July 8, 2010

NRC 2010-0065
10 CFR 50.90

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

Point Beach Nuclear Plant, Units 1 and 2
Dockets 50-266 and 50-301
Renewed License Nos. DPR-24 and DPR-27

License Amendment Request 261
Extended Power Uprate
Response to Request for Additional Information

References:
(1) FPL Energy Point Beach, LLC letter to NRC, dated April 7, 2009, License Amendment Request 261, Extended Power Uprate (ML091250564)
(2) NRC Electronic Mail to NextEra Energy Point Beach, LLC, dated April 16, 2010, Draft – Request for additional Information from Reactor Systems RE: Extended Power Uprate - Round 3 (ML101060302)
(3) NextEra Energy Point Beach, LLC letter to NRC, dated January 13, 2010, License Amendment Request 261, Extended Power Uprate, Response to Request for Additional Information (ML100140163)
(4) NRC letter to NextEra Energy, dated December 22, 2009, Point Beach Nuclear Plant, Units 1 And 2 -Request For Additional Information From Reactor Systems Branch Re: Extended Power Uprate (TAC Nos. ME1044 and ME1045) (ML093500203)

NextEra Energy Point Beach, LLC (NextEra) submitted License Amendment Request (LAR) 261 (Reference 1) to the NRC pursuant to 10 CFR 50.90. The proposed license amendment would increase each unit's licensed thermal power level from 1540 megawatts thermal (MWt) to 1800 MWt, and revise the Technical Specifications to support operation at the increased thermal power level.

Via Reference (2), the NRC staff determined that additional information was required to enable the staff's continued review of the request. In addition, Reference 2 requested additional clarification of NextEra responses to NRC RAIs submitted by letter dated January 13, 2010 (Reference 3), issued by NRC letter dated December 22, 2009 (Reference 4). The enclosure provides the NextEra response to the NRC staff's request for additional information.

This letter contains no new Regulatory Commitments and no revisions to existing Regulatory Commitments.

The information contained in this letter does not alter the no significant hazards consideration contained in Reference (1) and continues to satisfy the criteria of 10 CFR 51.22 for categorical exclusion from the requirements of an environmental assessment.

In accordance with 10 CFR 50.91, a copy of this letter is being provided to the designated Wisconsin Official.

I declare under penalty of perjury that the foregoing is true and correct.
Executed on July 8, 2010.

Very truly yours,

NextEra Energy Point Beach, LLC

Larry Meyer
Site Vice President

Enclosure

cc: Administrator, Region III, USNRC
Project Manager, Point Beach Nuclear Plant, USNRC
Resident Inspector, Point Beach Nuclear Plant, USNRC
PSCW

ENCLOSURE

NEXTERA ENERGY POINT BEACH, LLC
POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2

LICENSE AMENDMENT REQUEST 261
EXTENDED POWER UPRATE
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION

The NRC staff determined that additional information was required (Reference 1) to enable the Reactor Systems Branch to complete its review of License Amendment Request (LAR) 261, Extended Power Uprate (EPU) (Reference 2). In addition, Reference 1 requested additional clarification of NextEra responses to NRC RAIs submitted by letter dated January 13, 2010 (Reference 3), issued by NRC letter dated December 22, 2009 (Reference 4). NextEra's response to the NRC staff's request for additional information is provided below. The following information is provided by NextEra Energy Point Beach, LLC (NextEra) in response to the NRC staff's request.

Follow Up Question 1

Question 2.8.5.1-1

How were the limiting break sizes, 0.59 ft^2 (Unit 1) and 0.63 ft^2 (Unit 2), determined for the analyses of Steam System Piping Failures at Full-Power?

NextEra Response

The analysis of the hot full power (HFP) steam line break (SLB) event performed in support of the PBNP EPU follows the standard Westinghouse methodology developed for this event. Under that methodology, the event is analyzed over a spectrum of break sizes in order to identify the most limiting overpower condition. The spectrum of breaks considered range from 0.1 ft^2 to 1.4 ft^2, where the maximum value is based on the steam generator exit nozzle flow restrictor flow area. In the PBNP analysis, this range of break sizes is explicitly modeled for both steam generator types (Model 44F for Unit 1 and Model Δ47 for Unit 2). The limiting case for each of the PBNP units corresponds to the case that reaches the highest peak core average heat flux, as this will yield the most limiting DNBR [departure from nucleate boiling ratio] and kW/ft results for the event. Based on this, a break size of 0.59 ft^2 was found to be the most limiting for Unit I, while a 0.63 ft^2 break was most limiting for Unit 2.

Followup Question From the NRC Staff Reviewer

a) *What is the standard Westinghouse methodology developed for this event?*

b) *Is this methodology approved by the NRC for use with respect to two-loop plants at EPU conditions?*

NextEra Response

a) The NRC-approved SLB topical report, WCAP-9226-P-A, Revision 1 (Reference 5), examined breaks from both hot shutdown (zero power) (HZP) and at-power initial conditions. The methodology and analyses for at-power breaks is described in Section 3.2. As concluded in Section 4.0, "For steamline breaks occurring while the reactor is at power, it has been shown that the reactor trips provided by the reactor protection system are adequate to insure that the DNB [departure from nucleate boiling] design basis is not violated prior to and immediately following reactor trip." Section 2.5 of the NRC safety evaluation report (SER) for WCAP-9226 notes that audit calculations confirmed that the results were conservative for typical Westinghouse three and four-loop plants. The audit calculations included full-power cases.

   Note that the SLB topical report further concluded that "the largest double-ended steamline rupture at end of life, hot shutdown conditions with the most reactive RCCA [rod cluster control assembly] in the fully withdrawn position is a limiting and sufficiently conservative licensing basis."

   Consistent with that conclusion, historically only the HZP case (which bounds the post-trip phase of a break from at-power) was analyzed and presented in the FSAR for Westinghouse plants. However, over the years changes to the protection system setpoints, lead/lag time constants, and response times have been made for some plants which may not be bounded by the generic assumptions of the SLB topical report. As a result, Westinghouse now typically performs plant-specific analyses of the full-power SLB scenario to confirm that the applicable acceptance criteria are met. The plant-specific analyses use the conservative methods and assumptions described in the SLB topical report to maximize the peak core power and minimize the DNBR.

b) The SLB topical report (Reference 5) did not specifically present results for two-loop plant designs. As described in the Westinghouse response to RAI 212.11 (see Section D of the topical report), the report was submitted to the NRC for the purpose of addressing the spectrum of break sizes and power levels for plants being licensed under the guidelines of Regulatory Guide (RG) 1.70, Rev. 2. Because there were no domestic two-loop plants that required licensing to these guidelines, the report was limited to three and four-loop Westinghouse pressurized water reactor (PWR) plants. However, the general SLB transient trends and effects are the same regardless of the number of coolant loops. As noted in Section 2.4 of the NRC SER for WCAP-9226, the sensitivity analyses in the SLB topical report were performed for a three-loop plant, but the trends of the analyses are also applicable for four-loop plants. Similarly, the same SLB analysis methods are used by Westinghouse for two-loop plants. Note that a full-power SLB analysis based on these methods was submitted and approved for the two-loop R. E. Ginna EPU program.

This is further supported by the response to an RAI on the Westinghouse RETRAN code topical report, WCAP-14882-P-A (Reference 6). The benchmark analyses in that report were performed for a four-loop plant. The response to NRC RAI Question 2 documented in letter NSD-NRC-98-5765 (see Appendix B of the report), justifies the application of the results to two and three-loop plants.

