NEXTera ENERGY POINT BEACH

January 13, 2011

NRC 2011-0003
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 letter to NextEra Energy Point Beach, LLC, dated November 18, 2010, Point Beach Nuclear Plant, Units 1 and 2 - Request for Additional Information Re: License Amendment Request (LAR-261) Associated with Extended Power Uprate (TAC Nos. ME1044 and ME1045) (ML103200066)
(3) NextEra Energy Point Beach, LLC letter to NRC, dated December 1, 2010, License Amendment Request 261, Extended Power Uprate, Response to Request for Additional Information (ML103360147)
(4) NRC electronic mail to NextEra Energy Point Beach, LLC, dated December 22, 2010, Point Beach Nuclear Plant, Units 1 and 2 - EPU SGTR Review Resolution Plan (TAC Nos. ME1044 and ME1045) (ML103570332)
(5) NRC electronic mail to NextEra Energy Point Beach, LLC, dated December 30, 2010, Point Beach Nuclear Plant, Units 1 and 2 - Request for Additional Information (SRXB) re: EPU Review (TAC Nos. ME1044 and ME1045) (ML110120386)

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 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 is required to enable the staff's continued review of the request. NextEra responded to the request for additional information in Reference (3). Via References (4) and (5), the NRC determined that additional clarification was needed for NextEra's Reference (3) response. Enclosure 1 provides the NextEra response to the NRC staff's request for clarification.

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 January 13, 2011.

Very truly yours,

NextEra Energy Point Beach, LLC

FOR

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 1

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 the review of License Amendment Request (LAR) 261, Extended Power Uprate (EPU) (Reference 2). NextEra Energy Point Beach, LLC (NextEra) responded to the request for additional information in Reference (3). Via Reference (4), the Reactor Systems Branch determined that additional information was required. Following a NRC desk audit conducted at Westinghouse's Rockville, Md. Offices on December 29, 2010, the information request in Reference (4) was revised by Reference (5). The following information is provided by NextEra in response to the NRC staff's request for clarification.

Question 1

Under loss of offsite power (LOOP) conditions, identify the sources of power that plant personnel would use to operate each atmospheric dump valve (ADV), including the control room switches and the valve operator in order to regulate instrument air to open and close the valve, and provide indication of the position of the valve.

NextEra Response

The atmospheric dump valve (ADV) controls are powered from 120 V instrumentation (battery backed) AC buses. The ADV position indication lights are powered from 125 V DC vital buses, which are powered from safety-related batteries D05 and D06.

The ADVs require air to operate remotely from the control room. The ADVs receive air from the instrument air (IA) system headers, which supply air to both Unit 1 and 2 ADVs. There are two compressed air systems that supply air plant-wide; the IA system and the service air (SA) system. The SA system is normally cross-tied to supply the IA system automatically or manually.

The IA compressors are powered from the safety-related 480 V AC buses (1B03 and 2B04), which can be powered from emergency diesel generators (EDGs) (G01 and G04). The SA compressors are powered from the safety-related 480 V AC buses (1B04 and 2B04), which can be powered from the EDGs (G03 and G04). On a loss of offsite power (LOOP), the EDGs will automatically restore power to the safeguards buses. If previously operating and stripped by a LOOP, the IA compressors may be manually energized by cycling the control switches in the control room to the off position to reset the breaker, and then to the on position to restart the compressor. This is accomplished from the control room with no field action required.

Question 2

Considering a case where ONLY the air in ONE unit's instrument air receiver is available during a LOOP, assess whether the ADVs can be operated and the amount of time that the ADVs would be available. Consider a conservatively low volume of air available in the instrument air receiver, demands on the instrument air (IA) system any other air-operated equipment aligned to IA at the time, and configuration of the IA system during a LOOP.

NextEra Response

Per Reference (5), a response to Question 2 is no longer required.

Question 3.a

Please provide the following information concerning instrument air (IA) availability under various possible loss of offsite power (LOOP) conditions concurrent with a reactor trip following a steam generator tube rupture (SGTR):

For a LOOP only affecting the unit with the ruptured steam generator, provide information to demonstrate that the IA provided by the unaffected unit's IA compressor provides adequate air supply to meet the demands of both units.

