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Sent: Friday, April 16, 2010 10:43 AM
To: Hale, Steve; COSTEDIO, JAMES
Subject: Draft - Request for Additional Information from Reactor Systems RE:
Extended Power Uprate - Round 3

Steve

By letter to the U.S. Nuclear Regulatory Commission (NRC) dated April 7, 2009 (Agencywide Documents Access and Management System Accession No. ML091250564), FPL Energy Point Beach, LLC, submitted a request to increase each unit's licensed core power level from 1540 megawatts thermal (MWt) to 1800 MWt reactor core power, and revise the technical specifications to support operation at this increased core thermal power level.

The Reactor Systems Branch has reviewed the information provided, and determined that in order to complete its evaluation, additional information is required. We would like to discuss the questions, in draft form below, with you in a conference call.

This e-mail aims solely to prepare you and others for the proposed conference call. It does not convey a formal NRC staff position, and it does not formally request for additional information.

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DRAFT

**Round 1 RAI (Expedited Review) re PBNS EPU Application**

**Question 2.8.5.1-1**

*How were the limiting break sizes, 0.59 ft<sup>2</sup> (Unit 1) and 0.63 ft<sup>2</sup> (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 PBNS 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<sup>2</sup> to 1.4 ft<sup>2</sup>, where the maximum value is based on the steam generator exit nozzle flow restrictor flow area. In the PBNS 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 PBNS units corresponds to the case that reaches the highest peak core average heat flux, as this will yield the most limiting DNBR and kW/ft results for the event. Based on

this, a break size of 0.59 ft<sup>2</sup> was found to be the most limiting for Unit 1, while a 0.63 ft<sup>2</sup> 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?

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 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 lbrn. 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<sup>2</sup> 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 lbrn of steam is released by that time?

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.

#### 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 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 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), 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].

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.

**Round 3 RAI re PBNS EPU Application**

**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 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).

**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?

#### **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.

#### **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 boroated 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.

#### **2.8.5.2.1 Loss of External Electrical Load, Turbine Trip, and Loss of 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.

#### **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).

#### **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).

#### **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.

#### **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.

#### **REFERENCES**

- [1] FPL Energy Point Beach, LLC letter to NRC, dated April 7, 2009, License Amendment Request 261, Extended Power Uprate (ML091250564)
- [2] NRC letter to NextEra Energy Point Beach, LLC, 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)
- [3] WCAP-9226-P-A, Revision 1 (Proprietary), "Reactor Core Response to Excessive Secondary Steam Releases," February 1998.

- [4] Nuclear Safety Advisory Letter NSAL-07-10, Loss-of-Normal Feedwater/Loss-of-Offsite AC Power Analysis PORV Modeling Assumptions, November 7, 2007 (enclosed with [2] above)