POINT BEACH

~~THIS LETTER CONTAINS PROPRIETARY INFORMATION IN ACCORDANCE WITH 10 CFR 2.390~~

September 8, 2010

NRC 2010-0136
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 August 26, 2010, Point Beach Nuclear Plant, Units 1 and 2 - Requests for Additional Additional Associated with Extended Power Uprate (TAC Nos. ME1044 and ME1045) (ML102440095)

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. Enclosure 1 provides the NextEra proprietary response to the NRC staff's request based on input from the Point Beach Nuclear Plant (PBNP) nuclear steam supply system (NSSS) vendor. Upon the removal of Enclosure 1, the balance of this letter may be considered non-proprietary. Enclosure 2 provides the NextEra non-proprietary versions of the Enclosure 1 response. Enclosure 3 provides Westinghouse authorization letter CAW-10-2922 with accompanying affidavit, Proprietary Information notice and Copyright notice that supports Enclosure 1. Enclosure 4 provides the remaining NextEra responses to the NRC staff's request.

The affidavit sets forth the basis on which the information may be withheld from public disclosure by the Commission and addresses with specificity the considerations listed in Paragraph (b)(4) of 10 CFR 2.390.

NextEra requests that the information which is proprietary to Westinghouse be withheld from public disclosure in accordance with 10 CFR 2.390. Correspondence with respect to the copyright or proprietary aspects of the items listed above or the supporting Westinghouse affidavit should reference CAW-10-2922 and should be addressed to J. A. Gresham, Manager, Regulatory Compliance and Plant Licensing, Westinghouse Electric Company, LLC, P.O. Box 355, Pittsburgh, Pennsylvania 15230-0355.

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 September 8, 2010.

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 2

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

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

The NRC staff determined that additional information was required (Reference 1) to enable the Mechanical and Civil Engineering Branch to complete its review of License Amendment Request (LAR) 261, Extended Power Uprate (EPU) (Reference 2). The following information is provided by NextEra Energy Point Beach, LLC (NextEra) in response to the NRC staff's request.

Introduction

By letter to the Nuclear Regulatory Commission (NRC) dated April 2, 2009 (Agencywide Document and Management System Accession No. ML091250564), the licensee of the Point Beach Nuclear Plant (PBNP), Units 1 and 2, NextEra Energy Point Beach, LLC, submitted a license amendment request (LAR), pursuant to the requirements of Title 10 of the Code of Federal Regulations Section 50.90, "Application for Amendment of License or Construction Permit." The LAR proposes to increase the power level of the current Renewed Operating License (OL) to 1,800 megawatts thermal (MWt), approximately 17% above the current licensed thermal power (CLTP) of 1,540 MWt and approximately 18.5% above the Original Licensed Thermal Power (OLTP) of 1,518.5 MWt.

The Mechanical & Civil Engineering Branch staff has reviewed the LAR licensing report (LR) for power uprate. The staff has identified that additional information is needed to complete the review. The staff's request for additional information (RAI) is attached. This request does not include items related to safety-related valves and pumps since review of these components is performed by the Component Integrity, Performance and Testing Branch. Please note that EMCB RAIs related to LR Section 2.2.1, "Pipe Rupture Locations and Associated Dynamic Effects" and Section 2.2.5, "Seismic and Dynamic Qualification of Mechanical and Electrical Equipment", if required, will be submitted via a separate memorandum.

Requests for Additional Information

EMCB RAI 14

For the vessel support, LR Table 2.2.2.3-3 shows fatigue CUF of 0.995 for CLTP to 60 year plant renewed life and [0.842] for post-EPU.

a) *Clarify whether the EPU CUF value of 0.842 is applicable for the 60 year plant renewed life?*

   Note 2 of Table 2.2.2.3-3 states that: "Number 0.842 was calculated using a stress concentration factor (SCF) of 1.5 applied to thermal stresses, as determined from a finite element analysis. The pre-EPU cumulative fatigue usage factor 0.995 applied on overly conservative SCF of 3.27 to the thermal stresses."

b) *Please provide a description which clearly shows how these stress concentration factors have been developed and the geometry that they apply to.*

NextEra Response

a) The EPU CUF value of 0.842 for the external support brackets is applicable for the 60 year plant renewed life.

   Note 2 of Table 2.2.2.3-3 states that: "Number 0.842 was calculated using a stress concentration factor (SCF) of [ ] a,c applied to thermal stresses, as determined from a finite element analysis. The pre-EPU cumulative fatigue usage factor 0.995 applied an overly conservative SCF of [ ] a,c to the thermal stresses."

b) The original stress report (OSR) used SCFs from Figure A.7-1 of U.S. Department of Commerce, Office of Technical Services report PB-151-987, "Tentative Structural Design Basis for Reactor Pressure Vessels and Directly Associated Components." This document was a pre-cursor to the American Society of Mechanical Engineers (ASME) Code. The [ ] a,c SCF was taken directly from the figure and pertains to fillets on a stepped bar subject to tensile loading.

   In the OSR, the [ ] a,c SCF was used to calculate peak stresses at the 1.125 inch fillet juncture at the bottom of the external support bracket and the vessel shell. It was also used to calculate the peak stresses at the compound fillet lower corner junctures of the external support bracket and the vessel shell. The compound fillet lower corner junctures resulted from blending the 1.125 inch fillet and the 2 inch fillet between the sides of the external support bracket bottom plate and the vessel shell. The limiting location for fatigue in the OSR was at one of the compound fillet lower corner junctures. Therefore, the new SCF developed, as described below, was applicable to the same limiting compound fillet lower corner juncture.

The SCF was calculated by applying linear scaling between the thermal peak stresses from a 3-D finite element model versus the reported thermal peak stresses in the OSR. Linear scaling was possible given the method used to calculate the thermal peak stresses (σ_{Peak}) in the OSR. The method used was as follows:

$$\sigma_{Peak} = SCF \times Q$$

where Q is the secondary membrane plus bending stress through the vessel thickness in the region of the limiting compound fillet lower corner juncture. The finite element model geometry and thermal boundary conditions were made to be the same as those considered in the OSR.

A heatup transient and 100% steady-state load case was analyzed using the same thermal boundary conditions and material properties as listed in the OSR. Therefore, the FEA and OSR secondary membrane plus bending stress through the vessel thickness in the region of the limiting compound fillet lower corner juncture will be essentially equivalent. Peak thermal stress in the axial, hoop, and radial directions was recorded and compared to the peak thermal stress (hoop and axial) provided in the OSR. The maximum thermal peak stress ratio was calculated for each time point in the heatup transient and the 100% steady-state load case.

Case	**Peak Stress (FEA) (ksi)**	**Peak Stress (OSR) (ksi)**	**Peak Stress Ratio (FEA/OSR)**	**SCF (FEA)**
Heatup	[ ] a,c	[ ] a,c	[ ] a,c	[ ] a,c
	[ ] a,c	[ ] a,c	[ ] a,c	[ ] a,c
	[ ] a,c	[ ] a,c	[ ] a,c	[ ] a,c
100% Steady-State	[ ] a,c	[ ] a,c	[ ] a,c	[ ] a,c

The SCF was calculated using the following equation:

SCF = Peak Stress Ratio x [ ] a,c

A maximum SCF of [ ] a,c was calculated. The average of all the SCFs in the above table was calculated to be 1.46, but a slightly higher value of [ ] a,c was used in the evaluation. The thermal peak stresses in the OSR were first divided by [ ] a,c and then multiplied by the new [ ] a,c SCF. The [ ] a,c SCF was left on the pressure and external load stresses because the total stress was dominated by the thermal stress. Also, the [ ] a,c SCF calculated was only applicable for thermal loadings, not mechanical loadings. The pressure, thermal and external load stresses were all combined and new total stresses calculated for all transient times. The new total stresses were then evaluated for EPU conditions and the cumulative fatigue usage recalculated producing a final cumulative fatigue usage of 0.842.

EMCB RAI 18

PBNP EPU LAR Section 2.2.2.5.7 predicts a pre-uprate and post-uprate tube wear values for the PBNP Unit 2 SG tubes for 40 years design life and states that: "This amount of wear will not significantly affect tube integrity and is judged to be acceptable." Please indicate the amount of tube wear beyond which the tube structural integrity is considered to be affected and your technical basis for this judgment. In addition, provide the EPU evaluated tube wear for the PBNP Unit 1 SG tubes and the method of evaluation.

NextEra Response

For Unit 2, the post-uprate wear is calculated to be [ ] a,c for the life of the plant. This represents [ ] a,c through-wall wear. Therefore, it is viewed to be acceptable since it is well below the Technical Specification limit of 40% through-wall, and the calculated structural limit is [ ] a,c through-wall. The calculation for the structural limit is contained in LAR 261, Attachment 5, Section 2.1.9, Steam Generator Tube Inservice Inspection.

While wear rates were not specifically calculated for Unit 1, a review of similar steam generator models to the Model 44F steam generators in Unit 1 show that the Unit 2 wear rate results are typical for similar steam generators.

Based on eddy current testing, neither unit shows many tubes (less than 1%) that have demonstrated wear. Using a conservative uprate factor that modified the calculated wear rate for tubes left in service, it is demonstrated that tube integrity will still be maintained in both units until the next scheduled steam generator tube inspection. While the EPU can result in additional tubes exhibiting wear, the number is expected to be acceptable based on the current behavior of the steam generators.

EMCB RAI 24

Please clarify whether the ratio values in Tables 2.2.2.7-2 and 2.2.2.7-3 are for EPU or CLTP and update these tables to show calculated and allowable values from both CLTP and EPU. Note 1 of Table 2.2.2.7-2 indicates that the pressurizer spray nozzle has failed to meet the ASME Section III NB-3222.2 primary plus secondary stress intensity requirement of 3Sm and has been qualified by the alternate rules of the simplified elastic-plastic analysis of sub-paragraph NB-3228.3. If this condition is for stress intensity calculated at EPU conditions, please provide a quantitative summary of the evaluation which shows that the special rules for exceeding 3Sm, as provided by (a) through (f) of sub-paragraph NB-3228.3 have been met. In the requested summary, please show calculated and allowable values and not just ratios, as currently included in the above-mentioned tables.

NextEra Response

The ratio values in Table 2.2.2.7-2 are for current licensed thermal power (CLTP). The EPU did not change the maximum ranges of stress intensity for the pressurizer components.
Table 2.2.2.7-2 is replaced with the following:

Component	Calculated Stress Intensity Range (ksi)	Allowable Stress Intensity Range (ksi)
Spray Nozzle	[ ] c,e (1)	39.60
Upper Head	[ ] c,e	90.00
Surge Nozzle	[ ] c,e	57.90
Safety and Relief Nozzle	[ ] c,e	39.54
Support Skirt and Flange	[ ] c,e	69.30
Lower Head	[ ] c,e	58.20
Heater Well	[ ] c,e	69.90
Manway	[ ] c,e	57.84
Instrument Nozzle	[ ] c,e	57.84
Immersion Heater	[ ] c,e	49.20

NOTE:
(1) Quantity shown is the stress intensity range with thermal bending removed. The range of primary plus secondary stress intensity exceeded the $3S_m$ limit, but this is permitted, provided the rules of NB-3228.3 of the ASME Code are met. Those requirements have been satisfied for this component.

The spray nozzle exceeded the 3Sm limit in the original evaluation. This was not changed by the EPU. The NB-3228.3 requirements were satisfied in the original stress report.

For Table 2.2.2.7-3, the values in the table are for CLTP. They did not change for EPU and are applicable for EPU.

The stress allowable for the pressurizer support anchor bolts is 4.5 ksi and the calculated stress value is [ ] b,c ksi.

EMCB RAI 26

For the RPV internals, as shown in LR Table 2.2.3-3, that exceed the NB-3222.2 primary plus secondary stress intensity requirement of 3Sm at EPU conditions, please provide a quantitative summary of the evaluation which shows that the 3Sm code limit is met when excluding thermal bending stresses and that the remainder of NB-3228.3 requirements (b) through (f) have also been satisfied.

NextEra Response

The components that exceed the NG-3222.2 primary plus secondary stress intensity requirement of 3Sm at EPU conditions from LAR 261, Attachment 5, Table 2.2.3-3 are:

- Upper Core Plate Alignment Pins
- Core Barrel Assembly Upper Girth Weld (UGW)
- Core Barrel Assembly Lower Girth Weld (LGW)
- Lower Radial Restraints – Key Weld

A quantitative summary of these component evaluations are discussed below.

1. Upper Core Plate Alignment Pins

Maximum Stress Intensity (psi)

Transient	Stress Range S_{31}		
	S_{12}	S_{23}	S_{31}
OBE	[ ] a,c	[ ] a,c	[ ] a,c
(UU2+UD2)Range	[ ] a,c	[ ] a,c	[ ] a,c
(NU1+ND1)Range	[ ] a,c	[ ] a,c	[ ] a,c

(Note that the maximum range for mechanical plus thermal stresses < 3Sm; therefore, no elastic-plastic fatigue analysis is required)

Following the maximum transient combinations, the fatigue usage factors are calculated below.

Because these welds are not full-penetration, inspectable welds, a weld quality factor of 4.0 is used per ASME Code.

1. OBE + UU2 + UD2

S_a = [ ] a,c

The corresponding allowable cycles from ASME Code fatigue curve I-9.2-1 are n = [ ] a,c cycles, and the applied number of cycles N = 400. Thus,

U_2 = [ ] a,c

2. UU2 + UD2

S_a = [ ]^{a,c}

The corresponding allowable cycles from ASME Code fatigue curve I-9.2-1 are n = [ ]^{a,c} cycles, and the applied number of cycles N = 280. Thus,

U_3 = [ ]^{a,c}

3. NU1 (1,000 s) + ND2 (80 s)

S_a = [ ]^{a,c}

The corresponding allowable cycles from ASME Code fatigue curve I-9.2-1 are n = [ ]^{a,c} cycles, and the applied number of cycles N = 20,700. Thus,

U_8 = [ ]^{a,c}

Total fatigue usage factor becomes $U = \Sigma U_i$ = [ ]^{a,c} < 1.0

2. Core Barrel Assembly Upper Girth Weld

The summary of peak stress at the outer surface of the UGW is:

Load Condition	σr (psi)	σz (psi)	σy (psi)	Classification
Deadweight	---	---	[ ]^{a,c}	Pm
Core Barrel Deflection	---	---	[ ]^{a,c}	Qb
Pressure Differential	[ ]^{a,c}	[ ]^{a,c}	[ ]^{a,c}	Pm
FIV	---	---	[ ]^{a,c}	Pm
OBE	---	---	[ ]^{a,c}	Pb
Thermal	---	[ ]^{a,c}	[ ]^{a,c}	Q

As the shear stress is zero, the radial, circumferential, and axial stress components are the principal stresses. Then,

σ1 = σr
σ2 = σz
σ3 = σy

The principal stresses from the above table are as follows:

σ1 = [ ]^{a,c}

σ2 = [ ]$^{a, c}$

$\sigma 3$ = [ ] a, c

$\sigma 3$ = [ ] a,c

The stress differences are as follows:

S12 = [ ] a,c

S23 = [ ] a,c

S31 = [ ] a,c

Stress Intensity SI = [ ] a,c > 3Sm = 49,200 psi

Since the 3Sm limit is not satisfied, a simplified elastic-plastic analysis for fatigue must be performed in accordance with Subsection NG-3228.3 of the ASME Code, provided that the requirements of (a) through (f) below are met:

(c) The stress differences are as follows (without thermal):

S12 = [ ] a,c

S23 = [ ] a,c

S31 = [ ] a,c

Stress Intensity SI = [ ] a,c < 3Sm = 49,200 psi (without thermal)

(d) The value of Sa are multiplied by the factor Ke

Ke = 1.0 + (1-n)/n(m-1) ((Sn/3Sm) -1), for 3Sm < Sn < 3*m*Sm

For austenitic steel:

n = [ ] a,c; m = [ ] a,c; 3Sm = 49,200 psi; with Sn = [ ] a,c

Therefore,

Ke = [ ] a,c

Then, the alternating stress, with a weld quality factor of 1.0 according to ASME Code, is as follows:

Salt = [ ] a,c (Sij)
Salt = [ ] a,c

From Figure I-9.2.1 of the ASME Code, the number of allowable cycles corresponding to:

Salt = [ ]^{a,c}

N = [ ]^{a,c} cycles

Consider only 400 OBE cycles, → U1 = [ ]$^{a, c}$

Without seismic, the maximum stress range or stress intensity becomes:

Sn = [ ]^{a,c}

Then,

Salt = [ ]^{a,c}

U2 = [ ]^{a,c}

U = U1 + U2 = [ ]^{a,c} < 1.0

(c) Stays the same and the procedure of NG-3227.6 is not required.

(d) Meets the thermal ratcheting requirement of NG-3222.5 since the maximum allowable range of thermal stress (y') calculated on the elastic basis is greater than the calculated value of [ ]^{a,c} psi:

y' = [ ]^{a,c}
[ ]^{a,c}
[ ]^{a,c}
x = [ ]^{a,c}
y' = [ ]^{a,c}

$y' = (\sigma)_{tensile\text{-}thermal} / (\sigma)_{yield}$; and $x = Pm / (\sigma)_{yield}$

Then,

$(\sigma)_{tensile\text{-}thermal}$ = [ ]^{a,c} > [ ]^{a,c}

(e) Satisfied since the temperature does not exceed 700°F.

(f) Satisfied since Sy/Su = [ ]^{a,c} < 0.8

3. Core Barrel Assembly Lower Girth Weld

Summary of peak stress at the outer surface of the LGW (2) is as follows:

Load Condition	σr (psi)	σz (psi)	σy (psi)	Classification
Deadweight	---	---	[ ] a,c	Pm
Core Barrel Deflection	---	---	[ ] a,c	Qb
Pressure Differential	[ ] a,c	[ ] a,c	[ ] a,c	Pm
FIV	---	---	[ ] a,c	Pm
OBE	---	---	[ ] a,c	Pb
Thermal	---	[ ] a,c	[ ] a,c	Q

As the shear stress is zero, the radial, circumferential, and axial stress components are the principal stresses. Then,

$\sigma 1 = \sigma r$
$\sigma 2 = \sigma z$
$\sigma 3 = \sigma y$

Following the above procedure, principal stresses from the above table are:

$\sigma 1$ = [ ] a,c

$\sigma 2$ = [ ] a,c

$\sigma 3$ = [ ] a,c

The stress differences are as follows:

S12 = [ ] a,c

S23 = [ ] a,c

S31 = [ ] a,c > 3Sm = 49,200 psi

Since the 3Sm limit is not satisfied, a simplified elastic-plastic analysis for fatigue must be performed in accordance with Subsection NG-3228.3 of the ASME Code provided that the requirements of (a) through (f) below are met:

(c) The stress differences are as follows (without thermal):

The principal stresses from the above table are as follows:

$\sigma 1$ = [ ] a,c

$\sigma 2$ = [ ] a,c

$\sigma 3$ = [ ]^{a,c}

The stress differences are as follows:

S12 = [ ]^{a,c}

S23 = [ ]^{a,c}

S31 = [ ]^{a,c} < 3Sm = 49,200 psi

(d) The Sa value is multiplied by factor Ke

Ke = [ ]^{a,c}

Then, the alternating stress, Salt = ½ x 1.32 x Max |(Sij)|

Salt = [ ]^{a,c}

From Figure I.9-2 of the ASME Code, the number of allowable cycles corresponding to:

Salt = [ ]^{a,c}

N = [ ]^{a,c} cycles

Consider the umbrella (U) cycles for Normal + Upset is 21,380 cycles,

U = [ ]^{a,c} < 1.0

(c) Stays the same and the procedure of NG-3227.6 is not required.

(d) Meets the thermal ratcheting requirement of NG-3222.5, since the maximum allowable range of thermal stress (y') calculated on the elastic basis is greater than the calculated value of [ ]^{a,c} psi:

y' = [ ]^{a,c}
[ ]^{a,c}
[ ]^{a,c}
x = [ ]^{a,c}
y' = [ ]^{a,c}

$y' = (\sigma)_{tensile\text{-}thermal} / (\sigma)_{yield}$; and $x = Pm/(\sigma)_{yield}$

Then,

$(\sigma)_{tensile\text{-}thermal}$ = [ ]^{a,c} > [ ]^{a,c}

(e) Satisfied since the temperature does not exceed 700°F

(f) Satisfied since Sy / Su = [ ]^{a,c} < 0.8

4. Lower Radial Restraints – Key Weld

For the Lower Radial Restraints – Key weld, a revision to the stress calculations was performed for EPU conditions subsequent to submittal of LAR 261. The calculation revision indicates that the "After EPU" stress intensity no longer exceeds the 3Sm allowable with a 0.7 weld quality factor for primary-plus-secondary stress intensity, as required by NB-3222.2. By copy of this request for additional information (RAI) response, the values for the Lower Radial Restraints - Key Weld "After EPU" and allowable stress intensities presented in Table 2.2.3-3 of Attachment 5 to LAR 261 are replaced with the following:

After EPU Stress Intensity ($P_m + P_b + Q$) = [ ] [a,c] ksi
Allowable Stress Intensity ($3S_m$)*(0.7) = 35.6 ksi

<u>Conclusion</u>

Based on the quantitative information provided above, these components are within the allowable limits of Subsection NG of the 1998 Edition of the ASME Code Section III, Division I, including 2000 Addenda and, therefore, are acceptable.

<u>References</u>

(1) NRC electronic mail to NextEra Energy Point Beach, LLC, dated August 26, 2010, Point Beach Nuclear Plant, Units 1 and 2 - Requests for Additional Additional Associated with Extended Power Uprate (TAC Nos. ME1044 and ME1045) (ML102440095)

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

ENCLOSURE 3

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

LICENSE AMENDMENT REQUEST 261
EXTENDED POWER UPRATE

WESTINGHOUSE AUTHORIZATION LETTER, ACCOMPANYING AFFIDAVIT,
PROPRIETARY INFORMATION NOTICE, AND COPYRIGHT NOTICE
CAW-10-2922

7 pages follow

Westinghouse

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Proj letter: WEP-10-93

CAW-10-2922

September 3, 2010

APPLICATION FOR WITHHOLDING PROPRIETARY
INFORMATION FROM PUBLIC DISCLOSURE

Subject: WEP-10-93 P-Attachment, "Point Beach Nuclear Plant Units 1 and 2 – Response to the Request for Additional Information from Civil and Mechanical Engineering Branch Related to License Amendment Request No. 261 Extended Power Uprate (EPU) (TAC Nos. ME 1044 and ME 1045)" (Proprietary)

The proprietary information for which withholding is being requested in the above-referenced report is further identified in Affidavit CAW-10-2922 signed by the owner of the proprietary information, Westinghouse Electric Company LLC. The affidavit, which accompanies this letter, sets forth the basis on which the information may be withheld from public disclosure by the Commission and addresses with specificity the considerations listed in paragraph (b)(4) of 10 CFR Section 2.390 of the Commission's regulations.

Accordingly, this letter authorizes the utilization of the accompanying affidavit by NextEra Energy Point Beach LLC.

Correspondence with respect to the proprietary aspects of the application for withholding or the Westinghouse affidavit should reference this letter, CAW-10-2922, and should be addressed to J. A. Gresham, Manager, Regulatory Compliance and Plant Licensing, Westinghouse Electric Company LLC, P.O. Box 355, Pittsburgh, Pennsylvania 15230-0355.

Very truly yours,

J. A. Gresham, Manager
Regulatory Compliance and Plant Licensing

Enclosures

CAW-10-2922

AFFIDAVIT

COMMONWEALTH OF PENNSYLVANIA:

ss

COUNTY OF ALLEGHENY:

Before me, the undersigned authority, personally appeared J. A. Gresham, who, being by me duly sworn according to law, deposes and says that he is authorized to execute this Affidavit on behalf of Westinghouse Electric Company LLC (Westinghouse), and that the averments of fact set forth in this Affidavit are true and correct to the best of his knowledge, information, and belief:

J. A. Gresham, Manager
Regulatory Compliance & Plant Licensing

Sworn to and subscribed before me
this 3rd day of September 2010

Cynthia Olesky
Notary Public

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Cynthia Olesky, Notary Public
Manor Boro, Westmoreland County
My Commission Expires July 16, 2014
Member, Pennsylvania Association of Notaries

(1) I am Manager, Regulatory Compliance & Plant Licensing, in Nuclear Services, Westinghouse Electric Company LLC (Westinghouse), and as such, I have been specifically delegated the function of reviewing the proprietary information sought to be withheld from public disclosure in connection with nuclear power plant licensing and rule making proceedings, and am authorized to apply for its withholding on behalf of Westinghouse.