NextEra Response

During normal two-unit full power operation, IA header flow is approximately 365 scfm for both units. Each IA compressor is rated for 553 scfm at 100 psig. A single air compressor runs, loading and unloading, as needed, to supply all of the IA demand for both units, with the second compressor in automatic backup mode.

A unit trip results in a net long-term reduction in IA demand due to various air-operated valves (e.g. main feedwater regulating valves, turbine governor valves, temperature control valves on turbine lubricating oil coolers) closing. However, if a safety injection (SI) occurs, as expected for a steam generator tube rupture (SGTR), there will be a short-term additional load due to recharging the accumulators for the new feedwater isolation valves (FIVs) on the affected unit. This additional load is approximately 174 scfm total for the two FIVs, and will decrease as the accumulators charge.

For the single unit LOOP scenario, the IA compressor powered from a safety-related bus associated with the affected unit will be stripped from its 480 V AC safety-related bus. The other IA compressor will automatically provide IA powered by the unaffected units 480 V AC safety-related bus.

The remaining IA compressor has adequate capacity to handle both the normal loads for one unit and the loads following a loss of power to a tripped unit experiencing a SGTR and accompanying SI.

Question 3.b

For a LOOP affecting both units, describe the procedural evolution through which the crew operating the SGTR-unaffected unit would be proceeding. Identify the applicable procedure, the step, and at what time the crew operating the SGTR-unaffected unit would take steps to ensure the availability of IA.

NextEra Response

For the assumption of a SGTR concurrent with a LOOP affecting both units, the unit unaffected by the SGTR would execute Steps 1 through 4 of emergency operating procedure EOP-0, "Reactor Trip or Safety Injection," and then transition to EOP-0.1, "Reactor Trip Response." The most immediate indication of a problem with IA would be identified by the instrument air header pressure low alarm which is backlit in green to provide additional prompt recognition and differentiation from other alarms that may be experienced. Actions for restoration of IA are specified in the alarm response procedure for this alarm. As the event progresses, a problem with IA and/or operation of the ADVs may be identified at Step 1 of EOP-0.1, which requires verification of reactor coolant system (RCS) temperature control. Further in the procedure, Step 6.d requires verification that at least one IA compressor is running, and if not, restoration of IA per abnormal operating procedure AOP-5B, "Loss of Instrument Air," is specified. Both of these steps occur early in the procedure to ensure availability of IA for both units, and well before the ADV on the unaffected steam generator for the affected unit is needed.

It is anticipated that restoration of IA would be completed in ample time from event initiation to assure IA is available for ADV operation when needed to mitigate the SGTR affected unit. This was shown in the dual unit LOOP simulator demonstration performed for the NRC staff during the site audit on January 6, 2011. NextEra will evaluate establishing a time for restoration of instrument air as a time critical operator action for a dual unit LOOP scenario in accordance with the Operations administrative procedure for control of time critical operator actions.

Question 3.c

Notwithstanding either unit's offsite power availability, but considering instead a loss of IA due to power supply problems, describe the indication of such a loss and the restoration procedure. Address the priority with which IA restoration is carried out, compared with the priority the crew would be using to follow the applicable SGTR response procedures. Include a discussion of any field actions necessary to complete this evolution, or confirm that only control room actions are necessary.

NextEra Response

The following annunciators in the control room provide an indication of problems with the IA and SA systems:

- AIR SYSTEMS COMMON TROUBLE in alarm (CO1A 1-8)
- INSTRUMENT AIR HEADER PRESSURE LOW in alarm (CO1A 1–9)
- SERVICE AIR HEADER PRESSURE LOW in alarm (CO1D 1-1)
- SERVICE AIR RUNNING COMPRESSOR TRIP in alarm (CO1D 2-1)
- INST. AIR RUNNING COMPRESSOR TRIP in alarm (CO1D 2-2)
- SERVICE AIR STANDBY COMPRESSOR START in alarm (C01D 3-1)
- INST. AIR STANDBY COMPRESSOR START in alarm (CO1D 3-2)

As noted in the NextEra response to Question 3.b, the Instrument Air Header Pressure Low alarm is backlit in green to provide additional prompt recognition and differentiation from other alarms that may be experienced.

