate the LASER-calculated power distribution shapes in FACTRAN to eliminate this non-conservatism. We find the use of the LASER-calculated power distribution in the FACTRAN code acceptable."*** **Justification** The condition of concern (T(centerline) – T(surface) on the order of 3000°F) is expected for transients that reach, or come close to, the fuel melt temperature. As this applies only to the RCCA ejection transient, the LASER-calculated power distributions were used in the FACTRAN analysis of the RCCA ejection transient for PBNP.

Reference

A.2-1 WCAP-15063-P-A, Revision 1 (with Errata) "Westinghouse Improved Performance Analysis and Design Model (PAD 4.0)," J. P. Foster and S. Sidener, July 2000.

A.3 RETRAN for Non-LOCA Safety Analysis

Table A.3-1: RETRAN for Non-LOCA Safety Analysis

Limitations, Restrictions, and Conditions
1. ***"The transients and accidents that Westinghouse proposes to analyze with RETRAN are listed in this SER (Table 1) and the NRC staff review of RETRAN usage by Westinghouse was limited to this set. Use of the code for other analytical purposes will require additional justification."***

Justification

The transients listed in Table 1 of the SER are:

- Feedwater system malfunctions
- Excessive increase in steam flow
- Inadvertent opening of a steam generator relief or safety valve
- Steam line break
- Loss of external load/turbine trip
- Loss of offsite power
- Loss of normal feedwater flow
- Feedwater line rupture
- Loss of forced reactor coolant flow
- Locked reactor coolant pump rotor/sheared shaft
- Control rod cluster withdrawal at power
- Dropped control rod cluster/dropped control bank
- Inadvertent increase in coolant inventory
- Inadvertent opening of a pressurizer relief or safety valve
- Steam generator tube rupture

The transients analyzed for PBNP using RETRAN are:

- Excessive increase in steam flow (FSAR Section 14.1.7, Excessive Load Increase Incident)
- Steam line break (FSAR Section 14.2.5, Rupture of a Steam Pipe)
- Loss of external electrical load (FSAR Section 14.1.9, Loss of Extrernal Electrical Load)
- Loss of all alternating current power to the station auxiliaries (FSAR Section 14.1.11, Loss of all AC Power to Station Auxuliaries)
- Loss of normal feedwater flow (FSAR Section 14.1.10, Loss of Normal Feedwater)
- Loss of reactor coolant flow (FSAR Section 14.1.8, Loss of Reactor Coolant Flow)
- Locked rotor accident (FSAR Section 14.1.8, Loss of External Electrical Load)
- Uncontrolled rod withdrawal at power (FSAR Section 14.1.2, Uncontrolled Rod Withdrawal from Subcritical)

As each transient analyzed for PBNP using RETRAN matches one of the transients listed in Table 1 of the SER, additional justification is not required.

Table A.3-1: RETRAN for Non-LOCA Safety Analysis

Limitations, Restrictions, and Conditions	
2.	***"WCAP-14882 describes modeling of Westinghouse designed 4-, 3, and 2-loop plants of the type that are currently operating. Use of the code to analyze other designs, including the Westinghouse AP600, will require additional justification."***
	Justification The PBNP consists of two 2-loop Westinghouse-designed units that were "currently operating" at the time the SER was written (February 11, 1999). Therefore, additional justification is not required.
3.	***"Conservative safety analyses using RETRAN are dependent on the selection of conservative input. Acceptable methodology for developing plant-specific input is discussed in WCAP-14882 and in Reference 14 [WCAP-9272-P-A]. Licensing applications using RETRAN should include the source of and justification for the input data used in the analysis."***
	Justification The input data used in the RETRAN analyses performed by Westinghouse came from both PBNP and Westinghouse sources. Assurance that the RETRAN input data is conservative for PBNP is provided via Westinghouse's use of transient-specific analysis guidance documents. Each analysis guidance document provides a description of the subject transient, a discussion of the plant protection systems that are expected to function, a list of the applicable event acceptance criteria, a list of the analysis input assumptions (e.g., directions of conservatism for initial condition values), a detailed description of the transient model development method, and a discussion of the expected transient analysis results. Based on the analysis guidance documents, conservative plant-specific input values were requested and collected from the responsible PBNP and Westinghouse sources. Consistent with the Westinghouse Reload Evaluation Methodology described in WCAP-9272-P-A (Reference A.3-1), the safety analysis input values used in the PBNP analyses were selected to conservatively bound the values expected in subsequent operating cycles.

Reference

A.3-1 WCAP-9272-P-A, "Westinghouse Reload Safety Evaluation Methodology," S. L. Davidson (Ed.), July 1985.

A.4 LOFTRAN for Non-LOCA Safety Analysis

Table A.4-1: LOFTRAN for Non-LOCA Safety Analysis

Limitations, Restrictions, and Conditions
1. *"LOFTRAN is used to simulate plant response to many of the postulated events reported in Chapter 15 of PSARs and FSARs, to simulate anticipated transients without scram, for equipment sizing studies, and to define mass/energy releases for containment pressure analysis. The Chapter 15 events analyzed with LOFTRAN are:* • *Feedwater System Malfunction* • *Excessive Increase in Steam Flow* • *Inadvertent Opening of a Steam Generator Relief or Safety Valve* • *Steamline Break* • *Loss of External Load* • *Loss of Offsite Power* • *Loss of Normal Feedwater* • *Feedwater Line Rupture* • *Loss of Forced Reactor Coolant Flow* • *Locked Pump Rotor* • *Rod Withdrawal at Power* • *Rod Drop* • *Startup of an Inactive Pump* • *Inadvertent ECCS Actuation* • *Inadvertent Opening of a Pressurizer Relief or Safety Valve* *This review is limited to the use of LOFTRAN for the licensee safety analyses of the Chapter 15 events listed above, and for a steam generator tube rupture..."* **Justification** For PBNP, the LOFTRAN code was used in the analyses of the rod cluster control assembly drop transient (FSAR Section 14.1.3, Rod Cluster Control Assembly Drop) and ATWS. As each of these transients matches one of the transients listed in the SER, additional justification is not required.

A.5 VIPRE for Non-LOCA Thermal/Hydraulics

Table A.5-1: VIPRE for Non-LOCA Thermal/Hydraulics

Limitations, Restrictions, and Conditions
1. ***"Selection of the appropriate CHF correlation, DNBR limit, engineered hot channel factors for enthalpy rise and other fuel-dependent parameters for a specific plant application should be justified with each submittal."*** **Justification** The WRB-1 correlation with a 95/95 correlation limit of 1.17 was used in the DNB analyses for the PBNP 14×14 422V+ fuel. The use of the WRB-1 DNB correlation is based on the notification change which introduces the 14x14 422V+ mid-grid design (NPL 97-0538, CAW-97-1166). The basic change is reverting back to the larger OD fuel rod as in standard fuel but with a new Low Pressure Drop mid-grid design. The applicability of WRB-1 to the LPD mid-grid was justified under FCEP (WCAP-12488-A). The use of the plant specific hot channel factors and other fuel dependent parameters in the DNB analysis for the PBNP 422V+ fuel were justified using the same methodologies as for previously approved safety evaluations of other Westinghouse two-loop plants using the same fuel design.
2. ***"Reactor core boundary conditions determined using other computer codes are generally input into VIPRE for reactor transient analyses. These inputs include core inlet coolant flow and enthalpy, core average power, power shape and nuclear peaking factors. These inputs should be justified as conservative for each use of VIPRE."*** **Justification** The core boundary conditions for the VIPRE calculations for the 422V+ fuel are all generated from NRC-approved codes and analysis methodologies. Conservative reactor core boundary conditions were justified for use as input to VIPRE. Continued applicability of the input assumptions is verified on a cycle-by-cycle basis using the Westinghouse reload methodology described in WCAP-9272-P-A (Reference A.5-1).
3. ***"The NRC Staff's generic SER for VIPRE set requirements for use of new CHF correlations with VIPRE. Westinghouse has met these requirements for using WRB-1, WRB-2 and WRB-2M correlations. The DNBR limit for WRB-1 and WRB-2 is 1.17. The WRB-2M correlation has a DNBR limit of 1.14. Use of other CHF correlations not currently included in VIPRE will require additional justification."*** **Justification** As discussed in response to Condition 1, the WRB-1 correlation with a limit of 1.17 was used in the DNB analyses of 422V+ fuel for PBNP. For conditions where WRB-1 is not applicable, the W-3 DNB correlation was used with a limit of 1.30 (1.45, for pressures between 500 psia and 1,000 psia).

Table A.5-1: VIPRE for Non-LOCA Thermal/Hydraulics

itations, Restrictions, and Conditions

"Westinghouse proposes to use the VIPRE code to evaluate fuel performance following postulated design-basis accidents, including beyond-CHF heat transfer conditions. These evaluations are necessary to evaluate the extent of core damage and to ensure that the core maintains a coolable geometry in the evaluation of certain accident scenarios. The NRC Staff's generic review of VIPRE did not extend to post CHF calculations. VIPRE does not model the time-dependent physical changes that may occur within the fuel rods at elevated temperatures. Westinghouse proposes to use conservative input in order to account for these effects. The NRC Staff requires that appropriate justification be submitted with each usage of VIPRE in the post-CHF region to ensure that conservative results are obtained."

Justification

For application to PBNP safety analysis, the usage of VIPRE in the post-critical heat flux region is limited to the peak clad temperature calculation for the locked rotor transient. The calculation demonstrated that the peak clad temperature in the reactor core is well below the allowable limit to prevent clad embrittlement. VIPRE modeling of the fuel rod is consistent with the model described in WCAP-14565-P-A and included the following conservative assumptions:

- DNB was assumed to occur at the beginning of the transient,
- Film boiling was calculated using the Bishop-Sandberg-Tong correlation,
- The Baker-Just correlation accounted for heat generation in fuel cladding due to zirconium-water reaction.

Conservative results were further ensured with the following input:

- Fuel rod input based on the maximum fuel temperature at the given power,
- The hot spot power factor was equal to or greater than the design linear heat rate,
- Uncertainties were applied to the initial operating conditions in the limiting direction.

Reference

A.5-1 WCAP-9272-P-A, "Westinghouse Reload Safety Evaluation Methodology," S. L. Davidson (Ed.), July 1985.

A.6 NOTRUMP for Small Break LOCA

NOTRUMP SER Restriction Compliance Summary

The following table contains a synopsis of the NRC imposed Safety Evaluation Report (SER) restrictions/requirements and the Westinghouse compliance status related to these issues. Not all the items identified are clearly SER restrictions, but sometimes state the NRC's interpretation of the Westinghouse Evaluation Methodology utilized for a particular aspect of the Small Break Loss Of Coolant Accident (LOCA) Evaluation Model.

WCAP-10054-P-A and WCAP-10079-P-A (References A.6-1 and A.6-2)
WCAP-10054-P-A is titled "Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code," and is dated August, 1985. The following summarizes the SER restrictions and requirements associated with this WCAP:
1. SER Wording (Page 6)
"The use of a single momentum equation implies that the inertias of the separate phases can not be treated. The model therefore would not be appropriate for situations when separate inertial effects are significant. For the small break transients, these effects are not significant."
SER Compliance
Inherent compliance due to the use of a single momentum equation.
2. SER Wording (Page 8)
"To assure the validity of this application, the bubble diameter should be on the order of 10^{-1}-2 cm. As long as steam generator tube uncovery (concurrent with a severe depressurization rate) does not occur, this option is acceptable."
SER Compliance
Westinghouse complies with this restriction for all Appendix-K licensing basis calculations. Typical Appendix-K calculations do not undergo a significant secondary side system depressurization in conjunction with steam generator tube uncovery due to the modeling methodology utilized.
3. SER Wording (Page 14)
"The two phase multiplier used is the Thom modification of the Martinelli-Nelson correlation. This model is acceptable per 10CFR50 Appendix K for LOCA analysis at pressure above 250 psia"
SER Compliance
The original NOTRUMP model was limited to no less than 250 psia since the model, as contained in the NOTRUMP code, did not contain information below this range. Westinghouse extended the model to below 250 psia, as allowed by Appendix K paragraph I-C-2, and reported these modifications to the NRC via the 1995 annual reporting period (NSD-NRC-96-4639).
4. SER Wording (Page 16)
"Westinghouse, however, has stated that the separator models are not used in their SBLOCA analyses."
SER Compliance
Westinghouse does not model the separators in the secondary side of the steam generators for Appendix-K Small Break LOCA analyses; therefore, compliance exists.
5. SER Wording (Pages 16-17)
"Axial heat conduction is not modeled." and "Deletion of clad axial heat conduction maximizes the peak clad temperature."
SER Compliance
The Westinghouse Small Break LOCA is comprised of two computer codes, the NOTRUMP code which performs the detailed system wide thermal hydraulic calculations and the LOCTA code which performs the detailed fuel rod heatup calculations. The NOTRUMP code does not model axial conduction in the fuel rod and therefore complies. The LOCTA code has always accounted for axial conduction as is clearly stated in WCAP-14710-P-A which supplements the original NOTRUMP documentation.
6. SER Wording (Page 17)

"...; critical heat flux, W-2, W-3, or Macbeth, or GE transient CHF (the W-2 and W-3 correlations are used for licensing evaluations);..."
SER Compliance
The information presented here indicates that the NRC apparently misstated that Westinghouse was utilizing the W-2,W-3 correlations for Critical Heat Flux (CHF) in the fuel rod heat transfer model. A review of the analyses performed by Westinghouse, including those in WCAP-11145-P-A, indicates that the Macbeth CHF correlation has been utilized for all Appendix-K analyses performed by Westinghouse. This is consistent with the slab heat transfer map as described in WCAP-10054-P-A. In addition, the Macbeth correlation is specifically called out in Appendix K I-C-4-4 as an acceptable CHF model. In a supplemental response to NRC questions (Specifically question 440.1 found in Appendix-A of WCAP-10054-P-A, Page A-10), a description of the core model describes the Macbeth as being utilized as the CHF correlation in the NOTRUMP Small Break LOCA model.
7. SER Wording (Page 21)
"The standard continuous contact model is not appropriate for vertical flow,..."
SER Compliance
The standard continuous contact flow links are not utilized when modeling vertical flow in the Appendix-K NOTRUMP Evaluation Model analyses; therefore, compliance is demonstrated.
8. SER Wording (Page 27)
"..., the hardwired choice of one fuel pin time step per coolant time step should result in sufficient accuracy."
SER Compliance
The NOTRUMP code continues to utilize only one fuel pin time step per coolant time step and therefore complies with this requirement.
9. SER Wording (Page 47)
"The code options available to the user but not applied in licensing evaluations were not reviewed."
SER Compliance
Westinghouse complies with this requirement.
10. SER Wording (Page 53)
"4. Steam Interaction with ECCS Water, a. Zero Steam Flow in the Intact Loops While Accumulators Discharge Water."
SER Compliance
Per paragraph I-D-4 Appendix-K, the following is stated: "During refill and reflood, the calculated steam flow in unbroken reactor coolant pipes shall be taken to be zero during the time that accumulators are discharging water into those pipes unless experimental evidence is available regarding the realistic thermal-hydraulic interaction between the steam and the liquid. In this case, the experimental data may be used to support an alternate assumption." As can be seen, the specific Appendix-K wording can be considered applicable to Large Break LOCAs only since Small Break LOCAs do not undergo a true refill/reflood period. However, the Westinghouse Small Break LOCA Evaluation Model methodology is such that for break sizes in which the intact loop seal restriction is not removed (WCAP-11145-P-A Page 2-11), steam flow through the intact loop(s) is automatically (artificially) restricted via the loop seal model. While not specifically limited to zero, the flow is drastically reduced via the application of the artificial loop seal restriction model. For breaks sizes above which the loop seal restriction is removed (typically >= 6 inch diameter breaks), this criterion is not explicitly adhered to. The implementation of the COSI condensation model into NOTRUMP (As approved by the NRC in WCAP-10054-P-A, Addendum 2, Revision 1), which is based on additional experimental documentation and improved modeling techniques, more accurately models the interaction of steam with Emergency Core Cooling Water in the cold leg region. This experimental documentation supports the more accurate modeling of steam/water interaction in the cold leg region as allowed by Appendix-K. Note however that even with the COSI condensation model active, the accumulator injection condensation model still utilizes the conservative model as originally licensed in the NOTRUMP code.
11. SER Wording (Page 7 of enclosure 2)

"Per generic letter 83-35, compliance with Action Item II.K.3.31 may be submitted generically. We require that the generic submittal include validation that the limiting break location has not shifted away from the cold legs to the hot or pump suction legs."
SER Compliance
Westinghouse submitted WCAP-11145-P-A in support of generic letter 83-35 Action Item II. K.3.31. As part of this effort, verification was provided which documented that the cold leg break location remains limiting.
WCAP-10054-P-A, Addendum 2, Revision 1 (Reference A.6-3)
WCAP- 10054-P-A, Addendum 2, Revision 1 is titled "Addendum to the Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code: Safety Injection into the Broken Loop and COSI Condensation Model," and is dated July 1997. The following summarizes the SER restrictions and requirements associated with this WCAP:
1. SER Wording (Page 3)
"It is stated in Ref. 5 that the range of injection jet velocities used in the experiments brackets the corresponding rates in small break LOCAs for Westinghouse plants and that the model will be used within the experimental range. Also in References 1 and 5 Westinghouse submitted analyses demonstrating that the condensation efficiency is virtually independent of RCS pressure and state that the COSI model will be applied within the pressure range of 550 to 1200 psia."
SER Compliance
The coding implementation of the COSI model correlation in the NOTRUMP model restricts the application of the COSI condensation model to a default pressure range of 550 to 1200 psia and limits the injection flow rate to a default value of 40 lbm/sec-loop. The value of 40 lbm/sec-loop corresponds to the 30 ft. /sec velocity utilized in the COSI experiments. As such, the default NOTRUMP implementation of the COSI condensation model complies with the applicable SER restrictions.
WCAP-11145-P-A (Reference A.6-4)
WCAP-11145-P-A, is titled "Westinghouse Small Break LOCA ECCS Evaluation Model Generic Study With The NOTRUMP Code," and is dated 1986. No specific SER restrictions were provided by the NRC as part of this WCAP review; however, the SER contains verification that the requirements of Item II.K.3.31 have been satisfied (i.e. break location study).
1. SER Wording (Page 5)
"We therefore, find that the requirements of NUREG-0737, Item II.K3.31, as clarified by Generic Letter 83-35, have been satisfied.
SER Compliance
We find that a condition of the safety evaluation for NOTRUMP as applied to Item II.K.3.30 has been satisfied. The limiting cold leg break size for a 4-loop plant was reanalyzed at pump suction and at hot leg locations. The results confirmed that the cold leg break was limiting."
WCAP-14710-P-A (Reference A.6-5)
WCAP-14710-P-A, is titled "1-D Heat Conduction Model for Annular Fuel Pellets," and is dated May 1998. No specific SER restrictions are provided by the NRC in this document; however, a conclusion was reached regarding the modeling of annular pellets during Small Break LOCA event.
1. SER Wording
"Based on its conclusions that the explicit modeling of annular pellets, as described in WCAP 14710(P), provides a more realistic representation in W Appendix K ECCS evaluation models of the annular pellets, while retaining conservatism in those evaluation models, the staff finds that the explicit modeling of annular pellets, as described in WCAP-14710(P), in W Appendix K LOCA evaluation models permits those models to continue to satisfy the regulations to which they were approved, and is, therefore, acceptable for incorporation into those models."
SER Compliance
Westinghouse performs sensitivity studies to assess the impact of modeling annular pellets on plant specific analyses.

References

A.6-1 WCAP-10054-P-A, "Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code" N. Lee, et al., August 1985.

A.6-2 WCAP-10079-P-A and WCAP-10080-A, "NOTRUMP - A Nodal Transient Small Break And General Network Code," Meyer, P. E., August 1985.

A.6-3 WCAP-10054-P-A, Addendum 2, Revision 1, "Addendum to the Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code: Safety Injection into the Broken Loop and COSI Condensation Model," C. M. Thompson, et al., July 1997.

A.6-4 WCAP-11145-P-A, "Westinghouse Small Break LOCA ECCS Evaluation Model Generic Study with the NOTRUMP Code," S. D. Rupprecht, et al., 1986.

A.6-5 WCAP-14710-P-A, "1-D Heat Conduction Model for Annular Fuel Pellets," D. J. Shimeck, May 1998.

