UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

July 27, 2017

Mr. Robert Coffey
Site Vice President
NextEra Energy Point Beach, LLC
6610 Nuclear Road
Two Rivers, WI 54241

SUBJECT: POINT BEACH NUCLEAR PLANT, UNIT 1 - ISSUANCE OF AMENDMENT TO APPROVE H*: ALTERNATE REPAIR CRITERIA FOR STEAM GENERATOR TUBE SHEET EXPANSION REGION (CAC NO. MF8218)

Dear Mr. Coffey:

The U.S. Nuclear Regulatory Commission has issued the enclosed Amendment No. 260 to Renewed Facility Operating License No. DPR-24 for the Point Beach Nuclear Plant (Point Beach), Unit 1. The amendment consists of changes to the technical specifications (TSs) in response to your application dated July 29, 2016, as supplemented by letter dated April 20, 2017.

The amendment makes changes to TS 3.4.13, "RCS Operational LEAKAGE," TS 5.5.8, "Steam Generator (SG) Program," and TS 5.6.8, "Steam Generator Tube Inspection Report," in order to implement the H* (pronounced H-star) alternate repair criteria on a permanent basis. The licensee provided additional information by letter dated April 20, 2017.

A copy of our related safety evaluation is also enclosed. The Notice of Issuance will be included in the Commission's biweekly Federal Register notice.

Sincerely,

Mahesh L. Chawla, Project Manager
Plant Licensing Branch III
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-266

Enclosures:
1. Amendment No. 260 to DPR-24
2. Safety Evaluation

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

NEXTERA ENERGY POINT BEACH, LLC

DOCKET NO. 50-266

POINT BEACH NUCLEAR PLANT, UNIT 1

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 260
License No. DPR-24

1. The U.S. Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by NextEra Energy Point Beach, LLC (the licensee), dated July 29, 2016, as supplemented by letter dated April 20, 2017, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 4.B of the Renewed Facility Operating License No. DPR-24 is hereby amended to read as follows:

   B. Technical Specifications

   The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 260, are hereby incorporated in the renewed operating license. NextEra Energy Point Beach shall operate the facility in accordance with the Technical Specifications.

3. This license amendment is effective as of its date of issuance and shall be implemented within 90 days of the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

David J. Wrona, Chief
Plant Licensing Branch III
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment: Changes to the
Technical Specifications and
Renewed Facility Operating License

Date of issuance: July 27, 2017

ATTACHMENT TO LICENSE AMENDMENT NO. 260

POINT BEACH NUCLEAR PLANT, UNIT 1

TO RENEWED FACILITY OPERATING LICENSE NO. DPR-24

DOCKET NO. 50-266

Replace the following pages of Renewed Facility Operating License No. DPR-24, and Technical Specifications with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

Renewed Facility Operating License

REMOVE	INSERT
-3-	-3-

Technical Specifications

REMOVE	INSERT
3.4.13-1	3.4.13-1
3.4.13-2	3.4.13-2
5.5-8	5.5-8
5.5-8a	5.5-8a
5.5-9	5.5-9
5.5-10	5.5-10
5.5-11	5.5-11
5.5-12	5.5-12
5.5-13	5.5-13
5.5-14	5.5-14
5.5-15	5.5-15
5.5-16	5.5-16
5.5-17	5.5-17
5.5-18	5.5-18
None	5.5-19
5.6-7	5.6-7

D. Pursuant to the Act and 10 CFR Parts 30, 40 and 70, NextEra Energy Point Beach to receive, possess and use in amounts as required any byproduct, source or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

E. Pursuant to the Act and 10 CFR Parts 30 and 70, NextEra Energy Point Beach to possess such byproduct and special nuclear materials as may be produced by the operation of the facility, but not to separate such materials retained within the fuel cladding.

4. This renewed operating license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations: 10 CFR Part 20, Section 30.34 of 10 CFR Part 30, Section 40.41 of 10 CFR Part 40, Sections 50.54 and 50.59 of 10 CFR Part 50, and Section 70.32 of 10 CFR Part 70; and is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified below:

A. Maximum Power Levels

NextEra Energy Point Beach is authorized to operate the facility at reactor core power levels not in excess of 1800 megawatts thermal.

B. Technical Specifications

The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 260, are hereby incorporated in the renewed operating license. NextEra Energy Point Beach shall operate the facility in accordance with Technical Specifications.

C. Spent Fuel Pool Modification

The licensee is authorized to modify the spent fuel storage pool to increase its storage capacity from 351 to 1502 assemblies as described in licensee's application dated March 21, 1978, as supplemented and amended. In the event that the on-site verification check for poison material in the poison assemblies discloses any missing boron plates, the NRC shall be notified and an on-site test on every poison assembly shall be performed.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.13 RCS Operational LEAKAGE

LCO 3.4.13 RCS operational LEAKAGE shall be limited to:

a. No pressure boundary LEAKAGE;

b. 1 gpm unidentified LEAKAGE;

c. 10 gpm identified LEAKAGE; and

d. 72 gallons per day (Unit 1) and 150 gallons per day (Unit 2) primary to secondary LEAKAGE through any one steam generator (SG).

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RCS operational LEAKAGE not within limits for reasons other than pressure boundary LEAKAGE or primary to secondary LEAKAGE.	A.1 Reduce LEAKAGE to within limits.	4 hours
B. Required Action and associated Completion Time of Condition A not met. <u>OR</u> Pressure boundary LEAKAGE exists. OR Primary to secondary LEAKAGE not within limit.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.13.1	---------------------------NOTES------------------------- 1. Not required to be performed until 12 hours after establishment of steady state operation. 2. Not applicable to primary to secondary LEAKAGE. --- Verify RCS Operational LEAKAGE is within limits by performance of RCS water inventory balance.	In accordance with the Surveillance Frequency Control Program
SR 3.4.13.2	---------------------------NOTE--------------------------- Not required to be performed until 12 hours after establishment of steady state operation. --- Verify primary to secondary LEAKAGE is $\leq$72 gallons per day (Unit 1) and $\leq$ 150 gallons per day (Unit 2) through any one SG.	In accordance with the Surveillance Frequency Control Program

5.5 Programs and Manuals

5.5.8 Steam Generator (SG) Program (continued)

for all SGs and leakage rate for an individual SG. Leakage is not to exceed 500 gallons per day per SG.

3. The operational LEAKAGE performance criterion is specified in LCO 3.4.13, "RCS Operational LEAKAGE."

c. Provisions for SG tube plugging criteria. Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 40% of the nominal tube wall thickness shall be plugged.

The following alternate tube plugging criteria shall be applied as an alternative to the 40% depth based criteria:

For Unit 1 only, tubes with service-induced flaws located greater than 20.6 inches below the top of the tubesheet do not require plugging. Tubes with service-induced flaws located in the portion of the tube from the top of the tubesheet to 20.6 inches below the top of the tubesheet shall be plugged upon detection.

This alternate tube plugging criteria is not applicable to the tube at row 38 column 69 in the A steam generator, which is not expanded in the hot leg the full length of the tubesheet. This tube has been removed from service by plugging (during U1R31).

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. For Unit 1, the number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube from 20.6 inches below the top of the tubesheet on the hot leg side to 20.6 inches below the top of the tubesheet on the cold leg side and that may satisfy the applicable tube plugging criteria. For Unit 2, the number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube plugging criteria.

5.5 Programs and Manuals

For Unit 1 and Unit 2: The tube-to-tubesheet weld is not part of the tube. In addition to meeting the requirements of d.1, d.2, and d.3 below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. A degradation assessment shall be performed to determine the type and location of flaws to which the tubes may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what location.

1. Inspect 100% of the tubes in each SG during the first refueling outage following SG installation.

2. i. Unit 1 (alloy 600 Thermally Treated tubes): After the first refueling outage following SG installation, inspect each SG at least every 48 effective full power months or at least every other refueling outage (whichever results in more frequent inspections). In addition, the minimum number of tubes inspected at each scheduled inspection shall be the number of tubes in all SGs divided by the number of SG inspection outages scheduled in each inspection period as defined in a, b, and c below. If a degradation assessment indicates the potential for a type of degradation to occur at a location not previously inspected with a technique capable of detecting this type of degradation at this location and that may satisfy the applicable tube plugging criteria, the minimum number of locations inspected with such a capable inspection technique during the remainder of the inspection period may be prorated. The fraction of locations to be inspected for this potential type of degradation at this location at the end of the inspection period shall be no less than the ratio of the number of times the SG is scheduled to be inspected in the inspection period after the determination that a new form of degradation could potentially be occurring at this location divided by the total number of times the SG is scheduled to be inspected in the inspection period. Each inspection period defined below may be extended up to 3 effective full power months to include a SG inspection outage in an inspection period and the subsequent inspection period begins at the conclusion of the included SG inspection outage.

   a) After the first refueling outage following SG installation, inspect 100% of the tubes during the next 120 effective full power months. This constitutes the first inspection period;

   b) During the next 96 effective full power months, inspect 100% of the tubes. This constitutes the second inspection period; and

5.5 Programs and Manuals

c) During the remaining life of the SGs, inspect 100% of the tubes every 72 effective full power months. This constitutes the third and subsequent inspection periods.

ii. Unit 2 (alloy 690 Thermally Treated tubes): After the first refueling outage following SG installation, inspect each SG at least every 72 effective full power months or at least every third refueling outage (whichever results in more frequent inspections). In addition, the minimum number of tubes inspected at each scheduled inspection shall be the number of tubes in all SGs divided by the number of SG inspection outages scheduled in each inspection period as defined in a, b, c and d below. If a degradation assessment indicates the potential for a type of degradation to occur at a location not previously inspected with a technique capable of detecting this type of degradation at this location and that may satisfy the applicable tube plugging criteria, the minimum number of locations inspected with such a capable inspection technique during the remainder of the inspection period may be prorated. The fraction of locations to be inspected for this potential type of degradation at this location at the end of the inspection period shall be no less than the ratio of the number of times the SG is scheduled to be inspected in the inspection period after the determination that a new form of degradation could potentially be occurring at this location divided by the total number of times the SG is scheduled to be inspected in the inspection period. Each inspection period defined below may be extended up to 3 effective full power months to include a SG inspection outage in an inspection period and the subsequent inspection period begins at the conclusion of the included SG inspection outage.

a) After the first refueling outage following SG installation, inspect 100% of the tubes during the next 144 effective full power months. This constitutes the first inspection period;

b) During the next 120 effective full power months, inspect 100% of the tubes. This constitutes the second inspection period;

c) During the next 96 effective full power months, inspect 100% of the tubes. This constitutes the third inspection period; and

d) During the remaining life of the SGs, inspect 100% of the tubes every 72 effective full power months. This constitutes the fourth and subsequent inspection periods.