(2) I am making this Affidavit in conformance with the provisions of 10 CFR Section 2.390 of the Commission's regulations and in conjunction with the Westinghouse Application for Withholding Proprietary Information from Public Disclosure accompanying this Affidavit.

(3) I have personal knowledge of the criteria and procedures utilized by Westinghouse in designating information as a trade secret, privileged or as confidential commercial or financial information.

(4) Pursuant to the provisions of paragraph (b)(4) of Section 2.390 of the Commission's regulations, the following is furnished for consideration by the Commission in determining whether the information sought to be withheld from public disclosure should be withheld.

(i) The information sought to be withheld from public disclosure is owned and has been held in confidence by Westinghouse.

(ii) The information is of a type customarily held in confidence by Westinghouse and not customarily disclosed to the public. Westinghouse has a rational basis for determining the types of information customarily held in confidence by it and, in that connection, utilizes a system to determine when and whether to hold certain types of information in confidence. The application of that system and the substance of that system constitutes Westinghouse policy and provides the rational basis required.

Under that system, information is held in confidence if it falls in one or more of several types, the release of which might result in the loss of an existing or potential competitive advantage, as follows:

(a) The information reveals the distinguishing aspects of a process (or component, structure, tool, method, etc.) where prevention of its use by any of Westinghouse's competitors without license from Westinghouse constitutes a competitive economic advantage over other companies.

(b) It consists of supporting data, including test data, relative to a process (or component, structure, tool, method, etc.), the application of which data secures a competitive economic advantage, e.g., by optimization or improved marketability.

(c) Its use by a competitor would reduce his expenditure of resources or improve his competitive position in the design, manufacture, shipment, installation, assurance of quality, or licensing a similar product.

(d) It reveals cost or price information, production capacities, budget levels, or commercial strategies of Westinghouse, its customers or suppliers.

(e) It reveals aspects of past, present, or future Westinghouse or customer funded development plans and programs of potential commercial value to Westinghouse.

(f) It contains patentable ideas, for which patent protection may be desirable.

There are sound policy reasons behind the Westinghouse system which include the following:

(a) The use of such information by Westinghouse gives Westinghouse a competitive advantage over its competitors. It is, therefore, withheld from disclosure to protect the Westinghouse competitive position.

(b) It is information that is marketable in many ways. The extent to which such information is available to competitors diminishes the Westinghouse ability to sell products and services involving the use of the information.

(c) Use by our competitor would put Westinghouse at a competitive disadvantage by reducing his expenditure of resources at our expense.

(d) Each component of proprietary information pertinent to a particular competitive advantage is potentially as valuable as the total competitive advantage. If competitors acquire components of proprietary information, any one component may be the key to the entire puzzle, thereby depriving Westinghouse of a competitive advantage.

(e) Unrestricted disclosure would jeopardize the position of prominence of Westinghouse in the world market, and thereby give a market advantage to the competition of those countries.

(f) The Westinghouse capacity to invest corporate assets in research and development depends upon the success in obtaining and maintaining a competitive advantage.

(iii) The information is being transmitted to the Commission in confidence and, under the provisions of 10 CFR Section 2.390, it is to be received in confidence by the Commission.

(iv) The information sought to be protected is not available in public sources or available information has not been previously employed in the same original manner or method to the best of our knowledge and belief.

(v) The proprietary information sought to be withheld in this submittal is that which is appropriately marked in WEP-10-93 P-Attachment, "Point Beach Nuclear Plant Units 1 and 2 – Response to the Request for Additional Information from Civil and Mechanical Engineering Branch Related to License Amendment Request No. 261 Extended Power Uprate (EPU) (TAC Nos. ME 1044 and ME 1045)," (Proprietary) dated September 2010, for submittal to the Commission, being transmitted by NextEra Energy Point Beach LLC letter and Application for Withholding Proprietary Information from Public Disclosure, to the Document Control Desk. The proprietary information as submitted for use by Westinghouse for Point Beach Units 1 and 2 is expected to be applicable for other licensee submittals in response to certain NRC requirements for Extended Power Uprate submittals.

This information is part of that which will enable Westinghouse to:

(a) Provide input to the Nuclear Regulatory Commission for review of the Point Beach EPU submittals.

(b) Provide results of customer specific calculations.

(c) Provide licensing support for customer submittals.

Further this information has substantial commercial value as follows:

(a) Westinghouse plans to sell the use of similar information to its customers for purposes of meeting NRC requirements for licensing documentation associated with EPU submittals.

(b) Westinghouse can sell support and defense of the technology to its customer in the licensing process.

(c) The information requested to be withheld reveals the distinguishing aspects of a methodology which was developed by Westinghouse.

Public disclosure of this proprietary information is likely to cause substantial harm to the competitive position of Westinghouse because it would enhance the ability of competitors to provide similar information and licensing defense services for commercial power reactors without commensurate expenses. Also, public disclosure of the information would enable others to use the information to meet NRC requirements for licensing documentation without purchasing the right to use the information.

The development of the technology described in part by the information is the result of applying the results of many years of experience in an intensive Westinghouse effort and the expenditure of a considerable sum of money.

In order for competitors of Westinghouse to duplicate this information, similar technical programs would have to be performed and a significant manpower effort, having the requisite talent and experience, would have to be expended.

Further the deponent sayeth not.

PROPRIETARY INFORMATION NOTICE

Transmitted herewith are proprietary and/or non-proprietary versions of documents furnished to the NRC in connection with requests for generic and/or plant-specific review and approval.

In order to conform to the requirements of 10 CFR 2.390 of the Commission's regulations concerning the protection of proprietary information so submitted to the NRC, the information which is proprietary in the proprietary versions is contained within brackets, and where the proprietary information has been deleted in the non-proprietary versions, only the brackets remain (the information that was contained within the brackets in the proprietary versions having been deleted). The justification for claiming the information so designated as proprietary is indicated in both versions by means of lower case letters (a) through (f) located as a superscript immediately following the brackets enclosing each item of information being identified as proprietary or in the margin opposite such information. These lower case letters refer to the types of information Westinghouse customarily holds in confidence identified in Sections (4)(ii)(a) through (4)(ii)(f) of the affidavit accompanying this transmittal pursuant to 10 CFR 2.390(b)(1).

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ENCLOSURE 4

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 Mechanical and Civil Engineering Branch to complete its review of License Amendment Request (LAR) 261, Extended Power Uprate (EPU) (Reference 2). The following information is provided by NextEra Energy Point Beach, LLC (NextEra) in response to the NRC staff's request.

Introduction

By letter to the Nuclear Regulatory Commission (NRC) dated April 2, 2009 (Agencywide Document and Management System Accession No. ML091250564), the licensee of the Point Beach Nuclear Plant (PBNP), Units 1 and 2, NextEra Energy Point Beach, LLC, submitted a license amendment request (LAR), pursuant to the requirements of Title 10 of the Code of Federal Regulations Section 50.90, "Application for Amendment of License or Construction Permit." The LAR proposes to increase the power level of the current Renewed Operating License (OL) to 1,800 megawatts thermal (MWt), approximately 17% above the current licensed thermal power (CLTP) of 1,540 MWt and approximately 18.5% above the Original Licensed Thermal Power (OLTP) of 1,518.5 MWt.

The Mechanical & Civil Engineering Branch staff has reviewed the LAR licensing report (LR) for power uprate. The staff has identified that additional information is needed to complete the review. The staff's request for additional information (RAI) is attached. This request does not include items related to safety-related valves and pumps since review of these components is performed by the Component Integrity, Performance and Testing Branch. Please note that EMCB RAIs related to LR Section 2.2.1, "Pipe Rupture Locations and Associated Dynamic Effects" and Section 2.2.5, "Seismic and Dynamic Qualification of Mechanical and Electrical Equipment", if required, will be submitted via a separate memorandum.

Requests for Additional Information

EMCB RAI 1

It is noted that the PBNP EPU licensing report (LR) specifies that the plant design basis code of record for BOP piping analysis is the USAS B31.1 Power Piping Code, 1967 Edition. Please verify and/or identify the code utilized in qualifying nuclear steam supply systems (NSSS) and balance of plant (BOP) piping and pipe supports for EPU conditions. If different from the plant design basis code of record, provide justification and confirm that the calculated values for piping and supports utilized the original code of construction allowable values.

NextEra Response

Balance of Plant (BOP) Piping and Supports

The EPU evaluations for balance of plant (BOP) piping systems were evaluated to the USA Standard (USAS) B31.1 Power Piping Code, 1967 Edition, which is the original code of record for BOP piping systems.

The original code of record for the evaluation of BOP pipe supports is American Institute of Steel Construction (AISC), Manual of Steel Construction, Sixth Edition. Updated revisions to this code can be used provided the requirements and intent stipulated in the original codes of record have been satisfied. The EPU evaluations for BOP pipe supports were evaluated using the AISC code, Sixth Edition, including updated revisions through the Ninth Edition. In the above cases, the requirements and intent stipulated in the alter codes of record have been satisfied.

NSSS (RCS) Piping and Surge Line Thermal Stratification

For the NSSS piping (reactor coolant system (RCS) piping), the Point Beach Nuclear Plant (PBNP) Final Safety Analysis Report (FSAR) Table 4.1-9 states that the code requirement is the USAS B31.1 Power Piping Code and that the version of the Code which was in effect at the time the original component was ordered is applicable. Other sections of the PBNP FSAR (e.g., Section 4.2, page 4.2-14) state that the piping and fittings are designed to the B31.1, 1955 Edition. Based on the review of the existing plant design basis analysis of record (AOR) evaluations and qualifications performed for the steam generator replacement program and fuel upgrade program, NextEra concluded that the American National Standards Institute (ANSI) Code for Pressure Piping, B31.1, 1973 Edition was utilized as the code of record. This is considered acceptable because the equations presented in the 1955 version of the code are identical to the equations presented in the 1973 version of the code. Also, per the note in ANSI B31.1, 1973 Edition, the B31.1, 1967 Edition through B31.1, 1972 Edition, have been revised and consolidated into one publication and re-designated B31.1, 1973 Edition. The PBNP NSSS piping evaluations and qualifications for EPU conditions also utilized the ANSI Code for Pressure Piping B31.1, 1973 Edition, as was used in the existing plant design basis AOR. Therefore, the code of record allowable values used in the existing plant design basis AOR are used for the EPU evaluation.

For the pressurizer surge line, considering only the effects of thermal stratification, the American Society of Mechanical Engineers (ASME) Code, 1986 Edition used is in compliance with NRC Bulletin No. 88-11 (Reference 3) and as documented in LAR 261, Attachment 5, Section 2.2.2.1.2, Input Parameters, Assumptions, and Acceptance Criteria. Reference (3) fatigue analysis should be performed in accordance with the latest ASME Code, Section III requirements incorporating high cycle fatigue. The original code of record for the pressurizer surge line thermal stratification is the ASME Code, Section III, 1986 Edition. For the current licensing basis at PBNP and for EPU conditions, the evaluation of the pressurizer surge line, considering only the effects of thermal stratification, was performed and found to be in compliance with both the NRC Bulletin 88-11 and the original code of record.

RCS Supports (Except Reactor Vessel Supports)

The original code of construction for RCS supports (steam generator (SG), reactor coolant pump (RCP) and pressurizer) was AISC, Sixth Edition. Updated revisions to this code can be used provided the requirements and intent stipulated in the later codes of record have been satisfied.

The existing plant design basis AOR evaluation for PBNP, NSSS supports (SG, RCP and pressurizer) performed during the 1995 and 2001 timeframe (including the RSG program) utilized the AISC, Eighth Edition and ASME Code, Section III, Subsection NF, 1974 Edition as the code of record. The allowable values for AISC, Sixth Edition and the allowable values for AISC, Eighth Edition are comparable. Also, the allowable values for AISC, Eighth Edition and the ASME Code, Section III, Subsection NF, 1974 Edition are comparable. Therefore, the current code of record used in the existing plant design basis AOR is used for the EPU evaluations. In the above cases, the requirements and intent stipulated in the later codes of record have been satisfied.

EMCB RAI 2

Confirm that the reactor coolant system (RCS) piping and supports, components, primary equipment nozzles and supports, associated reactor coolant loop (RCL) branch piping and supports, did not experience an increase in stresses due to the EPU because the existing analysis contains loads which envelop the loads at EPU conditions.

NextEra Response

While the existing analyses remained bounding for some discrete components and supports, several components and supports required re-analyses due to increased or previously unanalyzed loads. The following response discuses each of the groupings of piping, supports, components, and primary equipment, to describe which remained bounded, and those that required new analyses.

For the determination of stresses, the inputs to be considered are loads due to primary system operating pressure, seismic excitation, deadweight, plant operating temperatures and loss of coolant accident (LOCA) forces. Primary system operating pressure does not change, and seismic and deadweight loads are not expected to change under EPU conditions.

However, the PBNP reactor vessel support stiffness was modified which changed the seismic loads. Please refer to the NextEra response to EMCB RAI 16 for further discussion of the revised reactor vessel support modeling. The revised seismic loads were included as part of the various component EPU evaluations as noted in the component responses below.

Plant operating temperatures changed for the EPU (lower T_{cold}, higher T_{hot}), resulting in a change to the thermal inputs to the component, piping and support evaluations. The plant operating temperature changes also revised the loadings associated with the design transients listed in LAR 261, Attachment 5, Table 2.2.6-1. These revised loadings are included in the component EPU evaluations and noted below. Plant operating temperature changes affected the LOCA forces, and the corresponding component and piping LOCA loads and motions for the EPU. The impacts of these changes are discussed below.

NSSS (RCS) Piping

The RCS piping pressure loads, deadweight loads, and seismic excitation did not change from the existing design basis AOR.

The following affected loads were re-evaluated:

- Thermal loads due to changed plant operating temperatures (lower T_{cold} and higher T_{hot})
- RCS piping LOCA forces due to changed operating temperatures
- Reactor pressure vessel (RPV) LOCA forces due to changed operating temperatures
- RPV LOCA displacement due to corrected support structure stiffness

The PBNP design transients (LAR 261, Attachment 5, Table 2.2.6-1) pertain to fatigue design. The RCS piping is designed to USAS B31.1, which does not require fatigue analysis and is therefore unaffected by the changes in design transients.

The revised RCS loop piping analyses demonstrated that the stresses will remain enveloped by the previous analyses results as indicated in the note to Table 2.2.2.1-1 of LAR 261, Attachment 5.

Pressurizer Surge Line (Including Thermal Stratification)

The pressure loads, deadweight loads, and seismic excitation inputs from the design basis AOR were unaffected.

The operating thermal and thermal stratification loadings will change under EPU due to operating temperature and design transient inputs. These changes required an evaluation of the surge line stresses.

The evaluation of the surge line demonstrated that the stresses will remain enveloped by the previous analyses results and will remain within the acceptance criteria used in the previous analyses under EPU conditions.

RCS Branch Piping

Reactor coolant loop (RCL) branch piping evaluations which reconciled revised RCL displacements for EPU conditions concluded that existing design basis RCL branch piping analyses remain acceptable for EPU conditions (i.e., no change to stresses due to EPU).

Reactor Vessel

For the EPU, revised plant operating temperatures, design transients and interface loads with the reactor vessel were evaluated. Changes to the plant operating temperatures and design transients affected the transient thermal and pressure loadings on the various reactor vessel components. Transient thermal and pressure loading changes affect the reactor vessel component primary plus secondary stress intensity ranges and cumulative fatigue usage factors. The EPU transient thermal and pressure loading changes were evaluated for each reactor vessel component and the resulting primary plus secondary stress intensity ranges and cumulative fatigue usage factors were shown to be acceptable as listed in LAR 261, Attachment 5, Table 2.2.2.3-3.

The interface loads evaluated were those associated with the reactor internals, reactor coolant loop piping, vessel supports and safety injection system piping.

- Reactor internals interface loads consist of seismic and LOCA loads which both changed for the EPU as explained in the overall introductory paragraph to this RAI response. As shown in LAR 261, Attachment 5, Table 2.2.2.3-4, the EPU reactor internals interface loads with the reactor vessel were bounded by the allowable loads evaluated in the existing AOR.

- RCL piping interface loads consist of deadweight, thermal, seismic and LOCA loads acting on the reactor vessel inlet and outlet nozzles. Only the RCL piping thermal and LOCA interface loads changed for the EPU conditions. The thermal and LOCA interface loads were shown to be bounded by those evaluated in the AOR. Even though RCL piping seismic interface loads did not change for EPU conditions, an existing outlet nozzle safe shutdown earthquake (SSE) axial load was found to be larger than that qualified in the AOR. The increased stress due to this load was considered in the outlet nozzle faulted primary stress evaluation and shown to be acceptable.

- Vessel support interface loads, similar to the reactor internals interface loads, consist of seismic and LOCA loads which also changed for the EPU as explained in the overall introductory paragraph to this RAI response. The EPU operating basis and design basis earthquake vertical loads on the external support brackets were larger than those qualified in the AOR. However, the increased loads were factored into all external support bracket primary, primary plus secondary and fatigue EPU evaluations and shown to be acceptable.

- Safety injection system piping interface loads, similar to the RCL piping interface loads, consist of deadweight, thermal, seismic and LOCA loads acting on the safety injection nozzles. These loads were not previously evaluated in the AOR and only the LOCA loads changed for EPU conditions. All the loads were incorporated into the safety injection nozzle primary, primary plus secondary stress intensity range and cumulative fatigue usage factor evaluations and shown to be acceptable.

<u>CRDMs</u>

The CRDMs do not experience an increase in stresses due to the EPU because the existing analysis contains loads that envelope the loads at EPU conditions.

<u>Steam Generator</u>

The dynamic loading on the steam generator is unchanged or is enveloped by the original design basis. However, there are some changes to the component stresses due to thermal and secondary side pressure changes in the steam generators as a result of EPU conditions.

These changes were conservatively evaluated through comparative analyses that will increase the design basis stresses in accordance with pressure and temperature changes resulting from the uprate. These changes were evaluated and compared to the Code allowable and have been shown in Tables 2.2.2.5-1 and 2.2.2.5-2 of LAR 261, Attachment 5 to meet Code allowables in accordance with the original design basis.

RCPs

The EPU caused no changes to the stresses in the main flange and main flange bolted joint and the analysis of record remains bounding.

However, existing analysis for the RCP casing does not envelope EPU conditions. Increases for the EPU conditions due to the primary plus secondary pressure and mechanical loads, and the maximum steady-state thermal plus pressure and mechanical stresses, are shown in Table 2.2.2.6-1 of LAR 261, Attachment 5. These stresses were increased by 3.23% due to a difference in the heatup/cooldown temperature range between the design specification and the Model 93 casing stress analysis. The increased stresses remain below allowable limits, per the ASME Code, 1965 Edition.

Pressurizer

The revised transients have no effect on the primary stress evaluations performed previously for the pressurizer. The maximum ranges of primary plus secondary stress intensities remain unchanged for the pressurizer components at EPU conditions.

RV Internals

The existing AOR for the reactor internal components contained loads which enveloped or remained the same for some components and were increased in other components due to EPU conditions. In cases where the loads/stresses were increased due to EPU conditions, calculations were performed which reduced conservatisms (i.e., plant-specific NSSS design transients and plant-specific OBE loads instead of generic two-loop enveloped inputs) and to show that those components meet the ASME Code allowable stress limits and corresponding fatigue usage remains less than 1.0.

RCS Supports (Except Reactor Vessel Supports)

The deadweight and seismic loads on the RCS equipment supports (SG, RCP, and pressurizer) will not change due to EPU. The thermal and LOCA loads will change due to the changes in plant operating temperature and reactor vessel support stiffness. The revised support analyses for EPU conditions demonstrate that the RCS supports will remain within established allowable stress limits. The design transients described in LAR 261, Attachment 5, Section 2.2.6, are not a factor in the analysis of RCS component supports.

RPV Supports

See the NextEra response to Part a) of EMCB RAI 16.

EMCB RAI 3

Confirm that the current licensing basis at PBNP does not contain any requirements for fatigue evaluation of the above-mentioned systems, structures, and components (SSCs).

NextEra Response

For PBNP, the current licensing basis does not contain any requirements for fatigue evaluation for BOP systems.

There are fatigue requirements for reactor coolant system components as discussed below. Results of the fatigue evaluations for these components as a result of the EPU are provided in the tables from LAR 261, Attachment 5 referenced below.

NSSS (RCS) Piping and Surge Line Thermal Stratification

Per Table 4.1-9 of the PBNP FSAR and the existing design basis AOR, the code requirement of the NSSS (RCS) piping is based on the USAS B31.1, 1973 Edition, Code for Pressure Piping, which does not require a fatigue evaluation.

For the pressurizer surge line, considering only the effects of thermal stratification, the current licensing basis at PBNP includes a fatigue evaluation to address NRC Bulletin 88-11 (Reference 3). The code edition used is in compliance with the pressurizer surge line thermal stratification NRC Bulletin Number 88-11 and as documented in LAR 261, Attachment 5, Section 2.2.2.1.2. For the current licensing basis at PBNP and for EPU conditions, the evaluation of the pressurizer surge line, considering only the effects of thermal stratification, are in compliance with NRC Bulletin 88-11, and is performed to the 1986 version of the ASME code.

RCS Branch Piping

PBNP RCS branch piping evaluations are performed in accordance with the ASA B31.1 Code for Pressure Piping, 1955 Edition.

This code does not contain any requirements for fatigue evaluation for piping qualification.

Reactor Vessel

The current PBNP licensing basis for the Unit 1 and Unit 2 reactor vessels contains the following ASME Code requirements:

Unit 1 – 1965 Edition of ASME Code, Section III for the reactor vessel

Unit 1 – 1998 Edition through 2000 Addenda of ASME Code, Section III for the replacement reactor vessel closure head (RRVCH)

Unit 2 – 1968 Edition through Winter 1968 Addenda of ASME Code, Section III for the reactor vessel

Unit 2 – 1998 Edition through 2000 Addenda of ASME Code, Section III for the RRVCH

These ASME code editions contain requirements for fatigue evaluation. For instance, in the 1965 and 1968 Editions of the ASME Code, the fatigue requirements are contained in sub-paragraph N-415.2. In the 1998 Edition of the ASME Code, the fatigue requirements are contained in sub-paragraph NB-3222.4(e). The Unit 1 and Unit 2 reactor vessel fatigue results are listed in LAR 261, Attachment 5, Table 2.2.2.3-3 and are acceptable.

CRDMs

The CRDM stress analysis is based on ASME Code Section III criteria. The CRDM meets these criteria including requirements for fatigue evaluation. Fatigue evaluations are required for the CRDMs and are shown to be acceptable in Table 2.2.2.4-1 and Table 2.2.2.4-2 of LAR 261, Attachment 5.

Steam Generator

Fatigue evaluations are required for the steam generator per the ASME Codes delineated in LAR 261, Attachment 5, Section 2.2.2.5.1. Fatigue evaluations are shown to be acceptable in Table 2.2.2.5-1 for Unit 1 and Table 2.2.2.5-2 for Unit 2 of LAR 261, Attachment 5.

RCPs

The reactor coolant pumps are included in the discussion of metal fatigue as it relates to meeting the intent of the ASME Boiler and Pressure Vessel Code, Section III, Class 1 equipment. Original reactor coolant pump analyses for the Model 93 RCPs complied with this requirement by calculating cumulative fatigue usage factors for the casing (including the suction and discharge nozzles), the main flange, and the main flange bolted joint. RCP evaluations performed for the EPU concluded that the fatigue usage factor originally calculated remains valid under EPU conditions, as summarized in Table 2.2.2.6-1 of LAR 261, Attachment 5. Fatigue crack growth in the RCP motor flywheel was previously evaluated for all operating domestic Westinghouse plants, and determined to be negligible over a 60 year life of the flywheel. Inputs considered in that evaluation envelop EPU conditions. Fatigue crack growth therefore remains negligible for EPU conditions.

Fatigue evaluations are required for the RCPs and are shown to be acceptable in Table 2.2.2.6-1 of LAR 261, Attachment 5.