A.7 MULTIFLEX for LOCA Hydraulic Forces

The NRC Safety Evaluation Report (SER) for the MULTIFLEX 1.0 Evaluation Model can be found in the front of WCAP-8708 Rev. 2 (Reference A.7-1). This SER stipulates a number of conditions and limitations on the use of the MULTIFLEX 1.0 Evaluation Model for licensing basis calculations. The following is a review of these SER restrictions and requirements.

	Table A.7-1: MULTIFLEX 1.0
Limitations, Restrictions, and Conditions	
1.	**SER Restriction** - Use of Corrected Sonic Velocity (SER, page 11) ***SER Wording - "The sonic velocity, or wave speed, computed with the empirical equation of state was not consistent with the 1967 ASME Steam Tables. The corrected sonic velocity data is required for a licensing calculation."***
	SER Compliance – The MULTIFLEX code has been changed (prior to the issuance of Revision 1 to WCAP-8708) to compute revised sonic velocity. Therefore, Westinghouse is in compliance with this restriction.
2.	**SER Restriction** - Lower Plenum Modeling (SER, page 12) ***SER Wording - "In the modeling region from the downcomer annulus to the lower plenum, the equivalent pipe network provided an artificially short transport distance across the length of the lower plenum. The correct radial transport distance, the diameter of the pressure vessel, is required in the model for a licensing calculation."***
	SER Compliance - Westinghouse does not use the "artificially short" lower plenum length cited in the SER. Therefore, it can be concluded that Westinghouse is in compliance with this modeling requirement.
3.	**SER Restriction** - 10 Mass Point Downcomer (SER, page 12, 18, 19) ***SER Wording - "The peak lateral force for a calculation using a 10 mass point representation for the core support barrel shows an increase in loading of 4% over the reference 5 mass point case. The NRC, therefore, requires a 10 mass point model be used for a coupled licensing calculation."***
	SER Compliance - Standard methodology uses a 10 mass point structural model. Therefore, Westinghouse is in compliance with this requirement.
4.	**SER Restriction** - 1 Millisecond Break Opening Time (BOT) (SER, page 13) ***SER Wording - "The use of a one millisecond opening time, as specified by Westinghouse, is required for a licensing calculation. Longer break opening times will not be considered unless Westinghouse demonstrated that the proposed break opening time with current equivalent pipe network adequately predicts the results of applicable experimental data."***
	SER Compliance - Standard methodology uses a 1 millisecond BOT. Therefore, Westinghouse is in compliance with this restriction.
5.	**SER Restriction** - Use of "Question 18" Input Parameters (SER, page 12). Question 18 establishes a line-by-line review of MULTIFLEX input. Parameters, identifying those that are "Required for design basis blowdown analysis" ***SER Wording - "The response to Question 18 of reference 4 is to be included in the MULTIFLEX report to identify the acceptable input option for a licensing calculation."***
	SER Compliance - The inputs used in the response to Question 18 were reviewed against the MULTIFLEX inputs established as Westinghouse's current methodology. We can state that our current models conservatively bound the requirements for licensing basis calculations as described in the MULTIFLEX SER. Therefore, Westinghouse is in compliance with this restriction.

MULTIFLEX 3.0 Applications

As indicated in the SER of WCAP-15029-P-A (Reference A.7-3), WCAP-9735, Rev. 2 (Reference A.7-2) topical was submitted for NRC review, and again subsequently withdrawn. It was determined that "Evaluation of the MULTIFLEX 3.0 methodology is not a requisite for concluding that WCAP-15029 is acceptable". The Staffs discussion of MULTIFLEX 3.0 is shown below:

"The MULTIFLEX 3.0 program is described as a more sophisticated analysis tool for LOCA hydraulic force calculations than the currently approved version, MULTIFLEX 1.0. WCAP-15029 indicates that the MULTIFLEX 3.0 program enhancements of MULTIFLEX 1.0 include: the use of a two dimensional flow network to represent the vessel downcomer region in lieu of a collection of one dimensional parallel pipes; the allowance for non-linear boundary conditions at the vessel and downcomer interface at the radial keys and the upper core barrel flange in lieu of simplified linear boundary conditions; and the allowance for vessel motion in lieu of rigid vessel assumptions. WCAP-15029 indicates that these modifications are included in the MULTIFLEX 3.0 program that is used to estimate the LOCA hydraulic forces on the vessel and consequential forces induced on the fuel and reactor vessel internal structures. The staff concurs with the WOG that MULTIFLEX 3.0 provides a more accurate and realistic modeling approach. On this basis, and considering that MULTIFLEX 3.0 is based on the previously approved MULTIFLEX 1.0, the staff considers the application of MULTIFLEX 3.0 with the WCAP-15029 methodology reasonable and acceptable."

Only one of the four SER restrictions in WCAP-15029-P-A (Reference A.7-3) applies to analyses performed using MULTIFLEX 3.0. Limitation number 2 reads: "The noding to be used in the representation of the loading is demonstrated to be adequate by performing nodalization sensitivity studies or by some other acceptable methodology."

The current nodalization employed in the Westinghouse baffle-former bolting analyses has been validated through a series of calculations. Westinghouse has verified that the current MULTIFLEX code version produces equivalent results to those used in the original development of MULTIFLEX 3.0 modeling features, despite several changes in operating system and computer platform. Westinghouse has demonstrated that the current standard nodalization produces equivalent results to those used in original test cases. Westinghouse has performed a series of sensitivity studies on MULTIFLEX 3.0 models using the current nodalization. Also, the historical model validation cases were found to yield conservative results relative to test data. This collection of documentation supports the conclusion that analyses performed to the current nodalization meet the limitation in WCAP-15029-P-A (Reference A.7-3).

MULTIFLEX 3.0 has also been accepted for use in other applications which are limited by the same acceptance criteria, i.e. fuel qualification. The Control Rod Insertion program, documented in WCAP-15245 (Reference A.7-4), was performed using MULTIFLEX 3.0 and the analyses were reviewed and accepted by the Staff (Reference A.7-5). These analyses have been used as a template for additional applications limited by the same acceptance criteria.

The use of break opening times greater than 1 millisecond has also been approved by the US-NRC (Reference A.7-6) for baffle barrel-bolting analyses. However, the use of longer break opening times is not approved for use on a generic basis. Such applications will require additional justification.

References

A.7-1 WCAP-8708-P-A and WCAP-8709-A, "MULTIFLEX A FORTRAN-IV Computer Program for Analyzing Thermal-Hydraulic-Structure System Dynamics," K. Takeuchi, et al., September 1977.

A.7-2 WCAP-9735, Rev. 2 and WCAP-9736, Rev. 1, "MULTIFLEX 3.0 A FORTRAN IV Computer Program for Analyzing Thermal-Hydraulic-Structural System Dynamics Advanced Beam Model," K. Takeuchi, et al., February 1998.

A.7-3 WCAP-15029-P-A, WCAP-15030-NP-A, "Westinghouse Methodology for Evaluating the Acceptability of Baffle-Former-Barrel Bolting Distributions Under Faulted Load Conditions," December 1998.

A.7-4 WCAP-15245 (Proprietary), WCAP-15246 (Non-proprietary), "Control Rod Insertion Following a Cold Leg LBLOCA, D. C. Cook, Units I and 2," May 28, 1999.

A.7-5 Letter from John F. Stang (US-NRC) to Robert P. Powers (Indiana Michigan Power Company), "Issuance of Amendments - Donald C. Cook Nuclear Plant, Units I and 2 (TAC Nos. MA6473 and MA6474)," December 23, 1999.

A.7-6 WCAP-14748-P-A, revision 0, WCAP-14749-NP-A, revision 0, "Justification for Increasing Postulated Break Opening Times in Westinghouse Pressurized Water Reactors," December 1998.

A.8 RETRAN-SPNOVA-VIPRE (RAVE)

The NRC Safety Evaluation Report (SER) can be found in the front of WCAP-16259-P-A (Reference A.8-5). This SER stipulates a number of conditions and limitations on the use for licensing basis calculations. The following is a review of these SER restrictions and requirements.

Table A.8-1: RETRAN-SPNOVA-VIPRE (RAVE)

Limitations, Restrictions and Conditions
1. Consistent with the guidance contained in Generic Letter 88-16, "Removal of Cycle-Specific Parameters Limits from Technical Specifications," a methodology that is used in the evaluation of the cycle-specific safety limits and plant safety analyses needs to be incorporated into the technical specification (TS) list of references. Therefore, the implementation of RAVE on a plant-specific basis required a TS amendment by the plant when the RAVE methodology is first implemented for that plant.
Compliance
Compliance was demonstrated by adding WCAP-16259-P-A (Reference A.8-5) to the PBNP Technical Specifications change package.
2. Because of competing effects between the coupled computer codes, the most conservative assumptions will, in many cases, no longer be obvious. Sensitivity studies will need to be performed to determine the most conservative plant conditions. Since different core designs may exhibit different sensitivities, the first implementation of the RAVE sensitivity studies should be performed to ensure that the limiting conditions have been identified. The sensitivity results will accompany the analyses using the RAVE methodology whenever the RAVE methodology is first implemented for a plant and must be presented to the NRC staff for review and approval.
Compliance
Compliance was demonstrated by re-performing the sensitivity cases set forth in WCAP-16259-P-A for the Locked Rotor and Loss of Flow events for PBNP and the results which contain information considered proprietary to Westinghouse are included in **Appendix A(II)** for the staff to review.
3. As support for the TS amendment, licensees implementing RAVE should provide justification that SPNOVA, VIPRE and RETRAN computer codes and methodology are approved for use in compliance with the conditions identified in the NRC staff SEs. The methodology for use of the VIPRE code shall be considered to be reviewed and approved for use in the RAVE methodology if all three applications of VIPRE have been reviewed and approved by the NRC staff. The three applications of VIPRE are the whole-core model, the DNBR model, and the post-CHF fuel heat-up model. **If a specific plant has not been licensed for the use of the computer codes and methodology that are utilized by RAVE, then the licensee will need to take appropriate licensing action for application of these computer codes. Licensees will need to verify that the conditions and limitations imposed on each of the three NRC approved codes (SPNOVA, RETRAN, and VIPRE), encompassing the RAVE methodology, will continue to be satisfied each time the RAVE methodology is used.**
Compliance
SPNOVA (References A.8-1 and A.8-2), VIPRE (Reference A.8-3) and RETRAN (Reference A.8-4) have already been generically approved for use at Westinghouse plants, and are applicable to PBNP. Topical report references for the SPNOVA, RETRAN and VIPRE models are included as part of the EPU licensing package. All three applications of VIPRE were used consistently with the VIPRE models described in WCAP-16259-P-A and WCAP-14565-P-A, which were reviewed and approved by the NRC.

4. Westinghouse submitted analyses showing that for post-CHF core heat-up, VIPRE input, as modified by Westinghouse and FACTRAN, produce virtually identical results. Therefore, the NRC staff considers VIPRE to be equivalent to FACTRAN for performing post-CHF core heat-up calculations. As is permitted for FACTRAN, VIPRE can be used to show compliance with acceptance criteria for peak cladding temperature for a locked rotor event, fuel melting, and pellet enthalpy criteria as well as for DNBR evaluation. Neither VIPRE nor FACTRAN include the time-dependent physical changes that may occur in a fuel rod at elevated temperatures. Therefore, VIPRE cannot be used to predict such failures and another fuel code should be used to predict mechanical behavior.
Compliance The VIPRE post-CHF model was used only for performing post-CHF core heat-up (PCT) calculation to show compliance with acceptance criteria for peak cladding temperature for a locked rotor event and was not used to predict the mechanical behavior.
5. The code option selected for use with whole-core VIPRE model may not be conservative for calculation of reactivity feedback for elevated steam void fractions. Westinghouse performed sensitivity studies which demonstrated that the reactor power calculated by the RAVE methodology is insensitive to assumptions for core voiding up to a maximum steam void fraction of 30 percent. If the maximum void fraction in any RAVE reactivity feedback calculation exceeds 30 percent, additional justification will need to be provided for the steam/water separation model utilized in the VIPRE whole-core model to the staff for additional review of that application of RAVE.
Compliance For the events that require a separate hot rod calculation (DNBR and PCT), the VIPRE core feedback calculations are performed with the core conditions satisfying the 30% void fraction limit identified in the RAVE (WCAP-16259-P-A) SER. This is done to predict a conservative nuclear power response during the transient. The 30% void fraction limit was exceeded for the locked rotor peak pressure event due to the use of conservative assumptions that maximize pressure response. However, the impact of exceeding this void fraction limit was investigated and it was determined to be conservative with respect to overpressurization. The pressure penalty associated with the increased voiding in the core (which in turn increases the pressurizer surge) is greater than the benefit (reduction) seen in the nuclear power response due to higher voiding in the core. Therefore, exceeding the 30% void limit is conservative for the locked rotor peak pressure event and provides more limiting peak pressure results compared to the case which does not exceed the 30% void fraction limit.

References

A.8-1 Chao, Y. A., et al., "SPNOVA – A Multidimensional Static and Transient Computer Program for PWR Core Analysis," WCAP-12394-A and WCAP-12983-A, June 1991.

A.8-2 Letter from Liparulo, N.J. (Westinghouse) to Jones, R. C., (NRC), "Process Improvement to the Westinghouse Neutronics Code System," NTD-NRC-96-4679, March 29, 1996.

A.8-3 WCAP-14565-P-A and WCAP-5306-NP-A, "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis," Sung, Y. X. et al., October 1999.

A.8-4 WCAP-14882-P-A, "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," D. S. Huegel, et al., April 1999.

A.8-5 WCAP-16259-P-A and WCAP-16259-A, "Westinghouse Methodology for Application of 3-D Transient Neutronics to Non-LOCA Accident Analysis," Beard, C. L., et al., August 2006.

Appendix A(II)

WCAP-16259-P-A Safety Evaluation Report Compliance

Westinghouse compliance with the NRC SER conditions for WCAP-16259-P-A is addressed in Appendix A(I). To show compliance with SER item 2, PBNP specific sensitivity studies have been performed for the Locked Rotor and Loss of Flow events.

2. Because of competing effects between the coupled computer codes, the most conservative assumptions will, in many cases, no longer be obvious. Sensitivity studies will need to be performed to determine the most conservative plant conditions. Since different core designs may exhibit different sensitivities, the first implementation of the RAVE sensitivity studies should be performed to ensure that the limiting conditions have been identified. The sensitivity results will accompany the analyses using the RAVE methodology whenever the RAVE methodology is first implemented for a plant and must be presented to the NRC staff for review and approval.
Compliance Compliance was demonstrated by re-performing the sensitivity cases set forth in WCAP-16259-P-A for the Locked Rotor and Loss of Flow events for PBNP and the results are included **below** for the staff to review.

1.0 Locked Rotor and Loss of Flow and Sensitivity Studies

1.1 <u>Locked Rotor Rods-In-DNB</u>

Sensitivity studies were performed to determine the conservative direction of the key analysis inputs (Reference 1). The reference limiting case was established based on the results of the sensitivity cases. Table A-1 presents the sensitivity cases that were performed, consistent with Reference 1, to establish the reference limiting locked rotor rods-in-DNB case. Results of the sensitivity cases are discussed below. [ ]^{a,c}

1. [ ]^{a,c}

2. [ ]^{a,c}

3. [] [a,c]

4. [.] [a,c]

5. [] [a,c]

6. [] [a,c]

7. [] [a,c]

8. [] [a,c]

9. [] [a,c]

10. [] [a,c]

1.2 Locked Rotor – Peak Pressure/Peak Clad Temperature

Sensitivity studies were performed to determine the conservative direction of the key analysis inputs (Reference 1). The reference limiting case was established based on the results of the sensitivity cases. Table A-2 presents the sensitivity cases that were performed, consistent with Reference 1, to establish the reference limiting locked rotor peak pressure case. Results of the sensitivity cases are discussed below.

1. □ [a,c]

2. □ [a,c]

3. □ [a,c]

4. □ [a,c]

5. □ [a,c]

1.3 Loss of Flow

Sensitivity studies were performed to determine the conservative direction of the key analysis inputs (Reference 1). The reference limiting case was established based on the results of the sensitivity cases. Table A-3 presents the sensitivity cases that were performed, consistent with Reference 1, to establish the reference limiting loss of flow case. Results of the sensitivity cases are discussed below. [] [a,c]

Comparing the results of the sensitivity cases to the base case (Case 1) in Table A-3 for the complete loss of flow event shows the following:

1. [] [a,c]
2. [] [a,c]
3. [] [a,c]
4. [] [a,c]
5. [] [a,c]
6. [] [a,c]
7. [] [a,c]

8. ▯ [a,c]

9. ▯ [a,c]

10. ▯ [a,c]

▯ [a,c]

▯ [a,c]

References

1. WCAP-16259-P-A and WCAP-16259-A, “Westinghouse Methodology for Application of 3-D Transient Neutronics to Non-LOCA Accident Analysis,” Beard, C. L., et al., August 2006

Table A-1: Results of Sensitivity Study for Locked Rotor Rods-in-DNB Event

a, c

Key: BOC = Beginning of Cycle EOC = End of Cycle RTP = Rated Thermal Power
AO = Axial Offset ARO = All Rods Out N-1 = All Rods In Less Stuck Rod

Table A-2: Results of Sensitivity Study for Locked Rotor Peak RCS Pressure Event

a, c

Key: BOC = Beginning of Cycle EOC = End of Cycle RTP = Rated Thermal Power
AO = Axial Offset ARO = All Rods Out N-1 = All Rods In Less Stuck Rod

Table A-3: Results of Sensitivity Study for Loss of Flow Event

a, c

Appendix B
Additional Codes and Methods

Numerous analytical codes and methods were used to support the proposed PBNP Power Uprate. These have been reviewed against the codes and methods currently described in the FSAR. The codes listed below, which do not currently appear in the FSAR, are identified for the NRC's information, along with their functional application. All of these codes/methods have been determined by PBNP to be appropriate for use in their respective applications.