5.5 Programs and Manuals

3. For Unit 1, if crack indications are found in any SG tube from 20.6 inches below the top of the tubesheet on the hot leg side to 20.6 inches below the top of the tubesheet on the cold leg side, then the next inspection for each affected and potentially affected SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever results in more frequent inspections). If definitive information, such as from examination of a pulled tube, diagnostic non-destructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

   For Unit 2, if crack indications are found in any SG tube, then the next inspection for each affected and potentially affected SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever results in more frequent inspections). If definitive information, such as from examination of a pulled tube, diagnostic non-destructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

e. Provisions for monitoring operational primary to secondary LEAKAGE.

5.5 Programs and Manuals

5.5.9 Secondary Water Chemistry Program

This program provides controls for monitoring secondary water chemistry to inhibit SG tube degradation. The program shall include:

a. Identification of a sampling schedule for the critical variables and control points for these variables;

b. Identification of the procedures used to measure the values of the critical variables;

c. Identification of process sampling points, which shall include monitoring the discharge of the condensate pumps for evidence of condenser in leakage;

d. Procedures for the recording and management of data;

e. Procedures defining corrective actions for all off control point chemistry conditions; and

f. A procedure identifying the authority responsible for the interpretation of the data and the sequence and timing of administrative events, which is required to initiate corrective action.

5.5.10 Ventilation Filter Testing Program (VFTP)

A program shall be established to implement the following required testing of the Control Room Emergency Filtration System (F-16) at the frequencies specified in Regulatory Guide 1.52, Revision 2, and in accordance with ASTM D3803-1989 and the methodology of ANSI N510-1980, as prescribed below.

a. Demonstrate for the Control Room Emergency Filtration System (F-16) that an inplace test of the high efficiency particulate air (HEPA) filters shows a penetration and system bypass ≤1.0% when tested in accordance with the methodology of ANSI N510-1980, Section 10, excluding subsection 10.3, at a system flowrate of 4950 cfm ± 10%.

b. Demonstrate for the Control Room Emergency Filtration System (F-16) that an inplace test of the charcoal adsorber shows a penetration and system bypass ≤ 1.0% when tested in accordance with the methodology of ANSI N510-1980, Section 12, excluding subsection 12.3, at a system flowrate of 4950 cfm ± 10%.

5.5 Programs and Manuals

5.5.10 Ventilation Filter Testing Program (VFTP) (continued)

c. Demonstrate for the Control Room Emergency Filtration System (F-16) that a laboratory test of a sample of the charcoal adsorber, when obtained in accordance with the methodology of ANSI N510-1980, Section 13, excluding subsection 12.3, shows the methyl iodide penetration ≤ 2.5%, when tested in accordance with ASTM D3803-1989 at a temperature of 30°C and a relative humidity of 95%, applying the tolerances of ASTM D3803-1989.

d. Demonstrate for the Control Room Emergency Filtration System (F-16) that the pressure drop across the combined HEPA filters and the charcoal adsorbers is less than 6 inches of water when tested in accordance with the methodology of ANSI N510-1980, Sections 10 and 12, excluding subsections 10.3 and 12.3, at a system flowrate of 4950 cfm ± 10%.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the VFTP test frequencies.

5.5.11 Explosive Gas Monitoring Program

This program provides controls for potentially explosive gas mixtures contained in the on-service Gas Decay Tank.

The program shall include a limit for oxygen concentration in the on-service Gas Decay Tank and a surveillance program to ensure the limit is maintained. This limit shall be appropriate to the system's design criteria (i.e., whether or not the system is designed to withstand a hydrogen explosion).

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Explosive Gas Monitoring Program surveillance frequencies.

5.5 Programs and Manuals

5.5.12 Diesel Fuel Oil Testing Program

A diesel fuel oil testing program to implement required testing of both new fuel oil and stored fuel oil shall be established. The program shall include sampling and testing requirements, and acceptance criteria, all in accordance with applicable ASTM Standards. The purpose of the program is to establish the following:

a. Acceptability of new fuel oil for use prior to addition to storage tanks by determining that the fuel oil has:

   1. an API gravity or an absolute specific gravity within limits,

   2. a flash point and kinematic viscosity within limits for ASTM 2D fuel oil, and

   3. a clear and bright appearance with proper color;

b. Within 31 days of addition of the new fuel oil to storage tanks verify that the properties of the new fuel oil, other than those addressed in a. above, are within limits for ASTM 2D fuel oil; and

c. Total particulate concentration of the fuel oil is $\leq$ 10 mg/l when tested every 92 days in accordance with the applicable ASTM standard.

d. The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Diesel Fuel Oil Testing Program test frequencies.

5.5.13 Technical Specifications (TS) Bases Control Program

This program provides a means for processing changes to the Bases of these Technical Specifications.

a. Changes to the Bases of the TS shall be made under appropriate administrative controls and reviews.

b. Licensees may make changes to Bases without prior NRC approval provided the changes do not involve either of the following:

   1. a change in the TS incorporated in the license; or

   2. a change to the updated FSAR or Bases that requires NRC approval pursuant to 10 CFR 50.59.

5.5 Programs and Manuals

5.5.13 Technical Specifications (TS) Bases Control Program (continued)

c. The Bases Control Program shall contain provisions to ensure that the Bases are maintained consistent with the FSAR.

d. Proposed changes that meet the criteria of Specification 5.5.13b above shall be reviewed and approved by the NRC prior to implementation. Changes to the Bases implemented without prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71(e).

5.5.14 Safety Function Determination Program (SFDP)

This program ensures loss of safety function is detected and appropriate actions taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other appropriate actions may be taken as a result of the support system inoperability and corresponding exception to entering supported system Condition and Required Actions. This program implements the requirements of LCO 3.0.6. The SFDP shall contain the following:

a. Provisions for cross train checks to ensure a loss of the capability to perform the safety function assumed in the accident analysis does not go undetected;

b. Provisions for ensuring the plant is maintained in a safe condition if a loss of function condition exists;

c. Provisions to ensure that an inoperable supported system's Completion Time is not inappropriately extended as a result of multiple support system inoperabilities; and

d. Other appropriate limitations and remedial or compensatory actions.

5.5 Programs and Manuals

5.5.14 Safety Function Determination Program (SFDP) (continued)

A loss of safety function exists when, assuming no concurrent single failure, and assuming no concurrent loss of offsite power or loss of onsite diesel generator(s), a safety function assumed in the accident analysis cannot be performed. For the purpose of this program, a loss of safety function may exist when a support system is inoperable, and:

a. A required system redundant to the system(s) supported by the inoperable support system is also inoperable; or

b. A required system redundant to the system(s) in turn supported by the inoperable supported system is also inoperable; or

c. A required system redundant to the support system(s) for the supported systems (a) and (b) above is also inoperable.

The SFDP identifies where a loss of safety function exists. If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

When a loss of safety function is caused by the inoperability of a single Technical Specification support system, the appropriate Conditions and Required Actions to enter are those of the support system.

5.5.15 Containment Leakage Rate Testing Program

a. A program shall be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September, 1995 as modified by the following exception to NEI 94-01, Rev. 0, Industry Guidance for Implementing Performance Based Option of 10 CFR 50, Appendix J, Section 9.2.3, to allow the following:.

   (i) The first Unit 1 Type A test performed after October 7, 1997, shall be performed by October 7, 2012.

   (ii) The first Unit 2 Type A test performed after March 31, 1997, shall be performed by March 31, 2012.

5.5 Programs and Manuals

5.5.15 Containment Leakage Rate Testing Program (continued)

b. The peak design containment internal accident pressure, P_a, is 60 psig.

c. The maximum allowable containment leakage rate, L_a at P_a, shall be 0.2% of containment air weight per day.

d. Leakage rate acceptance criteria are:

1. Containment leakage rate acceptance criterion is $\leq 1.0\ L_a$.

2. During the first unit startup following testing in accordance with this program, the leakage rate acceptance are $\leq 0.6\ L_a$ for the combined Type B and Type C tests and $\leq 0.75\ L_a$ for the Type A tests.

3. Air lock testing acceptance criteria are:

   i. Overall air lock leakage rate is $\leq 0.05\ L_a$ when tested at $\geq P_a$.

   ii. For each door seal, leakage rate is equivalent to $\leq 0.02\ L_a$ at $\geq P_a$ when tested at a differential pressure of $\geq$ to 10 inches of Hg.

e. The provisions of SR 3.0.2 do not apply to the test frequencies in the Containment Leakage Rate Testing Program.

f. The provisions of SR 3.0.3 are applicable to the Containment Leakage Rate Testing Program.

5.5 Programs and Manuals

5.5.16 Reactor Coolant System (RCS) Pressure Isolation Valve (PIV) Leakage Program

A program shall be established to verify the leakage from each RCS PIV is within the limits specified below, in accordance with the Event V Order, issued April 20, 1981.

a. Minimum differential test pressure shall not be less than 150 psid.

b. Leakage rate acceptance criteria are:

1. Leakage rates less than or equal to 1.0 gpm are considered acceptable.

2. Leakage rates greater than 1.0 gpm but less than or equal to 5.0 gpm are considered acceptable if the latest measured rate has not exceeded the rate determined by the previous test by an amount that reduces the margin between measured leakage rate and the maximum permissible rate of 5.0 gpm by 50% or greater.

3. Leakage rates greater than 1.0 gpm but less than or equal to 5.0 gpm are considered unacceptable if the latest measured rate exceeded the rate determined by the previous test by an amount that reduces the margin between measured leakage rate and the maximum permissible rate of 5.0 gpm by 50% or greater.

4. Leakage rates greater than 5.0 gpm are considered unacceptable.

5.5.17 Pre-Stressed Concrete Containment Tendon Surveillance Program

This program provides controls for monitoring any tendon degradation in pre-stressed concrete containments, including effectiveness of its corrosion protection medium, to ensure containment structural integrity. The program shall include baseline measurements prior to initial operations. The Tendon Surveillance Program, inspection frequencies, and acceptance criteria shall be in accordance with Regulatory Guide 1.35, Revision 3, 1990.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Tendon Surveillance Program inspection frequencies.