IA restoration will be performed in accordance with alarm response procedures and AOP-5B. A copy of this procedure, along with copies of the alarm response procedures for the annunciators above, were made available to the NRC staff. The procedures describe specific actions to be taken in response to IA annunciations. Since IA is shared between the two units, either unit's operating staff is able to take action to restore IA. In most cases, it is anticipated that the operator on the unaffected unit would restore IA as a very high priority activity for support of both units.

The IA system is shared between the two units, and either one of the IA compressors can satisfy the air supply demands of both units. Total loss of IA due to power supply problems, with the exception of a dual unit LOOP, is highly unlikely. In the dual unit LOOP scenario, IA is restored from the control room by cycling the IA compressor control switches in the control room to the off position to reset the breaker, and then to the on position to restart the compressor. Additionally, IA is a highly reliable system and is included within the scope of and managed under the Maintenance Rule.

In addition to the IA system, from a defense-in-depth perspective, the SA system has two compressors, either one of which can also satisfy the air supply demands of both units. For the SA compressors, restoration following a dual unit LOOP is accomplished at the local control panel, if either of the IA compressors could not be restored.

Question 3.d

If a loss of IA were to occur, discuss how long the IA compressors would need to run before sufficient air is available to support plant operation in off-normal conditions.

NextEra Response

If all four of the IA and SA compressors become unavailable, and IA pressure is reduced to zero, then one of the air compressors would have to repressurize the system while supplying system demands. It is estimated to take less than five minutes for IA to reach a pressure sufficient to allow normal operation of the ADVs.

Question 3.e

Considering only a unit affected by an SGTR and concurrent LOOP, identify the applicable procedure, step, and Response Not Obtained actions that are carried out that would indicate a problem opening an atmospheric dump valve (ADV). Address why, per the SGTR margin to overfill safety analysis, the particular Response Not Obtained actions would be executed. Discuss the expected time elapsed between reactor trip and execution of this step. Also discuss the troubleshooting process, valve restoration procedures, and whether an operator would proceed to the next step in the applicable EOP before opening the ADVs.

NextEra Response

For a SGTR concurrent with a LOOP on the affected unit, IA would still be available to the ADVs on the affected unit because the IA system is shared between the units. If a total loss of all IA and SA occurs, which would require the loss of all four air compressors, coincident with the SGTR and LOOP, Response Not Obtained (RNO) actions would be relied on to open the ADV on the intact steam generator.

For the case described above, and if not identified sooner via other means, problems with opening an ADV on the intact steam generator may be identified in Step 8 of EOP-0. That step requires that RCS wide range cold leg temperatures be ≤ 547°F and stable.

If the ADV is not functional, decay heat would be rejected automatically via the main steam safety valves (MSSVs). The lowest MSSV setpoint is 1085 psig, corresponding to a saturated steam temperature of 556°F and consistent with the current license basis (CLB). Therefore, the RCS temperature would be no lower than 556°F. This would prompt the operator to go to the RNO column for the step. RNO 1 (low temperature) would not apply. RNO 2 (high temperature not trending lower) directs dumping steam to the condenser (not available) or via the ADVs. Lack of RCS temperature response to an open demand on the valve, closed light indication, loss of IA, and/or loss of control power would prompt the operator to dispatch personnel to take manual local control of the valve to dump steam.

This step (and the RNO) are "continuing action" steps. This means that the direction given continues to apply in all subsequent steps, and that execution of the procedure continues while attempting to establish temperature control. As long as steam generator pressure remains elevated (dumping steam through the MSSVs), the break flow rate from the ruptured generator is reduced to below that predicted by the margin to overfill (MTO) analyses.

If the problem with operation of the ADV is not identified prior to initiating rapid RCS cooldown (Step 11 of EOP-3, "Steam Generator Tube Rupture"), timing from the reactor trip to manual operation of the ADV on the intact steam generator is estimated to be between 20 and 25 minutes. This was demonstrated for the NRC staff during the site audit on January 6, 2011.