Follow Up Question 2

Question 2.8.5.1-3

Since the OPΔT trip function is not qualified for a harsh environment caused by the steamline break, the applicant states that the Hi- 1 containment pressure safety injection signal would generate a reactor trip signal before the time credited, in the analyses, for the OPΔT trip signal. What is the basis for this statement? What models and assumptions were used in containment pressure response analyses in order to yield conservatively late Hi- 1 containment pressure safety injection signals?

NextEra Response

The PBNP HFP [hot full power] SLB analysis does not differentiate between breaks inside and outside containment; a single analysis conservatively addresses both scenarios. The analysis explicitly models the overpower ΔT (OPΔT) reactor trip and low steam line pressure safety injection signals. Although the OPΔT function may not be available for all inside-containment cases (as a harsh environment caused by larger-sized, inside-containment steam line breaks may affect its proper functioning), the analysis performed conservatively utilizes this function to determine limiting DNBR and kW/ft consequences for the event. To address the potential unavailability of the OPΔT function under these conditions, the analysis includes a model that integrates the break mass flow rate and flags the time at which the total steam releases reach 10,000 lbm. With this information, the time at which the 10,000 lbrn value is reached has been confirmed to occur well before the time at which an OPΔT signal is generated.

As an example, for the limiting Unit 1 case (0.59 ft^2 break), if the break was assumed to occur inside containment, the steam releases reached a total of 10,000 lbrn at 12.4 seconds after the start of the transient (Hi-1 containment pressure signal could have been used to generate a safety injection signal, which produces a reactor trip). However, reactor trip is conservatively delayed in the analysis until the OPΔT reactor trip setpoint is reached at 21.8 seconds after event initiation; rods begin to insert into the core 2 seconds later. A similar behavior was seen for Unit 2. The DNBR and kW/ft calculations performed for this event, which are both very sensitive to the time at which the reactor is tripped, are based on a conservatively delayed reactor trip on OPΔT. Based on this, the DNBR and kW/ft calculations for this event are conservative and apply to both inside and outside containment steam line breaks.

As for the calculation of the 10,000 lbrn steam release value discussed above, a COCO computer code containment model was developed starting from the model used for the containment integrity analysis. Two changes were made to conservatively delay the time that the Hi-1 containment pressure setpoint was reached.

(1) The initial containment pressure was decreased to 14.7 psia.
(2) The surface area of the containment heat sinks was increased by 50%.

Applying mass and energy releases from a variety of steamline break sizes, it was determined that the Hi-1 containment pressure of 6 psig was always reached by the time that 10,000 lbrn of steam had been released from the break.

Followup Question From the NRC Staff Reviewer

Steamline break flow quality is commonly assumed to be 1.0 in order to maximize the rate of heat removal from the core. However, this assumption would not be conservative when it's used to predict the time that a high containment pressure setpoint might be reached. One can expect some entrainment in the break flow, especially for larger break sizes, and this entrainment would not cause as rapid a rate of containment pressurization as would dry steam.

a) *Would the Hi-1 containment pressure of 6 psig be reached by the time that 10,000 lbrn of steam is released from the break, if this steam were to contain a significant amount of water?*

b) *What is the steamline break size and entrainment level that causes the Hi-1 containment pressure setpoint and the low steamline pressure to be reached at the same time? How many lbm of steam is released by that time?*

NextEra Response

a) The Hi-1 containment pressure setpoint of 6 psig would not be reached by the time that 10,000 lbm of steam/liquid is released from the break, if the break effluent contained a significant amount of water. However, as discussed in the response to Item b below, the steam line break sizes for which the Hi-1 containment pressure setpoint is credited are not expected to result in substantial liquid entrainment.

b) The HFP SLB analysis is focused on defining a limiting break size that shows the core to remain above the applicable DNBR limit and below the kW/ft limit. The Hi-1 containment pressure setpoint is of importance only for showing that it would be reached prior to the OPΔT setpoint because the OPΔT trip has not been qualified for a harsh environment inside containment. The OPΔT trip is credited for relatively small breaks, ranging from approximately 0.3 ft^2 to 0.6 ft^2. Smaller breaks do not result in a reactor trip and larger breaks rely on the low steamline pressure signal. The limiting break size is the largest break that results in an OPΔT trip, which was determined to be 0.59 ft^2 for Unit 1 and 0.63 ft^2 for Unit 2. These break sizes would not be expected to result in entrained liquid based on the analysis results in WCAP-8822 (Reference 7) that show 0.6 ft^2 as the largest break resulting in a dry steam blowdown for pre-heat Model D steam generators when the break is initiated at full power. Although PBNP has different steam generators, this provides a general indication that that there should not be substantial liquid entrainment for these break sizes.

If some liquid were entrained in the break effluent and if the time of the Hi-1 containment pressure signal was delayed by a few seconds, it would not change the conclusion that the Hi-1 containment pressure setpoint is reached prior to the OPΔT setpoint. For Unit 1, the OPΔT setpoint is reached around 24.3 seconds (revised calculated value) after event initiation for the limiting break size. Based on the assumption of dry steam released, the Hi-1 containment pressure setpoint is reached in approximately 12.4 seconds after event initiation. Similar timing is calculated for Unit 2. The margin of almost 12 seconds between the timing of the two setpoints ensures that the Hi-1 containment pressure setpoint will be reached first regardless of whether there is entrained liquid in the break effluent.

The limiting break sizes that have been defined remain conservative; no more limiting break size would be defined if wet steam were assumed as part of the break effluent.

Follow Up Question 3

Question 2.8.5.1-6b

b) *What would be the result of a smaller steamline break that would not depressurize the RCS to the accumulator injection setpoint?*

NextEra Response

b) *Even very small steam line break sizes result in depressurization of the reactor coolant system (RCS) to the accumulator setpoint, although it takes somewhat longer than in the design-basis double-ended rupture case. However, despite delayed accumulator actuation, the core heat flux increases at a slower rate for these cases and the peak core heat flux is lower. The analyzed case is the most-limiting condition for core response.*

Question 2.8.5.1-6c

c) *What would be the result of an even smaller steamline break that would not depressurize the RCS to the safety injection system shutoff head?*

NextEra Response

c) *As noted above, even very small steam line break sizes result in depressurization to below the safety injection (SI) system shutoff head. As long as there is an unisolable break on the secondary side, the primary system cools down and depressurizes until actuation of safeguards systems occurs.*

Followup Question From the NRC Staff Reviewer

NextEra's response to Question 2.8.5.1-4 states, "As the break size is further reduced, no reactor trip signal will be generated, and a new equilibrium condition will be reached." The staff expects the existence of very small steam line break sizes that do not result in depressurization of the RCS to the accumulator setpoint, after reactor trip, or even to the safety injection system shutoff head. This can occur when the heat removal rate in the secondary system, including the steam flow through the steam line break, basically matches the heat generation rate in the core or even the heat added to the reactor coolant by the reactor coolant pumps. See Figures 3.2-8, 3.2-15 and 3.2-21 in [3]. Unfortunately, [3] is not in the PBNS licensing basis, since it deals only with three and four-loop plant designs, and the table, in [3], that covers very small steam line break sizes, Table 3.2-4, seems to be missing. Therefore, the staff requests assurance that PBNS, as a two-loop plant operating under EPU conditions, would be protected for all steam break sizes, down to the very small size that does not require protection.

NextEra Response

The response to Question 2.8.5.1-4 quoted in the follow-up question refers to the full-power SLB analysis. With the reactor at power, smaller break sizes may result in an increase in core power and a new equilibrium condition without reactor trip, similar to what happens for the excess load increase incident. At high reactor power, sufficient heat can be generated to maintain steam pressure to support turbine flow plus flow out a small break. The referenced figures from the

SLB topical report, WCAP-9226-P-A (Reference 5), also correspond to at-power break cases (Section 3.2).