CODE	APPLICATION
SW-QADCGGP	Radiation Shielding
PERC2	Gamma and Beta Radiation
STEHAM-PC	Main Steam Turbine Stop Valve Closure Forcing Function
WATHAM-PC	Feedwater Regulating Valve Closure and Pump start/stop.trip Forcing Function
NUPIPE-SWPC	Pipe Stress Analysis
PC-PREPS	Pipe Support Evaluations
ANSYS	Integral Welded Pipe Attachment Evaluations
GOTHIC	Containment Response/HELB Outside Containment
NSSS Plus	PCWG Parameters
WESDYN	Primary Loop Piping
DORT	RV Fluence
THRIVE	Internals
FROTH	LOCA Mass and Energy
WREFLOOD	LOCA Mass and Energy
EPITOME	LOCA Mass and Energy
SATAN VI	LOCA Mass and Energy
ATHOS	SG Thermal hydraulics
GENF	SG Thermal hydraulics
RADTRAD	Waste Gas Doses
FERRET	Neutron Exposure Evaluation
ASTRUM	BELOCA
OPTOAX	Setpoints
NSSSPlus	NSSS design parameter determination

APPENDIX C

SCOPE AND ASSOCIATED TECHNICAL REVIEW GUIDANCE
MATRIX 1
Materials and Chemical Engineering

Areas of Review (NRC Review Criteria)	Acceptance Criteria (PBNP Specific GDCs)	Other Guidance
Reactor Vessel Material Surveillance Program LR Section 2.1.1		
10 CFR Part 50, App. H 10 CFR 50.60 GDC-14 GDC-31	10 CFR Part 50, App. H PBNP GDC 34 PBNP GDC 36 ASME Sect XI Appendix G	FSAR 1.3.6 4.1 4.2 4.3 4.4 15.2.18 15.4.1
Pressure-Temperature Limits and Upper-Shelf Energy LR Section 2.1.2		
10 CFR Part 50, App. G 10 CFR 50.60 GDC-14 GDC-31	10 CFR Part 50, App. G 10 CFR 50 App H PBNP GDC 34 PBNP GDC 36 ASME Sect XI Appendix G	FSAR 1.3.6 4.1 4.2 4.3 4.4 7.4.2 15.2.18 15.4.1
Pressurized Thermal Shock LR Section 2.1.3		
10 CFR 50.61 GDC-14 GDC-31	10 CFR 50.61 10 CFR 50 App H PBNP GDC 34 PBNP GDC 36 PBNP GDC 9 ASME Sect XI Appendix G	FSAR 1.3.6 4.1 4.2 4.3 4.4 15.2.18 15.4.1

Areas of Review (NRC Review Criteria)	Acceptance Criteria (PBNP Specific GDCs)	Other Guidance
Reactor Internal and Core Support Materials LR Section 2.1.4		
10 CFR 50.55a GDC-1	10 CFR 50.55a PBNP GDC 1 WCAP-14577 ASME Sect XI	FSAR 1.3.1 1.3.2 1.4 3.1.2 3.1.3 3.2.3 4.1 4.2 4.4 15.2.17 15.2.23 15.2.24
Reactor Coolant Pressure Boundary Materials LR Section 2.1.5		
10 CFR 50.55a 10 CFR 50, App. G GDC-1 GDC-4 GDC-14 GDC-31 GL 97-01 IN 00-17s1 BL 01-01 BL 02-01 BL 02-02	10 CFR 50, App. G PBNP GDC 1 PBNP GDC 9 PBNP GDC 34	FSAR 1.3.6 3.1 3.2 4.1 4.2 4.4 15.4
Leak-Before-Break LR Section 2.1.6		
GDC-4	PBNP GDC 40 NUREG 1061 Vol. 3, Nov. 1984 SRP 3.6.3 Draft Aug. 1987	FSAR 4.1 6.1.1 9.0 15.4.3

Areas of Review (NRC Review Criteria)	Acceptance Criteria (PBNP Specific GDCs)	Other Guidance
Protective Coating Systems (Paints) - Organic Materials LR Section 2.1.7		
10 CFR 50 Appendix B RG 1.54	10 CFR 50 Appendix B RG 1.54 (partial) GL 98-04	FSAR 1.4 5.1.2.1 5.6.2.4 5.6.2.5 6.4.3 14.3.4
Flow-Accelerated Corrosion LR Section 2.1.8		
As stated in RS-001	EPRI Report, NSAC-202L-R3 Note 4* of RS-001 GL 98-08 IEB 87-01 IN 93-21	FSAR 15.2.11
Steam Generator Tube Inservice Inspection LR Section 2.1.9		
10 CFR 50.55a	10 CFR 50.55a Plant TSs GL 95-03 GL 97-06 BL 88-02	FSAR 4.4 15.2.19
Steam Generator Blowdown System LR Section 2.1.10		
GDC-14	PBNP GDC 9	5.2 5.4.2.1 10.1 11.5 Appendix A.2 Appendix A.5.2 Appendix I

Areas of Review (NRC Review Criteria)	Acceptance Criteria (PBNP Specific GDCs)	Other Guidance
Chemical and Volume Control System LR Section 2.1.11		
GDC-14 GDC-29	PBNP GDC 9 PBNP GDC 27 PBNP GDC 30 PBNP GDC 34	FSAR 4.1 5.2 5.7 9.3

APPENDIX C

SCOPE AND ASSOCIATED TECHNICAL REVIEW GUIDANCE
MATRIX 2

Mechanical and Civil Engineering

Areas of Review (NRC Review Criteria)	Acceptance Criteria (PBNP Specific GDCs)	Other Guidance
Pipe Rupture Locations and Associated Dynamic Effects LR Section 2.2.1		
GDC-4	PBNP GDC 40	FSAR 4.1 4.2 5.1 6.1 9.0 Appendix A.2 Appendix A.5

Areas of Review (NRC Review Criteria)	Acceptance Criteria (PBNP Specific GDCs)	Other Guidance
Pressure-Retaining Components and Component Supports LR Section 2.2.2 • LR Section 2.2.2.1 NSSS Piping, Components and Supports • LR Section 2.2.2.2 BOP Piping Components and Supports • LR Section 2.2.2.3 Reactor Vessel and Supports • LR Section 2.2.2.4 Control Rod Drive Mechanism and Supports • LR Section 2.2.2.5 Steam Generators and Supports • LR Section 2.2.2.6 Reactor Coolant Pumps and Supports • LR Section 2.2.2.7 Pressurizer and Supports		
10 CFR50.55a GDC-1 GDC-2 GDC-4 GDC-14 GDC-15	10CFR50.55a(a)(1) PBNP GDC 1 PBNP GDC 2 PBNP GDC 33 PBNP GDC 34 PBNP GDC 40 IEB 88-11 ACI-318-63	FSAR 1.4 3.1 3.2 4.0 4.1 4.2 4.4 5.1 5.2 5.3.2.1 5.6 6.1 7.2.2.1 9.1 15.3 15.4 Appendix A.5
Reactor Pressure Vessel Internals and Core Supports LR Section 2.2.3		
10 CFR 50.55a GDC-1 GDC-2 GDC-4 GDC-10	 PBNP GDC 1 PBNP GDC 2 PBNP GDC 6	FSAR 1.3.1 1.3.2 1.4 3.1.2 3.1.3 3.2.3 4.1 4.2 4.4 15.2.17 FSAR App A.5
Areas of Review	Acceptance Criteria	Other Guidance

(NRC Review Criteria)	(PBNP Specific GDCs)	
Safety-Related Valves and Pumps LR Section 2.2.4		
10 CFR 50.55a(f) GDC-1 GDC-37 GDC-40 GDC-43 GDC-46 GDC-54 GL 89-10 GL 96-05 GL 95-07	10 CFR 50.55a(f) PBNP GDC 1 PBNP GDC 38 PBNP GDC 46 PBNP GDC 57 PBNP GDC 59 PBNP GDC 63 GL 89-10 GL 95-07 GL 96-05 IEB 85-03 Plant TS	FSAR 1.3.1 Inservice Testing Program Document Component Maintenance Program (CMP) 2.2
Seismic and Dynamic Qualification of Mechanical and Electrical Equipment LR Section 2.2.5		
10 CFR 50 Appendix B 10 CFR 100 Appendix A GDC-1 GDC-2 GDC-4 GDC-14 GDC-30	10 CFR 50 Appendix B 10 CFR 100, Appendix A PBNP GDC 1 PBNP GDC 2 PBNP GDC 9 PBNP GDC 34 PBNP GDC 40 ACI-318-63	FSAR 1.4 2.1 2.2 2.8 2.9 4.1 4.2 4.3 4.4 5.1 5.6 6.1 8.0 9.0 Appendix A.5
NSSS Design Transients LR Section 2.2.6		
GDC -1 GDC-2 GDC-14 GDC-15	PBNP GDC 1 PBNP GDC 2 PBNP GDC 9 ACI-318-63	FSAR 1.3.1 1.3.2 1.4 4.1 5.1.1 14 Appendix A5.6

APPENDIX C

SCOPE AND ASSOCIATED TECHNICAL REVIEW GUIDANCE
MATRIX 3

Electrical Engineering

Areas of Review (NRC Review Criteria)	Acceptance Criteria (PBNP Specific GDCs)	Other Guidance
Environmental Qualification of Electrical Equipment LR Section 2.3.1		
10 CFR 50.49	10 CFR 50.49 IEB-79-01	FSAR 7.3.3.7 7.3.3.8 15.2.8
Offsite Power System LR Section 2.3.2		
GDC-17	PBNP GDC 39	FSAR 8.1
AC Onsite Power System LR Section 2.3.3		
GDC-17	PBNP GDC 39	FSAR 8.0
DC Onsite Power System LR Section 2.3.4		
GDC-17	PBNP GDC 39 GL-91-06	FSAR 8.7
Station Blackout LR Section 2.3.5		
10 CFR 50.63	10 CFR 50.63	FSAR Appendix A.1

APPENDIX C

SCOPE AND ASSOCIATED TECHNICAL REVIEW GUIDANCE
MATRIX 4

Instrumentation and Controls

Areas of Review (NRC Review Criteria)	Acceptance Criteria (PBNP Specific GDCs)	Other Guidance
Reactor Protection, Safety Features Actuation, and Control Systems LR Section 2.4.1		
10 CFR 50.55(a)(1) 10 CFR 50.55a(h) GDC-1 GDC-4 GDC-13 GDC-19 GDC-20 GDC-21 GDC-22 GDC-23 GDC-24	PBNP GDC 1 PBNP GDC 11 PBNP GDC 12 PBNP GDC 13 PBNP GDC 14 PBNP GDC 15 PBNP GDC 19 PBNP GDC 20 PBNP GDC 23 PBNP GDC 25 PBNP GDC 26	FSAR Chapter 7
Plant Operability LR Section 2.4.2.1		
GDC-13	PBNP GDC 12	FSAR 1.2.3 4.1 7.5.1.2
Pressurizer Component Sizing LR Section 2.4.2.2		
10 CFR 50.55(a)(1) 10 CFR 50.55(h) GDC-1 GDC-13 GDC-19 GDC-24	PBNP GDC 1 PBNP GDC 11 PBNP GDC 12 PBNP GDC 20	FSAR 4.1 FSAR 7.1 7.2 7.3

APPENDIX C

SCOPE AND ASSOCIATED TECHNICAL REVIEW GUIDANCE
MATRIX 5

Plant Systems

Areas of Review (NRC Review Criteria)	Acceptance Criteria (PBNP Specific GDCs)	Other Guidance
Flood Protection LR Section 2.5.1.1.1		
GDC-2	PBNP GDC 2	FSAR Appendix A.7
Equipment and Floor Drains LR Section 2.5.1.1.2		
GDC-2 GDC-4	PBNP GDC 2 PBNP GDC 40	FSAR 6.2 6.5 9.2 9.3 9.11 11.1 Appendix A.7 Appendix I.2
Circulating Water System LR Section 2.5.1.1.3		
GDC-4	PBNP GDC 2 PBNP GDC 40	FSAR 10.1 FSAR Appendix A.7
Internally Generated Missiles LR Section 2.5.1.2.1		
GDC-4	PBNP GDC 40	FSAR 4.1 6.1 9.0
Turbine Generator LR Section 2.5.1.2.2		
GDC-4	PBNP GDC 40	FSAR 9.4.3 10.1 14.1.12
Pipe Failures LR Section 2.5.1.3		
GDC-4	PBNP GDC 40	FSAR Appendix A.2

Areas of Review (NRC Review Criteria)	Acceptance Criteria (PBNP Specific GDCs)	Other Guidance
Fire Protection LR Section 2.5.1.4		
10 CFR 50.48 10 CFR 50 Appendix R GDC-3 GDC 5	10 CFR 50.48 10 CFR 50 Appendix R PBNP GDC 4 GL 86-10	FSAR 15.2.10 Fire Protection Evaluation Report Fire Hazards Analysis Report Safe Shutdown Analysis Report
Pressurizer Relief Tank LR Section 2.5.2		
GDC-2 GDC-4	PBNP GDC 2 PBNP GDC 40	FSAR 4.1 4.2
Fission Product Control Systems and Structures LR Section 2.5.3.1		
GDC-41	none	FSAR 6.4 Appendix C.1
Main Condenser Evacuation System LR Section 2.5.3.2		
GDC-60 GDC-64	PBNP GDC 17 PBNP GDC 70	FSAR 6.5 10.1 11.2 11.5 Appendix I
Turbine Gland Sealing System LR Section 2.5.3.3		
GDC-60 GDC-64	PBNP GDC 17 PBNP GDC 70	FSAR Section 10.1

Areas of Review (NRC Review Criteria)	Acceptance Criteria (PBNP Specific GDCs)	Other Guidance
Spent Fuel Pool Cooling and Cleanup System LR Section 2.5.4.1		
GDC-5 GDC-44 GDC-61	PBNP GDC 4 PBNP GDC 67 RS-001 Note 2	FSAR 9.4 9.6 9.9 Appendix A.6
Station Service Water System LR Section 2.5.4.2		
GDC-4 GDC-5 GDC-44	PBNP GDC 4 PBNP GDC 40 PBNP GDC 41 PBNP GDC 52	FSAR 5.3.2.1 FSAR 6.2 9.0 9.6 14.3.2 14.3.4 15.2.14 Appendix A.5 Appendix A.6
Reactor Auxiliary Cooling Water Systems LR Section 2.5.4.3		
GDC-4 GDC-5 GDC-44	PBNP GDC 4 PBNP GDC 40 PBNP GDC 41 GL 89-13 GL 96-06	FSAR 5.2 6.2 6.5 9.1 Appendix A.5 Appendix A.6 Generic Letter 89-13 Program
Ultimate Heat Sink LR Section 2.5.4.4		
GDC-5 GDC-44	PBNP GDC 4	1.3 2.5 9.1 9.6 9.10 10.1 Appendix A.6

Areas of Review (NRC Review Criteria)	Acceptance Criteria (PBNP Specific GDCs)	Other Guidance
Auxiliary Feedwater System LR Section 2.5.4.5		
GDC-4 GDC-5 GDC-19 GDC-34 GDC-44	PBNP GDC 1 PBNP GDC 2 PBNP GDC 4 PBNP GDC 11 PBNP GDC 12 PBNP GDC 37 PBNP GDC 38 PBNP GDC 40 PBNP GDC 41 PBNP GDC 42 NUREG 0737 II.E.1.1 Auxiliary Feedwater System	FSAR 5.2 7.4 10.1 10.2 14.1.10 14.1.11 14.2.4 14.2.5 Appendix A.1 Appendix A.2 Appendix A.6
Main Steam LR Section 2.5.5.1		
GDC-4 GDC-5 GDC-34	PBNP GDC 4 PBNP GDC 40 Plant TS	FSAR 4.1 5.1 6.0 7.2 7.3 7.4 7.6 7.7 9.3 10.0 10.1
Main Condenser LR Section 2.5.5.2		
GDC-60	PBNP GDC 70 Plant TS	FSAR 10.1
Turbine Bypass LR Section 2.5.5.3		
GDC-4 GDC-34	PBNP GDC 6 PBNP GDC 40	FSAR Section 3.1 4.1 7.1 10.1 FSAR Appendix A.2

Areas of Review (NRC Review Criteria)	Acceptance Criteria (PBNP Specific GDCs)	Other Guidance
Condensate and Feedwater LR Section 2.5.5.4		
GDC-4 GDC-5 GDC-44	PBNP GDC 4 PBNP GDC 40 For containment isolation function: • PBNP GDC 53 • PBNP GDC 57 Plant TS	FSAR 5.2 10.0 10.1 14.2.5
Gaseous Waste Management Systems LR Section 2.5.6.1		
10 CFR 20.1302 10 CFR Part 50, App. I GDC-3 GDC-60 GDC-61	10 CFR 20.1302 10 CFR Part 50, App. I 10 CFR 50 Appendix A GDC 3 PBNP GDC 17 PBNP GDC 18 PBNP GDC 69 PBNP GDC 70 Plant TS	FSAR 2.7 11.2 11.5 11.6 Appendix I FPER
Liquid Waste Management Systems LR Section 2.5.6.2		
10 CFR 20.1302 10 CFR Part 50, App. I GDC-60 GDC-61	10 CFR 20.1302 10 CFR Part 50, App. I PBNP GDC 17 PBNP GDC 18 PBNP GDC 69 PBNP GDC 70 Plant TS	FSAR 11.1 11.5 Appendix I

Areas of Review (NRC Review Criteria)	Acceptance Criteria (PBNP Specific GDCs)	Other Guidance
Solid Waste Management Systems LR Section 2.5.6.3		
10 CFR 20.1302 10 CFR Part 71 GDC-60 GDC-63 GDC-64	10 CFR 20.1302 10 CFR 71 PBNP GDC 17 PBNP GDC 18 PBNP GDC 70	FSAR 2.7 11.3 11.5 11.6
Emergency Diesel Engine Fuel Oil Storage and Transfer System LR Section 2.5.7.1		
GDC-4 GDC-5 GDC-17	PBNP GDC 40 PBNP GDC 4 PBNP GDC 39 Plant TS	FSAR 8.8 15.2.12
Light Load Handling System (Related to Refueling) LR Section 2.5.7.2		
GDC-61 GDC-62	PBNP GDC 66 PBNP GDC 68 PBNP GDC 69	FSAR 9.4
Circulating Water System LR Section 2.5.8.1		
		FSAR 2.5 10.1 11.1 Appendix A.7

APPENDIX C

SCOPE AND ASSOCIATED TECHNICAL REVIEW GUIDANCE
MATRIX 6

Containment Review Considerations

Areas of Review (NRC Review Criteria)	Acceptance Criteria (PBNP Specific GDCs)	Other Guidance
Primary Containment Functional Design LR Section 2.6.1		
GDC-16 GDC-50 GDC-38 GDC-13 GDC-64	PBNP GDC 10 PBNP GDC 12 PBNP GDC 49 PBNP GDC 50 PBNP GDC 52 PBNP CDG 70 NUREG II.E.4.2	FSAR 5.1 5.4 5.5 5.6 6.3.2 6.4 7 7.6.2 14.3.4
Subcompartment Analyses LR Section 2.6.2		
GDC-4 GDC-50	PBNP GDC 40 PBNP GDC 49	FSAR 4.1 5.1 6.1.1 9.0.1 14.3.4
Mass and Energy Release Analysis for Postulated Loss of Coolant LR Section 2.6.3.1		
10 CFR 50 Appendix K GDC-50	10 CFR 50 Appendix K PBNP GDC 49	FSAR 5.1 14.3.4 Appendix A.2 Addendum 2
Mass and Energy Release Analysis for Secondary System Pipe Ruptures LR Section 2.6.3.2		
GDC-50	PBNP GDC 10	(same as LR 2.6.1.1)

Areas of Review (NRC Review Criteria)	Acceptance Criteria (PBNP Specific GDCs)	Other Guidance
Combustible Gas Control in Containment LR Section 2.6.4		
10 CFR 50.44 10 CFR 50 46 GDC-5 GDC-41 GDC-42 GDC-43	None	FSAR 5.3
Containment Heat Removal LR Section 2.6.5		
GDC-38	PBNP GDC 52	FSAR 5.3 6.1.1 6.3
Pressure Analysis for ECCS Performance Capability LR Section 2.6.6		
10 CFR 50.46	10CFR 50.46	FSAR 14.3.2

APPENDIX C

SCOPE AND ASSOCIATED TECHNICAL REVIEW GUIDANCE
MATRIX 7

Habitability, Filtration, and Ventilation

Areas of Review (NRC Review Criteria)	Acceptance Criteria (PBNP Specific GDCs)	Other Guidance
Control Room Habitability System LR Section 2.7.1		
GDC-4 GDC-19	PBNP GDC 11 NUREG-0737, Item III.D.3.4, Control Room Habitability Requirements GL 2003-01	FSAR Section 7.1.2 7.5.3. 9.8 11.6.3
Engineered Safety Feature Atmosphere Cleanup LR Section 2.7.2		
GDC-19 GDC-41 GDC-61 GDC-64	PBNP GDC 11 PBNP GDC 17 PBNP GDC 69 NUREG-0737, Item III.D.3.4, Control Room Habitability Requirements	FSAR 6.3 6.4 9.5 9.8 11.2 11.5 11.6 Appendix C.1 LAR 241, Alternative Source Term
Control Room Area Ventilation System LR Section 2.7.3		
GDC-4 GDC-19 GDC-60	PBNP GDC 11 PBNP GDC 70 NUREG-0737, Item III.D.3.4, Control Room Habitability Requirements	FSAR Section 9.8
Spent Fuel Pool Area Ventilation System LR Section 2.7.4		
GDC-60 GDC-61	PBNP GDC 69 PBNP GDC 70	FSAR 2.6 9.5 14.2.1 Appendix I Section 1.5 Appendix I Section 2.6

Areas of Review (NRC Review Criteria)	Acceptance Criteria (PBNP Specific GDCs)	Other Guidance
Auxiliary and Radwaste Area and Turbine Areas Ventilation Systems LR Section 2.7.5		
GDC-60	PBNP GDC 70	FSAR 2.6 9.5 11.2 Appendix I, Section 1.5 Appendix I Section 2.6
Engineered Safety Feature Ventilation System LR Section 2.7.6		
GDC-4 GDC-17 GDC-60	PBNP GDC 70	FSAR 8.7.2 9.5 Appendix I Section 1.5 Appendix I Section 2.6
Other Ventilation Systems (Containment) LR Section 2.7.7		
GDC-4 GDC-17 GDC-60 GDC-61	PBNP GDC 37 PBNP GDC 39 PBNP GDC 40 PBNP GDC 69 PBNP GDC 70	FSAR 5.2 5.3 6.1.1 6.3 6.4 Appendix I Section 1.5 Appendix I Section 2.6