Pressurizer

Fatigue evaluations are required for the pressurizer and are shown to be acceptable in Table 2.2.2.7-1 of LAR 261, Attachment 5.

RV Internals

The original licensing basis for PBNP does not contain requirements for fatigue evaluation of the reactor vessel internals (RVI) components. RVI components were designed and manufactured prior to the availability of ASME Code Section III, Subsection NG, "Core Support Structures." Fatigue evaluations were, therefore, neither required nor performed for all reactor internal components. However, RVI components were evaluated for fatigue, based on the intent of ASME Code Section III, Subsection NG. RVI components evaluated for fatigue were shown to be acceptable and are listed in Table 2.2.3-3 of LAR 261, Attachment 5.

RCS Supports (Except Reactor Vessel Supports)

The original code of construction, the AISC Sixth Edition, Appendix B, required a fatigue evaluation at 20,000 stress reversal cycles. The AISC, Eighth Edition, has same requirements as the AISC, Sixth Edition. The design basis RCS supports (SG, RCP and pressurizer) loads do not approach this level of stress reversal cycles. Therefore, RCS supports do not require a fatigue evaluation for the EPU conditions.

RPV Supports

The RPV supports are not evaluated for the effects of fatigue. Appendix B of the AISC "*Specification for the Design, Fabrication and Erection of Structural Steel for Buildings*," dated February 12, 1969, requires a fatigue evaluation at 20,000 stress reversal cycles. The design basis RPV support loads do not approach this level of stress reversal cycles.

EMCB RAI 4

Tables 1-1 and 1-2 provide the RCS operating temperatures and pressures for EPU and current licensed thermal power (CLTP). Table 2.5.5.1-1 provides main steam (MS) operating and design temperature and pressure. Table 2.5.5.4-1 provides feedwater (FW) operating temperature and pressure. For the CLTP and EPU, please provide both the FW and RCS design temperatures and pressures.

NextEra Response

The current and EPU feedwater and condensate system design temperatures and pressures are provided below:

System Piping Segment	Current Design Press/Temp	EPU Design Press/Temp
From Condenser to Condensate Pump Suction	20 psig / 100°F	50 psig / 150°F
Condensate Pump Discharge and Heater Drain Pump Discharge to Feedwater Pump Suction	400 psig / 348°F (Max)	415 psig / 400°F (Max)
Feedwater Pump Discharge to No. 5 Feedwater Heaters	1525 psig / 436°F	1525 psig / 400°F
No. 5 Feedwater Heaters to Feedwater Regulating Valve Block Valves	1525 psig / 436°F	1525 psig / 480°F
From Feedwater Regulating Valves to Feedwater Isolation Valves	1310 psig / 436°F*	1315 psig / 480°F
From Feedwater Isolation Valves to Steam Generators	1310 psig / 436°F*	1270 psig / 480°F

* For current conditions, the feedwater isolation valves do not exist and the current design pressure and temperature listed is from the feedwater regulating valves to the steam generators.

The RCS design temperatures and pressures are provided in FSAR Table 4.1.6 and are shown below. These values do not change for the EPU.

	Design Press/Temp
Reactor Coolant System	2485 psig / 650°F
Pressurizer Surge Line	2485 psig / 680°F

EMCB RAI 5

Section 2.2.2.2.2.2 states that, "The two piping systems of most concern with respect to flow rate increases are main steam and feedwater systems."

a) *Identify all piping systems that would experience higher flow rates due to the EPU implementation.*

b) *Section 2.2.2.2.2.3 also states that "Additionally, the implementation of the EPU will result in higher flow rates for several piping systems. Piping systems experiencing these higher flow rates require review for potential flow induced vibration issues." Please discuss how these reviews were conducted and provide a summary of their results.*

c) *Provide a clear description of the planned activities to address flow-induced vibration (FIV) on susceptible systems.*

d) *Describe the methodology and provide the acceptance criteria for the evaluation of FIV for these piping systems.*

NextEra Response

a) The implementation of EPU will result in higher flow rates that will impact the levels of flow induced piping vibration in BOP piping systems that comprise the main power cycle. These piping systems include main steam, feedwater, condensate, extraction steam and heater drains (including heater vents and drains).

b) A plan has been developed for PBNP to address flow induced vibration in piping affected by power uprate. The plan began with the development of a program to address scope, method, evaluation and acceptance criteria. The scope includes the piping with increased flow rates resulting from EPU identified in the NextEra response to EMCB RAI 5, Item a), above.

With respect to piping vibration, the ability to analytically predict potential flow induced piping vibration displacements and resulting stresses due to higher flow rates resulting from EPU is complex. It involves assessing many piping system attributes, such as plant piping configuration, valve alignment and support locations and functions that are being modified as a result of EPU. The more effective method of precluding piping failures due to flow induced vibration due to changes from EPU is the implementation of the Point Beach developed plan to extensively monitor actual piping response to actual plant conditions. This method and plan has been successfully implemented for Extended Power Uprates (EPUs), Stretch Power Uprates (SPUs) and Measurement Uncertainty Recapture (MURs) for several PWR nuclear plants including Beaver Valley Units 1 and 2, Seabrook, Ginna, North Anna Units 1 and 2, Millstone Unit 3 and

Comanche Peak Units 1 and 2. This method provides a more proactive and reliable means for addressing potential piping vibration issues.

The piping identified in the NextEra response to EMCB RAI 5, Item a), above, will be observed by experienced piping testing engineers at several different plant operating power levels to identify areas where piping vibration displacement is occurring. The initial sets of observations (pre-baseline, as defined in the PBNP piping vibration monitoring plan) will be at the pre-EPU full-power level and will establish the baseline pipe vibrations. Several pre-baseline piping vibration walkdowns have already been performed. Walkdowns performed in March 2008, August 2008, September 2008, November 2008 and December 2009 provided specific data on existing piping vibration levels at PBNP Unit 1 and Unit 2. The walkdowns performed in November 2008 and December 2009 included observations of piping vibration following the implementation of the modification for the replacement of the No. 4 and 5 feedwater heaters for Units 1 and 2. The piping vibration levels observed during these five pre-baseline walkdowns were at levels that, based upon extensive engineering experience, result in piping vibration stress levels below stress criteria provided in ASME OM S/G-2003, Part 3. No detailed analyses were required to support this conclusion. NextEra also determined that there was no requirement to implement any piping or support modifications prior to the EPU implementation outage, because there were no potential piping vibration issues identified. An additional pre-baseline walkdown for each unit will be performed prior to entering each EPU outage to identify any potential piping vibration issues that should be addressed during the outage. Observations for EPU will take place at the post-EPU power level test plateaus (from 20% to 100% power) established for power ascension testing. By comparing the observed pipe vibrations/displacements at various power levels with those observed at the pre-baseline power level, increased pipe vibrations will be identified and the need for additional evaluations will be determined. As stated above, the acceptance criteria for all piping evaluations will be in accordance with ASME OM S/G 2003, Part 3.

c) As stated in the NextEra response to EMCB RAI 5, Item b) above, observed piping vibrations will be evaluated to ensure that damage will not result. For PWRs where the critical EPU-affected piping is accessible, the activities planned to address and assess piping vibrations are to monitor the piping before the EPU outage and during the plant heat-up and power ascension for EPU. The affected piping to be observed includes the lines that are modified by EPU and the EPU-affected lines that were identified through the PBNP corrective action program. The methodology to be used for the monitoring and evaluation of the piping vibration will be in accordance with ASME OM-S/G-2003, Part 3.

d) As described in the NextEra response to EMCB RAI 5, Item b) above, the methodology is based on performing a series of walkdowns spanning from the current plant condition to the completion of power ascension testing following the implementation of power uprate. Acceptance criteria for all piping evaluations will be in accordance with ASME OM S/G-2003, Part 3.

EMCB RAI 6

This RAI is in reference to EPU-LR Section 2.12.1.2.3.4, Vibration Monitoring. This section, in part, states that:

> *A Piping and Equipment Vibration Monitoring Program, including plant walkdowns and monitoring of plant equipment, will be established to ensure that steady state flow induced piping vibrations following EPU implementation are not detrimental to the plant, piping, pipe supports or connected equipment.*

a) Has the development of this program been completed? If not, provide the schedule for completion.

In the same section, it is also stated that:

> *The program scope will also include any lines or equipment within the monitored systems that have been modified or otherwise identified through the PBNP action report system as having already experienced vibration issues.*

b) Has this work been performed yet? If not, provide the schedule for completion.

EPU-LR Section 2.12.1.2.3.4 also states that:

> *Subsequent observations will take place at each EPU Test Plateau, as described in Section 2.12.1.2.3.1 above. By comparing the observed pipe vibrations/displacements at various power levels with previously established acceptance Criteria, potentially adverse pipe vibrations will be identified, evaluated and resolved prior to failure.*

c) Please list the acceptance criteria and supporting basis to be utilized for evaluating observed pipe vibrations and displacements at various EPU ascension power levels.

d) Have base line data at CLTP been gathered and have they been analyzed and projected to the EPU level to determine that at EPU power the allowable limits will not be exceeded? If yes, provide evaluation summaries which show that established acceptance criteria can be met for EPU conditions. If not, provide a justification why this work has not been performed yet.

NextEra Response

a) The development of this program has been completed, and several plant vibration walkdowns in support of this program have been performed. Refer to the NextEra response to EMCB RAI 5, Item b), for specific details related to this program.

b) Refer to the NextEra responses to EMCB RAI 5, Items b) and c), and the NextEra response to EMCB RAI 6, Item d) below, for details.

c) The acceptance criteria used for piping vibration is in accordance with ASME OM S/G-2003, Part 3. Refer to the NextEra response to EMCB RAI 5, Items b), c) and d), and EMCB RAI 6, Item d) below, for additional details on the supporting basis.

d) As described in the NextEra response to EMCB RAI 5, Item b), plant walkdowns have been performed in March 2008, August 2008, September 2008, November 2008 and December 2009 to obtain baseline vibration data at the current license basis power level. The relatively low amplitude piping vibration displacement levels observed during these baseline plant walkdowns were determined by engineering experience to develop stresses in the piping that are within acceptable stress limits as defined in ASME OM S/G-2003, Part 3. These baseline walkdowns were also used to develop a list of the most critical points, which will be specifically observed during the EPU power ascension process in accordance with the piping vibration plan. No additional analysis was required to conclude expected piping vibration stress levels are below stress criteria provided in ASME OM S/G-2003, Part 3, as discussed in the NextEra response to EMCB RAI 5, Item b).

The ability to analytically predict potential flow induced piping vibration displacements and resulting stresses due to higher flow rates resulting from EPU is complex. It involves assessing many piping system attributes, such as plant piping configuration, valve alignment and support locations and functions which are being modified as a result of EPU. The more effective method of precluding piping failures due to flow induced vibration under EPU conditions is the implementation of the PBNP developed plan to extensively monitor actual piping response to actual plant conditions. This method and plan has been successfully implemented for Extended Power Uprates (EPUs), Stretch Power Uprates (SPUs) and Measurement Uncertainty Recapture (MURs) for several PWR nuclear plants including Beaver Valley Units 1 and 2, Seabrook, Ginna, North Anna Units 1 and 2, Millstone Unit 3 and Comanche Peak Units 1 and 2. This method provides a more proactive and reliable means for addressing potential piping vibration issues.

EMCB RAI 7

Section 2.2.2.2.2 states that, "BOP piping and support systems were evaluated to assess the impact of operating temperature, pressure and flow rate changes that will result due to the implementation of EPU" and contains a list of "BOP piping and support systems that were evaluated for EPU conditions." The list follows this quoted statement. From this list, Table 2.2.2.2-1 of the LR indicates that only portions of the MS, FW, condensate, extraction steam and FW heater drains have been evaluated.

a) *Identify all systems (inside and outside containment) that experience increase in temperature, increase in pressure and an increase in flow rate.*

b) *For systems that experience increases in the above parameters, provide the method of your evaluation. Provide a quantitative summary of the maximum stresses and fatigue usage factors (if applicable) for original and EPU conditions with a comparison to the original code of construction allowable stress values. Include only maximum stresses and data at critical locations (i.e., nozzles, penetrations, etc). List all piping modifications (for pipe supports see (d) below) required due to EPU and the associated schedule for completion. For affected nozzles and containment penetrations, provide a summary of loads compared to specific allowable values for the nozzles and penetrations (include containment penetrations, steam generator (SG) and FW pump nozzles).*

c) *For the systems with a thermal change factor greater than 1.00, provide a description of pre-operational measures taken to identify locations that could potentially be subject to unacceptable thermal expansion interaction resulting in an unanalyzed plant condition that could potentially overstress piping and supports. In addition, confirm that a program will be in place for monitoring thermal expansion at the startup of the EPU. The EPU power ascension program (see LR page 2.12-4) does not appear to contain such a provision. In addition, page 2.12-14 of the LR states that the "EPU power ascension program will be developed." Please verify that this program has been developed.*

d) *For the systems in (b), state the method used for evaluating pipe supports when considering EPU conditions and confirm that the supports on the affected piping systems have been evaluated and shown to remain structurally adequate to perform their intended design function. Provide detail descriptions of all pipe support modifications needed to meet design basis at EPU conditions. In addition, list also type, size, loading (current and EPU) and location of supports that need to be modified and/or added due to the EPU.*

e) *Provide the schedule for completion of all piping and pipe support modifications and additions.*

NextEra Response

a) Portions of the following piping systems will experience an increase in temperature, pressure, and/or flow rate resulting from EPU. As such, detailed pipe stress and/or pipe support evaluations are required:

- Main Steam
- Condensate
- Feedwater
- Extraction Steam
- Heater Drains

With respect to pipe stress and support issues, no other piping systems contained temperature, pressure and/or flow rate increases that required detailed pipe stress and support evaluations. The auxiliary feedwater piping and supports have been addressed in separate requests for information (References 4 and 5).

b) The NUPIPE-SWPC computer program was used to evaluate piping systems which will experience an increase in temperature, pressure and/or flow rate, as described in LAR 261, Attachment 5, Section 2.2.2.2.2. The NUPIPE-SWPC program performs a linear-elastic analysis of piping systems subjected to thermal, static and dynamic loads and utilizes the finite element method of analysis to accommodate specific requirements in the piping analysis.

A summary of the maximum stress levels for current and EPU conditions, including a comparison to code of record allowable stress levels are provided in Attachment 1. For each piping system listed in this table, the stresses reported are at the most critical location of the piping system, corresponding to the piping location containing the highest stress interaction ratio. The stress interaction ratio is defined as the ratio of EPU stress divided by the allowable stress. These critical stress locations may be at equipment nozzles, containment penetrations, or any in-line piping component (e.g., valve, elbow, reducer, etc.) within the analytical boundaries of the piping stress model. Attachment 1 does not contain any cumulative usage factors since fatigue evaluations for BOP piping are not required per the current piping code of record USAS B31.1 Power Piping Code, 1967 Edition.

A summary of the piping modifications resulting from EPU modifications are provided in response to EMCB RAI 8.

With respect to pipe support modifications, specific details are provided in the NextEra response to EMCB RAI 7, Item d), below.

A summary of EPU loads and allowable values for steam generator and feedwater pump nozzles and containment penetrations that were affected by EPU are as follows:

Feedwater Pumps

See Attachment 2 for feedwater pump nozzle load summaries.

Steam Generators

See Attachment 3 for steam generator main steam nozzle load summaries.
See Attachment 4 for steam generator feedwater nozzle load summaries.

Containment Penetrations

See Attachment 5 for containment penetration main steam load summaries.
See Attachment 6 for containment penetration feedwater load summaries.

The stress values and load data provided in this response and referenced tables may change as result of final design and as-built conditions. The final results will remain within code allowable values and acceptance criteria.

c) During baseline walkdowns being performed for piping vibration, piping systems that will be subjected to a temperature increase associated with EPU (i.e., main steam, condensate, feedwater, extraction steam, and heater drains) will be inspected to identify locations where there is a potential for unacceptable thermal expansion interaction. The increases in thermal expansion displacements associated with EPU are expected to be less than 1/16 inch, and therefore, these increased displacements should not be a significant concern. However, during startup of the EPU, piping systems subjected to a temperature increase will be observed to identify any unacceptable conditions.

The plan/program for monitoring thermal expansion during power ascension following the implementation of EPU will be included in the Power Ascension Program which is being developed as part of the EPU implementation modification that implements the EPU and Power Ascension Program.

d) The pipe supports were evaluated for increased loads due to EPU by performing manual calculations and/or detailed computer analyses, using the PC-PREPS and ANSYS computer programs, as described in LAR 261, Attachment 5, Section 2.2.2.2.2. The PC-PREPS computer program performs a complete structural analysis, including an AISC code check, weld qualification and baseplate/anchor bolt qualifications. The

ANSYS computer program uses finite element analysis methods to perform detailed welded attachment analyses. The support evaluations have demonstrated that affected pipe supports, including new and modified supports, are acceptable for EPU conditions in accordance with current plant design basis.

Detailed data related to pipe supports requiring modification due to EPU are provided in Attachment 7 (Unit 1) and Attachment 8 (Unit 2). The subject tables provide the support number, piping system, pipe size, location, EPU load, and description of modification. Many of the support modifications involve new supports, or relocated supports, or supports where existing detailed analyses were not available, such that there is no existing load data available, or a comparison of current to existing loads would not be an accurate representation of a load increase due to EPU. Based on this observation, no current loads were provided in the tables.

The pipe support load data provided in this response and referenced tables may change as result of final design and as-built conditions. The final results will remain within code allowable values and acceptance criteria.

e) The final EPU modifications for Unit 1 will be installed during the Fall 2011 outage. The final EPU modifications for Unit 2 will be installed during the Spring 2011 outage. The implementation plan has been provided in Reference (6).

EMCB RAI 8

Section 2.2.2.2.2 states that "... main steam and feedwater pipe support modifications are required to mitigate the larger flow induced fluid transient loads that resulted due to EPU conditions." Please identify all piping systems that require modifications for EPU. Provide a detailed description of piping and pipe support modifications (including new supports) that are required for EPU. Include pipe line name, size, type and identification name of pipe support and the reason for the revision/addition.

NextEra Response

The following piping systems required modifications for EPU.

- Main Steam (pipe supports only)
- Feedwater
- Condensate
- Extraction Steam
- Heater Drains (including heater relief valve piping)

There were no main steam or feedwater "piping" modifications required to address fluid transient loads resulting from EPU. The main steam and feedwater modifications required to address fluid transient loads resulting from EPU were limited to "pipe support" modifications.

A summary of the piping modifications resulting from EPU modifications are as follows:

Feedwater and Condensate System

- Replacement of feedwater pumps require suction and discharge piping changes to match new nozzle locations and revised pump and motor arrangement
- Replacement of feedwater pump minimum recirculation lines and valves require larger diameter piping and valves
- Replacement of the feedwater heaters require piping changes to match new nozzle sizes and locations
- Installation of new feedwater isolation valves require piping changes to install new valves

Heater Drain System

- Modification of the heater drain pump minimum flow recirculation lines require piping changes to install automatic valve to open/close to maintain minimum pump flow
- Replacement of heater drain control valves require piping changes due to increase in valve size
- Replacement of the feedwater heaters require piping changes to match new nozzle sizes and locations
- Modification of the feedwater heater level controls require piping changes to facilitate new level transmitters and switches

Extraction Steam System

- Replacement of the feedwater heaters require piping changes to match new nozzle sizes and locations

Heater Relief Valve Piping

- Replacement of the No. 4 and 5 feedwater heater relief valves require discharge piping changes to accommodate larger relief capacity

In addition, minor small bore piping changes in the condensate, heater vents and drains, and service water systems associated with EPU modifications are being made.

For detailed summary of required pipe support modifications resulting from EPU, refer to the response for EMCB RAI 7, Item d). The pipe line name, size, type, and identification name of the pipe support, along with the reason for the revision/addition are included in the NextEra response to EMCB RAI 7, Item d).

EMCB RAI 9

EMCB RAI 9 refers to pipe stress summaries of the EPU LR Table 2.2.2.2-1.

a) Confirm whether stress summaries of Table 2.2.2.2-1 include stresses due to fluid transient loads associated with the EPU; such as turbine stop valve (TSV), main steam isolation valve (MSIV) and main feedwater isolation valve (MFIV) closure transients. If not, provide stress summaries of the feedwater and main steam piping evaluations that contain stresses due to EPU higher fluid transient loads. In addition, for main steam and feedwater nozzles and containment penetrations, provide a summary of loads compared to specific allowable values for the nozzles and penetrations.

b) The stress summaries of Table 2.2.2.2-1 are not based on the current plant piping configurations. Please update this table to show pipe stress summaries of EPU piping configuration and conditions.

c) Table 2.2.2.2-1 does not contain stress summaries for the sustained loads equation. Verify that pressure in piping systems (BOP and inside containment) is not affected by the proposed EPU.

NextEra Response

a) The stresses provided in LAR 261, Attachment 5, Table 2.2.2.2-1 included stresses due to fluid transient loads associated with EPU. The updated stress data provided in the NextEra response to EMCB RAI 9, Item b) below also includes stresses due to fluid transients, as applicable.

The main steam and feedwater nozzle loads and containment penetration loads, including their respective allowable values, are provided in the response for EMCB RAI 7, Item b).

b) The updated stress summaries reflecting EPU piping configurations and conditions are provided in the response for EMCB RAI 7, Item b). The pipe stress values provided in the NextEra response to EMCB RAI 7, Item b) and referenced tables may change as a result of final design and as-built conditions. The final results will remain within code allowable values and acceptance criteria.

c) The pipe stress sustained loads equation has been included in the updated stress summaries provided in the response for EMCB RAI 7, Item b). The updated sustained stress data has evaluated pressure changes and/or piping and support system configuration changes resulting from EPU that would potentially impact the sustained stress equation. The sustained stress levels for piping systems (BOP and inside containment) under EPU conditions remain within the current design basis allowable limits.

EMCB RAI 10

At the time of the EPU LAR submittal, some EPU required piping and pipe support analyses had not been performed or completed. On page 2.2.2-18 of the EPU LR, states that "...the piping and support evaluations will be performed as part of the overall design change package..." This is not acceptable to the staff. Please provide assurance that all piping and pipe support evaluations, including new and modified supports, have been completed and the evaluations have found that these SSCs are capable of maintaining their designed structural integrity for EPU conditions in accordance with the current plant design basis. Also, please provide the schedule for the required installations.

NextEra Response

The evaluations for all piping and pipe supports (including new and modified supports) for EPU conditions have been completed. These evaluations have demonstrated that piping and related pipe supports, including new and modified supports, are acceptable for EPU conditions in accordance with current plant design basis. Refer to the NextEra responses to EMCB RAI 7, EMCB RAI 8 and EMCB RAI 9 for evaluation results. The pipe stress values and pipe support loads provided in the NextEra responses to EMCB RAI 7, EMCB RAI 8 and EMCB RAI 9, may change as result of final design and as-built conditions. The final results will remain within code allowable values and acceptance criteria.

The final EPU modifications for Unit 1 will be installed during the Fall 2011 outage. The final EPU modifications for Unit 2 will be installed during the Spring 2011 outage. The implementation plan has been provided via Reference (6).

EMCB RAI 11

Please explain why the reactor pressure vessel (RPV) stress summary does not contain primary plus secondary stress intensity values compared to $3S_m$ for the RPV inlet and outlet nozzle support pads. If these values were not calculated for EPU, provide a justification.

NextEra Response

The original stress reports did not evaluate the primary plus secondary stress intensity ranges for the RPV inlet and outlet nozzle support pads. No explanation was given in the reports as to why the primary plus secondary stress intensity ranges were not evaluated; however, the ranges would be under the $3S_m$ limit based on the following discussion.

The RPV inlet and outlet nozzle support pads are seated in support shoes that make up part of the RPV support system. The average operating temperature of the support shoes is approximately 400°F. The largest temperature gradient in the nozzle support pads would be from the inside diameter of the outlet nozzle to the bottom of the support pad given that the outlet nozzle is exposed to higher reactor coolant temperatures than the inlet nozzle. Assuming a very conservative outlet nozzle inside diameter temperature of 650°F, the temperature gradient through the support pad would be 250°F through a metal thickness of approximately 12 inches. The linear thermal gradient hoop and axial stress is approximated using the following equation:

$$\sigma_\theta = \sigma_x = \pm\frac{E\alpha\Delta T}{2(1-\upsilon)}$$

where:
E = 26.05×10^6 psi
α = 7.33×10^{-6} in/in/°F
ΔT = 250°F
v = 0.3

The maximum linear thermal gradient stress would be approximately ±34 ksi. Note that material properties for SA-508 Class II at 650°F are used.