The situation is different for the case of breaks analyzed from a HZP, post-trip initial condition, which was the subject of Question 2.8.5.1-6. For HZP cases, the primary system pressure would still ultimately decrease to below the SI system shutoff head and accumulator actuation setpoint, even for very small break sizes, as noted in the previous responses. With the reactor tripped, the heat removal from the steam line break results in a cooldown and depressurization of the primary side coolant, and it is not possible to continuously support an equilibrium steam pressure condition, including the effects of reactor coolant pump heat addition and any heat addition from a return to power in the core.

Note that smaller break sizes do not actuate the high-high steam line flow setpoint, and thus the coincidence logic with low steam line pressure does not result in actuation of SI and steam line isolation. Actuation of SI in these cases occurs on low pressurizer pressure, and steam line isolation would not occur. However, the peak core heat flux and core peaking factors for these cases are not as severe as for the large double-ended rupture design basis case presented, which remains bounding for minimum DNBR and peak kW/ft. This is consistent with the findings of the SLB topical report, which examined a spectrum of break sizes for zero power (Reference 5, Section 3.1.3).

Follow Up Question 4

Question 2.8.5.2-3

If the restrictive acceptance criterion that the pressurizer does not become water solid were used for the Loss of Feedwater event, then why were the PORVs [power operated relief valves] not modeled?

NextEra Response

The analysis of the Loss of Normal Feedwater/Loss of AC Power (LONF/LOAC) events performed in support of the PBNP EPU explicitly considers cases where the pressurizer power-operated relief valves (PORVs) are assumed to be operable, and cases where these are assumed to be unavailable; the same conservative acceptance criterion of preventing pressurizer filling is applied in all cases. The most limiting of these scenarios (without PORVs for LONF and with PORVs for LOAC) are reported in LAR 261. This approach is consistent with the guidance provided in NSAL-07-10.

Followup Question From the NRC Staff Reviewer

It is conservative to assume the PORVs will operate when analyzing AOOs [anticipated operational occurrences] with respect to DNB safety limits, in order to keep core pressure relatively low. Analyses designed to demonstrate that the pressurizer will not fill, due to heat-induced coolant swell (not mass addition from the ECCS [emergency core cooling system]), may or may not be based upon operation of the PORVs, whichever leads to higher pressurizer water levels.

Limiting the peak RCS pressure to the PORV opening setpoint, as opposed to the opening setpoint of the pressurizer safety valves (PSVs), is expected to have a very small effect upon the peak pressurizer water level. NSAL-07-10 [4], however, claims that operation of the PORVs can produce non-conservative analysis results (i.e., lower peak pressurizer water levels, by as *much as five percent). A simple comparison of the specific volume of saturated water at the PORV opening setpoint (2350 psia) to the specific volume of saturated water at the PSV opening setpoint (2584.2 psia) indicates that the pressurizer water volume, at the higher pressure (i.e., when the PORVs do not open) would be about six percent higher than the pressurizer water volume, at the lower pressure (i.e., when the PORVs are assumed to operate). This is consistent with the five percent value given in [4]. It seems this result is based upon the underlying assumption of a pressurizer in equilibrium (i.e., pressurizer water and steam temperatures are the same: at the saturation value that corresponds to the pressurizer pressure). If the water temperature is assumed to become subcooled, as pressure rises (i.e., the conditions that can be expected during times of insurge from the RCS hot leg), then the calculated water volume would be slightly higher at the lower (i.e., when the PORV is open) pressure, by about one percent. Therefore, one cannot conclude, as NextEra does, that it is always conservative to assume the PORVs do not operate during LONF/LOAC events.*

The guidance contained in this NSAL [4] has not been reviewed and approved by the staff. Statements that derive from [4], such as, "The pressurizer PORVs were assumed to be inoperable in the limiting cases. These assumptions maximize the peak pressurizer water volume." are not justified. Since the PBNS analysis results show that there is ample steam space available during LONF/LOAC events, to account for peak pressurizer water volumes that can vary by up to six percent, it is not necessary to make any references to [4] in the LAR (e.g., Table 2.8.5.0-3 Pressure Relief Models for the RCS (Pressurizer) and MSS), or in the responses to questions in this RAI.

The staff requests (1) a response to Question 2.8.5.2-3 that does not allude to [4], and (2) the removal of all LAR references to [4], and all statements based upon the guidance of [4].

<u>NextEra Response</u>

Although the original response to Question 2.8.5.2-3 does imply that Nuclear Safety Advisory Letter (NSAL)-07-10 (Reference 8) provides guidance for the analysis of the LONF/LOAC events pertaining to the modeling of the pressurizer PORVs, that was not the intent. NSAL-07-10 was referenced only because it identifies an issue related to the availability (or non-availability) of the pressurizer PORVs and suggests that analyses of these events be performed both with and without pressurizer PORVs available to determine the most limiting condition on a plant-specific basis. In the PBNP EPU analysis of the LONF/LOAC events, cases were explicitly analyzed with and without pressurizer PORVs available. Statements made in the Licensing Report (LAR 261), and quoted in the followup question being addressed here, are based on conclusions reached in the PBNP-specific analysis of these events at EPU conditions and are not from NSAL-07-10. The mentioning of NSAL-07-10 in the Licensing Report Table 2.8.5.0-3 and in the RAI response identified that the issue has been dispositioned for the PBNP EPU Program. Note that Section 2.8.5.0 of the Licensing Report has another example of an NSAL being referenced for the same purpose as discussed above. However, the original RAI response has been modified, as shown below, to address the concern raised in the followup question.

The analysis of the LONF/LOAC events performed in support of the PBNP EPU considers cases where the pressurizer PORVs are assumed to be operable, and cases where these are assumed to be unavailable. The same conservative acceptance criterion of preventing pressurizer filling is applied in all cases. The most limiting of these scenarios (without PORVs for LONF and with PORVs for LOAC) are reported in the Licensing Report. This approach is consistent with the discussion presented in NSAL-07-10 (Reference 8).

Follow Up Question 5

Question 2.8.5.4.5-1

Please explain how, and in which operating modes, the Chemical and Volume Control System is designed to prevent uncontrolled or inadvertent reactivity changes which might cause system parameters to exceed design limits.

NextEra Response

This statement is not intended to portray the chemical and volume control system (CVCS) as a protection system. The CVCS provides a means of reactivity control in the form of boric acid solution neutron absorber in the RCS. Potential failures in the CVCS are analyzed as part of the PBNP final safety analysis report (FSAR) Chapter 14 accident analysis. The functions of the CVCS are described in Section 9.3 of the PBNP FSAR.

Followup Question From the NRC Staff Reviewer

Please revise this statement, in the LAR, so that it does not portray the CVCS as a protection system.

NextEra Response

Licensing Report Section 2.8.5.4.5, Chemical and Volume Control Malfunction, Paragraph 2.8.5.4.5.1.2, Introduction, is revised. The last sentence in the paragraph is revised to state:

"The CVCS, although not credited as a protection system, 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."

Round 3 RAI – LAR 261

2.8.4.2-1, Overpressure Protection During Power Operation

1. The Standard Review Plan (Section 5.2.2) states, "The reviewer identifies all of the reactor trip signals that occur during overpressure transients, including their setpoints and setpoint tolerances. The reviewer verifies that the second reactor trip signal, under worst-case conditions during an overpressure transient, is adequate to provide overpressure protection to the RCPB [reactor coolant pressure boundary] in conjunction with the installed overpressure protection systems or devices." Please provide the results (e.g., transient plots and sequence of events tables) from the analyses performed to demonstrate that the second reactor trip signal provides adequate overpressure protection during power operation under the proposed EPU conditions.