APPENDIX C

SCOPE AND ASSOCIATED TECHNICAL REVIEW GUIDANCE
MATRIX 8

Reactor Systems

Areas of Review (NRC Review Criteria)	Acceptance Criteria (PBNP Specific GDCs)	Other Guidance
Fuel System Design LR Section 2.8.1		
10 CFR 50.46 GDC-10 GDC-27 GDC-35	10 CFR 50.46 PBNP GDC 6 PBNP GDC 29 PBNP GDC 30 PBNP GDC 44	FSAR 3.1 6.2
Nuclear Design LR Section 2.8.2		
GDC-10 GDC-11 GDC-12 GDC-13 GDC-20 GDC-25 GDC-26 GDC-27 GDC-28	PBNP GDC 6 PBNP GDC 7 PBNP GDC 12 PBNP GDC 14 PBNP GDC 27 PBNP GDC 30 PBNP GDC 31 PBNP GDC 32	FSAR Chapter 3
Thermal and Hydraulic Design LR Section 2.8.3		
GDC-10 GDC-12	PBNP GDC 6 PBNP GDC 7	FSAR 3.1 3.2.2
Functional Design of Control Rod Drive System LR Section 2.8.4.1		
10 CFR 50.62(c)(3) GDC-4 GDC-23 GDC-25 GDC-26 GDC-27 GDC-28 GDC-29	10 CFR 50.62(c)(3) PBNP GDC 26 PBNP GDC 27 PBNP GDC 30 PBNP GDC 31 PBNP GDC 32 PBNP GDC 40 Plant TS	FSAR 3.1 3.2 3.4 4 5.1.2.7 5.3 7.2 7.7

Overpressure Protection During Power Operation **LR Section 2.8.4.2**		
GDC-15 GDC-31	PBNP GDC 9 PBNP GDC 33 PBNP GDC 34	FSAR 4.1 4.2 4.3 4.4 7.2
Overpressure Protection During Low Temperature Operation **LR Section 2.8.4.3**		
GDC-15 GDC-31	PBNP GDC 9 PBNP GDC 33 PBNP GDC 34 Plant TS GL 88-11 GL 90-06	FSAR 4.1 4.2 4.3 4.4 7.4.2 9.2 9.3
Residual Heat Removal System **LR Section 2.8.4.4**		
GDC-4 GDC-5 GDC-34	PBNP GDC 40 PBNP GDC 4	FSAR Section 9.2
Decrease in Feedwater Temperature, Increase in Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of a Steam Generator Relief or Safety Valve **LR Section 2.8.5.1.1**		
GDC-10 GDC-15 GDC-20 GDC-26	PBNP GDC 6 PBNP GDC 14 PBNP GDC 27 PBNP GDC 28 PBNP GDC 30	FSAR 3.1 7.1.2 9.3 14.1.6 14.1.7 14.2.5
Steam System Piping Failures Inside and Outside Containment **LR Section 2.8.5.1.2**		
GDC-27 GDC-28 GDC-31 GDC-35	PBNP GDC 9 PBNP GDC 30 PBNP GDC 32 PBNP GDC 33 PBNP GDC 34 PBNP GDC 44	FSAR 3.1, 4.1 6.1 6.2 14.2.5
Loss of External Load, Turbine Trip, and Loss of Condenser Vacuum **LR Section 2.8.5.2.1**		

GDC-10 GDC-15 GDC-26	PBNP GDC 6 PBNP GDC 9 PBNP GDC 29	FSAR 3.1 4.1 9.3 14.1.9
Loss of Non-emergency AC Power to the Station Auxiliaries LR Section 2.8.5.2.2		
GDC-10 GDC-15 GDC-26	PBNP GDC 6 PBNP GDC 9 PBNP GDC 29 PBNP GDC 30	FSAR 3.1 4.1 9.3 14.1.9 14.1.11
Loss of Normal Feedwater Flow LR Section 2.8.5.2.3		
GDC-10 GDC-15 GDC-26	PBNP GDC 6 PBNP GDC 9 PBNP GDC 29 PBNP GDC 30	FSAR 3.1 4.1 9.3 14.1.10
Feedwater System Pipe Breaks Inside and Outside Containment LR Section 2.8.5.2.4		
GDC-27 GDC-28 GDC-31 GDC-35	PBNP GDC 30 PBNP GDC 32 PBNP GDC 33 PBNP GDC 44	FSAR 3.1.2 4.1 6.2
Loss of Forced Reactor Coolant Flow LR Section 2.8.5.3.1		
GDC-10 GDC-15 GDC-26	PBNP GDC 6 PBNP GDC 9 PBNP GDC 29	FSAR 3.1 4.1 14.1.8
Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break LR Section 2.8.5.3.2		
GDC-27 GDC-28 GDC-31	PBNP GDC 30 PBNP GDC 32 PBNP GDC 34	FSAR 3.1 4.1 7.1.2 9.3.1 14.1.8
Uncontrolled Control Rod Assembly Withdrawal from a Subcritical or Low Power Startup Condition LR Section 2.8.5.4.1		

GDC-10 GDC-20 GDC-25	PBNP GDC 6 PBNP GDC 14 PBNP GDC 31	FSAR 3.1.2.1 7.1.2 7.2 14.1.1 14.1.2
Uncontrolled Control Rod Assembly Withdrawal at Power LR Section 2.8.5.4.2		
GDC-10 GDC-20 GDC-25	PBNP GDC 6 PBNP GDC 14 PBNP GDC 31	FSAR 3.1.2 7.2 14.1.1 14.1.2 14.1.4
Control Rod Misoperation LR Section 2.8.5.4.3		
GDC-10 GDC-20 GDC-25	PBNP GDC 6 PBNP GDC 14 PBNP GDC 31	FSAR 3.1.2.1 7.1.2 7.2 14.1.1 14.1.2 14.1.4
Startup of an Inactive Loop at an Incorrect Temperature LR Section2.8.5.4.4		
GDC-10 GDC-15 GDC-20 GDC-26 GDC-28	PBNP GDC 6 PBNP GDC 9 PBNP GDC 14 PBNP GDC 27 PBNP GDC 32	FSAR 14.1.5
Chemical and Volume Control System Malfunction that Results in a Decrease in Boron Concentration in the Reactor Coolant LR Section 2.8.5.4.5		
GDC-10 GDC-15 GDC-26	PBNP GDC 6 PBNP GDC 9 PBNP GDC 29 PBNP GDC 30	FSAR 3.1.2.1 4.1 9.3 14.1.4
Spectrum of Rod Ejection Accidents LR Section 2.8.5.4.6		
GDC-28	PBNP GDC 32	FSAR 3.1 14.2.6
Inadvertent Operation of ECCS and Chemical and Volume Control System Malfunction that Increases Reactor Coolant Inventory LR Section 2.8.5.5		

GDC-10 GDC-15 GDC-26	PBNP GDC 6 PBNP GDC 9 PBNP GDC 28 PBNP GDC 30	FSAR 3.1.2.1 4.1 4.2 9.3
Inadvertent Pressurizer Pressure Relief Valve Opening LR Section 2.8.5.6.1		
GDC-10 GDC-15 GDC-26	PBNP GDC 6 PBNP GDC 9 PBNP GDC 28 PBNP GDC 30	FSAR 3.1.2.1 4.1 14.3.1
Steam Generator Tube Rupture LR Section 2.8.5.6.2		
		FSAR 14.2.4
Loss –of-Coolant Accidents Resulting from Spectrum of Postulated Piping Breaks within the Reactor Coolant Pressure Boundary LR Section 2.8.5.6.3		
10 CFR 50.46 10 CFR 50 Appendix K GDC-4 GDC-27 GDC-35	10 CFR 50.46 10 CFR 50 Appendix K PBNP GDC 40 PBNP GDC 29 PBNP GDC 44	FSAR 3.1 6.1 6.2 14.3.1 14.3.2
Anticipated Transients Without Scrams LR Section 2.8.5.7		
10 CFR 50.62	10 CFR 50.62	FSAR 7.4.1
New Fuel Storage LR Section 2.8.6.1		
GDC-62	PBNP GDC 66 Plant TS	FSAR 9.4 Appendix A.6
Spent Fuel Storage LR Section 2.8.6.2		
GDC-4 GDC-62	PBNP GDC 40 PBNP GDC 66 Plant TS	FSAR 9.4 14.1.12 15.2.5 15.4.5 Appendix A.5 Appendix A.6

Loss of Residual Heat Removal at Midloop LR Section 2.8.7.1		
	GL 88-17	FSAR 9.2
Natural Circulation Cooldown LR Section 2.8.7.2		
	GL 81-21	FSAR 4.1

APPENDIX C

SCOPE AND ASSOCIATED TECHNICAL REVIEW GUIDANCE
MATRIX 9

Source Terms and Radiological Consequences Analyses

Areas of Review (NRC Review Criteria)	Acceptance Criteria (PBNP Specific GDCs)	Other Guidance
Source Terms for Input into Radwaste Management Systems Analyses LR Section 2.9.1		
10 CFR Part 20 10 CFR Part 50, App. I GDC-60	10 CFR Part 20 10 CFR Part 50, App. I PBNP GDC 70 Plant TS	FSAR 9.3.3 11.0 11.1 11.2 11.5 Appendix I
Radiological Consequences Analyses Using Alternative Source Terms LR Section 2.9.2		
10 CFR 50.67 GDC-19	10 CFR 50.67 GDC-19	LAR-241, Alternative Source Term
Radiological Consequences of Accidental Waste Gas Releases LR Section 2.9.10.1		
10 CFR 100 GDC-19	10 CFR 100 PBNP GDC-11 PBNP GDC 19	FSAR 11.2.5

APPENDIX C

SCOPE AND ASSOCIATED TECHNICAL REVIEW GUIDANCE
MATRIX 10

Health Physics

Areas of Review (NRC Review Criteria)	Acceptance Criteria (PBNP Specific GDCs)	Other Guidance
Occupational and Public Radiation Doses LR Section 2.10.1		
10 CFR 20 GDC-19	10 CFR 20 PBNP GDC-17 PBNP GDC 68 PBNP GDC 70 Plant TS NUREG 0737 II.B.2.2 "Plant Shielding Modifications for Vital Area Access NUREG 0737 II.B.3 "Post Accident Sampling Capability	FSAR 11.1 11.2 11.3 11.4 11.5 11.6 Appendix I Offsite Dose Calculation Manual Radioactive Effluence Controls Program

APPENDIX C

- **MATRIX 11**

SCOPE AND ASSOCIATED TECHNICAL REVIEW GUIDANCE

Human Performance

Areas of Review (NRC Review Criteria)	Acceptance Criteria (PBNP Specific GDCs)	Other Guidance
Human Factors LR Section 2.11.1		
10 CFR 50.120 10 CFR 55 GL 82-33 GDC-19	10 CFR 50.120 10 CFR 55 PBNP GDC 11 Plant TS NUREG 0737	FSAR 1.4 7.1.2 7.5.1.4 9.8 11.6.3 12.3 12.4 QATR

APPENDIX D

SUPPLEMENTAL ENVIRONMENTAL REPORT

Point Beach Nuclear Plant
Extended Power Uprate

This Appendix D contains the Environmental Report describing the impacts to the natural and human environment associated with the proposed Extended Power Uprate for the Point Beach Nuclear Plant.

1.0 Executive Summary

This Environmental Report contains the Point Beach Nuclear Plant (PBNP) Units 1 and 2 assessment of the environmental impacts of the proposed extended power uprate (EPU) from 1,540 megawatts-thermal (MWt) to 1,800 MWt per unit. The intent is to provide sufficient information for the U.S. Nuclear Regulatory Commission (NRC) to evaluate the environmental impact of the power uprate in accordance with the requirements of 10 CFR 51.

The environmental impacts of the proposed EPU are described and compared to those previously identified by the U.S. Atomic Energy Commission in the U.S. Atomic Energy Commission's (AEC) 1972 *Final Environmental Statement Related to Operation of Point Beach Nuclear Plant Units 1 and 2* and the NRC's Supplement 23 of the *Generic Environmental Impact Statement for the License Renewal of Nuclear Power Plants* (NUREG-1437) issued in August 2005 to address the license renewal of PBNP. This document demonstrates that the effects of operating under EPU conditions are bounded by the original analyses documented in the FES, the more recent Supplement 23 of the GEIS, or by current regulatory limits.

The PBNP EPU would be implemented with changes to plant systems that directly or indirectly interface with the human and natural environment. However, all necessary plant modifications would be implemented within existing buildings at PBNP, except for the replacement of two existing electrical transformers. These two transformers will replace the existing transformers and will be placed on the existing pad foundation with no ground disturbing activities. None of the proposed modifications would result in land disturbance or new construction outside of the established facility areas. The transmission system operator, American Transmission Company (ATC), will address any transmission system modifications based on all the existing and new demand and supply changes required for system reliability. ATC is responsible for securing the requisite permits and environmental approvals for any transmission facility construction necessary for any major system modification. There would be no change in the amount of water withdrawn from Lake Michigan for condenser cooling, and an approximate 17 percent increase in the amount of waste heat discharged to Lake Michigan. Generation of low-level radioactive waste would not increase significantly over the current generation rate, and would be bounded by FES values.

There would be an insignificant change in the volume of radioactive effluents (liquid and gaseous) released to the environment; however, the concentrations of radioactive nuclides of the liquid and gaseous releases will increase slightly and are bounded by the FES analysis (refer to LR Section 2.5.6.1, Gaseous Waste Management and LR Section 2.5.6.2, Liquid Waste Management). All offsite radiation doses would remain small and within applicable standards (refer to LR Section 2.10.1, Occupational and Public Radiation Doses). There would be no impact on the size of the regular operational plant workforce.

PBNP evaluated the compliance requirements associated with implementing the proposed EPU. PBNP will maintain compliance with Wisconsin State permits, licenses, approvals or other requirements currently held by the Plant. The Wisconsin Pollutant Discharge Elimination System (WPDES) permit would require no modification to accommodate the increase in heat rejected from the condensers. The Wisconsin Pollution Discharge Elimination System Permit was last issued for PBNP on July 1, 2004 and expires on June 30, 2009. A regular reapplication for renewal of the WPDES and Water Quality Certification from the State was submitted in December 2008 and PBNP will soon negotiate the new condition as a part of this renewal of the WPDES permit with the state of Wisconsin. By permit requirement, WDNR was notified by letter on July 30, 2008 of the planned production increase. PBNP commissioned a study that has evaluated the potential waste heat impacts of the uprate on the water quality and aquatic resources of Lake Michigan. The evaluation concluded that the environmental impacts from the increase in temperatures were negligible.

PBNP concludes that the environmental impacts of operation of both units at 1,800 MWt are either bounded by the impacts described in earlier National Environmental Policy Act assessments or constrained by applicable regulatory criteria. As a result, PBNP believes that the EPU operation would not significantly affect human health or the natural environment.

2.0 Introduction

Florida Power & Light Energy (FPLE) is committed to operating PBNP in an environmentally responsible manner. Plant activities including design, construction, maintenance, and operations are executed in a manner so as to protect the human environment and to responsibly manage natural resources. PBNP believes proper attention to the environment is essential to the well-being of our corporation, FPLE employees, neighbors to the site, and the broader global community. PBNP has operated for more than 36 years consistent with state and federal environmental regulations, while providing safe, reliable, and economical electrical power to electric ratepayers in Wisconsin.

PBNP has conducted a thorough environmental evaluation of the proposed extended power uprate (EPU) of PBNP from 1,540 megawatts-thermal (MWt) to 1,800 MWt. This would increase net electrical output to approximately 607 megawatts-electric (MWe). The proposed uprate would serve the future power requirements of the State of Wisconsin, the MidWest Independent System Operator, and the region.

This environmental evaluation is provided pursuant to 10 CFR 51.41 ("Regulations to Submit Environmental Information") and is intended to support the U.S. Nuclear Regulatory Commission (NRC) environmental review of the proposed uprate. The proposed EPU would require the issuance of an operating license amendment. The regulation (10 CFR 51.41) requires that applications to the NRC be in compliance with Section 102(2) of the National Environmental Policy Act (NEPA) and consistent with the procedural provisions of NEPA (40CFR 1500-1508). There are no NRC regulatory requirements or guidance documents specific to preparation of environmental reports for EPUs.

In 1972, the U.S. Atomic Energy Commission (AEC; predecessor agency to NRC) published the *Final Environmental Statement Related to the Operation of the Point Beach Nuclear Power Plant Units 1 and 2* (FES; AEC 1972). The AEC concluded that the issuance of the full term operating license, subject to certain conditions related to monitoring, was the appropriate course of action under NEPA. This decision was based on the analysis presented in the FES and the weight of environmental, economic, and technical information reviewed by the AEC. It also took into consideration the environmental costs and economic benefits of operating PBNP. The NRC subsequently issued the operating license to PBNP that authorized operation of each unit up to the maximum power level of 1,540 MWt.

In August 2005, the NRC published Supplement 23 of the *Generic Environmental Impact Statement for the License Renewal of Nuclear Power Plants* that addressed the license renewal of PBNP (NRC 2005). The NRC determined that the adverse environmental impacts of license renewal (i.e., operating an additional 20 years) are not so great that preserving the option of license renewal for energy-planning decision makers would be unreasonable. The decision was based upon the analysis presented in NUREG-1437, *Generic Environmental Impact Statement for the Renewal of Nuclear Power Plants* (GEIS; NRC 1996) and NUREG-1437, Supplement 23.

General information about the design and operational features of PBNP that are of interest from an environmental impact standpoint is available in several documents. In addition to the FES and Supplement 23 of the GEIS discussed above, another comprehensive source of information is the Final Safety Analysis Report (FSAR; PBNP 2008), prepared and maintained by PBNP.

This Environmental Report is intended to provide sufficient detail on both the radiological and non-radiological environmental impacts of the proposed EPU to allow the NRC to make an informed decision regarding the proposed action. It does not reassess the current environmental licensing basis or justify the environmental impacts of operating at the current licensed power level of 1,540 MWt. Rather, this document demonstrates that the effects of operating under EPU conditions are bounded by the original analyses documented in the FES, the more recent Supplement 23 of the GEIS, or by current regulatory limits.

3.0 Proposed Action and Need

Point Beach Nuclear Plant (PBNP) Units 1 and 2 are located in Manitowoc County, Wisconsin, on the western shore of Lake Michigan (see Figure 3-1). PBNP is a dual-unit plant that uses pressurized water reactors and nuclear steam supply systems designed by Westinghouse. FPL Energy Point Beach, LLC (FPLE/PBNP) operates the Point Beach Nuclear Plant pursuant to NRC Operating Licenses DPR-24 and DPR-27. Each reactor unit is supplied with steam generators that produce steam to turn turbines to generate electricity. Plant cooling is provided by a once-through system using water from Lake Michigan.

PBNP is located approximately 48 km (30 mi) southeast of Green Bay and 24 km (15 mi) north-northeast of Manitowoc. The area within 10 km (6 mi) of PBNP (See Figure 3-2) includes portions of Manitowoc and Kewaunee counties and is largely rural, characterized by farmland, woods and small residential communities. The nearest town is Two Creeks, approximately 2km (1 mi) north-northwest of the site. PBNP is approximately 10 km (6 mi) east-northeast of Mishicot, 13 km (8 mi) north of Two Rivers, and 18 km (11 mi) south of Kewaunee. The Oneida Indian Reservation is located on the western edge of Green Bay, approximately 56 km (35 mi) northwest of the plant. As seen in Figure 3-3, the PBNP property covers approximately 510 ha (1260 ac). (Ref: NUREG-1437 Supplement 23)

3.1 Proposed Action

The proposed action is to increase the licensed core thermal power for each of the PBNP units from the current 1,540 MWt to 1,800 MWt, which represents an increase of approximately 17 percent and would increase electrical output by approximately 90 MWe. This change in core thermal power would require the NRC to amend the facility's operating licenses. The PBNP EPU will involve extensive plant modifications to the secondary side of the plant. The increase in power level is planned to be accomplished in two increments; the first following the U1R32 Spring 2010 Unit 1 refueling outage beginning with Cycle 33, and the second following the U2R31 Spring 2011 Unit 2 refueling outage beginning with Cycle 32.