The original stress reports did provide pressure, thermal and external load stresses during each transient at the inside diameter and the bottom of the support pad for each respective RPV nozzle. These stresses were combined to form total stress intensities which were then used to calculate cumulative fatigue usage factors at the two locations.

The largest total stress range in the original stress reports occurs on the inside diameter of the outlet nozzle. The maximum total stress range is created from the steam pipe break and no-loss-of-function seismic events. The ±34 ksi linear thermal gradient stress calculated above is substituted for the peak thermal stress in the two transients that make up the largest total stress range. One transient has 34 ksi linear thermal gradient stress while the other transient has -34 ksi linear thermal gradient stress. Recombining the given pressure, linear thermal gradient and external load stresses results in a primary plus secondary stress intensity range of approximately 67 ksi which is well under the 80.1 ksi $3S_m$ limit.

For EPU conditions, the conservative 250°F temperature gradient would still be applicable, so the 34 ksi maximum linear thermal gradient stress would also apply for EPU conditions. The steam pipe break transient is not affected by EPU conditions. Any changes to the no-loss-of-function seismic event compressive stresses in the nozzle support pads would minimally impact the primary plus secondary stress intensity range since the thermal stress dominates this quantity. Therefore, the 67 ksi primary plus secondary stress intensity range would also be applicable for EPU conditions.

EMCB RAI 12

Please clarify whether the fatigue derived cumulative usage factors (CUFs) shown in tables of EPU LR Section 2.2, "Mechanical and Civil Engineering", are for the 60 year renewed plant life.

NextEra Response

The cumulative usage factors in the tables of EPU LR Section 2.2 are for the 60 year renewed plant life.

EMCB RAI 13

Were the stress analyses rerun or were scaling factors used with the CLTP or the original stress reports to determine EPU stress intensities and fatigue CUFs shown in LR Table 2.2.2.3-3? Provide your methodology which shows how the scaling factors were derived and how they were used to determine EPU stress intensities and fatigue CUFs from baseline stress reports. Also explain the "standard engineering approaches" used to evaluate changes in the thermal and pressure stresses, due to adverse changes in temperature and/or pressure variations from the baseline transients. Provide an example which shows the methodology used.

NextEra Response

The only reactor vessel component stress and fatigue analysis that was rerun for the EPU was the RRVCH flange evaluation. The original RRVCH flange evaluation was performed using the Westinghouse WESTEMS™ software. The original WESTEMS database was updated for EPU conditions and rerun to provide updated RRVCH flange stress and fatigue results. Scaling factors were applied to all other reactor vessel component EPU evaluations.

Listed in LAR 261, Attachment 5, Table 2.2.2.3-1 are the baseline stress reports supporting the CLTP. Collectively, these baseline stress reports constitute the AOR for the PBNP Unit 1 and Unit 2 reactor vessels. The original stress reports provided the initial reactor vessel component stress and fatigue results which have been modified by the RSG/uprating and RRVCH programs.

As mentioned previously, all reactor vessel component EPU evaluations (except the RRVCH flange) scaled the stresses derived in the RSG/uprating and RRVCH evaluations. For instances where the RSG/uprating did not affect the original stress report stresses while the EPU did, the original stress report stresses were scaled. The RRVCH evaluations completely replaced any analogous component evaluations in either the RSG/uprating or original stress reports.

The scaling factor method began by comparing the new EPU transients to those previously qualified in the AOR. To identify the EPU transients that were not bounded by AOR transients, the EPU and AOR transient data were expressed in terms of temperature variation (ΔT) for T_{hot} and T_{cold}, rate of temperature variation ($\Delta T/sec$) for T_{hot} and T_{cold} and pressure variation (ΔP). EPU transients (T_{hot} and T_{cold}) whose temperature variation, rate of temperature variation and/or pressure variation exceeded those for the AOR transients required further consideration in the RV component evaluations. LAR 261, Attachment 5, Table 2.2.2.3-2 lists the EPU transients that were not bounded by the AOR transients. Also listed in the table are the EPU transient parameters that were not bounded. When the T_{hot} or T_{cold} parameters are listed, it refers to the maximum factor calculated based on either the temperature variation or rate of temperature variation.

The transient temperature scale factors (T_{hot} and/or T_{cold}) were determined by dividing the EPU temperature variations by the AOR temperature variations as well as the EPU rate of temperature variations by the AOR rate of temperature variations. The maximum ratio calculated conservatively became the thermal scale factor for that transient. A similar approach was used for the EPU versus AOR pressure variations to develop the pressure scale factor for that transient. The methodology described so far constitutes the "standard engineering approaches" cited in LAR 261, Attachment 5, Section 2.2.2.3.

The EPU transient thermal and pressure scale factors developed were applied to the applicable RSG/uprating or original stress report transient primary plus secondary thermal and pressure stresses. The incremental thermal and pressure stress changes were then used to calculate new transient primary plus secondary stress intensities, which were then used to evaluate any changes to the maximum ranges of stress intensity for the reactor vessel component.

The EPU transient thermal and pressure scale factors were also conservatively applied to the applicable RSG/uprating or original stress report transient thermal and pressure stresses used to calculate transient total stresses for use in the reactor vessel component fatigue evaluations. The new transient total stresses were then evaluated for the impact on the reactor vessel component cumulative fatigue usage.

For the RRVCH component evaluations, except for the RRVCH flange, the scale factors were very conservatively applied directly to the transient primary plus secondary stress intensities and the fatigue pair alternating stress intensities. This approach was used due to the absence of the detailed transient thermal and pressure stresses in the existing RRVCH computer output.

The following provides a brief example of the methodology:

	ΔT	**ΔT/sec**	**ΔP**
AOR transient (a)	40	1.25	50
EPU transient (a)	45	1.50	75
Scale factor	1.125	1.20	1.5

Thermal scale factor = 1.20 (maximum of 1.125 and 1.20)
Pressure scale factor = 1.5

The AOR transient (a) primary plus secondary stresses (assuming external load stress is zero) is provided below:

	Pressure Stress			**Thermal Stress**			**Stress Intensity**
	Axial	**Hoop**	**Radial**	**Axial**	**Hoop**	**Radial**	
AOR Transient (a)	50	100	10	120	120	40	170
Scale Factors Applied	75	150	15	144	144	48	231

Other AOR transients affected by scale factors were scaled similarly and new stress intensities calculated. A check was then made for any changes to the maximum primary plus secondary stress intensity range. When a new maximum primary plus secondary stress intensity range was created, the new value was reported for the reactor vessel component for EPU conditions.

A similar approach was employed for the fatigue analysis of the reactor vessel component except that new total stress intensities were calculated and the fatigue evaluation was updated.

EMCB RAI 15

Please verify whether or not the fatigue CUF values shown on Table 2.2.2.3-3 reflect effects from environmentally assisted fatigue? If not provide a justification.

NextEra Response

NextEra determined that the environmental effects on the fatigue CUF values shown on LAR 261, Attachment 5, Table 2.2.2.3-3, were negligible. The dissolved oxygen content in the RCS was found to be below the minimum threshold value for the tensile stress producing transients. Therefore, it was not necessary to include the effects from environmentally assisted fatigue into the CUF values shown on LAR 261, Attachment 5, Table 2.2.2.3-3.

EMCB RAI 16

LR Table 2.2.2.3-6 contains the EPU revised "RPV support loads (per Support)."

a) Please explain whether these RPV loads were applied to each shoe of its support structure and discuss why the CLTP RPV support loads would change for EPU?

b) Please also provide the corresponding allowable loads for the EPU revised RPV support loads, as shown in Table 2.2.2.3-6.

NextEra Response

a) In the support structure analytical model the maximum individual RPV support load combinations (Normal, Upset, Faulted-1, and Faulted-2) were applied to each of the six support shoe locations simultaneously.

During a detailed review of the RPV system model for EPU it was discovered that the vessel support stiffness used in horizontal and vertical directions did not consider the complete flexibility of the reactor vessel support system. A corrective action was initiated by Westinghouse and the potential discrepancy was addressed for the current PBNP operation as well as for the proposed EPU conditions. The RPV system analyses were performed for both seismic and LOCA conditions using the revised vessel support stiffness values in horizontal and vertical directions. This revised analysis using a more flexible reactor vessel support system produced results that were higher than the previously analyzed loads as used in the current analysis of record. Since the RPV system analysis results feed into various other analyses, including the reactor vessel supports, the new loads were shown to be higher than previously analyzed loads and were reconciled for both the current operation as well as EPU conditions. The downstream analyses were confirmed to be acceptable and within allowable limits as part of the corrective action resolution.

b) There are four critical RPV support structural components; the support shoe, the leveling screw, the support structure pipe column and box beam. The results of the structural evaluation of these components for revised loadings under EPU conditions, in the form of stress interaction ratios, are provided in LAR 261, Table 2.2.2.3-5.

The requested allowable loads along with the corresponding actual load from LAR 261, Table 2.2.2.3-6 and the resultant stress interaction ratios, LAR 261, Table 2.2.2.3-5, for the support shoe and leveling screw are provided in Tables 16-1 and 16-2 below.

Table 16-1
RPV Support Shoe Actual vs. Allowable Load Comparison

Load Combination	Support Shoe[1]		
	Actual Load	Allowable Load	IR (<100%)
Normal	0.3 kips	627.8 kips	0.05%
Upset	89.3 kips	627.8 kips	14.22%
Faulted-1	177.3 kips	1,255.6 kips	14.12%
Faulted-2	228.3 kips	1,255.6 kips	18.18%

Note 1: The support shoe is subject to horizontal loads (V) only; see LR Table 2.2.2.3-6.

Table 16-2
RPV Support Leveling Screw Actual vs. Allowable Load Comparison

Load Combination	Leveling Screw (2 Screws)		
	Actual Load[1]	Allowable Load	IR (<100%)
Normal	142.3 kips	782.5 kips	18.19%
Upset	231.3 kips	782.5 kips	29.56%
Faulted-1	319.3 kips	1,056.4 kips	30.23%
Faulted-2	370.3 kips	1,056.4 kips	35.05%

Note 1: Includes additional shear load due to friction (i.e., 142 kips)

The requested allowable loads for the pipe column and box beam are not directly available as are the support shoe and leveling screw since the stress interaction ratios are based on a structural analysis of the combined support frame. The support frame analytical model is shown in Figure 16-1. The structural analysis produced critical member loads for the pipe column cross sections and the box beam cross sections. Critical or controlling member loads in the form of axial forces (tension and compression), biaxial shear forces, torsional moments, and biaxial bending moments were created. Actual member stresses were computed from the critical member loads and the corresponding cross section properties. Allowable stresses for tension, compression, shear, and biaxial bending were computed in accordance with the PBNP primary equipment support design basis requirements taken from Table A.5-3 of the FSAR. Stress interaction ratios were then computed with the axial tension and compression with biaxial bending combination equations shown in Figure 16-2 below. Shear stress interaction ratios were also computed with combined direct shear and shear due to torsion. The controlling stress ratios for the pipe column and the box beam cross sections are summarized in LAR 261, Table 2.2.2.3-5.

In summary, the structural qualification of the pipe column and the box beam for EPU conditions is demonstrated by showing that all combined actual stresses are less than the corresponding allowable stresses.

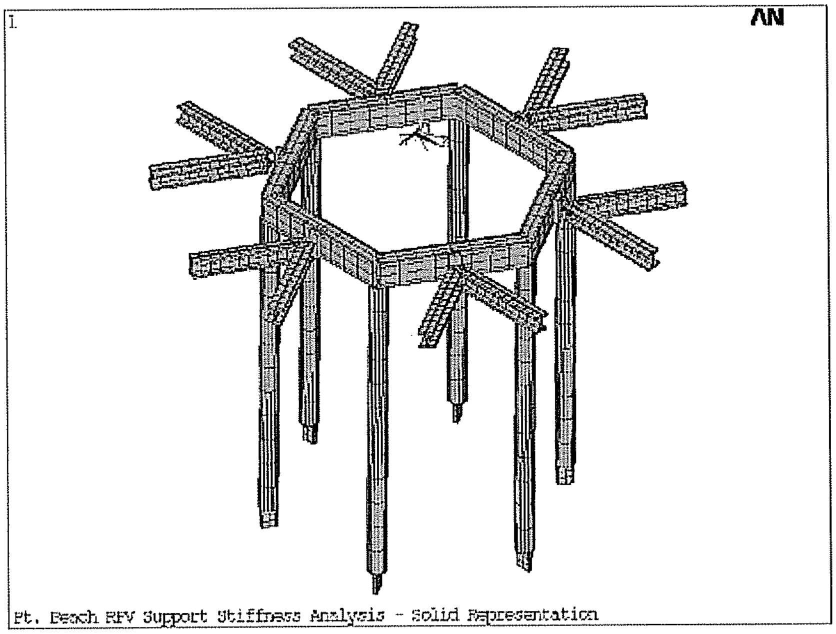

Figure 16-1 RPV Support Structure Analytical Model

$$\frac{f_a}{F_a} + \frac{C_{mx} f_{bx}}{\left(1 - \frac{f_a}{F'_{ex}}\right) F_{bx}} + \frac{C_{my} f_{by}}{\left(1 - \frac{f_a}{F'_{ey}}\right) F_{by}} \leq 1.0$$

$$\frac{f_a}{0.60 F_y} + \frac{f_{bx}}{F_{bx}} + \frac{f_{by}}{F_{by}} \leq 1.0$$

Figure 16-2 Combined Stress Interaction Equations

EMCB RAI 17

PBNP EPU LR Section 2.2.2.5.7 discusses the evaluation performed to address the effects of flow induced vibration (FIV) on the SG tubes due to the increased EPU flow. Please discuss the bases for your assumptions, acceptance criteria and the methodology used for calculating tube wear, vibration forces and stresses.

NextEra Response

Bases for Assumptions:

Fluidelastic Instability

Fluidelastic instability is a function of various parameters as indicated in the design basis analysis. Changes in operating conditions will modify some of these parameters and result in changes to the previously calculated values. The principle values that will change as a result of the uprate will be the secondary side fluid velocity (V) and the density (ρ). The fluidelastic stability ratio is related to the fluid velocity and density through the following relationship:

$$\text{Stability ratio} \propto \rho^{1/2} \times V$$

Turbulence

Turbulent displacements are a function of various parameters including density (ρ) and velocity (V) of the form $\rho(V^{(3+s)})^{0.5}$, where S (a turbulence constant) can range from 0.304 to 2.34. This means that displacements can be a function of ρV^{a} where "a" can range from 1.65, [(3+0.304)*0.5] to 2.67, [(3+2.34)*0.5] or $\sim\rho V^2$. For conservatism, the displacements are scaled using the conservative relationship:

$$y \propto (\rho V^2)^2$$

Wear Potential

The tube wear parameter is essentially a function of displacement. Therefore, any changes to this parameter would be proportional to displacements associated with turbulence. Therefore, wear can be modified using the same methods used for turbulence.

Acceptance Criteria:

The acceptance criteria are as follows:

1. Fluidelastic stability ratios < 1.0.

2. Amplitude of tube vibration due to turbulence no greater than half (1/2) of the gap between tubes. This considers the worst case scenario that the adjacent tubes are moving 180° out of phase.

   Unit 1: 1/2 * (1.2344 – 0.875) = 0.1797 inch

   Unit 2: 1/2 * (1.234 – 0.875) = 0.1795 inch

3. Demonstrate that unacceptably large rates of tube wear will not occur after the uprate. Note that 40% wear depth for the Model 44F and Delta-47 steam generators would be 0.4 x 50 mils = 20 mils.

Methodology:

Based on factors derived above, the original flow induced vibration (FIV) results are modified to address the effects of the EPU. These values for fluidelastic instability, turbulence, and tube wear were compared to the design basis allowable values and showed continued acceptability following the EPU.

Fatigue usage associated with general FIV resulting from the most limiting uprated operating condition has been calculated. In the original analysis, the limiting tube had a maximum FIV induced tube bending stress of <300 psi for Unit 1 and 410 psi for Unit 2. Conservative EPU calculations indicate that when these tubes are in operation at the uprated condition, the corresponding maximum stress levels would be 479 psi for Unit 1 and 655 psi for Unit 2. This level of stress is still well below the endurance limit of approximately 20 ksi at 1E11 cycles, and will not result in any fatigue usage factor increase.

EMCB RAI 19

SG tubes have been known to fail and rupture due to high cycle fatigue caused by vibration due to fluid-elastic instability. Discuss the applicability of the NRC Bulletin 88-02, "Rapidly Propagating Fatigue Cracks in Steam Generator Tubes," to the PBNP SGs.

NextEra Response

NRC Bulletin 88-02 (Reference 7) is not applicable to PBNP Units 1 and 2 replacement steam generators (RSG) because the tube support plates (TSPs) are fabricated of stainless steel. One of the prerequisites for high cycle U-bend fatigue is the formation of a dented tube support condition at the upper plate. This support condition is a result of a build-up of corrosion products associated with drilled holes in carbon steel TSPs. Since the broached stainless steel support plate in the RSG is designed to inhibit the introduction of corrosion products, the support condition necessary for the development of high cycle fatigue cannot occur. As a result, high cycle fatigue associated with unsupported inner row tubes cannot occur in the PBNP Units 1 and 2 steam generators.

EMCB RAI 20

PBNP EPU LR Tables 2.5.5.1-1 and 2.5.5.4-1 show that, at EPU power levels main steam and FW flow rates will increase by over 20%, while velocities in the main steam from SGs to TCSVs could increase by approximately 27% and condensate and feedwater system flow velocities are expected to increase by approximately 25% at EPU power level.

a) *Please provide for both units analysis summaries for the steam dryer, dryer supports, flow-reflectors (if applicable) and for other SG internals due to flow-induced loadings associated with fluid-elastic instability, vortex shedding or acoustic type loadings due to the EPU higher FW and steam flow. If these types of analyses for the SG internals have not been performed or flow-induced loads are not thought to be a concern for these components, provide a justification which supports your position.*

b) *Discuss whether any acoustic resonance could be generated at EPU flow or during power ascension to EPU power in the feedwater and main steam lines and describe how the acoustics-driven dynamic pressure loading acting on the components inside the steam generator under EPU conditions will be estimated. The discussion of the results presented in EPU LR Section 2.2.2.5 of the comparative assessment between geometries of BWR and PWR steam dryers does not demonstrate and is inconclusive as to why an acoustic type pressure wave cannot be generated and create a pressure loading on the dryer and its components.*

c) *Discuss procedures in place for preparation, response and preventive actions designed to detect and remove loose parts that could potentially occur due to component degradation as a result of the EPU increased main steam and FW flow. Also, please discuss the potential for damage that these loose parts could have to the safety-related SSCs.*

NextEra Response

a) EPU Flow loadings, including those associated with fluid-elastic instability, vortex shedding or acoustic type loadings are considered to be insignificant in the analysis of the SG dryer and dryer supports and other PBNP SG internals. There are no existing conditions identified in the piping systems connected to the SG that are potential sources for flow-induced acoustic resonances or system vibration that would adversely impact SG internals at EPU. Further, there is no history of vibration problems in these lines at PBNP. Many units with similar SG upper internal configurations have been visually inspected periodically in this region of the SGs and found not to have any indication of FIV degradation of the steam dryers or related supports. Furthermore, in-service experience has revealed no such phenomenon related to domestic PWR NSSSs.

As an additional consideration for EPU, the guidance provided in Regulatory Guide 1.20 (RG 1.20) (Reference 8) as it relates to PWR SGs has been followed. By taking into account industry operating experience, comparative evaluations and analysis have been completed to develop the overall conclusion that there are no predicted vibrational issues identified for the SG steam dryer assemblies and supports at EPU conditions. LAR 261, Attachment 5, Section 2.2.2.5.12 presents the steam dryer and dryer support evaluation summary in alignment with the RG 1.20 guidance on evaluation to flow-induced loadings on SG internals. This section indicates that the potential for FIV induced loadings have been carefully considered using the guidelines provided in

RG 1.20 and has concluded that FIV of the secondary moisture separators is not significant under EPU conditions.

In addition, the effect of increased flow at EPU conditions will be monitored through existing plant loose part monitoring system procedures and in-service inspections, including periodic SG eddy current testing, foreign object search and retrieval (FOSAR) and an SG upper internals inspection during each of the two scheduled outages following EPU. The two Westinghouse SG models operating at PBNP Units 1 and 2 do not use steam flow reflectors by design, and as a result, steam flow reflector FIV is not a plausible condition.

b) A search of the Institute of Nuclear Power Operations (INPO) database of operating experience (OE) reveals that operating BWR plants have reported FIV-related issues in the steam dryer region and PWR SGs lack similar experiences. Flow characteristics through a BWR steam dome are significantly different from those of a typical PWR SG, such as those operating at PBNP Units 1 and 2. In a BWR vessel, localized regions near the steam outlet nozzles may be continually exposed to steam flows in excess of 100 ft/s largely due to flow redirection. Steam flows of this nature may generate a concern for FIV related degradation issues, with a potential for significant stresses in the steam dryers and support structures.

The steam velocities and densities through the dryer region of the PBNP Units 1 and 2 SGs show relatively low FIV potential, with a maximum of approximately 5.4 ft/s and 1.7 lbm/ft^3, respectively, under the EPU conditions. Also, clearances between the dryer and SG steam exit nozzle are in excess of 35 inches with no major components near the steam exit and a direct steam flow path existing to the SG steam outlet nozzle. These low steam velocities and densities combined with considerable dryer clearances indicate a low potential for FIV concerns and cyclic acoustic-type pressure loads occurring at the SG dryers in the PBNP Units 1 and 2 SGs. Additionally, there has been no potential source identified for flow induced acoustic resonances or system vibration that would adversely impact RCS components such as SG internals. Therefore, acoustic resonance type loadings are considered to be insignificant in the analysis of the SG dryer and dryer supports and other SG internals.

Although there is no evidence of acoustical pressure load generation in the PBNP SGs and PWRs in general, analysis has also been performed to address the effects of BWR type acoustical loadings on the PBNP SG dryers for the EPU. This analysis assumed that acoustical energy of the same general magnitude seen in the BWR industry experiences is present at the SG steam outlet nozzle. A natural frequency, mode shape and corresponding stress analysis has been performed for the steam dryers of the PBNP Unit 1 and 2 SGs. The results of analysis concluded that the range of natural frequencies for the limiting dryer bank component is approximately 65 Hz to 250 Hz for the first twenty mode shapes. Upon determination of the structure natural frequencies and resulting mode shapes, classical deformation and stress analysis equations have been applied to calculate the maximum displacements and resulting stresses at the point of maximum postulated steam dryer structure deflection. The static and cyclical stresses resulting from the potential vibration are found to be below the ASME Code allowable and fatigue strength endurance limit of the dryer material. Therefore, should acoustical loadings of the magnitude observed in BWR industry experiences actually develop, the PBNP Unit 1 and 2 SG steam dryer and support structures are found to not be susceptible to vibrational fatigue failure and loose part generation as a result of EPU operating conditions.

Industry experience of PWRs at roughly 28 domestic plants operating 92 SGs with the same or similar types of dryer and support structures as those in service at PBNP Units 1 and 2 have no reported operational issues or failures related to FIV. This strong performance database of operating plant history is aligned with the RG 1.20 evaluation conclusions provided in LAR 261, Attachment 5, Section 2.2.2.5 and the Westinghouse determination that acoustic type FIV loadings in the SG steam dryer region is not a concern within the operational bounds of the EPU at PBNP Units 1 and 2.

c) The PBNP Loose Parts Monitoring System is an array of acoustic monitors whose primary function is protection of the steam generator tubesheet and the fuel against contact with debris. System sensor locations include the bottom of the reactor vessel (2), on the steam generator tubesheet, on the primary side of the SG tubesheet, and on the secondary side of the SG tube sheet. The sensor outputs are monitored automatically, and an alarm is initiated if the sound energy level exceeds a preset threshold. An alarm prompts further investigation and evaluation of the potential risk to the fuel cladding or primary system pressure boundary.