2. Describe how the maximum allowable power is determined for situations in which one or more main steam safety valves are not operable (Table 2.8.4.2-2).

NextEra Response

1. It was believed that the guidance set forth in Standard Review Plan (SRP) Section 5.2.2 was intended to be used during the review of analyses performed for an application for an operating license on a new plant. Specifically, it was believed that analyses performed in compliance with SRP Section 5.2.2 were intended to demonstrate that the PSVs contained in the design of a new plant had been conservatively sized to provide more than sufficient overpressure protection, not to demonstrate that an operating plant continues to provide adequate overpressure protection. As such, for a plant such as PBNP that was designed and licensed prior to the SRP being issued, it was expected that the Loss of Load/Turbine Trip (LOL/TT) analysis that was presented in Licensing Report Section 2.8.5.2.1, and in which the first safety grade reactor trip signal was credited, would sufficiently demonstrates that there continues to be adequate overpressure protection for the operation of PBNP at the proposed EPU conditions.

   In response to this RAI, a LOL/TT overpressure analysis was performed in which the first safety-grade reactor trip signal was assumed inoperable and the second safety-grade reactor trip signal was credited for protection. Also, consistent with precedent set forth during NRC review of analyses performed for the Comanche Peak stretch power uprate, this overpressure analysis was performed using nominal input values for select parameters. Specifically, the NSSS power, vessel average temperature (T_{avg}), pressurizer pressure, pressurizer water level, and reactor vessel coolant flow were assumed to initially be at their nominal values. A more realistic least-negative moderator temperature coefficient (MTC) was also assumed. In addition, the reactor trip setpoint, as well as the PSV and main steam safety valve (MSSV) setpoints, were assumed to be at their nominal setpoints, consistent with a design analysis.

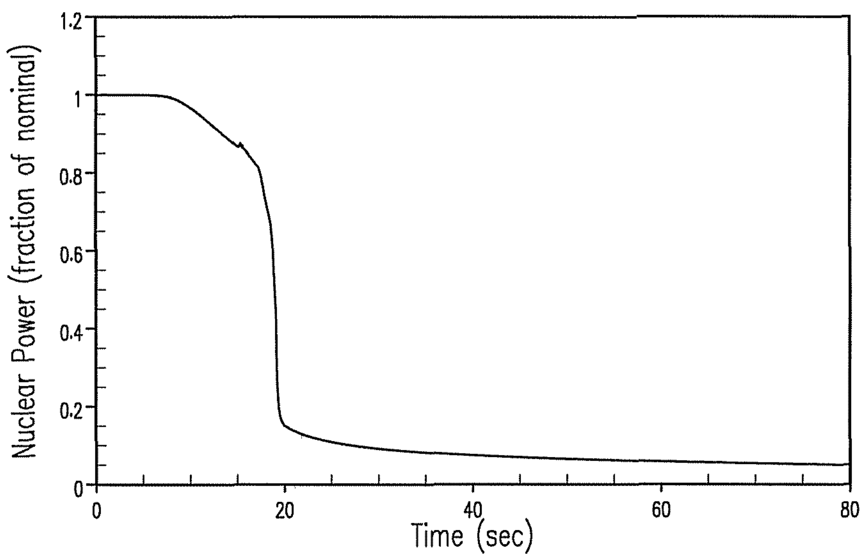
   The limiting results from the LOL/TT overpressure analysis performed for PBNP at the proposed EPU conditions with the first safety-grade reactor trip signal assumed inoperable and the second safety-grade reactor trip signal credited for protection are presented below.

Time Sequence of Events - Unit 1
Overpressure Case with Second Reactor Trip Signal Credited

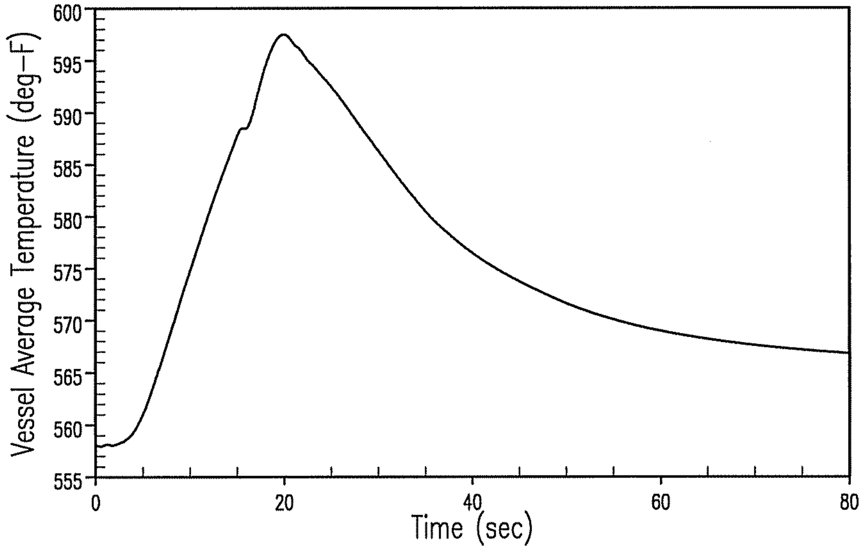
Event	Time (sec)
Loss of Load / Turbine Trip	0.0
High Pressurizer Pressure Reactor Trip Safety Analysis Setpoint Reached (not credited)	6.1
Pressurizer Safety Valves Open	7.9
First Main Steam Safety Valve Opens	14.6
OTΔT Reactor Trip Setpoint Reached	15.0
Peak RCS Pressure Occurs (2718.20 psia)	15.0
Rod Motion Begins	17.0

Time Sequence of Events - Unit 2
Overpressure Case with Second Reactor Trip Signal Credited

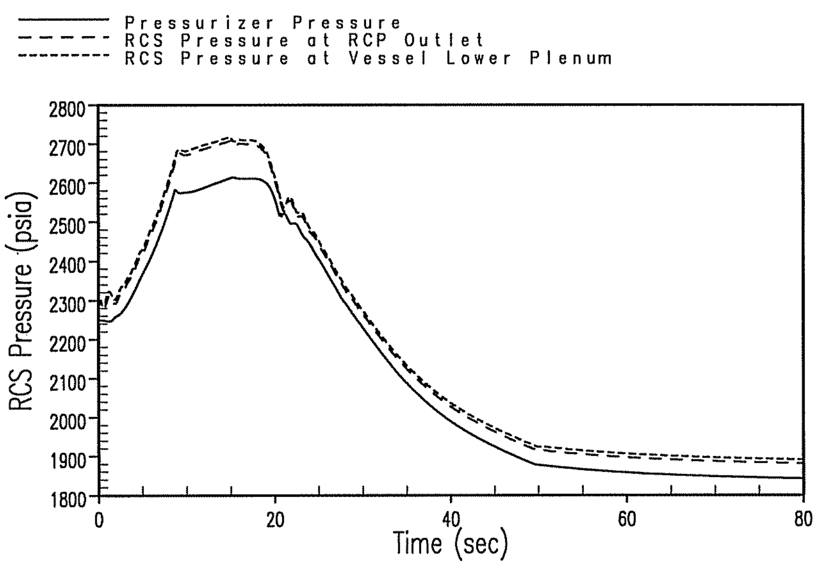
Event	Time (sec)
Loss of Load / Turbine Trip	0.0
High Pressurizer Pressure Reactor Trip Safety Analysis Setpoint Reached (not credited)	5.9
Pressurizer Safety Valves Open	7.7
First Main Steam Safety Valve Opens	14.2
Peak RCS Pressure Occurs (2743.55 psia)	15.0
OTΔT Reactor Trip Setpoint Reached	15.1
Rod Motion Begins	17.1