5.5 Programs and Manuals

5.5.18 Control Room Envelope Habitability Program

A Control Room Envelope (CRE) Habitability Program shall be established and implemented to ensure that CRE habitability is maintained such that, with an OPERABLE Control Room Emergency Filtration System (CREFS), CRE occupants can control the reactor safely under normal conditions and maintain it in a safe condition following a radiological event. The program shall ensure that adequate radiation protection is provided to permit access and occupancy of the CRE under design basis accident (DBA) conditions without personnel receiving radiation exposures in excess of 5 rem total effective dose equivalent (TEDE) for the duration of the accident. Additionally, separate from the CREFS, the program shall ensure CRE occupants can maintain the reactor in a safe condition following a hazardous chemical release or smoke challenge. The program shall include the following elements:

a. The definition of the CRE and the CRE boundary.

b. Requirements for maintaining the CRE boundary in its design condition including configuration control and preventive maintenance.

c. Requirements for (i) determining the unfiltered air inleakage past the CRE boundary into the CRE in accordance with the testing methods and at the Frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, "Demonstrating Control Room Envelope Integrity at Nuclear Power Reactors," Revision 0, May 2003, and (ii) assessing CRE habitability at the Frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, Revision 0.

d. Measurement, at designated locations, of the CRE Pressure relative to all external areas adjacent to the CRE boundary during the technical specification emergency mode of operation by the CREFS, operating at the flow rate required by the VFTP, at a Frequency of 18 months. The results shall be trended at a frequency of 18 months and used as part of the periodic assessment of the CRE boundary.

e. The quantitative limits on unfiltered air inleakage into the CRE. These limits shall be stated in a manner to allow direct comparison to the unfiltered air inleakage measured by the testing described in Paragraph c. The unfiltered air inleakage limit for radiological challenges is the inleakage flow rate assumed in the licensing basis analyses of DBA consequences.

f. The provisions of SR 3.0.2 are applicable to the Frequencies for assessing CRE habitability, determining CRE unfiltered inleakage, and measuring CRE pressure and assessing the CRE boundary as required by Paragraphs c and d, respectively.

5.5 Programs and Manuals

5.5.18 Control Room Envelope Habitability Program (continued)

g. An adequate supply of self contained breathing apparatus (SCBA) units in the CRE to protect CRE occupants from a hazardous chemical release.

h. Portable smoke ejection equipment per the Fire Protection Evaluation Report and Safe Shutdown Analysis Report to address a potential smoke challenge.

5.5.19 Surveillance Frequency Control Program

This program provides controls for Surveillance Frequencies. The program shall ensure that Surveillance Requirements specified in the Technical Specifications are performed at intervals sufficient to assure the associated Limiting Conditions for Operations are met:

a. The Surveillance Frequency Control Program shall contain a list of frequencies of those Surveillance Requirements for which the frequency is controlled by the program.

b. Changes to the frequencies listed in the Surveillance Frequency Control Program shall be made in accordance with NEI 04-10, "Risk-Informed Method for Control of Surveillance Frequencies," Revision 1.

c. The provisions of Surveillance Requirements 3.0.2 and 3.0.3 are applicable to the frequencies established in the Surveillance Frequency Control Program.

5.6 Reporting Requirements

5.6.8 Steam Generator Tube Inspection Report (continued)

e. Number of tubes plugged during the inspection outage for each degradation mechanism,

f. The number and percentage of tubes plugged to date, and the effective plugging percentage in each steam generator,

g. The results of condition monitoring, including the results of tube pulls and in-situ testing.

h. For Unit 1 only, the primary to secondary leakage rate observed in each SG (if it is not practical to assign the leakage to an individual SG, the entire primary to secondary leakage should be conservatively assumed to be from one SG) during the cycle preceding the inspection which is the subject of the report,

i. For Unit 1 only, the calculated accident induced leakage rate from the portion of the tubes below 20.6 inches from the top of the tubesheet for the most limiting accident in the most limiting SG. In addition, if the calculated accident induced leakage rate from the most limiting accident is less than 5.22 times the maximum operational primary to secondary leakage rate, the report should describe how it was determined, and

j. For Unit 1 only, the results of monitoring for tube axial displacement (slippage). If slippage is discovered, the implications of the discovery and corrective action shall be provided.

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 260

TO RENEWED FACILITY OPERATING LICENSE NO. DPR-24

NEXTERA ENERGY POINT BEACH, LLC

POINT BEACH NUCLEAR PLANT, UNIT 1

DOCKET NO. 50-266

1.0 INTRODUCTION

By application to the U.S. Nuclear Regulatory Commission (NRC, Commission) dated July 29, 2016 (Reference 1), NextEra Energy Point Beach, LLC (the licensee), submitted a request for a license amendment in the form of changes to the technical specifications (TSs) for Point Beach Nuclear Plant (Point Beach), Unit 1. The request proposed changes to TS 3.4.13, "RCS Operational LEAKAGE," TS 5.5.8, "Steam Generator (SG) Program," and TS 5.6.8, "Steam Generator Tube Inspection Report," in order to implement the H* (pronounced H-star) alternate repair criteria on a permanent basis. The licensee provided additional information by letter dated April 20, 2017 (Reference 2), that clarified the application, did not expand the scope of the application as originally noticed, and did not change the NRC staff's original proposed no significant hazards consideration determination as published in the *Federal Register* on December 6, 2016 (81 FR 87961).

2.0 REGULATORY EVALUATION

2.1 BACKGROUND

Point Beach Unit 1 is a two-loop Westinghouse designed plant with Model 44F replacement steam generators (SGs) that were installed in 1984. Each SG contains 3,214 tubes made from thermally treated Alloy 600 (Alloy 600TT). Both ends of each tube were hydraulically expanded for the full depth of the tubesheet. The tubes are supported by stainless steel tube support plates with quatrefoil holes and V-shaped anti-vibration bars.

Until the fall of 2004, no instances of stress corrosion cracking (SCC) affecting the tubesheet region of Alloy 600TT tubing had been reported at any nuclear power plant in the United States (U.S). In the fall of 2004, crack-like indications were found in tubes in the tubesheet region of SGs at Catawba Nuclear Station, Unit 2. These crack-like indications were found in a tube overexpansion (OXP) that was approximately seven inches below the top of the tubesheet (TTS) on the hot-leg side in one tube, and just above the tube-to-tubesheet (T/TS) weld, in a region of the tube known as the tack expansion region, in several other tubes. Indications were also reported near the T/TS welds, which join the tube to the tubesheet. An OXP is created when the tube is expanded into a tubesheet borehole that is not perfectly round. These out-of-round conditions were created during the tubesheet drilling process by conditions such as drill bit wandering or chip gouging. The tack expansion is an approximately 1-inch long expansion at each tube end. The purpose of the tack expansion is to facilitate performing the T/TS weld, which is made prior to the hydraulic expansion of the tube over the full depth of the tubesheet.

Since the initial findings at Catawba, Unit 2, in the fall of 2004, other nuclear plants with Alloy 600TT tubing have found crack-like indications in tubes within the tubesheet as well. Most of the indications were found in the tack expansion region near the tube-end welds and were a mixture of axial and circumferential primary water SCC. Over time, these cracks can be expected to become more extensive, necessitating more inspections of the lower tubesheet region, increased tube plugging or repairs, with increased associated costs and the potential for shortening the useful lifetime of the SGs. To avoid these impacts, the affected licensees and their contractor, Westinghouse, have developed proposed alternative inspection and repair criteria applicable to the tubes in the lowermost region of the tubesheets. These criteria are referred to as the H* criteria. The H* distance is the minimum engagement distance between the tube and tubesheet, measured downward from the TTS, that is proposed as needed to ensure the structural and leakage integrity of the T/TS joints. The proposed H* alternate repair criteria would exclude the portions of tubing below the H* distance from inspection and plugging requirements, on the basis that flaws below the H* distance are not detrimental to the structural and leakage integrity of the T/TS joints.

Requests for permanent H* amendments were proposed for a number of plants as early as 2005. The NRC staff identified a number of issues with these early proposals, and also with subsequent proposals made in 2009, and was unable to approve H* amendments on a permanent basis pending resolution of these issues. The NRC staff found it did have a sufficient basis to approve H* amendments on an interim (temporary) basis, based on the relatively limited extent of cracking existing in the lower tubesheet region at the time the interim amendments were approved. The technical basis for approving the interim amendments is provided in detail in the NRC staff's safety evaluations (SE) accompanying issuance of these amendments.

After licensees were able to resolve the issues raised by the NRC staff in 2005 and 2009, the staff was able to approve permanent H* amendments starting in 2012. Permanent H* amendments have been issued for other plants with Model 44F SGs, such as Turkey Point Nuclear Generating Station, Units 3 and 4 (Reference 3), and H.B. Robinson Steam Electric Plant, Unit 2 (Reference 4).

2.2 REGULATORY REQUIREMENTS AND GUIDANCE

The SG tubes are part of the reactor coolant pressure boundary (RCPB) and isolate fission products in the primary coolant from the secondary coolant and the environment. For the purposes of this safety evaluation, SG tube integrity means that the tubes are capable of performing this safety function in accordance with the plant design and licensing basis.

The general design criteria (GDC) in Appendix A to Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50 provide regulatory requirements that state the RCPB shall have "an extremely low probability of abnormal leakage and of gross rupture" (GDC 14), "shall be designed with sufficient margin to assure that the design conditions of the RCPB are not exceeded during any condition of normal operation, including anticipated operational occurrences" (GDCs 15 and 31), shall be of "the highest quality standards practical" (GDC 30), and shall be designed to permit "periodic inspection and testing...to assess...structural and leaktight integrity" (GDC 32). Point Beach, Unit 1, received a construction permit prior to May 21, 1971, which is the date the GDC in Appendix A of 10 CFR Part 50 became effective. Although the plant is exempt from the current GDC, the licensee states it is in compliance with the 1967 GDC that were in effect when Point Beach, Unit 1, was licensed, and discusses how Point Beach, Unit 1, meets each of these GDC in Section 4.1 of their Updated Final Safety Analysis Report. The staff's review of the 1967 GDC shows that the GDC applicable to the RCPB and SG are comparable to the requirements of the current GDC.