<u>Loose Parts Originating in the Feedwater System</u>

Loose parts originating in the feedwater system downstream of the No. 5 feedwater heater may pass into the SGs, and if so, could be detected by the loose parts monitoring system and actions to assess the condition would be initiated.

Continuous monitoring of SG integrity is provided by steam jet air ejector, blowdown, and steam line activity monitors, and periodically by primary-to-secondary leak rate calculations. Debris detected directly or indirectly in the SG secondary side would be evaluated, and appropriate corrective action to safeguard the continued integrity of the SGs taken via the corrective action process.

Flow generated loose parts that originate upstream of the No. 5 feedwater heaters, unless smaller than the diameter of the No. 5 feedwater heater tubes, would be caught and retained on the tube sheet of the heaters.

Practical operating experience suggests that large debris in the heaters is readily detected by audible indications because the debris continually circulates and impacts the heat exchanger end-bell and tube sheet. Such indications would prompt an assessment of the situation via the corrective action process.

<u>Loose Parts Originating in the Steam Generators or Main Steam System</u>

Similarly, transportable debris released from the steam system would either travel to the strainers at the inlet of the turbine control valves, or lodge in system components or dead-legs. If passed to the strainers, they would have no adverse effects on safety equipment and would remain there until detected and retrieved during routine outage maintenance.

It is possible that small debris released in the steam drum might drop down into the steam generator tube bundle. Such debris would be monitored for and detected by the loose parts monitoring system in the same way as debris arriving in the tube bundle from the feedwater system.

Particularly large transportable debris released into the steam system would be apparent by a decrease in steam flow in the partially obstructed line. This would be evidenced by one or more of the following indications:

- A change in turbine governor valve position(s),
- A change in the affected SG pressure and flow as compared to the other steam generator, and/or
- A change in plant efficiency.

Such indications would prompt further investigation and assessment via the corrective action process.

High density debris originating in the steam drum between the primary separators and the secondary separators would not be transportable due to the relatively low steam velocity between the separator stages. If sufficiently light with a larger drag cross section, debris might be transportable downstream of the secondary separators where flow velocity is higher. However, larger transportable debris would be caught on the flow limiting inserts installed in the SG outlet neck. This would be indicated by a change in SG pressure and flow as compared to the other SG as described in the above paragraph.

If debris were small enough to pass through the flow limiters, it would also be small enough to pass all the way downstream to the turbine control valve inlet strainers. It is not credible that such smaller debris would lodge in the steam flow venturies, though such obstructions would be immediately apparent by an abnormal steam flow indication. Indications of abnormal operation would prompt further investigation, assessment, and corrective action as appropriate.

The potential effects of released debris are limited to obstruction of safety related valves that interfere with their design function(s). In the case of the feedwater system, the valves of concern are the feedwater regulation valves (FRVs) due to their relatively small flow passages. These valves have caged plugs with relatively small flow passages, and are backed up by the redundant feedwater isolation valves that have a larger flow cross section than an FRV, and therefore would not be affected by debris that passes through an FRV. As such, the safety effect of debris that might interfere with the function of the FRVs is judged to be minimal.

The safety-related valves in the main steam system with active safety functions are the main steam safety valves (MSSVs), the atmospheric dump valves, the main steam isolation valves (MSIVs), the main steam non-return check valves, and the turbine stop valves.

The MSSVs and atmospheric dump valves are located on top of a stagnant, large diameter relief valve header that has no steam flow under normal operating conditions. Therefore, it is not considered credible for debris released in the MS system to reach these valves during normal operation. Conversely, when needed to function in response to abnormal transients, the system steam flows are either substantially lower (less than CLTP full flow) or of very brief duration until the transient is terminated. Consequently, the likelihood of transport of loose parts originating in the main steam system to these valves is considered very low.

Debris transported into the large diameter relief valve header would most likely fall to the bottom of the header and remain there. However, if it were sufficiently small to be carried by steam flow to the top surface of the header, debris should also be sufficiently small to only affect one of the valves supplied from the header (either the atmospheric dump, or one of the three MSSVs) supplied by the header. In any case, each steam generator is served by separate relief headers providing another degree of redundant protection against the effects of any single piece of debris.

The MSIVs, main steam non-return check valves, and turbine stop valves have large, unobstructed flow areas that are substantially larger than the throat of the steam generator flow limiting devices. Therefore, postulated debris being carried with main steam flow is not expected to lodge or remain in these valves and interfere with their function. Should such an unlikely event occur, the valves are redundant and serve to back up one another so that no single piece of debris could defeat the safety isolation function of the valves.

EMCB RAI 21

EPU LR Section 2.2.2.5 states that: "With the increased flow conditions within the steam drum expected from EPU conditions, material loss in the carbon steel steam drum components may be initiated or accelerated. Periodic steam generator inspections will detect degradation that may occur." Please provide the frequency of the scheduled inspections for the steam drum components and the supporting basis that drives these inspections.

NextEra Response

An engineering assessment of the potential impact of the planned EPU operating conditions on the steam drum components was completed. During the assessment, a review of steam generator industry history and the impact of erosion-corrosion degradation at uprated conditions was conducted. The engineering assessment concluded that material loss in the carbon steel steam drum components due to erosion-corrosion may be initiated or accelerated due to operation of the steam generator at EPU conditions.

An initial sample inspection of PBNP steam generators from each unit during refueling outages U1R30 (Spring 2007) and U2R29 (Spring 2008) was conducted, and the results of the inspections showed that there was no significant erosion-corrosion damage or material degradation of the steam generator upper internals.

An additional evaluation of the steam drum upper internal components was completed for potential material loss following EPU. The evaluation utilized conservatively high wear rates compared to industry inspection findings on similar generators with similar flow velocities for the steam drum components. The most limiting components were evaluated for material loss for two operating cycles at EPU conditions. The resulting conservatively high material loss would not affect the components structural integrity. Utilizing a conservative inspection frequency of one operating cycle for the initial inspection following uprate will ensure the structural integrity of the Steam Drum components is maintained.

The recommendations from the assessment and evaluation noted above included that after every plant operating cycle for both units, inspections of the steam drum components be performed to determine if the increased flow rates have initiated or accelerated the erosion-corrosion process. The frequency of this inspection interval may be altered/extended after initial inspections are completed. Note that LAR 261, Commitment #17 stated, "A formal monitoring program for the steam generator steam drum components will be implemented prior to operation of each unit at EPU conditions. The monitoring will be conducted over two operating cycles to confirm components are performing adequately at EPU operating conditions. See LR Section 2.2.2.5, Steam Generators and Supports."

Consistent with the commitment noted above, inspections of the steam generator upper internals will be performed after installation of the modifications associated with the moisture separator assemblies. These inspections will provide a baseline assessment of the steam generator upper internals prior to operating at EPU conditions. Inspections of the upper internals will be performed during the first two refueling outages following the EPU uprate on each unit to determine if the increased flow rates have initiated or accelerated the erosion-corrosion process. The frequency of the inspections may be adjusted following these inspections. In addition, aging management reviews will continue to be performed on the steam generator feedwater rings, J-nozzles, and feedwater ring supports using the Water Chemistry Control Program and the Steam Generator Integrity Program.

EMCB RAI 22

EPU LR Section 2.2.2.5, with respect to the structural adequacy of the steam drum components states that: "flow-induced vibration of these components during uprated conditions is considered to be enveloped by the original design basis evaluations due to the limited change in flow parameters within the steam drum under EPU conditions." Please describe the original design basis evaluations and provide references of these evaluations which have been performed for the steam drum components that include flow-induced loads. Also, please describe how the flow parameters in the original design basis evaluations envelop the EPU increased flow conditions.

NextEra Response

Detailed stress analyses of the steam drum components were performed for the significant loadings that could potentially occur on steam drum components. Assessments of the flow induced vibration (FIV) potential of the steam drum components were made during the design of the PBNP steam generators, and it was recognizing that cyclic FIV loadings were not significant for the reasons discussed below. As a result, a detailed FIV analysis was not required for either the original design structural analysis or the structural analysis that addressed the EPU.

It has been Westinghouse's experience that fluid loadings of steam drum components has not resulted in any degradation or repair of these components that could be attributed to FIV. Other degradation mechanisms have been observed in this region and have been primarily limited to flow accelerated corrosion (FAC). Industry experience for PWR steam generators indicate that unacceptable FIV is not occurring in this region of the steam generator.

FIV is a function of various parameters including fluid density (ρ) and fluid velocity (V). In the steam drum region, the fluid is primarily composed of steam which has lower values of density versus the density for liquid water. As a result, the dynamic pressure (ρV^2) in this region is also low and would result in only small FIV loadings. The individual modular primary moisture separators in the PBNP steam generators are physically smaller than moisture separators in other model steam generators. The PBNP moisture separators are well supported and as a result, the structures would be expected to have high natural frequencies. FIV potential is also a function of natural frequency, and components having lower natural frequencies tend to have a larger potential for an unacceptable FIV response. Since the PBNP separators would tend to have larger natural frequencies than other designs, the potential for an unacceptable FIV response would be even further reduced.

Design basis analysis of the PBNP Unit 1 and Unit 2 steam generator steam drum components considered load conditions that could potentially result in a significant stress or displacement of any structure in the steam drum. The analysis focused on conditions that produced primary stresses in the components. For Unit 1, the potential effects of cyclic loading were considered and were addressed in a component specific fatigue analysis. In this region of the steam generator, the limiting component with respect to cycle loadings was determined to be the riser barrel/lower deck plate fillet weld. The analysis performed for this weld determined that the fatigue usage was acceptable for the applied cyclic loadings. FIV could potentially result in fatigue usage accumulation in some steam generator components, however, these loads were not considered to be significant in this region due to past Westinghouse and industry experience, the low magnitude of the loads and the general robustness of the associated structures. In addition, the PBNP Unit 2 stress report clearly states, "At the elevation of the upper internals, thermal and pressure loads due to steam temperature changes during operating transients are negligible. Therefore, it is concluded that fatigue usage in this area is not a concern and only primary stresses will be evaluated." Recognizing that cyclic FIV loadings are not significant for the reasons discussed above, a detailed FIV analysis was not required for either the original design basis structural analysis or the structural analysis that addressed the EPU.

EMCB RAI 23

Please confirm that EPU LR Section 2.2.2.1 indicates that for the NSSS piping and supports the current analyses on record contain load and transient input data that bound those of the EPU conditions.

NextEra Response

NSSS Piping and Surge Line Thermal Stratification

See the NextEra response provided for EMCB RAI 2.

NSSS Supports (SG and RCP)

See the NextEra response provided for EMCB RAI 2.

EMCB RAI 25

a) *For EPU LR Section 2.2, "Mechanical and Civil Engineering," please verify that, where a different code or code edition than the original code of construction has been utilized, a documented code reconciliation exists that allows such use and that the allowable values from the original code of construction have been utilized with the reconciled (later) year code. As an example, LR Section 2.2.2.7 concludes that: "[The] pressurizer components meet the stress intensity/fatigue requirements of the ASME Code Section III, 1965 Edition with Addenda through Summer 1966 for all proposed EPU operation." However, the same section indicates that the stress and fatigue evaluations have been performed in accordance with a later ASME Code edition. The code edition year is not mentioned.*

b) *For sub-sections in LR Section 2.2 where the acceptance criteria and evaluation does not mention either the code, code section and/or code year, please provide that information. For instance, in the case of the reactor coolant pumps and supports, Section 2.2.2.6 indicates that the acceptance criteria at EPU conditions for stress limits and fatigue usage requirements are in accordance with the American Society of Mechanical Engineers (ASME) Code, Section III. However, it does not mention the code year.*

NextEra Response

NSSS (RCS) Piping and Surge Line Thermal Stratification

a) See the NextEra response to EMCB RAI 1.

b) See the NextEra response to EMCB RAI 1.

RCS Branch Piping

a) See the NextEra responses to EMCB RAI 1 and EMCB RAI 3.

b) See the NextEra responses to EMCB RAI 1 and EMCB RAI 3.

Reactor Vessel

a) For the EPU, one set of reactor vessel component evaluations was performed and shown to be applicable to Unit 1 and Unit 2. However, the results were evaluated against each unit's code of construction according to the following:

   For Unit 1, the reactor vessel component results (except the RRVCH and its components) were evaluated to the original code of construction, the 1965 Edition of the ASME Code, Section III.

   For Unit 2, the reactor vessel component results (except the RRVCH and its components) were evaluated to the original code of construction, the 1968 Edition through Winter 1968 Addenda of the ASME Code, Section III.

   For both Unit 1 and Unit 2, the RRVCH and its components were evaluated to the 1998 Edition through 2000 Addenda of the ASME Code, Section III. Documented code reconciliations to the Unit 1 and Unit 2 codes of construction were performed in the Unit 1 and Unit 2 RRVCH design reports.

b) The Acceptance Criteria in LAR 261, Attachment 5, Section 2.2.2.3 lists the applicable codes of construction for the Unit 1 and Unit 2 reactor vessels, and they are re-iterated in the above response to Item a).

CRDMs

a) The CRDM AOR for EPU conditions are completed in accordance with the ASME Code, Section III, 1998 Edition with Addenda through 2000. The AOR includes reconciliation of the ASME Code requirements for the ASME Code edition used in the AOR to those used for the original construction Code, ASME Section III 1965 Edition, through Summer 1966 Addenda for Unit 1 and Summer 1967 Addenda for Unit 2.

b) Please see the response provided for Item a).

Steam Generator

a) The Code year and Addenda used in the qualification of the Unit 1 Model 44F and Unit 2 Model Delta-47 replacement steam generators for the EPU analyses is unchanged from the original RSG. Therefore, no Code reconciliation was required to be performed. The RSG design basis for steam generators is as noted in LAR 261, Attachment 5, Section 2.2.2.5.1.

Where the original construction code, ASME Code, Section III 1965 Edition, through Summer 1966 Addenda, did not contain the specific material used for steam generator hardware items, a later ASME Code was used for the material properties, and the Code year is provided in LAR 261, Attachment 5, Section 2.2.2.5.9. The allowable values were based on original construction ASME Code year of the 1965 Edition, through Summer 1966.

b) The design basis for the installed steam generators is provided in LAR 261, Attachment 5, Section 2.2.2.5.1. The applicable ASME Code year for each steam generator hardware item is provided in LAR 261, Attachment 5, Section 2.2.2.5.9.

RCPs

a) This question is not applicable to the RCPs. No code reconciliation was performed because the PBNP RCPs were not certified to an original code year of construction.

b) LAR 261, Attachment 5, Section 2.2.2.6 does not indicate the code year for the acceptance criteria for the stress limits and fatigue usage requirements for the reactor coolant pumps at EPU conditions because the Model 93 RCPs were not required to be N-stamped to a particular code year. The age of the RCPs predates specific code requirements for pumps. Rather than being certified to a particular code year and addenda, the RCPs were analyzed to the intent of the ASME Code available at that time. Stress analyses for the PBNP RCPs consists of a series of generic Model 93 stress reports for the casing, main flange, and main flange bolted joint, which utilized design criteria from the ASME Code, Section III, 1965 Edition.

Pressurizer

a) The ASME Code, Section III, 1986 Edition, is discussed in LAR 261, Attachment 5, Section 2.2.2.7.1. NRC Bulletin 88-11 (Reference 3) required a later edition of the ASME Code for pressurizer surge nozzle high cycle fatigue calculations. No later Code edition was mentioned in LAR 261, Attachment 5, Section 2.2.2.7.

b) ASME Code editions used in the evaluations were cited in LAR 261, Attachment 5, Section 2.2.2.7. The pressurizer evaluation used ASME Code, Section III, 1965 Edition with Addenda through Summer 1966.

RV Internals

a) PBNP Units 1 and 2 were built before the implementation of Subsection NG of the ASME Code; therefore, no specific ASME Code year is applicable for Section 2.2.3 of LAR 261, Attachment 5. The ASME Boiler and Pressure Vessel Code, Section III, Division 1, 1998 Edition with 2000 Addenda, "Code Section NG-3222 and NG-3228.3," was chosen to meet the intent of the ASME Code. The original analyses for the PBNP reactor internals adopted the allowable stress criteria of Article 4 of the ASME Boiler and Pressure Vessel Code Section III, Section 1, 1968 Edition with Addenda through Winter 1968.

   Comparison of the allowable stress and fatigue criteria presented in Subsection NG of the 1998 Edition of the ASME Code Section III, Division I, including 2000 Addenda with Article 4 of the 1968 Edition with Addenda through Winter 1968, demonstrates that the criteria used in this analysis are reconciled with the requirements and the allowable stress limits. Also, the fatigue usage criteria in the 1968 Edition with Addenda through Winter 1968 are identical to those in the 1998 Edition including 2000 Addenda of the ASME Code.

b) See the NextEra response provided above for Item a).

RCS Supports (Except Reactor Vessel Supports)

a) See the NextEra response provided for EMCB RAI 1.

b) See the NextEra response provided for EMCB RAI 1.

RPV Supports

a) For the RPV supports, the original design basis design requirements were used for the EPU project. The design basis requirements for the RPV supports design are contained in Table A.5-3 of the PBNP FSAR. This table provides the Normal, Upset and Faulted allowable stress limits for a couple of the materials used in the RPV support construction. Although not specifically mentioned, these stress limits are identical to the "working stress" requirements of the AISC "*Specification for the Design, Fabrication and Erection of Structural Steel for Buildings*," dated February 12, 1969. For the Faulted loading combination the allowable stress limits are 90% of yield for direct tension stress and tension stress due to bending and 54% of tensile yield for shear stresses.

Compressive stresses are not specifically addressed in the PBNP Table A.5-3. However, for EPU, the AISC Part 1 allowable compressive stress was used for the Normal and Upset loading conditions and 90% of the AISC critical buckling stress was used for the Faulted loading condition.

b) See the NextEra response provided above for Item a).

<u>EMCB RAI 27</u>

For LR Table 2.2.3-3, please provide an explanation which demonstrates why, at EPU conditions, the primary plus secondary stress intensity range of some vessel internal components has been greatly reduced. Also, please explain, quantitatively, how the baffle-former bolts have been evaluated and qualified since the table does not contain a stress and fatigue usage summary for these components.

<u>NextEra Response</u>

The components listed in Table 2.2.3-3 that were evaluated and shown to have reduced component primary plus secondary stress intensity range due to EPU conditions include:

- Upper Core Plate Alignment Pins
- Lower Support Columns
- Core Barrel Assembly Outlet Nozzle
- Lower Core Support Plate

The current analysis of record is based on Westinghouse two-loop generic plant assessments and envelops most of the Westinghouse two-loop plants. As part of the PBNP EPU analyses, some of this conservatism in the generic analysis was removed using plant-specific inputs to obtain additional margin and demonstrate acceptability of the PBNP reactor internal components structural integrity. In general, stresses due to mechanical loads, such as OBE and vibrations, are not impacted for EPU conditions. The thermal analysis contained other limiting thermal transients, such as excessive feedwater and reactor coolant system (RCS) depressurization, that were used in generic two-loop design report and are not applicable to PBNP. These conservatisms were removed, and new thermal stresses were calculated. In addition, there are some geometrical differences in generic two-loop design compared to PBNP, which is the main reason for the reduction in primary plus secondary stress intensity range for some vessel internal components.

The test program for which the baffle former bolts were evaluated was performed in such a manner that the primary plus secondary stress check required by Subsection NG of the ASME Code is satisfied. In lieu of the cyclic stress requirements of Article NG-3222.4(e) of Subsection NG of the ASME Code, the test program was performed within the requirements of Article II-1500 of ASME Code, Section III, Division 1, Appendix II. This is permitted per Article NG-3222.4(a) of Section III, Subsection NG of the ASME Code. The basis for baffle-former bolt qualification is based on these test results rather than stress and fatigue qualification.

The methodology used for baffle bolt fatigue is summarized as follows:

(1) The baffle plate temperature difference is generated using Westinghouse computer code TEMFOR.
(2) From the temperature difference, the baffle bolt displacements due to normal and upset conditions are calculated.
(3) The allowable cycles are determined based on displacement and cyclic data methodology developed for Westinghouse design plants for both normal and upset temperature differences.
(4) The cumulative baffle bolt fatigue usage is determined for all normal and upset transients except the loading and unloading normal transient.
(5) The allowable number of normal loading and unloading transient cycles is determined based on a maximum allowable bolt fatigue usage of 0.9999.

Based on the temperature difference and the average bolt displacement calculations, a bolt displacement of 0.016275 inch was obtained, and the limiting bolt location was above the pin displacement of Plate 3 at a temperature difference of 48.4°F. From this data, a limiting number of 8,240 upset transients were obtained for a cumulative fatigue usage of 0.9999.

The normal and upset transients calculated in this analysis gave a baffle bolt fatigue usage of 0.5825. The cumulative baffle bolt fatigue usage factor was set at a maximum of 0.9999. The remaining baffle bolt fatigue usage for loading and unloading transients is the difference of 0.9999 and 0.5825. NextEra determined that the maximum allowable transients for the loading and unloading transient cycles was 3,545 cycles, corresponding to a fatigue usage factor of 0.9999.

The results of this analysis confirmed that the baffle bolts remain acceptable as long as the number of loading and unloading transient cycles is limited to 3,545. This limitation is contained in LAR 261, Attachment 5, Table 2.2.6-1, Note 1.

EMCB RAI 28

Table 2.2.3-2 of the LR for the guide tubes provides a value of 266.0x10^{-6} in/in strain from measured strain data as an acceptable (or allowable) mean strain and 65.0x10^{-6} in/in for alternating dynamic strain. Please explain where the data that established these values originated from and why these values are applicable to the PBNP guide tubes.

NextEra Response

The acceptable guide tube mean (static) and dynamic strain value of 266.0x10^{-6} in/in and 65.0x10^{-6} in/in, respectively, were obtained using the stress and the fatigue allowable stress limits of the ASME Code Section III, Division 1, 1998 Edition with 2000 Addenda by converting it to the corresponding strain values.

Evaluations were performed to predict PBNP responses by using the in-plant prototype measurement from R.E. Ginna (Ginna). The scaling of structural response due to flow-induced vibration (FIV) was performed according to analytical and experimental formulations relating to such parameters as flow rates and temperature changes, which may affect the amplitude of the response, and consequently the maximum stress (strain) range. The scaling law is an approximation of the FIV forces independent of what the fluid dynamic source may be (i.e., laminar, flow-induced, cross-flow, turbulent, vortex shedding, steady-state, transient). The scaling law was used to obtain corresponding guide tube responses due to FIV for PBNP and are provided in LAR 261, Attachment 5, Table 2.2.3-2. Since the guide tube design of PBNP Units 1 and 2 are identical to the Ginna guide tubes, the measured mean and dynamic strains obtained from Ginna are applicable to PBNP.

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In Tables 2.2.3-1 and 2.2.3-2 of the LR, the current analyses of record (AOR) values originated from Ginna. Please explain where the "After EPU" column values originate from. Also, please provide an explanation of why, from all of the vessel internals components, only the guide tubes and the thermal shield top support bolts and flexures have been evaluated for flow induced vibration.

NextEra Response

The "After EPU" values for PBNP were calculated as part of the EPU project. These evaluations involved use of fully instrumented test data from a two-loop prototype plant (Ginna). This data is representative of all two-loop plants, and from this data, the response of the PBNP reactor internals were scaled for the EPU operating conditions. The scaling of structural response due to FIV was performed according to analytical and experimental formulations relating to such parameters as flow rates and temperature changes, which may affect the amplitude of the response, and consequently, the maximum stress (strain) range. The scaling law is an approximation of the FIV forces independent of what the fluid dynamic source may be (i.e., laminar, flow-induced, cross-flow, turbulent, vortex shedding, steady-state, or transient).

Based on the analysis performed for PBNP, the reactor internals response due to FIV is small and well within the allowable based on the high-cycle fatigue endurance limit for the material. Specific FIV evaluations are performed only for the guide tubes and the thermal shield top support bolts and flexures. The guide tubes are selected to ensure control rod insertion. Therefore, it is necessary to show that the response due to FIV remains within acceptable limits. The thermal shield top support block bolts and flexures are selected based on the thermal shield bolt failure in one of the three-loop plants that was observed in the past.