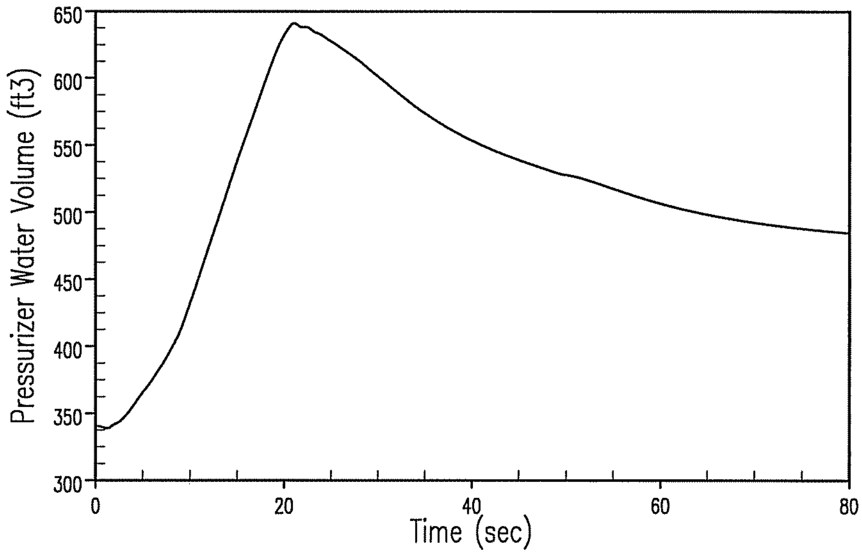
Nuclear Power - Unit 1
Overpressure Case with Second Reactor Trip Signal Credited



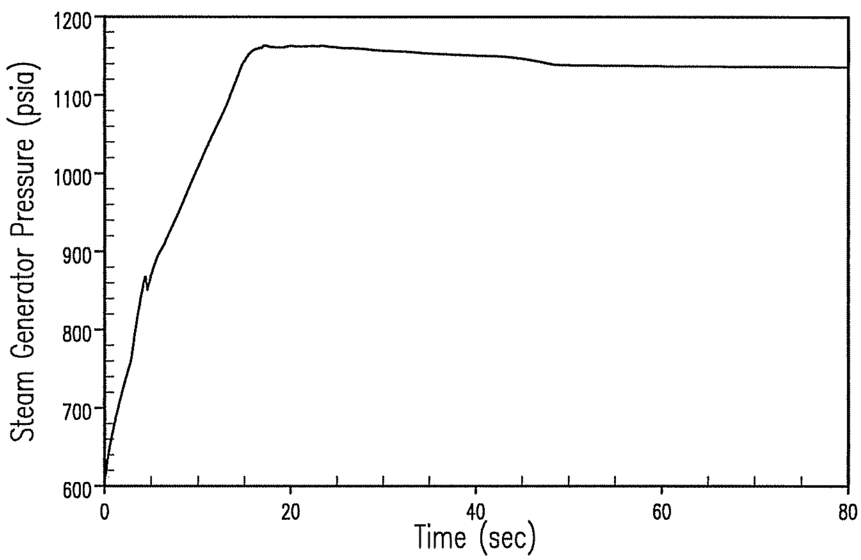
Vessel T_{avg} - Unit 1
Overpressure Case with Second Reactor Trip Signal Credited



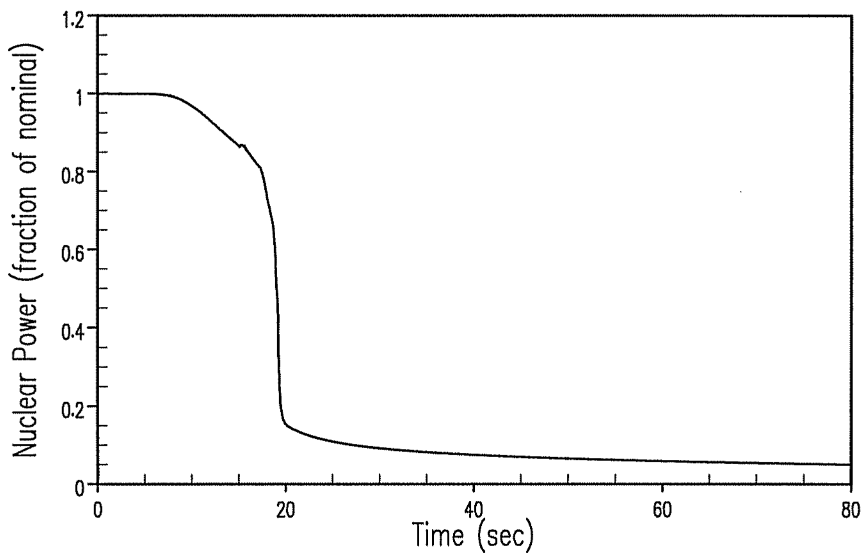
RCS Pressure - Unit 1
Overpressure Case with Second Reactor Trip Signal Credited



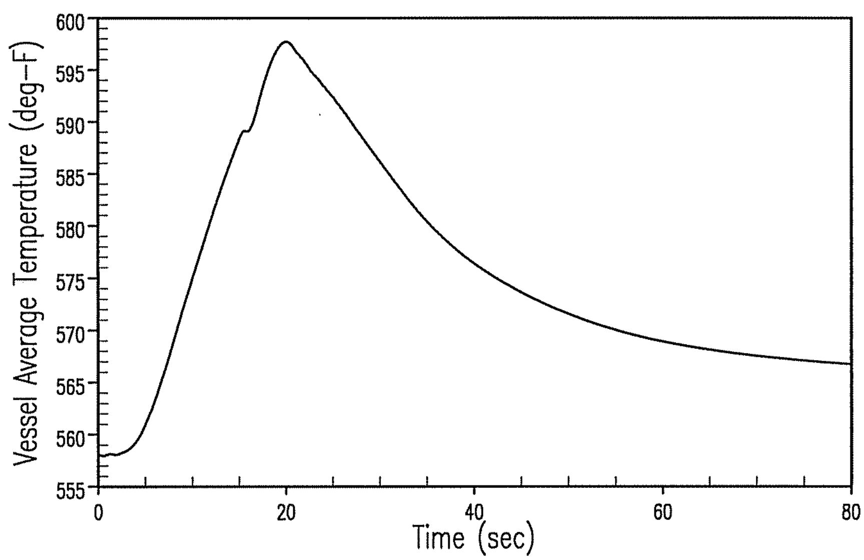
Pressurizer Water Volume - Unit 1
Overpressure Case with Second Reactor Trip Signal Credited