3.2 Need for Action

The proposed action provides FPLE/PBNP LLC with the capability to increase the electrical output of PBNP by approximately 90 MWe per unit and to supply low cost, reliable, and efficient electrical generation to the State of Wisconsin. In their February 2007 Final Report on "Strategic Energy Assessment Energy 2012" (Docket 5-ES-103) the Public Service Commission of Wisconsin forecasted an average annual growth rate of 2.35 percent in electricity demand. In addition, the report noted that the new planned generation, of which the PBNP EPU is a part, will reduce Wisconsin's reliance on the currently congested transmission grid connections to Illinois and will maintain a robust planning reserve margin. The Wisconsin Public Service Commission has an 18 percent reserve margin requirement. Therefore the proposed EPU at PBNP contributes to meeting the goals and recommendations of the State of Wisconsin with efficient and reliable nuclear electrical generation that represents stable fuel prices, low cost, and reduces greenhouse gas emissions. (Ref: February 2007 Final Report on "Strategic Energy Assessment Energy 2012," the Public Service Commission of Wisconsin, (Docket 5-ES-103))

References

3.1 February 2007 Final Report on "Strategic Energy Assessment Energy 2012," Public Service Commission of Wisconsin, (Docket 5-ES-103)

Figure 3-1
50-Mile Region

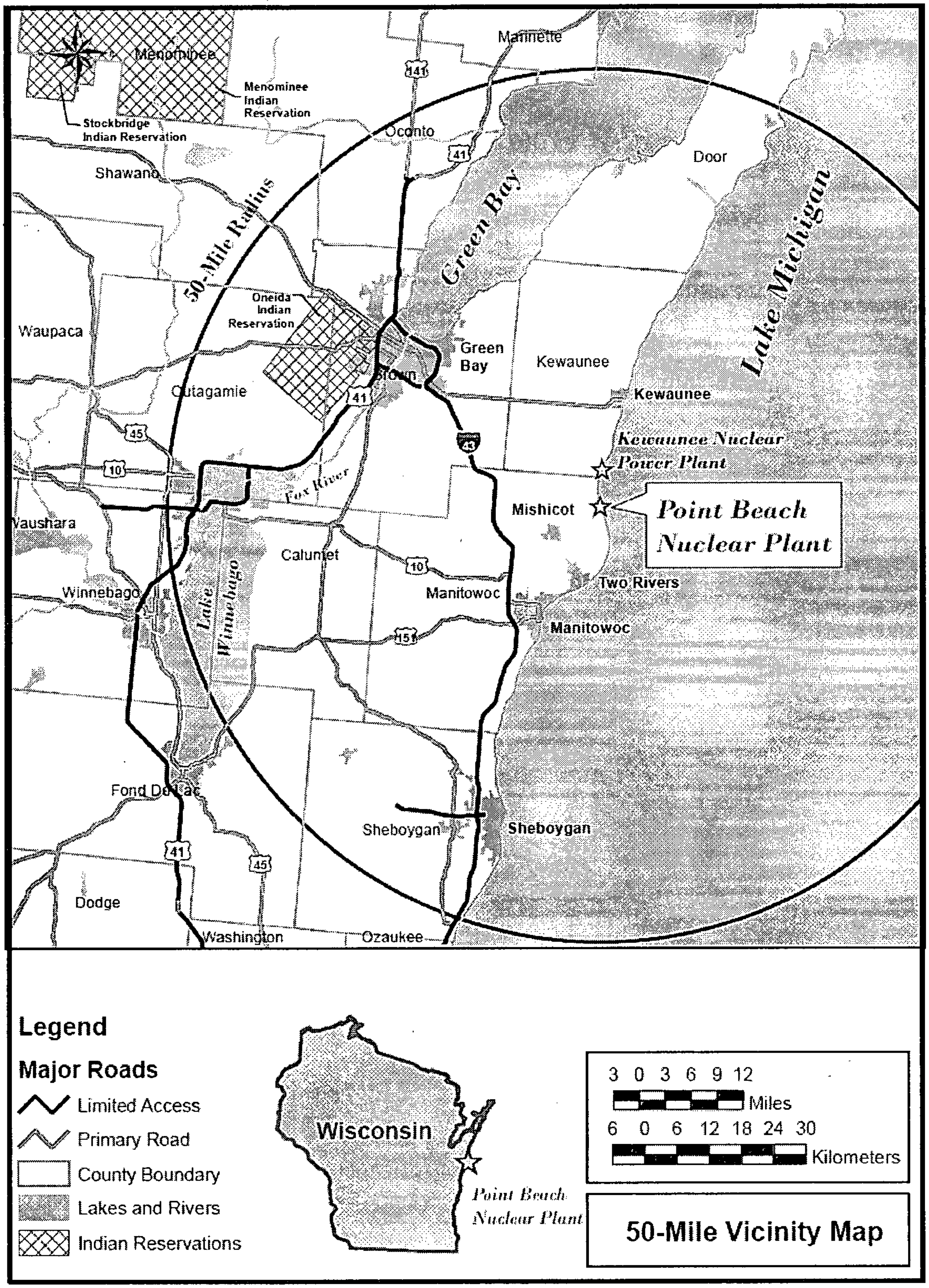


Figure 3-2
6-Mile Region

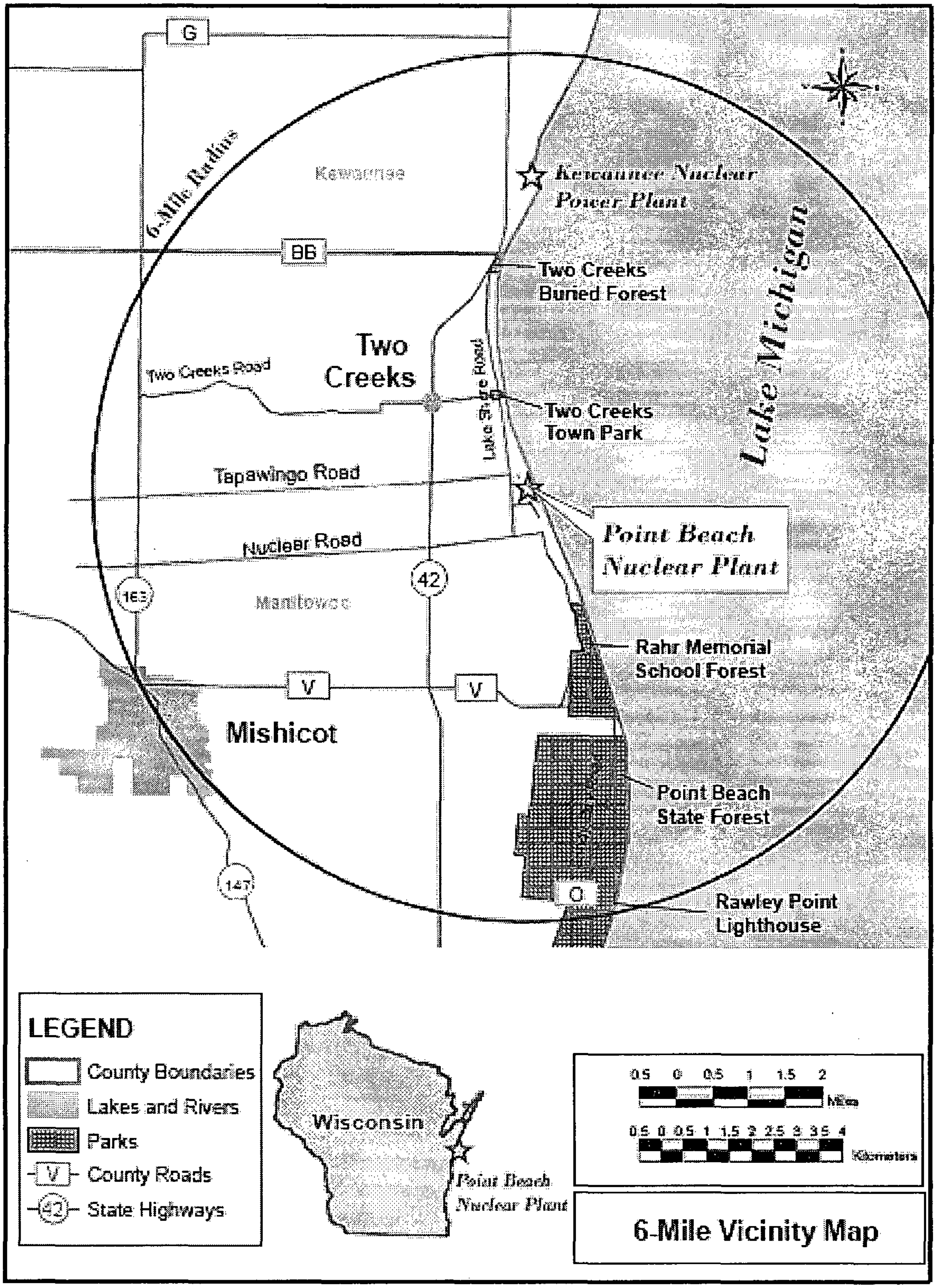
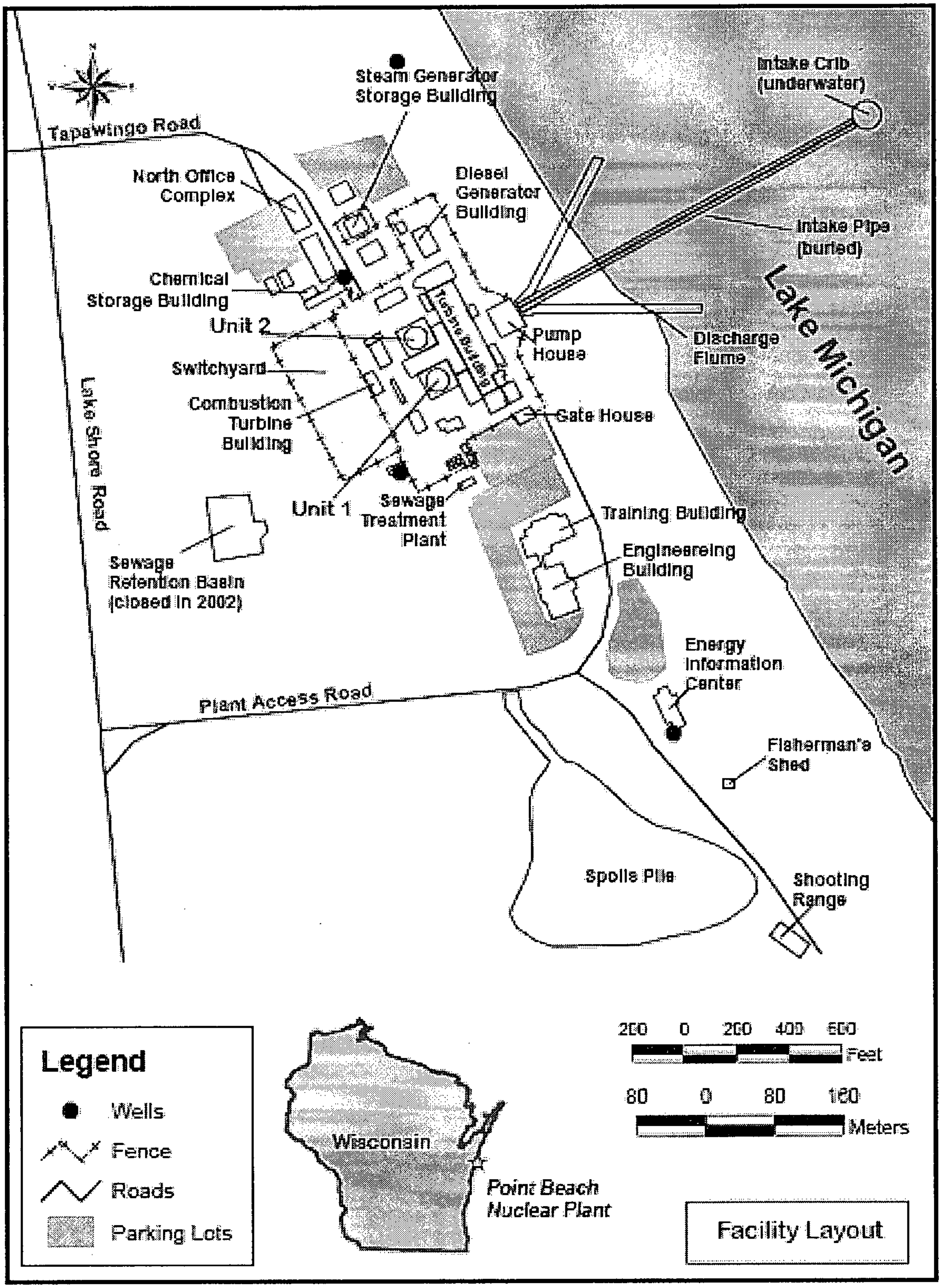


Figure 3-3
PBNP Site Map



4.0 Overview of Operational and Equipment Changes

The primary means of producing more power are a change in the fuel management, an operational change in reactor thermal-hydraulic parameters, and an upgrade of the balance of plant capacity by component replacement or modification. Changes include replacing the high-pressure side of the turbine, replacing all of the feedwater heaters, feedwater and condensate pumps and motors to operate at higher capacity, providing supplemental cooling for some plant systems, implementing electrical upgrades to accommodate the higher currents and to improve electrical stability, other modifications to accommodate greater steam and condensate flow rates, and providing instrumentation upgrades that include replacing sensors or measurement equipment, and changing operational setpoints. The EPU is the combination of these changes that achieve the desired power level for the most reasonable capital cost.

In general, light water reactors are designed with an as-built equipment capability to increase power up to 7 percent above the original licensed power level. For power uprates beyond this level, as is planned for PBNP, more extensive plant modifications are generally required to increase capability. Table 1.0-1 of the EPU Licensing Report (LR) lists the modifications needed to implement the proposed 17% EPU at PBNP.

Each PBNP unit was originally designed to produce a reactor thermal output of 1,518.5 megawatts-thermal (MWt). All steam and power conversion equipment, including each turbine generator, was originally designed to permit generation of 523.8 megawatts (MW) of gross electrical power. Unit 1 achieved commercial operation in December 1970 and Unit 2 achieved commercial operation in October 1972. Since being placed into commercial operation, each unit underwent a low-pressure turbine retrofit modification that increased the unit design output to 537.96 megawatts-electric (MWe). In 2003, PBNP underwent a 1.4 percent uprate which increased the rated thermal output to 1,540 MWt and increased the gross electrical power to 545 MWe (518 MWe net).

PBNP recognizes the following major modifications that have been completed since the PBNP was first operated, in part, to provide the opportunity to increase power at PBNP with limited additional modifications of the reactor and plant safety systems.

Upgrade of Moisture Separator/Reheaters – 1987 for Unit 1 and 1988 for Unit 2

Steam Generator Replacements – 1984 for Unit 1 and 1996 for Unit 2

Addition of Emergency Diesel Generators - 1994

Low Pressure Turbine Replacements – 1998 for Unit 1 and 1999 for Unit 2

Fuel upgrade – 2002 for Unit 1 and Unit 2

RV Head replacements – 2005 for Unit 1 and Unit 2

Installation of Leading Edge Flow Measurement – 2003 for Unit 1 and Unit 2

Although the modifications on the secondary side will be extensive, the required additional modifications are generally of relatively short installation duration. The required modifications to achieve the EPU will be accomplished in refueling outages completing in the Spring 2010 on Unit 1 and the Spring 2011 on Unit 2.

5.0 *Socioeconomic Considerations*

The proposed EPU at PBNP would provide economic benefits to the surrounding communities through the continuation of revenues paid to the local Two Rivers municipality, local business revenues funded by EPU installation activities and continued operation, and continued employment of the local population of existing permanent and temporary workers at PBNP.

5.1 *Current Socioeconomic Status*

PBNP currently employs approximately 650 people on a full-time basis and 150 long and short-term contractors on a regular basis. This workforce is augmented by approximately an additional 700 persons, on average, during regularly scheduled refueling outages on each unit. Employment at PBNP benefits both the local and the regional economies when employee salaries flow through the communities as they purchase goods and services and also contribute income, sales, and personal property taxes. In addition, fees on gross receipts are paid by FPL Energy Point Beach LLC as the owner of PBNP and are paid directly to the State of Wisconsin.

Wisconsin Qualified Wholesale Electric Companies, like PBNP, pay a gross-receipts license fee on electricity sales instead of paying property taxes under Wisconsin Statute 76.28(9). These annual fees are paid to the Wisconsin Department of Revenue – Bureau of Property Tax. The annual fee is equivalent to 1.59% of the plant operating revenues for the previous calendar year. The State of Wisconsin Bureau of Property Tax then distributes the fee paid in lieu of property tax by FPLE for PBNP to the appropriate municipal and county taxing authorities. Since FPLE has operated PBNP only since September 2007, FPLE does not have the basis to represent the typical annual license fee for operation of PBNP for a full calendar tax year.

5.2 Extended Power Uprate Impacts to Socioeconomics

The proposed EPU is not anticipated to affect the size of the regular FPLE workforce. Workforce numbers for the 2010 outage, when the first phase of EPU modifications will be completed, will be approximately 500 workers more than the typical supplemental outage workforce of 700 employees. However, the outage will be of short duration and of a small enough magnitude as to not adversely alter local housing availability, traffic patterns or public water supply and sewer systems in the general vicinity of PBNP. Employee incomes and the purchases of goods and services afforded by those incomes, along with the personal property taxes paid by PBNP employees would continue to contribute positively to the communities in the vicinity of PBNP during and after the uprate related outage periods.

FPLE payments to engineering and consulting firms, plant equipment suppliers, and local service industries for implementation of the proposed EPU would have a positive, though temporary impact on local and regional economies. There would also be economic benefit to both the regional and local economies of the enhanced viability of PBNP's long-term operation resulting from the additional electrical generation. That expanded financial viability over the long term, associated with PBNP EPU operation, will help regional planners and local governments organize, plan and develop the long term sustained growth for the area.

Manitowoc County and municipalities in the vicinity of PBNP will continue to benefit from FPLE payments of annual license fees paid in lieu of property taxes. These revenues support public services such as public education, police services, fire protection, road maintenance, local recreational facilities and programs and other municipal services. If the PBNP revenue after the 17% power level uprate also increases by 17%, then the license fees paid in lieu of property taxes should also increase by 17%.

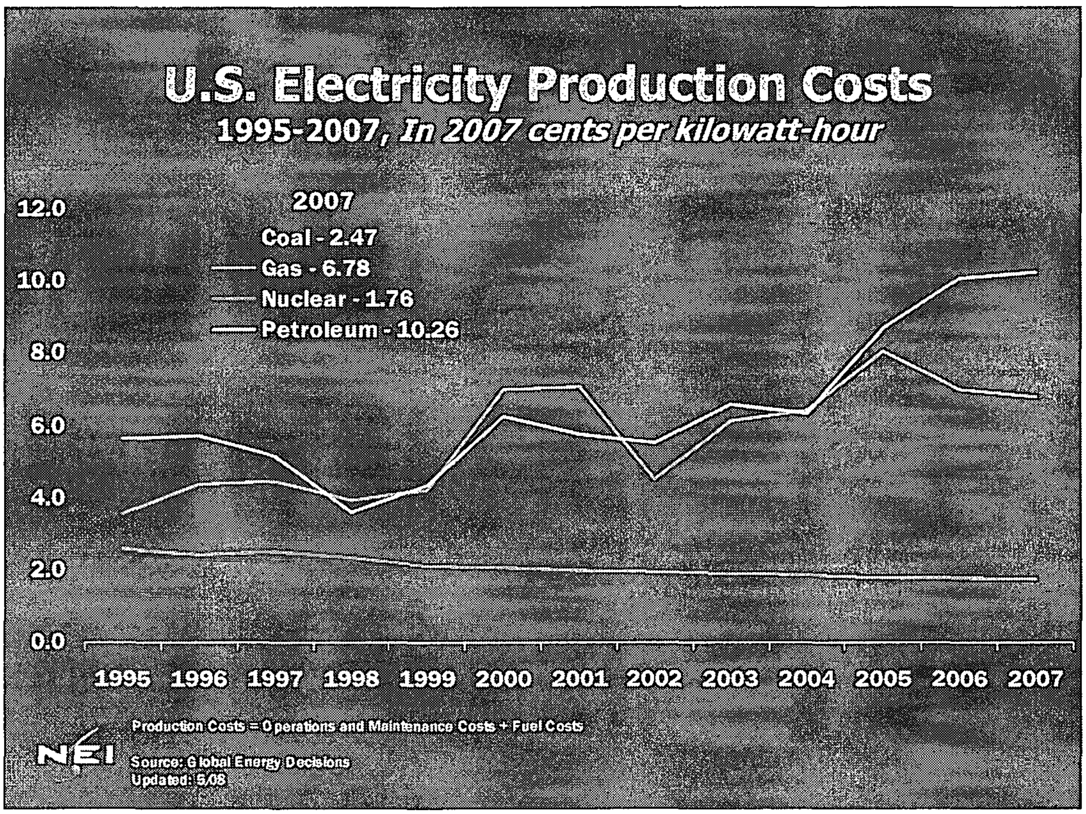
5.3 Conclusion

After the EPU, PBNP will continue to provide a positive contribution to the local and regional economies of continued, and likely increased, license fee payments in lieu of property taxes to the local governments and additional payments for goods and services associated with the proposed EPU implementation. The continuation of employment of the local population with normal operation of PBNP and the associated expenditures for goods and services and contributions to payroll taxes, sales taxes, and taxes on properties owned by PBNP employees would positively impact the local and regional economy.