Strain gauge measurements on other key upper and lower internals, such as, lower support plate, lower support columns, lower radial support keys, upper core plate and upper core plate alignment pins were not taken during in-plant testing of Ginna. However, it has been shown in similar circumstances that the maximum stress due to FIV at the lower support columns and lower support plate for a Westinghouse three-loop plant were only 65 psi and 225 psi, respectively. Consequently, the stresses at these components due to FIV for PBNP would also be negligible for the EPU conditions.

Based on the above discussion, the guide tubes and the thermal shield top support bolts and flexures evaluated for PBNP Units 1 and 2 are reasonable. The evaluation results demonstrate that these components remain functional and structural integrity is maintained at EPU conditions in regards to FIV response of the reactor internal components.

References

(1) NRC electronic mail to NextEra Energy Point Beach, LLC, dated August 26, 2010, Point Beach Nuclear Plant, Units 1 and 2 - Requests for Additional Additional Associated with Extended Power Uprate (TAC Nos. ME1044 and ME1045) (ML102440095)

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

(3) U.S. Nuclear Regulatory Commission, "Pressurizer Surge Line Thermal Stratification," NRC Bulletin No. 88-11, dated December 20, 1988 (ML031220290)

(4) NextEra Energy Point Beach, LLC letter to NRC, dated October 9, 2009, License Amendment Request 261, Extended Power Uprate, Response to Acceptance Review Questions (ML092860098)

(5) NextEra Energy Point Beach, LLC letter to NRC, dated January 8, 2010, License Amendment Request 261, Extended Power Uprate, Auxiliary Feedwater System Pipe Stress Analysis Information (ML100110037)

(6) NextEra Energy Point Beach, LLC letter to NRC, dated February 11, 2010, License Amendment Request 261, Extended Power Uprate, Withdrawal of Expedited Review Request (ML100470786)

(7) U.S. Nuclear Regulatory Commission, "Rapidly Propagating Fatigue Cracks in Steam Generator Tubes," NRC Bulletin No. 88-02, dated February 5, 1988 (ML031220043)

(8) U.S. Nuclear Regulatory Commission, "Comprehensive Vibration Assessment Program for Reactor Internals during Preoperational and Initial Startup Testing," Regulatory Guide 1.20, Revision 3, dated March 2007 (ML070260376)

ENCLOSURE 4
ATTACHMENT 1

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

LICENSE AMENDMENT REQUEST 261
EXTENDED POWER UPRATE

PIPE STRESS SUMMARY AT EPU CONDITIONS

14 pages follow

Piping Analysis Description	Loading Condition (Note 2)	Existing Stress (psi) (Note 4)	EPU Stress (psi)	Allowable Stress (psi)	Stress Interaction Ratio (Note 1 & 3)
Unit 1, Main Steam Inside Containment Loop A Steam Generator 1-HX-1A to Penetration P-1	Equation 8 (Sustained)	11,112	11,112	17,500	0.64
	Equation 9B (Occasional)	17,849	19,107	21,000	0.91
	Equation 9C (Occasional)	19,107	21,405	31,500	0.68
Unit 1 Main Steam Inside Containment Loop B Steam Generator 1-HX-1B to Penetration P-2	Equation 8 (Sustained)	10,786	10,786	17,500	0.62
	Equation 9B (Occasional)	12,371	12,676	21,000	0.60
	Equation 9C (Occasional)	13,506	13,546	31,500	0.43
Unit 1 Main Steam Outside Containment	Equation 8 (Sustained)	12,130	10,552	17,500	0.60
	Equation 9B (Occasional)	19,107	20,930	21,000	0.997
	Equation 9C (Occasional)	23,608	25,081	31,500	0.80
Unit 2 Main Steam Inside Containment Loop A Steam Generator 2-HX-1A to Penetration P-1	Equation 8 (Sustained)	10,800	11,057	17,500	0.63
	Equation 9B (Occasional)	19,297	20,706	21,000	0.99
	Equation 9C (Occasional)	29,046	29,984	31,500	0.95
Unit 2 Main Steam Inside Containment Loop B Steam Generator 2-HX-1B to Penetration P-2	Equation 8 (Sustained)	11,100	10,885	17,500	0.62
	Equation 9B (Occasional)	12,517	12,320	21,000	0.59
	Equation 9C (Occasional)	14,186	13,929	31,500	0.44

Piping Analysis Description	Loading Condition (Note 2)	Existing Stress (psi) (Note 4)	EPU Stress (psi)	Allowable Stress (psi)	Stress Interaction Ratio (Note 1 & 3)
Unit 2 Main Steam Outside Containment	Equation 8 (Sustained)	14,849	14,698	15,000	0.98
	Equation 9B (Occasional)	19,107	20,827	21,000	0.99
	Equation 9C (Occasional)	26,241	27,206	31,500	0.86
Unit 1 Feedwater Inside Containment Loop A	Equation 8 (Sustained)	7,450	9,311	15,000	0.62
	Equation 9B (Occasional)	14,780	15,119	18,000	0.84
	Equation 9C (Occasional)	20,643	20,812	27,000	0.77
	Equation 11 (Sustained + Thermal)	17,692	18,277	37,500	0.49
Unit 1 Feedwater Inside Containment Loop B	Equation 8 (Sustained)	N/A	9,257	15,000	0.62
	Equation 9B (Occasional)	11,163	11,293	18,000	0.63
	Equation 9C (Occasional)	12,630	12,706	27,000	0.47
	Equation 11 (Sustained + Thermal)	22,220	23,009	37,500	0.61
Unit 1 Feedwater Outside Containment	Equation 8 (Sustained)	5,975	13,761	15,000	0.92
	Equation 9B (Occasional)	17,098	17,970	18,000	0.998
	Equation 9C (Occasional)	26,556	26,114	27,000	0.97
	Equation 11 (Sustained + Thermal)	17,858	19,254	37,500	0.51

Piping Analysis Description	Loading Condition (Note 2)	Existing Stress (psi) (Note 4)	EPU Stress (psi)	Allowable Stress (psi)	Stress Interaction Ratio (Note 1 & 3)
Unit 2 Feedwater Inside Containment Loop A	Equation 8 (Sustained)	7,920	9,660	15,000	0.64
	Equation 9B (Occasional)	14,027	14,588	18,000	0.81
	Equation 9C (Occasional)	16,310	16,691	27,000	0.62
	Equation 11 (Sustained + Thermal)	17,351	17,708	37,500	0.47
Unit 2 Feedwater Inside Containment Loop B	Equation 8 (Sustained)	8,070	8,780	15,000	0.59
	Equation 9B (Occasional)	12,324	12,625	18,000	0.70
	Equation 9C (Occasional)	15,960	16,133	27,000	0.60
	Equation 11 (Sustained + Thermal)	14,508	14,785	37,500	0.39
Unit 2 Feedwater Outside Containment	Equation 8 (Sustained)	6,920	14,008	15,000	0.93
	Equation 9B (Occasional)	17,528	17,561	18,000	0.98
	Equation 9C (Occasional)	26,444	25,306	27,000	0.94
	Equation 11 (Sustained + Thermal)	20,960	23,675	37,500	0.63
Unit 1 Condensate Inlet and Outlet to FWH-20A & 20B	Equation 8 (Sustained)	N/A	5,121	15,000	0.34
	Equation 10 (Thermal)	N/A	4,335	22,500	0.19

Piping Analysis Description	Loading Condition (Note 2)	Existing Stress (psi) (Note 4)	EPU Stress (psi)	Allowable Stress (psi)	Stress Interaction Ratio (Note 1 & 3)
Unit 1 Extraction Steam Inlet to FWH-20A & 20B	Equation 8 (Sustained)	N/A	3,335	15,130	0.22
	Equation 11 (Sustained + Thermal)	32,700	34,546	42,350	0.82
Unit 1 Heater Drains Outlet from FWH-20A & 20B to HD Tank	Equation 8 (Sustained)	N/A	4,286	15,000	0.29
	Equation 10 (Thermal)	N/A	6,827	22,500	0.30
Unit 1 Heater Drains Outlet from FWH-21A to FWH-20A	Equation 8 (Sustained)	N/A	6,399	15,000	0.43
	Equation 10 (Thermal)	7,497	8,852	22,500	0.39
Unit 1 FWH-20A & 20B Vent Piping from Drain Tank	Equation 8 (Sustained)	N/A	2,390	15,000	0.16
	Equation 10 (Thermal)	N/A	4,718	22,500	0.21
Unit 1 Extraction Steam Inlet to FWH-21A & 21B	Equation 8 (Sustained)	N/A	7,423	14,690	0.51
	Equation 10 (Thermal)	7,842	10,702	27,110	0.39
Unit 1 FWH-20A & B and FWH-21A&B RV Discharge	Equation 8 (Sustained)	N/A	2,161	15,000	0.14
	Equation 10 (Thermal)	15,900	16,751	22,500	0.74
Unit 1 Heater Drains Outlet from FWH-21B to FWH-20B	Equation 8 (Sustained)	N/A	14,362	15,000	0.96
	Equation 10 (Thermal)	N/A	9,296	22,500	0.41

Piping Analysis Description	**Loading Condition** (Note 2)	**Existing Stress (psi)** (Note 4)	**EPU Stress (psi)**	**Allowable Stress (psi)**	**Stress Interaction Ratio** (Note 1 & 3)
Unit 1 Heater Drains Inlet FWH-21A & 21B	Equation 8 (Thermal)	N/A	11,165	15,000	0.74
	Equation 10 (Thermal)	17,682	17,346	22,500	0.77
Unit 1 MSR to Heater Drain Tank	Equation 10 (Thermal)	11,799	12,256	22,500	0.54
Unit 1 Loop A Main Steam to Inlet of AFW Pump Turbine	Equation 10 (Thermal)	7,990	10,387	22,500	0.46
Unit 1 Loop B Main Steam to Inlet of AFW Pump Turbine	Equation 10 (Thermal)	6,600	8,580	22,500	0.38
Unit 2 Loop A Main Steam to Inlet of AFW Pump Turbine	Equation 10 (Thermal)	6,540	8,502	22,500	0.38
Unit 2 Loop B Main Steam to Inlet of AFW Pump Turbine	Equation 10 (Thermal)	6,510	8,463	22,500	0.38
Units 1 & 2 MS Inlet Piping MSR A, B, C & D	Equation 10 (Thermal)	2,657	2,904	22,500	0.13
Extraction Steam from Crossunder Piping (H.P. Turbine Nozzles to Preseparator)	Equation 8 (Sustained)	N/A	4,668	15,130	0.31
	Equation 10 (Thermal)	N/A	7,117	27,220	0.26
Unit 2, 4th Point Heaters A & B Drain Outlet Piping	Equation 8 (Sustained)	N/A	3,654	15,000	0.24
	Equation 10 (Thermal)	N/A	6,543	22,500	0.29

Piping Analysis Description	Loading Condition (Note 2)	Existing Stress (psi) (Note 4)	EPU Stress (psi)	Allowable Stress (psi)	Stress Interaction Ratio (Note 1 & 3)
Unit 2, 5th Point Heater B Drain Outlet to 4th Point Heater B	Equation 8 (Sustained)	N/A	5,344	15,000	0.36
	Equation 10 (Thermal)	N/A	9,204	22,500	0.41
Unit 2, 5th Point Heater A Drain Outlet to 4th Point Heater A	Equation 8 (Sustained)	N/A	6,791	15,000	0.45
	Equation 10 (Thermal)	N/A	8,513	22,500	0.38
Unit 2, 4th and 5th Point Heaters A and B Noz. N6 to Atmospheric Blowoff Tank	Equation 8 (Sustained)	N/A	2,511	15,000	0.17
	Equation 9 (Occasional)	N/A	6,746	27,000	0.25
	Equation 11 (Sustained + Thermal)	N/A	18,112	37,500	0.48
Unit 2, 1st Point Heaters A & B Inlet and 3rd Point Heaters A & B Outlet Piping.	Equation 8 (Sustained)	N/A	9,915	15,000	0.66
	Equation 11 (Sustained + Thermal)	N/A	26,570	37,500	0.71
Unit 2, 1st Point Heaters A & B Steam Inlet Piping, (Nozzle N3A)	Equation 8 (Sustained)	N/A	1,265	15,000	0.08
	Equation 11 (Sustained + Thermal)	N/A	2,469	37,500	0.07
Unit 2, 1st Point Heaters A & B Steam Inlet Piping, (Nozzle N3B)	Equation 8 (Sustained)	N/A	1,832	15,000	0.12
	Equation 11 (Sustained + Thermal)	N/A	4,186	37,500	0.11

Piping Analysis Description	**Loading Condition** (Note 2)	**Existing Stress (psi)** (Note 4)	**EPU Stress (psi)**	**Allowable Stress (psi)**	**Stress Interaction Ratio** (Note 1 & 3)
Unit 2, 1st Point Heaters A & B Steam Inlet Piping, (Nozzle N3C)	Equation 8 (Sustained)	N/A	1,099	15,000	0.07
	Equation 11 (Sustained + Thermal)	N/A	3,598	37,500	0.10
Unit 2, 1st Point Heaters A & B Steam Inlet Piping, (Nozzle N3D)	Equation 8 (Sustained)	N/A	1,843	15,000	0.12
	Equation 11 (Sustained + Thermal)	N/A	6,460	37,500	0.17
Unit 2, 1st Point Heaters A & B Operating Air Outlet Piping (Nozzle N8)	Equation 8 (Sustained)	N/A	1,676	15,000	0.11
	Equation 10 (Thermal)	N/A	2,517	22,500	0.11
Unit 2, 2nd Point Heaters A & B (FW Outlet) to 3rd Point Heaters A & B (FW Inlet Piping)	Equation 8 (Sustained)	N/A	4,005	15,000	0.27
	Equation 10 (Thermal)	N/A	8,196	22,500	0.36
Unit 2, 2nd Point Heaters A & B,Extraction Steam Inlet (Nozzle N23A)	Equation 8 (Sustained)	N/A	2,059	15,000	0.14
	Equation 10 (Thermal)	N/A	1,178	22,500	0.05
Unit 2, 2nd Point Heaters A & B,Extraction Steam Inlet (Nozzle N23B)	Equation 8 (Sustained)	N/A	3,527	15,000	0.24
	Equation 10 (Thermal)	N/A	4,152	22,500	0.18
Unit 2, 2nd Point Heaters A & B, Operating Air Outlet Piping (Nozzle N28)	Equation 8 (Sustained)	N/A	3,343	15,000	0.22
	Equation 10 (Thermal)	N/A	1,380	22,500	0.06
Unit 2, 3rd Point Heaters A & B, Steam Inlet Piping (Nozzle N3)	Equation 8 (Sustained)	N/A	10,546	15,000	0.7
	Equation 10 (Thermal)	N/A	7,693	22,500	0.34

Piping Analysis Description	**Loading Condition** (Note 2)	**Existing Stress (psi)** (Note 4)	**EPU Stress (psi)**	**Allowable Stress (psi)**	**Stress Interaction Ratio** (Note 1 & 3)
Unit 1, FW Pump Suction Piping	Equation 8 (Sustained)	N/A	9,437	15,000	0.63
	Equation 10 (Thermal)	N/A	21,511	22,500	0.96
Unit 2, 1st Point Heaters A & B, Drain Outlet Piping	Equation 8 (Sustained)	N/A	1,053	15,000	0.07
	Equation 10 (Thermal)	N/A	1,086	22,500	0.05
Unit 2, 2nd Point Heaters A & B, Drain Outlet Piping	Equation 8 (Sustained)	N/A	1,207	15,000	0.08
	Equation 10 (Thermal)	N/A	5,047	22,500	0.22
Unit 2, 3rd Point Heaters A & B, Drain Outlet Piping	Equation 8 (Sustained)	N/A	7,182	15,000	0.48
	Equation 10 (Thermal)	N/A	2,452	22,500	0.11
Unit 2, 1st Point Heaters A & B, Emergency Drain Cooler Bypass Piping	Equation 8 (Sustained)	N/A	5,844	15,000	0.39
	Equation 10 (Thermal)	N/A	7,618	22,500	0.34
Unit 2, 2nd Point Heaters A & B, Emergency Drain Cooler Bypass Piping	Equation 8 (Sustained)	N/A	4,614	15,000	0.31
	Equation 10 (Thermal)	N/A	10,696	22,500	0.48
Unit 2, 3rd Point Heaters A & B, Emergency Drain Outlet Piping	Equation 8 (Sustained)	N/A	4,746	15,000	0.32
	Equation 10 (Thermal)	N/A	10,085	22,500	0.45
Unit 1, 4th Point Heater A, Liquid Level Control Connection Tree	Equation 8 (Sustained)	N/A	10,558	15,000	0.71
	Equation 10 (Thermal)	N/A	11,883	22,500	0.53

Piping Analysis Description	Loading Condition (Note 2)	Existing Stress (psi) (Note 4)	EPU Stress (psi)	Allowable Stress (psi)	Stress Interaction Ratio (Note 1 & 3)
Unit 1, 4th Point Heater B, Liquid Level Control Connection Tree	Equation 8 (Sustained)	N/A	10,659	15,000	0.71
	Equation 10 (Thermal)	N/A	13,610	22,500	0.60
Unit 1, 5th Point Heaters A & B, Level Tree Piping	Equation 8 (Sustained)	N/A	13,492	15,000	0.90
	Equation 10 (Thermal)	N/A	6,371	22,500	0.28
Unit 1, Feedwater Pump A, Recirculation Piping	Equation 8 (Sustained)	N/A	6,609	16,275	0.41
	Equation 9 (Occasional)	N/A	8,519	29,295	0.29
	Equation 11 (Sustained + Thermal)	N/A	21,315	43,719	0.49
Unit 1, Feedwater Pump B, Recirculation Piping	Equation 8 (Sustained)	N/A	7,052	16,275	0.43
	Equation 9 (Occasional)	N/A	8,491	29,295	0.29
	Equation 11 (Sustained + Thermal)	N/A	16,901	43,719	0.39
Unit 1, Heater Drain Tank Pump Recirculation Replacement Piping	Equation 8 (Sustained)	N/A	4,116	15,000	0.27
	Equation 10 (Thermal)	N/A	12,176	22,500	0.54
Unit 1, Heater Drain Tank Pump Discharge Replacement Piping	Equation 8 (Sustained)	N/A	6,364	15,000	0.42
	Equation 10 (Thermal)	N/A	13,185	22,500	0.59
Unit 1, Heater Drain Tank Dump to Condenser Piping	Equation 8 (Sustained)	N/A	5,224	15,000	0.35
	Equation 10 (Thermal)	N/A	6,841	22,500	0.30

Piping Analysis Description	Loading Condition (Note 2)	Existing Stress (psi) (Note 4)	EPU Stress (psi)	Allowable Stress (psi)	Stress Interaction Ratio (Note 1 & 3)
Unit 1, 1st Point Heaters A & B Inlet and 3rd Point Heaters A & B Outlet Piping	Equation 8 (Sustained)	N/A	6,824	15,000	0.45
	Equation 11 (Sustained + Thermal)	N/A	27,465	37,500	0.73
Unit 1, 1st Point Heaters A & B Steam Inlet Piping (Max. stress of all Parts analysed)	Equation 8 (Sustained)	N/A	1,843	15,000	0.12
	Equation 10 (Thermal)	N/A	4896	22,500	0.22
Unit 1, 1st Point Heaters A & B Operating Air Outlet Piping	Equation 8 (Sustained)	N/A	1,631	15,000	0.11
	Equation 10 (Thermal)	N/A	2,506	22,500	0.11
Unit 1, 2nd Point Heaters A & B Feedwater Outlet Piping	Equation 8 (Sustained)	N/A	4,147	15,000	0.28
	Equation 10 (Thermal)	N/A	8,210	22,500	0.36
Unit 1, 2nd Point Heaters A & B Extraction Steam Inlet Nozzle (Max. stress of Part 8 & Part 9)	Equation 8 (Sustained)	N/A	4,586	15,000	0.31
	Equation 10 (Thermal)	N/A	4,178	22,500	0.19
Unit 1, 2nd Point Heaters A & B Operating Air Outlet Piping	Equation 8 (Sustained)	N/A	4,366	15,000	0.29
	Equation 10 (Thermal)	N/A	1,380	22,500	0.06
Unit 1, 3rd Point Heaters A & B, Steam Inlet Piping	Equation 8 (Sustained)	N/A	10,546	15,000	0.70
	Equation 10 (Thermal)	N/A	7,693	22,500	0.34
Unit 1, 1st Point Heaters A & B, Drain Outlet Piping	Equation 8 (Sustained)	N/A	1,507	15,000	0.10
	Equation 10 (Thermal)	N/A	1,045	22,500	0.05
Unit 1, 2nd Point Heaters A & B, Drain Outlet Piping	Equation 8 (Sustained)	N/A	3,520	15,000	0.24
	Equation 10 (Thermal)	N/A	4,338	22,500	0.19

Piping Analysis Description	Loading Condition (Note 2)	Existing Stress (psi) (Note 4)	EPU Stress (psi)	Allowable Stress (psi)	Stress Interaction Ratio (Note 1 & 3)
Unit 1, 3rd Point Heaters A & B, Drain Outlet Piping	Equation 8 (Sustained)	N/A	5,126	15,000	0.34
	Equation 10 (Thermal)	N/A	1,998	22,500	0.09
Unit 1, 1st Point Heaters A & B, Emergency Drain Cooler Bypass Piping	Equation 8 (Sustained)	N/A	6,449	15,000	0.43
	Equation 10 (Thermal)	N/A	8,474	22,500	0.38
Unit 1, 2nd Point Heaters A & B, Emergency Drain Cooler Bypass Piping	Equation 8 (Sustained)	N/A	4,395	15,000	0.29
	Equation 10 (Thermal)	N/A	11,116	22,500	0.49
Unit 1, 3rd Point Heaters A & B, Emergency Drain Outlet Piping	Equation 8 (Sustained)	N/A	4,611	15,000	0.31
	Equation 10 (Thermal)	N/A	9,635	22,500	0.43
Unit 1, Heater Relief Line Piping from Nozzle 6 of the 4th & 5th Point Heaters to Atmospheric Blowoff Tank	Equation 8 (Sustained)	N/A	1,995	15,000	0.13
	Equation 9 (Occasional)	N/A	6,000	18,000	0.33
	Equation 11 (Sustained + Thermal)	N/A	21,752	37,500	0.58
Unit 1, Heater Drain Tank Level Tree Replacement Piping	Equation 8 (Sustained)	N/A	13,993	15,000	0.93
	Equation 10 (Thermal)	N/A	10,065	22,500	0.45
Unit 2, Generator Bus Cooler Replacement Piping	Equation 8 (Sustained)	N/A	4,284	15,000	0.29
	Equation 10 (Thermal)	N/A	14,735	22,500	0.65
Unit 1, Condensate Pump Motor Cooler Replacement Piping (Supply & Return)	Equation 8 (Sustained)	N/A	2,543	15,000	0.17
	Equation 10 (Thermal)	N/A	21,673	22,500	0.96

Piping Analysis Description	**Loading Condition** (Note 2)	**Existing Stress (psi)** (Note 4)	**EPU Stress (psi)**	**Allowable Stress (psi)**	**Stress Interaction Ratio** (Note 1 & 3)
Unit 1, FW Heaters 1-3 Level Tree Replacement Piping	Equation 8 (Sustained)	N/A	12,775	15,000	0.85
	Equation 10 (Thermal)	N/A	20,254	22,500	0.90
Unit 1, Generator Bus Cooler Replacement Piping	Equation 8 (Sustained)	N/A	6,295	15,000	0.42
	Equation 10 (Thermal)	N/A	18,183	22,500	0.81
Unit 2, Condensate Pump Motor Cooler Replacement Piping (Supply & Return)	Equation 8 (Sustained)	N/A	2,777	15,000	0.19
	Equation 10 (Thermal)	N/A	12,110	22,500	0.54
Unit 2, FW Heaters 1-3 Level Tree Replacement Piping	Equation 8 (Sustained)	N/A	12,781	15,000	0.85
	Equation 10 (Thermal)	N/A	20,253	22,500	0.90
Unit 1, SGFP Seal Water & Lube Oil Cooling Water Replacement Piping	Equation 8 (Sustained)	N/A	10,270	15,000	0.68
	Equation 10 (Thermal)	N/A	4,601	22,500	0.20
Unit 1, Feedwater Pumps 1P-28A & 1P-28B Warm-Up Replacement Piping	Equation 8 (Sustained)	N/A	8,089	15,000	0.54
	Equation 10 (Thermal)	N/A	8,671	22,500	0.39
Unit 2, Heater Drain Tank Pump Recirculation Replacement Piping	Equation 8 (Sustained)	N/A	4,172	15,000	0.28
	Equation 10 (Thermal)	N/A	14,143	22,500	0.63
Unit 2, Heater Drain Tank Pump discharge Replacement Piping	Equation 8 (Sustained)	N/A	9,345	15,000	0.62
	Equation 10 (Thermal)	N/A	13,504	22,500	0.60

Piping Analysis Description	**Loading Condition** (Note 2)	**Existing Stress (psi)** (Note 4)	**EPU Stress (psi)**	**Allowable Stress (psi)**	**Stress Interaction Ratio** (Note 1 & 3)
Unit 2, Heater Drain Tank Dump to Condenser Piping	Equation 8 (Sustained)	N/A	4,330	15,000	0.29
	Equation 10 (Thermal)	N/A	6,596	22,500	0.29
Unit 2, Qualification of MSR D Reheater Line 2”-ED-2 Piping & Pipe supports for Vibration associated with EPU conditions	Equation 8 (Sustained)	N/A	5,599	18,700	0.30
	Equation 10 (Thermal)	N/A	16,644	26,375	0.63
Unit 2, Heater Drain Tank Level Tree Replacement Piping	Equation 8 (Sustained)	N/A	12,629	15,000	0.84
	Equation 10 (Thermal)	N/A	11,249	22,500	0.50
Unit 2, Feedwater Pump A, Recirculation Piping	Equation 8 (Sustained)	N/A	7,179	16,275	0.44
	Equation 9 (Occasional)	N/A	20,504	29,295	0.70
	Equation 11 (Sustained + Thermal)	N/A	36,496	43,719	0.83
Unit 2, Feedwater Pump B, Recirculation Piping	Equation 8 (Sustained)	N/A	6,425	16,275	0.39
	Equation 9 (Occasional)	N/A	14,295	29,295	0.49
	Equation 11 (Sustained + Thermal)	N/A	21,154	43,719	0.48
Unit 2, Feedwater Pump Suction Replacement Piping	Equation 8 (Sustained)	N/A	7,826	15,000	0.52
	Equation 11 (Sustained + Thermal)	N/A	34,052	37,500	0.91

Piping Analysis Description	Loading Condition (Note 2)	Existing Stress (psi) (Note 4)	EPU Stress (psi)	Allowable Stress (psi)	Stress Interaction Ratio (Note 1 & 3)
Unit 2, SGFP Seal Water & Lube Oil cooling Water Replacement Piping	Equation 8 (Sustained)	N/A	10,073	15,000	0.67
	Equation 10 (Thermal)	N/A	7,767	22,500	0.35
Unit 2, Feedwater Pumps 2P-28A & 2p-28B Warm-Up Replacement Piping	Equation 8 (Sustained)	N/A	10,555	15,000	0.70
	Equation 10 (Thermal)	N/A	13,577	22,500	0.60
Unit 2, Feedwater Isolation Valve Air & Nitrogen Supply Piping	Equation 8 (Sustained)	N/A	3,876	6,000	0.65
	Equation 9B (Occasional)	N/A	7,115	7,200	0.99
	Equation 9C (Occasional)	N/A	9,950	10,800	0.92
	Equation 11 (Sustained + Thermal)	N/A	11,967	15,000	0.80

NOTES:

(1) The Design Margin is based on the ratio of EPU stress divided by the Allowable stress.