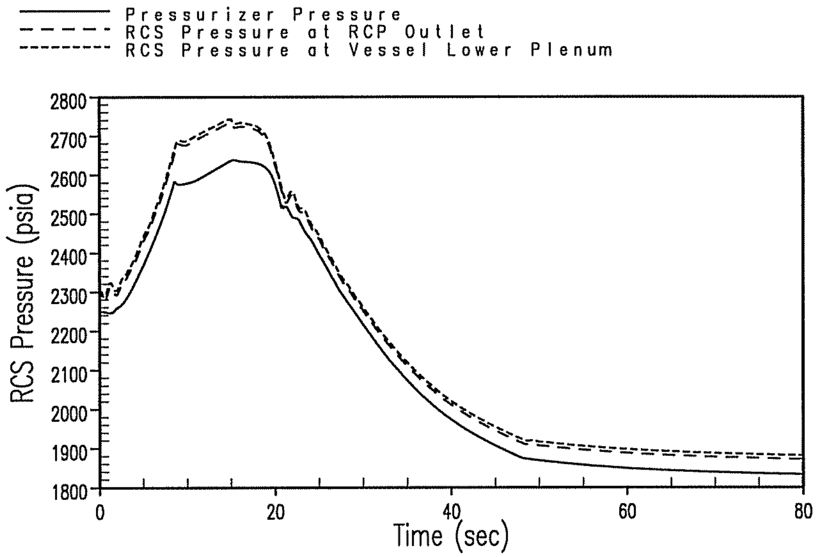
Steam Generator Pressure - Unit 1
Overpressure Case with Second Reactor Trip Signal Credited



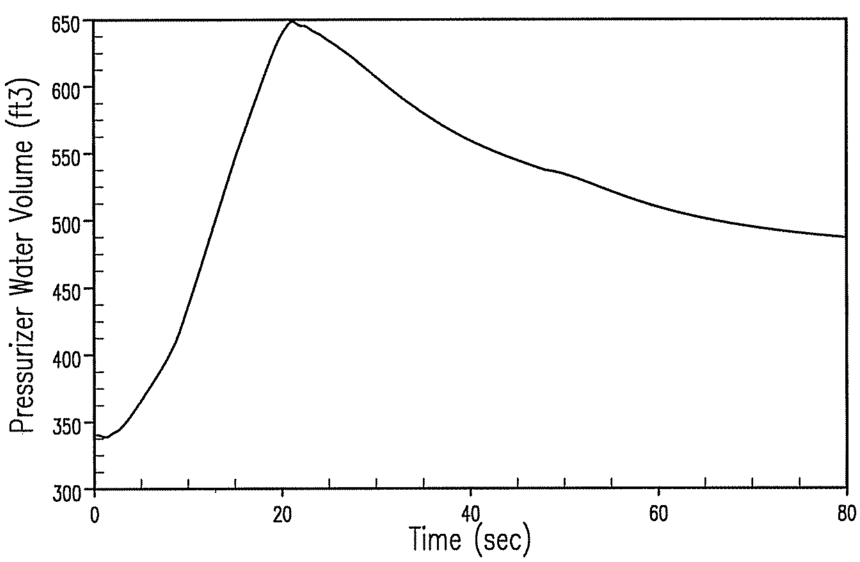
Nuclear Power - Unit 2
Overpressure Case with Second Reactor Trip Signal Credited



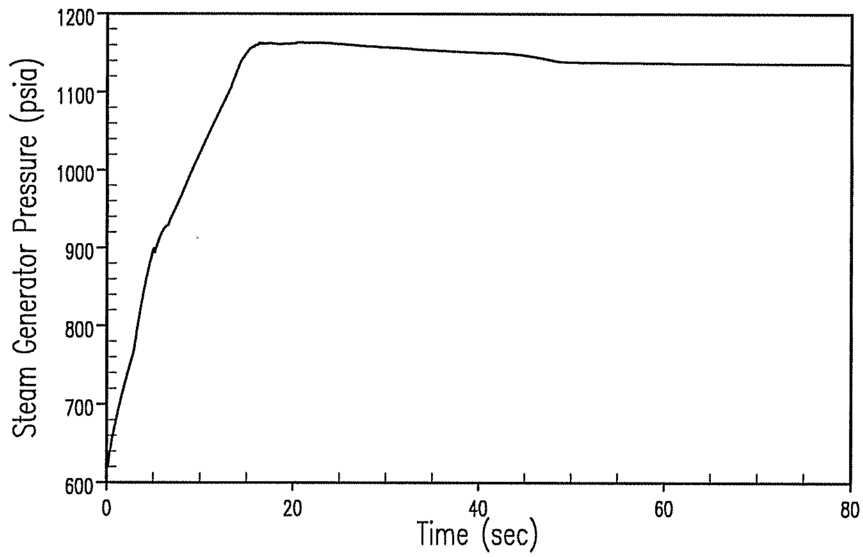
Vessel T_{avg} - Unit 2
Overpressure Case with Second Reactor Trip Signal Credited



RCS Pressure - Unit 2
Overpressure Case with Second Reactor Trip Signal Credited



Pressurizer Water Volume - Unit 2
Overpressure Case with Second Reactor Trip Signal Credited



Steam Generator Pressure - Unit 2
Overpressure Case with Second Reactor Trip Signal Credited

2. The calculation method presented in Westinghouse NSAL-94-001 (Reference 9) and contained in Attachment 1 of NRC Information Notice 94-60 (Reference 10) was used to determine the maximum allowable power level associated with one or more MSSVs inoperable. This method is consistent with that used to determine the values currently presented in PBNP Technical Specification (TS) Table 3.7.1-1.

2.8.5.1.1.2.3, Increase in Steam Flow

1. *Section 2.8.5.1.1.2.3.1, Introduction, states that, "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." In the analyses of this event, the various available reactor trips are conservatively not credited. Do the analysis results indicate that any of the reactor trip setpoints would be reached?*

NextEra Response

A review of the computer simulation runs performed in the analysis of this event confirms that the various reactor trip functions available for this event would not be actuated, as the respective safety analysis setpoints would not be reached.

2.8.5.0, Accident and Transient Analyses

1. *Please explain how the accident and transient analyses account for steady-state uncertainties in the nuclear instrumentation that may accumulate over the 24-hour calorimetric calibration interval.*

NextEra Response

The 24-hour calorimetric comparison to the power range nuclear instrumentation system (NIS) channels required by Surveillance Requirement (SR) 3.3.1.2 is applicable to only the Power Range Neutron Flux - High reactor trip function (Function 2.a in TS Table 3.3.1-1). The associated accident analysis for which this reactor trip is the primary (limiting) trip is the Uncontrolled Rod Withdrawal at Power transient.

Margin has been provided between the Power Range Neutron Flux - High reactor trip setpoint and the upper limit specified in the Uncontrolled Rod Withdrawal at Power transient analyses for the Power Range Neutron Flux - High reactor trip function. This margin accounts for steady-state uncertainties in a power range nuclear instrumentation system (NIS) channel that may accumulate during the 24-hour interval between consecutive performances of SR 3.3.1.2.

Specifically, SR 3.3.1.2 requires adjustment of the NIS channel if the absolute difference between the calorimetric heat balance and the NIS channel output is greater than 2%. The 2% limit is consistent with NUREG 1431 Standard Technical Specifications SR 3.3.1.2. Although plant procedures require adjustment of the NIS channel if the absolute difference is greater than 0.75%, the larger 2% limit allowed by SR 3.3.1.2 will be used in this discussion, for conservatism.

The Uncontrolled Rod Withdrawal at Power transient requires that the Power Range Neutron Flux - High reactor trip occur at 118% of the current full power level, and at 116% of the EPU full power level. The nominal trip setpoint (NTSP) for this function is 107%. Therefore, the margin provided between the NTSP and the Analytical Limit is (118% – 107%) = 11% for current power and (116% – 107%) = 9% for EPU.

The setpoint calculation for the Power Range Neutron Flux - High reactor trip function determined that the Limiting Trip Setpoint (LTSP) that is offset from the Analytical Limit by the total loop uncertainty is 111.61% at current power and 109.61% at EPU. The margin provided between the LTSP and the NTSP is (111.61% – 107%) = 4.61% for current power and (109.61% – 107%) = 2.61% for EPU.