Section 50.55a to 10 CFR specifies that components which are part of the RCPB must meet the requirements for Class 1 components in Section III of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), except as provided in 10 CFR 50.55a(c)(2), (3), and (4). Section 50.55a further requires that throughout the service life of pressurized-water reactor (PWR) facilities like Point Beach, Unit 1, ASME Code Class 1 components must meet the Section XI requirements of the ASME Code to the extent practical, except for design and access provisions, and pre-service examination requirements. This requirement includes the inspection and repair criteria of Section XI of the ASME Code. The Section XI requirements pertaining to inservice inspection of SG tubing are augmented by additional requirements in the TS.

Section 182(a) of the Atomic Energy Act requires nuclear power plant operating licenses to include TSs as part of any license. In 10 CFR 50.36, "Technical specifications," the NRC regulatory requirements related to the content of the TSs are established. The TS requirements in 10 CFR 50.36 include the following eight categories: (1) safety limits, limiting safety system settings, and limiting control settings; (2) limiting conditions for operation (LCO); (3) surveillance requirements (SRs); (4) design features; (5) administrative controls; (6) decommissioning; (7) initial notification; and (8) written reports.

The regulation at 10 CFR 50.36(c) (5) defines administrative controls as "the provisions relating to organization and management, procedures, recordkeeping, review and audit, and reporting necessary to assure the operation of the facility in a safe manner." Programs established by the licensee, including the SG program, are listed in the administrative controls section of the TSs to operate the facility in a safe manner. For Point Beach, Unit 1, the requirements for performing SG tube inspections and repair are in TS 5.5.8, while the requirements for reporting the SG tube inspections and repair are in TS 5.6.8.

The TS for all PWR plants require that an SG program be established and implemented to ensure that SG tube integrity is maintained. For Point Beach, Unit 1, SG tube integrity is maintained by meeting the performance criteria specified in TS 5.5.8.b for structural and leakage integrity, consistent with the plant design and licensing basis. TS 5.5.8.a requires that a condition monitoring assessment be performed during each outage in which the SG tubes are inspected, to confirm that the performance criteria are being met. TS 5.5.8.d includes provisions regarding the scope, frequency, and methods of SG tube inspections. These provisions require that the inspections be performed with the objective of detecting flaws of any type that may be present along the length of a tube and that may satisfy the applicable tube repair criteria. The applicable tube repair criteria, specified in TS 5.5.8.c, are that tubes found during inservice inspection to contain flaws with a depth equal to or exceeding 40 percent of the nominal wall thickness shall be plugged, unless the tubes are permitted to remain in service through application of alternate repair criteria provided in TS 5.5.8.c, such as is being proposed for Point Beach, Unit 1. The NRC staff reviewed the proposed alternate plugging criteria and determined that use of the proposed alternate repair criteria does not affect the integrity of the

SG tubes and, therefore, the SG tubes still meet the design requirements and the requirements for Class 1 components in Section III of the ASME Code.

Point Beach, Unit 1, TS 3.4.13 includes a limit on operational primary-to-secondary leakage, beyond which the plant must be promptly shutdown. Should a flaw exceeding the tube repair limit not be detected during the periodic tube surveillance required by the plant TSs, the operational leakage limit provides added assurance of timely plant shutdown before tube structural and leakage integrity are impaired, consistent with the design and licensing bases. The proposed amendment would reduce the limit on primary to secondary leakage from the current value of 150 gallons per day (gpd) to a more restrictive value of 72 gpd.

As part of the plant's licensing basis, applicants for PWR licenses are required to analyze the consequences of postulated design-basis accidents (DBAs), such as a SG tube rupture and a steam line break (SLB). These analyses consider primary-to-secondary leakage that may occur during these events and must show that the offsite radiological consequences do not exceed the applicable limits of 10 CFR Section 50.67 or 10 CFR Section 100.11 for offsite doses; GDC 19 for control room operator doses (or some fraction thereof as appropriate to the accident); or the NRC-approved licensing basis (e.g., a small fraction of these limits). No accident analyses for Point Beach, Unit 1, are being changed because of the proposed amendment and, thus, no radiological consequences of any accident analysis are being changed. The proposed changes maintain the accident analyses and consequences that the NRC has reviewed and approved for the postulated DBAs for SG tubes.

3.0 TECHNICAL EVALUATION

3.1 Proposed Changes to the TS

The current TSs are shown below with the proposed changes. The proposed changes are shown in markup form for clarity, with additions shown in bold text and deletions shown with strikethrough text.

3.1.1 The TS 3.4.13 is being revised as shown below:

3.4.13 RCS Operational LEAKAGE

LCO 3.4.13 RCS operational LEAKAGE shall be limited to:

a. No pressure boundary LEAKAGE;
b. 1 gpm unidentified LEAKAGE;
c. 10 gpm identified LEAKAGE; and
d. **72 gallons per day (Unit 1) and** 150 gallons per day **(Unit 2)** primary to secondary LEAKAGE through any one steam generator (SG).

APPLICABILITY: [Text is unchanged/not shown]

ACTIONS: [Text is unchanged/not shown]

SURVEILLANCE REQUIREMENTS

SR 3.4.13.1 [Text is unchanged/not shown]

SR 3.4.13.2 Verify primary to secondary LEAKAGE is **≤ 72 gallons per day (Unit 1) and** ≤ 150 gallons per day **(Unit 2)** through any one SG.

SR 3.4.13.2 [Notes and frequency requirements are unchanged/not shown]

3.1.2 The TS 5.5.8.c is being revised as shown below:

TS 5.5.8 <u>Steam Generator (SG) Program</u>

c. Provisions for SG tube repair criteria. Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 40% of the nominal tube wall thickness shall be plugged.

The following alternate tube plugging criteria shall be applied as an alternative to the 40% depth based criteria:

For Unit 1 only, tubes with service-induced flaws located greater than 20.6 inches below the top of the tubesheet do not require plugging. Tubes with service-induced flaws located in the portion of the tube from the top of the tubesheet to 20.6 inches below the top of the tubesheet shall be plugged upon detection.

This alternate tube plugging criteria is not applicable to the tube at row 38 column 69 in the A steam generator, which is not expanded in the hot leg the full length of the tubesheet. This tube has been removed from service by plugging (during U1R31).

3.1.3 The TS 5.5.8.d is being revised as shown below:

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. **For Unit 1, the number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube from 20.6 inches below the top of the tubesheet on the hot leg side to 20.6 inches below the top of the tubesheet on the cold leg side and that may satisfy the applicable tube plugging criteria. For Unit 2, the** ~~The~~ number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube plugging criteria.

For Unit 1 and Unit 2: The tube-to-tubesheet weld is not part of the tube. In addition to meeting the requirements of d.1, d.2, and d.3 below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. A degradation assessment shall be performed to determine the type and location of flaws to which the tubes may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what location.

1. [Text is unchanged/not shown]
2. [Text is unchanged/not shown]
3. **For Unit 1, if** ~~If~~ crack indications are found in any SG tube **from 20.6 inches below the top of the tubesheet on the hot leg side to 20.6 inches below the top of the tubesheet on the cold leg side,** then the next inspection for each affected and potentially affected SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever results in more frequent inspections). If definitive information, such as from examination of a pulled tube, diagnostic non-destructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

   For Unit 2, if crack indications are found in any SG tube, then the next inspection for each affected and potentially affected SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever results in more frequent inspections). If definitive information, such as from examination of a pulled tube, diagnostic non-destructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

3.1.4 The TS 5.6.8 is being revised as shown below:

5.6.8 Steam Generator Tube Inspection Report

a. – g. [Text is unchanged/not shown]

h. **For Unit 1 only, the primary to secondary leakage rate observed in each SG (if it is not practical to assign the leakage to an individual SG, the entire primary to secondary leakage should be conservatively assumed to be from one SG) during the cycle preceding the inspection which is the subject of the report,**

i. **For Unit 1 only, the calculated accident induced leakage rate from the portion of the tubes below 20.6 inches from the top of the tubesheet for the most limiting accident in the most limiting SG. In addition, if the calculated accident induced leakage rate from the most limiting accident is less than 5.22 times the maximum operational primary to secondary leakage rate, the report should describe how it was determined, and**

j. **For Unit 1 only, the results of monitoring for tube axial displacement (slippage). If slippage is discovered, the implications of the discovery and corrective action shall be provided.**

3.2 Technical Discussion

The T/TS joints are part of the pressure boundary between the primary and secondary systems. Each T/TS joint consists of the tube, which is hydraulically expanded against the bore of the tubesheet, the T/TS weld located at the tube end, and the tubesheet. The joints were designed in accordance with the ASME Code, Section III, as welded joints, not as friction joints. The T/TS welds were designed to transmit the tube end-cap pressure loads from the tubes to the tubesheet, during normal operating and DBA conditions, with no credit taken for the friction developed between the hydraulically expanded tube and the tubesheet. In addition, the welds serve to make the joints leak tight.

This design basis is a conservative representation of how the T/TS joints actually work, since it conservatively ignores the role of friction between the tube and tubesheet in reducing the tube end-cap load that is transmitted to the T/TS weld. The initial hydraulic expansion of the tubes against the tubesheet produces an "interference fit" (between the tubes and the tubesheet); thus, producing a residual contact pressure between the tubes and tubesheet, which acts normally to the outer surface of the tubes and the inner surface of the tubesheet boreholes. Additional contact pressure between the tubes and tubesheet is induced by operational conditions as will be discussed in detail below. The amount of friction force that can be developed between the outer tube surface and the inner surface of the tubesheet bore is a direct function of the contact pressure between the tube and tubesheet, multiplied by the applicable coefficient of friction.

To support the proposed TS changes, the licensee's contractor, Westinghouse, has defined a parameter called H* (pronounced H-star). The parameter H* is the distance below the TTS over which sufficient frictional force, with acceptable safety margins, can be developed between each tube and the tubesheet to prevent significant slippage or pullout of the tube from the tubesheet, assuming the tube is fully severed at the H* distance below the TTS. The analyses used to define the H* parameter assumed tube end-cap pressure loads associated with normal operating and DBA conditions. For Point Beach, Unit 1, the proposed H* distance is 20.6 inches. Given that the frictional force developed in the T/TS joint over the H* distance is sufficient to resist the tube end-cap pressure loads, it is the licensee's and Westinghouse's position that the length of tubing between the H* distance and the T/TS weld is not needed to resist any portion of the tube end-cap pressure loads. Thus, the licensee is proposing to change the TS to not require inspection of the tubes below the H* distance and to exclude tube flaws located below the H* distance (including flaws in the T/TS weld) from the application of the TS tube plugging criteria. Under these changes, the T/TS joint would now be treated as a friction joint extending from the TTS to the H* distance below the TTS, for purposes of evaluating the structural and leakage integrity of the T/TS joint.