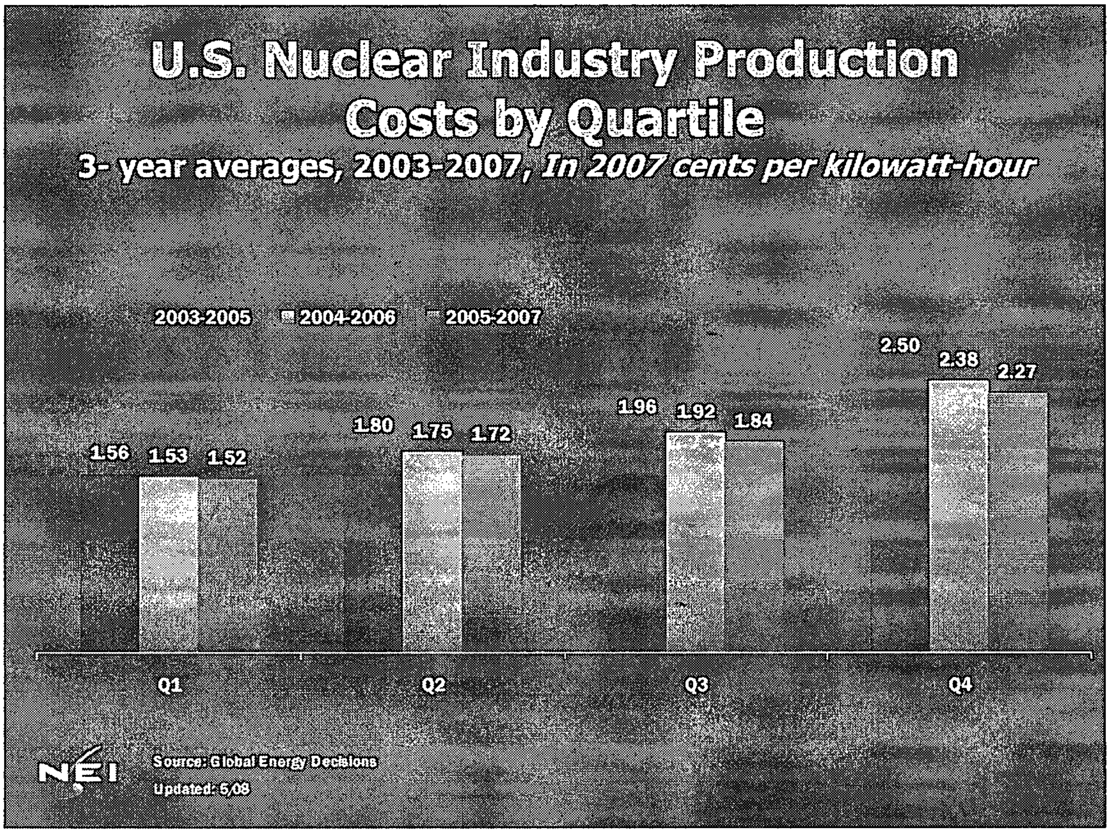
6.0 Cost – Benefit Analysis

The largest direct benefit resulting from the proposed EPU to PBNP's current capacity is the additional supply of approximately 90 megawatts per unit of reliable electrical power for residential and commercial customers.

A national comparison of electric generation alternatives, updated through June of 2007, indicates that nuclear power generation production costs are lower than that of coal-fired power, oil-fired power, and natural gas-fired power production. Power production costs represent a combination of fuel, operations, and maintenance costs. The figures below, from the Nuclear Energy Institute, show that the production cost of existing nuclear generating facilities are considerably less than oil or natural gas fired steam electric generation sources and even less than that of coal.



In addition, the US Nuclear industry continues to reduce the cost of production each year as can be seen in the following bar chart of three year average costs. This second NEI figure illustrates that the production cost of nuclear generation has continued to decrease in recent years. (Reference 6.2)



A quantitative evaluation of environmental costs of alternatives would not be necessary to recognize that significant new environmental impacts would be avoided by implementing an EPU at PBNP compared with other new power development options to deliver additional capacity. Unlike fossil fuel plants, an EPU would not result in a significant source of nitrogen oxides, sulfur dioxide, particulates (PM_{10} and $PM_{2.5}$), carbon dioxide, or other regulated atmospheric pollutants as a part of normal operations. Routine operation of PBNP at EPU conditions would not contribute to greenhouse gases or acid rain and would likely displace operation of other fossil generating plants in the region.

The radiological effects of the uranium fuel cycle are described in 10 CFR 51.51 and 51.52 and are classified as small. The PBNP EPU radiological effects fall within the bounds of the tables in 10 CFR 51.52. Although the proposed action would produce additional spent nuclear fuel, this increase would be accommodated by PBNP's existing spent fuel storage strategy.

Based upon these considerations, it is reasonable to conclude that the proposed PBNP EPU would provide a cost-effective utilization of an existing asset, with minimal environmental impact, making it the preferred means of securing additional generating capacity to support the growing electric load in Wisconsin.

References

6.1 NEI – Electricity production costs access 8/8/2008 at NEI web site
http://www.nei.org/filefolder/US_Electricity_Production_Costs.ppt#259,1,Slide 1

6.2 NEI - U.S. Nuclear Industry Production Costs by Quartile (2003 - 2007) accessed at NEI on 8/8/2008 at NEI web site
http://www.nei.org/filefolder/US_Nuclear_Industry_Production_Costs_by_Quartile.ppt

7.0 Non-Radiological Environmental Impacts

The existing terrestrial and aquatic natural environmental conditions in the vicinity of the PBNP are well characterized in the recently filed Environmental Report of the PBNP License Renewal Application. See Attachment E of the Application of Renewed Operating License – Point Beach Nuclear Plant Units 1 and 2 (Reference 7.1) for a full characterization of the current natural and human environment conditions in the vicinity of PBNP.

7.1 Terrestrial Impacts

Land use impacts, transmission line impacts, noise effects and potential impacts to terrestrial biota of the proposed uprate would be negligible. No EPU related impacts are anticipated. No new construction is planned outside of existing facilities, and no new expansion of buildings, roads, parking lots, equipment storage areas, or transmission facilities on site would be required to either complete the EPU modifications or operate PBNP at EPU conditions. The EPU will not require substantial additional storage of industrial chemicals, fuels, or create the need for additional storage tanks on site.

FPLE is not aware of any significant historical or archeological resources that have been affected to date from operation of PBNP. The PBNP License Renewal Environmental Report describes the historical and archeological resources in the vicinity of the plant. Because no land disturbance would be required on site to implement the uprate, the potential for impacts to historical/archeological resources would be negligible.

On site, the EPU would not require any new transmission lines, transmission line reconductoring, or new transmission equipment to support the EPU operation. The existing generator step up transformers will be replaced with similar, but larger capacity transformers on the existing pad foundations to accommodate EPU operation. Minor modifications internal to existing switchyard equipment are being studied. There will be no environmental impacts from these changes.

The uprate will contribute more power to the Wisconsin electric grid which is managed by American Transmission Corporation (ATC). The Interconnection System Impact Study Report, prepared by ATC for the PBNP uprate indicates that a number of system upgrades may be needed. ATC will take the PBNP Uprate into consideration as they plan future improvements to the Wisconsin electric transmission system along with local load changes and the capacity and reliability of existing transmission equipment. In the event that new electric sources, such as the EPU for PBNP, or new load demand require changes in the existing Wisconsin transmission system, ATC will take responsibility to evaluate the necessary grid modifications, plan and design any upgrades, and seek the appropriate regulatory and environmental approvals prior to implementing construction.

Right-of-Way maintenance is conducted by ATC. However, there is no reason to expect any change in transmission line vegetation management as a result of the EPU.

The increase in electrical power output would cause a corresponding increase in current on the transmission system, and this would result in an increased magnetic field. However, in other similar project uprates, the NRC has already reached a conclusion that the chronic effects of EMF on humans are not qualified at this time, and no significant impacts to the terrestrial biota have been identified.

7.2 Aquatic Impacts

The PBNP site is located on the western shore of Lake Michigan in Manitowoc County. Cooling water is withdrawn at a depth of approximately 22 feet from an offshore intake located approximately 1,750 feet east of the shoreline. The plant has two discharges also located offshore but only about 200 feet from the shoreline. The current cooling water flow rate through PBNP is 680,000 gpm and will be unchanged with EPU operations.

Recent studies of thermal effects of the discharge operating under EPU conditions have been completed by FPLE for the PBNP EPU. These studies specifically reviewed the previous determination of the impacts of the cooling water system thermal impacts of PBNP operations including the original five year study initiated in 1972 by Limnetics. That previous study was the first 316 (a) demonstration completed for PBNP and the results satisfied the Wisconsin DNR that the location and operation of PBNP had minimal impact on the aquatic environment. On each 5-year renewal of the Wisconsin PDES (WPDES) permit, the DNR has concurred with this assessment of the thermal effects of PBNP operations.

In addition, FPLE has reviewed the plant operating systems and associated non-radiological discharges for potential changes associated with the EPU. Chemical discharge limits for primary outfalls systems such as runoff drains, yard drains, low volume wastes, and metal cleaning wastes are set in the PBNP Wisconsin Pollutant Discharge Elimination System Permit. No impact on the environment is anticipated as the discharges from these systems are not expected to significantly change under the proposed EPU conditions.

The EPU will have only one identified off site impact to the natural environment, and that is the approximately 17% increase in waste heat added to the discharge. Since there will be no change in plant discharge flow rates, this 17% increase in waste heat will increase the average delta T of the cooling across the steam condenser by approximately 17%. PBNP has conducted more than 20 surveys throughout the years of operation to monitor and define the limits and extent of the thermal discharge plume into Lake Michigan. In every renewal of the WPDES discharge permit, the Wisconsin DNR has continued to approve the operation of PBNP.

FPLE has conducted modeling of the existing thermal discharge plume and has made projections of the temperature, size and dimensions of the plume with PBNP operating at EPU conditions. The modeling included a verification review of previous studies as well as development of the fluid dynamic model to estimate the three dimensional changes in the PBNP discharge when operating under EPU conditions.

The modeling demonstrated there will be a larger surface plume for the discharge when the EPU increases the existing 11.5 degrees C maximum delta T by 2 degrees C. The 6 degree C surface plume area will increase from 27 to 39 acres in size. The 4 degree C thermal plume will increase from 79 to 105 acres in size. Finally the 2 degree C thermal plume will increase from

315 acres to 390 acres or an approximate 24% increase in area. However, outside of the immediate area of the two discharge points, only the top 6 feet of water depth in Lake Michigan will be affected by the thermal plume. There are almost no changes in the characteristics of the vertical plume effects as a result of EPU operations. This means that there are also no impacts to the natural benthic community as a result of the uprate.

Although the plant will operate at a higher delta T, the potential for cold shock incidence will be no different than under current operation. Generally, only one generating unit is shut down at any time. The outages occur in the spring and fall and are separated by a 6 month or 12 month period to accommodate the 18 month refueling cycles of the reactor. Cold shock has greater potential to injure fish when the outage occurs when both units are shut down and also in the very late fall and winter when ambient lake temperatures are lowest. During any planned PBNP outage, the second unit would be expected to continue operation and thus any fish already acclimated to the warm discharge could continue to inhabit the thermal discharge of the second unit. In addition, PBNP is expected to operate continuously with both units through the coldest winter months when local electric demand is generally highest.

One conclusion of the recent aquatic ecology studies and modeling is that although the thermal plume will be larger under uprate conditions, it is not expected to disrupt the balanced indigenous aquatic community at PBNP.

7.3 Threatened and Endangered Species

As noted in Attachment E of the Application of Renewed Operating License – Point Beach Nuclear Plant Units 1 and 2 (Reference 7.1) the PBNP site has no known occurrences of federally listed threatened and endangered species. However, the beach could be a suitable nesting habitat for piping plover (Charadrius melodus), and three other species could potentially occur in the region including bald eagle (Haliaeetus leucocephalus), dwarf lake iris (Iris lacustris) and dune thistle (Cirsium pitcheri). The GEIS however, concluded that continued operation of the PBNP and its associated transmission line ROWs for an additional 20 years during the renewal term would have small potential for impact on threatened and endangered species.

Since the proposed uprate would not have impact on any of the potential habitats of these species, the NRC conclusions in the GEIS should remain unchanged.

References

7.1 PBNP. 2004. Application of Renewed Operating License – Point Beach Nuclear Plant Units 1 and 2 – Appendix E – Environmental Report.

8.0 Radiological Environmental Impacts

8.1 Radiological Waste Streams

The radioactive waste systems at PBNP are designed to collect, process, and dispose of radioactive wastes in a controlled and safe manner. The design basis for these systems during normal operations is to limit discharges in accordance with 10 CFR 50, Appendix I. Adherence to these limits and objectives would continue under the proposed EPU.

Operation at the proposed EPU conditions would not result in any physical changes to the solid waste, liquid waste, or gaseous waste systems. The safety and reliability of these systems would be unaffected by the proposed EPU. Also, the proposed action would not affect the environmental monitoring of any of these waste streams or the radiological monitoring requirements of the PBNP Radiation Protection Program. Under normal operating conditions, the proposed action would not introduce any new or different radiological release pathways and would not increase the probability of an operator error or equipment malfunction that would result in an uncontrolled radioactive release from the radioactive waste streams. LR Section 2.5.6.1, Gaseous Waste Management, LR Section 2.5.6.2, Liquid Waste Management, and LR Section 2.5.6.3, Solid Waste Management, provide a detailed evaluation of effects that the proposed EPU may have on the solid, liquid and gaseous radioactive waste systems. LR Section 2.10.1, Occupational and Public Radiation Doses, provides an evaluation of the impact of EPU on the annual dose to the public. The following subsections summarize the conclusions of these sections and compare the results against the impacts of the radiological waste system documented in the US AEC FES related to the operation of PBNP (Reference 8.1) and the US NRC GEIS for License Renewal for PBNP (Reference 8.2).

8.1.1 Solid Waste

Solid radioactive wastes include solids recovered from the reactor-coolant systems, solids in contact with the reactor process system liquids or gases, and solids used in the reactor-coolant system operation. Licensing Report Section 2.5.6.3, Solid Waste Management System, provides an evaluation of effects the proposed EPU may have on the solid waste management system. The largest volume of solid radioactive waste is low-level radioactive waste (LLRW) which includes sludge, oily waste, bead resin, spent filters, and dry active waste (DAW) from outages and routine maintenance. DAW includes paper, plastic, wood, rubber, glass, floor sweepings, cloth, metal, and other types of waste routinely generated during routine maintenance and outages. Table 8-1 presents the average annual volume and activity of LLRW generated at PBNP for the five-year period 2002 - 2006.

Table 8-1
Average Annual Low-Level Radioactive Waste Generated at PBNP
During the 2002 – 2006 Time Period

	Cubic feet	Curies
Resins, sludges, evaporator bottoms, etc.	791	84.4
Dry Low-Level Waste	10,434	7.7
Irradiated, Non-Fuel Reactor Components	0	0
Other Wastes	1,112	0.001
Overall Five Year Average	**12,337**	**92.2**

References 8.3, 8.4, 8.5, 8.6 & 8.7

The results of the evaluation presented in LR Section 2.5.6.3 indicate that the proposed EPU has no significant effect on the generation of solid waste volume from the primary and secondary side systems since the systems functions are not changing and the volume inputs remain the same.

The proposed EPU would result in an increase in the equilibrium radioactivity in the reactor coolant which in turn would impact the concentrations of radioactive nuclides in the waste disposal systems. Thus, it is expected that the activity levels for most of the solid waste would increase proportionately to the increase in long half-life coolant activity bounded by a 17.6% maximum increase based on current operation at licensed power level of 1540 MWt and EPU operation at the analyzed power level of 1811 MWt (includes a 0.6% margin for power uncertainty). The activity contained in the waste following uprate is estimated to be bounded by an increase of 20.6%, i.e., 17.6% /0.855 (average weighted capacity factor for years 2002 – 2006). The increase in the overall volume of waste generation resulting from EPU is expected to be minor. As noted in Table 8-1 and discussed above, the activity contained in the solid waste is comparable to the activity (175.3 Ci) identified in Section 2.1.4.3 of the USNRC GEIS (Reference 8.2) related to the operation of PBNP. The USAEC FES (Reference 8.1) did not provide numerical Curie values for the solid waste although 280 ft^3 of spent resins and one hundred and two hundred 55-gallon drums of liquid concentrates and miscellaneous materials were expected annually.

Section 8.2 of this appendix addresses the impact of the EPU increase in solid waste activity on the off-site doses.

8.1.2 Liquid Waste

Liquid radioactive wastes include liquids from the reactor process systems and liquids that have become contaminated with process system liquids. Table 8-2 presents liquid releases from PBNP for the five-year period from 2002 through 2006. As noted in Table 8-2, approximately 124 million gallons and 69 millicuries of fission and activation products were released in an average year. PBNP assumes the volume to be representative for future normal operations, because, as indicated in LR Section 2.5.6.2, "Liquid Waste Management System", the proposed EPU implementation would not significantly increase the inventory of liquid normally processed by the liquid waste management system. This conclusion is based on the fact that system functions are not changing and the volume inputs remain the same.

The proposed EPU would result in an increase (approximately 17.6%) in the equilibrium radioactivity in the reactor coolant which in turn would impact the concentrations of radioactive nuclides in the waste disposal systems. In the secondary coolant, I-133, a halogen, increased by approximately 19.1% and is used to represent that chemical class in the liquid releases.

However, the releases would remain bounded by Table 3 of the USAEC FES. The FES estimated annual releases of 2000 curies of tritium and 20 curies of all other nuclides. The GEIS reported an annual release of 748 curies of tritium and 0.16 curies of all other nuclides based on 2003 effluent data.

Section 8.2 of this appendix addresses the offsite radiation dose consequences of the EPU effluent releases.

Table 8-2
Liquid Effluent Releases from PBNP, 2002 – 2006

Year	Volume Released (gallons)	Activity Released (Ci)	Tritium (Ci)
2002	125,000,000	8.0E-02	560
2003	105,000,000	1.57E-01	748
2004	110,000,000	2.3E-02	608
2005	181,000,000	5.3E-02	553
2006	99,500,000	3.4E-02	607
Annual Average	**124,100,000**	**6.9E-02**	**615**

References 8.3, 8.4, 8.5, 8.6 & 8.7

8.1.3 Gaseous Waste

Gaseous radioactive wastes are principally activation gases and fission product radioactive noble gases resulting from process operations including continuous degasification, gases used for tank cover gas, gases collected during venting, and gases generated in the radiochemistry laboratory. Table 8-3 presents gaseous releases from PBNP from 2002 through 2006. The evaluation presented in LR Section 2.5.6.1, Gaseous Waste Management Systems, indicates that implementation of the proposed EPU does not significantly increase the inventory of carrier gases normally processed in the gaseous waste management system, since plant system functions are not changing and the volume inputs remain the same.

The proposed EPU would result in an increase (approximately 17.6% for noble gases, and 17.6% for particulates, iodines and tritium where tritium is the dominant particulate and iodine class dose component) in the equilibrium radioactivity in the reactor coolant, which in turn increases the activity in the waste disposal systems and the activity released from the Station.