Because available margin between the calculated LTSP and the NTSP for both current and EPU conditions exceeds the 2% limit allowed by SR 3.3.1.2, the Power Range Neutron Flux - High reactor trip function will support the reactor trip assumption of the Uncontrolled Rod Withdrawal at Power transient analysis, even if a maximum allowed 2% NIS channel uncertainty existed over the 24-hour surveillance interval.

2.8.5.1.2, Steam System Piping Failures Inside and Outside Containment

1. *Tables 2.8.5.1.2-1 and 2.8.5.1.2-1 indicate that the time at which the safety injection signal is generated depends upon steamline pressure; but the time at which borated water enters the core depends upon the reactor coolant system pressure. There is a short time, about two seconds, during which the SI pumps are operating at full speed; but not delivering any flow to the reactor coolant system. How long can these pumps operate in this manner before they sustain some damage?*

2. *Tables 2.8.5.1.2-1 and 2.8.5.1.2-1 indicate the sequences of events for the maximum steamline break size in both units. What are the sequences of events for smaller break sizes, or breaks with entrainment, during which the low steamline pressure SI signal would still be expected to be generated relatively early; but the reactor coolant system depressurization would progress more slowly, such that the time the SI pumps operate without delivering flow would be prolonged?*

3. *Expand the response to Question 2 to address system effects in general, such as the rate of SI delivery with respect to the reactor coolant system depressurization upon the analysis results.*

NextEra Response

1. The system is designed with the expectation that the SI pumps will at times operate when the RCS pressure is above the shutoff head of the pumps. As described in Section 6.2 of the PBNP FSAR (page 6.2-11), under the heading "Safety Injection Pumps":

   " ... A minimum flow bypass line is provided on each pump discharge to recirculate flow to the refueling water storage tank in the event the pumps are started under low flow or shutoff head conditions. The minimum flow line must be available for the Safety Injection pumps to be considered operable because some accidents and transients for which Safety Injection is required do not result in sufficient injection flow to provide adequate pump cooling. ..."

   These pumps can operate continuously with the minimum flow path provided by the system design

2. In general, the sequence of events for smaller break sizes or breaks with entrainment would be the same or similar to that of the double-ended rupture case analyzed, but with different times. Steam line breaks smaller than the maximum double-ended rupture case would result in slower RCS depressurization. The time during which the SI pumps operate without injecting may be increased, depending on the time of SI actuation, whether from High-high steam line flow coincident with low steam line pressure (relatively large breaks) or from low pressurizer pressure (smaller breaks). The system, however, is designed to operate under these conditions without damage to the pumps, as described above.

3. The SI flow rate is a function of the RCS pressure, so the amount of borated water injected as a function of time depends on the rate of RCS depressurization. A smaller steam line break results in a slower RCS cooldown and depressurization. This results in a slower increase in core reactivity due to moderator feedback, which delays return to power, if any, and decreases the subsequent rate and severity of the core power increase. Smaller steam line breaks may result in a later SI actuation on low pressurizer pressure and slower SI delivery, with no steam line isolation if the high-high steam line flow coincident with low steam line pressure actuation logic is not satisfied. However, as described in the response to the follow-up to Question 2.8.5.1-6c, the peak core heat flux and core peaking factors for these smaller break cases are not as severe as for the large double-ended rupture design basis case presented, which remains bounding for minimum DNBR and peak kW/ft.

2.8.5.2.1, Loss of External Electrical Load, Turbine Trip, and Condenser Vacuum

1. *Table 2.8.5.2.1-2 indicates that the peak reactor coolant system pressures, attained in the loss of load analyses that are based upon the proposed EPU conditions (2739.6 psia for Unit 1 and 2745.3 for Unit 2), are lower than the corresponding peak reactor coolant system pressures that are based upon the current licensed power level conditions (2741.9 for Unit 1 and 2747.5 for Unit 2). Please explain why the calculated peak reactor coolant system pressures are lower when the proposed EPU conditions are applied.*

NextEra Response

As discussed in the last paragraph of Licensing Report Section 2.8.5.2.1.2.4, to meet the applicable primary side pressure limit for the proposed EPU, the positive PSV setpoint tolerance was reduced from the pre-EPU value of +3 percent to a value of +2.5 percent for the proposed EPU. 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 proposed EPU, and the safety analysis signal delay time was reduced from the pre-EPU maximum value of 2.0 seconds to a maximum value of 1.0 second for the proposed EPU.

As a result of these changes, there was enough analysis margin generated to not only offset the increase in power associated with the proposed EPU, but to also gain a small amount of analysis margin compared to the applicable primary side pressure limit (2748.5 psia). Specifically, with these changes, the peak RCS pressures attained in the LOL/TT analyses performed at the proposed EPU conditions (2739.6 psia for Unit 1 and 2741.9 psia for Unit 2) are slightly lower than those calculated in the analyses based on the current licensed power level (2745.3 psia for Unit 1 and 2747.5 psia for Unit 2). Therefore, these changes result in enough analysis margin to offset the increase in power associated with the proposed EPU and still gain 5.7 psi of analysis margin for Unit 1 and 5.6 psi of analysis margin for Unit 2.

2.8.5.2.2, Loss of Non-Emergency AC Power to the Station Auxiliaries

1. *One would expect that, after operating at the higher EPU power level, there would be more decay heat to be removed by the auxiliary heat removal system during a Loss of Non-Emergency AC Power to the Station Auxiliaries. Consequently, the pressurizer water level would be expected to swell to a higher level than that for the same AOO, analyzed under pre-EPU conditions. Please explain why lower peak pressurizer water volumes are calculated for the EPU Loss of Non-Emergency AC Power to the Station Auxiliaries than for the pre-EPU Loss of Non-Emergency AC Power to the Station Auxiliaries (see Table 2.8.5.2.2-2).*

NextEra Response

The consequences of a loss of normal feedwater (for both with and without offsite power conditions) would be more limiting at the EPU power level than at current operating power level. However, as part of the EPU, several modifications related to the auxiliary feedwater (AFW) system have been proposed. As applicable, these plant modifications have been accounted for in the transient analysis models used for this event. Most notably, the minimum AFW flow available for the event was increased, and the delay time for AFW flow initiation was reduced.

The table below summarizes the impact on key analysis input changes that resulted from the AFW system modifications.

Regarding the five AFW-related input parameters listed in the table below, the directions of conservatism are as follows: minimum for Low-Low Steam Generator Water Level (LLSGWL) AFW actuation setpoint, minimum for AFW flow rate, maximum for AFW temperature, maximum for AFW purge volume, and maximum for AFW actuation delay. Based on these directions of conservatism, the comparison shown below demonstrates that the AFW-related input parameter values used in the EPU LONF and LOAC analyses are bounded by (i.e., less limiting than) or equivalent to those of the current LONF and LOAC analyses. Therefore, the use of these revised values for these critical input parameters in the EPU analyses of this event help demonstrate that the conservative acceptance criterion of preventing pressurizer filling during this event is satisfied at the proposed EPU power rating. In fact, the analysis margin gained through the use of these revised inputs more than offsets the analysis margin lost due to the increased power for the LOAC cases (both units) and one of two LONF cases (Unit 2); the LONF results for Unit 1 are still slightly more limiting at EPU conditions.