The regulatory standard by which the NRC staff has evaluated the subject license amendment is that the amended TSs should continue to ensure that tube integrity will be maintained, consistent with the current design and licensing basis. This includes maintaining structural safety margins consistent with the structural performance criteria in TS 5.5.8.b.1 and the design basis. In addition, this includes limiting the potential for accident-induced primary-to-secondary leakage to values not exceeding the accident-induced leakage performance criteria in TS 5.5.8.b.2, which are consistent with values assumed in the licensing basis accident analyses. Maintaining tube integrity in this manner ensures that the amended TS comply with all applicable regulations. The NRC staff's evaluation of joint structural integrity and accident-induced leakage integrity is discussed in Sections 3.3 and 3.4 of this SE, respectively.

3.2.1 H* Calculation Process

The calculation of H* consists of the following steps for each loading case considered:

1. Perform initial H* estimate (mean H* estimate) using the lower SG assembly model, the integrated 3-DSub Model (3DSM), and the T/TS interaction model, assuming nominal geometric and material properties, and that the tube is severed at the bottom of the tubesheet for purposes of defining the contact pressure distribution over the length of the T/TS crevice. This step yields a mean H* estimate, which is deterministically based.

2. The next step performs a probabilistic analysis of the potential variability of H*, relative to the mean H* estimate, associated with the potential variability of key input parameters for the H* analyses. This leads to a "probabilistic" estimate of H*, which includes (i.e., bounds) the mean estimate. The NRC staff's evaluation of the probabilistic analysis is provided in Sections 3.3.8 and 3.3.9 of this safety evaluation.

3. Finally, a crevice pressure adjustment is added to the probabilistic estimate of H*, to account for the crevice pressure distribution that results from the tube being severed at the final H* value, rather than at the bottom of the tubesheet, which was the starting assumption in Step 1, above. This step is discussed and evaluated in Section 3.3.11 of this safety evaluation.

3.3 Joint Structural Integrity

3.3.1 Acceptance Criteria

Westinghouse conducted extensive analyses to establish the H* distance necessary to resist pullout under normal operating and DBA conditions. Based on the physical geometry of the SG tubesheet, the NRC staff finds that pullout is the structural failure mode of interest, since the tubes are radially constrained against axial rupture by the presence of the tubesheet. The axial force that could produce pullout derives from the end-cap pressure loads, due to the primary-to-secondary pressure differentials associated with normal operating and DBA conditions. Westinghouse determined the needed H* distance on the basis of maintaining a safety factor of 3 against pullout under normal operating conditions and a safety factor of 1.4 against pullout under DBA conditions. The NRC staff finds that these are the appropriate safety factors to apply to demonstrate structural integrity, because they are consistent with the safety factors embodied in the structural integrity performance criteria in TS 5.5.8.b.1 and with the design basis; namely, the stress limit criteria in Section III of the ASME Code.

The above approach equates tube pullout to gross structural failure, which is conservative. Should the pullout load be exceeded, tube slippage would generally be limited by the presence of adjacent tubes and support structures, such that the tube would not be expected to pull out of the tubesheet.

Under the proposed license amendment, TS 5.6.8.j will require the results of slippage monitoring to be included as part of the SG tube inspection report required by TS 5.6.8. In addition, TS 5.6.8.j will require that if slippage is discovered, the implications of the discovery and corrective actions taken shall be included in the report. The NRC staff finds that slippage is not expected to occur for the reasons discussed in this SE. However, in the unexpected event it should occur, it will be important to understand why it occurred so that the need for corrective action can be evaluated. Therefore, the NRC staff concludes including slippage monitoring in the SG tube inspection report required by TS 5.6.8 is acceptable.

3.3.2 Lower SG Assembly Model

A detailed three-dimensional (3-D) finite element analysis (FEA) of the lower SG assembly was performed, to calculate tubesheet displacements due to primary pressure, secondary pressure, and the temperature distribution throughout the entire lower SG assembly. The lower SG assembly model in the proposed H* analysis consists of the lower portion of the SG shell, the tubesheet, the channel head, and the divider plate, and is essentially the same as the "revised" model used in previous H* analyses (Reference 5), but has two notable differences. First, the new lower SG assembly model uses an integrated three-dimensional sub model (3DSM) for calculating T/TS contact pressures, instead of the square-cell model used in previous H* analyses. Second, the divider plate in the new lower SG assembly model is modeled as fully intact and non-degraded. Both of these changes are discussed further in Sections 3.3.3 and 3.3.4, below.

As in previous H* analyses, the lower SG assembly model generates the overall thermal and structural displacements under SLB and normal operating conditions. The thermal and structural displacements are then transferred to the 3DSM, for calculating the axial contact pressure distribution within the thickness of the tubesheet. The licensee noted that the thermal and structural loads used in the proposed H* analysis reflect the parameters in the current licensing basis of Point Beach, Unit 1, including an increase to the primary system pressure during SLB conditions, which resulted from an extended power uprate license amendment (Reference 6) that was approved in 2011. The worst-case sector for generating T/TS contact pressure was previously shown to be the region of the tubesheet perpendicular to the divider plate in the SG (Reference 7). The licensee confirmed (Reference 2) this was still the worst-case sector after the lower SG assembly model was changed to include an attached divider plate.

The 3DSM uses the mean material property values of Model 44F SGs (Reference 7) to calculate the T/TS contact pressure distribution for the worst sector of the SG. Then the T/TS contact pressure distribution, the coefficient of friction, and the contact surface area between the tube and tubesheet are used to calculate the mean H* distance at the critical radius of the tubesheet. The same coefficient of friction value (0.2) is used that was accepted by the NRC previously in other H* amendments (Reference 4). The critical radius was found by comparing the effects of horizontal and vertical tubesheet displacement, when moving from the center to the periphery of the tubesheet (Reference 2).

As an initial condition, the square-cell model assumed that each tube was fully expanded and in contact with the inner surface of the tubesheet bore under room temperature, atmospheric pressure conditions, with zero residual contact pressure from the hydraulic expansion process. The 3DSM also used these same initial conditions. The NRC staff finds the assumption of zero residual contact pressure in all tubes to be a conservative assumption.

Primary pressure acting on the inside tube surface, and crevice pressure[1] acting on both the tube outside surface and tubesheet bore surface, are not modeled directly in the 3DSM, just as in the square-cell model. Instead, the primary side (inside) of the tube is assumed to have a pressure equal to the primary pressure minus the crevice pressure. Note the crevice pressure varies as a function of the elevation being analyzed, as discussed below in Section 3.3.5.

The NRC staff concludes that integration of the 3DSM into the 3-D model of the lower SG assembly provides increased accuracy of the calculated H* distance and is acceptable.

3.3.3 3-D Sub Model (3DSM)

The 3DSM is a three-dimensional, single structural cell model, of one tube through the entire depth of the tubesheet, centered on one tube pitch. The purpose of the 3DSM is to calculate the T/TS contact pressures generated during all postulated operating and design basis conditions. The contact pressure and coefficient of friction between the expanded tube and the tubesheet determine the resistance to tube pullout. Previous applications for H* had used the square-cell model for calculating T/TS contact pressure (References 3 and 4). The square-cell model is a two-dimensional model, which divides the tubesheet thickness into a stack of horizontal slices that do not interact with each other. The contact pressure of each slice was calculated and then summed, to determine the resistance to tube pullout. Due to the bounding assumptions made in the Point Beach, Unit 1, SG design specifications, the square-cell model did not calculate sufficient resistance against tube pullout for a portion of the SG tubes at Point Beach, Unit 1. As a result, Westinghouse developed the 3DSM as a more accurate representation of the contact pressures generated within the SG tubesheet.

The 3DSM differs from the square-cell model by accounting for the bending of the tubes and the tubesheet, which was conservatively ignored in the square-cell model. Accounting for tube and tubesheet bending increases the amount of T/TS contact pressure calculated by the 3DSM, as compared to the square-cell model. As this is a more accurate representation of the actual condition of the tubes within the SG, the NRC staff finds this acceptable. Additionally, the three-dimensional nature of the 3DSM allows for direct application of the pull out force (i.e., the end cap load) on the tubes, thereby allowing the Poisson contraction effect to be directly included in the calculation of the T/TS contact pressure. Because the slices of the square-cell model were not coupled in the horizontal planes, the effect of Poisson contraction on contact pressure was previously calculated separately, using classical thick-shell equations. Eliminating the separate calculation eliminates an uncertainty that was part of this approximation, which the NRC staff finds acceptable.

To benchmark that the new 3DSM behaved similarly to the square-cell model used in previous H* analyses, the contract pressure analysis that was previously performed with the square-cell model was repeated with the 3DSM. However, because the 3DSM is a continuous structure that accounts for tube and tubesheet bending, only temperature and internal pressure loads were applied to the 3DSM. This provided a comparison of predicted T/TS contact pressures, under the same loading conditions, for both the 3DSM and the square-cell model. The results showed that the 3DSM calculated T/TS contact pressures were similar to the previous square-cell model, when tube and tubesheet bending was not considered.

[1] Although the tubes are in tight contact with the tubesheet bore surfaces, surface roughness effects are conservatively assumed to create interstitial spaces, which are effectively crevices between these surfaces. See Section 3.3.5 for more information

The benchmarking comparison revealed that because of manner in which the loads were applied in the 3DSM, two "end effects" were found at the top and bottom of the tubesheet.

The bottom "end effect" was a jump in contact pressure at 2 inches above the bottom of the tubesheet. This jump in pressure was caused by directly mapping the tube displacements from the coarse mesh tubesheet model to the bottom face of the tube in the 3DSM. To eliminate this localized bottom "end effect," a constant, conservative, contact pressure was applied from the bottom of the tube to the first inch of the tube in the 3DSM.