(2) The Equation Numbers shown correspond to ASME Section III, NC/ND-3650 equation numbers.

(3) With respect to piping analyses containing stress interaction ratio greater than 0.90 for EPU conditions, it should be noted that the existing stress interaction ratio (for the same loading condition) for all these piping analyses, with the single exception of U1 Main Steam Piping Inside Containment Loop A, are currently greater than 0.90. For example, the U2 Main Steam Piping Inside Containment Loop A, Equation 9C, has a reported stress interaction ratio of 0.95 based on the ratio of 29,984 (EPU stress) divided by 31,500 (allowable stress). The existing stress interaction ratio for this piping is 0.92 based on the ratio of 29,046 (current stress) divided by 31,500 (allowable stress). Hence, for this piping system, the actual stress increase resulting from EPU is insignificant. Additionally, all stress levels resulting in stress interaction ratio less than or equal to 1.0 are acceptable limits in accordance with USAS B31.1 code of record. The allowable stress levels for the USAS B31.1 code are stress levels that are well below material ultimate stress limits.

(4) Where information is not provided, the information was not available.

ENCLOSURE 4
ATTACHMENT 2

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

LICENSE AMENDMENT REQUEST 261
EXTENDED POWER UPRATE

MAIN FEEDWATER PUMP NOZZLE LOAD SUMMARY

5 pages follow

Table 7-8.1						
Equipment: Pump 1-P28A (Discharge) **Absolute Max. Thermal Cases 1, 2, 4** Ref. 129187-P-0015 (Node 5)						
Load Type	Reactions in Local Coordinates (lb, ft-lb)					
	Fx	Fy	Fz	Mx	My	Mz
ABS_{MAX}(Weight + Thermal)	784	2220	968	1468	2854	7810
Vendor Allowable	806	2402	2139	3309	4827	11507
I.Ratio (STATIC ONLY)	0.97	0.92	0.45	0.44	0.59	0.68

Table 7-8.2						
Equipment: Pump 1-P28A (Discharge) **Absolute Max. Thermal Cases 3, 5, 6, 7** Ref. 129187-P-0015 (Node 5)						
Load Type	Reactions in Local Coordinates (lb, ft-lb)					
	Fx	Fy	Fz	Mx	My	Mz
ABS_{MAX} (Weight + Thermal)	861	1711	877	1468	3279	5608
API Allowable	3200	2600	4000	9400	4600	7000
I.Ratio (STATIC ONLY)	0.27	0.66	0.22	0.16	0.71	0.80

Table 7-8.3						
Equipment: Pump 1-P28B (Discharge) **Absolute Max. of All Thermal Cases** Ref. 129187-P-0015 (Node 195)						
Load Type	Reactions in Local Coordinates (lb, ft-lb)					
	Fx	Fy	Fz	Mx	My	Mz
ABS_{MAX} (Weight + Thermal)	1915	862	1796	3890	4239	2605
API Allowable	3200	2600	4000	9400	4600	7000
I.Ratio (STATIC ONLY)	0.60	0.33	0.45	0.41	0.92	0.37

Table 7-8.4						
Equipment: Pump 1-P28A (Discharge) **Absolute Max. from All Thermal Cases** Ref. 129187-P-0015 (Node 5)						
Load Type	Reactions in Local Coordinates (lb, ft-lb)					
	Fx	Fy	Fz	Mx	My	Mz
Weight+Thermal+OCC-1	1851	2715	2151	2046	6937	9479
Weight+Thermal+OCC-2	1359	2537	1810	1826	5240	8494
MAX	1851	2715	2151	2046	6937	9479
Vendor Allowable	4040	4540	5476	27073	16844	11287
I.Ratio (TRANSIENT ONLY)	0.46	0.60	0.39	0.08	0.41	0.84

Table 7-8.5						
Equipment: Pump 1-P28B (Discharge) **Absolute Max. Value from All Thermal Cases** Ref. 129187-P-0015 (Node 195)						
Load Type	Reactions in Local Coordinates (lb, ft-lb)					
	Fx	Fy	Fz	Mx	My	Mz
Weight+Thermal+OCC-1	3435	2322	3292	8903	8457	5501
Weight+Thermal+OCC-2	2963	1665	2742	6983	6884	4342
MAX	3435	2322	3292	8903	8457	5501
Vendor Allowable	4040	4540	5476	27073	16844	11287
I.Ratio (TRANSIENT ONLY)	0.85	0.51	0.60	0.33	0.50	0.49

Table 7-8.6						
Equipment: Pump 1-P28A (Suction) **Absolute Max. of All Thermal Cases** Ref. 129187-P-0046 (Node 850)						
Load Type	Reactions in Local Coordinates (lb, ft-lb)					
	Fx	Fy	Fz	Mx	My	Mz
ABS_{MAX} (Weight + Thermal)	1439	976	2930	5590	4170	4004
API Allowable	3800	3000	4600	10800	5400	8000
I.Ratio (STATIC ONLY)	0.38	0.33	0.64	0.52	0.77	0.50

Table 7-8.7						
Equipment: Pump 1-P28B (Suction) **Absolute Max. of All Thermal Cases** Ref. 129187-P-0046 (Node 1280)						
Load Type	Reactions in Local Coordinates (lb, ft-lb)					
	Fx	Fy	Fz	Mx	My	Mz
ABS_{MAX} (Weight + Thermal)	738	513	1959	2657	3047	3292
API Allowable	3800	3000	4600	10800	5400	8000
I.Ratio (STATIC ONLY)	0.19	0.17	0.43	0.25	0.56	0.41

Table 7-8.8						
Equipment: Pump 2-P28A (Discharge) **Absolute Max. Thermal Cases 1, 2, 3, 4, 5, 7** Ref. 129187-P-0018 (Node 3005)						
Load Type	Reactions in Local Coordinates (lb, ft-lb)					
	Fx	Fy	Fz	Mx	My	Mz
ABS_{MAX}(Weight + Thermal)	1847	868	4981	7395	6011	1207
Vendor Allowable	2337	1098	6276	9355	7604	1527
I.Ratio (STATIC ONLY)	0.79	0.79	0.79	0.79	0.79	0.79 *

* It should be noted that the Interaction ratio value of 0.79 for all loading directions is due to the fact that the calculated loads were increased by the same percentage (approximately 26%) due to the pump qualification performed by the vendor.

Table 7-8.9						
Equipment: Pump 2-P28A (Discharge) **Absolute Max. Thermal Case 6** Ref. 129187-P-0018 (Node 3005)						
Load Type	Reactions in Local Coordinates (lb, ft-lb)					
	Fx	Fy	Fz	Mx	My	Mz
ABS_{MAX} (Weight + Thermal)	1182	906	1719	7742	3617	3856
API Allowable	3200	2600	4000	9400	4600	7000
I.Ratio (STATIC ONLY)	0.37	0.35	0.43	0.82	0.79	0.55

Table 7-8.10						
Equipment: Pump 2-P28B (Discharge) **Absolute Max. Thermal Cases 1, 2, 4, 6 (See Note 1)** Ref. 129187-P-0018 (Node 3180)						
Load Type	Reactions in Local Coordinates (lb, ft-lb)					
	Fx	Fy	Fz	Mx	My	Mz
ABS_{MAX}(Weight + Thermal)	764	1899	1691	2615	3815	9096
Vendor Allowable	806	2402	2139	3309	4827	11507
I.Ratio (STATIC ONLY)	0.95	0.79	0.79	0.79	0.79	0.79

Table 7-8.11						
Equipment: Pump 2-P28B (Discharge) ***Absolute Max. Thermal Case 7*** Ref. 129187-P-0018 (Node 3180)						
Load Type	Reactions in Local Coordinates (lb, ft-lb)					
	Fx	Fy	Fz	Mx	My	Mz
ABS_{MAX}(Weight + Thermal)	3223	365	1974	1450	4404	385
Vendor Allowable	4077	502	2497	1834	5571	574
I.Ratio (STATIC ONLY)	0.79	0.73	0.79	0.79	0.79	0.67 *

* It should be noted that the Interaction ratio value of 0.79 for all loading directions is due to the fact that the calculated loads were increased by the same percentage (approximately 26%) due to the pump qualification performed by the vendor.

<u>Table 7-8.10, Note 1:</u>

It should be noted that the maximum "weight + thermal" Fx load for Thermal Cases 3 and 5 is 1307 lbs, which is greater than the indicated Fx allowable of 806 lbs. However, the corresponding "weight + thermal" Case 3 and 5 Fy and Fz loads, and Mx, My and Mz moments are significantly less than the indicated allowables. Also, the My and Mz loads are the governing loads with respect to the static evaluations for determining coupling misalignment acceptability. As such, these two thermal Fx loading conditions (i.e., Thermal Cases 3 and 5) are acceptable.

Table 7-8.12						
Equipment: Pump 2-P28A (Discharge) **Absolute Max. from Thermal Cases 1, 2, 3, 4, 5, 7** Ref. 129187-P-0018 (Node 3005)						
Load Type	Reactions in Local Coordinates (lb, ft-lb)					
	Fx	Fy	Fz	Mx	My	Mz
Weight+Thermal+OCC-1	3859	3551	7591	21055	15709	6274
Weight+Thermal+OCC-2	3258	2572	6349	16018	12024	4672
MAX	3859	3551	7591	21055	15709	6274
Vendor Allowable	4882	4492	9577	26635	19872	7936
I.Ratio (TRANSIENT ONLY)	0.79	0.79	0.79	0.79	0.79	0.79

Table 7-8.13						
Equipment: Pump 2-P28A (Discharge) **Absolute Max. from Thermal Case 6** Ref. 129187-P-0018 (Node 3005)						
Load Type	Reactions in Local Coordinates (lb, ft-lb)					
	Fx	Fy	Fz	Mx	My	Mz
Weight+Thermal+OCC-1	3194	3589	4329	21402	13315	8923
Weight+Thermal+OCC-2	2593	2610	3087	16365	9630	7321
MAX	3194	3589	4329	21402	13315	8923
Vendor Allowable	4040	4540	5476	27073	16844	11287
I.Ratio (TRANSIENT ONLY)	0.79	0.79	0.79	0.79	0.79	0.79 *

Table 7-8.14						
Equipment: Pump 2-P28B (Discharge) **Absolute Max. from Thermal Cases 1, 2, 3, 4, 5, 6** Ref. 129187-P-0018 (Node 3180)						
Load Type	Reactions in Local Coordinates (lb, ft-lb)					
	Fx	Fy	Fz	Mx	My	Mz
Weight+Thermal+OCC-1	3171	2669	3067	6393	8768	10683
Weight+Thermal+OCC-2	3168	2314	2653	5301	7376	10021
MAX	3171	2669	3067	6393	8768	10683
Vendor Allowable	4040	4540	5476	27073	16844	11287
I.Ratio (TRANSIENT ONLY)	0.78	0.59	0.56	0.24	0.52	0.95

Table 7-8.15						
Equipment: Pump 2-P28B (Discharge) **Absolute Max. from Thermal Case 7** Ref. 129187-P-0018 (Node 3180)						
Load Type	Reactions in Local Coordinates (lb, ft-lb)					
	Fx	Fy	Fz	Mx	My	Mz
Weight+Thermal+OCC-1	5087	1135	3350	5228	9357	1972
Weight+Thermal+OCC-2	5084	780	2936	4136	7965	1310
MAX	5087	1135	3350	5228	9357	1972
Vendor Allowable	6435	1436	4238	6614	11837	2494
I.Ratio (TRANSIENT ONLY)	0.79	0.79	0.79	0.79	0.79	0.79 *

Table 7-8.16						
Equipment: Pump 2-P28A (Suction) **Absolute Max. of All Thermal Cases** Ref. 129187-P-0093 (Node 1270)						
Load Type	Reactions in Local Coordinates (lb, ft-lb)					
	Fx	Fy	Fz	Mx	My	Mz
ABS_{MAX} (Weight + Thermal)	278	145	1091	666	2817	2577
API Allowable	3800	3000	4600	10800	5400	8000
I.Ratio (STATIC ONLY)	0.07	0.05	0.24	0.06	0.52	0.32

Table 7-8.17						
Equipment: Pump 2-P28B (Suction) **Absolute Max. of All Thermal Cases** Ref. 129187-P-0093 (Node 825)						
Load Type	Reactions in Local Coordinates (lb, ft-lb)					
	Fx	Fy	Fz	Mx	My	Mz
ABS_{MAX} (Weight + Thermal)	2537	798	3345	8004	4862	5378
API Allowable	3800	3000	4600	10800	5400	8000
I.Ratio (STATIC ONLY)	0.67	0.27	0.73	0.74	0.90	0.67

* It should be noted that the Interaction ratio value of 0.79 for all loading directions is due to the fact that the calculated loads were increased by the same percentage (approximately 26%) due to the pump qualification performed by the vendor.

ENCLOSURE 4
ATTACHMENT 3

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

LICENSE AMENDMENT REQUEST 261
EXTENDED POWER UPRATE

STEAM GENERATOR MAIN STEAM NOZZLE LOAD SUMMARY

1 page follows

Main Steam (Unit 1)

Nozzle: (Steam Generator 1HX-1A)

Description	Forces (Kips)		Moments (in-Kips)	
	Axial (F_a)	Shear (F_V)	Bending (M_b)	Torsion (M_t)
Total Loads =(DW + SSE + TT + TH)	46.2	143	7,090.2	9,124
WNES Allowable	320	368	18,562	10,550

Nozzle: (Steam Generator 1HX-1B)

Description	Forces (Kips)		Moments (in-Kips)	
	Axial (F_a)	Shear (F_V)	Bending (M_b)	Torsion (M_t)
Total Loads =(DW + SSE + TT + TH)	32.0	110.6	6,138.2	9,349.6
WNES Allowable	320	368	18,562	10,550

Main Steam (Unit 2)

Nozzle: (Steam Generator 2HX-1A)

Description	Forces (Kips)		Moments (in-Kips)	
	Axial (F_a)	Shear (F_V)	Bending (M_b)	Torsion (M_t)
Total Loads =(DW + SSE + TT + TH)	49.7	193.3	9,344.6	10,348.1
WNES Allowable	320	368	18,562	10,550

Nozzle: (Steam Generator 2HX-1B)

Description	Forces (Kips)		Moments (in-Kips)	
	Axial (F_a)	Shear (F_V)	Bending (M_b)	Torsion (M_t)
Total Loads =(DW + SSE + TT + TH)	30.6	96.4	5,153.2	11,515 *
WNES Allowable	320	368	18,562	11,515 *

Notes:
DW = Dead Weight, SSE = Safe Shutdown Earthquake, TT = Turbine Trip,
TH = Thermal.
WNES = Westinghouse Nuclear Energy Systems
* Total loads approved by vendor

ENCLOSURE 4
ATTACHMENT 4

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

LICENSE AMENDMENT REQUEST 261
EXTENDED POWER UPRATE

STEAM GENERATOR FEEDWATER NOZZLE LOAD SUMMARY

1 page follows

Feedwater **(Unit 1)**

Nozzle: (Steam Generator 1HX-1A)

Description	Forces (Lbs)		Moments (ft-lbs)	
	Axial (F_a)	Shear (F_V)	Bending (M_b)	Torsion (M_t)
Total Loads =(DW + SSE + OCCU + TH)	5,332	11,951	104,501	91,335
WNES Allowable	220,000	353,624	648,181	312,500

Nozzle: (Steam Generator 1HX-1B) (All loads in Local coordinates)

Description	Forces (Lbs)		Moments (ft-lbs)	
	Axial (F_a)	Shear (F_V)	Bending (M_b)	Torsion (M_t)
Total Loads =(DW + SSE + OCCU + TH)	10,173	16,733	116,467	104,664
WNES Allowable	220,000	353,624	648,181	312,500

Feedwater **(Unit 2)**

Nozzle: (Steam Generator 2HX-1A)

Description	Forces (Lbs)		Moments (ft-lbs)	
	Axial (F_a)	Shear (F_V)	Bending (M_b)	Torsion (M_t)
Total Loads =(DW + SSE + OCCU + TH)	9,043	12,914	149,057	98,698
WNES Allowable	220,000	353,624	648,181	312,500

Nozzle: (Steam Generator 2HX-1B)

Description	Forces (Lbs)		Moments (ft-lbs)	
	Axial (F_a)	Shear (F_V)	Bending (M_b)	Torsion (M_t)
Total Loads =(DW + SSE + OCCU + TH)	6,327	12,178	111,369	55,246
WNES Allowable	220,000	353,624	648,181	312,500

Notes:
DW = Dead Weight, SSE = Safe Shutdown Earthquake, OCCU = Occasional,
TH = Thermal.
WNES = Westinghouse Nuclear Energy Systems

ENCLOSURE 4
ATTACHMENT 5

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

LICENSE AMENDMENT REQUEST 261
EXTENDED POWER UPRATE

CONTAINMENT PENETRATION MAIN STEAM LOAD SUMMARY

1 page follows

Unit 1

Penetration: (P-1) (EB-1-MS-69-A2)

Description	Forces (Kips)		Moments (ft-Kips)	
	Axial (F_a)	Shear (F_V)	Bending (M_b)	Torsion (M_t)
Total Loads (Calculated)	73.727	93.723	626.712	302.066 *
Allowable	353.0	353.0	975.0	302.066 *

Penetration: (P-2) (EB-1-MS-65-A1)

Description	Forces (Kips)		Moments (ft-Kips)	
	Axial (F_a)	Shear (F_V)	Bending (M_b)	Torsion (M_t)
Total Loads (Calculated)	65.882	33.938	344.439	123.348
Allowable	353.0	353.0	975.0	136

* Total load qualified by stress evaluation

Unit 2

Penetration: (P-1) (EB-2-MS-69-A2)

Description	Forces (Kips)		Moments (ft-Kips)	
	Axial (F_a)	Shear (F_V)	Bending (M_b)	Torsion (M_t)
Total Loads (Calculated)	100.568	109.166	806.713	317.425 *
Allowable	353.0	353.0	975.0	317.425 *

Penetration: (P-2) (EB-2-MS-65-A1)

Description	Forces (Kips)		Moments (ft-Kips)	
	Axial (F_a)	Shear (F_V)	Bending (M_b)	Torsion (M_t)
Total Loads (Calculated)	61.855	24.975	225.778	78.362
Allowable	353.0	353.0	975.0	136

* Total load qualified by stress evaluation

ENCLOSURE 4
ATTACHMENT 6

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

LICENSE AMENDMENT REQUEST 261
EXTENDED POWER UPRATE

CONTAINMENT PENETRATION FEEDWATER LOAD SUMMARY

1 page follows

Unit 1

Penetration: (P-3)

Description	Forces (Lbs)		Moments (ft-lbs)	
	Axial (F_a)	Shear (F_V)	Bending (M_b)	Torsion (M_t)
Total Loads (Calculated)	24,998	20,246	123,752	87,253
Allowable	192,000	185,000	870,000	1,125,000

Penetration: (P-4)

Description	Forces (Lbs)		Moments (ft-lbs)	
	Axial (F_a)	Shear (F_V)	Bending (M_b)	Torsion (M_t)
Total Loads (Calculated)	25,723	24,572	114,540	26,999
Allowable	192,000	185,000	870,000	1,125,000

Unit 2

Penetration: (P-3)

Description	Forces (Lbs)		Moments (ft-lbs)	
	Axial (F_a)	Shear (F_V)	Bending (M_b)	Torsion (M_t)
Total Loads (Calculated)	20,208	18,858	121,188	125,824
Allowable	192,000	185,000	870,000	1,125,000

Penetration: (P-4)

Description	Forces (Lbs)		Moments (ft-lbs)	
	Axial (F_a)	Shear (F_V)	Bending (M_b)	Torsion (M_t)
Total Loads (Calculated)	32,728	10,575	103,989	12,412
Allowable	192,000	185,000	870,000	1,125,000