Comparisons of Key Input Parameter Values for LONF and LOAC Analysis

Key Input Parameter	Current LOAC/LONF Analysis	EPU LOAC Analysis	EPU LONF Analysis
Low-Low Steam Generator Water Level (LLSGWL) AFW Actuation and Reactor Trip Setpoint, %NRS	17	20	
AFW Flow Rate, gpm	200	275	
AFW Temperature, °F	120	100	
AFW Purge Volume, ft^3	20	20	
AFW Actuation Delay, seconds after reaching LLSGWL	300	60(1), 60-90(2), 90-150(3)	30(1), 30-60(2), 60-120(3)

(1)AFW flow is initiated.
(2)AFW flow ramps from 0% to 80% of full flow.
(3)AFW flow ramps from 80% to 100% of full flow.

2.8.5.2.3, Loss of Normal Feedwater Flow

1. *One would expect that, after operating at the higher EPU power level, there would be more decay heat to be removed by the auxiliary heat removal system during a Loss of Normal Feedwater Flow. Consequently, the pressurizer water level would be expected to swell to a higher level than that for the same AOO, analyzed under pre-EPU conditions. Please explain why a lower peak pressurizer water volume is calculated for the Unit 2 EPU Loss of Normal Feedwater Flow than for the pre-EPU Unit 2 Loss of Normal Feedwater Flow (see Table 2.8.5.2.3-2).*

NextEra Response

See response to RAI 2.8.5.2.2 above.

2.8.5.3.2, Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break

1. *Explain why the analysis results for the locked rotor event, as listed in Table 2.8.5.3.2-2, Results for Single RCP Locked Rotor and Comparison to Previous Results, are less limiting at EPU conditions than the results for current conditions.*

NextEra Response

The less limiting results listed in Table 2.8.5.3.2-2 for the EPU conditions are due to the use of the USNRC-approved Westinghouse advanced 3D neutron kinetics (RAVE^{TM}) methodology (WCAP-16259, Reference 11). The previous results corresponding to current (pre-EPU) conditions were based on a more conservative point kinetics methodology. The main difference is due to the nuclear power response. WCAP-16259 contains comparisons of the nuclear power responses for both methodologies for a sample plant.

2.8.5.5, Inadvertent Operation of Emergency Core Cooling System and Chemical and Volume Control System Malfunction that Increases Reactor Coolant Inventory

1. *How many minutes does the operator have, beginning at the time the first safety-grade alarm is received or the reactor is tripped (whichever comes first), to diagnose a Chemical and Volume Control System (CVCS) malfunction, and prevent the filling of the pressurizer due to excessive or unplanned charging? Assume the charging rate that would develop as the result of a single failure or operator error. How is this time interval determined?*

2. Verify, by simulator testing or by other means, that the operators will prevent the filling of the pressurizer, due to excessive charging caused by a CVCS malfunction, within the time interval determined in (1) above.

NextEra Response

1. PBNP annunciators are not safety grade. The two non-safety grade alarms available to alert operators of increasing pressurizer level are:

   - Pressurizer high level deviation alarm on level of 5% above pressurizer program level. Under EPU conditions at full load T_{avg} of 577°F, the pressurizer program high level limit is 47.0% of pressurizer level span. The corresponding high level deviation alarm for EPU conditions at full load T_{avg} of 577°F is 52% of pressurizer level span.

   - Pressurizer high level alarm at 70% of pressurizer level span. The corresponding times for the operator to respond to a chemical and volume control (CVCS) system malfunction to prevent filling the pressurizer are as follows:

   - Alarm at 52% of pressurizer level span:

   - The nominal steam volume in the pressurizer is 415 ft^3 at 52% of pressurizer level span. As stated in LAR 261, Attachment 5, Section 2.8.5.5, Inadvertent Operation of Emergency Core Cooling System and Chemical and Volume Control System

Malfunction that Increases Reactor Coolant Inventory, on Page 2.8.5.5-3, the chemical and volume control system (CVCS) contains three positive displacement charging pumps which can deliver a maximum total flow of 181.5 gpm (60.5 gpm per pump). PBNP normally operates with two charging pumps running; one pump in auto and one in manual. Assuming the two operating charging pumps are pumping maximum flow, the minimum time to fill the pressurizer for two pump operation is:

$$\frac{415\ ft^3\ \times\ 7.48\ gallons/ft^3}{121\ gallons/minute} = 25.6\ minutes$$

- Alarm at 70% of pressurizer level span:

- The nominal steam volume in the pressurizer is 260 ft^3 at 70% of pressurizer level span. Assuming the two operating charging pumps are pumping maximum flow, the minimum time to fill the pressurizer for two pump operation is:

$$\frac{260\ ft^3\ \times\ 7.48\ gallons/ft^3}{121\ gallons/minute} = 16.0\ minutes$$

- The reactor trip setpoint on high pressurizer level is 80% of level span. The nominal steam volume in the pressurizer is 175 ft^3 at 80% of pressurizer level span. Assuming the two operating charging pumps are pumping maximum flow, the minimum time to fill the pressurizer for two pump operation is:

$$\frac{175\ ft^3\ \times\ 7.48\ gallons/ft^3}{121\ gallons/minute} = 10.8\ minutes$$

2. In response to RAI IHPB HF-1, NextEra letter dated April 29, 2010 (Reference 12) provided a description of the requirements for verification and validation of the emergency operating procedures and abnormal operating procedures.

References

(1) NRC Electronic Mail to NextEra Energy Point Beach, LLC, dated April 16, 2010, Draft-Request for additional Information from Reactor Systems RE: Extended Power Uprate- Round 3 (ML101060302)

(2) FPL Energy Point Beach, LLC letter to NRC, dated April 7, 2009, License Amendment Request 261, Extended Power Uprate (ML091250564)

(3) NextEra Energy Point Beach, LLC letter to NRC, dated January 13, 2010, License Amendment Request 261, Extended Power Uprate, Response to Request for Additional Information (ML100140163)

(4) NRC letter to NextEra Energy, dated December 22, 2009, Point Beach Nuclear Plant, Units 1 And 2 -Request For Additional Information From Reactor Systems Branch Re: Extended Power Uprate (TAC Nos. ME1044 and ME1045) (ML093500203)

(5) WCAP-9226-P-A, Revision 1 (Proprietary), Reactor Core Response to Excessive Secondary Steam Releases, February 1998.

(6) WCAP-14882-P-A (Proprietary), “RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses,” April 1999.

(7) WCAP-8822, Mass and Energy Releases Following a Steamline Rupture, September 1976. [SER: Letter from Cecil O. Thomas (NRC), Acceptance for Referencing of Licensing Topical Report WCAP-8821 (P) / 8859 (NP), TRANFLO Steam Generator Code Description, and WCAP-8822 (P) / 8860 (NP), Mass and Energy Release Following a Steam Line Rupture, August 1983.

(8) Westinghouse Nuclear Safety Advisory Letter NSAL-07-10, Loss-of-Normal Feedwater/Loss-of-Offsite AC Power Analysis PORV Modeling Assumptions, November 7, 2007

(9) Westinghouse Nuclear Safety Advisory Letter NSAL-94-001, Operation at Reduced Power Level with Inoperable MSSVs, January 20, 1994.

(10) NRC Information Notice 94-60, Potential Overpressurization of the Main Steam System, August 22, 1994.

(11) WCAP-16259-P-A (Proprietary) and WCAP-16259-NP-A (non-Proprietary), Westinghouse Methodology for Application of 3-D Transient Neutronics to Non-LOCA Accident Analysis, August 2006.

(12) NextEra Energy Point Beach, LLC letter to NRC, dated April 29, 2010, License Amendment Request 261, Extended Power Uprate, Response to Request for Additional Information (ML101190456)