The "end effect" at the TTS was a spike in T/TS contact pressure, caused by bending of the tubesheet in the model, which applied pressure to the tube. This was caused by the 3DSM's use of a constant diameter for the tube, rather than inclusion of the reduction in diameter that occurs above the expansion transition. Use of the constant diameter tube led to a conservative calculation of Poisson's contraction, which the NRC staff finds acceptable. To compensate for this "end effect," the 3DSM was altered in two ways. The tube in the 3DSM was extended a distance above the tubesheet, so that applying the end cap load to the tube reduced the contact pressure "end effect," due to Poisson contraction at the TTS. In addition, a post-processing technique was used to set the contact pressure, at and above the bottom of the expansion transition (BET), to zero. Since application of the end cap loads to an extended tube within the 3DSM more closely represents the manner in which the end cap loads are physically applied in actual SGs, and since the tube is not in contact with the tubesheet above the expansion transition, NRC staff finds these changes to the 3DSM acceptable. In conclusion, the NRC staff finds the 3DSM acceptable.

3.3.4 SG Divider Plate Modeling

Some non-U.S. units have experienced cracks in the weld between the divider plate and the stub runner attachment on the bottom of the tubesheet. To address this operating experience, previous H* analyses had modeled the divider plate without the stub runner (i.e., the top five inches of the divider plate), which had resulted in calculation of a longer (more conservative) H* distance. In contrast, the new 3DSM shows T/TS contact pressures increase when the SG is modeled without the stub runner, which resulted in a shorter calculated H* distance. The two reasons for this change are the assumed operating temperatures during design basis accidents at Point Beach, Unit 1, and the 3DSM accounting for tube and tubesheet bending, which had not been accounted for in the previous square-cell model.

The low temperatures assumed for both the primary and secondary sides of the faulted SG during SLB conditions are the principle contributors to reduced T/TS contact pressures. Because the deflections of the tubesheet are dependent on differential temperature and pressure, a zero differential temperature results in reduced tubesheet bending and hence, reduced T/TS contact pressure. Modeling the divider plate as physically attached to the tubesheet in the 3DSM further reduces tubesheet bending and results in an increased H* distance.

Because of these differences, the proposed H* analysis models the divider plate as fully attached and non-degraded in the lower SG assembly model, which results in a more conservative analysis that the NRC staff finds acceptable.

3.3.5 Crevice Pressure Evaluation

The H* analyses postulate that interstitial spaces exist between the hydraulically expanded tubes and tubesheet bore surfaces. These interstitial spaces are assumed to act as crevices between the tubes and the tubesheet bore surfaces. The NRC staff finds that the assumption of crevices is conservative since the pressure inside the crevices acts to push against both the tube and the tubesheet bore surfaces, thus reducing contact pressure between the tubes and tubesheet.

For tubes that do not contain through-wall flaws within the thickness of the tubesheet, the pressure inside the crevice is assumed equal to the secondary system pressure. For tubes that contain through-wall flaws within the thickness of the tubesheet, a leak path is assumed to exist from the primary coolant inside the tube, through the flaw, and up the crevice to the secondary system. Hydraulic tests were performed on several tube specimens that were hydraulically expanded against tubesheet collars, to evaluate the distribution of the crevice pressure from a location where through-wall holes had been drilled in the tubes, to the top of the crevice location. The T/TS collar specimens were instrumented at several axial locations to permit direct measurement of the crevice pressures. Tests were run for both normal operating and main SLB pressure and temperature conditions.

The NRC staff finds that the use of the drilled holes, rather than through-wall cracks, is conservative since it eliminates any pressure drop between the inside of the tube and the crevice at the location of the hole. This maximizes the pressure in the crevice at all elevations, thus reducing contact pressure between the tubes and tubesheet.

The crevice pressure data from these tests were used to develop a crevice pressure distribution as a function of distance between the TTS and the H* distance below the TTS, where the tube is assumed to be severed. These distributions determine the appropriate crevice pressure at each axial location through the thickness of the tubesheet. The gradient of pressures applied to the inside diameter of the tubes in the 3DSM was calculated by subtracting the crevice pressure from the primary pressure, for the appropriate plant condition (i.e., normal operating pressure (NOP) or SLB), which the NRC staff finds acceptable.

Because the crevice pressure distribution is assumed to extend from the H* location, where crevice pressure is assumed to equal primary pressure, to the BET, where crevice pressure equals secondary pressure, an initial estimate as to the H* location must be made before iteratively solving for H* using the T/TS interaction model. The resulting new H* estimate becomes the initial estimate for the next H* iteration.

3.3.6 Bottom of the Expansion Transition Considerations

The diameter of each tube transitions from its fully expanded value to its unexpanded value near the TTS. The BET region is located a short distance below the TTS, to avoid any potential for over-expanding the tube above the TTS. In early H* analyses, a 0.3-inch adjustment was added to the mean H* estimate to account for the BET location being below the TTS, based on a survey of BET distances conducted by Westinghouse. Use of the square-cell model in later H* analyses made the need for a BET adjustment unnecessary, as the model showed a loss of contact pressure over a distance from the TTS that was greater than the possible variation in the BET location.

Integrating the 3DSM into the lower SG assembly model allows the current H* analysis to set contact pressure between the tube and the tubesheet to zero, for the distance above the BET to the TTS. The distance from the TTS to the BET was measured for all the tubes in all the Point Beach Unit 1 SGs, and a 99th percentile dimension was used for all tubes in the H* analysis (Reference 8). Above this dimension, the internal pressure in the SG tubes was constant, and the contact pressure between the tube and the tubesheet (from the BET to the TTS) was set to zero. The NRC staff concludes that the proposed value for the distance from the BET to the TTS adequately accounts for the range of BET values at Point Beach, Unit 1.

3.3.7 Poisson Contraction Effect

The axial end-cap load acting on each tube is the force generated by the primary-to-secondary pressure differential in the tube that attempts to pull the tube vertically from the tubesheet. The axial end-cap load stretches the tube in the axial direction and causes a slight contraction in the radial direction, due to a material property known as Poisson's Ratio. This Poisson contraction effect, by itself, reduces the T/TS contact pressure and, thus, increases the H* distance. Unlike the square-cell model used previously, the 3DSM calculates the Poisson contraction effect directly within the FEA model, which eliminates a potential uncertainty that existed in the square-cell model. In the 3DSM, the axial end-cap load is applied as an equivalent pressure at the end of the tube above the tubesheet. However, to avoid a spike in contact pressure at the TTS, the tube in the 3DSM had to be extended above the TTS, and the pressure applied at the extended tube end. The pressure spike was an artifact of the model, due to use of the expanded tube's diameter in the 3DSM. Using the expanded diameter in the model, and then changing contact pressure above the BET to zero, simplified the 3DSM, and allowed for faster processing of the 3DSM. Since the 3DSM accounted for the physical reality of the BET location, by setting contact pressure above the BET to zero, the NRC staff finds this simplification of the 3DSM acceptable.

In the 3DSM, the axial end-cap load is applied as an equivalent pressure at the end of the tube extension above the tubesheet. This equivalent pressure is calculated by dividing the axial end-cap load by the cross sectional area of the nominal tube diameter. However, in the 3DSM, the tube is modeled at the expanded tube diameter. Consequently, the effective force on the tube extension is conservative, because the equivalent pressure is applied over a larger area than that of the nominal unexpanded tube, which leads to a larger (conservative) calculation of the Poisson contraction.

The axial end-cap force is resisted by the axial friction force developed at the T/TS joint. Thus, the axial end-cap force begins to decrease with increasing distance into the tubesheet, reaching zero at a location before the H* distance is reached. This is because the H* distances are intended to resist pullout under the end-cap loads with appropriate factors of safety applied, as discussed in Section 3.3.1. As was performed in previous H* analyses, there was no safety factor applied to the material property of Poisson's ratio. The NRC staff has not reached a conclusion on this point; however, since the effect of Poisson's contraction was conservatively calculated (by using the value for the expanded diameter of the tube), the staff finds the method for calculating the Poisson contraction acceptable.

3.3.8 Acceptance Standard - Probabilistic Analysis

The purpose of the probabilistic analysis is to develop an H* distance that ensures with a probability of 0.95 that the population of tubes will retain margins against pullout consistent with criteria evaluated in Section 3.3.1 of this safety evaluation, assuming all tubes to be completely severed at their H* distance. The staff finds this probabilistic acceptance standard is consistent with what the NRC staff has approved previously and is acceptable.

For example, the upper voltage limit for the voltage based tube repair criteria in NRC Generic Letter 95-05 (Reference 9) employs a consistent criterion. The NRC staff also notes that use of the 0.95 probability criterion ensures that the probability of pullout of one or more tubes under normal operating conditions and conditional probability of pullout under accident conditions is well within tube rupture probabilities that have been considered in probabilistic risk assessments (References 10 and 11).

In terms of the confidence level that should be attached to the 0.95 probability acceptance standard, it is industry practice for SG tube integrity evaluations, as embodied in industry guidelines, to calculate such probabilities at a 50 percent confidence level. This is commonly referred to as the 95/50. The NRC staff has been encouraging the industry to revise its guidelines to call for calculating such probabilities at a 95 percent confidence level (i.e., 95/95) when performing operational assessments and a 50 percent confidence level when performing condition monitoring (i.e., 95/50) (Reference 12). The calculated H* distances supporting the current amendment request have been evaluated at the 95 percent confidence level.

Another issue relating to the acceptance standard for the probabilistic analysis is determining what population of tubes needs to be analyzed. For accidents such as SLB or feed line break, the NRC staff and licensee find that the tube population in the faulted SG is of interest, since only that SG experiences a large increase in the primary-to-secondary pressure differential. As the limiting condition for Point Beach, Unit 1, is SLB, the proposed H* probabilistic analysis included the tube population of the faulted SG only, which the NRC staff finds acceptable.

Based on the above, the NRC staff concludes that the proposed H* distance in the subject license amendment request is based on acceptable probabilistic acceptance standards evaluated at acceptable confidence levels.

3.3.9 Probabilistic Analyses

3.3.9.1 Previous H* Analyses

Sensitivity studies were conducted during the initial H* analysis (Reference 7), and showed that H* was highly sensitive to the potential variability of the coefficients of thermal expansion (CTE) for the Alloy 600 tubing material and the SA-508 Class 2a tubesheet material. Given that no credit was taken in the initial H* analysis for residual contact pressure associated with the tube hydraulic expansion process[2], the sensitivity of H* to other geometry and material input parameters was judged by Westinghouse to be inconsequential and were ignored, with the exception of Young's modulus of elasticity for the tube and tubesheet materials. Although the Young's modulus parameters were included in the initial H* analysis sensitivity studies, these parameters were found to have a weak effect on the computed H* distance. Based on its review of the analysis models and its engineering judgment, the NRC staff found that the sensitivity studies adequately captured the input parameters that may significantly affect the value of H*. This conclusion was based, in part, on no credit being taken for residual contact pressure during the H* analysis.