The projected releases would remain bounded by Table 3 of the US AEC FES which estimated average annual releases of 10,000 Ci for Noble Gases, and 0.2 Ci for Particulates and Iodines. Section 2.1.4.2 of the USNRC GEIS reported noble gas releases of 0.89 Ci, iodine-131 releases of 1.5E-04 Ci, particulate releases of 8.7E-05 Ci and tritium releases of 61.5 Ci based on the 2003 annual effluent data.

Section 8.2 addresses the offsite radiation dose consequences of the EPU effluent releases.

Table 8-3
Gaseous Effluent Releases from PBNP, 2002 – 2006

Year	Noble Gases (Ci)	Particulates and Iodines ($T_{1/2}$ > 8 days) (Ci)	Tritium (Ci)
2002	3.87E+00	2.39E-05	58.3
2003	8.94E-01	1.46E-04	61.5
2004	1.30E+00	2.17E-07	60.5
2005	6.59E-01	1.17e-04	65.6
2006	4.33E+00	7.54E-07	74.5
Annual Average	**2.21E+00**	**5.76E-05**	**64.1**

References 8.3, 8.4, 8.5, 8.6 & 8.7

8.2 Radiation Levels and Offsite Dose

8.2.1 Operating and Shutdown In-Plant Levels

In-plant radiation levels and associated doses are controlled by the PBNP Radiation Protection Program to ensure that internal and external radiation exposures to station personnel, contractor personnel, and the general population will be as low as reasonably achievable (ALARA), as required by 10 CFR 20. PBNP has a policy of maintaining occupational dose equivalents to the individual and the sum of dose equivalents received by all exposed workers to ALARA levels.

Licensing Report Section 2.10.1.2.1, Normal Operation Radiation Levels and Shielding Adequacy, provides an analysis of the impact of the proposed EPU on radiation levels and shielding adequacy and the resulting occupational dose. The analysis considered the impact of increasing the core power level on neutron flux and gamma flux in and around the core, fission product and actinide activity inventory in the core and spent fuels, N-16 source in the reactor coolant, neutron activation source in the vicinity of the reactor core, and fission/corrosion products activity in the reactor coolant and downstream systems. The results indicate that in-plant radiation sources are anticipated to increase approximately linear with the increase in core power level.

Shielding is used throughout PBNP to protect personnel against radiation emanating from the reactor and their auxiliary systems, and to limit radiation damage to operating equipment. FPLE has determined that the current shielding designs would be adequate for the increase in radiation levels that may occur after the proposed EPU. The increase is offset by:

- conservative analytical techniques typically used to establish shielding requirements,
- conservatism in the original design basis reactor coolant source terms used to establish the radiation zones, and
- Plant Technical Specification 3.4.16 which limits the reactor coolant concentrations to levels significantly below the original design basis source terms.

Therefore, no new dose reduction programs are planned and the ALARA program would continue in its current form.

8.2.2 Offsite Doses at Power Uprate Conditions

Licensing Report Section 2.10.1.2.4, "Normal Operation Radioactive Effluents and Annual Dose to the Public," provides an analysis of the impact of the proposed EPU on offsite doses using scaling techniques based on NUREG-0017, Revision 1 methodology (NRC). This analysis conservatively projects maximum doses from normal operation under the proposed EPU conditions using the following:

- plant core power operating history during years 2002 through 2006,
- the reported gaseous and liquid effluent and dose data during that period,
- NUREG-0017 equations and assumptions, and
- conservative methodology.

Base case doses were calculated by taking the average five-year doses (organ and whole body) coupled with annual core power levels and extrapolating the doses to that equivalent to operation with a 100 percent capacity factor. To predict doses under the proposed EPU conditions, the analysis assumes that the maximum increase in radioactivity content of the liquid and gaseous releases is proportional to the percentage increase in the primary and secondary coolants over that of the base case.

Offsite doses from liquid effluents are summarized, adjusted and averaged for 2002 through 2006 (Table 8-4). For the five-year period, average annual whole body dose extrapolated to 100 percent power and 100 percent capacity factor was 7.79E-03 mrem and to the critical organ 8.15E-03 mrem. FPLE predicts the maximum annual whole body and organ doses (all pathways) from liquid effluent releases would increase approximately 17.6% for the whole body (i.e., 9.2E-03 mrem) and 19.1% for the critical organ (i.e., 9.7E-03 mrem - critical organ dose is based on I-133 in Unit 2 Secondary Coolant), which are well below the regulatory standards contained in 10 CFR 50, Appendix I.

Table 8-4
Average Off-Site Dose Commitments from Liquid Effluents (PBNP)

Type of Dose	Appendix I Design Objectives (2 units)	Base Case 2002 – 2006 Adjusted Doses	Scaled Post-EPU Annual Dose	Percentage of Appendix I Design Objectives for EPU Case
Liquid Effluents				
Dose to total body from all pathways	6 mrem/yr	7.79E-03 mrem/yr	9.2E-03 mrem/yr	0.15%
Dose to any organ from all pathways	20 mrem/yr	8.15E-03 mrem/yr	9.7E-03 mrem/yr	4.9E-02%

Doses to individuals from gaseous releases are summarized, adjusted and averaged for 2002 through 2006 (Table 8-5). For the five year period, the annual doses were extrapolated to 100 percent power and 100% capacity factor. The maximum extrapolated impact of EPU on these doses were estimated at 17.6% for noble gases as well as for the category of particulates and iodines (based on tritium being the dominant dose contributor in this category). These doses are significantly below the regulatory design objectives listed in 10 CFR 50, Appendix I.

Table 8-5
Average Off-Site Dose Commitments from Gaseous Effluents (PBNP)

Type of Dose	Appendix I Design Objectives (2 units)	Base Case 2002 – 2006 Adjusted Doses	Scaled Post-EPU Annual Dose	Percentage of Appendix I Design Objectives for EPU Case
Gaseous Effluents				
Gamma Dose in Air	20 mrad/yr	5.34E-04 mrad/yr	6.3E-04 mrad/yr	3.1E-03%
Beta Dose in Air	40 mrad/yr	3.10E-04 mrad/yr	3.6E-04 mrad/yr	9.1E-04%
Dose to total body of an individual	10 mrem/yr	5.17E-04 mrem/yr	6.1E-04 mrem/yr	6.1E-03%
Dose to skin of an individual	30 mrem/yr	9.23E-04 mrem/yr	1.1E-03 mrem/yr	3.6E-03%
Radioiodines and Particulates Released to the Atmosphere				
Dose to any organ from all pathways	30 mrem/yr	3.12E-02 mrem/yr	3.7E-02 mrem/yr	0.12%

The maximum average direct shine dose due to solid waste would be projected to increase to no more than 20.6% (=17.6%/0.855) due to the activity increase in the waste. This would occur as a) the current waste decays and its contribution decreases, b) stored radwaste is routinely moved offsite for disposal, and c) waste generated post EPU enters into storage.

The 40 CFR 190 whole body dose limit of 25 mrem to any member of the public includes a) contributions from direct radiation (including skyshine) from contained radioactive sources within the facility, b) the whole body dose from liquid release pathways, and c) the whole body dose to an individual via airborne pathways.

As noted in the PBNP Annual Radioactive Effluent Reports "the operation of the plant has had no effect on the ambient gamma radiation", thus the annual direct shine dose due to plant operation during the pre-EPU 5 yr period evaluated was deemed "negligible." For the EPU, the direct shine dose due to plant operation would increase by the increase percentage of the power level, i.e., 17.6%, however, as discussed above, the direct shine contribution due to accumulation of stored solid radwaste including fuel storage at the PBNP ISFSI, could increase to no more than 20.6%. A conservative bounding scaling factor of 20.6% would not change the estimated EPU direct shine dose at the site boundary which would remain negligible. It is noted that procedures and controls in the ODCM monitor and control this component of the off-site dose and would limit, through administrative and storage controls, the offsite dose to ensure compliance with the 40CFR190 whole body dose limits.

Taking into consideration the estimated annual EPU whole body dose of 9.8E-03 mrem due to gaseous and liquid effluent releases (6.1E-04 mrem/yr and 9.2E-03 mrem/yr, respectively), and the negligible direct shine dose contribution, it is concluded that the 40CFR190 whole body dose limit of 25 mrem/yr will not be exceeded by EPU.

References:

8.1 Final Environmental Statement Related to the Operation of the Point Beach Nuclear Power Plant Units 1 and 2 (FES; AEC 1972).

8.2 NUREG-1437, Supplement 23, August 2005, Generic Environmental Impact Statement for License Renewal of Nuclear Plants"

8.3 PBNP 2002 Annual Monitoring Report, dated April 29, 2003

8.4 PBNP 2003 Annual Monitoring Report, dated April 29, 2004

8.5 PBNP 2004 Annual Monitoring Report, dated May 2, 2005

8.6 PBNP 2005 Annual Monitoring Report, dated April 28, 2006

8.7 PBNP 2006 Annual Monitoring Report, dated April 30, 2007

9.0 Environmental Effects of Uranium Fuel Cycle Activities and Fuel and Radioactive Waste Transport

NRC regulations 10 CFR 51.51 (Table S-3) provide the basis for evaluating the contribution of the environmental effects of the uranium fuel cycle to the environmental impacts of licensing a nuclear power plant. NRC regulations 10 CFR 51.52 (Table S-4) describe the environmental impacts of transporting nuclear fuel and radioactive wastes. The tables were developed in the 1970s. Since that time, most plants have increased both their uranium-235 enrichment and the fuel's burnup limits.

In 1999, in connection with the Generic Environmental Impact Statement for License Renewal of Nuclear Power Plants, NRC reviewed transporting higher enrichment and higher burnup fuel to a geologic repository (NRC 1999). The conclusion of that evaluation was that Table S-4 applies to spent fuel enriched up to 5 percent uranium-235 with average burnup for the peak rod to current levels approved by NRC up to 62,000 MWd/MTU, provided higher burnup fuel is cooled for at least 5 years before being shipped.

Since the fuel enrichment for the EPU will not exceed 5.0 percent U-235 and the rod average discharge exposure will not exceed 62,000 MWd/MTU, the potential environmental impacts of the proposed PBNP power uprate will remain bounded by these conclusions and will not be significant to human health or the environment.

PBNP is currently licensed to use uranium-dioxide fuel that has a maximum enrichment of 5.0 percent by weight of uranium-235. The typical average enrichment for a fuel reload has increased over the life of the station up to approximately 4.8 percent.

For PBNP under EPU conditions, the burnup limit is unchanged (the upper exposure limit is bounded by maintaining fuel within the NRC-approved vendor specific exposure limits), and the U-235 enrichment limit of 5% by weight is not exceeded; therefore, the PBNP EPU fuel cycles will continue to remain bounded by the impacts listed in Tables S-3 and S-4 of 10 CFR Part 51.

Increasing the electrical output at PBNP is accomplished primarily by generating higher steam flow in the steam generators and supplying it to the turbine generator. The higher steam flow is achieved by increasing the reactor power level and feedwater flow to the steam generators. The additional reactor energy requirements for EPU are met by increasing the reload fuel batch size. The EPU does not require any changes to fuel design.

PBNP currently replaces on the average 36 to 40 of the fuel assemblies in the reactor core at approximately 18-month intervals. The refueling schedule would remain the same following implementation of the EPU. During the Spring 2010 refueling outage, the PBNP Unit 1 transition core for the planned uprate will be loaded with more than one third of the core. The average fuel assembly discharge burnup for the uprate is expected to be approximately 52,000 MWd/MTU with no fuel pins exceeding the maximum fuel rod burnup limit of 62,000 MWd/MTU. Reload design goals would maintain the PBNP 18-month fuel cycles within the limits bounded by the impacts analyzed in Tables S-3 and S-4 of 10 CFR Part 51. Therefore, FPLE concludes that impacts to the uranium cycle and transport of nuclear fuel from the proposed action would be insignificant and not require mitigation.

References

9.1 NRC (Nuclear Regulatory Commission). 1999. Generic Environmental Impact Statement for License Renewal of Nuclear Plants (NUREG-1437, Vol. 1, Addendum 1). Division of Regulatory Improvement Programs, Office of Nuclear Reactor Regulation, August 1999.

10.0 Effects of Decommissioning

Environmental impacts from the activities associated with the decommissioning of any nuclear power reactor before or at the end of an initial or renewed license period are evaluated in the Generic Environmental Impact Statement for Decommissioning of Nuclear Facilities, NUREG-0586, Original and Supplement 1 (Ref 10.1 and 10.2). The conclusions of this report are that environmental impacts of decommissioning are generally small and that only two environmental issues would require site-specific evaluation, threatened and endangered species and environmental justice. The NRC procedures for all phases of decommissioning are described in NRC regulations (Title 10 of the Code of Federal Regulations, part 20 subpart E, and parts 50.75, 50.82, 51.53, and 51.95).

The FES for PBNP did not evaluate the environmental effects of decommissioning. In 1988, however, NRC published the Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities (NUREG-0586; NRC 1988) that discusses decommissioning of nuclear power plants. Procedures for decommissioning a nuclear power plant are found in NRC regulations at 10 CFR 50.75, 50.82, 51.23, and 51.95.

The incremental environmental impacts associated with decommissioning activities resulting from continued plant operation during the renewal term are evaluated in the Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS), NUREG-1437, Volumes 1 and 2 (U. S. Nuclear Regulatory Commission 1996; 1999 (Ref. 3). The evaluation in NUREG-1437 includes a determination of whether the analysis of the environmental issue could be applied to all plants and whether additional mitigation measures would be warranted. Supplement 23 discusses in Chapter 7, the effects of the later decommissioning on the local Point Beach environment. For all the environmental issues reviewed in Supplement 23, the NRC staff concluded that impacts of license renewal would be small and mitigation would not be sufficiently beneficial to be warranted.

Prior to any decommissioning activity at PBNP, FPLE would submit a post shutdown decommissioning activities report to describe planned decommissioning activities, any environmental impacts of those activities, a schedule, and estimated costs. Implementation of an EPU does not affect FPLE's ability to maintain financial reserves for decommissioning nor does the EPU alter the decommissioning process.

The potential environmental impacts on decommissioning associated with the proposed EPU would be due to the increased neutron fluence. As a result, the amount of activated corrosion products could increase, and consequently, the post-shutdown radiation levels could increase. PBNP expects the increases in radiation levels as a result of operations under the proposed EPU conditions to be insignificant, and would be addressed in the post-shutdown decommissioning activities report.

References

10.1 NRC (Nuclear Regulatory Commission). 1988. *Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities* issued in 1988 (NUREG-0586).

10.2 NRC (Nuclear Regulatory Commission). 2002. NUREG-0586 - Generic Environmental Impact on Decommissioning of Nuclear Reactors. Supplement 1. Regarding the Decommissioning of Nuclear Power Reactors. Main Report, Appendices A through M. Final Report. November 2002.

10.3 NRC (Nuclear Regulatory Commission). 2005. Generic Environmental Impact Assessment for License Renewal of Nuclear Plants. Supplement 23. Regarding Point Beach Nuclear Plant, Units 2 and 3. Final report. Division of Regulatory Improvement Programs. August 2005.

Purpose

This appendix describes the application of Limiting Safety System Settings (LSSS) in the Technical Specifications for the Reactor Protection System (RPS) and Engineered Safety Features Actuation System (ESFAS), the method used to develop the LSSS values for functions, the methods used to maintain the functions operable, and the control of the methods in design basis documents.

Limiting Safety System Settings

10 CFR 50.36 requires that Limiting Safety System Settings (LSSS) be included in the Technical Specifications (TS). LSSS values for RPS and ESFAS functions that initiate at an adjustable setpoint are established in TS Tables 3.3.1-1, Reactor Protection System Instrumentation, and 3.3.2-1, Engineered Safety Feature Actuation System Instrumentation. The LSSS is the limiting value for the nominal trip setpoint that protects the safety analyses and is calculated such that there is 95% probability and 95% confidence level the instrument channel will trip prior to the process variable exceeding an established limit. The calculated LSSS is referred to as the Limiting Trip Setpoint (LTSP) in the setpoint calculation.

The LTSP for a trip or initiating function is calculated by subtracting total loop uncertainty (TLU) from the Analytical Limit (AL) or Process Limit (PL) for process variables that increase towards the limit, and by adding TLU to the AL or PL for variables that decrease towards the limit. An LSSS value for a specific function is rounded in a conservative direction from the calculated LTSP, resulting in the value included in the Technical Specification tables. The calculation of the LTSP and TLU are performed in accordance with ISA standard 67.04 criteria. ISA 67.04 requirements are implemented at Point Beach in Design Guide DG-I01, Instrument Setpoint Methodology, which was used as the basis for all instrument setpoint calculations supporting LR Section 2.4.1.

Analytical Limits (AL) are established by a Safety Analysis for FSAR design basis events. The Analytical Limit is the process value at which a protective action initiation occurs to ensure that a safety limit is not exceeded. If there is no AL for a specific function, a Process Limit (PL) such as the limit of an instrument span may be used in place of an AL. If the AL is outside the instrument span, the span limit is used as the PL to assure the function will occur within the instrument span.

In some cases, an AL or PL is not provided for an RPS/ESFAS function. For example, RPS and ESFAS interlocks and bypasses that allow bypassing of and automatically reinstate protective functions are not specifically credited in the safety analyses and have no AL or PL associated with them. For interlocks and bypasses, a LSSS is determined based on the expected as-found tolerance for the FTSP setpoint, rather than on a LTSP.

Each function whose LSSS is changing per this license amendment request and the source of the AL or PL for that function are described in LR Section 2.4.1. Manual-action switches, breaker status inputs, and SI input for the ESFAS to the RPS do not have adjustable setpoints and there is no LSSS value included in the Technical Specifications for these functions.

The Field Trip Setpoint (FTSP) is the nominal setting installed in an instrument loop in accordance with Point Beach calibration and functional test procedures. The FTSP is lower than or equal to the LSSS for process variables increasing towards the setpoint, and higher than or equal to the LSSS for process variables decreasing towards the setpoint. The difference between the FTSP and the LSSS is conservative design margin.

Total Loop Uncertainty

Total Loop Uncertainty (TLU) accounts for all known instrument error such as process measurement effects, calibration uncertainties, reference accuracies, environmental effects, and instrument drift. Random and independent uncertainty terms are combined using the square root sum of squares (SRSS) method and bias terms are included algebraically. For setpoints approached from one direction, a single-sided conversion factor is used to convert the random component of TLU from a two-sided error to a single-sided error prior to combining random and bias uncertainties.

Calibration and Surveillance Criteria

Calibration and surveillance requirements defined in the Technical Specifications are performed in accordance with Point Beach surveillance and maintenance procedures. Instrument loops are surveilled by placing them in bypass or trip and injecting a test signal in place of the process variable. The point at which actuation of the final setpoint device occurs is recorded as the as-found value. Limits have been established so that instrument loops that are not performing within the expected accuracy as defined in the TLU calculation are identified and corrected, and that out-of-tolerance conditions are evaluated in the Point Beach Corrective Action Process. Instrument loops found outside of the as-found limit, referred to as rack as-found (RAF) during the Channel Operational Test (COT) surveillance, are not Operable as defined in the Technical Specifications. The RAF for a loop is calculated as the SRSS of the setting tolerance, rack drift, and rack measurement test equipment uncertainty terms used in the TLU calculation for that loop. RAF is a two-sided acceptance criterion centered around the FTSP.

A Technical Specification instrument loop that is found outside of the RAF must be corrected before it is placed back in service in accordance with applicable plant maintenance and operating procedures. The corrective action may include component replacement if it is determined a component has failed, cannot be calibrated to within its as-left tolerance, is not repeatable during calibration activities, or has an adverse performance history. Technical Specification instrument loops found outside of the RAF will be entered into the Corrective Action Process for evaluation. The evaluation should consider the adequacy of the steps taken to restore the loop to service, relevant plant conditions, generic implications, and identify any follow-up actions.

PBNP calibration procedures include an as-left tolerance for setting devices in instrument loops. These setting tolerances allow for component accuracies, linearity, repeatability and other effects. The setting tolerances, referred to as rack as-left (RAL) tolerances, are based on the accuracies of the modules involved, operating experience, and/or historical values. When a Technical Specification instrument is found outside its RAL during a calibration or surveillance requirement, it must be returned to within its RAL value before it is returned to service.

