October 16, 2009

NRC 2009-0096
TS 5.6.8

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

Point Beach Nuclear Plant, Unit 1
Docket 50-266
Renewed License No. DPR-24

Response to Request for Additional Information
Fall 2008 Unit 1 (U1R31) Steam Generator Tube Inspection Report

Reference: (1) NextEra Energy Point Beach, LLC letter to NRC, dated May 7, 2009, Fall 2008 Unit 1 (U1R31) Steam Generator Tube Inspection Report (ML091280187)

(2) NRC letter to NextEra Energy Point Beach, LLC dated September 25, 2009, Point Beach Nuclear Plant, Unit 1 – Request for Additional Information Regarding the 2008 Steam Generator Tube Inservice Inspection Reports for Refueling Outage 31 (TAC No. ME1247) (ML092650639)

NextEra Energy Point Beach, LLC (NextEra) submitted the Fall 2008 Unit 1 Steam Generator Tube Inspection Report via Reference (1), documenting the scope and results of the inspection in accordance with Technical Specification 5.6.8 reporting requirements. Reference (2) transmitted the NRC staff's request for additional information.

Enclosure 1 provides the NextEra response to Reference (2).

This letter contains no new commitments and no revisions to existing commitments.

Very truly yours,

NextEra Energy Point Beach, LLC

James Costedio
Licensing Manager
Point Beach Nuclear Plant

Enclosure

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

**ENCLOSURE 1**

**NEXTERA ENERGY POINT BEACH, LLC**
**POINT BEACH NUCLEAR PLANT, UNIT 1**

**RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION**
**FALL 2008 (U1R31) STEAM GENERATOR TUBE INSPECTION REPORT**

The following information is provided by NextEra Energy Point Beach, LLC in response to the NRC staff's request for additional information (Reference 1) regarding the Fall 2008 Unit 1 (U1R31) Steam Generator Tube Inspection Report.

***Question 1***

*It was indicated that a visual foreign object search and retrieval was performed at various locations on the secondary side of the steam generators (SGs). Please discuss the scope and results of any other secondary side inspections performed.*

**Response**

During U1R31, the scope of the secondary side visual inspections included the following for both SG A and SG B:

- Steam drum (upper shell and upper internals including primary and secondary moisture separator assemblies), feedwater ring and J-nozzles
- Top (sixth) support plate quatrefoil inspection
- Flow distribution baffle (FDB)
- Post-chemical cleaning and sludge lance cleanliness visual inspection and foreign object search and retrieval (FOSAR)

SG A and B Inspection Results

A visual inspection of the steam drum and upper internals was conducted. Residual dry chemical residue and rust coloring was noted on much of the components post-chemical cleaning. Flow impingement patterns were seen on the feedwater ring, on the outside of some primary moisture separator riser barrels as well as under and around several J-nozzles, as previously reported. Erosion of the feedwater ring and riser barrel areas was not discernable by touch. Inside the feedwater ring, possible wear marks were noted in SG B nearing the tee at the bottom concaved portion of the distribution ring with no discernable pattern. These will be monitored as part of the secondary side integrity program.

Thin wafers of rust colored debris were noted in-bundle of the primary separator riser barrels. The consistency was brittle, breaking apart easily in hand, and is likely magnetite or scale pieces fallen from the riser tubes.

An inspection of the top (sixth) support plate was conducted. No anomalies on the lower U-bends or foreign objects on the support plate were observed. Quatrefoils were inspected as well. The degree of blockage within observed individual foils was 0%. Based on these visual inspections, overall aggregate blockage is estimated to be 0%. Scale was visible in crevices, but no pattern was discernable as to extent or location.

The flow distribution baffle was noted as clean with no discernable scale on the tubes or in crevice regions.

Tubesheet cleanliness and FOSAR visual inspections included the annulus, no-tube lane and select in-bundle columns during U1R31 following chemical cleaning and sludge lancing. FOSAR results are as previously reported in Reference (2). Cleanliness visuals showed the annulus free of debris or sludge. The no-tube lane contained diminished remnants of sludge debris ranging from 1/4" to 1/2" high and confined to the center stay rod area. In-bundle visual examinations revealed remnant skeletal bridging and collars within the previous sludge pile region limited to a few columns near the center.

***Question 2***

*In prior SG reports it was indicated that the sludge height could have exceeded 3 inches. It was indicated that for outer diameter stress corrosion cracking in the sludge pile, an examination for 3 inches above and below the top of the tubesheet was performed. Please discuss why the entire sludge pile height was not inspected with a rotating probe. Please discuss whether the chemical cleaning reduced the sludge pile height.*

**Response**

The sludge height estimated in Reference (3) was based upon eddy current test results. Based on industry experience and guidance, the highest likelihood of outer diameter stress corrosion cracking within the sludge pile is on the hot leg, near the transition zone, given the stress region and possible chemical concentration point. A 100% +Point™ examination of the hot leg top of tubesheet was conducted following chemical cleaning. In addition to the +Point™ examination, a 100% examination of tubing in this region was conducted using a bobbin coil. Visual examinations showed the sludge pile was essentially eliminated except for remnant skeletal bridging and collaring. No explicit measuring of the collars were made, however visual inspection supports a highest estimated collar of approximately 1".

***Question 3***

*It was indicated that 34 indications of wear were identified in 27 tubes near the top of the tubesheet in SG A. Please discuss why table 3 does not list all 34 indications. If the indications were not sized, please discuss the basis for keeping these tubes in service.*

**Response**

As described in Reference (2), there were 27 tubes with 34 bobbin probe indications in SG A attributed to mechanical wear above the top of tubesheet. Based on subsequent examination using +Point™ probes, Table 3 represents those indications which were confirmed as mechanical wear degradation. The remaining indications that did not confirm as wear based on subsequent +Point™ probe examination remained in service and were assigned a tracking code for monitoring in future inspections.

## References


(1) NRC letter to NextEra Energy Point Beach, LLC dated September 25, 2009, Point Beach Nuclear Plant, Unit 1 – Request for Additional Information Regarding the 2008 Steam Generator Tube Inservice Inspection Reports for Refueling Outage 31 (TAC No. ME1247) (ML092650639)

(2) NextEra Energy Point Beach, LLC letter to NRC, dated May 7, 2009, Fall 2008 Unit 1 (U1R31) Steam Generator Tube Inspection Report (ML091280187)

(3) FPL Energy Point Beach, LLC letter to NRC, dated March 14, 2008, Spring 2007 Unit 1 (U1R30) Steam Generator Tube Inspection Report (ML080770187)