[2] Residual contact pressures are sensitive to variability of other input parameters.

These sensitivity studies were used to develop influence curves describing the change in H*, relative to the mean H* value estimate, as a function of the variability of CTE and Young's modulus, relative to the mean values of CTE and Young's Modulus. Separate influence curves were developed for each of the four input parameters. The sensitivity studies showed that of the four input parameters, only the CTE for the tube and tubesheet materials interacted with one another. A combined set of influence curves showing the variability of H* to changes in these principal variables was created. A map of this variability is known as a "response surface."

When the square-cell model was implemented by Westinghouse, it became impractical to develop a response surface, due to the extreme number of calculations required; therefore, a rationale was developed and documented that supported use of the original thick-shell equation based response surface.

With development of the 3DSM to replace the square-cell model, calculation of the response surface directly and efficiently is capable once again, and is the method used in the proposed H* amendment.

3.3.9.2 Proposed H* Analysis

The current H* analysis uses a Monte Carlo sampling approach, which provides realistic treatment of uncertainties, and which the NRC staff has reviewed and accepted in the past (References 3 and 4). The sensitivity of H* to variations in the tube and tubesheet CTE was calculated to determine the response surface, using the 3DSM for a range of material property variations and combinations. Because prior H* analyses (e.g., References 5 and 7) have shown that the H* distance increases when the tube CTE varies negatively from its mean, and the tubesheet CTE varies positively from its mean, it was not necessary to develop a response surface for the full range of possible CTE values. Based on this prior experience, the range of tube and tubesheet CTEs were narrowed to reduce the calculation effort.

The Monte Carlo sampling of the response surface provided the estimated values of H*. In addition, the response surface results provided the specific combination of variables that led to the high probability values of H*, because the specific values of the random sample variables were saved in the calculation process. The upper 10 percent tail of the H* distribution results from the Monte Carlo analysis were output as a 4-column by 10,000-row matrix. The four columns in the matrix were: (1) the rank order statistic (i.e., 9,001 to 10,000), (2) the estimated H* value at the given rank order, (3) the variation in tubesheet CTE about its mean value (in terms of standard deviation), and (4) the variation in tube CTE about its mean value (in terms of standard deviation).

The values of tube and tubesheet CTE used in the final H* analysis are selected based on the rank order statistics that met the required probabilistic goals for H*. For the whole bundle analysis, the 95/50 H* value that would resist pull out during a postulated SLB, corresponds to a rank order statistic of 9500 out of 10000 trials, ordered in increasing value (Reference 1). The order statistic for higher confidence intervals (e.g., 95 percent) involves calculating the run-to-run variance in Monte Carlo order statistics and calculating a bounding order statistic to ensure a higher confidence interval. For the whole bundle analysis, the 95/95 H* value that would resist pullout during a postulated SLB, corresponds to a rank order statistic of 9536 out of 10000 trials.

Since the current probabilistic analysis has been refined in scope, based on knowledge gained from previous probabilistic analyses performed for H* amendments, and since the remainder of the proposed analysis uses the same methods as applied in previous H* amendments, the NRC staff finds the proposed probabilistic analysis acceptable.

3.3.10 Coefficient of Thermal Expansion

During operation, a large part of contact pressure in a SG T/TS joint is derived from the difference in CTE between the tube and tubesheet. As discussed in section 3.3.9.2, the calculated value of H* is highly sensitive to the assumed values of these CTE parameters. Early reviews of CTE test data acquired by an NRC contractor, Argonne National Laboratory (ANL), suggested that CTE values might vary substantially from values listed in the ASME Code for design purposes. In Reference 13, the NRC staff highlighted the need for a rigorous technical basis of the CTE values, and their potential variability, to be employed in future H* analyses.

In response, Westinghouse had a subcontractor review the CTE data in question, determine the cause of the variance from the ASME Code CTE values, and provide a summary report (Reference 14). The analysis of the CTE data revealed that the CTE variation with temperature had been developed using a polynomial fit to the raw data, over the full temperature range from 75 °F to 1300 °F. The polynomial fit chosen resulted in mean CTE values that were significantly different from the ASME Code values from 75 °F to about 300 °F.

When the raw data was reanalyzed using the locally weighted least squares regression method, the mean CTE values determined were in good agreement with established ASME Code values.

Westinghouse also formed a panel of licensee experts to review the available CTE data in open literature, review the ANL provided CTE data, and perform an extensive CTE testing program on Alloy 600 and SA-508 steel material to supplement the existing database. Two additional sets of CTE test data (different from those addressed in the previous paragraph) had CTE offsets at low temperatures that were not expected. Review of the test data showed that the first test, conducted in a vacuum, had proceeded to a maximum temperature of 1300 °F, which changed the microstructure and the CTE of the steel during decreasing temperature conditions. Because of the altered microstructure, the CTE test data generated in the second test, conducted in air, was also invalidated. Because of the large "dead band" region and the altered microstructure, both data sets were excluded from the final CTE values obtained from the CTE testing program. The test program included multiple material heats to analyze chemistry influence on CTE values and repeat tests on the same samples were performed to analyze for test apparatus influence. Because the tubes are strain hardened when they are expanded into the tubesheet, strain hardened samples were also measured to check for strain hardening influence on CTE values.

The data from the test program was combined with the ANL data that was found to be acceptable and the data obtained from the open literature search. A statistical analysis of the data uncertainties was performed by comparing deviations to the mean values obtained at the applicable temperatures. The correlation coefficients obtained indicated a good fit to a normal distribution, as expected. Finally, an evaluation of within-heat variability was performed due to increased data scatter at low temperatures. The within-heat variability assessment determined that the increase in data scatter was a testing accuracy limitation that was only present at low temperature. The CTE report is included as Appendix A to Reference 7.

The testing showed that the nominal ASME Code values for Alloy 600 and SA-508 steel were both conservative relative to the mean values from all the available data. Specifically, the CTE mean value for Alloy 600 was greater than the ASME Code value and the CTE mean value for SA-508 steel was smaller than the ASME Code value. Thus, the H* analyses utilized the ASME Code values as mean values in the H* analyses. The NRC staff finds this to be conservative because it tends to lead to an over-prediction of the expansion of the tubesheet bore and an under-prediction of the expansion of the tube, thereby resulting in an increase in the calculated H* distance. The statistical variances of the CTE parameters from the combined database were utilized in the H* probabilistic analysis.

Based on its review of the Westinghouse CTE program, the NRC staff concludes that the CTE values used in the H* analyses are fully responsive to the concerns stated in Reference 13 and are acceptable.

3.3.11 Crevice Pressure Adjustment

As discussed in Step 3 of Section 3.2.1, the H* calculation process is performed with the initial assumption that the tube is severed at the bottom of the tubesheet, for calculating the distribution of crevice pressure as a function of elevation. After the initial H* distance is calculated, if the tube is then assumed to be severed at the initially computed H* distance, and Steps 1 and 2 of Section 3.2.1 repeated, a new H* distance is calculated that will be incrementally larger than the first estimate. This process is repeated until the calculated change in H* distance becomes very small, which is a process known as convergence. By repeating the convergence process with initial H* distances that vary over the thickness of the tubesheet, a crevice pressure adjustment curve can be created.

For previous H* analyses that were performed for Model 44F SGs, the limiting plant condition had been NOP. Because SLB is the limiting condition for Point Beach, Unit 1, the crevice pressure adjustment curve had to be recreated. However, because prior experience had established the range of interest for the principal variables that affect the H* distance (i.e., the tube and tubesheet CTEs), it was not necessary to consider the entire range of variation for these variables when developing the new crevice pressure adjustment curve. Therefore, the new curve that was developed used initial predictions of H* between 19 and 21 inches, with tube and tubesheet CTE values that bound the CTE variations for the inputs used in the 95/50 and 95/95 H* calculations, as discussed in Section 3.3.9, above. Since the method used to calculate the crevice pressure adjustment curve for Point Beach, Unit 1, was based on analyses the NRC staff had reviewed and found acceptable in previous H* analyses, the NRC staff finds their use acceptable.

3.4 Leakage Considerations

Operational leakage integrity is assured by monitoring primary-to-secondary leakage relative to the applicable TS LCO in TS 3.4.13, "RCS Operational LEAKAGE." In addition, it must also be demonstrated that the proposed TS changes do not create the potential for leakage during a DBA to exceed the accident induced leakage performance criterion in TS 5.5.7.b.2, which are based on the leakage values assumed in the plant licensing basis accident analyses.

If a tube is assumed to contain a 100 percent through-wall flaw some distance into the tubesheet, a potential leak path between the primary and secondary systems is introduced between the hydraulically expanded tubing and the tubesheet. The leakage path between the tube and tubesheet has been modeled by the licensee's contractor, Westinghouse, as a crevice consisting of a porous media. Using Darcy's model for flow through a porous media, leak rate is proportional to differential pressure and inversely proportional to flow resistance. Flow resistance is a direct function of viscosity, loss coefficient, and crevice length.

Westinghouse performed leak tests of T/TS joint mockups to establish loss coefficient as a function of contact pressure. A large amount of data scatter, however, precluded quantification of such a correlation. In the absence of such a correlation, Westinghouse has developed a leakage factor relationship between accident induced leak rate and operational leakage rate, where the source of leakage is from flaws located at or below the H* distance.

Using the Darcy model, the leakage factor for a given DBA is the product of four ratios. The first ratio is the ratio of the primary-to-secondary pressure difference during DBA conditions divided by the primary-to-secondary pressure difference for NOP conditions. The second quantity is the ratio of viscosity for primary water during NOP conditions divided by the viscosity during DBA conditions. The third quantity is the ratio of the T/TS crevice length during NOP conditions divided by the crevice length during DBA conditions. This ratio equals one, provided it can be shown that positive contact pressure is maintained along the entire H* distance for both NOP and DBA conditions.