ENCLOSURE 4
ATTACHMENT 7

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

LICENSE AMENDMENT REQUEST 261
EXTENDED POWER UPRATE

SUMMARY OF UNIT 1 PIPE SUPPORTS REQUIRING MODIFICATION

5 pages follow

ITEM	SUPPORT	SYSTEM	PIPE SIZE	BUILDING LOCATION	EPU LOAD (lbs)	DESCRIPTION / TYPE
1	EB-1-A1001X	MS	30"	F	52500	Adjust existing rod clearances
2	EB-1-B1001X	MS	30"	F	52500	Adjust existing rod clearances
3	EB-1-H20	MS	30"	F	57500	Support is modified to strut
4	EB-1-H200	MS	3"	F	500	Support is modified to add weld
5	EB-1-H201	MS	3"	F	500	Add weld to integral welded attachment
6	EB-1-H202	MS	30"	A	47000	Verify gaps, notify Engineering and then modify in accordance with hanger detail
7	EB-1-H20A	MS	30"	F	50000	Support is modified to strut
8	EB-1-H5	MS	30"	A	23000	Modify support to replace strut
9	EB-1-H6	MS	30"	A	33919	Verify gaps and install saddle/shims if required
10	EB-1-H7	MS	30"	A	14198	Verify gaps and install saddle/shims if required
11	EB-1-H9	MS	30"	F	60000	Support is modified to strut
12	EB-1-H9A	MS	30"	F	50000	Support is modified to strut
13	EB-1-R225	MS	30"	A	23783	Verify gaps and install saddle/shims if required
14	EB-1-R226	MS	30"	A	56998	Verify gaps and install saddle/shims if required
15	EB-2-EA1	MS	18"	T	9000	Modify support frame using tube steel
16	EB-2-H11	MS	6"	T	2442	Add plate to integral welded attachment
17	EB-2-H13	MS	6"	T	2269	Add plate to integral welded attachment
18	EB-2-H17	MS	16"	T	14000	Replace rod hanger with Fig 211 Size 3 strut.
19	EB-2-H200	MS	16"	T	9000	Support is modified to add weld
20	EB-2-H3	MS	18"	T	27200	Modify support by replacing strut
21	EB-2-H4	MS	18"	T	9000	Modify support by replacing strut
22	EB-2-HA	MS	18"	T	15100	Replace rod hanger with Fig 211 Size 3 strut.
23	EB-2-HB	MS	16"	T	5900	Replace pipe clamp
24	HB-12-H5	MS	10"x6"	T	2718	Add weld to integral welded attachment
25	HB-12-H7	MS	10"x6"	T	2761	Verify and add integral welded attachment
26	DB-1-5	FW	20"	T	11000	Replace existing rod hanger and frame
27	DB-1-7	FW	16"	T	12500	Replace trunnion support
28	DB-1-8	FW	16"	T	13500	Add cover frame, through bolts, & lubrite plate
29	DB-1-9	FW	16"	T	11640	Increase frame members & verify pipe lug welds
30	DB-1-10	FW	16"	T	13049	Replace spring hanger to suit new pipe location
31	DB-1-11	FW	16"	T	10762	Replace spring hanger to suit new pipe location
32	DB-1-13	FW	20"	T	11811	Reset variable spring load
33	DB-1-14	FW	16"	T	12442	Verify/Add weld to trunnion/pipe & add lubrite plate
34	DB-1-15	FW	16"	T	21301	Add saddle, hold-down frame, & lubrite plate
35	DB-1-17	FW	6"	T	3586	Verify/Add weld to lugs
36	DB-1-19	FW	16"	T	4563	Replace trunnion support
37	PS DB-01-HS-01	FW	6"	T	2967	New snubber located on riser adjacent to EB-9-2A
38	EB-9-1	FW	16"	T	11136	Verify/Add weld to trunnion/pipe & add lubrite plate

ITEM	SUPPORT	SYSTEM	PIPE SIZE	BUILDING LOCATION	EPU LOAD (lbs)	DESCRIPTION / TYPE
39	EB-9-2	FW	16"	T	16202	Verify/Add weld to trunnion/pipe & add lubrite plate
40	EB-9-2A	FW	6"	T	4535	Add vertical hold-down
41	EB-9-3	FW	16"	T	9565	Replace existing rod with Anvil Fig 211 Size 3 Strut
42	EB-9-3A	FW	16"	T	7026	Replace existing rod with Anvil Fig 211 Size 3 Strut; replace support steel
43	EB-9-4	FW	16"	T	2879	Add trunnion weld, hold-down frame, & lubrite plate
44	EB-9-5A	FW	16"	T	7806	Replace existing rod with Anvil Fig 211 Size 2 Strut
45	EB-9-5B	FW	6"	T	5532	Replace existing rod with Anvil Fig 211 Size 1 Strut
46	EB-9-6A	FW	16"	T	10910	Offset the existing strut clamp
47	EB-9-8	FW	16"	T	2861	Replace existing rod with Anvil Fig 211 Size C Strut
48	EB-9-8A	FW	16"	T	8037	Replace existing rod with Anvil Fig 211 Size 2 Strut
49	EB-9-16	FW	16"	A	12000	Replace rods with Anvil Fig 211 Size 2 Struts
50	EB-9-18	FW	16"	F	9000	Replace pipe clamp & replace spring with Anvil Fig B-268 Size 16
51	EB-9-H200	FW	16"	F	11000	Replace existing strut with Anvil Fig 211 Size 3 Strut
52	EB-9-H201	FW	16"	F	20000	Add a tube steel brace & additional weld to a cover plate
53	EB-9-S922	FW	16"	A	32700	Replace existing steel frame with tube steel frame
54	PS DF-1A-H101	FW	16"	T	4000	New axial restraint
55	PS DF-1A-H102	FW	16"	T	1000	New snubber
56	PS DF-1A-H103	FW	16"	T	6500	New spring hanger
57	PS DF-1A-H104	FW	16"	T	1000	New snubber
58	PS DF-1A-H105	FW	16"	T	10000	New axial & moment restraint
59	PS DF-1A-H106	FW	16"	T	14500	New spring hanger
60	PS DF-1A-H107	FW	16"	T	2000	New snubber
61	PS DF-1B-H101	FW	16"	T	3800	New spring hanger
62	PS DF-1B-H102	FW	16"	T	7500	New axial restraint
63	PS DF-1B-H103	FW	16"	T	7200	New spring hanger
64	PS DF-1B-H104	FW	16"	T	8000	New axial & moment restraint
65	PS DF-1B-H105	FW	16"	T	3500	New spring hanger
66	EB-9-FW-H4	FW	16"	C	16000	Replace pipe saddle
67	EB-9-FW-H5	FW	16"	C	14000	Replace pipe saddle
68	EB-9-FW-H10	FW	16"	C	4420	Verify gap & modify support to provide additional clearance if needed
69	GB-4-3	COND	18"	T	3608	Shorten rod & replace pipe clamp with elbow lug
70	GB-4-31	COND	12"	T	2785	Replace trunnion support
71	GB-4-32	COND	12"	T	6052	Replace trunnion support
72	GB-4-36	COND	12"	T	4347	Shorten rod
73	GB-4-37	COND	12"	T	7069	Shorten rod
74	GD-1-12-A	EXTR	12"	T	941	Shorten rod
75	GD-1-12-B	EXTR	12"	T	1300	Shorten rod

ITEM	SUPPORT	SYSTEM	PIPE SIZE	BUILDING LOCATION	EPU LOAD (lbs)	DESCRIPTION / TYPE
76	S-EB-6-H39	HD	6"	T	500	Relocate support; install new support steel
77	S-EB-6-H41	HD	6"	T	800	Replace variable spring and associated hardware
78	PS DD-2A-H101	FW	8"	T	6500	New sway strut
79	PS DD-2A-H102	FW	8"	T	2500	New sway strut
80	PS DD-2A-H103	FW	8"	T	1500	New spring hanger
81	PS DD-2A-H104	FW	8"	T	4200	New rod hanger
82	PS DD-2A-H105	FW	8"	T	1200	New sway strut
83	PS DD-2A-H106	FW	8"	T	4000	New trunnion support
84	PS DD-2B-H101	FW	8"	T	1500	New spring hanger
85	PS DD-2B-H102	FW	8"	T	800	New spring hanger
86	PS DD-2B-H103	FW	8"	T	800	New spring hanger
87	PS DD-2B-H104	FW	8"	T	3200	New sway strut
88	PS DD-2B-H105	FW	8"	T	2300	New rod hanger
89	PS DD-2B-H106	FW	8"	T	1500	New sway strut
90	PS DD-2B-H107	FW	8"	T	1100	New lateral restraint
91	PS DD-2B-H108	FW	8"	T	2600	New rod hanger
92	PS DD-2B-H109	FW	8"	T	3000	New rod hanger
93	PS DD-2B-H110	FW	8"	T	4000	New trunnion support
94	GF-3-11	HD	4"	T	800	Replace trunnion support
95	GF-3-12	HD	4"	T	1100	Replace trunnion support
96	GB-3-101	HD	3"	T	450	Replace spring support
97	GB-3-102	HD	3"	T	565	Replace spring support
98	GB-3-103	HD	4"	T	500	Replace rod hanger with spring hanger
99	GB-3-2	HD	12"	T	2700	Verify fillet weld size
100	GB-3-3	HD	12"	T	4750	Replace trunnion support
101	GB-3-4	HD	12"	T	2250	Verify fillet weld size
102	PS GB-03-H101	HD	8"	T	2700	New spring hanger
103	HB-18-3	HD	12"	T	4500	Replace trunnion support with sway strut
104	PS R-GB-4-6	COND	18"	T	3600	Change lateral restraint to vertical / lateral; verify welds
105	PS R-GB-4-7	COND	18"	T	1000	Relocate lateral restraint; modify structural framing
106	PS GB-4-47	COND	18"	T	3500	Replace rod hanger
107	PS GB-4-D	COND	18"	T	5700	Replace rod hanger
108	PS GB-7B-H101	COND	18"	T	5500	New rod hanger
109	PS GF-7A-H101	COND	18"	T	3800	New spring hanger
110	PS GF-7A-H102	COND	18"	T	4000	New sway strut
111	PS GF-7B-H101	COND	18"	T	3800	New spring hanger
112	PS GF-7B-H102	COND	18"	T	4000	New sway strut
113	GB-4-H21	COND	12"	T	5500	Relocate & replace spring hanger
114	GB-4-H24	COND	12"	T	5500	Relocate & replace spring hanger

ITEM	SUPPORT	SYSTEM	PIPE SIZE	BUILDING LOCATION	EPU LOAD (lbs)	DESCRIPTION / TYPE
115	GB-4-H20	COND	12"	T	3500	Replace rod hanger
116	GB-15-101	EXTR	20"	T	3387	Relocate & replace trunnion type support
117	GB-15-102	EXTR	20"	T	3387	Relocate & replace trunnion type support
118	GB-15-103	EXTR	20"	T	3370	Relocate & replace trunnion type support
119	GB-15-104	EXTR	20"	T	3370	Relocate & replace trunnion type support
120	GB-15-105	EXTR	18"	T	27573	Relocate & replace trunnion type support
121	GB-15-106	EXTR	18"	T	27573	Relocate & replace trunnion type support
122	HB-6-101	HD	4"	T	500	Replace rod hanger
123	HB-6-102	HD	4"	T	500	Replace rod hanger
124	HB-6-103	HD	2 1/2"	T	500	Replace rod hanger
125	HB-6-104	HD	2 1/2"	T	500	Replace rod hanger
126	HB-6-1	HD	10"	T	2400	Replace spring hanger
127	HB-6-2	HD	10"	T	2400	Replace spring hanger
128	HB-6-3	HD	10"	T	3200	Replace spring support
129	HB-6-4	HD	10"	T	3200	Replace spring support
130	HF-6-8	HD	10"	T	3200	Replace spring hanger
131	HF-6-12	HD	10"	T	3200	Replace spring hanger
132	HF-5-102	HD	8"	T	1600	Replace spring hanger
133	HF-5-103	HD	6"	T	1000	Replace spring hanger
134	HF-5-105	HD	8"	T	1600	Replace spring hanger
135	HF-5-106	HD	6"	T	1000	Replace spring hanger
136	HB-6-19	HD	6"	T	3000	Replace spring hanger
137	HB-6-20	HD	6"	T	3000	Replace spring hanger
138	HB-6-21	HD	8"	T	4000	Replace spring support
139	HB-6-22	HD	8"	T	4000	Replace spring support
140	HB-5-7	HD	6"	T	1200	Replace spring support
141	HB-5-8	HD	6"	T	700	Replace spring support
142	HB-5-9	HD	6"	T	1200	Replace spring support
143	HB-5-10	HD	6"	T	700	Replace spring support
144	HB-11-1	HD	6"	T	327	Relocate spring hanger, shorten rod, replace elbow lug
145	HB-11-2	HD	6"	T	1000	Replace rigid vertical support
146	HB-11-3	HD	6"	T	1000	Replace clamp & shorten rod
147	HB-11-4	HD	6"	T	500	Replace clamp & shorten rod
148	HB-11-5	HD	6"	T	1000	Replace clamp & shorten rod
149	HB-11-6	HD	6"	T	700	Relocate support; replace clamp & shorten rod
150	HB-11-7	HD	6"	T	1000	Replace clamp & shorten rod
151	HB-11-8	HD	4"	T	750	Replace rod hanger with strut
152	HB-11-9	HD	6"	T	450	Replace elbow lug & shorten rod
153	HB-11-10	HD	6"	T	500	Replace clamp & shorten rod

ITEM	SUPPORT	SYSTEM	PIPE SIZE	BUILDING LOCATION	EPU LOAD (lbs)	DESCRIPTION / TYPE
154	HB-11-12	HD	6"	T	800	Verify weld pattern & size
155	HB-11-13	HD	6"	T	500	Verify weld pattern & size
156	HB-11-101	HD	6"	T	2500	New lateral sway strut
157	HB-11-102	HD	6"	T	500	New spring hanger

System Description
MS - Main Steam
FW - Feedwater
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COND Condensate
HD - Heater Drains & Vents

Building Location Description
A - Auxiliary Bldg
C - Containment Bldg
F - Façade Structure
T - Turbine Bldg

ENCLOSURE 4
ATTACHMENT 8

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

LICENSE AMENDMENT REQUEST 261
EXTENDED POWER UPRATE

SUMMARY OF UNIT 2 PIPE SUPPORTS REQUIRING MODIFICATION

4 pages follow

ITEM	SUPPORT	SYSTEM	PIPE SIZE	BUILDING LOCATION	EPU LOAD (lbs)	DESCRIPTION / TYPE
1	EB-1-MS-2H1	MS	30"	C	15760	Change Cold Setting
2	EB-1-MS-2H7	MS	30"	C	8000	Change Cold Setting
3	EB-1-2HB	MS	30"	F	22884	Adjust to achieve gaps
4	EB-1-2HC	MS	30"	F	51928	Adjust to achieve gaps
5	EB-1-2H5	MS	30"	A	26000	Replace Size 3 strut with Size 4 Strut
6	EB-1-2H6	MS	30"	A	34852	Verify gaps and modify as required
7	EB-1-2H7	MS	30"	A	19170	Verify gaps and modify as required
8	EB-1-2H9	MS	30"	F	62000	Replace rod hanger with Size 7 Strut
9	EB-1-2H9A	MS	30"	F	50000	Replace rod hanger
10	EB-1-2H15	MS	30"	A	65000	Verify and add welds, as required
11	EB-1-2H19	MS	30"	F	32000	Add weld as indicated
12	EB-1-2H20	MS	30"	F	62000	Replace rod hanger with Size 7 Strut
13	EB-1-2H20A	MS	30"	F	50000	Replace rod hanger
14	EB-1-R250	MS	30"	A	24805	Verify gaps and modify as required
15	EB-1-R251	MS	30"	A	66066	Verify gaps and modify as required
16	EB-2-EA6	MS	24"	T	6989	Verify gaps, modify as directed
17	EB-2-2H1	MS	24"	T	7000	Reset spring to cold settings
18	EB-2-2H3	MS	24"	T	26000	Add Size 4 strut and new welds
19	EB-2-2H4	MS	18"	T	9147	Rotate and re-weld strut end bracket
20	EB-2-2H5	MS	16"	T	6133	Verify strut end paddle not bound; rotate bracket if needed
21	EB-2-2H11	MS	6"	T	2575	Modify elbow lug attachment
22	EB-2-2H13	MS	6"	T	2400	Modify elbow lug attachment
23	EB-2-2H15	MS	16"	T	18600	Replace existing strut with Size 4 Strut
24	EB-2-2H17	MS	16"	T	6977	Replace rod hanger with Size 1 Strut
25	EB-2-2H200	MS	16"	T	8500	Remove shim, verify gap, & add weld
26	HB-12-2H5	MS	10"x6"	T	2654	Add weld to pipe lug
27	HB-12-2H7	MS	10"x6"	T	2698	Add weld to pipe lug
28	PS DF-01-001	FW	16"	T	8000	New axial & moment restraint
29	PS DF-01-002	FW	16"	T	11500	New spring hanger
30	PS DF-01-003	FW	16"	T	6000	New snubber
31	PS DF-01-004	FW	16"	T	6500	New spring hanger
32	PS DF-01-005	FW	16"	T	7500	New spring hanger
33	PS DF-01-006	FW	16"	T	8000	New axial & moment restraint
34	PS DF-01-007	FW	16"	T	8000	New spring hanger
35	PS DF-01-008	FW	16"	T	7000	New snubber
36	PS DB-01-2H8	FW	20"	T	15000	Replace 1 1/4" rod with 1 3/4" rod
37	PS DB-01-2H11	FW	20"	T	23000	Replace rod hanger
38	PS DB-01-2H12	FW	20"	T	16000	Replace pipe saddle & increase rod size
39	PS DB-01-2H17	FW	16"	T	12500	Increase rod size

ITEM	SUPPORT	SYSTEM	PIPE SIZE	BUILDING LOCATION	EPU LOAD (lbs)	DESCRIPTION / TYPE
40	PS DB-01-DET3	FW	6"	T	3500	Replace 2-way restraint
41	PS EB-09-2H1	FW	16"	T	16000	Add hold-down frame & lubrite plate
42	PS EB-09-2H4	FW	6"	T	3000	Add hold-down frame & lubrite plate
43	PS EB-09-2H6	FW	16"	T	6000	Replace existing rod with Anvil Fig 211 Size 1 Strut
44	PS EB-09-H200	FW	16"	F	10000	Add section of tube steel
45	PS EB-09-H201	FW	16"	F	30000	Replace strut with larger size Anvil Fig 640 Size 5
46	PS EB-09-S922A	FW	16"	F	28000	Remove collars and install new trunnions
47	PS DB-01-HS-01U	FW	6"	T	4000	Add new snubber
48	GD-1-2H101	EXTR	12"	T	1100	Relocate spring hanger & shorten rod
49	GD-1-2H102	EXTR	12"	T	1500	Relocate spring hanger & shorten rod
50	DB-1-2H18	FW	16"	T	7000	Replace trunnion type support
51	DB-1-2H19	FW	16"	T	6500	Replace trunnion type support
52	GB-4-2H31	COND	14"	T	8853	Replace trunnion type support
53	GB-4-2H32	COND	14"	T	2406	Replace trunnion type support
54	HB-4-2H101	HD	6"	T	1200	Relocate & replace spring support
55	HB-4-2H102	HD	6"	T	1500	Relocate & replace spring support
56	GB-4-2H36	COND	12"	T	4800	Shorten rod & replace elbow lug with trunnion
57	GB-4-2H37	COND	12"	T	12460	Replace rod hanger
58	DB-1-2H9	FW	16"	T	25000	Replace riser clamp with 2 trunnions
59	DB-1-2H10	FW	16"	T	15000	Replace riser clamp with 2 trunnions
60	GB-2-2H101	HD	10"	T	631	Shorten rod
61	GB-2-2H102	HD	10"	T	631	Shorten rod
62	GB-2-2H103	HD	12"	T	1800	Relocate & replace rigid support with spring
63	GB-2-2H104	HD	12"	T	1900	Relocate & replace rigid support with spring
64	GB-2-2H105	HD	8"	T	1500	Shorten rod
65	HB-11-2H31	HD	6"	T	500	Relocate & replace spring support
66	HB-11-2H32	HD	6"	T	1000	Replace rigid vertical support
67	HB-11-2H33	HD	6"	T	1000	Replace clamp & shorten rod
68	HB-11-2H34	HD	6"	T	1000	Replace clamp & shorten rod
69	HB-11-2H35	HD	6"	T	1000	Replace clamp & shorten rod
70	HB-11-2H36	HD	6"	T	700	Relocate support; replace clamp & shorten rod
71	HB-11-2H37	HD	6"	T	1000	Replace rod hanger with strut
72	HB-11-2H38	HD	6"	T	500	Replace rigid support with spring; replace clamp & shorten rod
73	HB-11-2H39	HD	6"	T	700	Replace clamp & shorten rod
74	HB-11-2H40	HD	6"	T	1800	New axial restraint
75	HB-11-2H41	HD	6"	T	800	New spring hanger
76	GB-4-2H21	COND	12"	T	5000	Relocate & replace spring hanger
77	GB-4-2H24	COND	12"	T	5000	Relocate & replace spring hanger
78	GB-4-RH33	COND	16"	T	4500	Relocate riser clamp & install longer rods

ITEM	SUPPORT	SYSTEM	PIPE SIZE	BUILDING LOCATION	EPU LOAD (lbs)	DESCRIPTION / TYPE
79	GB-4-2H20A	COND	12"	T	3500	Replace rod hanger
80	W-2A-2H101	EXTR	20"	T	3387	Relocate & replace trunnion type support
81	W-2B-2H101	EXTR	20"	T	3387	Relocate & replace trunnion type support
82	W-4A-2H101	EXTR	20"	T	3370	Relocate & replace trunnion type support
83	W-4B-2H101	EXTR	20"	T	3370	Relocate & replace trunnion type support
84	W-7A-2H101	EXTR	18"	T	27573	Relocate & replace trunnion type support
85	W-7B-2H101	EXTR	18"	T	27573	Relocate & replace trunnion type support
86	HB-6A5	HD	4"	T	500	Replace rod hanger
87	HB-6B5	HD	4"	T	500	Replace rod hanger
88	HB-6A6	HD	2 1/2"	T	500	Replace rod hanger
89	HB-6B6	HD	2 1/2"	T	500	Replace rod hanger
90	HB-6-2H1	HD	10"	T	1800	Replace spring hanger
91	HB-6-2H2	HD	10"	T	1800	Replace spring hanger
92	HB-6-2H3	HD	10"	T	3232	Replace spring support
93	HB-6-2H4	HD	10"	T	3232	Replace spring support
94	10-HF-6A2	HD	10"	T	3200	Replace spring hanger
95	10-HF-6B2	HD	10"	T	3200	Replace spring hanger
96	160-A	HD	8"	T	1500	Replace spring hanger
97	160-B	HD	8"	T	1500	Replace spring hanger
98	105-A	HD	6"	T	1000	Replace spring hanger
99	105-B	HD	6"	T	1000	Replace spring hanger
100	HB-6A3	HD	6"	T	2500	Replace spring hanger
101	HB-6B3	HD	6"	T	2500	Replace spring hanger
102	HB-6A4	HD	8"	T	4000	Replace spring support
103	HB-6B4	HD	8"	T	4000	Replace spring support
104	HB-5-2H7	HD	6"	T	1000	Replace spring support
105	HB-5-2H8	HD	6"	T	700	Replace spring support
106	HB-5-2H9	HD	6"	T	1000	Replace spring support
107	HB-5-2H10	HD	6"	T	700	Replace spring support
108	02-GF-3-11	HD	4"	T	800	Replace trunnion support
109	02-GF-3-12	HD	4"	T	1100	Replace trunnion support
110	02-GB-3-101	HD	3"	T	475	Replace spring support
111	02-GF-3-103	HD	4"	T	500	Replace rod hanger with spring hanger
112	02-GF-3-104	HD	3"	T	450	New spring support
113	PS GB-3-2H3	HD	12"	T	5300	Replace trunnion support
114	PS GB-03-2H101	HD	8"	T	2700	New spring hanger
115	HB-18-2H3	HD	12"	T	4500	Replace trunnion support with sway strut
116	PS DD-02-001	FW	8"	T	2200	New sway strut
117	PS DD-02-002	FW	8"	T	2200	New rod hanger

ITEM	SUPPORT	SYSTEM	PIPE SIZE	BUILDING LOCATION	EPU LOAD (lbs)	DESCRIPTION / TYPE
118	PS DD-02-003	FW	8"	T	3200	New rod hanger
119	PS DD-02-004	FW	8"	T	8400	New sway strut
120	PS DD-02-005	FW	8"	T	8000	New trunnion support
121	PS DD-02-006	FW	8"	T	2000	New spring hanger
122	PS DD-02-007	FW	8"	T	3663	New 4-way restraint
123	PS DD-02-008	FW	8"	T	5500	New trunnion support
124	PS GB-04-2H47	COND	18"	T	6000	Replace pipe clamp
125	PS GB-07-001	COND	18"	T	4500	New rod hanger
126	PS GF-07-001	COND	18"	T	5000	New rod hanger
127	PS GF-07-002	COND	18"	T	4000	New spring hanger
128	PS GF-07-003	COND	18"	T	4000	New sway strut
129	PS GF-07-004	COND	18"	T	4000	New spring hanger
130	PS GF-07-005	COND	18"	T	3000	New sway strut

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