The response timing for the SGTR with LOOP and failure of the ADV to open remotely scenario exceeds the timing assumed in the SGTR with LOOP MTO analysis by several minutes. However, there is reasonable assurance that health and safety of the public will be maintained for the following reasons:

- Conservatisms in the MTO analysis such as initial steam generator mass assumptions and application of setpoint uncertainties
- Overfill margin of between 30 ft^3 and 70 ft^3 in the ruptured steam generator for current licensed thermal power (CLTP) and EPU, respectively, and approximately 150 ft^3 is available in the main steam lines
- Dose margins, at least a factor of four to dose acceptance criteria
- The low probability of the scenario occurring
  - Design basis SGTR, with maximum double ended tube rupture flow
  - Dual unit LOOP
  - Loss of all four air compressors

Based on the above, the CLB and EPU MTO analyses are conservatively bounding and provide reasonable assurance that health and safety of the public will be maintained.

Question 4

Considering a case where local manual operation would be required, discuss how the valve is operated locally (i.e., hand-wheel, crank, hooking up auxiliary air, etc.), and provide the location and accessibility of the manual valve operator. Discuss how a person dispatched to operate the valve locally would access the valve. Considering the evolution through the steam generator tube rupture (SGTR) EOPs, indicate when the need for local, manual operation would be identified and how long, following identification of need for local, manual action, it would take for a person to reach the local valve operator and cycle the valve open. Discuss how communication would be established to control the valve position. Discuss the qualification of the person dispatched to operate the valve and whether they have previously demonstrated performance of this task.

NextEra Response

Local manual operation of the ADVs is accomplished by handwheels on the air actuators. The valve stems are horizontal, the hand wheels are in the vertical plane. The valves are well marked and easily accessed with no interferences from adjacent structures and equipment to make manual operation difficult. The valve operators and handwheels are accessible from permanent platforms at El. 85', and local indication of stem position correlating to valve position is provided. This was demonstrated for the NRC staff during the site audit on January 6, 2011.

As requested by the NRC staff during the site audit on January 6, 2011, the following additional information related to the ADVs is provided:

- Flow is over the seat.
- It takes 12 turns to open the valve.
- The rim force required to fully open the valve is 140 lbs. The 140 lbs is a maximum. The ADV valve trim includes a pilot valve which balances the pressures acting on the plug, so once the pilot valve is opened, the forces to open the valve are minimized.
- Technical Specification (TS) Surveillance Requirement (SR) 3.7.4.1 verifies ADV operation by a local manual opening test with the handwheel for each ADV.

The need for manual operation of the ADVs and timing is described in the NextEra response to Question 3.e above. Communication between the control room and the operator at the ADV would be accomplished with portable radios. As demonstrated during the NRC site audit on January 6, 2011, the auxiliary operator (AO) would require approximately two and a half minutes from being instructed to locally open an ADV to reach the ADV at the 85' elevation of the affected unit's facade from the operator station at panel C-59 on primary auxiliary building (PAB) El. 26'.

Considering manual operation of the ADVs is required by certain fire protection scenarios, operations personnel assigned to manually operate the ADVs are qualified and have demonstrated proficiency in this task. On-the-job training (OJT) and an associated task performance evaluation (TPE) to locally operate the atmospheric steam dump control valves is included in the training qualification manual for initial AO training in the PAB. A job performance measure (JPM) to locally operate the atmospheric steam dump control valves is also included in the list of JPMs for final qualification of an AO for PAB watchstanding.

Question 5

Do the ADVs have dedicated air accumulators? If not, has consideration been given to installing such accumulators to improve ADV reliability in LOOP condition?

NextEra Response

The ADVs do not have dedicated air accumulators. The installation of accumulators has not been considered based on the above discussions on the IA and SA configuration and the extremely unlikely event of loss of all IA following a SGTR.

References

(1) NRC letter to NextEra Energy Point Beach, LLC, dated November 18, 2010, Point Beach Nuclear Plant, Units 1 and 2 - Request for Additional Information Re: License Amendment Request (LAR-261) Associated with Extended Power Uprate (TAC Nos. ME1044 and ME1045) (ML103200066)

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(5) NRC electronic mail to NextEra Energy Point Beach, LLC, dated December 30, 2010, Point Beach Nuclear Plant, Units 1 and 2 - Request for Additional Information (SRXB) re: EPU Review (TAC Nos. ME1044 and ME1045) (ML110120386)