The fourth quantity is the ratio of loss coefficient during NOP conditions to loss coefficient during the DBA conditions. Although the absolute value of these loss coefficients are not known, Westinghouse has assumed that the loss coefficient is constant with contact pressure such that the ratio is equal to one. The NRC staff agrees that this is a conservative assumption, provided there is a positive contact pressure for both conditions along the entire H* distance and provided that contact pressure increases at each axial location along the H* distance when going from NOP to DBA conditions. In the H* analysis by Westinghouse (Reference 10), the T/TS contact pressures at SLB conditions did not exceed those at NOP conditions, and the contact pressure criterion is not met. Therefore, the loss coefficient ratio between NOP and SLB conditions cannot be assumed to equal one.

As mentioned above, the large scatter of the loss coefficient versus contact pressure data prevented direct use of this data in applying Darcy's leakage model. Instead, Westinghouse considered two alternate approaches. Both approaches used leak rate testing data from Model D5 SGs, as no leak rate data was available for Model 44F SGs. Since the purpose of analyzing this data is not to determine absolute leak rates, but rather, to determine the significance of a functional relationship between loss coefficient and contact pressure, and the ratio of leak rates between SLB and NOP conditions, the NRC staff finds the use of Model D5 leak rate data acceptable.

The first approach considered a number of assumed parametric relationships between loss coefficient and T/TS contact pressure. The second approach used application of the parallel plate theory to calculate a flow area based on the leakage test results and relates that flow area (and consequential leak rate) to the contact pressure conditions for the test specimens, to develop leak rates for both NOP and SLB conditions.

In the parametric approach, a number of mathematical functions that represented potential functional relationships between loss coefficient and contact pressure were assumed and then applied to the Darcy formulation for leakage through a porous medium. Each of the mathematical functions that were considered assumed that loss coefficient should increase with increasing contact pressure, and the functions were each within the available test data. The purpose was to investigate to what degree a presumed function between loss coefficient and contact pressure would affect the leak rate ratio between SLB and NOP conditions.

This approach assumed that leak rate through the crevice above the H* distance could be considered a network of flow resistances in which the total resistance was the sum of individual segment resistances. The model used eleven different axial segments through the tubesheet thickness. The eleven segment lengths were those defined by the structural model in the original H* analysis for Point Beach, Unit 1 (i.e., the square-cell model), but the actual analysis of these segments was performed using the new 3DSM (Reference 2). At the end-point of each segment, contact pressures were calculated as part of the normal H* calculations. The assumptions necessary for this approach were that the local crevice length was the distance between the axial locations where contact pressures were calculated, and that the contact pressure that applies over the local crevice length is the average of the contact pressures at the end-points of the local length. The total resistance to leakage above the H* distance was the sum of the local resistances in the segments above the H* distance.

For the mathematical functions evaluated, the maximum leak rate factor occurred using the relationship that had the greatest slope through the test data. Westinghouse does not consider this a realistic representation of the data, because it artificially forces a fit from essentially the minimum value at the lowest contact pressure to the maximum value at the highest contact pressure. Additionally, this relationship for loss coefficient flattens out and is predicted to go negative if extrapolated to higher contact pressures, which is inconsistent with the hypothesis that loss coefficient increases with increasing contact pressure. Therefore, Westinghouse did not consider the mathematical function with the greatest slope to be a physically realistic representation of the data. Based on the initial premise that that loss coefficient increases with increasing contact pressure, the NRC staff finds this to be acceptable.

Of the remaining four relationships that Westinghouse analyzed, the highest leak rate factor calculated was 5.22, which is the value proposed for use in the current H* analysis.

Westinghouse performed additional analyses using parallel plate flow theory, benchmarked with the leak rate versus contact pressure data previously discussed. These analyses showed that resistance to leakage under both SLB and NOP conditions is primarily developed in the lower portion of the H* distance and that the leak rate ratio existing in this region dominates the overall leakage ratio existing over the entire H* distance. While the leak rate ratio in the higher portions of the tubesheet was greater than the 5.22 value calculated with the Darcy equation, the leak rate ratio calculated in the bottom portion of the tubesheet was bounded by the 5.22 value. While SLB is the limiting case for Point Beach, Unit 1, the lower region of the H* distance, where most of the resistance to leakage is developed, retains significant contact pressure in all loading cases. Given that the H* analysis assumes residual contact pressure is zero, the NRC staff concludes that the calculated leakage factor of 5.22 is a reasonably conservative bound for all relevant loading conditions.

In previous H* amendments, licensees have provided commitments (like the one shown below) describing how the leakage factor will be used to satisfy TS evaluations for condition monitoring and operational assessments.

> For Unit X, for the Condition Monitoring (CM) assessment, the component of operational leakage from the prior cycle from below the H* distance will be multiplied by a factor of x.xx and added to the total accident leakage from any other source and compared to the

allowable accident induced leakage limit. For the Operational Assessment (OA), the difference in the leakage between the allowable accident induced leakage and the accident-induced leakage from sources other than the tubesheet expansion region will be divided by x.xx and compared to the observed operational leakage. An administrative limit will be established to not exceed the calculated value in the event that TS 3.4.13 is no longer bounding.

Including this commitment as part of the Point Beach, Unit 1, license amendment is not required. Details of how the condition monitoring and operational assessments are performed are generally not included in the license, including the TS. Extensive industry guidance on conducting condition monitoring and operational assessments is available as part of the industry initiative Nuclear Energy Institute (NEI) 97-06 (Reference 15). The subject license amendment request includes new reporting requirements (TS 5.6.8.h, i, and j) relating to operational leakage existing during the cycle preceding each SG inspection and condition monitoring assessment, and the associated potential for accident-induced leakage from the lower portion of the tubesheet below the H* distance. These reporting requirements will allow the NRC staff to monitor how the leakage factor is actually being used, and are acceptable.

The subject license amendment request also includes a new operational limit on primary-to-secondary leakage in TS 3.4.13 LCO limit for primary-to-secondary leakage of 72 gpd. This change provides added assurance that during a hypothetical DBA, the resulting primary-to-secondary leakage will be within the accident induced leakage performance criteria in TS 5.5.9.b.2. In addition, this change minimizes the likelihood of having to establish a reduced administrative limit as stated in the last sentence of the aforementioned commitment. The NRC staff finds this proposed change to be acceptable.

3.5 SUMMARY

Since the initial proposal for a permanent H* amendment in 2009, the supporting technical analyses have undergone substantial revision to address NRC staff questions and issues. The current analyses supporting the proposed permanent amendment still embody uncertainties and issues (e.g., should a factor of safety be applied to the Poisson's contraction effect) as discussed throughout this safety evaluation. However, it is important to acknowledge that there are significant conservatisms in the analyses. Some examples, also discussed elsewhere in this safety evaluation, include taking no credit for residual contact pressures associated with the hydraulic tube expansion process, the assumed value of 0.2 for coefficient of friction between the tube and tubesheet, and taking no credit for constraint against pullout provided by adjacent tubes and support structures. The NRC staff has evaluated the potential impact of the uncertainties and concludes these uncertainties to be adequately bounded by the significant conservatism within the analyses and proposed H* distance.

The NRC staff finds the proposed changes to the Point Beach, Unit 1, TSs ensure that tube structural and leakage integrity will be maintained with structural safety margins consistent with the design basis and with leakage integrity within assumptions employed in the licensing basis accident analyses, without undue risk to public health and safety. Based on this finding, the staff further concludes that the proposed amendment meets 10 CFR 50.36 and, thus, the proposed amendment is acceptable.

4.0 STATE CONSULTATION

In accordance with the Commission's regulations, on June 30, 2017, the NRC staff notified the State of Wisconsin official (Mr. Jeff Kitsembel, Nuclear Engineer, Public Service Commission of Wisconsin) of the proposed issuance of the amendment. The State official had no comments.

5.0 ENVIRONMENTAL CONSIDERATION

This amendment changed a requirement with respect to the installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20 or change a surveillance requirement. The staff has determined that the amendment involves no significant increase in the amounts and no significant change in the types of any effluent that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously published a proposed finding that this amendment involved no significant hazards consideration and there has been no public comment on such finding (81 FR 87961). Accordingly, these amendments meet the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of this amendment.

6.0 CONCLUSION

The Commission has concluded, based on the considerations discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) there is reasonable assurance that such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendments will not be inimical to the common defense and security or to the health and safety of the public.

7.0 REFERENCES:

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Alternate Repair Criteria (H*) (TAC NO. ME9448)," August 29, 2013 (ADAMS Accession No. ML13198A367).

5. Westinghouse Electric Company LLC, WCAP-17330-NP, Revision 1, "H*: Resolution of NRC Technical Issue Regarding Tubesheet Bore Eccentricity (Model F/Model D5)," June 2011 (ADAMS Accession No. ML11188A108).

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9. NRC Generic Letter 95-05, "Voltage Based Alternate Repair Criteria for Westinghouse Steam Generator Tubes Affected by Outside Diameter Stress Corrosion Cracking," August 3, 1995 (ADAMS Accession No. ML031070113).

10. NUREG-0844, "NRC Integrated Program for the Resolution of Unresolved Safety Issues A-3, A-4, and A-5 Regarding Steam Generator Tube Integrity," September 1988.

11. NUREG-1570, "Risk Assessment of Severe Accident-Induced Steam Generator Tube Rupture," March 1998.

12. NRC Meeting minutes, "Summary of the January 8, 2009, Category 2 Public Meeting with the Nuclear Energy Institute (NEI) and Industry to Discuss Steam Generator Issues," February 6, 2009 (ADAMS Accession No. ML090370782).

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14. Nuclear Energy Institute (NEI) letter dated July 7, 2008, ADAMS Accession No. ML082100086, transmitting Babcock and Wilcox Limited Canada letter 2008-06-PK-001, "Re-assessment of PMIC measurements for the determination of CTE of SA 508 Steel," dated June 6, 2008, (ADAMS Accession No. ML082100097).

15. NEI 97-06, Revision 3, "Steam Generator Program Guidelines," January 2011 (ADAMS Accession No. ML111310708).

Principal Contributor: A. Johnson, NRR/DE/ESGB

Date of issuance: July 27, 2017

SUBJECT: POINT BEACH NUCLEAR PLANT, UNIT 1 - ISSUANCE OF AMENDMENT TO APPROVE H*: ALTERNATE REPAIR CRITERIA FOR STEAM GENERATOR TUBE SHEET EXPANSION REGION RE: (CAC NO. MF8218) DATED JULY 27, 2017

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DATE	07/17/17	06/13/17	07/28/17	07/17/17
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