As discussed in LR 2.4.1, a note has been added to the Technical Specification tables providing COT operability criteria that require that when a loop is found outside its RAL but inside its RAF, that the loop be returned to within the RAL at the completion of the surveillance. An additional note has been added requiring evaluation of loop conditions when the as-found FTSP is outside the RAF. The two notes are applicable to all Reactor Protection System and Engineered Safety Feature Actuation Systems instrument functions with LSSS values that initiate at specific setpoints, including those without Analytical Limits.

Design Basis Requirements

A description of the LSSS, RAF, and RAL determination method including design basis requirements will be added to the Point Beach FSAR Section 7.2. The FSAR will describe, in general, the basis for the LSSS and the surveillance and calibration requirements discussed above. The basic calculation methods for calculating TLU, RAF and RAL will be included. These will become design basis requirements and will provide a framework for 10 CFR 50.59 evaluations for plant modifications. Not withstanding the specifics of any particular 10 CFR 50.59 evaluation, the design basis requirements specified in the FSAR should not prohibit Point Beach from making changes to the following:

- The FTSP, provided the FTSP is at or conservative to the LSSS
- The TLU, provided the basic calculation methods are consistent, and the TLU does not exceed the difference between the LSSS and the applicable AL or PL.
- The individual uncertainty terms within the TLU, RAF, and RAL including the characterization of uncertainties, the use of terms as random or bias, and the magnitude of individual terms.

Calculation Summaries

Summaries of setpoint calculations that provide a basis for the LSSS values discussed in LR Section 2.4.1 are provided. Only portions of the calculations applicable to the RPS or ESFAS functions are summarized and only non-zero terms are shown. Summaries are not provided for the reactor trip functions for OTΔT, OPΔT and Steam Flow/Feedwater Flow mismatch because of the complexity of the calculations. The calculations are available for review upon request. This summary uses the following terms and acronyms which may vary from the summarized calculations:

AL	Analytical Limit
CE	Calorimetric Flow Error
FE	Flow Element Error
FTSP	Field Trip Setpoint
IR	Insulation Resistance Effect
La	Lead/Lag Accuracy
Ld	Lead/Lag Drift Allowance
Lmte	Lead/Lag Measurement & Drift Allowance
Lv	Lead/Lag Setting Tolerance
LSSS	Limiting Safety System Setpoint
LTSP	Limiting Trip Setpoint
OL^+	Upper Operability Limit
PA	Ambient Pressure Effect
PE	Process Error
PL	Process Limit
RAL	Rack As-Left Tolerance
RAF	Rack As-Found Tolerance
Rd	Rack Drift Allowance
Rmte	Rack Measurement & Test Equipment Accuracy Uncertainty
RTP	Reactor Thermal Power
Rv	Rack Setting Tolerance
Sd	Sensor Drift Allowance
St	Sensor Temperature Uncertainty
Sp	Sensor Pressure Effect
Sv	Sensor Setting Tolerance
SRSS	*Square Root Sum of Squares of terms that follow in ()*
TLU	Total Loop Uncertainty

The setpoint calculations use the following basic formulas:

LTSP = AL or PL + TLU (for decreasing process)
= AL or PL - TLU (for increasing process)

TLU = SRSS (random terms) + bias terms (for two-sided uncertainties)
= 0.839 * SRSS (random terms) + bias terms (for single-sided uncertainties)

RAL = +/- Rack Setting Tolerance (Rv)

RAF = +/- SRSS(Rv, Rd, Rmte)

Parameter: Steam Generator Narrow Range Level
Summary of Calculation Note Number CN-CPS-07-6

Low-Low SGNR Water Level – RPS Reactor Trip, ESFAS Aux Feedwater

0-100% instrument span = 0-100% SGNR Water Level span

AL = 20% span
TLU = 0.839 * SRSS(Sd, Sv, St, Sspe, Rd, Rv) + PE
= 9.23% span
Sd = +/- 0.877% span
Sv = +/- 0.5% span
St = +/- 0.751% span
Sspe = +/- 0.637% span
Rd = +/- 0.212% span
Rv = +/- 0.5% span
PE = + 7.96%
LTSP = 20 + 9.23 = 29.23% span (LSSS rounded up to $\geq$ 29.3%)
FTSP = 30% span
RAL = +/- 0.5% span
RAF = SRSS(Rv, Rd) = +/- 0.543% of span

Low SGNR Water Level RPS Trip

0-100% instrument span = 0-100% SGNR Water Level span

AL = None, PL =0% (Instrument Span Limit)
TLU = 0.839 * SRSS(Sd, Sv, SSpe, Rd, Rv) + PE
= 9.95% span
Sd = +/- 0.877% span
Sv = +/- 0.5% span
St = +/- 0.751% span
Sspe = +/- 0.637% span
Rd = +/- 0.222% span
Rv = +/- 0.5% span
PE = + 8.68% span
LTSP = 9.95% span (LSSS rounded up to $\geq$ 10%)
FTSP = 30% span
RAL = +/-0.5% span
RAF = SRSS(Rv, Rd) = +/- 0.547% of span

High-High SGNR Water Level ESFAS Feedwater Isolation

0-100% instrument span = 0-100% SGNR Water Level span

AL = None, PL = 97% span (Maximum Reliable Indication Limit)
TLU = 0.839 * SRSS(Sd, Sv, St, Sspe, Rd, Rv) + PE
= -6.04% span
Sd = +/- 0.877% span
Sv = +/- 0.5% span
St = +/- 0.751% span
Sspe = +/- 0.637% span
Rd = +/- 0.212% span
Rv = +/- 0.5% span
PE = - 4.77% span
LTSP = 90.96% span (LSSS rounded down to $\leq$ 90%)
FTSP = 78% span
RAL = +/- 0.5% span
RAF = SRSS(Rv, Rd) = +/-0.543% span

Parameter: Pressurizer Pressure
Summary of Calculation No: 2009-0001

Low Pressurizer Pressure Reactor Trip

0-100% instrument span = 1700-2500 psig
AL = 1840 psig
TLU = 0.839 * SRSS(Sd, Sv, Ss, St, Rd, Rv, La, Ld, Lmte, Lv, PA) + PE
= 2.334% span = 15.7 psig
Sd = +/- 0.844 % span
Sv = +/- 0.5 % span
Ss = +/- 1.0% span
St = +/- 1.538 % span
Rd = +/- 0.222% span
Rv = +/- 0.5% span
La = +/- 0.5% span
Ld = +/- 0.5% span
Lmte = +/- 0.083% span
Lv = +/- 0.5% span
PA = +/- 0.25 % span
PE = - 0.092% span
LTSP = 1840 + 15.7 = 1855.7 psig (LSSS rounded up to ≥ 1860 psig)
FTSP = 1925 psig
RAL = +/- 0.5% span
RAF = SRSS(Rv, Rd) = +/-0.547% span (for Bistable)
RAF = SRSS(Lv, Ld, Lmte) = +/-0.712% span (for L/L module)

High Pressurizer Pressure Reactor Trip

0-100% instrument span = 1700-2500 psig
AL = 2403 psig
TLU = 0.839 * SRSS(Sd, Sv, Ss, St, Rd, Rv, PA) + PE
= -1.909% span = -15.3 psig
Sd = +/-0.844 % span
Sv = +/-0.5 % span
Ss = +/-1.0% span
St = +/-1.538 % span
Rd = +/-0.222% span
Rv = +/-0.5% span
PA = +/-0.25 % span
PE = -0.092% span
LTSP = 2403 – 15.3 = 2387.7 psig (LSSS rounded down to ≤ 2385 psig)
FTSP = 2365 psig
RAL = +/- 0.5% span
RAF = SRSS(Rv, Rd) = +/- 0.547% span

Parameter: Pressurizer Pressure
Summary of Calculation (Doc) No: 2009-0001

Low Pressurizer Pressure SI Actuation

0-100% instrument span = 1700-2500 psig

AL = 1648 psig, however PL = 1700 psig due to range limitation
TLU = 0.839 * SRSS(Sd, Sv, Ss, St, Rd, Rv, PA) + PE
= 3.406% span = 22.9 psig
Sd = +/- 0.844 % span
Sv = +/- 0.5 % span
Ss = +/- 1.0% span
St = +/- 1.538 % span
Rd = +/- 0.222% span
Rv = +/- 0.5% span
PE = - 0.092% span
PA = +/- 0.25 % span
LTSP = 1700 + 22.9 = 1722.9 psig (LSSS rounded up to ≥ 1725 psig)
FTSP = 1735 psig
RAL = +/- 0.5% span
RAF = SRSS(Rv, Rd) = +/- 0.547% span

Pressurizer Pressure SI Unblock

0-100% instrument span = 1700-2500 psig

AL = None
TLU = N/A
LSSS = ≤ 2005 psig
FTSP = 2000 psig
RAL = +/- 0.5% span
RAF = SRSS(Rv, Rd) = +/- 0.547% span
Rd = +/- 0.222% span
Rv = +/- 0.5% span

Parameter: Power Range Nuclear Instrumentation
Summary of Calculation No: 2009-0002

Power Range Neutron Flux – High Reactor Trip

0 – 100% instrument span = 0 – 120% RTP

AL = 116% RTP
TLU = 0.839 * SRSS(Ra, Rd, Rmte, Rv, PE)
= -6.342% span = -6.39 RTP
Ra = +/- 2.0% span
Rd = +/- 2.0% span
Rmte = +/- 0.596% span
Rv = +/- 0.833% span
PE = +/- 5.583% span
LTSP = 116 – 6.39 = 109.61 RTP (LSSS rounded down to $\leq$ 109% RTP)
FTSP = 107% RTP
RAF = SRSS(Rv, Rd, Rmte) = +/- 2.247% span = +/- 2.696% RTP
RAL = +/- 0.833% span = 1.0% RTP

Power Range Neutron Flux – Low Reactor Trip

0 – 100% instrument span = 0 – 120% RTP

AL = 35% RTP
TLU = 0.839 * SRSS(Ra, Rd, Rmte, Rv, PE)
= -6.342% span = - 6.39 RTP
Ra = +/- 2.0% span
Rd = +/- 2.0% span
Rmte = +/- 0.596% span
Rv = +/- 0.833% span
PE = +/- 5.583% span
LTSP = 35 – 6.39 = 28.61 RTP (LSSS rounded down to $\leq$ 28% RTP)
FTSP = 20% RTP
RAF = SRSS(Rv, Rd, Rmte) = +/- 2.247% span = +/- 2.696% RTP
RAL = +/- 0.833% span = 1.0% RTP

Parameter: Power Range Nuclear Instrumentation
Summary of Calculation No: 2009-0002

Power Range Neutron Flux – Interlock P-9

0 – 100% instrument span = 0 – 120% RTP
AL = None
TLU = N/A
LSSS = ≤ 38% RTP for Tavg < 572°F
= ≤ 53% RTP for Tavg ≥ 572°F and end-of-cycle coastdown
FTSP = 35% RTP for Tavg < 572°F
= 50% RTP for Tavg ≥ 572°F and end-of-cycle coastdown
RAF = SRSS(Rv, Rd, Rmte) = +/- 2.247% span = +/- 2.696% RTP
RAL = +/- 0.833% span = 1.0% RTP

Power Range Neutron Flux – Interlock P-8

0 – 100% instrument span = 0 – 120% RTP
PL = 45% RTP
TLU = N/A
FTSP = 35% RTP
OL^{+} = FTSP + SRSS(Rv, $Rd_{3\sigma}$)
Rv = +/- 0.833% span
$Rd_{3\sigma}$ = +/- 3.0 % span
OL^{+} = 35% + 3.73% RTP (LSSS rounded to ≤ 38% RTP)
RAF = SRSS(Rv, Rd, Rmte) = +/- 2.247% span = +/- 2.696% RTP
RAL = +/- 0.833% span = 1.0% RTP

Power Range Neutron Flux – Interlock P-7

0 – 100% instrument span = 0 – 120% RTP
AL = None
TLU = N/A
LSSS = 13% RTP
FTSP = 10% RTP
RAF = SRSS(Rv, Rd, Rmte) = +/- 2.247% span = +/- 2.696% RTP
RAL = +/- 0.833% span = 1.0% RTP

Power Range Neutron Flux – Interlock P-10

0 – 100% instrument span = 0 – 120% RTP
AL = None
TLU = N/A
LSSS = ≥ 6% RTP and ≤ 12% RTP
FTSP = 9% RTP
RAF = SRSS(Rv, Rd, Rmte) = +/- 2.247% span = +/- 2.696% RTP
RAL = +/- 0.833% span = 1.0% RTP

<u>Parameter</u>: Intermediate Range Instruments
Summary of Calculation No: 2009 -0003

<u>IRM High Flux Reactor Trip</u>

AL = None
TLU = N/A
FTSP = 25% RTP
OL^+ = FTSP + SRSS(Rv, $Rd_{3\sigma}$)
  Rv = +/- 0.10% span
  $Rd_{3\sigma}$ = +/- 3.0 % span
OL^+ = 43.47% RTP (LSSS rounded to $\leq$ 43% RTP)
RAF = SRSS(Rv, Rd, Rmte) = +/- 2.010% span = +/- 0.201 Vdc
  Rv = +/- 0.10% span
  Rd = +/- 2.0 % span
  Rmte = +/- 0.177% span
RAL = +/- 0.10% span

<u>IRM Permissive P-6 Unblock</u>

AL = None
TLU = N/A
LSSS = $\geq 4 \times 10^{-11}$ amps
FTSP = 1.0×10^{-10} amps
RAF = SRSS(Rv, Rd, Rmte) = +/- 5.087% span = +/- 0.6×10^{-10} amps
  Rv = +/- 3.763% span
  Rd = +/- 2.0% span
  Rmte = +/- 2.778% span
RAL = +/- 3.763% span = +/- 0.500×10^{-10} amps

Parameter: Turbine Impulse Pressure
Summary of Calculation No: 2007 -0001

Turbine Impulse Pressure P-7 Unblock

AL = None
TLU = N/A
LSSS = ≤ 13% Turbine Power
FTSP = 10% Turbine Power = 41.1 psig
RAF = SRSS(Rv, Rd, Rmte) = +/- 1.667% span = +/- 10.8 psi
Rv = +/- 0.5 % span
Rd = +/- 1.59% span
Rmte = +/- 0% span
RAL = +/- 0.5% span = +/- 3.3 psi

Parameter: Pressurizer Water Level Instrumentation
Summary of Calculation Note No: CN-CPS-07-2

Narrow Range Pressurizer Water Level – High Reactor Trip

0-100% Instrument span = 0-100% Pressurizer Level

AL = None, PL = 100% instrument span
TLU = 0.839 * SRSS(Sa, Sd, Sv, Smte, Sp, St, Rd, Rv) + PE
= -14.41% span
Sa = +/- 0.25% span
Sd = +/- 1.105% span
Sv = +/- 0.5% span
Smte = +/- 0.374%
Sp = +/- 1.395% span
St = +/- 2.317% span
Rd = +/- 0.212% span
Rv = +/- 0.5% span
PE = -11.853% span
LTSP = 100 – 14.41 = 85.59% span (LSSS rounded to ≤ 85% span)
FTSP = 80% span
RAF = SRSS(Rv, Rd) = +/- 0.543% span
RAL = +/- 0.5% span

Parameter: Containment Pressure Low Range Instruments
Summary of Calculation No: PBNP-IC-17

High Containment Pressure – Safety Injection

0 – 100% instrument span = 0-60 psig

AL = 6 psig
TLU = 0.839 * SRSS(Sd, Sv, St, Rd, Rv)
= +/- 1.13 % span = +/- 0.678 psi
Sd = +/- 0.518% span
Sv = +/- 0.5% span
St = +/- 1.09% span
Rd = +/- 0.212% span
Rv = +/- 0.25% span
LTSP = 6 – 0.678 = 5.322 psig (LSSS rounded to $\leq$ 5.3 psig)
FTSP = 5 psig
RAF = SRSS(Rv, Rd) = +/- 0.328% span
RAL = +/- 0.25% span

High-High Containment Pressure – Containment Spray

0 – 100% instrument span = 0-60 psig

AL = 30 psig
TLU = 0.839 * SRSS(Sd, Sv, St, Rd, Rv)
= +/- 1.13 % span = +/- 0.678 psi
Sd = +/- 0.518% span
Sv = +/- 0.5% span
St = +/- 1.09% span
Rd = +/- 0.212% span
Rv = +/- 0.25% span
LTSP = 30 – 0.678 = 29.322 psig (LSSS rounded to $\leq$ 28 psig)*
FTSP = 25 psig
RAF = SRSS(Rv, Rd) = +/- 0.328% span
RAL = +/- 0.25% span

* The containment spray actuation function uses signals from two containment pressure ranges in a two-out-of-three taken twice coincidence logic. The LSSS value chosen for the function is the most conservative of the LTSPs calculated for the two pressure ranges. The LTSP in calculation PBNP-IC-19 is the basis for the LSSS value.

Parameter: Containment Pressure Intermediate Range Instruments
Summary of Calculation No: PBNP-IC-19

High-High Containment Pressure – Steam Line Isolation

0 – 100% instrument span = 0 - 90 psig

AL = None, PL = 20 psig
TLU = 0.839 * SRSS(Sd, Sv, St, Rd, Rv)
= +/-1.496% span = +/-1.347 psig
Sd = +/- 0.518% span
Sv = +/- 0.5% span
St = +/- 1.538% span
Rd = +/- 0.212% span
Rv = +/- 0.5% span
LTSP = 20 – 1.347 = 18.653 psig (LSSS rounded to ≤ 18 psig)
FTSP = 15 psig
RAF = SRSS(Rv, Rd) = +/- 0.543% span
RAL = +/- 0.5% span

High-High Containment Pressure – Containment Spray Actuation

0 – 100% instrument span = 0 - 90 psig

AL = 30 psig
TLU = 0.839 * SRSS(Sd, Sv, St, Rd, Rv)
= +/-1.496 % span = +/-1.347 psi
Sd = +/-0.518% span
Sv = +/-0.5% span
St = +/-1.538% span
Rd = +/-0.212% span
Rv = +/-0.5% span
LTSP = 30 – 1.347 = 28.653 psig (LSSS rounded to ≤ 28 psig)
FTSP = 25 psig
RAF = SRSS(Rv, Rd) = +/- 0.543% span
RAL = +/- 0.5% span

Parameter: Steam Line Pressure Instruments
Summary of Calculation No: PBNP-IC-39

Steam Line Pressure – Low Safety Injection

0 -100% instrument span = 0 -1400 psig
AL = 395.3 psig
TLU = 0.839 * SRSS(Sd, Sv, Ss, St, Rd, Rv, La, Ld, Lmte, Lv, PA) + PE
= 8.601% span = 120.41 psig
Sd = +/- 0.518% span
Sv = +/- 0.5% span
St = +/- 8.0% span
Rd = +/- 0.212% span
Rv = +/- 0.5% span
La = +/- 0.5% span
Ld = +/- 0.5% span
Lmte = +/- 0.083% span
Lv = +/- 0.5% span
IR = 1.808% span
LTSP = 395.3 + 120.41 = 515.71 psig (LSSS rounded to ≥ 520 psig)
FTSP = 530 psig
RAL = +/- 0.5% span
RAF = SRSS(Rv, Rd) = +/- 0.543% span (for Bistable)
RAF = SRSS(Lv, Ld, Lmte) = +/- 0.712% span (for L/L module)

Parameter: Low Tavg Interlock Instruments
Summary of Calculation Note No: CN-CPS-07-11

Tavg Low Interlock

0 – 100% instrument span = 530 – 630 °F

AL = 540 °F
TLU = See Note 1
= 1.71% span = 1.71 °F
LTSP = 540 + 1.71 = 541.71 °F (LSSS rounded to ≥ 542 °F)
FTSP = 543 °F
RAF = SRSS(0.5, 0.196) = +/- 0.537% span (Bistable)
RAF = SRSS(.05, .2, .107) = +/- 0.232 % span = +/- 0.470 mVdc (Current Source)
RAF = SRSS(0.083, 0.429, 0.033) = 0.438 % span (Amplifier)
RAF = SRSS(0.5, 0.061) = 0.504 % span = +/- 2.1 mVdc (E/I Converter)
RAL = +/- 0.5% span (Bistable)
RAL = +/- 0.10 mVdc (Current Source)
RAL = +/- 0.083% span (Amplifier)
RAL = +/- 0.5% (E/I Converter)

Note 1 – Because of the complexity of this calculation, please refer to the actual calculation for details